Deutsche Bank
Markets Research

Europe
United Kingdom
Oil & Gas
Integrated Oils

Industry

Oil & Gas for Beginners

Date
25 January 2013

Industry Update

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A guide to the oil & gas industry

The basics of the 'Black Stuff'

Deutsche Bank's overview of the global oil & gas industry. Structured in three parts, this layperson's guide includes details on the workings of the oil & gas industry, key oil producing countries and a summary of the assets and portfolios of the leading European and US oil & gas companies.

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The strategic commodity

As the dominant source of our energy needs for the better part of the last 60 years, crude oil has held influence over the politics and economic strategies of nations more than any other commodity, frequently proving the source of instability, dispute and war. From the birth of Standard Oil through the expropriation of Yukos, the oil industry has similarly found itself the subject of frequent controversy, with the companies involved often achieving profits and wielding power greater than the nations in which they are based. For an industry that, at its most basic involves little more than drilling a hole in the ground in the hope of finding the 'black stuff', the modern day oil industry is a remarkable amalgam of politics, economics, science and technology. Huge and diverse, it is also one that can at times prove bewildering, and not just for the uninitiated.

The industry, the countries and the major companies – all in one

With this in mind, in January 2008 the Global Oil & Gas Team at Deutsche Bank first published a document that we hoped would prove of good use for beginners and industry old hands alike – Oil & Gas for Beginners. Some five years and several reprints later, we have mustered the strength to update and expand our original text. Structured in three parts it contains contributions from Deutsche Bank's global team of oil & gas analysts, many with backgrounds in the industry as well as drawing on Deutsche Bank's longstanding relationship with Wood Mackenzie, one of the industry's leading research houses. In the initial Industry Section we look at what shaped today's industry, the geology of oil, and its applications together with how it's found, how it's extracted & refined and how it's taxed. In the second Countries Section we review the oil & gas production outlook and histories for the leading OPEC and non-OPEC producers including details of the major fields, their tax systems, energy infrastructure and, of course, the status of their reserves. Finally, in the Companies Section we review the portfolios of the leading international oil companies that comprise the bulk of the oil & gas sector's stock market capitalisation, providing asset value breakdowns and an overview of the major business activities and growth projects.

For the uninitiated and more learned reader alike

Although ***Oil & Gas for Beginners*** is intended as a beginners guide we hope that it will also find favour with the more experienced reader. Overall, we trust that our audience will find it a useful document and entrust it with a permanent slot on an already overcrowded desk. So for those of you who want to know more about the life cycle of a basin, the Earth's geologic clock, why an Indian bean has proven key to unconventional extraction or any number of industry relevant themes read on. We hope that what you find will prove both interesting and informative.

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Section I: The Oil & Gas Industry

A Brief History of Oil

From biblical times…

Crude oil has been known and used since ancient times

Crude oil has been known and used since ancient times with reference to it made by most historians since records of world history began. Noah is said to have used it to caulk his Ark; the bible refers to its application as a roofing material in Babylon; the Egyptians used it to help preserve mummies whilst Alexander the Great was known for his use of oil to create flaming torches to frighten his enemies. Beyond its obvious application as a source of fire, the substance was also highly valued by several civilizations for its medicinal properties; for the Chinese it served as a skin balm; for Native Americans a treatment for frostbite.

A small town in Pennsylvania

Yet the modern oil era almost certainly commenced in 1859 in Titusville, Pennsylvania, when Colonel Edwin Drake struck oil some 69 feet underground. The commercial objective being pursued was to extract ‘rock’ oil, which, it had been discovered, could be refined to produce kerosene for illumination. At 15 barrels-a-day Drake’s discovery prompted a mad rush to drill for ‘the black stuff’. Within a year Pennsylvania was producing almost 500,000 b/d; two years later over 3m b/d was oozing out of the Pennsylvanian hills. The modern oil industry had been born.

The mother of today’s industry …

This explosion in production, however, brought with it its own problems. Although demand for kerosene also surged as copious supplies made it ever more affordable, the absolute lack of discipline that surrounded both the supply of oil and its refining meant that the newly found kerosene industry was extremely volatile. Into this arena emerged one particular businessman who was intent on bringing structure, order and profit to the kerosene refining industry. Through the Standard Oil Company, John D Rockefeller set about establishing a business that was to have absolute influence over the US refining and oil producing industries. By 1890, using business practices that invariably sought to eliminate competition, Standard Oil controlled almost 90% of the refined oil flows in the United States. It determined the price at which its products would be sold on the open market and it told the producers the price that they would receive for their oil. In effect it was, to all extents and purposes, the US oil industry, a position it largely retained until its dissolution under anti-trust legislation by the US Supreme Court courts in 1911 into 34 independent companies.

… through the daughters that she spawned

Standard Oil’s dissolution was as much the beginning of an era

Yet Standard Oil’s dissolution was as much the beginning of an era as it was the end. For the companies which were born as a result by and large proved those which would go on to shape the industry as we know it today. Exxon, Chevron, Texaco, Conoco and much of BP, amongst others, can all trace their roots back to Standard Oil. And in their desperate pursuit through much of the 20th century to secure new sources of oil from across the globe, not least the Middle East, they gave birth to the national oil companies that dominate today’s production. Saudi Aramco, the National Iranian Oil Company, the Iraqi National Oil Company, the Kuwait Oil Company, ADNOC and PDVSA were all established in large part by the ‘sisters’ that emerged from the break-up of Standard Oil.

More sustainable than your average state

Indeed, it is perhaps an irony that an industry whose sustainability is constantly in question should be comprised of companies that have a history that is longer than that of several modern day countries. Governments may come and go and wars may pass. Yet in pursuit of that life-giving incremental barrel of reserves, the major oil companies have evolved into the industrial behemoths that stand today and will, almost certainly, still stand tomorrow.

Setting the scene

The oil industry has a long and colourful history and before discussing the major players we need to set the scene; we do this starting with the summary timeline below:

Figure 1: A brief history of oil

Time	Oil price, $/bbl (2006)	World oil prod. mil bbl/d	What happened	
1849-57			End of whale oil	Kerosene distilled from crude and kerosene lamp invented - forces whale oil from market.
1846			Baku percussion drilling	First successful percussion well drilled in Baku.
1859			Drake's US well	First oil well is drilled in U.S. at Titusville, Pennsylvania, by Colonel Edwin Drake (69 feet).
1863-70	62		Standard Oil born	John D. Rockefeller starts his first refinery in Cleveland and founds Standard Oil.
1872			Baku oil boom	
1878	25		Oil recession	Thomas Edison invented the electric light bulb, eliminating demand for kerosene.
1886	16		The car arrives	Gasoline powered automobiles introduced to Europe by Karl Benz and William Daimler
1901	23		Texas oil boom	Spindletop blow-out heralds birth of Texaco, Gulf and the Texas oil industry
			Baku: 50% world oil	Baku supplies just over 50% of the worlds oil, and 95% of Russian oil
1907	16		RD/Shell born	Shell and Royal Dutch combined.
1908	16		Iran oil and BP born	Anglo-Persian (BP) finds oil in Iran.
1910	13		Mexico oil found	Oil discovered in Mexico by Mexican Eagle (later bought by RD/Shell)
1911	13		Death of Standard Oil	U.S. Supreme court orders the dismantling of Standard Oil on antitrust violation grounds.
1914-18	20		WW I	WW I - cavalry gives way to mechanised warfare.
1917	25		Russian revolution	RD/Shell, Nobel and Exxon all lose assets
1922	20		Venezuela oil found	Oil discovered in Venezuela by RD/Shell
1928	14		Iraq oil found	Oil discovered by IPC (BP, RD/Shell, Total, Exxon, Mobil, Gulbenkian) in Iraq
1930	15		East Texas oil found	East Texas oilfield discovered (largest in U.S. at the time) and over-produced
1931	9	4	Oversupply, price crash	World oil glut; Great depression starts. U.S. oil prices fall from 96 to 10 cents/bbl
1931-1938	14		US starts prodn quota	Texas Railroad Commission enforces production quota and shutins to stabilise crude prices
1932	13	5	Iran nationalisation	Shah Reza of Iran cancels Anglo-Persian concession, but quickly backtracks
1933	11	5	Saudi entered	Socal (Chevron) win a large oil concession from King Ibn Saud of Saudi Arabia
1938	16	6	Ghawar discovered	Oil found in Saudi Arabia ('the single greatest prize in all history')
			Mexico nationalisation	Mexico nationalises U.S. and U.K. oil company assets
			Kuwait oil found	Oil discovered in Kuwait
1939-1945	14		WW II	WW II – all governments realise control of oil is vital for security
1943	14	6	Venezuela 50/50 deal	Venezuelan contracts renegotiated to give a 50/50 profit split - a landmark event.
1947	17	9	Offshore born	Kerr-McGee drills first successful offshore well in the GoM
1950	14	10	Saudi state share raised	Aramco 50/50 deal agreed
1951	13	12	Iran nationalisation.	Iran nationalised assets of Anglo-Iranian (renamed from Anglo-Persian, later BP)
1956	14		Suez crises	Suez canal closed, disrupting world oil transport; US surge capacity and NOCs cope well
1959	15	19	Oversupply	Late 1950s oil oversupply 'glut'
			Libyan oil found	Oil found in Libya
1960	13	21	OPEC created	OPEC formed in Baghdad (initially Saudi Arabia, Iran, Iraq, Venezuela, Kuwait)
			Indonesia nationalisation	Indonesia oil industry nationalisation
1967	11	37	The 'Six day war'	The 3rd Arab-Israeli war; Israel pre-emptively attacks Egyptian-led forces near its borders
			Arab oil embargo	Arab oil embargo (Saudi Arabia, Kuwait, Iraq, Libya, Algeria) against nations friendly to Israel
			Nigeria civil war	Nigerian civil war breaks out – 500kb/d oil exports blockaded
			10bn bbls field in Alaska	10bn oilfield discovered in Alaska by ARCO
1969	10	44	North Sea oil discovered	
1970	9	48	End of the buyers markets	World demand closed gap with supply, power shifts to the Middle East producers
			US oil peak	US peak oil production year - no more US surge capacity
			Libya state share raised	Libya raises profit share from 50% to 55% and forces through a 30% oil price hike
			Iran state share raised	Iran forces profit share up to 55% from 50%
			Venezuela share raised	Venezuela unilaterally raises state profit share to 60%

Source: Deutsche Bank

Figure 2 contd: A brief history of oil

1973	15	58	Oil embargo	Yom Kippur war: Arab oil embargo in response to U.S. support for Israel
			Oil prices up c.4x.	Prices rise from $2.9 to $11.6/bbl (money of the day)
1974	48	59	Iraq nationalisation	Iraq nationalisation (BP, Shell, Exxon lost assets in Iraq Petroleum Co.)
			Saudi partial nationalisation	Aramco 60% nationalised (Chevron, Texaco, Exxon, Mobil impacted)
1975	43	56	Kuwait nationalisation	Kuwait nationalises oil industry
			Venezuela nationalisation	Venezuela nationalises oil industry
1979	88	66	Iranian revolution	Shah deposed in Iranian revolution, oil prices touch $40/bbl despite no shortage of oil
			Oil price shock	By 1981 oil prices has risen to $34 from $13/bbl, post the Iranian revolution
1980	91	63	Saudi nationalisation	Aramco 100% nationalised
1982	69	57	OPEC introduces quotas	Quotas used by OPEC for fist time to prevent oversupply
1986	27	60	Oversupply - price collapse	OPEC fails to prevent oversupply - oil prices fall from $29/bbl to $10/bbl
1991	30	65	Gulf war I	Iraq invades Kuwait and is swiftly defeated by the Americans; Oil briefly touched $40/bbl
1998-2001			Super mergers	BP-Amoco-Arco, Exxon-Mobil, Chevron-Texaco, Conoco-Philips, Total-Elf-Fina
1998			Oil price collapse	Asian crisis recession drives oil price collapse
2003	32	77	Gulf war II	Second Iraq war
2003-08	147	87	Oil price shock	Iraq on verge of civil war, Iran nuclear tensions, strong oil demand growth from emerging markets, surprisingly inelastic world demand and dwindling capacity cushion help drive prices to almost $150/bbl; Various host nations raise taxes and state share
2008-09	33		Price collapse	Global financial crisis precipitates a decline in oil demand and oil prices collapse to lows of $33/bbl. Economic recovery sees oil prices stabilise around $70-80/bbl.
2010-11	79		Price recovers	Arab Spring and economic recovery combined with continued high costs see price recover.
2012-	109		End of the cycle?	US onshore is reborn as tight oil emerges as significant new supply source. Combined with an end to the super-cycle is oil moving to a new age?

Source: Deutsche Bank

Key points to note are:

- **Standard Oil – the mother of all grandmothers**, founded by John D. Rockefeller in 1870 was the largest and best run company of its, and perhaps any age. Its pursuit of efficiency included relentless price wars and other methods to destroy competition and in 1911 the Supreme Court decided various antitrust laws had been violated. The ensuing enforced break-up of the company gave birth to 34 new companies, including the ancestors of Exxon, Mobil, Chevron, Texaco, Arco and others.

- **The key companies have been around a long, long time**. ExxonMobil, BP, Conoco and Shell can all trace their past back over 100 years. Total can look back on 80 years and Eni on over 50 years.

- **Nationalisation is not new**. In fact the first attempt was by the Shah of Iran in 1932, who was unhappy with the terms that Anglo-Persian (from which BP was born) had convinced Iran to sign up to back in 1903. However the Shah rapidly backed down for an insignificant improvement in terms. Mexico nationalised in 1938 but this proved self destructive as a wealth of alternative supplies existed.

- **The Texas Railroad Commission – the forerunner to OPEC**. The late 1920s glut caused by the start of the great depression and the over production of the huge East Texas discovery prompted the Texas Railroad Commission (the state regulator for oil production) to impose production quotas. Whilst these were initially resisted, laws were passed that gave the Commission more power and it successfully took the lead in regulating US production until 1970, when excess capacity finally disappeared. In a sense OPEC took over the role that the Commission had previously played, and which was fulfilled by Rockefeller before that.

- **The Middle East carve up**. Until the 1970s the IOCs had a huge influence on Middle East oil development and production. American and British/Dutch companies made all the major discoveries in Iran, Iraq, Kuwait and Saudi Arabia, and controlled everything from wellhead to car gas tank, with little disclosure. The perceived IOC exploitation (for 'unfair' returns) is a fundamental factor behind the current characteristics of the Middle East oil industry.
- **If it doesn't affect oil supplies, it doesn't matter to oil prices.** Notable by their absence are the Korean War (1950-53), Cuban Missile Crisis (1962) and the Vietnam War (1965-75). All had no meaningful impact on prices because oil supplies were never under threat.
- **1970 pivotal.** Although OPEC was created in 1960 (a global version of the Texas Railroad Commission, upon which it was partially modelled) it wasn't until 1970 that US oil production peaked. The US hence lost its 'surge' capacity cushion for the first time, which had enabled it to weather previous supply disruptions, including two Arab oil embargos.

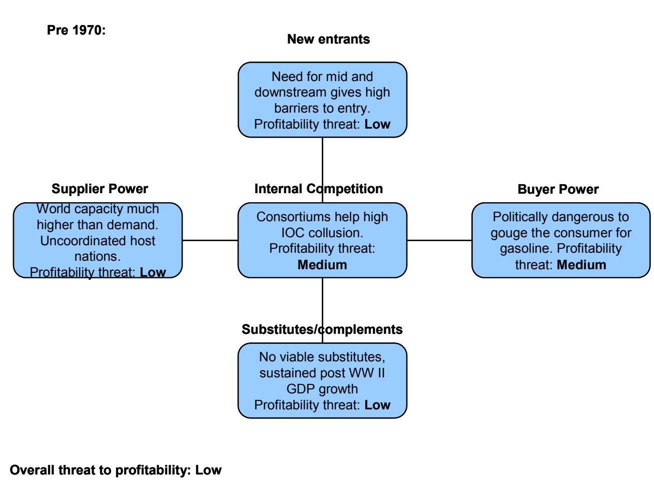
Prior to 1970 the IOCs held the bulk of industry power, almost uninterrupted. The period from 1970 to 1979 was pivotal in the evolution of power from western oil companies towards resource holding nations, and we have seen another surge in this theme in recent years.

Classical analysis suggests recent shifts are structural

Classical analysis suggests recent shifts are structural

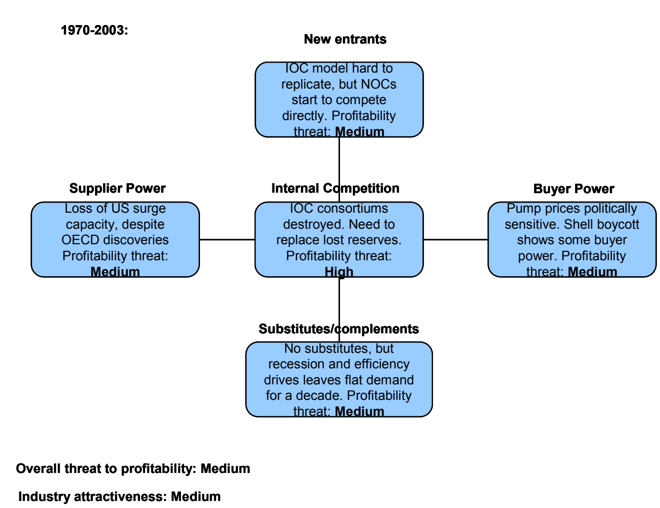
Time will tell whether recent adverse changes (from an IOC perspective) in contract terms and field ownership are cyclical blips that will reverse (as has occurred several times in the past), or not. The classic approach to analysing an industry's profitability (by breaking down the threats to that profitability) doesn't appear to give any comfort for a conventional IOC, as we depict below.

Figure 3: Industry threats to profitability, pre-1970



Source: Deutsche Bank

Figure 4: Industry threats to profitability, 1970-2003

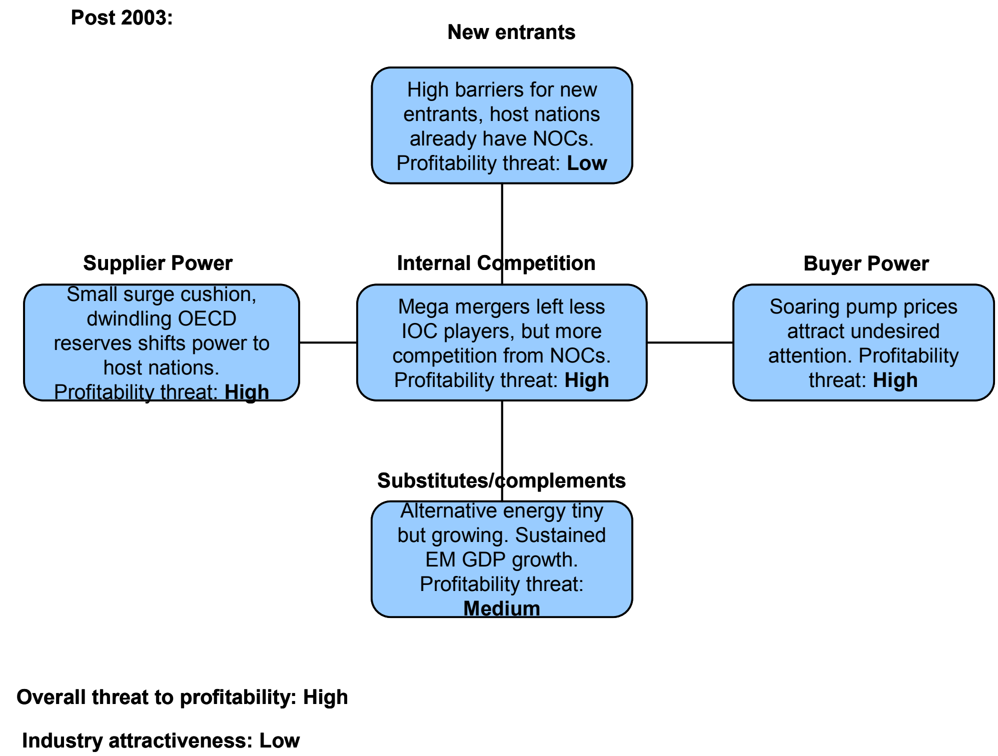


Source: Deutsche Bank

Prior to 1970 - IOC heaven. The key industry characteristics were oversupply (which gave host nations little power), high barriers to entry (because of the need for 'outlets' in an oversupplied world – i.e. a mid and down-stream), collusion to a high degree (due to the same players being in all the main assets) and growing markets. The threats to industry profitability were generally low making it an attractive industry, although of course oil companies had to be ever mindful of not being seen to charge 'too much' at the pump for political reasons.

From 1970 to 2003 – the wheels come off. From the early 1970s to the early 2000s we see drastic changes. Worldwide demand had largely closed the gap with supply, the US no longer had a surge capacity and although the 1970s saw stagnant demand growth, growth resumed in the 1980s and 1990s. From an IOC perspective supplier power (i.e. the host nations) increased strongly in the early 1970s, but was offset to some degree by Alaskan and N. Sea mega-field developments in the 1980s. Whereas previously new entrants could not credibly compete with IOCs, the nationalisations of the early 1970s gave birth to NOCs that in time would start to compete directly, at least for conventional oil projects. We therefore characterise this era as having 'medium' threats to profitability and hence 'medium' profitability attractiveness to IOCs overall.

Figure 5: Industry threats to profitability, post-2003



Source: Deutsche Bank

The threats to profitability of IOCs are high relative to previous eras

Post 2003 – further tightening. OECD mega-fields have started to decline, and strong emerging market demand growth has handed yet more power to the major resource holders in the Middle East, Russia and Venezuela. Increased terrorism activities have put oil infrastructure at heightened risk, and geopolitical stability in the Middle East has fallen in the aftermath of Gulf War II and with the emergence of Iranian nuclear ambitions. Correspondingly the oil price has risen by almost a factor of five, and resource holders have raised both taxes and NOC stakes at the expense of IOCs. Supplier power is thus high (which has led to a huge increase in the cost of actually producing oil), competition for new acreage or M&A deals from NOCs is also high, the high pump prices raise consumer discontent and even the green movement is gathering momentum (both for environmental reasons and as countries seek to reduce their exposure to less stable oil producing regions). Moreover as the events of 2008/09 showed all too clearly, oil prices are increasingly volatile in comparison to costs that are all too sticky; a combination that makes sanctioning projects all the more difficult. All in all the threats to profitability of IOCs are high relative to previous eras and hence industry attractiveness is low, at least relative to the past.

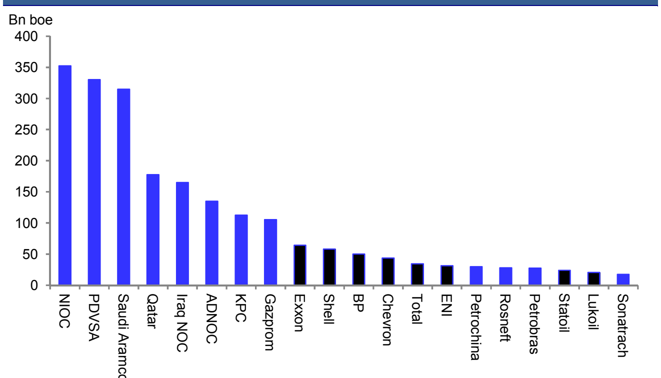
IOCs and NOCs

The term IOC (International Oil Company) is usually taken to mean a large, western, listed, integrated oil company (e.g. Exxon or BP), whereas an NOC (National Oil Company) generally refers to a majority state owned oil company that has often grown out of large domestic reserves. In some cases the NOCs have evolved directly from previous consortiums of IOCs – such as Aramco (Saudi Arabia), NIOC (Iran), INOC (Iraq) and KOC (Kuwait).

The term IOC (International Oil Company) is usually taken to mean a large, western, listed, integrated oil company

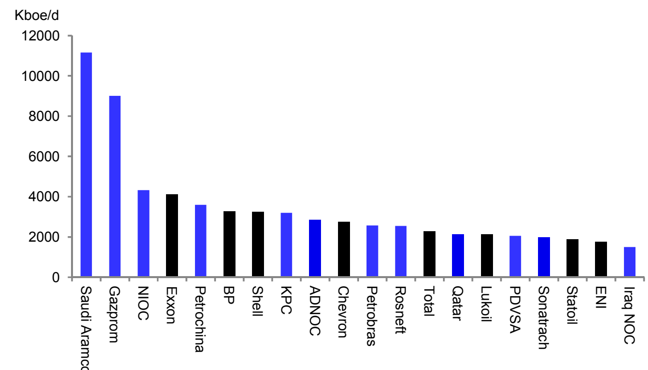
The fundamental difference in the reserve holdings between these two groups of industry players is clear in the left hand chart below:

Figure 6: IOC and NOC oil and gas reserves (billion boe) end 2012E



Source: Wood Mackenzie, BP Statistical Review 2010, Deutsche Bank estimates
Note: 2P WoodMackenzie estimates used for IOCs, BP statistical review and company data used for NOCs.

Figure 7: IOC and NOC oil and gas production 2012E (million b/d)

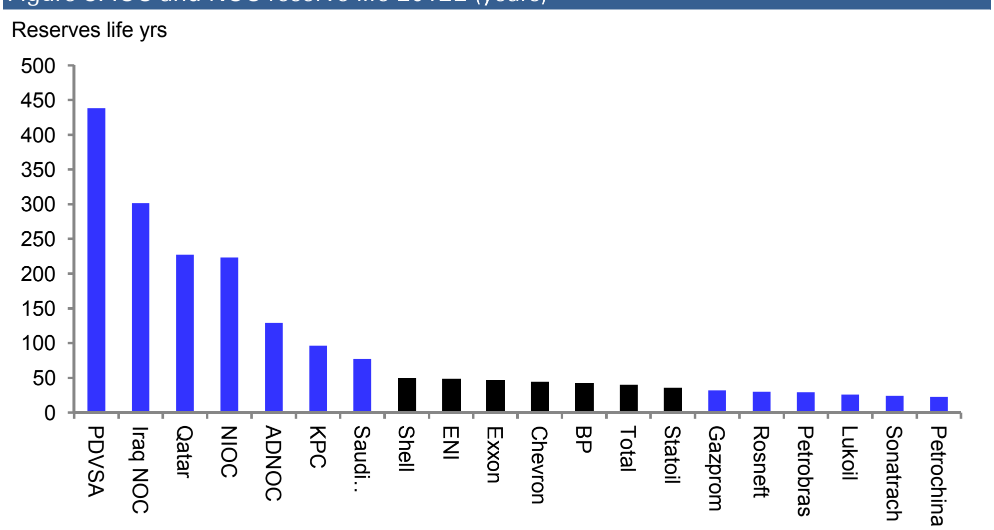


Source: Wood Mackenzie, Deutsche Bank estimates

From a reserves perspective it would seem the NOCs (and hence resource holding nations of the Middle East, Russia and Venezuela) should have the bulk of industry power. But this of course is only true in a market that is short of oil, and for most of the last century the world has basically been in an oversupply situation. For the last few years, however, supply/demand has been relatively tight and if this persists, the superior growth potential of the NOCs versus the IOCs is clear.

From a reserves perspective it would seem the NOCs (and hence resource holding nations of the Middle East, Russia and Venezuela) should have the bulk of industry power

Figure 8: IOC and NOC reserve life 2012E (years)



Source: Deutsche Bank estimates using data from Wood Mackenzie and the BP Statistical Review 2010

The IOC Sisters – 100 years in the making

The IOCs (Exxon, Shell, BP, Total and Chevron being pre-eminent), have long, colourful histories.

The IOCs (Exxon, Shell, BP, Total and Chevron being pre-eminent) have long, colourful histories. It is not too much to say that these companies more than any others played major roles in shaping the world we live in. The last 60 years worldwide GDP growth, business theory and practice, economics and antitrust laws have all been hugely influenced by their activities and decisions, as have the current geopolitical issues in countries such as Saudi Arabia, Iran, Iraq and Venezuela.

1870-1911, the titans are born. Rockefeller's Standard Oil had over 40 years to build itself into a huge integrated oil company that almost totally dominated the US industry before its break-up in 1911. BP's forerunner (Anglo-Persian) was created in 1908 to develop Iran and Royal Dutch and Shell merged in 1907 to better develop Indonesian Oil and compete internationally with Standard Oil. The descendents of these companies, along with Gulf and Texaco, were to dominate the world's oil industry, not to mention the economic fate of several countries, for most of the last century.

Pre WW II - masters of the world. In the 30 years leading up to WW II, worldwide consumption had grown from less than 0.5 million b/d to 6 million b/d, driven mainly by strong growth in US GDP and car usage. The early 1930s oil glut (partly due to the discovery of the huge East Texas field and the great depression) did little to deter the IOCs from ambitious international exploration programs. In some cases the motivation was simply to lock other companies and oil out of an oversupplied market, but by 1940 the end result was that the IOCs were all-powerful. BP dominated Iranian oil while Iraqi oil was controlled by a consortium of BP, RD/Shell, Total, Exxon and Mobil. Kuwait had been shared out between BP and Gulf and Saudi Arabia, containing the greatest field ever found, was controlled by Chevron, Texaco, Exxon and Mobil (Aramco).

Post WW II - the fight back begins. WW II had shown the world's governments just how strategically important oil supplies were and the Middle East governments unsurprisingly wanted more of the pie. The Saudi government forced Aramco to accept a profit split of 50/50 in 1950 and Iran nationalised Anglo-Persian's (BP) assets in 1951. Iran's nationalisation was shortly undone in all but name but BP lost significant share and the warning signs to the IOCs must have been clear. Although the 'Seven Sisters' (Exxon, Mobil, Chevron, Texaco, RD/Shell, BP and Gulf) remained immensely powerful, they slowly but surely gave profit share ground over the two decades leading up to 1970. However despite the creation of OPEC in 1960, it was not until 1970, when US oil production peaked and it lost its surge capacity that the theory of Arab oil power finally became a reality.

1970s – the new reality. The implications of the loss of US surge capacity were not lost on the countries where the IOC's precious reserves lay. The Yom Kippur war of 1973 and associated Arab oil embargo drove up the oil price by c.4x and in a wave of nationalisation the Seven Sisters were forced to sell (if they were lucky) the bulk of their assets in Iraq, Saudi Arabia, Kuwait and Venezuela. The Iranian revolution of 1979 removed any lingering IOC ownership in the Middle East heartland and sent oil prices spiralling upwards once again. The days of IOC supremacy were over.

1980s – a reprieve in the form of Alaska and the North Sea. The events of the 1970s forced the IOCs to look elsewhere for oil, and the late-1960s discoveries of huge reserves in Alaska and the North Sea were the answer. BP, RD/Shell, Exxon and Mobil were instrumental in exploiting these areas, and the North Sea discoveries gave birth to a new western NOC; Statoil in Norway.

1990s – profits under threat – mega mergers. By the mid-1990s a flat oil price environment, stricter terms and competition from the Middle East NOCs (that the sisters had unwillingly given birth to) made it clear that the culture of perks and large numbers of expatriates on high salaries could no longer be sustained. Profitability was under pressure; BP caused shock waves when it cut its dividend for the first time in 1992 and several of the other majors were also experiencing financial stress. BP showed the way forward with its acquisition of Amoco announced in 1998 – the largest merger ever at the time. The other majors quickly realised that the synergies that BP-Amoco would benefit from would leave them behind unless they followed suit. Exxon and Mobil announced their merger in 1999 and Chevron and Texaco did the same in 2000. Elsewhere Total acquired Fina in 1998 and then Elf in 1999 and Conoco and Phillips merged in 2001. Of the majors only RD/Shell refrained from major M&A activity.

Of the original seven sisters that so dominated the world's oil industry for much of the last century, four remain; Mobil went to Exxon, Gulf and then Texaco went to Chevron.

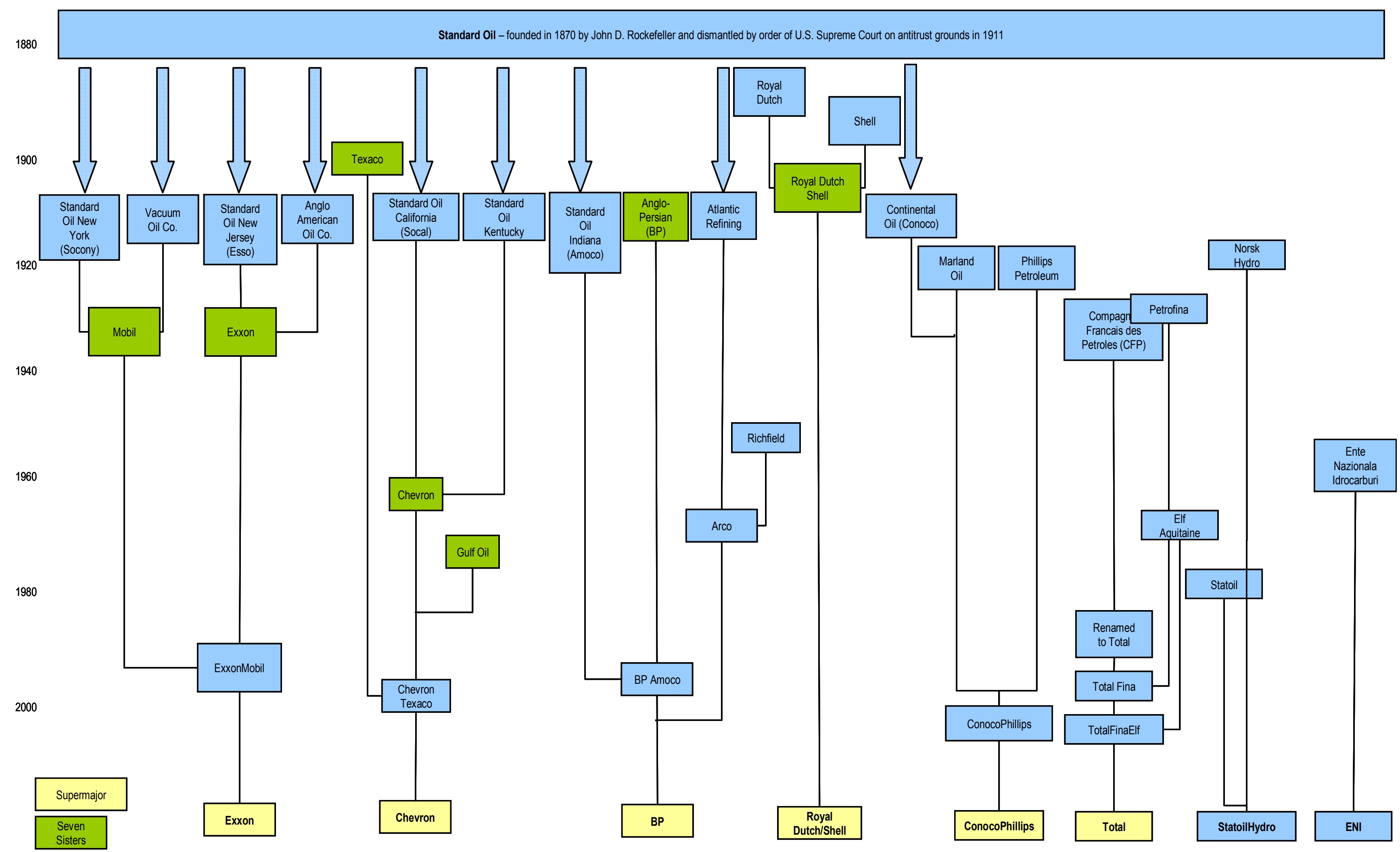
Of the original seven sisters that so dominated the world's oil industry for much of the last century, four remain Exxon, Chevron, Shell and BP

2000s – power moves further towards the resource owners. Since 2003 oil prices have risen from just above $20/bbl to just over $100/bbl. Oil is a finite resource and it appears as though the low hanging fruit has been picked; even Saudi Arabia has to use enhanced production techniques on nearly all of its fields. However demand has marched onwards, driven in part by a multi-year surge in emerging economies. In the face of restrained industry investments over the last decade, there is now little effective supply cushion. This worsening supply/demand situation, when coupled with increased geopolitical tensions, and perhaps the influx of speculative money into oil trading, can explain the bulk of the recent oil price rise.

None of these factors appears particularly transitory, and the major resource-owning countries that have IOC presences have tightened the tax screws once again. Conventional oilfield development opportunities under reasonable terms are currently hard to find and we appear to be at an inflexion point. But the IOCs are still vital for large, integrated, hostile environment or technically challenging projects and the recent escalation in power towards NOCs is by no means the death knell for the remaining seven sisters or their peers. Whether in the deepwater or LNG, for example, semi-traditional resource opportunities requisite of substantial capital, technology and/or market presence continue to offer good scope for monetisation by the larger IOCs.

2007 and tomorrow – unconventionals afford the IOC's a new opportunity set. Moreover, as the oil price has risen so too have previously uneconomic resource types become financially viable with the sustained period of elevated prices enabling new extraction techniques to be honed and development costs consequently reduced thereby further cementing these new sources of hydrocarbon's viability. Not least amongst these sources has been the emergence of seemingly ubiquitous supplies of onshore tight oil and shale gas. As these resource types are increasingly accessed across the globe so too will those that can grow their business from non-conventional production eventually find themselves at an advantage relative to those that persist with the 'old' conventional oil IOC model.

Figure 9: The major IOCs family tree



Source: Deutsche Bank

The International Oil Companies

Exxon, is a direct descendent of Standard's heart; Standard Oil New Jersey

Almost 100 years after his company was broken up, Rockefeller's legacy is still huge. One of the world's most valuable companies, Exxon is a direct descendent of Standard's heart -- Standard Oil New Jersey.

Standard Oil, as mentioned earlier, was founded by John D. Rockefeller in 1870, and rapidly consolidated the refining companies in Eastern US into one organisation. By the 1911 Supreme Court dismantling ruling, this consolidation had extended into almost total control of upstream, downstream and midstream US operations, with significant overseas activities. Its domination was achieved at the expense of using its size to achieve unfairly advantageous terms from railroads for transit fees, by crushing out all competition via price wars and by extensive use of bribes. Rockefeller merely saw his company as bringing order and stability to a market that otherwise would be characterised by boom and bust cycles and correspondingly chaotic pricing. In his eyes, Standard Oil benefited the consumer, despite the lack of price competition.

Exxon – leader of the pack for nearly a century. Today's Exxon stems directly from four Standard Oil companies. Its 1998 merger with smaller sister Mobil was the largest corporate deal in US history and was remarkable in that it reunited the two largest companies of the Standard Oil Trust – dismantled almost 90 years earlier by the US Supreme Court.

Chevron – found the greatest prize in history. Standard Oil of California (Socal) was only part of Standard Oil for eleven years before the breakup, and eventually became Chevron. Chevron negotiated the concessions in Saudi Arabia in 1933 and then discovered the 'single greatest prize in history' in 1938 – the world's biggest oilfield, Ghawar. Its merger with Gulf in 1984 was the biggest ever at the time and was followed up in 2001 by the merger with Texaco (which was born out of the post 1901 Texas oil boom and was never part of Standard Oil).

BP born in Iran. BP's history dates back to 1901 when William Knox D'Arcy won a large Iranian concession. He found the first commercial oil in the Middle East in 1908 and formed the Anglo-Persian Oil Company (later to become Anglo-Iranian, then BP). After losing the bulk of its Iranian production to nationalisation in 1953 BP's next major success was in the North Sea in the 1960s. As discussed above it has caused seismic shifts in the industry with its trailblazing M&A over the last two decades; the merger with Amoco in 1998, acquisition of Arco and Castrol in 2000 and then entry into Russia with 50% of TNK-BP in 2003. However, disaster in the US Gulf of Mexico in April 2010 following blowout at its Macondo well and consequent release of up to 5million barrels of oil, shook the company to its foundations. Some $40bn of legal and clean up costs later at the time of writing BP's future shape and ambitions remain unclear with the company pushed into the largest divestment programme in corporate history as it has sought to meet its substantial civil and, potentially, criminal liabilities.

Royal Dutch Shell was formed with the merger between the British Shell (created as an oil shipping company in 1878) and Holland's Royal Dutch (created in 1890 following an oil discovery in the Dutch East Indies) in 1907. Together they were able to fight on equal terms with the international growth aspirations of Standard Oil. RD/Shell did not get involved with the mega-mergers, although it did buy Enterprise Oil (the UK's largest E&P at the time) and Pennzoil-Quaker State (a US motor oil business and descendent of Standard Oil) in 2000.

Conoco can trace its history back to Standard Oil via Continental Oil, but is actually more dominated by its Phillips legacy. Phillips was built on a string of discoveries in Oklahoma starting in 1905 by Frank Phillips. The merger between Conoco and Phillips was agreed in 2001. However, in 2011 the enlarged group became the first major integrated oil company to elect to split itself into two with the company's refining and downstream activities spun-out to shareholders as a separate company, Phillips 66.

Total was founded by the French government in 1924 and gained its first major overseas production via a share in the Iraq Petroleum Consortium (IPC). Its acquisition of Fina in 1998 was seen as motivated by a desire for downstream assets rather than cost synergy potential, and was followed by the acquisition of rival French oil firm Elf, in 1999.

The term **'supermajors'** usually refers to the five largest IOCs – Exxon, Chevron, RD/Shell, BP and Total.

The term 'supermajors' usually refers to the five largest IOCs – Exxon, Chevron, RD/Shell, BP and Total.

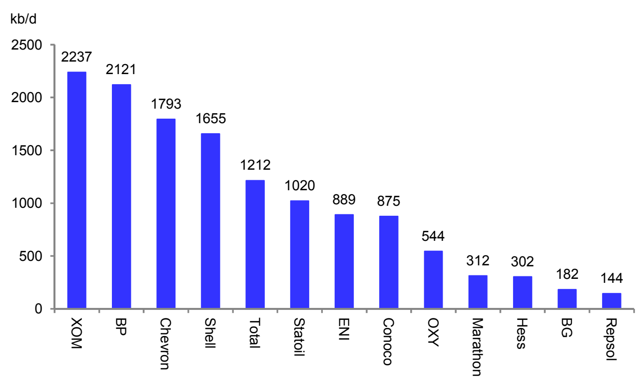
The other two IOCs in the previous figure are Statoil and Eni:

Statoil and Norsk Hydro announced in 2006 that they would merge their oilfield operations to form "StatoilHydro" (later shortened to Statoil). Norsk Hydro started off as a Norwegian fertilizer company in 1905, whereas Statoil was established as a Norwegian state oil company in 1972 to develop the Norwegian North Sea. The merger was completed late in 2007 and in theory gives the company enough scale to compete for all but the world's largest projects.

Eni (Ente Nazionale Idrocarburi) was founded by the Italian state in 1953 and was led for many years by the charismatic Enrico Mattei, who in the 1950s was a vocal critic of the Seven Sisters. Eni was also involved in the M&A activity of the late 1990s, and was reported to be in discussions with Elf until Total placed the winning bid. Eni bought the UK E&P companies British Borneo (2000), Lasmo (2001), Burren Energy (2007) and First Calgary Petroleum (2008), while it has also been active in acquiring assets.

