Consequences of a heavier and sourer barrel

David Wood of David Wood & Associates looks at the impact of more heavy and sour crudes coming to the market, including the emergence of a Middle East sour crude futures market.

The average quality of crude oil produced worldwide continues to become heavier (higher density/more carbon rich) and sourer (higher in sulphur) as the light sweet crude oil fields are depleting (**Figure 1**). Medium gravity, sour crudes dominate the oil production from the Middle East and Russia, and heavier crudes are dominating remaining oil reserves. 'Sweet' crude is defined as having a sulphur content of less than 0.5%. Oil containing more than 0.5% sulphur by weight is said to be 'sour'.

The global average crude oil quality evolves continuously with time as new fields are developed and those that have produced for many years deplete. The newer fields tend to be heavier and sourer. The average global crude oil currently produced has an API gravity close to 32° and a sulphur content in excess of 1 weight percent (wt %). Only some 20% of global oil production supply can be classified as light and sweet, with the remaining 80% or so classified as medium/heavy and sour.

The largest crude oil volumes being traded globally, primarily on term contracts to buyers in Asia, are Middle Eastern grades close to Arab Light in composition (ie 30° to 35° API gravity; 1.5% to 2% sulphur). It is crude grades of this quality and better that are in demand by refiners as they yield more of the high value, very low sulphur, lighter products (eg gasolines and light gas oils) more easily and cheaply (**Figure 2**).

Only refining processes can make the product outputs match market demand. Unfortunately, the average crude feedstock is moving to the left in **Figure 2** (towards lower quality) and the average product barrel required by the market is moving to the right (higher quality). Not only is this impacting refining costs and the requirements for modern refineries to invest in deep conversion technologies to remain competitive, it is also leading to a widening differential between light sweet crude grades and heavy sour crude grades.

Heavier, sourer crudes are worth less

Several Opec members (eg Venezuela, Iran, Saudi Arabia, Iraq and Kuwait) rich in heavy-sour crude (eg Bachaquero BCF 17 blend from Venezuela with 16.3° API and 2.35% sulphur) are finding it increasingly difficult to find markets for their heaviest and sourest crudes. However, heavy-sour crudes are widely distributed around the world and are not just part of the Opec basket. They include Russian Urals, Mexican Maya and Brazilian Marlim, as well as some crudes from the Caspian Sea and deepwater Gulf of Mexico. The market is continuing to demonstrate its reluctance to buy heavier crudes by the increase in price differentials between heavy-sour and light-sweet grades. For example, the average discount of Arab Heavy crude to spot WTI almost doubled from $6.22 to $11.77 *between the periods 2000 to 2003 and 2004 to mid-2006*.

Synthetic crude oil derived by extensive and costly upgrading of tar sands and bitumen deposits (eg Canada's Athabasca and Venezuela's extra-heavy crude (10° API) trade at even larger discounts to light-sweet crudes because of high refining costs. **Table 1** outlines the remaining fossil fuel reserves and their associated carbon contents. There is much uncertainty in these figures, with most confidence in the proved reserves, which for oil, gas and coal collectively, amount to some 950bn toe that contain some 900mn tonnes of carbon (mn tC). Concern over peak oil is often very much focused on proved conventional oil reserves, but heavy oil and tar sands

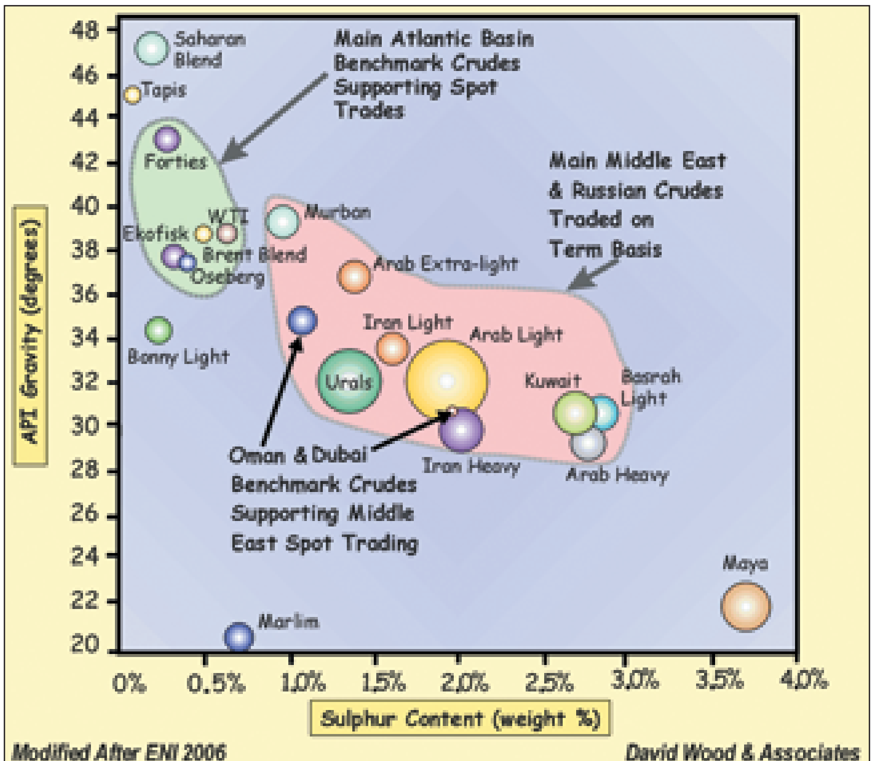

Figure 1: Density versus sulphur content (wt %) of prominent crude oils in 2005. Bubble sizes are proportional to 2005 production volumes. Arab Light and Urals crudes have substantially higher production volumes than other crudes

