OIL

Medium-Term Market Report 2014

Market Analysis and Forecasts to 2019

iea
International Energy Agency

OIL Medium-Term Market Report 2014

Market Analysis and Forecasts to 2019

International Energy Agency

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea (Republic of)
Luxembourg
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

The European Commission also participates in the work of the IEA.

International Energy Agency
1974•2014
Secure • Sustainable • Together

International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

www.iea.org

FOREWORD

This edition of the *Medium-term Oil Market Report* can best be seen as a guide to that uncharted territory, tomorrow's oil market and industry. Each one of its sections unveils a world that is at once familiar and oddly different from today's reality. The supply story has two sides: on the one hand, the non-conventional success story, arguably the most transformative oil-market development of the last five years, continues to unfold, but undergoes a change of its own as growth starts slowing in the United States but picks up elsewhere. By the end of the decade, other countries will likely be adding to supply in a significant way, and the non-conventional oil industry will have matured into a more global phenomenon. On the other hand, political risk in North Africa and the Middle East, far from receding, is only becoming a larger threat to oil investment and production, as the latest developments in Libya and Iraq show only too well. Within OPEC, Iraq remains the main source of most of the expected capacity growth, but this expansion looks increasingly at risk.

On the demand front, the potent mix of sustained high prices, growing inter-fuel competition and environmental concerns opens a new chapter in the history of oil consumption. While peak oil demand outside of the OECD may still be years away, peak oil demand growth could be in sight. Meanwhile, international crude markets, despite continued growth in oil demand, are projected to shrink in both volume and geographic diversity, with Asia the ever-growing magnet for global crude flows, and China overtaking the United States as the world's top crude importer as early as this year.

But it is the refining industry that may see some of the most consequential changes, as capacity further concentrates in four main regions – China and non-OECD Asia, the Middle East, Russia and North America – at the expense of Europe, Latin America and Africa. The continued globalisation of the refining industry, compounding the impact of a steep increase in the supply of non-crude liquids bypassing the refining sector altogether, will redefine the way products are delivered to consumers and the nature of energy security. As demand, feedstocks supply and processing capacity evolve, the risk of worrisome global product imbalances is also on the rise.

If the last five years seemed eventful for the oil market and industry, there is every reason to believe that the next five will be no less transformative. Expectations of supply, demand, but also midstream and downstream capacity paint a picture of oil markets that by the end of the decade is quite distinct from today's, which itself is a far cry from that of five years ago. The pace and scope of change will have far-reaching consequences not just for the oil market itself, but also for the broader economy, climate policy, international trade and energy security.

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

Maria van der Hoeven
Executive Director
International Energy Agency

ACKNOWLEDGEMENTS

This publication was prepared by the Oil Industry and Markets Division (OIM) of the International Energy Agency (IEA). Its main authors are Lejla Alic, Toril Bosoni, Anselm Eisentraut, Charles Esser, Diane Munro, Matthew Parry and Andrew Wilson. Valerio Pilia and Ryszard Pospiech provided essential research and statistical support. Annette Hardcastle provided editorial assistance. Antoine Halff, head of OIM, edited the report. Keisuke Sadamori, director of the IEA's Directorate of Energy Markets and Security, provided guidance.

Other IEA colleagues provided important contributions including Christian Besson, Federico de Luca, Suleyman Bulut, Anne-Sophie Corbeau, Tim Gould, Alexander Körner, Olivier Parada, Kristine Petrosyan, Christopher Segar, Jan Stelter, Tali Trigg and Michael Waldron.

The IEA Communications and Information Office provided production assistance and support. Particular thanks to Rebecca Gaghen and her team; Muriel Custodio, Astrid Dumond, Greg Frost, Angela Gosmann, Jean-Luc Lacaille and Bertrand Sadin.

Questions and comments should be addressed to OilMarketReport@iea.org.

TABLE OF CONTENTS

LIST OF BOXES

LIST OF FIGURES

LIST OF MAPS

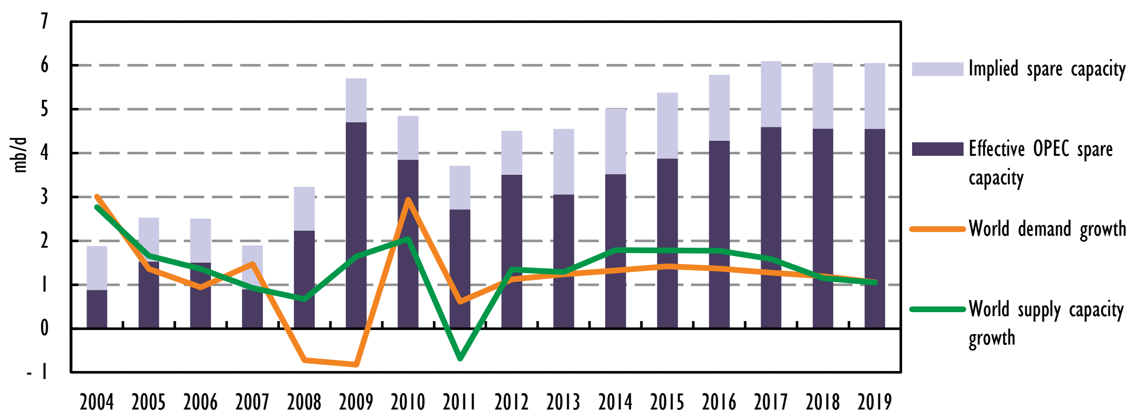
LIST OF TABLES

EXECUTIVE SUMMARY

While the non-conventional supply revolution that is reshaping the oil market and industry has been widely recognised as a game changer, this transformation is playing out in unexpected ways and against an evolving backdrop. How long will the rise in US tight oil and Canadian oil sands last and where will it leave North American oil production at the end of the decade? Will other countries have managed to replicate the US success by then? Will OPEC producers need to "make room" for this new supply, or will political disruptions in the Middle East and North Africa go on or even worsen? Will the new supply fuel demand growth, compounding the impact of the cyclical recovery evident since the end the Great Recession continue, or will sustained high oil prices cause it to decelerate and bring a "peak" in oil consumption? How will the shifts in global refining capacity, brought about in part – but not only – by the North American supply revolution, affect the way products are delivered to consumers? These are some of the questions that this edition of the *Medium-Term Oil Market Report* (*MTOMR*) seeks to answer.

It is hard to overstate the degree to which the North American supply boom has, since its onset, consistently defied expectations. In this *Report*, the baseline of US and Canadian production for 2013 is 330 kb/d greater than had been expected last year, 420 kb/d greater than forecast in 2012, 2.20 mb/d higher than anticipated in 2011, and 3.21 mb/d above 2010 projections. Understandably, the unlocking of this new resource if often described as having ushered in an era of renewed energy "abundance". Yet the easing of oil prices that many had expected in its wake has yet to be felt. Nor has global supply kept up so far with the boom in North American production. In fact, in contrast with North American supply, global oil supply has surprised on the downside. Oil markets are in many ways tighter today than they were at the onset of the US shale and tight oil boom, and considerably tighter than they were a year ago. Not surprisingly, far from falling back from their highs under the weight of the new non-conventional supply, oil prices have remained stubbornly elevated.

Figure ES.1 Medium-term oil market balance



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

Whether from "below-ground" or "above-ground" reasons, supply growth from conventional sources has dramatically slowed for reasons which on the face of it have little if anything to do with the unlocking of new non-conventional supply. OPEC production in 2013 was 850 kb/d lower than it had been a year earlier, partly offsetting record growth of 1.35 mb/d in North American supply, which itself accounted for all of the growth in non-OPEC. Although OPEC's crude capacity outlook for the medium term looks broadly in line with recent trends, with 2.08 mb/d of incremental capacity projected from 2013 to 2019, most of that increment is now expected to originate from a single country, Iraq, the group's second-largest oil exporter, which itself is subject to considerable political risk. While Iraq managed to lift production and export to 30-year highs recently, above-ground threats to supply remain elevated against the backdrop of weak institutions, bureaucratic red tape and a dramatic resurgence of sectarian violence in the wake of the Syrian civil war, culminating at the time of writing in a fast-moving military campaign by Sunni insurgents in the north and centre of the country.

Meanwhile, the world's appetite for oil continues to increase, but a combination of high oil prices, environmental concerns, technology advances and other factors signals that oil demand, like supply, may be going through a process of transformation. An inflexion point will likely be reached in the second half of this decade after which fuel-switching away from oil and conservation measures will likely blunt the demand impact of economic and population growth, causing oil consumption growth to decelerate.

Table ES.1 Global balance summary (million barrels per day)

	2012	2013	2014	2015	2016	2017	2018	2019
GDP growth assumption (% per year)	**3.10**	**2.95**	**3.52**	**3.82**	**3.89**	**3.90**	**3.87**	**3.82**
Global demand	**90.19**	**91.43**	**92.76**	**94.18**	**95.55**	**96.82**	**98.01**	**99.06**
Non-OPEC supply	53.37	54.70	56.12	57.26	58.36	59.40	60.33	60.93
OPEC NGLs, etc.	6.25	6.31	6.50	6.78	6.99	7.03	7.07	7.12
Global supply excluding OPEC crude	**59.62**	**61.01**	**62.61**	**64.04**	**65.35**	**66.43**	**67.40**	**68.06**
OPEC crude capacity	**35.08**	**34.98**	**35.16**	**35.52**	**35.98**	**36.48**	**36.67**	**37.06**
Call on OPEC crude + stock ch.	**30.57**	**30.42**	**30.14**	**30.14**	**30.20**	**30.39**	**30.61**	**31.00**
Implied OPEC spare capacity*	4.51	4.56	5.02	5.38	5.79	6.10	6.06	6.05
Effective OPEC spare capacity**	3.01	3.06	3.52	3.88	4.29	4.60	4.56	4.55
as percentage of global demand	*3.3%*	*3.3%*	*3.8%*	*4.1%*	*4.5%*	*4.7%*	*4.7%*	*4.6%*
Changes since May *MTOMR 2013*								
Global demand	**0.41**	**0.86**	**0.96**	**1.06**	**1.17**	**1.24**	**1.33**	
Non-OPEC supply	0.02	0.27	0.33	0.23	0.51	0.78	1.02	
OPEC NGLs, etc.	-0.06	-0.25	-0.25	-0.12	0.00	0.06	0.07	
Global supply excluding OPEC crude	**-0.04**	**0.03**	**0.08**	**0.11**	**0.51**	**0.84**	**1.09**	
OPEC crude capacity	**0.09**	**-0.38**	**-1.14**	**-0.85**	**-0.68**	**-0.31**	**-0.08**	
Call on OPEC crude + stock ch.	**0.45**	**0.83**	**0.88**	**0.95**	**0.66**	**0.40**	**0.24**	
Adjusted call on OPEC crude + stock ch.*	**0.91**	**1.08**	**0.98**	**0.63**	**0.57**	**0.00**	**0.00**	
Implied OPEC Spare Capacity*	-0.36	-1.21	-2.02	-1.80	-1.34	-0.71	-0.32	
as percentage of global demand	*-0.6%*	*-1.3%*	*-1.5%*	*-1.0%*	*-0.5%*	*-0.6%*	*0.0%*	

* OPEC capacity minus "call on OPEC + stock ch."

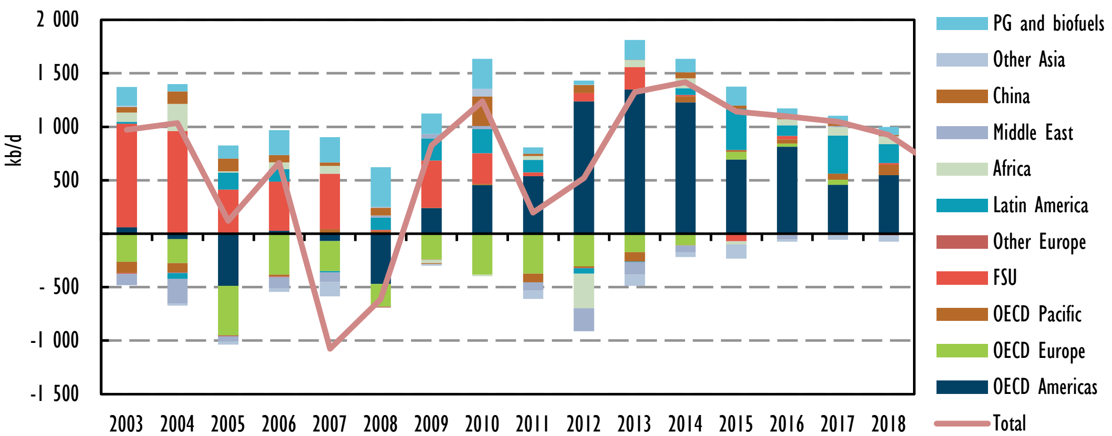
** Historically effective OPEC spare capacity averages 1.5 mb/d below notional spare capacity.

Often lost in discussions about the oil market outlook is the challenge of bringing midstream and downstream infrastructure in line with fast-changing supply and product demand. A downside of surging US production is the less-than-perfect match between this very light resource and the type of oil products the global consumer needs most. The need to overcome this hurdle is adding momentum to a mutation of the downstream and midstream sectors already spurred by the demand shift from mature OECD economies to fast-growing emerging and industrialising markets. Paradoxically, despite growing oil consumption overall, crude trade is shrinking as more feedstock is getting refined close to the wellhead. But this should not be misread as an indication that the oil market is getting less interconnected. On the contrary, the linkages between oil consumers and producers are only getting deeper, with product trade on the rise and producers, refiners, traders and consumers tied together in increasingly complex and multipronged relationships.

The non-conventional supply revolution enters a new phase

On the plus side, the shale and light tight oil (LTO) revolution will likely start spreading beyond the United States before the end of this decade, sooner than we previously expected. The resource potential outside of the United States is considerable – by some estimates, US shale and light tight oil resources may not amount to more than about 15% of the total – and many countries with a promising shale and/or tight oil endowment aspire to replicate the US success story. While no single one of them may offer the unique combination of above-ground and below-ground attributes that made the US boom possible, several are nevertheless taking policy steps on the tax and regulatory front to hasten the development of their non-conventional potential, and will benefit from the knowledge base and technological advances gained in the United States.

Figure ES.2 Annual non-OPEC supply growth



Among these countries, Russia amended its tax and royalty regime to incentivise investment in its vast but challenging shale resource. International oil companies (IOCs) are responding, and Russian firms have entered into several bilateral joint-venture agreements to develop parts of the huge Bazhenov shale formation. Argentina, two years after having expropriated Repsol's stake in YPF, moved to settle with the Spanish company, thus facilitating the return of foreign companies. Meanwhile, Mexico is undertaking the largest reform of its energy sector since the nationalisation of its oil industry in 1938, welcoming companies in the upstream again. While that reform is not specifically geared at tight oil developments, the country does enjoy a large shale and tight oil endowment, some of which directly abuts the Eagle Ford. The timing of the reform, in the wake of the US non-conventional revolution, could unlock this resource before the end of the decade, though the real impact of the Mexican "apertura" is not expected until the 2020s. By 2019, we project that tight oil supply outside of the United States may reach 650 kb/d, including 390 kb/d from Canada, 100 kb/d from Russia and 90 kb/d from Argentina. Tight oil already accounts for roughly half of production of about 70 kb/d at Mexico's Chicontepec formation, which we forecast will roughly double by the end of the decade. Australia, which also enjoys a large potential, may produce marginal amounts of tight oil by 2019. And this will only be the beginning of larger-scale supply growth in the following decade.

Meanwhile, even as those developments start adding to supply at the margin, tight oil production growth from the United States continues on a large scale. Its transformative impact, both for the country and for the world as a whole, cannot be emphasised enough. Less than ten years ago, the United States was the world's largest importer of refined products, with 2.5 mb/d of product inflows in 2005. Its crude production seemed inexorably in decline. Today it has become the world's largest liquids producer, ahead of Saudi Arabia and Russia, as well as its largest product exporter, with outflows of 2.9 mb/d and net exports of 1.5 mb/d on average in 2013. By the end of the decade, North America as a whole will have achieved energy "independence" and have become a net oil exporter with a net crude imports projected at 2.6 mb/d per day and potential net product exports of around 3.5 mb/d, making it a titan of unprecedented proportions in product markets. With this comes the challenge of balancing the product slate to fit world demand patterns and of adapting storage and export infrastructure to the increased volumes.

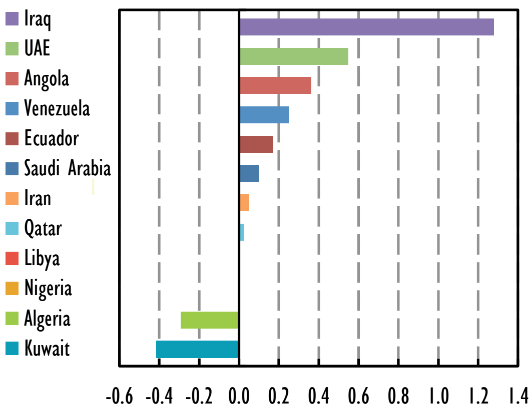
That is not to say that US tight oil supply growth will go on forever. Even as US supply reaches this unprecedented level, output growth is expected to slow. Several factors suggest a production plateau may be in sight, including a rising percentage of supplies that require a higher breakeven price; increased focus on cash flow rather than acquiring new acreage by producing companies; higher interest rates that increase financing costs for new drilling; and reduced resource estimates on undeveloped shale plays such as the Monterey in California.

OPEC supply experiencing turbulence

Not everything is rosy about crude supply in the next five years. In contrast with the non-conventional boom, conventional supply, despite several bright spots, faces headwinds. This is especially true of OPEC. Production declines in 2013 should not necessarily be construed as an indication of slower-than-expected capacity growth in the medium term. At 2.08 mb/d for 2013-19, forecast OPEC capacity growth looks on paper in line with historical trends, but as much as 60% of the increase is expected in beleaguered Iraq, where sectarian strife reached an apex in early June, as this *Report* was going to press. Given Iraq's precarious political and security situation, the forecast is laden with downside risk. Equally, a planned recovery in Libya looks increasingly elusive for the short term and may even be derailed in the medium term.

Despite much speculation to the contrary, OPEC's recent output performance and medium-term production outlook have little to do with US output growth or competition from non-conventional supply. Ageing fields are an issue for almost all OPEC producers, but above-ground woes have escalated, with IOCs shying away from extremely poor investment frameworks in many member countries, especially given more attractive terms in less risky non-OPEC countries. As a result, the majority of OPEC members open to foreign investment have failed to attract enough capital and expertise to nurture development. In many of them, political turmoil and security concerns are a growing impediment to supply growth, if not a cause of outright disruptions.

Figure ES.3 Incremental OPEC crude production capacity 2013-19 (mb/d)



As OPEC is a diverse group of countries, blanket statements cannot adequately capture its dynamics. But enough OPEC countries are facing headwinds for the output from the group as a whole to be affected. Iran remains something of a wild card given the uncertain outcome of current nuclear negotiations with the five permanent members of the UN Security Council plus Germany and the European Union, or

P5+1, but even an easing of international sanctions, if it were to be achieved, is unlikely to lead to a rapid recovery in production growth from its recent doldrums. Iraqi production remains in steep growth mode, but there, too, above-ground and security issues are a challenge and have caused production delays. Growth is not as fast as previously expected due to insecurity, red tape, corruption and other factors. At the time of writing, a military offensive by Sunni Islamist insurgents that achieved lightning gains, overrunning the cities of Mosul – Iraq's second largest – and Tikrit, brought home to markets – and to the world at large – how unstable and volatile the Iraqi political situation remains. This offensive is not only raising concerns about future production from operating and new projects, but casting a pall on the functioning of the country's government institutions and even on regional stability. Meanwhile, Saudi Arabia continues to invest in production capacity but is not pursuing net production capacity growth; new supply will allow old fields to rest while the Kingdom also seeks to boost domestic gas production for power generation. Supply will also increasingly be refined at home.

Beyond OPEC countries, above-ground issues in the form of resource nationalism have caused unexpected project delays which have adversely affected the growth forecast. While the cycle of tax and royalty increases and contract renegotiations sparked by the market rally of 2002-08 appears to have run its course, the rise in local-content requirements observed in recent years across many host countries is curbing production growth. In Brazil, domestic industry is more robust and diversified than in many other large petroleum producers, and hence, more capable of meeting industrial needs, but local-content requirements are onerous and complex, with variance depending on such things as water depth, category of expenditure and development phase. Moreover, ultra-deepwater fields require highly sophisticated technology and equipment that is often not found even among Brazil's diverse industrial base. Companies have also sometimes overpromised on local content in an effort to win bids.

Kazakhstan's local content requirements were somewhat vague and weak when projects such as Tengiz and Karachaganak were developed more than a decade ago, but in the past five years have been considerably strengthened, notably in terms of local workforce requirements, including for management positions. Some analysts have blamed a lack of skills among required local labour for some of the problems with devastating pipeline leaks on the Kashagan project. Mexico, in opening up its oil sector, has set local-content requirements at a comparatively low rate of 25% in new secondary legislation to be considered by Congress in coming months. While the problems that local-content policies seek to address are genuine and the underlying concerns of policymakers fully justified, excessively onerous, inflexible and poorly targeted local-content requirements can easily backfire and slow down the pace of projects coming from foreign and private-sector investment. This has apparently been a factor behind recent delays in several producing countries

The policy ground is shifting under the biofuel industry

The biofuel industry, too, is going through a period of transformation that will likely continue to play out in the second half of the decade. Policy support for biofuels in the two largest biofuel producer countries, Brazil and the United States, had stemmed in part from their perceived value as an oil substitute to lessen the dependence on imported oil. Both countries have since discovered and developed large non-conventional crude reserves, and biofuels may in part have been a victim of non-conventional oil's success. In both Brazil and the United States, as well as in the European Union, the policy ground has been shifting from under the biofuel industry, resulting in a lower production outlook than had been expected for the rest of the decade. By the same token, however, the persistence of high oil prices has opened up new markets for biofuels in oil-importing, developing economies. Policy support for biofuels in those frontier markets is rapidly growing, partly offsetting the dimmer outlook in the OECD and Brazil.

In each of the three major markets – the United States, Brazil and Europe – biofuels are facing headwinds of a slightly different nature. In the United States, a surprise contraction in gasoline demand since biofuel mandates were first introduced has exposed unsuspected flaws in ethanol policy and caused uncertainty about future policy direction. In Brazil, the ethanol industry is not only facing steep land and labour cost increases, but appears to have become the unintended victim of inflation-targeted gasoline price controls which are severely undercutting ethanol plant economics. Production capacity growth has ground to a halt, several plants have already gone under and more capacity may be at risk. In the European Union, after complaints about unfair trade practices led to the imposition of anti-dumping tariffs on some biofuel imports, concerns have shifted to the environmental sustainability of conventional biofuels, the use of which may or may not be capped as a result. In all three markets, a much-anticipated breakthrough in advanced, or second-generation, biofuels that would make them commercially viable is proving elusive.

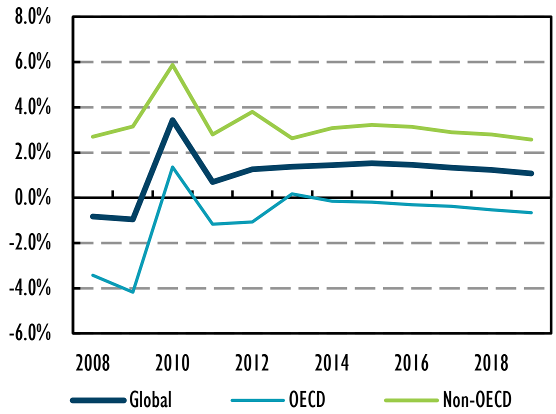
On the other hand, policy support for biofuels is burgeoning in emerging or developing economies, in particular oil-importing countries that subsidise fuel consumption, and where a domestic biofuel industry looks like a good way to cut product import requirements and lower the fuel import bill. Several countries in non-OECD Asia and Africa have thus recently adopted new blending mandates, or ramped up existing targets for biofuels. In view of these partly offsetting developments global biofuel production is forecast to grow to about 2.3 mb/d in 2019, up roughly 350 kb/d or 18% from 2013 levels, but roughly 50 kb/d below the 2018 production levels we projected last year.

An inflexion point in demand growth

While the prospects for replacing oil with biofuel in some markets may have dimmed at the margin, the dynamics of oil demand are also evolving. In aggregate, global oil demand is projected to expand, breaching the 100 mb/d mark by the end of 2019, but not averaging that level on an annual basis until 2020. That equates to demand growth of 7.6 mb/d over the forecast period, 2013-19. The projected rise in demand, however, is not likely to be linear. Before the end of the decade, the market looks likely to reach an inflexion point after which demand growth may start to decelerate, as a combination of high oil prices, environmental concerns and cheaper and cleaner fuel alternatives kick in, leading to both fuel switching away from oil and overall fuel savings. While "peak demand" for oil, other than in mature economies, may still be many years away, peak oil demand growth for the market as a whole is already in sight.

Economic and population growth have traditionally been the two key drivers of oil demand growth, but in future may be partly eclipsed by growing inter-fuel competition, efficient technologies and environmental policies. Thus, a cyclical uptrend in oil demand that parallels the underlying economic recovery since the financial crisis and the Great Recession becomes more muted toward the end of the decade. From a low point of 610 kb/d in 2011, oil demand growth reached an estimated 1.1 mb/d in 2012 and 1.2 mb/d in 2013, and is forecast to gain further momentum, averaging 1.3 mb/d in 2014 and 1.4 mb/d in 2015, as global economic growth picks up from 3.0% in 2013 to 3.8% in 2015. Beyond that, oil demand is projected to gradually slow, easing back to 1.1 mb/d by 2019, as growing supplies of natural gas increasingly start taking market share away from oil at the margin, whether supported by economics or environmental policies, and efficiency targets quell demand growth.

Figure ES.4 Global oil demand growth



The demand headwinds will be stronger in some markets than others. In the United States, oil savings will be driven by an abundance of shale gas, a relatively low-cost and comparatively clean alternative to oil, compounding the impact of efficiency policies. Tightening fuel efficiency standards for automobiles and changing consumer preferences look set to send US gasoline demand (roughly 10% of the global demand barrel) back on the declining course on which it embarked in 2007, and from which it briefly strayed in 2010 and the second half of 2013. Other notable sectors that have benefited from strong efficiency gains in recent years include the US airline industry, which has seen a broadly declining demand trend – despite increased air travel demand – since 2006, and manufacturing in general. As discussed in the previous edition of this Report, plentiful gas will increasingly displace oil at the margin in the US transport sector, including rail and road freight, a prospect that would have seemed unthinkable a few years ago. In OECD Europe, too, oil continues to be pushed out of stationary uses in favour or gas and renewables and may begin to lose its grip at the margin on the transport sector.

It had long been assumed that oil use would start contracting in the OECD but would more than make up for it in the rest of the world, as advanced and emerging economies continued to converge economically. That assumption still holds. Indeed, the non-OECD region is expected to overtake the OECD in oil use as early as 2014, after which it will leave industrialised countries increasingly far behind in oil consumption. But even in the emerging and industrialising world, pressure is building to rein in oil consumption. Three sets of factors support this trend: the high environmental cost of unbridled oil use; the high financial cost of oil and fiscal cost of oil subsidies in import-dependent emerging economies; and the high opportunity cost of run-away oil demand growth in oil-exporting countries.

The world's environmental cost of oil use is most evident in China, the world's second-largest consumer and the largest crude oil importer as of 2014, where air and water emissions from coal burn, but also oil use, have become both a health hazard and a threat to social stability. As in the United States, albeit on a lower scale, natural gas supply is growing and gaining market share, first and foremost at the expense of coal, the country's dominant source of energy and by far the dirtiest fuel, but also of oil, including residual fuel oil in stationary uses and distillate for transport. Meanwhile, the broader strategic reorientation of the Chinese economy, away from export-geared, energy-intensive industries in favour of more consumer-centred economic activities, and a policy decision to shift the economy into lower gear, both point to a slower pace of oil demand growth.

India is a textbook case for the demand effects of high oil prices in non-OECD, oil-importing economies. Stung by the cost of diesel subsidies amid sustained high oil prices, the government has adopted a policy of gradual lowering subsidies, which has immediately reduced diesel demand growth. India may reach full diesel price deregulation by year-end, putting further downward pressure on growth. Currency fluctuations have been a compounding factor, at times further increasing the subsidy burden in local currency, and cementing the government's resolve to bring it down. Meanwhile, as prices stay stubbornly high, several other non-OECD oil-importing countries face mounting pressures on price subsidies, and some Asian economies have adopted biofuel targets, or strengthened existing ones, in a bid to reduce their oil bill.

Figure ES.5 IEA average import price assumption

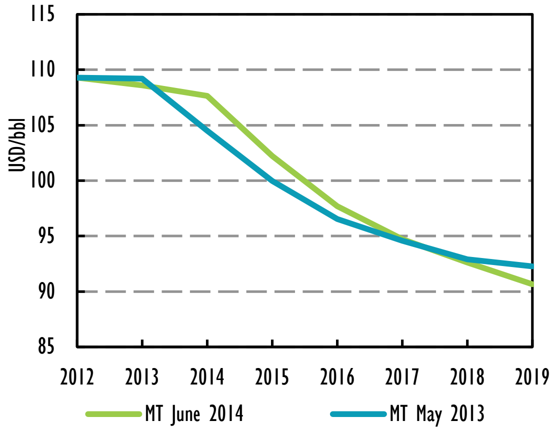
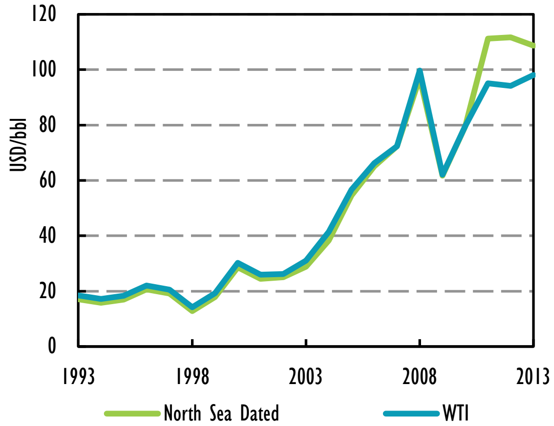


Figure ES.6 Historical benchmark crude prices



Last but not least, Saudi Arabia is seeking to set an example among oil exporting countries in its efforts to restrain domestic demand growth and curtail the ballooning opportunity cost of lost revenues. A rapidly expanding population, the export windfall of high oil prices, and a deep-rooted approach to free or discounted energy access as a sovereign entitlement, have propelled the Kingdom to the seventh rank among the world's leading oil consumers, from the 10th slot in 2005. So steep has been the climb that some observers have suggested that on current trends, oil export revenues could sink to a trickle within a generation. The government has reacted and introduced conservation policies of unprecedented scope, including the Kingdom's first efficiency standards for buildings and appliances, while also promoting gas, and even renewables, for power generation. Demand growth will not vanish overnight, but may slow from the frantic pace of the last few years.

In addition to OECD and non-OECD oil demand losses, international marine bunkers, which make up their own demand category alongside OECD and non-OECD demand, could also shift away from oil if ship owners were to opt for liquefied natural gas (LNG) as their fuel of choice to meet new emission standards. Air quality regulations had long missed international bunkers, but two new sets of laws will soon plug that hole. As of January 2015, sulphur standards for ships sailing in so-called "emisssion control areas" (ECAs) along coastal lines in parts of Europe and North America will be lowered, even as the geographical scope of the ECAs gets gradually extended. Then, in the next decade, the International Maritime Organisation plans to drop sulphur standards for ships outside the ECAs to 0.5% from 3.5% currently. Ship owners have several options, each with its costs and benefits, to meet the new standards, including LNG, scrubbing technology and fuel-switching from residual fuel oil to lower-sulphur gasoil. While all of these options will likely be part of the solution, uncertainty about their relative scales and the exact timing of the shift clouds the outlook.

OPEC spare production capacity may be lower than it appears

Downward pressures on demand growth, combined with a continued surge in non-conventional crude supply, make in theory for comfortable supply/demand balances, but the new prevailing reality of heightened supply risk suggests otherwise. Recent experience serves as something of a cautionary tale: Despite booming non-OPEC production, crude markets tightened in 2013 and inventories had to be drawn down to make up for a gaping supply shortfall. Supply disruptions and natural decline rates on mature assets largely offset non-conventional growth, so that while supply gains of 1.14 mb/d in the United States alone nearly fully met global demand growth of 1.24 mb/d, total liquid supply, including biofuels and refinery gains, in fact averaged just about half of that demand increase. OECD total commercial oil inventories plummeted in the second half of 2013 and have remained uncomfortably tight so far in 2014.

On paper, forecast supply and demand growth for the rest of the decade imply a comfortable level of OPEC spare production capacity, i.e., the notional difference between OPEC's nominal crude production capacity and the amount of OPEC crude needed to balance the market, normally a good indicator of the relative tightness or looseness of market balances. Implied spare capacity rises by 1.23 mb/d between 2013 and 2016 and plateaus at just above 6 mb/d for the remainder of the forecast period to 2019. The trouble is that much of that spare capacity is itself subject to high disruption risks, or is off-limits to the market for reasons independent from OPEC policy, such as domestic unrest or international sanctions. In practice, only a fraction of OPEC's implied production capacity will likely be available to the market at any given time, and nearly all of that in Saudi Arabia. For the rest of the decade, this "effective" spare capacity may not exceed 4.6 mb/d, and will likely remain below 4 mb/d in 2014- 15.

Outside of OPEC, the frequency and duration of supply disruptions has greatly increased in recent years, due both to the higher incidence of unscheduled outages spanning most of the supply world, and a growing tendency for scheduled field maintenance in mature oil provinces to last longer than planned. Although disruptions have abated somewhat in the first half of 2014 compared with 2012 and 2013, the potential for outages to exceed expectations and historical averages cannot be ruled out.

In crude trade, all roads lead to Asia

Surging North American production has had a profoundly disruptive effect on international crude trade flows and will continue to do so for the rest of the decade. Growing domestic supply in the United States and Canada has displaced US and Canadian imports and diverted them to other markets. US imports of Nigerian crudes, a set of mostly light, sweet grades with which US tight oil competes, are a case in point: from a high of 1.4 mb/d in November 2007, by early 2014 they had plunged to a trickle of 40 kb/d. European crude imports have also dropped, but for entirely different reasons: a steep decline in European refining activity. Asian crude imports, on the other hand, have grown both in absolute levels and as a percentage of the global market. Chinese imports reached a record of 6.8 mb/d in April 2014, versus US imports of 7.3 mb/d that month, or 4.6 mb/d if imports from neighbouring Canada are stripped out of the total. China is expected to overtake the United States in gross crude imports as early as this year.

This rebalancing of crude trade will gain further momentum for the rest of this decade. By 2019, the United States, thanks to a combination of rising production and domestic demand attrition, will have become an even larger oil exporter than it is today, though its crude imports, notably from Canada, will remain substantial. Taken in aggregate, North America will have become a net oil exporter. The non-OECD economies will overtake those of the OECD in crude imports as early as 2017, led by Asia. By the end of the decade, Asian crude imports (including Chinese, other non-OECD Asian and OECD Asian imports) will reach a projected 22.1 mb/d, or 65% of internationally traded crude and 27% of total crude production.

The redirection of flows is just part of the story for crude trade, the other being a forecasted drop in aggregate crude trade volumes. While the world's appetite for oil continues to grow, international long-haul crude trade is projected to shrink as producers keep more and more of their crude at home and refiners source more and more feedstock locally. The key drivers here are North America and the Middle East. The former has emerged as a powerhouse in merchant refining and is increasingly running its own crude. The latter remains the world's leading crude exporter over the forecast period but loses market share at the margin, as a result of rapid refining capacity growth aimed at both domestic and foreign markets. The net result is that crude markets contract in both volume and geographic reach: less crude is traded internationally, while the main trade routes increasingly converge on Asia from producers in the Middle East, Africa and the former Soviet Union (FSU). By the end of the decade, though, westbound trans-Pacific trade also rises, as Asian refiners import growing volumes of feedstock from South America and, at the margin, North America.

US regulatory statutes restricting crude (and condensate) exports have played an important role in shaping the impact of North American supply growth on global markets. As North American production continues to increase, those regulations have moved up the policy agenda in Washington amid growing (though not unanimous) calls for a regulatory overhaul, fuelled by concerns that persistent export restrictions might soon constrain supply, as the capacity of regional refineries to absorb further production growth may not be unlimited. In this *Report*, we assume that the main US regulatory framework governing crude exports remains in place but provides sufficient flexibility to allow marginal export growth without undergoing a full-blown reform. Changing market circumstances may lead to a less restrictive interpretation of existing statutes, including a potential reclassification of field condensates as an exportable product, further gains in internal North American crude trade, etc. In this view, the current statutes will allow at least marginal growth in North American exports in the form of Canadian crude and US condensate by the end of the decade. The potential impact of a broader overhaul of US crude export regulations is the object of several ongoing studies by other forecasters. We have not attempted here to duplicate their efforts. Suffice it to say that a full lifting of US crude export restrictions would likely lead to an increase in both imports and exports of crude by the United States compared to our forecast. How that would affect net balances remains to be assessed.

The refining industry enters the age of globalisation

The refining industry continues to undergo massive expansion and restructuring through to the end of the decade, but some building plans are being scaled back in the face of rebounding overcapacity. Global crude processing capacity is forecast to increase by 7.7 mb/d, reaching nearly 105 mb/d in 2019. This is somewhat lower than the 9.5 mb/d growth projected for 2013-18 in the *MTOMR 2013*, reflecting delays and cancellations affecting Chinese and Latin American projects. Despite the scaling back of plans, global surplus refining capacity is set to grow to a steep 2 mb/d by the end of the decade.

The geographical distribution of new capacity is highly uneven and almost entirely focused outside of the OECD, with nearly half of the increment in non-OECD Asia. By the end of the decade, the map of global refining, like that of crude trade flows, will thus have changed almost beyond recognition, with world-scale refining hubs in Asia, the Middle East and the United States crowding out legacy capacity in Europe and OECD Asia Oceania. Refinery rationalisation has already cut OECD crude distillation capacity by 4.6 mb/d since the financial crisis of 2008, including 1.8 mb/d in Europe, but these closures have only brought fleeting relief to global refining margins. With margins coming under renewed pressure from new builds and average plant utilisation rates in decline, rationalisation is once again in the cards. When the dust settles, plant closures will have left some markets highly dependent on product imports.

Figure ES.7 CDU expansions 2013-19 by region

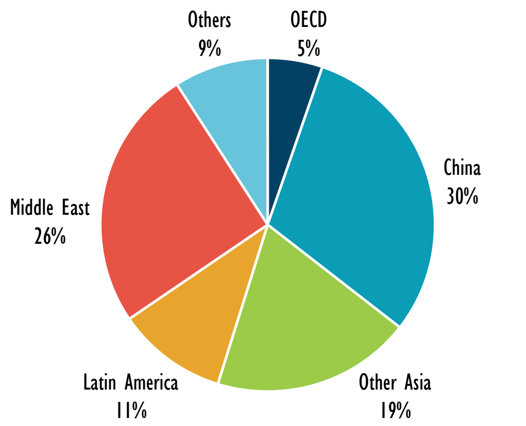
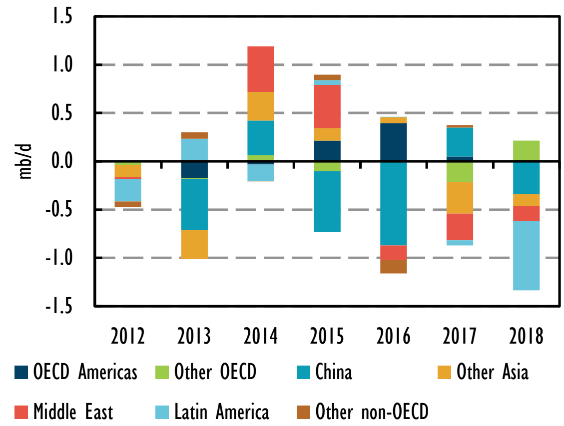


Figure ES.8 Revisions to CDU capacity since *MTOMR 2013*



There is no single factor behind refinery expansions, but rather a variety of drivers. Many North American refiners already enjoyed economies of scale, easy access to terminals and state-of-the-art technology. The non-conventional supply revolution has given them additional competitive advantages in the form of discounted feedstock and lower energy costs. With domestic demand in decline, refining has turned into a major export industry in the United States, which has become the world's largest product exporter. Hydrocarbon exports, including oil, natural gas and petrochemicals, are now the top category of US exports ahead of agricultural products. By the end of the decade, North America as a whole is projected to sit on excess product volumes of staggering proportions. Current crude export restrictions are not the only factor behind the growth in North American refining. Whether a full removal of current restrictions on US crude exports (not the working assumption of this *Report*) would cause US refining activity to moderate is unclear, as US refiners would likely continue to enjoy significant competitive advantages even if US crude price discounts were to narrow. Demand-side factors, such as a lack of market outlets for incremental gasoline or naphtha, might prove to be a bigger constraint on capacity growth.

In Asia and the Middle East, regional product demand growth is a key driver behind expected refinery expansions, though refineries in the Middle East and part of Asia will also be increasingly export-driven. Budget cuts at Petrobras's downstream operations will likely result in delayed expansions in Latin America. Nevertheless, growth east of Suez will cause the non-OECD share of global refining to increase significantly over the forecast period. While in terms of oil demand, the non-OECD is only projected to overtake the OECD this year, it already tops the OECD in refining capacity; the gap between the two areas will continue to widen in the next few years. It may be argued that with the exception of North America, the OECD has been effectively "offshoring" its refining industry, just as it has with its broader industrial base. Given price-distorting features in the oil sector of many non-OECD economies, global refining activity levels may thus in the future prove less immediately responsive to market signals than they have been in the past.

Growing supply of unrefined oil products will add downward pressure on refining margins in the next few years. Those include ethane, liquefied petroleum gases (LPGs) and pentanes that can replace refinery naphtha supplied as a by-product or co-product of US natural gas, in addition to biofuels and, at the margin, coal-to-liquids and gas-to-liquids. Natural gas liquids will represent 10% of global supply by 2019, and changed economics make for new overseas trade in ethane.

Is a gasoline glut the latest threat to supply?

In contrast with crude trade, product trade increases significantly over the forecast period, extending current trends. While Europe, Latin America and Africa are generally at the receiving end of product flows originating in North America, the Middle East, Russia and Asia, regional imbalances and flows vary greatly by product. Generally speaking, the surge in non-conventional supply is welcome news for consumers, but this new source of feedstock does not equally benefit all product markets. Incremental North American crude and condensate supply is particularly rich in light ends, like gasoline and naphtha, whereas demand growth generally centres on middle distillates like diesel and jet fuel.

Based on demand, supply and refining capacity forecasts, surging LTO, condensate and natural gas liquid (NGL) supply in North America looks set to cause a light-distillate glut by the end of the decade. Growing NGL and condensate supplies are increasingly displacing naphtha for petrochemical use. This helps make North American naphtha and gasoline balances exceptionally loose, with potential net exports surging to a massive 1.3 mb/d in 2019. Despite plant closures, European refiners still face surplus light-distillate production of 650 kb/d as a by-product of needed middle distillates, while refinery expansions and upgrades lift the light-distillate surplus to 1 mb/d in the Middle East and 530 kb/d in the FSU. Only in Asia, and to a lesser extent in Africa, are there significant import requirements. Under current European policies that favour diesel over gasoline for light vehicle use, securing market outlets for light distillates may be a challenge, and refineries with high light-distillate yields will find themselves at a disadvantage. In emerging markets, demand growth is already shifting to gasoline compared to earlier expectations.

Opportunities for higher naphtha and LPG uptake in the petrochemical sector could provide and outlet for rising light-product supply. Surging US output of deeply discounted ethane has already spurred a cycle of investment in ethylene crackers in the United States. Based on current and expected projects, by 2019 ethane demand from the fast-growing petrochemical sector could bump against midstream capacity constraints, exceeding the market's capacity to deliver the feedstock by upwards of 500 kb/d. By then a supply glut might have made naphtha more price competitive against ethane, however, allowing the market to rebalance.

The middle-distillate market looks more balanced and will likely remain the most profitable for refiners. While Europe faces a ballooning middle-distillate deficit of 1.6 mb/d in 2019, from just under 1.0 mb/d in 2013, additional new supplies are forthcoming from the Middle East, Russia and the United States. These will also need to meet booming demand from Africa. Fuel oil markets, meanwhile, look set to tighten, as the FSU cuts supplies even faster than demand contracts elsewhere – unless marine bunkers transition out of residual fuel oil faster than forecast.

Key policy outcomes loom large in the medium term

Seldom has the potential impact of energy policy changes been as apparent as today. Shifts in emissions standards, efficiency standards, biofuel requirements, trade policy, pipeline policy, "fracking" regulations and nuclear policy, among others, could all dramatically alter the outcome of supply and demand projections.

At least three sets of above-ground, policy-related issues may be seen as particularly relevant to the oil market outlook of the next five years: US crude export policies; a potential easing of international sections targeting the Iranian oil sector; and the timing of the International Maritime Organisation's implementation of tighter sulphur standards for international marine bunkers.

For the purpose of this *Report*, we assume business-as-usual conditions unless a policy shift is already in the making or appears as a foregone conclusion, or strong probability. As noted, the regulatory framework governing US crude exports is assumed to remain in place but to provide some flexibility in managing a looming condensate overhang. A different outcome could potentially affect our forecast, particularly as regards crude and product trade flows, refining capacity and even liquid supply. Iranian crude production is also assumed to remain nearly flat through the end of the decade, although a hypothetical lifting of international sanctions could pave the way to higher production. While we recognise that sanctions may be eased, we assume that a full normalisation of relations with Iran will be a somewhat gradual process and will take time to translate into supply growth. Upstream developments may also be slowed by other factors unrelated to sanctions. In view of the resumption of direct talks with Iran and the progress achieved so far, the forecast of Iranian capacity has nevertheless been raised from the levels projected in the *MTOMR 2013*, when capacity was forecast to edge lower.

Finally, the timing of the IMO adoption of low-sulphur bunker standards remains somewhat uncertain. The organisation has said it would assess in 2018 whether the 2020 target for adoption of the new standards ought to be pushed back to 2025. While that review process brings flexibility to the implementation of the policy, is also makes the timing of the industry steps needed to comply with it somewhat unclear. While both dates are beyond our forecasting timeframe, early market impacts will likely precede the policy's effective date. Statements by many industry participants to the effect that the 2020 target cannot be realistically met have not been taken as indicative of a likely date change. Nevertheless, clarification as to the effective date of the policy could potentially affect industry responses one way or the other.

Other market-related medium-term developments

Several issues and developments relevant to the medium-term oil market have been intentionally left out of this *Report*. These include an examination of the considerable security implications of refining industry changes in the medium term, as well as a discussion of the market impact of financial-industry regulatory changes. We also have refrained from explicitly addressing the possibility of adjustments to the current oil pricing regime, including potential changes to existing oil price benchmarks and price-assessment mechanisms, changes in the role of commodities futures exchanges and the potential for new Asian or other exchanges, and the possibility of new crude and product benchmarks.

Recently, changes in financial regulations have caused many banks to reduce their commodity-market exposure and activities, while the commodity trading industry has undergone a process of restructuring. Major oil companies also appear to be playing a new role in commodities markets as provider of financial services for third-party hedgers and market participants. By the end of the decade, financial markets and hedging tools and opportunities available to market participants may be very different from what they are today. Changes in crude production and in the geographic distribution of oil demand and crude flows may also lead to changes in the way oil is priced and in the menu of reference benchmark grades used for pricing purposes. Finally, deep changes across the entire product supply chain, including, but not limited to, the hollowing-out of European and OECD Asian refining and increased dependence in those regions on product imports, will bring both costs and benefits. A thorough assessment of the security implications of those changes is fully warranted. The focus of this *Report* is simply to lay the foundation for those studies and forecast and analyse the fundamental backdrop against which those issues will play out through the end of this decade.

1. DEMAND

Summary

- **Global oil demand is forecast to rise to 99.1 mb/d by 2019, a gain of 1.3% per annum** from 91.4 mb/d in 2013. In aggregate, global demand is projected to grow by 7.6 mb/d over the forecast period. Demand will likely breach 100 mb/d on a quarterly average basis for the first time in late 2019.

- **Fuel switching, efficiency gains and clean-air regulations start eroding demand growth toward the end of the decade as oil faces mounting inter-fuel competition not only in stationary uses but also in transport.** Annual demand growth has been recovering steadily since the low point of 2011, in line with the broader global economy, but will likely slow down again after reaching a high of 1.5% in 2015, thanks to a combination of efficiency improvements, fuel switching to natural gas and other fuels, environmental restrictions and a shift toward a less energy-intensive model of economic activity in many developing nations.

- **The amalgamated fuel switch, from oil into other products such as natural gas and renewable energy, is forecast to amount to roughly 1.5 mb/d** 2013-19. The majority of the swing estimated as attributable to the transport and power sectors, respectively forecast at 53% and 41% shares.

- **For the first time, non-OECD economies will in the next five years consume more oil than those of the OECD. The gap between the two will steadily widen henceforth.** Non-OECD economies are projected to overtake those of the OECD in oil demand as early as 2014. Post-2014, non-OECD oil demand growth will more than offset a slow contraction in OECD demand. Looking past the OECD/non-OECD split, the combined Asia Oceania region (i.e. including OECD and non-OECD) is set to become the world's largest consuming region in 2015, a mantle previously held by the Americas (OECD and non-OECD).

- **Net gains in the petrochemical and transportation sectors, despite inter-fuel competition in transport, underpin oil demand growth worldwide**, partly offset by drops in the power-generation and residential sectors.

Table 1.1 Global oil demand (mb/d), 2013-19

	2013	2014	2015	2016	2017	2018	2019	CAGR
OECD Americas	24.0	24.1	24.1	24.0	23.9	23.8	23.6	-0.3%
OECD Asia Oceania	8.4	8.3	8.2	8.2	8.1	8.1	8.1	-0.7%
OECD Europe	13.6	13.6	13.6	13.6	13.5	13.4	13.4	-0.3%
FSU	4.6	4.7	4.8	4.9	5.0	5.1	5.2	2.1%
Other Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.8	2.1%
China	10.1	10.4	10.9	11.3	11.7	12.0	12.3	3.3%
Other Asia	11.7	12.1	12.4	12.8	13.1	13.4	13.8	2.7%
Non-OECD Americas	6.6	6.8	6.9	7.0	7.2	7.3	7.4	2.0%
Middle East	8.0	8.2	8.5	8.8	9.1	9.5	9.8	3.5%
Africa	3.7	3.9	4.1	4.2	4.4	4.6	4.8	4.1%
World	**91.4**	**92.8**	**94.2**	**95.5**	**96.8**	**98.0**	**99.1**	**1.3%**

- **Like global crude supply, the demand barrel is getting significantly lighter, thanks in part to new sulphur regulations for bunker fuels.** The marine transportation sector had long lagged others in terms of environmental protection but is catching up, as legislative efforts to cut marine pollutants encourage a shift away from high-sulphur fuel oil. Fuel shifts in marine transport will likely start occurring during the forecast period, gaining further momentum in the following decade.

- **Demand in the United States, the world's largest oil market, edges down in the medium term,** as fuel savings from efficiency gains outweigh the effect of economic and population growth. Total US demand will fall by 0.4 mb/d between 2013 and 2019, to 18.9 mb/d.

- **Chinese demand growth shifts to a lower gear.** China, the world's second largest oil user, accounts for roughly 30% of global oil demand growth over the forecast period, down from the near-60% share of global growth in the previous six years.

- **Africa experiences some of the world's fastest oil-demand growth rates,** thanks to a combination of robust economic growth, high energy intensities and the effect of price subsidies. The region today ranks at the bottom of the range in per-capita oil use. Volumes remain small.

- **Oil demand from the power sector declines everywhere but the Middle East.** Insufficient natural gas supply, strong economic and demographic growth and the prevalence of price subsidies keep Middle Eastern power-sector oil use on a rising trend.

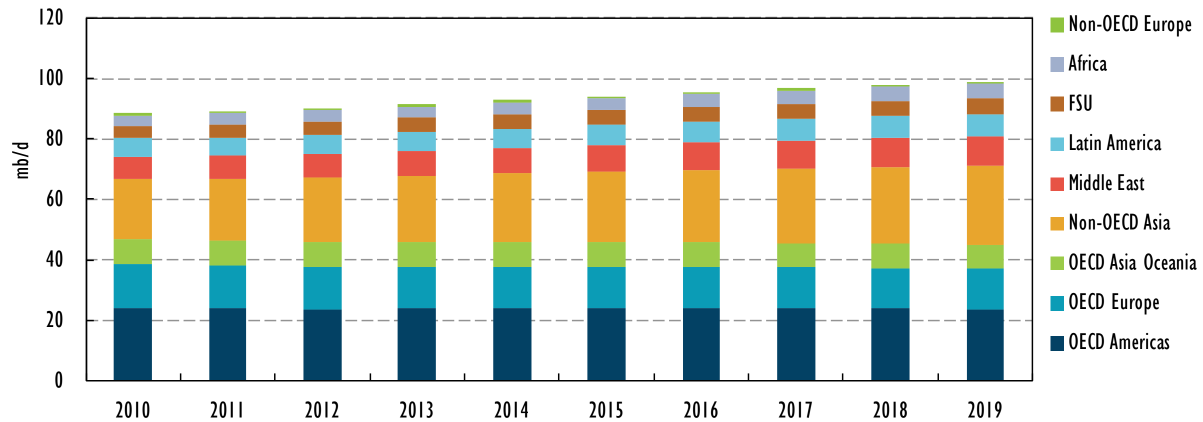
Overview

Global oil demand is forecast to rise to 99.1 mb/d in 2019 from around 91.4 mb/d in 2013, a per annum gain of around 1.3%. In aggregate, demand is expected to grow by 7.6 mb/d in the six-year period, less than the 9 mb/d growth projected for supply capacity. Among the many factors that feed into the forecast, the two key exogenous variables have traditionally been the macroeconomic landscape and oil price assumptions. Those factors point to a steady expansion of demand in the next five years, with growth expected to pick up momentum in 2014 and 2015, extending the trend of 2012 and 2013. The year 2015 may, however, mark something of a tipping point, when efficiency gains and environmental policies start eating into demand at the margin, allowing growth to slow somewhat.

The economic growth assumptions used in this *Report* are taken from the International Monetary Fund's (IMF) April *World Economic Outlook,* which forecasts global gross domestic product (GDP) expansion of 3.6% in 2014, rising to 3.9% in 2015 and around 4% thereafter. Combined with the assumption of slightly moderating oil prices, this steady, albeit modest, improvement in macroeconomic conditions, extending the current recovery, supports continued demand growth in the medium term.

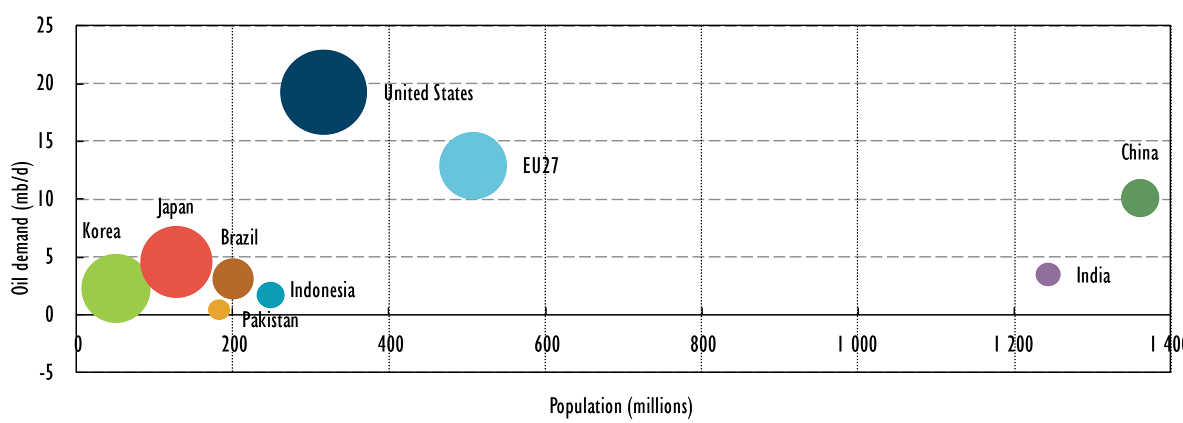
The Brent futures price curve is used as the oil price input. While the forecasting values of futures markets is debatable at best, the forward curve does indicate the price level that market participants can lock in and, in that sense, helps shape expectations of future supply and demand conditions. At the time of writing, futures markets show the oil price falling by roughly 12% from the front of the curve to the end of the decade. While oil prices for most crude grades have now held around record highs for three consecutive years, futures markets are not pricing in any further gains for the medium term amid signs of robust non-OPEC oil supply growth. Modestly lower prices at the end of the curve should not however be misconstrued as a forecast, but rather reflect the prevalence of producer hedging amid reduced investor buying interest for long-dated contracts.

Figure 1.1 Global oil demand



Other demand drivers include expectations of efficiency gains, the low level of per capita oil demand in many emerging market regions, changing patterns of energy intensity in China and other developing economies, fuel-switching out of oil (estimated at around 1.5 mb/d through the forecast) and a new round of environmental restrictions worldwide. On balance, those factors exert a moderating impact on consumption, allowing demand growth to decelerate somewhat post-2015. Developing economies like China and Saudi Arabia, both among the world's top consumers, are taking steps to rein in oil demand growth, while international efforts to curb shipping emissions also support fuel switching at the margin by the end of the decade.

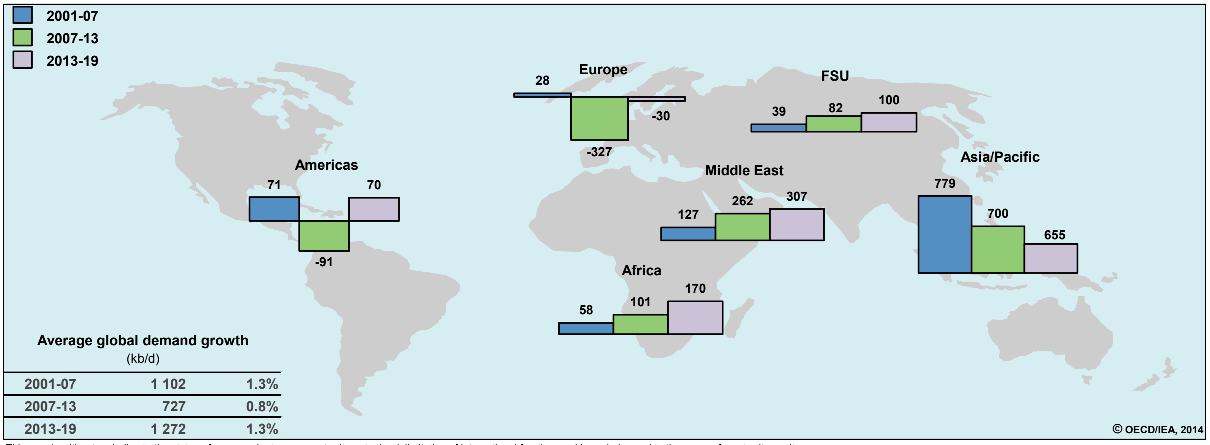
Figure 1.2 Per capita oil demand



Given slightly slower growth in the latter part of the forecast period, global demand is not forecast to surpass 100 mb/d before 4Q19, when it is projected to reach 100.2 mb/d. On an annual basis, global demand does not surpass 100 mb/d before 2020. Through the forecast, the strongest growth is expected in Asia (i.e. combined OECD Asia Oceania and non-OECD Asia), a momentum that proves critical in the region's ascendancy to the position of being the world's biggest oil consumer, from 2015, a position previously held by the Americas.

Within this relatively benign global landscape, two opposing trends emerge: a modest decline in OECD demand and, on balance, continued robust expansion in non-OECD countries. OECD oil demand is forecast to edge down by around 0.4% per annum from around 46.1 mb/d in 2013 to 45.0 mb/d by 2019. In contrast, deliveries in non-OECD countries rise to 54.0 mb/d by 2019 from 45.4 mb/d in 2013, a compound per annum gain of approximately 2.9%. Non-OECD oil use is forecast to surpass that of the OECD for the first time in 2014, after which point the gap between the two steadily widens.

Map 1.1 Oil demand growth, average per annum growth, kb/d

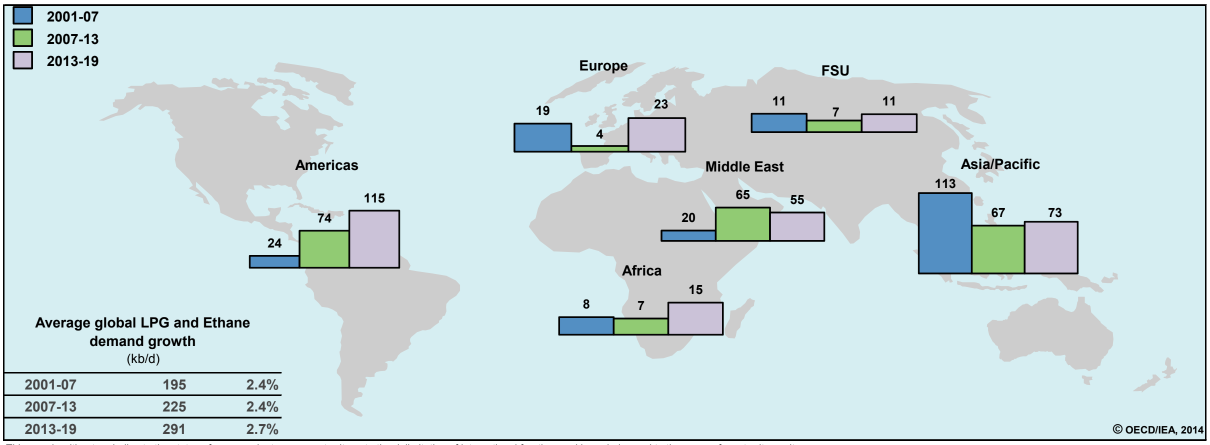


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

While oil is used for many purposes, it is the petrochemical and transport sectors that are forecast to lead growth in the medium term. As in the past, oil will continue to compete with other fuels in stationary uses such as power generation, industrial production and space heating, where it will increasingly be displaced by 'cleaner fuels', such as natural gas and renewable energy (and electricity from natural gas and renewable energy), or possibly cheaper ones like coal (and coal-generated electricity). In contrast, oil's dominance of the transport sector looks more entrenched. But it is no longer as unchallenged as it once was. For the first time, oil faces competition in the transport sector, notably with the spread of electric or natural-gas powered vehicles, as well as natural gas inroads into rail and marine transportation. This fuel-on-fuel competition will only play out at the margin in the medium term. Improvements in hybrid engine technology may paradoxically extend oil's lock on road transport. In the shipping industry, global efforts to cut air emissions strengthen the case for natural gas as a bunker fuel, though ship owners will have other options to reduce their footprint, including switching to lower-sulphur gasoil or installing scrubbers on their vessels. While large swings in the bunker fuel markets are unlikely before the next decade, demand patterns may start shifting earlier on (see "The changing fuel requirements of the global shipping industry"). Fuel competition in general will not arrest, let alone reverse, oil demand growth from the transport sector in the forecast period, but only curb the pace of growth at the margin, with larger shifts more likely in the following decade.

Like transportation, the petrochemical industry accounts for a fast-growing share of oil demand, driven both by demand-side factors, such as economic growth and rising consumption in Asia, and supply-side ones, namely the availability of competitively-priced feedstock in North America and the Middle East, but also the relatively low labour costs that exist across much of non-OECD Asia. Demand for petrochemical-based products is closely correlated with economic growth, hence it will likely rise through the forecast as the macroeconomic backdrop itself improves, supporting above-trend growth in the two key oil-based petrochemical feedstocks, naphtha and LPG (which includes ethane in IEA definitions). Three key regions – the United States, the Middle East and Asia – will lead petrochemical demand growth (see "An industry on the move: the rise of the petrochemical sector as a leading driver of oil demand growth"). Liquefied petroleum gas (LPG) demand is forecast to garner additional support in relatively poor economies, such as Africa, where it is forecast to increasingly gain market share from biomass as a cooking fuel.

Map 1.2 LPG demand growth, average per annum growth, kb/d



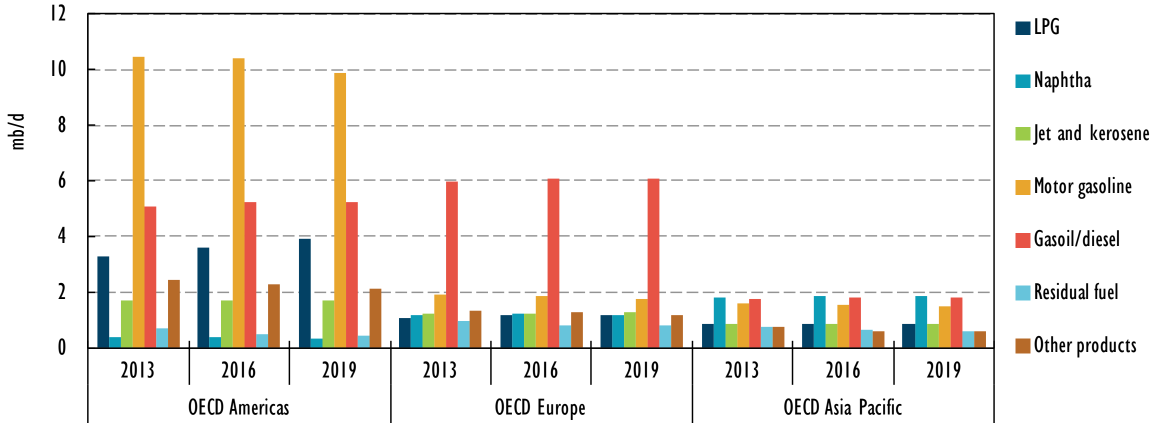
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Comparing this *Medium-Term Oil Market Report (MTOMR)* with last year's reveals important changes, including significant upward adjustments to baseline demand. Whereas the *MTOMR 2013* assessed total global oil deliveries at 90.6 mb/d for 2013, that estimate has been raised by nearly 840 kb/d, to 91.4 mb/d. OECD countries took the lion's share of this upside correction, adding roughly 625 kb/d of demand, as their economies performed significantly better than expected in the second half. The euro area exited recessionary conditions in mid-year, leading to a 280 kb/d revision in baseline demand to 13.6 mb/d for 2013. The Japanese economy also exited recession at mid-year, lifting the estimate of OECD Asia Oceania demand for the year by 70 kb/d, to 8.4 mb/d. The strong performance of the US economy in the second half also added 275 kb/d to the OECD Americas estimate, to 24.0 mb/d. Despite those adjustments, the overall growth trend post-2014 remains little changed from last year's *MTOMR,* as the factors behind it remain largely unaffected.

OECD

OECD oil demand is forecast to edge lower in the next five years, with the decline spanning all of the three main OECD regions. Several structural factors underpin the trend. Although their health is improving, OECD economies are expected to expand at a slower pace than non-OECD ones. OECD economies as a rule are also less industrially oriented, and thus have lower energy intensities, than those in the non-OECD regions. They also tend to be subject to tighter environmental standards. The sharpest OECD declines are expected in the Asia Oceania region, underpinned in part by a gradual restart of Japanese nuclear power generation capacity.

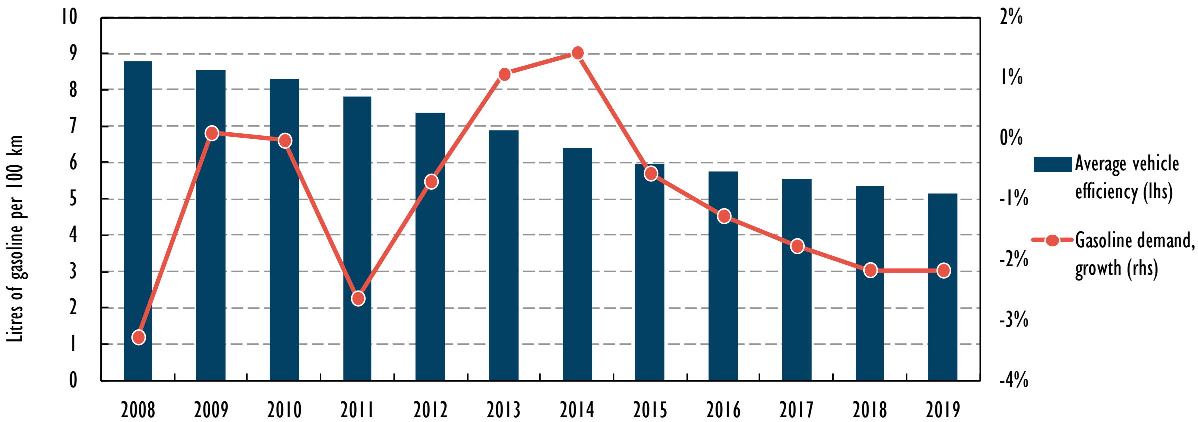
Figure 1.3 OECD oil demand



Americas

The OECD Americas region accounted for over half of all OECD demand in 2013, or 24.0 mb/d, and is expected to contract by 0.3% per annum on average to 23.6 mb/d in 2019. The United States dominates the group, with deliveries estimated at roughly 18.9 mb/d for the US50 in 2013, edging down by 0.3% per annum to 18.6 mb/d by 2019.

Figure 1.4 US gasoline demand growth and average vehicle efficiency



This overall decline conceals a contrasted outlook by product. The recent, and forecast to continue, resilience of the US industrial sector sustains gains in gasoil (supported by rail, see "Transport sector") and LPG demand, the latter driven by the so-called US petrochemical "renaissance" (see "An Industry on the move: the rise of the petrochemical sector as a leading driver of oil demand growth"). Other products show declines. US gasoline demand, which alone accounts for close to one-tenth of global oil demand, is forecast to contract by an average of around 1.1% per annum. US gasoline demand bounced back to 8.8 mb/d in 2013 from 8.7 mb/d in 2012, reversing a protracted decline, but is expected to resume its downtrend as the US vehicle fleet becomes increasingly more efficient.