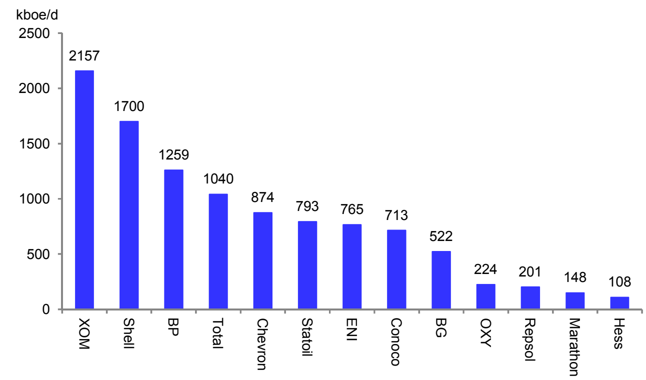
The IOCs Compared

Figure 10: 2012E Oil Production by company



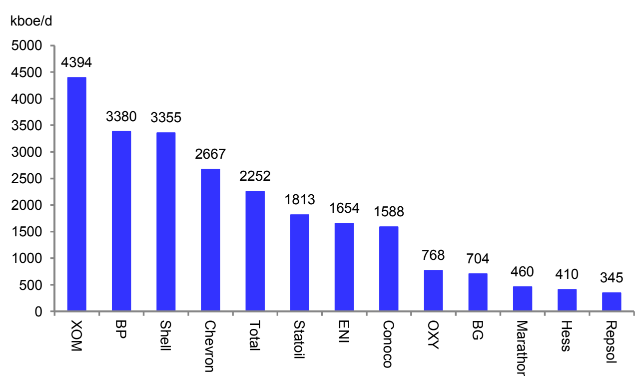
Source: Company data, Deutsche Bank estimates

Figure 11: 2012E Gas Production by company



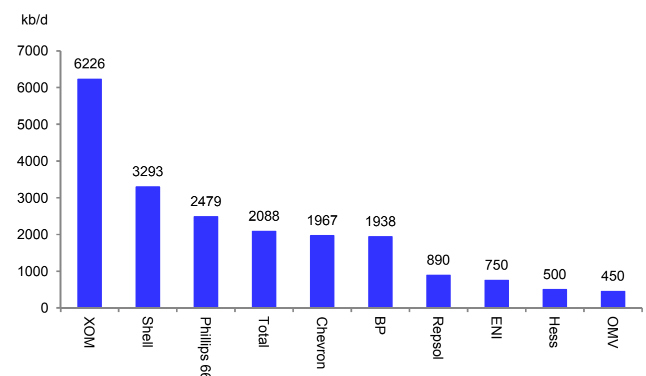
Source: Company data, Deutsche Bank estimates

Figure 12: 2012E Total Production by company



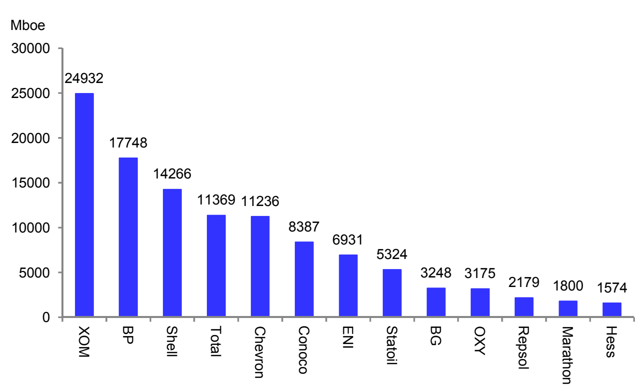
Source: Company data, Deutsche Bank estimates

Figure 13: 2009 Refining Capacity by company



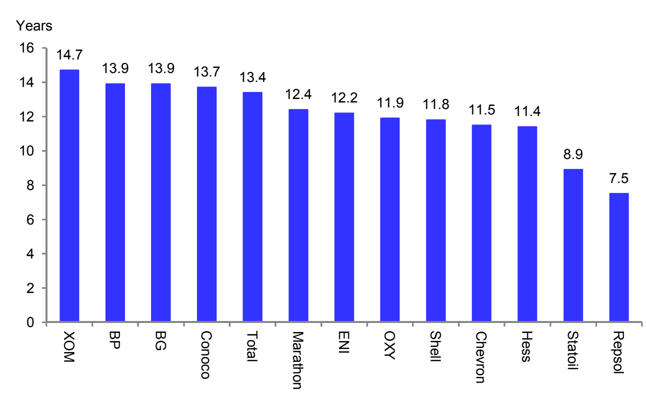
Source: Company data, Deutsche Bank estimates

Figure 14: 2011 1P reported reserves by company



Source: Company data, Deutsche Bank estimates

Figure 15: Reserve Life by Company 2011



Source: Company data, Deutsche Bank estimates

Figure 16: Western Majors – Production by Geography 2012E

Country	Exxon	BP	Shell	CVX	Total	Conoco	Eni	Repsol	Statoil	OXY	BG	MRO	Hess
Canada	5%	1%	7%	2%	1%	17%	-	-	1%	0%	-	9%	-
US (Alaska)	3%	5%	-	-	-	13%	1%	-	-	-	-	4%	-
US (Deepwater GOM)	1%	8%	6%	4%	1%	1%	4%	7%	2%	-	-	4%	12%
US (GOM Shelf)	1%	-	-	4%	-	-	1%	-	-	-	-	1%	-
US (Lower 48)	21%	11%	4%	13%	1%	26%	0%	1%-	5%	41%	8%	26%	15%
Total N.America	**31%**	**25%**	**17%**	**23%**	**3%**	**57%**	**6%**	**8%**	**7%**	**41%**	**8%**	**44%**	**27%**
Argentina	0%	4%	0%	1%	2%	-	-	-	-	7%	-	-	-
Bolivia	-	0%	-	-	1%	-	-	10%	-	0%	3%	-	-
Brazil	-	0%	2%	1%	-	-	-	2%	2%	-	4%	-	-
Colombia	-	-	-	1%	-	-	-	1%	-	4%	-	-	-
Ecuador	-	-	-	-	-	-	0%	3%	-	-	-	-	-
Peru	-	-	-	-	-	-	-	8%	-	-	-	-	-
Trinidad & Tobago	-	9%	-	2%	1%	-	1%	40%	-	-	12%	-	-
Venezuela	-	-	0%	3%	3%	-	1%	12%	1%	-	-	-	-
Total S.America & Caribbean	**0%**	**13%**	**2%**	**8%**	**7%**	**0%**	**2%**	**76%**	**3%**	**11%**	**19%**	**0%**	**0%**
Croatia	-	-	-	-	-	-	1%	-	-	-	-	-	-
Denmark	-	-	3%	1%	-	-	-	-	-	-	-	-	3%
France	-	-	-	-	1%	-	-	-	-	-	-	-	-
Germany	2%	-	1%	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	0%	-	-	-	-	-	0%	-	-	-	-
Italy	-	-	1%	-	-	-	13%	-	-	-	-	-	-
Netherlands	8%	-	10%	0%	2%	-	-	-	-	-	-	-	-
Norway	8%	1%	5%	0%	13%	9%	8%	-	75%	-	1%	18%	7%
Spain	-	-	-	-	-	-	-	1%	-	-	-	-	-
UK	3%	6%	5%	3%	6%	7%	3%	-	0%	-	18%	6%	7%
Total Europe	**21%**	**7%**	**25%**	**4%**	**22%**	**16%**	**25%**	**1%**	**75%**	**0%**	**19%**	**24%**	**17%**
Azerbaijan	1%	4%	-	1%	1%	-	-	-	3%	-	-	-	2%
Kazakhstan	4%	-	0%	14%	-	-	4%	-	-	-	11%	-	-
Kirgizstan	-	-	-	-	-	-	-	-	-	-	-	-	-
Russia	1%	24%	6%	-	10%	1%	1%	-	0%	-	-	-	11%
Turkmenistan	-	-	-	-	-	-	0%	-	-	-	-	-	-
Total FSU	**6%**	**28%**	**6%**	**15%**	**11%**	**2%**	**5%**	**0%**	**3%**	**0%**	**11%**	**0%**	**13%**
Bahrain	-	-	-	-	-	-	-	-	-	3%	-	-	-
Iran	-	-	-	-	0%	-	0%	-	-	-	-	-	-
Iraq	1%	1%	0%	-	0%	-	1%	-	0%	5%	-	-	-
Oman	-	0%	7%	-	1%	-	-	-	-	9%	-	-	-
Qatar	17%	-	9%	-	5%	5%	-	-	-	21%	-	-	-
Saudi Arabia	-	-	-	4%	-	-	-	-	-	-	-	-	-
Syria	-	-	0%	-	0%	-	-	-	-	-	-	-	-
United Arab Emirates	7%	7%	4%	-	10%	-	-	-	-	2%	-	-	-
Yemen	0%	-	-	-	4%	-	-	-	-	4%	-	-	-
Total Middle East	**25%**	**8%**	**20%**	**4%**	**20%**	**5%**	**1%**	**0%**	**0%**	**45%**	**0%**	**0%**	**0%**

Source: Deutsche Bank estimates Note: 0% indicates a presence

Figure 17: Western Majors – Production by Geography 2012E (cont'd)

Country	Exxon	BP	Shell	CVX	Total	Conoco	Eni	Repsol	Statoil	OXY	BG	MRO	Hess
Nigeria	7%	-	10%	9%	11%	4%	10%	-	1%	-	-	-	-
Algeria	-	3%	-	-	2%	0%	6%	5%	2%	-	-	-	1%
Egypt	-	3%	1%	-	-	-	13%	-	-	-	25%	-	-
Libya	-	-	-	-	3%	3%	14%	10%	0%	4%	-	10%	5%
Tunisia	-	-	-	-	-	-	1%	-	-	-	6%	-	-
Total N.Africa	**7%**	**6%**	**11%**	**8%**	**16%**	**7%**	**44%**	**15%**	**3%**	**4%**	**32%**	**10%**	**6%**
Angola	4%	6%	-	7%	9%	-	7%	-	6%	-	-	2%	-
Chad	1%	-	-	1%	-	-	-	-	-	-	-	-	-
Congo	-	-	-	1%	3%	-	4%	-	-	-	-	-	-
Equatorial Guinea	1%	-	-	-	-	-	-	-	-	-	-	20%	14%
Gabon	-	-	1%	-	2%	-	-	-	-	-	-	-	-
Total W.Africa	**6%**	**6%**	**1%**	**9%**	**14%**	**0%**	**11%**	**0%**	**6%**	**0%**	**0%**	**22%**	**14%**
Australia	2%	3%	3%	4%	0%	1%	1%	-	-	-	3%	-	-
Bangladesh	-	-	-	4%	-	-	-	-	-	-	-	-	-
Brunei	-	-	6%	-	0%	-	-	-	-	-	-	-	-
China	-	0%	1%	1%	0%	3%	1%	-	-	-	-	-	-
India	-	2%	-	-	-	-	0%	-	-	-	3%	-	-
Indonesia	1%	2%	-	6%	6%	6%	1%	-	-	-	-	-	7%
sMalay/Thai JDA	-	-	-	-	-	-	-	-	-	-	-	-	11%
Malaysia	2%	-	4%	-	-	0%	-	-	-	-	-	-	1%
Myanmar	-	-	-	1%	1%	-	-	-	-	-	-	-	-
New Zealand	-	-	1%	-	-	-	-	-	-	-	-	-	-
Pakistan	-	-	-	-	-	-	4%	-	-	-	-	-	-
Philippines	-	-	1%	1%	-	-	-	-	-	-	-	-	-
Thailand	0%	-	-	8%	2%	-	-	-	-	-	6%	-	4%
Timor Leste/Australia JPDA	-	-	-	-	-	3%	1%	-	-	-	-	-	-
Vietnam	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Asia Pacific	**5%**	**7%**	**16%**	**25%**	**9%**	**13%**	**8%**	**0%**	**0%**	**0%**	**12%**	**0%**	**23%**
Group Production (kboe/d)	4322	3380	3,354	2639	2,318	1565	1688	344	1,811	760	687	455	406

The major NOCs

Four of the world's most powerful NOCs were born directly from consortium set up by western IOCs before WW II (the national oil companies of Saudi Arabia, Iran, Iraq and Kuwait). Dominated by the seven sisters, for decades these secretive western consortiums indirectly controlled the Middle East economies, and inevitably disputes and resentment arose between them and the host nations. Although pressure in the form of increased state profit share had been gradually submitted to by the consortiums since the Saudi's first extracted a 50/50 split from Aramco in 1950, the issue of reserves ownership and control always simmered beneath the surface, until eventually exploding in the early 1970s. It is several of these companies that in 1960 established the Organisation of Petroleum Exporting Countries or OPEC, which we discuss in the following section.

Four of the world's most powerful NOCs were born directly from consortium set up by western IOCs before WW II

Saudi Aramco is the direct descendent of the Chevron subsidiary that won the concession in Saudi Arabia back in 1933. Now the world's largest oil company, and with the largest reserves, it is recognised as a professional, well run organisation with strong onshore and shallow offshore technical expertise. Aramco has oil and gas production capacity of c.12mboe/d and combined reserves of 313bn boe.

NIOC (Iran). The National Iranian Oil Company dates back to 1951 when the Iranian Prime Minister (Mohammed Mossadegh) nationalised the industry in response to the Anglo-Iranian Oil Company's (BP) long-term refusal to materially improve the state share. A coup ensued, and by 1954 whilst NIOC still existed, control of the country's existing fields were placed with a consortium of western IOCs. The revolution of 1979 put 100% of the industry into the hands of NIOC but its performance was severely impacted by the 1980-88 Iran-Iraq war. Current buyback contract terms are relatively unattractive and long delays have occurred in key projects in which foreign companies are involved. NIOC has oil and gas production capacity of c.6mboe/d and combined reserves of 352bn boe.

INOC (Iraq). The Iraq National Oil Company was created in 1966 but can trace the history of its assets back to 1928 when the Iraq Petroleum Company (IPC) discovered the massive Kirkuk field. In 1961 Iraq nationalised the industry but left IPC (BP, RD/Shell, Total, Exxon, Mobil, Gulbenkian) controlling all of the existing production. This was redressed by Saddam Hussein in 1971 when all of Iraq's oil assets were nationalised and handed over to INOC. Post the 2003 Iraq War it remains unclear what the ultimate structure of the Iraq oil industry will be. However, in 2009 the country awarded a number of service contracts to a mix of foreign IOCs and NOCs. At present INOC has oil and gas production of c.2.7mboe/d and combined reserves of 165bn boe.

KOC (Kuwait). Kuwait Oil Company was created in 1934 as a 50/50 venture between BP and Gulf and had its first commercial discovery in 1938. In 1975 KOC went the same way as neighbouring consortiums and was 100% nationalised. Gulf War I (1991) started as a result of Iraq invading Kuwait, partly motivated by Iraq's desire for the KOC oilfields. KOC has oil and gas production of c.2.6mboe/d and combined reserves of 112bn boe.

Qatar Petroleum. QP was born out of the 1974 nationalisation of assets held by various IOCs (BP entered the country back in 1934). The key asset today is the giant North Field, shared with Iran (where it's called South Pars) – the largest non-associated gas field in the world. QP is the major shareholder in the Qatargas (QP, Total, Exxon) and Rasgas (QP, Exxon) subsidiaries, which have been set up to exploit the North Field. QP has oil and gas production of c.1.5mboe/d and combined reserves of 181bn boe.

PDVSA (Venezuela). Petroleos de Venezuela (PDVSA) was created in 1975, at the same time that the oil industry was nationalised. Prior to this Exxon, Mobil, Chevron, Texaco, Gulf and RD/Shell, amongst other IOCs, had been exporters. The 1990s saw PDVSA struggling to meet its desired production capacity of 4mb/d, so the marginal fields and the Orinoco heavy oil belt were re-opened to foreign investment. Strikes by PDVSA management and workers occurred in 2002, and President Chavez responded by firing 12,000 of the 38,000 workforce, many of which were forced to find work overseas. The company thus lost a large portion of its skilled human capital base, and is thought to only be producing c2mb/d of oil currently, versus a claimed capacity of 3.2mb/d. PDVSA has oil and gas production of c.2mboe/d and combined reserves of 207bn boe.

Gazprom (Russia) can trace its origins back to 1943 when a separate Soviet gas industry was created (i.e., distinct from oil). Russia has the highest gas reserves of any country. Mikhail Gorbachev's reforms provided the catalyst for the state to list 40% of the company in 1994, but for much of the rest of the 1990s Gazprom was accused of widespread corruption. Under the Putin-appointed Alexei Miller (2001) Gazprom has been successfully reformed; it has a monopoly on Russian gas exports and has emerged as a major world power in the global oil and gas industry. Gazprom has oil and gas production of c.8mboe/d and combined reserves of 105bn boe.

Rosneft (Russia), will become the world's largest oil company following the 2013 expected completion of its agreed acquisition of TNK-BP for c$55bn, an event that in many ways marks a complete turnaround in the company's fortunes over the space of just two decades. Rosneft was established in 1993 on the basis of assets previously held by Rosneftegaz, the successor to the Soviet Union's Ministry of Oil & Gas and as such accounted for much of what then was the Russian oil industry. The allocation and award of its assets in the establishment of ten integrated companies, not least to a clutch of oligarchs, effectively resulted in its near complete dismantling. Yet, following a failed plan to merge the company with Gazprom, the company re-emerged as Russia's second largest oil company, and official state champion, as a consequence of its purchase of the sequestered Yukos oil business in late 2004 through a much criticised auction process. Subsequent to this purchase the the enlarged company was floated in 2006 in one of the world's largest IPO's with 15% of its equity listed on the London and Russian exchanges for around $10.7bn. More recently in 2012 the company announced that it had reached agreement with BP and AAR to acquire their joint interests in TNK-BP. In so doing Rosneft has established itself as the world's largest oil and gas company with production of over c4mb/d or some 40% of that of the entire Russian state. The company is 75% owned by the Russian state and will be 19.75% owned by BP plc.

Petrobras (Brazil) is a Brazilian integrated oil company founded in 1953, with 56% of its shares owned by the government. It has a reputation for being a professional deepwater field developer and operator, despite a disaster in 2001 when the Petrobras 36 Oil Platform (the world's largest platform at the time) exploded and sank. Petrobras currently produces c2.2mb/d and has reserves of 27bn boe.

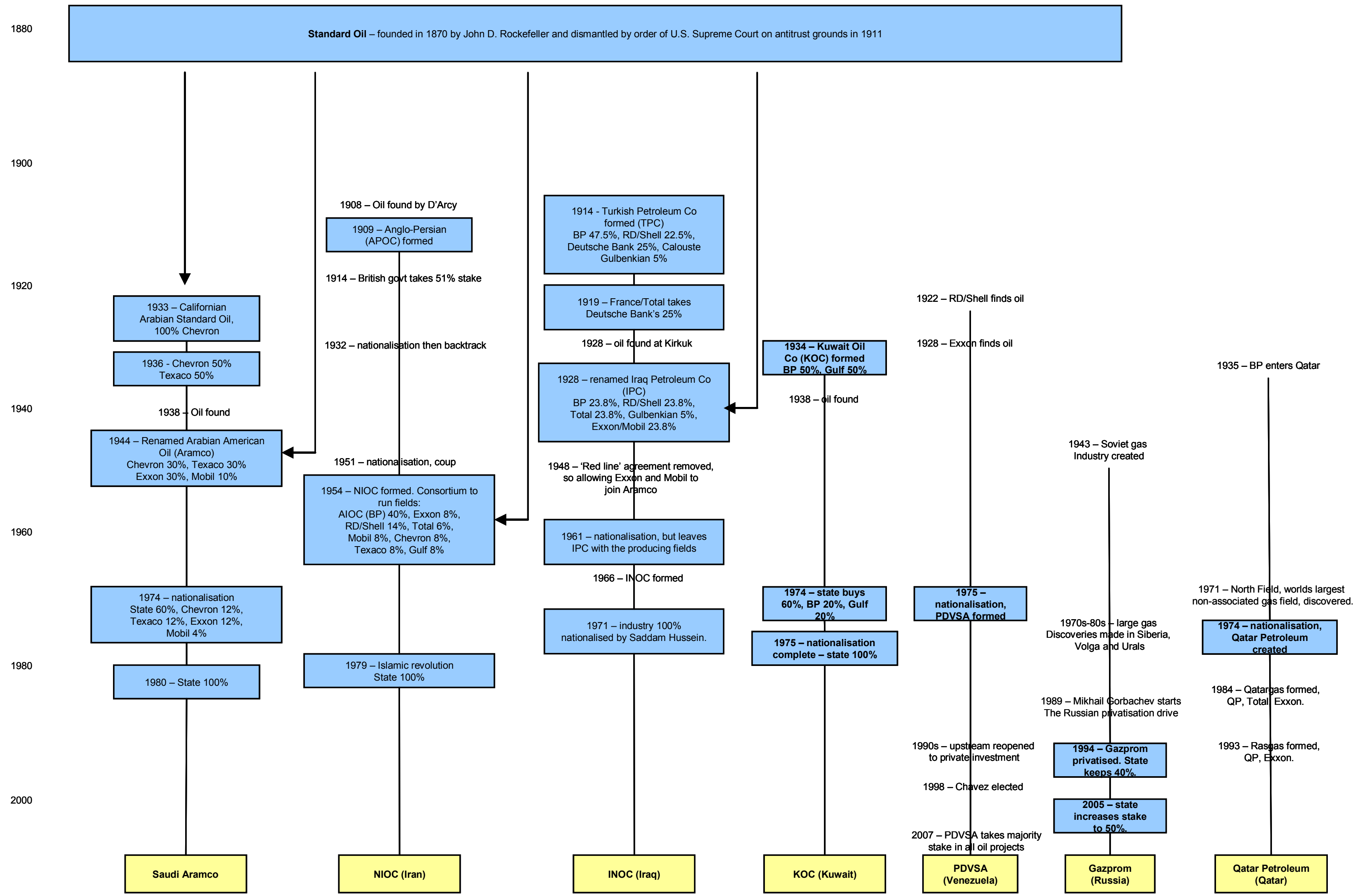
Pemex (Mexico) can trace its history back to the country's nationalisation of the industry in 1938. It is state owned and has a monopoly over all Mexican upstream and downstream operations. Pemex is hamstrung by the fact that much of its revenues go direct to the government and the technology and skills that are required to both slow down field decline and explore deeper water requires foreign company participation, which is prohibited under Mexican law. Pemex has oil and gas production of c.3mb/d and has combined reserves of 15 bn boe.

Petronas (Malaysia) was created in 1974 by the Malaysian government and remains state owned. It started LNG exports from Sarawak in 1983 (with RD/Shell) and has expanded its LNG production since that date, and also acquired interests overseas. Petronas has oil and gas production of c.1.3mb/d and reserves of 13bn boe.

CNPC (P.R.C.) is the P.R.C.'s state-owned oil and gas company, was created in 1988 and is the descendent of the Fuel Ministry created in 1949. It is the second largest company in the world by number of employees. In 1999 its major domestic assets were listed in a separate company, Petrochina. CNPC has been very active in acquiring acreage and assets internationally over the last decade, including in Venezuela, Sudan, Peru, Turkmenistan, Algeria and Kazakhstan. CNPC has oil and gas production of 3.6mb/d and reserves of 32bn boe.

The figure overleaf depicts the family tree of the major NOCs, illustrating clearly the wave of nationalisations that occurred post 1970.

Figure 18: The major NOCs family tree



Source: Deutsche Bank

OPEC

Through co-ordination of production, the Organisation of Petroleum Exporting Countries (OPEC) stands as the single most important supply-side influence in global oil and energy markets. Accounting for around 42% of world oil production but over 55% of the oil traded internationally, OPEC has substantial influence over the direction of crude pricing, and one that looks likely to increase given that the countries that comprise OPEC account for almost 80% of the world's proven oil reserves. At its simplest, OPEC effectively works as a supply-side swing, with the members seeking to co-ordinate their production through periodically agreed production allocations thereby ensuring that the market for oil remains roughly 'in balance' at a particular price band.

OPEC stands as the single most important supply-side influence in global oil and energy markets

A brief history

OPEC describes itself formally as a permanent, inter-governmental organisation which was created in September 1960 by five founding members; Iran, Iraq, Kuwait, Saudi Arabia and Venezuela. These five were later joined by nine other members namely Qatar (1961), Indonesia (1962 albeit suspended in 2009), Libya (1962), the UAE (1967), Algeria (1969), Nigeria (1971), Ecuador (1973), and Gabon (1975-94) although subsequent years saw these two latter members, both of whom were only modest oil producers, suspend their membership of the organisation. More recently, in 2007 Angola was admitted to OPEC and Ecuador ended its suspension, re-entering the cartel. Today's OPEC thus comprises 12 members.

OPEC's Charter

Headquartered in Vienna, Austria OPEC's objective from the start has been 'to co-ordinate and unify petroleum policies among member countries in order to secure fair and stable prices for petroleum producers; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the industry'. Through the early years of the organisation, limited co-ordination between the members and the ongoing dominance of the international oil companies (IOCs) meant that OPEC's influence on oil markets and pricing was modest. Indeed, the presence of the IOCs through production concessions in many member countries meant that OPEC's ability to influence production quantities was somewhat limited. However, angered by the low price of oil in the early 1970s and a belief that the production policies used by the international majors were resulting in minimal returns for the countries within whose borders crude reserves lay, the member countries started to re-nationalise their oil assets and flex their collective strength. Moves by Libya to oust BP in 1971 were soon followed by similar initiatives amongst other producing nations. In a world dependent upon oil, OPEC had suddenly realised its power.

The OPEC charter: to co-ordinate and unify petroleum policies among member countries in order to secure fair and stable prices for petroleum producers; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the industry'

Figure 19: Which year did you nationalise? OPEC initiatives to reclaim assets

Country	Year	Companies plundered
Kuwait	1977	Texaco, Chevron
Libya	1971	BP, Occidental
Iraq	1972	Exxon, BP, Shell
Iran	1973	BP
UAE	1973	BP, Total, Shell
Nigeria	1974	BP
Saudi Arabia	1976	Texaco, Chevron, Exxon, Mobil
Venezuela	1975	
Qatar	1977	Shell

Source: Deutsche Bank

1973 and the Yom Kippur War

Indeed, this recognition culminated in 1973 when, in response to US support for Israel in the Yom Kippur War, the Arab nations enacted an embargo on oil exports to the US. The result was sudden and devastating with oil prices broadly quadrupling overnight and an energy-hungry world falling into recession. For perhaps the first time the developed world recognised the power that now vested with the oil producing nations.

How does OPEC work?

OPEC works by virtue of its members collectively agreeing on the level of supply that is necessary to keep the market in balance

In essence OPEC works by virtue of its members collectively agreeing on the level of supply that is necessary to keep the market in balance and the oil price within a pre-determined range. Represented by the Oil and Energy Ministers of the OPEC member countries, the cartel meets at least twice a year to assess and review the current needs of the oil market and alter, if necessary, its level of production. Dependent upon market conditions, meetings can, however, be more frequent.

Introduced in 1982, through collective agreement each member of OPEC is allocated a production quota. Although OPEC has never defined how the production quotas of the different member countries are established they are believed to be representative of each country's 'proven' reserves base, amongst others. The quota represents the oil output that a member state agrees to produce up to assuming no other restrictions are in place and assuming the country remains in compliance (which as the charter says is at the discretion of the member country). Frequently, however, different member states will produce well above or below their official quota, with production more likely proving representative of a member's production capability then its actual quota level. Thus where Venezuela retains a production quota of over 3mb/d its current production capacity is little more than 2.6mb/d. By contrast although Algeria's quota is only 890kb/d it regularly produces nearer 1.2mb/d. Note that the c7mb/d of NGL production with OPEC member countries falls OUTSIDE the quota system i.e. no restrictions exist.

What is established at each OPEC meeting is the extent to which OPEC believes that the world crude oil market is over or under supplied. In making this decision the organisation will consider inventories, expected demand and the current price of crude oil, amongst others. Politics will also invariably play its role as indeed will be the price required by its members to balance budgets. Having considered the supply position OPEC will then determine whether it needs to supply more or less crude to the market.

Figure 20: OPEC's Ingredients

Member	Production Nov 2012	Production capacity 2012	% OPEC total	Spare capacity	% OPEC Spare	Official reserves	Reserves as % global	Price for budget b/even ($/bbl)
Saudi Arabia	9.90	11.88	34%	1.98	52%	265	16.0%	95
Iran	2.70	3.20	9%	0.50	13%	155	9.4%	125
Iraq	3.21	3.29	9%	0.08	2%	141	8.5%	105
UAE	2.65	2.79	8%	0.14	4%	98	5.9%	90
Kuwait	2.78	2.84	8%	0.06	2%	102	6.2%	70
Qatar	0.73	0.79	2%	0.06	2%	25	1.5%	50
Nigeria	1.88	2.57	7%	0.69	18%	37	2.2%	110
Libya	1.45	1.51	4%	0.06	2%	48	2.9%	100
Algeria	1.18	1.20	3%	0.02	1%	12	0.7%	110
Venezuela	2.47	2.60	7%	0.13	3%	298	18.0%	100
Angola	1.80	1.85	5%	0.05	1%	11	0.7%	85
Ecuador	0.48	0.54	2%	0.06	2%	8	0.5%	115
	31.23	35.06	100%	3.83	100%	1200	72.6%	96

Source: Source: Deutsche Bank, IEA; OPEC, BP Statistical Review

Should less supply be required it will set a production ceiling for the organisation as a whole with each member state agreeing a reduction in its current level of production (and vice versa). In this way OPEC seeks to ensure that the market is adequately supplied. Importantly, member countries must agree by unanimous vote on any such production ceilings and output allocations. A majority cannot overrule a minority and central to the OPEC charter is that each member country retains absolute sovereignty over its oil production. It should, however, be noted that Saudi Arabia's clear dominance of production and 'swing' (or spare) capacity mean that its acceptance of policy will almost certainly be required if a proposal is to succeed.

Why is OPEC able to influence prices?

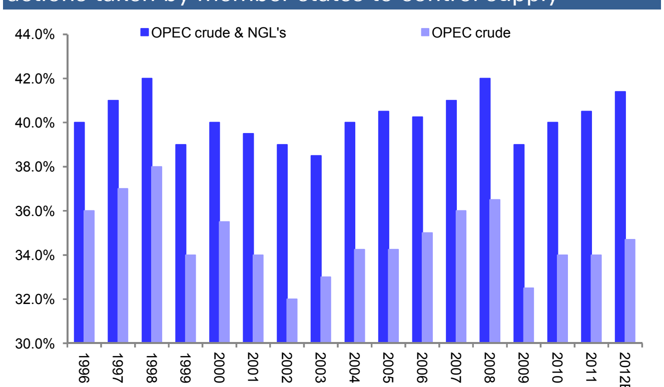
OPEC's ability to influence oil prices reflects its dominance of world reserves (77% in 2006) and the substantial and growing share of world oil and NGL production that is accounted for by its members

OPEC's ability to influence oil prices reflects its dominance of world reserves (73% in 2011) and the substantial and growing share of world oil and NGL production that is accounted for by its members and, consequently, the impact that changes in their production policy can have on world oil supply. In 2011, oil production by OPEC members (including Angola) is estimated to have accounted for around 30mb/d or 34% of world demand for crude oil and natural gas liquids (although as stated NGLs are outside the organisation's quota system. If NGL's are include OPEC's share stands at nearer 40%). Where all countries outside OPEC seek to operate at full capacity, it is purely within OPEC that spare oil production capacity resides (and this predominantly in Saudi Arabia).

The 'call' on OPEC

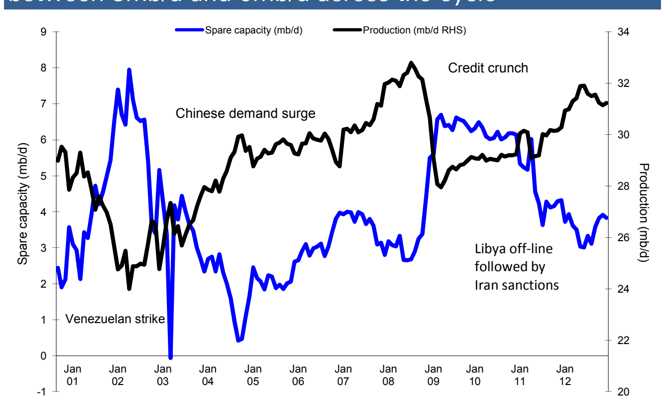
In effect, OPEC therefore acts to meet the **CALL** on oil supply by consumers that cannot be met by the non-OPEC producers (hence the term the 'call on OPEC'). OPECs importance to supply also means, however, that commodity market pricing is heavily influenced by its ability to supply and as such, the level of spare capacity that resides amongst its members. To the extent that OPEC is operating towards full capacity, the price of crude oil will most likely reflect broad concerns that, in the event of an unexpected supply disruption, OPEC might be unable to ensure the supply of sufficient crude oil to world markets. Equally, at times of significant excess spare capacity the price of crude oil will likely fall reflecting both the likely availability of sufficient supplies of crude oil and commodity markets' recognition that, on past occasions, a build in spare capacity has often been associated with poor adherence to production quotas by certain members of the cartel (i.e. quota 'cheating') as they seek to obtain additional revenues from the supply of crude.

Figure 21: OPEC – Market share is illustrative of the actions taken by member states to control supply



Source: Deutsche Bank

Figure 22: OPEC production and spare capacity – trending between 3mb/d and 6mb/d across the cycle



Source: Deutsche Bank

The diagram above depicts recent moves in OPEC production and spare capacity. It emphasizes that on several occasions in the past decade, strong global growth meant that at times OPEC was stretched to capacity with very little slack left in the system. Towards the end of 2008 a modest build in new OPEC capacity, not least within Saudi Arabia, coincided with a very sharp downturn in demand as the global financial crisis struck. As a consequence spare capacity within OPEC moved back towards levels not seen since 2002 at which time the global economy was similarly facing more challenging economic conditions. Subsequent economic recovery not least in emerging markets which remain the key driver of demand growth, combined with supply issues associated first with the overthrow of Colonel Gadafi in Libya and more recently sanctions against Iran have, however, seen spare capacity within OPEC retrace significantly to just over 3mb/d. Looking forwards with economic growth weak and non-OPEC supply showing signs of recovery, most significantly in North America, we would expect spare capacity to build. This does, however, assume little by way of geopolitical unrest in the Middle East which, history tells us, is likely to prove an optimistic view.

Because OPEC does not have the power to force its members to adhere to their production quotas but instead relies upon their mutual compliance, past efforts to contain the level of supply have invariably seen certain members failing to adhere or 'cheating' on their production ceilings. Based on past behaviour compliance by the Gulf States, (Saudi Arabia, Kuwait, Qatar and the UAE) tends to be high whilst that of Nigeria, Iran and Venezuela often waivers.

What price does OPEC want?

From the mid-1980s through the start of the current decade, OPEC adopted specific policies on pricing

From the mid-1980s through the start of the noughties, OPEC adopted specific policies on pricing, informing the market of the crude oil price that it would look to achieve for the OPEC basket (see below) and using the quota system to try and maintain prices at around its targeted level. Initially, the organisation set a specific price as its objective with $18/bbl targeted between 1986 and 1991 before an increased $21/bbl was set as a target through the balance of the 1990s. Often poor discipline amongst its members and erosion of its market share meant, however, that the crude oil price invariably traded below its target such that, from 1999, a new approach was adopted – that of maintaining the price within a $22-28/bbl target band.

This policy proved far more successful and the target band has never officially been revised. Over the past decade, however, it is only too apparent that OPEC's price intentions have changed and dramatically. Initially this was evidenced by the organisation's 2004 initiatives to defend a $40/bbl oil price, a $55/bbl price in late 2006 and to defend a $60/bbl oil price as the financial crisis hit in late 2008. More recently, the Saudi's who with some 55% of the organisations spare capacity clearly dominate the organisations ability to manage prices, have indicated that they are comfortable with an oil price of around $100/bbl despite the more bullish calls from certain other members, not least Iran. Important here no doubt is the fact that with oil exports on average accounting for over 45% of OPEC members' GDP, an oil price of at least $95/bbl is now a pre-requisite if they are to balance their domestic budgets and meet the ever increasing expectations of their citizens for an improvement in living standards.

The OPEC basket

The OPEC basket comprises a mix of 12 different blends of crude produced by the member countries. In determining the price band for crude oil that OPEC wishes to see in world markets it is this basket that is key. As of June 2010 the basket comprised Saharan Blend (Algeria), Girassol (Angola), Oriente (Ecuador), Iran Heavy, Basra Light (Iraq), Kuwait Export, Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine, Arab Light (Saudi Arabia), Murban (UAE) and Merey (Venezuela). Note that with the OPEC basket both heavier and more sour than Brent it trades at a typical 3-5% discount.

What is the western IOCs exposure to OPEC?

What is the western IOCs exposure to OPEC?

For the IOCs, decisions by OPEC to introduce production restrictions or to manage the pace of capacity growth clearly hold potential implication. For those companies that derive a significant proportion of their oil production in OPEC territories, volumes at a time when restrictions are being implemented will almost certainly be reduced. With this in mind in the table below we detail our estimates of the companies' oil production by OPEC territory together with the percentage of total oil production and hydrocarbon production that is OPEC sourced. What is evident from this is that even today, OPEC territories remain a very important source of IOC barrels with the 12 member states representing some 26% of the oil production for the western companies (14% group production) included below. Through their interests in Angola (25% of OPEC aggregate barrels), Nigeria (30%) and the UAE (26%) each of Total, Chevron, ENI and Exxon in particular derive material oil barrels from OPEC nations most although, with the profitability per OPEC barrel tending to be much lower than that elsewhere, the significance of this production to upstream profits is likely to be far lower than the volume percentage may indicate.

Figure 23: The western majors production of crude oil in OPEC territories (2012E)

Country *	BP	RDS	XOM	CVX	Total	COP	ENI	Repsol	Hess	Oxy	BG	Statoil	MRA
Saudi Arabia (2%)				3%**									
Iran (0%)													
Iraq (3%)	3%		1%				1%			1%			
Kuwait (0%)	0%	0%	0%										
UAE (26%)	10%	9%	13%		20%								
Venezuela (6%)	1%		5%	4%		1%	14%				1%		
Nigeria (30%)	0%	14%	12%	14%	10%	3%	11%					3%	
Angola (25%)	7%	0%	6%	10%	14%		11%					11%	3%
Algeria (1%)	1%	0%	0%	0%	0%								
Qatar (0%)													
Libya (8%)					3%	5%	9%	26%	7%	2%		1%	14%
Ecuador (0%)													
As % oil (26%)	20%	23%	31%	32%	53%	8%	33%	40%	7%	3%		16%	17%
As % group (14%)	13%	12%	16%	21%	28%	4%	17%	17%	5%	2%		9%	12%
Group oil prodn kb/d	**2,133**	**1,655**	**2,237**	**1,793**	**1,212**	**875**	**889**	**144**	**302**	**544**	**182**	**1,020**	**312**
Total prodn kboe/d	**3,362**	**3,354**	**4,322**	**2,639**	**2,318**	**1,565**	**1,688**	**344**	**406**	**760**	**687**	**1,812**	**455**

*Source: Source: Deutsche Bank * % represents the proportion of IOC barrels sourced from this territory as a % of overall oil production **Partitioned zone (assumed 50% Kuwait and 50% S Arabia)*

In the beginning .....

A brief summary

Although the earth is thought to have been formed over 4.5 billion years ago, it is only over the last 500 million years that the sources of crude oil and gas have been laid down.

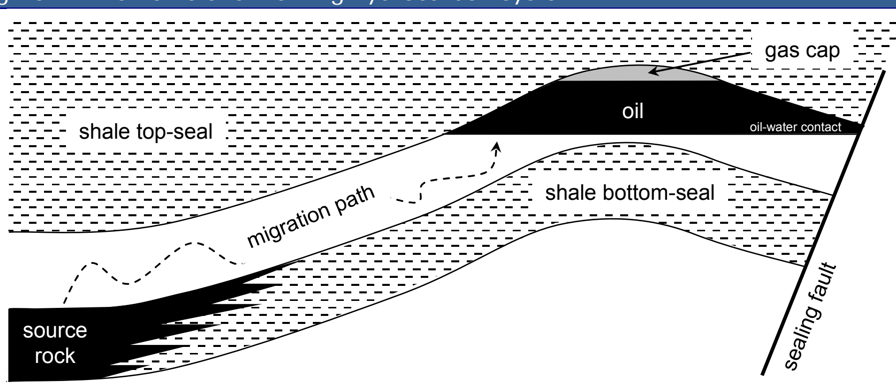
It is only over the last 500 million years or so that the sources of crude oil and gas have been laid down

At its simplest, the deposition of organic matter from plants and micro-organisms in waters with little if any oxygen, or at a rate faster than that at which they could be consumed, led to the establishment of layers of organic matter and very fine silt particles on the sea bed which were subsequently buried and compacted as the earth's conditions changed. As these organic rich 'source rocks' were buried over time and subjected to ever greater pressures and temperatures so the organic matter was broken down to form hydrocarbons in the earth's 'source' kitchen. The greater the temperature and pressure the more the hydrocarbon chains were broken down from bitumen to oil to natural gas.

Once formed, compaction may have driven these hydrocarbons from the host rocks in a process known as migration. Because the hydrocarbons formed were less dense but occupied a greater volume than the organic matter from which they were formed, they migrated upwards via micro fractures in the source rock into new depositional stratum. This process of migration is likely to have continued until the oil or gas reached an impermeable layer of rock whereupon it was trapped, with the rock which it was trapped in, most likely sandstone or limestone, effectively acting as a 'reservoir'.

For oil and gas to accumulate each of these elements must coincide (source, reservoir and trap). Equally, all must occur within a 'dynamic system' where each can interact with the other. Sadly, it is the multiple of the probabilities of each of these occurring that determines the likelihood of geologic success. Moreover the extent to which this oil or gas can be extracted will depend on a number of factors. Not least amongst these are the porosity and permeability of the reservoir rock i.e. the extent to which space exists between the grains of the rock and the ease with which fluid can flow through those spaces.

Figure 24: Elements of a working hydrocarbon system



Source: Deutsche Bank

Why 'Rock Doctors' matter

In short, without even considering the odds around the successful exploration for oil and gas a great number of factors need to align for hydrocarbons to have been established. First and foremost amongst these are that, at some point in the earth's history, the conditions for deposition were in place. With over 90% of the world's oil & gas reserves generated in six source rock intervals which represent only 4% of the earth's entire history, our review of oil's formation starts with a look at the 'Rock Record' of time.

90% of the world's oil & gas reserves were generated in six source rock intervals and only 4% of the earth's history

Geologic time and rock record

The Earth's c4.5 billion year history can be sub-divided into a series of episodes

Using the rock record, the Earth's c4.5 billion year history can be sub-divided into a series of episodes. These episodes are uneven in length, and their preservation at any one place is typically highly incomplete—the rock-record often skewed toward preservation of the unusual.

As a result, 'type sections' have been established around the world that are considered to best represent each episode or historic epoch. These are then dated using two methods:

- The relative time scale – based on study of the evolution of life across the layers of rock
- The radiometric time scale – based on the natural radioactivity of chemical elements

Construction of a relative time scale is underpinned by the principle of '**superposition**' – one of the great general principles of geology. Superposition states that within a sequence of layers of sedimentary rock, as originally layed down, the oldest layer is at the base and that the layers are progressively younger with ascending order in the sequence.

In the table below we outline the major subdivisions of the geologic record.

Figure 25: Major subdivisions of the geologic record

Eon	Era	Period	Epoch	(Mln years) from	to
Phanerozoic	Cenozoic	Quaternary	Holocene	0.01	0
			Pleistocene	1.8	0.01
		Tertiary	Pliocene	5.3	1.8
			Miocene	23.8	5.3
			Oligicene	33.7	23.8
			Eocene	54.8	33.7
			Paleocene	65	54.8
	Mesozoic	Cretaceous		144	65
		Jurassic		206	144
		Triassic		248	206
	Paleozoic	Permian		290	248
		Upr Carboniferous*		323	290
		Lr Carboniferous*		354	323
		Devonian		417	354
		Silurian		443	417
		Ordivician		490	443
		Cambrian		543	490
Precambrian				4500	543

Source: Deutsche Bank

* Upr Carboniferous equivalent to Pennsylvanian, Lr Carboniferous equivalent to Mississippian

Although life on earth is thought to first have emerged in excess of 3.5 billion years ago, the record of multi-cellular life only really expands during the Phanerozoic Eon - a relatively 'brief' period which captures the Earth's last half a billion years, c12% of geologic time.