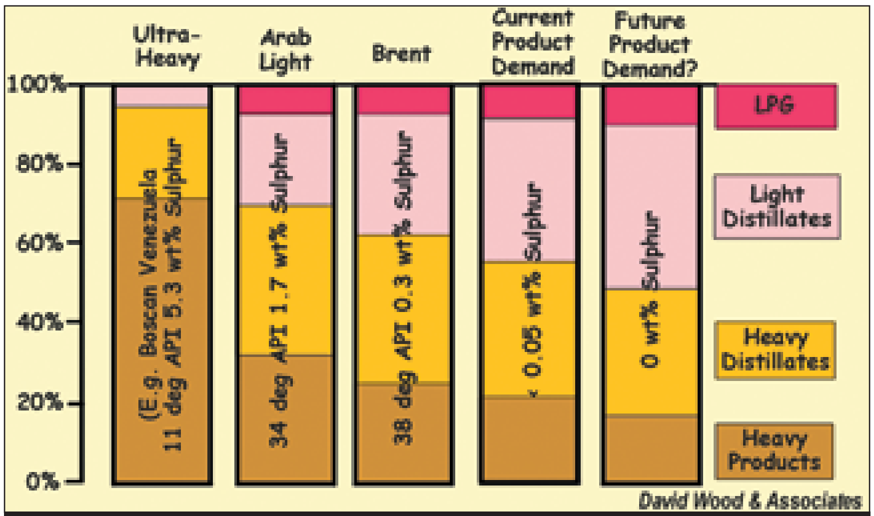

Figure 2: Distillation yields from different crudes fail to provide the lighter product mix the market requires. Expensive deep conversion (cracking) and sulphur removal processes are required to breakdown the heavy products into lighter products. The heavier and sourer the crude oil, the more extensive and expensive the cracking and sulphur removal processes become ????????????????

seem set to make an increasing component of future oil supply if 3P reserves are taken into account.

Unconventional heavy oil, tar sand, bitumen and oil shale account for a substantial component of the remaining oil resources, but they are substantially less attractive sources of energy supply. It is important to take into account the energy used and emissions generated to find, extract, process and deliver that resource to energy consumers and then subtract that amount from the amount of energy the resource contains. It takes some 2 boe to obtain three barrels of usable oil from oil sands. This compares with 1 boe consumed to deliver 20 barrels of conventional oil from a developed oil field and eight barrels of conventional oil from a yet to be developed oil field. Hence, it is going to become more costly, time-consuming and generate more emissions per energy unit supplied to access and refine the unconventional oil reserves.

Crude feedstocks to refineries in Western Europe and North America traditionally supplied by light, sweet crudes from mature producing basins such as the North Sea are progressively being replaced by crudes with lower qualities. In such circumstances refiners have to be flexible and progressively invest in conversion technologies in order to remain profitable.

US Gulf Coast refineries, which are amongst the most sophisticated and complex in the world because they have invested heavily in deep conversion and coking capacity, have been able in the past three years to capitalise on that investment by buying heavy-sour crudes (eg Maya) at a discount and produce light, high value products from it to sustain double figure refining margins. This has triggered investment by Middle East Opec countries to upgrade their refining capabilities (eg the large new refinery recently sanctioned in Kuwait) in attempts to improve the margins they can achieve from their heavier crudes.

Improving trading conditions

The declining liquidity of the physical base of the reference crudes (WTI, Brent and Dubai/Oman) and the narrowness of the spot market in terms of quality has caused many oil-exporting and oil-consuming countries to look for an alternative market to derive the price of the reference crude they are trading. The widening price differentials between light-sweet benchmarks crudes (WTI and Brent) and heavy-sour crudes increases the need for more widely spot traded lower quality crudes to provide a benchmark for futures trading in such

