US Tight Oils: prospects and implications

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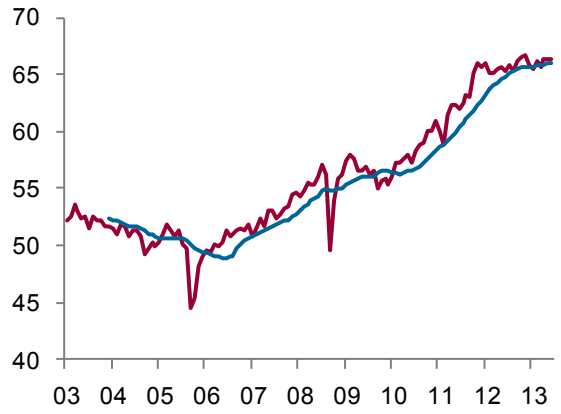
1. Introduction

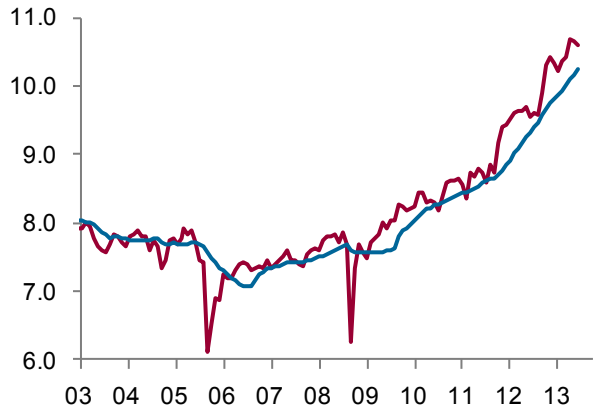
The USA has been at the heart of oil and gas production growth over the past few years thanks to the commercialization of shale production in the country. Such has been the dramatic increase in US oil and gas production (see Figures 1 and 2) that US crude oil benchmark prices fell at one point by around $20–$40 relative to international benchmarks, and gas prices hit a bottom of $1.91 per MMbtu before recovering slightly, while the US refining industry has seen its profits soar to record highs as a result of exploiting this cheap crude. Cheap gas prices have displaced large volumes of coal from the US power sector and have provided a new source of life for the chemical industry, which is restarting chemical plants that had been closed a few years ago due to the loss of competitive edge on rising feedstock costs. Low gas prices are also creating a renaissance in US petrochemicals with various companies, such as the Dow Chemical Company, undertaking large-scale investments to start up new petrochemical plant. The positive impact of the growth of shale extends beyond the oil and gas industry. Expectations of a long-lasting era of cheap energy are creating hopes that the USA will become a manufacturing hub once again, able to regain its competitive edge over Asia and the Middle East. The same expectations are resulting in calls for 'energy independence' – in other words, the ability of the USA to reduce its dependence on foreign oil and gas to negligible volumes, or indeed to zero, as domestic production would be able to meet all of the country's demand requirements. The concept of 'energy independence' has been a key goal for US politicians since the time of Nixon, with the usual explanation that it would reduce America's vulnerability to 'unstable petroleum-producing regions like the Middle East and West Africa'.[1]

Figure 1: US gas output and 12 month ma, bcf/d



Source: EIA

Figure 2: US liquids output and 12 month ma, mb/d



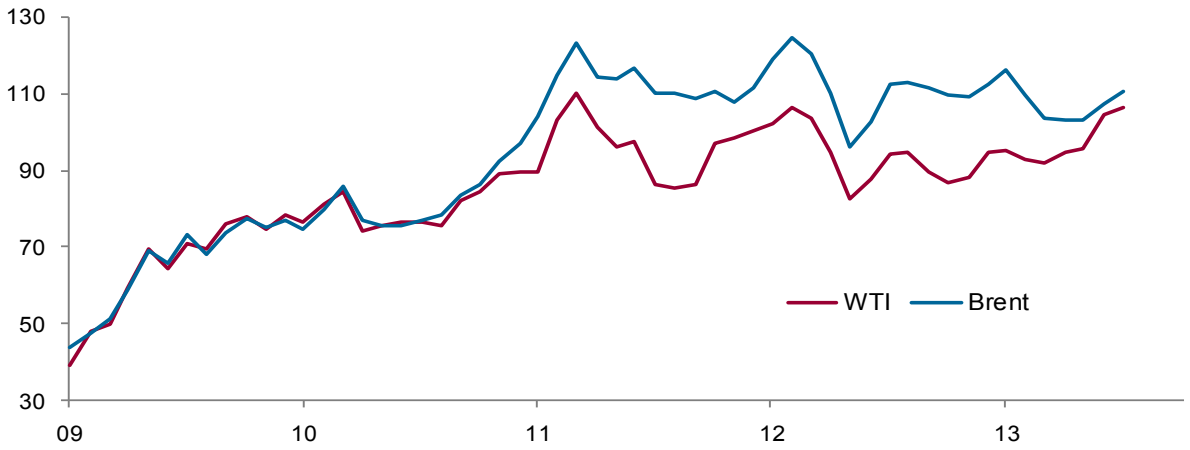
Source: EIA

This paper analyses the implications of US tight oils growth on both US and global energy markets. So far, the limited literature on US tight oils growth has focused primarily on refining, and in particular on the implications for gasoline and diesel. Other papers have focused largely on the prospects for tight oils, together with the resulting challenges. This paper plans to reveal the links between the local and global impacts of shale growth. In

[1] *The Boston Globe*, 26 May 2013.

particular, the paper argues that one of the main consequences of the growth in US tight oil production has been the unusual spatial crude oil price divergence for global oil benchmarks. Economic theory would suggest that since there is a global market for oil, growth in US oil production, all else being held equal, would translate into lower global oil prices due to arbitrage conditions arising from the relative ease with which oil can be shipped around the world. However, the reality has been different. Between 2011 and H2 13, US oil prices alone have fallen sharply in relation to the waterborne oil market (see Figure 3).

Figure 3: Evolution of WTI and Brent monthly average prices, $/barrel



Source: Bloomberg

Two main factors have been responsible for reducing intra-US arbitrage opportunities: infrastructure bottlenecks and crude export restrictions. The rapid growth in US tight oils caught the US midstream sector by surprise, with the latter being unable to cope with the expansion in the upstream. This resulted in US crude prices decoupling from the rest of the world; this was led by WTI and then by regional crude grades such as Bakken and Permian, as pockets of regional oversupply occurred. Naturally the midstream did not sit still, but reacted to these huge dislocations. Supported by refineries, new pipelines were brought on stream while others reversed, all geared towards shifting crude from the oversupplied Midwest (the heart of the tight oils boom), to the Gulf Coast where crude prices were trading in line with international benchmarks, offering a significant premium. Even rail wagons were brought in to carry crude around the USA; this offered greater flexibility and respite to producers, who were otherwise forced to accept anywhere up to $50 discounts to international benchmarks, due to lack of takeaway capacity. Refineries started reaping the benefits of cheaper domestically produced barrels which replaced imports, boosting their refining margins. While the cost of the infrastructure bottleneck is borne by oil producers, the benefits of reduced prices, many believe, should be with consumers. But that is only true to the extent that this local oil price reduction is passed through to prices for refined products – primarily gasoline and diesel fuel – which benefit consumers. Otherwise, as has been the case here, the benefits are captured by refiners in the areas of the dislocated crude.

The second factor which has, to some extent, limited arbitrage has been US crude export restriction. However, although the USA does not allow crude exports, the arbitrage mechanism still works to a certain extent, as the USA is the largest importer of crude oil. As its domestic production increased, the USA started to reduce its imports, which led to increased availability of crude to the rest of the world – a de facto export. As long as the USA is obliged to import oil, restrictions on its exports should not prevent shale oil from influencing global markets as backing out (displacing) imports has the same effect on global markets as permitting US exports would have. Of course, in theory, a point could come where the USA had displaced all the light crude imports that it possibly could, while imports of heavier grades for its upgraded refineries were still required, but then the continued growth of light crude domestically could risk creating a glut in the country unless exports were allowed. Thus, while not an issue of imminent importance, it may be necessary to consider allowing some US exports (or light oil swaps for heavy grades) down the line to avoid a situation of continued US imports of heavy grades accompanied by a domestic glut of light crudes.

While the impact of tight oils growth on global prices has been limited so far (in the last two years Brent prices have continued to fluctuate in the $100–$110 price range) there have been some significant impacts on global price differentials; this has primarily played out through the narrowing of light–heavy crude differentials and by increasing competition in some key markets, mainly Asia. Tight oils quality is extremely light and the surge in production has dented demand for other light grades, such as Saharan and Nigerian, especially as the marginal refining demand is for heavy crude. The tight oils have also impacted these grades through the product markets. Crude from shale plays is rich in naphtha and gasoline but poor on distillates and fuel oil. Due to rising volumes of light-ends (propane, naphtha, gasoline, among others) the USA's production and exports (global crude grades which have a high proportion of light end yields) have come under immense pressure, which has in turn impacted the structure of light, sweet benchmarks such as Brent. Thus the onslaught of US shale is perhaps best seen as having localized price level impacts but global price differential effects.

Furthermore, reduced US imports have led to greater availability of crude to the rest of the world, increasing competition among producers. For instance, West African barrels are proving to be attractive in Asia – this is also helped by extremely low freight rates, at a time when other crude exporters such as Russia, Mexico, and Venezuela, among others, are also trying to move away from Western markets and capture the main growth market of Asia. This has resulted in Asian consumers not being limited to Middle Eastern producers alone, but with an increased number of alternatives to secure their crude – be it the FSU, Latin America, or West Africa. Naturally, the implication of this is that Middle Eastern producers now have to become more aggressive in pricing to Asian refineries, in order to maintain market share. Increased production of tight oils will lead to additional moves by exporters to the USA (namely Venezuela, Mexico, Nigeria among others) to look East to find buyers for their crude. Once the Panama Canal expands, this trend will intensify further. Thus, Middle Eastern and Latin American producers may have to revisit some of their marketing and pricing strategies with regards to Asia if they want to maintain their market share in the region.

The rest of the paper is divided into two parts. In the first, we focus on the impact of tight oils growth on the US market, in particular on: the dislocation of benchmarks, the US refining sector, and trade flows. Since the local

and global impacts are closely interlinked, in the second part, we draw out some of the implications of the US tight oil growth on global oil markets.

2. The Impact of Tight Oil Growth on US Oil Markets: Benchmarks, Refineries, and Trade Flows

2.1 Impact on Benchmarks

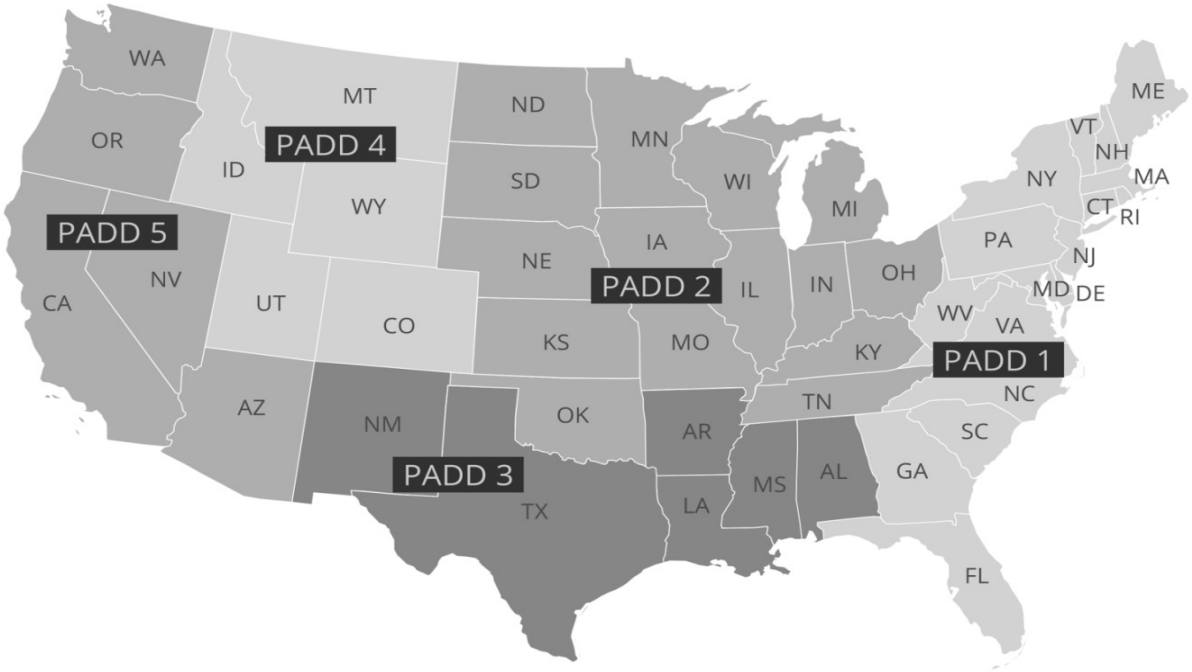
For most of the 20th century, Tulsa, Oklahoma was known as the 'Oil Capital of the World' and it developed into one of the most important hubs in the oil industry. A major oil gusher at Glenpool, 15 miles south of Tulsa, was discovered in 1905 and, by 1907, Oklahoma became the USA's largest oil producer. Major oil basins at Cushing, also in Oklahoma, were subsequently discovered in 1912 and Cushing became a centre for exploration and production of nearby oil fields; in 1915 it produced around 30 per cent of higher-grade US oil. In 1928 the Oklahoma City Field, which soon became the nation's largest oil producing basin, was discovered. From 1916 to1929, several major oil and oil service entities were founded in Oklahoma, and at least two refineries operated in Cushing, while other refineries were built around the region for easy access to the crude oil. As a result, a significant network of pipelines and tanks were built to serve the refineries in the region. Indeed, although nearby oil fields began to run dry in the 1940s, the web of infrastructure and storage that had been built to service the Cushing refineries influenced the decision taken by NYMEX (New York Mercantile Exchange) to start using Cushing as the pricing point for WTI paper contracts in 1983.

