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Oxford ENERGY FORUM

A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

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Opening this issue of Forum devoted to changes in the refining sector, Antoine Halff outlines the tectonic shifts in oil products trading that are currently reshaping the oil market. Using data from the IEA's recently released *Medium-Term Oil Market Report*, Halff says that growth in refining capacity between 2012 and 2018 will far exceed that of crude oil capacity and oil product demand. The refining investments will be concentrated in emerging markets, and will likely usher in a whole new chapter in product supply and pricing. Not only will this entail new requirements for product storage, price discovery and reporting, and hedging, Halff says it will also have profound consequences for supply security.

Amrita Sen looks at the dynamics of global refining. After a period of tightness in the mid 2000s (particularly in middle distillates markets), refining capacity expanded rapidly over the last few years, with the market now suffering from overcapacity. While European refineries have been hit the hardest, Asian refineries would also feel the squeeze (particularly Indian refineries) as imports from the Middle East decline and as they face tougher competition in Europe. Sen predicts that from the second half of 2013, the products market will be in surplus and despite weak margins, we are not likely to see much rationalisation in refining capacity as many refineries in non-OECD countries will continue to operate despite weak profit margins.

The price spread between light and heavy crude oils is important for refiners because it determines how heavily refiners invest in upgrading capacity at their plants, and how much they invest in conversion capacity in the future. Ehsan ul-Haq and Peter Stewart discuss the future of light and heavy crude oil spreads and the implications for the benchmark pricing system. The balance between light and heavy crude oils in the refining mix varies under different crude oil price scenarios, as the outright price determines which resources will be developed at the margin. Ul-Haq and Stewart argue that this will have consequences for the benchmarks used in crude oil pricing.

Craig Brown argues that despite the confluence of factors lending support to European refining margins, the outlook for European refineries remains bleak. The general decline in US gasoline demand depressed further by US ethanol blending

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mandates in 2013 and the loss of competitiveness vis-à-vis US refineries which are benefiting from cheaper crude feedstock options and lower priced natural gas to fuel their refineries will increase the pressure on European refineries. Brown expects refinery rationalisation in Europe to be delayed at least until 2015 when labour union agreements expire.

Alois Virag also acknowledges that the European refining industry faces a multiplicity of challenges including new legislation and growing global competition which are squeezing margins. In such a tough environment, operational and organisational efficiency will be the key to the success and survival of European refineries. He argues that vertical integration with upstream operations and retail markets as well as horizontal integration between refineries and petrochemical plants are routes to greater resilience.

James Henderson examines the massive investment in upgrading capacity that is being made by Russian refiners, after the government changed the tax system for crude oil and oil product exports. The key lever has been the export tax on fuel which Henderson says has already been increased by more than 70 percent and will rise further if plans to make it equivalent to the crude oil export tax by 2015 are implemented. Henderson's analysis suggests that the investment will not only reduce heavy fuel oil exports from Russia, but will create a surplus of gasoline in the country, as well as further increasing exports of low sulphur diesel from Russia. This is likely to have significant consequences for Atlantic Basin refiners.

John Kingston looks at the potential for the USA to become an exporter of oil and gas as a result of the shale boom. While the prospects are rosy in theory, Kingston says massive investment will be needed in the country's ageing energy infrastructure for the predictions to become a reality. But he cites work by Craig Pirrong, a professor at the University of Houston, who says the forward curve on the Brent–WTI spread is showing just how much potential is there, and that those numbers are 'big'. That raises the prospect that much of this infrastructure will get built.

US shale production is leading to a surge in supplies of NGLs including ethane, and petrochemical companies have announced a string of ethane cracker projects to capture the 'ethane advantage'. However, there are concerns among the US chemical industry that LNG exports could erode their price advantage and so these companies are strongly lobbying against export projects. Richard Mallinson argues that while there are several segments of the chemical industry, such as fertiliser manufacturing, where methane is the feedstock and hence natural gas prices have a clear bearing on manufacturing costs, the link between LNG exports and NGLs (which are distinct from methane) is less clear. He notes that while rising domestic production and expanding transportation infrastructure look set to cap ethane prices, the approval of LNG exports may pose a somewhat unexpected threat because of higher Btu specifications for natural gas in key potential export markets.

Stephen George says that biofuels have been a significant factor in the shuttering of more than 3.4 million barrels per day of refining capacity in the Atlantic Basin since 2009. Global biofuels demand has risen from around 500,000 b/d in 2004 to around 2.3 million b/d in 2013 and is set to hit 3.5 million b/d by 2020. Government mandates have ensured rising demand for biofuels on both sides of the Atlantic, in the face of declining absolute fuel demand. George traces the development of biofuels in the three main markets: Brazil, the USA and the European Union. He says refiners are concerned about biofuels policy as lack of certainty about the future makes investment planning difficult for an industry that already faces environmental constraints and strong competition from refiners outside the Atlantic Basin region.

Emmanuel Vaz notes that one of the biggest surprises in the Atlantic Basin has been the rapid increase in imports of oil products. As the gap between domestic demand and production continues to widen, this is creating many challenges for Latin American governments. While in principle the gap could stabilise in the next two to three years, delays in the current refining projects could see Latin America's imports exceed 2 million b/d by the end of this decade. There are many reasons to believe that many

of the refining projects currently announced would be delayed due to factors such as poor margins, poor project management and shareholder pressure to divert funds towards the upstream where returns are much higher. Vaz however emphasises the importance of subsidies as creating a vicious circle where lower prices encourage demand while at the same time lowering profitability of downstream operations and reducing the incentive to invest.

Roberto Carmona and Edgar Jones note that although Latin America (Brazil, Venezuela and Mexico) will continue to run a surplus of heavy crude, the potential of further growth of this particular type of crude will become more limited as a result of multiple factors including decline rates, lack of investment and increase in domestic demand. The decline in the supply is already having some repercussions on international trade flows of heavy crude. Paradoxically, despite the limited growth potential, heavy crude oil from Latin America may not find its way to the USA as Gulf Coast refineries continue to run light sweet crude. This would lead to a reduction in US consumption of intermediate and heavy crudes of up to 2 million b/d, forcing Latin America producers to seek new markets in Asia.

Neil Fleming looks at the potential for refining investment in Africa. Fleming says that oil demand in sub-Saharan Africa is forecast to jump by 50 percent in the next decade, outstripping growth in the rest of the world by a factor of around four to one. That growth will lead by 2020 to a doubling in the shortfall in oil products in Africa. This marks a wide-open investment opportunity in theory, but the reality is more complex. Fleming's analysis suggests that it is difficult to assemble the political will and investment resources to build refineries in Africa. China has been the most enterprising investor in the African downstream so far, but even it is scaling down its appetite for such deals.

Finally, Peter Stewart says that the development of shale gas could represent a Black Swan for the refining sector. Natural gas has given US downstream companies a competitive edge for the time being, providing cheaper power for refiners and a competitively-priced source of ethane for petrochemical plants. Stewart sees this as a double-edged sword for the refining sector, however. In the longer term, the potential to develop natural gas in transport represents a significant challenge ahead for beleaguered Atlantic Basin refiners that may have consequences for refining investment decisions.

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The Impact of Refining Sector Changes on Patterns of Oil Product Trading

ANTOINE HALFF

The global oil market is undergoing a profound transformation, the depth of which is inadequately captured by the popular cliché 'the new oil map'. For the changes underway in the market go beyond a mere geographical reallocation of supply and demand or even refining capacity. The supply chain itself – the way oil is being delivered from the wellhead to end-users – is transforming. The old system, in which crude trading was largely global but refining and distribution were mostly local, is being turned on its head. Product trading is globalising and the product supply chain is getting both longer and more fragmented, an evolution which carries significant implications for supply security and prices.

Those tectonic shifts in product trading are first and foremost a consequence of the evolution in the refining industry. According to the International Energy Agency's recently released *Medium-Term Oil Market Report (MTOMR)* 2013, global refining capacity is slated to jump by 9.5 mb/d from 2012 to 2018. That expansion far exceeds the forecast increase in crude supply capacity (8.4 mb/d) over the same period, let alone that in global demand (6.9 mb/d). Virtually all of the expected increase in refining capacity will come from emerging market and industrialising economies. China alone, extending recent trends, is expected to account for roughly 45 percent of the increment, followed by the Middle East with nearly 25 percent. This would bring refineries in advanced economies outside of the United States under severe pressure. Some 4 mb/d of OECD crude distillation capacity has already been idled or earmarked for shutdown since the 2008 financial crisis, including 1.2 mb/d last year alone and 0.8 mb/d in 2011. To keep utilisation rates at traditional, pre-financial crisis levels, another 4.5 mb/d of capacity or more may have to shut down in the next few years. European refineries, some 15 of which will have closed by end-year since 2008, would be most at risk.

Changing demand patterns only partly account for these refining shifts. For the first time this quarter, the non-OECD region is expected to consume more oil than the OECD, a gap which is forecast to widen steadily over the next few years. Taken in aggregate, however, non-OECD refining capacity is expanding much faster than regional demand. The non-OECD region already accounts for more than 50 percent of global refining capacity, a share projected to jump much higher by 2018, the end of the *MTOMR* forecast period. However steep the current contraction in European oil demand may appear, the region's refining capacity is also falling even faster than its oil use. European product imports – despite weak economic and demand growth – are surprisingly robust.

Changes in refining capacity, compounding the impact of shifting supply and demand patterns, are redirecting crude and product trade flows. Despite a projected increase in global oil demand, the *MTOMR* forecasts that international crude trade will drop by 900,000 b/d. This will be more than offset by rising product flows. Crude oil is increasingly being refined near the wellhead: this is true both of North America, where rising production of US Light, Tight Oil (LTO) and Canadian oil sands is displacing crude imports, and of the Middle East, where refining capacity expansions are keeping more crude at home for internal use or to be exported as products.

The redistribution of regional capacity is thus resulting in a significantly longer supply chain. Refining is increasingly becoming an export industry. A string of refining powerhouses dots the coastal lines of the 'new oil map'. The United States, which only yesterday ranked as the world's number one net product importer, has virtually overnight become one of its top two exporters – thanks to falling domestic demand, cheap natural gas and a growing supply of 'price-advantaged' domestic crude. Indian refiners, whether state- or privately owned, continue to build up their refining capacity, in large part for export. In China, where demand growth has recently shifted to a lower gear, refiners nevertheless continue to aggressively expand. As a result, diesel, gasoline and jet fuel exports have surged, and are expected to keep growing as more refining capacity comes on stream in the next few years. The Middle East, led by Saudi Arabia, is expanding downstream through joint ventures with foreign partners to diversify its economy and capture more of the value chain. While that is partly meant for domestic purposes, meeting local demand at subsidised prices clearly is not what the foreign partners have in mind. Russia has long been a large product exporter as well as a major crude supplier.

At the other end of the trade, more and more countries – whether they are undergoing economic expansion like Latin America or contraction like Europe – are growing dependent on product imports. OECD Europe, for example, has long relied on imports to meet its jet fuel needs, but its dependence is reaching new highs – despite weak demand. The region is generally short middle distillates, including diesel and jet fuel. In France, net imports of jet fuel from non-European countries now roughly equal domestic production; in the United Kingdom, they recently passed it as the top supply source. Import dependence would increase dramatically if more European refining capacity were to close. Across the Atlantic, Mexico is going down a similar path with rising imports of gasoline (now superior to domestic production) and diesel. Contrary to accepted wisdom, this is not all due to rising demand, but also, whether by design or accident, to falling domestic output. Although state oil company PEMEX keeps several aggressive refinery expansion projects on the books, in practice it may have found it expedient to rely on US imports rather than splurge on its own capacity.

As the product supply chain becomes longer, it is also getting more fragmented. No longer are product markets supplied predominantly by vertically integrated international oil companies or local refiners firmly embedded in their markets and often supported by their own local

distribution network. Enter a new cast of characters: new independent refiners, independent distributors, profit-seeking transportation and storage companies recently spun off from refining companies or integrated IOCs, foreign National Oil Companies (NOCs) increasingly active in international product markets beyond their borders and – most importantly – international trading houses. Traders like Gunvor admit to a shift in their core business from crude to product trade. Their customers increasingly rely on them to meet their fuel needs.

For consumer markets, increased reliance on long-haul product imports comes with both risks and benefits. Trading companies are inherently nimble and quick to spot arbitrage opportunities. But their incentives differ markedly from those of refiners. Whereas the latter seek to leverage their refining assets by running their plants as high as possible, trading firms thrive on arbitrage opportunities and volatility. The inherent risk of a refiner-based supply model is thus that of overproduction and low refining margins, whereas that of a trader-based supply chain is undersupply.

The longer the supply chain, the higher the risks of disruption. Unless oil is pre-positioned near markets, long-haul suppliers tend not only to be slow but can even appear reluctant to respond to supply disruptions. That is not just a direct function of extended sailing times. Given the lags of long-haul trade, suppliers can be understandably hesitant to respond to remote supply disruptions, lest the issue be corrected before their shipments reach destination or others get there first. That is why refinery accidents in the insulated, hard-to-reach US West Coast market often have such a steep impact on local prices and the resulting supply shortfalls can take months to fix. In the case of European jet imports, many of the region's top suppliers – Saudi Arabia, Kuwait, the United Arab Emirates, Qatar and India – are themselves not risk-free.

Increased reliance on long-haul product trade thus necessarily translates into higher storage requirements, which in turn carries price implications. There must be a wide enough price differential between product import markets and suppliers to cover transport costs and capital costs over sailing periods. There must also be a wide enough spread between prices in the low- and high-demand seasons to cover storage and capital costs. The current transformation of the product supply chain might thus translate into increased price volatility. Shifts in US product pricing over the last 10 years may be a harbinger of future trends: the spread between New York Harbour and US Gulf Coast gasoline prices has generally widened at the margin as the East Coast has progressively become more dependent on Gulf Coast shipments to supplement local refining output in meeting demand. That increase could pale, however, in comparison to future price spreads between product importers and exporters.

Finally, as the product supply chain gets more vertically fragmented, it will also become more integrated horizontally. This will support the emergence of a new international trading infrastructure. Global refining capacity already is getting increasingly concentrated around major regional hubs, clusters of giant plants geared to serve both local and long-haul markets. The Reliance-Essar combo in Jamnagar, in India's Gujarat state, is a case in point, as are the Houston or Corpus Christi clusters in Texas. To support international product trade, these global refining hubs will need to be backed by a network of large import and export terminals, global trading hubs located at strategic locations to facilitate access to market and break-bulk and bulk-building operations. The Caribbean islands, long established as storage and terminal nexus for crude and residual fuel oil at the crossroads of several major tanker routes, is thus being revamped and expanded to double as a platform for light product trade. Several tank farms – BORCO in the Bahamas, the NuStar facility in St Eustatius and others – are reportedly developing light product storage capacity there. Other large international terminals are likely to sprout at locations ranging from Northwest Europe to Fujairah to South Korea to Singapore to support the growth in international trade.

One cannot fully appreciate the impact of the growth in non-OECD refining if one sees it simply as an effect of the growing in non-OECD demand. Rather, the regional reshuffle in refining capacity will likely usher in a whole new chapter in product supply and pricing. This will entail new requirements for product storage, price discovery and reporting, and hedging. Market transparency may suffer if inventory changes at non-OECD storage hubs are not adequately reported. Market participants may also support the emergence of new product benchmarks to reflect the changing reality of trade flows and the shifting supply chain. Finally, governments and private companies will be forced to reassess supply risks and revisit their emergency preparedness measures. ■

Scarcity to Abundance: The changing landscape of global refining

AMRITA SEN

The problems facing the global refining industry are well documented – significant overcapacity, regional mismatches between capacity and demand, and now, a rapidly changing crude slate. Refining margins have in general failed to catch up to the highs of 2008, when an acute shortage of refining capacity led to record margins. Yet 2012 saw some significant improvements in margins and middle distillate cracks, with some areas even seeing product cracks breach 2008 highs.

While global demand remained sluggish, it was the supply side that resulted in shoring up of margins. The combination of delays to new projects and accelerated shutdown of oil refineries resulted in global refining capacity actually shrinking marginally last year (by around 0.28 mb/d).

Significant refinery rationalisations, amounting to 1.1 mb/d in 2012, also cut into growth, driven in particular by closures in Europe (including Petroplus' refineries) and North America (including the 0.35 mb/d St. Croix refinery and the

0.24 mb/d Aruba refinery which was converted to a product terminal). Moreover, a spate of refinery outages since the summer of last year coincided with fairly heavy seasonal maintenance to help shore up margins, particularly for diesel.

However, on a global basis, following the strength in Q1 primarily due to regulatory reasons impacting light ends in the USA, product cracks and margins have come under immense pressure and rightly so, as refining capacity additions (Table 1) are well outpacing end product demand.

Extreme tightness in middle distillates markets since late 2006 led to a steady stream of refinery capacity additions in the subsequent years. Over 2009 and 2010, net capacity additions to global refining capacity averaged 1.3 mb/d each year, although the downturn in demand in late 2008/early 2009 created significant breathing space in the refining sector. While the sharp upswing in oil demand that followed in 2010 helped absorb some of the excess refining capacity, product markets were no longer suffering from lack of distillation capacity. In fact, the subsequent slowdown in demand growth and fall in margins led to something of a slowdown in capacity additions in 2011.

Although refining capacity additions continued unabated in non-OECD countries, particularly Asia, shutdowns of non-profitable refineries in Europe, Japan and North America helped mask their effects somewhat. Indeed, despite 2 mb/d of gross capacity additions in 2012, the net increase in global refining capacity was around 1 mb/d. With various unplanned outages at old and poorly maintained refineries through 2012 and the fact that new capacity additions primarily came online in Q4, the negative impact on product prices was not felt in 2012. Today, however, the pace of shut downs has slowed; the new capacity added in Q4 2012 and Q1 2013 is operating at full rates, particularly in Asia, and even previously unprofitable refineries have had such stellar margins that utilisation rates have soared.

Indeed, capacity additions are set to outpace demand growth for both 2013 and 2014, by 0.8 mb/d and 1.5 mb/d respectively. Additions in emerging markets lead the way, with the 0.3 mb/d IOC Paradip refinery in India, the 0.4 mb/d SATORP Jubail refinery in Saudi Arabia, various refinery additions amounting to 0.7 mb/d in China – including Chengdu, Kunming, Shandong and Hebei – and a 0.12 mb/d Byco refinery in Pakistan all added in 2013. In 2014, the additions are even larger, with the 0.4 mb/d Yanbu refinery in Saudi Arabia, 0.4 mb/d Takreer refinery in Ruwais, 0.23 mb/d RNEST refinery in Brazil and a 0.3 mb/d addition to the Skikda refinery in Algeria.