Remaining Recoverable Fossil Fuel Reserves & Their Carbon Contents

Hydrocarbon Resource Type	Proved Reserves	Units	Proved (Gtoe)	3P Lowside Estimate	Units	3P Lowside (Gtoe)	3P Highside Estimate	Units	3P Highside (Gtoe)	Carbon Content Proved Reserves	Carbon Content 3P Lowside (Mt)	Carbon Content 3P Highside (Mt)
Natural Gas	6348	tcf	165	15000	tcf	390	25000	tcf	650	102	240	400
Natural Gas Liquids (NGL)	200	Gbarrels	20	500	Gbarrels	50	1000	Gbarrels	100	15	38	75
Conventional Oil	1000	Gbarrels	140	1750	Gbarrels	245	2900	Gbarrels	406	120	211	349
Heavy Oil	400	Gbarrels	69	1000	Gbarrels	172	1950	Gbarrels	336	61	153	299
Extra-Heavy Oil	200	Gbarrels	34	1500	Gbarrels	259	3250	Gbarrels	560	31	230	499
Oil Sand & Bitumen	400	Gbarrels	69	2000	Gbarrels	345	3900	Gbarrels	672	61	307	598
Total Commercial Oil	**2200**	**Gbarrels**	**332**	**6750**	**Gbarrels**	**1071**	**13000**	**Gbarrels**	**2075**	**289**	**939**	**1821**
Total Commercial Oil + Gas			**498**			**1461**			**2725**	**390**	**1179**	**2220**
Oil Shales (not commercial)				2000	Gbarrels	345	4000	Gbarrels	690	0	307	614
Hard Coal	479	Gtonnes	239	750	Gtonnes	375	1500	Gtonnes	750	263	413	825
Brown Coal	430	Gtonnes	215	750	Gtonnes	375	1500	Gtonnes	750	237	413	825
Total Coal	**909**	**Gtonnes**	**455**	**1500**	**Gtonnes**	**750**	**3000**	**Gtonnes**	**1500**	**500**	**825**	**1650**
Total Hydrocarbons			**952**			**2556**			**4915**	**890**	**2311**	**4484**

Unit Conversions:	3P = Proved + Probable + Possible	
1 tonne (average) crude oil	7.14 barrels (Average~ 29 degree API)	
1 bcf natural gas	0.026 million tonne of oil equivalent (toe)	
1 tonne of NGL	10 barrels	
1 tonne bitumen	5.8 barrels	
1 tonne coal	0.5 toe	G = billion

Approximate Carbon Contents million tonnes carbon (Mt) / Mtoe:		
Natural Gas	0.62	Mt/Mtoe
NGL / LPG	0.75	Mt/Mtoe
Crude Oil	0.86	Mt/Mtoe
Bitumen	0.89	Mt/Mtoe
Coal	1.10	Mt/Mtoe

Data Sources: Various (including BP, EIA, Schlumberger)

David Wood & Associates

Figure 1: Remaining reserves of fossil fuels and their carbon contents. Heavy oil, tar sands make up large components of the 3P reserves and pose more of an emissions issue than conventional oil reserves

crudes. This has led a shift to the futures markets for reference pricing.

The Dated Brent price reference has been replaced for some exports to Europe from Saudi Arabia, Kuwait and Iran by the ICE (IPE) Bwave (Brent weighted average) price from the futures market, placing the futures market at the heart of pricing system for large volume crude trading. However, Brent futures prices are not ideal for price discovery of the large volumes of heavier crude moving eastward to Asian customers from the Middle East. In June 2006, the Dubai Mercantile Exchange (DME) announced details of the Oman crude oil futures contract to fill this gap in the market. DME launched its jet fuel futures in November 2006 in conjunction with Emirates Airlines. However, the launch of the Oman crude oil futures has been delayed, and was due to begin trading shortly after *Petroleum Review* went to press.

Once launched, the 1,000 barrels Oman crude oil futures contracts are to be cleared by Nymex, which hold 50% of DME (the other 50% is held by Tatweer – Sheikh Mohammad Al Maktum's Dubai Holdings, with the Omani government acquiring a 30% stake in December 2006). DME's aim is to establish a tradable futures contract in the Middle East. However, some doubt a futures contract based on Omani crude could efficiently perform the role of price discovery. Not all Oman production is available for spot trade, with the Omani government selling part of its oil on long-term contracts. PDO's dominance increases the chance of an Omani spot market being manipulated or squeezed, thereby increasing price risk exposure for buyers and traders on the new exchange. Such fears may undermine the confidence of the major Middle East crude exporters in this new market. In late 2006, many analysts bluntly stated that either Oman change its crude pricing policy or the DME contract would fail.

There are clearly concerns over the physical delivery process and benchmark pricing, crucial elements if the Oman contract is to succeed where other sour crude futures have failed in the past. Oman's strong support for the contract through its equity participation in the exchange and its decision in late 2006 to adopt forward pricing of its crude oil based on the daily settlement price of DME's Oman crude oil futures contract instead of the current retroactive pricing (official government posted price) mechanism have built some confidence among the oil traders. There is still some way to go therefore before the Oman crude oil futures proves itself.

However, the emergence of an effective Middle East sour crude futures market does now seem likely to play a key role in trading and pricing the growing volumes of heavy sour crude from the Middle East to Asia. Once established, with high liquidity and large numbers of participants, such a market could become more significant than Brent and WTI futures markets in determining global crude oil pricing. Better trading mechanisms, along with strong demand for lower quality crudes, should help Opec achieve better prices for its heavy-sour crude.