Despite Oklahoma's declining production by the middle of the 20th century, its crude oil pipeline infrastructure continued to grow over the next several decades, with larger pipes and improved technology being used. During World War II (WWII), it was necessary to distribute oil across the nation more effectively. As a result, the War Department established the Petroleum Administration for Defense. This administration created five Petroleum Administration for Defense Districts (PADDs) across the USA. Each PADD oversaw the refining and distribution of oil within its own district (see Figure 4) and US crude oil pipeline infrastructure is divided into PADDs. While these PADDs were created for gasoline rationing, they are used today for supply monitoring. Most crude in PADDs 2, 3, and 4, together with fuel imported from Western Canada, travels through the Cushing Oil Trading Hub (COTH) for redistribution via the vast pipeline network to refineries in PADDS 2, 3, and 4.

Thus, the COTH first developed as an oil trading centre, before becoming the official price settlement point for light sweet futures contracts in the form of West Texas Intermediate (WTI) crude – the benchmark against which most types of North American crude are priced. The COTH has supplied crude oil from Gulf Coast imports and domestic Mid-Continent areas to Midwest refining markets – commonly known as PADD 2 – for the last four decades. As such, the crude pipeline system evolved from the pre-WWII era – which mostly covered the distribution of domestic supply from the Mid-Continent to refining markets – to a position of moving both domestic supplies and Gulf Coast (or PADD 3) imports to the interior of the country (mostly through Cushing) from where crude could be redistributed to refineries across the Midwest. As Canadian oil production grew, the crude oil pipeline system was reversed partially once more, this time to deliver crude oil produced in Alberta,

Canada to the COTH, where Canadian crude could be distributed to both Midwest refineries, which also continued to take imported crude from the Gulf Coast through the southern pipeline system.

Figure 4: PADD designations in the USA



Source: Energy Aspects

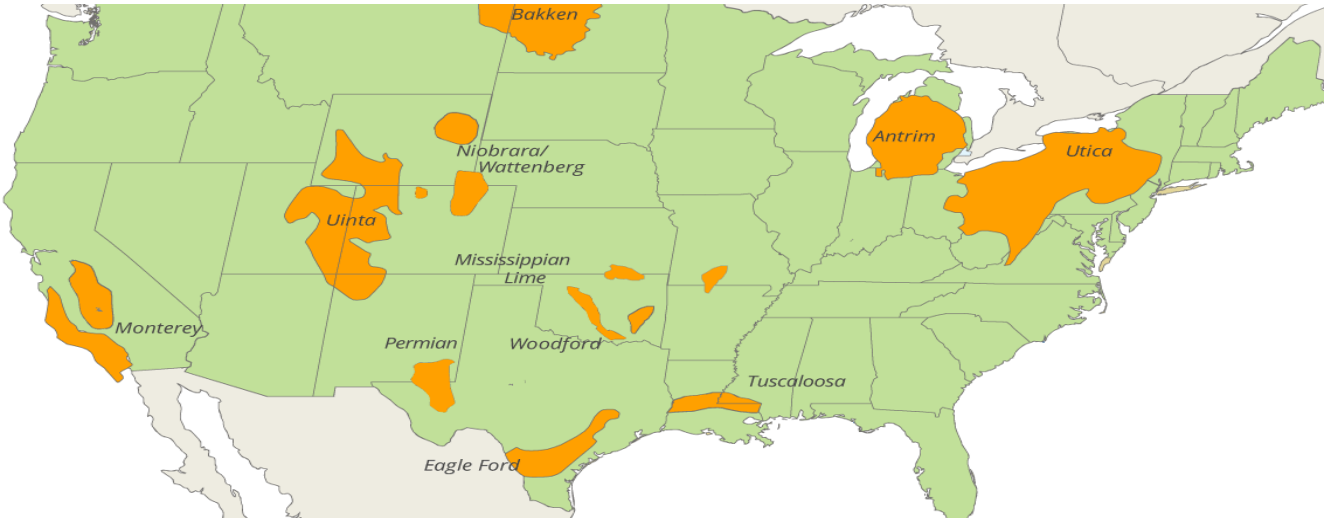
Ultimately, however, Cushing is a landlocked interconnection point through which crude volumes move. The Cushing pipeline interconnect is spread over nine square miles and has crude oil storage capacity of around 65 million barrels, 50 million barrels of which is currently operable. Due to pipeline logistics, once the oil flows outwards from Midland towards Cushing, WTI can only go in one direction: north, towards Chicago. Thus, if there is a shortfall in demand from refineries in the Chicago area, there are no opportunities to redirect oil flows out of Cushing towards other refining centres where there might be a greater demand for crude oil. In general, the logistical constraints at Cushing can result in a short-term build-up in crude at Cushing, which then logically creates significant downward pressure at the front of the WTI futures curve. Feedback then creates distorted sets of time spreads, which are reflected in the large differential between nearby and more distant contracts, for example, the WTI time structure flips into a fairly steep contango. Second, WTI decouples from Brent, and other benchmarks such as Light Louisiana Crude (LLS); this is evident in the large differential between the two prices.

Despite changes to the pipeline system and Cushing's limitations, the COTH has remained the primary trading hub for US crudes. A large part of the COTH's prominence results from the links between Cushing and WTI (one of the world's most popular crude benchmarks). The start of WTI as a benchmark dates back to January 1981,

when Ronald Reagan spearheaded governmental decontrol of oil prices. This fostered an immediate convergence of WTI spot prices into a single commodity (prior to decontrol these had been split into various categories under the control mechanics) resulting in a major change in trade dynamics, which created the foundations necessary for the successful launch of a paper contract in domestic light sweet crude at Cushing, Oklahoma; this was designated as West Texas Intermediate (WTI) by the New York Mercantile Exchange (NYMEX) in March 1983.[2] However, ultimately, Cushing and any crude that is delivered at the COTH are governed by the infrastructure logistics of the US Midwest.

The shale revolution in the USA since 2010 has made matters significantly worse, creating an oversupplied Midwest and pushing WTI prices to a steep discount of over $25 to other global benchmarks. This has been by far the most prolonged and severe period of price dislocation. The main problem is that when localized conditions become dominant, the WTI price can no longer reflect the supply–demand balance in the USA, nor can it act as a useful international benchmark for pricing crude oil. Given the frequency of the recent dislocations and the duration and severity of the current dislocation of WTI to other benchmarks, the reliability of WTI as an international pricing benchmark has been put into question.

Figure 5: US major shale play areas



Source: Energy Aspects

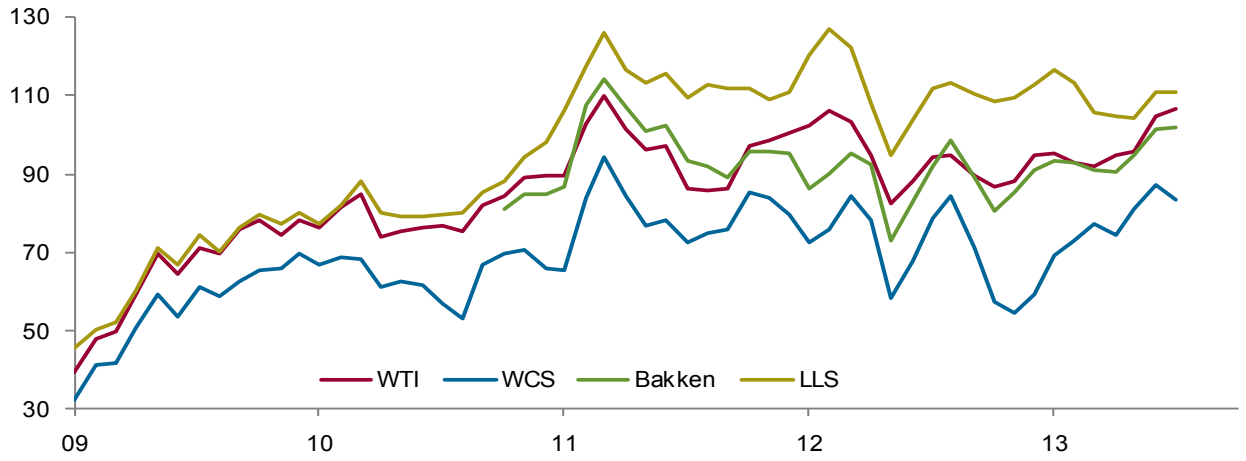
The shale revolution and infrastructure bottleneck limiting arbitrage

Shale basins in the USA have been discovered in the US Midwest, Texas, and parts of the East Coast (see Figure 5), with oil concentrated first in the North, followed by Texas. As shale plays in the Williston Basin (Bakken) gained considerable momentum, accompanied by increases in Canadian output, the needs of Chicago refineries proved insufficient to absorb this production growth, which led to all crude grades produced in the north being significantly discounted relative to WTI. The growth of shale plays in the south then started bringing

[2] 'The Role of WTI as a Crude Oil Benchmark', K. D. Miller, M. T. Chevalier, and J. Leavens, prepared for CME group, Purvin & Gertz Inc., January 2010.

further volumes up to Cushing from the Permian and the bottleneck in the Midwest became even more glaring; even Permian Basin crude prices dislocated downwards. Given that the vast majority of the USA's existing infrastructure was geared towards moving imported crude from import terminals (for instance in the Gulf Coast), to inland refineries, the absence of infrastructure to move crude from the north to the south caused severe infrastructural logjams. Indeed, since 2011, Bakken crudes started to discount at about $10 to WTI, while West Canadian Select (WCS) traded a further $15 below Bakken (see Figure 6), all at a time when WTI itself was trading at a $20 discount to Brent. This, then, reduced demand for crude from Cushing (WTI was the most expensive crude in the region), resulting in further pressure on the WTI benchmark. While pipeline flows initially adjusted, with Seaway, Capline, and Spearhead (pipelines flowing towards Cushing) sending significantly lower volumes through 2011, there were limited options available to curtail flows to Cushing further. Inventories in Canada started to increase, with any rally in WTI prices being met by higher volumes on the Spearhead pipeline as Canadian barrels sought out higher prices. Oil producers bore the brunt of this dislocation; their profit margins were squeezed substantially and their borrowing soared to finance funding.

Figure 6: Evolution of WTI, LLS, Bakken, and WCS monthly average prices, $/barrel



Source: Bloomberg

Rail allows some arbitrage, but has significant barriers

Burgeoning inventories (Cushing at record highs at 50 mb) and depressed regional oil prices (Bakken and Permian, among others) resulted in various new pipeline projects being planned since end 2011 in order to alleviate infrastructure issues and provide improved returns to producers who, in some instances, barely managed to break even. However, building or reversing pipelines is a process associated with time lags of about two years, and so producers began using far less efficient and more costly methods – such as trucks and rail – in a desperate attempt to move crude out of the basins, as the only alternative was to shut down production. Soon, rail wagons started to provide a way around pipeline bottlenecks, with nearly 0.6 mb/d of crude being hauled by rail by the end of 2012, up y/y by 46.3 per cent. Crude volumes were also being carried by barges down rivers towards refineries, such was the extent of disconnect between crude values in the Gulf Coast and the North (US Midwest and Canada). Rail also offered producers the ability to reach the East and West Coasts –

regions which domestic US pipelines did not serve and which were entirely dependent on costly imported crude. Indeed, even when taking into account the high costs associated with railing ($12 average to the Gulf Coast, $18 to the East Coast, and so on), the scale of dislocation ($40 or so) was such that it still offered benefits to refineries when compared to imported crude. Most of the crude-by-rail headed towards the Gulf Coast (offloading capacity 0.5 mb/d) initially, but it is increasingly heading to the East Coast (offloading capacity set to rise to 0.5 mb/d by Q3 13) and also the West Coast (0.1 mb/d).