The Canadian demand outlook is even weaker, with an average projected decline rate of 0.6% assumed through the next six years, reflecting more subdued macroeconomic expectations there. Economic growth in Canada is expected to average out at around 2.2% per annum, 2013-19, versus average GDP gains of

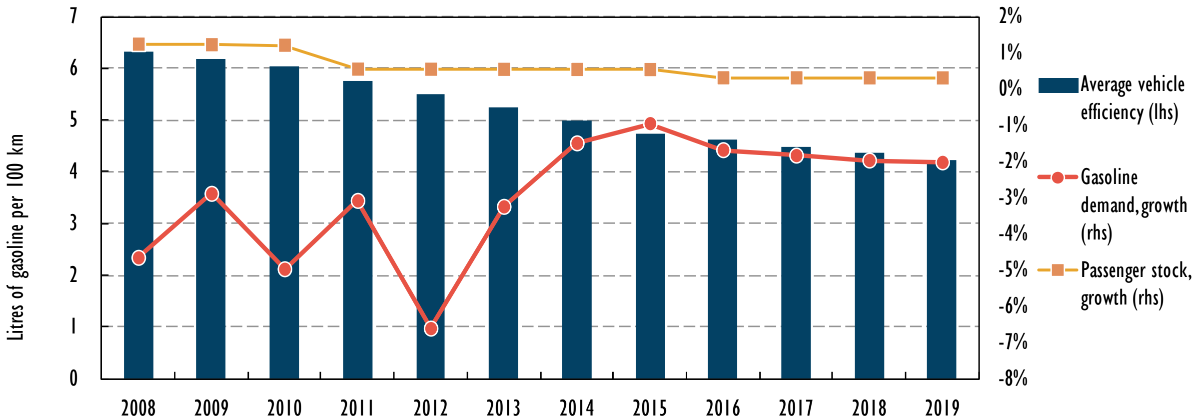
2.6% for the United States and 3.2% for Mexico. Absolute gains in oil demand are forecast for both Chile and Mexico, with growth in these two countries fuelled in part by their more robust industrial outlooks.

Europe

European oil demand fell to 13.7 mb/d in 2013, down by 0.8% on the year, its slightest decline in three years. Demand growth in northern Europe blunted the impact of declines elsewhere. **Germany** saw oil deliveries of 2.4 mb/d in 2013, 0.7% up on the year, breaking a two-year downtrend. In contrast, Mediterranean countries such as **Spain**, **Italy** and **Greece** continued to see sharp declines in oil use in 2013, as their debt-ridden economies continued to ail.

Looking forward, a relatively benign 0.3% per annum decline trend is foreseen, 2013-19, bringing regional demand down to around 13.4 mb/d by 2019. Absolute declines in gasoline, residual fuel oil and 'other products' are forecast to more than offset some fairly modest projected gains in LPG, jet/kerosene and gasoil/diesel (see "Transport sector"). Holding the European gasoline demand forecast down are the assumptions of ongoing efficiency improvements in the vehicle stock, albeit at a less dramatic pace than assumed in the United States, and the near-flat passenger vehicle stock. A notable degree of uncertainty, however, surrounds the European demand forecast encapsulated in the heightened state of macroeconomic uncertainty that surrounds the European economy in general.

Figure 1.5 European gasoline demand growth and average vehicle efficiency



The regional split of European demand is expected to continue over the medium term. Demand in northern European nations such as the **Netherlands** and **Sweden** is expected to flat-line and that in southern economies forecast to trend lower, albeit more gently than the previous six-year period, with average decline rates of around 1.3% for **Spain** and 2.1% for **Italy**.

Asia Oceania

The oil demand trend in OECD Asia Oceania largely hinges on the availability of nuclear capacity in **Japan**. The Great East Japan Earthquake and Tsunami of 2011 caused Japan to switch off its nuclear-power generation capacity, lifting demand for oil and other substitute boiler fuels. Japanese nuclear capacity was kept off-line through most of 2014. Plans to return this capacity to service have yet to be realised. In April 2014, Prime Minister Shinzo Abe said that he saw nuclear power as an "important base-load power source" and announced a plan to gradually bring back those reactors that had passed a Japanese Nuclear Regulation Authority (NRA) fitness test. The 20-year Strategic Energy Plan released 11 April 2014, the first such plan since the Fukushima Daiichi nuclear disaster, addresses a variety of key energy issues, including the role of nuclear power in Japan's energy mix, but does not explicitly spell out the pace at which nuclear capacity is to be brought back online. Based on current NRA inspections, this forecast assumes a slow and gradual return to a maximum of 59 terawatt hours (TWh) by 2016, a level at which it would then remain through 2019. At the time of writing, there was still no certainty as to the schedule of plant restarts in the summer, the peak electricity-demand season.

Overall OECD Asia Oceania demand is expected to edge down to around 8.1 mb/d by 2019 from 8.4 mb/d in 2013, an average per annum decline rate of 0.7%. These figures obscure intra-regional contrasts, however, with a relatively steep drop in Japan outweighing modest gains elsewhere. The speed of Japanese nuclear capacity restarts is a wild card. Some press reports have questioned whether more than two-thirds of installed capacity can pass the latest, more stringent, NRA tests.

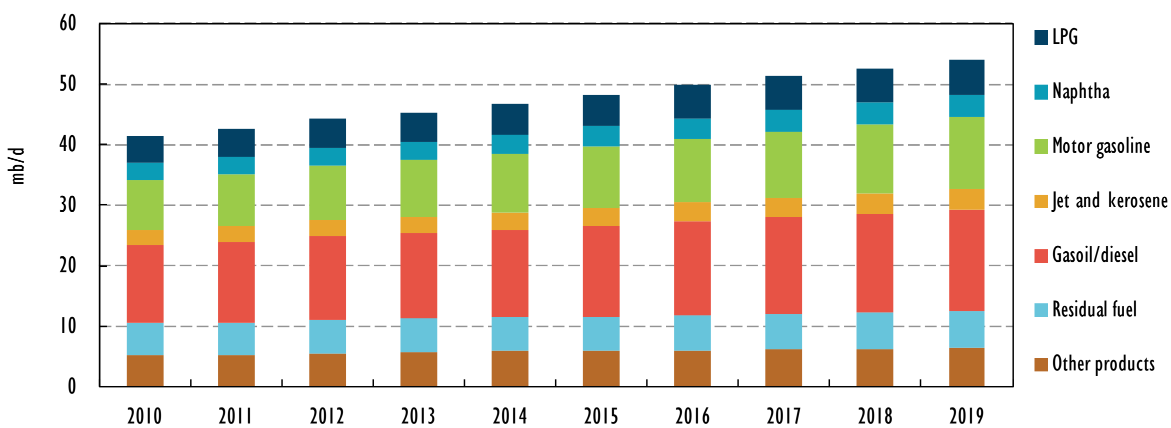
Non-OECD

With strong gains forecast across most non-OECD regions, total non-OECD oil deliveries will likely overtake the OECD for the first time in 2014. Henceforth the gap between these two consuming regions is likely to widen, with OECD countries accounting for a diminishing share of the market. The stronger assumed non-OECD macroeconomic underpinnings (compared to OECD) are the main driver for this additional demand. Global industrial activity has largely shifted from the OECD to non-OECD regions, accounting in part for higher energy intensities of the developing world. Further raising non-OECD prospects, relative to OECD, is the fact that environmental controls tend to be stricter in developed economies. For example, on average emission controls are less stringent in non-OECD ports.

Table 1.2 Non-OECD oil demand (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
LPG (including ethane)	4.9	5.0	5.3	5.4	5.6	5.7	5.8	3.1%
Naphtha	3.0	3.2	3.3	3.4	3.5	3.7	3.7	3.3%
Motor gasoline	9.3	9.7	10.1	10.6	10.9	11.3	11.7	3.9%
Jet fuel and kerosene	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.3%
Gas/diesel oil	14.1	14.4	15.0	15.5	15.9	16.4	16.8	3.0%
Residual fuel oil	5.5	5.7	5.7	5.8	5.9	6.0	6.1	1.7%
Other products	5.7	5.8	5.9	6.0	6.1	6.2	6.4	1.9%
Total products	**45.4**	**46.8**	**48.3**	**49.8**	**51.2**	**52.7**	**54.0**	**2.9%**

Figure 1.6 Non-OECD oil demand



Box 1.1 OECD versus non-OECD demand: Beyond the tipping point

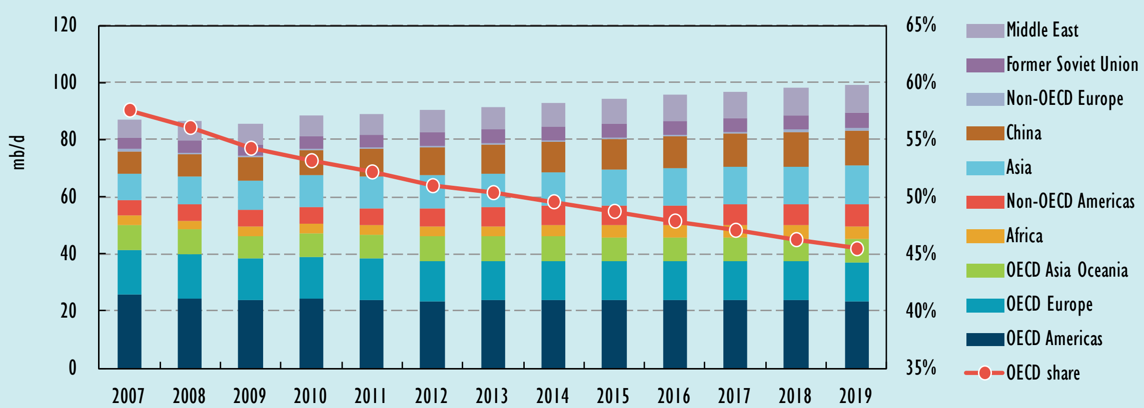
For fifteen years demand from non-OECD countries has been rising at a faster pace than that from OECD countries, but the latter still accounted for the majority of global oil use. The next five years mark the beginning of a new chapter in oil's history, as for the first time emerging and recently industrialised economies will consume more oil than their so-called industrialised counterparts, and the gap is expected to widen steadily over the period.

Partitioning the world between "emerging" and "industrialised" economies inevitably involves a degree of arbitrariness and over-simplification. Here we consider the member states of the Organisation for Cooperation and Development (OECD) as a proxy for industrialised and mature economies, and the "non-OECD" countries as representative of the emerging and newly industrialised ones. On a quarterly basis, non-OECD countries already overtook their OECD counterparts in oil demand in 4Q13, a position that reversed in 1Q14 on seasonal factors. Non-OECD oil deliveries are projected to have inched back above those of the OECD in 2Q14. With a compound per annum non-OECD growth trend of around 2.9% forecast for the 2014-19 period, compared to an annual decline rate averaging around 0.4% for the OECD, emerging and newly industrialising economies will then carry the mantle of 'the world's largest oil consuming region' for the foreseeable future.

Post-recessionary bounces aside, the OECD oil demand trend has been on a generally falling trajectory since 2006, when all three major OECD regions (America, Europe and Asia-Oceania) were in decline. Already prior to 2005, most economies in the region had increasingly turned toward the less energy-intensive service-sector, but after four consecutive years of double-digit percentage point oil price gains the previously modestly rising OECD demand trend stuttered to a halt, from 4Q05.

Initially, the rise in non-OECD demand and the contracting trend in the OECD were mirror images of each other, at least in directional terms if not in scale, reflecting the hollowing out of the OECD's industrial base and the offshoring of energy-intensive OECD industrial and manufacturing activities to lower-labour cost economies of the non-OECD region. Hence the particularly strong growth in non-OECD demand for industrial fuels, and the contraction in increasingly service-oriented mature economies. As non-OECD economies expanded, however, domestic consumer demand in those countries also increased. Rising household incomes translated into fast-rising vehicle ownership rates and booming automobile sales, as well as rising demand for electric appliances and other energy-consuming goods.

Figure 1.7 Non-OECD to become world's biggest oil consumer, post-2013



Box 1.1 OECD versus non-OECD demand: Beyond the tipping point (continued)

The already rapidly rising non-OECD deliveries stepped in to replace falling OECD oil-use. Total non-OECD deliveries at 39.1 mb/d in 2009, stood 5.0 mb/d over 2005, this sharp gain more than offset the corresponding OECD loss, of 4.9 mb/d. Indeed, non-OECD demand momentum has been a remarkably resilient performer in recent years, as the per annum growth trend averaged plus 1.5 mb/d in the next five-years, 2010-14, equivalent to a total non-OECD gain of 7.6 mb/d. Over this same period, OECD oil use contracted by 0.4 mb/d, leaving a net global five-year adjustment of plus 7.2 mb/d.

Table 1.3 OECD oil demand by region (mb/d)

	2004	2005	2006	2007	2008	2009	2010	2011
Americas	25.7	25.9	25.7	25.8	24.6	23.7	24.1	24.0
Europe	15.6	15.7	15.7	15.6	15.5	14.7	14.7	14.3
Asia Oceania	8.9	8.9	8.8	8.7	8.4	8.0	8.2	8.2
Total OECD	**50.2**	**50.5**	**50.2**	**50.1**	**48.4**	**46.4**	**47.0**	**46.5**

Looking forward to the next five years, the dominance of non-OECD demand looks entrenched, with non-OECD demand forecast to reach 54.0 mb/d in 2019, and OECD demand to fall to 45.0 mb/d. But these headline trends conceals further shifts and new contrasts. Within the non-OECD region, Chinese demand growth, which in the last twelve years had been the single most powerful engine of global demand growth, is shifting to a lower gear. Chinese demand for gasoil and residual fuel has already swung into contraction, with consumer fuels and transport fuels now leading growth. Like the broader Chinese economy, the country's oil demand growth is expected to continue being reshaped by the transition from an export-oriented, energy-intensive economic model to one that increasingly targets the rising domestic consumption unlocked by continued gains in household incomes. As the Chinese economy continues to mature, the Chinese fuel mix and demand barrel will look increasingly like those of advanced OECD countries.

In contrast with easing oil demand growth in China, demand in other non-OECD countries will gain momentum. Africa and many smaller non-OECD Asian economies, for example, are forecast to see accelerating demand trends over the forecast period, as industrial-base of these economies expands, alongside sharp upticks in vehicle ownership rates and per capita energy consumption trends.

Meanwhile in the OECD too, headline trends conceal regional contrasts, with potentially stronger growth in North America than in the rest of the group. In the United States and Canada, the North American supply revolution has triggered an industrial revival, but this is mostly fuelled by natural gas, rather than oil. South of the border, Mexico's demographic trends (notably its age pyramid) and per- capita oil consumption make it resemble factors driving growth in developing economies, setting the stage for potentially steeper consumption growth.

Given these, now seemingly entrenched, regional demand patterns it was only really a matter of time before non-OECD deliveries exceeded OECD, i.e. intermittently from 4Q13 but likely permanently from 2Q14. The question now becomes one of how much bigger the non-OECD will become, and from a base of roughly 50% non-OECD:50% OECD in 2014, non-OECD's market dominance is forecast to rise steadily through to 55%:45% by 2019.

The significance of this relative regional shift should not be downplayed, as it highlights a general global macroeconomic development: that of poorer, more populated emerging and newly industrialised countries rising to exceed the combined weight of the economies of the richer, more service-orientated OECD. As non-OECD economies get richer, however, the very significance of this market dichotomy will subside, with OECD and non-OECD nations essentially becoming more alike and the focus on the oil markets then best centred on global and regional aggregates instead of OECD/non-OECD splits.

Transportation fuels are forecast as dominating non-OECD oil demand growth through the forecast, with total non-OECD gasoil/diesel demand forecast to expand by 2.4 mb/d between 2014 and 2019. Non-OECD motor gasoline demand will grow by around 2.0 mb/d, and jet/kerosene deliveries by an estimated 0.5 mb/d. In total, non-OECD oil demand is forecast to grow by 7.2 mb/d over the forecast period.

Roughly half of the forecast increase in non-OECD demand is attributable to non-OECD Asia. Of that non-OECD Asian increase, half of this again is accounted for by China. Of the projected 8.7 mb/d total non-OECD oil demand growth, 2013-19, 22% is accounted for by the Middle East, 12% by Africa, 9% by Latin America and 7% by the economies of the former Soviet Union and from non-OECD Europe.

Asia

At roughly 21.8 mb/d in 2013, non-OECD Asian oil demand is forecast to account for around half of all non-OECD deliveries. China takes the lion's share of this category, accounting for about half of all non-OECD Asian demand, or a quarter of non-OECD demand. Asian demand is forecast to grow by roughly 4.3 mb/d from 2013 to 2019, again accounting for roughly half of the forecast growth in non-OECD consumption. China contributes 2.2 mb/d of the increment, India 0.6 mb/d, Indonesia 0.4 mb/d, Singapore 0.2 mb/d and the rest of non-OECD Asia 0.9 mb/d.

Although China's contribution to global demand growth continues to loom large, Chinese oil demand is no longer growing as fast as it once did. In line with the broader Chinese economy, Chinese demand growth has shifted to a lower gear, and is expected to further decelerate over the forecast period, in line with the broader economy and in response to the government's efforts to improve air quality.

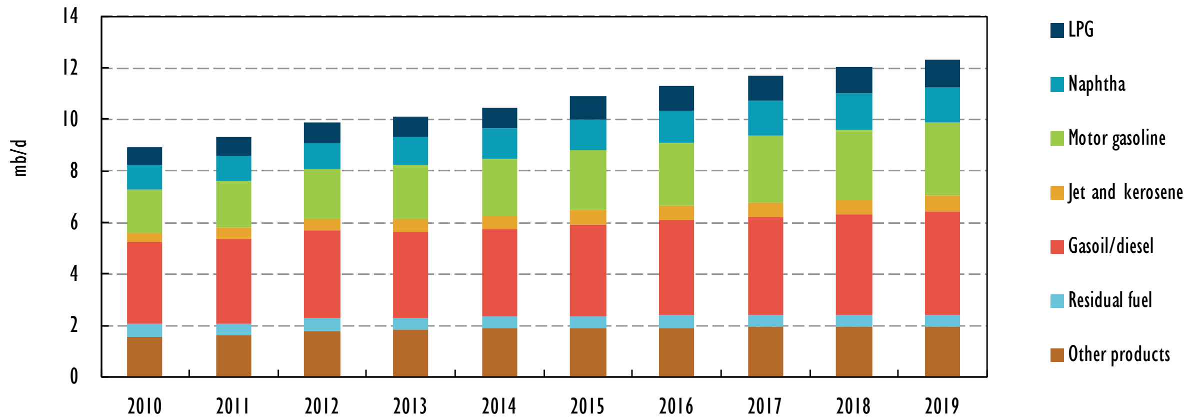
Having risen by an average of roughly 9% in 2008-13, China's economy is expected to ease into a growth rate of around 7.0% for 2014-19. Similarly, Chinese oil demand growth is forecast to slow to 3.3% in 2013-19 from 4.9% in 2007-13. In addition to gearing down, the Chinese economy is also shifting from an export-driven, industrial model to a more domestically focused, consumer-oriented one, and is thus becoming less energy intensive.

Even at an assumed 3.3% per annum growth rate, Chinese demand still accounts for 2.2 mb/d of incremental oil use, equivalent to the combined total oil use of Indonesia, Pakistan and Sri Lanka (and not simply their growth). With only 54 passenger cars per 1 000 people in China (using the latest World Bank data), compared to more than 400 in the United States, it is road transport fuels that dominate the Chinese growth outlook, accounting for roughly two-thirds of total Chinese oil demand growth over the forecast period.

Big gains are also foreseen in the jet fuel market, with forecast income growth driving a compound per annum gain of over 4% in deliveries. China's petrochemical sector is also rapidly expanding, providing around one-quarter of the total anticipated Chinese demand gain.

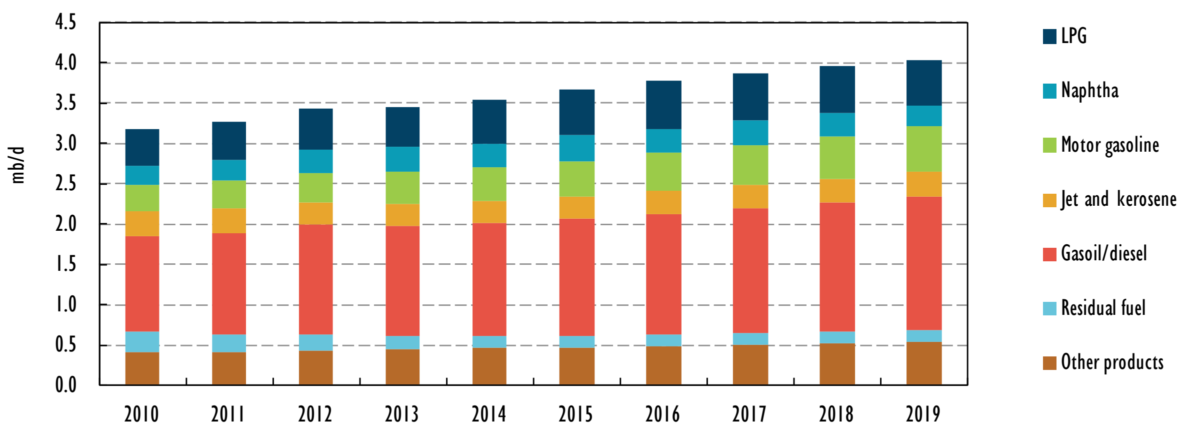
Slowing the Chinese demand story in recent years have been the absolute demand declines seen in residual fuel oil and more recently gasoil/diesel. As the government has increasingly realised the severity of its pollution problems efforts have been made to encourage additional efficiency and fuel switching to natural gas. As of 2013, as a consequence of deliberate government measures, China became the third-largest gas user behind the United States and Russia, and since 2013 ahead of Iran. With its greater level of air-borne pollutants, coal has been one of the main targets for product switching, although not exclusively as the government has also made a concerted effort to encourage some switching from oil to gas. A particular example of this is in the city bus and taxi markets, as many vehicles have already been converted over to natural gas, at the expense of diesel, with this trend set to continue through the forecast. Roughly half a million natural gas vehicles (NGV) were added in 2012, which when supported by plans for rapid expansions in both the compressed natural gas and liquefied natural gas filling station capacity, should see China becoming the world's largest NGV market by 2015.

Figure 1.8 Chinese oil demand



A strong jump is also forecast in non-OECD Asia's second largest economy, India, where oil deliveries are forecast to rise to 4.0 mb/d in 2019 from approximately 3.5 mb/d in 2013, equating to a compound per annum growth rate of 2.6%. Transportation fuels drive growth, with rapid gains forecast in both the passenger-vehicle and freight fleets. Demand in the gasoil/diesel sector, which accounts for roughly two of every five barrels consumed in India, is forecast to grow by around 3.6% per annum through the forecast. Gasoline demand is forecast to grow at an even faster clip, of 5.9% per annum, as the gradual elimination of diesel subsidies will encourage some fuel switching to gasoline at the expense of diesel, while demand for non-road gasoil may likewise lead to some fuel switching to natural gas. Through 2019, India is forecast to enjoy better natural gas supplies than in recent years, including both domestically produced natural gas and imported LNG (see this years *Medium-Term Gas Market Report*), undermining demand growth for refined products at the margin.

Figure 1.9 Indian oil demand



In contrast with transport fuels, demand for residual fuel oil and kerosene is expected to contract. Fuel oil demand will fall by an average of around 2.5% per annum, 2013-19, due to reduced industrial and power sector usage. Indian kerosene demand, meanwhile, is forecast to fall steadily in favour of natural gas and LPG, as Indian government policy seeks to phase out its use as a low-income cooking fuel. Drops in kerosene use will be too low to offset rising air travel demand for jet fuel, however, so that combined jet fuel/kerosene demand continues to edge up.

Middle East

Some of the strongest gains in the oil demand forecast originate from the energy-rich economies of the **Middle East**. Supporting deliveries will be economic growth, which has benefited from high energy export revenues in the region's producer countries. Demand also finds support from high government spending and the persistence of oil product price subsidies. Having risen by an average of around 3.7% in 2007-13, total Middle Eastern oil demand is forecast to grow further at a similar pace in 2013-19. Absolute demand growth is forecast to span all the main product categories and sectors of the economy, with the steepest expansion forecast in the oil-intensive petrochemical sector (see "An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth").

Domestic transportation fuel demand is also forecast to rise steeply through the medium term, with 3% to 4% per annum gains in both gasoline and gasoil. Underpinning the robust Middle Eastern transportation forecast will be the rapidly expanding population base, the IMF's still relatively strong economic growth predictions and the persistence in many countries of generous price subsidies. Indeed, the United Nations *World Population Prospects* of 2012 outlines a population gain of around 20% between 2010 and 2020, while the IMF foresees GDP growth of around 3.8% per annum over the same period. On the other hand, the car ownership rate in the many Middle Eastern economies is already quite high. For example, in Kuwait the car ownership rate already exceeds even that of the United States.

Table 1.4 Middle East oil demand (mb/d)

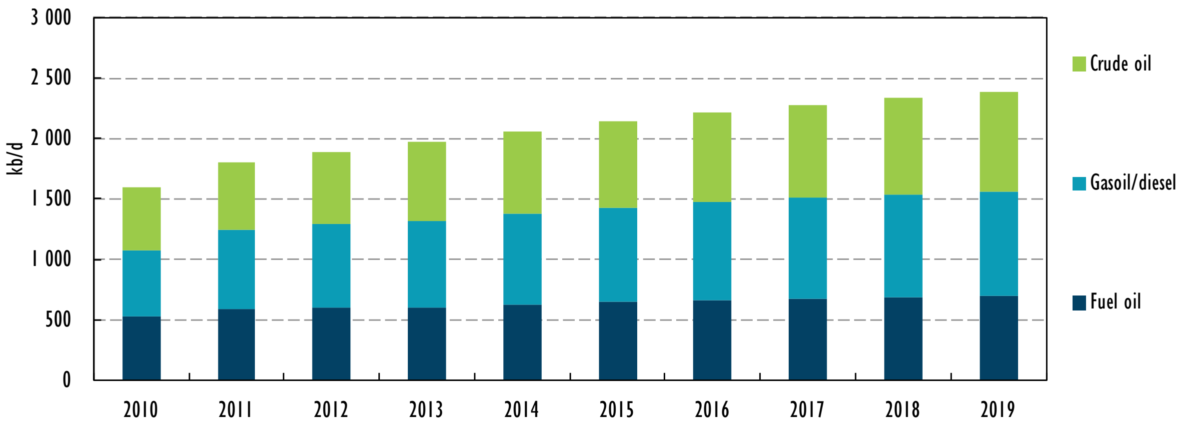
	2013	2014	2015	2016	2017	2018	2019	CAGR
LPG (including ethane)	1.3	1.3	1.4	1.4	1.5	1.6	1.6	3.9%
Naphtha	0.1	0.1	0.2	0.2	0.2	0.2	0.3	21.1%
Motor gasoline	1.5	1.5	1.6	1.6	1.7	1.8	1.8	3.7%
Jet fuel and kerosene	0.4	0.5	0.5	0.5	0.5	0.5	0.6	3.9%
Gas/diesel oil	2.3	2.3	2.4	2.5	2.5	2.6	2.7	3.0%
Residual fuel oil	1.5	1.6	1.6	1.6	1.7	1.7	1.8	2.6%
Other products	0.9	0.9	0.9	1.0	1.0	1.0	1.0	2.5%
Total products	**8.0**	**8.2**	**8.5**	**8.8**	**9.1**	**9.5**	**9.8**	**3.5%**

While oil demand from the power sector is globally declining, the Middle East bucks that trend. Efforts to replace oil with natural gas in the Middle Eastern power generation sector are less widespread and less successful than is generally assumed. Over the past decade, natural gas has gained market share at the expense of oil, as the share of natural gas in the Middle Eastern power generation sector grew from 61% in 2000 to 64% in 2010, before falling back to 60% in 2011. Oil's relative share of the Middle Eastern power market is moving as a mirror image to gas, down from around 39% in 2000, to 36% in 2010, but back up to 40% in 2011.

Fuel switching is forecast to cut oil's share of the Middle Eastern power generation market again over the forecast period, to 32% by 2019 (albeit still rising in absolute terms), though this will not be due entirely to natural gas, but also to alternatives energy sources such as renewable energies, which in aggregate are forecast to amount to around 6% of total Middle Eastern power-sector generation capacity by 2019.

Despite falling as share of the total power market, the amount of oil that is specifically used to generate electricity is forecast to rise in the next five years. Considerably more ambitious plans, particularly concerning solar and wind in the Middle East, are in the pipeline but beyond the 2014-19 forecasting horizon.

Figure 1.10 Middle East power-sector oil demand



In the meantime, insufficient natural gas supplies will likely force continued dependence on oil in the power sector in many Middle Eastern countries. Gas supplies from Oman, for example, will remain somewhat subdued until 2018, when the Khazzan-Makharem gas field is due to come on line.

Three different oil products traditionally satisfy the majority of this Middle Eastern power-sector oil requirement: residual fuel oil; gasoil/diesel; and crude oil burned directly by the power-sector. Relatively evenly balanced shares of the total Middle Eastern oil demand pot have historically been seen between these three categories, with *Energy Statistics and Energy Balances of Non-OECD Countries* (IEA, 2013) showing gasoil/diesel out in front, at approximately 36.8% of Middle Eastern power-sector oil use in 2011, followed by residual fuel oil (at 32.4%) and crude oil (30.8%). These respective shares are then forecast to remain reasonably consistent through 2019, albeit with some swing away from fuel oil to crude oil, continuing the previous trend.

Price subsidies will also buoy demand in many Middle Eastern economies. Even in crisis-hit Syria, for example, the government continues to pour vast sums of money into subsidising petroleum products, spending nearly USD 270 million in 1Q14 according to Energy Minister Sulaiman al-'Abbas. Due to the political situation in the region, subsidy reform is unlikely to occur in a meaningful way prior to 2019.

Since last year's *MTOMR,* the Middle Eastern demand estimate has been revised upwards, with roughly 225 kb/d added to the estimate for Middle Eastern oil demand in 2018. Iran, Qatar and Kuwait account for most of the forecast adjustment, as additional deliveries in these partly offset by cuts elsewhere, notably to Syria and Saudi Arabia. The Iranian demand estimate of 2.1 mb/d for 2018 has been adjusted upwards by around 220 kb/d on a stronger IMF economic forecast for the country. Both the Qatari and Kuwaiti demand estimates have been revised upwards, respectively by 150 kb/d and 110 kb/d for 2018, driven by upward adjustments to the estimate of petrochemical demand (see "An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth"). The downside revision for Syria reflects the impact of the country's civil war, and that for Saudi Arabia, reduced – though still rising – petrochemical requirements.

Box 1.2 Saudi Arabian oil demand has been rising fast but may begin to slow

Like that of many countries in the Middle East, oil demand in Saudi Arabia has risen strongly in recent years as the country rose to the seventh rank among oil consumers in 2013, from tenth back in 2005, but its growth rate looks likely to ease somewhat in the next few years. While a slowdown in Saudi demand growth would mark an important shift in regional demand dynamics, incremental Saudi consumption will nevertheless remain high compared to those of other countries, and the Kingdom is expected to make a large contribution to global demand growth in the next five years.

Saudi oil use reached an estimated 3.0 mb/d in 2013, up from 2.1 mb/d in 2007, equating to a compound per annum growth rate of 6.1%, 2007-13. Over the next six-years another 0.7 mb/d is likely to be added, to 3.7 mb/d, as growth eases to around 3.6% per annum 2013-19.

As with many energy exporting countries, very low retail energy prices in Saudi Arabia are stimulating demand, but that is not the whole story. There are wider structural reasons why Saudi energy demand has been high and rising, but may decelerate somewhat over the next six years:

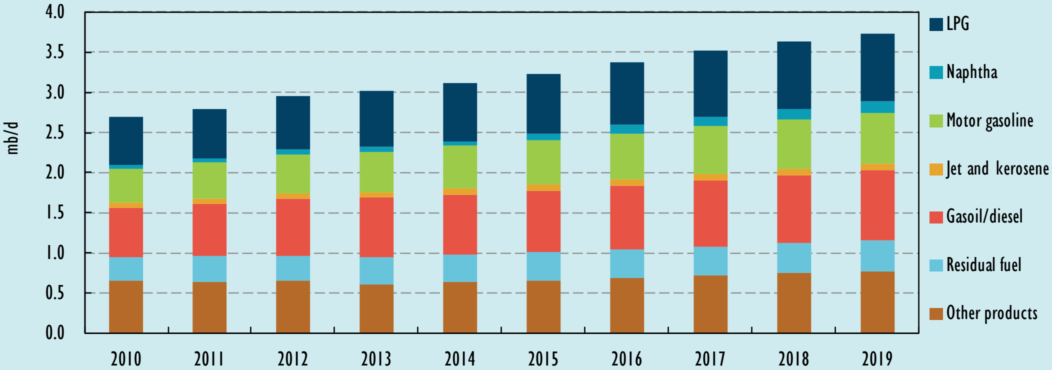
- Strong economic growth: Due to the relatively high oil price environment of recent years, Saudi Arabia has been one of the best performing G-20 economies. Saudi Arabia has a GDP of USD 711 billion; making it the 19th biggest economy. From an economic growth perspective, Saudi Arabia is ranked even higher, with a real GDP growth rate averaging 6.1% per annum, 2008–12, putting Saudi Arabia in third place in the G-20, behind only the Chinese and Indian economies. The IMF is, however, forecasting that the average rate of economic growth in Saudi Arabia will fall to 4.2%, 2014-18. This weaker economic growth trend, with all else being held equal, equates to a slowdown in Saudi Arabian oil demand growth.
- Energy intensive industries: Government policy in Saudi Arabia has long sought to leverage the country’s energy abundance to foster the development of energy-intensive industries, ostensibly in a bid to diversify the economy away from pure energy-plays and capture a greater share of the total energy value chain. This has led to a vicious circle of cheap energy input prices and rising energy demand. The petrochemical industry is a case in point. Saudi Arabian policy has identified the development of a large petrochemical sector as a key strategic target, something it initially did as early as the 1970s, first with the promotion of a national champion, SABIC, and latterly through joint ventures between Saudi Aramco and foreign companies. Despite these efforts, the petrochemical sector today only contributes a small share of GDP (roughly 1%) and has a relatively limited employment effect, yet it consumes large amounts of investments and feedstock. Similarly, the growing aluminium smelting industry, which has been heavily supported by the government, significantly raises demand for electricity. On balance, those policies have caused Saudi Arabia to buck the global trend toward reduced energy intensity in the global economy. Total primary energy consumption per dollar of GDP in Saudi Arabia has risen by 138% between 1980 and 2010 while in China it has fallen by 67%. In the next five years, growth in Saudi petrochemical demand for oil is expected to slow down in percentage terms, but from a higher base, resulting in a similar volume growth in 2013-19 as in the previous six-year period. Increasingly concerned about the consequences of runaway domestic demand growth, the Saudi government has been shifting its policy in favour of less fossil-energy-intensive industries. In particular, the government is keen to encourage those industries based around renewable energy, for example, lessening the economy’s dependence upon oil.
- Demographic growth: The Saudi population has grown very rapidly - by 180% between 1980 and 2010, reaching 28.3 million at the end of 2012 (including 8.4 million foreign residents according to the 2010 official census). Although the rate of increase has slowed, the population could reach 35.6 million by 2030 and 40.3 million by 2050[1]. As an example of short-term projections, the IMF predicts a Saudi Arabian population of 30 million as of 2013 reaching 33.8 million by 2019.[2]

[1] World Population Prospects: The 2012 Revision, http://esa.un.org/unpd/wpp/index.htm.
[2] IMF, World Economic Outlook, April 2014.

Box 1.2 Saudi Arabian oil demand has been rising fast but may begin to slow (continued)

- Geography: Saudi Arabia constitutes an imposing land mass of 2 149 690 square kilometres (about the size of the United States east of the Mississippi). There are vast distances between the main population centres and industrial areas. In general the population density of the Kingdom is very low: 12.91 persons per square kilometre, whereas the worldwide average is 53.70 people, 36.44 in the OECD and 144.1 for China. These factors lead to very high fuel consumption requirements across the transportation sector.

Figure 1.11 Saudi Arabian oil demand



- Climate: Saudi Arabia is very hot and dry, requiring enormous quantities of electricity consumption for air conditioning (almost 55% of total annual electricity demand) especially in summer when temperatures can reach 45^{o} C. Saudi Arabia scores well over 3 000 Cooling Degree Days (CDDs) per year, compared with 1 000 for Iran. This also adds to the seasonality of demand to the point where the summer peak demand is now nearly twice the winter average. The kingdom is also experiencing an increasing need for water: Saudi Arabia gets very little rain, only about four inches a year on average making it one of the world's most arid regions. Huge amounts of energy are used for water desalination to cover ever increasing water needs. Per capita consumption of water is 235 litres per day which is, according to a report prepared in 2012 by the country's Saline Water Conversion.
- Corporation (SWCC), 91% higher than the international average. Furthermore, demand for water in Saudi Arabia is growing by more than 8.8% annually. The Kingdom runs the largest desalination programme in the world (17% of total world output which provides 60% of total water supply in the Kingdom). Saudi Arabia pumps the equivalent of 0.3 mb/d of oil only to operate the publicly held SWCC stations which supply two thirds of desalinated water. Furthermore, the water usage, like electricity usage, is heavily subsidised, as the cost of desalinated and distributed water could go up to USD 4/tonne while the billing price could be as low as USD 0.03/tonne.
- Policy-induced waste: low and subsidised energy prices, which have well-founded social and political objectives, massively reduce the incentives for saving energy and make energy efficiency policies harder to implement.
- The Saudi government is acutely aware that it will need to find acceptable ways of moderating energy demand. These may include both demand- and supply-measures:
  - Energy use efficiency: Riyadh recently introduced industry standards (for buildings, appliances including air-conditioners, etc), which if continued and diligently implemented have the capacity to deliver large energy savings. The Saudi Energy Efficiency Centre (SEEC), for example, compelled the Saudi Arabian Ministry of Commerce and Industry to confiscate 50 000 air conditioners from stores that did not meet its energy saving requirements for 2014. Yet the SEEC still complains of a lack of efficiency standards and enforcement mechanisms in insulation and lighting, hence providing for more possibilities to economise on Saudi Arabian oil use if ever these limitations are met. The SEEC particularly criticises the Saudi Arabian Building code, especially EE section 601 (passed in 2007), as too complicated, overly long and not sufficiently enforced.

Box 1.2 Saudi Arabian oil demand has been rising fast but may begin to slow (continued)

- Energy generation efficiency: The Saudi Electricity Company (SEC) has committed to a list of projects over the coming decade combining both improved efficiency in existing plants and the building of new generating capacity. This plan includes the conversion of gas power plants to combined-cycle technology, aimed at increasing the generating capacity of these plants by 50% without adding fuel. The potential improvements include increasing the thermal efficiency of the plants running on crude oil, from about 28% to 44%, and running at gas to 54% after conversion to combined-cycle.
- Fuel switching to renewable energy: Concurrently, Riyadh is aiming to develop renewable electricity generation capacity. Current Saudi Arabian plans envisage up to 41 gigawatts of solar capacity and 17.6 gigawatts of nuclear by 2032.
- Fuel switching to natural gas: Natural gas, in Saudi Arabia, is forecast as reclaiming its rising share of the total power mix, 2013-19, as orders of significant volumes of combined cycle gas turbines increase the efficiency of future gas use.
- Subsidy reform: As far as prices and subsidies are concerned the Electricity Cogeneration Regulatory Authority (ECRA) is reducing the level of subsidies on electricity at the retail level by raising prices for upper monthly consumption bands while increasing the ceiling of low price electricity for poorer families. Electricity prices for non-household users, meanwhile, saw a near 10% hike in 2010, still leaving them at approximately one-third of production costs, thus highlighting not just the desire to tackle the issue but also the scope that still exists for further adjustments. The double-digit percentage point gains in government spending that have been seen in recent years, and supported the Saudi Arabian economy and in turn the robust oil demand trend, are unlikely to endure through the forecast. The Middle East Economic Digest put its estimate for government spending growth down to +2% for 2013 and acknowledged the strong possibility of an absolute decline in 2014.

Overall we are forecasting an expansion of over 3% in Saudi Arabian oil demand in 2014, to 3.1 mb/d, a pace that is likely to pick up through to 2016, peaking at 4.6%. Despite efforts to diversify the economy towards less energy-intensive sectors, strong petrochemical sector requirements are expected to lift naphtha demand, while natural gas supply constraints inflate the power sector oil requirement. By 2019, Saudi Arabia is expected to run as the world's seventh largest oil consumer, with nearly one-quarter of its 3.7 mb/d demand attributable to gasoil and similarly sized shares to LPG (including ethane) and 'other products', which includes the direct burn by the power sector. With such strong demand growth more than outpacing the associated projections for Saudi capacity, export volumes are likely to be forced down.

Latin America

Latin American oil demand is forecast to rise to 7.4 mb/d in 2019 from 6.6 mb/d in 2013, a growth rate of 2% per year in 2013-19, down from growth of 3.7% in 2007-13. Three key factors influence this deceleration: a weaker macroeconomic background; continued fuel switching and ongoing efficiency gains.

As in other economies, the Latin American transport sector is expected to lead the expansion, with more than nine-tenths of oil demand growth attributable to either motor gasoline, jet/kerosene or gasoil/diesel, compared to 80% in 2008-13. Despite this persistent strength, the overall projected growth trend for road transport fuels is likely to decelerate. Thus, the Latin American passenger vehicle fleet is projected to increase by 16 million vehicles to 100 million cars in 2019, down from growth of 19 million in the previous five years. Growth in vehicle miles travelled is also expected to drop, with a per annum gain of 3.4% foreseen, 2014-19, versus the near 5% expansion, 2008-13. Anticipated gains in Latin American freight activity are similarly decreased, from 6.9% (2008-13) to 4.7% (2014-19).

Table 1.5 Latin American oil demand (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
LPG (including ethane)	0.64	0.65	0.65	0.66	0.68	0.69	0.70	1.5%
Naphtha	0.20	0.20	0.20	0.20	0.19	0.20	0.21	1.1%
Motor gasoline	1.73	1.80	1.89	1.95	2.01	2.06	2.11	3.4%
Jet fuel and kerosene	0.29	0.29	0.30	0.31	0.32	0.32	0.33	2.5%
Gas/diesel oil	2.16	2.21	2.30	2.34	2.39	2.43	2.47	2.3%
Residual fuel oil	0.79	0.82	0.79	0.80	0.80	0.80	0.80	0.3%
Other products	0.79	0.78	0.79	0.78	0.78	0.78	0.78	-0.1%
Total products	**6.59**	**6.76**	**6.92**	**7.04**	**7.17**	**7.29**	**7.42**	**2.0%**

Roughly flat forecasts of Latin American residual fuel oil and 'other product' demand amount to a notable climb-down from previous trends, as both the power sector requirement and, to a lesser degree, the bunker fuel market experience some form of product switching. With a near 6% per annum gain in Latin American power-sector natural gas usage, some switching out of oil products will occur. Meanwhile, Latin American based-vessels will likely migrate in part from residual bunkers to gasoil to meet North American and northern European emission requirements, adding to the downside on fuel oil.

Former Soviet Union

The recent escalation in geopolitical tensions in the region should see only tentative upward steps being taken in oil use across the economies of the former Soviet Union. According to the IMF's April 2014 *World Economic Outlook*, economic growth in the region is forecast to fall back to around 1.9% in 2014, having seen plus 4% per annum gains as recently as 2010-12. Momentum is then forecast to accelerate once again towards the end of the medium-term time frame, as the macroeconomic framework which underpins oil demand also recuperates. Over the five-year forecast, 2014-19, roughly 0.5 mb/d of additional barrels are thought likely to be added, taking the average up to 5.2 mb/d in 2019.

Table 1.6 Former Soviet Union oil demand (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
LPG (including ethane)	0.45	0.46	0.48	0.48	0.48	0.50	0.51	2.3%
Naphtha	0.33	0.33	0.35	0.36	0.36	0.39	0.41	3.5%
Motor gasoline	1.18	1.19	1.20	1.22	1.24	1.27	1.29	1.5%
Jet fuel and kerosene	0.34	0.35	0.35	0.36	0.37	0.38	0.39	2.1%
Gas/diesel oil	1.04	1.05	1.06	1.08	1.10	1.12	1.13	1.5%
Residual fuel oil	0.42	0.42	0.42	0.43	0.44	0.45	0.46	1.6%
Other products	0.86	0.89	0.91	0.94	0.97	1.00	1.03	3.0%
Total products	**4.61**	**4.68**	**4.77**	**4.87**	**4.97**	**5.09**	**5.21**	**2.1%**

Despite the relatively bleak economic conditions, at least modestly rising oil deliveries should be maintained through 2019, as some support is likely regarding oil-use from the relatively high number of infrastructure projects that are in the pipeline, such as the construction effort for the 2018 football World Cup and the Moscow ring road scheme. An additional downside risk, however, needs to be factored in over the regional demand forecast, to reflect the ongoing heightened level of macroeconomic uncertainty that surrounds the region at present.

Africa

A strong demand trend is forecast, through 2019, supported by a combination of relatively robust underlying macroeconomic assumptions and the region's very low current per-capita energy consumption. Starting from an estimated 3.7 mb/d in 2013, African oil demand is forecast to add 1 mb/d over this six-year period, equivalent to a growth trend of around 4% per annum. All of the major African product categories are forecast to maintain strong growth, through to 2019, with particularly sharp gains envisaged in road transport demand. Strong growth in road transportation fuel will underpin the overall African demand forecast as the total African passenger vehicle stock is likely to rise sharply, by 4.6% per annum 2013-19, while the assumed efficiency gains of this embryonic vehicle fleet are likely to be marginal.

Despite the fact that relatively robust growth prospects are forecast for the African region as a whole, country specific divergences exist. Some of the most rapid clips are envisaged across West Africa, with generally slower trend projections assumed for much of north and southern Africa, a divergence that generally reflects the discrepancy that exists between the IMF macroeconomic projections, albeit with the African continent as a whole rising sharply.

Table 1.7 African oil demand (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
LPG (including ethane)	0.36	0.38	0.40	0.41	0.43	0.44	0.45	3.7%
Naphtha	0.02	0.02	0.03	0.03	0.04	0.04	0.05	13.6%
Motor gasoline	0.94	0.99	1.02	1.07	1.11	1.15	1.20	4.1%
Jet fuel and kerosene	0.32	0.33	0.35	0.36	0.38	0.39	0.41	4.2%
Gas/diesel oil	1.39	1.45	1.52	1.59	1.65	1.72	1.78	4.2%
Residual fuel oil	0.42	0.45	0.44	0.46	0.48	0.49	0.51	3.1%
Other products	0.28	0.30	0.32	0.33	0.33	0.34	0.36	4.2%
Total products	**3.74**	**3.91**	**4.08**	**4.25**	**4.42**	**4.59**	**4.76**	**4.1%**

Other non-macroeconomic issues also heavily influence the African oil demand forecast, as numerous countries, such as Morocco, have announced specific government intentions to reduce, or at least curb the growth rate, of what many governments deem to be relatively expensive imported, oil demand. The Moroccan Energy Minister Abdelkader Amara, for example, has stated that efforts will be made to reduced total energy consumption by 12% by 2020, with the power sector a particular target. From an oil point of view and across Africa as a whole we are sceptical of the likely success of such plans.

Non-OECD Europe

Accounting for just over 0.7% of global oil deliveries in 2013, at 675 kb/d, non-OECD Europe is expected to see a reasonable +2.1% per annum growth rate, 2014-19. Growth is forecast across the main product categories, reflecting the relatively supporting macroeconomic situation that the IMF is spelling out for the region. Non-OECD European economic growth, having struggled in the four years through 2012, is forecast to rebound through the forecast, with GDP growth of around 3.2% per annum assumed, 2013-19.

Although reasonable gains in oil demand are forecast to occur across non-OECD Europe, the most rapid clip is pin-pointed on Gibraltar, which although admittedly small in absolute terms, at roughly 60 kb/d in 2013, is likely to see strong gains through the forecast. The predicted uptick in global trade flows, consequential on the strengthening macroeconomic recovery, raises requirements on shipping-flows which are very likely to be reflected in additional oil deliveries at major water-borne transport hubs/bunker ports like Gibraltar. This last factor explains why the non-OECD European demand forecast entails such strong gains in fuel oil use compared to other product categories.

Table 1.8 Non-OECD European oil demand (kb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
LPG (including Ethane)	0.06	0.06	0.06	0.06	0.07	0.07	0.07	3.5%
Naphtha	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-4.7%
Motor gasoline	0.09	0.09	0.09	0.09	0.10	0.10	0.10	2.4%
Jet fuel and kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	2.2%
Gas/diesel oil	0.26	0.27	0.28	0.28	0.29	0.29	0.30	2.3%
Residual fuel oil	0.13	0.13	0.14	0.14	0.14	0.15	0.15	2.1%
Other products	0.09	0.10	0.10	0.10	0.10	0.10	0.10	1.7%
Total products	**0.68**	**0.69**	**0.70**	**0.72**	**0.73**	**0.75**	**0.76**	**2.1%**

Transport sector

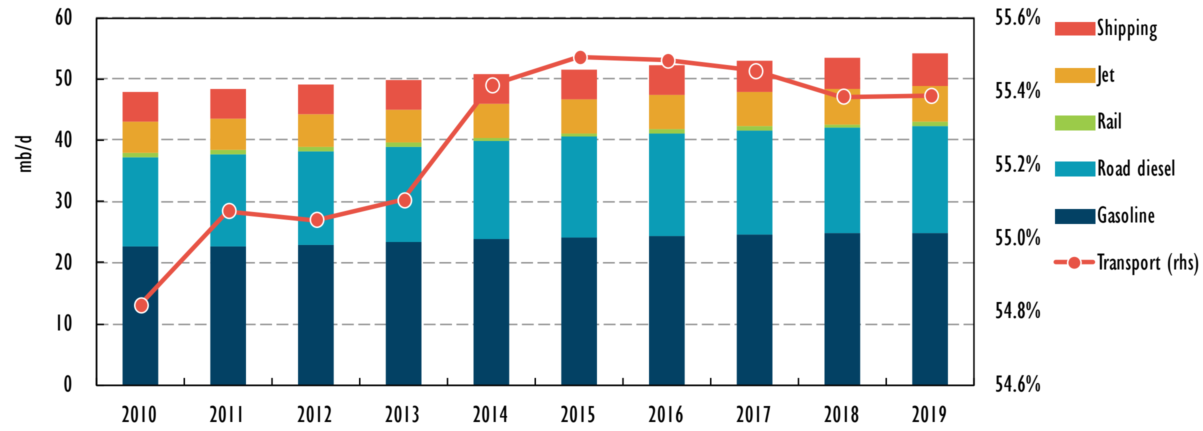
At an estimated 50.4 mb/d in 2013, the total amount of oil used in the transport sector accounts for roughly 55.1% of total global oil demand, a ratio that has remained relatively constant over recent history and is expected to continue through 2019. With it being such a dominant component of overall oil demand, it is on the transport sector that we focus most of our attention. Note the regional sections (above) often contain individual references to their transport forecasts and the assumptions that determine them. Four key means of transport account for all of this oil – road, rail, air and water. Road dominates, at roughly 43.2% of total oil demand in 2013, with gasoline accountable for roughly 59% of this total road oil use, the majority of the rest attributable to road diesel. Air travel, meanwhile, accounted for nearly 5.9% of total oil use in 2013, rail 0.7%. International bunkers, or the amount of oil that is used by the international shipping industry, accounted for another 4.3% of global oil deliveries in 2013. Bunkers are not all water-borne oil-use, however, as domestic navigation also accounted for another 1.0% of oil demand, equivalent to roughly 890 kb/d in 2013.

Transport sector oil use is forecast to rise, fairly steadily, through to 2019, as generally escalating traffic flows (road, rail, air and water) prove more than sufficient to offset the negative influence otherwise provided by the increasingly more efficient propulsion methods that are chosen. Emerging and newly industrialising economies are generally forecast to outperform OECD economies. The total scale of the non-OECD vehicle pool is forecast to expand at a much more rapid clip, than those for the OECD, partly because they are often greater beneficiaries of price-subsidies but also due to greater tendency for looser emission controls, hence quelling (other than from an income perspective) the requirement for more efficient engine choices.

Global transport fuel demand is forecast to rise to around 54.8 mb/d in 2019, equivalent to an average per annum growth rate of 1.4%, 2013-19. Although this amounts to a very slight acceleration on the previous six-year trend, when it averaged 1.3% growth per annum 2007-13, it hides a multitude of other 'issues' that the following analysis of the individual transport markets seeks to make clearer.

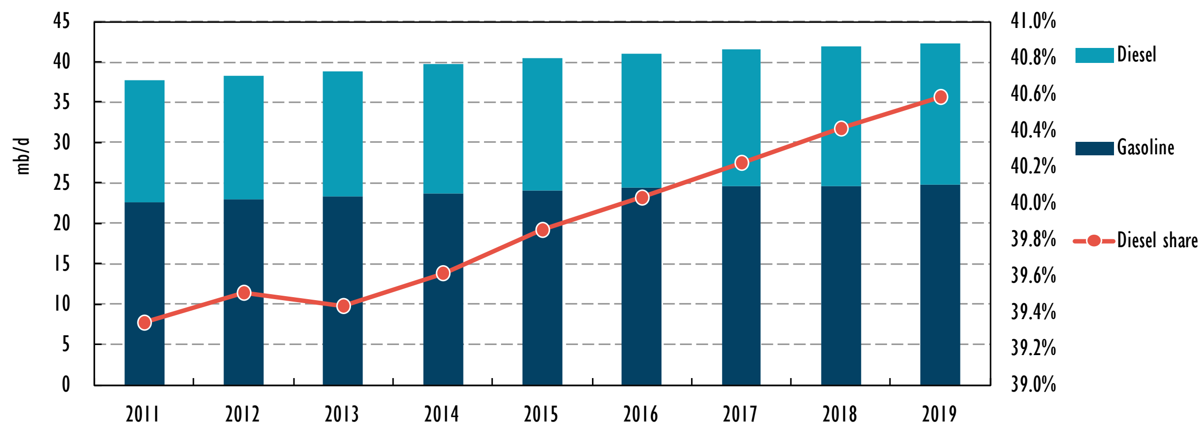
The global **road transportation** fuel market is dominated by motor gasoline, which accounts for nearly two of every three barrels of oil that are used on the roads. The remainder is largely diesel, with only a small amount attributable to LPG. Gasoline's dominant market share, is on a slow but steady downtrend, however, as diesel engine technology makes inroads into the total carpool. Back in 2007, for example, over 60% of all global road oil use was attributable to gasoline (38% diesel). A gradual increase in the popularity of diesel engines, particularly in Europe and OECD Asia Oceania, saw gasoline's share of the global road transport market fall below 60% in 2011, with diesel accordingly up above 39% for the first time. After a minor dip in 2013, as many diesel-reliant European economies suffered from weak economic conditions in 1H13, the global dieselisation trend continues through 2019.

Figure 1.12 Relative share of transport use in total global oil demand



A potential wildcard in all this is related to concern that diesel engines cause higher air pollution, with particularly acute problems seen in many European cities in the spring of 2014. The issue has the potential to reverse, or at least soften, the dieselisation forecast, as although new diesel engines with the correct filtration systems fitted abate the problem, political pressure to equalise the tax treatment on gasoline and diesel (most European countries apply higher levels of taxation on gasoline), would negatively impact diesel.

Figure 1.13 Global road oil demand



The assumed relative efficiency gains of the freight and passenger vehicle stocks, through to 2019, are one of the key factors that contributes to the more rapid growth forecast for diesel over gasoline. Freight is much more heavily reliant upon diesel, whereas passenger vehicles tend to use either, depending on the domestic market (the United States heavily skewed towards gasoline, whereas

France diesel). With the impressive efficiency gains having been achieved by industry recently in the freight sector, a sub-1% per annum efficiency gain in the freight stock is assumed, 2013-19, whereas these technological developments still have some way to go to filter into the total passenger fleet, leaving plenty of scope for a larger near 1.3% per annum efficiency gains. Overall road diesel demand is forecast to add approximately 1.9% per annum, 2013-19, rising from 15.6 mb/d in 2013 to 17.5 mb/d in 2019. With gasoline forecast to add around 1.6 mb/d over this same period, to 24.9 mb/d, this is equivalent to a more subdued 1.1% per annum gain.

Total road transport fuel demand is expected to rise through the forecast, up from around 39.5 mb/d in 2013 to 43.1 mb/d in 2019. This gain in road oil transport fuel demand is equivalent to a compound growth rate of around 1.5% per annum, 2013-19, roughly matching the forecast growth trend for the overall transport metric. Non-OECD economies are forecast to provide the majority of the upside, as much lower non-OECD vehicle ownership rates leave room for stronger growth. OECD road transport demand will actually edge lower through the forecast as already plump vehicle ownership ratios, escalating congestion problems, rapid vehicle efficiency gains and relatively higher retail prices all act to stem the OECD road transport fuel demand figures.

Indeed, global growth in road transportation fuel deliveries are likely to lag somewhat behind their own inherent possibilities, as escalating traffic congestion restrains the vehicle miles travelled statistics. Traffic levels in major metropolises worldwide are forecast to rise through the medium-to-long-term as road construction plans in all but the most forward-thinking developing economies are likely to lag behind the population statistics.

In the United Kingdom, for example, where the Office of National Statistics estimates that the population is likely to rise by around 10 million (i.e. by more than one-sixth) over the next 25 years, resulting in roughly four million more drivers, already cramped UK roads will become even more congested. The average time wasted in congested traffic conditions in the UK is already thought to have been around 30 hours per person in 2013, an hour up on 2012, according to traffic consultant INRIX, and is likely to worsen according to the director of the Royal Automobile Club (RAC) Foundation, Professor Stephen Glaister. The UK government forecast a 40% increase in the UK traffic volume through to 2040. Professor Glaister claims that the UK government has “promised to raise spending (on roads) in the next parliament but this is back-loaded towards 2020,” hence restraining growth in UK transport fuel demand well below its potential trajectory.

With some fairly ambitious plans for increased use of natural gas in the road transportation fuel market, the ratio of gas-in-road-transport is forecast to break the 3%-threshold in 2018 (from 1.8% in 2013). Chinese and US freight, bus, taxi and courier services are forecast to play leading roles in the prospective switch, as plans are already being established to set up commercial gas refuelling stations in these markets, long the largest obstacle to more rapid gains in gas-in-transport.

The global air travel industry accounted for roughly 5.9% of total oil use in 2013, making it the second largest transport fuel market after road. This ratio is forecast as holding through the medium-term time frame, i.e. 2013-19, as the projected rate of jet fuel growth, at around 1.5% per annum, only marginally exceeds the overall growth metric for oil products as a whole. Starting at around 5.4 mb/d in 2013, global jet fuel demand is forecast to add around 0.5 mb/d over the six-year time frame through 2019.

Sharp escalations in non-OECD jet fuel demand, feeding off predictions of rapid expansions in emerging market passenger numbers, will underpin the relatively robust global jet fuel forecast. Indeed, escalating non-OECD deliveries will more than offset the modest OECD decline rates that are envisaged due to flatter OECD flight trends and the negative impact that is attributable to more efficient engine-technology.

The most rapid gains are forecast for the Middle Eastern, non-OECD Asian and African jet fuel markets, as air passenger numbers in these markets see robust growth. The number of African flights is likely to rise sharply, 2013-19, supported by the sharply escalating macroeconomic base and exceptionally low start point of the data. Non-OECD Asian flight numbers, meanwhile, are likely to benefit from continued rapid income growth in the region. Middle Eastern jet fuel use is particularly forecast to benefit from some ambitious airport expansion plans and the rapidly expanding population base.

The Saudi Arabian market alone is likely to see two new carriers in 2015, Al-Qahtani Aviation and Al-Maha, respectively running under the SaudiGulf and Qatar Airways brands. Al-Qahtani has already spent more than USD 2 billion on new aircrafts, and plans to launch its first flights from it Dammam base in 1Q15. Qatar Airways is also reportedly targeting a 2015 launch for Al-Maha. Numerous airport expansion plans are already under way in Saudi Arabia, such as King Abdulaziz International Airport in Jeddah, which commands a total budget of USD 28 billion and will eventually take capacity up to 80 million passengers a year by 2035. The airport is already on a rapid growth path, with 27 million passengers handles in 2012 (the latest full year of data), up from 23 million in 2011. The General Authority of Civil Aviation is carrying out expansions at three of its four international airports and 15 of its 24 domestic airports, at a total cost of approximately USD 34.9 billion.

The international rail market, although small in absolute scale at roughly 0.7% of total global oil demand in 2013, is forecast to rise steadily through the medium-term time frame. Growth in rail's oil-use is forecast as escalating by around 1.8% per annum, 2013-19. The economies of the OECD dominate global rail use, accounting for nearly two-thirds of all oil used directly by the rail sector. It is important to remember, however, that measurements of oil products used in the rail sector do not include oil that is used in the power sector that then moves electric trains.

The volumes of oil moved by railroads in OECD Americas have become a particular thorny issue recently, as increasing amounts of oil have had to be moved across the country due to insufficient pipeline capacity. The pace of the future growth track of rail's oil-use is, of course, heavily dependent upon future pipeline developments and the geographical locations of future oil discoveries. Another possible risk-factor for rail is the rate at which future developments in non-oil powered trains emerge. In the United States, for example, a number of railcar providers are working on developing gas-powered locomotive engines, the widespread adoption of which would dramatically cull forecasts of oil used in the OECD Americas.

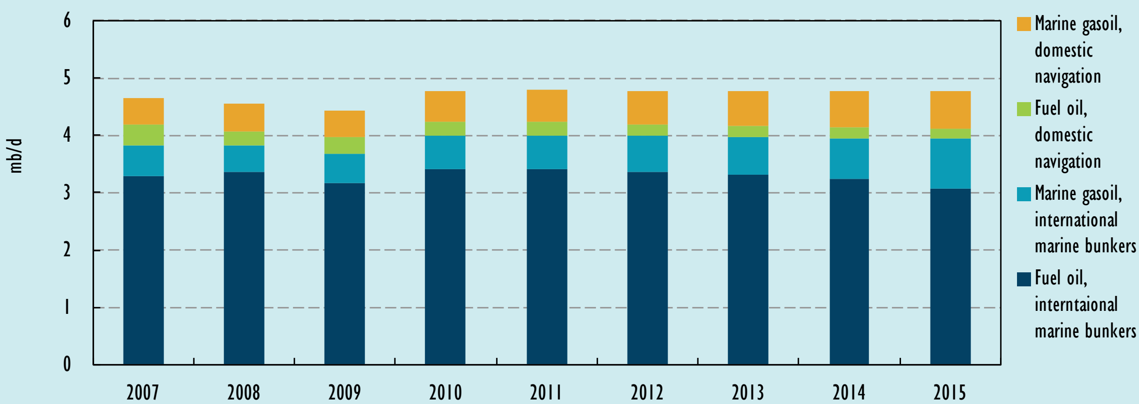
The US Energy Information Admistration (EIA) recently published some interesting research on the possibilities of liquified natural gas (LNG) powered trains. In a paper published mid-April 2014, the EIA concluded that "class one railroads (i.e. major US railroads) are considering the use of LNG to fuel locomotives because of significant cost savings. Following years of tight price linkage, spot prices for crude oil (North Sea Brent) and natural gas (Henry Hub) diverged around 2005. In 2012, the Brent spot price was about seven times the Henry Hub spot price on an energy equivalent basis. That differential is projected to narrow in the midterm, but a persistent gap is expected to continue, with crude oil prices more than three times higher than natural gas" going out to 2040.

Box 1.3 The changing fuel requirements of the global shipping industry

Since the adoption of coal-fired steam ships in the 19th century and the attendant surge in international trade, marine transportation has emerged as one of the world's largest – if poorly measured - sources of energy demand. In the early 20th century oil replaced coal as the marine fuel of choice. More recently however, natural gas has begun to encroach on the dominance of oil, partly in a bid to address the environmental challenges raised by marine fuel consumption.

Despite their widespread use, marine bunker fuels have until now counted among the least regulated fuels in terms of emissions, but that is rapidly changing. The legislation governing marine emissions is expected to significantly tighten in the next decade or so. The exact timing and impact of the new regulations is still unclear, however. In addition to increased natural gas use for marine transportation, tighter bunker rules expected in the medium term may also lead to the displacement of high-sulphur residual fuel oil used for marine transportation by higher-quality, lower-sulphur gasoil. Scrubbers may also be adopted on ships to reduce the emissions from the use of lower-quality, higher-sulphur fuels.

Figure 1.14 Global shipping oil demand



The impact of changing emission requirements will depend on many factors, not least the size of the bunker fuel market. The latter is shrouded in uncertainty, with a broader range of estimates than for most other products. For example, a near three mb/d range exists between the extremes of the widely quoted predictions, from a low of roughly 3.5 mb/d for 2011 to a high of 6.5 mb/d. For the purpose of this *Report*, we estimate global bunker fuel demand on international waters at around 4.0 mb/d for 2011. This marks an upward adjustment from estimates from the *World Energy Statistics and Energy Balances* (IEA, 2013), intended to correct for suspected under-reporting in some regions, such as the former Soviet Union and non-OECD Asia, where marine bunkers are often misreported as fuel oil for inland consumption. Of this total daily international shipping requirement, we estimate that around 85% is accounted for by fuel oil, with the rest largely attributable to marine diesel.

An additional 0.9 mb/d of oil products was used in 'domestic navigation' in 2011, i.e. oil products used for internal, domestic shipping and not used on international waters (for example, river/canal barges and river ferries). Marine diesel already accounted for approximately 70% of this total 'domestic navigation' use, as lower emissions from marine diesel compared to residual fuel oil long made it the fuel of choice on internal waterways, often subject to tighter emission controls than international waters. Combined oil demand for water-borne transit thus amounted to 4.8 mb/d in 2011. For the purposes of this analysis, however, we focus our attention on the large international marine bunker fuel market, excluding 'domestic navigation'.

Box 1.3 The changing fuel requirement of the global shipping industry (continued)

Mounting concerns about high levels of pollution from shipping fleets have led to two sets of new regulations, each with its own timeline. First, so-called Emission Control Areas (ECAs) have been established in some coastal regions. In these ECA, ships are held to certain bunker fuel sulphur limits. These ECAs are being doubly expanded: new regions are being added to them, while their sulphur standards are concurrently being tightened. At the same time, the International Maritime Organisation (IMO) is considering sulphur limits for bunkers outside of ECAs, albeit less constraining ones than in the ECAs.

Map 1.3 ECAs in the world as of 2014

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

The tightening of ECAs' sulphur standards is taking effect as early as January 2015 and is expected, in our analysis, to result in a switch of around 240 kb/d from high-sulphur fuel oil use to low-sulphur marine gasoil. ECAs were borne out of the International Convention for the Prevention of Pollution from Ships (MARPOL) adopted by the IMO in 1973. The ECAs include the North Sea, the Baltic Sea and coastal areas off North America. Beginning July 2010, vessels travelling in ECA waters had to limit the sulphur-content of burnt fuel to no more than 1%. The new rules taking effect in January 2015 will further tighten ECA fuel standards to a maximum 0.1% sulphur. We modelled the shipping industry, initially without the 2015 tighter 0.1% sulphur regulation then applied this additional restriction, the difference being a swing of roughly 240 kb/d from fuel oil to gasoil. It should be noted that vessels are only required to reduce the sulphur content of their emissions in the ECA but can switch back to higher sulphur bunker fuels outside the ECA, if they have dual fuel engines/fuel switching capabilities.

Switching to lower-sulphur oil products, such as marine diesel, is not – at least in theory – the only option available to reduce water-borne pollutants. The adoption of 'scrubber' technology is another possibility. A scrubber is a unit that essentially filters bunker fuel gases before they are released into the atmosphere, so that heavier-sulphur fuel oil can still be used. Yet another option would be to switch to another lower emission fuel such as LNG. Neither of these options, which we will explore in detail below, can easily be deployed by January 2015, however. Industry sources suggest that another option post-2015 will concern the blending of low-sulphur fuel oil to an 'off spec' fuel which would comply with sulphur limits but would have a higher concentration of particulate matter and other pollutants than marine gasoil. At first glance, this option seems likely to remain marginal, but its use could become more widespread depending on the price differentials between fuel oil and marine gasoil.

Box 1.3 The changing fuel requirement of the global shipping industry (continued)

The size of the ECA was widened in January 2014 to include the US areas of the Caribbean Sea. This effectively meant that ships passing through waters adjacent to the coasts of Puerto Rico and the US Virgin Islands also had to adhere to 1% sulphur limit, tightening to 0.1% from January 2015. Further ECA additions are under consideration including the Mediterranean Sea, waters along the northern coast of Norway, Mexico and Japan. Such moves have, however, floundered in recent years as macroeconomic weaknesses have held back change. The Mediterranean provides a particularly illuminating example, as discussions have been ongoing for many years, hampered recently by the severity of the economic travails of both Southern Europe and North Africa. A general lack of willingness to commit outside of the EU has held back efforts, as has a reluctance to reform the busy Suez-Gibraltar shipping route. Separate EU legislature, to 0.5% sulphur, in the Mediterranean is due to be imposed in 2020, although compliance close to African waters is likely to be an issue.

In addition to the tightening of ECA standards by 2015, the broader tightening of emission limits to areas outside of ECAs will entail an extension of sulphur-restrictions to 0.5% from the current 3.5% limit. The timescale for that switch is somewhat unclear: the move to lower sulphur standards was originally scheduled for 2020, but the IMO kept open the option of pushing it back to 2025, depending on the outcome of an assessment of market conditions, including a fuel availability study, scheduled for 2018. The IMO has refrained from providing any guidance or clue as to which way it might go in 2018.

The scope of the changes required by a switch of 0.5% sulphur bunkers in non-ECA areas is considerably greater than that involved by tough ECA rules. Huge changes will have to be enforced if the global bunker fuel market, that currently uses roughly 3.3 mb/d of fuel oil (3.5 mb/d if we include 'domestic navigation'), is going to be able to achieve these international 0.5% sulphur limits. Rather than a mass switching from fuel oil to marine gasoil, it is likely that a combination of the above-mentioned options will be deployed. Cost considerations will play the driving role in determining which option ship-owners choose. The availability of alternate fuels will also come into play, independent of prices. For instance, a large-scale switch to LNG bunkers would call for a sufficiently large network of LNG fuelling terminals, which would require much of the pre-existing infrastructure being retrofitted to handle bunkering services and others built from scratch.

Furthermore, sulphur emissions are not the only pollutant that international bodies, such as the IMO, are trying to get under control, with a generally increased pressure emerging to cleanse the water-borne energy-burn. Indeed, many observers are likening the current push to 'clean up' the shipping industry with the drive to reduce car emissions over the 1980s and 1990s. If this is the case, regulations governing particulate matter, nitrogen oxide and carbon dioxide may also be implemented over the longer term.

Marine gasoil provides the most easily deployable option for the impending tightening of environmental legislation, providing fuel is available. This fuel is seen as the easy option by ship-owners since the vast majority of modern ocean-going vessels are able to run on it without undergoing costly retrofits. This option permits ship-owners to immediately bunker with marine gasoil and thus become compliant without any requirement to 'lay up' their vessels in dry dock, thus incurring opportunity costs. If this is the case, the price premium of marine gasoil versus residual fuel oil would likely be passed onto consumers in the form of higher freight costs, leading to higher end-use prices. Increased fuel supplies from new and upgraded refineries in the Middle East, the United States and Russia are already flowing to market. In the latter, pending changes to fuel export duties scheduled for 1 January 2015, are expected to curb Russian fuel oil exports, but in turn raise middle distillate supplies as refineries complete upgrading projects.

