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](image)

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.

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<tr>
<th>Table ES.1 Global balance summary (million barrels per day)</th>
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<tr>
<td><strong>2012</strong></td>
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<td>GDP growth assumption (% per year)</td>
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<td>Global demand</td>
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<tr>
<td>Non-OPEC supply</td>
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<td>OPEC NGLs, etc.</td>
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<td>Global supply excluding OPEC crude</td>
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<td>OPEC crude capacity</td>
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<td>Call on OPEC crude + stock ch.</td>
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<tr>
<td>Implied OPEC spare capacity*</td>
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<td>Effective OPEC spare capacity**</td>
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<td>as percentage of global demand</td>
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<th>Changes since May MTOMR 2013</th>
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<td>Adjusted call on OPEC crude + stock ch.*</td>
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<td>Implied OPEC Spare Capacity*</td>
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<td>as percentage of global demand</td>
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* 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
EXECUTIVE SUMMARY

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.

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.

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

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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.
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-gear, 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

![IEA average import price assumption](image1)

**Figure ES.6** Historical benchmark crude prices

![Historical benchmark crude prices](image2)

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 “emission 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 refiners 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.
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.