Pipeline adjustments allowing arbitrage again

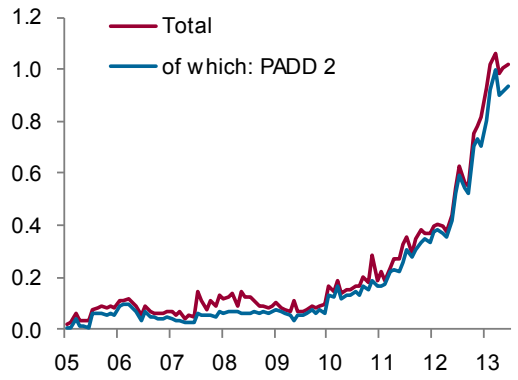
Meanwhile, in the world of pipelines, the same pipelines that were reversed to allow sufficient crude to flow to Cushing started being reversed yet again, while new ones are also being built, to take crude away from Cushing towards the Gulf Coast, where crude values are the highest in the country (see Figures 7 and 8). The 0.15 mb/d Seaway pipeline was the first of these pipelines to be reversed, in May 2011, finally allowing Cushing an outlet. The Seaway pipeline was then expanded to 0.4 mb/d in early 2013. Next in line was the reversal of the Longhorn pipeline, another line that had previously carried crude from the Gulf Coast to the Midwest. Longhorn began to carry oil in the opposite direction in April 2013. With the 1 July start-up of the new Permian Express Phase 1, and the West Texas Gulf pipelines, increasing Permian basin volumes are being diverted towards the Gulf Coast, away from the COTH. This has already been seen in lower flows on the Basin and Centurion pipelines, the two key pipelines carrying crude from the Permian basin to Cushing. The new Permian basin pipelines already divert some 0.4 mb/d of crude away from Cushing, and the 0.4 mb/d Keystone XL southern leg begins operation in December 2013 (see Figure 9). The line-fill requirements for these new pipelines have also helped absorb quite significant volumes of tight oils production. Early in 2014, Seaway starts its parallel pipeline, which will carry another 0.4 mb/d of crude from Cushing to the Gulf Coast. Total takeaway capacity (1.2 mb/d directly and 0.4 mb/d indirectly through diversion via the Permian) will then far exceed production growth in the Midwest region and incoming pipeline capacity.

Clearly, even with lower refinery runs (assuming that higher WTI prices reduce refinery margins and then lower runs in turn), Cushing will have more than enough available infrastructure to transport volumes down to the Gulf Coast. Not all of this will be utilized, but the option is available; WTI will thus no longer be a landlocked crude, having gained easy access to the Gulf Coast. This is already helping WTI prices to reconnect with Gulf Coast values, and in turn with international benchmarks such as Brent – the difference being infrastructure costs between the two points (Cushing and the Gulf Coast). However, given the large volumes of crude flowing as long-term committed barrels on these pipelines, WTI and other US regional Midwest grades can easily be traded within those infrastructure costs, depending on market positioning. In other words, brief periods where WTI trades at parity, or even higher than Brent, cannot be ruled out, just as happened in late July 2013, when a large percentage of flows on the new pipelines had already been committed and hence would not be altered even if the differential narrowed to levels that would not make transportation economical. Thus, the adjustment of pipeline infrastructure is crucial in reversing intra-US limits to arbitrage, as crudes from different basins can now be interlinked via pipeline.

Does the arbitrage risk breaking down again?

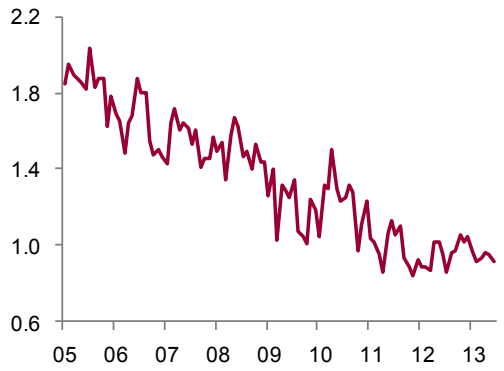
While infrastructural bottlenecks have caused the bulk of the dislocations in US benchmarks, and are now being rectified, there is a case to be made for all US benchmarks continuing to trade at lower values to the rest of the world, should the growth in tight oils continue at its current pace. So far Gulf Coast prices, such as the local benchmark LLS, have remained connected with the rest of the world, as the USA continues to import nearly 8 mb/d of crude, and is far from self-sufficient. However, the improved access from Cushing to the Gulf Coast comes with its own problems. The new pipelines are effectively just transferring the US Midwest inventory glut to the Gulf Coast, as the infrastructure finally realigns to chase the highest value of crude in the country. The Gulf Coast could receive over 3 mb/d of additional crude from the north over the course of the next few years if production growth from both North Dakota and Canada remains strong, especially now that Canadian crude is also being railed in fairly significant volumes (0.15–0.2 mb/d annually). Equally, the Gulf Coast region's own production is growing fast, with the Eagle Ford and Permian basins both seeing steady increases in production. Granted, the US Gulf Coast hosts nearly half of the country's refining capacity, but the supply of light sweet crude could outstrip the region's oil demand in the medium term, after the upgraded Gulf Coast refineries have readjusted to process the lighter slate (explored in the next section) and blended with heavier grades to create medium look-alikes (explored in the section on trade flows). This, in theory, could pressurize LLS and other Gulf Coast crude prices in relation to global benchmarks, decoupling lighter grades from the rest of the world, until exports are allowed.

Figure 7: Inter-PADD flows to the Gulf Coast, mb/d



Source: EIA, North Dakota rail authority, Energy Aspects

Figure 8: Flows out of the Gulf Coast, mb/d



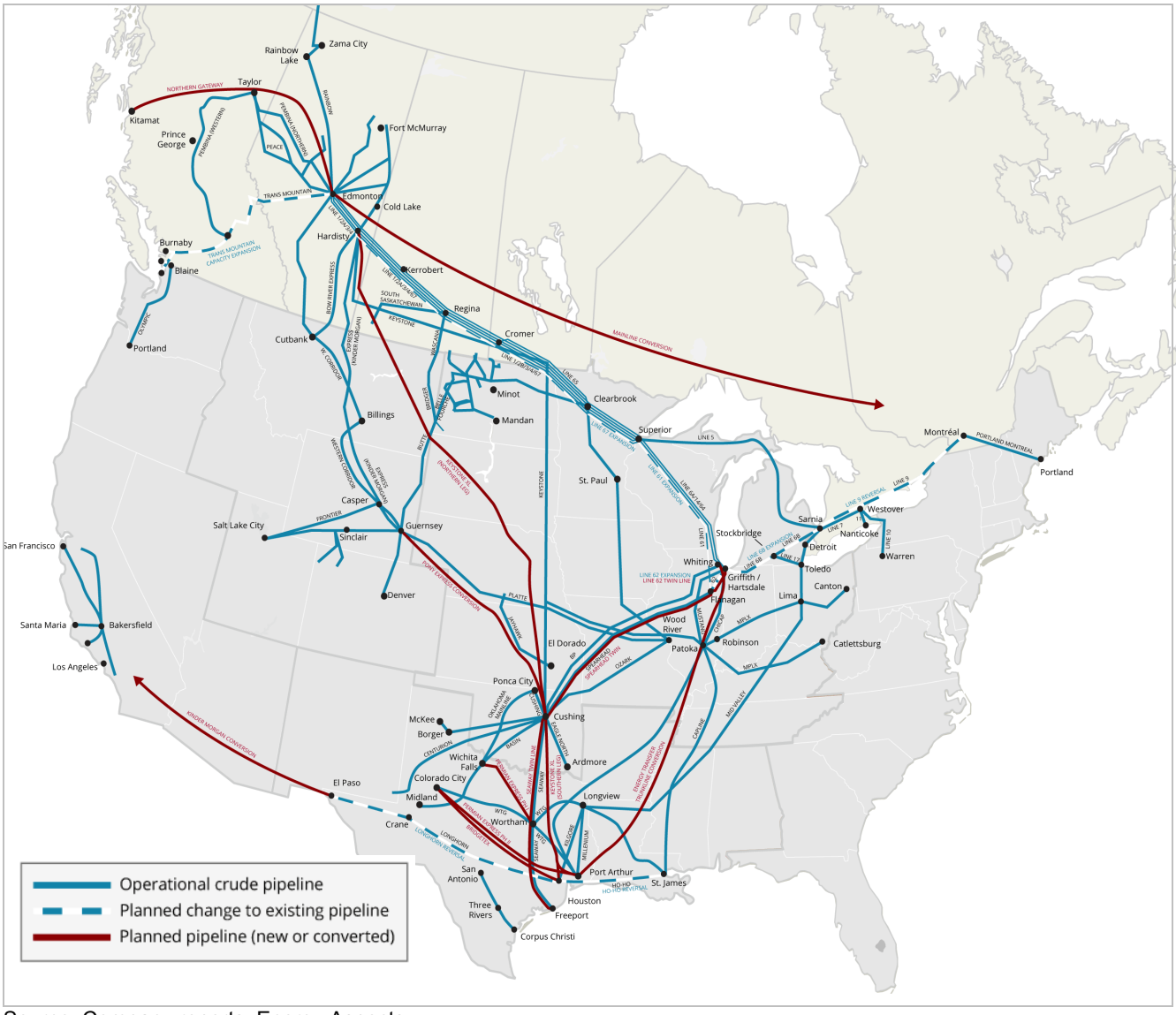
Source: EIA

Against a backdrop of strengthening WTI, pipeline flows are likely to readjust, as the attractiveness of sending crude down to the Gulf Coast erodes. For instance, crude from the Permian basin will have the ability to swing into either Cushing or the Gulf Coast and the decision on where to direct barrels will ultimately depend on which destination is yielding more favourable values, adjusted for pipeline costs. The more that WTI prices rally and LLS prices fall, the stronger will be the incentive for Permian producers to switch away from the Gulf Coast and revert to sending barrels to Cushing. Moreover, by end 2014/15, more pipelines will be scheduled to bring crude towards Cushing, this time because Canadian producers will have expanded infrastructure to resolve the growing bottleneck in their own country as production outstrips consumption. For instance, Enbridge announced

a Flanagan South crude pipeline expansion from Illinois to Cushing with an initial capacity of 0.6 mb/d, with the possibility of expanding throughput to 0.8 mb/d by end 2015. If the much debated Keystone XL pipeline gets the go ahead from the US government, it is likely to bring another 0.8 mb/d to Cushing by end 2016. Smaller pipelines are also being planned from Colorado and the Mississippian Lime area to Cushing, in order to transport growing tight oils production from the nearby basins. Once a programme of capacity expansions on the Enbridge pipeline system in the Bakken area are realized, over 0.3 mb/d of extra production will be heading (potentially via the northern segment of Keystone XL) down to Cushing. Thus, by 2016, the net result (highly dependent on the fate of Keystone XL) may well be an overall increase in pipeline capacity towards Cushing and the US Midwest of over 2 mb/d, with the variability of actual volumes flowing on these pipelines making WTI prices extremely volatile.

However, this strand of thinking ignores two very important issues. First, that there is a significant amount of crude flows on pipelines such as Seaway and Permian Express Phase 1 on long term commitments (~90 per cent), making it very difficult for flows to readjust in response to price changes. This is precisely why WTI has already reached parity with Brent once already this year and Cushing is set to reach operational minimum levels of around 25 mb in the coming months, and will require another spike in WTI prices to incentivize run cuts in order to refill Cushing once again. Second, the argument of a US Gulf Coast (USGC) glut also ignores problems with the different US crude grades, as the next few sections will explore. Domestic production in the Gulf Coast itself is extremely light in quality, mostly 'super lights' (API of greater than 50), which pose significant problems for refineries trying to process them. As a result, there can easily be a position where there will still be demand for WTI even though the Gulf Coast is filled with light crude, because of the vast quality differences. In fact, it is Eagle Ford crude (the lightest and poorest quality of all), that is likely to become the distressed barrel trying to find an alternative home. It is therefore important to not simply analyse light, medium, and heavy crude balances but also to divide up the light grades by API, as demand for crude grades of API greater than 45 is likely to reduce. As a result, these super light barrels will cease to be counted as 'light sweet' crudes when analysing balances. Thus, a true glut of light sweet crudes in the Gulf Coast may not materialize over the next few years.