Whether marine gasoil would be available in sufficient quantities is questionable, however, and will depend on several factors, including production capacity (driven by refinery upgrades and yield changes), adjustments in refining feedstock quality, and competing demands from other sectors. Reduced availability would limit the scope for a mass replacement of fuel oil bunkers with marine diesel.

Box 1.3 The changing fuel requirement of the global shipping industry (continued)

Also depending upon the degree to which non-sulphur emissions are tightened in the future, switching to marine gasoil may not be sufficient to meet future environmental demands on bunker fuels. In the short-term, at least, relative gasoil shortfalls may put additional pressure on prices, raising the incentives on the refining industry to produce diesel while adding to the pressure on consumers to switch to more efficient engines. Therefore, upon the introduction of the 2015 MARPOL legislation, gasoil supply could rapidly tighten. Scrubber technology offers the possibility of meeting tighter emission standards while still burning heavier fuels. A downside of scrubbers is that the technology is still relatively expensive and often, at this point still, plagued with problems. Such teething-problems are, of course, common with any new technology and likely to be ironed-out eventually through time. Prices for scrubbers as well are generally expected to come down, particularly by 2025, and as the relative prices of marine diesel rises then so will the incentive to adopt such alternative technologies such as scrubbers. However, when considering scrubber adoption, it is not only the fixed costs of installation that have an impact. The retro-fitting of a scrubber to an existing vessel can involve taking the particular vessel out of service for up to six weeks in a dry dock, and then another few weeks at sea, adding opportunity costs to fixed costs. Few ship owners with vessels operating in ECAs appear to have opted for this option so far. As of September 2013, the Exhaust Gas Cleaning Systems Association, the body which represents the companies manufacturing scrubbers, reported that only 62 vessels (mostly ferries and cruise ships) had been declared as retro-fitted with scrubber technology to comply with the MARPOL regulations. Scrubbers also take up precious cargo space on a vessel and thus cut into revenues. This gives shippers a clear incentive to delay installing scrubbers as long as possible so as to avoid incurring unnecessary costs.

Like scrubbers, LNG provides an attractive long-term option, but at present ships retrofitted with LNG boilers and storage capacity (though not newly built LNG-powered vessels) remain far from cost-competitive and LNG faces many hurdles if it will become the bunker fuel of choice in the future. Refuelling facilities are so far only being provided at the largest terminals, or individual ferry docking points specifically designed for LNG. The necessary infrastructure is unlikely to be built until a mass-shift is made over to LNG and more clarity on marine fuel policy and implementation timelines facilitates necessary investments, a classic chicken-and-egg problem. At present LNG only provides an option on newbuilds, as the retrofit costs at present reportedly deem this option untenable.

Another important hurdle to the adoption of LNG concerns the extra cost of transporting LNG to smaller bunkering centres. For example, in order for many bunkering ports on the Baltic and Mediterranean to receive supplies, specific infrastructure such as pipelines or LNG barges has to be built. Therefore, bunkering costs may be higher than at a port such as Rotterdam which has direct access to gas pipelines.

The final hurdle concerns the lack of regulations for LNG bunkering. This may deter investment, especially from cruise ships and oil tankers, until the policy visibility improves. Notably, there are safety issues for transporting cargoes with a low flash point, such as gasoline, point by LNG. Few ship-owners wish to make an investment decision to equip a tanker with an LNG powered propulsion system to see it outlawed by the time the vessel is delivered. However, it should be noted that a number of administrations, notably in the European Union and North America, are working to develop safety and environmental standards for LNG bunkering.

These hurdles notwithstanding, LNG bunkering is starting to expand. Current information suggests that it is favoured by ship-owners whose vessels are plying their trade on fixed routes. Passenger ferry companies have been early adopters where they have access to LNG bunkering at both ends of their routes. Although this *Report* considers that the penetration of LNG into bunkering markets will not occur on a large scale within our forecast period, LNG warrants extensive discussion here since many of the final investment decisions which will influence the future of LNG bunkering such as vessel ordering and storage tank construction will be taken before end-2019.

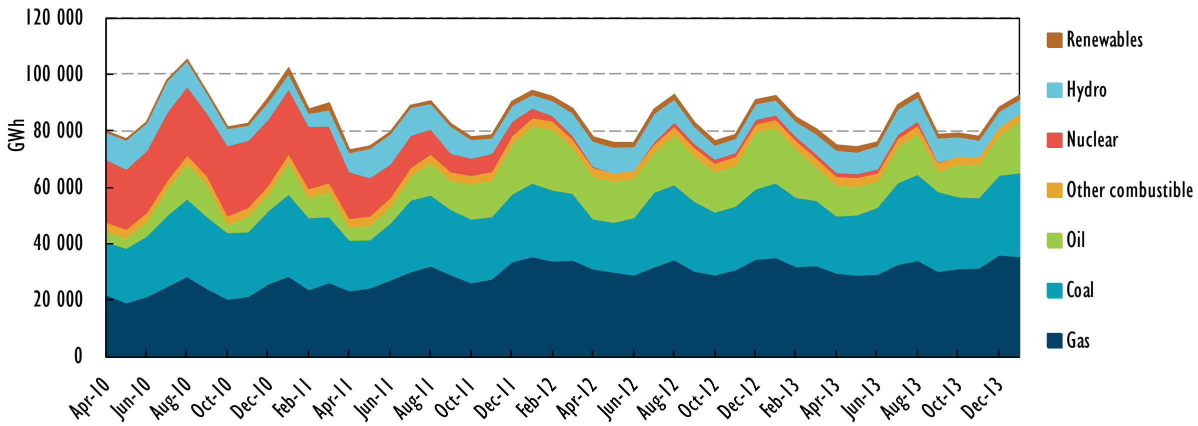
In the EIA's work, this equates to a wide gap between LNG and diesel prices, even after accounting for natural gas liquefaction costs that exceed refining costs. In the EIA's reference case, intensively used class one railroads, the net present value (i.e. the discounted value of future returns, taking into account interest rates) of future fuel savings "for an LNG locomotive compared to a diesel counterpart is well above the roughly USD 1 million higher cost of the LNG locomotive and tender." High initial investment costs, technological challenges, infrastructural constraints on LNG, uncertainty over future interest rates and the relative costs of oil and gas have delayed any major investments at this point, beyond talk of 'a potential switch in the future'. Hence it is only over the longer-term that any mass switching of rail-propulsion looks likely, i.e. until after our 2019 forecasting horizon. The potential for rail-switching must, however, be considered a wildcard to the forecast through its latter stages.

The global shipping industry, which includes international marine bunkers and domestic navigation, uses roughly 5.3% of total global oil demand. Historically residual fuel oil has dominated this sector, but increasingly gasoil is forecast as taking market share as tighter environmental standards demand such a move (see "The changing fuel requirements of the global shipping industry"). Roughly 0.3 mb/d of additional oil demand is likely to be added, 2013-19, equivalent to a compound per annum expansion of 1.2%. Non-OECD markets will see more rapid gains than OECD, consequential on the additional economic growth and in-turn trade flows that are likely in the markets. Movements to cleaner natural gas, particularly in the long term and increasingly on short regular trips such as ferries, are likely to dampen the potential momentum of oil product demand in shipping.

Power generation sector

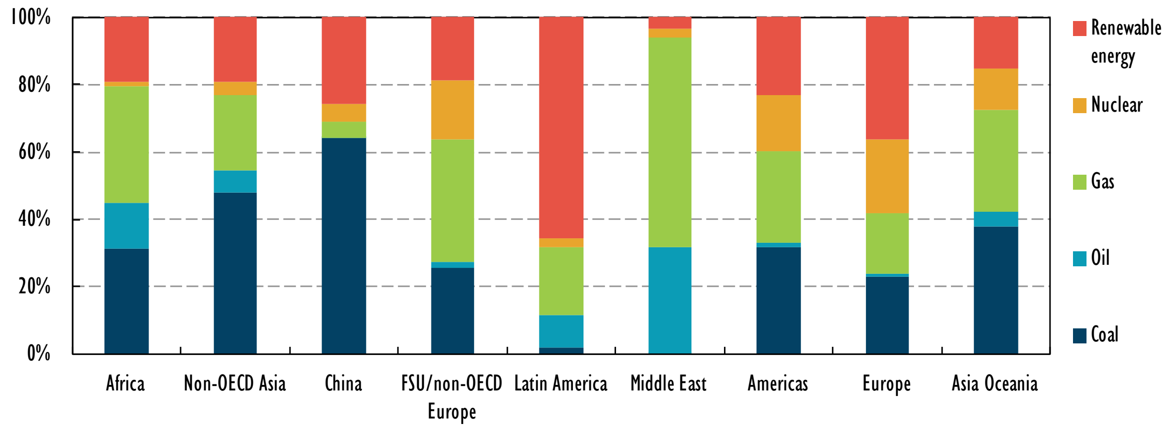
The global electricity sector accounted for roughly 5.8% of total oil product demand in 2011. The ratio of oil used in power generation has been on a steady decline for some time now, but saw a temporary reprieve since Japan was forced to shut its nuclear-power capacity from mid-2011, a momentum that started to reverse again from the middle of 2013 and is forecast to continue to back out through the forecast (see "Asia Oceania"). With the notable exception of the Middle East, 2013-19, the power sector's share of the global oil market is likely to fall, as using oil for power generation is often uneconomical.

Figure 1.15 Sources of power supply in Japan, April 2010 to December 2013



Due to its higher relative market cost, oil is only really used extensively for generating electricity where large price subsidies are provided, which typically occurs in big oil-producing countries, or as an emergency fuel. Diesel oil is also used increasingly for back-up power generators in emerging or newly industrialised economies where grid electricity is insufficient or unreliable. Chronic blackouts and brownouts have led to increased imports of back-up generators, and increased associated demand for diesel fuel, in countries ranging from China and Pakistan to Nigeria and Venezuela. Diesel demand for such a purpose can be unpredictable, however, linked as it is to unforeseen power outages.

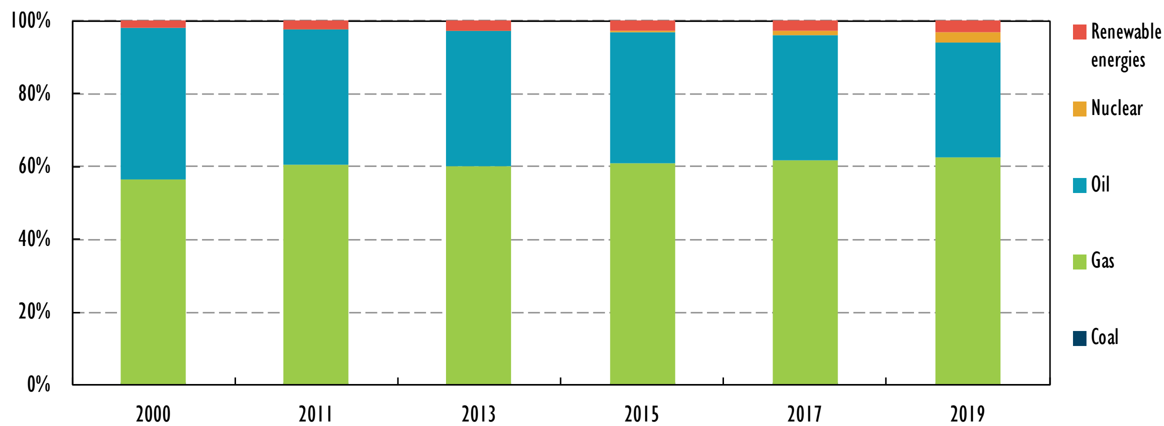
Figure 1.16 Power generation mix by region, 2019



Other than as a temporary replacement source of electricity generation, the power-sector is likely to play a declining role in oil demand, the Middle East being the most notable exception. As alluded to in Figure 1.10, Middle Eastern power-sector oil demand will rise steadily through to 2019, escalating from around 1.9 mb/d in 2012 up towards 2.4 mb/d in 2019. The share of total Middle Eastern demand used in the power sector remained remarkably stable throughout, at roughly one in every four barrels delivered.

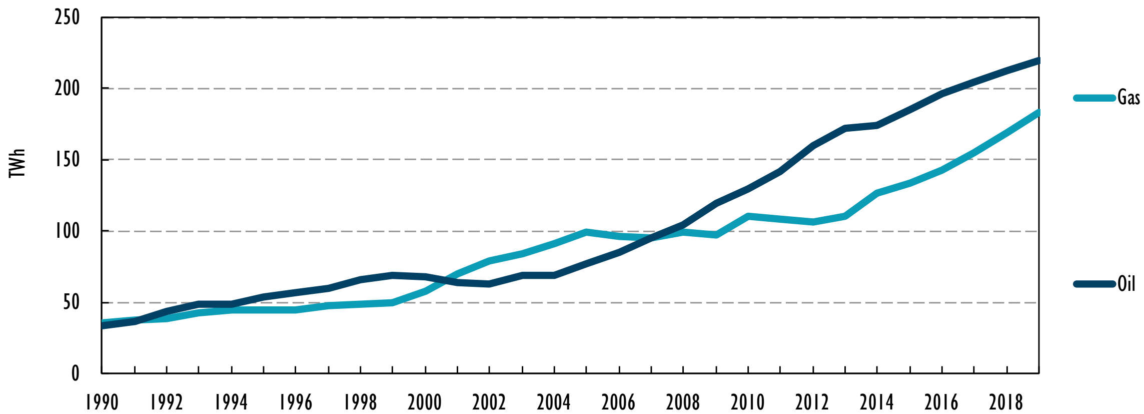
Conscious efforts to reduce this oil-ratio will continue, through to 2019, albeit to little avail as Middle Eastern governments realise that directly subsidising oil products to the power sector equates to lost oil revenues elsewhere. Investments into alternatives, such as solar and gas, are there but at an insufficient pace to keep up with the additional requirements put upon it by the rapidly expanding population base. Any changes in investment climate offer the potential to alter this balance, potentially dampening the power-sector oil need, or vice-versa.

Figure 1.17 Middle East power generation mix, 2000-19



In Iraq, for example, negotiations commenced in 1Q14 for four independent power projects, with a combined additional capacity of roughly 6 000 megawatts (MW). The arrangement is split into three stages, firstly to develop three new 1 000 MW gas-fired power plants; secondly, to convert them to 1 500 MW combined-cycle facilities; and thirdly, to establish a fourth 1 400 MW steam-turbine plant. Plans are occurring for a further four independent power projects at a later date. The Iraqi Electricity Ministry intends for the country to have 31 685 MW of electricity capacity by 2020, versus 2013 capacity of 11 025 MW. Under the terms of the plans, purely gas-powered plants will occupy 30.2% of the total Iraqi capacity, thermal 32.1%, combined-cycle 17.8%, renewables 1.3%, leaving the rest to independent power projects.

Figure 1.18 Generation by oil and gas-fired plants in Saudi Arabia



Even historically big power sector oil consuming nations, such as **Saudi Arabia**, are likely to make a concerted effort to reduce their dependency on oil (see "Saudi Arabian oil demand has been rising fast but may begin to slow"). For example, Saudi Arabia is planning on generating 23 900 MW of electricity from renewable energy by 2020 (rising to 54 000 MW by 2032). The forecast assumes a gentle deceleration in the Saudi Arabian usage, consequential on efficiency gains and efforts to reduce the oil dependence in the power sector. The government has announced plans for 23 900 MW of electricity from renewable energy, by 2020. The policy encompasses an installed renewable capacity of 5.1 gigawatts (GW), rising to 23.9 GW by 2020. Past the time frame of this *Report*, the target for 2032 is 54 GW, with solar accounting for 41 GW.

In Africa, **Egypt** is reportedly considering the construction of a nuclear power plant in an effort to utilise its apparently rich uranium reserves. Efforts to build four gigawatts of nuclear capacity, by 2025, are reportedly under way, with Russian co-partners being considered. If such plans go ahead their construction would be medium-term supportive of oil product demand, but long-term negative, as power station demand switches over to nuclear. Short-term support for Egyptian power-sector oil demand comes from reports that the Arab Fund for Economic and Social Development is loaning USD 195 million to the al-Wadiya oil-powered power plant. This along with further loans, from the World Bank and OPEC Fund for International Development, should help to address the Ministry's of Petroleum's request for funds to help cover imports of fuel oil and diesel to cover summer gas shortages.

The **Moroccan** government has awarded multiple contracts for the construction of additional coal and solar power projects. Already starting from a fairly low base in 2011, roughly equivalent to one-quarter of total electricity use, the latest construction plans will see the North African country increasingly diversify away from oil.

Residential sector

Residential oil demand accounted for roughly 5.7% of total global oil deliveries in 2011, a ratio that is likely to ease back further through the forecast due to further efficiency gains in the residential sector and continued product switching. Of the estimated 5.0 mb/d of oil products that were consumed globally by the residential sector in 2011, roughly half were LPG, a third gasoil/diesel and the remainder kerosene.

Ongoing efficiency gains are likely to lead the residential sector's global market share down towards 5% by 2019, with the turnover cycle for residential equipment/appliances relatively short and subject to legislative measures that force greater efficiency. These pressures carry a particular weight in the economies of the OECD, hence the rapid pace of decline envisaged there. Non-OECD residential oil-use will likely continue to edge higher, through 2019 albeit not at a pace sufficient to offset the declines in the OECD. Africa, for example, will continue to support relatively strong gains in LPG demand as it continues to gain market share as a cooking fuel from biomass, charcoal and animal waste.

Petrochemical sector

Accounting for over 10% of total global oil product demand, the petrochemical sector consumes large portions of both naphtha and LPG (which includes ethane in our definition). As a result of the close correlation that exists between petrochemical demand and industrial activity, petrochemical deliveries are forecast to outpace the overall demand metric through 2019. The ratio of petrochemical demand to the overall deliveries will accordingly rise, edging up to around one in every eight barrels consumed by 2019. The relative global weighting of LPG versus naphtha will increasingly shift towards LPG as the forecast progresses, as the increased availability of LPG in the United States has impacted relative prices.

The United States, Middle East and China will provide the majority of the upside support for petrochemical oil use, 2013-19 (see "An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth"), as a varied mix of relative cost advantages furnish great profit margins in these regions. Absolute declines in other regions, such as OECD Europe, cloud the forecast.

Box 1.4 An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth

Although oil is generally thought of as an energy source, in fact it is also largely used for non-energy purposes such as petrochemical production. This non-energy use of oil is indeed rapidly increasing and will continue to do so in the next five years, partly in response to changes in the quality of oil production, i.e. rising supply of light tight oil from non-conventional North American plays and associated liquids produced as a co-product of natural gas extraction. Following work undertaken in conjunction with Argus DeWitt by 2019, the petrochemical industry is forecast to account for roughly an eighth of the demand barrel, up from a tenth in 2013. Not surprisingly, the petrochemical and refining industries are increasingly integrated, both in terms of their physical facilities and as a vertically integrated business model. Given the complexity and fragmentation of the petrochemical industry, however, understanding the implications of this growing non-energy use for oil can be a challenge.

Most, but not all, of the forecast growth in both LPG and naphtha demand stems from changes in petrochemical use. The LPG that we are referring to here comprises of propane, butane and ethane. LPG, however, is also heavily used for residential purposes in fast-growing emerging and newly industrialising economies, ranging from Africa to India, as well as for power generation in some markets (Japan) and agricultural purposes such as crop drying in North America, among other uses. Previously naphtha was the most widely used liquid feedstock in the petrochemical industry, but the product mix has evolved in recent years as a consequence of rising LPG production, particularly in the OECD Americas.

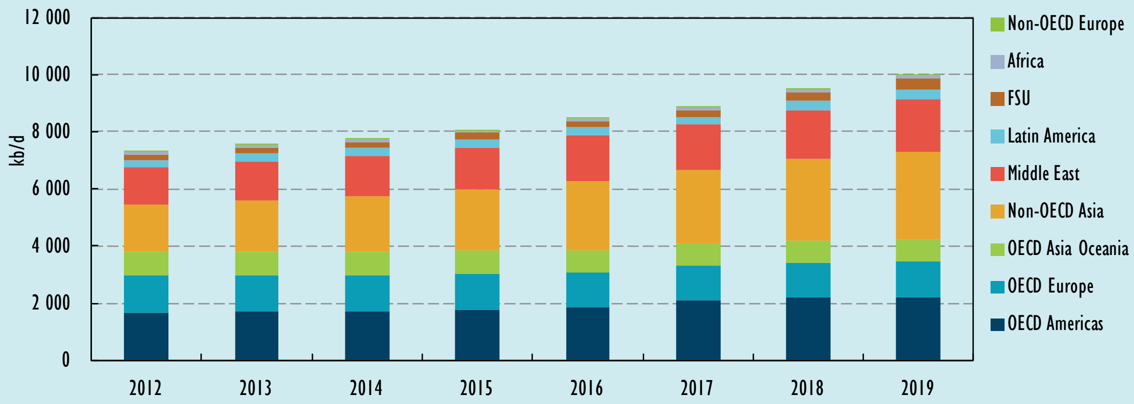
Box 1.4 An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth (continued)

Petrochemicals can be broken down into two main groups: olefins and aromatics. Olefins, or alkenes, include propylene and ethylene, and are traditionally produced via steam cracking of a light hydrocarbon liquid, such as LPG or naphtha. The choice of fuel largely depends upon availability and relative prices at the time of making the respective investment/production decision. Olefins are the main building blocks used in the manufacture of polyethylene, polyester and a number of other important petrochemical products. They also play a key role in the packaging, construction, textile, electronic and transportation industries.

Aromatics include benzene, toluene and xylene (BTX) isomers, and are traditionally derived by either steam cracking naphtha or by the catalytic reforming of naphtha in an oil refinery. Although naphtha has traditionally been used to produce aromatics, the technology now exists for either LPG or naphtha to be used. Aromatics are important because they are used in the production of various essential petrochemical products, such as polystyrene, nylon, polyurethane foams, polyester, styrene and phenol.

Given the flexibility of the petrochemical industry in its feedstock use, forecasting petrochemical demand for oil is an exercise doubly fraught with uncertainty, as it involves both projecting the overall level of activity in this specific industry but also about making individual assumptions about which feedstock it will favour. Stripping the industry back to the bone, the main driver of overall petrochemical demand and hence activity is macroeconomic growth. We use the projections of the IMF's *World Economic Outlook* (IMF *WEO*) released in April 2014 as our basic assumptions in this area for the forecast period. Looking at the olefin balance, the projected choice of feedstock in the industry is determined on a crack-by-cracker basis. We assume that producing one tonne of ethylene requires either 2.4 tonnes of butane, 2.3 tonnes of propane, 1.2 tonnes of ethane or 3.2 tonnes of naphtha. The choice of feedstock is weighted against the relative cost of each individual feedstock, at each cracker, with respect to the cracker's potential operating rate. Other than oil products, both coal and methanol are also potentially used in the petrochemical process and hence have to be factored into the global petrochemical balance, adding a layer of risk to the forecast as the relative price of these competing fuels can swing widely, thus affecting potential oil requirements.

Figure 1.19 Ethylene capacity



Source: Argus DeWitt

Forecasts of petrochemical capacity can be made with relative confidence through 2017, as most plans to add capacity during this period are relatively well known. Looking further forward, i.e. 2018-19, requires a more complex degree of assessment. Post-2017 forecasts of petrochemical capacity are much more heavily subject to political and macroeconomic change, hence the important from here of the economic forecasts of the IMF's *WEO April 2014,* which we couple with projections of the relative availability of the various petrochemical feedstocks.

Box 1.4 An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth (continued)

Steam cracker capacity is forecast to surge by approximately 2.6 mb/d or 36% to 9.9 mb/d of ethylene by 2019, from an installed capacity of 7.3 mb/d of ethylene in 2012. Most of these incremental additions are foreseen in the resource-rich OECD Americas and Middle East. Robust gains are also forecast in China and other non-OECD Asia, underpinned by relatively cheap labour and the rapid expansion of Asian demand for petrochemicals. Assuming global operating rates in the mid-80% range, global ethylene production is projected to soar by around 2 mb/d or 32% to 8.2 mb/d in 2019 from 2012 levels.

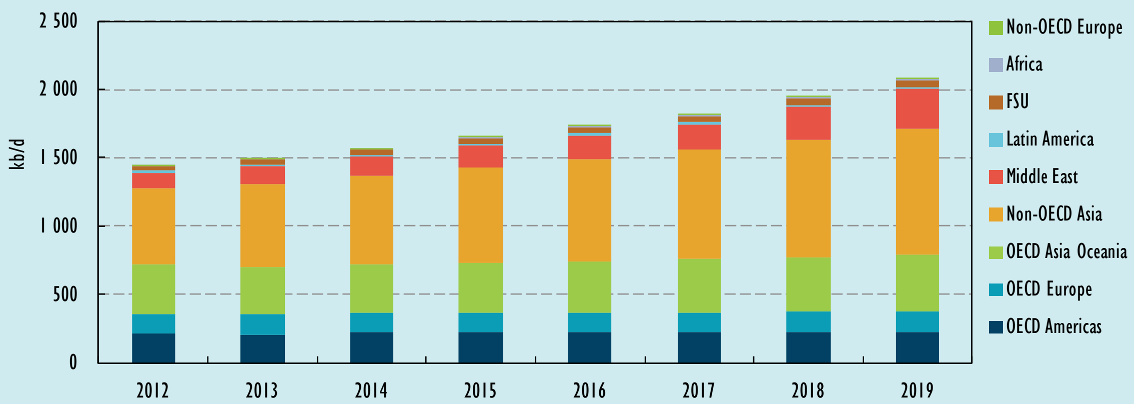
Most incremental OECD American ethylene capacity will use relatively low-cost LPG (which includes ethane) as its feedstock of choice, leveraging the surge in local LPG supply as a consequence of the US shale revolution. In contrast, demand for naphtha in OECD Americas is expected to contract.

Ethane is also forecast to remain the dominant olefin feedstock in the Middle East, underpinning a robust Middle Eastern LPG demand forecast. But Middle Eastern demand for naphtha is also expected to rise, albeit to a lesser degree than that forecast for LPG, as a number of mixed-feed crackers are planned for Kuwait, Qatar and Oman, while notable capacity expansions are also assumed for United Arab Emirates and Saudi Arabia. Developments in Iran, meanwhile, are limited to the second phase of the Kavian cracker in 2015.

With a number of rationalisations assumed in the respective petrochemical industries of OECD Europe and OECD Asia Oceania, 2013-19, the global petrochemical demand forecast will not universally rise. Relatively high-cost naphtha crackers in these regions look amongst the vulnerable facilities to closure. Additionally in Europe, consequential on changes in the relative availability of products in OECD America, the petrochemical feedstock mix will increasingly shift towards LPG at the expense of naphtha, thanks to an influx of relatively more cost-competitive imported LPG.

Propane, a key component in our amalgamated LPG number, is used extensively in propane dehydrogenation (PDH) units. These essentially make propylene, a key petrochemical product widely used in the packaging, tobacco and pharmaceutical industries. Global PDH capacity is forecast to triple through the forecast, to 0.6 mb/d by 2019, with close to one-half of these gains attributable to China and one-third the OECD Americas.

Figure 1.20 Crude used in production of aromatics



Source: Argus DeWitt

The aromatics balance, meanwhile, is dependent upon known capacity expansions through 2017 and beyond that, as with the other petrochemical forecasts the assumed macroeconomic projections (once again based upon IMF's *WEO April 2014* GDP projections). Detailed aromatics demand projections vary greatly by product (i.e. the BTX isomers), with the strongest gains forecast for mixed xylenes (which are forecast to rise by 6% per annum through the forecast), used in the production of plastic bottles and a number of industrial applications.

Box 1.4 An industry on the move: The rise of the petrochemical sector as a leading driver of oil demand growth (continued)

With total aromatics production forecast to expand by around two-fifths globally over the seven years through 2019, the incremental volumes of naphtha that will be required to support such production estimates will also surge, to 2.1 mb/d in 2019, a compound per annum growth trend of approximately 5.4%. The Middle East, China and the rest of non-OECD Asia will underpin this growth in naphtha demand for aromatics manufacturing, respectively rising by an average of around 15.0%, 8.0% and 6.8% per annum, 2012-19. Strong gains are also foreseen in the former Soviet Union and Africa, albeit from a much lower base. Flatter trends are envisaged in OECD America and OECD Asia Oceania, with respective per annum gains of 1.1% and 1.8%, beneath their own GDP tracks. No growth is assumed in European aromatics.

In aggregate, incremental petrochemical activity is forecast to lift global oil demand by 2.7 mb/d from 2012 to 2019, including 1.3 mb/d of ethane, 0.8 mb/d of naphtha, 0.5 mb/d of propane and 0.1 mb/d of butane. Naphtha demand is forecast to surge to 7.1 mb/d by 2019. Growth will be both supply- and demand-driven: in large manufacturing-oriented and fast-growing markets of Asia, macroeconomic expansion will underpin growth, while in North America and the Middle East the availability of relatively low-cost feedstock will be the main driver. Strong demand from OECD Americas will dominate the ethane expansion, as forecasts of relatively abundant US LPG supply will provide petrochemical facilities with a strong competitive advantage in the form of relatively cheap ethane.

China dominates the projected naphtha and propane gains, 2013-19, with the Chinese petrochemical sector forecast as likely to thrive on account of still relatively low-labour costs and plentiful government support. Rapid gains are also then envisaged across the economies of the oil-rich Middle East, as the availability of low-cost feedstock continues to support their international competitiveness.

2. SUPPLY

Summary

- **Total global supply capacity is forecast to increase by a robust 9 mb/d to 105 mb/d by 2019** from 2013 levels, rising nearly 1.5 mb/d per year on average. This is in line with the rate of growth experienced in 2013 and closely shadows demand. US light tight oil (LTO) production continues to account for much of the growth (27% of the aggregate gain over the forecast period), while OPEC contributes a smaller portion, at 21%. By 2019, North America will account for 20% of global production capacity, up from 18% in 2013, while OPEC's share inches down to 42%, from 43%.

- **Supply of both natural gas liquids (NGLs) and field condensate is forecast to grow at an exceptionally fast clip in the next five years, increasing their share of total liquid supply.** NGL production capacity jumps up to 10.7 mb/d by 2019, from 9.1 mb/d in 2013, while that of field condensate surges to 7.1 mb/d from about 5.6 mb/d. Global oil supply thus is increasingly made up of non-crude liquids, some of which bypasses the downstream industry.

- **Non-OPEC oil supply is expected to grow by 6.2 mb/d to 60.9 mb/d in 2019 from 2013**, at an annual average of 1.0 mb/d. More than half of the non-OPEC growth comes from North American LTO and Canadian oil sands production, offsetting declines at mature fields elsewhere. US tight oil is forecast to reach 5.0 mb/d by 2019, up 2.5 mb/d from 2013 levels. Producers such as Argentina, Brazil, Mexico, and Kazakhstan contribute more toward the end of period.

- **OPEC crude capacity expansions are projected to post a net increase of 2.08 mb/d to 37.06 mb/d, with Iraq tipped to capture the lion's share of the growth.** Worsening political instability and security problems, however, continue to undermine expansion plans in most African member countries, including Nigeria, Algeria and Libya.

- **Global biofuel production is expected to grow to about 2.3 mb/d in 2019, up roughly 350 kb/d or 18% from 2013 levels**. Projected production in 2018 is more than 50 kb/d below the production levels projected in the *MTOMR 2013*. After a decade of fast growth, policy support is waning in OECD countries, notably the United States and the European Union, as well as in Brazil, but burgeoning in new non-OECD markets such as Southeast Asia.

Figure 2.1 World oil supply capacity growth

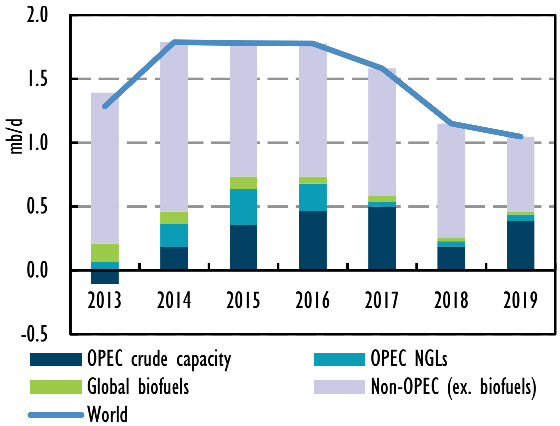
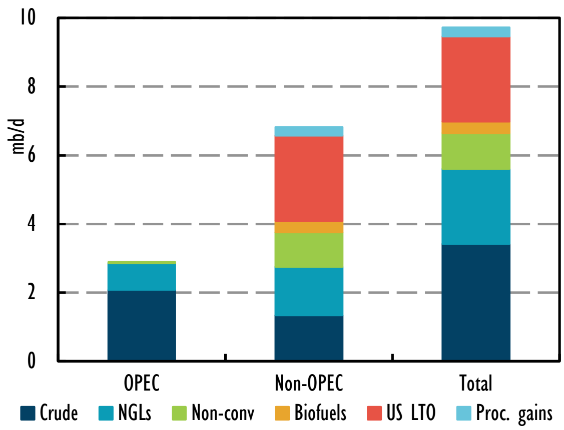


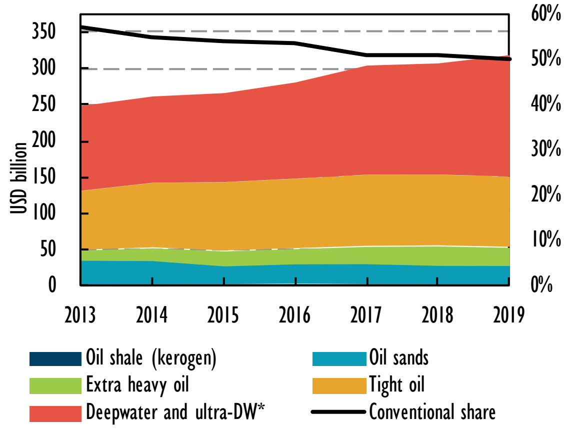
Figure 2.2 Global liquids growth 2013-19



Trends in global supply

Global supply capacity is forecast to rise by a strong 9 mb/d to 105 mb/d by 2019 from 2013 levels, up nearly 1.5 mb/d per year on average. As in recent years, non-OPEC growth will continue to outpace capacity growth in OPEC for the forecast period, in both percentage and absolute terms. US LTO production continues to account for much of the growth (27% of the aggregate gain over the forecast period), while OPEC crude producers contribute 21%.

Figure 2.3 World trends in Capex



* That which excludes the other four non-conventional categories.
Source: IEA analysis of Rystad Energy data.

OPEC capacity, including crude and non-crude liquids, is forecast to grow by 2.9 mb/d, to 44.2 mb/d, an increase of 6.9%; whereas non-OPEC production is expected to be augmented by 6.2 mb/d, to 60.9 mb/d, a rise of 11.4%. Hence, the share of total world productive capacity shifts away by a percentage point from OPEC (43% to 42%) to non-OPEC (57% to 58%) by the end of the forecast period.

Capital expenditure and production continue to shift away from conventional onshore and shallow-water production towards deepwater and unconventional supplies. The compound annual growth rate (CAGR) for capex (including exploration capex) 2013-19 on conventional onshore and shallow-water production is estimated to fall by -0.7%, whereas the comparable CAGRs for tight oil, deepwater, and extra-heavy oil capex are 2.5%, 5.3%, and 8.7%, respectively. Capex on conventional fields is set to decline from 57% of global spending in 2013 to just under 50% by 2019, further confirming the trend (see Figure 2.3). This is consistent with IEA projections of an increase in investment in the upstream oil sector, from USD 320 billion in 2000-13 to USD 510 billion in 2014-20 (2012 dollars), reflecting increasing costs and complexity (*World Energy Investment Outlook 2014*).

Political and security issues continue to have a significant impact on global supply, injecting a worrisome downside risk to the forecast. In OPEC, the outlook for Iraq, Libya, and Nigeria has been undermined by geopolitical and security concerns while Iran is still under the cloud of a comprehensive international sanctions regime. Indeed, OPEC's implied spare capacity averages 5.6 mb/d over the 2013-19 forecast but the group's effective capacity, i.e., readily available to the market is forecast at just 4.1 mb/d for the period (see "OPEC's effective spare capacity re-examined"). The impact on non-OPEC producers is less severe, though a still substantial 800 kb/d of combined lost capacity from Colombia, South Sudan, Syria and Yemen will affect 2014 production.

Indeed, the development of unconventional and difficult to reach resources continues apace, with international oil companies increasingly focussing their efforts on countries with lower political and security risks. While North America will remain the centre of non-conventional production, with its huge oil sands, tight oil, and deepwater Gulf of Mexico production, other regions will increasingly bring on new non-conventional capacity. In Brazil, which has long-since surpassed US deepwater output, ultra-deepwater production is on track to steadily increase while Argentina and Russia will produce shale oil production from formations in the Vaca Muerta and the Bazhenov, respectively.

Extra-heavy oil now makes up about 50% of Colombia's production, with that percentage set to increase. The rising importance of unconventional and difficult resources is also true in several OPEC countries, with deepwater Angola production set to increase, and Colombia's OPEC neighbours, Ecuador and Venezuela, set to make investments to expand extra-heavy output in Venezuela or develop new heavy oil fields in the Amazon rain forest in Ecuador. Many non-OECD countries have mature areas that also require enhanced oil recovery (EOR) techniques in order to maintain or increase output. Use of EOR on the large mature fields of Western Siberia in Russia in order to stem declines can be expected to expand, as will use on China's huge but mature Daqing and Changqing fields. In the Middle East, Oman has plans to expand EOR to other fields from the initial large Mukhaizna project. Even within OPEC, with considerable undeveloped conventional potential in some places, countries with mature fields, such as Bul Hanine in Qatar, will require very expensive EOR investments in order maintain production.

OPEC supply

OPEC production capacity growth is forecast to rise by 2.08 mb/d by 2019, to 37.06 mb/d, with Iraq expected to provide just over 60% of the growth. Worsening political instability and security problems in most African countries, however, continue to undermine expansion plans in Nigeria, Algeria and Libya. Overall, after Iraq, the United Arab Emirates and Angola are key contributors to the group's net increases, while Venezuela, Ecuador, Saudi Arabia, Iran and Qatar are expected to provide smaller increments. Kuwait and Algeria post the largest declines, with both countries underperforming due to chronic political inertia and poor investment climates.

Despite best efforts to factor in probable delays to otherwise set project plans, the projections are laden with downside risks given the seemingly deteriorating political situations in key producers Iraq, Libya and Nigeria. In addition, a high degree of uncertainty surrounds the outlook for sanctions-hit Iran. Collectively, Libya, Iran and Nigeria currently have approximately 3 mb/d of production capacity shut-in due to political turmoil and militant activity.

Figure 2.4 OPEC crude production capacity

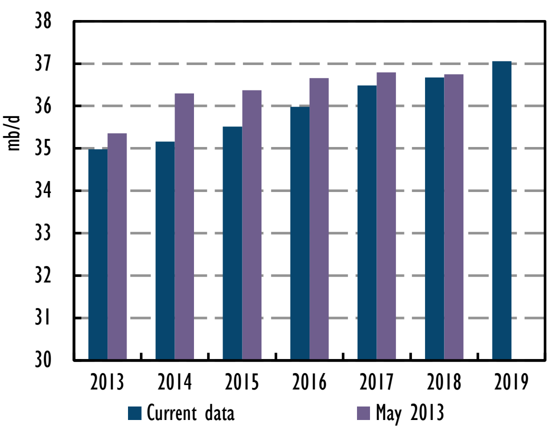
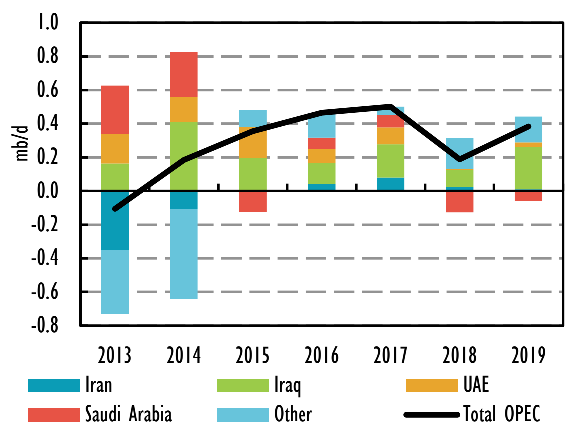


Figure 2.5 Change in OPEC production capacity



OPEC's increasingly volatile production landscape, however, is partly mitigated by its slowly eroding share of global supply growth. OPEC crude is now projected to provide about 23% of the net 9.13 mb/d increase in global oil supply capacity over the 2013-19 period compared with an average 30% to 35% over the previous five years. Non-OPEC supply, led by growing shale oil and gas production in North America, continues to capture the growing share of global supply. Indeed, the increased political risk in some key OPEC countries has increasingly led to international oil companies (IOCs) shifting their capital expenditures to the safety of non-OPEC countries. New project additions in OPEC countries of just 6.80 mb/d are down a steep 1.91 mb/d compared to the *MTOMR* 2013 (8.71 mb/d). The largest project increments are expected in 2014 and 2016, at 1.37 mb/d and 1.7 mb/d, respectively. The tail-end of the forecast, however, sees a dearth of projects due to delays in final investment decisions and local content requirements among other issues.

New capacity will be partially offset by annual field decline rates of around 850 kb/d per year, or 3.6% from the existing production base. *MTOMR* capacity estimates are based on a combination of new project start-ups, and assessed base load supply, net of mature field decline.

A number of OPEC producers appear to be at an acute stage in managing mature reserves with costly EOR projects and other advanced technology needed to maximise recovery rates at complex geological structures. Indeed, Qatar is about to embark on a redevelopment of its relatively small 45 kb/d Bul Hanine field, with state Qatar Petroleum prepared to pay USD 11 billion or around USD 244 000 per barrel for the project.

Table 2.1 Estimated sustainable crude production capacity (million barrels per day)

	2013	2014	2015	2016	2017	2018	2019	2013-19
Algeria	1.18	1.18	1.14	1.06	0.98	0.92	*0.89*	(0.29)
Angola	1.88	1.84	1.97	1.96	2.07	2.12	*2.24*	0.36
Ecuador	0.53	0.57	0.59	0.63	0.66	0.70	*0.70*	0.17
Iran	3.06	2.95	2.96	3.00	3.08	3.10	*3.11*	0.05
Iraq	3.26	3.67	3.87	3.99	4.19	4.29	*4.54*	1.28
Kuwait	2.88	2.86	2.82	2.79	2.70	2.58	*2.47*	(0.41)
Libya	1.42	1.04	1.16	1.20	1.31	1.38	*1.42*	0.01
Nigeria	2.31	2.21	2.21	2.32	2.21	2.29	*2.30*	(0.01)
Qatar	0.74	0.73	0.72	0.74	0.73	0.75	*0.77*	0.03
Saudi Arabia	12.26	12.53	12.40	12.47	12.54	12.41	*12.36*	0.10
UAE	2.87	3.02	3.20	3.29	3.39	3.39	*3.42*	0.55
Venezuela	2.60	2.56	2.49	2.54	2.64	2.74	*2.85*	0.25
OPEC	**34.98**	**35.16**	**35.52**	**35.98**	**36.48**	**36.67**	**37.06**	**2.08**

Box 2.1 OPEC's effective spare capacity re-examined

Political turmoil in OPEC countries has complicated the task of assessing the level of OPEC spare crude production capacity. Historically, the calculation of OPEC spare production capacity was in part meant to capture the amount of crude production capacity that the organisation's member countries chose to withhold from the market as a matter of policy, whether to support prices or to comply with production quotas. The idea was that in the event of a supply disruption or a spike in demand, the countries enjoyed the option of activating that production to balance the market. Whether or not to activate that production depended on a collective decision by OPEC or a sovereign decision by the member states. The amount of spare production capacity was largely a function of the difference between installed or nominal capacity and actual production levels. Over the years, however, some OPEC member country governments, for various reasons, have lost control over part of their production capacity. This is the case for example of Nigeria where sabotage forced the closure of onshore portions of the Niger Delta, or Iran, whose access to markets and investment has been curtailed by internal sanctions.

Box 2.1 OPEC's effective spare capacity re-examined (continued)

To account for this new reality, the IEA in 2005 introduced in the *Oil Market Report (OMR)* the concept of "effective" spare capacity, designed to capture the difference between nominal capacity and the fraction of that capacity actually available to the market. 'Effective' spare capacity was obtained by adjusting notional capacity for a rolling average of the observed difference between installed, i.e. implied, capacity and recent estimates of actual supplies available to the market.

The estimated 'effective' spare capacity as distinct from the nominal measure is aimed at providing a more realistic snapshot of current and future upstream supply flexibility. On paper, OPEC's implied spare capacity rises by 1.23 mb/d between 2013 to 2016 but plateaus at just above 6 mb/d for the remainder of the forecast period to 2019. In practice, however, it is clear that only a fraction of this nominal capacity is available to market. In the *MTOMR* 2013, the estimation of 'effective' spare capacity was discontinued, as supply disruptions in Libya due to that country's civil war of 2011 were thought to have been a one-off. Given that disruption risks in Libya and elsewhere have since become entrenched, we have returned to assessing this data for the medium term. In view of the recent developments, we have also cut the reference period for calculating the rolling average used as adjustment factor to assess "effective" spare capacity to four quarters, from eight quarters previously. This has effectively increased estimated ineffective spare capacity to 1.5 mb/d, from 1 mb/d earlier. According to this method, OPEC effective spare capacity is forecast to ramp up to 4.55 mb/d in 2019, from 3.06 mb/d in 2013.

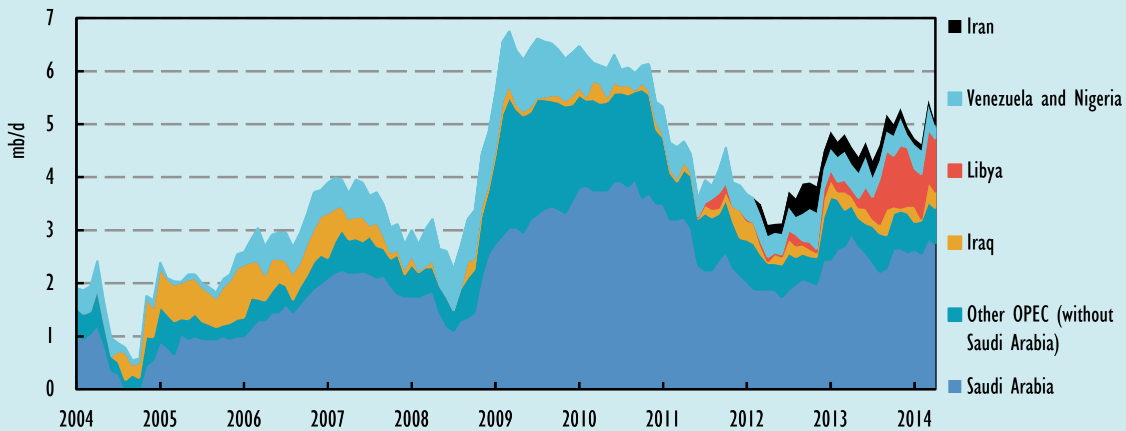
Table 2.2 OPEC spare production capacity outlook 2013-19 (million barrels per day)

	2013	2014	2015	2016	2017	2018	2019
OPEC Crude Capacity	34.98	35.16	35.52	35.98	36.48	36.67	37.06
Call on OPEC Crude + Stock Ch.	30.42	30.14	30.14	30.20	30.39	30.61	31.00
Implied OPEC Spare Capacity*	4.56	5.02	5.38	5.79	6.10	6.06	6.05
Effective OPEC Spare Capacity**	3.06	3.52	3.88	4.29	4.60	4.56	4.55
Changes since May 2013 MTOMR							
OPEC Crude Capacity	-0.38	-1.14	-0.85	-0.68	-0.31	-0.08	
Call on OPEC Crude + Stock Ch.	0.83	0.88	0.95	0.66	0.40	0.24	
Implied OPEC Spare Capacity*	-1.21	-2.02	-1.80	-1.34	-0.71	-0.32	

* OPEC capacity minus "call on OPEC + stock Ch".

** Historically effective OPEC spare capacity averages 1.5 mb/d below notional spare capacity.

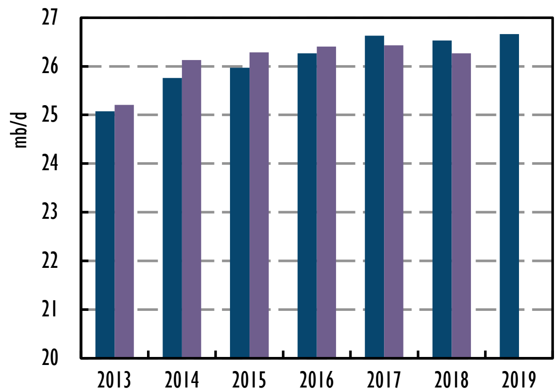
Figure 2.6 OPEC spare capacity



Capacity growth centered in the Middle East

OPEC's Middle East producers are set to provide 75% of the group's capacity growth over the forecast period. With the exception of Saudi Arabia, however, all Middle East producers have suffered some delays to project timelines as both above and below ground issues slow project developments. Mature fields are increasingly costly and technically challenging to develop, especially in the United Arab Emirates, Kuwait and Qatar. Chronic political and security instability in Iraq, moreover, has injected a worrisome downside risk to the forecast (see Box 2.2 "Iraq production capacity growth wide of target"). Meanwhile, progress over Tehran's nuclear programme with the international community since end-2013 sparked renewed interest by IOCs in Iran in early 2014. The diplomatic negotiations, however, remain difficult and the initial optimism has now given way to caution as the current 20 July deadline to reach a permanent agreement nears.

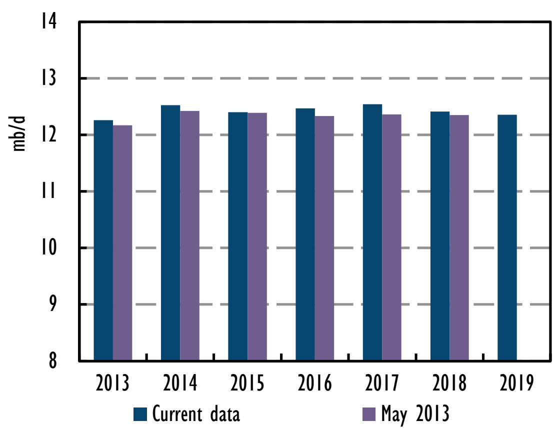
Figure 2.7 Middle East crude oil production capacity



Regional capacity is projected to increase by a net 1.59 mb/d to 26.66 mb/d, with Iraq providing 80% of the growth. Capacity increases from Saudi Arabia, Iran and Qatar largely remain flat over the period while Kuwait's is expected to edge lower.

Saudi Arabia is expected to deftly manage its production capacity at around its official 12.5 mb/d target. Saudi crude production capacity is forecast to rise just shy of a net 100 kb/d to 12.36 mb/d by 2019, with new field start-ups largely offsetting planned mothballing of mature production. Saudi Arabia has a current programme of work that is intended to maintain production capacity at around 12.5 mb/d rather than boost overall capacity. Indeed, in the state oil company's recently released annual report, Saudi Aramco has signalled a clear shift in the future to developing its non-associated and unconventional gas reserves.

Figure 2.8 Saudi crude production capacity



Total gross capacity additions amount to a steep 1.45 mb/d over the forecast period, with the giant offshore Manifa adding 900 kb/d by end-2014, followed by a 250 kb/d upgrade at the Shaybah field to 1 mb/d starting in 2016. Last, Saudi Aramco will bring on an additional 300 kb/d to the 1.2 mb/d Khurais field in early 2017. The new capacity will help offset natural decline rates but also enable Saudi Aramco to reduce capacity at workhorse fields in North Ghawar. At the same time, resting the reservoirs will allow Saudi Aramco to introduce new technology that will ultimately improve extraction and recovery rates.

The first 500 kb/d tranche of the 900 kb/d Manifa field project, located offshore in shallow waters, started production in April 2013. The final 400 kb/d is expected to be online by the end of 2014.

Output of heavy Manifa crude is earmarked exclusively for processing at the country's three new refinery projects, which are designed in part to export products. The first tranche is already supplying Saudi Aramco's 400 kb/d Jubail plant, a joint venture with Total, which was commissioned in late 2013 and is expected to reach full capacity mid-2014. A steady ramp-up in Manifa output is expected in 2H14 to supply the new 400 kb/d Yanbu refinery operated by Aramco Sinopec Refining Company (YASREF) on the Red Sea, a joint venture with Sinopec, which is expected to reach full capacity by 3Q14. Some crude oil from the Manifa field is also eventually expected to be processed at the 400 kb/d Jizan refinery in the southwest of the country, which has a current start-up date of 2017.

In addition to its current slate of projects, Saudi Aramco could notionally increase capacity beyond this target if needed. Plans on the back burner include three fields with the potential to add a further 1.9 mb/d, and include an additional 900 kb/d of Arab Medium crude from the Zuluf field, 300 kb/d of Arab Extra Light from the Berri field and 700 kb/d of heavy crude from Safaniyah, the world's largest offshore oil field.

Iran's production capacity is projected to remain largely unchanged over the forecast period, up a small 50 kb/d to 3.11 mb/d. Iran previously saw a downgrade of 1 mb/d in the wake of far-reaching US and EU sanctions imposed on the country's oil, financial and insurance sectors in 2012, which is not fully captured in our current timeline. Iranian crude oil production has fallen from an average 3.7 mb/d in 2010 and just over 3.6 mb/d in 2011 to an average 2.68 mb/d in 2013.

This forecast does not include a judgement one way or another for the likely outcome of ongoing high-level talks over Iran's nuclear programme with the international community but rather estimates capacity based on the assumption that even with a permanent resolution to the conflict it would be post-2018 before any significant volume increases would materialise.

The talks between Tehran and the P5+1 – the five permanent members of the United Nation's Security Council plus Germany and the European Union – are currently scheduled to conclude 20 July 2014 but negotiations could be extended a further six months under the interim deal, the Joint Plan of Action (JPOA), agreed in November 2013 in Geneva. The JPOA allowed for a very limited easing of sanctions on Iran's oil and banking sectors but the comprehensive sanctions regime remains in effect pending a permanent settlement of the nuclear dispute. Reaching a final settlement that would place broad, verifiable limits on the scope of Iranian nuclear activities in exchange for a phased removal of sanctions is expected to be a protracted process, which in turn suggests any easing or lifting of sanctions would, at best, see only a modest growth in capacity by the end of the forecast period given the multitude of issues plaguing Iran's oil sector.

This year's *Report*, however, does forecast a significant upward revision to production capacity compared with 2013, in large part following the election of President Hassan Rouhani and the re-appointment of Bijan Namdar Zanganeh, oil minister under past President Mohammed Khatami, to his old post. Zanganeh had built a good working relationship with the international oil industry, when he was able to increase production despite the imposition of a first round of US sanctions. Since his reappointment by President Rouhani, he has restored a measure of professionalism in the country's approach to its sanction's hit oil and gas sector and restructured the sector to curb the role of the inexperienced Revolutionary Guards and their contracting companies, who had taken larger role in the oil sector over the past decade. Capacity is now projected to be some 730 kb/d higher than the 2.38 mb/d seen in last year's forecast on expectations of improved operations at the oil ministry and state National Iranian Oil Company (NIOC).

Figure 2.9 Iran crude oil production capacity

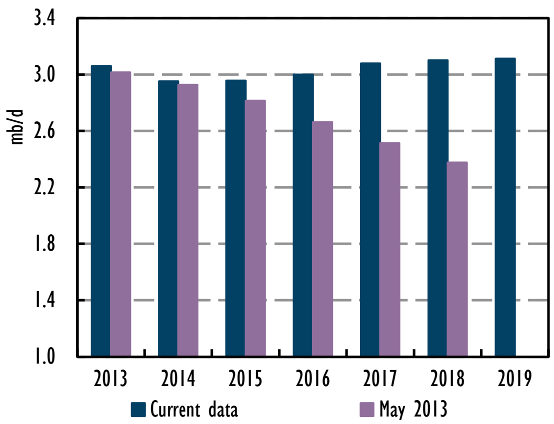
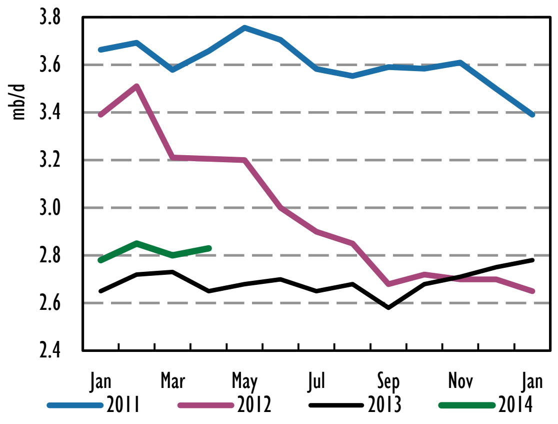


Figure 2.10 Iran crude oil production



That said, Oil Minister Zanganeh's plans to increase production capacity to a lofty 5.7 mb/d by 2018, contingent on a complete lifting of sanctions and rapidly attracting foreign investment, appear overambitious. Under the previous government, severely constrained financing and cash flow problems stemming from the sanctions regime sharply reduced NIOC's ability to even perform field maintenance work and infrastructure repairs, which has led to an acceleration in the decline rate of the country's mature fields. Information on Iran's oil fields is very limited given the lack of foreign participants in the sector but estimates for field decline rates range from 8% to 12% in recent years. Even before the latest sanctions were implemented, Iranian capacity was on a slow downward path given the drought of new field developments stemming from the unpopular buyback contracts as well as a lack of infill drilling and EOR projects. The new administration and oil ministry, however, have reportedly launched an extensive programme to improve field maintenance and recovery rates since the fourth quarter of 2013.

Iran's oil ministry is currently preparing a new upstream contract model to attract IOCs, with a list of projects expected to be announced in November 2014. The draft Iran Petroleum Contract (IPC) requires IOCs to shoulder all the upfront costs through to production. Once production starts, the IOCs must form a joint venture with NIOC or its affiliates, with the foreign partners receiving a percentage of production known as "cost petroleum." A separate fee may be offered for riskier fields. IOCs would receive payments on capital and operating costs in five to seven years after first production. The new IPC model is clearly an improvement on the unpopular buy-back contracts but a number of issues have emerged with the draft version that have made companies wary, including agreeing plateau targets and costly penalties for not meeting them.

The first projects expected to be on offer are for EOR at Iran's largest fields, Ahwaz, Marun, Gachsaran and Agha Jari. The capacity of the four fields combined reportedly had a peak of just over 2 mb/d but latest estimates put that figure closer to 600 kb/d in 2013. Roughly 50% of the country's production comes from fields that are more than 70 years old and in desperate need of enhanced recovery methods and rehabilitation with new technology. The country's production peaked in 1974 at just over 6 mb/d.

The latest round of talks over Iran's nuclear programme appear to have strengthened the oil ministry's resolve to pressure the few foreign companies operating in the country over inadequate progress at key projects. The country's only major foreign partners, China's state oil company CNPC and Sinopec, are under increasing pressure to fast-track stalled projects designed to increase capacity. Indeed, the oil ministry cancelled CNPC's contract for the massive 600 kb/d South Azadegan project in April 2014 reportedly due to a lack of commitment on the part of China's state oil company. CNPC signed the USD 2.5 billion contract three years ago and planned to development the project in two parts, with first Phase 1 schedule to bring on 320 kb/d by mid-2014 and Phase 2 a further 280 kb/d by 2017. To date only 7 of around 160 wells planned have been drilled.

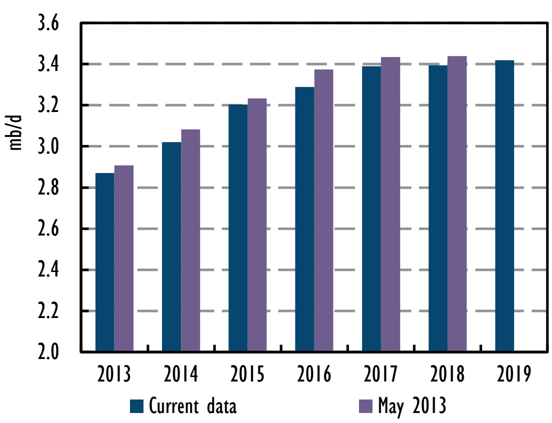
Adding to Iran's frustration, the Azadegan field shares a border with Iraq, where the field is known as Majnoon and production has now reached 200 kb/d. CNPC has also come under criticism for its slow progress with its North Azadegan contract but work is progressing faster at this sister project. Officially, phase 1 of the project is slated to start in mid-2015, but this is likely to be delayed until early 2016, with initial output tipped at 75 kb/d. The Chinese companies report that sanctions have caused chronic delays in bringing needed equipment and technology into the country, with payment issues also a major problem. Crucially, progress has also been slowed because all three fields require extensive de-mining, which has been made more difficult under sanctions.

China's Sinopec is also falling behind at the Yadavaran field, with only limited progress despite an initial planned 2012 start-up. Sinopec, along with a NIOC subsidiary, was awarded the contract for the 300 kb/d Yadavaran joint venture in 2007. Current production is estimated at just 25 kb/d versus plans to raise output to 85 kb/d in 2012. There is no timeline to increase output further, which could likely lead to a cancellation of Sinopec's contract.

The smaller 35 kb/d South Pars project has been pushed back to 2017 from earlier start dates of 1Q15 and an initial 2013 start.

The **United Arab Emirates** is on course to post a net increase of 550 kb/d, to an average 3.42 mb/d by 2019, just shy of the country's 3.5 mb/d target for the period. UAE offshore production capacity is forecast to increase by a gross 500 kb/d with the expansion of the Upper Zakum fields and start-up of the Umm Lulu, Nasr and Satah al Razboot (SARB) projects. The pace of growth, however, has been delayed by a shortage of rigs. Separately, expansion of Lower Zakum was expected to add around 100 kb/d bringing total field capacity to 425 kb/d in 2015 but the project has now been delayed until 2020.

Figure 2.11 UAE crude production capacity

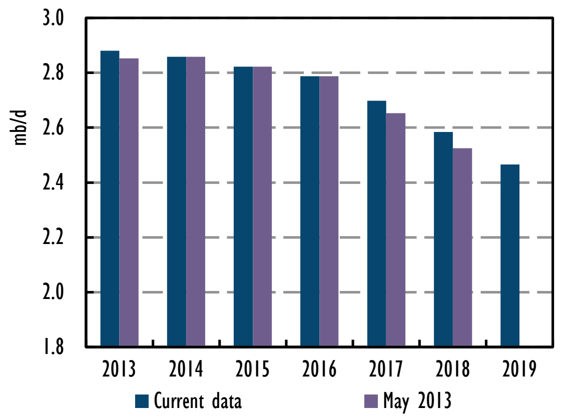


The Upper Zakum field is slated to rise by 250 kb/d to 750 kb/d but the start date has now been pushed back from 2015 until 2017. First oil from the 105 kb/d Umm Lulu is expected in July 2014, a year behind the original schedule. The start up of the smaller 65 kb/d Nasr field is now set for January 2015. The 100 kb/d SARB project is on track for an end 1Q15 inauguration.

Abu Dhabi's ongoing saga of renewal of its legacy concession contracts has led to project delays and under investment in its onshore fields. The onshore concessions expired in January 2014 and offshore concessions will in 2018. In January this year, the United Arab Emirates formally ended its 75-year old concession agreements with international oil companies, with state-owned Abu Dhabi National Oil Company (ADNOC) becoming the sole shareholder of its onshore operating subsidiary Adco. ADNOC had a 60% interest in Adco, with BP, ExxonMobil, Shell and Total holding 9.5% each and Partex 2%. ADNOC has invited 10 companies, including Rosneft, ENI, Statoil, South Korea's KNOC, Japan's Inpex, CNPC and all of its Adco partners minus Portugal's Partex. A final decision on the new concessions could come later this year or early 2015. Some former partners baulked about having to share proprietary technology with new foreign partners, which is required for the country's ageing and complex geology. The previous modest USD 1/bbl profit has been raised to USD 2.85/bbl, but this is still low by industry standards. Indeed, in a surprise move it appears Exxon Mobil has now walked away from the bidding, unwilling to share its advanced technology with lesser competitors, though it still has a major stake in the country with its Upper Zakum joint venture.

Given the near total absence of development projects on the books, **Kuwait's** production capacity looks set to decline by 415 kb/d to 2.47 mb/d by 2019. Indeed, latest official plans to boost Kuwaiti crude oil production capacity to 4 mb/d by 2020 appear unrealistic given that the country's governing body has yet to agree on even a limited opening of the upstream sector for more than 30 years. State-owned Kuwait Petroleum Corp (KPC) continues to push proposals for enhanced technical service agreements (ETSA) contracts in a bid to revive heavy oil and EOR projects. It has been 15 years since the first ETSAs were proposed and subsequently rejected by the contentious Parliament.

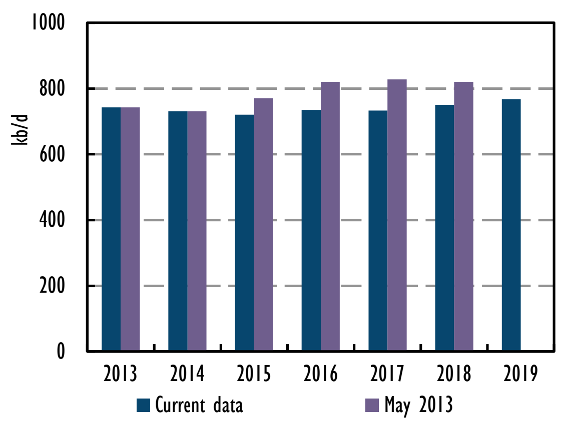
Figure 2.12 Kuwait crude production capacity



Plans to adopt ETSAs for the northern fields have failed to materialise year after year and now KPC says it will go it alone on developing the relatively meagre 60 kb/d heavy oil Ratqa field from the Lower Fars reservoir in the northern region on the border with Iraq. Indeed, the latest modest effort to develop Ratqa is in stark contrast to Iraq's massive development of the Rumaila field, which shares the same structure with Ratqa, and is producing over 1.2 mb/d. After many delays, KOC issued a new engineering, procurement and construction (EPC) tender for the USD 4.2 billion Ratqa Lower Fars project. Current planned capacity is less than 10% of the original 700 kb/d proposal by KOC and ExxonMobil in 2007. Start-up of Ratqa from the Lower Fars has been pencilled in for 2017 at 60 kb/d and KOC is hoping to increase capacity to 120 kb/d by 2020.

Qatar's crude oil production capacity is forecast to rise by around 30 kb/d to 770 kb/d by 2019 but some additional capacity is coming online at exceptionally steep costs. Current projects in the pipeline include redevelopment plans at the onshore Dukhan field and the offshore Bul Hanine. The larger Dukhan field is slated to increase capacity by 75 kb/d to 300 kb/d in 2015. Qatar Petroleum plans to double the 45 kb/d Bul Hanine field to 90 kb/d starting in 2016. Estimated costs at a staggering USD 11 billion or equal to around USD 244 000 per barrel, a fraction of the cost of some Saudi fields of around USD 16 000 per barrel costs and nearly double the now legendary

Figure 2.13 Qatar crude production capacity



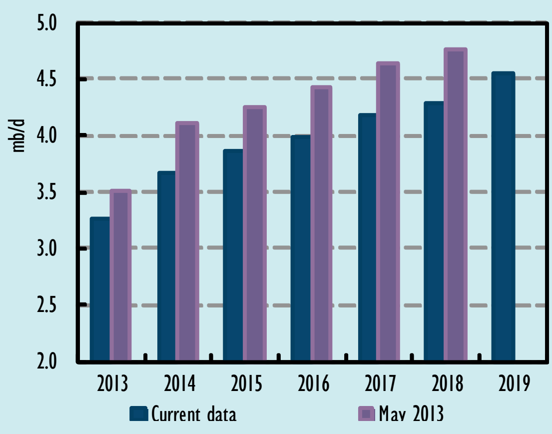
Kashagan project in Kazakhstan, which is pegged USD 120 000/bbl. Indeed, a significant part of the costs is the redevelopment of the ageing infrastructure and development of new offshore central processing facilities. While Qatar is the region's powerhouse in NGL production, the government has made maintaining crude oil production levels of around 800 kb/d a priority, despite the steep costs.

Maersk embarked on a two-year rehabilitation programme at the challenging al-Shaheen field in 2013, but the current programme is designed to maintain the field's 300 kb/d crude production capacity. Occidental is also undertaking a steep USD 3 billion, 100 well development at the 100 kb/d Idd al Shargi field, though the costly programme is aimed at merely maintaining current capacity levels. Qatar's development costs are relatively steep given the complex geology and as a result the reservoirs require partners that possess the most advanced technology available.

Box 2.2 Iraq production capacity growth at risk

A rapid escalation in violence in northern Iraq in June has underscored the fragile state of the country's security structure. Even before the latest attacks across a large swath of the country's northern and central region by the al Qaeda splinter group Islamic State for Iraq and Syria (ISIS), the outlook for Iraq's crude oil production capacity growth had already been downgraded in this *Report* amid security and institutional issues. Iraq crude oil production capacity growth has been reduced by 470 kb/d from the *MTOMR 2013*. Iraq production capacity is now forecast to increase by a conservative 1.28 mb/d to 4.54 mb/d by 2019 but still accounts for a significant 60% of OPEC's total increase for the 2013-19 period. That compares with Baghdad's latest preliminary plans of 8.5-9 mb/d by 2020. The latest wave of insurgency clearly weighs on the forecast; while the region currently affected by the strife accounts for a relatively small portion of Iraq's output, the situation at the time of writing was fluid.

Figure 2.14 Iraq crude production capacity



On 10 June, ISIS fighters took control of Mosul, Iraq's second largest city, and were moving to control other key areas of central and northern Iraq. Iraq's southern oil export facilities are currently the country's only export outlet after the closure of the Iraq-Turkey pipeline in early March due to violence in Anbar province, affecting about 250 kb/d of exports. The Kirkuk-Ceyhan pipeline now looks increasingly likely to remain closed indefinitely. Official data from the central government for 2013 shows total Iraqi crude production averaged 2.98 mb/d, with the north of Kirkuk averaging 650 kb/d and the south, where all the IOCs operate, at 2.33 mb/d. In addition, the Kurdistan Regional Government (KRG) reports crude production averaged 215 kb/d in 2013, bringing the country's total to 3.2 mb/d.

Prior to the latest uprising, Baghdad faced serious challenges in meeting its ambitious production targets. The lack of institutional capacity at the administrative continues to lead to delays to contract awards for infrastructure plans that anchor projects.

Indeed, upstream expansion plans for the key southern region of the country have also been thrown in disarray due to chronic problems at major export terminals. Export facilities in the south, however, managed to post impressive gains in early 2014 after years of delays but volumes may be capped until 2018 due to mismanagement of the coastal Fao storage project in Basrah. The Fao depot is a crucial way station for crude transiting from the oil fields to the export terminals at the Gulf.