It is today almost universally accepted that hydrocarbons originate from organic matter, therefore it is to this most recent portion of the earth's history that commercial oil and gas generation is confined.

Basic geology

The search for oil and gas is focused within the upper levels of the Earth's '**crust**'. This crust varies between 0 and 40 km thick, and sits on top of the molten 'mantel'. The crust can broadly be sub-divided into two types – oceanic and continental.

As implied by its name, **oceanic crust** underlies the oceans, and is dominated by dense 'basaltic rocks' – rich in iron and magnesium-based minerals, but with little quartz. Its greater density means it sits lower than its continental counterpart. **Continental crust** is dominated by less dense 'granitic rocks' – rich in quartz and feldspar minerals, which lends it a relative buoyancy versus that under the oceans. Oil and gas exploration is exclusively focused within the upper layers of the Earth's continental crust.

Plate tectonics… geology's unifying theory

The Earth's crust is divided into c.12 ridged **plates**. Radioactive decay within the Earth releases heat and drives convection of the molted 'mantle'. Across geologic time, this causes the Earth's plates to 'drift' - the plates sliding over the partially molten, plastic 'asthenosphere' (upper mantle). The speed of this motion varies both within and between plates, but typically occurs at c.1cm per year – about the rate at which your fingernails grow.

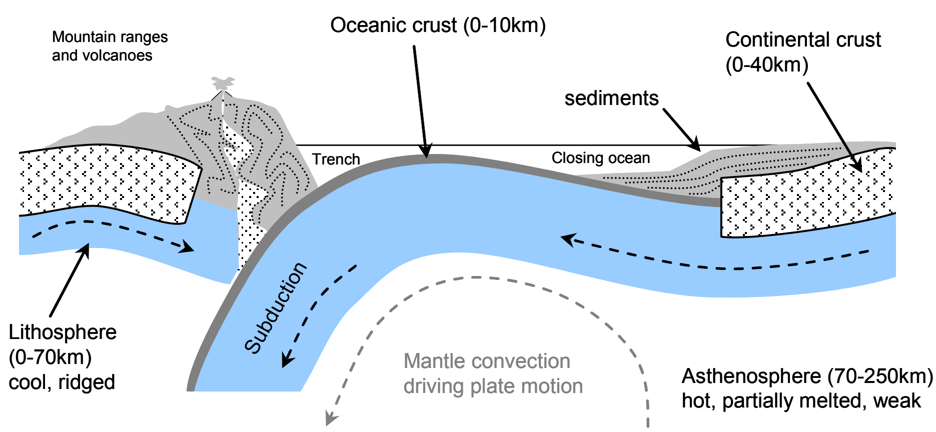
As they drift, the plates interact at their margins - new crustal material being created at mid-ocean ridges, and destroyed in subduction zones. These subduction zones are marked by deep ocean trenches and high mountain ranges. Across geologic time '**plate-tectonic drift**' has opened and closed oceans, and built and destroyed mountain chains.

Through this process the minerals that combine to make different 'rock types' may have passed many times through the 'rock-cycle' and it is these building blocks which form oil and gas **source rocks**, **reservoirs** and **seals**.

The minerals that combine to make different 'rock types' have passed many times through the 'rock-cycle'

Plate movements also deform the crust, producing folds and faults. This forms structures within which oil and gas could concentrate - '**structural traps**' being the most visually obvious, and hence most commonly drilled, style of oil and gas accumulation.

Figure 26: Schematic cross section through a convergent plate margin



Source: Deutsche Bank

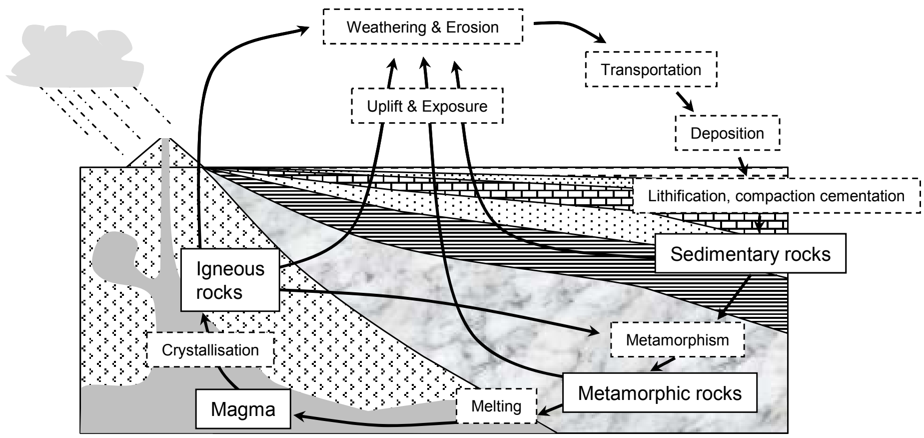
Rock types and the rock cycle

Rocks are divided according to their process of origin into 3 major groups: igneous, sedimentary and metamorphic. These are then sub-divided according to mineral composition and '**texture**' (grain/crystal size, size variability, rounding/angularity, preferred orientation).

Rocks are divided according to their process of origin into 3 major groups: igneous, sedimentary and metamorphic.

Across time, minerals pass between the groups via a continuous process of sedimentation, burial, deformation, magmatism, uplift and weathering – known as the '**rock cycle**'.

Figure 27: The rock cycle



Source: Deutsche Bank after Hutton (1727 to 1797)

Igneous rocks. Igneous rocks form through the cooling of minerals from a molten, or magmatic, state. In continental settings they are characterized by high levels of silica, and, when eroded, they deliver both quartz (sand) and clays (mud) into sedimentary systems. Sand is the fundamental building block of most reservoirs, clays being the fundamental building block of most seals.

Sedimentary rocks. Sedimentary rocks form the host to almost all oil and gas reserves. They are deposited in layers, within depressions known as **sedimentary basins** and are floored by '**basement**' igneous/metamorphic rocks. These basins form as the earth's crust is deformed, the layered nature of their fill reflecting the cyclical process of deformation, uplift and erosion. Sediments are divided into two broad sub-groups – detrital and chemical.

- **Detrital** sediments are composed of fragments of rock or mineral, eroded from pre-existing rocks – a signature of the mechanical processes of erosion, transportation and deposition by terrestrial, ocean or wind currents, preserved in their fabric. Also referred to as **clastic** (from the Greek klastos, to break), examples include conglomerate, sandstone and mudstone/shale.

- **Chemical** sediments are precipitated from solution, mostly in the ocean. Limestone and dolomite are the most common form (calcium and magnesium carbonates), but within oil & gas geology another important form are evaporitic deposits, including gypsum and halite, crystallized from evaporating seawater, generally referred to as 'salt'.

Metamorphic rocks. As rocks are buried or have igneous bodies injected into them, they are exposed to elevated temperature and pressure conditions. In a subtle form, this is a key process in the conversion (maturation) of organic matter into oil and gas. However, taken further, this leads to the transformation, or 'metamorphism' of rocks into new types. Typically this change is to the detriment of reservoir quality.

Hunting for sand…

Sandstone and limestone account for c19% and c9% of the Earth's sedimentary rocks respectively

Sandstone and limestone account for c19% and c9% of the Earth's sedimentary rocks respectively, and these form almost all the world's discovered oil and gas **reservoirs** – hydrocarbons sitting between the mineral/rock grains in sandstone, and within voids in limestone.

Enveloping these rocks is a background of mudstone and shale – which accounts for c67% of the Earth's sedimentary rocks. These fine-gained rocks accumulate in low-energy environments, during periods of quiet deposition. Typically impermeable, they form good '**seals**' to prevent the escape of hydrocarbons, and their conditions of deposition can also favor the preservation of organic matter – meaning they may be an effective hydrocarbon **source.**

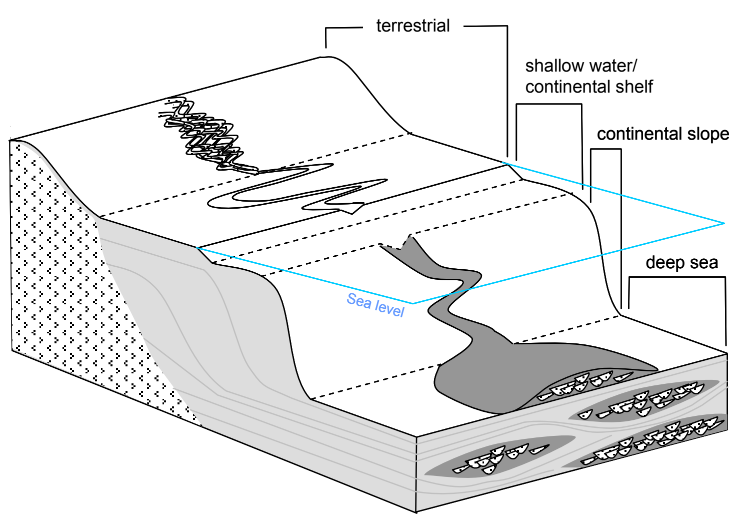
- In this context, one of the exploration geologist's principle tasks is to develop and apply models that help predict the distribution of reservoir units within a background of mud.

Unraveling depositional settings

The processes that shaped the Earth through geologic time (wind action, rivers, waves etc) are broadly the same as those observed today (the principle of **uniformitarianism**). Therefore, by understanding the relative distribution of sand/carbonate/mud within modern depositional systems, it is possible to subdivide basin fills in the rock-record into units, whose set of characteristics, or '**facies**', reflect their environment of deposition.

At any one point in time a whole series of depositional environments will coexist from dry-land, into shallow water and then out into the deep ocean (see below). These environments contain sediments/rocks which have differing source, seal and reservoir potential.

Figure 28: Schematic transition in depositional environments from land-to-sea



	Reservoir	Source	Seal
Continental environments			
Alluvial fan	✓		
Aeolian desert	✓		
Braided stream	✓		
Lake		✓	✓
Floodplain	✓	✓	✓
Leveed meandering channel	✓	✓	✓
Dunes	✓		
Shallow water			
Tidal flats	✓	✓	
Barrier islands	✓		
Beach	✓		
Lagoon		✓	
Reefs	✓		
Carbonate muds			✓
Deepwater			
Canyons	✓		
Turbidite channels	✓		
Ponded mini-basins	✓		
Toe-of-slope fans	✓		✓
Abysal plain		✓	✓
Slope aprons		✓	✓

Source: Deutsche Bank

A key control on grain-size distribution across these environments, and hence reservoir quality/seal integrity, is the path and energy of the currents eroding, transporting or depositing the rock/mineral fragments. As velocity falls, heavier particles are deposited.

Slope gradient is a major factor dictating the energy of flows, and, broadly speaking, sediments tend to become finer grained moving from land out into the deep oceans.

In more detail, the erosive power of rivers falls between mountainous areas and flood plains, before rising again into shallow water, where sediments are churned by waves and tides. Below storm-wave-base, energy levels fall, before rising again within focused channel corridors, as flows accelerate down the continental slope, before slowing and expanding across the deep ocean floor.

Reading the rock record

Through geologic time however, the pattern of depositional systems does not remain static. In response to **rises/falls in sea-level** and/or the **uplift/subsidence of the land**, the whole land-to-sea depositional system may advance seaward or retreat landward.

Viewed at any one geographic point, this shift is likely to be marked by an abrupt change in the depositional signature preserved within the rock record, which should be clearly marked both within well logs and on seismic.

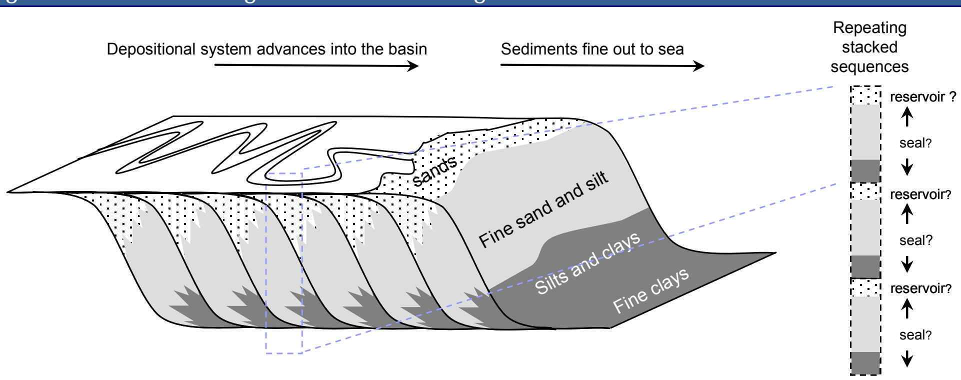
A seaward shift in the system (**progradation/regression**) is typically marked by coarser sediments such as beach sands overstepping finer sediments such as continental slope silts and muds. At the same time, exposure and erosion of the old beach-line is likely to release large volumes of sand into the deeper parts of the basin – thus maximizing the potential to concentrate sands into reservoirs.

In contrast, a landward move in the shoreline (**retrogradation/regregression**) is typically marked by the abrupt drowning of shoreline sands and their draping in slope muds. These muds are regionally extensive, can be used to map clear time-horizons through the basin fill, and may form highly efficient seals. Falling sea-level can also isolate a basin from wider patterns of ocean circulation. This may lead it to stagnate, falling oxygen levels favoring the preservation of organic material, which could then mature into hydrocarbon source rocks.

Repeated advances and retreats in depositional systems result in a **cyclic sequence** of rocks – potential reservoir sand/limestone encased within sealing mud. As such, the mapping of such sequences, both in terms of space and time, is one of the most powerful predictive tools used in the search for oil and gas.

The mapping of cyclic sequences is one of the most powerful predictive tools used in the search for oil and gas.

Figure 29: An advancing shoreline and its signature within the rock record



Source: Deutsche Bank

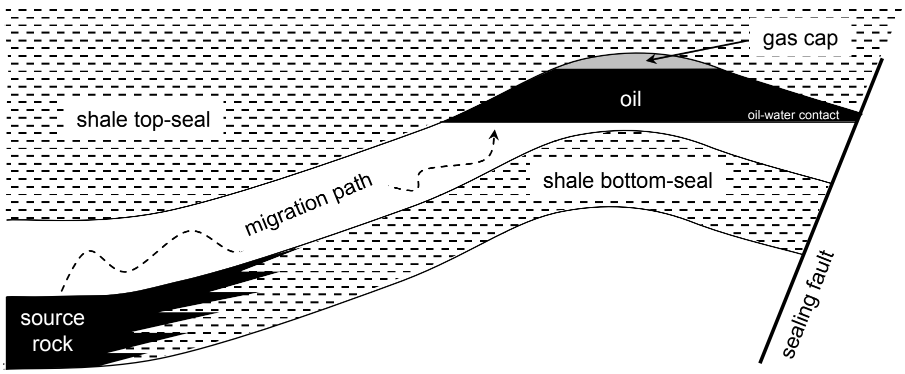
Working hydrocarbon system

To accumulate oil & gas in economic quantities four elements must coincide

To accumulate oil & gas in economic quantities four elements must coincide.

- A 'source rock' is needed to generate the hydrocarbons *Source*
- A suitable 'reservoir' interval is needed to bear the hydrocarbons *Reservoir*
- A 'trap' is needed to contain the hydrocarbons *Trap*
- All three elements must occur within a 'dynamic' system where each can interact *Dynamic*

Figure 30: Elements of a working hydrocarbon system



Source: Deutsche Bank

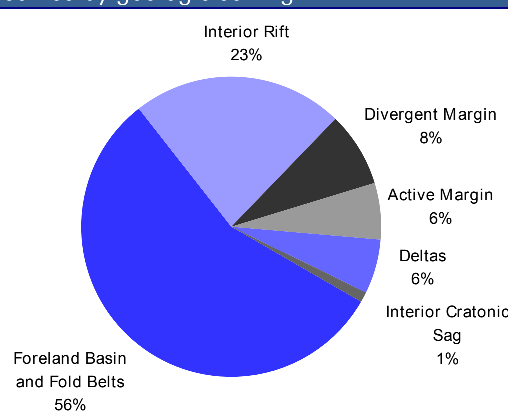
The exploration for and appraisal of oil and gas is an exercise in risk management. The risk associated with a prospect can be represented by an assumed '**probability of geologic success**' (Pg) - defined as the product of the probabilities of the 4 elements above.

$$P_g = P_{source} \times P_{reservoir} \times P_{trap} \times P_{dynamics}$$

The combination of each of these factors in a way that is supportive of the generation of commercial quantities of oil and gas is by far the exception rather than the rule.

This leads to an uneven distribution of oil & gas spatially and across time. In the chart below we outline the occurrence of reserves across the Earth's main types of geological setting.

Figure 31: Oil and gas reserves by geologic setting

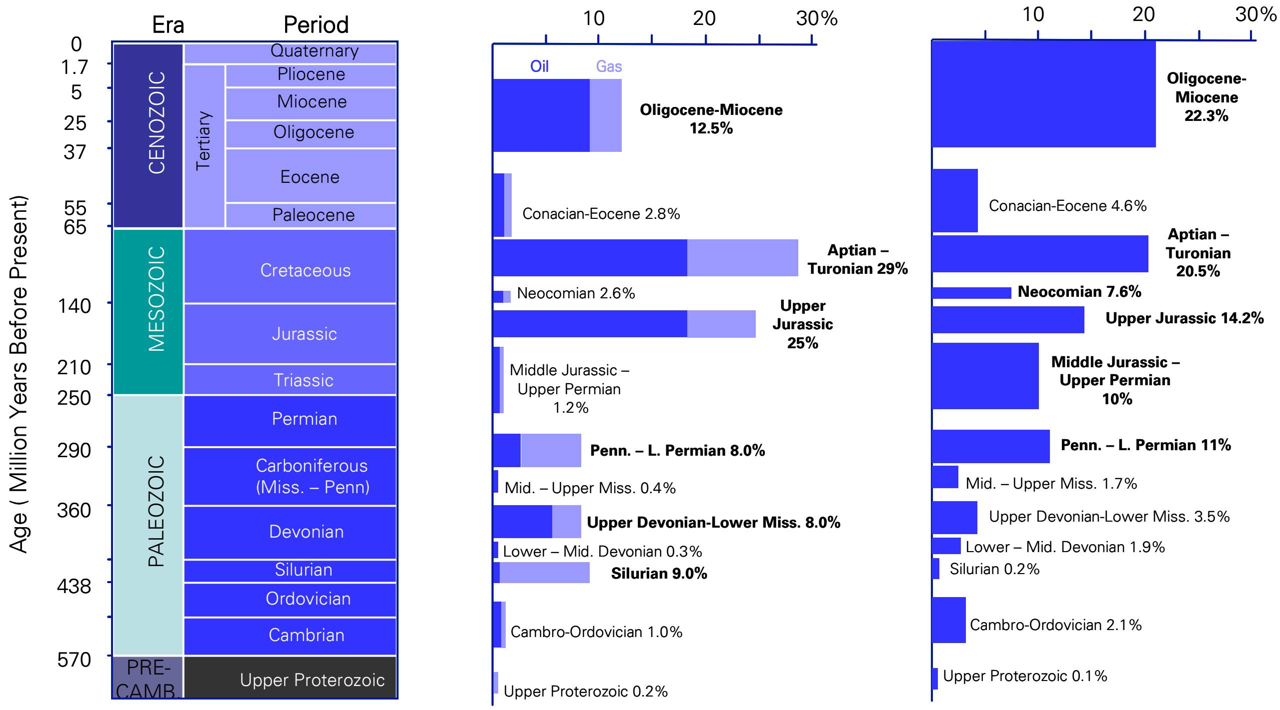


Source: Deutsche Bank

Across geologic time, 91.5% of the world's oil and gas reserves were generated in just six source rock intervals. These six intervals, however, only account for c33% of Phanerozoic time – or just 4% of the Earth's entire history.

Similarly, 96.4% of the world's oil and gas is trapped within just six reservoir intervals.

Figure 32: Distribution of oil and gas source rocks and reservoir intervals across geologic time (Phanerozoic)



Source: Deutsche Bank, data from Ulmishek and Klemme USGS Bull., 1931, 1990

Source rocks

It is almost universally accepted that hydrocarbons originate from organic matter – principally small plankton, algae etc. The best evidence for this is the presence within oil and gas of the pigment porphyrin; the only known sources of which is hemin, which gives blood its red colouring, and chlorophyll, the green colouring of plants. These organic-rich sediments are fine grained (deposited within low energy environments), dark in colour and are often referred to as **sapropels**.

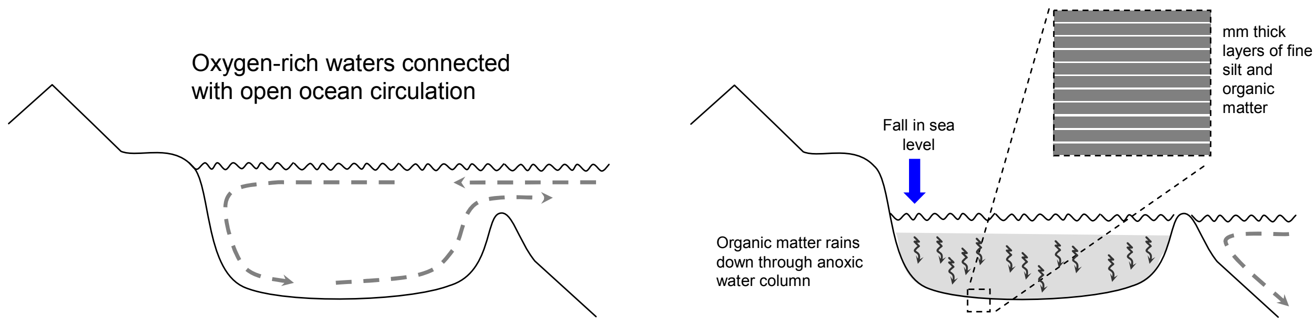
It is almost universally accepted that hydrocarbons originate from organic matter – principally small plankton, algae, etc

Conditions needed for organic matter build-up

Although no single cyclical geological process can be identified driving conditions which favor source rock formation, generally speaking, for organic matter to be preserved in quantities large enough to generate commercial quantities of hydrocarbons, it needs to accumulate under conditions of quiet deposition in a setting where levels of oxygen within the water column are low enough to dissuade microbes, worms and other creatures from consuming it.

Locations where these conditions occur include sediment-starved narrow seas and isolated basins. In such locations, water masses may for periods of time become separated from wider ocean circulation, the water column may stagnate, leading to oxygen-starved or even **anoxic** conditions. Such quiet environments are typified by fine-grained sediments such as mud and shale, and the basins often referred to as 'black shale basins'.

Figure 33: Basin isolation and the establishment of anoxia



Source: Deutsche Bank

Anoxia can also be generated under conditions where organic matter from seasonal planctonic/algal blooms simply rains down through the water column at a rate faster than that at which the sea-floor organisms can consume it. The laminated organic/silt nature of many source rocks is often cited as reflecting the seasonality of such events.

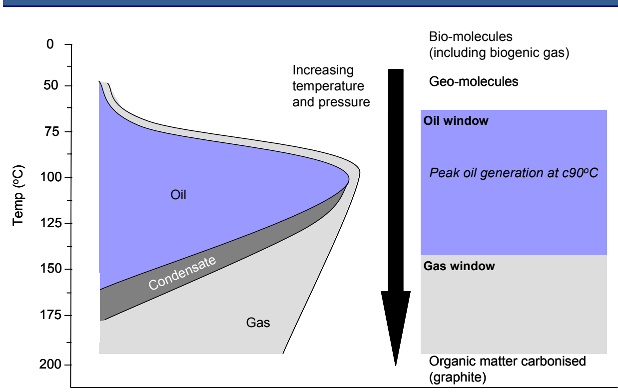
Source rock maturity… the 'oil window'

The preservation of organic matter is only the first step in the generation of oil and gas. As geological time passes, these '**immature**' organic-rich rocks are buried. As the depth of burial increases the organic matter is exposed to greater pressures and temperature and the process of '**maturation**' begins. This is said to occur within the '**source kitchen**'.

On average, maturation to oil begins at c120°F (50°C), peaks at 190°F (90°C) and ends at 350°F (175°C). This range of temperatures defines the '**oil window**'. Below this window natural gas is generated. The depth of these temperature thresholds is dependent on the 'geothermal gradient' within the Earth's crust. On average, this is c1.4°F per 100 ft, although it can be very variable depending on the geological context.

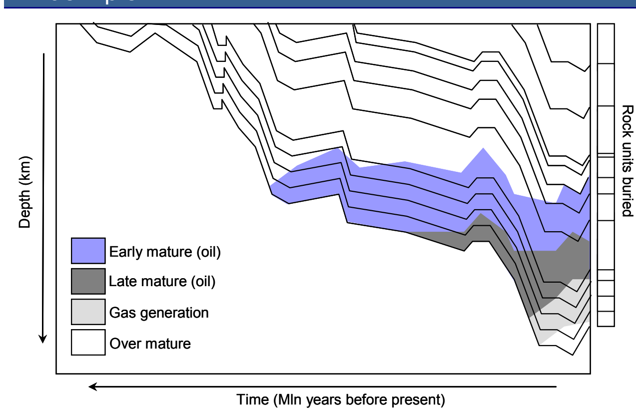
At higher temperatures, oil molecules are converted into lighter hydrocarbons, producing gas. Above 500°F (260°C), the source becomes '**over mature**' – hydrocarbon chains are broken down and organic material is carbonized. Finally, it has been observed that higher temperatures and greater burial depths are required for generation within younger rocks compared with older rocks.

Figure 34: Burial and the transformation of organic material



Source: Deutsche Bank

Figure 35: Schematic basin burial history and maturity window plot

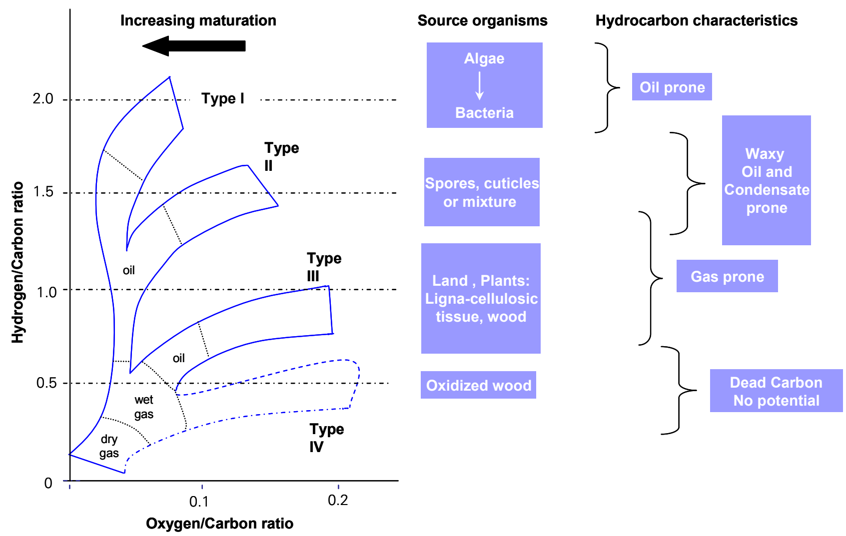


Source: Deutsche Bank

Hydrocarbon types

Locked within oil and gas is the geochemical signature of the types of organic matter from which it formed. This results in a four-fold classification of kerogen (organic matter), each of which has different hydrocarbon characteristics – outlined below.

Figure 36: Van Krevelen diagram showing changes of kerogen with maturation



Source: Deutsche Bank , re-drawn from data by Van Krevelan

Migration

Once formed, compaction may drive hydrocarbons from the host source rocks in a process known as migration

Once formed, compaction may drive hydrocarbons from the host source rocks in a process known as migration. This process is most often sub-divided into three parts:

- **Primary migration** - movement of oil/gas through the low permeability mature source rock. This typically occurs directly in the hydrocarbon phase movement via micro-fractures.

As temperatures increase, organic matter converts to bitumen and oil – which have lower densities, and occupy a larger volume than the original kerogen. Products are then expelled into adjacent fractures. At even higher temperatures and pressures, liquid hydrocarbons can be dissolved in the gas phase. As this migrates upward, temperatures and pressures reduce, and the oil-phase re-condenses. A source rock's low permeability means small molecules tend to be preferentially released – the rock's '**expulsion efficiency**' measuring the percentage of a particular hydrocarbon escaping.

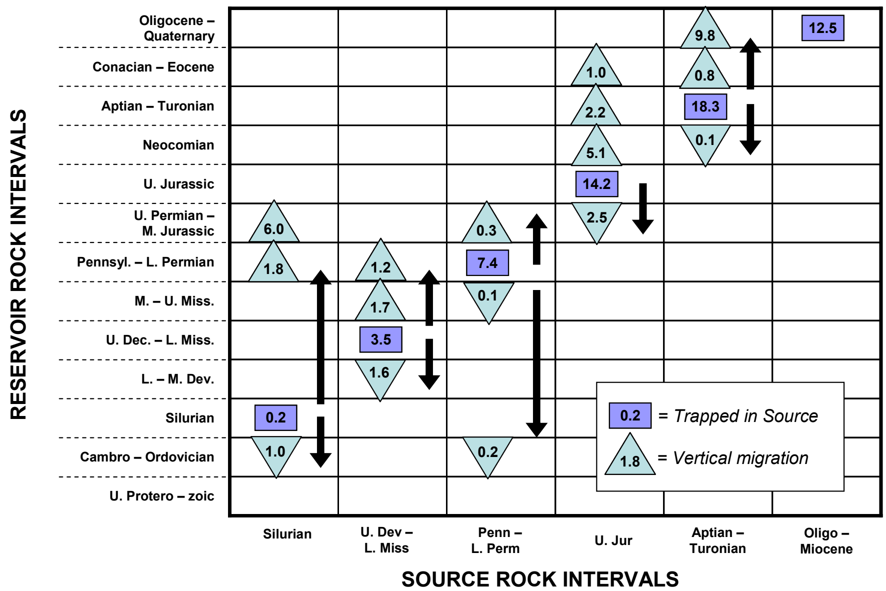
- **Secondary migration** - movement of oil/gas through carrier rocks or reservoir rocks outside the source rock, or movement through fractures within the source rock.

Hydrocarbon buoyancy is the main force driving secondary migration. This migration typically occurs either through internal permeability or via faults and joints. Generally speaking tensile fractures and normal faults tend to be more open than those formed in compressional regimes where reverse faulting is more dominant (see later). In detail, along the plain of a fault, zones of fractured rock ('**breccias**') can increase permeability. However, in finer grained rock clay **'gorges'** can form effective barriers to flow.

- **Tertiary migration** - movement of a previously formed oil and gas accumulation.

In the chart below we examine the formation and migration of the world's oil and gas.

Figure 37: Vertical migration of the world's reserves (%)



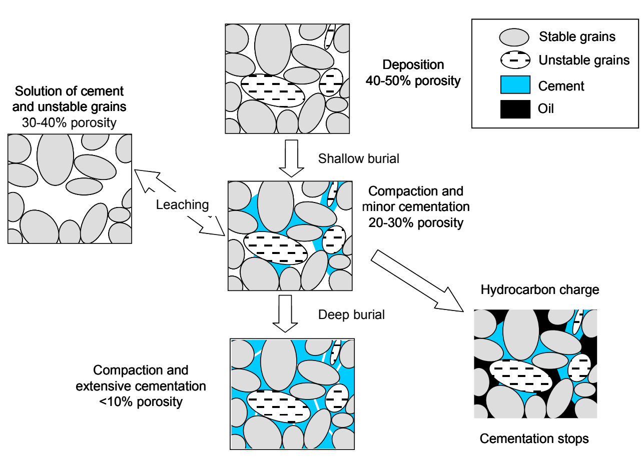
Source: Deutsche Bank, data from Ulmishek and Klemme USGS Bull., 1931, 1990

Reservoir quality

Key for high quality reservoir formation is the combination of porosity and permeability

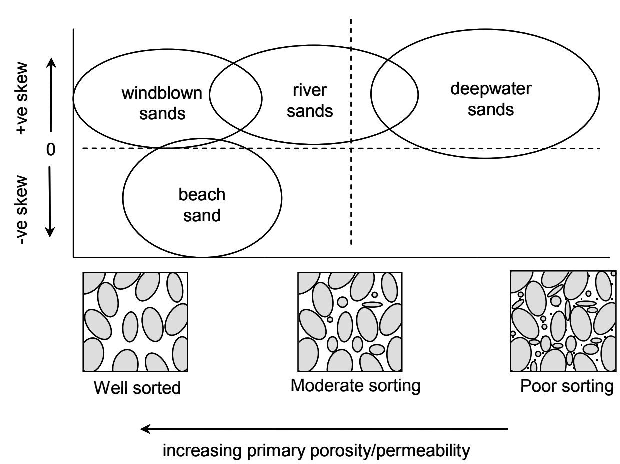
Key for high-quality reservoir formation is the combination of porosity and permeability at the micro-scale, with few internal barriers to flow at the medium-/macro-scale. **Porosity.** Porosity describes the fraction of a rock's bulk volume accounted for by void space between its constituent grains. For sandstones, porosity is usually determined by the sedimentological processes under which the rock's constituents were originally deposited - **primary porosity** referring to the original porosity of a rock. This may, however, be enhanced by the action of chemical leeching of minerals or the generation of a fracture system. This overprint is referred to as **secondary porosity**. For carbonates, the porosity is mainly the result of such post-depositional changes. Post depositional 'cements' however can also reduce porosity

Figure 38: Evolution of porosity with burial



Source: Deutsche Bank, Selley, 1985

Figure 39: Grain sorting and depositional environment



Source: Deutsche Bank, Bjorlykke, 1989

Although porosity is independent of grain-size, it is strongly a function of the degree of grain-size uniformity (sorting) within a sediment – porosity decreasing as sorting becomes poorer. Sorting is again an expression of the environment in which the sands were deposited.

Permeability: Permeability, measured in millidarcies (mD), describes the ease with which a fluid can pass through the pore spaces of a rock. A clastic rock's permeability is strongly influenced by grain size but is also a function of sorting, and can be strongly directional. Similarly to porosity, post-depositional processes can both enhance and reduce permeability.

Effective porosity: Petroleum geologists often refer to '**effective porosity**' – this is the pore space that contributes to fluid flow through the formation - defined as a rock's porosity after excluding all isolated pores and pore volume occupied by water adsorbed on clay minerals or other grains.

A hydrocarbon-bearing reservoir rock with porosity but low, or no permeability is described as '**tight**'. Such tight reservoirs can be encouraged to flow via forcibly imposing secondary porosity through fracturing (see later).

The effects of burial: Compaction reduces porosity with depth – porosities in sandstones and carbonates at depths >3km are much more variable than in shale, this being due to chemical alteration (**diagenesis**), cementation and dissolution.

Internal barriers to flow

Having examined how the depositional environment has a key control on porosity and permeability at the micro-scale, we now move to the meso- and macro-scale.

Sections of reservoir sand are often interrupted by laterally continuous horizons of mudstone. These might be of a scale below the resolution of seismic, but can have a fundamental impact on flow properties and the economics of field development.

By way of illustration, we schematically outline below the rate of flow and ultimate hydrocarbon recovery performance across a range of depositional sub-settings within a deepwater system.

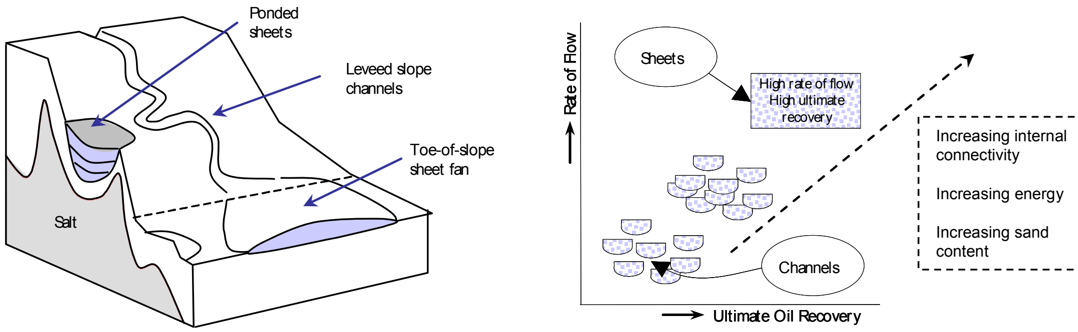
Sands within such a system are delivered down the continental slope by 'turbidity current'—the deposits of which are referred to as '**turbidites**'. Turbidites are sediment-driven gravity flows—a close relation to snow avalanches, but where as an avalanche transports snow within air, a turbidity current transports sand and mud within a current of turbid water.

Sands within such a system are delivered down the continental slope by 'turbidity current' – the deposits of which are referred to as 'turbidites'

These flows range in energy—some being sand dominated with the capacity to transport house-sized boulders, to much weaker flows, which are little more than moving suspensions of mud and silt. Flows within systems dominated by sand-sized particles tend to be more energetic and erosive—cutting into underlying sediments and dumping sand onto sand. This results in internally well connected reservoir units with few internal barriers to flow.

In contrast, flows within systems with a greater mud component tend to be focused within channels, which in turn are often confined by levees. In such settings, the focus of flow periodically shifts, with individual sand bodies separated by draping muds. Such reservoirs tend to have more internal mudstone horizons, these potentially forming barriers to the flow of hydrocarbons.

Figure 40: Various depositional settings within deepwater and their differing production characteristics



Source: Deutsche Bank

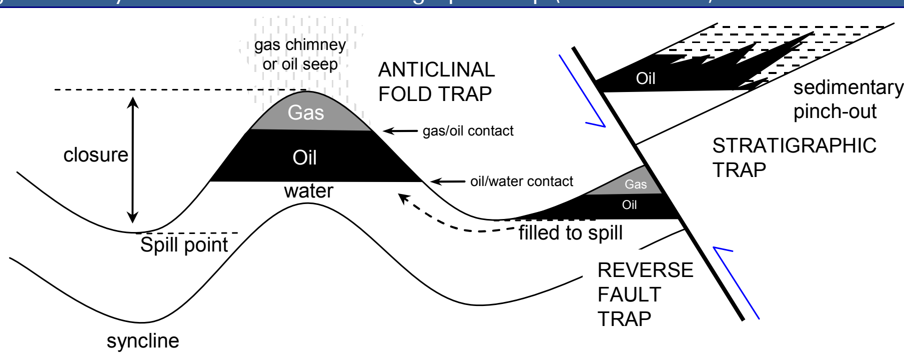
The trap and seal

A hydrocarbon trap occurs where porous and permeable reservoir rocks are encased in such a way that they are '**sealed**' against the vertical and horizontal escape of oil and gas.

Crucial to the success of any potential trap are its proximity to hydrocarbon migration pathways, the permeability of its seal, and the height of its **closure** (see below). Ideally the seal will be impermeable to oil and gas, however if escape is at a slower rate than the supply of hydrocarbons from the source, a commercial accumulation could still occur.

Crucial to the success of any potential trap are its proximity to hydrocarbon migration pathways, the permeability of its seal, and the height of its closure

Figure 41: Styles of structural and stratigraphic trap (cross section)



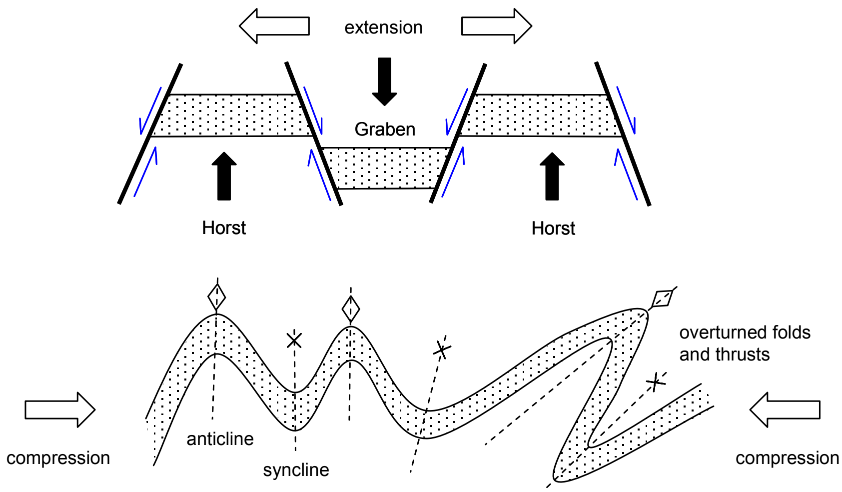
Source: Deutsche Bank

Traps are broadly divided into 2 end-member types, but in practice most are a **combination**.

Structural traps

Structural traps are produced by the deformation of the Earth's crust. Below we outline two broad styles of 'tectonic' setting – **extensional** and **compressional**. Extensional settings tend to be characterized by '**graben**' formation and 'normal faulting' – the earth's crust stretching and thinning. In compressional settings, structures include folds, thrusts and reverse faults.

Figure 42: Extensional and compressional structures (cross section)



Source: Deutsche Bank

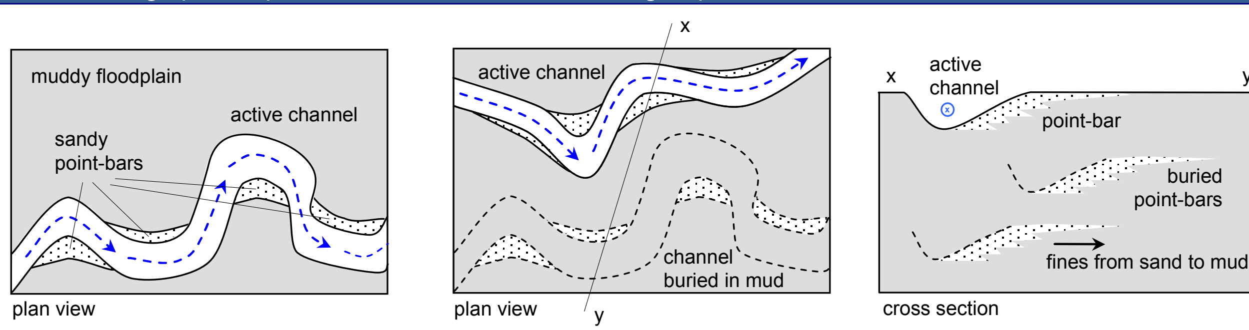
Stratigraphic traps

Stratigraphic traps occur due to lateral transitions of rock-type within depositional systems or via the alteration of sediment properties during burial.

Lateral facies. In the chart below we schematically illustrate the migration of a meandering river across a muddy floodplain. Through the river is transported a mix of sand and mud. Sideways movement in this channel is achieved via erosion around the outside of each bend, and deposition on the inside. As the current slows, it preferentially drops the heaviest fraction of its load – sandy point-bars building on the inside of each meander.

Periodically the channel coarse switches, and the previous channel and its point-bars are covered in floodplain overbank muds – these sealing the point-bar sands.