Figure 9: US and Canadian crude pipelines (August 2013)



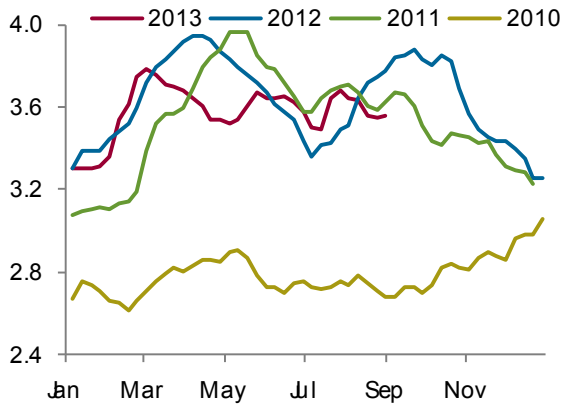
Source: Company reports, Energy Aspects

2.2 Impact on Refining

While the dislocations in US crude oil prices theoretically create lower realized profits for US domestic producers, they open up cheap feedstock prices for consumers. However, it is the intermediaries (in the form of refineries) that have reaped the benefits of low crude prices, with end product prices continuing to be linked to global product prices, which are linked to global crude prices. Average US gasoline and diesel prices have continued to rise in line with underlying oil prices), with RBOB gasoline prices averaging a record high $2.92 per gallon in 2012 and heating oil a record $3 per gallon, despite extremely cheap US crude oil prices (see Figure 13 and 14). This is primarily due to the fact that the USA permits exports of oil products, enabling any dislocation to be arbitraged away – discussion of which is beyond this paper's scope. Further, this can be backed by empirical findings where: 1) refineries have been operating at near full capacity with utilization rates well over 90 per cent, 2) build-up of crude oil inventory has not been mirrored in product markets, where total inventories still remain

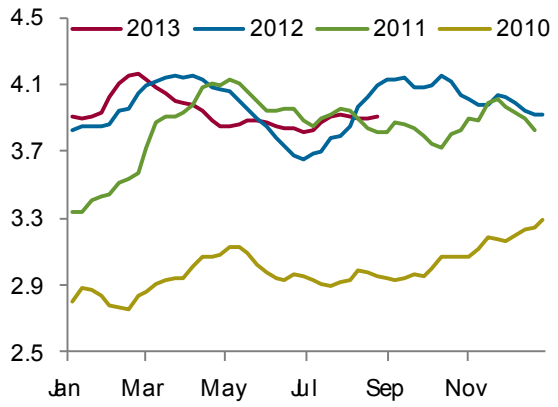
below the five-year average; and 3) the USA continues to import oil products in areas such as the Midwest and East Coast, while exporting the surplus in the Gulf Coast. Following Borenstein and Kellogg,[3] these facts are consistent with a model in which US refineries are consuming, where possible, as much low-priced crude as their capacity can handle and are receiving the rents generated by depressed crude oil prices in regions such as the Midwest.[4]

Figure 10: US retail gasoline prices, $/gallon



Source: EIA

Figure 11: US retail diesel prices, $/gallon



Source: EIA

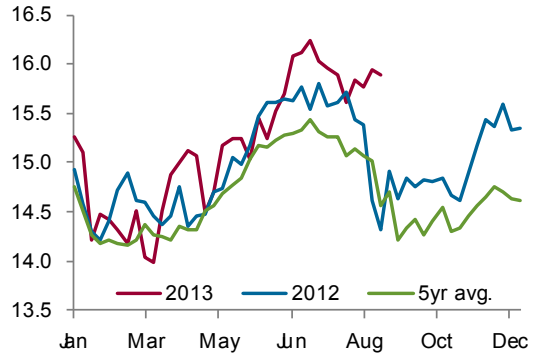
Consequently, and despite the difficulties of processing some parts of the growing volumes of lighter crudes, US refineries have been ramping up runs, to near record highs of well above 16 mb/d (see Figure 12), and exporting significant volumes of oil products, particularly to booming Latin American markets and also to European and African markets. This has made the USA one of the most formidable players in the products market. Moreover, low natural gas prices, which provide US refineries with a competitive advantage over its counterparts in the rest of the world, have also boosted profits. Thus, export capacity creep, where major exporting refineries have increased their capacity by small volumes in recent months, is already visible. As of 1 January 2013, US refining capacity has increased by around 0.5 mb/d y/y to 17.8 mb/d. Even with US refinery margins likely to come under pressure due to rising crude prices, on a relative basis, US refineries will continue to remain more competitive than their European counterparts. Also, with a fairly stagnant domestic demand, they will continue to focus on the export market. This is a major threat to European refineries, especially with the growing share of gasoline and light-ends currently being produced by US refineries, due to their feedstock becoming progressively lighter. US gasoline exports are reaching Africa and parts of Latin America, traditionally regions that used to be European strongholds. Worse, Europe is a large exporter of naphtha to Asia, and a significant change in the

[3] 'The Incidence of an Oil Glut: Who Benefits from Cheap Crude Oil in the Midwest?', Borenstein and Kellogg, NBER working paper, June 2012.

[4] Recent announcements by US refineries underpin this view. Major US refiners, such as Valero Energy, Marathon Petroleum, and Phillips 66, had managed to displace significant (if not the entire) quantities of imported crudes they had processed previously, replacing them with crude from Eagle Ford, Bakken, Utica, and Louisiana fields. As a result of exploiting cheap dislocated crudes, their earnings had more than doubled. For instance, Phillips 66 noted that 68% of the crude slate run at its US plants had the relevant price advantages (up from 60% the previous year), and the profit in their refining unit jumped to $922 million in Q1 2013, from $393 million the year before (Phillips 66 Quarterly Earnings Call).

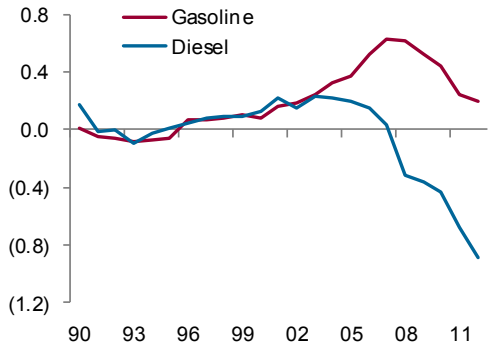
markets has come about with the surge in US propane exports. These are increasingly heading to Europe, displacing the more expensive naphtha feedstock wherever substitution is possible. By the end of 2013, the USA could have as much as 15 per cent of the global LPG export business. In any case, increased availability of tight oils, natural gas liquids (NGLs), and natural gas is helping to resurrect the US chemicals and petrochemicals industries, and additional ethylene production was always going to weigh on Asian and European crackers relying on naphtha for feedstock, potentially leading to their closure. The falling away of gasoline and naphtha demand – key drivers for the sustainability of European refineries – is likely to pressurize light-end prices.

Figure 12: US refinery runs, mb/d



Source: EIA

Figure 13: US net import of products, mb/d



Source: EIA

US finished product exports have risen from around 1 mb/d in 2005 to a record high of 2.7 mb/d in 2012, with diesel seeing the bulk of the increase, climbing from 0.14 mb/d in 2005 to above 1 mb/d in 2012. Although the USA remains a net importer of gasoline (see Figure 13), exports from the Gulf Coast to growing demand centres in Latin America have risen almost four fold since 2005 to above 4 mb/d. Both these trends have continued into 2013. Separately, exports of NGLs, mainly in the form of LPG and propane, have also hit record highs, with the former up from a mere 50 thousand b/d in 2005 to nearly 0.2 mb/d in 2012, and the latter from 37 thousand b/d to above 0.2 mb/d by the end of 2012. Even pentane exports are now above 0.1 mb/d, 16 times the amount in 2005.

US Midwest: cheap crude has boosted profit margins for refineries

US Midwest refineries have benefitted the most from this dislocation, with two years of record margins, thanks largely to the severe dislocation of WTI and other Midwest crude grades. As discussed in the previous section, WTI, Bakken, Syncrude, and WCS prices all traded at severe discounts to Brent, ranging from –$25 to –$50 at various points through 2011 and 2012. As a result, US Midwest refining margins remained at record highs. As Borenstein and Kellogg note:

> *Our results imply that the primary beneficiaries of depressed Midwest crude oil prices have been Midwest refiners rather than Midwest consumers (Midwest and Canadian crude oil producers are, of course, bearing the costs). We emphasize that this outcome does not imply that Midwest refiners are exerting market power. Instead, they are operating at or near their production capacity while benefitting from the fact that the*

marginal refined product suppliers in PADD 2—refineries on the Gulf Coast—are producing from more-expensive crude oil.[5]

Not all the strength in US Midwest refining margins is down to the growth in light tight oils. US Midwest refineries, over the course of the past few years, have upgraded to exploit growing Canadian volumes, attempting to capture the discount at which heavy crudes have historically traded. What the growth in domestic US crude has done is to create further bottlenecks in the US pipeline infrastructure. This has resulted in Canadian crudes trading at steeper discounts than arguably would have been the case otherwise.

However, given the recent rebound in US Midwest and Canadian crude prices, refinery margins are coming under pressure. For instance, US Gulf Coast cracking margins, based on WTI, averaged $22 per barrel in 2012 and $18 in 2011, compared to $6.50 in the previous five years. The strength of Gulf Coast margins continued in the first half of 2013, averaging $20 per barrel; however, since the pick-up in WTI prices commenced in April, margins have started to come down sharply, averaging around $14 in June and falling below $5 in September.

Of course, executives at publicly held US oil refiners have been at pains to reassure investors that the dislocations once seen in the North American crude oil market will return, once again delivering bumper profits to refineries. However, private equity firms are already starting to dispose of the smaller refineries that would have been mothballed if they were not benefitting from dislocated crude. ACON Investments and TPG Capital, the two private equity groups that control the general partner of Northern Tier Energy, a Minnesota oil refiner, are selling off part of their controlling stake in the firm, cashing out more than $250 million from their investment. While reasons for selling could be many and varied, one cannot ignore the fact that the easy money in the investment has been made and the going is only going to get tough from here as the oil distribution network has made significant strides to clear the Midwest bottleneck and as a result has erased most of the price dislocations. Worse still for the Midwest refineries, they do not have easy access to export markets, as their Gulf Coast counterparts do. Indeed, having outperformed the global oil index over the past 18 months, peaking at 80% in Q1 2013, shares of the US refining sub-sector has come off sharply since Q1 2013. In fact, following this correction in share prices of US refining companies, valuations collected by Bloomberg have moved back in line with averages seen over the past three years, when considering the price/book value (P/BV) metric.

The so called 'golden era' of US refining is slowly drawing to a close, even if these refineries continue to enjoy cost advantages such as cheap electricity and natural gas prices, compared to their European counterparts. Thus, following the changes to pipeline configurations, US Midwest crude dislocations are set to disappear for a while, and this is likely to affect utilization rates at refineries, with the potential for run cuts, particularly in the Midcontinent, becoming non-trivial.

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[5] 'The Incidence of an Oil Glut: Who Benefits from Cheap Crude Oil in the Midwest?', Borenstein and Kellogg, NBER working paper, June 2012.

US East Coast: rail allowing arbitrage of dislocated crude

Another group of refineries benefitting from cheap domestic light sweet crude is found in the US East Coast. These refineries have, until recently (end-2012), been entirely dependent on the more expensive imported crude, unlike their compatriots in the Midwest that have benefitted from landlocked and hence depressed crude prices. By the end of 2011, East Coast refiners were paying almost $11 above the national average price of inputs for refineries – more than $17 above the Midwest and $9 above the Gulf Coast. As a result, these gasoline-biased refineries were on the verge of exit from the market, with some even announcing closures. However, East Coast refineries are beginning to get a new lease of life, mainly because it is now possible to rail discounted shale oil to any part of the USA, thereby lowering the cost of inputs to these refineries significantly. Not only does crude from North Dakota lower input prices for these refineries, Bakken crude also produces more gasoline, to which these simple refineries are geared. As a result, refineries that had been idled or shut down – such as Sunoco's 0.34 mb/d Philadelphia and 0.18 mb/d Marcus Hook refineries and ConocoPhillips' 0.19 mb/d Trainer refinery – are being restored to operations.

Although a lifeline for East Coast refineries, the benefits rely on Bakken prices remaining significantly depressed in comparison to international benchmarks. This is due to the extremely high cost of railing and barging crude from Bakken to the East Coast refineries, with estimates for these transport costs ranging from $15 to $20 per barrel. For instance, at the peak of the dislocations, Bakken prices were trading at a $20 discount to WTI, which itself was at a $20 discount to Brent. Thus, even after paying a substantial fee for railing Bakken crude to the East Coast, the feedstock cost was $20 cheaper than imported European and Nigerian grades. Lately however, greater takeaway capacity and rising regional demand (with new refineries coming online in North Dakota) are resulting in a narrowing of the differential between Bakken prices and imported crudes (Brent-related), eroding the competitiveness of Bakken crude used by refineries. Of course, a large part of Bakken transported by rail is on long-term contracts, while for spot volumes producers are resorting to discounting wellhead prices to allow Bakken crude to arbitrage all over the USA. However, if the midstream manages to keep up with the upstream over the next few years which seems to be the most likely case(thereby avoiding significant discounts in crude prices), the competitiveness of US refineries in the Midwest and the East Coast is likely reduce, and refinery utilization, which has been well above 95 per cent (as these refineries have been running at maximum capacity to exploit the stellar refining margins) risks coming down to historical averages of around 80–85 per cent.

US West Coast: constrained by geography

Similarly, West Coast refineries, dependent on high-cost imported crudes, are trying hard to secure cheaper domestic crude. The state's refiners have long depended on crude from now-shrinking fields in California and Alaska. Imported crude, sourced from Argentina to Asia, now meets half of California's demand, up from just 10 per cent in 1995. Although California has the largest shale play in the country, (the Monterey shale) output growth has been disappointing and producers have struggled with geology that differs from other fast-flowing reserves. Since the Rockies represent an expensive barrier to the development of pipeline competition, the West Coast is highly attractive for the crude-by-rail market.