That said, the proportion of complex refining units (hydrocrackers and cokers) is rising and these are usually subject to more complications and delays. Equally, some of these CDU additions have already been delayed for months or even years (e.g. Petrobras' refineries), so there remains some downside risk to the overall capacity addition figures. But even adjusting for possible delays and cancellations, refining capacity is set to significantly outpace end product demand over the next few years. Not surprisingly, product prices are reeling under the pressure of the extra supplies and in order to balance the market, run cuts will be essential.

"European demand is at its lowest in 20 years and continuing to decline."

Europe is by far the worst impacted region. European demand is at its lowest in 20 years and continuing to decline. Europe's mismatch of diesel biased demand and gasoline biased simple refineries is well documented. European net imports of oil products were more than halved during the last decade, to just over 0.5 mb/d in total in 2011. However, the region's middle distillate imports averaged nearly 1 mb/d. A structural mismatch in demand and supply has meant that refineries have had to sell their surplus gasoline at discounted prices, with North America the largest buyer but also exports to Africa and Middle East on the rise. That is set to start changing from this year, given the vast capacity additions taking place in the Middle East itself. Moreover, Russia continues to upgrade its refineries, with the aim being to supply Europe with higher value products. However, this has significant effects on fuel oil balances, which are likely to become tighter due to lost supplies from both Russia and the Middle East.

European margins are not the only ones likely to come under pressure from the growth of Middle Eastern refineries; Asian refining, too, is likely to see a change in 2013, due to the type and location of capacity additions.

The Middle East is currently a large importer of products, particularly diesel, but once Saudi Arabia's 0.4 mb/d Jubail refinery becomes operational, those needs are likely to reduce towards the end of the year. Once the 0.4 mb/d Yanbu refinery comes online next year, Saudi Arabia is likely to be entirely self-sufficient, and may even develop a small surplus. Jubail alone is expected to increase Saudi diesel production capacity by around 0.176 mb/d, while Yanbu and the 0.4 mb/d Jazan refinery in 2017 are likely to take

Table 1: Refining Capacity Additions by Region, mb/d

	2013	2014	2015	Total
Africa	0.04	–	0.10	**0.14**
Asia	1.20	0.88	2.66	**7.30**
Europe	–	–	–	**–**
FSU	0.16	0.05	–	**0.21**
Middle East	0.45	0.80	–	**1.58**
Latin America	0.05	0.40	–	**0.45**
North America	–	0.03	–	**0.03**
Global	**1.89**	**2.16**	**2.76**	**9.71**

Source: Bloomberg, Company reports, Energy Aspects

total Saudi diesel capacity to over 0.45 mb/d, compared to current diesel demand which peaks in the summer months at just under 0.9 mb/d. Thus, Saudi Arabia is likely to become a net exporter of distillates over the next few years until domestic consumption catches up. Similarly, the addition of these refineries is likely to eliminate Saudi Arabia's need for gasoline imports starting in 2014, although for both products, we see Saudi remaining a small importer, on balance, this year.

Exports from the region will have serious implications for Indian refiners in particular. India currently exports between 0.4–0.55 mb/d (1.6–2.1 mt per month) of diesel, mostly to Europe and Africa. But with lower shipping costs to Europe, the Middle East is likely to provide stiff competition in the future. Already upgrades to existing refineries are allowing the region to produce low sulphur diesel. Abu Dhabi National Oil Company (ADNOC) is already planning to offer diesel with a sulphur content of 10 ppm for 2013 contracts, making it the first Gulf producer to export ultra-low sulphur diesel on a term basis. However, we believe that rising East African demand and lost exports from Japan still offer India some market outlets this year, as does India's ability to produce high-sulphur gasoil (for which there is high demand in Africa and Latin America), although competition is likely to get stiff as we head through this decade.

Even with the Asian region, other countries are adding significant capacity, including the 0.12 mb/d refinery in Pakistan and another 0.7 mb/d capacity addition in China, following similar additions last year. With Chinese refinery additions running ahead of domestic demand, China is turning into a small net exporter of products, and has become a small net exporter of diesel over the past few months. Meanwhile, the refinery addition in Pakistan is likely to reduce diesel imports requirements substantially. Thus, although we see diesel demand recovering to 3.5 percent this year following a rather weak 2012, we do not see Asian diesel prices supported beyond the period of refinery maintenance.

From H2 2013, therefore, product markets are likely to be in significant surplus, putting pressure on product prices and margins. The problem however is that despite weak margins, new refineries in non-OECD countries, more often than not supported by government subsidies, are likely to add to the glut in products. These refineries are being built to make the host countries self-sufficient in the product markets. The refineries span both traditional crude oil producers (Saudi Arabia, UAE, Brazil) and crude importers (China, India, Pakistan). Second, while the on-going pressure on margins and product prices in the past few years should ultimately lead to the closure of the least profitable refineries around the world (in other words those in Europe, especially in the Mediterranean), the problem is that currently margins are weakest in regions where refineries are unable to close down due to government pressure. With unemployment in countries like Italy, Spain and France already at historical highs, governments are strongly opposed to allowing closures of non-profitable refineries, since they tend to directly and indirectly support tens of thousands of jobs.

Thus, refining margins must decline further to levels where more competitive refineries in countries like the UK and USA are forced to shut down if the market is to be balanced. ■

Light and Heavy Crude Availability and the Challenge for Refiners

PETER STEWART and EHSAN UL-HAQ

The balance between light and heavy crude oil is important for refiners for three reasons: first, the light–heavy spread impacts on current upgrading capacity utilisation; second, the future course of the spread is a factor in determining the type and capacity of conversion units to build; and finally, the spread is relevant to which crude oil benchmarks will best represent the global crude mix in the future.

Quality specifications for petroleum products have tightened and the demand barrel has shifted relentlessly towards higher value lighter and lower sulphur oil products in recent years. This has forced refinery configurations to become ever more complex.

The growth in demand for light products looks set to continue; demand growth for gasoline and diesel is expected to grow rapidly as freight traffic and passenger vehicle fleets expand in high population emerging market countries.

These trends in demand, and the fact that nearly two-thirds of the world's oil reserves have been located in the Middle East, a region that traditionally has been the source of relatively heavy and higher sulphur crude, have favoured the building of deep conversion refineries in recent years. However, as the refining stock has become more sophisticated, the rise in oil prices to above $100/barrel has encouraged the large-scale development of unconventional crude oil resources that could never have been commercialised at lower prices. Because of this, the price spread between light and heavy crude oils has become a moving target.

Crude oils that produce higher yields of light products such as gasoline and diesel in a refinery are typically described as 'light' while those that make heavier products such as residual fuel oils and bitumen are described as 'heavy'. Unfortunately, in the real world, there is very little standardisation of terminology. Today, crude oils with an API gravity of more than 28–30 are typically seen as lighter grades. Twenty years ago, light crudes were typically considered as ones with an API above 34. Geographical variations also exist. For example, the Indonesian crude Minas is generally considered as heavy sweet in Asia in spite of having an API of around 34, as most grades in the region are lighter.

The balance of light versus heavy products in a crude oil is more precisely determined through the distillation curve of the crude oil. Based on this curve, the products can be split into groups from the lightest to the heaviest products, and this is used to determine the Gross Product Worth (GPW) of the crude oil.

Naphtha, gasoline, jet, diesel and gasoil are considered as lighter products while low-sulphur fuel oil (LSFO) and high-sulphur fuel oil (HSFO) are heavy parts of the barrel. Typically a five-cut yield is used based on the proportion of LPGs, naphthas, kerosenes, gasoils and fuel oils in the crude oil; however, four-, six- and seven-cut yields may also be used.

The density of a crude oil, typically measured by the API gravity, is often used as a simple proxy for the yield of different products in the crude oil, and therefore of whether a crude is light or heavy. As is well known, crude oils range from very heavy grades with an API of around 10 to light condensates with API gravities above 40.

The light–heavy spread is typically measured by comparing the price of pairs of 'benchmark' crude oils in the different geographical regions: for instance, Maya–WTI in the USA, Brent–Urals in Europe, Brent–Dubai in the Middle East, and Dubai–Tapis in Asia. However, because the value of each crude oil in such a pair may be affected by a multitude of factors other than the quality difference, such as infrastructure bottlenecks, these measures provide only a high-level snapshot of the relative value of light and heavy crude oil.

Conversion Capacity Utilisation

Recent trends have seen a rise in light crude production compared to heavy sour crude. This trend coincided with a wave of refinery building which came on stream in the period 2009–2013, most of which is deep conversion capacity such as coker-hydrocracker and residual fluid catalytic crackers which typically maximise value when the light–heavy spread is wide. Indeed, many of the decisions to build such units were taken in the years immediately after light–heavy spreads blew out in 2005 to unusually wide levels because of the shortage of upgrading capacity at the time.

Due to rising shale production in the USA, lighter crude supply in the Americas has increased at a faster pace than heavy crude production. Tight oil supplies have displaced significant volumes of light sweet crude oil that were traditionally imported from Nigeria and Algeria. As the volume of crude oil from sub-salt Brazil gradually ramps up, Angolan supplies also, which have typically headed transatlantic, are increasingly being directed into Asia.

As US shale production rises, there will be growing efforts to export these barrels and to get rid of the surplus mostly concentrated in the Midwest. At present, oil producers in the USA are not allowed to send oil to other countries. Many analysts believe that the Obama Administration might allow exports to some friendly countries. The United States is already delivering around 130,000 b/d of crude mostly to Canada while some of these barrels are being processed to refined products, which can be exported. There are also reports of this crude being put into different processing units to convert them into products, which can no longer be classified as crude oil. If allowed, exports of crude will put pressure on lighter crude in countries that acquire these barrels. This has the potential to narrow the light/heavy differential globally.

In Saudi Arabia, the balance between light and heavy crude available on the international market has changed as light streams have been marketed and heavier grades have been used domestically, either for direct-burning in power stations to meet soaring electricity demand, or to feed the kingdom's own refineries. The Manifa oilfield started up production recently and will increase heavy crude production from the region but a key part of this is being used to offset declining production at other fields in the kingdom.

As Saudi Arabia builds sophisticated new refineries at Jubail, Yanbu and Jizan, which are geared to using heavy feedstocks, and as it goes ahead with joint-venture downstream investments in countries such as China, which are also maximised by using poorer quality crude oils, the future availability of heavier feedstocks can no longer be considered as assured. Similar trends can be seen in other OPEC Gulf countries such as Kuwait which are planning to build sophisticated refineries capable of meeting ultra low sulphur specifications of diesel and gasoline that have become the norm in the developed countries because of environmental standards.

These trends have seen a narrowing of light–heavy spreads in recent years, albeit that these spreads are volatile and erratic. In 2005, the Urals–Brent spread widened to $8–9/barrel and the Brent–Dubai spread widened to as much as $14/barrel; in recent years, both spreads have been close to parity at times. The same trend is seen in WTI–Maya, although the latter spread has been distorted by the infrastructure bottlenecks besetting the US sweet crude benchmark.

Investment Trends

Looking forward, it is crucial for refiners to estimate the relative value of light and heavy crude oils in their investment decisions. A refinery that decides to spend billions of dollars on sophisticated and expensive conversion capacity in order to be able to process heavy crude oils will be at a competitive disadvantage if he finds that he can just as cheaply have bought light sweet crude oil to make the light products required. However, because the outright level of oil price is important in terms of which reserves are developed, there can be very little certainty as to which qualities of oil will preponderate in the crude oil slates of the future.

For instance, high oil prices would potentially favour the development of unconventional and ultra-heavy crude oils. Venezuelan heavy production has been hit hard in recent years due to the exodus of key management at the state oil company, PdVSA, with most estimates showing a drop of at least 1 mb/d since 1999. But Venezuela has the largest reserves of unconventional oil in the world – around 500 billion barrels estimated to be trapped in the Orinoco sands, which could be exploited if oil prices were high enough. If this great resource were to be exploited, the current tightness of heavy crude oil could be alleviated.

Similarly, Canada is also currently facing headwinds due to the lack of pipelines to the US Gulf Coast with its output from oil sands unlikely to grow significantly in the next few years from its present level of less than 2 mb/d. Even if prices remain at current levels of around $100/barrel for North Sea Brent a part of the future investment is likely to either be scrapped or delayed. This is likely to curtail heavy crude supply in the near future. Any big drop in oil prices to $50–60/barrel, however, would result in prices falling below the long-run marginal cost of oil sands, and would stop this resource being developed.

Meanwhile, North Sea oil production has been declining both in the UK and Norway, and much of this oil is light and

sweet in quality. Interesting here, however, is the kind of oil that can be developed under different price scenarios. For instance, the UK has abundant reserves of very heavy conventional oils that were explored in the 1970s and 1980s but were not developed because oil prices were too low – let's not forget that crude oil prices dropped below $10/barrel in 1986 and 1998.

In reality, the feedback loops of different levels of oil price in developing different types of resource are more subtle than this.

The high price scenario argues for ultra-heavy oil being developed, reducing the value of heavy crude oil relative to light grades, but it would also encourage development of gas in transport, shifting some of the demand for light products to non-liquid fuel. The high price scenario also would continue to favour development of tight oil and shale oil through fracking. These resources in the USA are typically light in quality. So what you could get is a dumb-bell crude slate, lots of light oil, lots of ultra-heavy oil, and a relatively tight middle of the barrel. In contrast, a low price scenario would favour the development of deep water conventional oils which have a range of different qualities but within narrower limits, while the unconventional resources at the very light and very heavy ends of the spectrum would be relatively tightened.

Benchmarks

These trends have a bearing on which – if any – of the oil benchmarks that are currently used to price oil will have longevity.

Currently, the most widely used crude oil benchmark is North Sea Dated Brent. In the past, this represented a single crude oil blend gathered from the Brent fields in the North Sea but, as production of Brent Blend itself has declined, the benchmark has morphed to reflect the lowest in value of a group of broadly similar crude oils produced from under the North Sea: initially, Forties and Oseberg and more recently Ekofisk were allowed for delivery as dated Brent, and it is likely that other grades will be allowed by the main Price Reporting Agency Platts in its price assessment process in the future. Platts dated Brent is widely referenced in oil and gas contracts around the world, increasingly, in Asia and Australia, but also in the west in Canada and Latin America. These countries are far outside the traditional range of geographies in which the North Sea crude oils have typically been refined.

Although Brent is dominant in international crude oil pricing, different geographical regions have different light and heavy benchmarks. In the absence of a typical heavy grade in Europe, Urals from Russia is typically compared with Brent to reflect the value of the sweet/sour differential. In the United States, WTI has lost some of its status as a sweet benchmark due to its land-locked delivery point, and Louisiana Light Sweet (LLS) is used as a physical light sweet marker. While Maya from Mexico is seen as a heavy benchmark in North America, many also use Western Canadian Select (WSC), although the latter faces similar problems as WTI in delivering to the Gulf Coast. In Asia, Malaysian crude Tapis has so far been the light sweet benchmark but its dwindling production and rising supply of the Russian grade ESPO is likely to change that. Dubai from the Middle East remains the key heavy benchmark in Asia in spite of its falling output with Oman also being used as a marker.

Whether these benchmarks remain representative depends to a large extent on which oil reserves are developed over time. There are many theories as to what conditions must be met for a grade of crude oil to become a benchmark. Among the key factors are 1) that the benchmark grade is representative of the crude oil quality that is typically used in a region and 2) that it reflects the value of the marginal barrel in the region.

At least in theory, the spot market is used in oil pricing because market value is determined by the marginal unit of production. In the old days, heavy oils from the Middle East and Russia formed the base load of a refiner's crude oil slate, while lighter grades from regions such as the North Sea and Africa were used at the margin to optimise the yield. So it was natural to use a light sweet oil such as Brent Blend to represent the 'marginal' barrel.

Whether this will be the case in a decade is up for grabs. Heavy and light crude oil reserves are not evenly distributed around the world. If more heavy oil is developed under certain price scenarios, the existing benchmarks may become less representative of the overall crude oil slate in a region. This is not necessarily a problem in itself, provided the benchmark still reflects the marginal barrel being used by refiners. But if the definition of the marginal barrel also changes, the existing benchmarks may become less relevant.

Europe Refining Landscape: Boom to Bust in 2013

CRAIG BROWN

On the heels of steep refinery rationalisation in the Atlantic Basin, 2012 was a year of significant rebound for Europe's ailing refining sector. Simple refining margins improved to 5-year highs supported by strong gasoline exports to the northeast United States and abrupt capacity shut-ins at home. The rebound continued strongly into 1Q 2013, with refinery crack spreads showing a further 24 percent quarter-on-quarter improvement on 2012 figures (Figure 1).

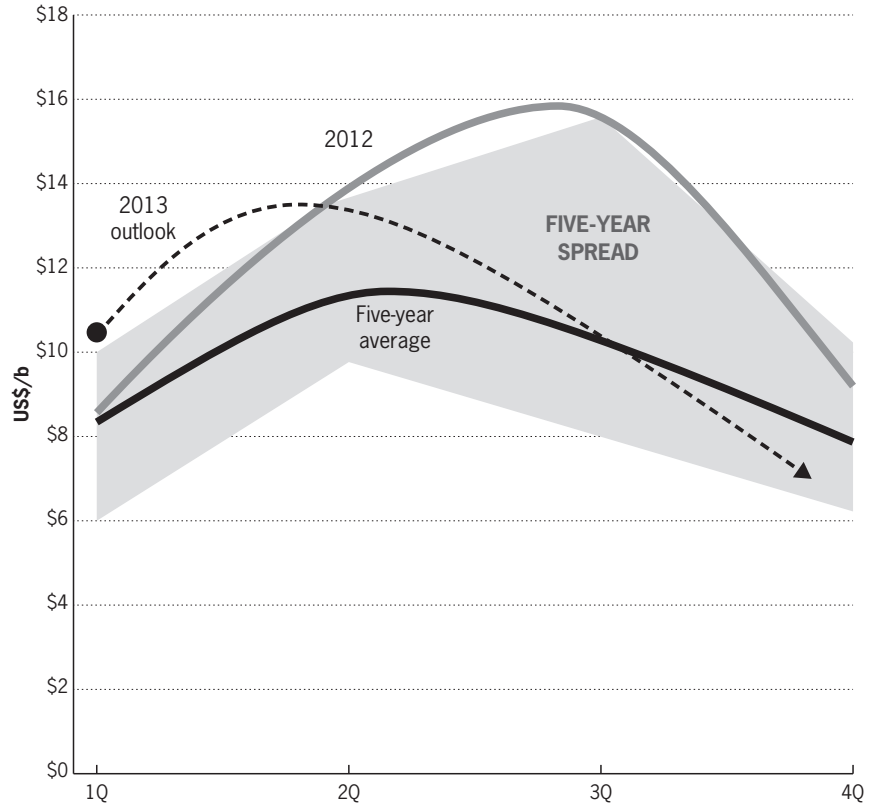
However, a number of structural factors that provided a brief respite to Europe's refining sector in 2012 will evaporate, eroding the atypically healthy margins enjoyed in 2012.