Figure 43: Stratigraphic trap formation via lateral facies changes (plan-view and cross section)

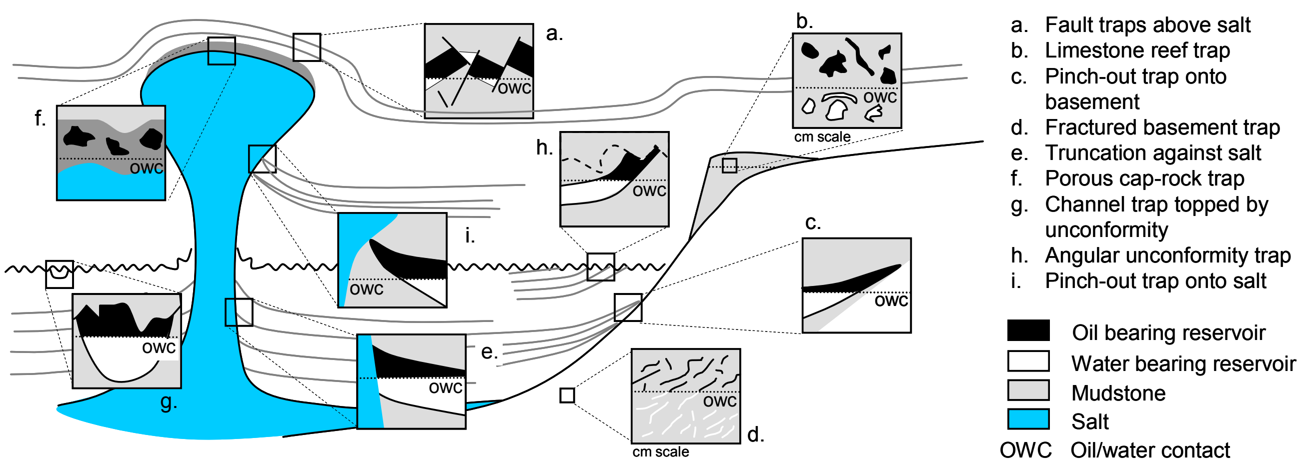


Source: Deutsche Bank

Other stratigraphic trap types – reefs, unconformities and salt dome pinch-outs

A wide range of other stratigraphic trap styles occur – some of which are illustrated below.

Figure 44: Range of stratigraphic trap styles at the basin scale (in cross section)



Source: Deutsche Bank

Reservoir volumetrics

The volume of hydrocarbons 'in-place' is described by the measures oil initially in-place (OIIP) and/or gas initially in place (GIIP)

Within the reservoir, the volume of hydrocarbons 'in-place' is described by the measures oil initially in-place (**OIIP**) and/or gas initially in place (**GIIP**). OIIP is more commonly referred to in terms of stock tank oil initially in place (**STOIIP**) – the in-place oil volume, but measured at the Earth's surface temperature and pressure.

Only a portion of this oil/gas is 'moveable'; only a portion of which is recoverable to surface.

Variables in the equation

When calculating reserve/resource estimates, a company uses a range of statistical methods to capture uncertainty surrounding the discovery. Key variables in this analysis include:

- Gross rock volume – how big is the container?
- Net-to-gross – how much reservoir sand is there versus shale?
- Net pay - The 'net pay' refers to the length of the column in metres or percent within the reservoir that is hydrocarbon bearing
- Porosity – how much volume do the voids between the sand grains form?
- Hydrocarbon saturation – what % of this space is filled with oil/gas versus water?
- Recovery factor – how much can you get out? (permeability is a key factor)
- Formation volume factor – how will the oil volume vary between reservoir and surface?

Each of these variables is assigned a range of values with an associated probability. A **Monte Carlo simulation** is then run to repeatedly sample random values from the parameter probability distributions – this resulting in a range of resource volumes which are then sorted to yield a **success case probability density function** for the prospect's resource.

In frontier exploration areas, P50 resource forms c25% of P10 volume estimates; P90 resource forms c25% of P50

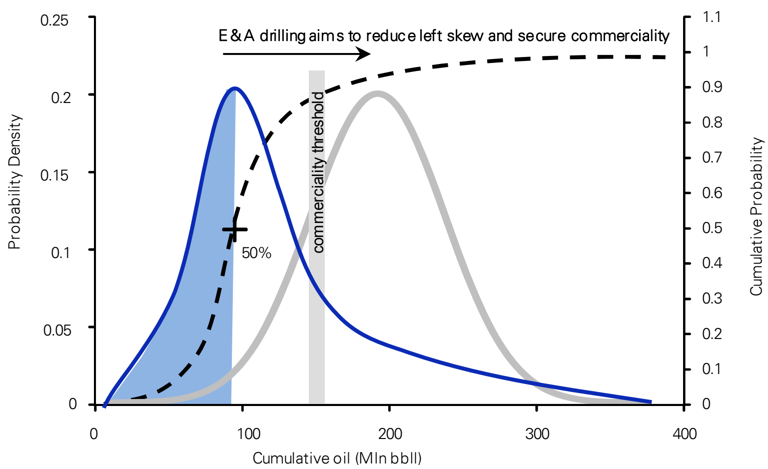
The data would then be presented for a prospect as P10, P50 and P90 resource estimates. In the success case, these equate respectively to at least 10%, 50% and 90% probabilities that the resource quantities identified will equal or exceed the resource estimate.

At the exploration stage, a prospect's probability density function has a strongly asymmetric left-skew:

- As a broad rule of thumb, in frontier areas it can be assumed that P50 resource forms c25% of the P10 volume estimate; the P90 resource c25% of the P50.

Appraisal aims to convert left-skew to right; well data ultimately allowing the geologist/engineer to replace in a probabilistic view of hydrocarbon volume with a deterministic model, against which investment/development decisions can be made.

Figure 45: Success case probability density function, drilling aims to remove left-skew



Source: Deutsche Bank, Wood Mackenzie

Getting it out

The Life Cycle of a Basin

Hydrocarbon basins typically follow a lifecycle of licensing-exploration-development-decline-abandonment.

Hydrocarbon basins typically follow a lifecycle of licensing-exploration-development-decline-abandonment. The maturity of a basin is important for a variety of reasons, including:

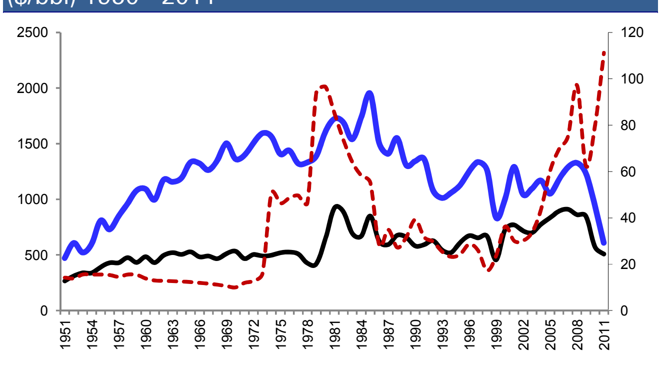
- Tax and incentives that the host nation needs to put in place to attract investments.
- State revenues and national budget planning.
- Which companies will be most interested in investing; IOCs, independents or mature field specialists for example.

Licensing – establish some legal rights

Before any exploration work can start in an unexplored basin, there needs to be a legal framework put in place so that oil companies have some assurance that they will have a legal right to make money out of any discoveries.

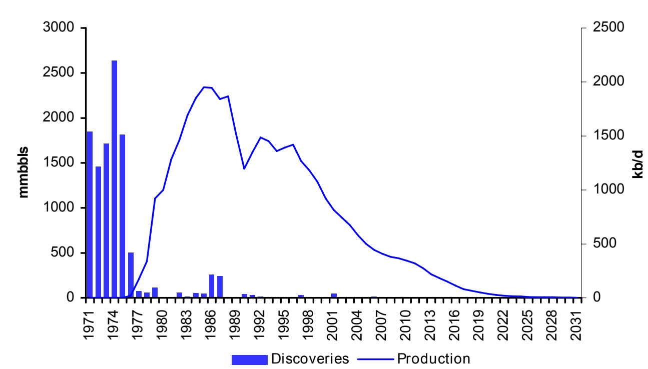
Host governments usually auction leases for exploration acreage at regular intervals and occasionally will commission seismic surveys of the acreage under offer to provide some basic information to prospective bidders. Assuming the acreage is of interest to the industry, bids will all be submitted by a certain cut-off date. Each bid may include an upfront fee, and often has other commitments, such as to acquire a certain amount of seismic data, and/or drill at least a specified number of wells. Lease durations vary greatly around the world; UK licenses are typically awarded for 25 years, whereas in the US the usual initial term is 10 years, although these can usually be extended for a fee or further work commitment. The lease is usually awarded under one of two fiscal regimes; production sharing contracts (PSCs) or tax & royalty concession (see section on taxation).

Figure 46: Global E&A activity (wells per year) and Brent ($/bbl) 1950 - 2011



Source: Deutsche Bank, Wood Mackenzie

Figure 47: North Sea (UK) discoveries and production, 1971-2040E



Source: Deutsche Bank. Wood Mackenzie

Exploration – still a high risk game

Once acreage is obtained, the oil company will usually commission a seismic survey, from which potential reservoir targets are selected. Once the targets have been ranked in order of attractiveness, a drilling company and associated service companies (supply boats, helicopters, cementing, mud logging etc) are hired and the target is 'drilled up'.

Historically, E&A activity across the upstream industry has broadly risen and fallen on a 12-month lag to crude prices (*see figure above*).

With a mixture of skill and luck the oil company will hopefully make a discovery at some point in its drilling campaign, however even with the advantage of modern seismic the chance of finding commercial oil or gas is still less than 20% (*see later discussion*). Assuming a commercial discovery is made then a flurry of industry interest will often result with bids for new acreage often rocketing.

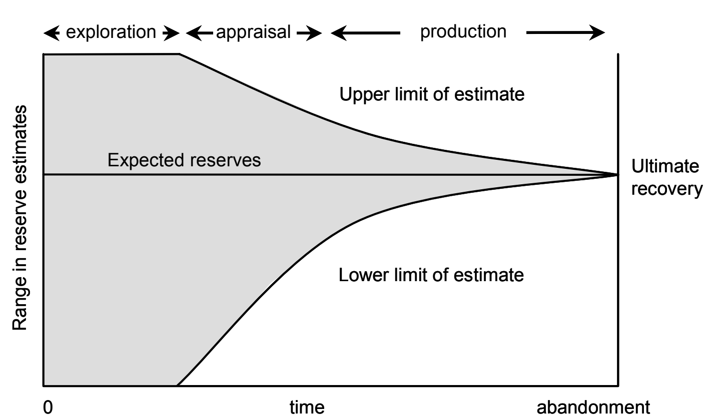
Development – put the infrastructure in place

After discoveries the challenge is to develop the fields, which can take a surprisingly long time. In the following figure for the Northern North Sea for example, the delay of 12 years between a peak in discoveries and peak in production is high, but not uncommon.

Development involves drilling all the production (and if need be, injection) wells, and building infrastructure such as platforms, pipelines, processing plants and possibly export terminals. The development phase for large fields can involve huge capex outlays, and depending upon local regulations, can kick start a significant local services industry such as in the UK or Norway. Typically, the oil company (be it NOC or IOC) will put out tenders to the oil service industry for the front end engineering and design (FEED) of any future production installation. Once the service companies have tendered their bids, the IOC/NOC will assess the economic feasibility of the project, and if the outlook appears positive, selected service companies will be contracted to proceed with more advanced designs and, ultimately, field development.

Ideally the total oil waiting to be discovered in a basin would be known to all parties. The government could ensure it creates terms that maximize its revenues, could make long-term economic plans, oil companies could drill with greater certainty of success and the service industry could be established knowing the appropriate amount of work is inevitably going to be forthcoming. Unfortunately we don't live in an ideal world; the best the industry can do is make estimates of what reserves remain to be discovered and, as the following figure shows, such estimates can be highly inaccurate until quite late in the basin's (or field) life.

Figure 48: Typical progression of field reserve estimates over time

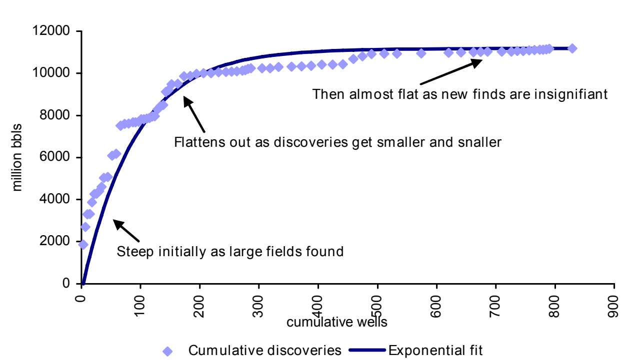


Source: Deutsche Bank

Early in a basin's life the approach to estimating ultimate basin reserves is to use so-called 'creaming curves'.

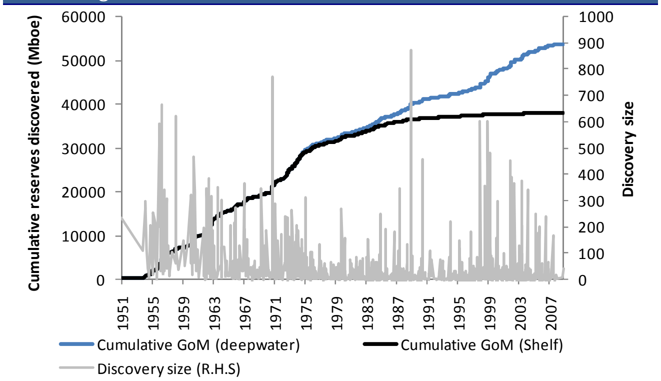
A creaming curve is a plot of cumulative discoveries versus cumulative wells, as shown in the following left hand figure (Northern North Sea). The reserves growth curve shown for the Gulf of Mexico on the right (cumulative discoveries by year) is often also labeled as a creaming curve, which is not strictly correct.

Figure 49: Creaming curve – Northern North Sea, with exponential fit curve (million bbls)



Source: Deutsche Bank, Wood Mackenzie

Figure 50: Gulf of Mexico shallow and deepwater creaming curves (Mln boe)



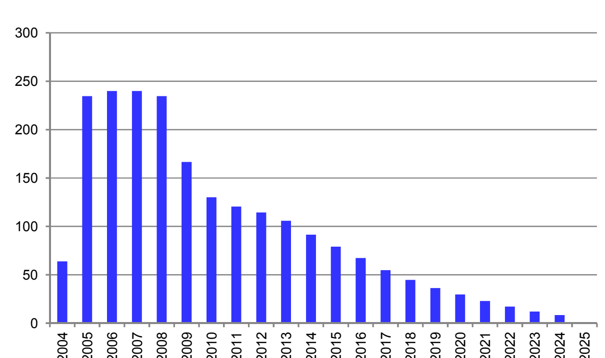
Source: Deutsche Bank, Wood Mackenzie

With a creaming curve we expect to see initial steep rises as larger fields are found first, simply by virtue of the fact that they are easier to see on seismic and are hence drilled-up first. As initial success attracts further exploration activity so more fields will be found, but the average size of discoveries will inevitably fall. The curve will resemble an exponential, with an asymptote towards the basins ultimate recoverable reserves. Early on in a basin's life an exponential curve can be fitted to the actual discovery data and used to extrapolate what the ultimate reserves to be discovered in a basin might be, although the ex-ante accuracy of this approach is generally poor. It is also neither impossible or particularly uncommon for a basin to have more than one creaming curve; data graphed above from the Gulf of Mexico illustrating that as the GoM's conventional shallow-water areas matured; technology opened deeper waters. As this in turn has showed evidence of maturing, activity has pushed into the ultra-deep.

Decline – prolonging the death throws as long as possible

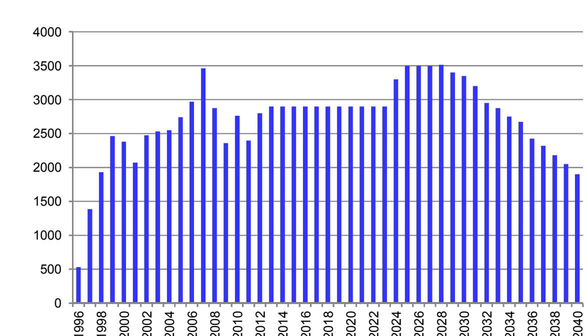
Oil and gas fields have quite different production profiles; oil tends to peak quickly, plateau for a relatively short time then deliver a long tail of decline. A non-associated gas field will usually have a long plateau of 20Y or more, as with the Troll field shown below.

Figure 51: Kizomba A oil production (Angola)



Source: Deutsche Bank, Wood Mackenzie

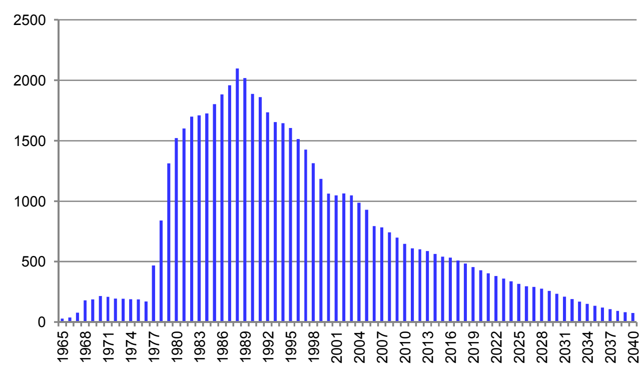
Figure 52: Troll gas production (Norway)



Source: Deutsche Bank, Wood Mackenzie

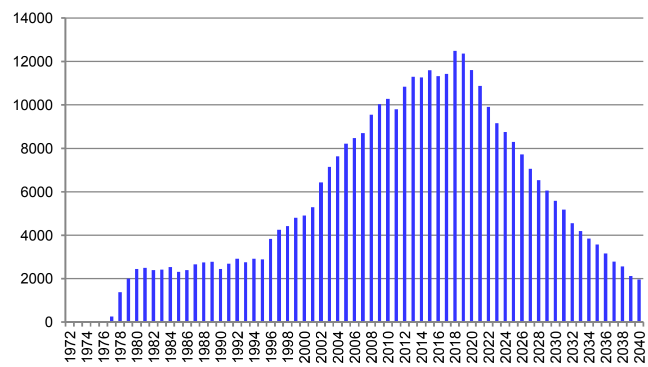
When these profiles are aggregated at the basin level, for oil a similar profile to individual fields is sometimes seen, i.e. a relatively steep rise followed by a long decline. However, for gas the basin production profile can take various forms depending upon the mix of associated and non-associated fields brought online and the use of LNG. That being said, the Norwegian gas profile shown below is not atypical.

Figure 53: Alaska liquids production 1965-2040E



Source: Deutsche Bank, Wood Mackenzie

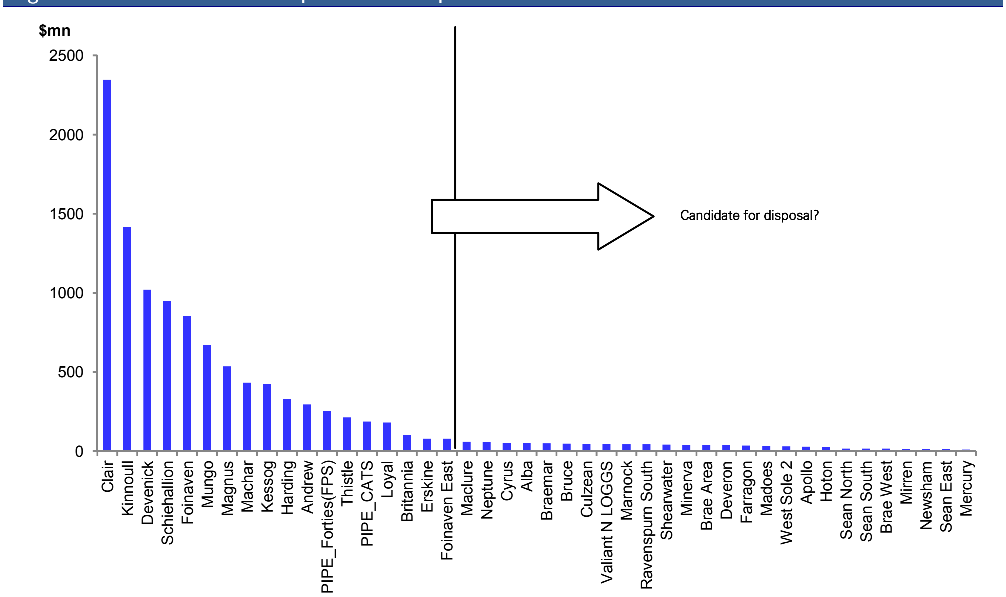
Figure 54: Norway gas production 1970-2040E



Source: Deutsche Bank, Wood Mackenzie

During the decline phase, field free cash flow generation diminishes not just as a consequence of lower volumes, but also due to the higher costs associated with enhanced production techniques and maintaining aging infrastructure. IOCs typically have a large list of potential worldwide project investments and invariably, putting money into squeezing the last drops of oil out of an old oilfield doesn't make the cut and the fields are sold. In the following figure for example, at a $65/bbl long-term oil price BP has several fields in the North Sea that are so insignificant in terms of value to the company that they may well be candidates for disposal. Small E&P companies such as Venture, Paladin and Dana have historically very successfully taken over such depleted fields and extended the useful lives by several years.

Figure 55: BP UK assets – potential disposals as fields decline in value



Source: Deutsche Bank

The US shallow GoM is a prime example of this, where since the 1970s the IOCs have sold most of their fields to smaller independent oil companies such as Apache. These smaller organisations are better setup to extract maximum value from old fields; they have lower corporate cost bases, are more nimble in their decision making and generally have a more entrepreneurial culture than their larger cousins.

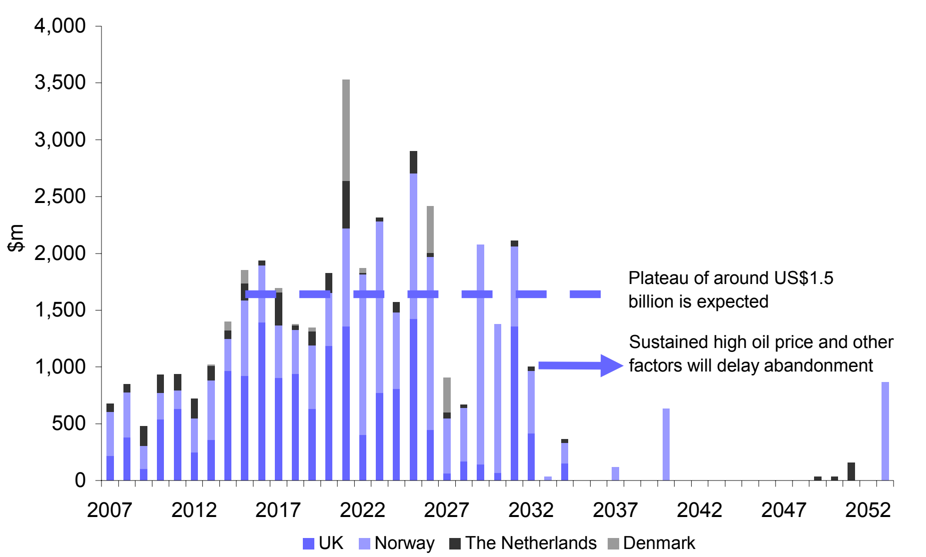
Abandonment. At some point the cost of extracting any remaining oil will not be justified by commodity prices, and the field will need to be abandoned. Onshore this usually entails plugging the wells with cement and steel plugs, and returning the land to its original condition. Offshore the dismantling of large platforms requires careful planning and the use of large cranes; it can be a capital intensive and risky affair.

Can be very expensive. Taking the North Sea as an example, after three decades of production, there are a large number of facilities that are approaching the end of their lives. Forty fields have been decommissioned in total so far, and a further 66 are in the process of being decommissioned. In the UK the legal liability for decommissioning a field's platforms, pipelines, etc. lies with the original partners, however in Norway and Holland the legal liability can be passed on to successive field owners. The risk with the Norwegian and Dutch approach is that it is often smaller oil companies that manage a field through its final few years of low production life, and these companies may struggle to fund the potentially expensive decommissioning and clean-up process.

To give an idea of the scale of costs, the ongoing decommissioning of the North West Hutton field is expected to cost c.$285m, and the decommissioning of Total's Frigg field is expected to take six years and end up costing c.$700m.

A growing market. The North Sea decommissioning market represents an important source of future revenues for engineering, diving and heavy lift service companies, amongst others. Wood Mackenzie estimates that the value of the North Sea decommissioning market is c$40bn, with the market expected to grow steadily over the next 15 years, as shown in the figure below.

Figure 56: North Sea estimated future decommissioning costs



Source: Deutsche Bank, Wood Mackenzie

In terms of accounting for future decommissioning costs, oil companies take provisions each quarter through the P&L.

Field Operations

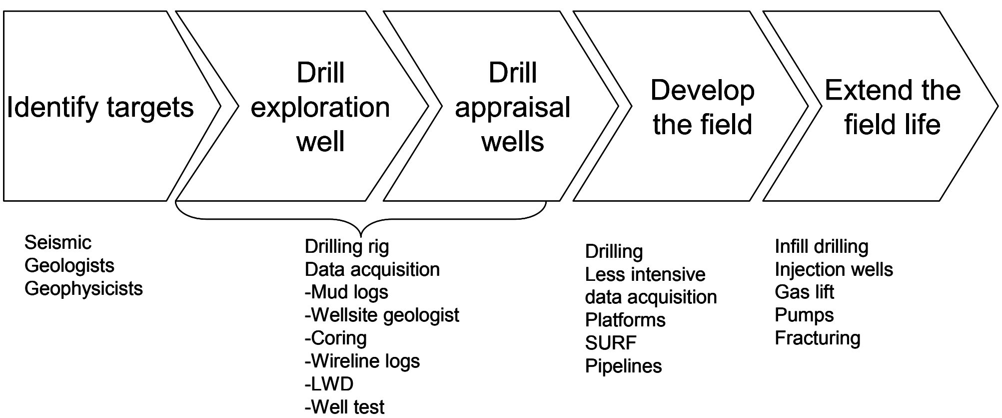
Little has changed

Edwin Drake is credited as being the first man to successfully drill for oil in the USA, almost 150 years ago. His twin innovations were to drill using steam power rather than hand digging, and to use steel pipe liners to stop water flooding causing the hole to collapse.

Edwin Drake is credited as being the first man to successfully drill for oil in the USA

Despite nearly a century and a half of subsequent innovation, the operations involved in finding and developing oil fields face the same underlying technical challenges that Drake faced; the only certain way of knowing if a reservoir exists is to drill a hole through it, and such discoveries are still worthless unless an economical way to transport the oil or gas to a consuming market can be found. To overcome these underlying challenges a field will typically evolve through the following lifecycle:

Figure 57: The life cycle of an oil field



Source: Deutsche Bank

The equipment involved at each step in the timeline above has become vastly more advanced, but it still solves the same underlying challenges that the pioneers of 150 years ago faced.

First step - where to look?

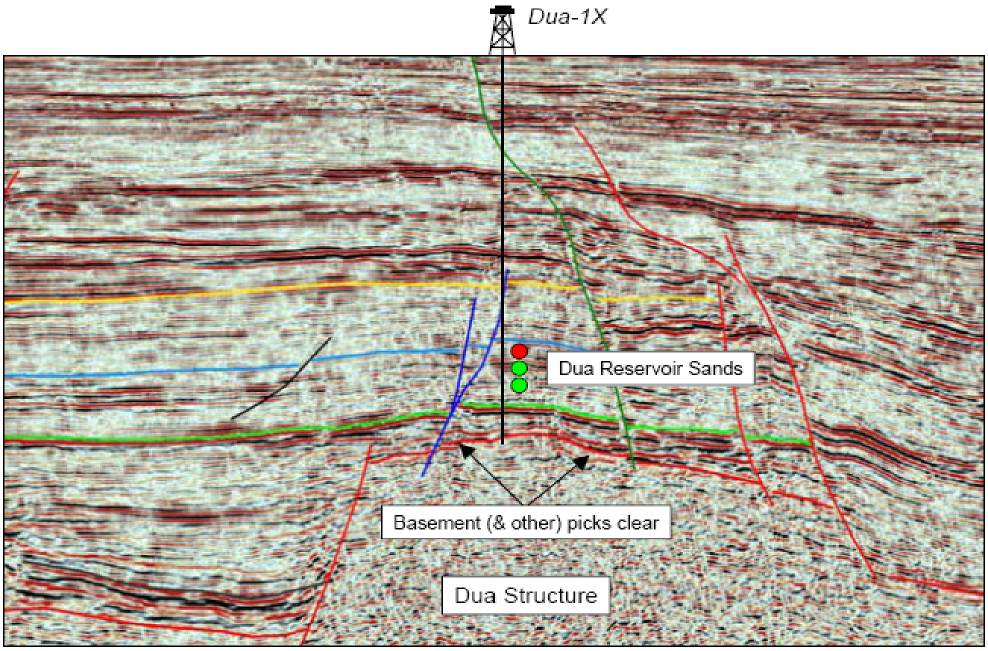
In the early days of the industry local seepages of oil were an obvious indication that a reservoir might lie in the rocks below. Surface geological indications gave some additional hints about the underlying structure of rock formations and hence where a trap might exist. Unfortunately this approach doesn’t work for the deeper and smaller fields that are the target of today’s exploration efforts, and since as early as the 1930s seismic techniques have been used to try and ‘see’ below the surface and so increase the chances of exploration success.

Seismic operations use sound waves to try and create an image of subsurface rock layers

Land Seismic

Seismic operations use sound waves to try and create an image of subsurface rock layers. If such an image can be created with sufficient detail then potential areas where oil and gas might be trapped can be identified, and then a drilling company can be hired to drill the prospect.

Figure 58: Picking a prospect using a modern-day seismic

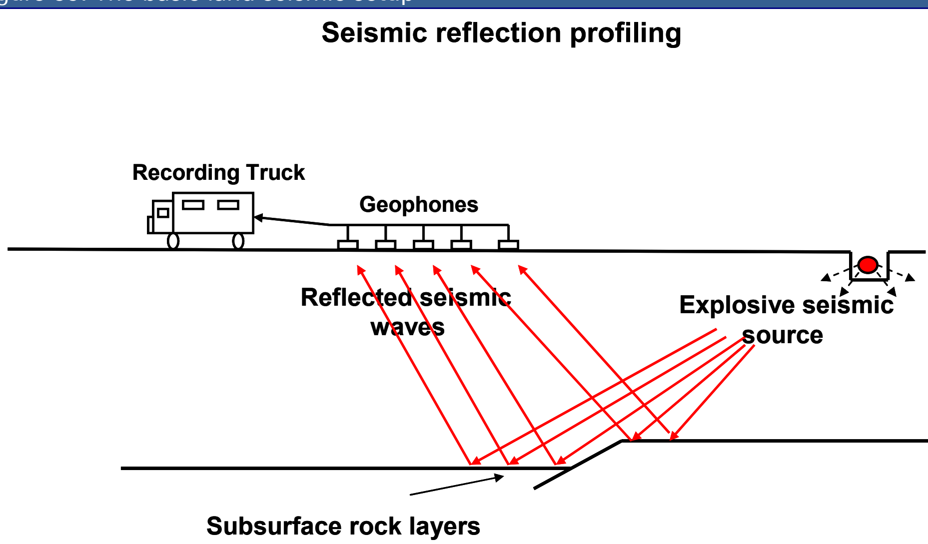


Source: Premier Oil – used with permission

So how can sound be used to create such an image, and what are the limitations?

During a seismic survey, sound waves are generated by a loud 'bang', for example by the detonation of dynamite in a hole dug in the ground, or from an air gun in the water. The sound wave energy propagates down through the earth and then is partially reflected by each rock strata boundary back to the surface. Geophones placed at the surface record all such reflections, which are then digitised and stored.

Figure 59: The basic land seismic setup



Source: Deutsche Bank

On land the source of energy (i.e. the 'bang') is usually either dynamite or a specialist truck, called a vibroseis truck (or a 'thumper' truck). Whichever source is used, it is moved to different locations and all the data from each geophone is recorded for each shot. At the end of a seismic survey there is a vast amount of data that in its raw form is useless – it is just a load of squiggles that require significant amounts of processing.

Processing and interpretation is not straight forward

Processing is an exercise in reverse engineering. It has to try and deliver a model of the earth's crust that fits the recorded data and the energy source used. The recorded data is the source 'bang' after having been modified by the earth's rock and the geophones.

Mathematically, backing out a model of the rock formation given the recorded data and the source wavelet is a 'de-convolution' problem. This is easy enough to complete using today's computers, but is complicated by several factors that conspire to make the process of seismic processing and interpretation as much an art as a science:

- The geophones and recording system introduce distortions – i.e. what gets recorded is not exactly what arrived at the geophones.
- The signal to noise (S/N) ratio decreases with depth – the deeper the reflections have travelled to and from, the more attenuated the energy is, and the lower the S/N ratio is. Lower S/N ratios imply less reliable processed results.
- Filters are applied to the recorded data to try and remove distortions introduced by equipment and setup, but such filters invariably also remove some useful information, and so decrease the S/N ratio.
- Mathematically there may be multiple possible solutions (i.e. models of a sequence of reflective layers in the earth's crust) that fit the data. The results can therefore be ambiguous.
- The solution is often very sensitive to small changes in applied filters and other model assumptions.

Results are in time, not depth. Seismic processing results in a picture that is scaled in time, rather than depth. Estimates of velocity of sound in rock can be made to try and convert the seismic image to depth (rather than time), but this is inaccurate and can result in the estimated depth of an identified target reservoir being wrong by several hundred feet. From a drilling perspective hitting potential reservoirs much higher than expected is potentially dangerous.

Seismic processing results in a picture that is scaled in time, rather than depth.

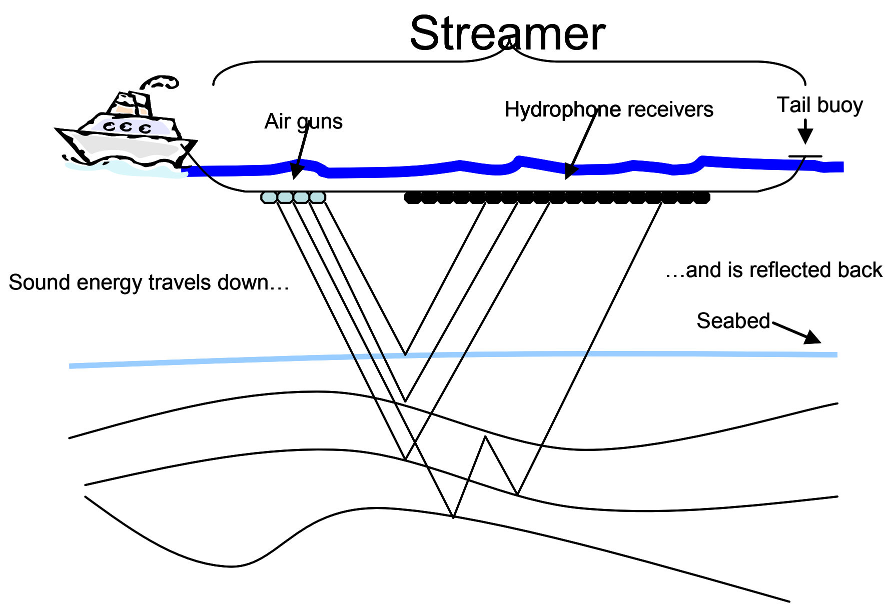
Surface seismic can be accurately tied into depth by the use of well bore seismic data (see later), but unfortunately this can only be performed once an exploration well has been drilled – a chicken and egg scenario. The end result is that for wildcat exploration wells, despite all the sophistication of modern seismic, as the drill bit gets anywhere near any targeted horizons great care must be taken.

Offshore seismic

Offshore seismic is logistically easier than land based operations as there is no need to continuously move geophones around by hand and dig holes for explosive devices (not to mention dealing with a local population that might not be too keen on dynamite blowing up bits of their land).

However the nature of a modern offshore seismic acquisition vessel means that it is a far more capital intensive operation than land. Historically, this has led to significant 'boom and bust' cycles in the seismic sector as major E&Ps tend to be more willing to dial up and down their exploration budgets depending on the oil price. A modern acquisition vessel can cost $250m and due to the wear and tear of its salt water-based operations, generally the expensive seismic cables, streamers, airguns and hydrophones (the water-based equivalent of geophones) must be replaced every six years.

Figure 60: Offshore seismic operations



Source: Deutsche Bank

2D/3D/4D/multi azimuth – what are they?

2D/3D/4D/multi azimuth – what are they?

The term '3D' has become common throughout the industry but what does it mean? It basically comes down the amount of data recorded and not surprisingly, the more data that is acquired, the greater the processing options the better the end interpretations.

Note that in general the performance of receivers (geophones or hydrophones), energy sources and the entire data acquisition chain has gradually improved over time and so data acquired today is likely to be higher quality than that recorded as recently as ten years ago. 'Higher quality' implies better S/N ratios and higher resolution – both of which are major contributors to improved post-processing results.

- **2D** – A single line of acquisition data is recorded, so meaning that an interpretation can only be made on a single slice of the earth. This is typically used for fast surveys of large areas in virgin territory.
- **3D** – multiple parallel lines of data are acquired, so allowing a cube of interpreted data to be created, giving a 3D image of what is happening subsurface. 3D data is usually acquired when either 2D and/or exploration drilling throws up something interesting that needs to be investigated in greater detail, or when existing seismic data is of an older generation.
- **4D** - this involves running the same seismic surveys again and again over time, the idea being that it is possible to see how the fluids within a field move over time. In practice it has had limited success and is not a widely used application.
- **Multi azimuth** – has enjoyed high profile success in the US GoM in 2006 with the Jack discovery being attributed in part to multi azimuth imaging. The idea is to 'illuminate' more of the target subsurface geology than is possible with conventional 3D (below attenuating salt domes for example). This is achieved by using more than one energy source location (i.e. there will be at least two vessels shooting air guns during the survey).

Assessing risk and reward

Once the geophysicists have identified a set of targets, the next step is to assess the likelihood of discovering an active hydrocarbon system.

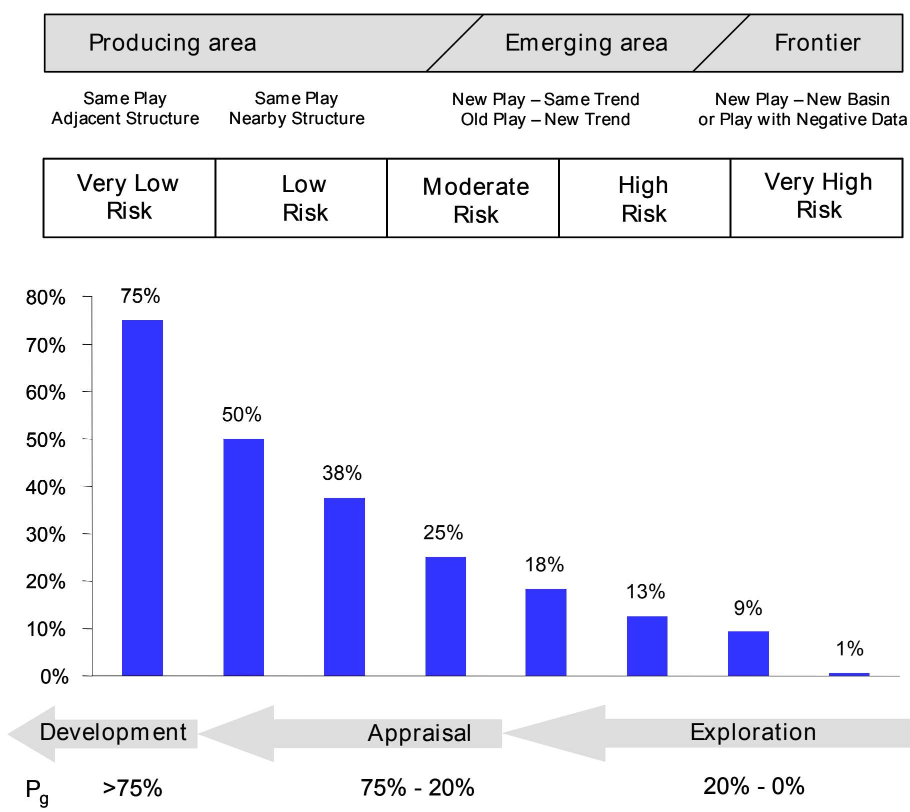
Exploration for, and appraisal and development of, oil and gas is an exercise in risk management.

Exploration for, and appraisal and development of, oil and gas is an exercise in risk management. In 1997, Chevron published a land-mark paper outlining its approach to risk assessment – defining geologic success (Pg) as the product of the probabilities of 4 principle elements that must coincide in order to accumulate oil & gas in economic quantities: source, reservoir, trap/seal and their connection within a 'dynamic' system where each can interact with the other.

$$\mathbf{P_g = P_{source} \times P_{reservoir} \times P_{trap} \times P_{dynamics}}$$

The table below outlines the general distribution of project risking through a typical cycle of exploration/appraisal/development activity.

Figure 61: Geological success within differing scenarios



Source: Otis & Schneidermann, AAPG Bulletin 81, Deutsche Bank

Following the identification of a prospect on seismic, key steps in the reduction of uncertainty include drilling or **'spudding'** the first exploration well often termed the **'wild cat'**, and testing that well – testing providing tangible evidence on which meaningful recoverable reserve estimates can be made.

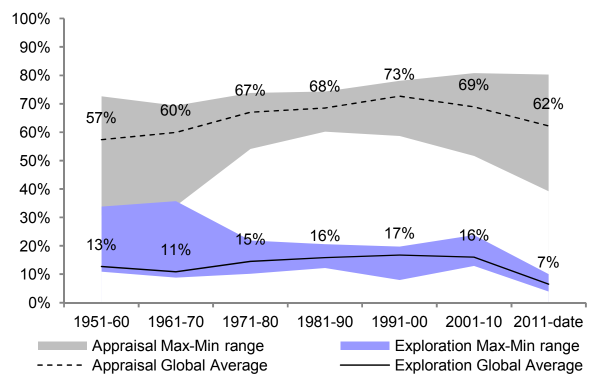
Note that the date on which a wild-cat well is spudded refers to that on which it first breaks ground.

Benchmarking exploration success rates

So what are the typical drilling success rates seen in industry and how has recent technology impacted on these? Analysis of 107,772 E&A wells, drilled across 109 countries between 1951 and 2010 indicates that on a global basis, average exploration and appraisal commercial success rates have risen only modestly over the last six decades (for analysis-sake we ignore the more limited 2011-YTD dataset):

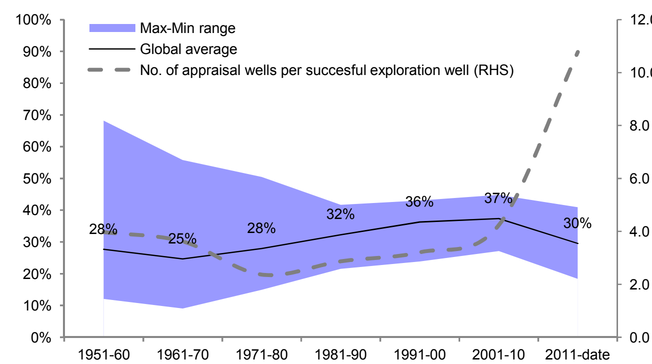
- Commercial exploration success rates rising from 13% to 16%; averaging 15%
- Appraisal success rates rising from 57% to 69%; averaging 66%
- Combined commercial E&A success rising from 28% to 37%; averaging 31%

Figure 62: E&A success rates and high-low range*



*Source: Deutsche Bank, Wood Mackenzie, * 2011-YTD ignored due to limited dataset*

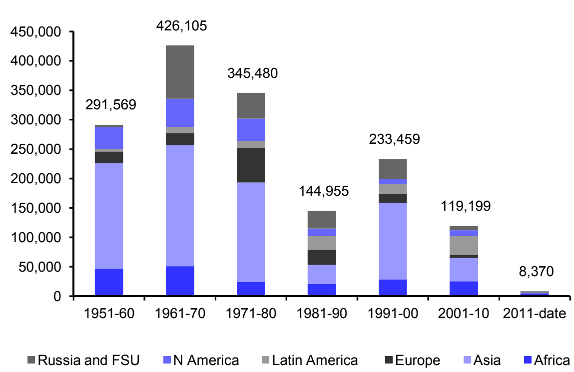
Figure 63: Combined E&A success rate/range and number of appraisal wells per exploration success*



*Source: Deutsche Bank, Wood Mackenzie, * 2011-YTD ignored due to limited dataset*

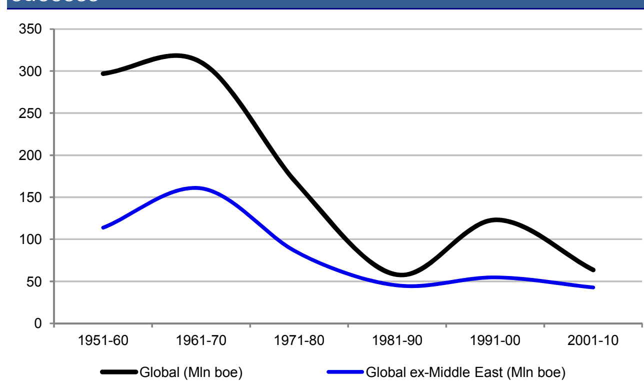
Although the high-low range around this data (on a regional basis) has tightened materially; the average baseline discovery size has remained **c60 Mln boe** since the 1970s. However, at the same time, the number of appraisal wells required to bring this volume to development has risen materially (*see above*).