Northwest refineries are far closer to North Dakota or Alberta production than to the Gulf Coast. In fact, Canadian crude supplies traded at prices approaching an average discount of $40–$50 to Alaskan North Slope (ANS) crude through 2011 and 2012, while according to figures from Valero, estimated rail costs from Alberta to the West Coast stood at $13 per barrel. At the same time, ANS crude traded at around an average premium of $25–$40 to Bakken crude, with figures from Tesoro showing rail costs of around $13–$20 a barrel from the Bakken area to Washington State. Since many Californian refineries run on heavier sour crudes, WCS delivered by rail represents a very attractive alternative. New rail loading terminals are also being developed in the Rockies; these will be able to transport crude from the Niobrara basin to the Northwest.

Although the price incentives are clearly in place, the build out of rail capacity is challenging and time consuming. Currently, only around 80 thousand b/d of Bakken crude from North Dakota is moved west to Washington State by Tesoro and US Oil refining (the rail costs between North Dakota and Washington State are about $13 per barrel, according to Tesoro) and once there, it struggles to move south to other refineries. Phillips 66, NuStar Energy, Shell, and BP are all looking into moving crude to Washington State, with various permits in place to take offloading capacity to 0.2 mb/d in the West Coast, primarily in Washington. By 2014, this total is expected to rise to nearly 0.4 mb/d, but this would still represent only a small proportion of the region's current 1.2 mb/d of imports.

Worse, there has been less progress on moving crude all the way to California. Alon USA Energy is building a 70 thousand b/d rail unloading terminal and reconfiguring its 94 thousand b/d refinery to handle lighter Bakken crude by the end of 2013. Apart from Alon, only Valero has announced plans to build rail receiving terminals (at its Benecia, CA and Wilmington, CA refineries) to handle both Bakken and Western Canadian heavy crude. The project is expected to be complete in 2014. The permitting process to build these terminals, however, is rather slow in California; it takes nearly a year to gather all the necessary permits to build a rail offloading terminal. And now that the price advantage of using domestic crudes such as the Bakken is fast eroding, due to infrastructure developments, there may be a slightly lower incentive to push forward with these permits.

Overall, despite these measures, foreign imports into this region can only increase, given the swift decline in the region's crude production, unless dedicated terminals that can handle meaningful volumes are built to give Californian refineries access to increased supplies of domestic crude. Moreover, California is implementing a law that requires emissions to fall below, or to equal, 1990 levels by 2020. This will involve billions of dollars of investment to upgrade refineries to meet the requirement. One component of the law might also affect efforts to use more domestic crude: the Low Carbon Fuel Standard (LCFS) requires Californian refineries to run crudes produced in more environmentally friendly ways. The regulations are yet to be finalized, but LCFS could possibly be an issue with Bakken crude, due to high volumes of natural gas flared during production, or with even cheaper Canadian crude due to the high level of emissions produced during extraction. The higher carbon emissions of truck or rail transportation of crude in comparison to pipelines are also likely to add to the carbon intensity that will determine the crude that West Coast refineries will be able to process under LCFS.

US Gulf Coast: quality issues with US shale bites

However, not all refineries are likely to benefit equally from the growth of tight oils in the USA, even if prices were to remain dislocated. US shale sits at the extreme right of the API gravity spectrum; the bulk of tight oils production being light sweet crude, with a significant percentage consisting of super-lights (50 API+) and very high volumes of condensate. Crude oils with a higher API are usually priced at a premium to heavier crude, in part because they yield greater volumes of the more valuable products (gasoline and distillates) and can be processed by far less sophisticated and energy intensive refineries. A light crude typically yields 25 per cent naphtha and lighter products, 30 per cent middle distillates, 30 per cent gas oils, and 15 per cent bottoms. The higher the API, the greater the volume of light products (such as naphtha and gasoline) produced. Heavy crude, on the other hand, yields much more fuel oil, but still spreads over the different fractions.

These technical features are important for two reasons. First, both the US Midwest and Gulf Coast refineries have added a significant amount of new upgrading capacity, including a large tranche of coker capacity, to process heavier grades because just a few years ago the marginal supply barrel was getting heavier, led by incremental supplies from Canada, Brazil, and Venezuela. The US Midwest refineries expected to capture a higher value from discounted Canadian heavy crude, while the Gulf Coast refineries remained focused on capturing higher value from discounted heavy waterborne crudes, and eventually tapping into the heavy Canadian supply once it was able to make its way down to the Gulf Coast through the Keystone XL and various other pipelines. As a result, these refineries invested in upgrading capacity to take advantage of cheaper heavy crude. Since then, Brazilian production has continued to disappoint and Canadian crude has failed to reach the Gulf Coast due to pipeline politics, while at the same time, the US boom in shale oil has altered the API gravity and sulphur content of domestic crude.

These upgraded refineries are not usually equipped to handle the larger yields of light end products (such as LPGs and light naphthas) that are produced from lighter crudes. If the crude distillation unit (CDU) is set up to run heavy crude but instead gets fed light slates, it is likely that the top of the tower will be flooded, as more light products will be produced than the unit is designed to handle. Under these circumstances, some refiners are likely to produce excess volumes of light intermediate refinery streams (reformer feed and light straight run) while others are likely to find themselves short of heavier intermediate streams, such as fluid catalytic cracking unit (FCCU) feed. Many US refineries are not configured to process increasing quantities of light crudes; this is due to column limitations, compressor constraints, and overhead cooling issues – all of which can limit charge rates. Consequently, the refiner either has to reduce capacity or reverse the recent retrofit, which is likely to be an extremely expensive process, but one that seems inevitable given the growth of super light crude oil.

Clearly, with the Gulf Coast being the largest refining centre in the USA, this creates a significant mismatch between supply and demand of light and heavy crude. The problems do not end there. Refineries have also complained about the variability of Eagle Ford crude, whereby the quality of the crude they receive differs shipment by shipment. As a result, various refineries are running large batches of Eagle Ford to simply test their properties and product yields; in general they find a rather large (40 per cent) naphtha cut and less than 5 per cent bottoms/residual fuel oil, with 30 per cent of the crude they are receiving being spiked with condensates.

Second, the tight oil crudes are light not just by the API measure, but also on diesel yields. Bonny Light (one of the Nigerian crudes getting backed out of the Gulf Coast by rising domestic production) has kerosene (360–500°F cut) and diesel (500–650°F) yields at 20.8 per cent and 24.8 per cent respectively. For Bakken crude, the numbers are much lower at 14.7 per cent and 14.3 per cent. Condensates, which make up more than half of Eagle Ford production, have even lower kerosene/diesel yields – well below 5 per cent. The tight oils are high on naphtha, and are thus biased towards producing more gasoline.

For the past two years, US Gulf Coast refineries have benefited from a booming diesel market, due to the growing demand in Latin America and refinery closures in Europe, where demand remains biased towards distillates. As a result, according to EIA figures, US diesel exports have soared to record levels. Moreover, Gulf Coast refineries are well equipped to remove sulphur from the distillate pool, in order to meet the European and US ultra-low sulphur diesel specifications. In contrast, US domestic demand for gasoline has fallen over the last five years (EIA). Although gasoline exports have been growing, the international market for gasoline is far more competitive than it is for diesel and hence offers lower margins.

Some Gulf Coast refineries have made significant adjustments to accommodate the quality mismatch. Many, like Valero, are shelving plans for their new coker units as they do not see light–heavy differentials staying wide enough to justify another coker. Others, like Citgo, a major refiner of heavy grades, have started to blend Eagle Ford crudes at their refineries, replacing Venezuelan and Nigerian crudes. Some, such as Marathon Petroleum, moved to an entirely domestic crude slate, mostly from Eagle Ford, earlier this year. This has definitely reduced the amount of lights and medium crudes being imported by the USA, but there are limits to how much a refinery can adjust in order to process these lighter crudes.

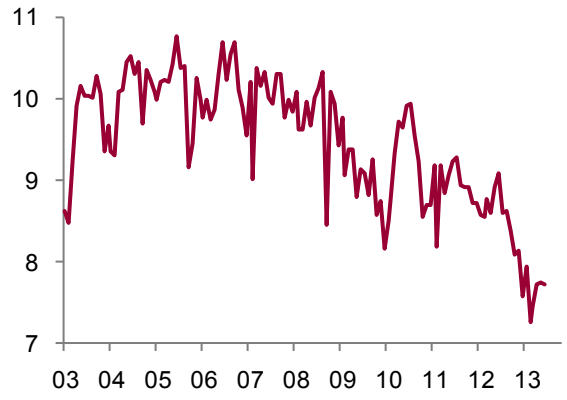
Clearly, the benefits of a dislocated crude market have not been homogenous for all US refineries. The Midwest refineries gained the most, being at the heart of the crude price dislocations, followed by Gulf Coast refineries, as a significant amount of the dislocated crude made its way to the region with the highest crude value. Lured by the steep discounts, East Coast and West Coast refineries also started to sign up to railing and barging crude from North Dakota all the way to the refineries. However, as infrastructure bottlenecks started to disappear, so did the crude price dislocations, thereby eating into refinery margins. This process was also aided by the slight slowing in growth rates of tight oils output itself and, more importantly, by the increasing growth of super light oil in the overall mix, which has resulted in refineries, particularly in the Gulf Coast, being unable to process much of this domestic oil due to quality issues and varying metal and sulphur content. Gradually, the golden era for Midwest refineries of record high margins from dislocated crude is drawing to a close, while East Coast and West Coast refineries are finding themselves tied to domestic crude prices whose values are rising swiftly and which, when adjusted for extremely high rail costs, are often turning out to be more expensive than imported barrels. It now seems that the easy gains for refineries from the tight oils boom have been made; moving forward, any comparative advantage will depend on a refinery's location (proximity to facilities such as export terminals) and the right quality of crude.

2.3 Impact on Trade flows

A large part of the call for US energy independence implies that the USA, currently the largest importer of crude oil, should halt imports for its domestic needs (or at least to back out all waterborne exports) and rely entirely on tight oils output from the USA and heavier crude through pipelines from Canada.

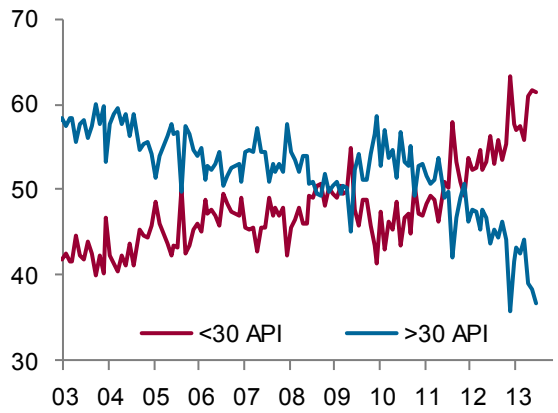
US crude oil imports peaked in 2005 at an annual average of 10.12 mb/d and flatlined through to 2007, staying above 10 mb/d. Since then, however, they have been falling steadily, reaching a low of 7.6 mb/d in Q1 2013 (see Figure 14). A large part of the initial drop in imports has been a demand-led process. Sharp falls in US oil demand began in late-2007, gained pace in early-2008, and then became even more severe after the onset of the financial crisis in September 2008. From 20.6 mb/d in May 2007, demand fell to as low as 18.2 mb/d in May 2009. Since then the overall trend in US demand has been flat to slightly down. Currently, US demand is slightly higher than 2012 levels and is broadly on a par with 2009 levels, implying that the reduction of imports since 2010 has largely been driven by the growth in tight oils output.

Figure 14: US crude oil imports, mb/d



Source: EIA

Figure 15: US crude imports by gravity, %



Source: EIA

Naturally, suppliers to the USA have been facing a shrinking market for the last five years, but some producers have been more affected than others. This trend was in motion even before the growth of domestic light sweet crude as US refineries, mainly in the Gulf Coast and the Midwest, were in the process of upgrading their refineries to be able to process the cheaper heavier crude grades coming from Canada, Brazil, and Venezuela. As a result, imports from countries with heavy crude were on the rise and those producing lighter grades (Nigeria and Algeria), on the decline (see Figure 15). Indeed, compared to the peak of total oil imports in 2005, by 2008 (well before the tight oils growth picked up) total imports of light sweet crude were lower by 0.3 mb/d and medium grades by 0.4 mb/d, while heavier grades were higher by 0.3 mb/d.

Of course, this trend was accentuated by the light tight oils revolution, which led to an extreme domestic imbalance between light and heavy differentials.