The restoration of capacity utilisation rates in the northeast United States' refining sector in 2H 2012, along with ongoing projects to debottleneck gasoline flows from the Gulf Coast refining complex to northeast product markets will gradually displace Europe's gasoline export opportunities through 2013. As refining conditions progressively deteriorate and margins retreat, another round of European capacity rationalisation looms on the horizon.

Atlantic Basin Refinery Shut-in provided a brief Respite in 2012

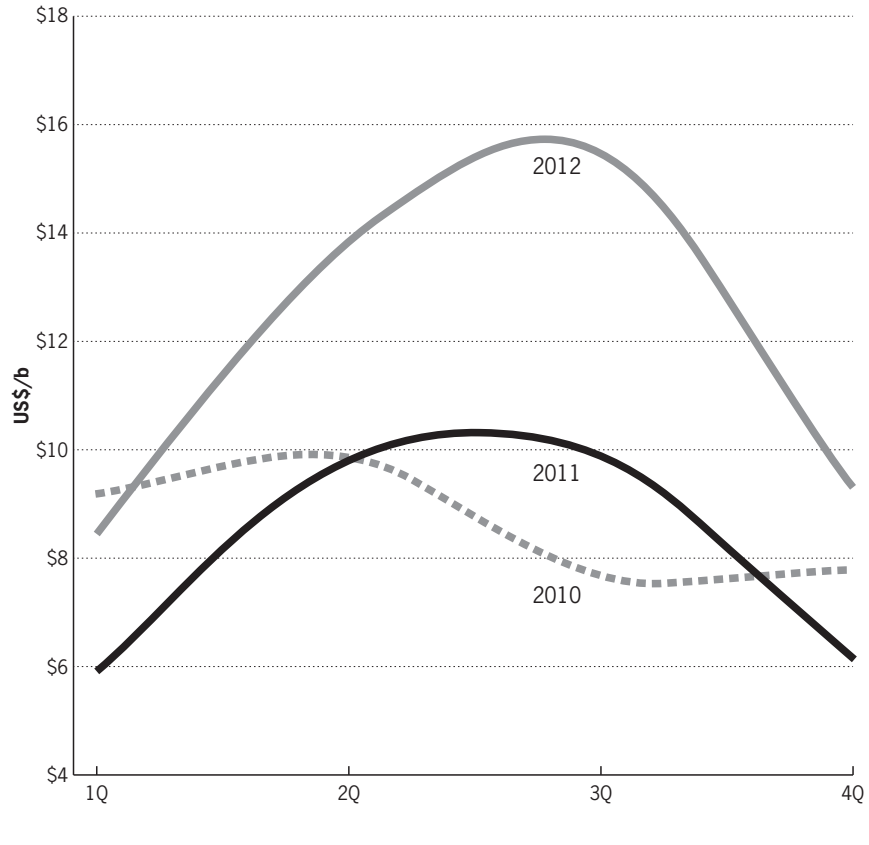
A total of 681 kb/d of capacity was shut-in

Figure 1: Five-year 3-2-1 crack spread comparison



Source: PFC Energy

Figure 2: Europe 3-2-1 crack spread comparison



Source: PFC Energy

across Europe over the course of 2012, with an additional 585 kb/d of capacity permanently removed from the US side of the Atlantic Basin. Capacity shut-ins were led by the abrupt idling of Petroplus's five refineries throughout Europe in early 2012, with three sites indefinitely idled and two sites only partially utilised from April 2012. While three of these sites would eventually be purchased and restarted within the year, the permanent closure of the UK's Coryton refinery and the prolonged idling of France's Petit Couronne rendered some 313 kb/d of capacity offline in Northwest Europe in 2012. Across the Atlantic, some 360 kb/d of capacity remained idled in the Northeast United States moving into 2012 (Trainer and Marcus Hook refineries), while the 350 kb/d Hovensa site and 235 kb/d Aruba site were permanently mothballed in February and April 2012. Although the 185 kb/d Trainer site would be restarted later in the year under the banner of Delta Airlines, 2012 saw some 1.4 mb/d of capacity idled or eliminated across Western Europe and the Atlantic Basin, providing abnormally strong support for European refining margins.

Refinery Margins see strong Recovery in 2012

On the heels of steep capacity rationalisation, 2012 became a year of recovery for European refining margins. Over 700 kb/d of shut-in and idled capacity in the US Atlantic Basin alone, combined with logistical bottlenecks between the US Gulf Coast refining complex and the northeast US product markets, supported high gasoline spot prices on the East Coast. Robust gasoline export opportunities and the ease in domestic refining overcapacity aligned to support relatively buoyant European refinery margins throughout 2012, with simple 3-2-1 crack spreads averaging $11.78/b in 2012 against $7.93/b in 2011 (Figure 2).

Favorable Scenario will be short-lived

Nevertheless, the confluence of factors lending support to European refining margins is poised to evaporate over the coming months. The restarting of idled capacity in the northeast United States in the second half of 2012 facilitated a sharp deterioration in simple margins for

"... improving capacity utilisation in the USA is poised to apply significant import competition to Europe's gasoil/ diesel markets."

EU refiners that was visible by 3Q 2012. While the announced closure of Hess's 70 kb/d Port Reading/New Jersey refinery in January 2013 provided temporary respite, a number of developments within the USA will gradually ease US gasoline imports going forward, eroding the export opportunities enjoyed by European refiners in 2012.

The restart of the 185 kb/d Trainer site in late-2012 will continue to cut into PADD 1 import volumes through 2013 and marginally offset the shut-in of the Port Reading site. Meanwhile, completion of a major refinery overhaul in Port Arthur, Texas and the 125 kb/d capacity expansion of Colonial pipeline capacity through 2013–14 (a main product conduit between the Gulf Coast refining complex and the US East Coast product market) will facilitate increasing USGC gasoline transfers to PADD 1, applying further downward pressure on European gasoline imports. Combined with the ongoing deterioration of demand in the US East Coast gasoline market, USEC net gasoline imports will continue to trend downward through 2013. Europe's gasoline exports to the USA could be even further depressed by US ethanol blending mandates in 2013, which will increase compliance costs for gasoline exports to the USA and further erode the favorable margin landscape enjoyed in 2012.

Meanwhile, improving capacity utilisation in the USA is poised to apply significant import competition to Europe's gasoil/diesel markets. Already under pressure from complex refineries in the Middle East and India, European refiners will increasingly find themselves at a competitive disadvantage to gasoil-exporting refineries in the United States benefiting from cheaper crude feedstock options and significantly lower priced natural gas to fuel their refineries. The confluence of these factors in the context of weakening gasoil demand across Europe (down -1.2 percent year-on-year in 2012) will put even more downward pressure on the domestic market landscape.

Further Refinery Rationalisation will be delayed

Despite the deteriorating conditions facing Europe's refining sector in 2013, however, refining capacity is likely to remain relatively static through the year. Temporary shut-ins in 2012 across Italy and France are expected to remain in place through 2013 and will likely persist into 2014 given the unfavorable market. In April it was announced that Petroplus's Petit Couronne site in France, offline since Q1 2012, had failed to find an acceptable buyer after successive bidding rounds, and the site will remain permanently offline. Moving into 2014, however, labour union agreements in France and Italy designed to buffer against further job losses will presumably delay additional rationalisation. While French labour union strikes advocated government intervention (even nationalisation) of Petit Couronne, they ultimately failed to save the facility, Europe's largest refiner Total (with some 1.8 mb/d of Europe-wide equity refining capacity) has publicly pledged no rationalisation before 2015, a move that will temporarily offset the potential wave of immediate closures looming in France. Italian oil giant ENI, on the other hand, has similarly agreed to labour union requests through at least end-2014, pledging no permanent closures over the next two years.

While the deteriorating refining environment exerts further downward pressure on Europe's refining margins, further refinery rationalisation is anticipated to be kept relatively at bay. Although various factors are offsetting permanent closures through 2013–14, the playing field will be open for steep rationalisation as labour union agreements expire in 2015. ■

Transition in the European Refining Sector: Strategies to meet present and future industry challenges from a Central European perspective

ALOIS VIRAG

The European refining industry faces a multiplicity of challenges. New legislation and growing global competition are squeezing margins. Operational and organisational efficiency will hold the key to success and survival for European refiners. Vertical integration with upstream operations and retail markets, as well as on-site horizontal integration between refineries and petrochemical plants are routes to greater resilience.

Current and future European legislative Framework

The current European legislative framework is driven by the 20-20-20 targets, i.e. a 20 percent reduction in greenhouse gases, a 20 percent renewable share, and a 20 percent increase in energy efficiency. These targets are reflected in the main directives relevant to energy-intensive industries such as refining, namely the:

- *Emissions Trading System Directive (ETS)*
- *Renewable Energy Directive (RED)*
- *Energy Efficiency Directive (EED)*

The Emissions Trading System is designed to reduce carbon emissions by creating an allowance market. The number of allowances is being progressively lowered under Phase III of the scheme, which runs until 2020, in order to meet the 20 percent target. A benchmark system for the free allocation of CO_2 certificates was introduced for oil refining in 2013. The benchmark is set by the best 10 percent of the refineries; certificates that are not allocated must be purchased on the open market unless this is obviated by carbon saving investments. The purpose of the free allocations is to avoid forcing refining to relocate to regions with less stringent carbon legislation, resulting in the import of carbon-intensive oil products into Europe.

Under the RED, the transport sector

is required to attain a 10 percent renewable share by 2020. In the case of road transport fuels this is to be achieved by blending fossil fuels with biofuels, but technical limitations and shortages of sustainable biomass make this a challenging objective. Proposed amendments to the RED would make compliance still harder to achieve. The RED would include a cap on conventional biofuels and an indirect land use change (ILUC) factor to address the sustainability of biomass. The former amendment would also have a major impact on the chances of hitting the *Fuel Quality Directive (FQD)* carbon reduction targets.

The EED goal is to increase end-use efficiency by 1.5 percent per year. Those responsible for meeting it are the energy suppliers. The derogations granted to EU Member States in transposing the EED will erode market harmonisation.

Another directive aimed directly at the oil industry is the *Fuel Quality Directive (FQD).* Following the 2009 amendments, the FQD now incorporates a carbon reduction target of 6 percent of fossil road fuels (base year 2010), with compliance to be achieved by blending biofuels. In addition, recent Commission proposals seek to achieve upstream emission reductions counting towards the 6 percent goal by distinguishing between conventional and unconventional crude sources through differential carbon intensity default values. In the absence of a political decision the Commission is currently performing an impact assessment on several carbon intensity differentiation methodologies, from crude-by-crude to EU averaging values. New proposals are expected to be unveiled during the summer.

Further legislation in the pipeline includes the *ETS Backloading and Clean Power for Transport* packages. The former would further shrink the number of CO_2 allowances so as to increase the cost of carbon, thereby stimulating carbon saving investment. The aim is to promote road transport decarbonisation by facilitating the development of electricity, compressed natural gas (CNG), liquefied natural gas (LNG), and – in the longer run – hydrogen infrastructure.

Besides the aforementioned legislation, oil demand is likely to be affected by other legislation including an *Energy Tax Directive (ETD)*, and *ETS in Aviation* and carbon targets for vehicles (including a 95 g/km target for cars).

Finally, the refining industry must also cope with a battery of clean production legislation including the *Industrial Emissions Directive (IED)*.

The Energy Roadmap 2050 plots the long-term perspective. This focuses on further improvements in energy efficiency, and decarbonisation of the economy by between 80 percent and 95 percent depending on the scenario adopted by the Commission. Working towards the decarbonisation target implies making electricity, generated mainly from renewables, the predominant energy form. The consequence would be a massive decline in oil demand. The outcome of the roadmap would be a primary energy share for oil of around 15 percent in 2050, compared to over one-third today.

The EU 20-20-20 targets, and the Energy Roadmap 2050 and Transport Roadmap, have set the scene for the current debate on *Europe's objectives for 2030*. A green paper was recently published on the subject.

Increased global Competition and its Triggers

The EU is a mature oil market with a fully developed capital base. Many of Europe's refineries are relatively small. Declining oil demand due to increased end-use efficiency and other factors will lead to low capacity utilisation, as seen in Southern Europe last year. Imports from the Middle East, the Indian subcontinent and North America are also piling on the pressure on Europe's refining industry. The export refineries have competitive advantages in terms of energy and feedstock costs, or economies of scale, or both. Fierce competition is expected over the next few decades, and numerous refinery closures would be likely even in the absence of the European legislative roadmap.

At the same time changes in the tax regimes of crude-exporting countries such as Russia are set to cause shifts in the composition of oil imports into Europe from crude towards refined products. Russian refineries are responding by expanding their conversion capacities – again adding to the difficulties of EU refiners. The petroleum exporters' move into refining and petrochemicals is a global trend.

Within Europe, energy costs recently reached almost 60 percent of total OPEX, and we expect further increases. This makes energy efficiency vital for the refining industry, but even if major gains are achieved Europe is unlikely to be able to hold its own on energy costs against the rest of the world, apart from Asia. Meanwhile plans to develop European shale gas and oil reserves have run into strong opposition which is likely to push them back far into the future.

The availability of exports to Europe, especially from energy and feedstock advantaged refineries, is having a major impact on refining margins, which are currently insufficient to fund investment in new or revamped capacity. Moreover, the narrowing heavy–light crude spread bodes ill for refining and marketing margins, and for investment in secondary processing capacity.

Recent trends in product sales and plant closures point to testing times ahead for the refining industry. Since the start of 2011 some 9 percent of European refining capacity has been closed down or mothballed.

Slower growth in the BRIC countries may also mean that the EU refining industry faces stronger headwinds. Products may be rerouted from these markets to other regions including Europe.

Implications for European Energy Supply Security

In the mature EU market existing legislation is already causing the substitution of oil by other primary energy sources.

- Natural gas is widely regarded as an enabler to the carbon free economy. The European roadmaps and alternative fuel package reflect this approach. If the European shale plays are eventually exploited the potential cost advantage of natural gas can accelerate the increase in its primary energy share.
- Coal is recovering because the combination of high oil prices and relatively low carbon costs has made it more attractive as an industrial energy source. The decarbonisation targets appear to be counterproductive. For instance, in Germany coal use grew last year.
- The renewable energy share is expected to rise, with wind, solar, and

hydro generation growing particularly fast. Renewable electricity is still dearer than power from fossil-fuelled thermal stations, but renewables are either mandated or subsidised.

Oil based energy forms are gradually disappearing from almost all end-use sectors except transport. Liquid energy forms will continue to play a major role in transport due to their high energy density and ease of use.

Heavy goods vehicles and aircraft are likely to remain mainly fuelled by oil for some time to come as hybridisation, electrification and natural gas still face significant technical obstacles.

This does not mean that all the liquid transport fuels needed will be refined in Europe. Large quantities of automotive diesel are already being drawn into Europe from Russia and the US Gulf Coast. The European refining industry is unable to meet the demand for diesel, and investment in new capacity in a contracting overall petroleum product market is unlikely to be an attractive proposition. Instead, swelling fuel imports will probably lead to still more refinery closures.

Europe will be forced to look for answers to the problem of dwindling refining capacity that address supply security and industrial competitiveness concerns at acceptable social and economic cost.

Liquid fuels and the refining industry are mainstays of European economic growth because of their role as sources of energy, petrochemical feedstock, process innovations, and employment.

Getting Things done to Survive

Put simply, the passport to survival in our industry is being better than the rest – but this has many sides.

Efficiency in everything is crucial to sustainable success in the refining business. Efficiencies leveraged by operational or organisational improvements can bring performance leadership, notably by pruning feedstock inputs and processing losses. Plant-wide optimisation, viewing the entire refinery as a single system, and investment decisions taken in the light of cost-benefit analyses of all sites will be essential. Organisational structures will need to be based on treating multiple sites as part of a single refinery network, permitting quick decisions drawing on the expertise of the entire operation.

Besides increased flexibility as a result of horizontal integration, vertical integration will be a key success factor. This means integrating the entire value chain from the wellhead to the consumer, opening the way for performance leadership.

A well run refining business can also be a platform for petrochemical integration, yielding high value added products – but only where this makes economic sense. A mix of horizontal and vertical integration is probably the best route to a resilient overall refining system. ■

Refinery Upgrades to Cause Dramatic Reduction in Russian Fuel Oil Exports

JAMES HENDERSON

The Russian refining system is the third largest in the world, ranking only behind the USA and China with approximately 275 mt of total capacity and 2011 throughput of 257 mt. However, despite this high output and capacity utilisation, the majority of Russia's refineries are of significantly lower quality than their global peers, with an average Nelson complexity index of just over 5 compared to a European average of 6.5 and a US average of 9.6. The fundamental reason for this difference is that all but one of the refineries in Russia were built during the Soviet era to service the USSR's enormous military and industrial complex, with more than 75 percent being constructed before 1970 and with a focus as much on producing fuel oil to power tanks and other military equipment as on producing light products for other transport needs. Power generation was also a major user of fuel oil in the Soviet era, with bunker fuel and demand from the railways accounting for the remainder of demand. As a result, by the end of the Soviet era approximately 45 percent of Russia's output of major oil products was accounted for by fuel oil, with 98 mt being produced in 1991.

The trends in Russia's refining sector during the 1990s mirrored the overall collapse in the country's oil industry, with product output falling by more than 40 percent between 1991 and 1998 in line with the country's economic decline. Almost no investment was made in upgrading refining capacity during this time, and therefore fuel oil output, although significantly reduced (to a low of 48 mt by 2000), continued to account for approximately 40 percent of the product mix. This continuing preponderance of lower quality products did not have a major impact on the economy, however, as the country's vehicle fleet continued to be relatively small and largely made up of Soviet-era vehicles using low-octane gasoline. The key problem was felt in the oil sector itself, where refinery utilisation fell to below 50 percent (and in some remoter refineries to much lower levels), meaning that the industry was running at a significant loss.