Figure 64: Total volume discovered per decade across the c108k E&A wells in our dataset (Mln boe)



Source: Deutsche Bank, Wood Mackenzie

Figure 65: Average volume discovered per exploration success

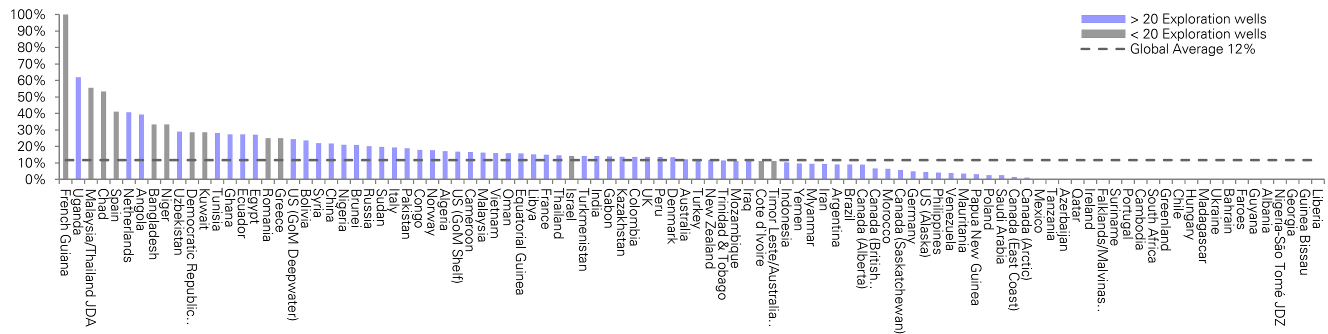


Source: Deutsche Bank, Wood Mackenzie

Country-by-country analysis… statistically inexact

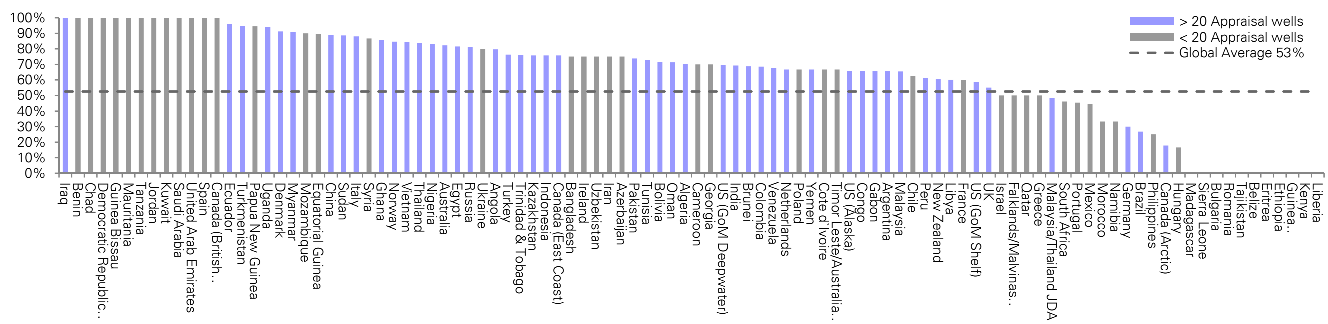
This global/regional analysis can be broken down on a country-by-country basis, however the statistical significance of the data breaks down; a material number of countries emerging as high or low outliers, but with very few wells drilled (*see below*).

Figure 66: Global commercial exploration success rate (2001 to 2010 year-to-date)*



Source: Wood Mackenzie, Deutsche Bank *

Figure 67: Global appraisal success rate (2001 to 2010 year-to-date)*

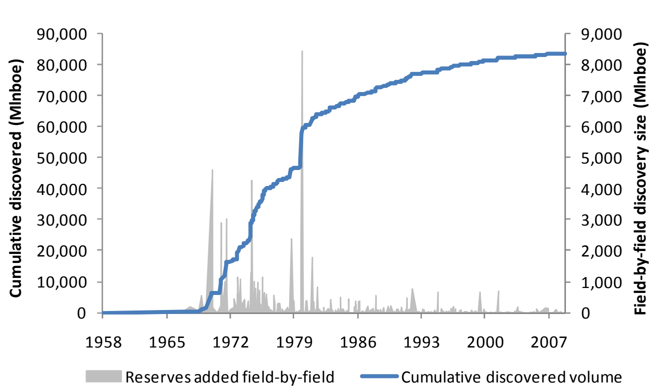


Source: Wood Mackenzie, Deutsche Bank

As success rates in a basin rise… the size of the prize shrinks

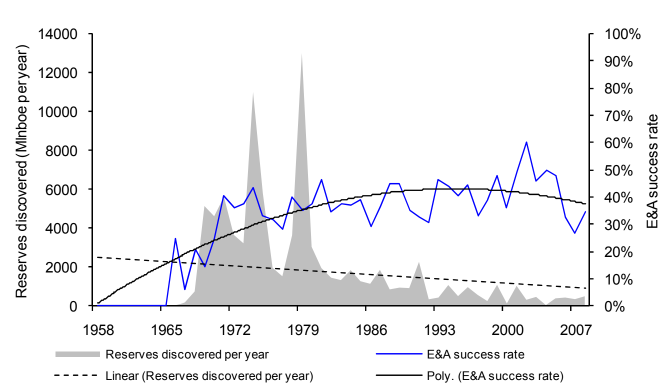
These static levels of success seem surprising, given significant advances in exploration technology (e.g. the application of 3D seismic and developments in sub-salt imaging). However, what this global data really highlights is a constant resetting of the exploration learning-curve as successful/growing companies constantly hunt for materiality. In basins with long exploration histories there is clear evidence that as more wells are drilled, and more data gathered, E&A success rates do increase through time (*see below*). However, as a basin matures the materiality of yet to be discovered volumes falls; large basin-opening finds replaced by smaller accumulations that leverage off existing infrastructure.

Figure 68: North Sea 'creaming curve' (Mln boe)



Source: Deutsche Bank, Wood Mackenzie

Figure 69: North Sea: discovery size vs. E&A success rate



Source: Deutsche Bank, Wood Mackenzie

The never-ending quest for materiality

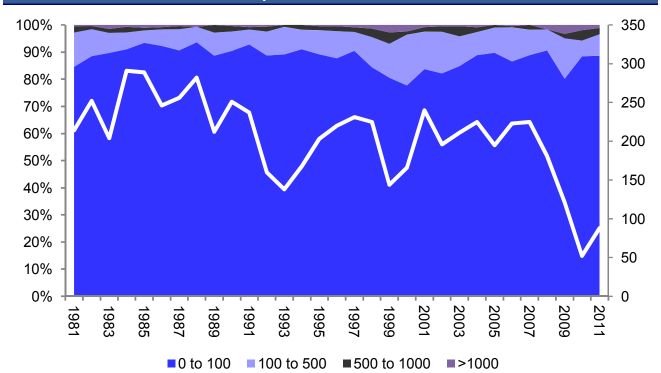
E&A drilling data also highlights the challenge of accessing material exploration volumes:

- Since 1981, 89% of the industry's commercially successful exploration wells have identified fields of 100 Mln boe or less. These discoveries account for 21% of the total oil volume and 12% of the gas volume discovered since 1981.
- In contrast, across the same period, just 2% of the successful exploration wells drilled made discoveries of 500 Mln bbl or greater; but the collective volumes identified account for 47% of the total oil volume and 71% of the total gas volume discovered since 1981.

From the integrated oil & gas majors (where simply standing still in volume terms is a constant battle) to the E&P sector (where investors are principally focused on the transformational potential of exploration success), this global record of static E&A success would appear a bleak backdrop for investment.

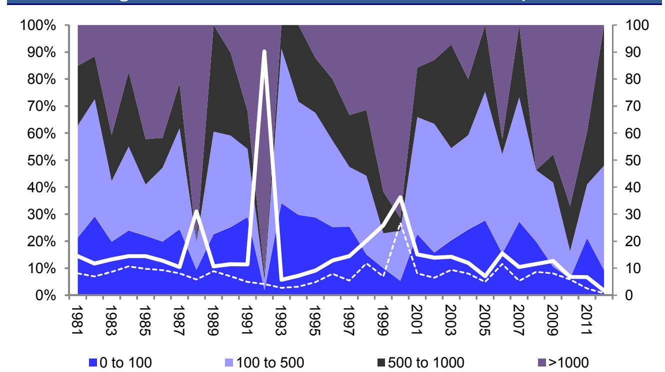
For the smaller players, although the 60 Mln boe base-line remains material, growth resulting from this exploration success and perhaps subsequent development inevitably forces them into more challenging prospectivity/frontier areas; where, although the materiality of the prize is larger, so too are the exploration uncertainties.

Figure 70: Successful exploration wells (number per year, line RHS) subdivided by field size identified



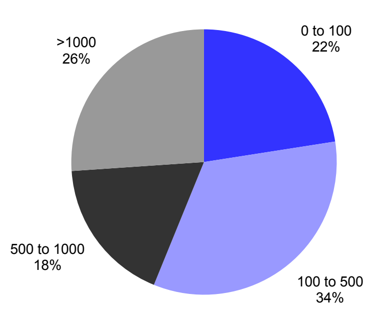
Source: Deutsche Bank, Wood Mackenzie

Figure 71: Global volume discovered (oil dotted line Mln bbl, oil & gas Mln boe solid line) subdivided by field size



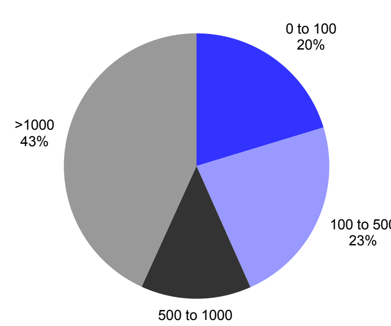
Source: Deutsche Bank, Wood Mackenzie

Figure 72: Distribution of trap size (Mln bbl) within total recoverable discovered oil reserve (1981-2009)



Source: Deutsche Bank, Wood Mackenzie

Figure 73: Distribution of trap size (Mln boe) within total recoverable discovered gas reserve (1981-2009)



Source: Deutsche Bank, Wood Mackenzie

Field Operations - Drilling

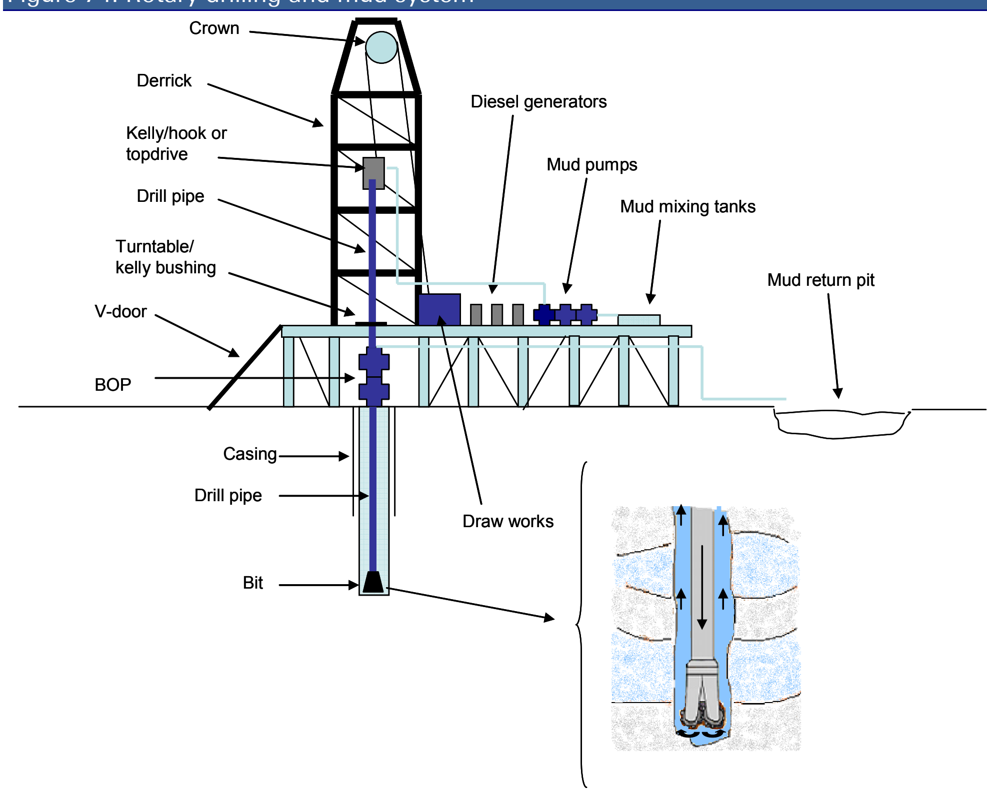
Up until the early 1900s well bores were 'drilled' by cable-drilling, Rotary drilling is the technique used by oil rigs around the world today.

The ability to drill a hole down several thousand meters to test a potential reservoir is often taken for granted by non-oil industry observers and analysts. Indeed advances in the equipment used have improved the success rates in reaching targets, and perhaps even more importantly (but often under-appreciated, even within the industry itself), the quality of hole drilled has improved. Higher quality well bores (straighter, less rugose) allow superior data to be acquired, and in a world where finding smaller reservoirs is the game, high quality data is paramount to understanding a reservoir, field and basin.

Up until the early 1900s well bores were 'drilled' by cable-drilling, which is still used for shallow water wells and foundation work on some building sites today. A cable pulls a heavy cylindrical weight up, and then simply lets it fall into the ground, and this slowly but surely makes the desired hole. Cable-drilling is only useful for very shallow wells, and by 1902 a new technique, rotary drilling, had been introduced in California.

Rotary drilling is the technique used by oil rigs around the world today. A hollow pipe with a drilling bit on the end of it is rotated by one of two methods; either a 'rotary table' or a 'top-drive'. The rotating bit cuts the rock beneath it, with the weight of the pipe pushing down on the bit carefully controlled, along with the speed of rotation, to ensure maximum cutting efficiency.

Figure 74: Rotary drilling and mud system



Source: Deutsche Bank

A fluid called **'mud'** (which is actually a cocktail of expensive chemicals and custom designed for each section of each well) is pumped down through the middle of the drill pipe, comes out the drill bit and is circulated back up the annulus between the drill pipe and the hole. This performs several vital functions:

- It carries away cuttings from the drill bit.
- It provides lubrication to try and prevent the drilling pipe from getting stuck.
- It provides a hydraulic pressure in the hole that prevents oil from 'blowing out'.
- It deposits a thin, impermeable layer of mud over the reservoir zones called 'mud cake'. This mud cake prevents further invasion and damage of the reservoir by drilling fluids and is vital from a data acquisition and productivity perspective.

Water-based mud - A problem with water-based mud systems is that water is readily absorbed by clay. Clay beds (or 'shale') hence tend to swell when drilled through by water-based mud, and this swelling can cause no end of technical difficulties. Even if the driller can avoid the pipe getting stuck, he/she typically has to waste valuable drilling time going over the clay zones and back-reaming them to try and get rid of all the 'sticky' points. Not only that, but when the wireline logging operation commences (see later), swelled up clay zones are often the points at which wireline instruments become stuck, and to get them out again can take days of unproductive rig time.

Oil-based mud (OBM) uses oil rather than water as the solvent, and as such is not absorbed by clay. OBM usually results in better quality, faster drilled holes. The downside is 1) it is more expensive that water-based mud and 2) the returns from the well bore are full of OBM and hence care (i.e. expense) has to be taken to prevent any of this oil contaminated waste entering the local environment.

Rotary table and top drive - The method used to rotate the drill pipe nearly always takes one of two forms; either a:

- Rotary table, where a circular section of the drill floor rotates and via a 'kelly bushing' so causes the drill pipe to rotate, or;
- Top drive, which is large electric or hydraulic motor which is positioned on top of the drill pipe.

The top drive, developed in the mid 1980s, was a big step forward in that it allowed more flexible drilling operations (mud can be pumped continuously no matter where the top of the pipe is in the derrick, whether back-reaming the drill bit up the hole or pulling the pipe out of hole – all of which are limited with a rotary table). The end result is fewer stuck pipes (and hence less lost wells), better hole quality (and hence better quality data from wireline logging) and better control when drilling deviated wells to target reservoirs.

Down-hole mud motors - For directional drilling (in which a well is guided, sometimes at a high angle, to a very specific target) another option exists; instead of rotating the entire pipe, a hydraulic motor just above the drill bit is powered by the pressure and flow of mud being pumped through the pipe, and this motor provides the power to rotate the bit. This setup makes it easier to 'steer' the drill bit.

The BHA stands for 'bottom-hole-assembly'. This refers to the bottom few hundred feet of the drill pipe and its basic form is usually made up by the drill bit followed by heavy pipe called 'collars' interspersed with larger diameter pipe with what look like fins on the side – so called 'stabilisers'. The BHA assembly provides weight for the bit to cut rock, rigidity to keep the hole as straight as possible and strength to transmit torque to the bit and absorb huge mechanical shocks as drilling progresses.

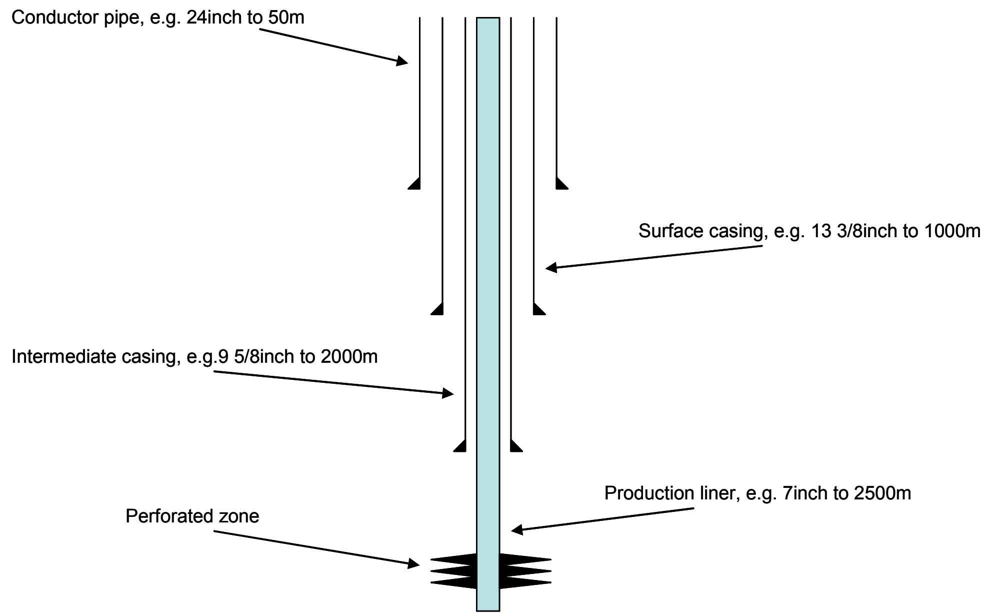
The BHA can include several optional elements that make it more complicated – mud motors for directional drilling. MWD (measurement-whilst-drilling) sensors to provide real-time direction and torque measurements or even LWD (logging-whilst-drilling) instruments that can record various physical properties of the formation drilled through.

Wells are nearly always drilled in stages, and when the bottom of each stage is reached the freshly drilled hole, known as 'open-hole', is cased off using steel pipe

Casing - Wells are nearly always drilled in stages, and when the bottom of each stage is reached the freshly drilled hole, known as 'open-hole', is cased off using steel pipe and so becomes 'cased-hole'. The main reason is to prevent the hole collapsing on top of the drill pipe (which might otherwise become stuck). A drilling program might for example look something like this:

- Pile-drive a 24 inch conductor pipe down to 50m.
- Drill open hole to 1000m with a 17 inch diameter bit.
- Pull out the drill pipe and set a 13 3/8 inch 'surface casing'.
- Drill on to 2000m using a 12 ¼ inch bit size.
- Pull out the drill pipe, run a basic wireline logging program (see later), then set a 9 5/8 inch 'intermediate casing'.
- Drill on to target depth of 2500m using an 8 ½ inch drill bit.
- Pull out the drill pipe, run a wireline logging program over the target zone, then if the indications are encouraging, set a 7 inch 'production liner' in preparation for more extensive testing.

Figure 75: Example well with four casing 'strings'



Source: Deutsche Bank

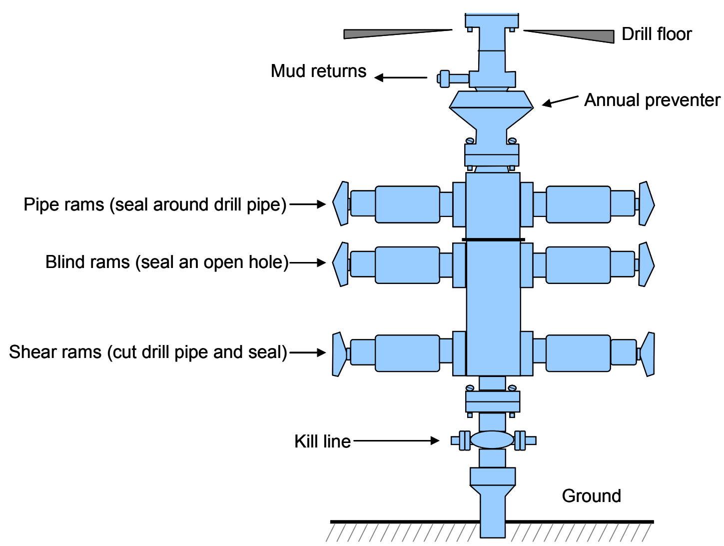
Cementing - The diameters quoted above are just generally used diameters around the world, but various other diameters are also in common use. To 'set' the casing it is first lowered into the well, then the drill-pipe is lowered (without a drill bit on the end) down inside the casing to the bottom, and is used to pump cement up the annulus between the outside of the casing and the hole. This cement will set and bond the casing to the rock formation that has been drilled through. In this way then the casing and cement together should isolate different reservoirs from each other and from the surface.

Wireline logging is a set of operations using cables and downhole instruments to acquire measurements that provide strong indications or whether any oil or gas has been found or not. We discuss wireline logging in more detail over the following pages.

BOPs. BOP stands for blow-out-preventer and is a large set of valves that sit on top of the well being drilled. The BOP will if required, seal the well quickly even if there is a drill pipe in the way. It has several sets of seals (called 'rams'), as shown in the following figure, which are used in different circumstances.

BOP stands for blow-out-preventor and is a large set of valves that sit on top of the well being drilled.

Figure 76: A blow-out preventer (BOP)



Source: Deutsche Bank

- **Pipe rams to control a kick.** In the case of the mud system failing to control the pressure of a reservoir, this reservoir will force fluid (oil, gas or water) into the well bore which will in turn displace mud out of the top of the well. The driller and mud engineers will see this (it is known as a 'kick') and try to regain control by quickly adding heavier mud into the borehole.

  However if no ready supply of heavy mud is available, it may be necessary to close the pipe rams – these are large rubber seals that will form around the drill pipe and seal in the kicking well. This buys time for the mud engineer to make up heavier mud, which when ready, is pumped down the center of the drill-pipe to 'kill' the well.

- **Shear rams in the last resort.** If following a kick the mud weight is not raised quickly enough, or if the pipe rams leak, the reservoir fluids will continue to enter the well bore. This will decrease the aggregate well bore fluid density, and thus its weight and hence a vicious circle is setup which can quickly (within minutes in some cases) spiral into a blow-out.

  A blow-out initially usually takes the form of a geyser of mud shooting into the drilling rig, but if left unchecked the geyser will become increasingly full of the oil or gas from the uncontrolled reservoir. Depending on the wind conditions, this oil and gas needs only one spark to ignite it and then death and destruction are a real possibility. To avoid this unpleasant scenario the BOP contains a set of 'shear rams', which will cut straight through the drill-pipe and seal the well off.

Another risk with kicks is that gas can contain H_2S (or 'sour gas'), and this is not friendly stuff. It smells like rotten eggs in concentrations of 5ppm, but quickly destroys one's sense of smell (so people think it has gone away), with inhalation proving fatal at around 20ppm.

Directional (incl. horizontal) wells

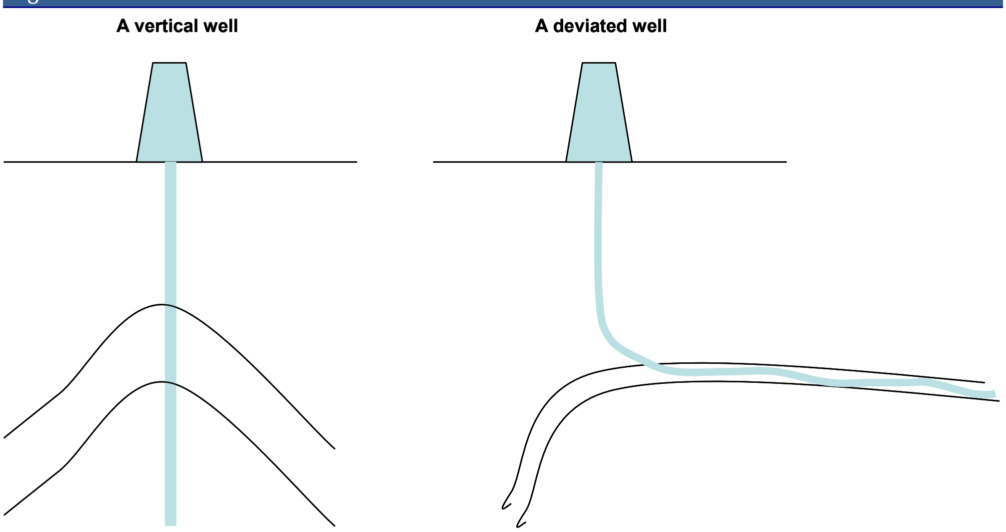
Identifying a potential reservoir trap and drilling straight down into the top of it is an obvious strategy. Here the challenge is to make sure the well is drilled straight, and a properly designed BHA, mud system, functioning rig equipment and an experienced driller should deliver.

However deviated wells are often required, for example:

- If development drilling dictates several wells targeting different zones in the reservoir all from one central platform location.
- If targeting a thin reservoir, acceptable flow rates might only be achieved if a long, horizontal well is drilled.
- Drilling an offshore target from the shore.
- The target lies under a built-up or environmentally sensitive area.

To accurately drill a deviated well is more challenging than a vertical well. In the past experienced directional drilling consultants contributed to what at times, was as much art as science. Today, science dominates; **MWD** (measurement whilst drilling) instruments placed near the drill bit give a real-time readout of exactly where the drill bit is heading and when coupled with a **down-hole motor** (powered by the drilling mud to add concentric power and steerability to the drill-bit), targets can usually be hit with precision. The scale and precision of modern horizontal wells are often likened to "dropping a plumb line from the top of the Empire State Building and then guiding it through the rear and front windscreens of every car parked in the nearby streets".

Figure 77: Vertical and deviated wells



Source: Deutsche Bank

Although directional drilling itself refers to any type of deviated well, the most prevalent in modern-day drilling activities is the **horizontal well**. Horizontal wells are deviated wells (acuter than 80 degrees) drilled along the pay-zone parallel to the reservoir (as in Figure 77). The main benefit of horizontal drilling is to allow for extended touch points between the well and the reservoir, thereby vastly improving the rate of flow of oil & gas than would a single vertical well. Horizontal drilling has arguably proven most effective in the drilling of tight and shale formations when combined with **hydraulic fracturing** (discussed in greater depth later).

Land and offshore rigs

The discussion so far covers most that is needed to be known about land rigs by an investor/analyst. Apart from scale of equipment and hence ability to drill deeper there simply isn't much more interest in the world of land rigs; they are relatively commoditised and the Chinese, Russians and Polish, amongst others, have been making very good ones for decades.

Offshore drilling

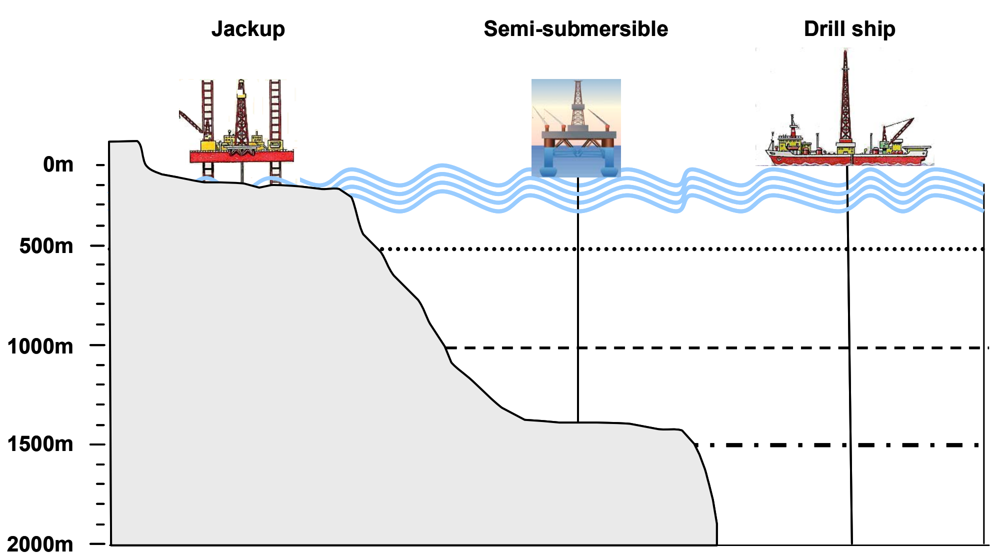
Drilling in the sea is more complicated than on land

Drilling in the sea is more complicated than on land; the lack of stability (for floaters), the corrosive environment, the more cramped conditions and the more difficult support logistics all dictate this. During drilling the offshore well needs to be extended from the seabed to the rig floor, so that the mud system can be controlled. This is achieved by using a **'drilling riser'**, which is a large diameter steel pipe that connects the top of the well on the seabed with the rig. The **BOP** can either be mounted on the seabed or be on top of the riser at the surface. Rigging up and down the riser for each well adds on to required rig time versus an onshore operation, and pressure testing the entire system is also more complicated than onshore BOP pressure testing.

Within offshore rigs there are two main categories; jackups and floaters.

Within offshore rigs there are two main categories; **jackups** and **floaters**. Jackups do not float, they stand on retractable legs which provide a stable platform from which to drill.

Figure 78: Offshore rigs



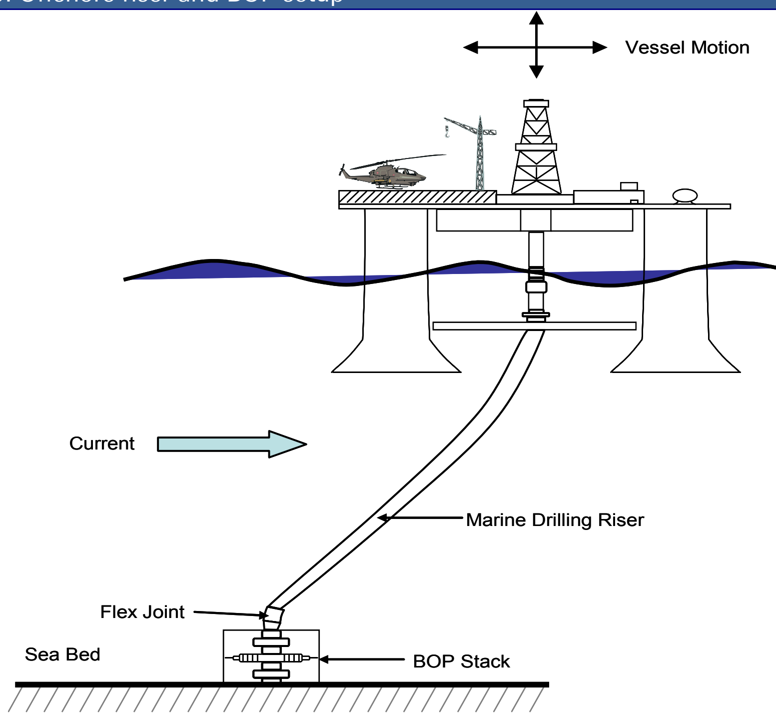
Source: Deutsche Bank

The **Jackup** can of course only work in water depths that are less than the length of its legs, and typically this limits operations to less than 400ft. When moving between drilling locations the hull is usually towed by tugs or carried by a specialist vessel, with the legs sticking high into the air. Once the jackup has arrived on location, the legs are lowered to the seabed, and then the hull is jacked up the legs, so raising itself out of the water.

Floaters are not limited to 400ft WD as they do not rely on standing on legs. They are essentially ships with drilling equipment, are usually self propelled and have a marine crew. When it arrives on location the floating rig needs to anchor with the help of support vessels, which can be a time-consuming process. However the main technical challenge versus jackups is the platform's floating nature; the rig will move up and down with tides if present, but the well bore of course doesn't i.e. the drill pipe will have a tendency to smash into the bottom of the hole simply with the heave of the rig. The solution involves using large hydraulic systems known as wave-motion-compensators. It adds up to yet more mechanical systems to operate, maintain, and potentially go wrong.

Drillship or semisub? Which of a drillship or semi-submersible is better is unclear, and basically seems to come down to availability as much as technical factors. It could be argued that transit speed between locations is faster for drillships and that keeping on station (whether by anchors or dynamic positioning) is easier in certain prevailing current locations with a long, thin ship-shape than a square semisub shaped hull. However the ship-shape layout limits space for an operation that uses ever larger equipment and ever more sub-contractors (that all want a bed to sleep in and a house for their equipment).

Figure 79: Offshore riser and BOP setup



Source: Deutsche Bank,

Logistics and supply. There is an entire industry that simply services the logistical needs of the offshore drilling industry. It includes:

- Catering – supply of food and onboard catering staff and cleaners
- Supply vessels – to supply fuel, food, water, chemicals, drill pipe, casing, cement and act as an offshore storage facility when deck space becomes tight.
- Support vessels – used to act as emergency support for evacuation in bad weather or kick/blow-out scenarios, sometimes for transport of personnel from shore or from rig to rig within a field, and occasionally as accommodation if there's no space left on the rig.
- Anchoring vessels – usually supply boats or dedicated powerful tugs that aid in the laying of anchors.
- Helicopters – the provision of helicopter transport and emergency support.

Drilling the well is only the start of the journey – in the next section we discuss in more detail the evaluation work undertaken after a well has been drilled.

Field Operations - Evaluation

Perhaps surprisingly, simply drilling a hole into the ground rarely conclusively reveals whether it has intersected an oil or gas reservoir. For an exploration well, successfully drilling a hole to the target depth is only the start of the story. The drilling of an exploration well is really just a means to an end, and that end is to acquire as much data and knowledge about the subsurface rocks and reservoirs as possible. If a well is drilled that is so crooked, rugose, or 'sticky' that no decent quality data can be acquired, then money has been wasted.

Rock Doctors and Mud Loggers – what has been drilled though?

Rock Doctors and Mud Loggers – what has been drilled though?

Exploration sites will almost always have a geologist working (the 'wellsite geologist', appropriately enough, or to some, the 'rock doctor'). The role of the wellsite geologist is to analyse the rock cuttings that circulate to the surface from the drill bit, and keep a record of what rock type (sandstone, shale, limestone etc) has been drilled though.

The rock doctor is not the only source of data during drilling, a 'mud logger' has equipment that is setup to continuously analyse and record any gas present in the mud returns from the well bore – a sudden increase in gas is an obvious indication that a hydrocarbon reservoir has been drilled through. The mud logger will also regularly take samples of the returned mud and see if it fluoresces under ultra-violet light – another key indicator of hydrocarbons. The wellsite geologist and mud loggers thus provide vital initial analysis on the subsurface structure. However as we discuss below, this data is often compromised and at best an incomplete picture – it needs to be complemented by additional data – typically from coring and/or wireline logging.

Mud – it hides the truth…

The mud system, whilst vital to keep control of a well, results in all but a very few wells being drilled in an **'over balanced'** condition – this is when the pressure of the mud in the well is greater than the reservoir fluid pressures. As such little or no reservoir fluids enter the well during drilling and so the wellsite geologist and mud logger are at a disadvantage when it comes to identifying whether oil or gas has actually been drilled through. The mud log can completely miss an oil or gas bearing reservoir.

Furthermore, although the geologist can use returned mud cuttings to identify what kind of rock has been drilled through, only a relatively rough estimate of the depth that the cuttings came from can be made (who knows how long a particular cutting took to circulate back to the surface?). In a world where reservoirs as thin as 5ft can be potentially commercial, not knowing where it is to within 100ft is a problem.

Coring – ideal but expensive

The best way to assess the formation that has been drilled through is to have physical samples. This can be achieved by 'coring', a process where a special drill bit and tubes inside the bottom hole assembly allow a continuous core to be taken whilst drilling. The downsides include:

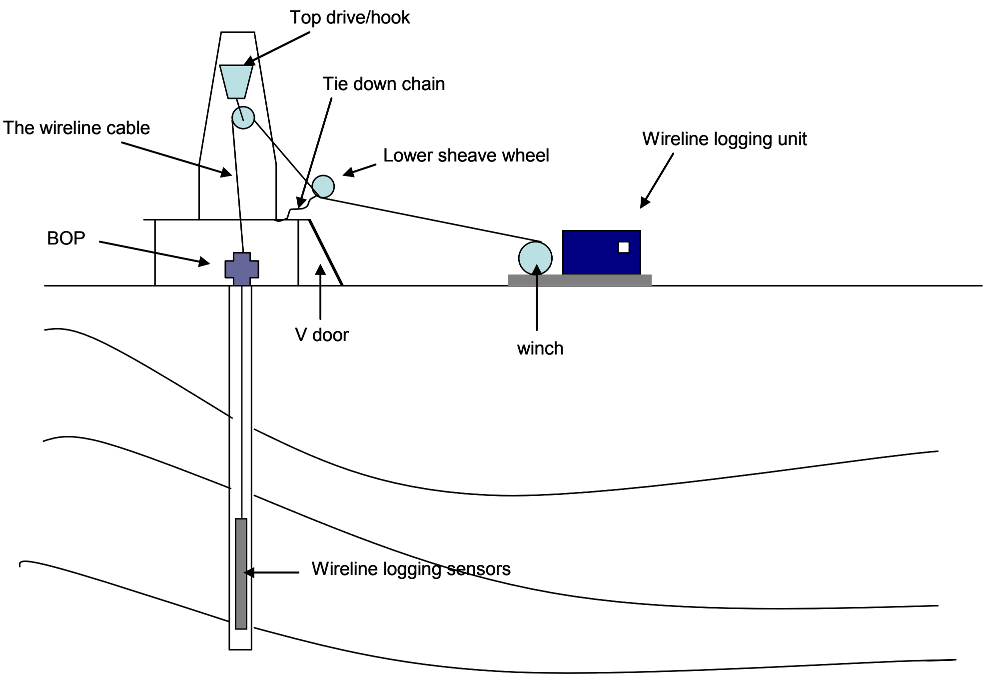
- Drilling is much slower than normal. The speed is limited whilst coring and far more trips in and out the hole with the drill pipe are required. Anything that slows down drilling time is a big issue when you consider $1m/day offshore costs are no longer unusual.
- It's not 100% reliable, there can be gaps in the core, or in the worst case, no core at all is gathered – and remember this is a one shot operation; if the core isn't taken properly then going back to try again is not an option (at least not in the same well).

Wireline logging the best compromise…

A bit of history - in 1927 Conrad and Marcel Schlumberger ran the first 'electric log' of an oil well in France. This involved lowering an electrode on the end of a long cable to the bottom of a well, and continuously recording the voltage difference between the electrode and the surface whilst pulling the electrode up slowly.

This simple procedure proved powerful, as reservoirs bearing water or hydrocarbon chemically react in different ways with drilling mud to produce different voltage differences – the SP (Spontaneous Potential) wire-line log was born.

Figure 80: A typical land wireline logging setup



Source: Deutsche Bank

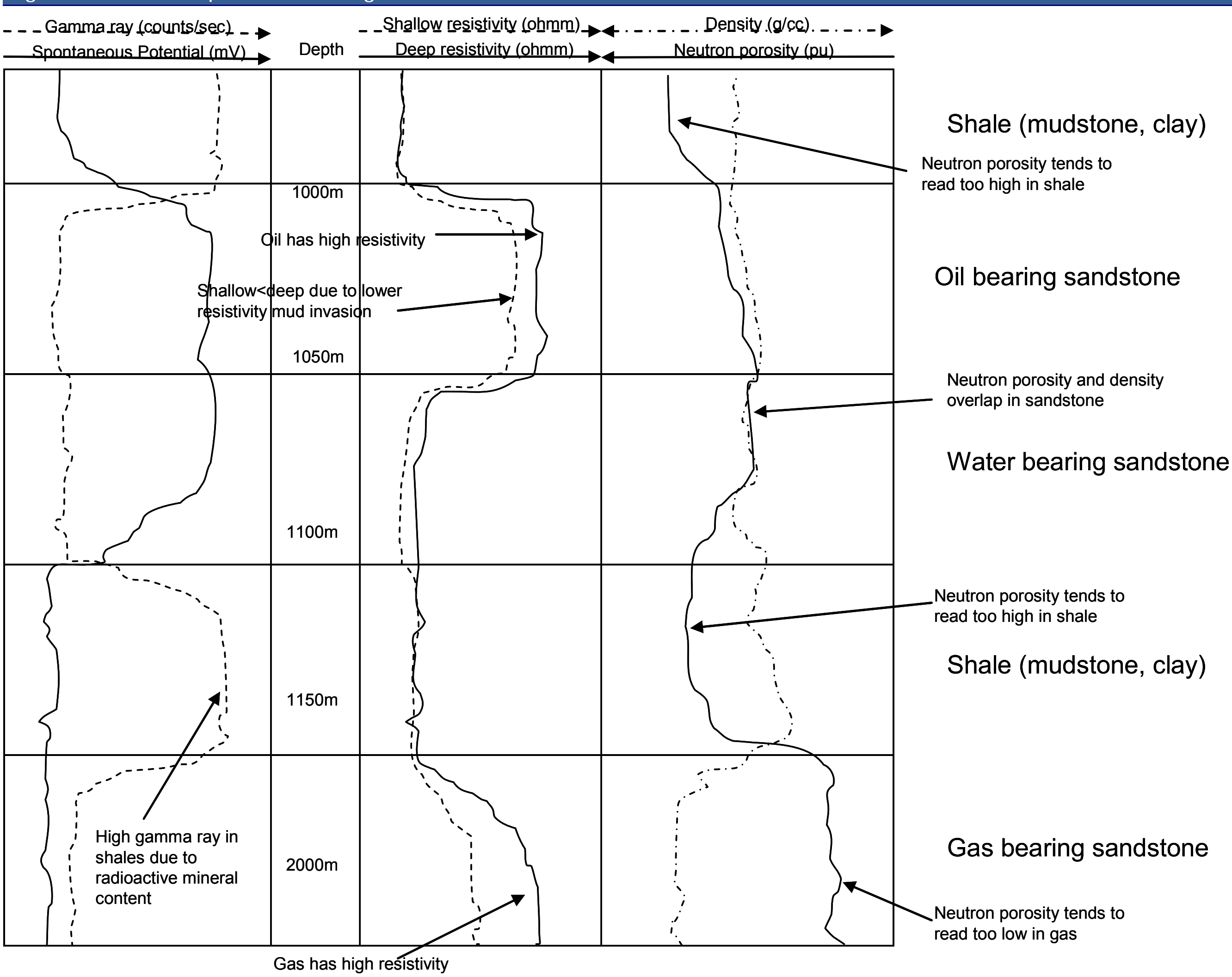
Wireline logging involves the lowering of instruments to the bottom of a well, then pulling them up slowly with a winch, whilst recording in high resolution the information provided

Wireline logging today still uses the same basic technique – i.e. the lowering of instruments to the bottom of a well, then pulling them up slowly with a winch, whilst recording in high resolution (and with high depth accuracy) the information provided by the instruments. The main wire-line devices ('tools') used today are the following.