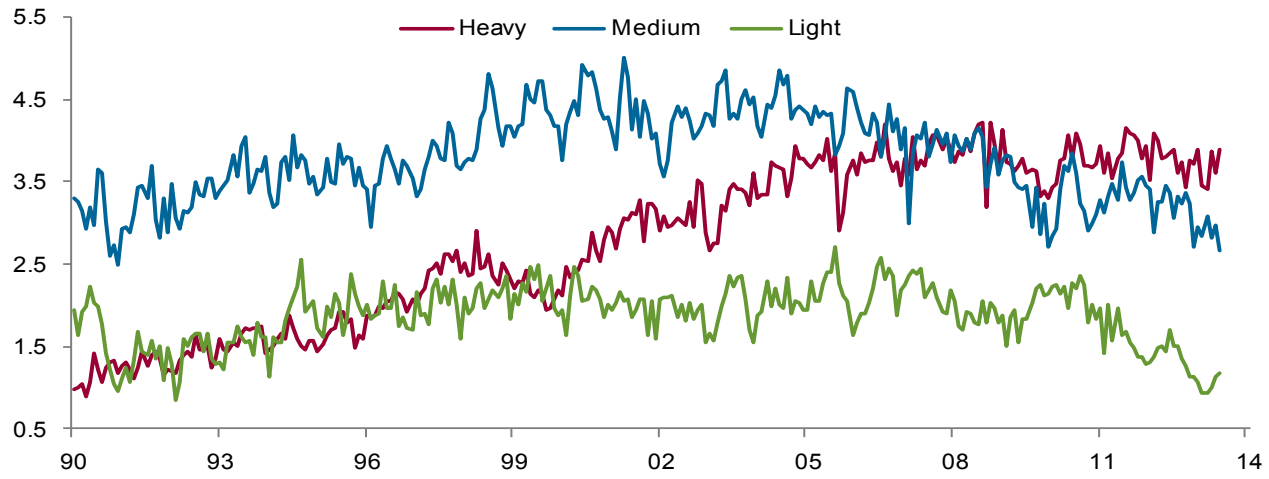
Light crude oil imports have been largely backed out

The natural extension of light tight oils reaching the Gulf Coast is of course the further backing out of US imports. Compared to 2005, light crude imports into the Gulf Coast are currently lower by 0.9 mb/d, and relative to 2007 (the peak for light imports) 2013 volumes are lower by over 1 mb/d. With the start-up of almost 1.4 mb/d of pipeline capacity carrying Eagle Ford light sweet crude to the Three Rivers, Corpus Christi, Port Arthur, and St. James refineries through 2013 and 2014, many expect that by the end of 2013 very few, if any, imported barrels of light sweet crude will be required in the Gulf Coast, especially as the demand is largely for heavier crudes (see Figure 16).

Meanwhile, in the East Coast, imports of light sweet crude had fallen to below 0.25 mb/d in February 2013(about half the volumes shipped to the East Coast in 2010) as increasing volumes of Bakken crude are being railed to these simple refineries which had been reliant on imported Brent-like crudes, particularly from West Africa. Compared to the 1997 peak of over 0.6 mb/d, Q1 13 light crude imports into the East Coast were down by around 60 per cent.

However, the pace of displacement of lighter barrels from here might be slightly slower than market expectations. Refineries in the Gulf Coast have been struggling with the quality of Eagle Ford crude. This is extremely high on condensates, which poses limits on how much can be used in place of foreign grades (see Section 2.2 Impact on Refining). Moreover, and perhaps most importantly (as discussed above) the domestic light sweet crude is significantly lighter on distillate yields in comparison with the West African barrels; this would continue to create a demand for some imports of light, sweet crude with better distillate yields, such as the Nigerian grades. Refineries, such as Marathon, have stated in various instances that some light sweet crudes will continue to be imported. Even in the East Coast, imports of light crude have started to pick up towards 0.45 mb/d in Q2 13, as domestic crude prices started rising and quality issues with domestic crudes started to come to the fore.

Figure 16: Imports of light, medium, and heavy crude grades into the USA, mb/d



Source: EIA

But a bid for good quality light grades remains

In fact, a direct consequence of the quality issues with light tight oils is that the backing out of imports is not limited to the light volumes. While light crudes cannot back out medium grades one-for-one due to refinery optimization consequences, a large part of the growing condensate volume in the tight oils stream is being blended with waterborne heavy crude imports and the slowly but steadily growing amounts of crude-by-rail from Canada, to create medium look-alikes. Even the Keystone XL Southern leg and twinned Seaway pipelines are likely to carry some heavy barrels down to the Gulf Coast by early to mid 2014. Thus, as more domestic crude is blended with heavier grades, it is imports of the medium crudes (defined here as 25–35 API) that are getting backed out (see Figure 16). However, once again, these blended crudes are low on distillate yields, as they are created as dumbbell crudes by blending super lights and super heavies, both poor on diesel yields and sometimes high on metal content. In the Gulf Coast, medium crude grade imports peaked well above 2.5 mb/d in 2005 and have halved to just 1.3 mb/d in Q1 2013. Similarly, in the East Coast, medium grades have fallen by nearly 0.45 mb/d from the highs of 2003. Indeed, there could be a plausible situation where some more medium slate (particularly those with API greater than 30) gets backed out as the condensate-rich light crudes are blended with rising volumes of heavy crude imports, but as was seen with the lights, above, there will be limits to the amount by which medium grade imports will be reduced, due to quality constraints.

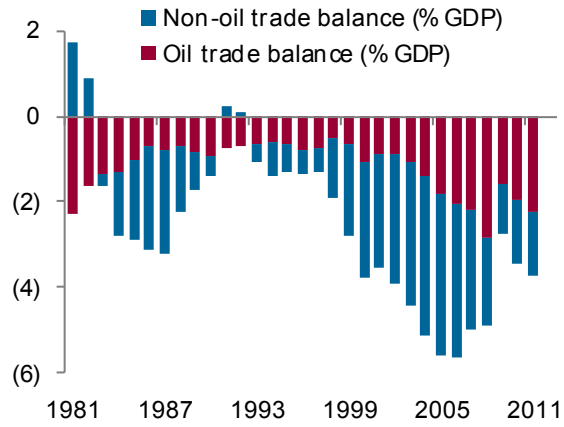
Nonetheless, the fact that some more medium grades can still backed out has direct consequences for exporters such as Saudi Arabia, Mexico, Iraq, Brazil, Colombia, and even Nigeria, among others. While Mexico, Venezuela, Brazil, and Saudi Arabia also supply the USA with large volumes of heavy crudes, and their medium grades sit at the low end of the range (less than 30 API), it is countries such as Nigeria – where output is biased towards medium and lighter grades and more is sold on a spot basis than long term contracts, whose volumes have been worst hit. Similarly, Iraqi imports look to be threatened, given that the bulk of imports from Iraq are 30 API or above, although companies supplying their US refineries directly from their production in Iraq may slow the process down. Put another way, crudes with API gravity of 30 or above will be gradually replaced by domestic crude to a certain extent over the coming years, with African and some Latin American producers the worse affected.

On the whole, US crude oil imports, which have declined by nearly 2.5 mb/d since the peak in 2005, have also seen a significant change in the quality and destination of the crude being imported. Due to the changes to refinery configurations, followed by the growth of light tight oils domestically, imports of light sweet crudes have fallen furthest. Relative to nearly 2.2 mb/d of light imports in 2005, imports are now just 1 mb/d. Medium crude grades have also declined, down by over 1 mb/d over the same time period to just under 3 mb/d (see Figure 16). The new and reversed pipelines, all geared towards carrying more crude to the Gulf Coast, could speed up the process of backing out some more medium grades, before blending constraints cap the process. Finally, imports of heavy crude grades are actually higher relative to 2005, by around 0.1 mb/d (see Figure 16). It is worth noting here, however, that although heavy crude imports are higher, the entire increase, and more, has come from Canada; as a result, heavy waterborne imports have declined, negatively impacting countries like Saudi Arabia and Venezuela. For instance, Venezuelan imports fell to below 0.8 mb/d in early 2013, well below the peak of 1.2 mb/d in 2004. Imports from Saudi Arabia are down from a figure of over 1 mb/d (through most of the late

1990s and early 2000s) to around 0.9 mb/d, having fallen to below 0.7 mb/d in 2009, with the latest increase partly due to the start-up of the Saudi Aramco joint venture refinery (the 0.325 mb/d Motiva refinery designed to process heavier crudes) at Port Arthur.

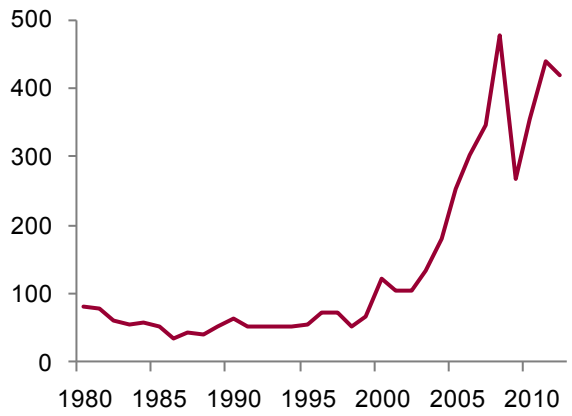
Overall, based on a definition of crudes with an API less than 25 as heavy, 25–35 as medium, and over 35 as light, the USA imports just over 1 mb/d of light crudes, around 3 mb/d of mediums, and close to 4 mb/d of heavy. Of these volumes, imports into the Midwest will remain largely intact, especially given the vast upgrading refining capacity present. Further, given the challenges of railing crude to California and the rapidly declining production in the region, it is fair to assume that imports to the West Coast will not be backed out over the next few years at least. Thus, replaceable crude volumes are 4.3 mb/d at most, which would imply no imports into the Gulf or East Coast. However, that is a highly unlikely situation given the grade quality issues, limits to the extent to which refiners can substitute condensate for crude, demand for heavier grades on the Gulf Coast, narrowing differentials between light sweet US grades and the rest of the world, and strategic investments by countries such as Saudi Arabia in refineries in the USA. Moreover, as more light crude reaches the Gulf Coast, imports of heavy crudes might increase in order continue blending to make medium look-alikes. Adjusting for these factors, a maximum of 2–2.5 mb/d of additional crude oil can be backed out over the next several years, assuming slightly downward trending demand. But due to quality issues in tight oils the actual volume of crude being backed out from here will be less than this, and will probably be around 1–1.5 mb/d.

Figure 17: US balance of trade, % of GDP



Source: Datastream

Figure 18: US oil imports, $ bn



Source: Datastream

It is important to note that despite the reduction in oil imports, the impact on the country's balance of payments has been limited so far. Oil constitutes 60 per cent of the trade balance (see Figure 17). While US oil imports have started to fall (down by 24 per cent since the 2005 peak, see Figure 18), the USA remains the world's largest importer of oil and the increase in oil prices has meant that the value of imports has not fallen in the same way. A further backing out in crude imports will help the trade balance no doubt, but given the discussion above, it is unlikely to be a material shift.

3. Global impacts

3.1 The US supply shock in a domestic perspective

The US tight oils revolution has been touted as a game changer by many. Of course, the size of the shock has been nothing short of phenomenal, with both 2011 and 2012 seeing 1 mb/d of year on year growth in US total liquids production, a feat previously achieved in the 1990s by the former Soviet Union (FSU). Having declined from 1985 through to 2008, US oil production reversed the course, largely due to the commercialization of tight oils. Since 2009, US oil production has seen a sustained period of growth, accelerating through 2010 and 2011. In late-2011, total US liquids output surged past 9 mb/d and then past 10 mb/d in 2012. The cumulative rise since early 2009 currently stands close to 3 mb/d, with the largest growth coming from crude oil (67 per cent), followed by natural gas liquids (26 per cent), and the remainder being made up of biofuels. The growth in shale oil, concentrated in North Dakota and Texas, has largely been responsible for the increases in the crude oil element. Given the disappointment related to non-OPEC supply performance through the second half of the last decade, the US renaissance has not only been a significant positive shock in terms of actual production profiles, but also in terms of sentiment, with market perception shifting towards a resource abundance mindset compared to one of scarcity just a few years ago.

Expectations have naturally been sky high given the recent performance of US supplies. US reserves have been described as 'two Saudi Arabias' by a US independent company CEO. Texas alone has been touted as the next big thing set to overtake Kuwait and UAE as the third largest oil producing 'nation' of the world. Thus, the natural expectation from a world awash in oil is that prices will fall, perhaps quite sharply, as shale revolutionizes an otherwise ailing non-OPEC supply picture, putting to rest the peak oil argument once and for all. This has been one of the key reasons why sentiment has turned bearish in the crude market, pressurizing the back end of the forward curve while expectations of long-term prices have come down considerably.

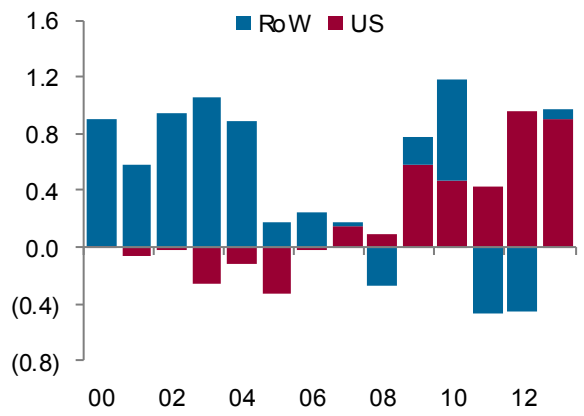
With faltering domestic demand but surging domestic production, US crude oil imports have fallen from 9.8 mb/d at the start of 2009 to around 7.5 mb/d in 2013, thereby backing out some 2 mb/d of crude to the global markets. US crude inventories also started to climb, soaring to record highs even as the rest of the world continued to draw stocks. Indeed, crude oil inventories in the OECD outside the USA have, since 2012, languished below the five-year average while US stocks have climbed to as high as 50 mb above seasonal averages. Clearly, seen through the prism of the USA, there seemed to be an oversupply of crude; this is in stark contrast to the rest of the world, which faced fairly robust demand but extremely weak non-OPEC supplies. This contrast was also visible in the differences between global and US crude oil prices.