Box 2.2 Iraq production capacity growth at risk (continued)

The more modest forecast belies the central government in Baghdad's already reduced capacity targets of around 8.4 mb/d for its giant fields by 2017-18, from initial projections of 12 mb/d when the upstream technical service contracts (TSCs) were first proposed in 2009. Finally paying heed to growing concerns about the unrealistic capacity targets agreed with foreign partners in 2009-10, Baghdad and the IOCs have entered into negotiations to change expectations. A final agreement has been reached with Eni to lower the production target for the Zubair field to 850 kb/d by 2020 versus 1.13 mb/d by 2017. Lukoil has also reduced its contractual terms for West Qurna 2 by 600 kb/d to 1.2 mb/d. BP and CNPC have in principle agreed to cut production target for the giant Rumaila field, to 2.1 mb/d from the original 2.8 mb/d by 2020. Negotiations are still taking place for West Qurna-1 and Majnoon. The contracts for the smaller fields are not expected to be changed.

Table 2.3 Iraq's main oil projects (in mb/d)

Project	Foreign partners	2014 Output Target	New 2020 Target	Plateau Original	Current Status
Rumaila*	BP, CNPC	1.39	2.1	2.85	Proposed
West Qurna-1**	ExxonMobil, Shell, CNPC, Pertamina	0.43	1.8	2.825	Preliminary
Majnoon*	Shell, Petronas	0.2	1.2	1.8	Proposed
West Qurna-2	Lukoil	0.2	1.2	1.8	Final
Zubair	ENI, Occidental, Kogas	0.39	0.85	1.25	Final
Ahdab	CNPC	0.135	0.2	0.2	--
Missan	CNOOC, TPAO	0.125	0.45	0.45	--
Halfaya	CNOOC, Total, Petronas	0.135	0.535	0.535	--
Gharraf	Petronas, Japex	0.05	0.23	0.23	--
Badrah	Gazpromneft, Kogas, Petronas, TPAO	0	0.17	0.17	--
Nasiriya	South Oil	0.04	0.3	0.3	--
Najmah	Sonangol	0	0.11	0.11	--
Qayara	Sonangol	0	0.12	0.12	--
Subtotal		**3.095**	**9.265**	**12.64**	
Kirkuk, NOC fields	North Oil Company	0.58	0.58		
Total federal capacity		**3.675**	**9.845**		

Baghdad made an exceptional push to increase production in the southern Basrah region in 1Q14 ahead of parliamentary elections in early April. Prime Minister Nouri al-Maliki garnered enough support to form a new a new government and serve a third term. Even prior to the June events, the Prime Minister had not been expected to succeed in forming a new functioning coalition government until early 2015. As a result, negotiations and finalisation of technical service contracts with IOCs are likely to be delayed further. Worse, challenges pulling together a new government may add further pressure to the fragile state of Iraqi political affairs. In the meantime the security situation in the country continues to worsen.

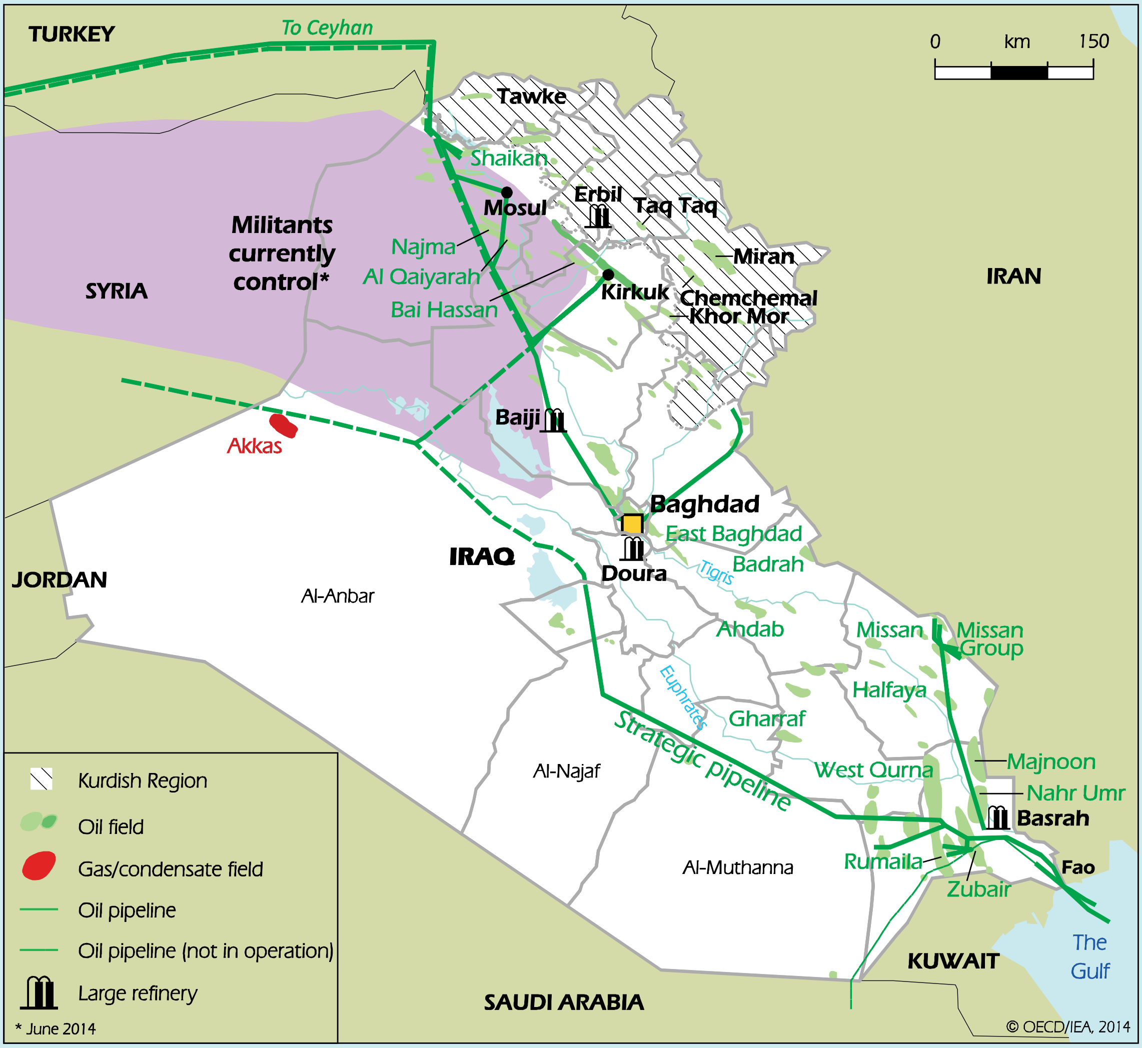
Against this fractious backdrop, foreign operators continue to grapple with growing security concerns. Angolan state oil company Sonangol exited its contracts for the Najmah and Qayara fields in Nineveh, which border the hostile Anbar province. Meanwhile, the backlog of bureaucratic approval for the multitude of contracts that must be signed off to move projects forward, such as visas for expatriate staff and customs documents for equipment, is around six to nine months.

The outlook for the southern Gulf region has been muddied by chronic delays to the USD 5 billion-plus Common Seawater Supply Project (CSSP), which underpins Iraq's massive upstream expansion programme. The CSSP is needed to provide treated seawater for the management of reservoir pressure at the Basrah region's developments, which is critical to supporting the planned EOR projects. The state South Oil Company (SOC) estimates that the fields need an average of 1.5 barrels of water to produce each barrel of oil.

Box 2.2 Iraq production capacity growth at risk (continued)

The CSSP was originally outsourced to ExxonMobil in 2010, but after the major pulled out of the project the contract was rebid and SOC awarded the management contract to US-based CH2M Hill in 2012. CH2M Hill is charged with preparing the pre-front end engineering and design (pre-FEED), environmental and safety assessment, the front end engineering and design (FEED) contract and the EPC contracts for the multitude of packages for the project. Two years on, the FEED contract has yet to be awarded. As a result, the CSSP is not expected to be operating until 2019 at the earliest.

Map 2.1 Iraq oil infrastructure



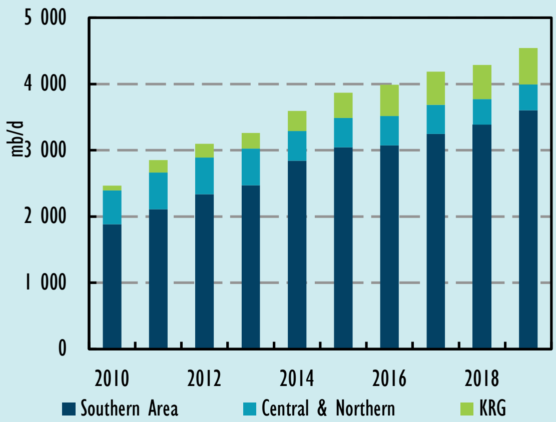
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

A long-awaited boost to southern crude oil exports was partially realised in March following the much-delayed expansion and more complete installation of the Single Point Moorings (SPM) that link production to the key onshore Fao terminal in the Gulf. But exports are up only around 300 kb/d compared with new nameplate capacity of 3.8 mb/d and much still needs to be completed to enable SOMO to increase exports beyond 3.5 mb/d, in particular new pumping stations and storage facilities.

Box 2.2 Iraq production capacity growth at risk (continued)

Indeed, the expansion of capacity at the Fao storage facility and offshore export infrastructure is likely to derail the ministry's projected production increases until at least 2018, experts warn. The State Company for Oil Projects (SCOP) has come under heavy criticism for the delays and management mayhem that have undermined the project. The Fao project was originally supposed to be finished by 2012, according to a 2007 Foster Wheeler feasibility study of the Iraqi Crude Oil Export Expansion Project. Seven years on, even the construction of storage tanks is years behind schedule, with SCOP delinquent in ordering equipment that require years of lead time before delivery. Plans call for at least 24 tanks, each one able to hold 365 000 barrels. To date, only four tanks are installed and technically operational.

Figure 2.15 Iraq crude oil production capacity



In the north of the country, ongoing attacks on oil infrastructure had already clouded the outlook prior to the latest escalation. The long-running dispute between Baghdad and Erbil over the political and regulatory status of the Kurdistan oil producing region led to the suspension of KRG exports through the Baghdad controlled Iraq-Turkey pipeline (ITP) and negotiations remain deadlocked. The KRG has attempted to export crude directly from the region via a parallel line to ITP to Ceyhan, but Baghdad countered by launching arbitration proceedings against the KRG, which is likely to further destabilise relations between them.

KRG production could theoretically reach 1 mb/d in five years but export constraints will temper growth, with operable capacity expected to rise from 240 kb/d in 2013 to 550 kb/d by 2019. A breakout in production is not expected until the legal issues are resolved. The conflict between Baghdad and the KRG over oil policy, payment issues and resource development has gone from bad to worse over the year, with only modest expectations for a solution in the medium term.

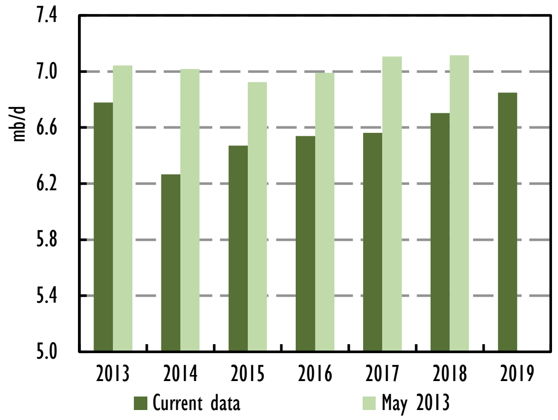
OPEC's African producers face myriad problems

Worsening political and security woes have dimmed the outlook for three out of four of OPEC's African members. OPEC's producers in the region post a marginal 70 kb/d increase in capacity over the forecast period, to 6.85 mb/d by 2019. Only Angola is on track to post significant growth by 2019. Just two years ago OPEC's African members were poised to post the largest regional increase in capacity, up by 2 mb/d to 8.02 mb/d by 2017.

Libya, Nigeria and Algeria are still reeling from increased security risks and political instability in the wake of the Arab Spring and rise of Islamists militants. Libya has posted a marked reversal of fortune since the *MTOMR 2013*, as a rekindling and escalation of violence between rebel groups and the newly-appointed Islamic government in Tripoli led to a sharp drop in production over the past 12 months. Meanwhile, the political wrangling over Nigeria's new Petroleum Industry Bill (PIB) has been put on the back burner as the country's leadership grapples with a serious Islamist insurgency in the northern part of the country. Algeria is still operating under the cloud of the deadly terrorist attack on In Amenas gas facility in early 2013 as well as bureaucratic inertia following the 2010 corruption scandals.

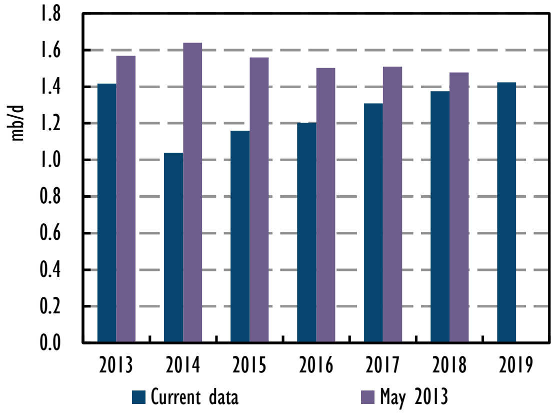
Against this ominous security backdrop, little progress has been made to improve uncompetitive contract terms amid challenging local content requirements. In the medium term, projects already in the pipeline are expected to maintain crude oil production capacity at current levels but post-2019 the outlook is less certain. Libya's lawlessness poses the biggest downside risk to our forecast, where we assume financial imperatives and a widespread fear among more extreme elements in the country of foreign intervention in the crisis will eventually force key parties to the negotiating table.

Figure 2.16 Africa crude production capacity



Nameplate crude oil production capacity in Libya is projected to average around 1.42 mb/d by 2019 but not before struggling to recover from exceptionally low levels in 2014. The recent escalation of fighting among rebel federalists, Islamist militants and government forces has upended the immediate outlook for production but for purposes of this forecast we assume capacity will recover over the medium term. Libya's unprecedented recovery in production post the 2011 civil war provides somewhat of a guideline of the country's capabilities to restore capacity once hostilities cease. Prolonged shut-in of fields, however, appears to have already inflicted some damage to fields and infrastructure, with current estimated operational capacity at just 1 mb/d compared to 1.7 mb/d prior to the civil war.

Figure 2.17 Libya crude production capacity

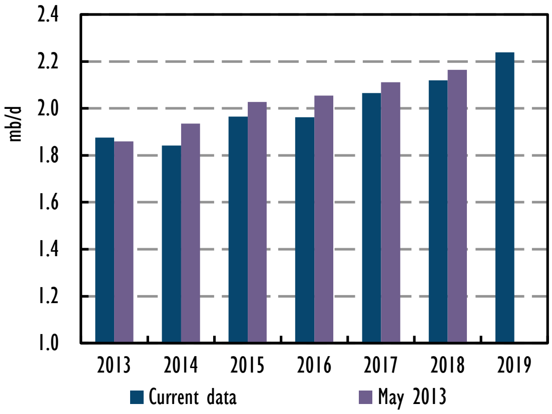


Rebel militias currently control the major ports of Es Sider, Ras Lanuf and Zueitina. The most recent negotiations for rebels to lift the blockade in the eastern region of the country in April collapsed following the contentious decision in early May and the decision by the country's parliament GNC to elect Islamist Ahmed Maitiq as Libya's fifth post-crisis prime minister. It is unlikely that a resumption of negotiations to restart production in the eastern region will take place until after the country's elections in September.

The country's oil bureaucrats continue to work on developing new investment terms as well as debate the role of the oil ministry versus the state-owned oil companies. None of these issues can be finalised, however, until a stronger governmental institutional structure, which includes the possibility of federal regions, and a constitution are in place. Despite frequent talks of new bidding rounds, in the medium term maintaining current capacity via field management and EORare expected to be the primary focus. Foreign companies have draw down most of their expatriate staff. The major investors seem prepared to sit it out, ready to return as soon as conditions stabilise.

Angola's crude oil production capacity is forecast to rise by a net 365 kb/d to 2.24 mb/d by 2019. However, new gross additions are sharply down from last year's report, with gross additions of 1.06 mb/d now compared with 1.66 mb/d in the *MTOMR 2013*. Angola's deep-water production has suffered technical problems related to water injection systems and floating, production, storage, and offloading (FPSO) facilities, among other issues. As a result, the country has missed its 2 mb/d production target for the past few years. To counter these issues, as well as offset the steep decline rates at its deep-water reservoirs, Angola plans to fast track exploration projects from 2014 onward by awarding up to 15 new blocks every two years and testing more wells in the promising pre-salt layer.

Figure 2.18 Angola crude production capacity



Despite the longer timeline, Angola is bringing on around a dozen deepwater projects, including its first sub-salt development, over the 2013-19 period. Total's 160 kb/d deepwater Cravo, Lirio, Orquidea and Violetta (Clov) are slated for start-up in July 2014, with production building to peak capacity by year end. Total's USD 16 billion, 200 kb/d ultra-deepwater Kaombo oil project is now planned for 2017. The country's first sub-salt development, the 100 kb/d Cameia field, is expected online in 2017.

Nigeria's production capacity is unchanged on a net basis over the forecast period, at 2.3 mb/d by 2019. The country's outlook has been revised 365 kb/d lower than last year's report on project delays, in part due to the deadlock over passing the controversial 'Petroleum Industry Bill' (PIB) in the legislature. Nigeria's inability to pass the complex, drawn-out legislation affecting contract terms and reorganisation of the state oil company, has led to a postponement of final investment decisions, with new projects totalling 780 kb/d in the pipeline by 2019. That is down 30% from total gross additions of 1.16 mb/d forecast last year.

The sharp escalation in violence by Islamic extremists Boko Haram in the northern region of the country, coupled with the resurgence in 'bunkering' (oil theft) along pipelines in the volatile Niger Delta, continue to destabilise the country and undermine the outlook for crude oil production capacity growth. The country's renewed efforts to clamp down on IOCs who fail to meet local content regulations are also proving problematic for foreign operators. The 'Nigerian Content Act', effective starting in 2010, calls for Nigerian oil and gas firms, including service companies, to be given first priority in the award of oil blocks, licenses and other related projects. For IOCs finding qualified Nigerian partners or contractors for the complex deep-water oil projects is challenging.

New projects coming online in the medium term include just two large offshore, deep-water projects and a half a dozen smaller ones. The ENI-operated Zabazaba and Etan fields are expected to add 120 kb/d of new capacity by 2015. The smaller Erha North 2 is also forecast to bring on 50 kb/d next year. The biggest projects are the 225 kb/d Bonga SW and Aparo fields, expected in 2016, and the 200 kb/d Egina, scheduled for 2018.

Algeria's crude oil production capacity is forecast to decline by 290 kb/d to 885 kb/d by 2019. Although there has been no further incident since the deadly terrorist attack on In Amenas gas facility in January 2013, prospects for capacity growth continue to be clouded by political uncertainty, security concerns, bureaucratic inertia and unattractive investment terms. State-owned Sonatrach revamped fiscal terms ahead of the January 2014 bid round, whether they go far enough to entice more IOCs won't be known until contracts are awarded this coming October. Sonatrach offered licenses for 31 blocks. New terms include a shift to an effective tax rate based on profits rather than gross revenue and a framework for developing tight oil and gas.

Figure 2.19 Nigeria crude production capacity

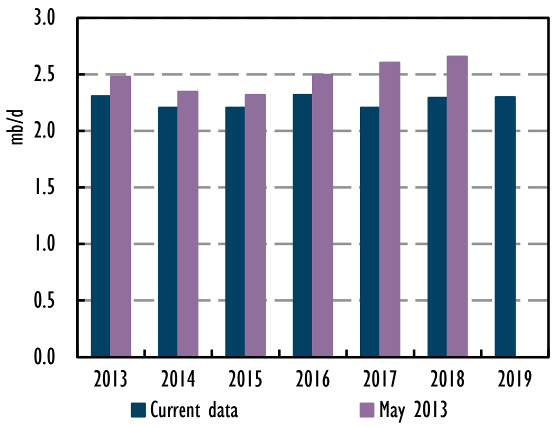
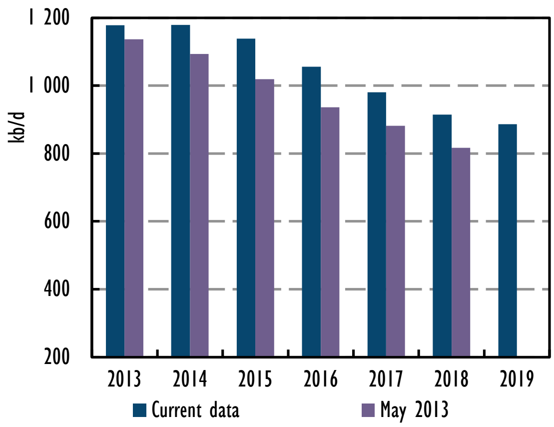


Figure 2.20 Algeria crude production capacity



Production capacity in Venezuela and Ecuador on upward trend

OPEC's Latin American producers are on course to increase capacity by a combined 420 kb/d to 3.5 mb/d by 2019. Venezuela's development of the massive Orinoco heavy oil belt is running well behind targets amid persistent project delays. The country nonetheless will increase net capacity by around 250 kb/d, to 2.85 mb/d. The new administration of Nicolas Maduro, installed as the successor to the late President Hugo Chavez, who died in 2013, has been under siege since early 2014 from opposition groups and the general public but the deteriorating political situation in Caracas has had a negligible impact on the oil sector. The bulk of Venezuela's oil production, refineries and export terminals are situated the Orinoco belt, Lake Maracaibo and Monagas state in the east of the country, far from the city centres where the protests are taking place. Chronic economic woes, an acute shortage of basic staples such as food as well as worsening crime rates have led to calls for the resignation of President Maduro. The government, however, continues to maintain control of the country's major blocs of power, including the military, Congress and the oil sector, with state-owned PDVSA largely staffed by regime loyalists. Should the political crisis continue to worsen and protesters gain momentum over the medium term, a change in leadership may prevail but for the time being analysts say the current level of unrest is not likely to lead to regime change in Venezuela.

Venezuela's major projects in the Orinoco region are running well behind schedule, in part due to an ongoing cash crunch to fund development. Total gross new production coming online during the forecast period fell to 840 kb/d for the 2014-19 forecast period, compared with a gross 1.24 mb/d of capacity estimated in *MTOMR 2013*. More than a half a dozen companies have abandoned projects in the Orinoco heavy oil belt. Malaysian state oil company Petronas quit the country in September 2013 due to disagreements with PDVSA over contract terms at the 200 kb/d Petrocarabobo, which called for an investment of USD 20 billion over 25 years. Russia's Lukoil is the seventh foreign partner to withdraw from the country, announcing plans to sell its stake at the Junin-6 block PetroMiranda project in 4Q13. Early production targets for PetroMiranda of 50 kb/d in 2013 faltered and output reached only a meagre 2 kb/d by 4Q13. The heavy oil development will be capped at 50 kb/d until an upgrader is completed post-2018. Meanwhile, ENI reported that its Junin Block 5 project is now expected to reach a modest 20 kb/d by 2016.

Figure 2.21 Venezuela crude production capacity

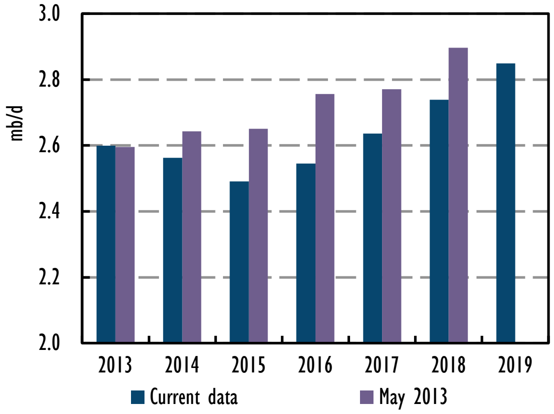
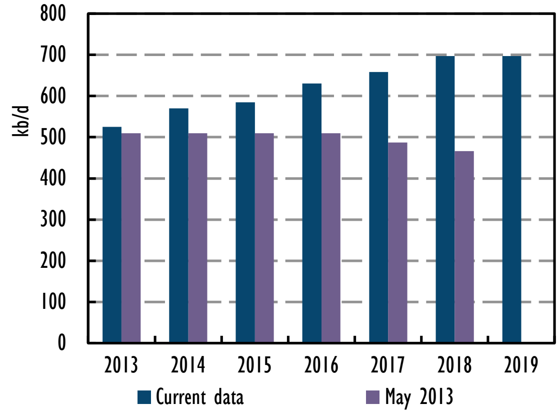


Figure 2.22 Ecuador crude production capacity



After years of stagnant production, **Ecuador** is poised to raise capacity nearly a third by 2019, up by around 170 kb/d to 700 kb/d. Key to the unprecedented growth was government approval for development of reserves in the Amazon rain forest despite protests from environmental groups. The Ishpingo-Tambococha-Tipuni oil fields are located within a UNESCO world biosphere reserve. The area is believed to hold some 900 mb, about a fifth of Ecuador's total reserves. Ecuador had tried to strike a bargain in 2007 to keep a moratorium on development of reserves from the Ishpingo, Tambococha and Tiputini fields in the Yasuní national park in exchange for wealthy nations' agreement to pay the government USD 3.6 billion over a decade, but this effort failed. Start-up of the first tranche of heavy oil production from the ITT fields is scheduled for 2016, with capacity rising to 200 kb/d by 2019. The Tambococha field is expected to bring first oil in 2016, followed eight months later by Tiputini and then by Ishpingo in 2018. Tiputini output would peak at 62 kb/d in 2017, Tambococha at 110 kb/d /d in 2020 and Ishpingo at 130 kb/d in 2025. Development would include a total of 360 oil wells - 300 inside the national park - and at least three platforms for the reinjection of formation water.

OPEC gas liquids supply

OPEC condensate and NGL output is forecast to grow at a brisk pace in the next five years, partly as a consequence of the group's strategic focus on natural gas developments. Production capacity of OPEC condensate and other natural gas liquids, and non-conventionals is forecast to rise by 810 kb/d to 7.12mb/d by 2019, up 120 kb/d from the *MTOMR 2013.* A concerted effort by Iran to ramp up capacity despite more stringent international sanctions accounts for around 40% of the growth. Libya, Saudi Arabia, the United Arab Emirates, and Qatar also post gains over the forecast period.

OPEC condensate capacity is projected to rise by 555 kb/d to 3.15 mb/d while NGLs are forecast to rise by 220 kb/d to 3.7 mb/d by 2019. The production ratio between condensates and NGLs rises from 43%/57% in 2013 to 46%/54% by 2019. Non-conventionals, including gas-to-liquids, rise a modest 35 kb/d to 280 kb/d by 2019. Expansion of NGL capacity is fuelled by the need for increased natural gas supplies used to meet strong demand at utilities, water desalination plants and industry as well as for reinjection at ageing oil fields.

Surging domestic natural gas demand for the residential and commercial sectors is behind **Iran's** renewed drive to increase production from the South Pars trains. The wide-ranging US and EU sanctions imposed on Iran's oil and financial sectors in 2013 exclude condensate and other gas liquids but banking restrictions have nonetheless reduced imports from customers. Iranian NGL capacity has been revised up by 300 kb/d to 915 kb/d by the 2019 end of the forecast period as long delayed projects are fast-tracked, though a large portion is expected to be earmarked for domestic use, including the petrochemical sector.

Figure 2.23 OPEC NGL production capacity

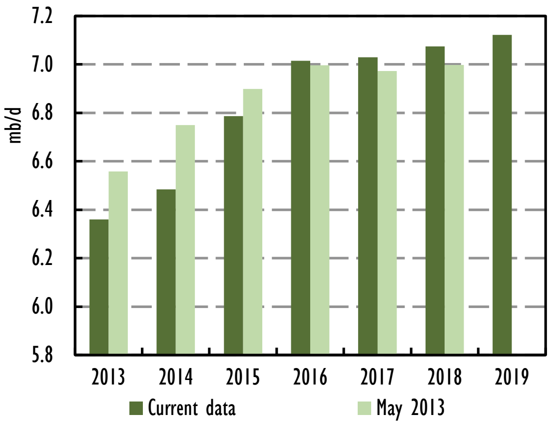
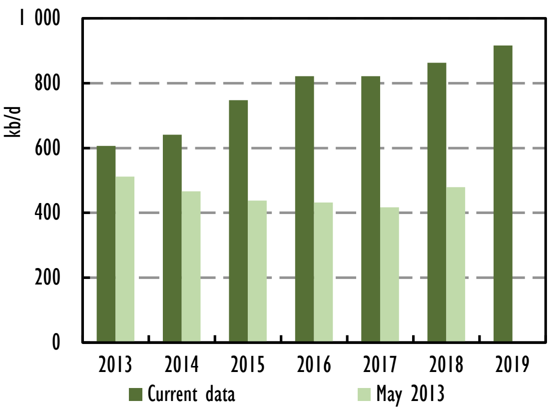


Figure 2.24 Iran NGL production capacity



South Pars developments have been severely delayed by cash flow constraints cutting into needed construction supplies and equipment under the sanctions regime while the withdrawal of foreign companies has limited the availability of new technology needed to maintain and expand infrastructure. The renewed efforts to develop the country's South Pars LNG projects under the new leadership at the oil ministry are behind the upward revision to the country's outlook.

Iran plans to launch the South Pars Phase 12 project in 4Q14, which includes new capacity of 75 kb/d of condensate and 30 kb/d of NGLs. Next online is South Pars 15-16 in 2018, which is slated to bring on 80 kb/d of condensate and 28 kb/d of other gas liquids. The remaining 100 kb/d stems from improved capacity rates at projects currently online, including Pars 6-8 and Pars 9-10.

Saudi Arabia, which holds OPEC's largest NGL capacity, is expected to increase production by around 135 kb/d, to 1.98 mb/d by 2019. The massive 275 kb/d Shaybah NGL development, which includes 190 kb/d of ethane for petrochemicals feedstock, is on track for start-up in late 2014. The Manifa field will contribute and additional 65 kb/d of condensate production by the end of 2014.

After rolling out all of its planned LNG trains by 2012, **Qatar** condensate, natural gas liquids and non-conventional capacity increase by a relatively modest 55 kb/d to 1.23 mb/d by 2019. The last big project online is the RasGas USD 10.3 billion Barzan gas project, which will add 50 kb/d to condensate capacity starting in 2015.

The **United Arab Emirates'** capacity is forecast to increase by 125 kb/d, to 865 kb/d by 2019. The Shah Sour Gas project is forecast to add around 50 kb/d of condensate (25 kb/d) and other natural gas liquids (25 kb/d) in 2017, delayed from 2H15. In addition, the Ruwais Integrated Gas Development (IGD) project launched in late 2013 continues to ramp up to nameplate capacity of 140 kb/d, with condensates pegged at 30 kb/d and NGLs at 110 kb/d.

Angola is forecast to raise gas liquids capacity by 65 kb/d to 140 kb/d by 2019 following the long awaited start-up Angola LNG (ALNG). The project has been plagued with problems, however, and was shut down in early May until mid-2015 following a massive gas leak in April at the 5.2 mt/y liquefaction plant, which includes production 50 kb/d of NGLs. The USD 10 billion Chevron-operated LNG plant has faced a series of technical problems since its June 2013 start-up. Other partners in the project include BP, Total, Eni and state oil company Sonangol.

Table 2.4 Estimated OPEC sustainable condensate and NGL production capacity (thousand barrels per day)

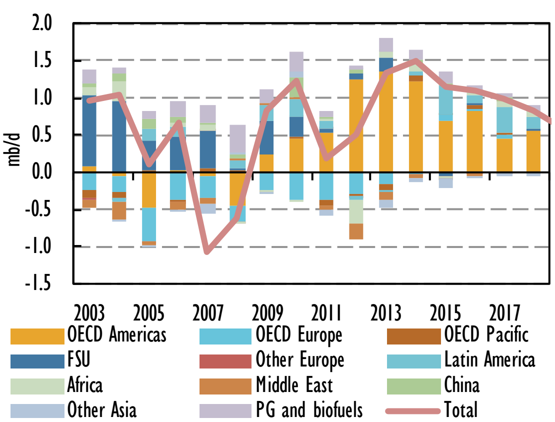
Country	2013	2014	2015	2016	2017	2018	2019	2013-19
Algeria	425	457	484	494	474	454	*434*	9
Angola	74	76	90	140	140	140	*140*	66
Ecuador	1	0	0	0	0	0	*0*	-1
Iran	607	641	747	822	822	863	*917*	310
Iraq	83	87	88	88	88	88	*93*	10
Kuwait	300	300	300	300	300	300	*300*	0
Libya	54	48	110	154	174	204	*204*	150
Nigeria	544	562	546	531	538	525	*514*	-30
Qatar	1 175	1 174	1 194	1 206	1 222	1 232	*1 232*	56
Saudi Arabia	1 839	1 850	1 910	1 955	1 965	1 975	*1 975*	136
UAE	741	819	828	828	848	848	*867*	126
Venezuela	225	210	210	205	187	170	*170*	-55
Total OPEC NGLs*	**6 069**	**6 225**	**6 506**	**6 723**	**6 758**	**6 798**	**6 845**	**776**
Non-Conventional**	244	271	271	271	271	271	279	35
Total OPEC	**6 312**	**6 496**	**6 778**	**6 994**	**7 030**	**7 070**	**7 124**	**811**

*Includes ethane.

**Includes gas-to-liquids (GTLs).

Non-OPEC supply

Figure 2.25 Non-OPEC supply – yearly change

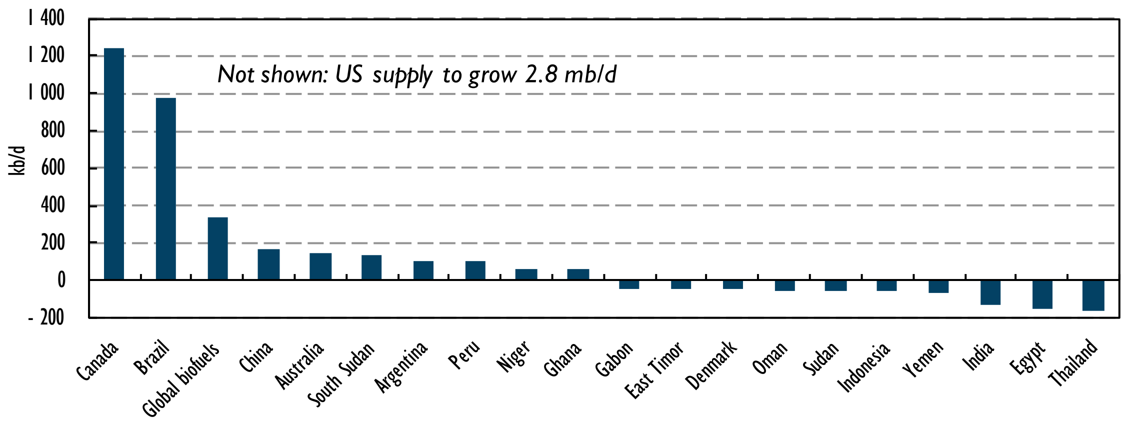


North America will continue to dominate global liquids production growth in the next five years as it has since 2012. Despite current logistical challenges in getting production to market, the United States and Canada will likely remain the two fastest-growing non-OPEC producers throughout the forecast period. US supply growth is nevertheless set to slow towards the end of the decade, reaching a plateau in 2019. Until 2016, however, growth rates in the United States and Canada are expected to remain high, as light tight oil (LTO) and other unconventional oil production continues to rise. Other producers, including Kazakhstan, Mexico and Argentina, will enjoy production gains, but their contribution to total non-OPEC supply will only start "moving the needle" towards the end of the decade, just as United States and Canadian supply growth starts slowing down.

To some extent, the same technologies that unlocked US LTO supplies will enable non-OPEC supply to grow outside of North America. In the next five years, those unconventional extraction technologies will start being applied in other non-OPEC producers on a larger scale than ever before, thanks in part to recent above-ground developments in the Former Soviet Union (FSU) and Latin America. In Russia, a revised Mineral Extraction Tax (MET) will spur the development of tight oil production in the Bazhenov play, but also in the Krasnodeninsky area, among others.

Unconventional oil supply prospects are also looking up in Argentina following a recent settlement between the government and Repsol, whose majority stake in YPF had been expropriated in 2012. Activity in the Vaca Muerta shale of Argentina may start adding to production in a big way after 2017. Initially the impact of these technologies will be more muted than in the United States and Canada, but towards the end of the decade their contribution to total output becomes meaningful.

Figure 2.26 Selected sources of non-OPEC growth/decline 2013/2019



Note: Not shown: US supply to grow 2.8 mb/d.

Potentially offsetting these gains, large-scale unplanned disruptions in non-OPEC countries continue to pose a significant risk to supply. Unplanned outages have always been a fact of life in the oil industry but scaled new annual highs of nearly 1.0 mb/d and 830 kb/d in 2012 and 2013, respectively – or even higher, depending on how they are assessed. This reflects a combination of factors, including aging fields, the increasing complexity and technically challenging nature of many new projects, extreme weather and heightened political risk in a period of socio-political upheaval in the MENA region and elsewhere.

Unplanned outages among non-OPEC producers have been somewhat lower so far in 2014 compared with the same time last year, averaging about 600 kb/d in the first five months, but the oil market has yet to enjoy a return to "normal" business conditions – if it ever does. Weather-related production problems in the United States and Russia in the early months of the year depressed output somewhat in 1Q14. Political turmoil in South Sudan, which came close to outright civil war, trimmed oil production by 100 kb/d in the first five months of the year. In Colombia, crude oil production fell to a 20-month low due to renewed attacks on pipelines, the impact of which was further exacerbated by indigenous protests that prevented repairs, cutting production by at least 100 kb/d in March and April. In addition to these unplanned events, planned outages are routinely getting longer. Heavy maintenance periods will likely characterise the industry to a greater extent as some offshore or other challenging environments mature.

Business environments, despite many positive developments in the industry, remain another large downside risk to supply. This applies notably to local-content policies, which in recent years have become so onerous as to delay production in places ranging from Brazil to Kazakhstan, trimming our production forecasts.

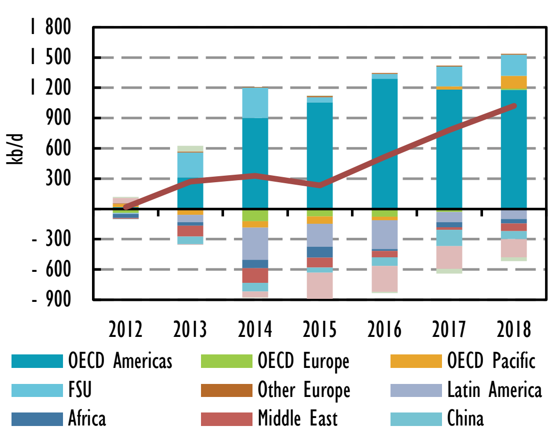
Table 2.5 Non-OPEC supply (mb/d), 2013-19

	2013	2014	2015	2016	2017	2018	2019	2013-19
OECD	20.9	22.1	22.9	23.8	24.3	25.0	25.3	4.3
OECD Americas	17.2	18.4	19.1	19.9	20.4	20.9	21.2	4.0
OECD Europe	3.3	3.2	3.2	3.3	3.3	3.3	3.2	-0.0
OECD Asia Oceania	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.3
Non-OECD	29.6	29.7	29.9	30.0	30.4	30.6	30.9	1.3
FSU	13.9	13.9	13.8	13.8	13.8	13.9	14.1	0.2
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-0.0
China	4.2	4.2	4.3	4.3	4.3	4.3	4.3	0.2
Other Asia	3.5	3.5	3.4	3.3	3.3	3.2	3.1	-0.4
Non-OECD Americas	4.2	4.2	4.6	4.7	5.1	5.3	5.4	1.2
Middle East	1.3	1.3	1.3	1.2	1.2	1.2	1.2	-0.1
Africa	2.3	2.4	2.4	2.5	2.5	2.6	2.6	0.3
Non-OPEC*	**50.5**	**51.8**	**52.8**	**53.8**	**54.8**	**55.6**	**56.2**	**5.6**
Processing Gains	2.2	2.2	2.3	2.3	2.3	2.4	2.4	0.3
Global Biofuels	2.0	2.1	2.2	2.2	2.3	2.3	2.3	0.3
Total-Non-OPEC	**54.7**	**56.1**	**57.3**	**58.4**	**59.4**	**60.3**	**60.9**	**6.2**
Annual Change	1.3	1.4	1.1	1.1	1.0	0.9	0.6	1.0
Changes from last MTOMR	0.3	0.3	0.2	0.5	0.8	1.0		

* Excluding processing gains and biofuels.

Revisions

Figure 2.27 Non-OPEC supply – revisions

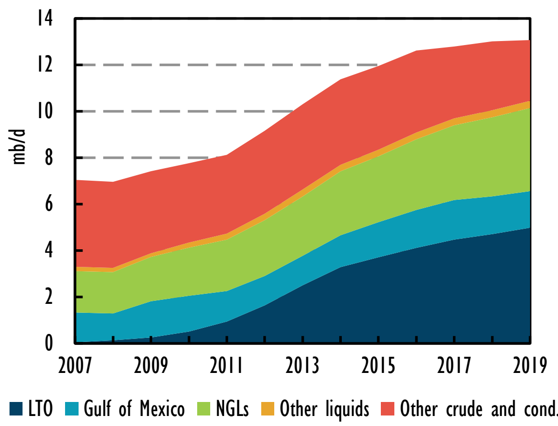


Our non-OPEC forecast was adjusted higher by about 1 mb/d for 2018 since the *MTOMR 2013*, with some of this as a result of a higher baseline (particularly in OECD Americas), as upward revisions to the OECD forecast supply more than offset reductions for the non-OECD. In the latter, nearly all regions outside of the FSU saw their production projections cut through the forecast period. Since the *MTOMR 2009*, our forecasts of non-OPEC supply growth have been consistently revised upwards, mostly on account of improved technology and recovery rates in North America.

OECD Americas

Non-conventional extraction technologies have been a game-changer for both for production of the **United States** and for world supply, whose effects will continue to be felt through the medium term. US total liquids production is forecast to surge to a high of 13.1 mb/d in 2019, from 10.3 mb/d in 2013, an average increase of about 470 kb/d per year. This growth rate is significantly lower, however, than the 1.1 mb/d growth recorded in 2013, the all-time record for a non-OPEC producer. Between 2013 and 2019, tight oil production is expected to rise by 2.5 mb/d, accounting for most of the total net increase in US output. The second largest source of US supply growth comes from non-crude liquids, specifically natural gas liquids (NGLs), production of which is expected to jump by more than 1 mb/d to 3.6 mb/d in 2019. By the end of the decade, NGLs will account for more than one quarter of total US liquid output, up from 2.1 mb/d in 2010.

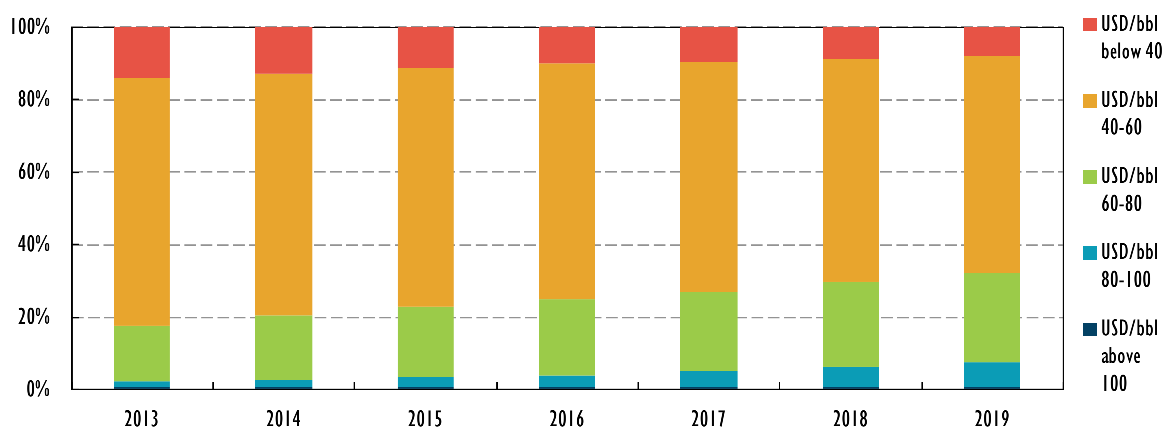
Figure 2.28 US oil production



The forecast of total US production has been revised upwards since the *MTOMR 2013*, reflecting increased operator efficiency, especially in the most prolific oil areas. US liquid production growth continues to defy expectations. The revised total output forecast of 13.0 mb/d for 2018 is 1.1 mb/d higher than projected in the *MTOMR 2013*. The growth rates for US oil output have been revised up for each of the years of the forecast period.

LTO production in the Bakken and Eagle Ford shale plays remains the backbone of US production growth, but other non-conventional areas provide support, including the Barnett, Niobrara and Permian Basin, with the Permian Basin having the largest output of the three. Oil produced in the Permian is made up of conventional (including with enhanced oil recovery [EOR] applied on mature fields) and unconventional resources and totalled more than 1 mb/d in 2013. Output is forecast to grow to over 1.3 mb/d in 2019.

Figure 2.29 Percent of US production of crude and condensate from tight and shale oil within breakeven price ranges



Source: IEA analysis of Rystad Energy data.

As of 2013, about 98% of crude oil and field condensate production from tight oil and shale oil had a breakeven price of USD 80/bbl or less, with 82% having a breakeven price of USD 60/bbl or less.[1] The percentage of production with higher breakeven prices is expected to grow, however, such that by 2019, nearly 8% of this production is expected to have a breakeven price of greater than USD 80 per barrel.

[1] Source: IEA analysis of Rystad Energy data. Note that breakeven prices are nominal Brent at the time of field sanctioning, with a net present value (NPV) as of 1 January 2014, and assumed annual inflation of 2.5% for 2015 forward.

This does indicate that a greater share of this non-conventional production could be sensitive to a drop from the price levels experienced in 2013 further out in the future. However, even in 2019, about 68% of this production is expected to still have a breakeven price of USD 60/bbl or less.

While a slowdown in LTO production growth is forecast for the end of the period, greater-than-expected technological advances could unlock yet greater output. The pace of improvement in onshore drilling technology and productivity continues to surpass expectations as exploration and production companies keep improving drilling techniques in tight formations. On the other hand, there has been a slowdown in acreage acquisitions by companies in the shale plays, as their focus shifts from expanding drilling acreage to boosting cash flow. This may lead to a slowdown in LTO production growth towards the end of the decade. An additional downside risk is higher interest rates, which could increase financing costs for new drilling, thereby potentially cutting new production on the margin.

Oil production in the Gulf of Mexico (GOM) was flat in 2013 but is forecast to rebound to 1.6 mb/d by the end of the decade. Last year's slide came as a consequence of slowed exploration activity since 2010, the effect of which was compounded by outages and infrastructure issues in and around the GOM in 2013. GOM production growth is expected to make a comeback following this nearly four-year dip in activity, however. More than 600 kb/d of new production capacity is set to come online in the next two years. We expect GOM production to rise to 1.7 mb/d by 2017, from a low point of 1.3 mb/d in 2012-13, surpassing the 1.56 mb/d record of 2009. New projects commenced operations in the GOM recently, including two new platforms operated by Shell and BP, respectively. Shell's Mars B Olympus started production in February 2014 and during the same month, BP announced operations at the Na Kika Phase 3 project. At least four other projects are slated to come online by end-2014 and several more, including LLOG Exploration's 100 kb/d Delta House project in 2015, are expected to begin production by end-2016 and beyond, boosting GOM output through the medium term. Chevron, Hess, Anadarko and Shell are bringing online infrastructure that will result in output growth of more than 400 kb/d by 2017, before GOM production swings back into slight decline. The current GOM forecast is based on current and planned projects and also includes adjustments for hurricane and maintenance outages.

Capital expenditures in the liquids upstream continue to rise, including in LTO. According to Rystad Energy, capital expenditures (including exploration capex) are expected to rise throughout the forecast period, with total expenditures (crude, condensate and NGLs) rising to USD 142 billion in 2019 (base year 2014), from USD 132 billion in 2013. In fact, capital expenditures are expected to increase each year except 2015, when they will remain roughly flat with 2014. LTO expenditures will also increase, though exploration capital only for LTO is forecast fall each year between 2013 and 2019, as exploration of new acreage declines somewhat. Latest US Bureau of Labor statistics reveal that upstream costs, as measured by oil and gas field machinery and equipment, along with support activities for oil and gas operations, have been increasing for nearly a year, though they held roughly flat in March and April 2014. These estimates include US and foreign companies that operate in the US upstream. Rising production costs against the backdrop of flat oil prices mean declining cash flow for companies. Continued declines in cash flow, particularly in the face of rising debt levels and possible future increases in interest rates, could challenge future exploration and development. Sustained oil price drops would, of course, also be a downside risk to production. Some analysts have noted that Master Limited Partnerships – more often used for midstream companies, but also increasingly used for financing upstream shale-play oil developments – are particularly vulnerable to higher interest rates, as distributions to unit holders would fall. Reduced spending levels could be offset by rising drilling and production efficiency, however.

As US crude production keeps expanding, concerns about a crude export 'wall' are moving to the front burner. The so-called crude 'wall' is defined as the point at which further growth in crude production bumps against both limitations in domestic market capacity to handle more light crude and current restrictions on US crude exports. Adjustments at various levels of the supply chain can help get over the "wall". Those include, among others: downstream – investments to realign existing refining capacity with a changing crude slate; midstream – an expansion of crude transportation infrastructure to deepen the marketing reach of incremental crude production and modifications to the Jones Act; and upstream – a realignment of crude export restrictions with a changed supply situation. This *Report* takes the continuation of current policy as base case, thus assuming that pipeline capacity and/or refining capacity adjustments will somehow suffice to relieve the growing pressure in the system. Field condensate, as opposed to plant pentanes, is also subject to export restrictions, and the fact that this condensate is often blended with crude oil could further complicate export issue if field condensate were to have different a different regulatory regime from crude oil (see "Natural gas liquids and condensates").

US NGL output is expected to grow to 3.6 mb/d by 2019, accounting for more than one third of global NGL supply at the end of the decade. The United States is the world's top NGL producer today and will remain so throughout the forecast period. United States NGL production is expected to jump by about 40% to 3.6 mb/d in 2019, from 2.6 mb/d in 2013. Such percentage growth is not unprecedented: US NGL output surged by 43% from 2007 to 2013. Several factors contribute to this substantial growth of US NGL supply:

- **Forecast strong growth in US natural gas production:** As noted in the *Medium-Term Gas Market Report 2014* (*MTGMR 2014*), US natural gas production is expected to jump to 797 bcm by 2019 from 688 bcm in 2013, a gain of about 16%. The United States has been able to increase its natural gas production greatly in recent years (compared to other mature provinces) because of the development of unconventional resources, particularly shale gas and tight gas. Although tight gas has been in production for decades, more recently US shale gas supply has boomed with the spread of hydraulic fracturing techniques. On the six most important US shale plays, natural gas production surged by over 125% from 2007 to 2013.[2] Even if, as expected, growth slows in the United States as a whole, as well as on some plays, the trend for overall US natural gas production remains upward, in contrast to most of the previous decade.

- **Expectations of continued large price differentials between dry gas and NGL (ethane excepted):** In 2013, dry gas at the Henry Hub in Louisiana averaged USD 3.73/MMBtu, while Mont Belvieu, Texas, prices for propane averaged USD 11.92/MMBtu and USD 14.22/MMBtu for butane.[3] This gives producers an incentive to target liquids-rich plays, all else equal. This is clearly visible on the Eagle Ford play in Texas, where drilling has been comparatively slow on the southern strip of the play, which has low liquid yields. Yet, dry gas production still increased from approximately 47 million cubic metres per day in 2007 to approximately 154 million cubic metres per day in 2013, focusing almost entirely on liquids-rich plays. Hence, we expect the average amount of liquids produced per molecule of dry gas to continue to increase in the United States.

- **Capital expenditure:** Although capex (including exploration capex) on pure upstream NGLs projects in the United States is forecast to decline from a high of USD 4.1 billion in 2012 to

2 Source: US EIA.
3 Sources: US EIA and Argus Media Ltd.

USD 1.4 billion by 2018, total capex on the upstream liquids sector, including capex on projects that combine crude oil, condensate and/or NGLs, is forecast to increase, as noted above. Natural gas capex is forecast to stay steady at between USD 50 billion and USD 55 billion for the forecast period.[4] Investment in natural gas processing capacity also continues to drive expansion. A study by Simmons & Co. estimated an expansion of processing capacity of 6.9% in 2013, with a further 3.2% of capacity growth forecast for 2014. We assume that price incentives will remain aligned such that, at least for liquefied petroleum gas (LPG) and pentanes, processing capacity investment will continue to support growth.

- **The development of new markets for US ethane:** While a lack of market outlets for ethane could potentially constrain NGL (and wet gas) production growth, the industry is taking steps to overcome this hurdle. Compared to other NGLs, ethane suffers from a narrower market – its main outlet is the petrochemical industry where it is cracked to produce ethylene – and higher shipping costs (unlike propane, it must be sent on refrigerated vessels if moved by ship). Ethane's relatively low price reflects this: around USD 192/tonne, compared to USD 524/tonne for propane and USD 616/tonne for butane at Mont Belvieu (2013 average).[5] Hence, US gas plant processors have increasingly "rejected" ethane back into the methane stream when its price falls below that of methane, taking into consideration transport and processing/separation costs. But ethane rejection, currently estimated at about 250 kb/d,[6] is itself constrained, as too much ethane mixed into a natural gas (methane) stream can raise its heat content to unsafe levels. While rising dry gas production gives scope for ethane rejection to increase somewhat, industry has also responded to the relatively low price of US ethane. There are plans for 10 new ethane crackers with a combined capacity of 12.5 million tonnes per year in the forecast period, in addition to about 1.5 million tonnes per year of capacity expansions at existing facilities set for completion in 2014. Midstream investment to bring ethane from the Marcellus play to various North American petrochemical centres and shipping terminals also continues. The Mariner West pipeline (which started operations in 4Q13 with an initial capacity of 50 kb/d) thus takes ethane from the Marcellus to the Sarnia, Ontario, petrochemical hub, while the Mariner East project (65 kb/d for phase 1; to be completed in 2015) uses mostly converted oil pipelines with new construction to take NGLs from the Marcellus and Utica shale formations east to port facilities near Philadelphia, from where it can be shipped elsewhere. A second phase that could transport additional liquids is planned for the end of 2016. The ATEX Pipeline (initial capacity 125 kb/d) began commercial service in January, taking ethane from the Marcellus Play in Pennsylvania to the Mont Belvieu hub. Ethane from the Williston Basin (site of the Bakken play) started pumping into the Alberta Ethane Gathering System in May 2014 via the 40 kb/d Vantage Pipeline. There are also plans to export ethane to Ineos' European petrochemical facilities starting in 2015, given that even with refrigerated shipping costs, US ethane is expected to be competitive with naphtha in Europe. This will be done from both Sunoco Logistics' Marcus Hook terminal on the Delaware River (the terminus of Project Mariner East), as well as from planned new ethane export facility near Houston.

- **Expansion of infrastructure for NGLs and LPG:** Unlike ethane, LPG (propane and butane/isobutane) has multiple uses, and thus is easier to market, but it too requires the expansion of transport capacity to sustain production growth. In April 2014, Oneok Partners completed its OD Sterling III NGL pipeline that can take unfractionated NGLs or split NGL types from Oklahoma to the Mont

[4] Source: Rystad Energy forecast. Real 2014 USD.
[5] Source: Argus Media Ltd. Houston close, midpoint pipeline fob.
[6] Source: RBN Energy. Similar quantities have been referenced in *Oil & Gas Journal*, but there is no official data on ethane rejection.

Belvieu hub. Current capacity is 193 kb/d, but can be expanded to 250 kb/d. The same company also completed in April 2014 the Bakken NGL Pipeline, which can transport 60 kb/d of unfractionated NGLs into the Overland Pass Pipeline, from which these NGLs can eventually head to storage in Kansas or storage/processing on the Gulf Coast. Local fractionation on the Marcellus Play is also expanding. Indeed, given the planned infrastructure build-up at the moment, the 400 kb/d capacity mixed-NGL Bluegrass Pipeline from the Marcellus and Utica plays has been shelved for the time being, though one of two companies developing the project, Williams, maintains that it remains a longer-term solution to future NGL output growth in the region and could still be implemented at some point in the future.

- **Propane and butane exports:** Net exports of LPG (including output from refineries) have increased markedly in recent years. The United States has gone from being a net importer of 21 kb/d in 2010 to a net exporter of 184 kb/d in 2013, helping to support price levels in the face of growing supply. Global demand for LPG is expected to grow significantly in the forecast period. Much investment is going into LPG export facilities on the Gulf Coast.

- **Continued need for pentanes for diluent in Canada:** Rising Canadian oil sands production requires diluent for transportation. Condensate/natural gasoline is a potential diluent, and given Canada's insufficient domestic production, US net exports to Canada of fractionated pentanes have become more important, rising to 140 kb/d in 2013 from just 32 kb/d as recently as 2010.[7] Hence, about 42% of US pentanes plus production was exported to Canada in 2013.

The United States alone already nearly matches the NGL output (excluding field condensate) of OPEC Middle East countries, and is expected to exceed their production by the end of the decade. Moreover, the United States is at the centre of what is already the world's largest NGL producing region, North America, making for a region that will far exceed all others in terms of NGLs by 2019.[8]

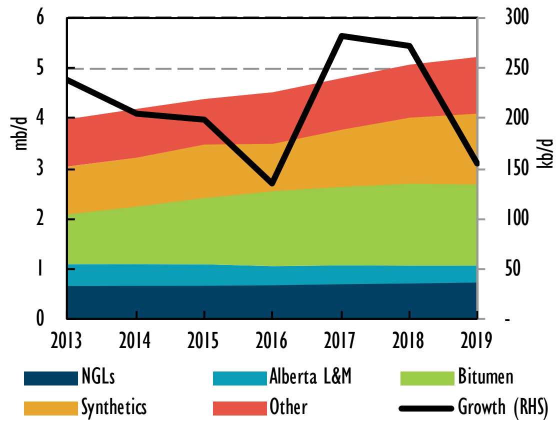
Canada's oil output is expected to grow steadily to 5.2 mb/d in 2019, up 1.2 mb/d from 2013. In-situ production of bitumen and mined synthetic crude will lead growth, with the former accounting for the ever-growing share of oil sands output, but a number of mined bitumen projects, including Phases II and III of Imperial's Kearl project, will also contribute. In 2013, oil sands production accounted for 49% of Canada's total output and grew by 150 kb/d during the same year. Oil sands output growth is projected to remain steady in 2014 despite new bitumen production, given heavy maintenance at a number of synthetics projects, likely totalling 170 kb/d for the year. Growth is forecast to gain momentum steadily from 2015 through 2019, when new project gains outpace continued maintenance outages. Total oil total sands output is projected to average 3.0 mb/d in 2019.

Further growth in Canadian production of light synthetic crudes will require producers to secure new market outlets, as US production of LTO, which is of comparable quality, continues to expand. Canadian producers have sought alternatives to shipping synthetic light crude south to the United States, where imports have been displaced by rising LTO supply. Options including shipping the crude to Canadian refineries in the Maritime provinces on the Atlantic coast, moving it to the Burnaby, British Columbia, refinery, and possibly exporting it to Asia (see "Trade sector" for more on this). Rail shipments from Alberta to the Maritimes have grown exponentially in the last two years and pipeline

[7] Source: US EIA.
[8] For more on natural gas production, as well as a special section with more detail on NGLs in the US context, see the IEA 2014 *Medium-Term Gas Market Report*.

capacity will be expanded to transport oil within Canada from major producing areas to refining centres. Canada's National Energy Board approved Enbridge's Line 9B reversal and expansion project which will run from Westover, Ontario to refineries and petrochemical plants in Montreal, Quebec and potentially Portland, Maine. At the time of writing, the Canadian government was slated to approve Enbridge Inc's Northern Gateway crude pipeline project to carry about 525 kb/d from Alberta's oil sands hub of Edmonton to a deepwater port in Kitimat, British Columbia, where the crude would be loaded onto tankers and shipped to international markets. Meanwhile, the potential to expand exports of crude oil from Canada's East Coast is another option. The United States is the mainstay of Canadian exports of crude oil and upgraded synthetics, receiving about 2.6 mb/d in 2013.

Figure 2.30 Canadian oil production



After peaking in 2013, Canadian E&P capital spending on liquids is forecast to decline in 2014 and 2015, before increasing slightly in the following two years. Planned investments on oil sands projects are expected to continue through completion. Continued increases of capex toward natural gas should also benefit liquids output.

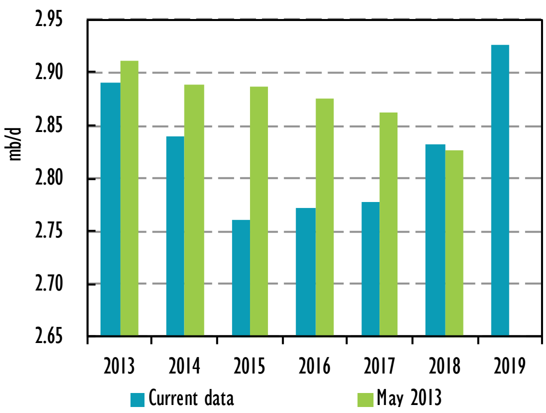
Natural gas liquids are forecast to grow to 740 kb/d in 2019 from 670 kb/d in 2013. This is despite natural gas output being expected to decline through 2016, and then level off toward the end of the forecast period. Canadian NGL production is seen to be flat in 2014, before slight gains in the following years. As in the United States, the expectation is that gas producers will focus new investment on liquids-rich plays, in particular the Duvernay shale play in Alberta, which will more or less compensate for declines in older conventional fields. Given the enormous Canadian diluent demand, producers have a clear incentive to invest in plays to obtain pentanes (as well as field condensate). Total upstream capex on the Duvernay play (including gas) increased from just USD 63 million in 2010 to USD 1 billion in 2013.[9] Ethane production in Canada is expected to decline in 2014, before flattening out for the rest of the forecast period, as new sources of less expensive ethane from the US disincentivise higher-cost extraction. Alberta has a dedicated ethane gathering system with a capacity of 330 kb/d that connects the province's NGL extraction facilities with its major petrochemical plants. As noted above, imported ethane from the United States now connects into the system. Despite a growth rate that is much weaker than that of its southern neighbour, at 10% from 2013-19, Canada will nevertheless remain one of the world's largest NGL producers.

The oil industry in **Mexico** is undergoing its largest transformation since the nationalisation of its oil sector in 1938. In December 2013, Mexican President Peña Nieto signed the country's landmark energy bill into law, which encompassed several constitutional changes, marking the first time significant legal reform took place in the energy sector in decades. The energy reform was passed in light of Mexico's precipitous fall in oil production since it peaked in 2004 at 3.8 mb/d, decreasing by nearly 1 mb/d in less than a decade.

[9] Source: Rystad Energy.

While current reforms of the energy sector are far-reaching, their real impact will only be evident at the end of the decade, leading to larger gains in the 2020s. Through 2017, we expect that production will remain about flat, with small declines evident in 2014 and 2015. However, in 2018 and 2019, we expect that reforms begin to bear fruit in terms of increased production and project total oil supply to increase by 50 kb/d and 100 kb/d, respectively. Mexico's total oil output is expected to reach 2.92 mb/d by 2019, up from 2.84 mb/d in 2013. Production gains during those two years will come from "low-hanging fruits" such as the application of EOR techniques to existing fields, as well as the easiest new fields to bring onstream.

Figure 2.31 Mexican oil production



Although the decrease in production since 2004 has been dramatic, state oil company Petróleos Mexicanos (Pemex) has been able to slow the declines that began in mid-2000s, when production fell in excess of 150 kb/d each year. Most of Mexico's oil production originates in the shallow offshore, with nearly all of the currently producing fields in a mature state. Pemex's success in slowing down the declines is mainly due to the start-up of the Ku-Maloob-Zaap (KMZ) field. But KMZ has failed to live up to the high hopes placed in it by the company, and in fact has already started to decline. Cantarell, at one point among the world's largest producing fields, has seen output decrease by 80% in less than a decade. The onshore Chicontepec formation, which is Mexico's largest onshore source of resources, at about 19 billion barrels, consists of extra-heavy oil and tight oil, both of which Pemex has had only limited success exploiting despite working on the formation for decades. Production remained at 2012 levels in 2013, at about 70 kb/d.

With most of the production originating from mature fields, Pemex has had difficulty in replacing its oil reserves despite increasing capital expenditures. The company would have to invest vast resources into exploration and development to increase the reserves. This at least in part helped precipitate the energy sector reforms as the necessary resources within Mexico and Pemex simply are not available. Pemex has also been constrained in its capital expenditures given the federal government's dependency on revenues from the state company

The timing of Mexico's oil reform is auspicious, happening at the same time new extraction technologies have unlocked vast reserves in the United States (including development of the bordering Eagle Ford shale and deepwater US Gulf of Mexico). In view of these advances, the potential effect of the reforms on Mexican oil production is huge: areas with the most promise, deepwater and shale, remain difficult and expensive to unlock but new investment and technology could turn Mexico into a major producer and exporter of oil. However, the phenomenon in the neighbouring United States means that additional Mexican output, particularly lighter grades, would have to find markets further afield for export.

Although many of the details of the reform remain to be worked out, a number of foreign oil companies have already expressed interest in taking part in exploration and development of Mexico's potential reserves, including the deepwater, shallow water and shale. Tremendous capacity building will be required to let the National Hydrocarbons Commission (CNH) and the Energy Secretariat (Sener) effectively administer a hydrocarbons sector that will become much more complicated. At present, the government has no experience regulating upstream oil and gas companies except Pemex and a few companies that have service contracts with it. New licenses issued to private companies may face legal challenges if they are deemed equivalent to concessions, which remain technically illegal under the new law. At the time of writing, the Mexican Congress is to consider secondary legislation that would specify how a multi-company upstream sector would be managed. The so-called 'round zero' has begun, in which Pemex submitted to the government a list of upstream fields and prospects that it would like to retain, and another of those that could be transferred to other companies through future bid rounds. The government is to make a decision by 17 September 2014 on which acreage Pemex will keep.

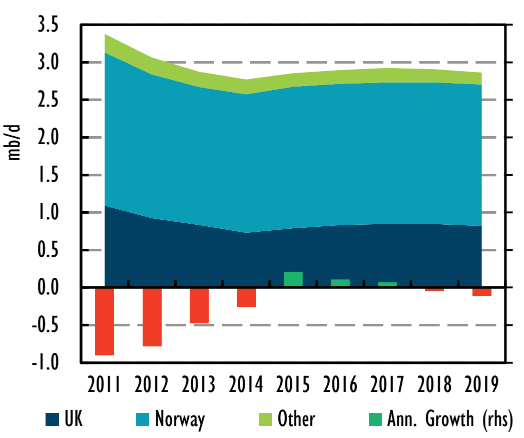
Pemex already has a number of fields in the exploration phase that are expected to add to output after 2017, including Campeche Oriente, Chalabil, Uchukil, Comalcalco, and Cuichapa. Although this year's *MTOMR* does not look beyond 2019, the potential for annual increases much greater than 2019's projected 100 kb/d is certainly there for the years following 2019, assuming the reform process delivers applications of capital and technology similar to other major OECD producers.

Mexican NGL production is expected to follow the path of its crude oil and natural gas production, gently declining from 360 kb/d in 2013 to 345 kb/d by 2014, holding steady in 2015 and 2016, and then increasing by 10 kb/d to 30 kb/d each in 2018 and 2019 as projects benefitting from the reforms process begin to bear fruit. Additional volumes of ethane are expected to be absorbed, as the Braskem/Idesa Ethylene XXI 1.05 million-metric-tonne-per-year cracker is expected to be online by the end of 2015. Total NGLs increase by 14% over 2013 by 2019, to 410 kb/d.

North Sea

Over the next five years, North Sea (including the Norwegian and Barents Seas) producers should manage to slow down a secular decline in production from that area that started in 2000, when production peaked at 6.3 mb/d. Nevertheless, the loss of North Sea supply from mature areas will be substantial, bringing total output to levels so low as to question the continued use of North Sea BFOE as a global benchmark without further adjustments to the benchmark's definition.

Figure 2.32 North Sea oil production



Total North Sea production – which includes supplies from the UK offshore, Norway, Denmark, Netherlands offshore and Germany offshore – is projected to decline to under 2.8 mb/d in 2014 before gradually rising back above 2.9 mb/d by 2017. The decline in the North Sea production is expected to be halted as new field production offsets reduced output from legacy fields.

Crude oil output from Brent, Oseberg, Forties and Ekofisk, which make up the BFOE price benchmark, is expected to decline each year through 2019 and fall to 520 kb/d that year. In 2013, BFOE production totalled 925 kb/d and, given production thus far in 2014, BFOE output is projected to average 865 kb/d for the year. Production of the benchmark has been in annual decline since Ekofisk was added to provide additional volumes in 2007.

Of the total North Sea output in 2019, approximately 800 kb/d (30%) will be produced in the United Kingdom, while about 1.8 mb/d (65%) will come from Norway. The other contributing countries will all see declines in production between 2013 and 2019, with their contribution to North Sea production accounting for the remaining 5%.

Arresting years of large declines (forecast to bottom out at 725 kb/d in 2014), **United Kingdom** production is forecast to rebound marginally between 2015 and 2017, before it falls again in 2018. The expected growth averaging about 40 kb/d per year until 2018 is the result of some new field startups offsetting declining production and currently producing fields undergoing redevelopment efforts, with total output averaging roughly 850 kb/d that year. We expect production to fall to 820 kb/d in 2019.

The increases in production through 2018 will mainly come from additional supplies originating in the West of Shetland Islands offshore area, which are expected to add about 200 kb/d of additional production capacity of both crude and non-crude liquids. For example, Total is overseeing the development of the Laggan and Tormore condensate and gas fields in the area, while BP is undertaking a number of redevelopment projects, including the Magnus and Clair Ridge fields. Furthermore, BP will complete the Quad 204 FPSO development, which is expected to extend the life of the Schiehallion oil field to 2035. The FPSO is expected to be installed and start producing in 2016 and begin production that year. Total production from Schiehallion field will rise by about 120 kb/d due to the Quad 204 FPSO.

Significant downside risks remain, however, as heavier-than-forecast maintenance and unplanned outages can result in a production decline, as has been the case every year since 2010. We adjust our production forecast for seasonal maintenance based on company announcements for the short-term and historical patterns in the medium term, and we also include an adjustment factor for unplanned maintenance and outages.