The economic problems for the refining industry were exacerbated in 1999 by the introduction of an export tax on oil products that was in line with the crude oil export tax introduced at the same time. The level of the tax was set on a relatively ad hoc basis until it was formalised in 2003 at 90 percent of the level of the crude export tax. This essentially meant that exports of fuel oil were very sub-optimal, given the lower price that they could generate compared to other oil products. This commercial issue for Russian refiners, combined with growing domestic demand for oil products as the Russian economy rebounded from the 1998/99 economic crisis, highlighted for the first time a growing problem of product imbalance in the sector. With the military and industrial complex in continuing decline and with the power sector increasingly switching to gas rather than fuel oil as its major fuel input, demand for fuel oil had also continued to fall, while at the same time demand for lighter products, in particular gasoline, had started to rise. Indeed, the biggest challenge was

meeting the demand for high octane gasoline, which was emphasised by the fact that Russia was exporting lower quality 92 Research Octane Number (RON) gasoline while importing higher RON products. Furthermore, given the lack of investment in the Russian refining system, every extra tonne of gasoline or other light product produced domestically necessitated the additional production of a tonne of fuel oil, for which there was a declining market. This fuel oil could not be sold domestically and had very marginal economics on the export market (where it ultimately had to be sold) due to the high export tax, leaving refiners with a dilemma – satisfy domestic demand for light products but generate poor returns on fuel oil exports, or reduce refinery throughput to lower the output of fuel oil but then fail to meet domestic demand for light products.

The debate between the oil industry and the Russian state over this issue lasted for two years, with the government making an initial concession to reduce the export tax on products to 65 percent of the crude oil levy in July 2004, before finally introducing a formal export duty scale for refined products based on the price of crude oil but offering significant discounts to the crude export tax. This change to the tax rules in favour of product exports was catalysed not only by the need to provide a more profitable outlet for Russian fuel oil but also by the intention of the Russian Administration to see the extra profits generated then re-invested in the upgrading of the country's refining system. From his earliest days in office President Putin had stated his desire to see Russia exporting less raw materials and more finished goods, and in the oil sector this was meant to be reflected in increased oil product sales as opposed to crude. A further implication of the lower product export tax was to reduce the pressure on domestic product prices, with light products now effectively being priced on an export netback basis. As a result a lower export tax meant a lower netback and a lower wholesale price in Russia.

"… all but one of the refineries in Russia were built during the Soviet era to service the USSR's enormous military and industrial complex …"

However, this change of affairs did not produce quite the impact that the Russian government had been expecting. The profitability of the Russian refining system certainly improved, and economic activity in the refining sector was therefore encouraged, with a particular impact on export sales but with benefits to the domestic fuel economy too. Refinery utilisation increased sharply from 72 percent in 2004 to a post-Soviet high of 93 percent in 2011 as Russian oil companies diverted as much crude oil as possible towards the lower tax environment enjoyed by product sales, with many of the major companies seeing close to 100 percent refinery utilisation in 2011. Unfortunately, one of the major failings of the new oil product tax regime was that, although oil companies were incentivised to produce more products and increase refinery activity, there was no real incentive to invest in upgrading capacity. Indeed the major commercial incentive over the period since 2004 has been to exploit the tax break to its fullest extent, and oil product exports rose from 71 mt in 2004 to around 130 mt in 2009–2011, with a particular emphasis on fuel oil exports. In contrast, although there were isolated examples of upgrading work being carried out, the overall complexity of Russia's refining sector remained remarkably stable. The average Nelson Complexity Index of a Russian refinery has only risen from 4.4 in 2004 to 5.1 in 2011, while the share of fuel oil as part of the output of major oil products has actually increased from 38 percent to 40 percent on the same timescale.

This lack of upgrading investment has been in direct contrast with the demands of the Russian domestic market, where a combination of increasing car ownership and an upgrading of the car fleet has led to a sharp increase in demand for higher quality oil products, in particular high octane gasoline. This trend is set to continue, as highlighted by LUKOIL CEO Vagit Alekperov in a recent strategy presentation, with vehicle ownership in Russia forecast to increase by 4 percent p.a. to 2021 while demand for gasoline is expected rise by 3.5 percent p.a. (the lower rate reflecting increasing vehicle efficiency), with premium gasoline accounting for the majority of this growth. In response to this situation, then Prime Minister Putin responded by temporarily increasing the gasoline export tax and more fundamentally calling a meeting of the leaders of Russia's major oil companies to discuss the strategic priorities for the country's refining industry.

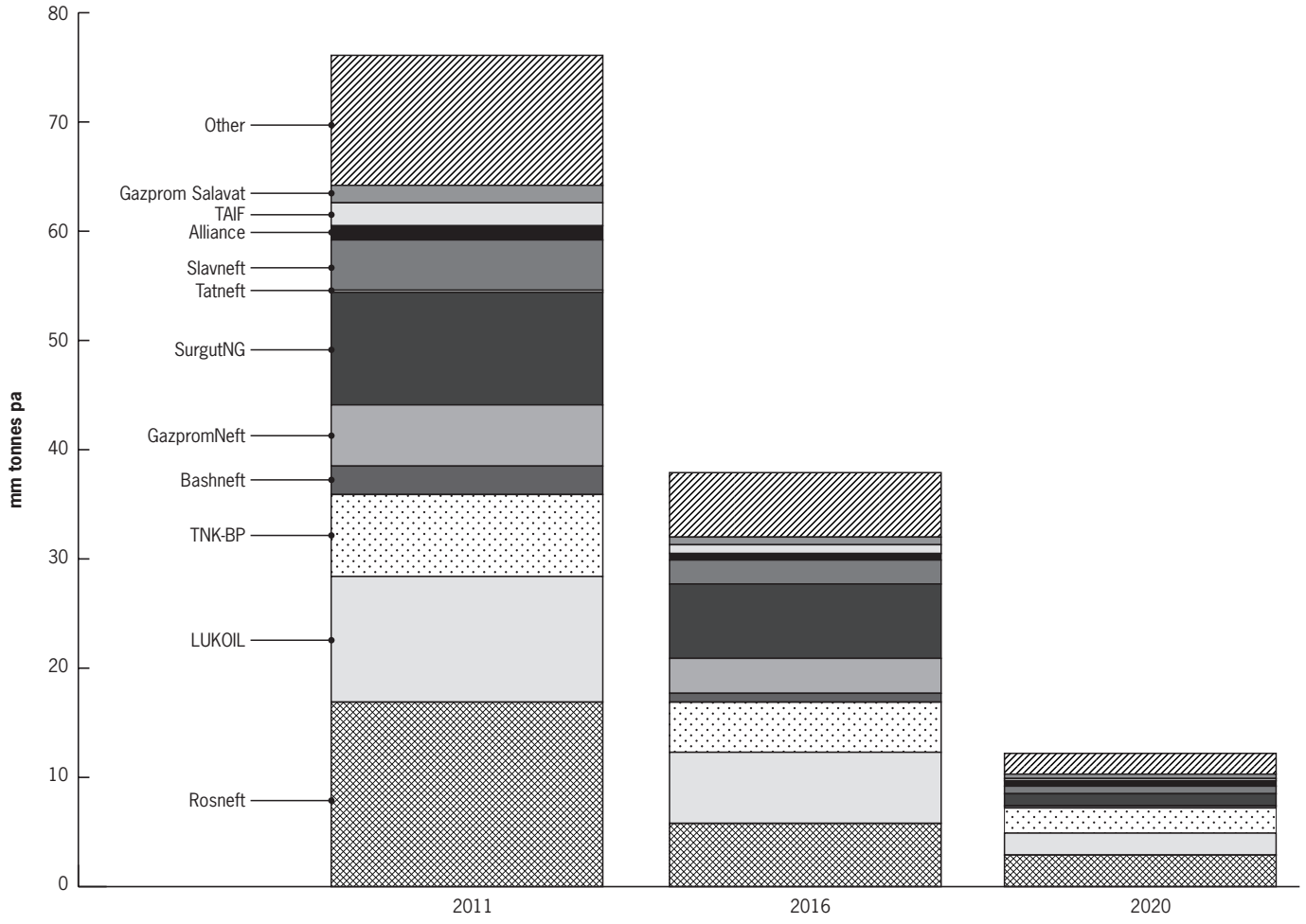
"… the Russian government has provided a clear fiscal incentive to encourage its domestic oil industry to upgrade the country's refining complex …"

This meeting, held in Kirishi near St Petersburg in July 2011, saw Putin express his dissatisfaction with the progress being made in the Russian refining sector and demand improvements catalysed by a further change in the tax regime. While the exact details of the commitments extracted from the companies have not been made public, Putin made clear that he wanted to see the implementation of the main targets of the Russian Energy Strategy to 2030 (published in 2009), which involved raising Russia's overall refining capacity to 285 mt, increasing overall refining depth from 72 to 85 percent by 2015 and decreasing fuel oil production by at least 17 percent.

In order to catalyse progress from the Russian oil companies, two spurs to action have been created. The first is an implicit threat that if the formal upgrading commitments are not met then the Federal Anti-Monopolies Service (FAS) will not allow oil companies to profit at the expense of Russian consumers, and will, in President Putin's words, 'respond with appropriate measures, including the appropriation of windfall profits'. A further incentive for oil companies to complete their refinery modernisation plans has been provided by the implementation of the new '60/66' tax regulation, which has increased the export tax on oil products while reducing the burden on crude oil exports.

Essentially the new rules, introduced in October 2011, have increased the export tax on fuel oil to 66 percent of the level of the crude export tax, have formalised the export tax on diesel at the same level and have increased the export tax on gasoline to 90 percent of the crude export tax. Furthermore, it has been proposed that the tax on fuel oil exports should

Figure 1: Forecast of Russian Fuel Oil Output by Company to 2020



Source: Company Data and Forecasts

rise gradually to a level of 90 percent, and perhaps even 100 percent, of the crude oil export tax by 2015, thus completely changing the commercial incentives for Russian refiners within four years. Under the new tax rules the export tax on fuel oil now accounts for 38 percent of the export price, underlining the incentive for Russian refiners to start to reduce their fuel oil output, especially as at lower oil prices there is a significant risk that product exports could now become unprofitable.

As a result of these tax changes the Deputy Head of the FAS Anatoly Golomolzin has noted, 'For the first time in many years Russian companies have begun to seriously attend to oil refining.' Although the exact timing of this investment is somewhat uncertain, being dependent on the development of government policy as well as the Russian product market, it nevertheless now seems inevitable that a significant upgrading of the Russian refining system will have occurred by the end of this decade. Indeed, the overall conclusion is that thanks to the improvements planned by all the Russian oil companies fuel oil output is set to decline sharply while production of gasoline, diesel and jet kerosene will increase to meet the changing needs of the Russian economy.

Figure 1 summarises just how dramatic the decline in Russian fuel oil production could be, showing an estimate based on individual company forecasts but adjusted in an attempt to reflect a likely outcome given the potential for delays and missed targets. Nevertheless, the overall conclusion is that fuel oil output could fall from 76 mt in 2011 to 38 mt in 2016 and to only 12 mt by 2020, with the potential for the latter number to be brought forward if all the companies meet their most aggressive targets.

This decline in fuel oil output will feed directly through to export sales, depending upon the trends in domestic demand. On the assumption that targets outlined in the Government's Energy Strategy are met it is possible to estimate Russian fuel oil demand of 9.5 mt in 2016 and 8.2 mt in 2020, down from around 12 mt in 2009. When these estimates are combined with the sharp anticipated fall in fuel oil production the impact on the potential decline in fuel oil exports becomes clear. Despite an estimated 5 mt fall in domestic demand by 2016, the current upgrading plans for Russia's refineries mean that supply could fall by more than 30 mt compared to 2009 levels (and more than 35 mt compared to the higher production in 2011), meaning that fuel oil exports could fall below 30 mt by 2016. These trends are then set to continue to 2020, with the gradual decline in domestic demand swamped by the continued fall in fuel oil output to an estimated 12 mt, meaning

that fuel oil exports could collapse to as low as 4 mt.

In short, the Russian government has provided a clear fiscal incentive to encourage its domestic oil industry to upgrade the country's refining complex and reduce fuel oil production. The key lever has been the export tax on fuel oil, which has already been increased by 71 percent and is set to rise further if plans to make it equivalent to the crude export tax by 2015 are implemented. At this point the economics of fuel oil exports would become very marginal at best, and would be likely to be loss-making, suggesting that the upgrading plans outlined above have strong economic rationale and that their implementation is very probable, if not guaranteed. If anything, this analysis has understated the potential for the fall in fuel oil production because it has taken into account the possibility of construction delays and uncertainty about the ability of all the Russian oil companies to implement their plans within such a short time period.

Furthermore, the potential exists for unintended consequences to undermine the speed of the overall shift in the shape of the refining industry in Russia. One example would be the concern expressed by a number of companies that if all the targeted increase in refinery complexity is achieved on the current timescale, there could well be a 4–7 mt gasoline surplus in Russia by 2016, a possibility confirmed by former Energy Minister Sergei Shmatko in April 2012 when he noted that gasoline consumption in 2015 could reach 39 mt compared with a targeted output of 44 mt. Clearly such an oversupply would not be attractive for Russian refiners, especially as the profitability of gasoline exports has been undermined by the new higher export tax, and this potential scenario could cause some companies to attempt to delay upgrading investment. A further complication could also be an excess production of diesel, of which Russia already has a surplus and where the export market in Europe would also be difficult. This would lead to the conclusion that, in tandem with Russia's refinery upgrading programme, a further drive to increase the domestic use of diesel-fuelled cars is also required, as highlighted by a recent study from the Skolkovo Energy Centre in Moscow. Nevertheless, the Russian government's firmly stated commitment to the regeneration of its country's refining industry and its determination to ensure that domestic demand for higher quality products is met would suggest that, although the exact timing of a reduction in fuel oil production may be unclear, a sharp decline in exports by 2016 seems inevitable, while by 2020 Russian fuel oil may have almost disappeared from global markets. ■

The Evolution of the Brent–WTI Price Differential

JOHN KINGSTON

The oil and gas production boom in the United States tends to assume a smooth-flowing infrastructure that in a few years will seamlessly deliver the country's growing hydrocarbon wealth to world markets. However, the investment needed to deliver that infrastructure will be enormous. Craig Pirrong, a professor at the University of Houston who specialises in markets and who has taken particular interest in petroleum, spoke at a Platts conference in early 2012 and tried to estimate what the value of that investment would be.

To do this, he took the prevailing Brent–WTI spread both at present and several years out the curve, where it was much narrower, and then looked at the two big projects planned to drain the US Midwest crude glut and ship some of it to the Gulf Coast: the Keystone XL Pipeline and the reversal of the Seaway Pipeline. Simplifying his methodology somewhat, he took the number of barrels planned by the reversals, ran a formula with those barrels and the Brent–WTI spread out along the curve, and calculated that the planned investments were worth approximately $10 million per day.

About a year later, he updated his numbers. Given the increase in the number of projects on the drawing board since that time, one might assume that the per diem figure would decline. It didn't. The growth in the spread of the Brent–WTI spread, despite the reversal of Seaway having begun in the interim, had blown out to $17.82 million per day ($6.5 billion per annum).

As he said in his blog: 'Big numbers' (http://www.cmegroup.com/education/files/craig-pirrong-2013-02-13.pdf):

> *'It is possible to calculate a similar number for pipeline capacity going into the U.S. Midcontinent. EIA reports that 1.19 million barrels a day of capacity from Canada to the Midcontinent is planned. Western Canadian Select quotes are available via CME only through February 2015 and are under –$20 a barrel for the entire two-year period: the nearby number is –$26 a barrel. I'll make a guess as to what the spread should be once the transport bottleneck is eliminated (because there are quality differences, and the distances are substantial, I don't know off the top what that should be). My guess is $5 a barrel. That gives us (.5) ($26+$5) (1.19mm) – ($5) (1.19mm), which equals $12.5 million a day. That number swings (.5) (1.19mm) for every dollar change in my guess.'*

They had become bigger because in early 2012, when Pirrong had made his first estimate, the spread between WTI and the Platts dated Brent assessment tracked near $10–$12. A year later, when the first barrels of the Seaway reversal were a mere drip compared to the one-year surge in US production and the fact that a lot of it was parked in Cushing, Oklahoma, finding it tough to find a home, that spread had blown out to the $20 level. (By late April, at the time of this writing, it had taken a drop down toward the $10 or less level, tightening as Seaway ramped up further and the surge in rail transport of crude, which by earlier this year was hauling close to 60 percent of all North Dakota crude output of 700,000 b/d, with takeaway capacity approaching 1 mb/d.)

It isn't clear whether the many companies that have planned significant capital projects to move US crude ran the same numbers as Pirrong, but they certainly

acted that way. Pirrong's two big projects in his 2012 calculations – Keystone XL and Seaway – have lots of company, which have been assumed by Pirrong in his early 2013 calculations.

- There's the Enbridge-Energy Transfer Partners' plan to take the giant south-to-north Trunkline natural gas pipeline and convert part of it to shipping crude in the opposite direction from Illinois to the eastern Gulf of Mexico. Its crude supply will come off Enbridge's existing line from Canada, and its capacity could be as high as 660,000 b/d.
- Another big project that won't even touch the USA but could divert significant amounts of Canadian crude from the glutted Midwest would be TransCanada's project to switch yet another natural gas pipeline – its need all but eliminated by the surge in output from the Marcellus Shale in the US Northeast – to shipping crude. That line runs from Alberta to Quebec, and TransCanada also plans to build an additional 870-mile line from Montreal, to New Brunswick in the Canadian Maritimes. Estimated capacity is 850,000 b/d.
- Then there are the projects that await the decision by the US State Department on whether to allow that portion of the Keystone XL pipeline that crosses the US–Canadian border to be built. (The portion between the NYMEX hub of Cushing, Oklahoma and Nederland, Texas, near Houston, is expected to be completed late in 2013, with capacity that could exceed 800,000 b/d). The Capline that sits woefully underutilised between the US Gulf and the Chicago area could be reversed. There are consultant reports suggesting a pipeline from the oil sands to the Canadian shores of Lake Superior, feeding a fleet of smaller tankers that could move oil around the Great Lakes and what one analyst estimated is 2 mb/d of refining capacity on or near the lakes' shores.

That's the thing about the booming US oil supply scenario: you can float an idea about moving oil from where it's plentiful to where it's needed, and almost anything seems possible. The explosion in rail traffic alone would have been inconceivable 4–5 years ago.

But once the supply gets out of the glutted areas and into the 'short' regions, that's where the US oil boom could begin to have an impact beyond the realignment of crude and some product shifts that already have occurred. For example, while rail has started to move Bakken crude to the beleaguered East Coast refinery sector, which underwent a wave of closings just a few years ago, a more permanent pipeline solution will probably be necessary for its long-term success. If all the pipeline projects discussed here come to fruition and the Brent–WTI spread gets down in the low single digits, the economics of rail may still work for some places, but they aren't going to work everywhere.

So, for example, one scenario sees the Enbridge plan to reverse its so-called Line 9 to take crude up from Chicago into the Montreal region as a possible first step toward also reversing the Portland Pipeline, which could then take crude off Line 9 to the US Atlantic coast port of Portland, Maine. From there, shipments to the East Coast by Jones Act tanker or ocean-going barge could give those East Coast refineries the steady supply of crude not priced off the Brent benchmark they will need to compete in the Atlantic Basin market. And then they suddenly become a revived competitor to Europe's industry, which already can generously be referred to as 'beleaguered'.