- **SP (Spontaneous Potential)** – helps detect water bearing reservoirs.
- **Gamma Ray** – indirectly detects the level of clay in the formation, i.e. shaliness.
- **Resistivity** – indicates possible hydrocarbon zones.
- **Micro resistivity** – very shallow and high resolution resistivity – helps indicate permeability and detect thin beds.
- **Caliper** – measures the diameter of the well, in either 1 or 2 axis.
- **Neutron and density** – porosity and lithology (identifies sandstone, limestone, shale, carbonates, volcanics). Also helps discriminate between gas and oil.
- **Sonic** – porosity and gas indicator.
- **Formation imaging** – hundreds of micro-resistivity sensors combine to give a 360 degree, very high resolution resistivity image of the well wall. Useful for fracture detection and lithological analysis.

- **Wellbore seismic** – a 'quickshot' ties in the surface seismic to depth rather than just time. A full 'VSP' (vertical seismic profile) survey gives a single seismic column that can be overlaid with a surface seismic.
- **Pressure and fluid sampling** – reservoir pressure gradient measurements discriminate between oil, gas and water zones. Reservoir fluid samples can be brought to surface for further analysis.
- **Sidewall cores** – samples of down-hole rock from specific depths are brought to surface and then used for further analysis.
- **Magnetic resonance logs** – measure formation permeability.

Figure 81: An example Wireline Log



Source: Deutsche Bank

The oil company will decide which combination of the above services are required for a particular well, but in general most exploration wells will have a combination or all of the above wireline services run.

The logging operation itself means that the wellbore is occupied by wireline equipment, and so whilst the wireline crew work hard for anything up to a week acquiring the required data, for the drilling crew its essentially downtime.

LWD - why not acquire the data whilst drilling?

Wireline logging has disadvantages – namely:

- The entire drilling operation has to go on hold whilst wireline logging is in progress.
- The data quality is sometimes compromised by poor borehole conditions and invasion of drilling mud into the formation.

A way to avoid these problems is to use 'logging whilst drilling' (LWD) tools to acquire largely the same data (resistivity, sonic, nuclear) whilst drilling.

LWD is technically more challenging than wire-line logging; the instruments need to be much stronger due to the immense mechanical stresses that are part and parcel of an active drill string, and the system has to cope with much lower real-time data transmission capabilities (there is no handy wire to transmit data along). However over the last 10 years the reliability issues have been largely resolved and a combination of mud-pulse telemetry systems and down-hole data storage adequately handle the data acquired in most scenarios.

The main disadvantages of LWD are:

- The costs of losing the equipment down-hole (due to stuck pipe) are much higher than for wireline instruments.
- The cost in rig time of equipment failure, as the entire drill string has to be pulled out is such a scenario that can be significant.
- There is a smaller scope of services available versus wireline implying the wireline crew might have to be on the rig anyway, but under-utilised and,
- It has potentially lower data resolution.

There's only one way to be sure – Well Testing

Despite the sophistication of LWD and wireline logging instruments, there remains only one way to be sure that a well will flow with commercial rates – a Well Test. A Well Test involves setting up equipment so that the reservoirs can flow oil and gas at controlled rates through surface valves also known as '***chokes***'. Measurement of the flow rates, properties of the fluids produced and fluid surface pressures yield invaluable information about not just the permeability, contents and potential flow rates of the reservoir, but also its physical size.

Appraisal wells – as much data as possible

'Appraisal' wells are drilled following a discovery exploration well, primarily to delineate the physical size of the reservoir and to gather as much additional information as possible. The key here, as for exploration wells, is one of data acquisition. An appraisal well that reaches its target depth but falls short on the data acquisition program (e.g., wireline or LWD equipment failure, or poor hole quality) is from a geologists perspective, a largely wasted drilling exercise.

'Appraisal' wells are drilled following a discovery exploration well, primarily to delineate the physical size of the reservoir

Field Operations - Development

Development drilling – efficiency is king

Development drilling differs from exploration and appraisal drilling in that data acquisition is no longer the main aim of the game

Development drilling differs from exploration and appraisal drilling in that data acquisition is no longer the main aim of the game. By this stage the field has (hopefully) been reasonably well understood and the locations of what will be the producing wells have all been selected. The goal in the development drilling phase is thus simply to drill targets as efficiently as possible. Whilst it is always potentially useful to have more data, during development drilling data acquisition programs are usually far less intense than during exploration drilling. A mud log and a single run of wireline tools may well be enough to confirm the reservoir has been intersected where expected.

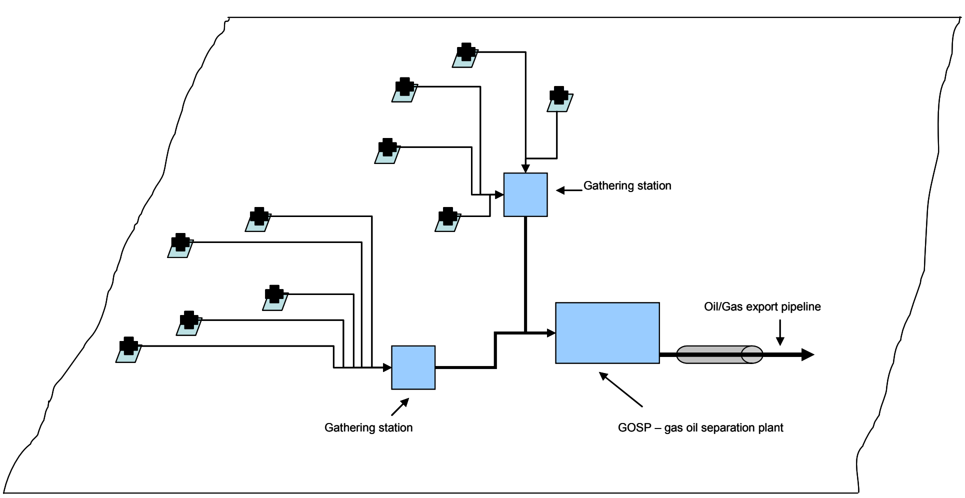
Development wells can be complex, with long horizontal sections to tap thin beds, and even multiple branches spurred off from a single surface well to target areas of a reservoir from one set of surface equipment. Fracturing and acidising of the reservoir may be used to help maximise well productivity and if need be, multiple injection wells may be included in the development drilling program to again aid field productivity

Field architecture

Once the development wells have been drilled, the drilling rig will leave the field and infrastructure will be put in place to allow the control of the producing wells, safe storage and export of oil and gas. As with drilling, the nature of these facilities is more complicated (and thus capital intensive) offshore than onshore. The same comment is true of gas versus oil; the infrastructure to handle gas production has to handle higher pressures of a much more mobile 'fluid' and as such usually demands higher specifications than the infrastructure that would handle the energy equivalent for oil.

Onshore – oil is usually straight-forward…

Figure 82: Typical onshore oilfield architecture



Source: Deutsche Bank

For oil the standard onshore field architecture is straightforward; oil is gathered by a network of pipes into a central treatment plant, where any associated gas and water is removed (a 'GOSP' – gas oil separation plant). The crude is then either piped or trucked to a refinery, or export terminal. The GOSP in a modern development will do something useful and environmentally sound with the 'waste' gas – either send it back to the field for re-injection or supply a local gas market of gas export LNG plant.

…gas less so

For most of the life of the oil industry, associated gas has been considered nothing more than an inconvenience encountered during oil production. The safest action to take was simply to burn it – i.e. 'flare' it. Today this is unacceptable in most countries not only from a wastage standpoint, but also because flaring is a contributor to greenhouse gases.

In the case of onshore gas wells (i.e. pure gas fields rather than 'associated gas' produced with oil), there are usually fewer producing wells required in the first place than for an oil field (since gas is far more mobile – i.e. it flows through even relatively low permeability rock much better than oil), but the wells still need to be tied back via pipe to a central processing station, where any water, sulphur or other impurities are removed.

If the gas is destined for local market distribution then it is usually treated to have an appropriate calorific value. Where local demand does not justify the development of a large gas field then LNG is usually the only option (although GTL economics will likely improve with time and technological learning). A large diameter pipe transmits the gas to the LNG plant where it is treated before being cooled to –162°C for export as a liquid.

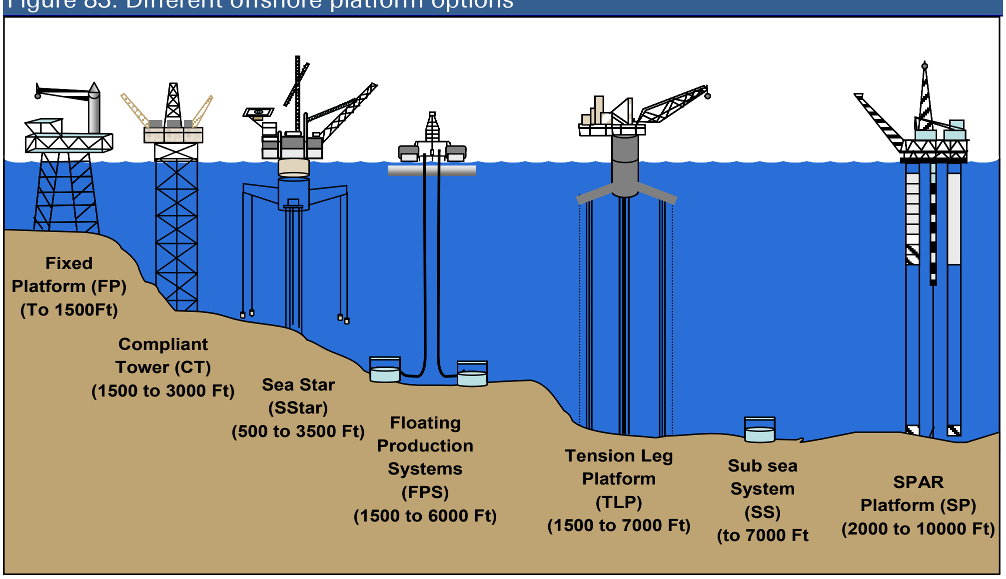
Offshore – as usual, deeper is tougher

The world's offshore oil and gas developments are dominated by permanent structures (i.e. 'platforms').

The world's offshore oil and gas developments are dominated by permanent structures (i.e. 'platforms'). In shallow waters (400ft or less) these usually stand directly on the seabed and are constructed from steel or concrete.

Offshore wells are extended via rigid pipe all the way to the platform, where control valves (the 'christmas tree') allow manual or remote opening/closing of each well independently. This setup also allows access to the wells at a later date for work-over or other remedial operations.

Figure 83: Different offshore platform options



Source: Deutsche Bank

In water depths greater than a few hundred feet, rigid platforms installed on the seabed start to become too expensive, just from the sheer volume of steel and cement that is required. A variety of solutions are used by the industry to develop such 'deep water' fields, including FPSOs (floating production, storage and offtake vessels), SPARs, TLP (tension leg platforms) and Compliant Towers.

FPS – floating production systems usually refers to **FPSOs** (floating production, storage and off-take vessels) or FPSSs (floating production semi-subs). FPSOs are ships that have been converted (typically from an oil tanker, or built from scratch) to accept production from subsurface wells, and store the produced oil until a tanker comes alongside to unload it. FPSOs can range in sophistication from simple barge-like vessels anchored via chains to huge dynamically positioned ships capable of separating out oil/gas and water, storing over 2 million bbls of oil and re-injecting produced water or gas. Some FPSO's have the capability to weathervane around a cluster of producing risers (via complex equipment known as a 'turret'), and/or quickly disconnect from producing fields (in the event of hurricanes for example). FPSOs are the most common solution to deepwater developments off the W. African coast, and have also been used extensively by Petrobras in developing their deepwater fields. The connection between the wells and the FPSO is either via rigid pipes (risers), flexible pipes or a combination of the two.

Floating production systems usually refers to FPSOs (floating production, storage and off-take vessels)

FPSOs have the advantage that there is a ready supply of oil tankers to convert, and shipyards are comfortable with building or modifying ship shaped vessels, however the fact that the vessel will float up and down with tide or swell means that the christmas tree usually has to be on the seabed rather than the FPSO, so making future well access a costly affair; the FPSO must be moved off location and a drilling rig hired.

A **SPAR** is basically a large cylinder with a deck on top, secured in place with anchors. SPARS have been used extensively in the North Sea and shallow water US GoM. They are cheap to fabricate, but have limited deck area and tend to have relatively large vertical movement in rough seas, so limiting access to wells for maintenance.

A SPAR is basically a large cylinder with a deck on top

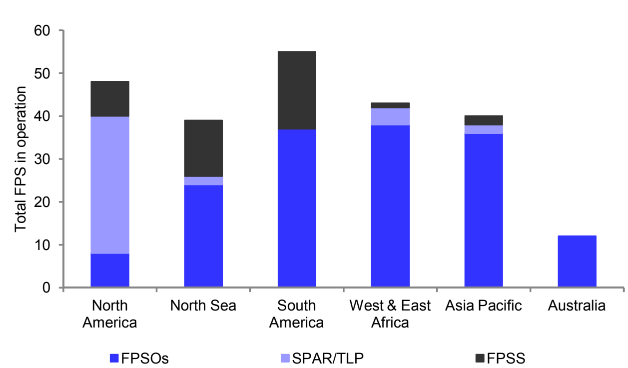
TLP stands for 'tension leg platform'. It has very limited storage capability and so is usually used where there is local pipeline infrastructure – shallow water GoM for example. It is anchored via steel tendons to the seabed that are under high tension. This makes the TLP platform relatively stable, so allowing the 'dry tree' solution of a steel riser from the seabed to deck, with a Christmas tree control valve on top.

TLP stands for 'tension leg platform'

How many installations are there globally?

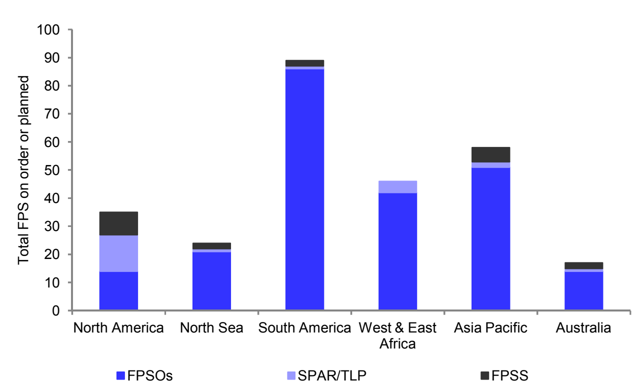
It is estimated that there c.240 floating production systems in operation. This is small when compared with the c6,000 fixed platforms but each floater is individually far more costly and with exploration success far higher in the deepwater, expected to continue to grow at a faster pace going forward. Reflecting this anticipated growth and high oil prices we note that the current backlog of *on order* or *planned* floaters now stands at c270 of which c60 have already converted into firm orders (under construction).

Figure 84: Currently producing FPSs by type & region*



Source: International Maritime Associates, FPSS = floating production semi-sub

Figure 85: c270 On order & planned floaters



Source: International Maritime Associates

Peering deeper

A platform is all that can be seen from the surface for a typical offshore development, but on the seabed all the development wells (whether producers or injectors) need to be connected to gathering stations and to the host platform. In the context of the upstream industry 'subsea' typically refers to the entire infrastructure 'below the waterline' and comprises a wide array of technologies from the manufacturing and installation of narrow-diameter rigid and flexible pipelines connecting subsea hardware to the surface facilities, to the highly-engineered subsea trees that sit on top of wells on the sea floor.

Why go subsea?

An advantage of subsea systems is in allowing for the development of satellite fields uneconomic if developed via standalone installations. Subsea systems are generally developed **a)** as part of the initial development plan (i.e. where a host facility is purpose-built to accommodate optimised field architecture) or **b)** where the need for subsea development is recognised after the host facility has been designed and is in operation.

Subsea completions - bypass the platform altogether?

As SURF infrastructure can be spread over a wide area an obvious evolution is to extend the tie backs all the way to the coast, and do away with the need for a platform altogether, so potentially saving capex and the need to support workers offshore.

For gas this is already being done, notably with Norway's Snohvit (Statoil) project, which transmits gas 140kms to a receiving terminal and LNG plant on the Norwegian coast. For oil however, long subsea tiebacks are more difficult. The cold seabed temperatures make the oil more viscous, to the extent that some grades simply will not flow without extremely powerful pumps and/or commingling with a solvent – but of course without a platform nearby such solutions imply that long power cables and chemical injection lines need to be laid from shore, so reducing project feasibility and economics.

Figure 86: Selection of deepwater/subsea development records

Deepwater/subsea records	Operator	Region	Field	Comment
Deepest floating facility	Petrobras	US GOM	Cascade	2,500m WD BW Pioneer FPSO
Deepest subsea tree	Shell	US GOM	Tobago	2,934m WD installed by Technip's Deep Blue
Longest oil subsea tieback	Shell	North Sea	Penguin	70KM tie-back, 175m water depth
Longest gas subsea tieback	Statoil	North Sea	Snohvit	143KM tie-back, 345m water depth

Source: Deutsche Bank

Cutting through the jargon – subsea equipment & infrastructure ("SURF")

Subsea '**trees**' are a collection of valves and spools that regulate the flow or oil & gas from a well. Fixed to the well-head, wet trees can also manage fluids or gas injected into the well. **Jumpers** and **flowlines** allow for the flow of oil & gas from wells (via the tree) to a **manifold**; which provides the interface whereby the flowlines from multiple wells commingle before moving to the host platform via a further flowline & production **riser**. Risers come in multiple forms; production risers for import or export fabricated out of rigid or flexible pipe (or both) in various configurations, the most common of which are attached risers, pull-tube risers, steel catenary risers and top-tensioned risers.

Umbilicals and **flying leads** are essentially housed electric cables providing the necessary electrical, hydraulic and chemical injection connection between a host facility and the subsea equipment. The ability to constantly monitor equipment (trees, manifolds) is a key requirement for the safe operation of subsea systems. To this end subsea equipment is equipped with **subsea control pods** that can be operated from the host platform to increase, decrease or shut-in production/flow rates entirely.

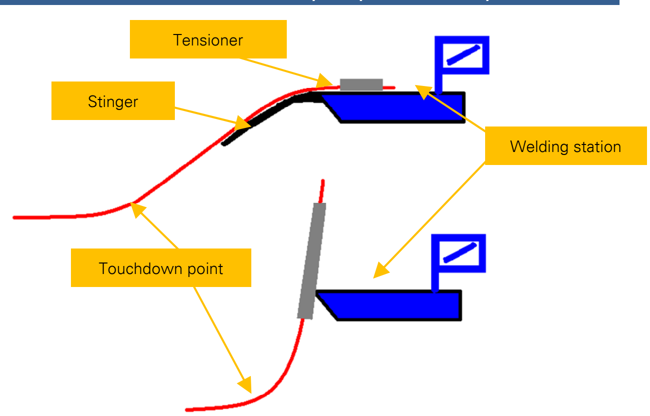
Pipelay installation & heavy-lift – a basic primer

The transportation & installation of offshore infrastructure (both installations and subsea infrastructure) offshore is highly costly. This reflects the requirement for specialised offshore construction vessels capable of lifting and installing heavy structures in deepwater/harsh conditions, as well as those equipped with sufficient tension-capacity on board to hold up to 60" diameter pipe in ultra-deepwater conditions. There are three primary methods of pipelay installation, namely **J-Lay**, **S-Lay** and **reel-lay**, with pipe-towing a fourth method that has limited use in today's market. While seeming somewhat trivial they can have a big impact, and are hence outlined below:

J-Lay is a method of pipeline installation whereby joints are welded on-board the vessel (rather than onshore) and are clamped into a vertically-erected tower 'feeding' the pipe onto the sea-bed. The 'J' refers to the shape of the pipe as it is fed from the clamp tower onto the seabed (see below). J-Lay exerts lower stress given that the pipe only flexes once when touching down on the sea-bed. The vertical orientation of the tower allows pipe to be laid in deep waters with capacity for large diameter pipe (typically up to 60"). Given the vertical orientation pipelay speeds can tend to be low, with the associated cost thereby limiting their use in inter-field and significant gas export lines.

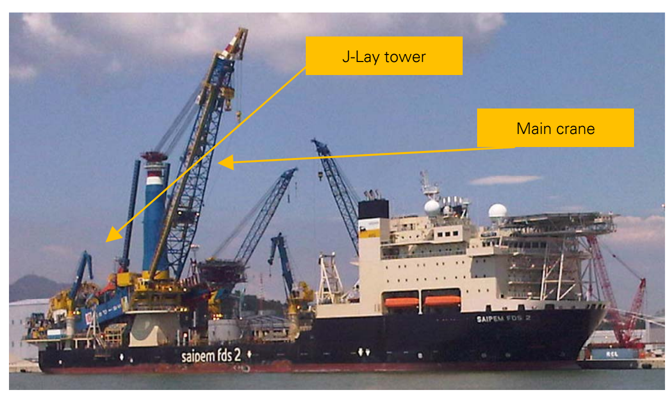
S-Lay is a more commonly employed and older method of pipelay installation. In S-Lay installation, pipe is fed off the 'firing line' of the vessel as the boat moves forward, curving downwards off the boat and again as it touches down on the sea-floor creating an 'S' shape as pipe is laid. In order to support the pipe as it exits the vessel S-Lay vessels typically have 'stingers' that extend many metres off the end of the vessel to control pipe curvature and reduce stress. S-Lay vessels tend to have faster pipe-lay speeds vs. that of J-Lay (Allseas' Solitaire claiming up to 9KM/day) with top-tension capacity further providing capability for large diameter pipe (also typically up to 60").

Figure 87: Schematic of a S-Lay (top) and J-Lay (bottom)



Source: Deutsche Bank

Figure 88: Saipem FDS2 in Indonesia



Source: S. Yoshida, used with permission

Reel or **rigid-reeled J-Lay vessels** utilise the flexible characteristics of long-length narrow diameter piping. Joints are welded onshore and wound around a reel where it is transported onto the pipelay vessel at a spoolbase before being taken out to shore for 'unwinding' (i.e. installation). Some reels unwind horizontally (S-lay) while others are done vertically (J-Lay). While lower cost, this reduces the max OD capabilities of vessels. 18" pipe at small lengths is possible in some instances, but 6-12" pipe more common.

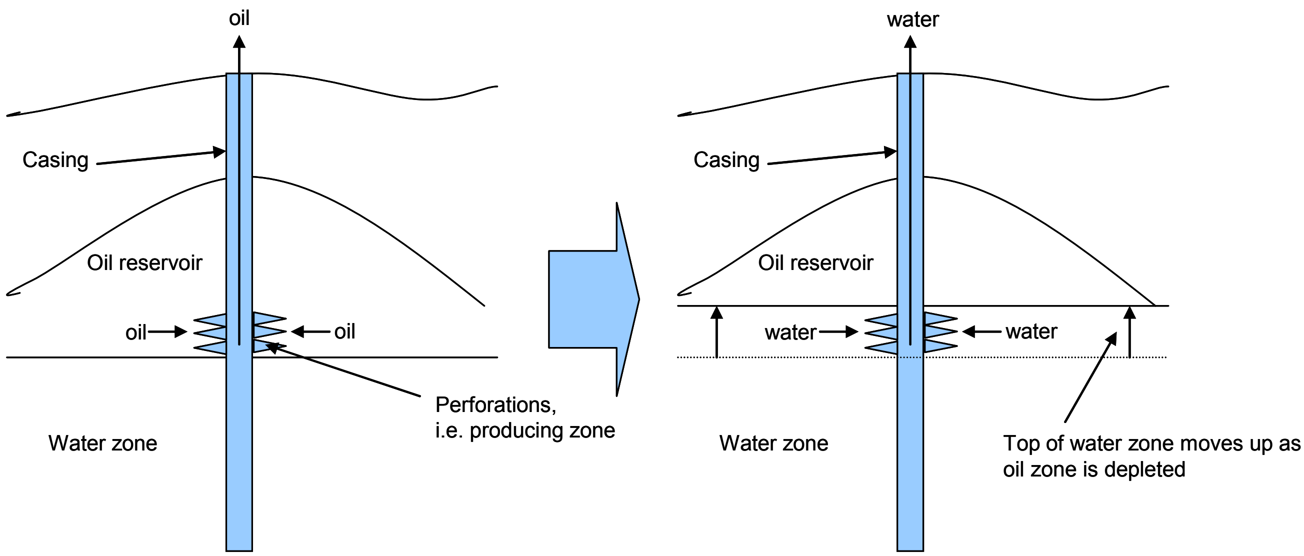
The final pipelay vessel worthy of specific mention here is the **flexlay** vessel, which is a subset of the wider subsea construction/infield development market (distinctly different from trunk-lay/heavy-lift, where typically only large diameter steel pipe is laid).

Extending the field life

As oil and gas is produced from a reservoir, so pressure may drop, sometimes surprisingly quickly. The problem with falling reservoir pressure is two-fold; flow rates fall and gas tends to break-out of the oil, with gas production increasing at the expense of the more valuable oil.

In addition, as the reservoir is depleted so the amount of water produced from the perforated zones will increase, implying a need to handle ever increasing amounts of unwanted water at the surface.

Figure 89: Rising water production as an oil reservoir is depleted



Source: Deutsche Bank

To maintain production at both optimum rates and mix, and to maximise the ultimate recovery factor of a reservoir, various solutions are possible:

- Drill more wells.
- Shut off lower water producing zones (via plugs set using wireline equipment).
- Install surface pumps – known as 'nodding donkeys'.
- Install down-hole pumps – ESPs (electric submersible pumps).
- Drill water or gas injection wells that help maintain reservoir pressure.
- Gas lift – install secondary tubing that allows gas to be pumped down the well to the reservoir level. This gas then commingles with produced oil, thereby lowering its density and helping it to flow to surface.
- Fracturing of the reservoir using large scale hydraulic pumps.
- Subsea processing (as discussed in the previous section).

Ultimately the goal of all the above factors is to increase the field's recovery factor.

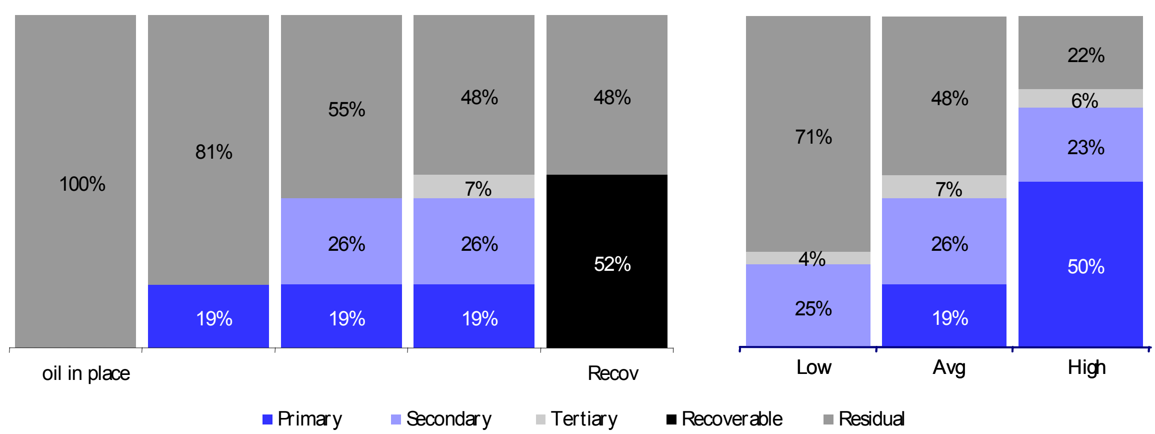
Recovery factors

When an oil and/or gas reservoir is produced, only a portion of the hydrocarbons initially in place is recovered to surface. Measured as a percentage of the in-place volumes, this is expressed as a **recovery factor**. A central focus within development is to maximize this factor. Three forms of recovery are recognized:

- **Primary recovery** - Uses only the natural energy of the reservoir, which in turn originates from burial of the reservoir units, and the natural buoyancy of both oil and gas in place.
- **Secondary recovery** – Involves adding energy to the natural system, for example by injecting water into the reservoir to maintain pressure and displace, or sweep, oil.
- **Tertiary recovery** - Includes all other methods used to maximize recovery.

Below we detail typical recovery factors within a reservoir – from oil initially in place (100%), through primary, secondary and tertiary recovery – this together recovering c.52% of oil initially in place. We also detail low and high scenarios around the 'average'. The buoyancy of gas means that recovery factors are materially higher (see below).

Figure 90: Typical primary, secondary, tertiary cumulative recovery factors and low-high range



Source: Deutsche Bank and Company data

Secondary and tertiary recoveries are together referred to as '**enhanced oil recovery**', or EOR. Over the following pages we briefly review primary recovery and a number of EOR techniques.

Primary recovery

The ultimate oil and gas recoveries observed in a field vary depending on the exact 'drive mechanism' that is in action. Four primary drive mechanisms are recognized:

- **Natural water drive** – Energy is provided via connection to an underlying pressurized aquifer which typically is many times the volume of the hydrocarbon reservoir. A pressure drop drives the expansion of both oil and water, resulting in a radial 'sweep' toward the production well.

- If the aquifer underlies the entire reservoir, the mechanism is described as 'bottom water drive', if just driven from the reservoir edge, it is described as 'edge water drive'.
- **Solution gas drive** – Also known as depletion drive, solution gas drive operates via the expansion of *dissolved* gas and liquid oil in response to a pressure drop – the change in volume driving production. In steep drilling reservoir units this mechanism is described as **gravity drainage**.
- **Gas cap drive** – Operates via the expansion of *free* gas in response to a pressure drop – gas cap expansion maintaining the pressure within the oil leg.
- **Compaction drive** – Energy for oil production is provided by the collapse of the rock's grain fabric and expansion of pore fluids when reservoir pressure drops.

In practice, most primary recovery is via a combination of these mechanisms, but generally speaking water drive is the most effective primary recovery mechanism for oil – primary recovery typically ranging between 25% and 40%, rising to 75%. For gas, gravity drainage, water drive and depletion drive can deliver recovery in excess of 80%.

Primary recovery rates typically ranges between 25% and 40

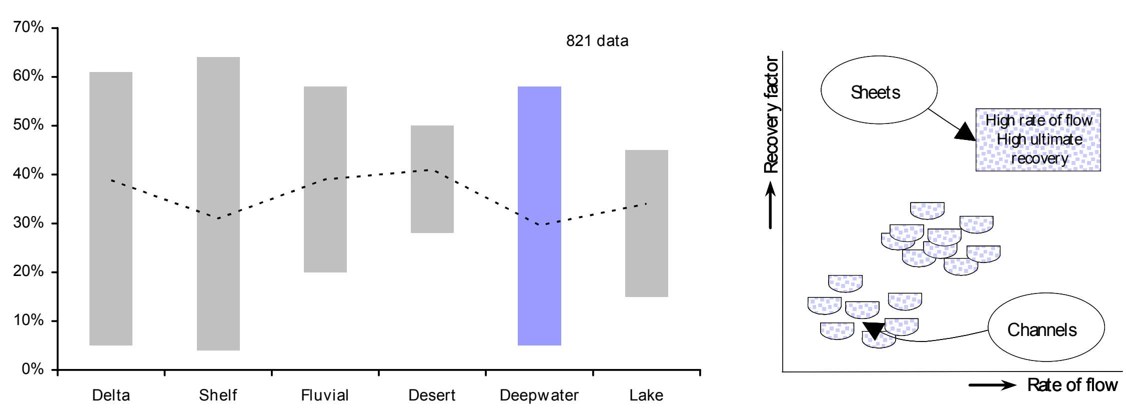
Depositional controls on recovery factor

Although deposition environment has a fundamental control on rock fabric, which in turn is one of the principle drivers of the way oil and gas is produced from rocks, commentators have found it difficult to prove statistically that depositional environment is a strong factor in determining recovery efficiency. This is evident in the chart below, where we present recovery factor data from 821 oil fields that produce from rocks deposited across a wide range of depositional environments.

However, within depositional environments, the spread in recovery can be related to some gross reservoir characteristics/geometries. By way of illustration we have focused on deepwater settings where observed recovery factors range from as low as c.5% up to c.60% - the average performance being c.30%.

At the gross reservoir scale, the lower end of the recovery range typically lies within laterally discontinuous, vertically poorly connected channelised deepwater systems. In contrast, laterally continuous sheet systems, characterized by sand-on-sand deposition, exhibit high recovery efficiency.

Figure 91: Recovery factor by depositional environment (dashed line average, bar shows range)



Source: Larue and Yue – The Leading Edge (2003), AAPG Explorer (2003), Deutsche Bank

Secondary recovery… waterflood

The principle method of secondary recovery is waterflood

The principle method of secondary recovery is **waterflood.** In waterflood, water is injected into one or more wells, arranged in a pattern that will maximize the displacement of oil toward a producer. At the production well oil only is initially produced.

However, as the front edge of the transition zone between the oil and water reaches the producer '**breakthrough**' occurs. After breakthrough, both oil and water are produced, and this '**water cut**' progressively increases, until the trailing edge of the transition zone is reached and only water is produced.

Tertiary recovery techniques

By altering the relative physical/chemical properties of reservoir liquids, EOR aims to increase recovery by maximizing displacement efficiency in a cost efficient way. Below we briefly summarize the principle EOR mechanisms which are currently employed.

- **Thermal EOR** is principally employed within accumulations of heavy oil – this being heated to reduce its viscosity and increase mobility. Common techniques include steamflood and cyclic steam injection - see section on oil sands.
- **Miscible liquid flooding** uses the principle that some fluids can mix with oil and therefore can be used to displace oil with no capillary resistance. Liquids used include methane, ethane, nitrogen and CO_2.
- **Polymer flooding** reduces the mobility of displacing water by increasing its viscosity. This is done to reduce instabilities in the oil-water flooding front – these resulting from water's mobility versus the oil it is being used to displace. This technique works best within high permeability reservoirs, and might be applied where high water cuts have developed in the late stages of waterflood.
- **Micellar floods** use **surfactants** to 'scrub' residual oil from pores by reducing interfacial tensions and creating emulsions of hydrocarbons and water.
- **Alkaline flooding**, also known as caustic flooding, uses NaOH or KOH to produce soap-like surfactants (see above). Given the relative availability of NaOH and KOH, caustic flooding is one of the cheapest EOR techniques.
- **Microbial EOR** remains experimental, but in theory harnesses micro-organisms together with a source nutrient, which when injected into the reservoir produce H_2, CO_2 and surfactants that together help mobilize the oil.

Oil Field Service Companies – where do they fit?

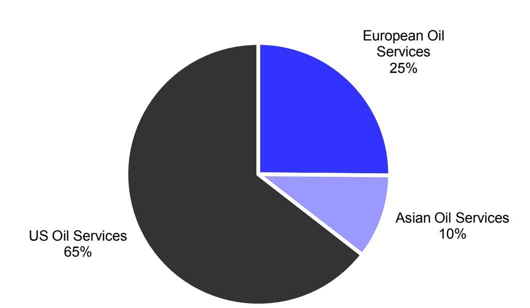
Throughout the latter half of the previous century and particularly during the oil price collapse and mega-mergers of the 1990s, IOCs sought to outsource the in-house ownership of services. This enabled the development of a specialised oilfield service industry, which today provides the majority of the technology (primarily assets and people) and innovation essential across the life cycle of an oil and/or gas development explained earlier in this chapter. The rationale for the outsourcing of service capability is built on sound industrial logic, and can be summarised in three key points;

- **Economies of scale** – Specialisation of companies in the service chain allows for intense competition among suppliers while further incentivising technical innovation that might not be the case from in-house ownership of services.
- **Capital efficiency** – A service company able to supply a wide range of clients (IOCs, NOCs, independents etc) would expect to be able to achieve higher rates of utilisation for their assets (e.g. drilling rigs) and therefore better return on capital employed than could an E&P limited by their own prospect inventory.
- **Accountability** – Having third-party supply of services arguably allows for increased accountability and efficient creation of reward structures between operator/contractor. Against this, however it could be argued outsourcing have frequently led to greater operational risk, execution delays and mis-pricing of contracts (a principal-agent and information asymmetries problem).

The service industry in context

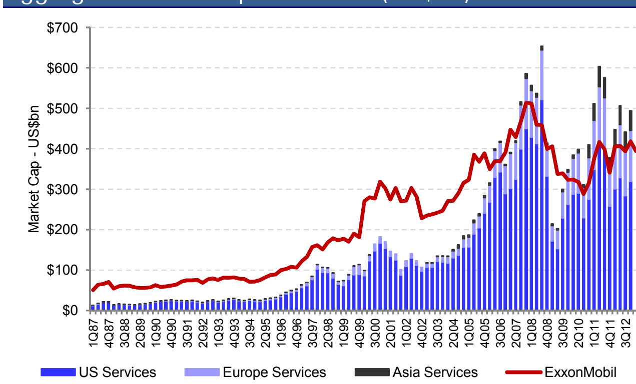
As the most mature oil & gas province, and one accounting for c60% of all wells drilled globally, the listed US service industry (more heavily involved in drilling & reservoir evaluation activities) dwarves that in Europe and Asia. Putting the industry in context, we estimate that the largest 75 service companies globally have an aggregate market capitalisation of cUS$475bn, of which c65% is US-listed, c25% in Europe and the remainder in Asia. The size and growth of the industry is perhaps neatly put in context when one considers that the value of the global listed oil service sector only recently surpassed the single largest E&P (ExxonMobil) in value (Figure 93). However it is worth pointing out that with the above 75 companies expected to account for cUS$350bn of revenues against what will be an anticipated US$620bn in upstream capital expenditure in 2012 (source: IEA), we are likely to be materially underestimating the current value of the overall activity servicing the oil & gas market.

Figure 92: Market cap split between the US, European and Asian oil service sectors (Dec/12)



Source: Deutsche Bank, Bloomberg Finance LP

Figure 93: Top 75 US, European and Asian Oil Service co aggregate market cap – absolute (US$bn) & vs. XOM



Source: Deutsche Bank

Global oil service chain – representative competitive landscape

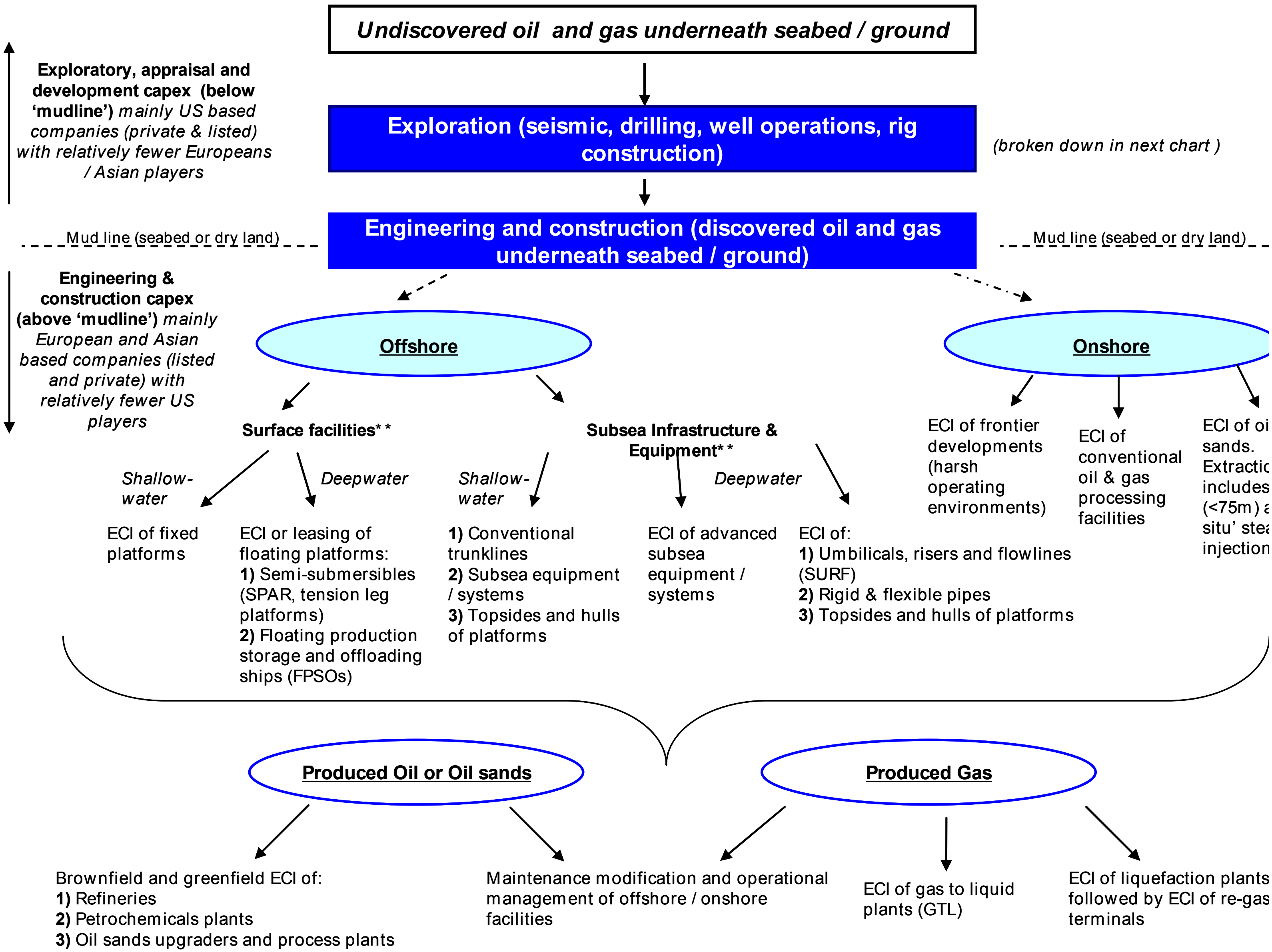
Below we have segmented the global service market by region, size (in terms of both market capitalisation and 2011 sales) and their positioning across the service chain.