Production of NGLs in the United Kingdom is expected to drop to just under 50 kb/d in 2014, a large decline from as recently as 2010, when the country was producing over 100 kb/d. Production is expected to flatten out to approximately 45 kb/d from 2015 onward, as some new gas projects with liquids such as Ithaca's Stella and Harrier fields and Serica's Columbus field come online, though mature fields will continue their decline.

Much like in the United Kingdom, **Norway's** total production is expected to increase slightly over the medium term. Development of fields close to existing infrastructure is expected to improve Norway's output. Overall, Norway's production is expected to edge up to 1.89 mb/d in 2018 from 1.84 mb/d in 2013, before it declines slightly in 2019, ending the decade at 1.88 mb/d.

A number of new projects increase Norway's production in the medium term, including bringing online the Ivar Aasen field, as well as adding capacity to current production at the Norne, Ekofisk and Eldfisk fields will boost production by about 150 kb/d starting in 2016. In early 2014, Statoil launched the first in what is expected to be a string of new projects over the next several years. The high-pressure, high-temperature Gudrun field started production in April, and the oil will be shipped to the Kårstø onshore plant via pipelines linked to the Sleipner field. Meanwhile, the Valemon field's start-up may be pushed back past 4Q14 as a result of a delay of the platform delivery. The Gina Krog and Aasta Hansteen fields are expected to come online in 2017 and produce 60 kb/d and 130 kb/d, respectively. Development of the Johan Sverdrup field, with cost estimates for phase 1 of well over USD 16 billion, is Norway's third-largest discovery in history and is expected to bring on significant production beyond the time period of this forecast. The first phase infrastructure should be approaching completion by the end of the forecast period, with expectations of production starting in 2020.

Norwegian NGL production, after reaching 305 kb/d (not including plant pentanes) in 2013, is forecast to increase by about 15 kb/d by 2016, and then hold flat for the remainder of the period. While much of the North Sea is as mature a province for NGLs as it is for crude, and is in decline, new projects provide an offset. The Edvard Grieg oil and gas field (set to start up end-2015 and to plateau at 100 kboe/d) is expected to bring on sizable new NGL production. The development of Ivar Aasen (phase 1 to be online in late 2016, at 16 kboe/d) will depend on the Edvard Grieg platform for liquids processing. The aforementioned Gina Krog field is also expected to deliver significant NGL production, which will be transported to Kårstø for processing and export. The aforementioned Valemon field is also expected to deliver a substantial amount of NGLs which will be piped to the nearby Kvitebjørn, with pentanes sent onward to the Mongstad refinery. All told, seven fields with combined NGL reserves of 8.3 million tonnes (approximately 85.5 million barrels) are scheduled to be brought online in the forecast period.[10]

Latin America

Brazil will be the second largest source of non-OPEC supply growth in the next five years after North America, with production rising to 3.1 mb/d in 2019 from 2.1 mb/d in 2013. Brazilian production is expected to achieve at long last a slight increase in 2014, reversing a two-year decline. Overall, oil production growth is expected to average about 160 kb/d per year between 2013 and 2019 as major projects start up, including the FPSOs in the Santos as well as Campos Basins. Brazilian output is expected to breach 3 mb/d in 2019, a year later than forecast in the *MTOMR 2013*. The delay is mainly due to project slippage and higher estimates of decline rates at currently producing fields.

Figure 2.33 Brazilian oil production

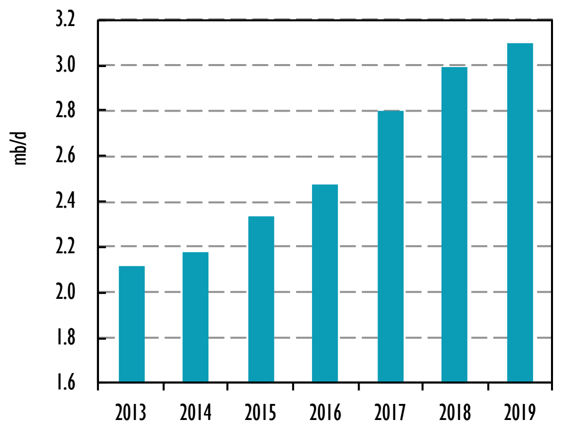
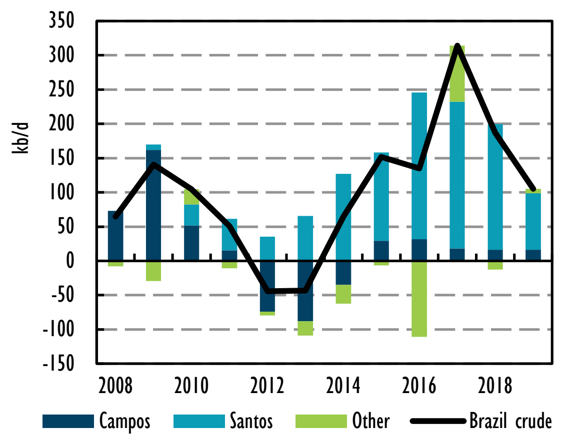


Figure 2.34 Brazil crude production growth by basin



Brazil's pre-salt production has been increasing at a healthy pace and reached a new record high of 430 kb/d in April 2014. Although pre-salt activity has in many ways been a success story in terms of production flows, it has been a bumpy road for Petrobras. Since 2010, the company has struggled to

[10] Source: Norwegian Petroleum Directorate.

achieve any annual growth in overall output, due to a combination of project delays and high decline rates at legacy fields. Decline rates in deepwater offshore fields are as high as 20% and have substantially increased over the last decade. More than 200 kb/d of new production capacity is needed just to offset declines.

Meanwhile, Petrobras faces severe cash constraints due to mammoth losses in its downstream operations. Brasilia's efforts to rein in inflation and keep gasoline prices down conflict with the financing needs of its national oil company. As the country's downstream monopoly, Petrobras must supply gasoline at government-controlled prices which have been maintained at unprofitable levels, even considering recent increases. This has caused Petrobras to haemorrhage cash as it imports petroleum products at international prices and sells them below cost. The company has run into significant debt, by some measures the most indebted oil and gas company in the world, at over USD 110 billion. In order to increase potential profitability, and reduce debt, Petrobras announced in February 2014 that it would reduce total investments for 2014-18 from USD 237 billion to USD 221, a net fall of USD 16 billion, with USD 26 billion in expenditure reduced in the refining sector. Upstream outlay will actually be increased by about USD 10 billion, as the company redirects resources to those areas most likely to bring a better and more rapid financial return. Besides the changed expenditure by Petrobras, which produces approximately 90% of Brazil's total petroleum liquids, numerous other companies such as Statoil and Chevron operate in the upstream sector. These companies are estimated to have spent about USD9 billion on development and exploration capex in 2013, with a projected increase to about USD14 billion annually by 2018.[11]

Changes to the upstream contract structure has also affected capacity, with production sharing agreements (PSAs) now replacing concession agreements. Foreign companies are less willing to invest in Brazil than they previously were on pre-sale fields, as the country appears to offer less attractive terms. Petrobras is now the mandatory operator of pre-salt oil fields. For some private-sector and foreign companies, making huge investments while depending on Petrobras to be the operator is unsatisfactory. Only one consortium bid on the development contract for the super giant offshore Libra pre-salt oilfield in October 2013, which could be taken as emblematic of less-attractive terms on offer. Yet, for Petrobras, which is obligated to participate according to the terms of the winning bid, a more competitive bidding process under which the winning consortium promised more generous terms to the government would result in Petrobras having to pay out more on the project. This would be a difficult position for the highly-indebted company, and is a quandary for Brazilian policymakers responsible for both government revenues and ensuring the success of a company in which the state is still the single largest shareholder.

Brazil's government, and by extension Petrobras, have focused on pre-salt fields as the driver of the country's potential. However, developing pre-salt fields is technically challenging and these resources require significantly more investment, time and technical ability than other deposits. Petrobras has seen a significant increase in production costs for existing wells, equipment, labour and materials, with more than 30% growth in costs between 2011 and 2013. The government remains heavily involved in the upstream, with rigid local-content requirements at times overburdening the sector and making it harder to meet project budgets and deadlines. Petrobras and other companies involved in the industry are required to use a certain percentage of Brazil-built ships, platforms and equipment in order to comply with government-mandated local content requirements. Nevertheless, since the

[11] Source: Rystad Energy.

beginning of 2013, a number of major projects have come online, and Petrobras expects that 13 others will start operating by the end of 2016. Given delays thus far, we expect that these projects, on average, will come on-stream two to three quarters after their scheduled start.

Medium-term oil production growth is expected to come mainly from the pre-salt area, with major contributions from the Lula, Sapinhoá and Parque das Baleias fields. In addition, the Roncador and Papa Terra fields will also contribute to growth. We expect that pre-salt production alone will grow to about 1 mb/d in 2019, but that this growth will be offset by decline rates, resulting in a net increase of 1 mb/d over the forecast period for all liquids output (given that there is growth in non-pre-salt fields).

Despite the dynamism of the upstream crude oil sector, NGL production in Brazil has been stagnant in recent years, with only modest growth expected in the forecast period. Moreover, the ratio of NGLs to crude oil is low compared to other offshore areas, such as the North Sea or the US Gulf of Mexico. Production is expected to remain flat at 90 kb/d this year and next from 2013 levels, with small gains lifting it later on to 110 kb/d by 2019. In part, this is based on expectations that Brazil's natural gas production will keep getting dryer, as it has done recently, so that NGL increases are modest in the face of expected rises in natural gas production. The Mexilhão gas field is expected to bring on sizable volumes of field condensate in the next few years, adding to Brazil's now marginal field condensate output of 11 kb/d.

Colombia is the second largest non-OPEC producer in non-OECD Latin America after Brazil, with total output of slightly over 1.0 mb/d in 2013. Exploration in the country has raised total reserves and Colombia has considerable shale oil potential. Nonetheless, lifting oil production much above current levels will be something of a challenge due to a combination of above-ground and below-ground problems. Below ground, the increased heaviness of the oil produced in the country (now about half of all output) makes it difficult to move from remote inland fields to coastal export terminals, making the country reliant on higher volumes of imported diluent (mostly naphtha). Above ground, a recrudescence of political unrest and pipeline attacks has revived concerns about political disruption risks. Although unrest is not new to Colombia and the government had in recent years managed to significantly reduce violence in the country, flare-ups occur periodically. Reduced violence as well as additional technology and pipeline capacity will be needed to sustain, let alone increase, Colombia's oil output. As recently as April 2014, Colombian crude oil production fell to a 20-month low because of rebel attacks on infrastructure and indigenous protests that prevented infrastructure repairs for over a month following the attack, resulting in at least 100 kb/d of disrupted production in March and April 2014. Beyond security problems, companies developing or attempting to develop Colombia's resources are faced with months-long waits for drilling permits and difficult logistics.

Colombia's total output is forecast to grow marginally to 1.1 mb/d in 2019. Colombia's reserves and production are concentrated in the Llanos Basin. This basin is expected to remain the backbone of the country's output through 2019, but activity is also expected to increase in the Catatumbo and Magdalena Basins. The largest field in the country, Rubiales, produced about 210 kb/d in 2013, and the operator, Pacific Rubiales (second-largest operator in the country after state company Ecopetrol), has plans to implement its STAR secondary recovery technology post-2016 to maintain output on the field should the company acquire new contract to replace its current one that expires in mid-2016. There remains a great deal of the country that is unexplored, which could potentially begin to yield results by the end of the forecast period. Important areas include CPO-14, CPO-17, and the Portofino blocks. Overall, we expect that the government will continue to dampen unrest and violence in the country, although some periodic disruptions have been built into the forecast. The forecast also assumes some increase in pipeline capacity.

Although **Argentina's** oil production remains comparatively small, this richly-endowed country is expected to start bridging the gap between its still modest share of global oil production and its much larger reserves towards the end of the decade. Its reserves include the world's fourth largest known shale oil deposits after Russia, United States, and China, and recent technological advances make it possible to unlock them. For technical, political and other reasons, this huge potential has remained largely untapped. In 2013, Argentina's oil production averaged 630 kb/d. But the conditions for development are looking up. Production is expected to remain roughly unchanged through 2016 and then begin to increase as development in the Neuquén Basin, specifically in the Vaca Muerta shale play, begins to expand. Output is forecast to reach 735 kb/d in 2019 and growth is expected to gain momentum in the next decade.

Recent settlement between Argentina's government and Repsol over expropriated YPF assets will help attract international investment in the country's unconventional resources, leading to development of the Vaca Muerta shale play. Argentina's government expropriated the majority stake in YPF from Repsol in 2012 but reached a compensation agreement with the company in early 2014. Under the agreement, Repsol will receive a package of dollar-denominated government bonds and sovereign debt valued at approximately USD 4.76 billion; in exchange, it will forego any legal claims against YPF. In March 2014, YPF contracted for 15 new rigs to work the Vaca Muerta play, with deliveries over the next few quarters.

With worries about political risk to foreign investors abating, international oil companies will look to extend their reach in the shale play. Chevron and ExxonMobil have already partnered with YPF in Vaca Muerta. Chevron is producing oil in the play while ExxonMobil is still in the early phases of well testing. Overall, Argentina's shale oil potential (technically recoverable) is estimated at 27 billion barrels, mainly in the Neuquén Basin, although potential resources exist in three other untested basins in the country, the Golfo San Jorge, Austral and Paraná Basins.

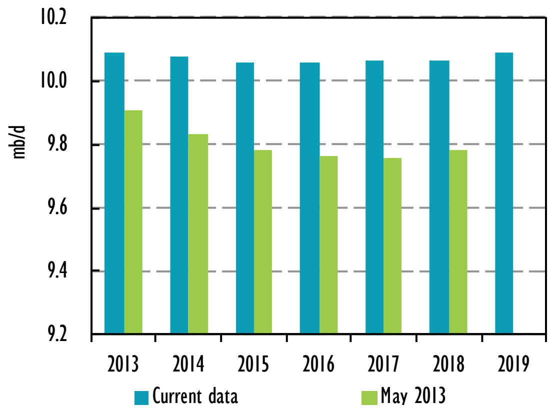
Former Soviet Union

Russia was the largest non-OPEC liquids producer (excluding biofuels and refinery processing gains) until this year, when it was overtaken by the United States. Russia's potential for growth is considerable, however, a lack of clarity on taxation, export duties and special treatment of greenfield projects, including unconventional development remains, possibly tempering growth.

Total liquids production is expected to increase to 11.0 mb/d in 2019 from about 10.9 mb/d in 2013 as new production and improved recovery rates offset a decline in brownfield production. Condensate production is also expected to increase as a number of large gas projects come online. Tight oil production in the Bazhenov play will come online in the latter years of the forecast. Tax breaks for tight oil deposits are expected to spur development of this prospective resource. A number of international oil companies have already teamed up with Russian majors to explore and test the commercial viability of the resource. So far Rosneft has formed partnerships with BP, ExxonMobil, Statoil and Total, while Gazpromneft and Shell and Total and Lukoil have also announced agreements.

We estimate that tight oil production in Russia could total more than 200 kb/d in 2019, however this estimate is less than half of the target level announced by the Russian government.

Figure 2.35 Russian crude oil production



Recently introduced changes to the Mineral Extraction Tax will likely improve the prospects for unconventional oil resources. Prior to these changes, companies had very little incentive to develop Russian tight oil resources, as higher costs associated with hydraulic fracturing and horizontal drilling made the projects uneconomic under the previous tax structure. Under the new MET terms, tight oil will see 20% to 100% relief for 10 to 15 years. The tax regime for tight oil production was introduced in 2013 and is applied to projects depending on permeability, extent of [future] field depletion and size of oil layers. Depending on these factors, various coefficients are applied to reduce the total level of MET owed by the oil company. The deep Tyumen deposits will have a high coefficient, resulting in no tax relief, while shale layers in the Bazhenov and the associated Abalak, Khadum and Dominak reservoirs will have complete MET relief for 15 years. MET relief is central to the development of Russia's tight oil. Much as with previous tax breaks for offshore fields, onshore greenfields and Arctic areas, MET relief for tight oil projects will provide growth support as only with the tax relief are many of these projects economically viable.

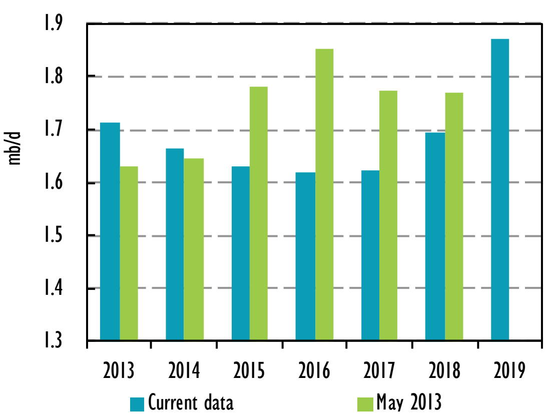
A number of domestic companies are already operating in the Bazhenov, while others are showing interest in the play. Surgutneftegas is Russia's largest shale oil producer, though Bazhenov accounts for less than 1% of its total oil output despite coming from as many as ten fields. While the company plans on expanding production in the area, further investment decisions will be made depending on the tax regime. Lukoil, too, is developing oil production in the formation in Western Siberia and hopes that the use of advanced drilling techniques will increase oil recovery rates. GazpromNeft's and Shell's Salym joint venture is currently conducting horizontal fracking appraisal tests on the Upper Salym portion of the formation. Meanwhile Rosneft estimates the production potential from tight oil resources with which the company has a share at about 300 kb/d by 2020.

Tensions with the West as a result of the recent standoff with Ukraine are not expected to affect the investment climate and Russia's production in a big way in the medium term, based on the sanctions levelled against individuals and businesses thus far. Several international oil companies have signed major commitments with Russian counterparts for large-scale projects since the outbreak of civil unrest in Ukraine. Those include Exxon Mobil's extension of its partnership with Rosneft; Total's creation of joint exploration venture for shale with Lukoil; and BP's creation of a joint venture for shale exploration with Rosneft. Individual sanctions on Russian oil executives look unlikely to have much effect on foreign investment, though Russian companies face higher borrowing costs after international rating agencies downgraded the country's sovereign debt.

Should tensions escalate in the future and sanctions become more severe and target more directly the oil sector, western companies may adopt a lower profile in Russia's upstream. Western operators are niche players in Russia's upstream sector in terms of their equity percentage of the country's total output, with their greatest presence in Sakhalin. Although so far the upstream oil sector has not been materially affected by sanctions, they have impacted Russia's economy and therefore have the potential to affect oil production in the longer term. The IMF downgraded its forecast of Russian economic growth in light of increased uncertainty given the situation with Ukraine, capital flight, and a reassessment of macroeconomic conditions. The country's demand is expected to decelerate in 2014, to an approximate growth rate of 1.7%, having risen to around 3.55% in 2013. Russia's diminished access to western capital markets may affect its oil and gas companies. Western technological expertise is critical for complex developments such as Russian Arctic and tight oil.

Total Russian NGLs and condensates were estimated at about 780 kb/d in 2013. Ethane and LPG production is expected to reach about 240 kb/d in 2019 (with that being mostly LPG), from an estimated 200 kb/d in 2014. Russia is, however, a significant producer of plant pentanes. Key to the expansion of Russia's NGLs have been private-sector companies such as Novatek and Sibur. Novatek has focused on developing wet-gas plays in the past decade as well as on stabilisation facilities that extract ethane, propane and butane from condensate. With Novatek's reported crude and condensate output (85% condensate in 2013) having doubled from about 50 kb/d to 100 kb/d in 2003-10, corresponding increases in NGLs from the company occurred. Away from the wellhead, Sibur extracted out about 150 kb/d of NGLs at its processing and fractionation plants in 2013. That is set to increase when its second gas fractionation unit at the Tobolsk facility comes online in 3Q14, nearly doubling the plant's capacity, to 185 kb/d. Gazprom, Russia's largest natural gas producer by far, also produces a large amount of condensate and NGLs – nearly 300 kb/d of just condensate in 2013 – and, plans to increase it by 20% by 2016. Gazprom intends to increase the processing capacity of all non-crude liquids to 23 million tons per year by 2020. Although this is an ambitious programme, some increase in gas liquid processing capacity is to be expected as the company focuses on raising output of NGLs and condensates from the Achimovsk Suite in the Yamalo-Nenets region. Gazprom's enormous 6.2 million-tonne capacity Orenburg gas plant processes liquids not only from Russian fields, but also from the Karachaganak field in Kazakhstan.

Figure 2.36 Kazakhstan oil production



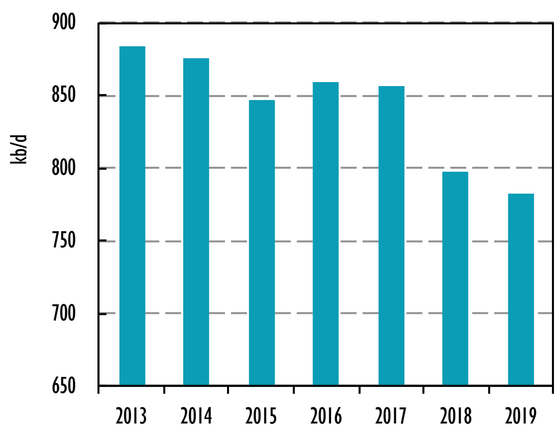
Total production from **Kazakhstan** is expected to increase to 1.9 mb/d by 2019, up 225 kb/d on 2013 levels, but all of the gain will occur in the last three years of the forecast period following new delays at the giant Kashagan field.

When the Kashagan field was initially discovered in 2000, producers had planned to bring it online within five years, but technical challenges along with environmental factors have contributed to repeated delays. The crude oil that the field contains has high sour gas content, providing myriad challenges to develop the project. First oil finally started to flow in September 2013, but production was almost immediately arrested when sour gas leaks were detected. Subsequent restart of the field in October 2013 was also quickly aborted and the field has been offline since then. It has become evident that Kashagan will not restart production until 2016. In recent announcements, the consortium that operates the field revealed that both oil and gas gathering lines will have to be replaced, adding further woes to a project that is more a decade behind schedule and has greatly exceeded its initial cost estimate.

While the field has proved technologically challenging, the latest setback may be related to above-ground issues as much as geological or technical problems. The gas line leaks were initially thought to be the result of the sour gas, which corroded the pipes, however since the announcement that even oil lines will need to be replaced, the apparent culprit appears to be the welding. The field development contract structure necessitated that pipeline welding be completed in accordance with the local content requirements, and local contractors be hired who may not have been qualified to complete this work.

Oil from Kashagan was the main driver of Kazakhstan's expected increase in total production, but with those volumes unavailable until 2Q16, output in the country is expected initially to fall through 2015 due to declines at mature fields, including Tengiz. Total production in Kazakhstan is then expected to increase in 2017 and through to 2019 as Kashagan's production comes online, and other projects help boost total output. The Karachaganak Phase III is expected to come online by the end of 2017. Karachaganak produces field condensate, rather than crude oil, but also sends natural gas for processing in Russia, where NGLs are extracted. NGL output is about 75 kb/d in Kazakhstan, but is forecast to increase as Karachaganak Phase III is implemented, reaching 110 kb/d in 2019.

Figure 2.37 Azerbaijan oil production



Azerbaijan's production will decline to 710 kb/d in 2019, a drop of 120 kb/d from the 2013 level. The Azeri-Chirag-Guneshli (ACG) field, which accounts for nearly 80% of the country's total output, has seen significant drops in production, partly due to natural declines but also severe maintenance issues. We expect that ACG output will fall to below 600 kb/d by the end of the forecast period. The Azerbaijan International Oil Company (AIOC), the operator of the ACG field, is hoping to limit declines at the field through the implementation of the Chirag Oil Project, the latest phase of which went online in January 2014. The final instalment of the USD 6 billion project included the West Chirag platform with a production capacity of about 185 kb/d with six wells. The output at the platform will increase to 60 kb/d by the end of this year and ramp up to through 2019.

The medium-term forecast for Azerbaijan has been revised downward compared with the *MTOMR 2013* due to a lower baseline estimate for 2013 and 2014. Azerbaijan's output will see a slight increase in 2016 due to the boost in production from the Chirag Oil Project as well as field condensate increases from Shah Deniz 2 in 2019, but the declining overall production trend will reappear by 2017.

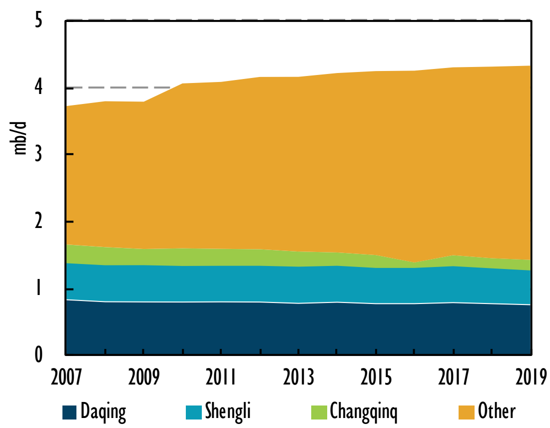
Non-OECD Asia

Overall non-OECD Asia oil output excluding China is expected to decline throughout the forecast period, falling about 125 kb/d between 2013 and 2019. China is among the few producers in non-OECD Asia that will see an increase in oil production, while most of the others, including former OPEC member Indonesia, will see production declines. While overall supply is expected to fall through 2019, demand for oil products will continue to grow at 3% each year in the region necessitating increasing volumes of oil to be shipped to the region to satisfy demand.

Total oil output in **China** is expected to grow to 4.3 mb/d in 2019, an increase of 170 kb/d compared with the 2013 average, continuing the increase in China's output since 2010. The projected average annual increase of 25 kb/d through 2019 is somewhat lower than the recent growth rate of 80 kb/d since 2001. China's projected production was revised downwards compared with the *MTOMR 2013* mainly due to a lower base in 2013. Output that year dropped due to severe flooding that affected various large onshore fields such as Daqing and fields in Shaanxi province operated by state company Shaanxi Yanchang Petroleum as well as, to a lesser degree, by pipeline problems. However, output will grow as companies expand offshore development and conventional production.

Medium-term production growth will be driven by a number of redevelopment projects in the country, including employment of EOR techniques at the Daqing and Changqing oil fields. The Daqing oil field has been in operation since 1959 and is the country's largest field. The roughly 800 kb/d Daqing field used to produce about 1 mb/d until a few years ago, but the use of EOR techniques and development of smaller fields in the area arrested years of precipitous declines. For much of the medium term, Daqing's production will remain at approximately 780 kb/d. However, towards the latter years of the forecast period, Daqing's production will fall to 770 kb/d. The Changqing oil field will continue to increase production through the end of the forecast period and reach 600 kb/d by the 4Q19. The use of horizontal drilling and hydraulic fracturing in low permeability reservoirs has resulted in better performance of wells and lower decline rates.

Figure 2.38 Chinese oil production



China enjoys the world's third-largest shale oil resources at an estimated 32 billion barrels but those pale in comparison to the country's shale gas resources (which rank first in the world). The shale oil resources in China are technically challenging. Although Chinese production is expected to benefit in the next five years from the application of unconventional extraction technologies to conventional fields, unconventional oil resources are forecast to provide only a marginal contribution in the medium term. China's shale resources are scattered across 150 basins and are found at much greater depths than those in the United States or Argentina, and are thus much costlier to develop. China also lacks necessary infrastructure and water for large-scale fracking operations. Although China's government has set ambitious targets for unconventional resource development of gas, the scope for meaningful expansions for oil prior to 2019 appears limited.

Other Asia

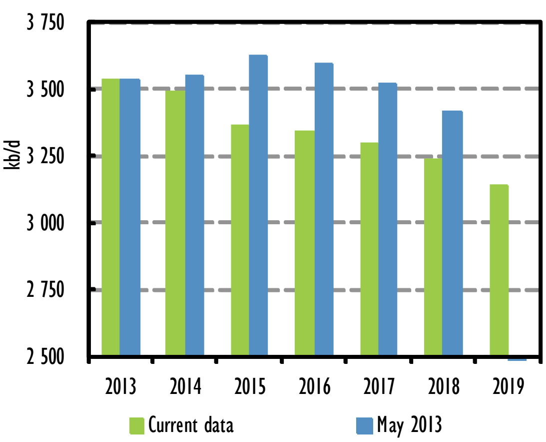
India's oil production is forecast to decline to 770 kb/d in 2019, falling about 130 kb/d from the 2013 level. The outlook for India remains roughly unchanged compared with the *MTOMR 2013* as the industry in India continues to be focused on halting declines to current production. Outside of the Rajasthan block, India's production is flat or declining. Marginal field development by Indian state oil companies ONGC and OIL is taking place but it will be largely to offset declines to Bombay High production. India's NGL production is expected to decline slightly in 2014, before increasing gradually in the rest of the forecast on heightened natural gas output. Production is forecast to rise from 110 kb/d in 2013 to 130 kb/d in 2019.

Malaysia's supply is expected to grow, albeit very slightly. Total output in 2019 is seen to average 670 kb/d, approximately 10 kb/d higher than in 2013. Increasing production in the Sabah and Sarawak areas are offsetting declining output at legacy fields, including Tapis. ExxonMobil and Petronas are employing water-alternating-gas (WAG, often considered a type of EOR) techniques at Tapis with the goal to increase oil recovery and extend the field's life. This is expected to result in approximately 20 kb/d of additional Tapis volume by 2018. Shell is participating in two other EOR projects in the offshore Sarawak and North Sabah areas. The Gumusut field is anticipated to begin production in the 3Q14, with the total output from the Gumusut-Kakap field expected to peak in 2016. Kakap has been in production since late 2012. Malikai development will produce first oil in 2018.

Viet Nam's output is anticipated to remain at roughly unchanged through 2019, averaging 340 kb/d. The Su Tu Nau field is expected to commence production by the end of 2014 with Phase I peak capacity of 50 kb/d. These volumes will contribute significantly to offset declines in the more mature areas.

Although **Indonesia's** government has ambitious goals to restore the country's oil production to 1 mb/d by 2015, progress at new fields thus far has been underwhelming and barring any major reversal of this, Indonesia's production will see a slight increase through 2016 before it begins to decrease again. The Banyu Urip field in East Java is expected to produce approximately 150 kb/d by the end of 2015 but delays at other key developments will continue to prevent production from recovering. The ExxonMobil-operated Cepu oil block is expected to triple its production to 80 kb/d by the end of 2014, while peak production of 165 kb/d could be reached by the end of 2015.

Figure 2.39 Non-OECD Asia ex China oil production



Middle East

The outlook for **Syria** and **Yemen** continues to be dominated by political turmoil. Given the lack of change to the political and security situation, the prospects for these two countries remain negative over the medium term. Syria's production is expected to remain below 100 kb/d through 2018 and then rise just above 100 kb/d in 2019 on the assumption that some stabilisation of the political process may take place by then. Yemen's production is expected to fall to 80 kb/d in 2019 from the 2013 average of 140 kb/d. The slide is due to mature field decline and lack of new investment. The continued violence and unrest further exacerbates these problems, leading to a precipitous decrease in the country's production throughout the forecast period.

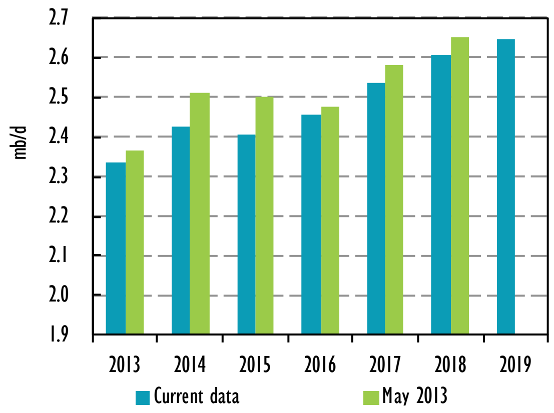
Oman's production is forecast to edge down to 890 kb/d in 2019, a fall of about 55 kb/d from the 2013 level. The decrease in production is driven by declines in mature fields, only partly offset by employment of EOR techniques, including miscible gas, steam injection and chemical EOR technologies. Occidental's Mukhaizna EOR project continues to produce at around 120 kb/d and will likely plateau at this level, despite an initial plan for 150 kb/d of peak production capacity. Other ramping EOR projects that should add around 40 kb/d in total in the medium term include Qarn Alam, Amal East and West steamflood. About 105 kb/d of Oman's liquids is field condensate, which is blended into heavier crudes such as Mukhaizna to lighten their grade prior to export.

Africa

Our overall outlook for African supply has been revised downward since last year, with the forecast for Ghana and South Sudan driving most of the revision. Expectations for South Sudan were much more positive last year, when a resolution to the dispute between the South Sudan and Sudan seemed imminent. We also revised our outlook for **Egypt** downward and now expect that its production will decrease to 550 kb/d in 2019 from 700 kb/d in 2013.

Sudan's production outlook in the medium term has remained largely unchanged. The forecast for **South Sudan's** output has been revised downwards on the back of the deteriorating security situation in the country. South Sudan produced approximately 100 kb/d of oil in 2013 and its production is forecast to rise to about 240 kb/d in 2019, with increases occurring in 2017 and beyond as investment is expected to pick up in 2015 and 2016. The possibility of a worsening conflict in the country remains and there is a significant downside risk to this forecast.

Figure 2.40 Non-OPEC Africa oil production



Ghana's forecast has been lowered and we now expect that the country's production will rise to 170 kb/d by 2019. The revision is due to changes in the near term: we reduced our outlook for 2014 as a result of the lack of a gas processing facility at the Jubilee field, which has necessitated that oil flow be reduced to less than 100 kb/d. The field operator is attempting to build a bypass gas line as the delays in the Atuabo gas processing plant and related infrastructure are causing the field's diminished output. Meanwhile, local-content requirements and political uncertainty will also affect total oil production. The Keta Basin may be a promising area to explore, yet any development is being hindered by high local-content requirements. Any future development of the Tweneboa-Enyenra-Ntomme (TEN) is highly uncertain as the maritime border dispute with Ivory Coast remains a hindrance.

A small amount of oil production (less than 5 kb/d) from **Uganda** will likely commence before the end of the forecast period. The government has set a target for production to commence by 2017, but the CNOOC/Total/Tullow consortium developing the Kingfisher field in the Lake Albert Rift Basin has announced that production will be delayed until at least late 2018, given that large amount of associated infrastructure is necessary for the project, from new roads to a new refinery.

Box 2.3 Natural gas liquids and condensates

Global non-crude liquids coming from gas fields, whether in the upstream or extracted from the gas downstream at processing facilities, are forecast to grow from 14.8 mb/d in 2013 to 17.8 mb/d in 2019. This includes all natural gas liquids (NGLs) and field condensates.

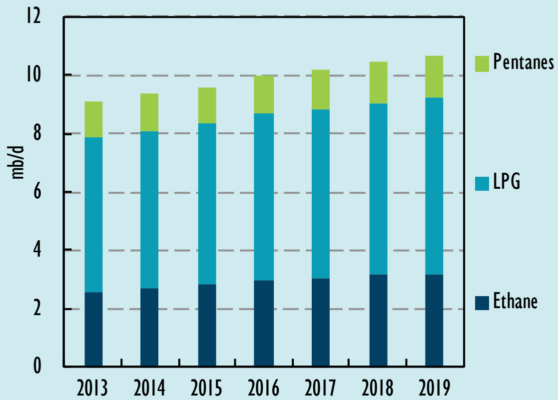
Such liquids increase from 16% of world liquids production in 2013 to 17% of global liquids production capacity in 2019, though unlike crude oil, there is little if any unused production capacity for these liquids in the forecast period figures.

Box 2.3 Natural gas liquids and condensates (continued)

A word on terminology and methodology

Natural gas liquids lend themselves to multiple definitions, and key statistical agencies around the world often use the term to mean different things. The IEA defines NGLs most broadly as the liquid or liquefied hydrocarbons produced in the processing, purification and stabilisation of natural gas. These are the portions of natural gas which are recovered as liquids in separators, field facilities, or gas processing plants. According to this definition, NGLs include but are not limited to ethane, propane, butane, pentane, natural gasoline and condensates.

Figure 2.41 World NGL production



Ethane, propane and butane (the latter two being grouped together as LPG, unless it is specifically noted that an LPG figure contains ethane) do not come directly from the gas field, but pentanes can also come directly from the field, without going through a processing plant, though a relatively simple separation process still occurs. These C_5+ hydrocarbons, are variously known as pentanes plus, natural gasoline, lease condensate, plant condensate, plant pentanes, etc. and are essentially chemically similar. Nevertheless, a basic distinction for these pentanes that is often maintained in data reporting is whether they come from the field or a plant. This distinction can be important for understanding the infrastructure associated with their production/extraction, but also in the US context on the policy level. In the United States, the world's largest producer of NGLs, what are termed 'pentanes plus' (from processing/ fractionation of natural gas) can be exported, whereas both 'lease condensate' (taken at field facilities) and 'plant condensate' (taken at inlet separators or scrubbers in natural gas processing plants at atmospheric pressure and ambient temperatures) cannot. Most countries do not distinguish in data series plant condensate from pentanes plus, and data presented here does not do so either, except for the United States, which only reports data for pentanes plus, but not plant (nor lease) condensate (which are both included in the US crude oil figures).

In OPEC countries, where only crude oil was historically subject to quotas, all non-crude liquids have traditionally been termed NGLs, even though by IEA standards only a fraction of them truly qualifies asgas plant liquids, and the rest is field condensate. In some OPEC countries and other non-OECD countries, pentanes coming from gas plants rather than the field are termed gas plant naphthas.

For the purposes of the *MTOMR*, we attempt, whenever possible, to isolate out ethane, LPG, and pentanes from gas plants as NGLs, and term what comes from the field as condensate. Exceptions to this rule are discussed on a country-by-country basis. Note that crude oil production estimates outside of OPEC tend to include field condensate as a component unless otherwise noted. This is in large part because most of the world's field condensate goes into a crude stream whether it be directly at a refinery, as diluent, to lighten a heavier crude grade for export, or sent to a condensate splitter (essentially a type of simple refinery). Nevertheless, given that condensate comes from gas fields (which have different economic drivers than crude oil fields), is sometimes lighter than even the lightest crude grades, has a light-ends yield that can limit its refining use, and is sometimes specially marketed and transported, distinguishing it from normal crude oil is worthwhile.

Box 2.3 Natural gas liquids and condensates (continued)

In forecasting medium-term NGL production, we take the *MTGMR 2014's* forecast of natural gas production as input, making the assumption that NGL production tracks the dry natural gas production from which it is extracted, with the significant caveat that new upstream project developments and changes in fields over time can result in a country's natural gas getting wetter (having a higher percentage of liquids) or dryer over time. Natural gas could also be flared or otherwise not utilised despite being stripped for liquids. Likewise, processing capacity and demand must be sufficient to handle the liquids so that the methane is not burned with a high percentage of other hydrocarbons mixed in (e.g. ethane rejection). Hence, beyond the natural gas forecast, gas-to-liquids production ratios, a study of mid-stream and downstream projects and past trends in gas-to-liquids ratios has gone into the forecast.

A Glance at world natural gas liquids

Natural Gas Liquids emanating from natural gas plants are the second-largest source of liquid supply after crude oil, with an estimated production of 9.1 mb/d in 2013, or 9% of total world liquids. They are also one of the fastest growing sources of supply, and their growth is altering the composition and quality of the global supply mix. NGL supply is forecast to increase by 17% to 10.7 mb/d by 2019, when they will constitute 10% of the world oil supply.

Not all NGLs are the same. Indeed, they vary greatly in quality and market value. Of the total estimated marketed production in 2013, it is estimated that ethane was about 28%, increasing to 29% of NGL supply by 2016. In contrast, gas plant LPGs (i.e., propane and butane), trend down slightly from being 57% to 55% of NGL supply. Plant pentanes rise from 14% in 2013 to 15% in 2015 and 16% in 2018. Ethane increases its percentage slightly based on greater petrochemical demand in the United States and the Middle East. Note that given ethane rejection, particularly in North America, ethane output could easily be higher if demand were to be higher than in this base case, assuming that the mid-stream infrastructure could be built to support that demand.

Table 2.6 World NGLs production (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
Ethane	2.6	2.7	2.8	3.0	3.0	3.1	3.2	2.9%
LPG	5.2	5.3	5.4	5.5	5.6	5.7	5.9	1.7%
Pentanes	1.3	1.4	1.4	1.5	1.5	1.6	1.7	3.5%
Total	**9.1**	**9.4**	**9.6**	**10.0**	**10.2**	**10.5**	**10.7**	**2.3%**

Two groups of producers, OECD North America and OPEC, have until now dominated world gas plant NGLs output, each with roughly 39% of the world's supply in 2013. Over the next five years, however, OECD North America will pull ahead of OPEC and expand its market share to 44% of the world's NGLs, whereas OPEC's market share will dip to 35% on flat output. Most of the OPEC output is in the Middle East, where it will remain throughout the forecast period.

Table 2.7 Selected regional NGL output (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
OECD N. America	3.6	3.8	3.9	4.1	4.3	4.5	4.7	4.0%
Rest of OECD	0.5	0.5	0.5	0.5	0.5	0.6	0.6	2.0%
OPEC Mid East	2.9	3.0	3.1	3.2	3.1	3.2	3.2	1.0%
Rest of OPEC	0.6	0.6	0.6	0.6	0.6	0.6	0.5	-0.4%
Non-OECD Non-OPEC	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.5%
Total	**9.1**	**9.4**	**9.6**	**10.0**	**10.2**	**10.5**	**10.7**	**2.3%**

Box 2.3 Natural gas liquids and condensates (continued)

While the proportion of ethane, LPG, and plant pentanes remains fairly stable year-on-year on a global basis, it varies greatly by region. In Africa, marketed ethane output is negligible, as there is little capacity to either use it locally or transport it to markets elsewhere. Ethane plays a marginal role in the FSU too, at just 12% of total gas plant NGLs on average 2013-19, as in cannot compete in the local petrochemical sector against the availability of relatively inexpensive naphtha (given export taxes in Russia) used by the petrochemical industry as feedstock. In the OECD and OPEC Middle East, however, ethane makes up a much greater percentage of marketed output, at 33% and 35%, respectively.

Some of the important trends in plant NGL supply in the forecast period include:

- Booming output from US shale plays: Along with the increases in LTO and dry natural gas, NGLs have also boomed, and expectations for NGLs are similar to those for crude and natural gas going forward (see section on the US). Canadian shale plays will help make up for reduced NGLs from declining conventional gas fields.
- A 17% increase in NGL production makes for a world somewhat less dependent on refiners for LPG. NGLs (particularly ethane) are likely to increasingly displace naphtha as feedstock in the petrochemical sector; while plant pentanes will also increasingly replace naphtha as diluent.
- Large offshore gas projects will contribute to the growth of NGLs, particularly in Asia. Projects such as Prelude and Ichthys offshore Australia (for LNG, both projected to come onstream for 2016) and Liwan 3-1 offshore China (started 2Q14) will contribute to supply growth outside of the two core NGL-producing regions.
- Ethane will be traded overseas: Ethane, like methane, must undergo liquefaction via refrigeration in order to be shipped by tanker, and then be unloaded at a facility with regasification. Liquefaction increases the density greatly (reduces volumes by a factor of 424:1) to make shipping economic, but nevertheless greatly adds to cost compared to obtaining ethane by pipeline. Although liquefaction costs had until now deterred long-haul shipping, expectations that the wide differential between international oil prices and North American ethane prices will continue is changing that reality: European petrochemical company Ineos has thus decided to begin importing ethane from the United States to European petrochemical facilities in 2015.
- Finally, a major factor behind the growth in NGL output is the increasing wetness of natural gas itself, i.e. the rising proportion of liquid hydrocarbons (including ethane) that can be pulled off for a given volume of dry natural gas (see Figure 2.45). (This reflects producers choosing wetter gas plays, not greater ability to extract ethane and more complex liquids from the methane.)

Condensates and pentanes

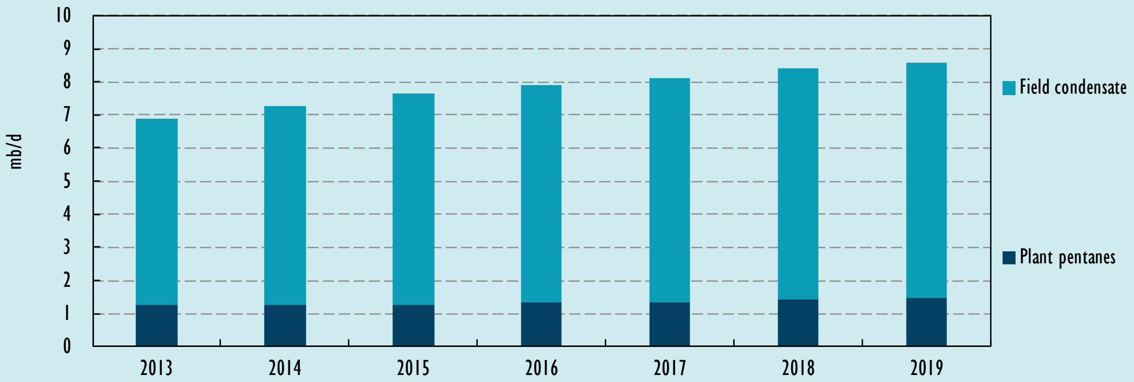
World field condensate production is forecast to grow to 7.1 mb/d by 2019, from an estimated 5.6 mb/d in 2013, a 27% increase. This would bring field condensate's share of world liquids production to 7% by the end of the decade, from 6% last year. In aggregate, NGLs and field condensate grow to 17% of world liquids production, from 15% in 2013. Because plant pentanes and field condensate can be used interchangeably, it is important to consider both liquids in terms of downstream implications. Together, pentanes of all sources are set to increase by 27% in 2019 from 2013.

Table 2.8 World condensate production (mb/d)

	2013	2014	2015	2016	2017	2018	2019	CAGR
Plant Pentanes	1.3	1.4	1.4	1.5	1.5	1.6	1.7	3.5%
Field Condensate	5.6	6.0	6.4	6.6	6.8	7.0	7.1	3.4%
Total	**6.9**	**7.4**	**7.8**	**8.1**	**8.3**	**8.6**	**8.8**	**3.2%**

Box 2.3 Natural gas liquids and condensates (continued)

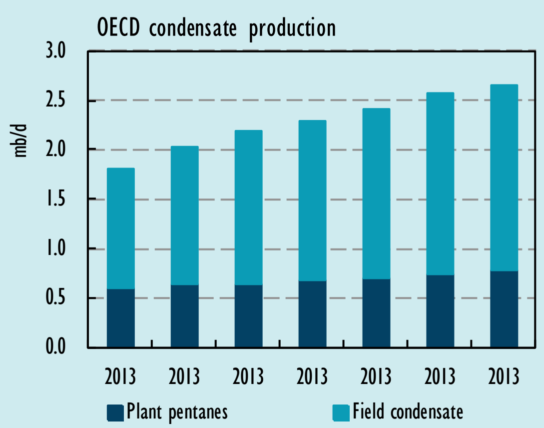
Figure 2.42 World condensate production

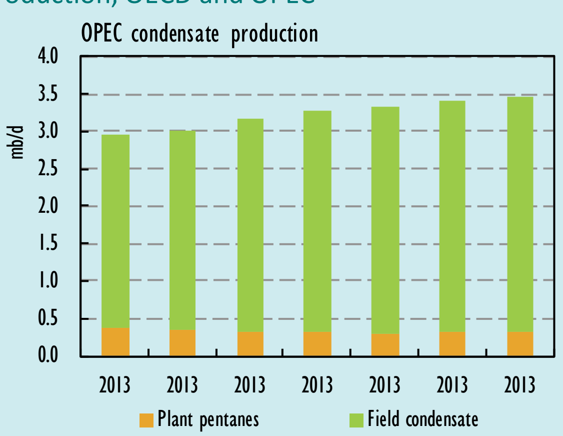


For OECD and non-OECD producer countries that do not provide an official breakdown of field condensate production, condensate supply must be estimated as a percentage of crude output. In the case of the OECD, however, condensate production accounts for a smaller share of marketed total liquids output than that of NGLs.

Most OECD field condensate comes from either the United States or Australia, with both countries are expected to show strong output growth in the forecast period. In the United States, incremental condensate output is a by-product or co-product of shale production – most of all, at Eagle Ford. We estimate that condensate supply not included in plant pentanes in the United States has nearly doubled from just over 500 kb/d in 2009 to about 1.0 mb/d by 2013, but is unlikely to expand at the same rate in the forecast period. Given price differentials with crude oil that reflect less capacity to absorb the condensate in North America as well as limits on exports, output is expected to reach just under 1.3 mb/d in 2016, and then grow by less than 100 kb/d for the remainder of the forecast period unless there are regulatory changes. Were legal limitations on exports (outside of Canada) of condensate other than pentanes plus to be lifted or reduced, one could expect some exports. Under such a scenario, condensate growth rates, particularly in the latter part of the forecast period would be higher and closely approximate the growth rates for crude oil. Depending on price differentials (currently substantial between North America and East Asia), regulatory changes, and output growth, industry could make various decisions about investing in new condensate splitters in the United States (see disposition table below), with more splitters likely in the absence of regulatory changes on field condensate exports. In Australia, though field condensate production has been essentially flat in recent years at between 130-150 kb/d, we expect condensate production to increase by about 200 kb/d by 2019, as large LNG projects such as Gorgon (2015, adds 40 kb/d), Prelude (2016, adds 35 kb/d) and Ichthys (2016, adds 100 kb/d) come online.

Figure 2.43 Condensate production, OECD and OPEC



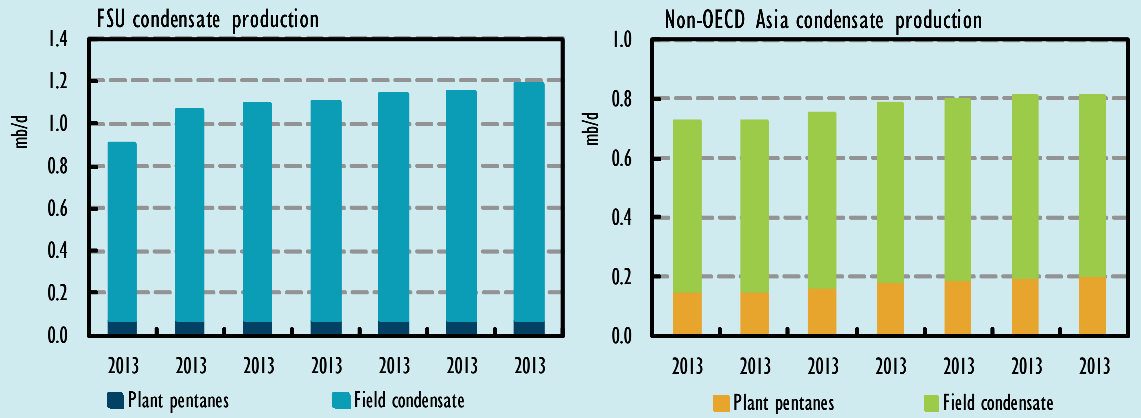


Box 2.3 Natural gas liquids and condensates (continued)

In OPEC countries, field condensate is always distinguished from crude oil and included in the broader NGL category. Unlike crude, it is not subject to production quotas. In several OPEC countries, including Iran, Nigeria, Qatar, Saudi Arabia and the United Arab Emirates, field condensate looms large in total liquids output. In Qatar, field condensate production of 780 kb/d exceeded crude output by 50 kb/d in 2013, making Qatar OPEC's largest condensate producer. Natural gas developments on the super giant North Field have yielded large increases in field condensate – over 350 kb/d since 2009. The Barzan gas development, also on the North Field, is expected to add another 50 kb/d by 2016. In Iran, which shares the North Field with Qatar (the Iranian sector is called South Pars), several gas development projects are planned that would increase condensate capacity by about 200 kb/d to 580 kb/d by 2019, the bulk of which is to come from South Pars, as well as development of the Kish (30 kb/d) and Farouz (10 kb/d) fields. Smaller amounts of condensate growth are expected in Saudi Arabia and the United Arab Emirates, both of which aim to increase dry gas output for power needs. Field condensate output capacity in Nigeria is expected to decline gradually with a lack of new investment. (For more OPEC condensate, see "OPEC gas liquids supply".)

Outside of the OECD and OPEC, the FSU is the most important condensate producer, at about 1.0 mb/d in 2013, growing to 1.2 mb/d by 2019. Russia accounts for most of this production, led by Gazprom and Novatek, whose liquids output is overwhelmingly made of condensate. Both companies have ambitious plans to increase condensate output at both existing and new fields, such that field condensate output in Russia is set to increase by 23% over 2013 by 2019. In Kazakhstan and Azerbaijan, the Karachaganak and Shah Deniz 2 projects are the main contributors to growth.

Figure 2.44 Regional condensate production



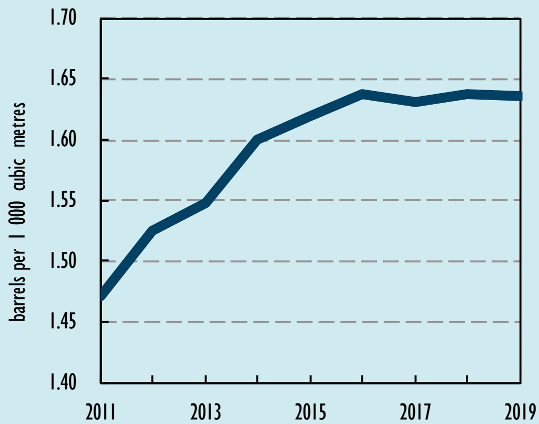
Field condensate production is also important in non-OECD Asia, including Thailand (up 10 kb/d to 100 kb/d over the forecast period); Viet Nam (up 10 kb/d to 90 kb/d); India (down 10 kb/d to 150 kb/d); Indonesia (about 50 kb/d throughout the forecast period); and Malaysia (up 10 kb/d to reach 50 kb/d). Data on Chinese field condensate production is scarce, though some condensate is almost certainly included in the country's crude oil numbers. New offshore projects with the participation of foreign companies are likely to report field condensate production (e.g. Liwan 3-1), but onshore condensate is estimated conservatively at about 50 kb/d, though it could be significantly higher. Papua New Guinea is set to become a small condensate producer with the PNG LNG project, which came online ahead of schedule in April 2014, with the first cargoes to ship in 3Q14. Although initial production will be small, beyond the forecast period condensate output could reach 60 kb/d.

Box 2.3 Natural gas liquids and condensates (continued)

Gas getting wetter through 2016

From slightly more than 1.5 barrels of NGLs and field condensate per thousand cubic metres of natural gas produced in 2011, the ratio increases to about 1.64 barrels per million cubic metres in 2016, and then levels off for the rest of the decade. This reflects that in the latter part of the forecast period, although gas continues to grow wetter in places such as North America and Australia, there is additional gas production in China, where known liquids output is small, and additional dry gas supplies come online in the OPEC Middle East while NGL offtake there grows much slowly.

Figure 2.45 Barrels of NGLs and condensates per tcm of gas production



In North America, the large price differential between dry gas and liquids (other than ethane) has continued to favour the development of liquids-rich plays (see section on United States in this chapter). For expensive offshore LNG projects in Australia, drawing off large amounts of NGLs and condensates can be key to the economics of the project. But, for much of the world with higher dry natural gas prices and few opportunities to market ethane, the incentive to focus on liquids-rich opportunities is less compelling. This could change in the future beyond the forecast period, particularly in other places where natural gas prices (including taxes) are also low compared to liquids, such as Iraq, though infrastructure investment is also a requirement for that to happen. Indeed, infrastructure also makes a great difference: special pipelines and gas plants must be built, and local economics, particularly in less-developed or isolated areas, can be prohibitive. Finally, there are differences in geology such that some gas fields have inherently more liquids than others.

Condensate usage

Field condensates and pentanes can be used as refining feedstock, either blended into the crude stream or run unblended through a condensate splitter. A condensate splitter is essentially a simple refinery that is designed to handle a very high yield of light ends, as condensate has very little heavy residual products that need cracking. A splitter is also advantageous because its construction and operational costs per barrel of capacity are lower than that of a conventional refinery. Given the increasing condensate production forecast and favourable economics of splitters, we estimate that splitter usage will grow, particularly as a result of new construction of these facilities. Given that conventional refinery use of condensates is already reaching near limits in North America, the amount blended into the crude stream by producer countries will decline slightly overall after 2015, and more steeply on a percentage basis.

Another use of condensate is as a diluent: certain ultra-heavy crudes, such as bitumen in Canada or Venezuela, or even heavy conventional crude in Colombia, are too viscous to be transported by pipeline unless they are blended with lighter products like condensate. Although naphtha derived from crude oil (or potentially even from a splitter) can be used as diluent, condensate is a common diluent, particularly in Canada. Diluent usage globally will grow, leading to increased condensate trade as heavy oil production and condensate are not produced commensurately in the same countries.

Condensates can also be used as a petrochemical feedstock instead of naphtha, particularly if the condensate has a high API and is relatively paraffinic. We estimate that about 4% of the world's condensate supply (including plant pentanes) is used by petrochemical facilities. Smaller, niche uses of condensates include direct burn for power generation (mostly in Saudi Arabia, about 60 kb/d worldwide), and use as a power source in gas field operations (less than 100 kb/d worldwide).

Box 2.3 Natural gas liquids and condensates (continued)

Much of the world's condensate is traded internationally before final use, either specifically as condensate, or blended into crude. For example, Karachaganak condensate in Kazakhstan is usually blended with crude and piped out for export through the CPC Pipeline; condensate in Oman is blended with heavy crudes such as Mukhaizna, and exported by tanker, mostly to Asia. The following table shows the disposition of condensates in producer countries. "Other" in the table is the aforementioned small amounts of direct burn for power and for powering field operations added to exports.

Table 2.9 Condensate disposition in producer countries (mb/d)

	2013	2014	2015	2016	2017	2018	2019
Condensate splitter	1.2	1.3	1.4	1.5	1.8	1.8	1.9
Diluent	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Blended into crude stream	2.4	2.7	2.7	2.7	2.5	2.5	2.6
Petrochemical	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Exports + other	2.8	3.0	3.1	3.3	3.4	3.6	3.7
Usage as % of total							
Condensate splitter	17%	17%	18%	19%	22%	21%	21%
Diluent	4%	4%	4%	4%	4%	3%	3%
Blended into crude stream	35%	36%	35%	33%	30%	29%	29%
Petrochemical	4%	4%	4%	4%	4%	4%	4%
Exports + other	41%	40%	40%	41%	41%	42%	42%

Biofuels supply

The geography of policy support for biofuels is changing. After a decade of fast growth, policy support is waning in OECD countries, notably the United States and the European Union, as well as in Brazil, but burgeoning in new non-OECD markets such as Southeast Asia. Although growth projections have been trimmed, global biofuel production is still expected to grow to about 2.3 mb/d in 2019, up roughly 350 kb/d or 18% from 2013 levels. This is more than 50 kb/d below the 2018 production levels projected in the *MTOMR 2013*.

After a period of rapid growth, biofuel production and consumption in the United States, European Union and Brazil appears to be shifting gears. In the United States, the design flaws of previous biofuel mandates have become manifest, leading to policy reviews which have introduced a measure of uncertainty in the market. In Brazil, the ethanol industry's economic situation is worsening, as a result, amongst others, of inflation-targeted gasoline price regulations undermining ethanol economics. In the European Union, ongoing controversy about the sustainability of biofuels has led to a proposed cap on conventional biofuel use that leaves the industry in limbo until a final decision on the proposal is taken.

At the same time, policy support is burgeoning in non-OECD countries, notably oil-importing economies that subsidise fuel consumption, where rising domestic biofuel production promises a valuable option to lowering the fuel import bill.

Due to the less optimistic outlook for the United States and Brazil, world ethanol output is now forecast to reach 1.76 mb/d in 2019. For 2018, the forecast has been cut by around 65 kb/d from levels projected last year. In contrast, expectations of **biodiesel** production have been revised marginally upwards. World biodiesel production is expected to edge up to 560 kb/d, up roughly 10 kb/d higher than projected in the *MTOMR 2013*, as stronger growth in non-OECD Asia outweighs downward revisions in the non-OECD Americas.

Figure 2.46 World biofuel production 2013-19

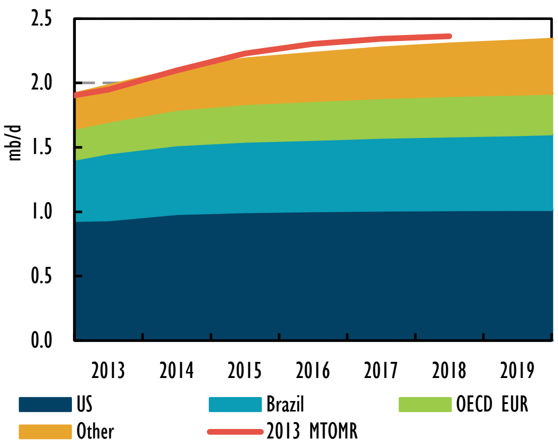
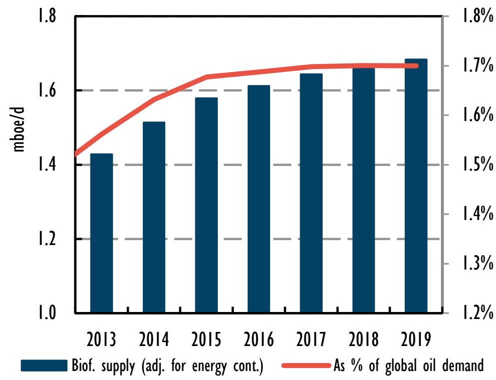


Figure 2.47 World biofuel production adjusted for energy content as share of global oil demand



The advanced biofuels industry faces headwinds but capacity is expanding. Operating capacity has reached around 30 kb/d[12] in 2013, and could reach 70 kb/d in 2019, if all projects currently under construction and announced come online as planned. Growth is slower than projected in last year's *MTOMR*, as a number of companies have cancelled or postponed projects as they struggle to secure investments in light of an increasingly uncertain policy framework in the two key markets, the European Union and United States.

The policy ground is shifting under the biofuels industry

The biofuel sector's future remains heavily dependent on policy support in virtually all markets around the world. Two main policy trends can be distinguished globally: in more mature markets of the United States, European Union and Brazil, where the biofuels industry underwent dramatic growth in the last decade, political support for biofuels appears to be waning and production growth is shifting to a lower gear. At the same time biofuels production and use are being supported in "frontier" markets by financial and fiscal policies designed primarily to reduce those markets' state energy import bill and redress their trade balance. Oil-import dependent countries in Southeast Asia and Africa that can ill afford the fiscal burden of transport-fuel subsidies and or high import bills amid stubbornly high oil prices beef up support measures for home-grown biofuels to replace imported diesel or gasoline.

In view of those trends, this year's projections of biofuel supply have been on balance adjusted downwards. Projections have been revised down for the United States or in the case of the European Union kept at the conservatively low level previously forecast by the *MTOMR 2013*. Despite upward adjustments for Asia, global biofuel supply is now forecast to reach only 2.31 mb/d in 2018 (down almost 50 kb/d compared to last year's projections), inching marginally up to 2.33 mb/d in 2019.

[12] In contrast to the previous medium-term analysis, hydrotreated biodiesel is not included in this number, because hydrotreated biodiesel technology has reached maturity, and main feedstocks are conventional biofuels feedstocks such as vegetable oils.

Established markets face slower production growth In the United States, which is the world's largest producer of biofuels, the Environmental Protection Agency (EPA) in late 2013 published a proposal to substantially lower the required volumes of biofuels under the Renewable Fuels Standard 2 (RFS2), the principal instrument that sets the minimum annual volume of renewable fuel (including ethanol and biodiesel) to be used in the United States (see December 2013 *OMR*). The decision to substantially reduce the volumetric targets for the RFS 2014 rule effectively acknowledges the challenges related to blending increasing amounts of ethanol into the gasoline pool. When the Renewable Fuels Standard adopted in 2005 was expanded to 2022 under the Energy Independence and Security Act of 2007, US gasoline consumption was assumed to grow, as it had done until then. In fact, US gasoline demand has since steeply contracted and, despite a partial rebound in 2014, current projections are for a renewed decline mainly due to the adoption of tighter fuel economy standards that lead to largely improved vehicle fuel efficiency.

While contracting demand reduces the overall size of the gasoline fuel pool, blending constraints are further constraining ethanol use. Ethanol already accounts for roughly 10% of US gasoline use and several parties, from gasoline retailers to automobile manufacturers, have flagged liability issues associated with using blends higher than E10. Additionally, the extra costs and logistical challenges of reconfiguring pumps and storage at fuel stations that would allow for use of higher-level blends such as E85 (containing 85% ethanol), pose barriers to enhanced blending of ethanol. In combination, those factors have effectively raised an ethanol "blend wall" suggesting that ambitious policy targets of rapid and steady growth in ethanol consumption may not be attainable.

RFS 2 targets for advanced biofuel consumption are also proving unrealistic. In practice, the availability of domestically produced advanced biofuels,[13] in particular that of cellulosic fuels, has fallen short of volumetric targets in the original RFS2. While the final 2014 rule had yet to be set at the time of writing, changes proposed by the EPA in November suggest that future volumetric targets for both conventional biofuels and advanced ones may be lowered and brought broadly in line with a 10% ethanol share in gasoline.

With the volume of ethanol that can be blended before reaching the "blend wall" set to shrink due to a reduction in US gasoline consumption over the medium term, and biofuels qualifying for the "advanced biofuels" category under the RFS2 available only at limited volumes in the United States, our projections on US ethanol output are substantially more pessimistic than in previous estimates. We now project US ethanol output to grow at an average of only 1.6% per year from 845 kb/d in 2013 to 930 kb/d in 2019, thus around 50 kb/d lower in 2018 than in the *MTOMR 2013*.

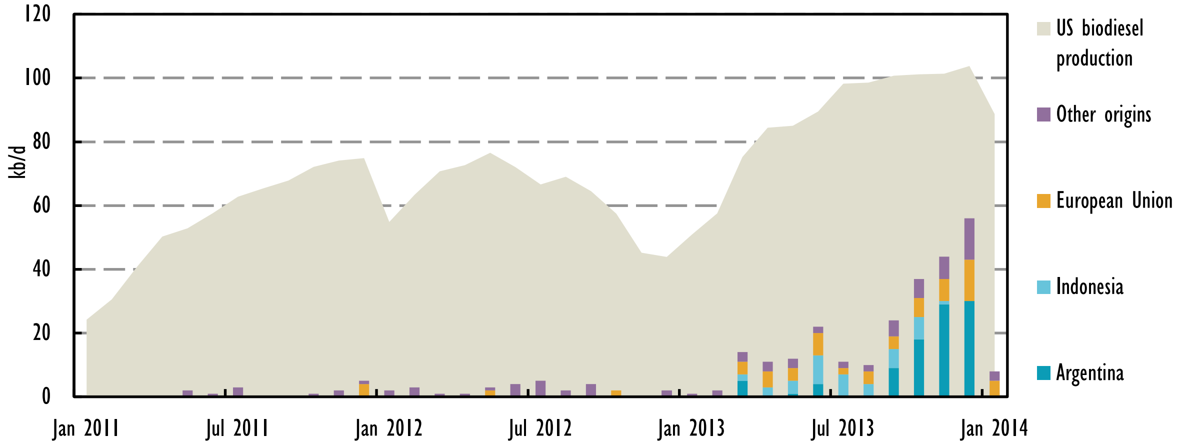
Meanwhile, despite having enjoyed a bumper year in 2013, the US biodiesel industry is also facing fresh challenges on the policy front following the expiration of the USD 1/gal blender's tax credit at the end of 2013. In May 2014 the Expiring Provisions Improvement Reform and Efficiency Act that included the re-introduction of the blender's tax credit did not pass the Senate, which means that biodiesel producers will have to stand their ground without additional financial incentives for now.

The re-introduction in early 2013 of the credit, which had been allowed to expire at the end of 2011, was an important driver to fuel a 14 kb/d year-on-year increase in US biodiesel output that year, to

[13] Under the RFS2, advanced biofuels are defined as non corn-based biofuels with a greenhouse-gas reduction of 50% compared to the reference fossil fuel.

87 kb/d. In addition, it also led biodiesel imports to climb to an average 20 kb/d, with monthly imports rallying to 57 kb/d in December 2013 before the expiration of the tax credit.

Figure 2.48 US biodiesel production and US biodiesel imports by origin, 2012-14



Source: IEA analysis; for biodiesel imports: US Energy Information Administration (2014), *US Imports by Origin,* www.eia.gov.

In absence of the blender's tax credit, biodiesel production is projected to drop 7 kb/d year-on-year in 2014 as physical demand is reduced by carry-over Renewable Identification Numbers[14] generated in 2013. Over the medium term, output should stabilise at 84 kb, in line with the current RFS 2 mandate for biomass-based diesel, unless the blender's tax credit is re-established or the RFS 2 quota for biodiesel is altered.

In the European Union, too, policy uncertainty has become a key element in the outlook for the biofuel industry. Since the European Commission first published a proposal in October 2012 to limit the share of conventional biofuels allowed to count towards its 2020 renewable energy target, the biofuel sector has remained in limbo. The proposal was triggered by an unresolved controversy over the sustainability of biofuels, focusing in particular on the difficulty of properly accounting in existing legislation for the potential impact of indirect land-use change on biofuels' greenhouse-gas balances. The proposal suggests to cap the share of biofuels in road transport fuel consumption at 5%, corresponding to the current average blending level in the European Union, rather than up to 10% originally mandated under the 2009 Renewable Energy Directive (Directive 2009/28/EC). The new target would dramatically limit any further growth in biofuels production. After the European Parliament in September 2013 voted for adopting a slightly amended 6% biofuel limit by 2020, the matter was handed back to Member States, which will need to seek a common position on the proposal, thus further delaying any definitive decision on the sector's future.

The 10% renewable energy in transport remains the official 2020 target in the European Union, but the ongoing policy uncertainty reinforces the conservative growth projections for European Union biofuels production adopted in last year's *MTOMR*. OECD Europe biodiesel production is projected to increase from 176 kb/d in 2013 to 212 kb/d in 2019, broadly in line with last year's projections. Germany

[14] The U.S. Environmental Protection Agency uses Renewable Identification Numbers to track renewable transportation fuels and monitor compliance with the Renewable Fuel Standard. The RIN is attached to the physical gallon of renewable fuel as it is transferred to a fuel blender. After blending, RINs are separated from the blended gallon and are used by obligated parties (blenders, refiners, or importers) as proof that they have sold renewable fuels to meet their RFS mandated volumes. RINs may be used to satisfy volume requirements for the current year or up to 20% of the following year's required RFS volumes. Obligated parties may also sell RINs amongst each other, with prices being determined by market factors.

(52 kb/d in 2019) followed by France (38 kb/d in 2019) remain the region's largest biodiesel producers. Ethanol production is projected to grow at an average 7% per year, twice as fast as biodiesel output, driven in part by two new plants with a combined capacity of 14 kb/d that recently came online in the United Kingdom. Ethanol output is projected to grow to 104 kb/d in 2019 from 70 kb/d in 2013, as production in the United Kingdom jumps to 16 kb/d from 6 kb/d over the same period, letting the country catch up with the two top producers, France (18 kb/d in 2019) and Germany (17 kb/d in 2019).