California also may be able to take advantage of the boom. While Bakken crude has mostly skipped the California refining sector, rail transport of it has made an impact in the refineries around Puget Sound in the state of Washington. But Bakken isn't the only booming production area in the country; the once-declining Permian Basin has surged as well, taking crude production in Texas that was less than 1.1 mb/d in 2004–2005 to more than 2.2 mb/d by the start of this year.

So with that in mind, Kinder Morgan is considering a plan to convert a portion of its El Paso Natural Gas pipeline system to take crude from the Permian Basin to southern California, a possibility that was raised by the company's president, Richard Kinder, in an earnings call earlier this year. He projected that maybe 300,000 to 400,000 b/d of crude would move if the project became reality.

US imports of crude oil into PADD 5 – the US West Coast – remains the one supply line of the country that hasn't seen a significant plunge, because the output surge in North Dakota and Texas, as well as other places, has no easy way to get there. Total crude imports into PADD 5 were solidly above 1 mb/d through 2012, not far off from historical averages. A pipeline from the Permian Basin to the Golden State would change that.

The totality of the shifts in the US import position were probably most stark when EIA monthly data came out in late February, on its usual two-month lag, for December US production, imports and exports. It showed that US net imports of crude and products had fallen to 5.987 mb/d, the first time they'd been under 6 mb/d since early 1991, and a staggering drop of about 7.3 mb/d from the all-time high in October 2005 of 13.354 mb/d. (Subsequent months after December showed an increase, proving if nothing else that upward and downward trends may be firmly in place, but the lines do have bumps).

And what happens to the NYMEX crude benchmark at Cushing in the midst of all this activity? It isn't fair to say any longer that it's completely landlocked; the reversal of the Seaway pipeline jumped to a capacity of 400,000 b/d in early January. Still, that's a drop in the bucket compared to the crude stocks at Cushing in excess of 50 million barrels, a number that would be a lot higher if not for the rail explosion.

But a new facility near Houston could be lining up to be the industry's next significant benchmark: ECHO. ECHO doesn't have a lot of storage, but it's at the crossroads of the new American crude oil picture. In fact, its initial storage was only 750,000 barrels. What it does have though is a direct tie to the rising output of the Eagle Ford crude in south Texas, plus a spur from the Seaway line, so barrels from Cushing can get into ECHO. So right there, you've got two key supply sources into that terminal, both of them light sweet crudes. Additionally, two planned projects that will take Permian crude away from Cushing and straight to the Gulf – Sunoco Logistics Partners' Permian Express Pipeline and Magellan's Longhorn reversal pipeline project – add more supply potential to the crude being stored at ECHO, or at least the highway to Gulf Coast refineries that runs through ECHO.

Should there be adequate takeaway capacity from Cushing on pipelines with fixed pipeline tariffs, that ECHO-Cushing spread – which would reflect the value of a new hybrid Gulf Coast light that would be distinct from the mishmash of light crudes that is still called WTI at Cushing – could become a new benchmark.

Toss in the possibility of the USA becoming a crude exporter – and the legalities of that are still to be resolved – and maybe the Gulf Coast market will start to claw back some of the benchmark status it has lost to Brent.

Craig Pirrong said much the same thing in his speech to the Platts conference last year. Looking at the fact that the WTI benchmark was bedeviled by the lack of takeaway capacity – but with economics that put up big dollar signs in front of those who might develop it – but also noting that Brent was suffering from declining North Sea output, he asked rhetorically: What is it easier to build.... North Sea production capacity, or North American pipeline capacity?

Given the projects on the board that already have impacted the market, and will do so in the future, the answer is fairly clear. ■

Get Cracking: The Resurgence of US Petrochemicals

RICHARD MALLINSON

Along with rising oil and gas output, the US shale boom has led to Natural Gas Liquids production rising from an average of 1.72 mb/d in 2005 to over 2.45 mb/d in February 2013. This has resulted in sharply lower NGL prices, benefiting the parts of the US chemical industry that use NGL feedstocks and prompting discussion of a 'petrochemical renaissance' in the United States.

Ethane and propane prices have seen the most significant price falls amongst NGLs. While low NGL product prices are weighing on producer profits, they mean lower petrochemical feedstock prices, creating very attractive margins for steam crackers and leading to high utilisation rates. The benefits of these low ethane and propane prices are particularly visible in terms of international competitiveness. Feedstock comes either in the form of ethane/propane or the heavier refinery-produced naphtha. In Europe and Asia, naphtha is the primary feedstock, which has long put these regions at a disadvantage to the Middle Eastern crackers that have had cheap ethane for a decade, because naphtha sits on the highest end of the feedstock cost curve. The fall in US NGL prices is now also giving American petrochemical manufacturers a significant price advantage over European and Asian plants.

Intent on capturing the 'ethane advantage', petrochemical companies have announced a string of expansions to existing ethane crackers and plans for large- scale new plants to come into service in 2016 and 2017. To give a sense of the scale of the potential revival of US petrochemicals manufacturing, total US ethane-fed ethylene capacity in 2012 was around 18.6 million tonnes per year (mt/y), and the proposed projects could add 9.9 mt/y of additional capacity by 2018. Although it is highly unlikely every one of the new projects would go ahead, particularly as a large ethane cracker costs some $4–5 billion, US ethane demand is definitely set to rise over the next five years.

Will Mont Belvieu stay balanced?

Increasing ethane demand prompts a question of whether US NGL production growth will keep pace and, more specifically, whether supplies of ethane at Mont Belvieu, Texas will be sufficient. Mont Belvieu is the principal pricing point for the very geographically concentrated US ethane industry, with over 95 percent of steam cracker capacity nearby on the Gulf coast. Total ethane supply averaged above 1 mb/d over 2012, with an expanding network of pipelines transporting NGLs from various shale plays to the Gulf Coast. The comfortably supplied Mont Belvieu market is behind most of the falls in ethane prices.

Lower ethane prices are negatively impacting the return producers and gas processors receive from NGLs. However, prices of heavier NGLs have fared somewhat better, largely protecting the economics of NGL extraction, and therefore we have not seen widespread production cutbacks. This is crucial in understanding why overall NGL production growth has not slowed yet. As long as there is a bid for heavier NGLs, producers are likely to keep increasing output, which is buoying ethane supplies. NGL production growth is predicted to average 7 percent per year over the next five years, slightly slower than the pace of recent years, with annual ethane production growth of 6.5 percent, taking Gulf Coast ethane supplies to around 1.46 mb/d by 2018. The lower growth rate for ethane reflects that at low prices, producers are motivated to 'reject' ethane into the natural gas stream rather than separating it along with other NGLs.

On the demand side, current plant expansions and de-bottlenecking projects will add around 1.4 mt/y of ethylene capacity between 2013 and 2015, equal to around 75 kb/d of added ethane demand. Up to six large new steam crackers are proposed to come online in 2016 and 2017, such as Dow's 1.5 mt/y plant in Freeport, Texas and the 1.5 mt/y Exxon-Mobil facility at Baytown, Texas. If all six projects went ahead, they would add more than 8.5 mt/y of ethane cracker capacity by the end of 2017, with 7 mt/y of the proposed additional capacity on the Gulf Coast (the exception is Shell's proposed 1.5 mt/y cracker in Pennsylvania). The cumulative result would be a rise in Gulf Coast ethane demand to around 1.5 mb/d by 2018, although as it is unlikely all six projects will go ahead, the actual growth in demand might be lower.

Comparing the growth of ethane supply and ethane demand, Mont Belvieu looks set to remain well supplied through to 2016, meaning ethane prices are likely to remain low. However, if most or all of the larger capacity new steam cracker projects go ahead and open by 2017, then the rapid increase in demand could result in a tightening of the ethane market for several years, before the continued growth in production brings the market back into surplus around 2019. While a tightening ethane market would send

price signals that should lead to increased production, there would inevitably be a lag in this response, meaning we could well see short-term rises in ethane prices around the time large new ethane crackers begin operating. For chemical firms currently deciding whether to make multi-billion dollar investments in new plants, determining whether any tightness in the ethane market would be short-lived or long-term is critical, as the economics of their projects are founded on low feedstock prices along with the benefits of cheap natural gas to fuel the new plants.

Could LNG Exports threaten the Chemical Renaissance?

As NGL volumes are likely to continue increasing in the coming years and pipeline infrastructure is coming online to transport ever greater volumes to the Gulf Coast, the petrochemicals industry expects to remain well supplied and see ethane prices capped. However, the industry has been increasingly vocal about a development that they believe would pose a serious threat to the petrochemical renaissance – large-scale LNG exports. On the back of the growth in shale gas production, the US government is inching towards approving a series of projects to export LNG to countries beyond the small number that have a Free Trade Agreement with the USA. One project – Cheniere's Sabine Pass terminal – has received approval, with 15 more applications currently awaiting decisions.

The prospect of LNG exports has created significant political debate in the United States. In early 2013 the Department of Energy released a study by NERA consulting; this suggested that allowing exports would have only limited impact on US gas prices. Opponents of LNG exports rushed to respond publicly and to lobby Congress. Dow Chemicals and other US chemical manufacturers have been at the forefront of the coalition criticising export proposals, because they see a risk of LNG exports driving up domestic prices and thereby eroding their current price advantage. For parts of the chemical industry the risk is very clear. For instance, ammonia and methanol manufacturing processes both use natural gas as a feedstock and a fuel and have been benefiting from the low US gas prices. If natural gas prices had been $1 higher in 2012, it would have added $356 million in feedstock and fuel costs for these two parts of the chemical industry.

"LNG exports could represent an unexpected threat to the petrochemical industry, which is benefiting from low US ethane prices."

Yet, a key argument deployed by opponents of LNG exports hones in on the revival in US ethylene production and the substantial investment being made in ethane crackers, along with the jobs these investments will generate, rather than focusing on the broader chemical industry. The link from LNG to NGLs is less immediately apparent. However, a closer examination confirms that LNG exports could have implications for ethane balances as well.

The reason is that natural gas is not pure methane; it also contains a small percentage of ethane and other hydrocarbons. In the USA, pipeline specifications keep the proportion of ethane around 2–5 percent, but in Europe and Asia the Btu specifications are higher and can equate to ethane content around 8 percent. That could be significant for LNG exports. The higher specifications might either be met by mixing more ethane in at terminals in the USA before the gas is liquefied, or by adding LPG to the gas stream after delivery and regasification. If the former approach were used by a number of LNG exporters, it could result in further tightening of ethane balances, particularly as many of these terminals are scheduled to start operating in 2017/18, just when balances already look set to tighten. Thus, LNG exports could represent an unexpected threat to the petrochemical industry, which is benefiting from low US ethane prices.

All of this has created a challenge for policy-makers who are considering LNG export applications. They must decide whether, and at what level, LNG exports would damage the resurgent US chemical industry. They are currently taking a slow and cautious approach, while trying to determine if a 'sweet spot' can be found with both LNG exports and an expanding chemical industry. This is likely to see a small number of the strongest export terminal applications approved and, when these become operational, close monitoring of the impact on domestic gas prices and investment by US chemical manufacturers, part of which will depend on the prospects for Mont Belvieu ethane balances. ■

The Impact of Biofuels Policy on Crude Oil Refineries

STEPHEN GEORGE

Since 2009, oil refiners in the Atlantic Basin have shuttered more than 3.4 million barrels of daily refining capacity in response to the region's declining oil demand. While much of this demand decline has been driven by recession and is unlikely to return anytime soon, a significant part of it can be attributed to the rising supply of biofuels. Government mandates are ensuring a rising demand for biofuels in the face of declining absolute fuel demand, with Atlantic Basin refiners caught in the balance.

Oil refiners and biofuels producers have been strange bedfellows now for the best part of a decade. The two industries have established an awkward coexistence, where conventional fuels production has been obliged to accommodate increasing volumes of renewable biofuels – principally bioethanol and biodiesel made from maize, soya and rapeseed methyl esters. Global biofuels demand has risen from around 500,000 b/d in 2004 to around 2.3 mb/d at 2013, and is expected to rise to around 3.5 mb/d by the close of this decade. The vast majority of this product is being supplied in the Atlantic Basin – Europe, North America and South America.

Viewed from the energy markets of

"Oil refiners and biofuels producers have been strange bedfellows now for the best part of a decade."

2006, biofuels were seen as an important alternative source of transport fuel supply at a time when demand was growing at a pace that threatened conventional supply lines – both for crude oil production and refining capacity. However, the world is a very different place in 2013, with global demand curtailed by economic stagnation in the more industrialised countries and new sources of oil and gas coming to market so quickly that OPEC producers are cutting production in an effort to sustain oil prices above $100 per barrel.

Biofuels policies were largely formulated ahead of the economic downturn, leaving the markets to cope with rising mandate-driven demand for biofuels while refiners are facing severe margin pressure from declining fuels demand, a rising regulatory burden and increasing overcapacity, especially in Europe and North America. Refiners' responses to rising biofuels supplies vary by market, largely in response to the structure of mandates.

Three Main Markets

The three largest markets for biofuels are Brazil, the United States and the European Union. Each market has a different mandate structure in place, where the particular market requirements of each govern how refiners respond.

Brazil

Brazil's market is the most straightforward, and the longest established, though there is some variability in the blending of bioethanol into the gasoline pool depending on the sugarcane harvest. Brazil's refiners also benefit from the country being a net importer both of gasoline and diesel, which means that its refiners are not highly pressured by their coexistence with the sugarcane ethanol industry that supplies 20–25 percent of their total gasoline pool as well as a fairly large hydrous ethanol supply to a car fleet that runs on ethanol rather than gasoline and an export stream of ethanol to the US and European markets.

Brazil's ethanol industry has roots back to the 1970s, when Brazil sought a measure of energy self-sufficiency in an era long before the discovery of vast quantities of crude oil in the offshore 'pre-salt' reserves. These reserves will ensure Brazil abundant supplies of conventional crude oil, though the commercialisation of this oil is taking far longer than either the government or the state oil company, Petrobras, anticipated.

With Brazil's economy and oil demand growing strongly, its refiners can essentially run without constraints on their supply to the domestic market. At the same time, the gasoline pool is capped at 25 percent ethanol maximum at present, which is obliging Brazil to import marginal conventional gasoline to meet domestic gasoline demand, even as it continues to produce more ethanol than it currently needs. Because they have grown up with a strong ethanol industry, Brazil's refiners are not well equipped with processing technology to produce gasoline to formulations used in other major markets.

Brazil also is encouraging rising production of biodiesel from its abundant soya crop grown in the south of the country. The blending policy provides incentives for blending domestic biodiesel, but does not support the import of biodiesel. Again, because Brazil is a net diesel importer, marginal supply does not impact on the country's refineries, which are making as much diesel as they can at present.

Brazil's products markets are growing, but planned new refinery additions are slowing as Petrobras concentrates its efforts upstream. This will lead to increased product import requirements in the medium term, but it makes real economic sense for Brazil's refining capacity not to outpace significantly its growing domestic demand.

United States

The US market is the most dynamic of the big three biofuels markets, and also the most problematic from the point of view of its refiners. The US mandate for biofuels blending is based on an absolute annual volume regardless of domestic demand. This mandate was established when US gasoline demand was strong and expected to continue rising above 10 mb/d. Instead, mandates have continued to push up the volume of ethanol required in the gasoline pool to 1 mb/d in 2013 while gasoline demand has fallen back to around 9 mb/d. This has forced the US gasoline pool to hit the so-called 'blendwall', where no more ethanol can enter the pool as conventional E10 gasoline (10 percent ethanol) due to volumetric constraints on the gasoline specification.

We are only now starting to see the impact of the blendwall as US refiners and blenders scramble to acquire enough Renewable Identification Numbers (RINs) to prove to the government that they have complied with US regulations. Prices for RINs have been soaring as both physical and financial players anticipate the coming inability to blend sufficient ethanol into the existing gasoline pool. Refiners may be obliged to pay a penalty for their inability to meet mandated volumes.

This problem is made worse by US regulation forcing up blending volumes year-on-year despite the US automotive fleet being incapable of taking more renewable fuel. The most recently published statistics (from 2011) show the total volume of alternative fuels being used at around 30,000 b/d. Of this, only about 25 percent is the high ethanol blend E85. Most of the alternative-fuelled fleet is powered by natural gas and propane. Only around 1 percent of the US car fleet is capable of burning E85.

US refiners strongly object to the current trajectory of the biofuels mandate. They point out that every gallon of ethanol competes one-for-one with a gallon of conventional gasoline. Refining utilisation has been dampened in the aftermath of the economic downturn, though it is showing some signs of strength of late, especially where refiners can access cheaper inland domestic crude oil linked to the price of West Texas Intermediate (WTI), the benchmark inland grade.

Refiners also object to the economic skew introduced by mandates. They welcome ethanol to compete with gasoline on a level playing field, while pointing out that the mandates will lead to market imbalances and price distortions such as those experienced in February, dubbed "RINsanity", when RIN prices soared and pushed up pump prices in response. The RIN situation could reach a breaking point later this year or early next year when refiners may no longer be able to deliver fuel that meets the US Renewable

Fuels Standard (RFS).

Finally, US refiners note with some justification that the RFS is not fit for its original purpose of providing 'Energy Independence and Security', as most marginal ethanol now needs to be imported from Brazil while US domestic production of conventional fuels is rising with the supply of tight oil crudes such as Bakken and Eagle Ford from US sources. The USA, they argue, is sorting out its own energy future in a market-efficient way and no longer needs more market-distorting ethanol. Domestic ethanol from maize consumed nearly 40 percent of the entire US crop. It is no longer really credible to suggest that biofuels are not having a distorting impact on food prices globally.

The US biodiesel industry has started from a much smaller base than ethanol. Current mandates for biodiesel are still only around 80,000 b/d (compared with 1 mb/d for ethanol), and much of this is presently being supplied from waste streams – animal fats and used cooking oil. US refiners have been more willing to work with these streams, as conventional refining hydroprocessing technology can be adapted to produce a drop-in replacement for diesel fuel. However, the potential to grow this stream is limited by the volume of available feedstocks – the US is already importing waste fats from Europe and other markets, such are the market forces at work to supply biodiesel RINs. As with imports of Brazilian ethanol, sometimes the US biofuels policy creates unintended consequences that are far outside the supply security expectations of its original framers.

Europe

Biofuels policy in the EU-27 countries is driven by common standards imposed by the Renewables Directive of 2009. This piece of legislation drew together strands of previous policies into a single more integrated framework aimed at increasing the renewables content of all EU energy. While different countries have different overall targets, all will adopt a common standard to incorporate 10 percent (by energetic content) renewables into their transport fuel supply. Countries have some leeway in defining how they will achieve these targets, but most countries' action plans are similar in requiring nearly equal 10 percent contributions for both gasoline and diesel streams.