3.2 The US supply shock in a global perspective

From a global standpoint, despite the size of the positive supply shock from the USA, Brent has managed to hover around and above $100 per barrel through 2011, 2012, and the first nine months of 2013. In other words, the growth of shale has not had any substantial impact on price levels. Part of the reason for global oil prices still being above $100 relates to the weaknesses in supplies elsewhere. In 2011, the growth in US production was entirely offset by declines in other non-OPEC countries, particularly in the North Sea and the FSU (see Figure

19). In 2012, geopolitical outages in the Middle East – in Syria and Yemen – added to supply problems. Of course 2011, 2012, and 2013 saw large OPEC supply outages as well, in the form of Libya, Iraq, and Iran, which resulted in losses of over 1 mb/d from the market for a prolonged period of time (see Figure 20). The growth in US tight oils production was clearly not sufficient to balance the market, as Saudi Arabia had to step in to fill this hole in the market. Thus, there have been enough moving parts elsewhere to offset US oil supply growth so far. Despite the significant addition to North American supplies over the past few years, OPEC has not had to cut supplies. OPEC supply has been stable at around 30 mb/d or higher, a healthy level compared to historical norms, with most of the variations caused by demand swings rather than a supply surge.

Figure 19: Non-OPEC oil production, y/y chng, mb/d



Source EIA, Energy Aspects

Figure 20: OPEC oil output ex Saudi Arabia, mb/d

Source: Energy Aspects

In fact, contrary to the general view in the market that the abundance of shale was going to create a supply glut in crude, or that it would be refined into products (meaning the oversupply would appear in product stocks), neither has really materialized. What has happened instead is that the crude overhang has been chewed up by refineries running hard, while product stocks have not built commensurately as end demand has actually picked up. While inventories were broadly tight in the rest of the world (due to supply shortfalls and pockets of demand strength), the USA did show a large crude overhang relative to five-year averages. Even that has now changed. Compared to an overhang of over 40 mb through most of 2013, August has seen that crude overhang reduce to 15 mb, thanks to a drop in crude stocks at a rate of nearly 1 mb/d since 21 June. Adjusted for a substantial level of linefills and tankfills of around 20 mb over the last year (which the EIA data includes as inventories) we believe US crude stocks are at the five-year average. And for all the talk around the booming Eagle Ford tight oil play, the flows being diverted from the Midwest to the Gulf Coast through rail and reversed pipelines, together with continued foreign imports at nearly 4 mb/d (to the GC), crude stocks in the Gulf Coast are now below the five-year average for the first time since March 2012. In the meantime, US product stocks (if one excludes the estimated 'other oils' category) have built in absolute terms, although not relative to seasonal averages,

supported by robust Latin American demand and an improving domestic economy. Thus, the inevitable glut is oil stocks has yet to materialize.

US output growth has been offset by shortfalls elsewhere

The correct way in which the US supply shock can be seen is, perhaps, not as something that should have collapsed prices, but instead as something that has prevented prices from being significantly higher. Imagine a world without the growth in US tight oils; if this were to be combined with the losses experienced in Libyan output and the existing sanctions on Iran, it would be a world with almost no spare capacity, as Saudi Arabia, the UAE, and Kuwait would have had to pump at their maximum production limits. Of course, demand would have fallen sharply to eventually balance the market, but had US output not grown, Brent prices might have been closer to $150 per barrel.

And yet, there is still a widespread view that the 2011–13 dynamics could change and an increase in US oil production will cause global oil prices to weaken sharply in the coming years. Perhaps the largest single argument against that outcome for the coming years is the experience of 2013, 2012, and 2011. If a large positive US oil shock did not cause prices to crater this year, or in either of the past two years, then why would a rise in US supply achieve that in the next few years (especially given that the year on year increases are already slowing down and given no material improvement in the rest of the supply centres (OPEC or non-OPEC) is evident at all)? If anything, countries that held great promise – such as Brazil, Kazakhstan, Azerbaijan, and even Canada – have all failed to live up to their initial expectations, due to a combination of high decline rates, high costs, and infrastructure bottlenecks. More importantly, the demand backdrop in the last few years has hardly been strong. Mired by extremely weak growth in Europe, and also by a slowing macroeconomic engine in China, oil demand growth has averaged around 0.8 mb/d, driven entirely by minimum growth in non-OECD countries outside China. However, for the first time in three years, the macroeconomic backdrop is slowly starting to pick up; this is evident in the significantly positive momentum in oil demand, which is helping to draw down stocks quite rapidly. Overall, for the last decade, non-OPEC supply as a whole has proved to be weaker than expected, but the disparity would have been enormous had US production not outperformed, and would have been larger still had demand growth been anywhere near 2010 or pre-2008 crisis levels.

Equally, for the coming years to be significantly different from the past three years, a different policy response from OPEC would be required, whereby Saudi Arabia and others would be unwilling to defend a price floor at around $100 by adjusting production, as they have done over the past few years. In other words, for global oil prices to find a new norm substantially below $100 per barrel, a perfect storm of factors – weak oil demand growth due to a fragile macroeconomic backdrop, an improvement in non-OPEC supplies outside the USA, a sharp increase in Iraqi production, and a breakdown in OPEC cohesion – would be required. Thus, the bearishness based on the idea that US oil supply alone is the key marginal factor that will determine global price outcomes may prove to be overoptimistic.

Shale requires high oil prices

However, if of the events listed above do happen in unison, it would be very difficult, if not almost impossible, to construct a case that oil prices will still remain buoyant. And should oil prices decline, tight oils production will be put at risk, given the high cost of production. What makes tight oils production costly is predominantly the high decline rates. The nature of tight oils wells is very different from that associated with conventional production – for example, the natural decline rate of a tight oils well is extremely high, in most cases between 50 and 70 per cent per annum. This produces a severe fall in output in a field, unless further hydraulic fracturing is carried out and new wells are brought online. Judging by production results published by producers, first-year decline rates in unconventional basins look to be of the order of 50 to 70 per cent, varying by basin and even within basins. They continue to decline steeply thereafter, and so offsetting decline rates in these basins becomes an additional cost burden for producers. In addition to funding the upfront capital costs to hold acreage, the costs of adding infrastructure (such as roads and gathering pipeline networks) and doing the science required to delineate sweet spots/completion and to drive growth, together with the high running costs of hydraulic fracturing processes, make the total variable cost far more expensive. The US shale industry spends close to $100 billion per annum to fund such activities; this represents a hefty breakeven price requirement for the industry as a whole. The high costs are also evident in the soaring debt levels of US independent producers, which have managed to grow production solely by fuelling debt.

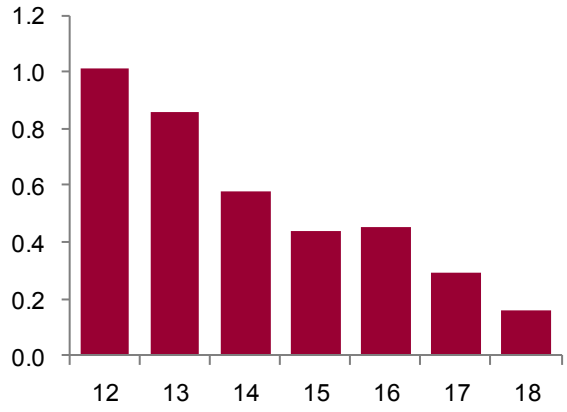
Thus, there is an internal inconsistency in the very argument put forward by many in the market – that tight oils growth would lead us to an era of cheap oil – because if prices fell much below $90 on a sustainable basis, it would not be profitable to produce from these resources. In other words, the primary reason for the growth in tight oils output is that oil prices stayed high, around $100, for a prolonged period of time. What tight oils do, at least in the near term, is to cap the upside in prices, making any runaway increase in average prices, beyond geopolitical or economic reasons, unlikely.

Shale exhibits very high decline rates and variability

A key question to ask here is: given the hefty decline rates that characterize shale plays, even in an environment of high oil prices, can the momentum in US tight oil production growth continue? This is particularly pertinent given today's expectation that the oil market will remain balanced in the future –essentially, relying on US production to continue outperforming. Continuing to grow at current levels implies incessant drilling, not just to hold production steady by offsetting decline rates, but to add to output levels. But that implies a doubling, tripling, or quadrupling of the service sector in the USA over time, even after adjusting for all the efficiency gains the producers are making. That is simply not feasible, and would imply that tight oils production growth is due to slow down quite dramatically, as drilling is unlikely to be able to keep up to offset these decline rates (see Figure 21). Moreover, currently, beyond Bakken in North Dakota and Eagle Ford and Permian in Texas (the three premier shale basins), no other shale play has shown nearly the same potential, disappointing on decline rates (indicative curves for Eagle Ford and Bakken are shown in Figure 22), costs, or recoverability. The latest reports on Niobrara and Utica are prime examples, with Ohio State stating that the oil wells in Utica have produced less than originally estimated in 2012, and that the oil from the play will be incidental to gas production. Thus, once these three key basins reach peak production, the lack of new finds to offset declines at these fields is likely to

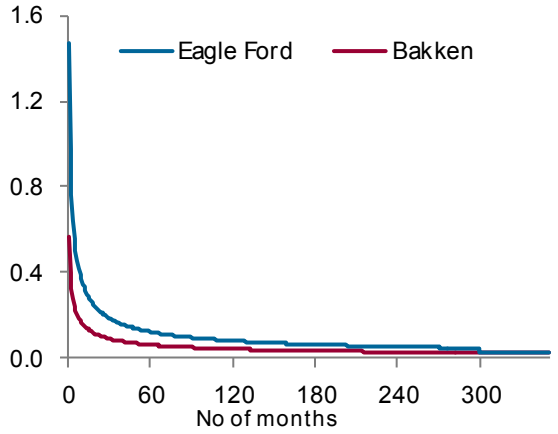
make overall output fall even faster. This is reflected by even some of the most optimistic forecasters, such as the IEA, who see growth in US oil output slowing dramatically from 1 mb/d in 2012 to just 0.16 mb/d by 2018.

Figure 21: IEA's US output growth, y/y chng, mb/d



Source: IEA

Figure 22: Type curves of tight oil plays, mb/d



Source: Company reports

The other issue with tight oils is that the resources are infinitely variable. There is little doubt that the world's shale oil resources are huge, but there are many unknowns that make it extremely difficult to estimate any shale reservoir's ultimate potential. Limited data on shale plays (less than five years' worth) makes it difficult to judge the long-term decline rates of these plays, as declines could be higher still for different oil molecules and tight rocks. Much as with natural gas, declines go unnoticed in the early years of drilling as high initial production rates and drilling activity lift output levels. But once drilling levels subside, steep decline rates are exposed and have served to flatten production in mature areas. The hydraulic fracturing technique is relatively expensive, and is particularly intensive in its use of fracturing crews and other oilfield service industry inputs. It is therefore relatively difficult to maintain steady increases from a given tight oil play because, over time, production rates decline and the increasing draw on specific oilfield service crews becomes more onerous once the initial phase of output take-off has passed. Moreover, to equate below-ground resources one-for-one with above-ground production entirely misses the critical issues of extraction, infrastructure, and transportation constraints which have delayed or substantially raised the costs of delivering oil through the last decade.

The geologies of each play vary significantly between basins and within each shale basin. The production mechanism itself is not understood, and the decline pattern even less so. Service companies, for instance, highlight that they have insufficient data or reservoir modelling capability to lend credibility to reserve or recovery numbers. As a result, many believe that today's approach to shale development is unsustainable, being more akin to the use of brute force rather than sophisticated technology. Indeed, the primary comparative advantage that companies can boast of is based on the quality and timing of the land they acquire. The current approach is characterized by horizontal wells spread evenly over the acreage, with entire horizontal sections being completed and fractured. This has resulted from the industry's inability to predict variations in shale quality. As a

consequence, there are large variations in well performance, and success is achieved only by maximizing the number of wells, to be certain of hitting enough sweet spots to make the development economic. This also results in large variations in forecasts. For US shale oil output, these vary from a low of 1.5 mb/d to a high of 6.5 mb/d by 2020, making long-term forecasting with conviction almost impossible.

Shale crude is too light

Beyond the geological and cost issues associated with tight oils, another key problem relates to crude quality. Tight oils sit at the extreme right of the API gravity spectrum, with a significant percentage consisting of super lights and very high volumes of condensate. Given the vast amount of coker capacity in the US Midwest and in the Gulf Coast (which is best suited to running heavier crude) the quality mismatch in the US crude oil spectrum could not be more apparent. Analysis of Texas data shows that the main producing counties responsible for the significant uplift in volumes over the last 12 months – namely DeWitt, Dimmit, Gonzales, Karnes, and Lasalle – are located predominantly in the wet gas window, or at the border of the oil/wet gas window. Anecdotal evidence has indicated that it is these regions which experience the greatest variation in crude quality and give the lowest diesel yields.