In light of the uncertain policy environment in combination with significant over-capacity in particular in the biodiesel industry, major capacity additions in the European Union look unlikely. Even in the longer run, the European Commission's recently proposed guidelines on state aid for environmental protection and energy (SWD[2014]139) are prohibiting any operating aid for conventional biofuels after 2020. It is thus unlikely to see any new plants for these fuels coming online even in the longer run. The ongoing discussions on a revision of the 2020 biofuel target and the absence of a longer-term policy framework for biofuels are also important challenges for the advanced biofuels industry. Advanced biofuels companies struggle to attract investments into their first commercial-scale projects, as highlighted for instance by the decision of Finnish company Vapo to shelve its 2 kb/d Ajos BtL project in Northern Finland despite being awarded EU funding of EUR 88 million.

In the non-OECD Americas, steady or increasing blending mandates should in theory provide a better environment for the industry. However, the biofuel industries in the region's two largest producing countries – Brazil and Argentina - are currently experiencing difficult operating conditions.

In Brazil, the world's second-largest ethanol producer, output exceeded expectations in 2013, reaching 470 kb/d – almost 40 kb/d higher than projected in the *MTOMR 2013* – on the back of a higher-than-expected sugarcane harvest. The medium-term outlook for Brazilian ethanol looks nonetheless gloomier than projected last year, for a number of reasons.

After suffering from a poor sugarcane harvest in the 2011/12 crushing season, the sugar- and ethanol industry has now fallen victim to a global bumper sugar crop that extended the global sugar surplus to a fifth year, and subsequently depressed sugar prices (Figure 2.50). Low sugar prices led most mills to favour ethanol over sugar production and shifted more of their capacity towards biofuel production.[15] However, with price controls on gasoline in place designed to rein-in inflation – a major government priority – the price competitiveness of ethanol in retail markets is undermined unintentionally and leaves producers with narrow profit margins. In combination with rising costs for labour and land, the current situation further exacerbates the already critical economic state of many sugar and ethanol producers. The government's decision taken last year, to waive of contributions to the social integration programme and social security financing (PIS and COFINS) on ethanol in order to improve the income situation in the sector, has not noticeably improved this situation.

There is no clear sign that the situation in the sugarcane sector will improve in the near future. Most analysts doubt that the government will revisit its gasoline pricing policies before the presidential election scheduled for October. Whether gasoline price controls can promptly be lifted after the election, regardless of its outcome, is an open question, despite a USD 2 billion trade deficit caused by gasoline imports in 2013. A raise in the 25% mandatory gasoline blend, that could provide some support to the sector, is currently not in sight, despite industry lobbying efforts. Further plant closures, in particular

[15] Many of the combined sugar and ethanol mills in Brazil can shift the ratio of output between the two end products between 40:60 either way.

of smaller and old mills, are therefore likely in the next years. Furthermore, the current situation makes investments into new mills and sugarcane fields unlikely as rising land prices have considerably reduced the attractiveness of green field developments.

Figure 2.49 Brazil biofuels production 2013-19

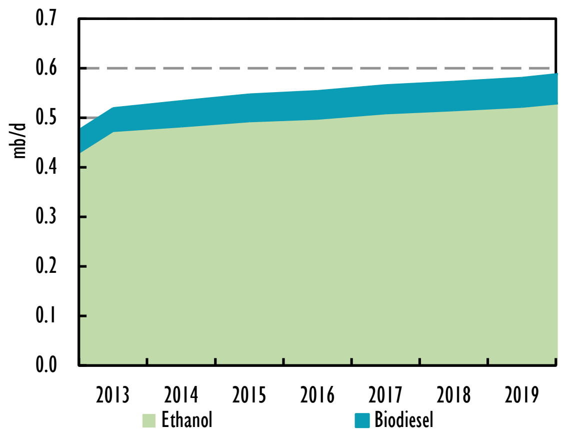
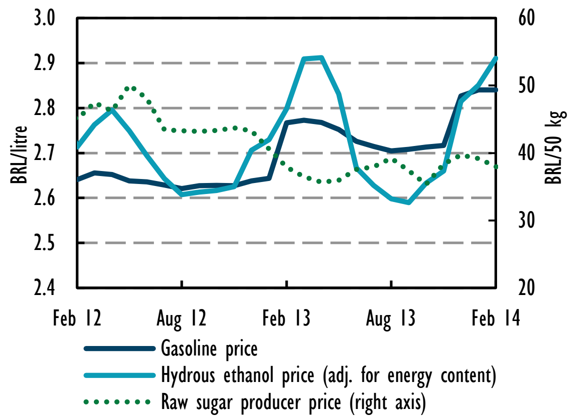


Figure 2.50 Ethanol and gasoline retail price and sugar producer price 2012-14, Brazil



Source: IEA analysis; data source for ethanol, gasoline and sugar prices, UNICA (2014), *UNICADATA*, www.unicadata.com.br.

Short-term export opportunities emerged early this year, when a cold spell reduced rail transport of ethanol to consumption centres and ethanol prices in the United States surged rapidly. However, the medium-term prospects for exports to the United States have substantially worsened since last year's *MTOMR*, in light of the suggested revision of the US RFS 2 "advanced biofuels" quota (see above). Despite the 2013 upward revisions in Brazilian ethanol production, our medium-term outlook of ethanol output is less optimistic. Due to a drought during the winter season, 2014 cane production is expected to be slightly higher than last season's harvest at best. Brazilian ethanol is thus projected to increase by only 10 kb/d to 482 kb/d in 2014. Over the medium-term, output is projected to reach 515 kb/d in 2018 (-20 kb/d vs. *MTOMR 2013*) and 522 kb/d in 2019, with growth in gasoline demand being an important driver.

Brazil's biodiesel output in 2013 reached 46 kb/d in line with last year's *MTOMR* projections. The Brazilian biodiesel industry's hopes to see an increase in the nation-wide 5% biodiesel blending mandate, which would help reduce the estimated USD 8 billion diesel trade deficit, have not materialised so far. We therefore project only a slow increase in biodiesel production to 59 kb/d in 2019, driven almost entirely by the country's growing diesel demand.

In neighbouring Argentina, biodiesel production took a hit from both domestic and international policy developments, after five years of rapid growth. The industry's situation started changing last year, when the European Union – Argentina's principal biodiesel export market – introduced provisional anti-dumping measures on Argentine biodiesel imports that were later adopted for five years. Some of the potential exports to the European Union were directed towards the United States, with volumes reaching 30 kb/d in November and December (Figure 2.48 above), thanks to the attractive market for biodiesel in the United States. But since this temporary outlet could not entirely compensate for the loss of the export market in the European Union, 2013 production dropped by 14 kb/d year-on-year to 34 kb/d, 6 kb/d lower than our projections in the *MTOMR 2013*. The short-term outlook for

Argentine biodiesel production continues to be bleak. With the expiration of the US blender's tax credit, there will be little scope for exports to this market, and despite the Argentine government's efforts to tackle the anti-dumping tariffs on biodiesel imports to the European Union at the World Trade Organisation (WTO), we do not expect this market to open up again in the near future.

The recent increase in the biodiesel blending mandate from 7% to 10% as of February 2014, and an additional 10% biodiesel mandate for oil-fired power plants, should in theory help to keep up the sector's production. However, the domestic reference prices for biodiesel are well below production costs (Figure 2.51), forcing many small producers to halt production. Biodiesel output is therefore expected to drop by 7 kb/d year-on-year in 2014, to 30 kb/d. Though some of the short-term challenges could be overcome, our medium-term forecast is less optimistic than in the previous *MTOMR* and we see biodiesel production increase to only 45 kb/d in 2019.

The considerably smaller ethanol sector in Argentina has been growing solidly in the last couple of years. With a 5% blending mandate for ethanol in place, and a number of corn-ethanol plants scheduled to come online in the next years, we see ethanol output more than doubling, from 5 kb/d in 2013 to 13 kb/d in 2019.

Figure 2.51 Argentine biodiesel production costs versus biodiesel reference price

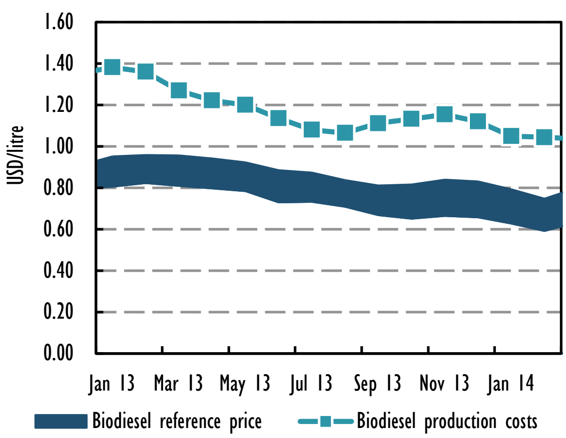
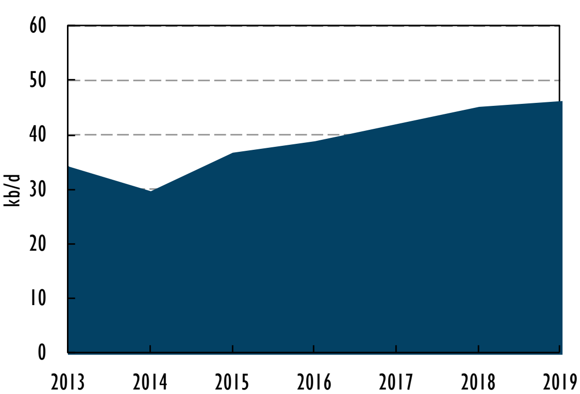


Figure 2.52 Argentine biodiesel production, 2013-19

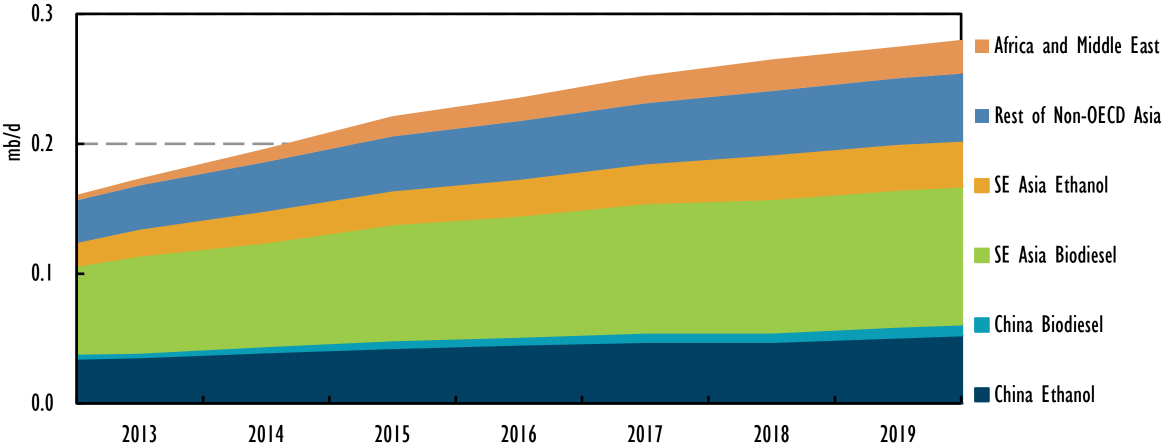


Source: IEA analysis; for biodiesel reference price: Secretaria de Energia, *Precios de Biodiesel*, www.energia.gov.ar.

Ambitious policies support growth in emerging biofuel markets – while some of the traditional markets in United States, European Union and Latin America are seeing political support fade, several countries in non-OECD Asia and Africa have adopted new blending mandates, or ramped up existing targets for biofuels. Energy security, support for rural economies, and/or changes in the competitiveness in export markets have triggered these developments that should spur biofuel production in these markets.

Indonesia – the biggest biodiesel producer in non-OECD Asia - has ramped up its domestic biodiesel mandate from B7 to B10 as of February 2014. The increase in the mandate followed the introduction of anti-dumping subsidies in the European Union, which significantly reduce Indonesia's export potential to this key market, and also intends to cut the consumption of subsidised diesel fuel in the country. 2014 biodiesel output is nonetheless projected to drop 2 kb/d year-on-year to 30 kb/d, as a combination of the European Union anti-dumping tariffs, the expiration of the US blender's tax credit, and a dry spell in the beginning of this year combined with signs of an El Niño year that could reduce crude palm oil production and raise prices. With such short-term challenges expected to be overcome, and the B10 mandate materialising, we project biodiesel output grow to more than 40 kb/d in 2018 and 2019, up 15 kb/d from last year's medium-term projections.

Figure 2.53 Non-OECD Asia, China, Africa and Middle East biofuel production, 2013-19



India is set for a growing ethanol production amid a relatively ambitious E5 mandate that slowly starts to materialise. Oil companies have reportedly secured first ethanol supplies through tenders, but are not yet on track to secure the full volume needed for a B5 blending. One of the key problems in ensuring the required volumes appears to be the gap between prices offered by the oil companies and those requested by the ethanol producers. We therefore do not expect the E5 mandate to be met, with production projected to reach only 14 kb/d in 2014, increasing to 19 kb/d in 2019.

Malaysia and the **Philippines** are following a similar pathway and are planning to raise policy support for biofuel use. The Philippines already introduced a new E10 mandate in April 2013 and a B5 mandate in October 2013. Malaysia is going to expand its B5 mandate nation-wide in July this year, and might further raise the mandate to B7 as of January 2015 in order to stabilise prices for crude palm oil. Amid these ambitions, we project Malaysian biodiesel supply to more than double from 6 kb/d in 2013 to 14 kb/d in 2019, up 5 kb/d in 2018 from our previous forecast. In the Philippines, we see biodiesel output grow less rapidly, from 4 kb/d in 2013 to 7 kb/d in 2019, due to limited biodiesel production capacity in the country. Spurred by the new E10 mandate, ethanol output should triple from 2 kb/d in 2013 to 6 kb/d in 2019.

Thailand, the largest ethanol producer in South-East Asia, is also seeing growing demand for both ethanol and biodiesel. The government's decision to phase out 91 octane gasoline, and to subsidise use of E20 has prompted a number of oil companies to offer the 20% ethanol blend at their retail stations, and should support further growth over the medium term to 24 kb/d in 2019, up from 16 kb/d in 2013.

Signs of a new era for biofuels are seen also in Africa and the Middle East. Among the key emerging markets in the region is **South Africa**, which will introduce long-awaited E2 and B5 mandates as of October 2015, and **Zimbabwe,** that mandated use of E10 in October 2013 and E20 as of later in 2014. Both countries should see an increase in biofuels production over the medium term, though a number of issues such as details on financial incentives in South Africa, or the availability of feedstocks in both countries, still need to be addressed. Nonetheless, we see African ethanol output grow from

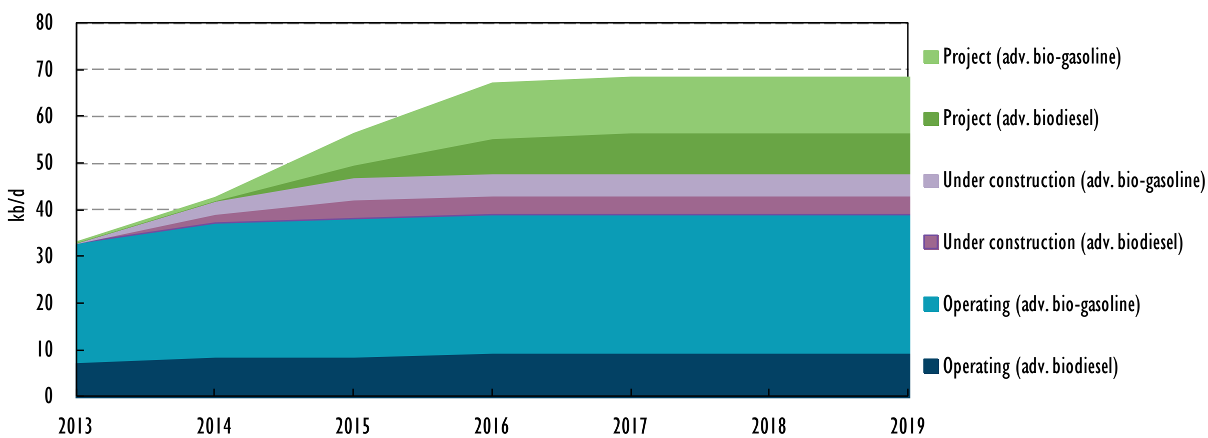
3 kb/d in 2013 to 14 kb/d in 2019, and biodiesel production to increase from 1 kb/d to 8 kb/d over the same period. Biofuel production on the continent should be driven by the suitable conditions for the cultivation of biofuel feedstocks such as sugarcane, in combination with a rapidly growing fuel demand in many countries. The considerably smaller investment needs compared to conventional oil refineries make biofuel plants an important option for countries looking to reduce their import bill for refined transport fuels.

Surprisingly, biofuels production is starting even in the Middle East, where the abundancy of crude oil reserves and the lack of biofuel feedstocks provide a rather challenging environment for the industry. This is the reason why the few projects that are online, or scheduled to be commissioned in the next years, are all based on waste feedstocks, typically used cooking oil. Since availability of waste feedstocks is limited, we don't expect much growth in biofuel production and total volumes of ethanol and biodiesel combined, which together reach only 2 kb/d over the medium term.

Advanced biofuels industry

The advanced biofuels industry faces strong headwinds but continues to grow as past investments come to fruition. Operating capacity – excluding hydrotreated biodiesel[16] – reached 33 kb/d in 2013. Companies such as Beta Renewables, backed up by chemical producer Mossi & Ghisolfi, opened commercial-scale plants last year, and more companies are scheduled to open their first commercial-scale production units this year. Among them are GranBio 's 1.4 kb/d cellulosic-ethanol plant in Brazil that is based on Beta Renewables' technology, POET's 1.6 kb/d and Dupont's 1.8 kb/d cellulosic ethanol plants in the United States, as well as UPM's 2 kb/d advanced biodiesel plant in Finland. Globally, we see the installed production capacity for advanced biofuels increase 10 kb/d year-on-year to 42 kb/d in 2014.

Figure 2.54 Advanced biofuel production capacity, 2013-19



Note: Does not include hydrotreated vegetable oil.

Growth has been slower than expected, though, due to the complex technical challenges involved. The industry's struggle is reflected in a number of companies going bankrupt, or shelving their projects amid greater-than-expected technological challenges, a difficult economic environment, or the lack of a long-term policy framework needed to justify capital-intensive investments. One of the latest examples

[16] In contrast to the methodology employed in the *MTOMR 2013*, estimates of advanced biodiesel capacity exclude hydrotreated biodiesel, capacity of which is assessed at 60 kb/d, as the technology has reached full maturity and fuels are often produced from conventional feedstock such as vegetable oils.

is the advanced biodiesel and gasoline producer KiOR, which had commissioned its first pre-commercial facility last year, but has since struggled to meet production targets and announced in April 2014 that it might have to file for bankruptcy in a few months unless new funding can be secured.

Based on announced projects and plants currently under construction, global capacity could grow to almost 70 kb/d in 2019. This is 10 kb/d lower than projected last year, as a number of large-scale projects have either been cancelled, postponed, or will be initially operated on non-renewable feedstocks. Global developments in the advanced biofuels industry are mainly dependent on two key markets - the United States and the European Union. In both markets, policy uncertainty is growing, as mentioned above. The ambitious target for cellulosic fuels under the RFS2, and the double-counting of advanced biofuels towards the EU 2020 targets, were not sufficient to trigger rapid deployment of advanced biofuels. The absence of a longer-term policy framework for biofuels beyond 2020 in the European Union and beyond 2022 in the United States, combined with current discussions on revising down current targets for biofuels, will make it very difficult for advanced biofuel producers to secure the necessary investments to scale-up production. This is one of the important downside risks that could undermine our projections. On the other hand, advanced biofuel plants have relatively short lead times of a couple of years, and new projects that are not yet on the horizon might come online in the later years of our projections.

3. CRUDE TRADE

Summary

- **The global trade in crude oil and marketed condensate is projected to contract by 1.1 mb/d to 34.0 mb/d over 2013-19** as more crude in North America and the Middle East continues to be refined closer to the wellhead. Nonetheless, crude trade is expected to increase between the Atlantic and Pacific basins.

- **Even as the volume of crude trade edges lower, the direction of crude flows continues to undergo a dramatic eastward shift.** Following increasing regional supply, the Americas will become a net-exporter of crude oil in 2019 while net imports into Asia surge by 2.8 mb/d, or 14% by the end of the decade. Chinese crude oil imports overtake those of the United States as early as 2014 and grow to 7.1 mb/d by the end of the decade. Imports into Europe edge down in line with contracting regional demand.

- **Overall imports into the non-OECD will surpass imports into the OECD over the forecast period.** The non-OECD is expected to increase imports by 3.0 mb/d to 17.6 mb/d in 2019 while OECD imports are projected to plunge by 4.2 mb/d to 16.4 mb/d.

- **The Middle East is expected to remain the key exporting region over the period.** However, its total exports are expected to shrink by 900 kb/d over the forecast as regional producers refine more crude at home, exporting some of it subsequently as products. In doing so, the region's share of total crude exports is seen declining to 47% by the end of the decade.

Figure 3.1 Regional crude exports, yearly change

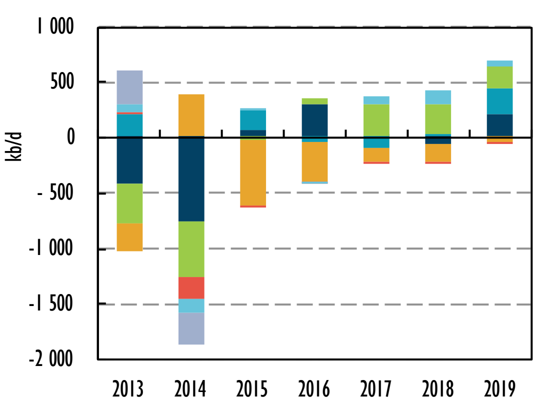
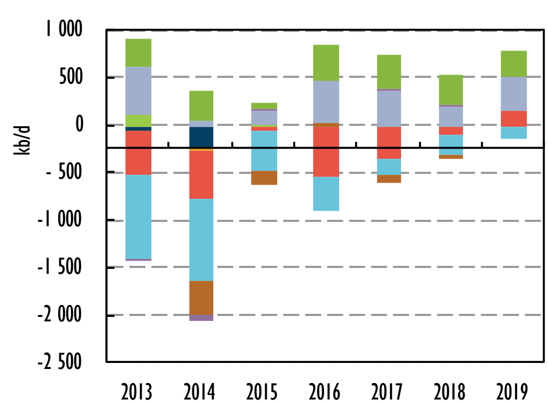


Figure 3.2 Regional crude imports, yearly change



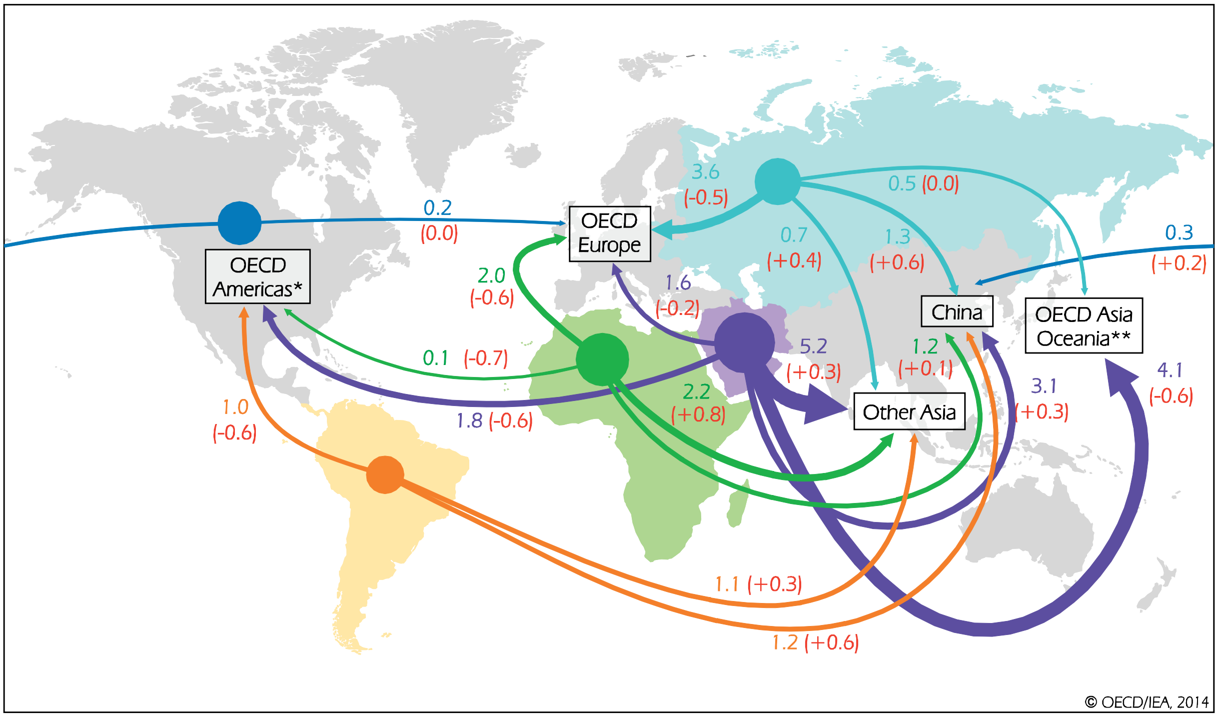
Overview and methodology

As in previous issues of the *MTOMR*, the inter-regional trade in crude oil and marketed condensate (from hereon in referred to as crude oil) has been modelled over 2013-19 as a function of projected oil production, demand growth and refinery utilisation with incremental supplies being allocated based on expectations of refinery capacity expansion. Regional OPEC crude production has been allocated based on the 'call on OPEC' over 2013-19 which is the calculated difference between projected global demand, non-OPEC supply and OPEC NGL and non-conventional production.

Additionally, This exercise has benchmarked historical crude trade against a selection of data sets including; OECD trade data (available through the IEA's Monthly Oil Data Service), customs data from non-OECD administrations and crude oil tanker tracking data. The forecast assumes no change in the regulatory framework regarding crude exports, including specifically in the United States, though it allows for some flexibility at the margin in the interpretation or implementation of current legislation against the backdrop of rapidly changing market conditions.

The global trade in crude oil is projected to decline by 1.1 mb/d to 34.0 mb/d over 2013-19 as the trend of producer countries expanding refinery capacity continues. This contraction equates to a fall of 0.6% on a compound annual basis, broadly in line with earlier forecasts presented in the *MTOMR 2013*, but from a significantly higher baseline. Historical trade volumes for 2013 have been revised upwards by 2 mb/d to 35 mb/d in view of new non-OECD trade data and upward revisions to data for supply, demand and refinery throughputs. In view of these baseline changes, the 2013-18 series is adjusted higher by 1.1 mb/d on average.

Map 3.1 Crude exports in 2019 and growth in 2013-19 for key trade routes



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

Notes: Excludes intra-regional trade. Red numbers in parentheses denote growth in period 2013-19.

* Includes Chile.

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

Although globally crude throughputs and oil demand continue to expand over the forecast period, crude trade bucks the trend. In 2013, 34% of global refinery crude requirements were traded inter-regionally. By the end of the decade, that proportion is projected to fall to 32%. Asia will account for the vast majority of that trade, buying 65% of its crude requirement from other regions, up from 55%

in 2013. As supply in the United States, Canada and Brazil grows, crude net imports into the Americas will steadily diminish over the forecast period from a highpoint of 2.3 mb/d in 2013. By 2019 the region is projected to be a net-exporter, providing a net 300 kb/d to global crude markets.

OECD imports are projected to plummet by 4.2 mb/d to 16.4 mb/d, below non-OECD imports levels, in 2019, as regional production in the OECD Americas increases while refinery activity in OECD Europe and OECD Asia Oceania is will continue to be curbed. In contrast, non-OECD imports are set to increase by 3.0 mb/d to 17.6 mb/d in 2019 as demand and refinery capacity expansion, notably in non-OECD Asia and the Middle East, continue to grow. These diverging trends will see non-OECD imports surpass those of the OECD in 2018 so that by 2019 the non-OECD will account for 52% of global imports, a rise of 11 percentage points compared to 2013.

The Middle East continues to dominate global crude trade by a wide margin over the forecast period, but its exports are set to decline both in absolute terms and as a share of the global market. Middle East crude exports are set to decline by an estimated 900 kb/d (-0.9% compound annual growth rate [CAGR]) in the wake of a 2.2 mb/d increase in regional refining capacity and a comparatively smaller gain of 1.5 mb/d in production capacity. The region's share of total crude exports is seen declining to 47% by the end of the decade from 49% in 2013.

Outside of the Middle East, African exports are expected to decline marginally by 250 kb/d to 6.3 mb/d in 2019. Consequently, Africa's market share of total global exports will stagnates at 19% throughout the forecast. This will see the region lose to the FSU its rank as the world's second largest crude exporter from 2014 onwards, as FSU exports are set to rise by 300 kb/d with its market share forecast to increase from 18% in 2013 to 20% in 2019. Elsewhere, Latin America is expected to see its market share inch up to 10% in 2019 from 9% in 2013 as exports grow by 300 kb/d after supply growth will eclipse higher downstream capacity.

Figure 3.3 Inter-regional export growth, 2013-19

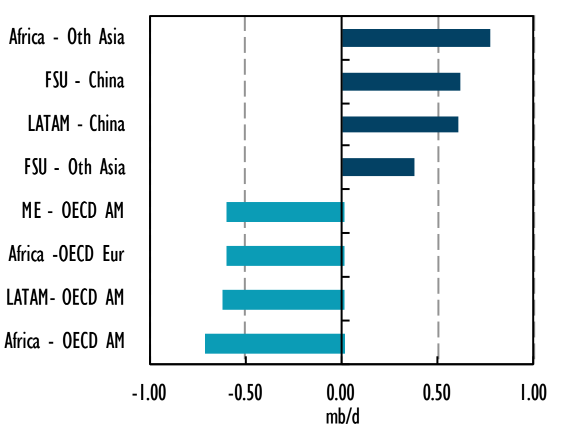
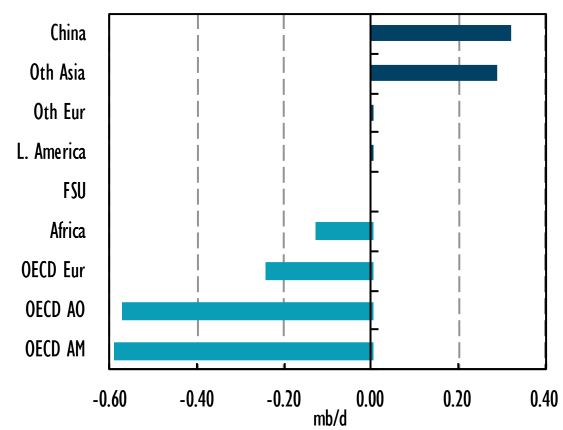


Figure 3.4 Middle East export growth, 2013-19



Regional developments

Middle East

The Middle East oil sector is undergoing a period of profound transformation, marked in part by fast-rising domestic oil demand and rapid increases in refining capacity, but relatively slower crude production growth outside of Iraq, especially considering continuing problems in non-OPEC Syria and Yemen. Exports from the Middle East are projected to fall by 900 kb/d to 16.1 mb/d by the end of the decade, representing the sharpest absolute decline amongst the major exporting regions. Offsetting crude supply growth projected for Iraq, the UAE and, at the margin, Saudi Arabia, regional producers are expected to aggressively expand their downstream capacity. These projects include; Saudi Aramco's 400 kb/d Jazan refinery, the 410 kb/d Ruwais complex in the UAE and Iran's Persian Star condensate splitters (three units of 120 kb/d each), all set to be commissioned by 2019. These projects will also surpass regional demand growth and thus regional refined product exports are expected to increase. Furthermore, the recent start-up of the Saudi Aramco / Total joint-venture Jubail refinery has already seen cargoes of gasoil and diesel head to East Africa and Europe. As the region holds the vast majority of OPEC's spare production capacity, it has the flexibility to increase exports if needed. Any upswing in demand, whether from a supply disruption elsewhere or from strategic stock building (not included in this *Report*'s demand projections), could lift the region's production and export levels above the forecast.

While overall Middle Eastern crude exports are forecast to edge lower, they will also be increasingly redirected eastwards to non-OECD buyers, further reinforcing the strategic energy partnership between Middle Eastern crude producers and consumers in emerging and industrialising Asia. OECD imports of Middle Eastern crudes are forecast to drop by a combined 1.4 mb/d as refinery rationalisation and soaring domestic supply reduce the need for these grades. China and 'Other Asia' will offset some of this fall as they increase imports from the region by approximately 300 kb/d each by 2019. Indeed, the growth from China and 'Other Asia' will more than offset the projected 550 kb/d fall in exports to OECD Asia Oceania, with shipments to Asia set to inch up by a net 50 kb/d over the forecast. In sum, these trends will see the OECD replaced as the major destination for Middle Eastern crudes with 54% of regional exports heading to the non-OECD in 2019, up from 49% in 2013.

Figure 3.5 Middle East crude and condensate disposition, 2013

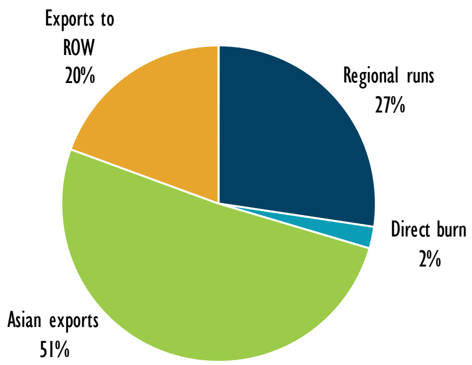
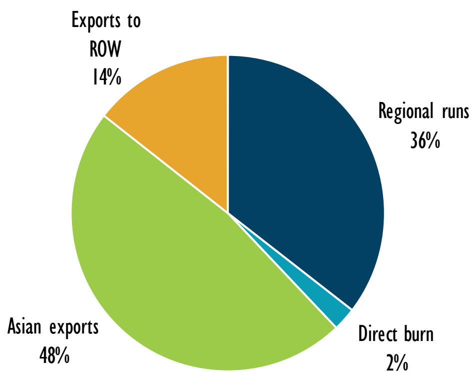


Figure 3.6 Middle East crude and condensate disposition, 2019



Africa

African crude exports are expected to plunge by 750 kb/d in 2014 versus 2013 due to supply disruptions in Libya, Sudan and South Sudan, but are projected to steadily retrace most of their losses to the end of the decade. Nonetheless, by 2019, exports are forecast to remain short of 2013 levels by 250 kb/d. As with Middle East crude, a pronounced shift in the destination of African crudes is projected to occur by 2019. As regional supplies of LTO and syncrude surge in the OECD Americas, slashing light and medium-light import requirements, imports of African crudes will almost entirely evaporate by the end of the decade, falling to trickle of about 100 kb/d, down by 700 kb/d from 2013 levels, and extending earlier dips of 2 mb/d over 2007-13. Indeed, African imports into the region only amounted to 350 kb/d in early-2014. Additionally, OECD Europe is also expected to curb purchases by 600 kb/d as refinery rationalisation intensifies. Volumes backed out of the Europe and the Americas will likely be sent eastwards. Exports to 'Other Asia' are projected to surge by 750 kb/d to 2.2 mb/d in 2019, the sharpest absolute growth across all trade routes, while Chinese imports of African crudes are projected to reach 1.2 mb/d in 2019, a rise of 100 kb/d on 2013 levels. Additionally, exports to OECD Asia Oceania are forecast to experience a slight uptick but remain relatively meagre at 400 kb/d.

Figure 3.7 Africa export growth, 2013-19

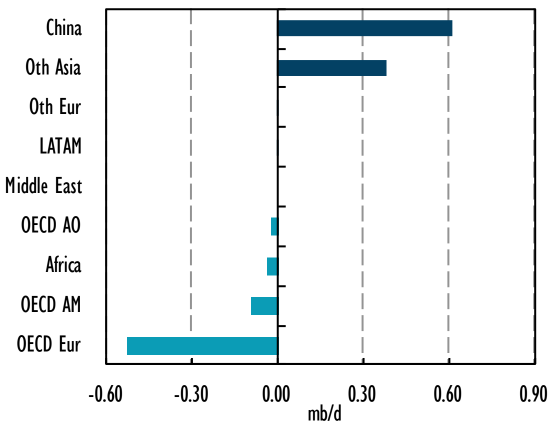
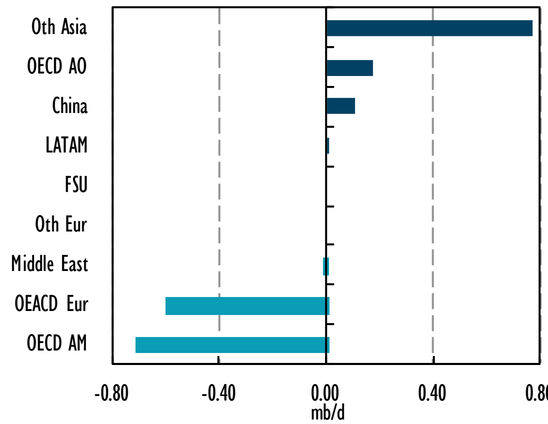


Figure 3.8 FSU export growth, 2013-19



The Former Soviet Union

The FSU is projected to see crude exports hit 6.7 mb/d in 2019, up 300 kb/d on 2013, and rebalance eastwards at an accelerating pace. While it was long expected, over the past year the pace of change has dramatically quickened after the 2013 takeover of TNK-BP by Rosneft and the subsequent USD 270 billion supply deal struck between Rosneft and CNPC. According to the terms of the contract, from 2014 Rosneft will ship 600 kb/d to China via routes including the East Siberia – Pacific Ocean (ESPO) pipeline spur to Daqing (due to be expanded to 600 kb/d by 2018), the port of Kozmino, and the Atasu–Alashankou pipeline under swap agreement with Kazakhstan. Given its investment plans for the development of a cluster of fields around the Vankor project and for other greenfield sites, Rosneft is expected to produce a minimum of 2.5 mb/d over 2013-19 and thus, even considering supply for its refineries, should be able to honour volumes stipulated in the contract. Consequently, when taking exports from other Russian companies and flows from other regional producers into account, Chinese imports of FSU crudes are seen rising steeply to 1.3 mb/d in 2019. This 600 kb/d increment represents the second highest growth across all trade routes. Meanwhile, the region's shipments to Europe, notably of Russian Urals, are set to fall by 500 kb/d to 3.6 mb/d. Despite recent tensions, Europe will still remain the FSU's largest customer, but its share of total FSU exports will slip to 54% in 2019 from 65% in 2013.

Looking across the medium term, save for a doubling of capacity along the ESPO spur to China, Russia has few firm plans to expand its crude export infrastructure. Nonetheless, it is clear that Russia can easily meet the projections of a sharp increase in eastwards crude exports since it already has enormous flexibility in its export infrastructure. Following the completion of a number of ambitious infrastructure projects such as the ESPO and BPS-2 pipelines and the Ust Luga terminal, crude export capacity growth has outstripped production growth which has left Russia with approximately 1.4 mb/d of spare crude export capacity. This spare capacity will allow producers to maximise their netbacks while also permitting Russia to minimise disruption to exports in the event of unscheduled maintenance or adverse weather at terminals, where previously exporters would have seen their shipments curtailed. Although Transneft must give exporters the green light to move their crude exports as they see fit, this flexibility will allow Russian crude to be efficiently transported either eastwards or westwards as market signals and other factors dictate.

Another consequence of the shift in FSU exports eastwards is that the quality of the Urals streams for western customers is likely to deteriorate, becoming progressively heavier and more sulphurous. This will be a by-product of more light western Siberian oil being diverted towards the ESPO. The Russian administration has promoted ESPO blend crude as a light, sweet Asian benchmark of the future and thus is eager for its quality to remain stable at close to 35.5 API and 0.5% sulphur. The grade is considerably lighter and less sulphurous than either the Urals streams from the Baltic (31.1 API, 1.4% sulphur) or Black Sea (31.3 API, 1.3% sulphur).

Latin America

Crude exports from Latin America are expected to grow by 300 kb/d to 3.5 mb/d in 2019 as a result of increasing supply prospects in Brazil, Colombia, Ecuador and Venezuela. This trend is a change to that presented in the *MTOMR 2013* when exports were projected to remain flat over 2012-18. The difference results from a less optimistic view of refinery capacity expansion where a number of projects, notably in Brazil, are now seen being cancelled or delayed until after 2019. A shift in the destination of Latin American crude exports is also set to occur as producers will increasingly send their crudes to Asia. China is expected to import 1.2 mb/d in 2019 while 'Other Asia' will import 1.1 mb/d. This increase in flows to Asia will be facilitated by improvements in infrastructure, notably the expansion of the Panama Canal to take Suezmax (1 mb) sized vessels, currently scheduled to be completed in 2016. Additionally, Ecopetrol and PDVSA have recently re-entered discussions to build a 600 kb/d pipeline to the Pacific which would bypass the Panama Canal altogether. Meanwhile, the OECD Americas is expected to curtail its imports by 600 kb/d to 1.0 mb/d in 2019 with the majority of the imports being heavy, sour grades such as those produced by Venezuela, which will be blended with domestically-produced light crudes for use in US Gulf Coast refineries.

OECD Americas

The possibility of a change in the regulatory framework governing US crude exports has moved to the top of the policy agenda since the *MTOMR 2013*. Several US lawmakers and industry groups have called for the current broad prohibition of most US crude exports to be revisited and for the statutes, a legacy of the 1970s, to be overhauled in view of today's changed North American supply circumstances. This forecast assumes no change in the current legislative framework, but considers the likelihood that it may be interpreted in such a way as to facilitate modestly higher gross crude exports out of the region. Indeed, much current discussion concerns the possibility of US condensate exports, while swap agreements (such as light for heavy oil) with Canada and Mexico have been mooted. Already there has been a notable increase in US crude exports to Canada, increasing rapidly to 250 kb/d on average in 2013. The forecast assumes that there will be an increase in intra-regional exports from the United States to Canada and Mexico as swap agreements (such as light for heavy oil) and special export licences will be allowed between the countries. Such agreements will help US refiners to optimise their crude slates while also acting as a 'release valve' in the event of supply surging ahead of refinery throughputs.

In Canada, rising volumes of domestic crude are set to be exported to US refining centres on the Gulf and West coasts by pipeline, rail or ship. Additionally, 300 kb/d of Canadian oil could be shipped to China by the end of the forecast. These volumes do not depend on the commissioning of new pipelines to evacuate Albertan oil to the Pacific Coast, since according to official data, Canada already exports the odd cargo to China, India, Malaysia and Singapore. It is presumed that volumes will grow in the event of an expansion of Canadian companies being permitted to re-export crude via the United States or by increasing volumes being railed to the Pacific Coast.

A caveat concerns the two pipelines to transport Albertan production to the Pacific currently in the planning stages: Enbridge's 525 kb/d Northern Gateway and Kinder Morgan's 890 kb/d Trans-Mountain Express. The final Federal decision on the former is currently scheduled for June 2014, if approved it could see the line completed by end-2018 at the earliest, while a final decision on the latter will not take place until 2015 at the soonest which will not see it commissioned until after 2019. If one or both of these lines get completed during the forecast, it would mean that Canadian exports to the Pacific Basin could steeply increase.

Figure 3.9 OECD Americas crude imports, 2013

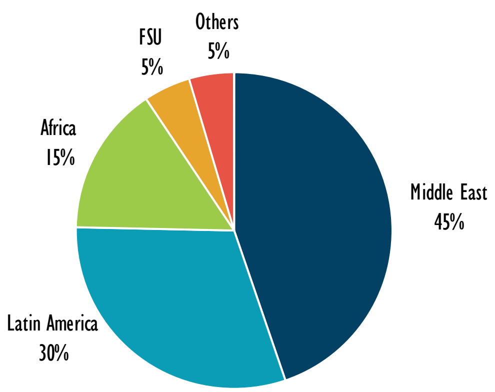
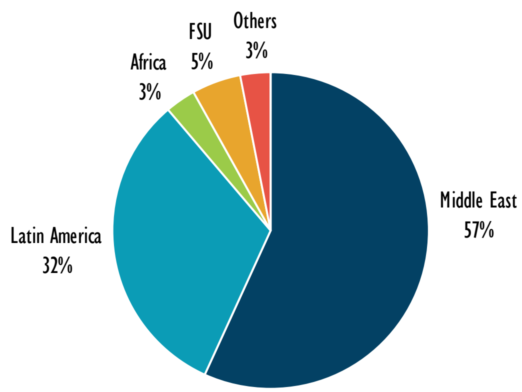


Figure 3.10 OECD Americas crude imports, 2019



On the imports side, shipments to the OECD Americas are expected to fall by 2.2 mb/d (-8.4% CAGR) to 3.1 mb/d in 2019 as domestic supply soars by 4.0 mb/d over the forecast. The bulk of imports are likely to be heavy, sour grades sourced from the Middle East or Latin America since the majority of the US Gulf's refining capacity is configured for heavy or medium-sour crudes. Therefore, heavy, sour grades are required for blending with domestically produced light oil so that refineries can operate efficiently. Over the forecast period, Latin American grades will fall by 600 k/bd but still account for 1 mb/d in 2019. Saudi Arabia is still expected to remain one of the region's main suppliers due to its presence in the Motiva refinery and the fact that it is seen as a 'safe' supplier, selling crude on long-term contracts. In contrast, imports from other Middle Eastern producers, notably Iraq and Kuwait are likely to fall away. By 2019, Middle Eastern grades will account for 57% of regional imports, a rise of 12 percentage points on 2013 as light and medium-light African exports are 'backed out' of the region. As stated previously, African exports are set to see their imports slump to 100 kb/d in 2019 and will thus be sent to Asian markets instead. Meanwhile, supplies from the FSU, mainly condensate used as diluent to transport Canadian bitumen will likely fall by 100 kb/d to 150 kb/d in 2019 as these are replaced by North American condensate. The remainder of the decline will be in imports of European crudes (-150 k/d) which are set to fall to 50 kb/d by 2019.

Europe

Europe is a crude net importer, despite still substantial, if diminishing, production from the North Sea. Crude imports to **Europe** (OECD Europe plus non-OECD Europe) are set to plunge by 1.4 mb/d to 8.0 mb/d in 2019, equating to a contraction of -2.6% on a compound annual basis, second only to that projected in the OECD Americas. Viewed against a projected 100 kb/d drop in regional production, the fall in total imports is even more acute. This is largely a product of a 200 kb/d contraction in regional demand and the European refining industry continuing to come under pressure which will likely see a contraction in runs from today's already historically low levels. The steepest cuts in imports into the region over the forecast will come from Africa (-600 kb/d) and the FSU (-550 kb/d) while Middle Eastern supplies are projected to drop by 250 kb/d. Despite the contraction in imports from the FSU, in 2019 the FSU is expected to be the region's largest supplier, accounting for 3.9 mb/d, considerably higher than the next biggest – Africa – with 2.0 mb/d.

In addition to imports, the region is a significant exporter with its domestically produced grades such as Brent being exported to as far away as Asia. With regional production set to drop by 100 kb/d to 3.2 mb/d by the end of the decade, in line with mature field decline, exports from the region are set to be curbed. By 2019, Europe is projected to export 100 kb/d, only 47% of the 350 kb/d exported in 2013.

OECD Asia Oceania

OECD Asia Oceania (including Israel) imports are forecast to contract by 620 kb/d (-1.7% CAGR), with refinery runs continuing to fall in Japan (where a tranche of capacity was shut ahead of an April 2014 deadline for upgrading or shuttering simple units) and Australia. Imports to the region from the Middle East are set to see the steepest decline as Japanese refinery rationalisation continues apace. Additionally, imports of Tapis from 'Other Asia' are set to contract as Japan reduces its direct burn for power generation as it ups LNG imports and its nuclear power plants slowly come back on line. It should also be noted that the region's imports of FSU crudes are set to remain stable at 500 kb/d. This figure includes approximately 250 kb/d of ESPO blend being imported by Korea and Japan, combined, while another 250 kb/d of Urals is shipped via Novorossiysk and imported by Israel. Elsewhere, imports from Africa are set to increase by 150 kb/d to 400 kb/d by the end of the decade.

Non-OECD Asia

The shift in global trade towards **non-OECD Asia** is projected to quicken over the forecast period. The region is set to account for a staggering 4.3 mb/d of demand growth between 2013 and 2019. It is also forecast to expand refining capacity over the forecast by a net 3.7 mb/d which will see the region's crude import requirement increase by 3.3 mb/d from 13.1 mb/d in 2013 to 16.4 mb/d in 2019. The growth in imports is expected to be split roughly equally between 'Other Asia' and China, both of which are seen increasing their crude imports by around 1.6 mb/d over the forecast.

China is expected to consolidate its position as the world's number one importing country over the forecast and is projected to increase imports by 1.7 mb/d over 2013-19 and import 7.1 mb/d by the end of the decade (4.6% CAGR) as it is set to expand its refinery capacity by 2.4 mb/d. This is a slightly slower pace than over 2007-13 when crude imports rose by 1.8 mb/d to 5.4 mb/d. It is expected that the Middle East will remain its key supplier, exporting 3.1 mb/d to the region in 2019, 300 kb/d above 2013. However, China is making efforts to diversify its crude imports with volumes from Africa, the FSU and Latin America all projected to rise above 1 mb/d by the end of the decade.

The main growth is forecast in imports from the FSU and Latin America which are both seen 600 kb/d higher in 2019. As stated above, the increase in shipments from the FSU will be assisted by long-term contracts and pipeline flows. This strategy will improve China's energy security by providing a number of refining centres in the West and North long-term access to crude supplies. China has also recently invested in a 440 kb/d pipeline running from the Myanmar coast to Kunming in China's interior will provide oil for a planned refinery joint venture with Saudi Aramco while also bypassing the Malacca Straits. Meanwhile, the lion's share of the extra supplies from Latin America are expected to come from Venezuela as oil flows towards China in payment for the numerous loans which China has provided Venezuela with over the past half-decade. On the flipside, it is anticipated China will import less oil short-haul from elsewhere in Asia. Shipments from 'Other Asia' to China are likely to contract by 100 kb/d as more oil will be required by that region as its refineries expand.

Figure 3.11 Chinese crude imports, 2013

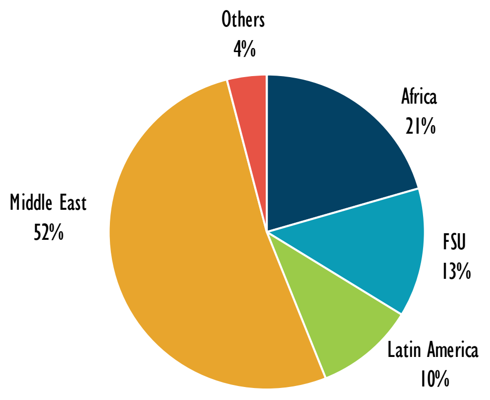
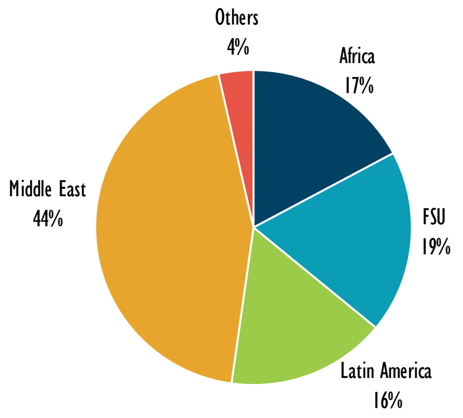


Figure 3.12 Chinese crude imports, 2019



Imports to '**Other Asia**' are projected to increase by 1.6 mb/d, reaching 9.3 mb/d in 2019 (3.1% CAGR). In doing so, the region will overtake OECD Europe in 2016 to become the globe's largest importing region. The Middle East is set to remain the region's key supplier throughout the forecast, accounting for 5.2 mb/d by the end of the decade, 300 kb/d more than in 2013. Nonetheless, the region will continue to diversify its imports. African imports are seen soaring by 750 kb/d to 2.2 mb/d by 2019 (7.3% CAGR), the highest projected absolute growth across all trades. As with China, there is a projected increase in long-haul seaborne trade into the region with deliveries from the FSU and Latin America set to grow by 400 kb/d and 300 kb/d, respectively. These will offset a contraction of European imports (-100 kb/d) which are seto fall as a result of declining production there.

Implications for the tanker market

The trends in trade presented throughout this section will likely provide a boost to beleaguered crude tanker markets as the absolute 0.9 mb/d drop in global crude trade will be more-than-offset by a 100 kb/d absolute increase in long-haul trade. Crude tanker rates have remained in the doldrums over the past five years as the fleet has rapidly expanded while the boost received from floating storage has fallen as its economics have dissipated. The outlook is brighter though as the tanker fleet is set to remain finely balanced over the coming few years, EA Gibson Shipbrokers project that over 2013-16 new orders and scrappings will largely offset one another. Therefore, if these fleet projections 'play out', the growth in trade between the Atlantic and Pacific basins will increase tonne-miles and thus help to tighten the VLCC fleet by tying up vessels for longer. For example, a vessel exporting Bonny

Light from Nigeria to the US Gulf will generally take 18 days for a round trip voyage but a vessel on a voyage between Nigeria and China will take 31 days, significantly longer. Additionally, expansion of the ESPO spur to China aside, the growth in the specific trade routes outlined on Map 3.1 will be facilitated by seaborne trade. It is also highly likely that some of the 0.8 mb/d decrease in the FSU exports to Europe will be borne by the Druzhba pipeline which will mean that not all of the 0.9 mb/d contraction in global trade will be felt by seaborne trade.

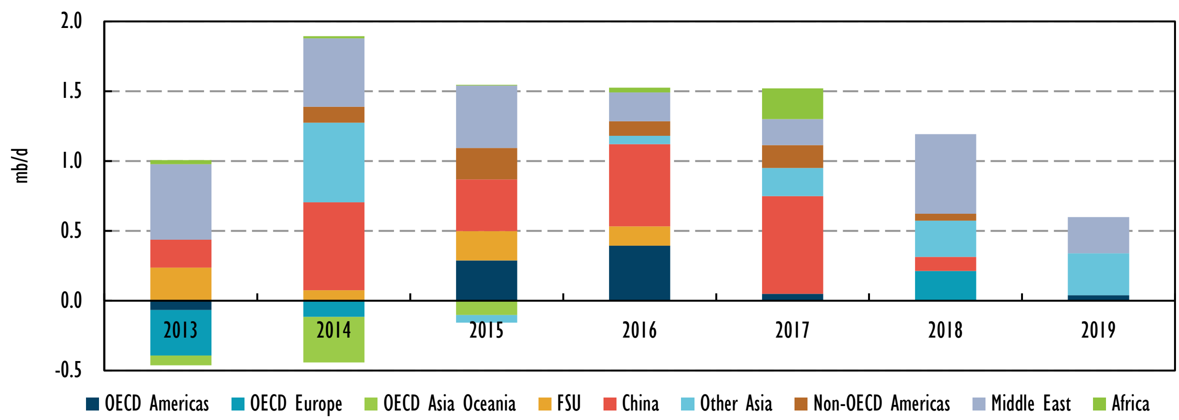
Furthermore, the decrease in crude trade will be more-than-offset by an increase in product trade exported from crude producing countries. It is also noteworthy that importing regions China and 'Other Asia', account for an astounding 4.3 mb/d of demand growth over 2013-19 which will have to be satisfied by either crude or refined product imports.

4. REFINING AND PRODUCT SUPPLY

Summary

- **Global refinery crude distillation (CDU) capacity is set to increase by 7.7 mb/d by 2019**, to 105 mb/d. 95% of the growth is coming from the non-OECD, including half from Asia. In the OECD, surging light tight oil (LTO) and condensate supplies spur downstream investments in the United States, offsetting continued capacity attrition in Europe, Japan and Australia. Upgrading and desulphurisation capacity is set to grow by 5.1 mb/d and 4.2 mb/d, respectively.

Figure 4.1 Global refinery crude distillation capacity additions



- **While refinery capacity expansions on paper look in line with forecast demand growth over the next five years**, surplus capacity is expected to increase by 2 mb/d, as about 25% of incremental demand will be met by supplies bypassing the refinery system, including natural gas liquids (NGLs), biofuels, gas-to-liquids (GTL) and coal-to-liquids (CTL).

- **Global refining margins are coming under renewed pressure as excess refining capacity rebounds.** After refinery shutdowns cut the global capacity overhang in 2012, lifting margins, since 2013 refining profitability is again eroding. Benchmark margins for simple plants in Europe and Asia remained negative through most of 2013 and into 2014, curbing throughputs. US refiners are faring better, thanks to discounted feedstock and low energy costs in the form of cheap natural gas.

- **Surging LTO and NGL supply looks set to cause a glut in global light-distillate supplies.** North American naphtha and gasoline balances look particularly loose, with net export potential surging to 1.3 mb/d in 2019. While Europe faces a ballooning middle-distillate deficit of 1.6 mb/d in 2019, from just over 1.0 mb/d in 2013, ample new supplies are forthcoming from the Middle East, Russia and the United States. These will also need to meet booming demand from Africa. Fuel oil markets, meanwhile, look set to tighten, as the Former Soviet Union (FSU) cuts supplies even faster than demand contracts elsewhere – unless marine bunkers transition out of residual fuel oil faster than forecast.

Box 4.1 New refining capacity squeeze margins in 2013 and 2014

Following a significant reduction in the global refinery capacity overhang in 2012 and a subsequent improvement in margins, since 2013 refining profitability has once again come under pressure from excess capacity. New projects and expansions provided a net gain of 0.5 mb/d in global crude distillation capacity (CDU) for 2013 and a further 1.5 mb/d in 2014, compared with only 80 kb/d in 2012. With surplus capacity on the rise, simple margins plummeted in 2013 and have yet to recover.

Figure 4.2 Simple refining margins

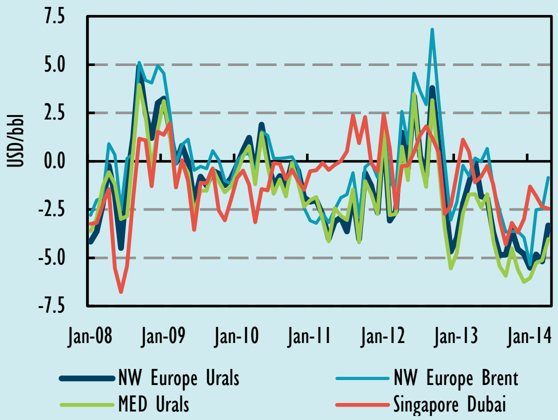
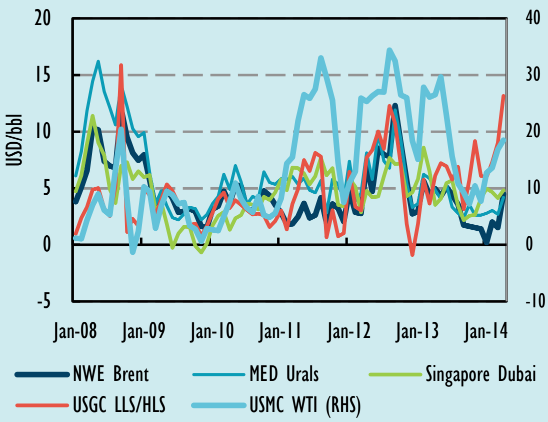


Figure 4.3 Global cracking margins



IEA's global indicator margins, based on refinery yields developed by KBC Advanced Technologies, are calculated for key primary product markets in Northwest Europe, the Mediterranean, Singapore, the US Midcontinent and Gulf Coast. The margins include refinery fuel but exclude other variable costs, depreciation and amortisation as well as all fixed expenses. Consequently, the margins should be taken as a proxy of change of profitability for a given refining centre, not of actual net cash margins, which of course are significantly lower. Actual net cash margins will depend on the size and complexity of the refinery, utilisation rates, local wages, employment, cost of capital, local regulations, etc.

Simple margins in both Singapore and Europe were firmly negative for most of 2013 and into early 2014. Brent hydroskimming margins in Northwest Europe, for instance, averaged a negative USD 1.75/bbl over 2013, and Urals USD -3.10/bbl. Simple margins on the Mediterranean were even worse. To stem losses, several operators cut runs and extended planned maintenance shutdowns. Others opted to idle plants until economic conditions improved, including Cepsa's Tenerife and Hellenic Petroleum's Thessaloniki refineries, both shut in 2013. During the peak autumn maintenance season in 2013, throughputs in OECD Europe plunged to 25-year lows, of 10.3 mb/d, yet the outages failed to materially lift margins.

Global cracking margins have fared better, but also came under renewed pressure after the sharp run-up in margins seen in the second half of 2012. US refiners continue to benefit from discounted crude and natural gas supplies, used as feedstock and refinery fuel, respectively. US Gulf Coast margins saw a spectacular collapse in the second half of 2012. Benchmark Heavy/Light Louisiana Sweet (HLS/LLS) margins plunged from USD 12.30/bbl on average in August 2012, to USD -0.90/bbl in December. Since then, regional cracking margins have improved and were most recently averaging USD 9.20/bbl in April, compared with USD 4.60/bbl in Europe. US Gulf Coast coking margins averaged a higher USD 12.75/bbl.

The increase in US Gulf Coast margins is underpinned by a steepening discount of Gulf Coast crude grades, compared to international benchmarks, as regional supplies have swelled. Margins in the Midcontinent remain higher overall, but have weakened comparatively as crude is being evacuated to the south, with increased pipeline capacity in place. Midcontinent refinery margins averaged USD 22.20/bbl in April, down from the USD 27.90/bbl average recorded a year earlier.

Refinery investment overview

Global refinery expansion plans look set to add a total of 7.7 mb/d of new crude distillation (CDU) capacity in the forecast period, reaching 105 mb/d in 2019. The non-OECD accounts for 95% of expansions, though surging LTO and condensate supplies are also spurring investment in the US downstream industry. A total of 770 kb/d of new crude and condensate processing capacity could come on stream in North America by 2019. After steep reductions in European refinery capacity over past years, with 1.7 mb/d of distillation capacity already closed since the financial crisis of 2008, minimal capacity has been committed to shut in 2014 and the coming five years. In contrast, OECD Asia Oceania saw its primary distillation capacity cut by a massive 570 kb/d in 2014, taking total regional capacity reductions to 1.3 mb/d since 2008, including 100 kb/d in 2015. While refinery closures are heavily weighted towards Japan, Australia's downstream industry is also currently going through a significant restructuring with three of the country's seven main refineries scheduled to close by next year.

Table 4.1 Global refinery crude distillation capacity (mb/d)

	2013	2014	2015	2016	2017	2018	2019	2019-13
OECD Americas	21.7	21.7	22.0	22.4	22.4	22.4	22.5	0.8
OECD Europe	14.8	14.7	14.7	14.7	14.7	14.9	14.9	0.1
OECD Asia Oceania	8.8	8.4	8.3	8.3	8.3	8.3	8.3	-0.4
FSU	8.8	8.9	9.1	9.2	9.2	9.2	9.2	0.4
China	13.6	14.2	14.6	15.2	15.9	16.0	16.0	2.4
Other Asia	11.2	11.7	11.7	11.8	12.0	12.2	12.5	1.3
Middle East	8.4	8.8	9.3	9.5	9.7	10.3	10.5	2.2
Other non-OECD	10.0	10.1	10.3	10.5	10.9	10.9	10.9	0.9
World	**97.2**	**98.7**	**100.0**	**101.6**	**103.1**	**104.3**	**104.9**	**7.7**

Within the non-OECD, Asia remains the main contributor to growth in the medium term, accounting for 48% of global capacity additions. China and Other non-OECD Asia add a combined 3.7 mb/d of new distillation capacity by 2019, after having expanded capacity by 5.1 mb/d in 2007-13. Through several large scale grassroots projects, the Middle East looks set to raise its crude processing capabilities by 2.2 mb/d, to reach 10.5 mb/d in 2019. Ambitious downstream expansion projects in Iraq, Iran and Kuwait, amongst others, could augment this further if sufficient progress is made on financing and project development in the coming year, though we maintain a fairly conservative outlook for these countries for the time being. Limited expansions are also seen coming from Latin America, Africa the FSU, with project delays and financing concerns continuing to stall developments in the former two, and investments in the FSU geared towards improving light product yields and quality rather than expanding distillation capacity.

Since the *MTOMR 2013*, the forecast for global crude distillation capacity additions for 2012-18 period has been cut by 1.9 mb/d as expansions plans are being revisited in several countries. Most of the reductions centre on China, where concerns about emerging overcapacity and local pollution, as well as the fallout from corruption scandals affecting the oil industry, have led both national companies and international players to scale back their investment plans for the coming years. Already in 2013, new refinery commissioning was pushed to 2014, while projects planned for the coming years have been delayed or stalled until the market outlook improves. Several projects in Other Asia have also been delayed. These include India's 300 kb/d Paradip refinery, which has been held back by typhoon damage and displacement of workers and delays in completing a captive power plant on the site.

In Brazil, Petrobras, weighed down by downstream losses and cash constraints, said in early 2014 that it would cut its planned downstream investments for the 2014-18 period by USD 26 billion, to USD 38.7 billion. Gasoline price controls in Brazil have taken a heavy toll on the company as it must supply gasoline to the retail market at a loss. While the first stages of the planned Premium I and Premium II refineries in the Northeast region remain scheduled for 2018-19, given recent experiences and the latest revision to the investment plan, the projects now look more likely to come on stream in 2020 or later. In Africa, despite a flurry of proposals to expand refinery capacity, most projects remain on the drawing-board and look unlikely to be completed before the end of the decade. Both Africa and Latin America are thus expected to remain large product importers in the coming five years.

Refinery utilisation and throughputs

Spare refining capacity is set to increase over the forecast period, as planned additions outpace growth in end-user demand for refined products, against the backdrop of rising supply of products that bypass the refinery system. Overall, firm investments could augment global refinery crude distillation capacity, including condensate splitters, by 7.7 mb/d by 2019, which is only slightly above forecast end-user demand growth of 7.6 mb/d. However, surging NGLs production will largely bypass the refinery system, compounding the impact of biofuel supply, direct crude burn and GTL and CTL supply. NGLs are mostly treated in fractionation facilities, which split them into ethane, propane, butane, and naphtha (plant pentanes) fit for end-user consumption.

Figure 4.4 Cumulative demand growth and sources of supply

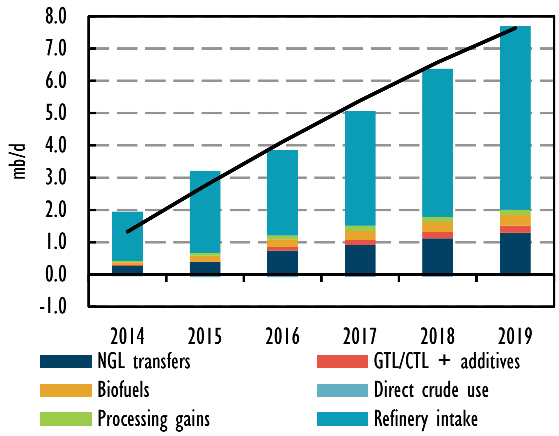
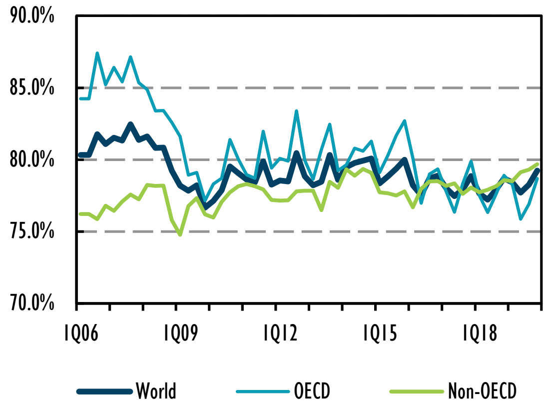


Figure 4.5 Refinery utilisation rates



As a result, the demand on refinery crude and condensate processing is estimated at 5.6 mb/d, some 2.0 mb/d less than refinery capacity expansions considered in this outlook. Some of the projects included here may thus be delayed or cancelled, while more refinery closures look inevitable in mature markets. OECD refinery utilisation rates have yet to recover from the collapse seen in 2008/2009, and are set to decline further through 2019 as OECD oil demand resumes its structural downtrend, contracting by a projected 1.0 mb/d over the period. Absent further refinery capacity reductions, OECD refinery utilisation rates are projected to fall further to 77% in 2019, from 80% on average in 2013 and 85% in 2008. Non-OECD refiners are expected to be able to maintain utilisation rates in the 78% to 79% range through 2019. To lift global utilisation rates back to 2006-08 levels, a total of 4.8 mb/d of capacity would have to shut.

Box 4.2 Crude oil quality: Lighter US slate leaves global average little changed

While on average, global refinery feedstock is projected to remain roughly unchanged over the 2013-19 period, this headline conceals stark contrasts and profound changes at the regional level. On a production weighted-average basis, global crude API gravity is expected to increase by less than 0.1 degrees, to 34.12 degrees, while sulphur content looks set to inch up by less than 0.01 percentage points, to 1.17%. As in previous reports, the evolution of feedstock quality is considered on a geographic basis of region of origin, thus not accounting for inter-regional trade flows.

Figure 4.6 Current gravity and sulphur

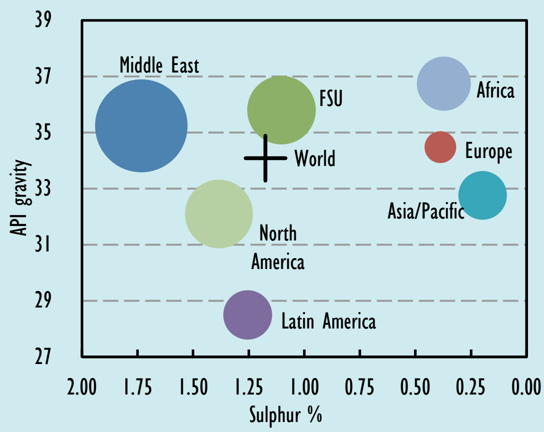
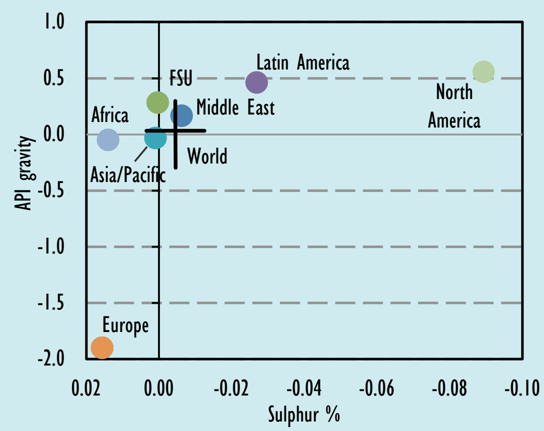


Figure 4.7 Changes in quality 2013-19



Note: Bubbles are proportionate in size to regional production.