The energetic content requirement is important, and wise. Unlike the US policy, Europe's biofuels requirement will scale with demand, so as demand has dropped across the EU in the wake of the economic crisis, total biofuels requirements have also dropped. However, it also imposes one important technical challenge on the region's refiners and blenders – ethanol and other oxygenated fuels (such as the ethers MTBE and ETBE) contain far less energy than conventional fuels. So a 10-percent energy requirement requires more like 15 percent by volume in the gasoline pool.

Another important challenge for EU biofuels policy is the sustainability requirement of the enabling legislation. Suppliers will have to demonstrate that biofuels both lower net CO_2 emissions by a significant level, and that they are not causing 'land use change', whether indirect or direct. This latter point is key, because it is hard to argue that growing crops for fuel does not necessitate the use of other land for food production, and the effects are most certainly indirect and therefore impossible to measure accurately.

Europe's refiners have taken a cautious view to biofuels uptake. For one, Europe's policies are less demanding than the US counterpart at only 10 percent of the demand barrel (US policy is closer to 20 percent by 2022, if fully implemented). European countries also have more time to implement, as they do not have to be at 10 percent until 2020. While some countries are already around 7 percent, others are currently lagging at 3–4 percent. All countries must be on a linear trajectory toward 10 percent, but the approach to 10 percent is not really expected until the last years of this decade.

The biggest impact on European refiners will be in gasoline markets. Europe already generates a structural surplus of gasoline. Every barrel of domestic gasoline made from ethanol will extend this surplus, obliging Europe's refiners to seek export markets in North America and West Africa. This means that refiners are accepting an export-parity price basis for gasoline, which has a negative impact on refining margins.

Refiners also will have to cope with formulations of gasoline that are increasingly difficult to make, in order to conform to European standards. In particular, EN228 gasoline, Europe's standard, is difficult to formulate with 10 percent renewable fuels and still simultaneously meet requirements for oxygen content and vapour pressure. Some balance of ethanol and ETBE will likely be required, with the ETBE made from bioethanol. Even then, some have already argued that this cannot be done in practice, which may require amendments or a waiver to EN228. As we get closer to 2020, we expect to hear refiners' concerns about blend formulation raised more urgently.

"The enthusiasm for biofuels that gripped global markets back in 2006 has largely gone off the boil …"

Europe's diesel markets are less at risk from rising supplies of biodiesel. Already Europe's markets are considerably short of diesel, so importing and blending biodiesel is essentially a parallel operation to conventional diesel imports currently practised in Europe. The bigger issue for biodiesel will be affordable availability of sustainable feedstocks. Current sustainability criteria would exclude many existing sources of biodiesel, including Argentinean soya methyl ester and palm methyl esters from Southeast Asia. For every barrel of domestic rapeseed oil Europe converts to biodiesel, an equivalent volume of non-GM food oil will have to be imported, which is a further challenge to sustainability criteria.

Other Markets

The enthusiasm for biofuels that gripped global markets back in 2006 has largely gone off the boil as technical, economic and financial realities have slowed the growth prospects for alternative fuels. Few other countries have made major forward commitments to biofuels. Most accept that putting the demand cart ahead of the supply horse will be bad for domestic fuel pricing, and few are pursuing as robust a growth policy as the three major markets above. Markets like Thailand, Colombia and Argentina are making the most progress toward biofuels use, but they are keeping their mandates in line with forecasts of domestic supply, which is likely to offer little pressure to their domestic refiners.

We also should not ignore the long-term potential for biofuels use in jet fuel. The aviation industry made great publicity about early flights using biojet blends. Enabling changes to jet fuel specifications have been approved that will allow jet fuel to be formulated with up to 50 percent hydrotreated biojet. The real problem here will be availability. Meeting 2050 emissions targets without the use of renewables fuel will be impossible, but until there are abundant supplies of sustainable biojet this market will likely languish, with prices for renewable jet fuel expected to remain far higher than conventional kerosene. We expect no serious momentum here until the middle of the next decade at least, as near-term improvements can be made by changes to flight practices and the use of lighter engineered materials in the airframe.

More Changes Ahead?

A key question for the future of biofuels mandates remains: Will the main markets stay the course?

US biofuels policy in its current form is infeasible. The current E10 blendwall is only the beginning. For the United States to meet its RFS requirements by 2022, the gasoline pool would need to be close to E30. The wiggle room provided by an E15 waiver may buy a little time, but the US private vehicle fleet will not be able to accommodate anything like E30 by 2022. The US is counting on the availability of 'advanced' biofuels to meet the growing supply line, but technology is far behind policy in this regard and there is no hope of so much fuel being available, even if there were a market for it. From within the US's fractious body politic, bipartisan support is emerging either to change or scrap the US renewables policy. The most sensible approach would be to cap it at current domestic supply levels, test the technical readiness periodically in future, and not to proceed until the market and the existing fleet are ready for such drastic change.

In Europe, too, there are calls to slow down the 10 percent mandate, primarily due to the sustainability agenda. With European demand in decline, overall CO_2 emissions have fallen. Forthcoming regulations will further lower emissions by improving fleet fuel economy. The issue of absolute CO_2 emissions reduction by 2020 or 2050 looks likely to be met at least partially on the demand side, which could allow Europe (and the world) more time to ramp up sustainable production of biofuels. Europe might impose some kind of double- or triple-counting regime that allows domestically produced or truly advanced biofuels such as cellulosic materials to satisfy more of the mandate and thus be able to relax the strict 10 percent mandate that otherwise will govern at 2020.

Refiners are doubtless concerned about the future of biofuels policy. Lack of certainty makes future investment planning difficult, and there are other threats to the downstream industry, including carbon emissions taxation and the emergence of new export-oriented competitors in the Middle East and Asia that may target Atlantic Basin markets with their surplus product. Any climb-down from current mandate trajectories that supports conventional product demand would be welcome in the refining sector. Any changes to biofuels policy that are based on common sense and sound supply fundamentals should be welcomed by all concerned. ■

Can Latin American Refining Investment Keep Pace with Demand?

EMMANUEL VAZ

One of the biggest surprises in Atlantic Basin products trade flows of recent years has been the sudden emergence of a burgeoning deficit in Latin America's oil products requirements. Net imports have mushroomed from a level of no more than about 50 kb/d in 2009, to over 1.75 mb/d last year – most of which is being supplied by grateful US refiners.

The increasing gap between regional demand and production is causing widespread problems for governments grappling with balance of trade and currency issues and has been created by the compounding forces of strong demand growth and deficient refining output. The region faces a major challenge in maintaining a growth in refinery capacity and utilisation, which can keep pace with demand in order to stem this growing shortfall.

Buoyed by relatively robust economic growth in recent years, the energy picture in Latin America is characterised by a strong demand for almost all fuel forms. In the case of oil, demand has risen by around one-tenth since 2009 and we expect a further increase of at least 1.3 mb/d by 2020. (Figures 1 and 2)

So, how much longer will this last? At best, it seems the level of net imports could stabilise in 2–3 years' time, but any slippage in refinery expansions could see a continued growth in imports towards the end of the decade, when they could reach over 2 mb/d.

Much of this demand growth is derived from the transportation sector. Gasoil demand for instance in both Mexico and Brazil grew by 6 percent year-on-year last year. Apart from the increasing fleet of vehicles, this reflects the extent to which some countries' economies have outpaced infrastructure expansion. This has led (in some cases) to an unusually high dependence on road freight; for example in Brazil, road freight accounts for over 60 percent of all goods transportation, almost twice the level compared to the USA and China.

The second main factor shaping oil demand in the region is the issue of subsidies. These are still widespread in the continent although there is a progressive shift underway, most notably in Mexico, Brazil and Argentina to reduce and eventually eliminate them. The subject is even being broached in Venezuela (lowest gasoline price in the world). Fuel prices in the country have seen no increase over the last 17 years and after the latest currency devaluation in March the 95 octane gasoline price in dollars slipped further to just 0.015 $/lt.

The third factor driving high demand growth is shortfalls in other energy forms, particularly for power generation, which directly impact on oil demand, usually residual fuel oil or diesel. Although this is sometimes the result of droughts affecting

"The region faces a major challenge in maintaining a growth in refinery capacity and utilisation …"

hydro-power, more often than not it is the result of inadequate investment: shortages of natural gas, insufficient water reservoirs, or inadequate power generating capacity all leading to surges in oil usage. Gasoil used in Venezuelan power plants last year was over one-third higher than in 2011, whilst fuel oil use in Mexico grew by 20 percent year-on-year during Q4 2012 as a result of shortfalls in natural gas supplies.

Turning to the refining sector, operations in Latin America have been characterised in the past few years by poor reliability, weak refinery margins and low utilisation. In the early part of this year the region's total refinery throughput was averaging only 5.9 mb/d of crude, representing about 77 percent utilisation, still 700 kb/d below the level of 2008, when oil demand was 600 kb/d lower.

Nor has Latin America escaped capacity closures. Two Caribbean refineries, Aruba and the Hovensa plant, with a combined capacity of about 735 kb/d, were shut down last year. Both these refineries were the wrong type of plant in the wrong place and were more orientated towards supplying the US market, at a time when the country was a major importer (as opposed to its current status as the world's largest gross products exporter). This may not be the end of refinery closures in this region either, since the long-term future of the 335 kb/d Curacao plant looks doubtful and there are over 300 kb/d of small, generally uneconomic plants in the Caribbean and Central America, which are being kept alive by the Petrocaribe agreement and the discounted crude supplied by PdVSA, which may be more difficult to maintain in the post-Chavez era.

Looking ahead to 2020, we believe that oil demand will continue to grow relatively robustly, although at a slower pace than recently, by around 15 percent overall compared to the 2012 level.

In all we can identify at least 5.5 mb/d of new refining projects in the region but achieving even half of these by 2020 will

Figure 1: Latin America – Projected Demand vs Refining, Base 2006 (mb/d)

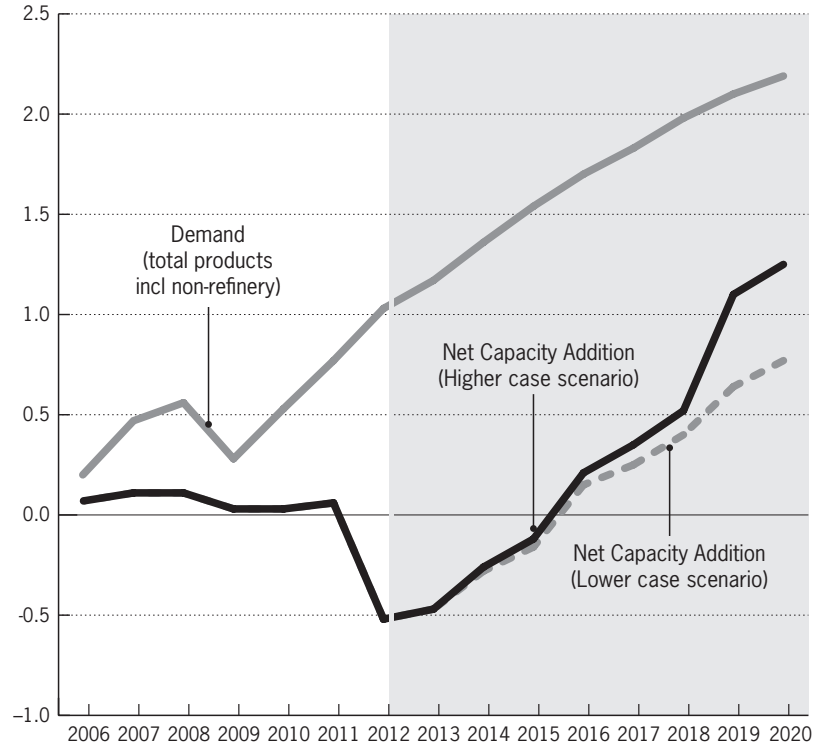
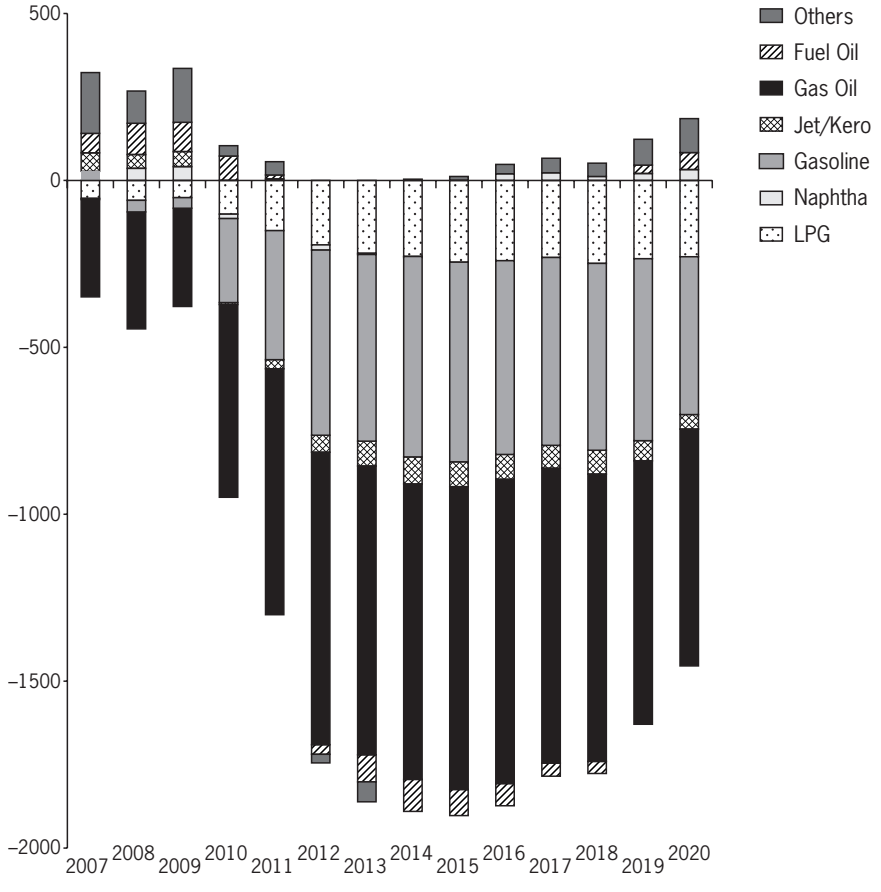


Figure 2: Latin America - Projected Net Oil Products Balance (kb/d)



be a major challenge. Unlike the buoyant investment programmes in the East, driven by fully-fledged state oil companies, investments in Latin American refineries are reliant on cash-strapped governments or commercially-driven financing and in particular face the following hurdles:

- Poor margins and subsidised fuel market prices;
- Sometimes poor project management and cost containment;
- Shareholder pressure to divert investment funds to the upstream sector;
- Political considerations overriding economics;
- The withdrawal of the integrated IOCs from the downstream sector and difficulties in finding credible partners to help fund the projects;

The single most important player in refining investment is Petrobras in Brazil, which is hampered only by its role as a semi-state entity. On the one hand it has the responsibility of providing domestic products for its growing home market, but on the other, it has to placate foreign shareholders who see the upstream as a much more attractive place to invest, particularly given the recent downgrading of production targets. Yet the company is suffering financially from high products imports and low domestic prices – reporting an $11bn loss last year from its downstream operations.

The company is thus revamping its major refining projects more along lines of profitability, with 'Premium' plants (totalling 900 kb/d) and the second stage of the COMPERJ refinery (165 kb/d). The 230 kb/d Abreu e Lima project, the first greenfield refinery in the country since 1980, epitomises the difficulties it faces: with construction initiated in 2007 and with a final cost currently estimated at around $17bn, it has yet to commence operations.

Petrobras has, nevertheless, learnt to maximise use of its existing capacity having recently had a consistent run of record high utilisation rates of about 97 percent during the first quarter of this year. In contrast, in Mexico, PEMEX's utilisation rate last year was only 70 percent and, although it inaugurated a new 165 kb/d expansion at its Minatitlan refinery in mid-2011, it has taken at least 18 months to begin operations at the new units and to raise runs above pre-expansion levels. Mexico meanwhile is desperately trying to start construction at the much-delayed new 250 kb/d refinery in Tula, but with cash-strapped PEMEX the only investor, this much-needed new plant will at best, we believe, come on stream in the latter years of this decade.

Above all, Venezuela highlights the difficulties faced in the refining sector of the region. Following a fire and major accident at its giant 640 kb/d Amuay refinery last August, the country saw its position as one of the region's major products exporters virtually disappear as it struggled to restart operations. Seven months after the accident, PdVSA is only now contemplating the full restart of the plant, which has been limping along at only 55 percent of capacity in recent months. PdVSA has a wide range of projects on its books but faced with funding limitations, has been seeking to finance much of these via loans granted by foreign banks and under joint ventures with other companies directly repaid in crude or products (usually Asian-based). However, the company seems likely to prioritise investments aimed at modernising the existing plants and increasing the heavy conversion capacity. Looking more vulnerable, however, are the more politically-inspired projects, such as the 300 kb/d El Pacifico refinery in Ecuador, the 150 kb/d El Supremo Sueno de Bolivar refinery in Nicaragua and the expansion of both the 36 kb/d Petrojam refinery in Jamaica and the 33 kb/d Refidomsa refinery in Dominican Republic.

In contrast, in Colombia, Ecopetrol's planned investment projects appear to have much more solid grounding. The company is planning to expand capacity at two refineries with a current combined capacity of 322 kb/d. Its programme for increasing capacity by 136 kb/d over the next four years seems to be on course and achievable. At the end of 2012, the expansion and modernisation of the 247 kb/d Barrancabermeja and 75 kb/d Cartagena refinery were reported to have advanced respectively to 14 percent and 74 percent of completion. The single most important difference between Ecopetrol and the larger state operators in Brazil, Mexico and Venezuela is the commercial basis on which its downstream operations stand since, alone out of these four countries, Colombia has no price subsidies and refining margins remain good.

Perhaps, therefore, subsidies are more important in influencing refining investment levels than might be assumed. Subsidised fuel prices in poor economies are politically sensitive and notoriously difficult to remove, yet maintaining them in high demand growth markets helps create a vicious circle where the enforced low profitability of downstream operations restricts investments and generates greater import needs, thus squeezing profits further. ■

Latin American Heavy Weights

EDGAR JONES and ROBERTO CARMONA

Mexico, Venezuela and Brazil contribute about 30 percent of world production of heavy and extra heavy crude oil, estimated at around 15 mb/d in 2012. Each of these three countries has a distinctive future production profile. Latin America will continue to run a surplus of heavy crude, but the supply of these types of grade will be increasingly restricted, either as a result of the natural decline in its fields, lack of investment, limited access to technology, political uncertainties or particular strategies in the energy sector leading to increasing domestic demand. This article explores some of the reasons behind the supply slowdown of heavy crude oil expected in each of these Latin American countries and some consequences in the international oil market over the next few years.