Figure 94: Representative competitive positioning across the global oil service supply chain

				Exploration							Development			Production/Other		
				Seismic			Drilling contractors				EPC/EPCI					
COMPANY	Region	Market Cap ($mn)	2011A Sales ($mn)	Onshore	Offshore	Other	Onshore	Offshore	Well Services	Equipment	Onshore	Offshore	Eng. services	Asset Support	E&P	Non O&G
AKER SOLUTIONS	EUROPE	5,559	6,554						■	■		■	■	■		
ALLSEAS	EUROPE	NA	NA									■	■			
AMEC	EUROPE	4,903	5,301										■	■		■
CAPE	EUROPE	417	1,174											■		
CGG-VERITAS	EUROPE	5,254	3,152	■	■	■										
DOCKWISE	EUROPE	951	399									■				
FUGRO	EUROPE	4,778	3,399	■	■	■			■							
HEEREMA	EUROPE	NA	NA									■	■			
HUNTING	EUROPE	1,889	990							■					■	
LAMPRELL	EUROPE	398	1,148									■				
MAIRE TECNIMONT	EUROPE	172	3,489								■		■			
PETROFAC	EUROPE	9,125	5,801						■		■	■	■	■	■	
PGS	EUROPE	3,732	1,253		■											
PROSAFE	EUROPE	1,955	450											■		
SAIPEM	EUROPE	17,047	16,603				■	■			■	■	■			
SBM OFFSHORE	EUROPE	2,622	3,157									■	■			
SCHOELLER BLECKMANN	EUROPE	1,673	539							■						
SEADRILL	EUROPE	17,137	4,192					■								
SUBSEA7	EUROPE	8,350	5,477									■	■			■
TECHNIP	EUROPE	12,930	8,983							■	■	■	■			
TECNICAS REUNIDAS	EUROPE	2,586	3,445								■					
TENARIS	EUROPE	24,250	9,973							■						
TGS-NOPEC	EUROPE	3,373	609		■	■										
WOOD GROUP	EUROPE	4,407	5,667										■	■		■
VALLOUREC	EUROPE	6,505	6,982							■						
BAKER HUGHES	US	17,959	19,831	■	■				■							
BECHTEL	US	NA	NA								■	■	■			■
CAMERON	US	13,929	6,959							■		■				
CORE-LABS	US	5,100	908						■	■				■		
DIAMOND OFFSHORE	US	9,449	3,322				■	■								
FMC TECHNOLOGIES	US	10,210	5,099							■		■				
FOSTER WHEELER	US	2,579	4,481								■	■	■			■
HALLIBURTON	US	32,192	24,829						■	■						
HELMERICH & PAYNE	US	5,922	2,544				■	■		■						
McDERMOTT	US	2,599	3,445									■	■			
KBR	US	4,415	9,261								■	■	■			■
NABORS	US	4,196	6,152				■	■		■						
NATIONAL OILWELL VARCO	US	29,179	14,658							■						
NOBLE CORP	US	8,800	2,696					■								
OCEANEERING	US	5,804	2,193							■		■		■		
OIL STATES INT'L	US	3,927	3,479							■						■
PRECISION DRILLING	US	2,281	1,959				■									
SCHLUMBERGER	US	91,999	39,540	■	■	■			■	■				■	■	
TIDEWATER	US	2,226	1,055									■		■		
TRANSOCEAN	US	16,052	9,142					■								
WEATHERFORD	US	8,558	12,990						■	■				■		
CHINA OILFIELD SERVICES	ASIA-PAC	7,793	3,035	■	■	■	■	■	■			■		■		
CHIYODA	ASIA-PAC	3,697	3								■		■			
DAEWOO E&C	ASIA-PAC	3,863	7								■		■			■
DSME	ASIA-PAC	4,854	13									■				
EZRA HOLDING	ASIA-PAC	913	559									■		■		
GS E&C	ASIA-PAC	2,730	8								■		■			■
HYUNDAI E&C	ASIA-PAC	7,281	11								■	■	■			■
JGC	ASIA-PAC	8,017	5								■		■	■		
KEPPEL CORP	ASIA-PAC	16,198	8,254									■	■			■
MODEC	ASIA-PAC	1,003	2									■	■			
SAMSUNG E&C	ASIA-PAC	6,184	9								■	■	■			■
SAPURA-CREST KENCANA	ASIA-PAC	5,155	NA					■				■	■	■	■	
SEMBCORP MARINE	ASIA-PAC	7,865	3,242									■				
STX-OSV	ASIA-PAC	1,256	2,228									■				
SWIBER HOLDING	ASIA-PAC	304	654									■		■		
WORLEY PARSONS	ASIA-PAC	5,894	5,819										■	■		■
TOTAL (LISTED)		500,393	297,126													

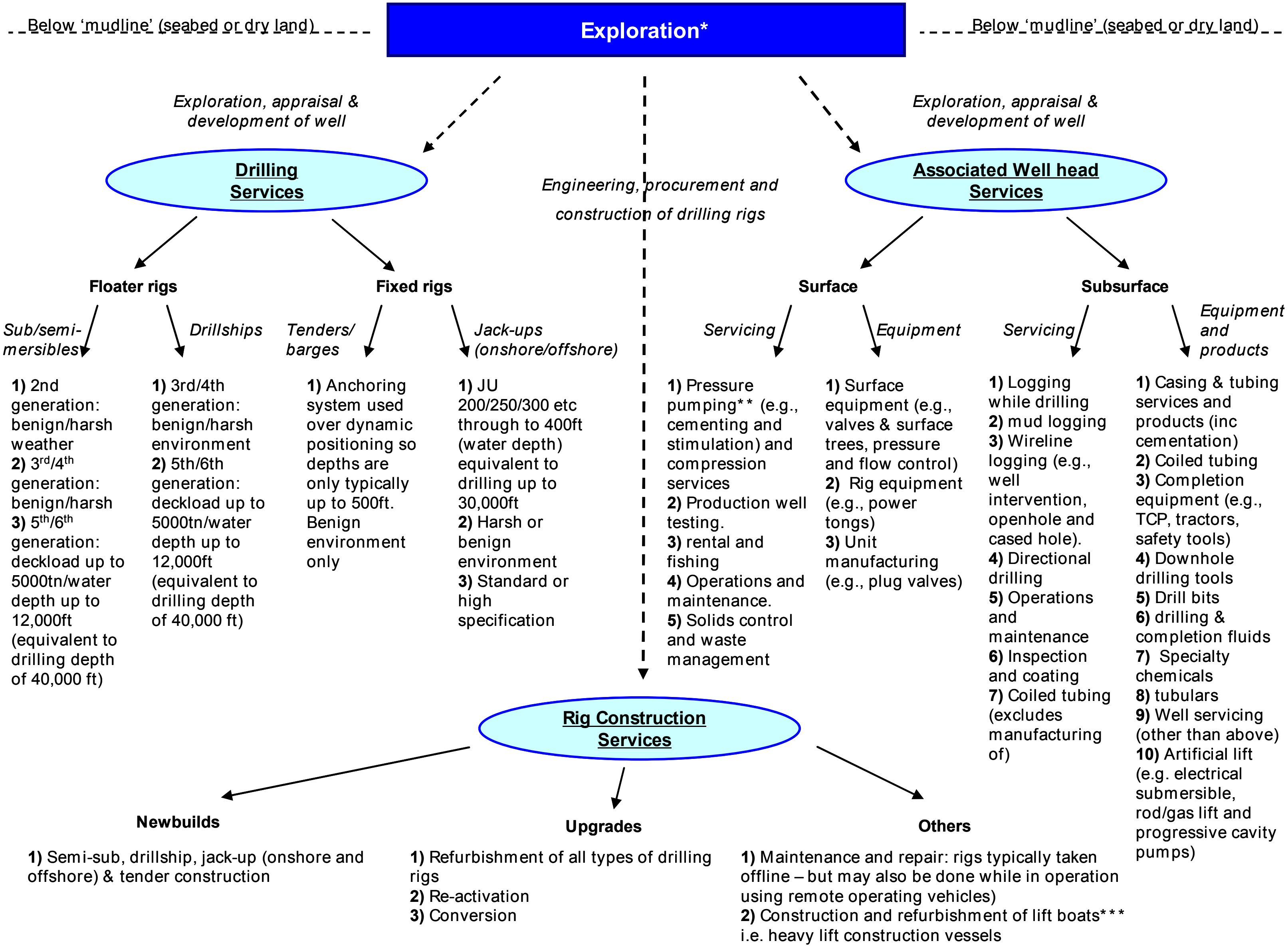
Source: Deutsche Bank Estimates, Datastream

Figure 95: Backbone functions of the service sector across the oil life cycle



Source: Deutsche Bank

Figure 96: Backbone functions of the service sector within exploration based activities



Source: Deutsche Bank

Key sector drivers & leading indicators

Service revenue is a function of the capital and operating expenditure of the E&P companies

At its simplest, the revenue of the oil service sector is a function of the capital and operating expenditure of the E&P companies, which is in turn governed by current and future expectations of the price of oil & natural gas. Clearly a number of other factors also matter (e.g. technological advances, weather, seasonal spending patterns, availability of finance, political unrest etc) but over time it is the supply/demand balance and market fundamentals which determine how incentivised companies are to invest.

There are a number of leading indicators that are widely used to gauge the outlook for demand across the oil service chain, five of which we summarise below:

- **Capex budgets** – Both IOCs and NOCs will typically begin formulating their capex budgets for the year ahead in the final quarter of the year. Many will then announce their forward spending plans to the market along with strategy days and final results. These tend to be closely watched as a leading indicator of future demand; albeit with history showing that in aggregate both IOCs and NOCs have tended to overspend, particularly in high oil price environments.

- **Rig counts** - Arguably the most closely watched measure of the level of demand for oil service content is the active rotary rig count, published weekly (US and Canada) and monthly (International) by Baker Hughes since 1944. When drilling rigs are active they consume products & services produced by the oil service industry, and hence the active rig count is considered the best leading indicator of demand for the products and services associated with drilling, completing, producing and processing hydrocarbons.

- **Day-rates** - Day rates for new rig contracts are often announced by the drilling companies, and can be easily monitored by industry observers. There are over 500 offshore working rigs in the world, typically working an average contract length of less than a year. The net result is a steady stream of new contract announcements each month that provide a valuable leading indicator of where industry costs and service company revenues are heading.

  Although less easily observable it is also possible to track trends through day-rate announcements for other less 'liquid' marine sectors, such as seismic vessels, supply boats, support vessels and installation/heavy-lift vessels.

- **Equipment orders** – A steady stream of new orders is the lifeblood of any manufacturing company, and it is no different with oil service sector. It is the convention for service companies to announce major equipment orders – rig orders, FPSO orders, subsea equipment orders and drilling packages are but a few examples that provide useful insights as to the level of demand across various parts of the service lifecycle.

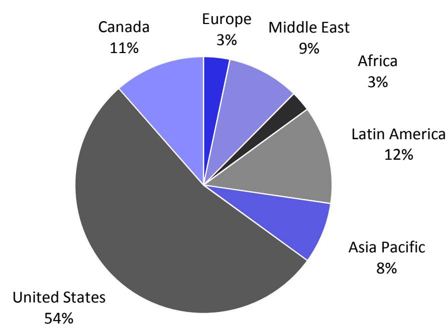
- **Backlogs** – Many oil service companies – primarily comprising the engineering & construction and drilling contractors – announce backlogs as a snapshot of the health of their businesses. Backlog is not an audited measure and its definition can vary from company to company but the general idea is to give an indication of the estimated value of as-yet unrecognised revenue. Depending on the type of work undertaken by the service company backlogs can have a shelf life from just a few months (typically in the case of equipment manufacturers) to well over two years (typically in the case of project-based E&C companies).

Below we outline in more detail the estimated size of the global oil service market and give an update/analysis of the recent trends seen in upstream costs.

Rig Counts

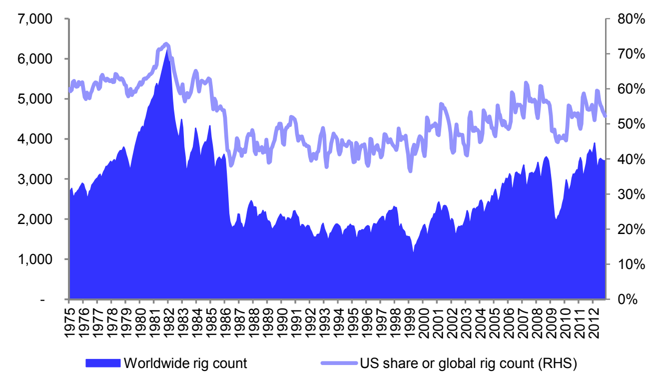
According to Baker Hughes, there are currently c3500 active rigs in operation globally. While representing a significant decline against the all-time recorded peak rig count at above 6000 in 1981, global rig counts have actually tripled in the past decade. Despite a decline in production over the period, the US has consistently accounted for c.50% of all global drilling activity over the period, with Latin America, Canada and Middle East the next most active regions over the past few years.

Figure 97: Split of global rigs - (2010-12 average)



Source: Deutsche Bank

Figure 98: Global rig counts & the US share of total

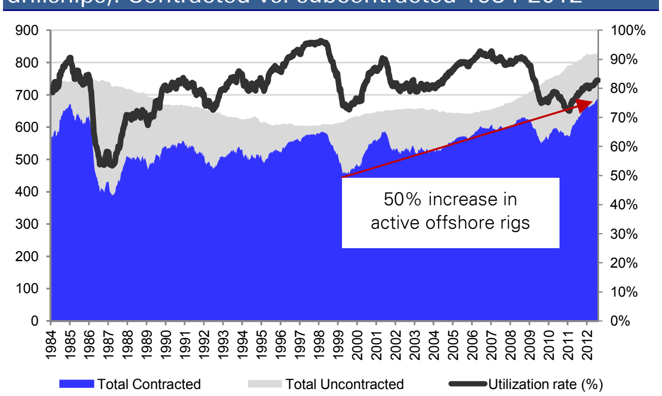


Source: Deutsche Bank

Day-rates

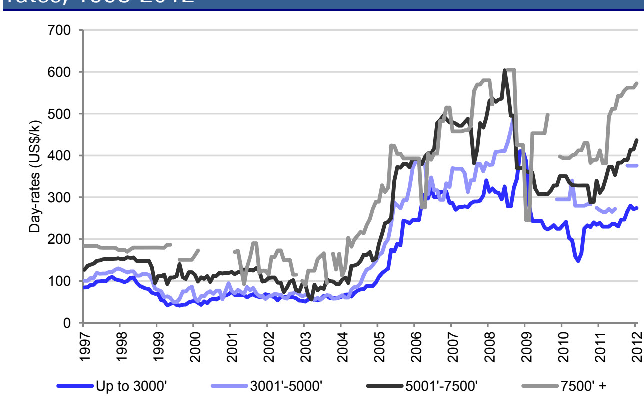
Drilling day rates behave as economists would expect; as demand outstrips supply so day rates quickly rise, and as soon as there is too much supply rates collapse. Through the prior cycle the long-lead time associated with bringing new capacity on stream set against the rapid rise in demand led to a c500% increase in deepwater day-rates. After a pause in 2009/10 as oil prices collapsed we have seen a rapid recovery in demand for all classes of rigs, driving day rates back towards record levels. The same drivers behind day rates tend to also drive the rest of the service industry supply/demand balance and hence when drilling day rates rise, so usually does the cost of all the other associated services – supply boats, helicopters, cementing, mud, wire-line logging etc.

Figure 99: Worldwide offshore fleet (jackups, semis, drillships). Contracted vs. subcontracted 1984-2012



Source: Deutsche Bank, ODS Petrodata

Figure 100: Deepwater and intermediate semi-sub day rates, 1998-2012

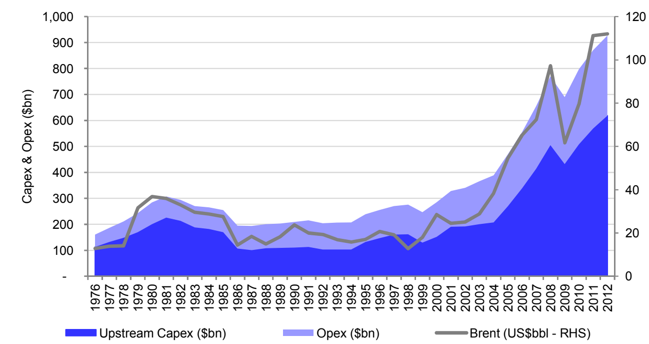


Source: Deutsche Bank, ODS Petrodata

Sizing the global service market

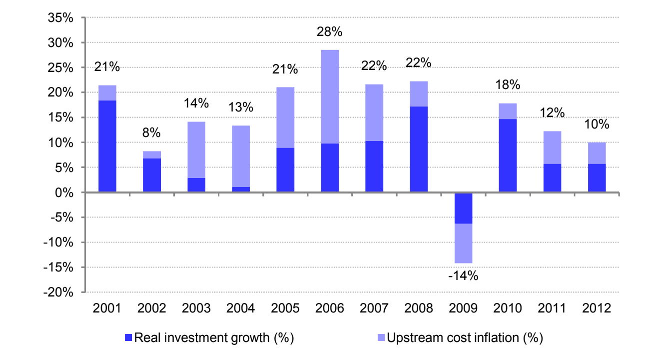
Data from the IEA suggests that upstream capex has grown c14% annually over the past decade, with growth rates peaking above 20% for four consecutive years prior to the financial crisis. After a brief pause in 2009 we have seen a further three years of growth with 2012 set to see an all-time record US$650bn spent on major exploration & development projects globally. While optically impressive, the IEA estimates that c.50% of the increase in nominal expenditure related to cost inflation rather than growth in underlying activity levels. The systematic increase in costs reflects a number of factors, including rising raw material costs and a tight supply-chain ill-equipped to cope with the massive surge in demand (this is discussed in greater depth later). Much of this was captured in the revenues and returns of the service companies.

Figure 101: Upstream capital and operating expenditure has rocketed over the past decade



Source: Deutsche Bank, IEA WEO 2012

Figure 102: However, c50% of the increase relates to cost inflation rather than real growth in activity

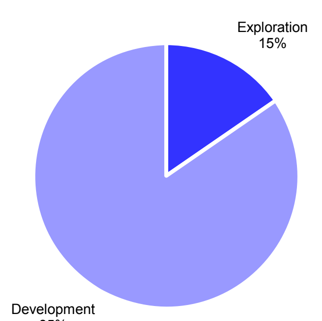


Source: Deutsche Bank, IEA WEO 2012

Where is the money being spent?

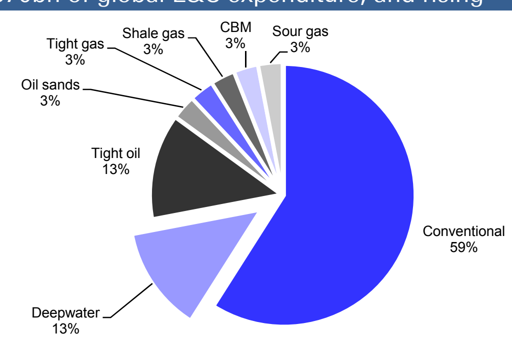
Of the US$650bn expected to be spent on upstream oil & gas exploration and development projects in 2012, we estimate that c15% relates to pure exploration. Within the larger development market conventional developments are expected to remain the largest area. However, investment in unconventional resource has outpaced that in conventional over the past few years, with high and rising investment in both deepwater (13%) and more recently US tight oil (13%) leading the way.

Figure 103: Development is the lions-share of global upstream capex



Source: Deutsche Bank

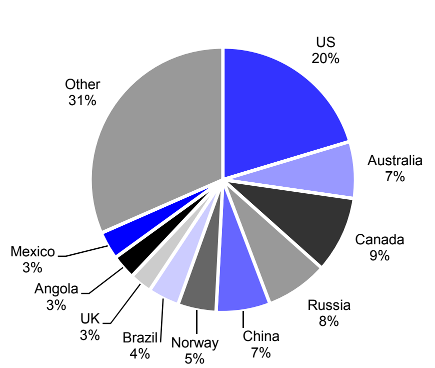
Figure 104: Deepwater accounts for broadly 15% or US$70bn of global E&C expenditure, and rising



Source: Deutsche Bank

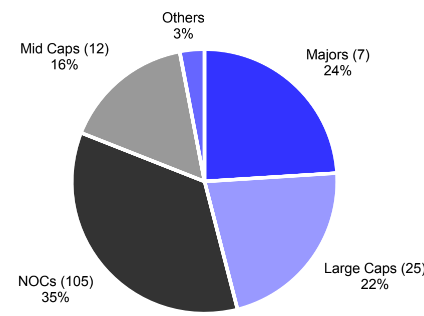
Global E&C spend is relatively diverse geographically, with the US accounting for ~20% of global development capex between 2010 and 2012, lagged by Canada, Australia, Russia, the UK/Norway, China and Brazil. In terms of the operator mix it is expected that majors & large-caps will account for half of all global E&C spend, trailed by the major global NOCs (c35%) and then mid/small-caps.

Figure 105: Global E&C spend by country, 2010-12e



Source: Deutsche Bank

Figure 106: Global E&C spend by client type



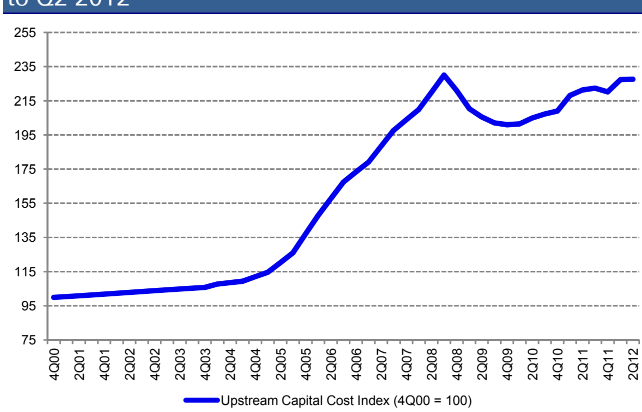
Source: Deutsche Bank

So what is in the cost of a barrel of oil?

The cost of the various field operations has been very much in the limelight over the last few years. Stories of the over-heated services market in Canada or of capital over-spend on complex projects such as ENI's Kashagan abounded in the run-up to the financial crisis. After brief delay to FID of projects in 2009/10 these concerns have again re-surfaced over the past couple of years as oil prices and activity levels have recovered.

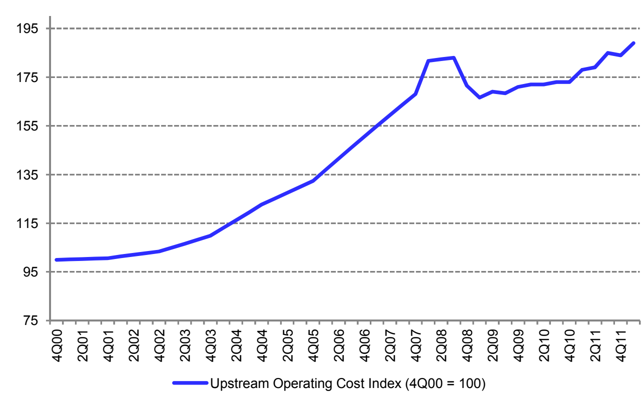
This perspective on rising costs is generally corroborated by third-party indices and bottom-up analysis of the IOC cost bases; a glance at average finding and development costs at the IOCs or at IHS-CERA's upstream cost indices highlights that between 2004 and 2008 capital and operating costs in the oil and gas industry more than doubled, with both further suggesting a return to peak costs has been swift following the dip in 2009.

Figure 107: IHS/CERA upstream capital cost index – 2000 to Q2 2012



Source: CERA, Deutsche Bank estimates

Figure 108: IHS/CERA upstream operating cost index – 2000 to Q2 2012



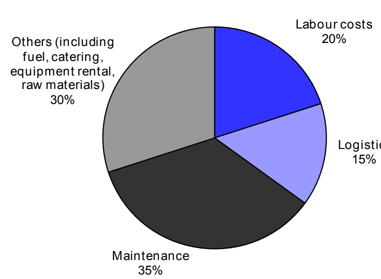
Source: Company data, Deutsche Bank estimates

In order to understand the drivers of this increase we must first understand exactly what the costs incurred in extracting a barrel of oil are. Excluding taxation (considered later on) the three key cost components are **exploration**, **capital** and **operating costs**.

- **Exploration –** the cost of finding resources. Also referred to as finding costs, it includes signature bonuses, seismic and exploration and appraisal drilling, as well as the cost of employees involved in exploration. In terms of accounting exploration costs are generally expensed if the well is unsuccessful but can be capitalised if the well is found to be successful for development.
- **Capital (or development costs) –** these are generally the largest component of the cost base and comprise such things as the engineering & project management, procurement of materials, construction and drilling. Capital costs are effectively the equivalent of FAS 69 development costs and can be capitalised on the balance sheet and depreciated in line with production.
- **Operating Costs –** these are the day-to-day operating expenses and comprise such costs as consumables (e.g. fuel, gas and chemicals used in the extraction of oil and/or gas), aircraft to fly staff to/from the rig, catering on the rig, transportation and other day-to-day maintenance of vessels. Accounting wise operating costs are expensed to the P&L in the period in which they are incurred.

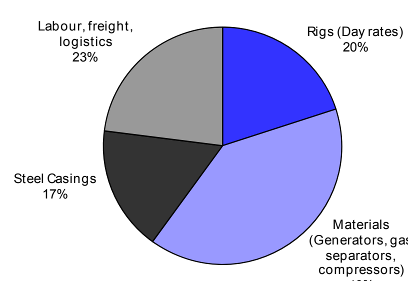
In an ideal world one would be able to get a good idea of the exact composition of both capital and operating costs. However, due to limited disclosure this industry is not one that lends itself easily to analysis. As illustrated below, the nature of costs vary significantly both by geography and development type of development.

Figure 109: Average OPEX split in Europe



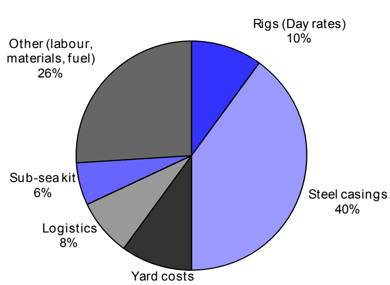
Source: RDS, Deutsche Bank Estimates

Figure 110: Average OPEX split in US onshore



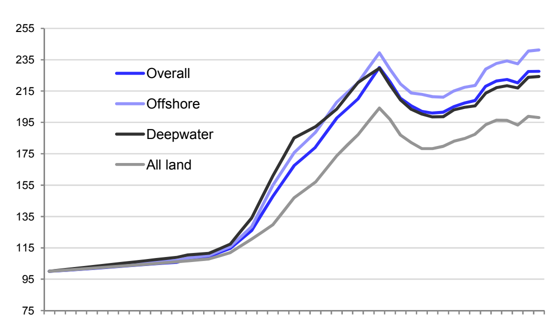
Source: RDS, Deutsche Bank Estimates

Figure 111: Average OPEX split in US offshore



Source: RDS, Deutsche Bank Estimates

Figure 112: CERA capital costs index by project type



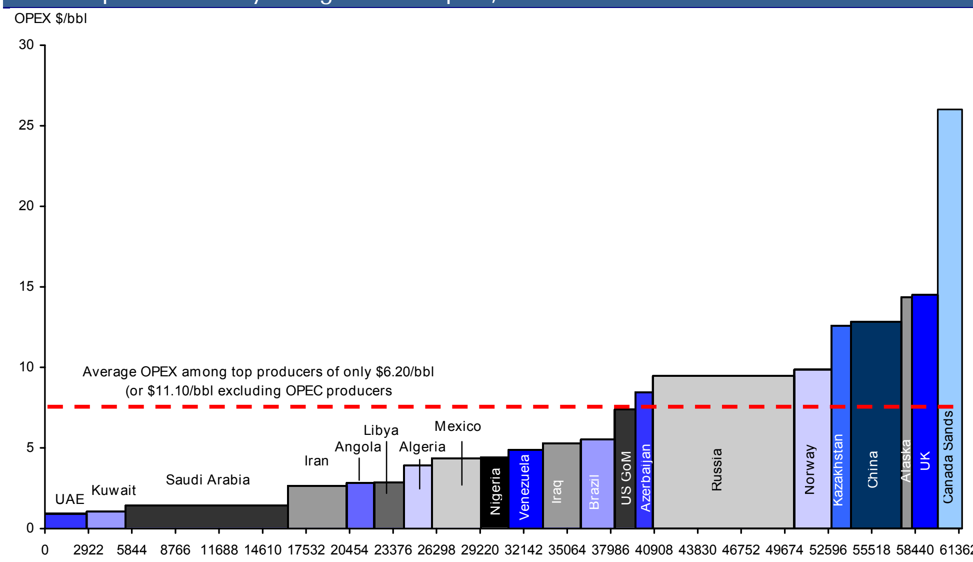
Source: CERA, Deutsche Bank estimates

How much does it cost to extract a barrel of oil?

In terms of cash operating costs to keep a field producing once it is on-stream, we present below an analysis we conducted using Wood Mackenzie's country-by-country database showing an estimate of the weighted average cash operating cost by country against 2009 production. What is immediately evident is that cash operating costs are higher in the more mature and/or complex regions, while OPEC has by far the lowest operating costs.

This is not surprising given the mature, non-growth regions are faced with declining production on infrastructure that was designed to handle higher volumes of production. Equally, lower costs and cost inflation in the Middle East in particular are not surprisingly given this is a growth region with often huge, lower complexity and readily accessible fields with good surrounding infrastructure. Shown below we estimate that in 2009 average cash operating costs excluding royalties amongst the world's top producing regions were only $6.20/bbl (or $11.10/bbl if OPEC territories are excluded).

Figure 113: Estimated OPEX cost of production ($/bbl) across major territories (where OPEX is predominantly lifting and transport)



Source: Wood Mackenzie GEM, Deutsche Bank estimates

Of course, the above only focuses on the operating costs associated with extracting a barrel of oil from different geographic territories. Add in the capital costs associated with exploration and development (c$20/bbl globally), taxation (average 67% rate globally) and expected return on investment (c15%) and the actual cost of developing a new green-field barrel of oil is significantly higher.

Indeed, looking at the growth projects that are expected to provide the basis for future supply and our analysis of the major growth regions not least US unconventionals, the US GoM, Brazil, Nigeria and Angola suggests that at present an average oil price of over $80/bbl is required for projects to deliver an above cost of capital return to the partners. This is not dissimilar to the $100/bbl suggested by OPEC as being 'fair'.

So what drove the increase in costs?

We believe the following factors constitute the key drivers of the oil and gas industry cost base and were pivotal in the rise and fall of the cost of producing oil:

Complexity of projects – given the various difficulties in accessing resource, IOC's have increasingly pushed into ever more complex projects such as deepwater, GTL, oil sands as well as ever harsher environments. This has led to longer development timelines and increased costs to develop the necessary technology and get the project operational. Below we show that the average delay to execution of major FPSO-based projects currently on-stream over the past decade at c25% (in-line with commentary from ENI).

Figure 114: A survey of major FPSO projects yields an average ~25% delay to original project schedules

Unit Name	Owner/Operator	Region	Type	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Execution	Delay to execution	Total time
Atlantis	BP	US GOM	FPSS												5	1	6
Cidade de Vitoria	Petrobras	Brazil	FPSO												2	1	3
Front Puffin	Sinopec	Australia	FPSO												2	1	3
Independence	Anadarko	US GOM	FPSS												5		5
Kikeh FPSO	Murphy	Malaysia	FPSO												4		4
Kikeh Spar	Murphy	Malaysia	SPAR												4		4
P-52	Petrobras	Brazil	FPSS												2	2	4
P-54	Petrobras	Brazil	FPSO												4		4
Piranema	Petrobras	Brazil	FPSO												3	1	4
Plutonio	BP	Angola	FPSO												2	2	4
Polvo	Devon Energy	Brazil	FPSO												3		3
Yulum K'ak'naab	Pemex	Mexico	FPSO												2	1	3
Agbami	Chevron	Nigeria	FPSO												3	1	4
Alvheim	Marathon	Norway	FPSO												4	1	5
Armada Perkasa	Afren	Nigeria	FPSO												2		2
Cidade de Rio das Ostras	Petrobras	Brazil	FPSO												2	1	3
Corvina	BPZ Energy	Peru	FPSO												1	1	2
Dhirubhai 1	Reliance Industries	India	FPSO												2		2
Blind Faith	Chevron	US GOM	FPSS												3	1	4
Gimboa	Sonangol	Angola	FPSO												2	1	3
Hai Yang Shi You 115	CNOOC	China	FPSO												3	1	4
Hai Yang Shi You 116	CNOOC	China	FPSO												3	1	4
Hummingbird	Venture	North Sea	FPSO												3	1	4
Moho Bilondo	Total	Congo	FPSO												3	1	4
Mondo	Exxon Mobil	Angola	FPSO												2	2	4
Neptune	BHP	US GOM	TLP												3	1	4
Ngujima-Yin	Maersk	North Sea	FPSO												3		3
P-51	Petrobras	Brazil	FPSS												2	3	5
Rubicon Intrepid	Otto Energy	Philippines	FPSO												2	1	3
Rubicon Vantage	Salamander Energy	Thailan	FPSO												2		2
Saxi-Batuque	Exxon Mobil	Angola	FPSO												3	1	4
Song Doc Pride	Petronas	Vietnam	FPSO												2	1	3
Stybarrow Venture	BHP Biliton	Australia	FPSO												4		4
Thunder Horse	BP	US GOM	FPSS												4	4	8
Akpo	Total	Angola	FPSO												3	2	5
Armada Perdana	ENI	Nigeria	FPSO												1	1	2
Azurite Marine	Murphy	Congo	FPSO												3		3
Cidade de Niteroi	Petrobras	Brazil	FPSO												2	1	3
Cidade de Sao Matheus	Petrobras	Brazil	FPSO												2	1	3
Cidade de Sao Vicente	Petrobras	Brazil	FPSO												1	1	2
															108	38	146
																Average delay	26.0%

Execution
Execution delay

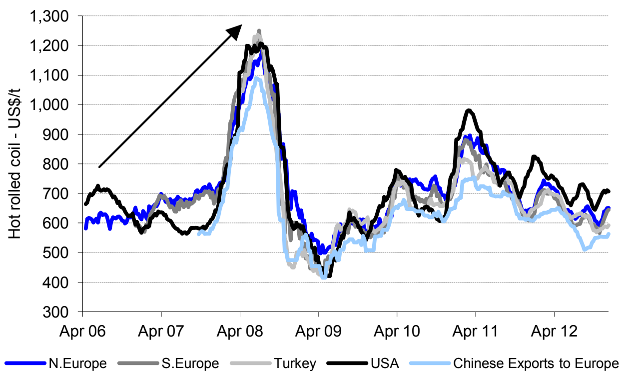
Source: Deutsche Bank

Service contracts – with supply limited but demand high, service companies generated increasing pricing power and were hence able to negotiate increasingly favourable contract terms. This passed on the rising risk of cost inflation (of consumables, labour, FX-risk etc) to the operators. Our bottom-up analysis suggests that cost plus contracts increased from c.20% of contracts signed in 2005 to nearer 30% in 2007.

Increased competition – at the same time that oil and gas enjoyed a period of investment growth so too did other industries, many of which use similar services and materials such as construction, metals and mining and shipping. The price of consumables such as fuel, gas and chemicals used in producing oil and gas, the price of steel (as shown below), even global food prices such as corn, rice, wheat (this would impact on catering costs in rigs) all rocketed through the period on increased demand from a number of sectors.

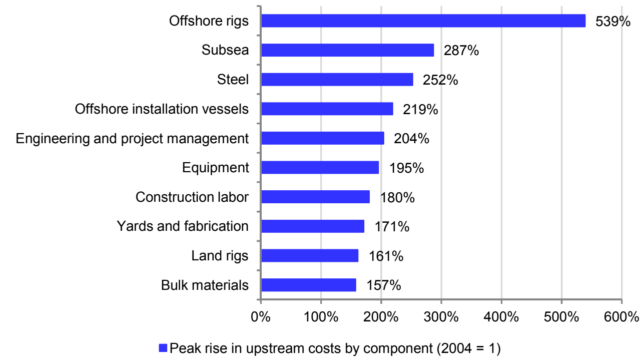
Tight services industry – this surge of interest in developing projects such as the Canadian oil sands meant the services industry grappled to keep up with demand. The clearest sign of a tight supply/demand balance is usually in the offshore markets, as evidenced by the c5x increase in deepwater day-rates (see previous section on day-rates).

Figure 115: Steel prices surged on high demand increasing the cost of rig/pipe construction



Source: CRU, Deutsche Bank estimates

Figure 116: Trough to peak rise in upstream capital costs by component (2004-2012)



Source: Baker Hughes, Deutsche Bank estimates

- **Labour shortage –** following major redundancies and outsourcing of in-house services through the oil price collapse and mega mergers of the late 1990s, most IOCs unexpectedly found themselves suffering from a shortage of experienced employees at a time when the industry embarked on a period of price-driven investment. In order to attract and re-train experienced engineers from other industries, higher salaries were often offered. For example the American Association of Petroleum Geologists indicates that the average annual salary for a geologist with 20-24 years experience went from $113k in 2005 to nearer $167k in 2008 i.e. annual growth of 14%.

  More recently a focus on local content and strict permitting laws in regions where development activity is highest (e.g. Brazil, Australia) has seen pockets of salary cost inflation return. We note for instance local content regulations and the shortage of qualified Oil & Gas labour in Brazil having driven c30% per annum increase in the salaries of qualified domestic labour to US$120k/annum, only a touch below that currently earned by qualified oil & gas labourers in the US.

Figure 117: Average dollar-denominated salary of Oil & Gas workers in different regions

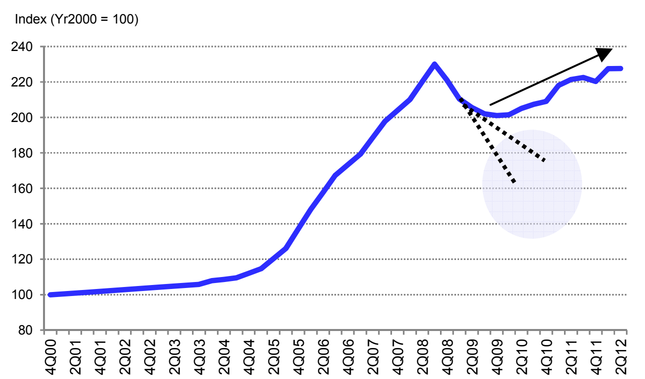
Local labour ($)	2010	2011	2012	2011/10	2012/11	Import labour ($)	2010	2011	2012	2011/10	2012/11
Algeria	33,800	42,900	40,600	27%	-5%	Algeria	107,800	93,400	89,200	-13%	-4%
Angola	53,600	33,500	48,400	-38%	44%	Angola	118,900	108,500	107,700	-9%	-1%
Australia	138,100	143,700	164,000	4%	14%	Australia	133,700	144,600	173,100	8%	20%
Brazil	72,500	99,500	119,600	37%	20%	Brazil	125,200	99,500	106,700	-21%	7%
Canada	112,800	129,900	128,700	15%	-1%	Canada	112,500	111,400	123,300	-1%	11%
China	51,600	49,400	55,700	-4%	13%	China	102,900	109,900	143,700	7%	31%
Indonesia	32,000	41,800	45,000	31%	8%	Indonesia	136,300	125,000	157,200	-8%	26%
Iran	37,300	40,900	52,200	10%	28%	Iran	89,300	83,400	93,900	-7%	13%
Iraq	32,600	21,700	36,900	-33%	70%	Iraq	N/A	94,800	131,000	nm	38%
Kazakhstan	30,700	32,400	39,700	6%	23%	Kazakhstan	88,100	129,400	128,500	47%	-1%
Libya	46,000	42,300	44,100	-8%	4%	Libya	78,700	87,400	69,200	11%	-21%
Norway	114,700	130,300	180,300	14%	38%	Norway	101,000	119,800	122,800	19%	3%
Russia	65,600	63,000	59,100	-4%	-6%	Russia	105,700	127,800	138,200	21%	8%
Saudi Arabia	67,600	61,200	102,900	-9%	68%	Saudi Arabia	86,400	65,200	67,100	-25%	3%
Singapore	56,700	66,300	79,700	17%	20%	Singapore	102,900	98,500	99,300	-4%	1%
United Kingdom	92,200	86,700	87,100	-6%	0%	United Kingdom	94,200	76,300	80,900	-19%	6%
USA	117,900	117,000	124,000	-1%	6%	USA	128,100	110,700	119,200	-14%	8%

Source: Hays Oil & Gas Salary Guide 2010, 2011, 2012

Where to from here?

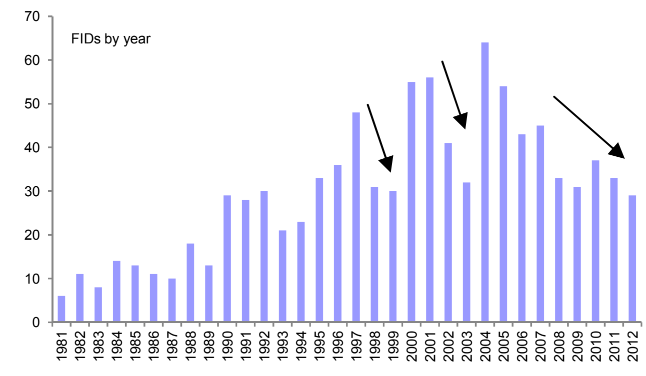
Although costs did initially fall from the peaks of 2008 as oil prices declined and FIDs were delayed, they have since quickly rebounded. Indeed, CERA cost-indices suggest that upstream capital costs have already surpassed the peaks seen during the previous cycle. Looking ahead, leading edge cost indicators suggest that despite the decline in FIDs seen over the past couple of years, costs are continuing to rise (leading edge day-rates having trended well above current averages and clear signs of bottlenecks emerging in the supply of skilled labour and certain equipment). With projections for further growth in activity levels, this would seem unlikely to abate near-term and is generally supported by bullish commentary around pricing from the service companies.

Figure 118: Harsh reality – declined only a modest 12% and have already risen beyond previous peaks



Source: IHS- CERA

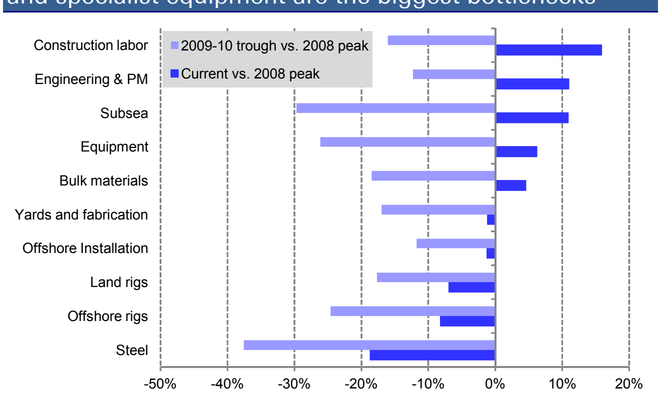
Figure 119: The sharp rise in costs has again led to a decline in the number of FIDs taken



Source: IHS-CERA

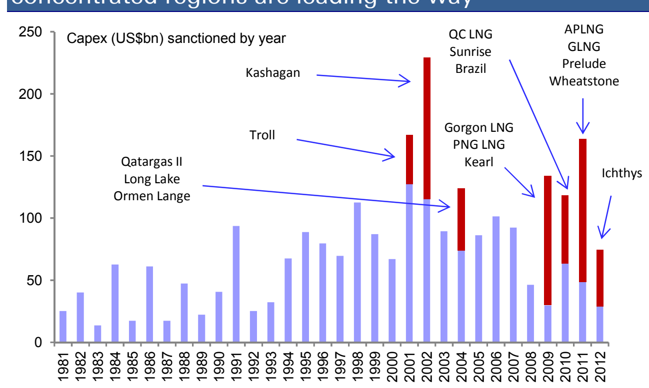
Digging deeper suggests forward cost inflation could be fairly broad-based, with particular pinch-points emerging for skilled labour and specialist equipment. Figure 115 shows the current cost index for sub-segments relative to their respective peak during the previous cycle (in blue) and their peak-to-trough decline during the 2009 downturn (in purple). It suggests that the areas where the supply chain has tightened fastest are those for labour and skilled engineers/project managers. With a contemporaneous reduction in global industrial activity over the period, steel and bulk materials have seen only modest recovery. 'Contracted' services – rigs and installation vessels – are seeing a slower recovery (reflecting average pricing), but continue to see positive price pressure.