In North America, this global trend disappears as the non-conventional supply revolution continues to fuel a condensate, US LTO, Canadian syncrude and oil-sands boom which is dramatically altering the feedstock landscape. In contrast with the rest of the world, average North American feedstock is getting lighter and sweeter, rising by 0.56 degrees to 32.6 degrees gravity and sliding by almost 0.1 percentage points to 1.29% in sulphur content, down from 1.38% currently. Within North America, feedstock quality is also becoming more disparate, with US LTO and condensate at one end of the scale, raising average US API gravity by almost 2.2 degrees, and Canadian oil sands and a slightly heavier than expected Mexican slate providing a partial offset at the other end. This is a change from the situation in late 2012, when overall North American API was forecast to increase by a steeper 1.5 degrees by 2017.

Latin America also is trending towards lighter and sweeter feedstock on average, as lighter pre-salt Brazilian crude growth of almost 800 kb/d balances heavier Venezuelan and Colombian production. FSU supplies are also projected to become lighter as Kashagan production is forecast to come back online after 2016.

In contrast, starting in 2016, North Sea crude from the United Kingdom and Norway is projected to become heavier by almost 2 degrees API and marginally sourer, as the region's mature lighter streams are forecast to decline and leave room to heavier grades, mostly Forties. African API gravity will remain below pre-2011 averages on Libyan and Nigerian lighter crude disruptions, although the impact of such disruptions will not affect the 2013-19 quality change, which is set to remain stable. Meanwhile, Middle East supplies are projected to become marginally lighter on Qatari and Iran condensate growth, counterbalanced by Saudi Arabia's Manifa heavy oil field coming online. Asia-Pacific feedstocks are forecast to remain stable in quality, as Malaysian and Vietnamese lighter grades decline will be offset by Australian condensate and lighter Indonesian crude.

Product supply balances

Global oil product markets have gone through a remarkable transformation in recent years, and further changes lie ahead. Most notable is the extraordinary reversal of fortune of the US refining industry, now the world's largest product exporter with 2.9 mb/d of gross exports in 2013, nearly three times as much as in 2005. On a net basis, the United States, which less than ten years ago imported a net 1.4 mb/d of oil products, recorded net exports of 1.5 mb/d last year. The broader OECD Americas region is expected to see net product exports rise from 1.3 mb/d in 2013 to an astounding 3.5 mb/d in 2019. Two-thirds of the increase comes from light ends, including ethane/LPG, naphtha and gasoline, while middle distillate and 'other products' surpluses could rise by around 300 kb/d each. Further efforts and investments to raise distillate yields appear likely in view of a looming overhang of naphtha and gasoline in the Atlantic Basin.

Box 4.3 Products supply modelling – seeking the pressure points

Our approach to modelling refined product supply is not designed to optimise the global/regional system, but rather to highlight where pressures may emerge within that system in the 2013-19 timeframe. A number of simplifying assumptions underpin the analysis, changes to any one of which generate a significantly different outcome. The aim is to identify any mismatch between existing and planned refining capacity and expected changes in crude feedstock quality and availability given current expectations of product demand growth. The model uses our current demand forecast, with global refinery throughput levels feeding off a balance whereby non-OPEC supply is maximised and OPEC acts as swing supplier. The model also assumes that the utilisation of higher-value crude capacity is maximised. Finally, we also assume an operational 'merit order', with crude preferentially allocated to demand growth regions and more complex refining capacity. Our approach is non-iterative, when of course, in reality the emergence of imbalances would tend to force changes in operating regime, crude allocation and ultimately capacity and investment levels themselves.

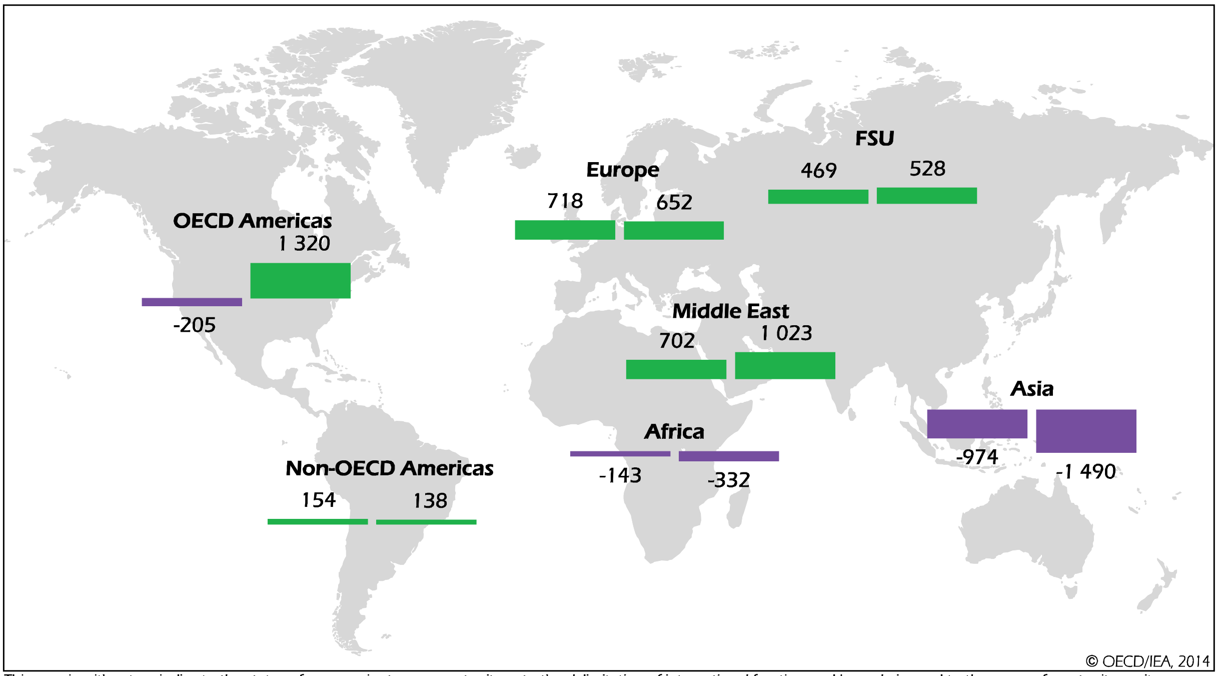
Refinery restructuring in OECD Europe and OECD Asia Oceania is expected to continue in the face of mounting competition not only from US refiners, which benefit from "advantaged" feedstock and refinery fuel, but also Russian refiners and state-of-the-art, large-scale plants that are coming on line in the Middle East. Over time, new product supply in the Middle East will be largely absorbed by regional demand growth. But even though Middle East product demand growth is amongst the highest in the world, at 1.8 mb/d over the forecast period, incremental middle-distillate demand from the Middle East will be less than regional supply growth. That will allow Middle East refiners and their joint-venture partners to earmark part of their output of high-value ultra-low sulphur diesel (ULSD) for export. Europe's middle distillate deficit is set to increase further through 2019 as throughputs are cut, yet the region will struggle to rid itself of surplus gasoline volumes. Recognising the structural imbalance in regional supply and demand, and in response to recent concerns over local pollution levels in several European cities, mounting pressures to, at national and at the European Union level, to alter existing preferential tax for diesel compared with gasoline, could lead to a reversal of the recent trends towards "dieselisation" of transport fuel.

Product supplies coming out of the FSU are expected to see moderate decline over the period, as regional oil product demand is forecast to rise by 0.6 mb/d, progressively cutting into exports. Upcoming export duty changes are also likely to reduce utilisation rates of simple refineries with high fuel oil yields, as direct crude exports will yield better netbacks than fuel exports. Reduced runs and increased upgrading capacity could cut regional fuel oil exports by half, from 1.3 mb/d in 2013 to just over 0.6 mb/d in 2019, offset in part by higher middle distillate supply. Lastly, Asia sees diverging trends. In China, refinery expansion plans are expected to stall, as refiners adjust to a slower pace of demand growth for key products and to minimise a looming overhang of product supply. In other non-OECD Asia, in contrast, demand growth is set to exceed additional supplies. Finally, OECD Asia Oceania will curb throughputs as demand continues to contract. The region will nevertheless remain a large importer of naphtha for the extensive petrochemical industry based in Japan and South Korea.

Light distillates

Developments in North America are set to transform global light distillate markets in the medium term. The region, still a net importer of gasoline and naphtha, is on track to become the world's largest exporter by 2019. Surging regional LTO, condensate and NGL supplies, compounding the impact of contracting regional demand (see Chapter 1. Demand, "Americas" section), will see light-distillate exports surge, possibly to as much as 1.3 mb/d in 2019. Fuel efficiency measures in the vehicle fleet, coupled with relatively flat gains in the total vehicle fleet, will cut regional gasoline demand by 550 kb/d over the period, while product switching in the petrochemical sector sees naphtha demand falling by 50 kb/d (see Chapter 1. Demand, "An industry on the move: the rise of the petrochemical sector as a leading driver of oil demand growth"). At the same time, surging NGL production lifts naphtha supplies by an estimated 200 kb/d. Condensates processed in simple refineries or dedicated splitters also mostly yield naphtha and gasoline. In all, regional refinery output is set to rise almost 700 kb/d, while demand falls by 600 kb/d.

Map 4.1 Product supply balances – gasoline/naphtha
Regional balances in 2013 and 2019 (thousand barrels per day)



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

Notes: Refinery production and supplies from other sources vs. end-user demand. Regional total does not add to zero due to feedstock trade and differences in product classification. Positive number indicates net-export potential, negative number net-import requirement.

In contrast, demand for gasoline is set to grow by 0.4 mb/d in Latin America. Increased supplies from Brazil and Colombia, and higher ethanol production will provide an offset, however. Europe will only slightly reduce its gasoline surplus, of 1.0 mb/d in 2013, as continued demand contractions balance lower refinery output. African gasoline import requirements will rise in line with demand growth, and the region could see net gasoline imports of around 0.6 mb/d in 2019, a 50% increase from 0.4 mb/d in 2013. The region remains a net exporter of naphtha, however, with Algeria, Egypt and Libya traditional suppliers to Europe. Asia remains a large product importer over the period, and sees its light distillate deficit rise sharply through 2019. Increased naphtha demand from the petrochemical sector and lower refinery output in OECD Asia Oceania, as the industry cuts capacity, will see net light distillate imports rise to 1.5 mb/d in 2019, from 1.0 mb/d in 2013. The imports are almost entirely accounted for by naphtha, while gasoline markets are more balanced overall.

Middle distillates

As global demand growth remains heavily weighted towards middle distillates, with 40% of the total increase accounted for by diesel/gasoil and a further 8% by jet/kerosene, middle distillate markets will continue to loom large in both global product trade and refinery margins in years to come. Over the next five years, according to our modelling exercise, European net distillate import requirements surge to 1.6 mb/d in 2019, from just over 1 mb/d in 2013, but European refiners continue to suffer from an overhang of gasoline supply which is getting harder and harder to market. The region's product imbalances, combined with its relatively high energy cost, forces refiners to curb output, in turn raising European dependence on product imports.

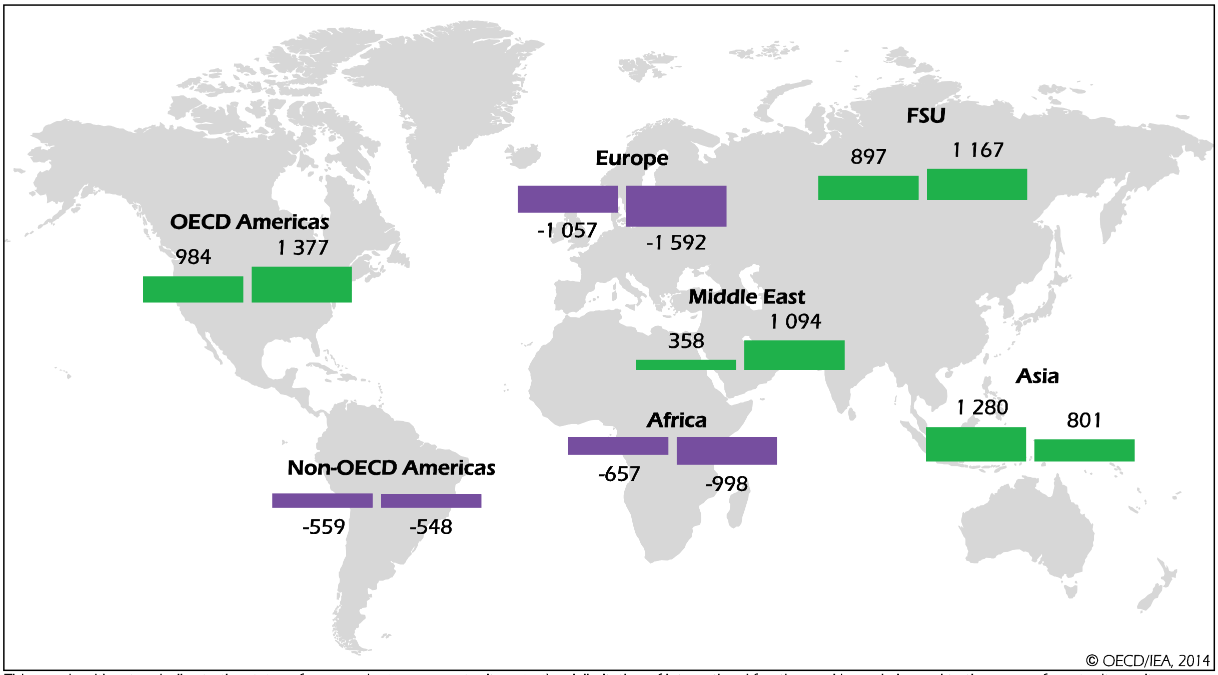
Even as European middle-distillate import needs increase in coming years, additional export volumes will be available from a variety of sources, chief among them North America, where refiners will continue to enjoy a competitive advantage in coming years and ramp up product exports, not only to Europe, but also to Latin America and Africa. US distillate exports will compete with those from the FSU, which continues to grow in importance as a distillate exporter. FSU exports are seen rising from 0.9 mb/d in 2013 to just under 1.2 mb/d by the end of the decade. Russian refiners have been investing heavily in recent years to raise diesel production at the expense of fuel oil, in anticipation of pending changes to the country's export-duty scheme (see Box 4.4 "New Russian export duty scheme curb FSU fuel oil exports"), while regional demand growth is forecast to remain modest.

The largest increment of middle-distillate export volumes is expected to come from the Middle East. Regional refinery capacity additions of close to 2.2 mb/d by 2019 outstrip total product demand growth of 1.8 mb/d, which will also in large part be met by NGLs bypassing the refinery system. Regional middle-distillate demand is set to rise by just under 0.6 mb/d by 2019, while refinery output could rise by 1.3 mb/d of diesel/gasoil and jet/kerosene combined, lifting distillate exports to an estimated 1.1 mb/d in 2019. The recently commissioned Jubail refinery in Saudi Arabia is expected to have distillate yields above 50%, while the Kingdom's 400 kb/d Yanbu refinery to be commissioned later this year plans to produce 260 kb/d of ULSD. The Ruwais refinery in the United Arab Emirates will bring additional volumes to market once commissioned early next year.

In Asia, diverging trends are emerging. A sharp deceleration in Chinese gasoil demand growth has recently led to surplus supplies. Indeed, the latest official trade statistics show China turned net exporter of middle distillates in 2013, with net outflows of about 140 kb/d. As the country continues to expand its downstream industry, excess volumes are expected to grow to over 300 kb/d by 2019. As discussed elsewhere, we expect Chinese corporate officials and policymakers to carefully manage refinery expansions with an eye to minimising surplus capacity and large-scale product exports as much as possible. Meanwhile, OECD Asia Oceania sees its middle-distillate balance tighten over the forecast period, as refinery consolidation and pressure on margins curb output while demand is largely unchanged. In other non-OECD Asia, current surplus jet and gasoil supplies will likely erode by the end of the decade, as only a handful of the many refinery projects currently on the drawing board are expected to be completed within this timeframe, and demand growth eclipse additional refinery supply.

Map 4.2 Product supply balances – gasoil/kerosene

Regional balances in 2013 and 20191 (thousand barrels per day)



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

Notes: Refinery production and supplies from other sources vs. end-user demand. Regional total does not add to zero due to feedstock trade and differences in product classification. Positive number indicates net-export potential, negative number net-import requirement.

Latin America's middle distillate import requirements are expected to stay around current levels, of 0.6 mb/d in 2013, as new refinery output just about covers demand growth of some 360 kb/d. Africa, on the other hand, will see its imports rise more dramatically, as very few new projects are progressing towards completion, and demand growth remains robust, albeit from a low base. African middle distillate demand is forecast to grow at 4.2% through 2019, or 480 kb/d of additional supply.

Fuel oil

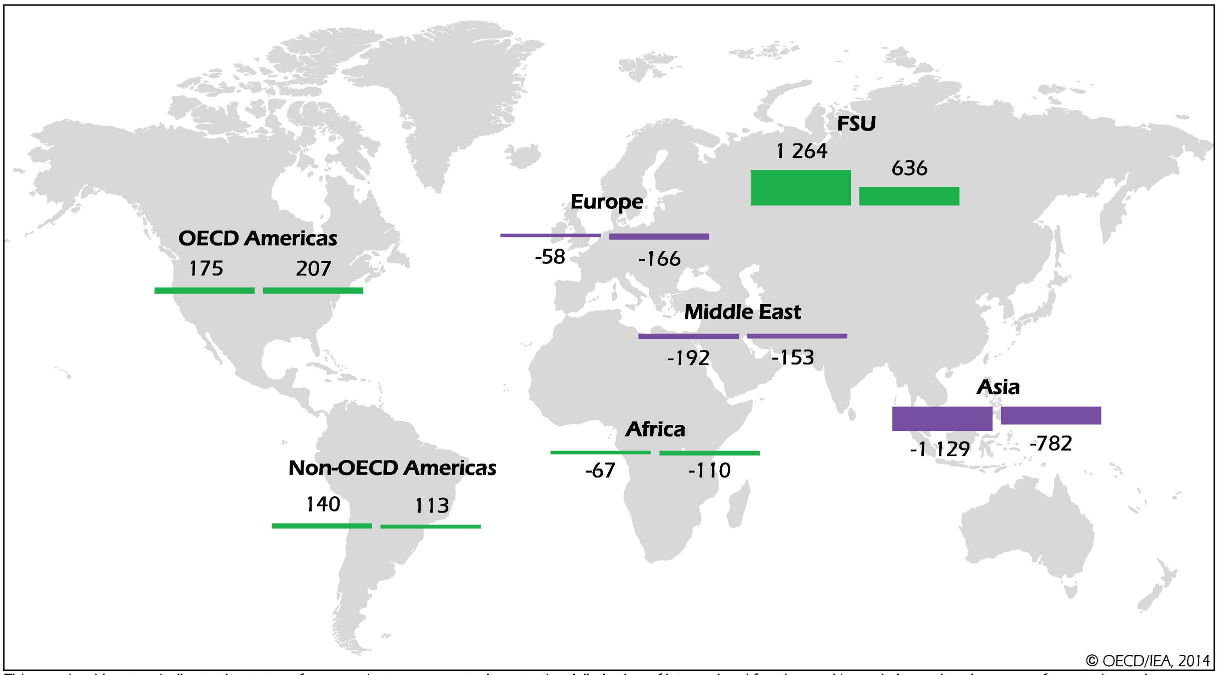
Global fuel oil markets are set to tighten significantly in coming years, as FSU exports, today the world's leading source of supply by a wide margin, plummet from current levels. Russian efforts to upgrade refineries, combined with pending changes to the country's export duty scheme, could slash the region's exports by more than half, to 0.6 mb/d at the end of the forecast from 1.3 mb/d in 2013.

In the OECD, Europe exported a net 60 kb/d of fuel oil in 2013, while the Americas exported just under 200 kb/d. The Asia Oceania region meanwhile imported some 150 kb/d, as Japanese thermal power generation continued to help plug the gap left by the Fukushima nuclear accident of 2011.

Continuing efforts to improve efficiencies and reduce emissions, meanwhile, are expected to have only a limited impact on global fuel oil demand. A 600 kb/d reduction in OECD fuel oil demand over the period will be entirely offset by increased consumption in the Middle East and non-OECD Asia, leaving global demand unchanged at 7.9 mb/d.

Map 4.3 Product supply balances – fuel oil

Regional balances in 2013 and 2019 (thousand barrels per day)



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

Notes: Refinery production and supplies from other sources vs. end-user demand. Regional total does not add to zero due to feedstock trade and differences in product classification. Positive number indicates net-export potential, negative number net-import requirement.

Asian net import requirements will decline through 2019, possibly to 0.8 mb/d, from 1.1 mb/d in 2013. Chinese fuel oil imports are forecast to remain around current levels, just exceeding 200 kb/d. Surplus refinery capacity at the country's main refineries has reduced fuel oil imports processed by the many independent 'teapot' refineries. Other non-OECD Asian countries, large fuel oil importers historically, will see their requirements diminish, to around 0.4 mb/d in 2019, from almost 0.7 mb/d estimated in 2013. Increased output from the region's new refineries more than offset the forecast increase in demand. Lastly, as discussed above, the OECD Asian countries will see import requirements fall back with the return of Japanese nuclear power plants and as some switching of bunker fuels to cleaner fuels start taking place towards the end of the forecast period.

Box 4.4 New Russian export duty scheme curbs FSU fuel oil exports

Upcoming reforms to the Russian export duty scheme, meant to eliminate the disincentive to upgrade fuel oil and encourage refineries to improve their conversion capacity, could have a significant impact on Russian fuel oil exports. The changes, scheduled to take effect on 1 January 2015, will set the export duty of fuel oil and crude at the same level, thus making simple refiners unprofitable. The revised duty-scheme has already led to a flurry of refinery investment in upgrading capacity. Nevertheless, overall refinery runs are expected to decline, as plants that have not upgraded will have to cut runs or shut.

Box 4.4 New Russian export duty scheme curbs FSU fuel oil exports (continued)

Until 2011, the fuel oil export duty was set at 40% of the Urals crude oil duty. Lower fees resulted in a higher netback value, calculated as the international price less the export duty, for fuel oil than for crude. On 1 October 2011, Russia increased the fuel oil export duty to 66% of that for crude oil. A government plan to raise it further, to 75%, in 2014, was derailed by a resolution issued over the New Year holiday, leaving it unchanged at 66%, as several upgrading projects had been delayed. While the same resolution confirmed the equalisation of the crude and fuel oil tariffs from the start of 2015, some speculation that it could again be put on hold, make the outlook for fuel oil supplies somewhat uncertain. For the purpose of this analysis, we assume that the fuel oil export duty will increase as planned early next year, curbing the refinery profitability of simple refiners. We estimate that runs will be cut by some 200 kb/d. Fuel oil exports are already declining, and averaged 1.3 mb/d in 1Q14, compared with 1.4 mb/d in 1Q13. The start-up of two large hydrocrackers in late 2013 and early this year is already reducing fuel oil supplies. Fuel oil is mostly used as feedstock and as bunker fuel, in Europe and further afield.

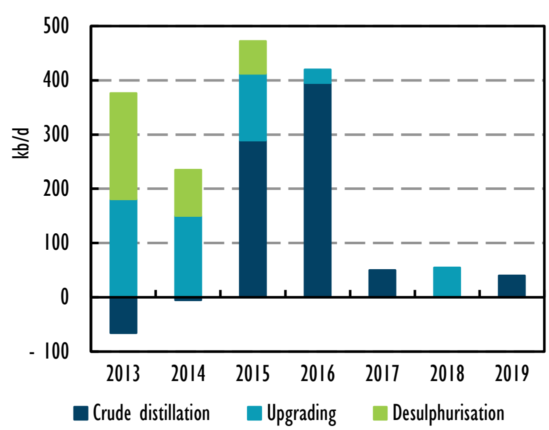
Regional developments

OECD Americas

Surging United States and Canadian crude oil, condensates and natural gas supplies, and restrictions in place preventing the exports of these, has led to a spectacular renaissance of the US refining industry over the last few years. US refinery activity continues to impress, with throughputs surging almost 750 kb/d year-on-year in the first four months of 2014, after having already increased by more than 300 kb/d on average from a year earlier in 2013. Cheap natural gas, used as a refinery fuel and making up the largest component of variable cost for a refinery, as well as discounted Canadian and US crudes compared with international benchmarks, have ensured healthy profits. In turn, the United States has transformed itself into the largest product exporter in the world, in record time. From importing a net 1.4 mb/d of oil products in 2005, less than a decade later, in 2013 it exported a net 1.5 mb/d.

Healthy refinery margins look set to spur more than 700 kb/d of new topping and condensate splitter capacity in North America over the next few years. The existing US refinery capacity is geared towards processing heavier crudes than the current feedstock available in the United States. Splitters are simple distillation towers that process condensates into light straight-run products, mostly light and heavy naphtha, but also kerosene, diesel and gasoil.

Figure 4.8 OECD Americas refinery capacity additions



Currently there is only one condensate splitter operating in the US; BASF-Total's 75 kb/d Joint Venture (JV) splitter in Port Arthur, Texas. Kinder Morgan is building two 50 kb/d condensate splitters at its Galena Park terminal on the Houston Ship Channel, the first of which will be operational in 4Q14, followed by the second unit commissioned during 2Q15. Martin Midstream Partners, Magellan and Castleton have also proposed 100 kb/d condensate splitters on the

Gulf Coast over 2015 or 2016 and Marathon is building two splitters with combined capacity of 60 kb/d at its Canton and Catlettsburg plants in the Midcontinent. In addition, Marathon is planning to add 30 kb/d of light crude processing capacity at its Robinson refinery by 2016.

Independent refiner, Valero, is also investing to increase its light sweet crude and condensate processing capabilities. In its latest investor presentation (March 2014), the company outlined plans for expanding light crude/condensate processing capacity by 185 kb/d (25 kb/d at McKee by 2015, and 90 kb/d topping unit at Houston and 70 kb/d topping unit at Corpus Christie by 2016). It also considers boosting capacity at its St Charles refinery, by 70 kb/d, but this project seems to still be in the planning stage, thus not included in these projections. Current discussion regarding the reclassification of condensates, potentially enabling exports, could derail some of the investment plans.

Table 4.2 US condensate splitter and topping unit expansions (kb/d)

Company	Location	Capacity	Expected start-up	Status
Condensate Splitters				
BASF-Total	Port Arthur	75	4Q01	Operational
Kinder Morgan	Houston	100	3Q14/3Q15	Under Construction
Castleton	Corpus Christie	100	4Q15	Proposed
Martin	Corpus Christie	100	2Q16	Proposed
Magellan	Corpus Christie	100	4Q16	Proposed
Marathon Petroleum	Canton	25	1Q15	Under construction
Marathon Petroleum	Catlettsburg	35	3Q15	Under construction
Topping Units				
Valero	Houston	90	1Q16	Proposed
Valero	Corpus Christie	70	1Q16	Proposed
Marathon Petroleum	Robinson	30	4Q16	Proposed
Other		60		
Total Additions		**775**		

To deal with the changing feedstock quality, US refiners are also overhauling distillation towers, furnaces, heat exchangers and downstream conversion units. Processing a higher share of light oil means that refiners are not able to make full use of expensive upgrading units installed over the past decades, before the LTO boom, when they were expecting the a heavier crude slate overall. Indeed, companies are already starting to adjust their plants to deal with the new feedstock reality. Shell applied for a permit to shut one of two coking units at its Martinez refinery in California in May, as it seeks to process a lighter crude slate at the plant.

North American downstream investments are not restricted to the United States. After almost three decades without any new regional refineries constructed, North West Upgrading Inc. broke ground on a new Canadian grassroots refinery in late 2013. The USD 5.7 billion Sturgeon project will process oils sands into mostly low-sulphur diesel, with the first 50 kb/d operational in 2016. The plant will eventually be able to process 150 kb/d of bitumen, and is backed by the Albertan government and Canadian Natural Resources (CNRL) who both hold a stake in the operations. Providing a partial offset, Imperial Oil shut its 88 kb/d Dartmouth refinery at the end of 2013. Tesoro's 94 kb/d Kapolei refinery in Hawaii avoided the same fate, however, as a last minute sale to Par Petroleum in mid-2013 ensured continued operation of the complex.

South of the border, Pemex put on hold the USD 12 billion Tula refinery in its last business plan. Instead the company plans to spend USD 3.5 billion to expand the existing Tula refinery by 40 kb/d by 2018 and to modernise three of its refineries to produce more gasoline and diesel. Pemex completed an expansion and a coking upgrade of its Minatitlan refinery last year, after numerous delays.

Under the reform process for Pemex, the downstream sector is to eventually be opened to private and foreign investment, with far fewer restrictions than in the upstream. This could include changes in the operations of Mexico's refineries, as currently higher quality crudes are exported to maximise Pemex revenues, even though some of Mexico's refineries are not optimised for the heavier feedstock, leading to inefficiencies. Lower light product yields compared to their US competitors and less efficient operations with higher outages suggest real opportunities for improvements. Attracting investment might be difficult, however, and will require clarity on the subsidies regime and how the sector will be opened up. Important secondary legislation is expected to come before the Mexican Congress later in 2014.

Figure 4.9 OECD Americas total refinery oil product supply vs. *OMR* demand

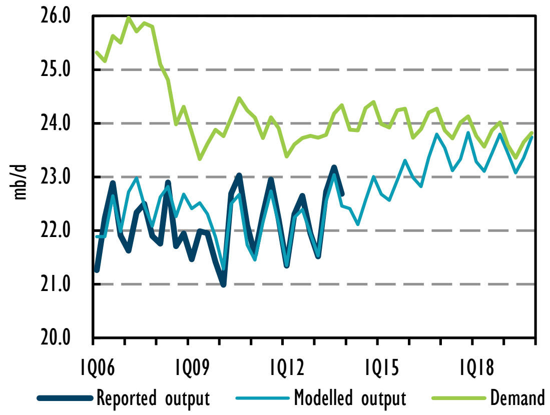
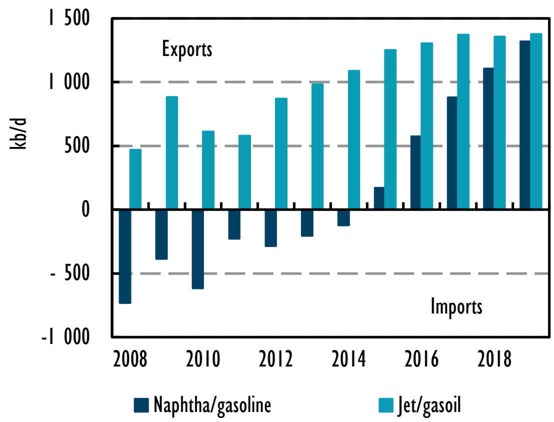


Figure 4.10 OECD Americas oil product balances



As the region expands its capacity, by a net 770 kb/d in total, to reach 22.5 mb/d by the end of the forecast period, and refiners continue to enjoy discounted feedstock and refinery fuel enabling them to run at high utilisation rates, regional refinery output is forecast to increase by about 1 mb/d. Further additional product supplies will come from fractionated NGLs, surging by 1 mb/d by 2019. Increased biofuels supplies will add another 90 kb/d. As a result, regional middle distillate exports could increase to 1.4 mb/d, from just under 1 mb/d in 2013. Naphtha and gasoline balances meanwhile will rise to 1.3 mb/d in 2019, a reversal from 2007, when net imports averaged 1.1 mb/d.

Europe

Faced with structurally declining demand and increased competition from outside the region, little investment is planned to increase European distillation capacity. The exception is in Turkey, where Azerbaijan's state company Socar is building a 200 kb/d refinery in Aliaga, near Izmir. The company secured new financing in May for the USD 5.5 billion STAR project, after the World Bank's International Financial Cooperation (IFC) and the European Reconstruction and Development Bank withdrew from the consortium backing the earlier this year. Turkey's Turcas Petrol announced in March that it would sell its 18.5% share in the project, leaving the refinery entirely in Azeri hands. The project is scheduled to be completed by 2017, but given the latest financing and ownership changes, we assume the project will be slightly delayed, to 2018.

Other European downstream investments are mostly geared towards improving middle distillate yields or product quality and include, amongst others, projects in Belgium, Italy and Turkey. Total is planning to invest EUR 1 billion on its Antwerp plant, by installing a new 20 kb/d hydrocracker by early 2016. Eni has announced it will spend USD 900 million on upgrading its Gela refinery in Italy, though the details of the investments are not yet known. In Turkey, Tupras is expected to complete their Residue Upgrade Project (RUP) of its Izmit refinery, by November 2014. The project, which includes a coker and a hydrocracker, will increase the plant's Nelson complexity index, an industry measure of secondary conversion to distillation capacity, from 7.78 to 14.5.

In non-OECD Europe, Lukoil subsidiary Neftochim Burgas is modernising its Burgas refinery in Bulgaria and is expected to commission a heavy hydrocracking complex in January 2015. In Bosnia and Herzegovina, Raffinerija Nafte Brod is looking to upgrade the country's sole refinery by 2016.

Figure 4.11 European refinery capacity additions

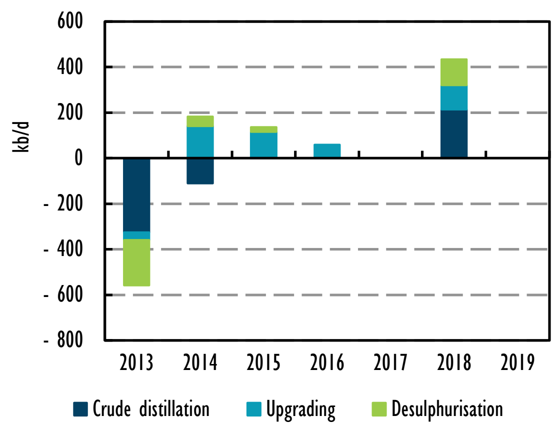
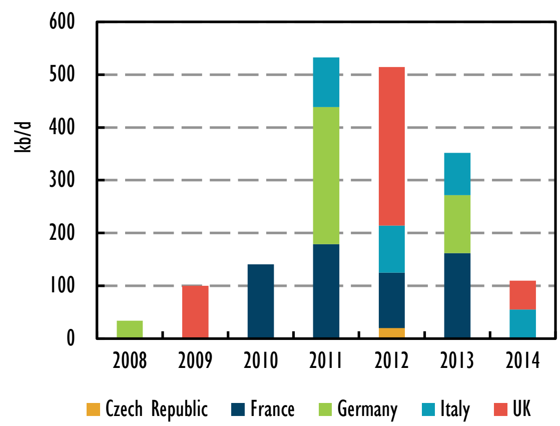


Figure 4.12 OECD Europe refinery closures



In 2013, another 350 kb/d of CDU capacity was shut in OECD Europe, reducing the region's nameplate capacity to 14.8 mb/d by end-year. Petroplus' 160 kb/d Petit Couronne refinery in France, Shell's 110 kb/d Harburg refinery in Germany, as well as Eni's 80 kb/d Venice refinery, were permanently shut. The latter was converted into a bio-refinery in 2Q14, processing palm-oil and other renewable feedstock into mostly diesel and jet fuel. Regional capacity will be reduced further in 2014, with 110 kb/d of capacity committed to shut so far. MOL closed its 55 kb/d Mantova refinery in Italy in early January, and Essar announced it will permanently halt a 55 kb/d CDU at its Stanlow plant in the United Kingdom later this year.

Despite the restructuring already taking place, European refiners continue to struggle with poor margins in 2013 and 2014. European simple refinery margins were negative for most of 2013, and weak at best for more complex plants (see Box 4.1 "Refinery margins squeezed by surplus capacity"). The weak margins prompted European operators to curb runs beyond that implied by reduced capacity and maintenance shutdowns. In October 2013, OECD Europe processed only 10.3 mb/d, the lowest level in more than 25 years. In 2H13, runs declined by 1 mb/d year-on-year. At the same time, middle distillate imports surged to their highest levels yet, of 1.4 mb/d on average in 4Q13. While throughputs have since recovered from those lows, regional refinery runs were still contracting by 0.5 mb/d annually in early 2014.

Pressures facing the European refinery industry are expected to persist through the medium term. Regional oil demand (including OECD and non-OECD Europe) continues to contract structurally, by another 200 kb/d through 2019, albeit at a slower rate than seen over recent years, as much of the fuel switching that drove the previous downside has been completed. Faced with poor margins and fierce competition from advantaged refiners outside the region, European throughput rates are likely to fall further. In this scenario, regional refiners will have to cut runs by almost 1.2 mb/d from 2013 levels to make room for new capacity in the non-OECD and the United States. Yet, this will only reduce the regions gasoline surplus from 1.0 mb/d in 2013 to 0.9 mb/d in 2019. Including naphtha supplies, net exports are unchanged at 0.7 mb/d. On the flipside, regional middle distillate import requirements would rise significantly, from 1.1 mb/d in 2013, to 1.6 mb/d in five years. Of this, 1.3 mb/d is gasoil. Fuel oil markets look relatively balanced as diminishing demand largely offsets lower supplies.

Figure 4.13 OECD Europe total refinery oil product supply vs. *OMR* demand

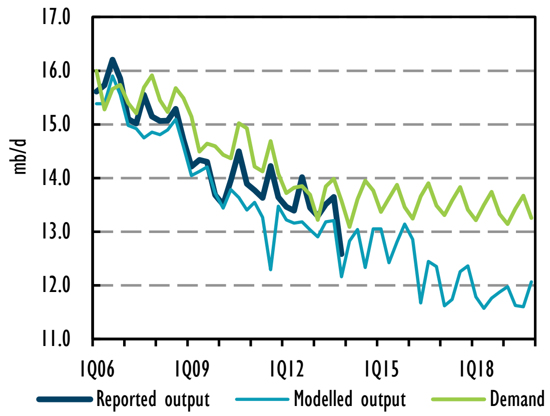
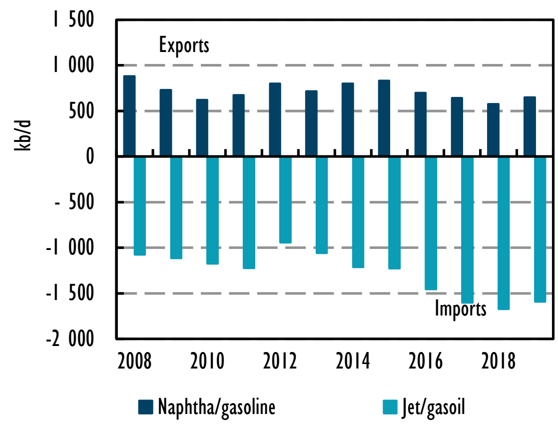


Figure 4.14 European oil product imbalances



OECD Asia Oceania

Refinery restructuring and consolidation efforts in OECD Asia Oceania continued in their stride over 2013 and early 2014. A total of 1.2 mb/d of crude distillation capacity has been shaved since 2008, of which 570 kb/d in 2014. The majority of the reductions stem from Japan, where sliding domestic demand and a co-ordinated government effort to increase the industry's efficiency has led to significant refinery closures. As of 1 April, 2014 Japan had cut its primary distillation capacity to 4.0 mb/d, from 4.9 mb/d in 2008.

Japan's industry ministry METI implemented an ordinance in July 2010, asking refiners to meet a cracking/CDU ratio of 13% or higher by the end of March 2014, effectively forcing plants to reduce their crude distillation capacity as investments in upgrading units have been hard to justify given the structural challenges facing the industry. To fulfil its obligation, Japanese oil companies have cut capacity as detailed below. METI is mulling further refinery consolidation as demand continues to contract. A new round of discussions at its expert committee level was launched earlier this year. Japanese oil product demand is forecast to shrink a further 400 kb/d by 2019.

Industry woes in the OECD Asia Oceania region have not been restricted to Japan. Australia's downstream industry is also going through significant transformation and consolidation. The country's refining and marketing sector, characterised by small and aging facilities, has undergone a massive restructuring in recent years. The industry, counting eight refineries in 2003, has struggled to compete with new, larger plants operating in the Asia Pacific region.

Figure 4.15 OECD Asia Oceania refinery capacity additions

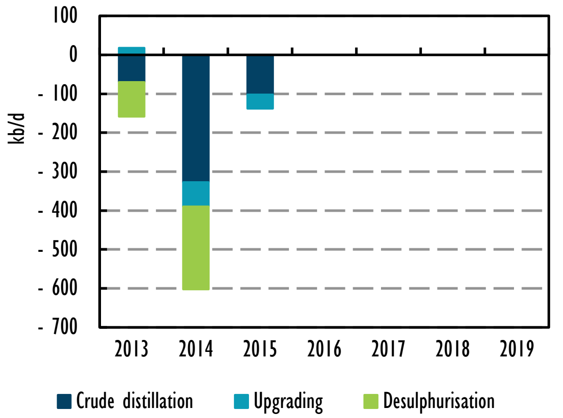
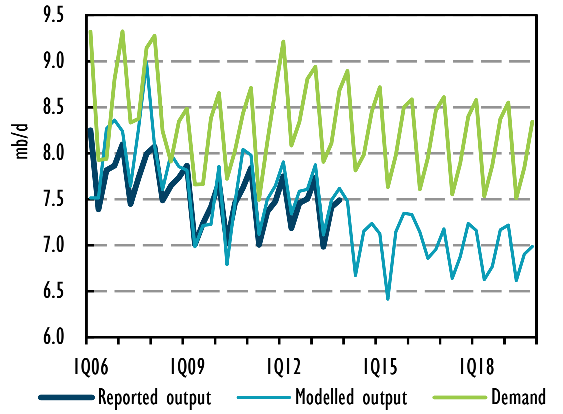


Figure 4.16 OECD Asia Oceania total refinery oil product supply vs. *OMR* demand



As a result, Australia is on track to reduce the number of its refineries to four, with a combined capacity of 430 kb/d by next year plus 100 kb/d of condensate splitting capacity, from 820 kb/d just a decade ago. In the latest blow to the country's industry, BP announced in early April it will cease refining operations at its 100 kb/d Bulwer Island refinery in Brisbane by mid-2015. ExxonMobil mothballed its 80 kb/d Port Stanvac refinery in 2003 and Shell converted its 80 kb/d Clyde refinery in Sydney to an import terminal in September 2012. The company averted the same fate for its 120 kb/d Geelong refinery however, as it agreed to sell the plant and 870-site service stations to European energy trader Vitol for USD 2.6 billion.

Caltex is on track to convert its 125 kb/d Kurnell plant to an import terminal by the end of this year, and with the Bulwer Island plant closing next year, Australia's refining capacity will have been nearly cut in half in a decade. According to the most recent IEA data, Australia consumed 1.1 mb/d of oil products in 2013, 150 kb/d higher than in 2003. Net oil product imports averaged 370 kb/d last year, of which 75% was middle distillates. Australia also imported some 240 kb/d of crude oil in 2013.

In contrast, South Korea's downstream industry is faring somewhat better. Two condensate splitters, with a combined capacity of almost 250 kb/d, are on track to be commissioned in 2014. Firstly, SK Energy is expected to commission a new 100 kb/d condensate splitter while a Total-Samsung JV plans to open a 145 kb/d splitter in Daesan in July. South Korean firms look well positioned to meet the increased demand falling out of the refinery closures in Australia, as it is expanding gasoline and diesel production capacity.

China

The recent slowdown in the Chinese economy and of its oil demand growth has put a damper on the country's refinery expansion plans. National champions and international players alike put the brake on its downstream projects in 2013 and 2014, as the country's surplus capacity swelled. The commissioning of several refinery projects slated for start-up in 2012/2013 only started trial runs in 2014, including PetroChina's 200 kb/d Pengzhou refinery in Sichuan and Sinochem's new 240 kb/d Quanzhou plant. Projects slated for completion over 2014 and coming years have also been pushed back. Moreover, several key projects have been stalled indefinitely.

With Chinese oil demand growth dropping to a six-year low in 2013, to some 230 kb/d (or 2.3%), domestic refiners and international oil majors are reconsidering their refinery investment plans. Less than a year ago, some 4.3 mb/d of new primary distillation capacity was scheduled for completion by 2018, by far exceeding expected demand growth even at that time. Growing concerns over the risks of oversupply in the Chinese fuels market have led to several projects delayed in recent months.

Figure 4.17 China refinery capacity additions

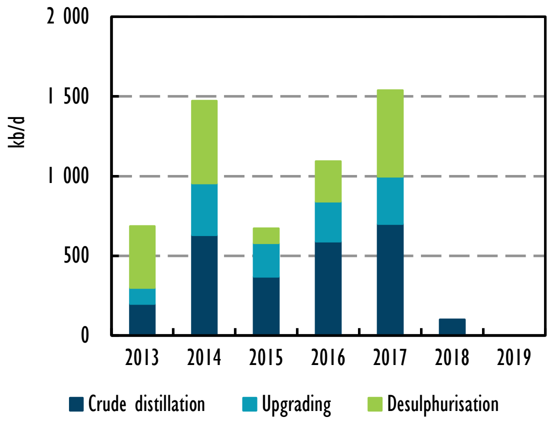
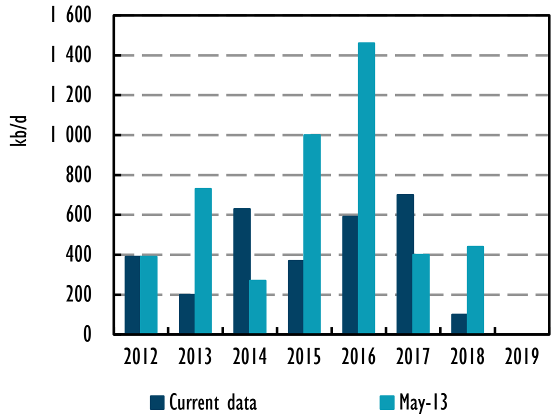


Figure 4.18 Revisions to Chinese expansion plans



Furthermore, China's environmental protection ministry suspended all approvals for PetroChina and Sinopec's new refining projects and expansions in September 2013, after the two companies failed to meet pollution targets for 2012. The approval ban was lifted in May 2014, however, despite continued concerns over emerging surplus capacity and heavy pollution levels.

At the start of the year, news emerged that BP had dropped plans to invest in a refinery in China and was dismantling the team assigned to the project. BP had considered investing in PetroChina's 200 kb/d Qinzhou refinery, which started operations in 2010. PetroChina also announced in January that it had put off starting up two new refineries and delayed the expansion of another due to the threat of overcapacity. The company now plans to start its 200 kb/d Kunming refinery in the Yunnan province in 2016, two years later than originally scheduled. The 100 kb/d expansion of the company's Huabei refinery has also been postponed from 2014 to 2015, according to officials. Lastly, the proposed 400 kb/d Jieyang refinery in Guangdong province, a JV with Venezuelan state oil company PDVSA, is now slated for completion in 2017, compared with an earlier target of 2013. Recent reports that work on the project has stalled and been delayed indefinitely, due to a disagreement over the price at which PDVSA would supply crude to the plant, could derail the project timeline further, if confirmed, and no agreement is reached.

PetroChina's plans to build a refinery and petrochemical complex in east China with Royal Dutch Shell and Qatar Petroleum also stalled last year due to land issues and as PetroChina decided to cut back on refinery spending. The proposed 400 kb/d Taizhou refinery and the 1.2 mt/y ethylene plant were to cost USD 13 billion and would have been the largest downstream investment so far by PetroChina. The company's JV project with Rosneft has been removed from our project list since last year's *Report*. CNPC and Rosneft signed an agreement on the 200 kb/d Tianjin refinery in October last year, to make a joint final investment decision (FID) in 2017 with start-up no later than the end of 2020. The refinery will receive Russian crudes under a long-term contract against prepayment.

Sinopec's chairman, Fu Changyu, warned in March that if the country did not take steps to rein in excess refinery capacity, the industry would have to cut utilisation rates sharply in coming years. Only one major refinery project featured in the company's latest annual report, the Guangdong Integrated Refining and Petrochemical Project, consisting of a 300 kb/d refinery and 800 kt ethylene cracker, both slated for completion in 2017. The project, which is to be built in Zhanjiang, is a JV with Kuwait Petroleum Corporation. Sinopec also pushed back the expansion of two of its refineries citing slowing demand. The Jiujiang refinery which was to be expanded by 100 kb/d this year, will now reportedly only be completed in late 2015, while the expansion of the company's Jingmen refinery in Hubei province has been delayed from 2015 to the end of 2016.

Figure 4.19 China total refinery oil product supply vs. *OMR* demand

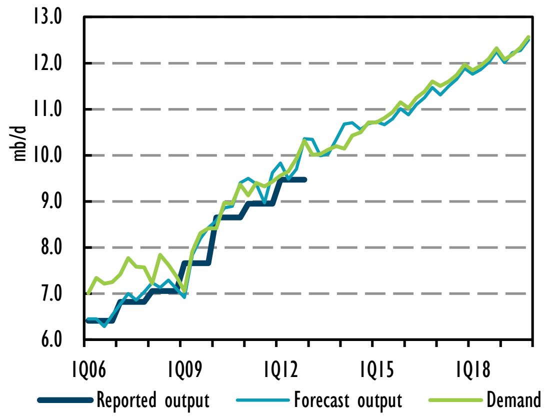
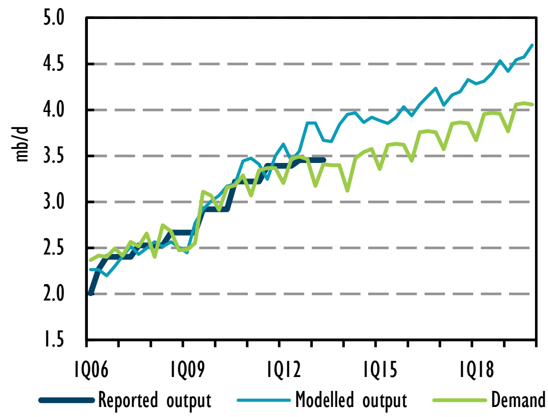


Figure 4.20 China gasoil/diesel refinery supply vs. *OMR* demand



In all, we see China adding 2.4 mb/d of new refining capacity by 2019, a third of world totals. The expansions are slightly higher than projected Chinese oil product demand growth, of some 2.2 mb/d over the same period, suggesting further project slippage or cancellations could emerge. We believe Chinese refiners will try to limit product exports by cutting utilisation rates, as has been the case in recent years. The sharp slowdown projected in Chinese gasoil demand growth will nevertheless lead to increased export potential of middle distillates, of up to 350 kb/d in 2019, from 140 kb/d in 2013.

Non-OECD Other Asia

In non-OECD Asia, India remains the key contributor to growth in the medium term, albeit at a slower rate than seen in recent years. Of the 1.3 mb/d growth expected in regional distillation capacity, 740 kb/d is expected to come from India. Of this, 420 kb/d had earlier been expected to come on stream in 2013, but delays will likely only see IOC's 300 kb/d Paradip refinery and the 120 kb/d Cuddalore plant completed towards year-end or in early 2015. IOC's Paradip project has been delayed on numerous occasions, most recently by a delay in the installation of a captive power plant by as much as 30 months. The power plant is now only expected to be completed by September 2014, after which the refinery can be commissioned. Smaller capacity additions are expected to come from an expansion of IOC's Panipat and Gujarat refineries, as well as a 120 kb/d expansion of BPCL's Kochi refinery. Numerous other expansions and new projects have been proposed and are possible, but thus far excluded from our forecast until plans firm up.

Elsewhere in the region, capacity additions are expected to be completed in Pakistan, Malaysia, and Viet Nam. Pakistan's Byco reportedly started its 120 kb/d Hub refinery in February 2014. The refinery, which the company bought from Petroplus and had shipped from the United Kingdom in 2006, was originally scheduled to start up in 2012. While stakeholders seem eager to move forward with the Khalifa Coastal Oil Refinery project, completion is not expected before 2020.

Figure 4.21 Non-OECD other Asia refinery capacity additions

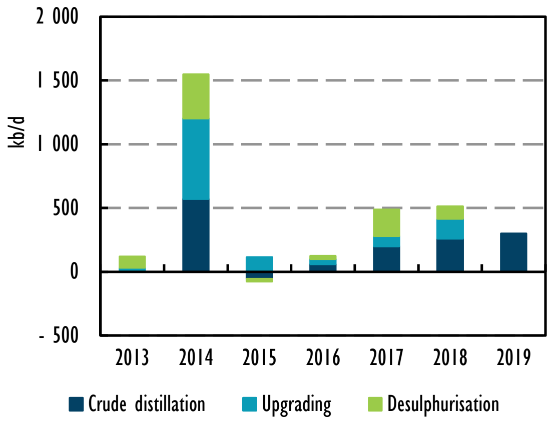
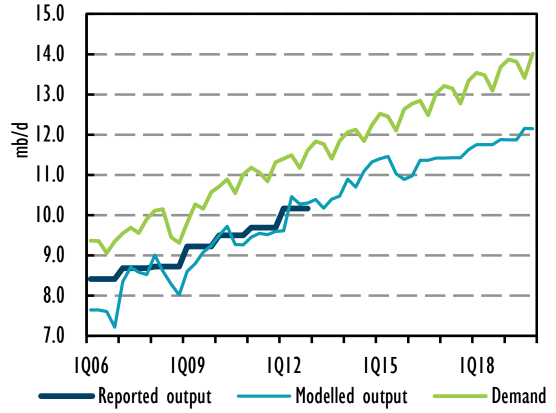


Figure 4.22 Non-OECD Asia total refinery oil product supply vs. *OMR* demand



Elsewhere in the region, capacity additions are expected to be completed in Pakistan, Malaysia, and Viet Nam. Pakistan's Byco reportedly started its 120 kb/d Hub refinery in February 2014. The refinery, which the company bought from Petroplus and had shipped from the United Kingdom in 2006, was originally scheduled to start up in 2012. While stakeholders seem eager to move forward with the Khalifa Coastal Oil Refinery project, completion is not expected before 2020.

In Malaysia, Petronas took a final investment decision on the development of its Refinery and Petrochemical Integrated Development (RAPID) project in early April, three years after first unveiling the plans. The USD 16 billion project includes a 300 kb/d refinery and a petrochemical plant, and is expected to be completed by end-2019, slightly later than the official 2017 target. Petronas had delayed its investment decision to study the viability of the plan for a naphtha-fed steam cracker in light of the slew of lower cost ethane fed petrochemical plants planned in the United States.

In Viet Nam, we include the JV Nghi Son refinery (Idemitsu (35.1%), Petrovietnam (25.1%), Kuwait Petroleum International (35.1%) and Mitsui Chemical (4.7%)). The JV took a final investment decision in January 2013 and started construction in 3Q13. While the official completion target is 3Q17, we expect this to slip to 2018. Other projects, such as the proposed Vung Ro and Nhon Hoi, and the expansion of the Dung Quat plant, are possible but still in the early phase so not included for now.

Equally, Indonesia continues to struggle to attract foreign investment to develop its downstream industry. Indonesia, which already imported about 300 kb/d of gasoline and 300 kb/d of gasoil in 2012, is expected to see its net product imports rise sharply through 2019, as demand expands by a further 365 kb/d, to 2.0 mb/d. The Indonesian government broke off negotiations with Kuwait and Saudi Arabia over the possible development of oil refineries, due to differences over taxation. Pertamina announced instead in September last year it was planning to spend USD 7 billion to upgrade its refineries and boost their combined capacity by 300 kb/d, though it seems financing remains unresolved also for this project. Nevertheless, a feasibility study is being undertaken by UOP, targeting project start-up by 2015 and completion by 2018. We also exclude Zhejiang Hengyi's proposed 160 kb/d refinery in Brunei, despite some progress made in 2013, as securing feedstocks still remains a challenge.

In Singapore, ExxonMobil started up a new diesel hydrotreater at its Jurong refinery in January 2014, boosting ULSD output by 57 kb/d to 157 kb/d.

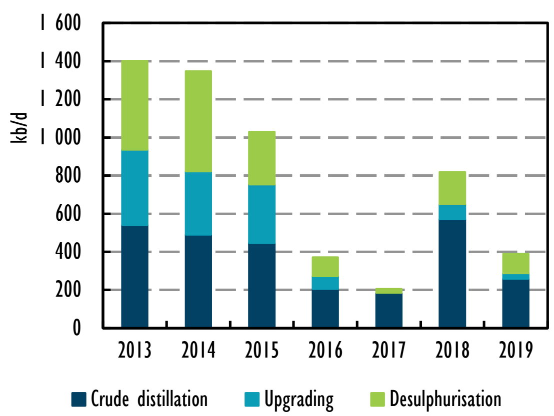
Unless other refinery projects move forward, the region's product import requirements will increase as demand continues to throttle ahead. Regional demand is forecast to expand by 2.1 mb/d through 2019, exceeding refinery expansions included in these projections. 48% of demand growth stems from middle distillates, though gasoline demand is also set to grow, adding 0.5 mb/d by the end of the forecast.

Middle East

In contrast to the quite more pessimistic outlook for refinery expansions in China and other non-OECD countries, Middle Eastern refinery expansion plans seem to be progressing on schedule and, if anything, have firmed up since one year ago. In all, the region is on track to bring on 2.2 mb/d of new distillation capacity by 2019, with Saudi Arabia the largest contributor. Ambitious downstream expansion plans in Kuwait, Iraq and Iran could lift capacity further, if sufficient progress is made towards project completion. For the time being, we remain cautious regarding these countries' ability to move ahead with several large-scale projects simultaneously, but will adjust upwards if project financing and partners are secured and projects move forward.

In Saudi Arabia, national state oil company Saudi Aramco's JV Jubail refinery with Total started successful operations in 2H13, with full capacity expected to be reached by mid-2014. Saudi Oil Minister Ali al-Naimi announced in January of this year that the Yanbu Aramco Sinopec Refining Company (YASREF)'s 400 kb/d Yanbu refinery is on track to be completed and operational (at capacity) by the third quarter of 2014. The JV project is slated to process heavy crude from Saudi Arabia's offshore Manifa field to produce 263 kb/d of ULSD and 90 kb/d of gasoline, amongst others. The proposed 400 kb/d Jazan refinery is expected to come on stream in 2017, from an initial target of 2016. The project was delayed by six-twelve months, linked to delays in tendering for an integrated gasification combined-cycle (IGCC) power plant alongside the refinery, which will use its vacuum residue, and as Aramco revised the plant's specifications.

Figure 4.23 Middle East refinery capacity additions



Also, the United Arab Emirates's new Ruwais refinery seems to be progressing in line with schedules. Oil Minister Suhail bin Mohammed al-Mazroui said in January that the 420 kb/d expansion was on track to be completed by end-2014. The plant will process Abu Dhabi's Murban crude oil when commissioned, probably in 1Q15. Abu Dhabi's International Petroleum Investment Company (IPIC) meanwhile extended a deadline for engineering, procurement and construction (EPC) bids on its proposed Fujairah refinery, which we for the time being excluded from our project list.

In Iraq, Baghdad has made some progress towards achieving its ambitious downstream development programme, including four greenfield refineries with a combined capacity of 740 kb/d and a total development cost of USD 26 billion. Besides building new refineries, the plan also calls for upgrades to existing plants. At the start of the year, contracts, worth USD 6.04 billion, were awarded to a consortium of South Korean firms led by Hyundai Engineering and Construction for the 140 kb/d Karbala refinery project. The contract has a duration of 54 months, setting the completion date to somewhere in 2019. Baghdad also signed an agreement for the 150 kb/d Misan greenfield refinery project to Swiss firm Satarem in October of last year, but the deal has come under scrutiny due to the company's lack of refining expertise. The ministry also had to extend a bid deadline for its planned 300 kb/d Nasiriya refinery to 23 June, as only one of the prequalified bidders submitted a bid bond ahead of the 23 January deadline. A new 70 kb/d crude unit at the Basra refinery was inaugurated on 1 March 2014, raising the plant's capacity to 210 kb/d.

Also in the northern Kurdistan region, refinery developments are progressing. Qaiwan, operator of the 44 kb/d Baizan refinery, has invited bids to expand the plant by 50 kb/d. The company aims to complete the CDU expansion by 4Q16 and upgrading units by 4Q17. Baizan is the second of two commercial refineries in Iraqi Kurdistan. The largest is the 80 kb/d Kalak refinery, west of Erbil and operated by the locally based Kar Group. The Erbil refinery started up with one 10 kb/d CDU in 2009, one in 2010, and subsequently added 20 kb/d and 40 kb/d. The company is now looking to add another 20 kb/d, to bring total capacity to 100 kb/d. There are also a number of small independent refineries in the region. Official KRG statistics released show 92.6 kb/d of crude going to local outlets in 2013, other than the three main refineries.

Iran's refinery expansion programme has been curtailed by international sanctions, as all sectors of country's oil industry. Iranian Minister of Petroleum, Bijan Zanganeh, stated last year he would prioritise downstream developments and in particular the completion of the 360 kb/d Persian Star condensate refinery – one of seven new refineries planned in the country. While there is huge uncertainty to the actual state-of-play, we assume the first unit will be delayed from 2015 as announced by the Ministry to 2017, and the other two commissioned in 2018 and 2019, respectively. Iran's National Oil Company reportedly completed the expansion of its Arak refinery in 2013, raising capacity by 80 kb/d.

After years of planning, it looks like Kuwait is finally getting its ambitious downstream project off the ground. The country has long been planning to boost its downstream capabilities and upgrade existing plants, but political wrangling between the government and the parliament has stalled progress. In February, however, the Central Tenders Committee finally approved the USD 12.01 billion Clean Fuels Project, intended to upgrade two of the country's refineries. The project will increase processing capacity at the 466 kb/d Mina al-Ahmadi refinery and the 270 kb/d Mina al-Abdullar refinery, to reach a total of 800 kb/d. The two plants are to process roughly 400 kb/d each. While the project is slated to be completed by 2018, we think it will only be completed by 2020 or later.

The country is also moving forward with its proposed Al Zour refinery project, with tenders for the 615 kb/d refinery's construction launched in May 2014. While start-up of the proposed refinery, which will be the largest in the Middle East, is scheduled for February 2019, also this project looks likely to slip to 2020 or later. Once the Clean Fuel's project becomes operational, the country's existing Shuaiba refinery is set to close down and the site turned into a storage terminal.

In Qatar, the foundation stone for the second condensate refinery to be built at Ras Laffan was put down in April of this year. The 146 kb/d condensate refinery will cost USD 1.5 billion and is to be completed in 3Q16. The plant will be built alongside an existing 146 kb/d splitter and once finished allow the country to process 349 kb/d of condensates, including a 57 kb/d splitter at the QP refinery in Messaieed.

State owned Oman Oil Refineries and Petroleum Industries Company (Orpic) awarded a USD 2.1 billion, 36-month contract for a major upgrade and expansion of the 116 kb/d Sohar refinery to a JV between UK's Petrofac and South Korea's Daelim at the end of 2013. The project, expected to be completed in 2016, will increase the refinery's ability to process heavy crudes. Sohar's planned 30 kb/d bitumen refinery is now expected to be completed by the end of 2015.

Figure 4.24 Middle East total refinery oil product supply vs. *OMR* demand

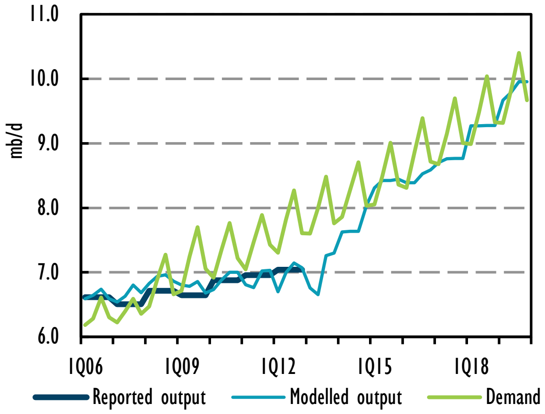
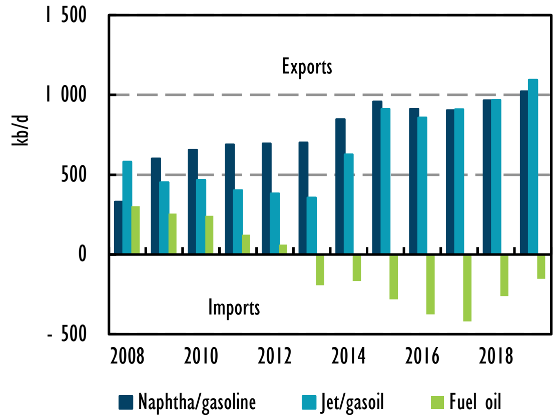


Figure 4.25 Middle East oil product balances



Over time, new product supply in the Middle East will be largely absorbed by regional demand growth. But even though Middle East product demand growth is amongst the highest in the world, at 1.8 mb/d over the forecast period, the region's export potential will rise significantly. Increasing NGLs production will further augment light product supplies, adding an estimated 200 kb/d through fractionation. The region, currently a small gasoline importer, but a significant naphtha exporter, will see gasoline imports vanish and naphtha exports staying level at around the 1 mb/d mark, or slightly higher. Incremental middle-distillate demand from the region will be significantly lower than supply growth, however, allowing Middle Eastern refiners and their joint-venture partners to make large volumes of high-value ULSD available for export. Current estimates show combined jet/gasoil surpluses rising to more than 1 mb/d in 2019, from just 350 kb/d estimated in 2013.

FSU

Refinery investments planned in the FSU in the medium term are heavily focussed on improving light product yields and gasoline and diesel quality. Crude distillation capacity is on paper set to increase by 420 kb/d by 2019, though the closure of some simple refineries is likely post-2015. The bulk of the new capacity is coming in Russia, who will add close to 300 kb/d of new distillation capacity, including a second 70 kb/d condensate splitter at Ust-Luga. The first splitter came on stream in 2013, and with the expansion of Rosneft's Tuapse refinery, helped lift Russian capacity and throughput levels to record highs. Russia refinery throughputs averaged 5.5 mb/d in 2013, an increase of 150 kb/d on the previous year and 900 kb/d higher than in 2007.

Offsetting some of these increases, and as discussed in Box 4.3 "New Russian export duty scheme curb FSU fuel oil exports", the pending equalisation of fuel oil and crude oil export duties will make simple refineries, with high fuel oil yields uneconomical and likely force the reduction in throughputs or closure of some of these. The same duties are behind the drive of Russia's refiners to curb fuel oil yields by installing cracking and coking capacity. At the end of 2013, Surgutneftegas completed a

95 kb/d hydrocracker, the largest in Europe/FSU, significantly increasing ULSD supplies. A total of 885 kb/d of upgrading capacity investments have been identified to come on stream over the 2013-19 period, as well as 385 kb/d of desulphurisation capacity.

Figure 4.26 FSU refinery capacity additions

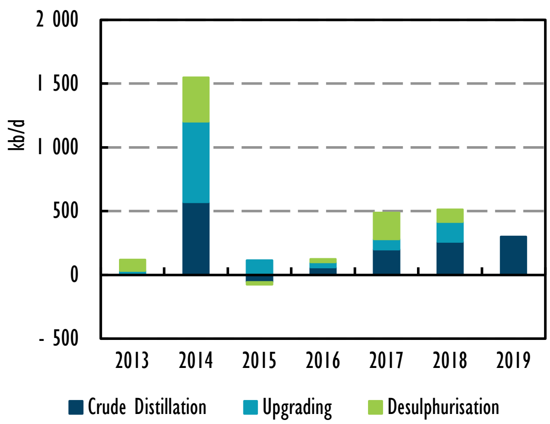
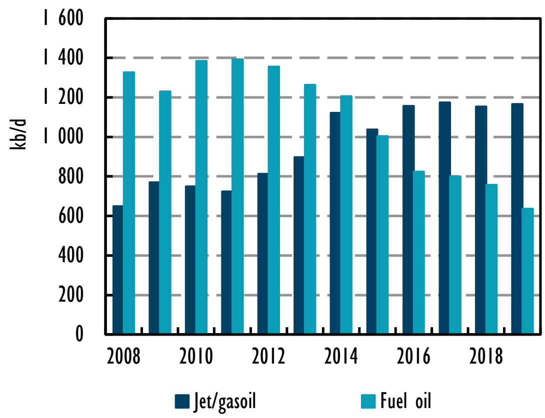


Figure 4.27 FSU key product export potential

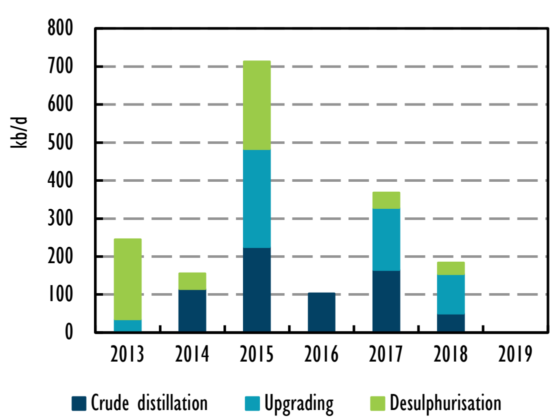


As a result of the investments above, regional product export patterns are set to see dramatic changes in coming years. As regional demand growth, of 0.6 mb/d, exceeds increased refinery capacity, product exports will diminish. The product balance will also shift markedly, as new upgrading units slash fuel oil supply. Fuel oil exports, used mostly as bunker fuel or as refinery feedstock in Europe or Asia, could plummet to just over 0.6 mb/d in 2019, from 1.3 mb/d in 2013. Including vacuum gas oil, exports were 1.6 mb/d in 2013. In turn, middle distillate export potential could rise from 0.9 mb/d in 2013, to almost 1.2 mb/d in 2019.

Latin America

Despite a rapidly growing product deficit and rising oil product imports, Latin American downstream capacity expansions over the next five years are expected to be minimal. The region is now seen adding just over 650 kb/d of new distillation capacity in the period from 2013 to 2019, a significant downward revision from the *MTOMR 2013*. Continued project slippage and cost overruns in Brazil as well as delays to Recope's planned Lima refinery in Costa Rica underpin the weaker numbers. The latter project was derailed in 2013 after the Costa Rican Controller's office rejected the feasibility study under which it was based because it was carried out by a subsidiary of CNPC, an arrangement prohibited by the JV agreement between Recope and CNPC formed in 2009 to upgrade the plant from 25 kb/d to 60 kb/d. A new feasibility study has been commissioned but the timeline of the project is now unclear so we have removed the plant from our project list.

Figure 4.28 Latin America refinery capacity additions



Continued delays to Petrobras' projects and allegations of corruption and mismanagement of the company's downstream investment portfolio, has led us to scale back on our expectations for the company's ability to bring on stream its new refineries in the Northeast planned for 2018 and 2019. Petrobras, weighed down by downstream losses and cash constraints, said in early 2014 that it would cut its planned downstream investments for the 2014-18 period by USD 26 billion, to USD 38.7 billion. While the first stages of the planned Premium I and Premium II refineries in the Northeast region remain scheduled for 2018-2019, given recent experiences and the latest revision to the investment plan, the projects now look more likely to come on stream in 2020 or later. Gasoline price controls in Brazil have taken a heavy toll on the company as it must supply gasoline to the retail market at a loss.