The continuing imports of Nigerian crudes indicate how light the tight oils slate actually is, because in order to receive an acceptable distillate cut, the refineries have to continue to rely on what one would call 'crude oil' with traditional characteristics, and hence resort to purchasing light crudes from countries such as Nigeria. Anecdotal evidence also suggests that North Sea barrels, traditionally defined as light sweet crude with API gravity of around 38, are heading to the Gulf as sour crude, with some refineries in the region running North Sea and Nigerian crudes to compensate for the lightness of tight oils. If the quality of incremental crude heading into storage is becoming lighter, it will be inflating the true stock levels to count them as 'usable' crude. The upcoming condensate splitters next year will help absorb some of this glut (although the naphtha and gasoline they produce may well be off-spec), but the underlying problem of crude quality simply cannot be ignored any more. Indeed, if it turns out that a significant chunk of the tight oils growth is of a quality that cannot even be used by refineries, the argument of a supply glut becomes even more feeble. Similarly, calls for US energy independence entirely ignore the divergence in quality between conventional crude oil and tight oils, which is one of the key reasons why US crude oil imports, following the initial backing out, have now stabilized around 7.5 mb/d through 2013, and have in fact been rising in recent months.

3.3 The impact on prices

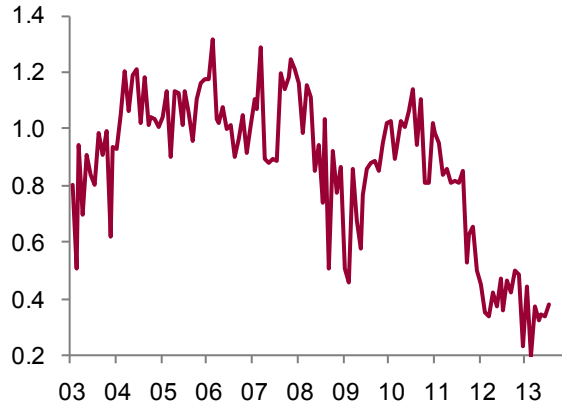
Crude prices and differentials

It is not that the growth of tight oils has not had an impact on global supplies or on the US domestic crude balance – clearly it has. As discussed, without the growth of tight oils, the supply–demand balance of the oil market would be entirely out of whack and oil prices significantly higher. Equally, without the growth of tight oils, US crude imports would still be close to 9 mb/d. But the question here is that of incremental growth and how one should perceive the discussion on the future of tight oils, with mainstream expectations tending to point towards exponential growth in a continuation of the trend of the past three years. Thus, it is worth bearing in mind that not only can incremental growth disappoint from here, given the high decline rates and constraints on the service

sector, but the incremental backing out of crude imports at the pace seen in 2012 will be put to the test, due to the quality problems discussed above.

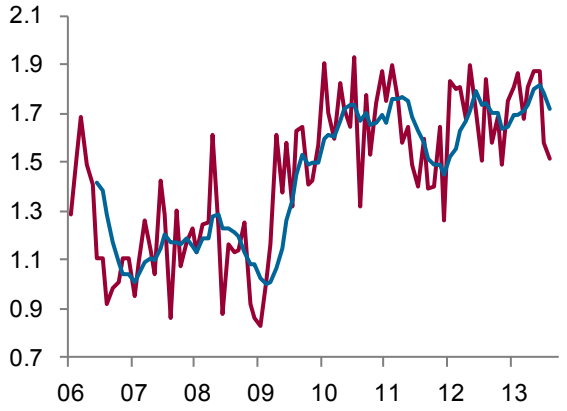
A different, and perhaps a more appropriate, way of judging the primary impact of tight oils and their continuing impact on global markets, is through the impact on trade flows, and hence on price differentials rather than on price levels. The impact on price differentials works through on various levels, through both crude and product flows, cutting across time spreads, inter crude spreads, and inter grade spreads. The growth in domestic production has meant that refineries in the USA have made changes in order to accommodate this increase. Citgo, Valero, and Marathon are all blending Eagle Ford crude to back out imported crudes. East Coast refineries have also restarted, having shut down in 2010/11 due to weak margins, as they are now able to access cheap domestic crude. This, together with a drop in domestic demand, has resulted in the sharp pullback seen in US crude imports, which are now over 2.5 mb/d lower than the 2007 peak. Not surprisingly, light crudes have borne the brunt of that adjustment, with producers such as Nigeria (see Figure 23) and Algeria the worst affected. For instance, without supply outages, Nigeria is finding it increasingly difficult to clear its programme without discounting its crude significantly. Nigerian price differentials have thus come under pressure, with any strength being largely derived from the plethora of supply outages rather than an increase in demand. Weakening Nigerian differentials also have a direct impact on the Brent structure, as they can yield the most attractive margins for refineries in the Atlantic basin, making the refineries switch away from Brent. This, in turn, can pressurize Brent spreads due to reduced appetite from European refineries. Clearly, the more the US Midwest pushes light sweet crude to the Gulf Coast, the more Nigerian grades stay weak, and pressurize the Brent structure.

Figure 23: Nigerian exports to the USA, mb/d



Source: EIA

Figure 24: West African exports to Asia, mb/d



Source: Energy Aspects

This change in trade flows also has implications for inter-crude spreads, particularly Brent–Dubai differentials. West African grades are increasingly popular in Asia (see Figure 24), with Indian imports of Nigerian crudes at nearly 20 per cent of total Nigerian exports. Asian countries usually take their highest volumes of crude from the Middle East, but Atlantic Basin crudes are increasingly making their way east. As European demand remains

weak for the foreseeable future, this trend of higher flows from West Africa to Asia is likely to persist. This has implications for Brent–Dubai, as an Asian pull of West African barrels can serve to widen the differential by lowering demand for Middle East crude, at the same time as reducing availability of African crude in Europe. Of course, stronger Asian demand is unlikely to boost demand for West African crude entirely at the expense of Middle Eastern grades, but West African grades are increasingly likely to become the marginal barrel determining the Brent–Dubai spread. Moreover, Latin American and FSU crudes are also increasingly heading to Asia, partly because Asia is the primary growth centre in global oil demand, but also because other exporters to the USA (primarily the Latin American countries), are diversifying away, thereby creating more competition for Middle Eastern producers, which in turn weighs on their regional differentials.

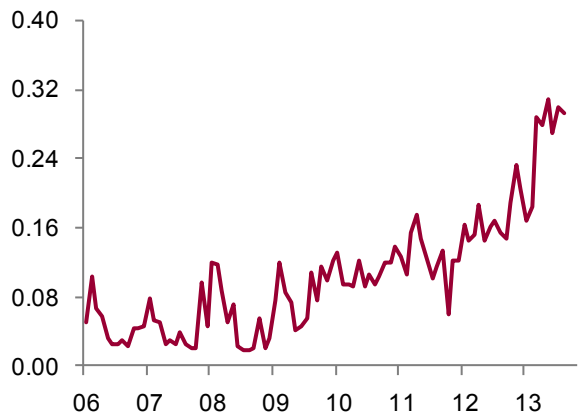
The diversion in trade flows also has significant implications for Middle Eastern producers, namely the OPEC member countries. Since the declining appetite for oil in the west and the burgeoning growth in the east, Middle Eastern producers have turned towards Asia in order to secure stable long-term importers for their crude. Moreover, given declining regional production and lack of alternative import outlets, the growing Asian economies were largely at the mercy of Middle Eastern suppliers through most of the last decade, which resulted in OPEC members often charging their Asian counterparts more than their European and US ones. However, cheaper West African barrels are now proving to be attractive in Asia. This situation is helped by extremely low freight rates, at a time when other crude exporters, such as Russia, Mexico, and Venezuela, are also trying to move away from Western markets and capture the main growth market of Asia. The resultant effect is that Asian consumers now have more alternatives to secure their crude, be it the FSU, Latin America, or West Africa. They are not limited to Middle Eastern producers alone. Naturally, the implication of this is that Middle Eastern producers will now have to become more aggressive in pricing to Asian refineries in order to maintain market share. As tight oils production grows, traditional exporters to the USA (such as Venezuela, Mexico, and Nigeria) will increasingly look east to find buyers for their crude. Once the Panama Canal expands, this trend will intensify further. Thus, Middle Eastern producers may have to revisit some of their marketing and pricing strategies with regards to Asia if they want to maintain their market share in the region.

The final mechanism through which tight oils have had, and will continue to have, a profound impact is on light–heavy differentials and on light-ends in general, which in turn have impacted term structures for the crude curves. This works through two separate avenues. On the one hand, the surge in light tight oils with a significant percentage of super lights (50 API+) comes at a time when refineries in the US Gulf Coast, the Midwest, and around the world have invested billions in new upgrading capacity because they expected the share of extra-heavy oils to grow, mostly with the development of oil sands and extra-heavy oil projects in Canada, Brazil, and Venezuela. Today, the marginal barrel of crude oil has become extremely light, starving the cokers of heavy crude oil and thereby narrowing light–heavy differentials. This has been evident in price action this year, with heavier crudes – such as Urals and Angolan grades – outperforming lighter grades such as Saharan and Nigerian, before the loss of Libyan crude resulted in widespread shortages in lighter grades, and took them higher since June 2013.

Product prices and differentials

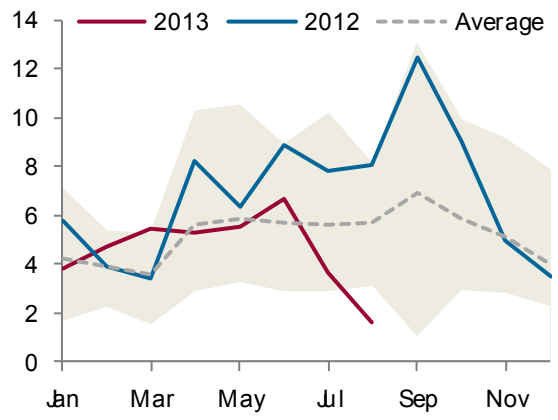
On the other hand, tight oils are also very high on naphtha and gasoline yields, in comparison to distillate and fuel oil yields. Some tight oils have almost no bottoms but can yield more than 50 per cent light-ends. The already negative impact on light crudes has been accentuated through the impact on the product market, as rising naphtha, propane, LPG, and gasoline supplies in the USA are now finding their way into the global market. With US exports of propane at a record high (see Figure 25), naphtha-based chemical plants are switching to propane, LPG, and other cheap light-end feedstocks, wherever substitution is possible. At a time when Asian economic growth is faltering somewhat, and the composition of GDP in countries around the world is changing from being more investment-driven to more consumption-led, naphtha demand is falling. Growing supplies of naphtha, or naphtha substitutes, are thus creating a glut of light-ends, reducing demand for lighter crudes. The decline in naphtha prices is also weighing on European refining margins (see Figure 26), as European refineries are biased towards producing more naphtha and gasoline. Meanwhile, rising gasoline exports from the USA are also taking away market share from European refineries – traditionally the suppliers of gasoline to Africa and even Latin America – while the USA's own gasoline import requirements are falling, given rising domestic supplies and declining demand. Light-end product prices have been under pressure for most of the year and will remain so, given the changes to supply against a backdrop of weak demand. Thus, crudes that yield more diesel and fuel oil will be in greater demand than those yielding naphtha and gasoline, further aggravating the narrowing in light–heavy crudes.

Figure 25: US propane exports, mb/d



Source: EIA

Figure 26: European Brent cracking margins, $/barrel



Source: Energy Aspects

4. Conclusion

The growth of tight oils in the USA has led to a profound change in the global oil market, but the primary impact has been on price spreads of both crudes and products through changes in trade flows, rather than on actual price levels. Thus, contrary to popular belief, the true impact on the oil market is more subtle than a simple

shifting of the entire oil supply curve upwards due to the advent of a new source of supplies; it is perhaps best seen as having localized price level impacts, but global price differential effects.

The discussions around decline rates, variability of basins, high costs, and the light quality of tight oils all highlight the various constraining factors that underpin the development of tight oils. The initial high growth rates have been impressive and have caught the market by surprise, depressing WTI prices and resulting in growing calls for US energy independence. However, not only may expectations of continued exponential growth of US tight oils production prove to be misplaced, but the poor quality of tight oils (especially against a backdrop of refining capacity that is designed to process heavy crudes) makes calls for US energy independence look misguided. Thus, tight oils cannot be thought of in isolation to the rest of the world, if the USA needs to continue to import crude oil, at prices determined by global supply and demand fundamentals. Put differently, the disconnect seen in US crude prices thus far has more to do with infrastructural bottlenecks than with the growth of tight oils. And this has been evident in the price action of WTI as well. Once these bottlenecks were ironed out, US crudes prices rose sharply, and are broadly trading on the basis of transportation costs between the different regions. It may well be that light crude grades in the USA trade at a steeper discount than their heavier counterparts, and that naphtha and gasoline prices weaken relative to distillates or to the bottom of the barrel, but as long as the USA needs to import crude oil, factors such as unrest in the Middle East, production declines in other non-OPEC countries, or strong demand growth in emerging markets, will all continue to impact US crude prices, and the USA will not be immune to these shocks.