Mexico

The decline of the Cantarell field in Mexico is one of the most dramatic cases of heavy oil supply reduction. The drama arises from both the volume of Maya crude reached at the peak of production in 2004, and from the ruthless decline that followed. Between 2004 and the time of writing in 2013, total production of heavy crude oil from Mexico has declined by over 1 mb/d – equivalent to more than the entire current production of Colombia. Akal, the main Cantarell field, went from producing more than 2.0 mb/d in 2004 to less than 206 kb/d in February 2013. This rapid decline has been partially offset by Ku-Maloob-Zap (KMZ), which increased its production from 300 kb/d in 2004 to a peak of 859 kb/d in February 2013. Pemex estimates that KMZ could continue producing 850 kb/d for four years, but even in the unlikely event that this ambitious goal could be achieved, total production of heavy crude oil will decline relentlessly as no new heavy field developments have been announced that could offset the fall in Cantarell's production that will eventually be added to that of KMZ.

The Mexican government is currently preparing to make structural reforms to the stagnant oil industry. The need to increase the country's oil production may result, it seems, in more opportunities for international participation in non-conventional tight oil and shale gas plays, although not in conventional production, nor in the deep waters of the Gulf of Mexico. In the best case, if indeed an increase in non-conventional production was achieved, this would not happen in the next five years and the crude would be of a rather light or condensate type.

Venezuela

There are some discrepancies in the production and crude oil export figures from Venezuela. The IEA and the EIA-DOE reported 2012 production of 2.5 mb/d. The BP Statistical Yearbook reported 2.7 mb/d in 2011. In March 2013, various private-sector agencies estimate production to be 2.75 mb/d including unconventional production, of which 640 kb/d are heavy oil and 920 kb/d extra heavy. OPEC, depending on whether it comes from secondary sources or directly from members of the organization, reports Venezuela's production at 2.33 and 2.74 mb/d, respectively.

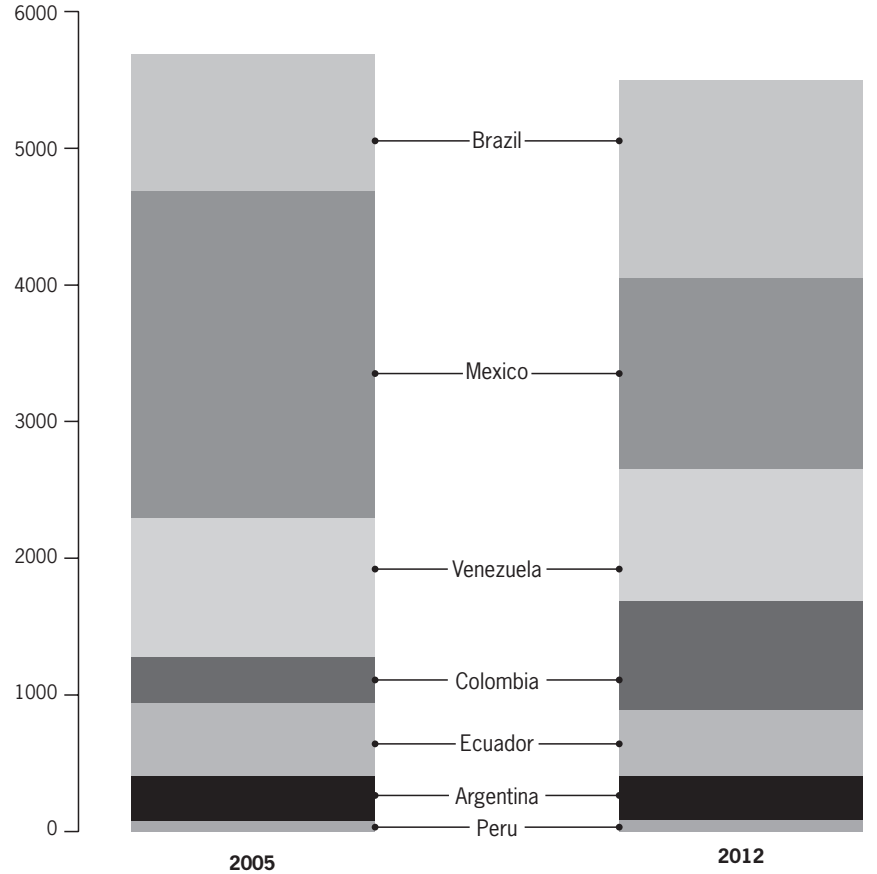
"The decline of the Cantarell field in Mexico is one of the most dramatic cases of heavy oil supply reduction."

Leaving semantic disputes and various estimation methodologies aside, Venezuela's crude production stability is facing significant challenges. Since the late nineties, total production has fallen by between 760 kb/d and 1 mb/d. One of the most frequently cited causes of this decline is the low level of investment resulting from greater domestic consumption encouraged by unrealistically low subsidised gasoline prices. Under Petrocaribe, several Latin American and Caribbean countries receive Venezuelan oil on preferential terms with deferred and/or in-kind payments. The poor management of PdVSA also weighs heavy on industry underperformance, a problem substantially worsened by the departure of many qualified personnel more than a decade ago.

A few years ago, Venezuela stood above Saudi Arabia as the holder of the largest proven reserves in the world with 296.5 billion barrels to 2011 reported in the BP Statistical Yearbook. According to the United States Geological Survey (USGS), the Orinoco Belt contains a mean volume of 513 billion barrels of technically recoverable heavy oil between 4 and 16 degrees API, with a recovery factor of about 15 percent. These incredibly abundant reserves have resulted in ill-advised and hasty decisions in the search to justify its rapid development.

It would be sensible not to expect significant changes in investment levels in Venezuela, nor technology transfers to develop the unconventional heavy reserves. Contrary to what investors would hope for, Venezuela finds itself engulfed in a morass of political uncertainty that does not bode well for the favorable development of its huge reserves.

Figure 1: Latin America Heavy Crude Oil Production (kb/d)



Source: Company reports, WoodMac and Petrologistics

Brazil

Brazil has become the new heavy oil powerhouse of Latin America with a current production of about 1.5 mb/d, with the key heavy oil projects concentrated in the Campos and Santos Basins. Most of the current heavy oil production is coming from the Campos Basin where the Marlim, Albacora, Roncador and Baliea fields are located. Marlim, Roncador and Albacora are about to enter their declining phase. There is a new generation of Campos Basin fields that will bring fresh volumes – Baleia Franca, Baleia Azul and Jubarte – but that is expected after 2015. These fields also share the common characteristic of having a pre-salt medium grade reservoir and a post-salt heavy crude oil reservoir. Santos Basin constitutes the future of Brazil heavy oil production with Iara, Franco and Lula. However, in the next few years Brazil´s heavy oil supply is not expected to increase significantly, at least not enough to compensate for Mexico´s continuous decline or for Venezuela's heavy oil supply stagnation. A combination of increasing domestic demand and lower capital liquidity will very likely limit Brazil´s heavy oil potential. National policies have also limited the alternatives and sometimes even delayed the development of fields. Brazil is struggling to meet its production targets due to the lack of skilled personnel, equipment and a still immature local services industry; recently the national content requirements were relaxed in order to provide some relief to producers.

The Heavy Trinity

Over the next few years, led by these three countries, Latin America will continue as the world's top supplier of heavy crude oil. However, there are significant downsides to the growth of their supplies. Latin America has lost about 121 kb/d of heavy crude oil production in the last seven years (Figure 1). Mexico has lost huge volumes that cannot be made up by the success of either Brazil or Colombia. On top of the decline in Mexico, we must also add the stagnant growth prospects of Venezuela's non-conventional heavy oil production.

The decreasing supply of heavy crude from Latin America and the growth of non-conventional light oil production in the United States have already begun to produce changes in the usual heavy oil flows. The regions with the largest heavy oil deficit will remain the U.S. Coast Gulf of Mexico (USGC) and Asia, particularly China and India. Maya crude is the benchmark for heavy crude imported into the USA. Increasing local production and declining supply from Mexico have led to a narrowing price spread between light and heavy crudes. In October and November 2012, Maya averaged more than 20 US$/b over WTI.

It is true that WTI is disconnected from the international market, but either way, compared to Brent, last March Maya averaged only 4.79 US$/b below the European marker, when in 2012 the average difference was about 12 US$/b. So, it is hardly surprising that USGC refiners are maximising their use of local light oils such as from Eagle Ford, or intermediates from the USGC deep waters to the detriment of Latin American heavy crude. Although high tech USGC refineries are certainly geared to process heavy crude, the light sweet crude runs could increase to 75 percent of refinery capacity while maintaining utilisation at over 90 percent, leading to a reduction in consumption of intermediate and heavy crudes of up to 2 mb/d, without impacting distillate production levels.

Heavy oil producers in Latin America have had growing success with Chinese and Indian private and national companies, with new high and increasing deep conversion refining capacity. Bilateral agreements between governments have led to an increased flow of oil between China and Venezuela, as well as Ecuador, both countries having signed long-term agreements to supply oil in exchange for soft loans. Mexico agreed to increase the flow of heavy oil to China during its most recent state visit to the Asian giant. Indian imports of Latin American crude doubled between 2009 and 2012. Venezuela is the third largest supplier of crude oil to India and the largest of heavy crude; Mexico, Brazil, Colombia and Ecuador have also increased their share in the country.

Notwithstanding the increasing market share of the Latin heavy players in Asia, there has to be a price balance to keep that flow open specially if it is not under term contracts. The spot flow of Latin American crude is finding increasing difficulties to reach the Indian market as higher prices are closing the arbitrage opportunities. Increasing prices of heavy crude from Latin America can be translated into increasing flow opportunities of heavy crude from West Africa or even from the North Sea, with similar vessel voyage days distance to Asia as Latin America. ■

Refining in Africa – a Chinese puzzle

NEIL FLEMING

Led by booming economies like that of Côte d'Ivoire, Mozambique and Ethiopia, sub-Saharan Africa's oil demand is set to jump by 50 percent in the next decade, outstripping growth in the rest of the world by a factor of around four to one.

That's the forecast from downstream African consulting specialists CITAC, who predict African oil demand will hit 5.1 mb/d in 2023, up from 3.4 mb/d in 2012. By 2020, demand is set to be some 4.5 mb/d, with West and Central African demand growing the fastest (44 percent), and North Africa likely to grow by 26 percent.

But while such demand growth signals perhaps that Africa's troubled economies may at long last be boarding the emerging markets train, it carries with it a significant burden: much of the additional refined products are likely to need to be imported.

The shortfall in oil products in Africa is set almost to double by 2020. The continent has been a net importer since 2007, but the situation is likely to become rather more extreme over the next seven years, according to CITAC's annual *Oil Refining in Sub-Saharan Africa* study. The

shortfall, taking into account all products except LPG, is expected to jump from 31.5 million tonnes/year (700,000 b/d) in 2012 to around 60 million tonnes/year (1.32 mb/d) in 2020. And despite North Africa's self-sufficiency in refining, and its ongoing exports of jet/kerosene, the continent overall has already seen its clean products shortfall grow six-fold from 8.5 million tonnes in 2001 to 52 million tonnes in 2011. This will increase by a further estimated 33 million tonnes by 2020, reaching 85 million tonnes per year (1.84 mb/d).

Why? Put bluntly, it's a very hard task to assemble the political will and investment resources to build a refinery in Africa right now.

Only 56 refineries have ever been built on the continent. Fourteen of those have closed, and two have merged at Port Harcourt in Nigeria. Africa overall has a refining capacity (on paper) of 3.2 mb/d, but 2012 refinery output was only some 2.4 mb/d, 61 percent of which came from North African operations – product that is unlikely to wind up south of the Sahara. More than half the balance (58 percent) comes from South Africa's four crude oil refineries, which between them generate some 530,000 b/d of products.

By contrast Nigeria, which has nameplate refining capacity of 445,000 b/d, produced only 95,300 b/d of products in 2012, and has for years been heavily dependent on imports of products from Europe.

The continent's governments are keenly aware of the issues they face. Not only is there a large shortfall in capacity, but much of the capacity that does exist is in grave need of upgrading. World Bank and other studies on air quality have concluded around $10–15 billion needs to be invested in improving oil products standards alone, to reverse dangerous declines in air quality in many African cities. This is before a single barrel of new capacity is added.

Then there's the fact that most of Africa's refineries are also too small to compete on the international stage: most world-class plants as of 2013 are at least 200,000 b/d in size. Port Harcourt, at 210,000 b/d, is Africa's only offering above this size, with South Africa's SAPREF running it a close second at 180,000b/d. Such plants are dwarfed, however, by complexes like India's Jamnagar complex, with its 1.24 million b/d of capacity. Even without building new refineries, therefore, there is theoretically a case for enlarging the existing ones.

These three factors – outright shortfall, low quality output, and lack of scale – have been responsible for African governments (mostly) making over *one hundred* announcements of proposed new refineries or refinery expansions in Africa.

But there is a giant gap between aspiration and reality, between what a government hopes for and what the commercial world is prepared to invest in, particularly at a time when the refining industry globally is challenged in a way it has rarely been in the past. There are plenty of other lower risk infrastructure projects, even in Africa. Significantly, the past seven years have seen a large-scale exit from African downstream markets by major oil companies, with Chevron, BP, and Shell selling substantial parts of their distribution and marketing empires outside South Africa to local companies, in particular Malaysian-owned Engen, and to trading houses such as Vitol and Trafigura. France's Total is the sole major left operating on a large scale across the continent, and shows little sign it is willing to invest in refining in the region. Expansion of the sector is indeed further constrained by the fact that – with the exception of Nigeria and South Africa – most local markets are simply too small to sustain a competitive refinery, and profits from long-haul products exports substantially lower than those from local sales... leaving the hope of competing on a world stage stuck in a Catch-22.

As a result, of all the announced new grassroots refineries, only *five* have actually been completed, and four were built by the Chinese – more specifically by CNPC, who put in a 110,000 b/d plant at Khartoum in Sudan, a 12,500 b/d plant at Adrar, Algeria, the 20,000 b/d refinery at N'Djamena, Chad, and the similarly-sized Zinder plant in Niger. China is involved in theory with further expansion in Khartoum, and possible projects in Uganda and Equatorial Guinea. The fifth new plant was Egypt's MIDOR refinery in 2001. Three refineries have been expanded since 2000 (Khartoum, Morocco's Mohammedia, and Cameroon's Limbé) and one has been debottlenecked at Skikda/Arzew in Algeria.

Much has been said and written about China's investment relationship with Africa. Untroubled by political niceties in countries like Sudan, and motivated by a seemingly unquenchable thirst for raw materials, the Chinese have dared to make investments unthinkable to Western businesses – and more importantly to Western banks. As a result, in 2010 alone, Chinese bilateral trade with Africa grew 45 percent to a record $115 billion. By 2015, it is expected to hit $325 billion. Back in 2005, it was somewhere below $40 billion.

Chinese refinery construction in Africa – at least at the outset – was positioned as a quid pro quo enterprise. Refineries, like other infrastructure projects (railways, for example) were offered in exchange for a lock on natural resources.

But as the reality of making refining work commercially in some African countries has hit home, even the Chinese appetite for such deals has waned. Beijing's trade partnerships are a great deal more about trade than about partnership. China's interest in African infrastructure development should not be mistaken for philanthropy. There has been hard pragmatism behind every proposed Chinese project, and equally hard pragmatism behind its decisions to pull out, or not to invest in the first place.

CNPC was supposed to be expanding its Chad plant to 50,000 b/d, for example. It holds a 60 percent stake in the refinery. But a row in 2011 over fuel prices soured the deal and led the Chad government early last year to suspend its agreement with the Chinese altogether. President Idris Deby, enthused by the refinery start-up, had decreed a three-month price 'jubilee', slashing gasoline prices to some

"... it's a very hard task to assemble the political will and investment resources to build a refinery in Africa right now."

"... the Chinese have dared to make investments unthinkable to Western businesses – and more importantly to Western banks."

67 cts/litre – about 40 percent of the price prevalent in Chad before the refinery opened. The move left the refinery $4.7 million in the red after only a few months of operation, according to CITAC's researches, and refining came to a halt in September that year. Once restarted, a continuing row led to CNPC's refinery General Manager being ejected from the country. From the Chad government's perspective, it was having its arm twisted by Beijing; from Beijing's, the expectation was that contractual commitments needed to be met. Despite a renegotiated deal, it was not until December 2012 that pump prices actually rose, however.

A similar story at Adrar in Algeria that led to refinery closure was theoretically settled by negotiation early in 2012, but the status of the plant remains unclear.

And famously a $2 billion Sinopec plan to build a refinery at Lobito in Angola earlier this century never even got off the ground. Sinopec pulled out in 2007, and as of 2013, state Angolan oil company Sonangol is still looking for investment partners for the project. The construction contract has been awarded to US company Kellogg Brown and Root, but the completion date has been pushed back from 2012 to 2014, or possibly 2015.

The question is now whether China's taste for refining investment may have cooled to the point where it will decline to participate in more projects altogether.

It is more than three years since an expansion of the Khartoum refinery was announced – but nothing has happened, not least because in the intervening time, Sudan has become two countries, and ownership of the oil, in which CNPC has various equity stakes, is in dispute.

It's too early to say that the Chinese affair with Africa is over. Chinese companies have after all completed over 500 infrastructure projects on the continent. Problems with a few high-profile projects should not overshadow that record. Nevertheless, recent experience may have underlined the need in Beijing to take additional care when assessing country risk – and a return to tighter agreements, perhaps more refinery processing agreements, is on the cards.

South Africa' PetroSA began a prefeasibility study on a 320,000–400,000 b/d refinery at Coega in 2008. In 2012 it signed a joint study agreement with Sinopec on the plant and in March this year moved ahead to a 'Framework Agreement', valid for two years, for construction of the plant. Such an agreement, however, is no guarantee that construction will go ahead.

And if Chinese enthusiasm has waned, it is hard to see from where else Africa can obtain both the funding and commitment to construct new plants.

Uganda is looking at building a small refinery to exploit the waxy crude find made by Tullow Oil in the northwest of the country in 2006. But the plan has been bogged down in a dispute with investors Total, Tullow and CNOOC over whether or not also to build a crude export pipeline. The investors are keen to build a small 30,000 b/d plant (with potential enlargements later) and export the rest. Uganda's President Museveni has floated grander refining ambitions, however, mooting a refinery as large as 180,000 b/d at times. CITAC understands a deal may now have been done for the smaller plant, though nothing has been signed, and meanwhile no actual crude oil is likely to flow from the find until 2014.