Brazil is still expected to commission two new refineries, with a combined capacity of 395 kb/d by 2019. The first phase of Petrobras' 230 kb/d Abreu e Lima refinery will be commissioned in 4Q14 followed by the second phase in 2Q15, several years after its original completion date of 2011 and way over budget. The latest cost estimates for the project are around USD 20 billion, two to three times the cost of similar refining capacity being built elsewhere in the world. The company's COMPERJ refinery is also delayed and the first 165 kb/d is now expected to be commissioned only in 2017.

In contrast, Colombia's Cartagena project seems to be on track to be completed by 2015. State oil company Ecopetrol halted the plant's single 80 kb/d crude distillation unit in March 2014 to allow for the doubling of the plant's capacity. The expansion and upgrade of the company's Barrancabermeja refinery is expected to be completed in 2018. The modernisation will raise the plant's conversion capacity from 75% to 96/97%, allowing it to run more heavy crude. The modernisations/expansions should allow for Colombia to become a net product exporter.

In mid-2011, Venezuela signed a USD 1.5 billion loan agreement with a consortium of Japanese banks, to finance the expansion of the Puerto la Cruz and El Palito refineries. PDVSA is planning to nearly double production from the 140 kb/d El Palito refinery, and raise capacity at Puerto la Cruz to 210 kb/d from 180 kb/d currently. A final investment decision for El Palito was taken in 2012 and Foster Wheeler, in consortium with Toyo Engineering Corporation from Japan and Y & V Ingeniería y Construcción from Venezuela won the EPC contract for the expansion. The project will likely only be completed post 2019, however.

At end-2013, PDVSA also let a contract to a consortium with Hyundai Engineering and Construction Co., Ltd. (HDEC), of South Korea and Wilson Engineering Services for Phase I of the new Batalla Santa Inés Refinery to be built in Barinas, Venezuela. With a capacity of 40 kb/d, the first phase of the refinery will process Venezuelan Guafita crude and will be commissioned in 2016, according to PDVSA. The state oil company, with Eni, is also planning to build a new 360 kb/d refinery in Puerto la Cruz, to include a 100 kb/d coking unit and 90 kb/d hydrocracker. The project is managed by a joint venture company PetroBicentenario (PDVSA 60% and Eni 40%), but is also expected to be completed after 2019.

Ecuador is planning to partially shut its 110 kb/d Esmeraldas refinery for 14 months starting in July, to upgrade the plant's catalytic cracker. Plans to build a new 300 kb/d facility on the Pacific Coast with PDVSA, have faced numerous obstacles including a lack of funding, leaving Ecuador reliant on product imports in the near term.

Overall, Latin America will remain a large product importer in the medium term, mostly likely from the United States, but the import dependency remains relatively unchanged. Regional demand growth of some 0.8 mb/d is almost equally split by increased gasoline and distillate consumption, with only minor increases in other products. Total refinery capacity increases of 660 kb/d are supplemented by modest growth in the biofuel supplies, further curbing import requirements. The largest product imports remain in middle distillates, estimated at around 0.6 mb/d in 2013 and through the forecast.

Africa

Africa's oil product import requirements are expected to increase in the medium term, as the continent continues to struggle to get new refinery projects off the ground while demand is forecast to rise by around 4% each year. Only 270 kb/d of new crude distillation capacity is expected to come on stream by 2019, despite ambitious plans for downstream expansion in a number of countries. Political instability, financial constraints and poor infrastructure add to economic viability concerns and continue to stall the progress of proposed refinery projects.

In 2013, Algeria's state-owned Sonatrach completed an upgrade and expansion of its Skikda refinery, lifting crude throughput capacity to 330 kb/d, from 300 kb/d previously. The company is also planning to expand and upgrade its Arzew and Algiers plants by a total of around 40 kb/d. In addition, the company is building a 100 kb/d topping refinery at Skikda and has announced plans to build four new refineries by 2018, located in Biskra, Tiaret, Ghardaia, and Hassi Messaoud, with a proposed capacity of around 100 kb/d each. The greenfield projects are still in the planning phase and excluded from our project list thus far.

Construction has also started on Sonangol's Lobito project in Angola. At the end of 2013, the state-owned company appointed Standard Chartered Bank to provide financial consulting for the construction of the refinery, the first 120 kb/d of which Sonangol hopes to commission in early 2017, followed by another 80 kb/d at a later stage. We do expect some delays to the project to at least the end of 2017, as final design has yet to be decided and the construction contracts signed.

Figure 4.29 Africa refinery capacity additions

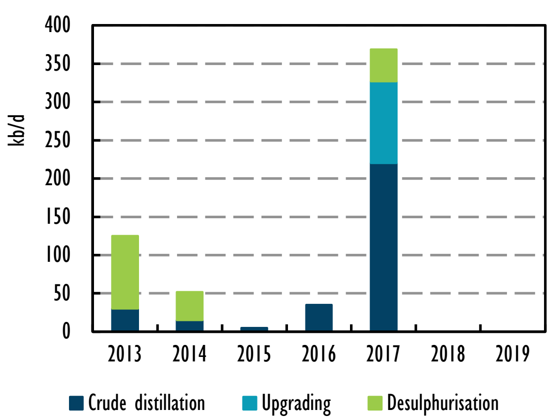
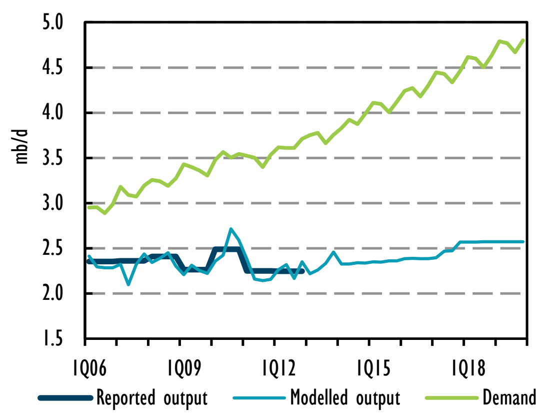


Figure 4.30 Africa total refinery oil product supply vs. *OMR* demand



The Egyptian Refinery Company (ERC) started construction of its new Mostorod refinery, north of Cairo in late 2013. The new refinery will convert fuel oil from an existing refinery nearby to produce mainly diesel. ERC hope to bring the project online in early 2017. The project has been delayed numerous times due to financing issues and then by the uprising of 2011 that toppled President Mubarak. ERC has secured funding through a USD 2.6 billion debt package and USD 1.1 billion in equity provided by the Egyptian General Petroleum Corporation, Qatar Petroleum International and Egyptian private equity firm Citadel Capital. Fuel subsidies continue to undermine Egypt's financial position, with these accounting for one-fifth of total budget spending in 2013.

Qatar Petroleum International pulled out of a USD 3 billion refinery project in Tunisia however. The mooted project was to have a capacity of between 250 kb/d and 350 kb/d and would have eliminated the nation's need for fuel imports. Instead, the Tunisian Refinery Company, Société Tunisienne de Raffinage, is moving ahead with plans to build a 120 kb/d refinery in Shikra. The project is estimated to cost between USD 2 billion and USD 2.5 billion. The project, still in its early planning stage is not included in our forecast.

As part of its agreement with the government of Uganda to develop the Albertine Graben oil fields, the JV (Tullow, Total, CNOOC) is to develop a refinery. The refinery is expected to cost USD 2.5 billion and be built in a phased manner with 30 kb/d capacity by 2018, raised to 60 kb/d in 2020, along with a crude pipeline to Kenya and a crude-fired power plant near the fields. Progress is being made on the refinery, with six bidders shortlisted for its construction.

South Sudan is planning two mini refineries to lower its dependency on imports from neighbouring countries. The first, a 5 kb/d plant to be built by a Russian company, will be located in Benitu in Unity State. The second, a 10 kb/d plant, will be built by US firm Ventech Engineers International in Thangrial in Upper Nile state. The plants were scheduled to be completed in 2013 and 2014, but were delayed due to difficulties in getting the equipment into the country and have since been put on hold due to increasing internal unrest. The assumption that the plants could come online in 2015/2016, hinges on a resolution to the current conflict and some stability restored.

To meet the challenge of rapidly increasing fuel import requirements and security of supply concerns, South Africa's national oil company is moving ahead with its proposed 300 kb/d Mthombo refinery project in the Eastern Cape of the country. PetroSA has signed a framework agreement with Sinopec for the project, which is estimated at USD 11 billion. The refinery will be designed to process heavy crudes that are challenging to process, which can be sourced from Venezuela, West Africa, the Middle East and Brazil. If favourable, the feasibility study could lead to front end engineering and design (FEED) made during the first half of 2014. In any event, the project would not be completed before 2020 at the earliest.

In Nigeria, a proposal to build a new 400 kb/d refinery has been met by both great enthusiasm and scepticism. Nigerian industrial conglomerate, Dangote, has already secured the USD 9 billion financing needed to build the country's first private refinery. While the project would eradicate the country's fuel import needs, it will do little to curb the government's costly fuel subsidy spending, as it plans to sell the products at international market prices to oil marketers, which in turn has to collect the subsidy from the government. While the project seems to have made some significant headways, real obstacles and challenges remain, and if the project makes it off the ground it will most certainly not be completed within the timeframe of this report.

In the absence of progress on these latter projects, Africa's fuel import requirements look on track to jump by as much as 0.7 mb/d overall in coming years. Regional demand is set to surge by around 1 mb/d, as the region's economies expand and consumers are often sheltered by expensive fuel subsidies. The same fuel subsidies, however, tend to make refinery projects uneconomical and keep them from seeing the light of day, as the financial terms offered by governments make them unviable. Africa is thus set to become increasingly short of refined products, providing beleaguered European refiners and their counterparts in the Americas and the Middle East with a growing market outlet.

5. TABLES

Table 1
WORLD OIL SUPPLY AND DEMAND

(million barrels per day)

	1Q13	2Q13	3Q13	4Q13	2013	1Q14	2Q14	3Q14	4Q14	2014	2015	2016	2017	2018	2019
OECD DEMAND															
Americas[1]	23.7	23.8	24.2	24.3	24.0	23.8	23.9	24.3	24.4	24.1	24.1	24.0	23.9	23.8	23.6
Europe[2]	13.2	13.8	14.0	13.6	13.6	13.1	13.6	13.9	13.8	13.6	13.6	13.6	13.5	13.4	13.4
Asia Oceania[3]	8.9	7.9	8.1	8.7	8.4	8.9	7.8	8.0	8.4	8.3	8.2	8.2	8.1	8.1	8.1
Total OECD	45.9	45.5	46.2	46.6	46.1	45.8	45.3	46.2	46.6	46.0	45.9	45.7	45.6	45.3	45.0
NON-OECD DEMAND															
FSU	4.3	4.5	4.8	4.8	4.6	4.4	4.6	4.9	4.9	4.7	4.8	4.9	5.0	5.1	5.2
Europe	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
China	10.0	10.0	10.1	10.2	10.1	10.1	10.4	10.5	10.7	10.4	10.9	11.3	11.7	12.0	12.3
Other Asia	11.8	11.8	11.4	11.8	11.7	12.1	12.1	11.8	12.2	12.1	12.4	12.8	13.1	13.4	13.8
Latin America	6.3	6.6	6.7	6.7	6.6	6.6	6.7	6.9	6.9	6.8	6.9	7.0	7.2	7.3	7.4
Middle East	7.6	8.0	8.5	7.8	8.0	7.9	8.3	8.7	8.0	8.2	8.5	8.8	9.1	9.5	9.8
Africa	3.8	3.8	3.7	3.8	3.7	3.8	3.9	3.9	4.0	3.9	4.1	4.2	4.4	4.6	4.8
Total Non-OECD	44.5	45.3	45.9	45.8	45.4	45.5	46.8	47.3	47.4	46.8	48.3	49.8	51.2	52.7	54.0
Total Demand[4]	**90.4**	**90.8**	**92.1**	**92.4**	**91.4**	**91.3**	**92.1**	**93.5**	**94.0**	**92.8**	**94.2**	**95.5**	**96.8**	**98.0**	**99.1**
OECD SUPPLY															
Americas[1]	16.8	16.7	17.4	17.9	17.2	18.1	18.3	18.4	18.9	18.4	19.1	19.9	20.4	20.9	21.2
Europe[2]	3.3	3.3	3.1	3.3	3.3	3.3	3.2	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.2
Asia Oceania[3]	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.5	0.6	0.6	0.7	0.7	0.8
Total OECD	20.6	20.5	21.1	21.6	20.9	21.9	22.0	21.9	22.7	22.1	22.9	23.8	24.3	25.0	25.3
NON-OECD SUPPLY															
FSU	13.8	13.8	13.8	14.0	13.9	14.0	13.9	13.8	13.9	13.9	13.8	13.8	13.8	13.9	14.1
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.2	4.2	4.0	4.2	4.2	4.2	4.3	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.3
Other Asia[5]	3.7	3.6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.4	3.3	3.3	3.2	3.1
Latin America[5,7]	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.3	4.2	4.6	4.7	5.1	5.3	5.4
Middle East	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
Africa[5]	2.2	2.3	2.4	2.4	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.6	2.6
Total Non-OECD	29.6	29.5	29.3	29.8	29.6	29.8	29.7	29.6	29.7	29.7	29.9	30.0	30.4	30.6	30.9
Processing Gains[6]	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.4
Global Biofuels[7]	1.5	2.0	2.4	2.2	2.0	1.7	2.1	2.5	2.1	2.1	2.2	2.2	2.3	2.3	2.3
Total Non-OPEC[5]	53.8	54.2	55.0	55.8	54.7	55.6	56.0	56.2	56.7	56.1	57.3	58.4	59.4	60.3	60.9
OPEC															
Crude[8]	30.5	30.9	30.6	29.8	30.5	30.0									
OPEC NGLs	6.3	6.3	6.3	6.4	6.3	6.4	6.4	6.6	6.6	6.5	6.8	7.0	7.0	7.1	7.1
Total OPEC[5]	36.7	37.2	37.0	36.2	36.8	36.4									
Total Supply[9]	90.6	91.4	91.9	92.0	91.5	92.0									
Memo items:															
Call on OPEC crude + Stock ch.[10]	30.3	30.4	30.8	30.2	30.4	29.3	29.7	30.8	30.7	30.1	30.1	30.2	30.4	30.6	31.0

1 As of August 2012 OMR, OECD Americas includes Chile.
2 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
3 As of August 2012 OMR, OECD Asia Oceania includes Israel.
4 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
5 Other Asia includes Indonesia throughout. Latin America excludes Ecuador throughout. Africa excludes Angola throughout.
Total Non-OPEC excludes all countries that were members of OPEC at 1 January 2009.
Total OPEC comprises all countries which were OPEC members at 1 January 2009.
6 Net volumetric gains and losses in the refining process and marine transportation losses.
7 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.
8 As of the March 2006 OMR, Venezuelan Orinoco heavy crude production is included within Venezuelan crude estimates. Orimulsion fuel remains within the OPEC NGL & non-conventional category, but Orimulsion production reportedly ceased from January 2007.
9 Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
10 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

Table 1a

WORLD OIL SUPPLY AND DEMAND: CHANGES FROM LAST MEDIUM-TERM REPORT

(million barrels per day)

	1Q12	2Q12	3Q12	4Q12	2012	1Q13	2Q13	3Q13	4Q13	2013	2014	2015	2016	2017	2018
OECD DEMAND															
Americas	-0.1	-0.2	-0.2	-0.1	-0.1	0.0	0.3	0.3	0.5	0.3	0.4	0.5	0.5	0.5	0.5
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.4	-0.1	0.3	0.3	0.4	0.5	0.5	0.5
Asia Oceania	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0	-0.1	-0.1	-0.1	-0.1
Total OECD	0.0	-0.1	0.0	0.1	0.0	0.2	1.1	0.7	0.5	0.6	0.8	0.8	0.9	0.9	0.9
NON-OECD DEMAND															
FSU	-0.1	0.0	0.0	0.0	0.0	-0.1	0.0	0.1	0.0	0.0	-0.1	-0.1	-0.2	-0.2	-0.2
Europe	0.0	-0.1	-0.1	-0.1	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	-0.2	0.1	0.1	0.1	0.1	0.1	0.1
Other Asia	0.1	0.1	0.0	0.0	0.1	0.2	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Latin America	-0.1	-0.1	-0.1	-0.2	-0.1	-0.1	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Middle East	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total Non-OECD	0.3	0.3	0.4	0.3	0.3	0.3	0.4	0.3	-0.1	0.2	0.2	0.2	0.3	0.3	0.4
Total Demand	**0.3**	**0.2**	**0.4**	**0.4**	**0.3**	**0.4**	**1.5**	**1.0**	**0.5**	**0.8**	**0.9**	**1.0**	**1.2**	**1.2**	**1.3**
OECD SUPPLY															
Americas	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.5	0.3	0.9	1.1	1.3	1.2	1.2
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	0.0	0.0
Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	-0.1	-0.1	0.0	0.0	0.1
Total OECD	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.4	0.3	0.7	0.9	1.2	1.2	1.3
NON-OECD SUPPLY															
FSU	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.4	0.2	0.3	0.1	0.0	0.2	0.2
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	0.0	-0.1	-0.1	-0.1	-0.1	-0.2	-0.1
Other Asia	0.1	0.1	0.0	0.1	0.1	0.1	0.0	-0.1	0.0	0.0	-0.1	-0.3	-0.3	-0.2	-0.2
Latin America	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.2	-0.1	-0.3	-0.2	-0.3	-0.1	-0.1
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	-0.1
Africa	0.0	0.0	0.0	-0.1	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0
Total Non-OECD	0.1	0.0	0.0	-0.1	0.0	-0.1	0.0	-0.1	0.0	0.0	-0.4	-0.7	-0.6	-0.4	-0.3
Processing Gains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Global Biofuels	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	-0.1	0.0	0.0
Total Non-OPEC	0.1	0.1	0.0	-0.1	0.0	-0.1	0.3	0.5	0.5	0.3	0.3	0.2	0.5	0.8	1.0
OPEC															
Crude	0.0	0.0	0.0	-0.1	0.0	0.0									
OPEC NGLs	0.0	0.0	-0.1	-0.1	-0.1	-0.2	-0.2	-0.3	-0.3	-0.2	-0.3	-0.1	0.0	0.1	0.1
Total OPEC	0.0	0.0	-0.1	-0.3	-0.1	-0.2									
Total Supply	**0.1**	**0.0**	**-0.1**	**-0.3**	**-0.1**	**-0.3**									
Memo items:															
Call on OPEC crude + Stock ch.	0.1	0.2	0.5	0.6	0.4	0.7	1.4	0.8	0.3	0.8	0.9	0.9	0.6	0.4	0.2

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	1Q13	2Q13	3Q13	4Q13	2013	1Q14	2Q14	3Q14	4Q14	2014	2015	2016	2017	2018	2019
Demand (mb/d)															
Americas[1]	23.73	23.79	24.18	24.34	24.01	23.82	23.87	24.30	24.43	24.11	24.11	24.03	23.93	23.80	23.60
Europe[2]	13.21	13.83	13.98	13.55	13.64	13.08	13.61	13.93	13.75	13.60	13.58	13.57	13.53	13.45	13.37
Asia Oceania[3]	8.93	7.90	8.09	8.68	8.40	8.89	7.81	7.98	8.45	8.28	8.21	8.15	8.11	8.09	8.06
Total OECD	45.87	45.52	46.24	46.57	46.05	45.79	45.29	46.21	46.63	45.98	45.89	45.75	45.58	45.34	45.04
Asia	21.84	21.80	21.52	22.04	21.80	22.21	22.55	22.33	22.95	22.51	23.33	24.10	24.82	25.49	26.07
Middle East	7.60	8.00	8.49	7.76	7.96	7.86	8.27	8.71	8.04	8.22	8.48	8.82	9.14	9.46	9.80
Latin America	6.35	6.57	6.71	6.73	6.59	6.56	6.73	6.89	6.87	6.77	6.92	7.04	7.17	7.29	7.42
FSU	4.30	4.50	4.83	4.82	4.61	4.42	4.60	4.85	4.85	4.68	4.77	4.87	4.97	5.09	5.21
Africa	3.75	3.78	3.66	3.76	3.74	3.83	3.93	3.88	3.99	3.91	4.08	4.25	4.42	4.59	4.76
Europe	0.64	0.68	0.68	0.70	0.68	0.67	0.69	0.68	0.70	0.69	0.70	0.72	0.73	0.75	0.76
Total Non-OECD	44.48	45.32	45.88	45.81	45.38	45.55	46.78	47.33	47.40	46.77	48.28	49.80	51.24	52.67	54.02
World	**90.35**	**90.83**	**92.13**	**92.38**	**91.43**	**91.34**	**92.07**	**93.54**	**94.03**	**92.75**	**94.18**	**95.55**	**96.82**	**98.01**	**99.06**
of which:															
US50	*18.66*	*18.67*	*19.13*	*19.28*	*18.94*	*18.82*	*18.82*	*19.16*	*19.25*	*19.02*	*19.03*	*18.96*	*18.87*	*18.75*	*18.56*
Euro5	*8.01*	*8.29*	*8.27*	*8.06*	*8.16*	*7.92*	*8.09*	*8.22*	*8.15*	*8.10*	*8.04*	*7.99*	*7.92*	*7.85*	*7.76*
China	*10.01*	*10.03*	*10.12*	*10.20*	*10.09*	*10.14*	*10.43*	*10.50*	*10.71*	*10.45*	*10.90*	*11.31*	*11.70*	*12.05*	*12.29*
Japan	*5.08*	*4.11*	*4.32*	*4.75*	*4.56*	*5.01*	*4.05*	*4.16*	*4.48*	*4.42*	*4.33*	*4.27*	*4.23*	*4.19*	*4.17*
India	*3.53*	*3.54*	*3.24*	*3.50*	*3.45*	*3.59*	*3.61*	*3.36*	*3.61*	*3.54*	*3.66*	*3.78*	*3.87*	*3.95*	*4.04*
Russia	*3.19*	*3.31*	*3.62*	*3.53*	*3.42*	*3.32*	*3.41*	*3.62*	*3.54*	*3.47*	*3.55*	*3.63*	*3.71*	*3.82*	*3.92*
Brazil	*2.97*	*3.06*	*3.12*	*3.17*	*3.08*	*3.10*	*3.14*	*3.21*	*3.24*	*3.17*	*3.25*	*3.30*	*3.36*	*3.41*	*3.47*
Saudi Arabia	*2.76*	*3.09*	*3.36*	*2.87*	*3.03*	*2.86*	*3.20*	*3.46*	*2.96*	*3.12*	*3.23*	*3.38*	*3.51*	*3.63*	*3.74*
Korea	*2.31*	*2.27*	*2.26*	*2.38*	*2.31*	*2.34*	*2.24*	*2.27*	*2.40*	*2.31*	*2.31*	*2.31*	*2.31*	*2.31*	*2.31*
Canada	*2.28*	*2.31*	*2.30*	*2.32*	*2.30*	*2.31*	*2.27*	*2.37*	*2.36*	*2.33*	*2.30*	*2.28*	*2.26*	*2.24*	*2.22*
Mexico	*2.11*	*2.14*	*2.09*	*2.08*	*2.11*	*2.02*	*2.12*	*2.10*	*2.14*	*2.09*	*2.09*	*2.09*	*2.10*	*2.11*	*2.11*
Iran	*1.79*	*1.80*	*1.81*	*1.79*	*1.80*	*1.87*	*1.85*	*1.83*	*1.84*	*1.85*	*1.91*	*1.97*	*2.04*	*2.09*	*2.15*
Total	*62.72*	*62.64*	*63.64*	*63.93*	*63.24*	*63.30*	*63.23*	*64.26*	*64.67*	*63.87*	*64.61*	*65.28*	*65.88*	*66.39*	*66.73*
% of World	*69.41*	*68.96*	*69.08*	*69.20*	*69.16*	*69.30*	*68.68*	*68.69*	*68.78*	*68.86*	*68.61*	*68.32*	*68.05*	*67.74*	*67.36*
Annual Change (% per annum)															
Americas[1]	1.5	0.8	1.9	2.4	1.7	0.4	0.3	0.5	0.4	0.4	0.0	-0.3	-0.4	-0.5	-0.8
Europe[2]	-3.7	0.0	0.9	-1.0	-0.9	-1.0	-1.6	-0.3	1.4	-0.4	-0.1	-0.1	-0.3	-0.6	-0.5
Asia Oceania[3]	-2.6	-2.0	-2.7	-1.3	-2.2	-0.5	-1.2	-1.4	-2.7	-1.4	-0.9	-0.6	-0.5	-0.3	-0.3
Total OECD	-0.84	0.06	0.77	0.69	0.17	-0.18	-0.51	-0.07	0.12	-0.16	-0.19	-0.31	-0.38	-0.53	-0.66
Asia	4.2	3.1	2.0	0.6	2.4	1.7	3.5	3.8	4.1	3.3	3.6	3.3	3.0	2.7	2.3
Middle East	4.1	2.3	2.6	2.0	2.7	3.4	3.4	2.6	3.5	3.2	3.2	4.0	3.6	3.6	3.6
Latin America	3.3	3.5	3.2	2.7	3.2	3.4	2.5	2.7	2.1	2.7	2.3	1.8	1.7	1.7	1.7
FSU	-0.3	1.6	4.2	4.7	2.6	3.0	2.3	0.5	0.6	1.5	1.8	2.1	2.0	2.5	2.4
Africa	3.8	4.7	1.7	1.5	2.9	2.1	4.0	5.8	6.1	4.5	4.5	4.1	4.0	3.8	3.7
Europe	-3.9	-0.6	2.2	4.1	0.5	4.0	2.6	0.0	0.3	1.7	2.3	2.1	2.2	2.1	2.0
Total Non-OECD	3.4	3.0	2.5	1.7	2.6	2.4	3.2	3.2	3.5	3.1	3.2	3.1	2.9	2.8	2.6
World	**1.2**	**1.5**	**1.6**	**1.2**	**1.4**	**1.1**	**1.4**	**1.5**	**1.8**	**1.4**	**1.5**	**1.5**	**1.3**	**1.2**	**1.1**
Annual Change (mb/d)															
Americas[1]	0.35	0.18	0.45	0.57	0.39	0.09	0.08	0.12	0.09	0.10	0.00	-0.08	-0.09	-0.13	-0.20
Europe[2]	-0.50	0.01	0.13	-0.13	-0.12	-0.13	-0.22	-0.04	0.20	-0.05	-0.01	-0.01	-0.04	-0.09	-0.07
Asia Oceania[3]	-0.23	-0.16	-0.23	-0.12	-0.19	-0.04	-0.09	-0.11	-0.23	-0.12	-0.07	-0.05	-0.04	-0.03	-0.02
Total OECD	-0.39	0.03	0.35	0.32	0.08	-0.08	-0.23	-0.03	0.06	-0.07	-0.09	-0.14	-0.17	-0.24	-0.30
Asia	0.88	0.66	0.42	0.12	0.52	0.37	0.75	0.81	0.91	0.71	0.82	0.77	0.72	0.67	0.58
Middle East	0.30	0.18	0.21	0.16	0.21	0.26	0.27	0.22	0.27	0.26	0.26	0.34	0.31	0.33	0.34
Latin America	0.20	0.22	0.21	0.18	0.20	0.21	0.17	0.18	0.14	0.18	0.15	0.13	0.12	0.12	0.12
FSU	-0.01	0.07	0.19	0.21	0.12	0.13	0.10	0.03	0.03	0.07	0.08	0.10	0.10	0.12	0.12
Africa	0.14	0.17	0.06	0.06	0.11	0.08	0.15	0.21	0.23	0.17	0.18	0.17	0.17	0.17	0.17
Europe	-0.03	0.00	0.01	0.03	0.00	0.03	0.02	0.00	0.00	0.01	0.02	0.01	0.02	0.02	0.02
Total Non-OECD	1.47	1.30	1.11	0.75	1.16	1.07	1.46	1.45	1.59	1.39	1.51	1.51	1.44	1.43	1.35
World	**1.08**	**1.33**	**1.47**	**1.07**	**1.24**	**0.99**	**1.23**	**1.42**	**1.65**	**1.32**	**1.42**	**1.37**	**1.27**	**1.19**	**1.05**
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
Americas[1]	0.01	0.17	0.34	0.53	0.27	0.16	0.24	0.54	0.68	0.41	0.49	0.51	0.53	0.54	
Europe[2]	0.08	0.72	0.39	-0.07	0.28	-0.10	0.47	0.43	0.50	0.33	0.39	0.45	0.49	0.50	
Asia Oceania[3]	-0.02	0.03	0.03	0.20	0.06	0.10	-0.01	-0.03	-0.04	0.01	-0.06	-0.11	-0.14	-0.13	
Total OECD	0.07	0.92	0.77	0.66	0.61	0.16	0.70	0.95	1.15	0.74	0.81	0.85	0.88	0.91	
Asia	0.44	0.31	0.23	-0.10	0.22	0.48	0.08	0.17	0.22	0.24	0.32	0.37	0.39	0.37	
Middle East	0.13	0.11	0.18	0.07	0.12	0.27	0.11	0.04	0.07	0.13	0.11	0.16	0.19	0.23	
Latin America	-0.14	-0.04	-0.12	-0.06	-0.09	-0.01	-0.09	-0.13	-0.12	-0.09	-0.10	-0.12	-0.13	-0.12	
FSU	-0.14	-0.05	0.05	0.01	-0.03	-0.21	-0.07	-0.08	0.00	-0.09	-0.13	-0.15	-0.18	-0.17	
Africa	0.10	0.10	0.00	0.01	0.05	-0.02	0.05	0.06	0.13	0.05	0.07	0.08	0.10	0.12	
Europe	-0.04	-0.05	-0.06	-0.03	-0.05	-0.06	-0.04	-0.05	-0.03	-0.05	-0.04	-0.04	-0.03	-0.03	
Total Non-OECD	0.35	0.39	0.29	-0.10	0.23	0.45	0.03	0.02	0.27	0.19	0.22	0.30	0.34	0.40	
World	**0.42**	**1.31**	**1.05**	**0.56**	**0.84**	**0.61**	**0.72**	**0.97**	**1.42**	**0.93**	**1.04**	**1.15**	**1.21**	**1.31**	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	0.11	1.02	0.61	0.04	0.42	0.20	0.01	-0.09	0.26	0.10	0.10	0.11	0.06	0.10	

1 As of the August 2012 OMR, includes Chile.
2 As of the August 2012 OMR, includes Estonia and Slovenia.
3 As of the August 2012 OMR, includes Israel.
* France, Germany, Italy, Spain and UK

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q13	2Q13	3Q13	4Q13	2013	1Q14	2Q14	3Q14	4Q14	2014	2015	2016	2017	2018	2019
OPEC															
Crude Oil															
Saudi Arabia	8.97	9.28	9.84	9.51	9.40	9.46									
Iran	2.70	2.68	2.64	2.71	2.68	2.81									
Iraq	3.03	3.16	3.04	3.08	3.08	3.29									
UAE	2.75	2.77	2.80	2.73	2.76	2.73									
Kuwait	2.53	2.58	2.56	2.53	2.55	2.53									
Neutral Zone	0.52	0.52	0.52	0.52	0.52	0.52									
Qatar	0.74	0.73	0.73	0.73	0.73	0.72									
Angola	1.76	1.76	1.71	1.64	1.72	1.57									
Nigeria	2.00	1.94	1.97	1.91	1.95	1.93									
Libya	1.38	1.31	0.62	0.30	0.90	0.37									
Algeria	1.15	1.15	1.15	1.14	1.15	1.07									
Ecuador	0.50	0.51	0.52	0.53	0.52	0.55									
Venezuela	2.45	2.55	2.52	2.47	2.50	2.45									
Total Crude Oil	30.48	30.93	30.61	29.81	30.45	29.99									
Total NGLs[1]	6.26	6.29	6.35	6.35	6.31	6.40	6.42	6.58	6.59	6.50	6.78	6.99	7.03	7.07	7.12
Total OPEC[2]	**36.73**	**37.22**	**36.95**	**36.16**	**36.77**	**36.39**									
NON-OPEC[3]															
OECD															
Americas[7]	16.78	16.69	17.43	17.88	17.20	18.15	18.27	18.42	18.87	18.43	19.12	19.93	20.39	20.94	21.25
United States[6]	9.81	10.05	10.53	10.84	10.31	11.03	11.35	11.43	11.71	11.38	11.96	12.62	12.80	13.02	13.08
Mexico	2.91	2.88	2.88	2.90	2.89	2.87	2.84	2.81	2.83	2.84	2.76	2.77	2.78	2.83	2.93
Canada	4.04	3.76	4.02	4.14	3.99	4.24	4.06	4.16	4.31	4.19	4.39	4.53	4.81	5.08	5.23
Chile	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Europe[8]	3.35	3.29	3.14	3.28	3.26	3.31	3.18	2.92	3.21	3.15	3.23	3.26	3.30	3.30	3.24
UK	0.90	0.88	0.75	0.81	0.83	0.79	0.75	0.60	0.78	0.73	0.79	0.83	0.85	0.85	0.82
Norway	1.84	1.84	1.80	1.88	1.84	1.94	1.84	1.75	1.84	1.84	1.89	1.88	1.88	1.89	1.88
Others	0.61	0.57	0.60	0.59	0.59	0.58	0.58	0.58	0.59	0.58	0.55	0.54	0.57	0.57	0.54
Asia Oceania[9]	0.45	0.50	0.51	0.47	0.48	0.48	0.53	0.56	0.58	0.54	0.56	0.59	0.65	0.75	0.78
Australia	0.37	0.42	0.43	0.40	0.41	0.40	0.44	0.47	0.48	0.45	0.47	0.51	0.57	0.67	0.70
Others	0.08	0.08	0.07	0.07	0.07	0.08	0.09	0.09	0.10	0.09	0.08	0.09	0.08	0.08	0.07
Total OECD	20.57	20.47	21.09	21.63	20.94	21.94	21.97	21.90	22.66	22.12	22.90	23.78	24.35	24.99	25.26
NON-OECD															
Former USSR	13.85	13.80	13.81	14.02	13.87	13.98	13.89	13.79	13.88	13.88	13.81	13.85	13.85	13.86	14.05
Russia	10.82	10.84	10.85	10.97	10.87	10.95	10.94	10.84	10.92	10.91	10.91	10.94	10.97	11.00	11.05
Others	3.03	2.96	2.96	3.05	3.00	3.04	2.95	2.94	2.95	2.97	2.90	2.90	2.88	2.87	3.01
Asia	7.86	7.82	7.50	7.68	7.71	7.73	7.75	7.71	7.71	7.72	7.63	7.61	7.62	7.57	7.49
China	4.20	4.23	4.05	4.22	4.18	4.23	4.26	4.21	4.23	4.23	4.26	4.27	4.32	4.33	4.34
Malaysia	0.69	0.65	0.64	0.64	0.66	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
India	0.90	0.90	0.89	0.90	0.90	0.90	0.89	0.89	0.88	0.89	0.88	0.87	0.84	0.80	0.77
Indonesia	0.87	0.87	0.82	0.81	0.84	0.81	0.81	0.82	0.81	0.81	0.83	0.85	0.84	0.81	0.78
Others	1.19	1.16	1.10	1.11	1.14	1.13	1.13	1.13	1.14	1.13	0.99	0.97	0.97	0.97	0.93
Europe	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.12	0.11	0.10	0.09
Latin America	4.13	4.15	4.18	4.23	4.18	4.22	4.23	4.23	4.28	4.24	4.62	4.72	5.08	5.25	5.37
Brazil[6]	2.07	2.10	2.12	2.18	2.12	2.18	2.20	2.16	2.18	2.18	2.34	2.48	2.80	2.99	3.10
Argentina	0.62	0.63	0.63	0.63	0.63	0.63	0.61	0.61	0.61	0.62	0.66	0.66	0.69	0.70	0.73
Colombia	1.01	1.00	1.02	1.00	1.01	1.00	0.99	1.04	1.07	1.03	1.12	1.08	1.09	1.07	1.07
Others	0.43	0.42	0.41	0.41	0.42	0.42	0.42	0.42	0.41	0.42	0.51	0.51	0.50	0.49	0.47
Middle East[4]	1.38	1.31	1.34	1.32	1.34	1.28	1.27	1.28	1.27	1.27	1.27	1.23	1.24	1.24	1.24
Oman	0.94	0.94	0.96	0.96	0.95	0.95	0.95	0.96	0.95	0.95	0.96	0.92	0.91	0.89	0.90
Syria	0.08	0.06	0.05	0.03	0.06	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.08	0.10	0.12
Yemen	0.18	0.12	0.14	0.14	0.14	0.12	0.11	0.11	0.11	0.11	0.11	0.10	0.09	0.09	0.08
Others	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.18	0.17	0.17	0.16	0.15
Africa	2.25	2.29	2.35	2.44	2.33	2.44	2.41	2.43	2.43	2.43	2.40	2.46	2.53	2.61	2.65
Egypt	0.71	0.70	0.69	0.68	0.70	0.67	0.67	0.66	0.65	0.66	0.61	0.60	0.59	0.57	0.55
Equatorial Guinea	0.27	0.26	0.27	0.27	0.27	0.28	0.27	0.28	0.29	0.28	0.32	0.28	0.26	0.25	0.28
Sudan	0.11	0.12	0.13	0.13	0.12	0.13	0.12	0.12	0.12	0.12	0.11	0.09	0.08	0.08	0.07
Others	1.16	1.21	1.26	1.36	1.25	1.36	1.35	1.37	1.37	1.36	1.36	1.49	1.60	1.71	1.74
Total Non-OECD	29.60	29.51	29.33	29.84	29.57	29.79	29.69	29.57	29.70	29.69	29.87	29.99	30.43	30.63	30.90
Processing Gains[5]	2.18	2.16	2.20	2.18	2.18	2.21	2.19	2.24	2.22	2.21	2.29	2.33	2.33	2.38	2.43
Global Biofuels[6]	1.48	2.02	2.36	2.15	2.01	1.67	2.11	2.46	2.14	2.10	2.19	2.25	2.30	2.32	2.34
TOTAL NON-OPEC[2]	**53.83**	**54.16**	**54.98**	**55.80**	**54.70**	**55.61**	**55.96**	**56.17**	**56.72**	**56.12**	**57.26**	**58.36**	**59.40**	**60.33**	**60.93**
TOTAL SUPPLY	**90.57**	**91.38**	**91.93**	**91.96**	**91.46**	**92.00**									

1 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE. Orimulsion production reportedly ceased from January 2007.
2 Total OPEC comprises all countries which were OPEC members at 1 January 2009.
Total Non-OPEC excludes all countries that were OPEC members at 1 January 2009.
3 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
4 Includes small amounts of production from Jordan and Bahrain.
5 Net volumetric gains and losses in refining and marine transportation losses.
6 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.
7 As of the August 2012 OMR, includes Chile.
8 As of the August 2012 OMR, includes Estonia and Slovenia.
9 As of the August 2012 OMR, includes Israel.

Table 3a

SELECTED NON-OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
OECD Americas				***OECD Europe***				Russia	Kuyumba	230	2018
USA	Big Foot	75	2014	Italy	Tempa Rossa	50	2018	Russia	Yamal LNG	100	2018
USA	Jack/St Malo	170	2014	Denmark	Hejre	35	2016	Russia	Tagulskoye	90	2019
USA	Lucius	80	2014	Norway	Gudrun/Sigrun	70	2014	Russia	Gazprom Condensate	170	ongoing
USA	Mars B (Olympus)	100	2014	Norway	Knarr (Jordbaer)	60	2014	Kazakhstan	Kashagan phase 1a (restart)	375	2016
USA	Tubular Bells (Gulfstar)	60	2014	Norway	Valemon	35	2014	Kazakhstan	Karachaganak phase 3	60	2019
USA	Delta House	100	2015	Norway	Ekofisk extension	50	2015	Azerbaijan	West Chirag Oil	150	2014
USA	Gunflint/Freedom	120	2015	Norway	Eldfish extension	20	2015	Azerbaijan	Shah-Deniz 2	150	2019
USA	Heidelberg	80	2016	Norway	Goliat	70	2015	***Asia***			
USA	Stones FPSO	50	2016	Norway	Edvard Grieg	90	2015	India	Krishna-Godavari	80	2017
USA	Vito	90	2017	Norway	Luno	45	2015	India	Vasai West and Bombay High redev.	100	2017
USA	Kaskida	100	2019	Norway	Ivar Aasen	100	2016	India	Rajasthan Block: Mangala, Aishwariya,	150	ongoing
USA	Mad Dog 2	130	2019	Norway	Martin Linge	45	2016	Indonesia	Banyu Urip (full field)	150	2015
Canada	Algar Lake	6	2014	Norway	Nona	15	2016	Indonesia	Gendalo Gehem	50	2017
Canada	Black Gold phase 1	10	2014	Norway	Gina Krog	70	2017	Malaysia	Kebabangan	40	2014
Canada	Cold Lake phases 14-16	40	2014	Norway	Njord	50	2017	Malaysia	Malikai	50	2017
Canada	Foster Creek F	45	2014	Norway	Aasta Hansteen	20	2018	Malaysia	Kasawari	30	2018
Canada	Hangingstone phase 1	12	2014	Norway	Hod	22	2018	Thailand	Ubon	30	2019
Canada	MacKay phase 1	35	2014	Norway	Trestakk	30	2018	Viet Nam	Sutu Nau	45	2015
Canada	Sunrise phase 1	60	2014	UK	Emerald	25	2014	***Latin America***			
Canada	West Ellis A1 A2	10	2014	UK	Greater Stella	15	2014	Brazil	Roncador P-55	180	2013
Canada	Blackrod phase 1	20	2015	UK	Kinnoul	40	2014	Brazil	Cidade de Ilhabela FPSO (Sapinhoá)	150	2014
Canada	Foster Creek G	40	2015	UK	Laggan-Tormore	20	2014	Brazil	Cidade de Mangaratiba FPSO	150	2014
Canada	Horizon phase 2A	10	2015	UK	Morrone	15	2014	Brazil	Parque das Baleias P-58 (pre-salt)	180	2014
Canada	Jackfish phase 3	35	2015	UK	Solan	20	2014	Brazil	Papa Terra P-61	100	2014
Canada	Kearl Phase 2	110	2015	UK	Golden Eagle	65	2015	Brazil	Roncador P-62	180	2014
Canada	Lindbergh phase 1	11	2015	UK	Monarb Redevelopment	50	2015	Brazil	Atlanta EPS	15	2015
Canada	Seal Main	10	2015	UK	Alma/Galia	20	2015	Brazil	Cidade de Itaguaí FPSO (Iracema Norte)	150	2015
Canada	Surmont phase 2	109	2015	UK	Cheviot (former Emerald)	25	2016	Brazil	Argonauta O-South, Massa (Conchas)	20	2016
Canada	Thickwood A1	10	2015	UK	Schiehallion Redevelopment/Quad 204	150	2016	Brazil	Lapa (Carioca) North (pre-salt)	80	2017
Canada	Wildwood	12	2015	UK	Western Isles	35	2016	Brazil	Lula (Central and Sul)	275	2017
Canada	Advanced Tri-Star-1	13	2016	UK	Clair expansion	90	2017	Brazil	Buzios (Franco) all phases	500	2018
Canada	Aurora South Train 1	100	2016	UK	Mariner	75	2018	Brazil	Iara Horst	140	2018
Canada	Christina Lake 3A	50	2016	***OECD Asia Oceania***				Brazil	Tartaruga Verde	100	2018
Canada	Christina Lake F	50	2016	Australia	North Rankin and Gorgon Liquids	80	2015	Brazil	Carimbe (tieback to Barracuda)	45	2019
Canada	Dover North phase 1	50	2016	Australia	Ichthys	130	2016	Colombia	Castilla (infill)	30	2014
Canada	Dover West Clastics phase 1	12	2016	Australia	Prelude	45	2017	Colombia	Guairuro	15	2016
Canada	Foster Creek H	40	2016	***FSU***				Colombia	Block CPO 14	20	2019
Canada	Horizon phase 2B	45	2016	Russia	Prirazlomnoye	120	2013	***Middle East***			
Canada	Kirby North Phase 1	40	2016	Russia	Trebs & Titov	90	2013	Oman	Harweel and other PDO EOR	40	ongoing
Canada	Legend Lake 1A	10	2016	Russia	Arkutun-Daginskoye	90	2014	***Africa***			
Canada	Pike 1A	35	2016	Russia	Dulimskoye	35	2015	Congo	Benguela-Belize (satellite)	35	2016
Canada	Saleski phase 1	11	2016	Russia	Tsentralnoye	100	2015	Congo	Moho North	125	2016
Canada	Taiga phase 1	23	2016	Russia	Vladimir Filanovsky	200	2016	Ghana	Tweneboa-Enyera-Ntomme	45	2016
Canada	Hebron	150	2018	Russia	Russkoye	150	2016	Ghana	Sankofa-Gye Nyame	60	2017
Mexico	Ayatsil-Tekel	300	2014-2016	Russia	Chayadinskoye (all phases)	80	2017	Ivory Coast	Acajou	10	2017
Mexico	Tsimin-Xux	144	2015	Russia	Novoportovskoye	175	2017	Uganda	Albert Basin (Kingfisher)	35	2019
Mexico	Onel	15	2016	Russia	Pyakyakhinskoye	35	2017				
Mexico	Navegante	15	2018	Russia	Yurubcheno-Tokhomskoye	45	2017				
Mexico	Chicontepec Expansion	15	ongoing	Russia	Bazhenov layer (incl Priobskoye)	200	2017-18				

Table 3b
SELECTED OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
Crude Oil Projects								***NGL & Condensate Projects***			
Algeria	El Merk (Berkin Block 208)	135	2013	Iraq	Zubair Phase 2	100	2017	Algeria	El Merk (condensate)	30	2013
Algeria	Bir Seba (Blocks 433a/416b)	20	2014	Iraq	Rumaila Phase 2	200	2019	Algeria	El Merk Block 208 (NGLs)	31	2013
Angola	CLOV (Block 17)	160	2014	Kuwait	Ratqa	60	2017	Algeria	Gassi Touil (condensate)	12	2013
Angola	Mafumeira Sul (Block 0)	110	2015	Libya	North Gialo/Waha	80	2017	Algeria	Gassi Touil (NGLs)	8	
Angola	Cinguvu\Nzanza	20	2015	Libya	Area 47 Ghadames Basin	25	2018	Algeria	MLE East Block 405 b (condensate)	10	2013
Angola	Lianzi (Congo-Brazzaville joint zone)	23	2015	Nigeria	Erha North 2	50	2015	Algeria	MLE East Block 405b (NGLs)	12	2013
Angola	Sangos/N'Goma (Block 15)	40	2015	Nigeria	Zabazaba/Etan	120	2015	Angola	Soyo LNG Project (condensate)	10	2013
Angola	Cabaca Norte-1 (Block 15)	40	2016	Nigeria	Bonga NW	45	2016	Angola	Soyo LNG Project (NGLs)	50	2013
Angola	Cabaca SE	40	2016	Nigeria	Bonga SW & Aparo	225	2016	Angola	Mafumeira Sul Phase 2	10	2015
Angola	Chissonga (Block 16)	100	2016	Nigeria	Etim/Asasa	60	2016	Iran	South Pars 12 (condensate)	75	2014
Angola	Cameia Block 21 (Sub-salt)	100	2017	Nigeria	Uge	80	2018	Iran	South Pars 12 (NGLs)	30	2014
Angola	Kaombo (Gindunga, Canela, Gengibre) (Central SE Zone)	200	2017	Nigeria	Egina	200	2019	Iran	Kharg NGL	20	2015
Angola	Mostrado, Cola, Salsa, Manjericao (Block 32)	80	2017	Qatar	Duhkan	50	2015	Iran	South Pars 15-16 (condensate)	80	2018
Angola	Malange	50	2018	Qatar	Bul Hanine	45	2016	Iran	Pars 15 & 16 (NGLs)	28	2018
Angola	Platino, Chumbo, Cesio (PCC) (Block 18W)	100	2019	Saudi Arabia	Manifa 1	500	2013	Libya	NC-98 (condensate)	100	2014
Ecuador	Pungarayacu--Phase 1	30	2015	Saudi Arabia	Manifa 2	400	2014	Nigeria	Gbaran/Ubie	20	2017
Ecuador	ITT (Ishpingo-Tambococha-Tiputini)	160	2016	Saudi Arabia	Khurais Expansion	300	2016	Qatar	Barzan (condensate)	50	2015
Ecuador	Pungarayacu--Phase 2	30	2018	Saudi Arabia	Shaybah Expansion	250	2016	Saudi	Manifa	65	2013
Iran	Paranj	50	2013	UAE	Bab CO2 Injection	75	2014	Saudi	Shaybah NGL	240	2014
Iran	Yaran	12	2014	UAE	Umm al Lulu	105	2014	Saudi	Hasbah (Wasit)	30	2014
Iran	Darkhovin	120	2015	UAE	Nasr	65	2015	UAE	IGD--Offshore Integrated Gas Dev. (Ruwais)	110	2013
Iran	Azadegan 2 North	75	2016	UAE	Upper Zakum expansion	250	2016	UAE	OGD Habshan-5 (NGLs)	60	2013
Iran	South Pars	35	2017	UAE	Satah al Razboot (SARB)	100	2018	UAE	Shah Sour Gas (NGL)	25	2017
Iran	Bahregansar	65	2019	UAE	Lower Zakum	2164	2018	UAE	Shah Sour Gas (condensate)	25	2017
Iraq	Gharaf	230	2013	Venezuela	Carabobo 1	90	2013	***GTL Projects***			
Iraq	Majnoon	200	2013	Venezuela	Junin Block 4--CNPC	250	2013	Nigeria	Escravos GTL	37	2013
Iraq	Badra	170	2014	Venezuela	Junin Block 5--ENI	200	2013				
Iraq	West Qurnah 1	150	2014	Venezuela	Carabobo 3	100	2016				
Iraq	West Qurnah 2	120	2014	Venezuela	PetroVictoria (Rosneft)	200	2017				

Table 4
WORLD REFINERY CAPACITY ADDITIONS
(thousand barrels per day)

	2014	2015	2016	2017	2018	2019	Total
Refinery Capacity Additions and Expansions[1]							
OECD Americas	-5	289	395	50		40	769
OECD Europe	-110				214		104
OECD Asia Oceania	-327	-102					-429
FSU	75	210	137				422
Non-OECD Europe							
China	630	370	590	700	100		2,390
Other Asia	570	-55	60	200	260	300	1,335
Latin America	115	225	103	165	50		658
Middle East	490	447	206	185	570	260	2,158
Africa	15	5	35	220			275
Total World	**1,453**	**1,389**	**1,526**	**1,520**	**1,194**	**600**	**7,682**
Upgrading Capacity Additions[2]							
OECD Americas	150	123	25		55		353
OECD Europe	72		20		106		198
OECD Asia Oceania	-63	-36					-99
FSU	105	225	283	40	151	80	884
Non-OECD Europe	68	116	40				224
China	325	209	250	297			1,081
Other Asia	632	116	40	80	156		1,024
Latin America		258		163	104		525
Middle East	332	307	66		80	28	814
Africa				107			107
Total World	**1,622**	**1,318**	**725**	**687**	**652**	**108**	**5,111**
Desulphurisation Capacity Additions[3]							
OECD Americas	85	60					145
OECD Europe	-3				114		111
OECD Asia Oceania	-213						-213
FSU	75	246	25	40			386
Non-OECD Europe	45	20					65
China	517	94	253	542			1,406
Other Asia	346	-20	26	209	98		659
Latin America	41	230		40	30		341
Middle East	526	275	99	21	168	102	1,191
Africa	37			42			79
Total World	**1,457**	**905**	**403**	**894**	**410**	**102**	**4,170**

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.
2 Comprises gross capacity additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC or RFCC capacity.
3 Comprises additions to hydrotreating and hydrodesulphurisation capacity.
4 New OECD members Chile and Israel are stil l accounted for in Latin America and Middle East, respectively. Estonia and Slovenia have no refineries

Table 4a
WORLD REFINERY CAPACITY ADDITIONS:
Changes from Last Medium-Term Report

(thousand barrels per day)

	2013	2014	2015	2016	2017	2018	Total
Refinery Capacity Additions and Expansions[1]							
OECD Americas	-171	-34	214	395	50		454
OECD Europe		-110			-214	214	-110
OECD Asia Oceania	-10	172	-102				60
FSU	75	27	50	-78			74
Non-OECD Europe							
China	-530	360	-630	-870	300	-340	-1,710
Other Asia	-300	298	130	60	-325	-120	-257
Latin America	226	-170	50	5	-50	-715	-654
Middle East	10	470	447	-152	-280	-161	335
Africa	-10	-31	5	-60	25		-71
Total World	**-710**	**982**	**164**	**-700**	**-494**	**-1,122**	**-1,880**
Upgrading Capacity Additions[2]							
OECD Americas	121	-71	59	25		55	189
OECD Europe		72	-115	20	-106	106	-23
OECD Asia Oceania		-17	-36	-80			-133
FSU	-3	-49	43	133	-50	56	130
Non-OECD Europe	7	-7	-18	40			22
China	-362	213	-22	-392	297	-90	-356
Other Asia	-286	471	96	40	-100	125	346
Latin America	61	-60	88	-20	-84	-156	-171
Middle East		136	267	-28	-241	-141	-7
Africa							
Total World	**-462**	**689**	**361**	**-262**	**-284**	**-45**	**-2**
Desulphurisation Capacity Additions[3]							
OECD Americas	-45						-45
OECD Europe		-3	-35		-114	114	-38
OECD Asia Oceania		-131					-131
FSU	166	-85	196	-10	40		307
Non-OECD Europe							
China	-413	378	-237	-597	542	-164	-492
Other Asia	-194	243	78	26	-75	88	165
Latin America	120	-70	70		-30	-215	-125
Middle East		496	235	-123	-241	-278	89
Africa							
Total World	**-366**	**827**	**308**	**-703**	**122**	**-455**	**-268**

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.
2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.
3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

Table 4b
SELECTED REFINERY CRUDE DISTILATION PROJECT LIST

Country	Project	Capacity (kbd) [1]	Start Year	Country	Project	Capacity (kbd)1	Start Year
OECD Americas							
Canada	North West Redwater Partnership - Edmonton	50	2017	China	Sinopec - Jiujiang	70	2015
Mexico	Petroleos Mexicanos - Tula Hidalgo	40	2019	China	CNOOC - Huizhou	200	2016
United States	Kinder Morgan - Galena Park	50	2014	China	CNPC/Saudi Aramco - Kunming/Anning	200	2016
United States	Western Refining Inc. - El Paso	25	2014	China	Sinopec - Jingmen	100	2016
United States	National Cooperative Refining Assoc. - McPherson	15	2014	China	China National Petroleum Corp. - Daqing Heilongjiang	90	2016
United States	Flint Hills Resources - North Pole	-95	2014	China	CNPC/PDVSA - Jieyang	400	2017
United States	Castleton Commodities - Corpus Christi	100	2015	China	Sinopec/KPC? - Zhanjiang	300	2017
United States	Kinder Morgan - Galena Park	50	2015	China	Sinopec - Hainan	100	2018
United States	Marathon Petroleum Co. LLC - Catlettsburg	35	2015	***Other Asia***			
United States	Marathon Petroleum Co. LLC - Canton	25	2015	Chinese Taipei	Chinese Petroleum Corp. - Kaohsiung	-205	2015
United States	Valero Energy Corp. - Sunray	25	2015	India	Indian Oil Co. Ltd. - Paradip	300	2014
United States	Virtual Engineering - Allen Parish	20	2015	India	Nagarjuna oil Co - Cuddalore	120	2015
United States	MDU Resources (W/Calumet) - Dakota Prairie Refining	20	2015	India	Indian Oil Co. Ltd. - Panipat	60	2016
United States	Martin Midstream Partners - Corpus Christi	100	2016	India	BPCL - Kochi	120	2018
United States	Valero Energy Corp. - Houston	90	2016	India	Indian Oil Co. Ltd. - Koyali, Gujarat	80	2018
United States	Valero Energy Corp. - Corpus Christi	70	2016	India	Indian Oil Co. Ltd. - Mathura	60	2018
United States	Magellan - Corpus Christi	50	2016	Malaysia	Petronas - Rapid	300	2019
United States	Marathon Petroleum Co. LLC - Robinson	30	2016	Pakistan	Byco Petroleum Pakistan Ltd. - Karachi	120	2014
United States	The Three Affiliated Tribes - Thunder Butte Petroleum Services	20	2016	Singapore	Jurong Aromatics Corporation - Jurong	110	2014
United States	Calumet Montana Refining - Great Falls	20	2016	Thailand	Thai Oil Co. Ltd. - Sriracha	30	2014
OECD Europe				Thailand	PTT PLC - Bangchak Bangkok	20	2015
Italy	Italiana Energia E Servizi SPA (MOL) - Mantova	-55	2014	Viet Nam	Petro vietnam/KPC/Idemitsu Kosan - Nghi Son	200	2017
Turkey	Socar - Aliaga/Izmir	214	2018	***Middle East***			
United Kingdom,	Essar - Stanlow	-55	2014	Iran	National Iranian Oil Co. - Persian Gulf Star Refinery	120	2017
OECD Asia Oceania				Iran	National Iranian Oil Co. - Persian Gulf Star Refinery	120	2018
Australia	Caltex Refineries (NSW) Ltd. - Kurnell	-124	2014	Iran	National Iranian Oil Co. - Persian Gulf Star Refinery	120	2019
Australia	BP PLC - Bulwer Island	-102	2015	Iraq	South Refining Company - Basra	70	2014
Japan	Tonen/General Sekiyu Seisei KK - Wakayama	-38	2014	Iraq	Kar-Group - Erbil	20	2014
Japan	Cosmo Oil Co. Ltd. - Yokkoaichi	-43	2014	Iraq	Qaiwan - Baizan	50	2018
Japan	Tonen/General Sekiyu Seisei KK - Kawasaki	-67	2014	Iraq	INOC-ORA - Karbala	140	2019
Japan	Idemitsu Kosan Co. Ltd. - Shunan, Yamaguchi (Tokuyama)	-120	2014	Oman	Sohar Bitumen Refinery - Sohar	30	2015
Japan	JX Energy - Muroran	-180	2014	Oman	Oman Refinery Co. - Sohar	60	2016
Korea	Samsung Total - Daesan	145	2014	Qatar	QatarPetroleum - Ras Laffan 2	146	2016
Korea	SK Corp. - Incheon	100	2014	Saudi Arabia	Aramco Sinopec - Yanbu	400	2014
Non-OECD Europe				Saudi Arabia	Saudi Aramco - Sumitomo - Rabigh 2	50	2017
FSU				Saudi Arabia	Saudi Aramco - Jazan	400	2018
Kazakhstan	Kazmunigaz - Pavlodar	50	2016	UAE-Abu Dhabi	Abu Dhabi National Oil Co. - Ruwais2	417	2015
Kazakhstan	Kazmunigas - Atyrau	48	2016	Yemen	Yemen - Hunt - Marib	15	2017
Kazakhstan	Kazmunigaz/CNPC - Chimkent	15	2016	***Non-OECD Americas***			
Russia	Antipinsky Refinery - Antipinsky	75	2014	Argentina	Repsol YPF SA - La Plata	25	2015
Russia	Novatek - Ust-Luga	70	2015	Brazil	Petrobras/Petroleos de Venezuela SA - Pernambuco State Abreu e Lima	115	2014
Russia	West Siberian Oil Refinery - Tomsk	60	2015	Brazil	Petrobras/Petroleos de Venezuela SA - Pernambuco State Abreu e Lima	115	2015
Russia	Verkhoturye - Sverdlovsk	60	2015	Brazil	Petrobras/Petroleos de Venezuela SA - COMPERJ	165	2017
Russia	Gazprom Neft - Moscow	120	2016	Colombia	Empresa Colombiana de Petroleos - Cartagena, Bolivar	85	2015
Russia	Gazprom Neft - Omsk	24	2016	Colombia	Empresa Colombiana de Petroleos - Barrancabermeja-Santander	50	2018
Russia	Gazprom Neft - Moscow	-120	2016	Peru	Petroperu SA - Talara, Piura	33	2016
China				Venezuela	Petroleos de Venezuela SA - Santa Inés (Barinas)	40	2016
China	Sinochem - Quanzhou Fujiang	240	2014	Venezuela	Petroleos de Venezuela SA - Puerto de la Cruz	30	2016
China	China National Petroleum Corp. - Pengzhou	200	2014	***Africa***			
China	Sinopec - Shijiazhuang	100	2014	Algeria	Naftec SPA - Arzew	25	2016
China	Sinopec - Yangzi	90	2014	Algeria	Naftec SPA - Skikda	100	2017
China	China National Petroleum Corp. - Huabei	100	2015	Angola	Sonangol - Lobito	120	2017
China	CNOOC/Shangdong Haihua - Haihua	100	2015	Sudan	Benitu	5	2015
China	CNOOC/ JV Partner - Yanchang Oilfield (Yongping)	100	2015	Sudan	Ventech Enigneers International - Thangrial	10	2016

Table 5
WORLD ETHANOL PRODUCTION[1]
(thousand barrels per day)

	2013	2014	2015	2016	2017	2018	2019
OECD							
OECD Americas[2]	877	934	947	954	956	955	957
United States	846	903	913	920	925	928	930
Canada	30	31	33	33	30	27	27
OECD Europe[3]	70	85	92	98	100	102	104
Austria	3	3	3	3	3	3	3
Belgium	7	8	7	7	7	7	7
France	15	16	16	17	18	18	18
Germany	13	16	16	17	17	17	17
Italy	1	2	3	3	4	4	4
Netherlands	5	5	6	8	8	8	8
Poland	5	5	6	6	6	6	6
Spain	7	7	7	8	8	8	8
UK	6	10	12	13	14	15	16
OECD Asia Oceania[4]	5	6	6	6	6	6	6
Australia	5	5	5	5	5	5	5
Total OECD	**952**	**1,025**	**1,045**	**1,058**	**1,063**	**1,064**	**1,067**
Non-OECD							
FSU	2	2	3	3	3	4	4
Non-OECD Europe	1	1	1	1	1	1	1
China	36	39	43	45	47	47	51
Other Asia	33	40	44	49	52	59	61
India	10	13	14	15	17	17	19
Indonesia	2	2	3	3	3	4	4
Malaysia	0	0	0	0	0	0	0
Philippines	2	3	4	5	5	6	6
Singapore	1	1	1	1	1	1	1
Thailand	16	18	18	19	21	23	24
Latin America	496	512	528	536	548	557	565
Argentina	5	8	10	12	12	13	13
Brazil	473	482	493	498	509	515	522
Colombia	6	8	9	9	10	11	12
Middle East	1	1	1	1	1	1	1
Africa	3	5	9	10	12	14	14
Total Non-OECD	**572**	**602**	**629**	**646**	**666**	**683**	**698**
Total World	**1,524**	**1,627**	**1,674**	**1,704**	**1,728**	**1,747**	**1,764**

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.
2 As of August 2012 OMR, OECD Americas includes Chile.
3 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
4 As of August 2012 OMR, OECD Asia Oceania includes Israel.

Table 5a
WORLD BIODIESEL PRODUCTION[1]
(thousand barrels per day)

	2013	2014	2015	2016	2017	2018	2019
OECD							
OECD Americas[2]	91	85	88	88	88	87	87
United States	87	80	84	84	84	84	84
Canada	3	5	5	4	4	3	3
OECD Europe[3]	176	191	200	204	207	211	212
Austria	5	5	5	5	5	5	5
Belgium	6	7	7	7	7	7	7
France	36	37	37	37	38	38	38
Germany	47	52	52	52	52	52	52
Italy	9	8	9	10	10	11	11
Netherlands	20	24	24	26	26	26	26
Poland	5	5	6	6	6	6	6
Spain	9	11	15	15	17	17	17
UK	4	4	5	6	6	6	6
OECD Asia Oceania[4]	15	15	16	16	16	16	16
Australia	6	6	7	7	7	7	7
Total OECD	**281**	**290**	**304**	**308**	**311**	**314**	**315**
Non-OECD							
FSU	1	1	1	1	1	1	1
Non-OECD Europe	3	3	3	3	3	3	3
China	4	5	6	6	7	7	8
Other Asia	76	81	91	95	102	105	108
India	1	1	1	2	3	3	3
Indonesia	32	30	35	37	40	42	42
Malaysia	6	9	11	12	13	13	14
Philippines	4	6	7	7	7	7	7
Singapore	15	15	16	17	17	18	18
Thailand	18	20	21	21	23	23	24
Latin America	93	95	106	110	115	119	121
Argentina	34	30	37	39	42	45	46
Brazil	46	51	54	56	57	58	59
Colombia	7	8	10	10	10	11	11
Middle East	0	0	0	0	1	1	1
Africa	1	4	5	6	8	8	8
Total Non-OECD	**178**	**188**	**212**	**222**	**236**	**245**	**251**
Total World	**459**	**478**	**516**	**530**	**547**	**560**	**566**

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.
2 As of August 2012 OMR, OECD Americas includes Chile.
3 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
4 As of August 2012 OMR, OECD Asia Oceania includes Israel.

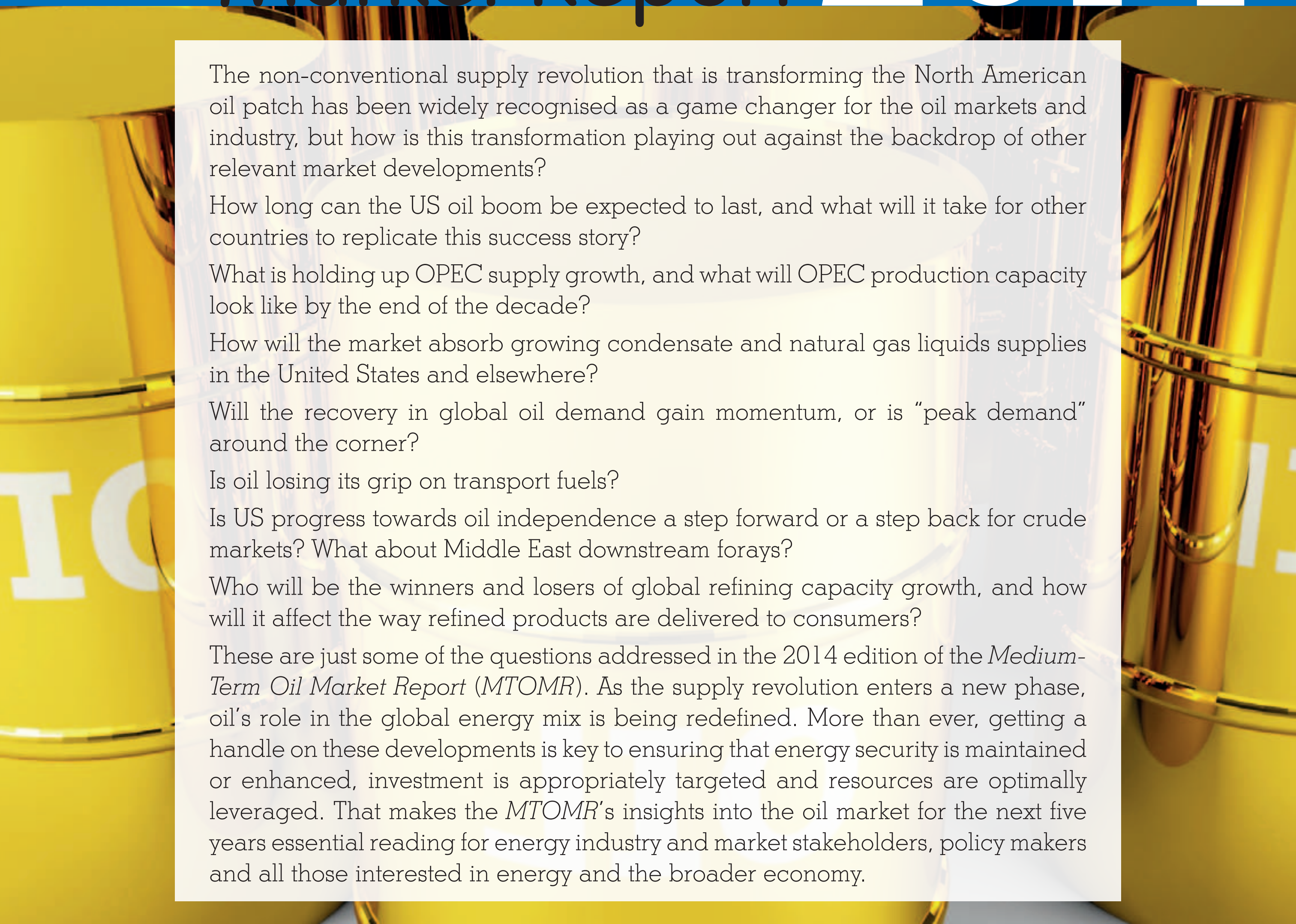
PEFC 10-31-1510

The paper used for this document has received certification from the Programme for the Endorsement of Forest Certification (PEFC) for being produced respecting PEFC's ecological, social and ethical standards. PEFC is an international non-profit, non-governmental organisation dedicated to promoting Sustainable Forest Management (SFM) through independent third-party certification.

IEA Publications, 9, rue de la Fédération, 75739 Paris cedex 15

Printed in France by ISI Print 2014
(612014151E1) ISBN 9789264211728; ISSN 2307-0269
Cover design: IEA. Photo credits: © GraphicObsession

OIL
Medium-Term Market Report 2014



The non-conventional supply revolution that is transforming the North American oil patch has been widely recognised as a game changer for the oil markets and industry, but how is this transformation playing out against the backdrop of other relevant market developments?

How long can the US oil boom be expected to last, and what will it take for other countries to replicate this success story?

What is holding up OPEC supply growth, and what will OPEC production capacity look like by the end of the decade?

How will the market absorb growing condensate and natural gas liquids supplies in the United States and elsewhere?

Will the recovery in global oil demand gain momentum, or is "peak demand" around the corner?

Is oil losing its grip on transport fuels?

Is US progress towards oil independence a step forward or a step back for crude markets? What about Middle East downstream forays?

Who will be the winners and losers of global refining capacity growth, and how will it affect the way refined products are delivered to consumers?

These are just some of the questions addressed in the 2014 edition of the *Medium-Term Oil Market Report* (*MTOMR*). As the supply revolution enters a new phase, oil's role in the global energy mix is being redefined. More than ever, getting a handle on these developments is key to ensuring that energy security is maintained or enhanced, investment is appropriately targeted and resources are optimally leveraged. That makes the *MTOMR*'s insights into the oil market for the next five years essential reading for energy industry and market stakeholders, policy makers and all those interested in energy and the broader economy.

Market Analysis and Forecasts to 2019

€100 (61 2014 15 1E1)
ISSN 2307-0269
ISBN: 978 92 64 21172 8