Equatorial Guinea, meanwhile, has also proposed to build a 20,000 b/d refinery in its Rio Muni province. And in Nigeria, grand plans for up to three new refineries have been floated. Most recently, in April 2013, Africa's richest man, Nigerian business mogul Alhaji Aliko Dangote, announced a plan to construct a 400,000 b/d refinery by 2016, investing up to $8 billion of his own money in the scheme. Even as he launched it, however, Dangote acknowledged that his plan might face stiff political opposition from interests benefiting from Nigerian products imports.

The conclusion seems clear: it will not be possible for African refining to keep pace with the continent's economic expansion over the next decade. But that expansion looks set to take place, refining assets or no.

By implication, investment in oil products supply will take place, but it will be investment in far less financially risky import, storage and distribution logistics. There will be a downstream oil boom. But it won't be in refining. ■

The Impact of Gas on Refining: A Double-edged Sword?

PETER STEWART

Shale formations in the United States have yielded large and increasing amounts of oil and gas through the process of hydraulic fracturing, or 'fracking'. Many other countries around the world are rolling out plans to repeat the US experiment. Because fracking is a controversial technology, it is unclear at this stage which countries will allow it, but those countries such as India and China which face the greatest growth in transportation fuel demand, also have large shale formations and are seeking to maximise use of the resource.

In this article, we argue that the advent of tight oil and shale gas has the potential to turn the dynamics and economics of fossil fuel supply on its head, not only in the USA but elsewhere, and represents a potential Black Swan event for the global refining sector.

The International Energy Agency headlined its 2011 World Energy Outlook 'Are we entering a golden age of gas?' It said unconventional natural gas resources are now as large as the conventional and projected that the share of gas in primary energy demand would rise from 21 percent to 25 percent by 2035. In its 2013 Annual Energy Outlook, the Energy Information Administration of the Department of Energy projected that the United States will transition from a net importer to a net exporter of natural gas, largely as a result of shale plays, although the EIA was less bullish than some studies which envisaged a US self-sufficient in oil and gas by 2020. Many companies are bullish on the prospects for tight oil and shale gas; for instance, BP's 2030 outlook projects that 'from 2011 to 2030, shale gas more than trebles and tight oil grows

more than six-fold. Together they will account for almost a fifth of the increase in global energy supply to 2030'.

The potential short-term benefits of shale for the manufacturing sector as a whole, including the refining and petrochemical sectors, have been extensively documented. The shale revolution benefits the refining sector in the USA by reducing the cost of refinery processes. The benefits are twofold.

Tight gas and shale gas provide a relatively cheap supply of methane that can be used to generate power within the refinery, freeing up fuel oil which can then be upgraded to make higher value products such as gasoline, kerosene and diesel. Methane can also be used to generate more hydrogen in the refinery's hydrogen plant, which can then be used to bring down desulphurisation costs of the higher value products.

Meanwhile, tight oil is typically light and sweet in quality, providing abundant supplies of light sweet crude oil to refineries which, in the past, have been geared to using heavier imported crude oils that require much more intensive processing. Although US refiners have invested billions of dollars in upgrading capacity to allow them to process heavy and ultra-heavy crude oils, because tight oil is typically very light in quality, it can be used to reduce the processing severity at secondary units, as well as to back out imported light sweet crudes in the US refining slate.

Further downstream, ethane derived as a by-product from shale gas production is being used as a relatively cheap feedstock in the petrochemical sector, reinvigorating that sector in the USA and prompting petrochemical companies to lobby the Obama administration to prevent further LNG exports. Cheniere's Sabine Pass LNG plant is the only one to have received an export licence so far, but petrochemical companies are worried that allowing further exports after the plants starts up in late 2015 will force up domestic gas prices. The most cost effective additions of petrochemical capacity in recent years have been of ethane-based petrochemical plants in the Middle East, but the advent of cheap natural gas opens a significant possibility of a renaissance of the fortunes of the petrochemical sector in the west, which has traditionally used relatively costly naphtha or Liquefied Petroleum Gas from within the refining process.

"… the advent of tight oil and shale gas has the potential to turn the dynamics and economics of fossil fuel supply on its head,"

Cheap gas also, of course, has direct benefits for the electricity sector and other energy-intensive industries such as steel and ceramics.

These developments have come after years of investment by the refining sector in coking and hydrocracking technologies which have assumed that the crude stock will become ever heavier, based on the premise that the Middle East, which has the biggest oil reserves, will gradually become more dominant in the supply mix. In 2013, US crude oil imports from traditional light sweet suppliers such as Nigeria and Algeria have also declined. So a final benefit of shale resources is that they reduce import dependence, improving the bargaining position of US refiners when importing crude oil.

Double-edged Sword

While the short-term benefits of tight oil and shale gas have been extolled by the refining sector, the long-term impacts of vast amounts of relatively low-priced gas on the sector have been less observed. Shale gas could potentially prove a double-edged sword for a refining industry that already faces overcapacity problems, particularly in the Atlantic Basin where shrinking demand and competing product flows look set to put European refiners under intense pressure in the future.

Currently more than two-thirds of all oil use is in the transportation sector, but the availability of cheap natural gas opens the door to a greater use of gas in the vehicle fleet and in marine transportation. New refineries being developed in Latin America and the Middle East, ambitious upgrading plans in Russia and the prospect of US exports currently being sold into Latin America being diverted to Europe as countries such as Brazil develop their own capacity, represent a looming 'perfect storm' for the industry.

"The shale revolution benefits the refining sector in the USA by reducing the cost of refinery processes."

The potential loss of market share in the energy mix of liquids to gas, particularly given tightening environmental constraints which have already encouraged biofuels at the expense of oil products, represents a further threat to the already beleaguered European refining sector.

How quickly this will happen is up for debate. Gas in transport has been much talked about for years, but it has always been a revolution that is about to happen rather than one that is actually underway.

In the road transportation sector, gas can be delivered to vehicles either as Compressed Natural Gas (CNG) or for larger heavy-duty vehicles as Liquefied Natural gas (LNG); or as Liquefied Petroleum Gas (LPG). The first two processes use methane: in CNG, the methane is compressed; whereas in LNG, the methane is supercooled to below -162 degrees Centigrade to make a usable fuel. In the case of LPG, the propanes and butanes derived from the distillation of crude oil are generally isolated from the liquid streams in the refinery and from there can be either used in gasoline production, sold as petrochemical feedstock or bottled for use in stoves and heating appliances, or as a fuel for cars and other vehicles. Although some LPGs are naturally occurring, most are a product of the refining process, whereas CNG and LNG substitute molecules (gasoline and diesel) that would be derived from the refining process.

CNG is already widely used in vehicles in a few emerging market countries. Passenger vehicle conversions to CNG can be done cheaply by adding a tank in the boot of the car, allowing dual-fuelling with gasoline; while buses and medium-duty vehicles are increasingly seen as environmentally desirable in public transport fleets.

For LNG, the main uses are in large trucks and mobile plant and machinery such as earth-moving equipment and so on. There is also potential that LNG

will be used as a replacement for diesel in locomotives on the railways. Meanwhile, in the marine sector, LNG is being considered as a potential alternative to diesel and fuel oil, the two oil products that are currently used as marine bunkers.

While slow fleet turnover rates make a substantial rise in gas-fuelled vehicle use unlikely in the near term, the pace of change in the marine sector may be more rapid.

At the bottom of the barrel, heavy fuel oil has always been the mainstay of marine transportation fuels for tankers and large ocean-going vessels, also providing refiners with a sink for unwanted sulphur, while products such as diesel have tended to be used in auxiliary systems to provide lighting and heat on board, or for smaller vessels geared to passenger transportation or for use in local waters.

The fleet of vessels that is currently fuelled by LNG is tiny. Outside the 100 LNG tankers that use the gas as a fuel, it consists of 20–25 passenger ferries and coastal vessels in Scandinavia, mostly in Norway and Sweden which have the only fuelling facilities. But steps are afoot to change that.

The European Union in January 2013 released a plan for boosting the use of gas in transport, which includes plans for LNG refuelling stations to be installed in 139 maritime and inland ports on the Trans European Core Network by 2020 and 2025 respectively. The proposals were made in a working paper *Actions towards a comprehensive EU framework on LNG for shipping*.

The EU action plan contains binding targets but member states will decide the appropriate policy instruments to attract private sector investment. The EU will work with the European Maritime Safety Agency to provide a comprehensive set of rules, standards and guidelines for LNG provision, bunkering and use in shipping by the end of 2014.

The action plan is intended to boost the infrastructure available to deliver LNG as a fuel to ships, whose demand for clean fuels will be boosted by new rules on emissions that go into effect in less than two years.

Meanwhile, from the start of 2015, ships operating in Emissions Control Areas (ECAs) will be subject to much tighter limits on emissions from bunker fuels, which looks set to push owners towards LNG-fuelled and dual-fuelled vessels in the years ahead to take advantage of the large gap between oil and gas prices. Sulphur limits in marine fuels have already been tightened from 4.5 percent maximum to 3.5 percent worldwide, and to 1 percent in the ECAs. From 2015, a 0.1 percent limit will be imposed in ECA regions, and from 2020 a 0.5 percent limit will apply worldwide, subject to a technical review in 2018. Nitrous oxide limits will also be tightened.

"The European Union in January 2013 released a plan for boosting the use of gas in transport …"

The upcoming tighter rules on emissions have prompted many ship-owners to look more actively at the costs of switching to gas. Diesel is lighter and less polluting than fuel oil, but the downside is that it is more expensive. Based on current prices, LNG is economic as a bunker fuel in the United States and in Europe, although the case for tankers using LNG is marginal in Asia where LNG spot prices hit record highs in 2013. So 2015 is likely to be a watershed in the long-running debate about whether gas would be a better fuel for ships than oil.

Regulatory Uncertainty

Most analysis of the potential role of gas in the fuels sector is based on projections of the future spot price of different fuels based on forecasts of the long-run marginal cost of the competing fuels. The reality is that government decisions play a major role in setting the retail prices of such fuels. Gasoline and diesel pump prices range from below spot prices in such regions as the Middle East to well above in Europe, where taxes and duties might form as much as two-thirds of the cost to the motorist. Thus the impact of gaseous fuels in different geographical regions will depend crucially on government decisions on the level of subsidy or fuel tax imposed for the individual fuels.

Thus, as well as the market risk inherent in all commodity pricing decisions, regulatory uncertainty also potentially has a bearing on the uptake of gas in the fuels sector.

It is notable that the countries where the penetration of NGVs is greatest are ones where the car fleet is relatively new, and where the government has a strong say in the energy mix. Among the countries with the largest NGV fleets, just five countries (Pakistan, Iran, Argentina, Brazil and India) make up 70 percent of the world's NGV fleet by vehicle numbers. Together with China, Italy, Ukraine, Colombia and Thailand, they make up 89 percent of the world's NGV fleet by vehicle numbers, based on data from the Natural Gas Vehicles Association.

The profile of NGV fleets differs between the emerging markets and the developed economies. In the former, typically, the NGV fleet comprises – at least based on vehicle numbers, which include low consumption vehicles such as three-wheelers/tuk tuks – light duty vehicles which are typically owned by individuals. Of course, such countries may also have large public fleets, for instance in India where city bus fleets are typically fuelled by CNG. In developed economies, however, the bulk of NGVs by vehicle numbers are medium and heavy duty vehicles and the light duty vehicle fleet is generally relatively small. The medium and heavy duty vehicles typically comprise trucks and buses owned by companies and local authorities, sometimes reflecting a desire to show off environmental credentials rather than simply acting in response to price considerations.

This balance could change. Political economy is a crucial factor in the allocation of subsidies in emerging markets. Many governments have either shifted or are in the process of switching their subsidy support away from 'expensive fuels' such as oil to 'cheaper' ones like gas.

For this reason, the high proportion of dual-fuelled vehicles in those countries where the market penetration of gas-fuelling is greatest is significant.

In the emerging markets, which are experiencing rapid growth in the private vehicle fleet, gas-fuelled vehicles are typically conventional cars which have been converted to be able to use gas for cost reasons. The cost of conversion has dropped to the equivalent of just $50 in some countries, so dual-fuel capability in passenger vehicles is cheap and can be achieved much faster than vehicle

turnover trends typically allow.

A major uncertainty for refiners building costly upgrading capacity is whether to gear new units towards diesel production or to gasoline production. A trend towards dual-fuelling in vehicles has potential implications for which oil products to maximise.

Vehicle ownership and use are increasing globally, and despite all the concern that vehicle emissions are contributing to global warming, environmental pressures have done nothing to reverse this trend. Slow fleet turnover patterns make it unlikely that the market share of conventional liquid fuels will significantly reduce in the developed countries in the coming years. On average, people keep their cars for at least several years, and typically are conservative in their choice of replacement vehicles. If there is a shift, it is likely to be as much towards electric hybrids rather than gas fuelling. The perception that gas-fuelling infrastructure is limited may take longer to shift than the reality of how many stations can deliver LPG or CNG.

However, in emerging markets with young populations, high population growth, rapidly rising real income, where many people are new to car ownership, the old rules may not apply. Where the infrastructure for car-fuelling is growing rapidly, adding CNG or LPG pumps is less of an issue than in retrofitting filling stations geared to delivering liquid fuels.

"Gas in transport has been much talked about for years, but it has always been a revolution that is about to happen rather than one that is actually underway."

Gasoline hybrid vehicles are easier and cheaper to make than diesel hybrids, so hybrid NGVs and conversions tend to have gasoline as their liquid fuel. Of the NGVs on the market, most of the models manufactured by the likes of Fiat and other manufacturers targeting the Alternative Fuelled Vehicle market are gasoline hybrids. This is the case even in the European Union, where diesel taxes have typically been much lower than those for gasoline.

One of the biggest choices faced by a refinery is whether to build conversion capacity, and which sort of conversion capacity to build. Although there are many types of configuration, and a great deal of flexibility in operation once the investment decision has been made, a basic choice is whether to install cracking capacity, generally through a fluid catalytic cracker or FCC, which optimises gasoline production; or to go down the coker-hydrocracker route, which typically facilitates production of low sulphur diesel. In recent years, based on very bullish projections of diesel demand in the emerging markets, the coker hydrocracker has been more in favour after many years in which FCCs were the default technology.

We have outlined that cheap shale gas has had a positive impact on refineries by lowering their fuel costs, but also that gas in transport represented a potential threat to the market share of liquid fuels. A third more subtle impact of cheap gas may be that it encourages the use of gasoline hybrid vehicles at the expense of diesel vehicles. This would particularly be the case if oil prices remain above $100/barrel and the US experiment with fracking was repeated in other countries. If the use of LNG in marine bunkers were also to displace diesel in the marine sector, there could over time be a marked shift in end-use demand towards the light end of the barrel. ■

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Asinus Muses

Money, happiness, and oil

Asinus has at last achieved self-knowledge. His constitutionally-gloomy take on the world and its denizens has been explained by geography: he lives at the wrong end of the country. As a deep southerner – any further south and his hooves would get wet – he is not only missing out on his piece of the record investment going to our North Sea oil industry and the economic dynamism it has brought to Aberdeen. He is also as far as he could possibly be from the care-free and cheerful atmosphere of one of Britain's top-five happiest locations: Aberdeenshire is not only benefiting from record low unemployment, but in a recent survey by PricewaterhouseCoopers came in the UK's top five in response to questions on life satisfaction, and in the bottom five on anxiety.

Bread and circus

Not all oil producers are in such effervescent mood. Venezuelans, having lost Chávez to cancer and voted in his anointed successor Nicolas Maduro by a narrow margin, are suffering rampant inflation and shortages of basic goods, most notably their staple, corn flour. Still, if bread is in short supply, the government at least had the political sense to provide circus: shortly after the election, which has been disputed by the opposition, legislators resorted to fisticuffs in the national assembly.

The USual suspects

Few will be surprised that the US has offered comfort to the Venezuelan opposition. The US secretary of state John Kerry has supported calls for a recount of the election, which Maduro won by 1.5 percent, and President Obama has so far refused to recognise Chávez's successor as President. While Asinus will not profess faith in the purity of this most recent expression of Venezuelan democracy, neither has he forgotten US support for the failed coup against Chávez in 2002, nor the alacrity with which the USA recognised the pro-US centre-right winner of Mexico's disputed presidential election in 2006, who beat the centre-left and rather less pro-US candidate by only 0.6 percent. While to US eyes Obama may look rather different from his predecessor, to others in their hemisphere the continuity is remarkable.

From failed state to Aztec tiger

In contrast, everyone seems to be jubilant about the outcome of Mexico's most recent election. The Institutional Revolutionary Party, or PRI, has returned to power after a 12-year hiatus that may turn out just to have been a temporary pause in its decades-long domination of Mexican politics. The first of the two intervening administrations, both of them run by the centre-right Party of National Action, was headed by Vicente Fox, who became known as Latin America's answer to George W. Bush – less because of his support for the US War on Terror (TM) than for his incompetence in his own mother tongue. By half way through the second PAN administration, amid economic stagnation and ever-rising drug violence, the CIA started to speak of the country as a 'failed state'. Certain observers started to refer to the ruling cadre as the Party of National Inaction. Now, six months into the PRI government, with labour and education reforms in the bag, and a promise to open up the notoriously-closed oil industry making the world of energy investors salivate with anticipation, the country is overflowing with investment and is being described as an 'Aztec tiger'. Asinus, with his finely-honed sense of animal injustice, is not amused: no tiger has ever been seen in the Western Hemisphere outside of captivity. Asinus notes that 'Aztec jaguar' would be more zoologically correct.

Corporate carnival

If investors are eyeing-up the promised Mexican feast, they are already partying in Brazil. Petrobras has just issued $11bn of bonds in the largest ever bond issue in an emerging market, as part of a long-term cash hunt to fund the development of their pre-salt oil fields.

Many happy (negative) returns

Petrobras's neighbour, the recently-re-nationalised Argentine oil company YPF, is on the same bond bandwagon, having just made its third bond offering to the local market. The Financial Times tells readers that the nationalisation was a 'self-defeating political choice' while simultaneously reporting that its previously-terminal production decline has been virtually halted, cash flow has risen, and that the bond issue is part of a planned $37bn of capital expenditure over the next five years. They also grumbled that the sale 'swamped the local bond market... squeezing out local issuers'. Asinus notes that those local issuers are hardly spoiling the public, with bank deposit rates of 12–15 percent compared to inflation well over 20 percent. Indeed, even YPF's 19 percent offering represents a real rate of return considerably south of nil. Though if YPF can't make money at those rates then Asinus may start to grumble along with the FT.

Party poopers

The core of the global economy could use some of this Latin spirit: it seems the only people not issuing bonds are those whose paper is most in demand, providing the lowest yields – governments in the rich countries whose love for the masochism of austerity is more than a match for Asinus's gloom.

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