Figure 120: Capital costs relative to 2008 peak – labour and specialist equipment are the biggest bottlenecks



Source: CRU, Deutsche Bank estimates

Figure 121: Capex sanctioned by year – mega projects in concentrated regions are leading the way



Source: Deutsche Bank, Wood Mackenzie

The FID data shown above largely reflects the trends that one might expect; as costs have continued to rise, the volume of FIDs taken has continued to fall (Figure 119). Costs are key; although the trend was exacerbated by the economic downturn, through 2008/9 we saw the number of FIDs taken by the industry fall back even at a time when the oil price was strongly rising.

On the one hand, the persistent decline in FID volumes (which peaked in 2004) could suggest that service sector backlog has peaked and that costs may begin to moderate, to the benefit of the operators. However this ignores a few key facts:

Firstly while the absolute *number* of FIDs has fallen since 2007, the value of the projects sanctioned has risen substantially. Indeed the aggregate value of 101 projects sanctioned in 2009-11 was 66% higher than those in the three prior years despite c20 projects less having made FID. The shift to fewer, larger projects is seen in the fact that 65% of developments sanctioned over the past four years relate to just 11 mega-projects (US$10bn+), seven of which were major Australian LNG projects – incidentally also a region currently seeing delays to FID of further projects.

Secondly, FID data explicitly excludes global spending on unconventionals. As a subset within this we note that investment in developing US tight oil reserves is expected to hit US$70bn in 2012 (from virtually nothing just a few years prior). One could also argue that capex associated with the monetisation of many standalone satellite fields through additional development drilling and subsea tie-backs – c.US$30bn in 2012 – are also not properly captured by the field FID data shown above.

The implication of this is that FID data materially underestimates the actual level of capital being committed to development activity by the industry. In this respect we may continue to see the volume of FIDs taken moderate, but costs continue to rise.

Are there any reasons to be optimistic?

Although we do see costs continuing to rise, we think it is unlikely that the industry as a whole will see a return to peak rates of inflation seen during the 2005-08 period (consistently above 10%). This is a function of the following observations:

- **Engineering intensity** – Operators are spending proportionately more time and capital in front-end engineering and the in-sourcing of project management. This may be already evident in the higher inflation in these areas, as shown in Figure 120. A strong body of evidence suggests that spending more at the front-end improves the ultimate project economics through reduction in scope for delays and cost overruns further down the line.
- **Contracting strategies** – Many major IOCs have been more active in signing up service capacity on longer-term framework or global service agreements where supply is more visible and the scope for an expansion in service margin is limited.
- **Increased capacity** – The growth in demand seen over the prior cycle spurred a construction cycle that will see many new-builds entering the market over the coming decade. Against this it is unclear how much of this capacity will be immediately absorbed by the market, or is replacing older and now defunct kit (and hence is not a net addition to global fleet).

Over the near and medium-term it would seem logical that costs will continue to rise. Ultimately, however, economics dictate that over the long-run they must move in line with the oil price.

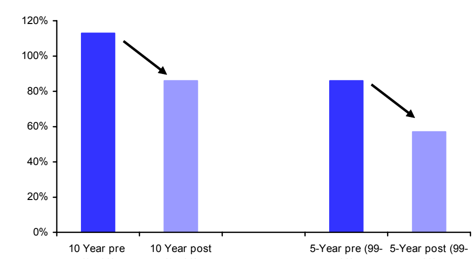
Oil & Gas reserves

A cautionary tale

In January 2004, Royal Dutch Shell stunned investor's by informing them that through inappropriate bookings over several years it had significantly overstated its proven oil and gas reserve base. At a stroke the company wiped out 3.9bn barrels or 20% of its previously reported proven oil & gas reserve base. Investors responded by marking the shares down by 8%, so removing around US$15bn from the company's market value.

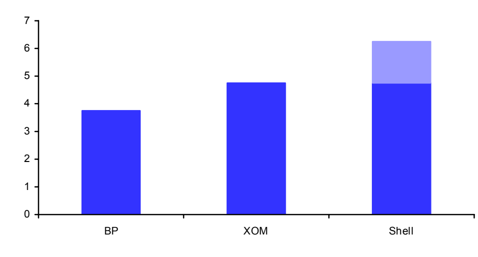
But where did the reserves go and how could almost 4 billion barrels of oil equivalent be there one day and not the next? Equally, how could a company of Shell's stature get its estimates so wrong? The answers largely came down to definitions of what can and cannot be considered a proven oil reserve under SEC definitions and the flexibility that companies have in interpreting those definitions. Of course, the oil resource was still there. It had not disappeared. However, for whatever reason Shell had inappropriately booked substantial resources as proven reserves for a number of years and in doing so conveyed an inaccurate picture of the company's exploration success and potential for growth over much of the previous decade. Almost overnight, understanding what could and could not be treated as a proven SEC reserve became a major industry issue with the credibility of ratios that had long been central to valuing an E&P business thrown into question. Put bluntly, oil & gas reserve accounting gained new prominence.

Figure 122: Shell reserves replacement ratios pre & post restatement



Source: Shell

Figure 123: Shell reserves restatement increases F&D costs/boe ($ 2003)



Source: Shell

A company's lifeblood

In many respects a company's reserves are representative of its lifeblood

In many respects a company's reserves are representative of its lifeblood. Oil discovery and production is after all what most exploration businesses are all about. The reserves statement is thus key to providing a view of the as yet un-depleted assets of the company and as such the potential for a company's future growth. It also affords a strong and yet potentially misleading representation of the extent to which a company's exploration efforts have met with success in any one year i.e. expressed as a percentage of current year production it illustrates both the extent to which the oil & gas reserve base of the company has been replenished over the preceding year and, by taking reserves in their entirety, how many years the current rate of production could be sustained for. At the same time, reserve recordings are also important to reported profitability. This is because oil companies amortise their production assets on a unit of depletion basis. Thus the greater the barrels of oil (or units) associated with an investment project (e.g. the reserves booked), the lower the level of amortization per unit of production.

Estimating reserves depends on technical & commercial considerations

Reserves estimates are fundamental to the value of company, but rest on inherent technical and commercial uncertainties. As a result, the process of definition, estimation & disclosure is regulated.

On the face of it, the recording and reporting of reserves data would seem fairly straightforward. A company explores, it discovers and it records the quantity of reserves found. It then amortises the cost associated with the discovery and exploration spend on those reserves on a unit of production basis. However, because determining the amount of oil and gas discovered, let alone its recoverability involves, amongst others, estimates of field size, rock porosity, rock permeability and fluid type, expressing the recoverable amount is by its very nature uncertain. Add to this uncertainty surrounding the economics of its extraction (i.e. at current prices is it economic to produce) and it is not hard to see that reserves accounting has the potential to be a very inexact science.

Yet because reserves are so fundamental to the value of a company investors need to have confidence in the estimate. Inaccuracies and both the sustainability and profitability of a company may be misstated. With this in mind and in an effort to protect investors, guidelines have been laid down by various regulatory bodies on reserves accounting with various definitions accorded to reserves dependent upon their status and the probability of their recovery. It is these guidelines, most significantly those that must be adhered to for compliance with the US SEC, that form the basis of today's reserve statements.

'Reserves' are defined by both SPE and SEC

So how are recoverable reserves defined? Clearly, the absolute level of reserves in a given field and their recoverability will never be known until production reaches the economic limit and the reservoir is abandoned. Any reserves estimate is thus almost certain to be inaccurate. With this in mind, the objective of the guidelines and requirements on reserves reporting is to provide investors with a realistic but, if anything, conservative estimate of available reserves.

Reserve definitions tend to focus on those guidelines provided by both the SEC and the Society of Petrochemical Engineers or SPE

From an industry standpoint, definitions and industry parlance tends to focus on those guidelines provided by both the SEC and the Society of Petrochemical Engineers (SPE). Some knowledge of both is therefore necessary. However, as mentioned previously, most significant for investors and, as a consequence, companies are those laid down by the SEC not least given that use of the SEC's definitions is obligatory under US reporting requirements. These tend to be more conservative in their approach, although after years of criticism on what was considered by many as their antiquated requirements, the agency recently updated their requirements to try better reflect technological developments within the industry.

The industry view: SPE definitions – Reserves & Resources; Proven, probable and possible

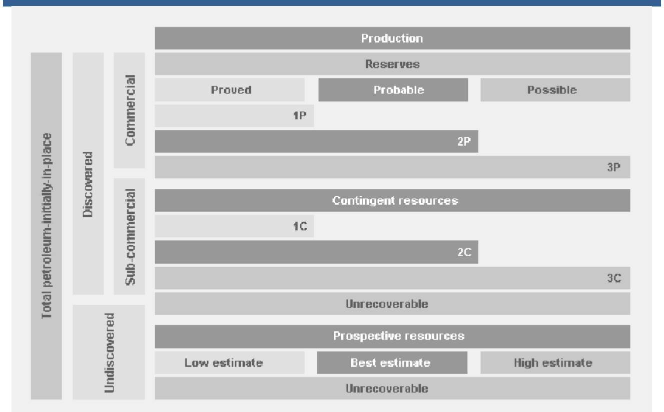
The SPE outlines a framework for defining volumes based on probabilistic assessment of potential size and an assessment of commercial & technical maturity (i.e. reserves and resources).

Whilst we have stated that it is the SEC definitions that are most important in determining *reported* recoverable reserves, the SPE definitions which are based on a more probabilistic approach are also important, not least as prior to the revisions performed by the SEC in 2009 the industry viewed SPE definitions as presenting a better representation of the reserves that might more realistically be recovered.

Reserves

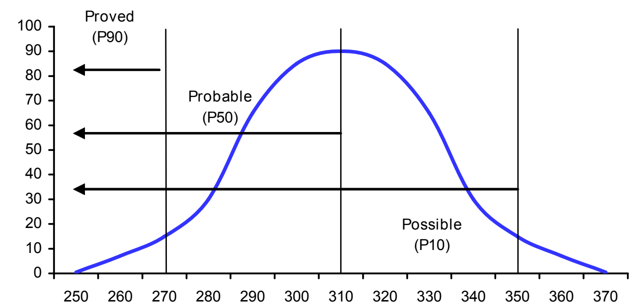
Under SPE definitions a clear distinction is made between reserves and resources. The total estimated hydrocarbons present in a reservoir are defined as **'Total Oil/Gas Initially-in-Place'** and may be sub-divided into discovered (in known accumulations) and undiscovered (dependent upon exploration success). The sub-set of discovered 'in-place' which is deemed as presently recoverable given the current technical understanding and commercial back-drop is defined as **reserves**. The sub-set of 'in-place' which is deemed as potentially recoverable dependent upon either technical developments (i.e. exploration success or further appraisal drilling) or a more favourable commercial position (for instance a higher oil price) is defined as **resource**. A schematic outlining the various SPE classifications can be seen in Figure 124.

Figure 124: A Schematic of the SPE Reserves & Resources classification matrix



Source: Galp Energia, Used with permission to company

Figure 125: SPE reserves: Diagrammatic view of the probabilistic definitions of 1P, 2P and 3P



Source: Deutsche Bank

Under the SPE's definitions, reserves are presented as proven, probable and possible depending upon the likelihood of their recovery. Thus:

- **Proven (1P) reserves.** These are those reserves that, to a high degree of certainty (90% confidence or P90), are recoverable from known reservoirs under existing economic and operating conditions. There should be relatively little risk associated with these reserves. A further sub-division distinguishes between *proven developed reserves* (reserves that can be recovered from existing wells with existing infrastructure and operating methods) and *Proven undeveloped reserves* (which require incremental development activity).
- **Proven plus Probable (2P) reserves**. These are those reserves that analysis of geological and engineering data suggests are more likely than not to be recoverable. There is at least a 50% probability (or P50) that reserves recovered will exceed the estimate of Proven plus Probable reserves. All told this is the level of oil that based on probability analysis is most likely to be recovered.
- **Proven, Probable plus Possible (3P) reserves**. These are those reserves that, to a low degree of certainty (10% confidence or P10), are recoverable. There is relatively high risk associated with these reserves. Reserves under this definition include those for which there is a 90% chance of recovery (proven), a 50% chance of recovery (probable) and up to a 10% chance of recovery (possible). Evidently, 3P reserves are the least conservative and, whilst ultimately 90% recovery may occur, from the outset the odds are that use of this measure will overstate the level of recovery.

Proven (1P) reserves are those reserves that, to a high degree of certainty (90% confidence or P90), are recoverable

Proven plus Probable (2P) reserves have at least a 50% probability (or P50) that reserves recovered will exceed the estimate.

Proven, Probable plus Possible (3P) reserves are those reserves that, to a low degree of certainty (10% confidence or P10), are recoverable

Perhaps the simplest way of considering these guidelines is by reference to the probability curve shown above (Figure 125). The curve represents the probability distribution of the amount of oil recoverable in a field under a multitude of different variables and sensitivities. Through reference to the curve is possible to interpret that, under the differing assumptions, in 90% of cases the field would hold at least 270m barrels of oil, in 50% at least 310m barrels of oil and 10% of cases at least 350m barrels of oil. Conservatively and on a P1 basis, the number of barrels that is exceeded by 90% of the scenarios plotted is that which would be recognised as the 1P reserve estimate or in this instance some 270m barrels.

Resources

As noted above, the sub-set of 'in-place' which is deemed as potentially recoverable dependent upon either technical developments (i.e. exploration success or further appraisal drilling) or a more favourable position (for instance a higher oil price) is defined as resource. Resources can be sub-divided into two categories (see Figure 124).

Contingent Resources are discovered but technical and/or commercial uncertainties prevent their being booked as reserves.

Contingent Resources (or technical reserves) are those quantities of hydrocarbons which are estimated, on a given date, to be potentially recoverable from known (discovered) accumulations, but which are not currently considered to be commercially recoverable. Contingent Resources may be of a significant size, but still have constraints to development. These constraints, preventing the booking of reserves, may relate to commercial factors (i.e. a lack of gas marketing arrangements) or to technical, environmental or political barriers. Thus, for example, in the world of LNG while the gas deposits required for plant throughput may be known to be in place, a project will almost certainly not be deemed commercial and investment approval granted until contracts have been signed for the majority of the LNG product. As such, even though the gas resources are known to exist, the absence of a secure market means that they cannot be treated as recoverable reserves. Contingent resources are classified in much the same way as commercial reserves, with 1C resource having a 90% confidence level around resource levels in place, 2C resource 50% confidence and 3C resource 10% confidence. Contingent resources are typically used by the industry as the most pertinent resource metric in asset transactions.

Prospective Resource represent estimates of the volumetric potential of undrilled prospects.

Prospective Resources (undiscovered resource) are those quantities of hydrocarbons which are estimated to be potentially recoverable from *undiscovered* accumulations. This estimate will be based on various technical assessments, including seismic data, and is clearly subject to considerable uncertainty given the absence of well data. For resource to be matured from Prospective to Contingent one or more exploration wells will clearly be required to prove the existence of hydrocarbons and allow for a refined estimate of potential recoverability. As for reserves and contingent resources, prospective resources may be subdivided into three categories – Low Case, Best Case and High Case estimate – based on a probabilistic assessment.

The accounting view: SEC Reserves – Proven developed and proven undeveloped.

Under SEC rules, reserves can only be recorded if, per the guidelines as laid down, there is a high degree of confidence that the reserves are recoverable.

Under SEC rules, reserves can only be recorded if, per the guidelines as laid down, they are deemed to be proved. Two types of recoverable reserves exist namely **proved developed** and **proved undeveloped**. Per SEC guidelines these are defined broadly (but not literally) as follows.

- **Proved oil & gas reserves.** These are estimated quantities of oil, gas, NGL's, synthetic oil/gas and other non-renewable natural resources that are intended to be upgraded into synthetic oil/gas which geological and engineering data demonstrate with a **reasonable certainty** are recoverable from known **reservoirs** under existing economic conditions (i.e. prices, costs, government regulation). A reservoir is considered proved if economic production is supported by actual production of conclusive formation tests (such as drilling) have been conducted. Adjacent undrilled areas that can with reasonable certainty be judged continuous with and economically producible can also be classified as reserves. In the absence of data on fluid contacts, reserves are limited by the lowest known hydrocarbons as established by geosciences, engineering and reliable technology. Reserves that can be produced economically through improved recovery techniques can also be included as proved if they have been successfully testing and such a project has been approved.

- **Proved developed oil & gas reserves.** Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells (or existing extraction technology in the case of oil sands) with existing equipment and operating methods. Reserves are also considered 'developed' if the cost of any required equipment is relatively minor compared to the cost of a new well. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
- **Proved undeveloped oil & gas reserves.** These are (summarily) those reserves expected to be recovered with reasonable certainty from new wells on un-drilled acreage or from existing wells where major expenditure is required for re-completion. Proved undeveloped reserves should only be booked where it is expected production will commence within five years unless specific circumstances exist. Following a review of SEC regulation, companies may now also book volumes to proved undeveloped reserves that can be recovered through improved recovery projects where the intended EOR technique has been proved effective by actual production from projects in the same reservoir or in an analogous reservoir, or based on other evidence that uses reliable technology to establish reasonable certainty.

The Final Investment Decision or FID

A field will only be included as recoverable once a final investment decision or FID has been taken

Importantly, however, use of terms like 'reasonable certainty', 'reasonably judged' and 'economically' also confer a considerable degree of latitude to companies in their determination of when a field is proven and the scale of the reserves which they may deem to be recoverable. As such, their application may be more or less conservative. In general, company practice has evolved such that a field will only be included as recoverable once a final investment decision (FID) has been taken, committing the company to the development of its acreage. The FID is thus a key indicator for investors and a potentially important indicator to the timing of reserve bookings.

Room for manoeuvre

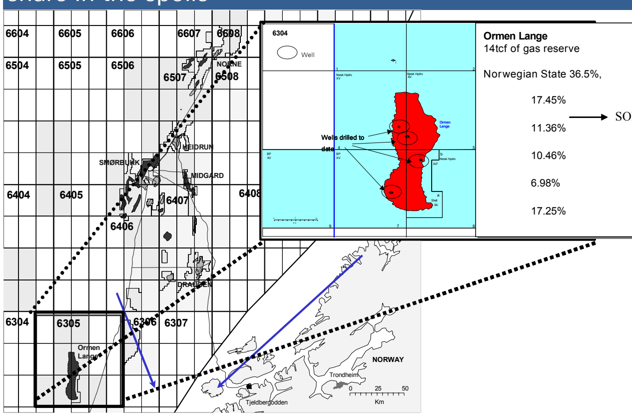
Within the parameters of the regulations, scope exists for companies to make different assessments of reserves at the same accumulation due to more or less aggressive application of the rules.

Yet, decisions on what level of reserves to report in any given year can be subject to huge variation and there is certainly the very real potential for companies to massage the level of recoverable reserves reported in any one year and so present a favourable profile of reserve replacement to the outside world.

As an example of quite how bookings and interpretations may vary we show below DB estimates of the bookings made of the Ormen Lange gas field in 2004. Ormen Lange is a major gas field within Norwegian territorial waters with an estimated 14 trillion cubic feet of gas reserves. Under the operatorship of Statoil, five partners were involved in its development at the time of FID (Statoil, Shell, Norsk Hydro, Exxon and BP. BP has subsequently sold its position and Statoil has acquired the Upstream operations of Norsk Hydro). With the FID taken in 2003 the partners were free to book the reserves as 'Proved' under SEC definitions in their 2003 accounts. Looking at the reserve bookings and the % shares owned it is possible to estimate the implied 'proved recoverable' reserves as interpreted by each of the different companies. As illustrated by Figure 127, despite the absence of any disputes between the partners over the field, these varied from an implied gross 800mmboe at Shell who, following the travails of their reserve restatement in 2004 almost certainly will have adopted an ultra conservative approach, to an implied gross c2bnboe by a more aggressive BP.

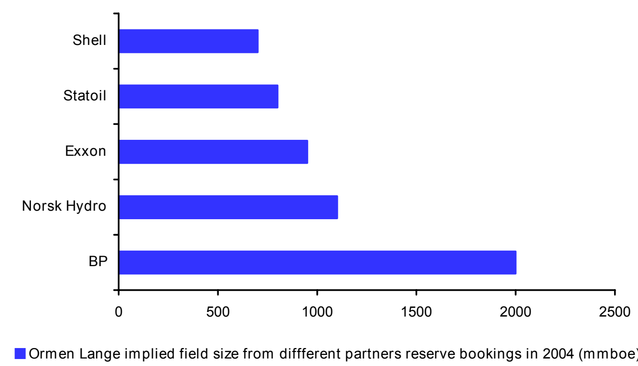
As stated, the point made here is not to say that one company is correct in its bookings and the other incorrect. The example does, however, illustrate that the SEC rules surrounding reserves replacement are subject to interpretation. It also shows how reserves replacement estimates can be manipulated by companies should they choose to, so enabling them to present a picture of future potential growth that most suits their needs at a particular point in time.

Figure 126: Ormen Lange – Five partners initially set to share in the spoils



Source: Wood Mackenzie; Deutsche Bank

Figure 127: Ormen Lange: Same field, same guidelines, different bookings



Source: Deutsche Bank

Techniques and technology have moved on

It is also important to observe that since the SEC rules were issued in 1978 industry technology and techniques have advanced considerably. In particular, advancements in down-hole and seismic technology have meant that significant investment decisions will be made in field extensions even though expensive 'flow testing' may not have occurred. This is particularly so in offshore developments such as the Gulf of Mexico where, given the water depths and environmental requirements, flow testing is extremely expensive and, because of reserve knowledge acquired through other means, largely unnecessary. Not surprisingly, the companies are reluctant to commit to expenditure that they deem expensive and unnecessary in order to satisfy the SEC's reserves booking requirements. This led to the SEC performing a comprehensive review of the regulation around the booking of reserves in 2008/09, with guidance updated to better reflect the modern day oil industry.

Some key elements of the SEC reserves reporting guidelines have recently changed.

Changes that were made to SEC reporting guidance include:

- Use of an average oil price (based on the closing price of the first of each month) in determining entitlement barrels (was the closing price on the last day of the reporting year, which in recent volatile markets led to significant swings in entitlement barrels, particularly in PSC regimes).
- Inclusion of unconventional hydrocarbons such as bitumen, oil shale or coal bed methane gas. The calculation of economic viability of unconventional reserves should be based on end product prices (i.e. on the price of syncrude in the case of oil sands as opposed to the price of bitumen). Companies must however highlight reserves that are non-traditional oil/gas.
- Technology that is considered reliable, that is it has demonstrated consistency and repeatability in the formation being evaluated may be used to establish reserves estimates and categories. This means that companies can now book reserves that have been discovered using technologies other than well/drilling (so long as meet reasonable certainty requirements and will be developed within normal timelines).

- Broadly speaking the reserves that companies may claim as proven under SEC rules correspond with 1P (or P90) reserves under SPE definitions. SEC rules do, however, add some additional constraints. First, the SEC guidelines require the use of the average market price of oil (as noted above) whereas under SPE rules long run budgeting assumptions are permitted. Second, SEC requirements dictate that only reserves recovered over the current license period can be included in recoverable reserves even though licenses are commonly extended. A more conservative approach than the SPE definition which allows inclusion of reserves recovered over the field life.
- Companies now also have the option to disclose probable and possible reserves should they wish to do so.

It is also worth noting that the SEC also provides guidance on those reserve types that do not qualify for treatment as reserves. In summary this is where recovery is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors. On example would be adjacent reservoirs to existing production that are isolated by major, potentially sealing faults and cannot be booked as reserves until such a time as those reservoirs are penetrated and evaluated.

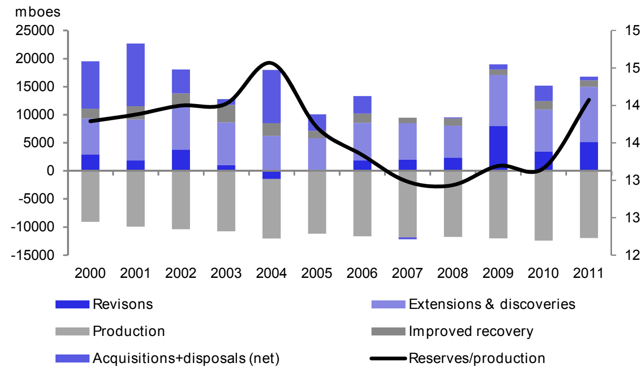
Reserve revisions

Because the estimation of reserves is inherently uncertain, it seems only natural that any estimate is dynamic with a point-in-time statement of reserves likely to be subject to revision as new information on the potential to recover oil from any given field becomes available. Similarly, as new reserves are discovered through exploration, existing fields extended by new drilling, or enhanced recovery techniques applied to existing fields so estimates of reserves are likely to alter. Each year all of this information is thus presented separately for both oil and gas reserves on a region by region basis in a company's reserves statement with the movements categorized according to the source of their alteration.

The estimation of reserves is dynamic. Revisions may occur either on existing assets (i.e. technical or commercial developments or benefit or incremental investment) or due to new discoveries

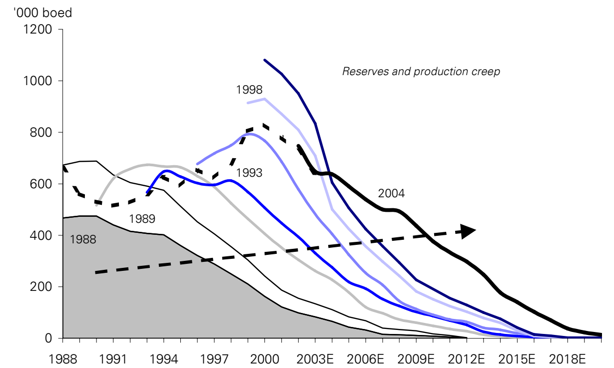
- **Technical revisions or revisions of estimates:** Technical revisions represent alterations to the initial estimate of the reserves that were deemed recoverable from a particular field. Given that the initial reserves estimate will typically have been presented on a conservative 1P basis, it would be reasonable to expect that they should in most cases represent additions although this need not necessarily be the case, particularly where a company is involved in profit sharing contracts at a time of rising oil prices (see later). Nonetheless, significant and repeated negative technical revisions with no good reason and investors are likely to question the quality of the reserves data. Note that no new capital expenditure should be associated with this sort of revision.
- **Discoveries & Extensions**: Where discoveries are self explanatory, new reserves may also be added by extending the boundaries of an existing field through drilling new wells or revising geological and engineering interpretations not known to exist when the opening balance reserves were estimated. Extensions are thus usually the result of successful drilling operations and will likely require significant capital investment for extraction.
- **Improved recovery:** Given time and technology, the potential for the extraction of oil from a field may prove greater than initially anticipated. Typically this will be because at the time the field was first included in the reserves statement, the potential for enhanced oil recovery would not have been assessed.
- **Acquisitions and disposals:** Shown separately, reserves movements on acquisitions and disposals highlight the reserves which have either been disposed of through the year or those acquired as asset parcels or through the purchase of another company.

Figure 128: Sources of industry reserve movements 2000-2011



Source: Company data, Deutsche Bank estimates

Figure 129: The North Sea: technical extensions and enhanced recovery can be key to production growth.



Source: Deutsche Bank estimates

Intuitively, it would seem natural to expect that the single most important driver of reserve movements would be those reserves discovered through exploration. However, as illustrated above the reality is often very different. We estimate that extensions and discoveries accounted for around 65% of the increase in reserves in the period 2000 to 2011 (excluding reserve acquisitions). This is also largely illustrated by production and reserve creep in the North Sea. Whilst a significant proportion of the extension of North Sea production will have resulted from the discovery of new fields, a substantial proportion of the improvement arose as a consequence of greater recovery rates than initially anticipated aided by improvements in technology and changed economic circumstances (in this case a notable favourable change in the basis of taxation).

Reserves: What do they actually tell us?

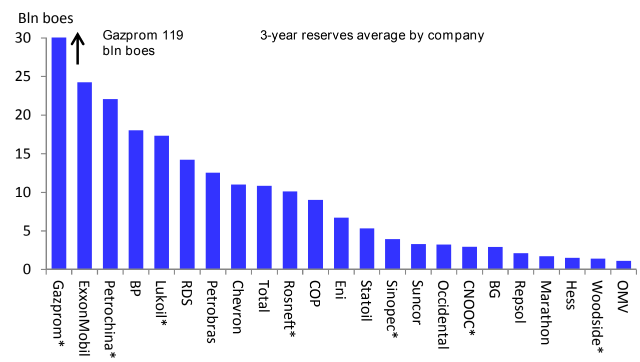
Reserves afford important information on outlook, business sustainability, asset value, exploration and development efficiency and a company's exploration capability

Conceptually, data on reserves is of paramount significance when assessing the valuation of an exploration and production business given that it affords important information on the outlook for near to medium term growth, business sustainability, asset value, exploration and development efficiency and a company's exploration capability. Indeed, of all of the ratios that are used to analyse a company's performance, it is those derived from the reserves statement that provide the most insightful information on a company's prospects and relative profitability.

- **Medium term growth**: On the basis that under SEC reserve rules companies' capital investment plans and reserve bookings go largely hand in hand, the reserves replacement ratio (i.e. aggregate reserve additions divided by annual production expressed as a percentage) affords a strong insight into near to medium term growth. This is because by booking the reserves the company is in large part indicating that investment plans are in place for the development of a set level of reserves. Thus reserve additions in excess of 100% on average over several years and the company is affording a strong indication that production is likely to grow. Similarly, reserve additions below 100% on average for a sustained period and pretty soon growth is likely to deteriorate.

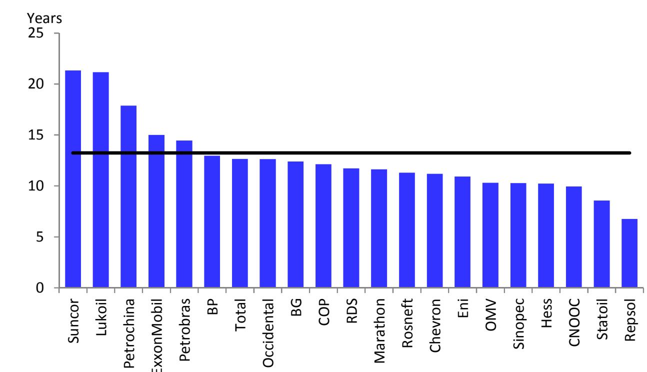
- **Business sustainability**: By dividing total year end reserves over annual production, investors are afforded a view of how many years a company could sustain production for at current levels. Clearly, as a resource based industry, the greater the number of years of potential production the greater the value of the company and the more sustainable the valuation. It should be noted that, for a growing business, to maintain proven reserves at a set number of years requires greater than 100% annual reserves replacement. Indeed, for a company growing at 1% annually over the long term with 10.0 years of reserves life, reserve replacement would have to run at 111% per annum if reserves life of 10.0 years were to hold constant.

Figure 130: 3-year (2009-2011) average SEC 1P reported reserves by company



Source: Deutsche Bank, company data *Not in line with SEC definition of 1P reserves

Figure 131: 3-year (2009-2011) average Reserve Life by Company; sector average of 13 years



Source: Deutsche Bank, company data

- **Asset value**: As a resource based industry, the absolute level of a company's reserves is clearly a central part of valuation affording investors a strong view of the company's net asset base and, consequently, a further means of assessing absolute value and inter-company comparisons.
- **Cost efficiency.** Combined with disclosed costs for exploration and development, reserves data provides investors with a view on the costs associated with discovering and developing a barrel of oil (typically expressed in US$ as finding and development costs per barrel of oil equivalent or boe). This affords investors with insightful information on the potential profitability of a company's operations and allows for useful inter-company comparisons. Taken over time, this cost information also provides insight into the direction of industry costs and efficiency. Key ratios include finding costs per boe, finding and development (F&D) costs per boe and technical costs.
- **Exploration capability:** Reserves data affords investors an insight into how successful a company has been relative to its peers at discovering new, commercial resources. All other things being equal, one would clearly expect a company that had shown consistent success in replacing its reserve base to be valued more highly than one whose record was less successful.
- **SEC Proved reserves versus 2P reserves:** To the extent that companies release estimates of their total resource base in addition to SEC reported reserves, investors are afforded some insight into the potential for near term reserves bookings and, potentially, how conservative companies are in their reserve bookings. Perhaps more significantly, the provision by consultants such as Wood MacKenzie of estimated 2P reserves data for the different oil majors affords a useful view of the extent to which companies may or may not be conservative in their SEC reserve bookings together with an idea of how much scope exists to replace reserves from the existing resource bank in the medium term future.

Reserves Accounting– FAS 69

FAS 69 sets out a comprehensive set of disclosures which all publicly traded oil and gas companies are required to publish annually. Necessary disclosures include; proved oil and gas reserve quantities, capitalised costs relating to oil and gas producing activities, costs incurred in oil and gas property acquisition, exploration and development activities, results of operations for oil and gas producing activities and a standardised measure of discounted future cash flows.

FAS 69 sets out a comprehensive set of disclosures which all publicly traded oil and gas companies are required to publish annually.

Disclosure of proved oil and gas reserves

Net (both operating and non-operating interests) quantities of proved and proved developed reserves of crude oil and natural gas must be disclosed as at the beginning and end of the year. Changes in net reserves should be disclosed separately as follows:

- Revisions of previous estimates: Changes in estimates resulting from development drilling/changes in economic factors
- Improved recovery: from application of improved recovery techniques
- Purchases of reserves in place from other companies
- Extensions and discoveries: extension of proved acreage and the discovery of new fields with proved reserves
- Production: volume of reserves exploited during the year
- Sales of reserves in place to other companies

If reserves relating to royalty interests are not included because the information is unavailable, that fact and the company's share of hydrocarbons produced should be disclosed for that year. The geographic location of the reserves should also be disclosed, in addition to oil and gas purchased under long-term supply agreements. As with all the disclosures detailed below, investments that are equity accounted should not be included but disclosed separately.

Disclosure of capitalised costs relating to producing activities

The aggregate capitalised costs and the aggregate accumulated depreciation, depletion and amortisation (DDA) incurred during the year must be disclosed.

Capitalised costs comprise all costs capitalised during the year on both proved and unproved properties. DDA costs represent the accumulated depreciation on capitalised oil and gas assets and is included in technical costs, which are calculated on a per barrel of oil equivalent basis. Technical costs also include exploration costs and production costs.

Disclosure of costs incurred in oil and gas property additions

Both property acquisition costs expensed during the year and finding and development costs must be disclosed. Finding and development costs are generally quoted on a per barrel of oil equivalent basis. Finding costs comprise the costs of the exploration and appraisal programmes, while development costs are the costs of constructing and installing the facilities to produce and transport the oil and gas. Together they compare the money spent to add reserves with the actual reserves added.

Disclosure of operational results

Operations for oil and gas producing activities must be disclosed in aggregate and for each geographic region.

Operations for oil and gas producing activities must be disclosed in aggregate and for each geographic region. This disclosure is effectively an income statement for FAS 69 purposes and includes:

- Revenues: must be separated into sales to third parties and sales to affiliates. All revenues must be shown at arms-length prices. Production or severance taxes should not be deducted in determining gross revenues but should be included as part of production costs. Royalty payments and net profit disbursements should be excluded from gross revenues.
- Production costs: also known as lifting or operating costs – comprise staff costs, on-site energy costs, rental of capital equipment and consumables such as drill bits etc.
- Exploration costs and DDA as explained above
- Income taxes: which are calculated using the statutory tax rate for the period

Disclosure of discounted future net cash flows

A standardised measure of discounted future net cash flows relating to an enterprise's interests in proved reserves and in reserves subject to purchase under long-term supply agreements must be disclosed at the year end. This incorporates the following:

- Future cash inflows: calculated by applying un-weighted average of the closing price on the first day of each month in the company's fiscal year
- Future development and production costs: estimated expenditure to be incurred in developing and producing the proved oil and gas reserves based on year end costs (assuming a continuation of existing economic conditions)
- Future income tax expenses: calculated by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows, less the tax basis of the properties involved
- Future net cash flows: future cash inflows less future development and production costs and tax expenses
- Discount: discount rate of 10% p.a. to reflect the timing of the future net cash flows
- Standardised measure of discounted future net cash flows: future net cash flows less the computed discount

In addition, the aggregate change in the standardised measure must be disclosed and if material should be presented in its individual components; net change in sales and transfer prices and in production costs related to future production, changes in estimated future development costs, sales and transfers of oil and gas produced during the period, net change due to extensions, discoveries and improved recovery, net change due to purchases and sales of mineral in place, net change due to revisions in quantity estimates, previously estimated development costs incurred during the period, accretion of discount, net change in income taxes and other.

Disclosure of current cost information

FAS 69 permits companies to use historical cost/constant dollar measures in computing assets and related expenses. Companies need to present supplementary information in a current cost basis if it has significant holdings of inventory and other non-hydrocarbon related property, plant and equipment balances.

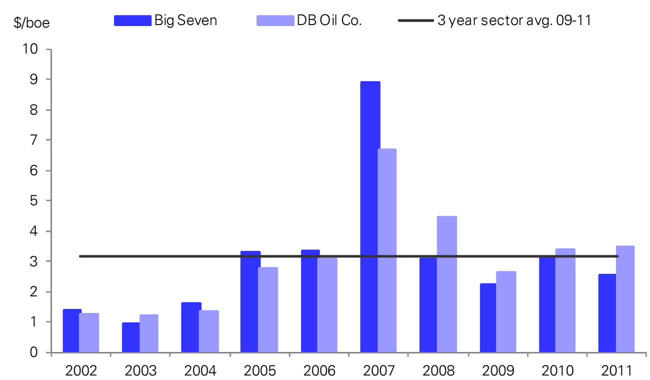
So how do analysts use FAS 69 information?

The most commonly used measures of upstream performance for analysing companies include finding and development costs, technical costs, DD&A, reserves replacement ratios and reserves life.

Finding costs. Finding costs comprise the costs of exploration and appraisal programmes alone i.e. how much did it cost the company to find each barrel of oil actually added to reserves in the year. Costs included would include drilling, lease or purchase of equipment, seismic assessments, cost of employees involved in exploration. Finding costs stand at c$3-3.50/boe, considerably higher than the $1-2/boe in the early '00s.

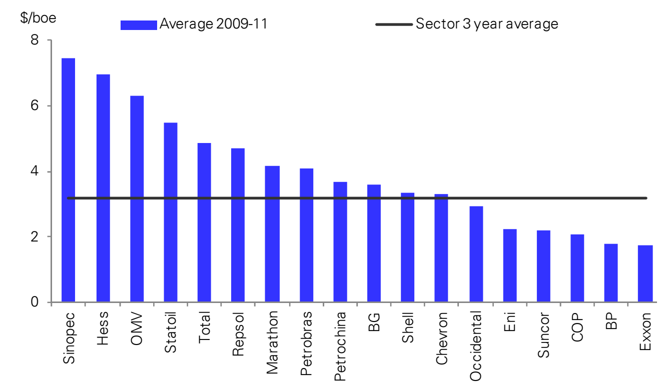
Finding costs = Total exploration costs divided by organic reserves additions (i.e. revisions, improved recovery & discoveries/extensions)

Figure 132: Sector average finding costs 2002-2011: 3-yr avg. c.$3.50/boe vs. avg. nearer $1.30/boe 2002-2004



Source: Deutsche Bank, company data

Figure 133: Company Finding costs per boe – 3 year average '09-11 vs. the sector average

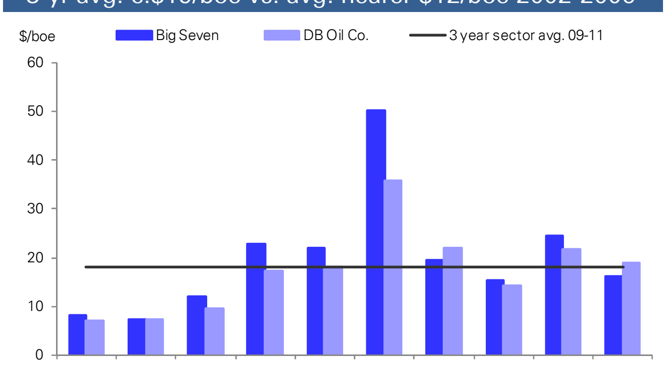


Source: Deutsche Bank, company data

Finding & Development costs: (F&D) Development costs relate to the construction and installation of the facilities to produce and transport oil and gas together with acquisition spend. F&D costs can be broken into four categories: three form part of the broad exploration and development cycle (acquisition of acreage, exploration and development of any successes) while the fourth is the purchase of existing reserves.

Finding & Development cost/bbl = Exploration plus development expenditure divided by organic reserves additions (i.e. revisions, improved recovery & discoveries/extensions)

Figure 134: Sector average F&D costs per boe 2002-2011 – 3-yr avg. c.$19/boe vs. avg. nearer $12/boe 2002-2006



Source: Deutsche Bank, company data

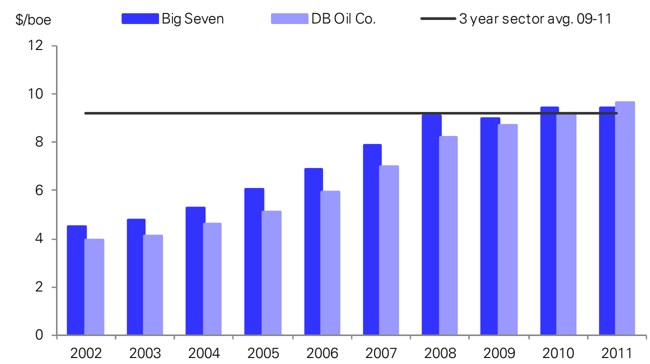
Figure 135: Company F&D costs per boe – 3 year average '09-11 vs. the sector average

Source: Deutsche Bank, company data

Depreciation, Depletion and Amortisation: (DD&A) represents the amortisation of the capitalised value of oil and gas properties on a unit of production basis.

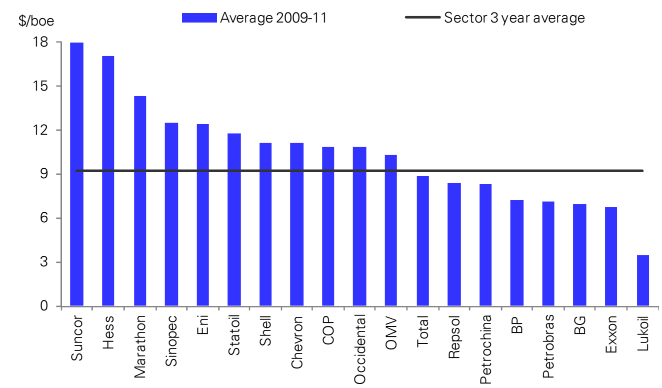
DDA = Depreciation, depletion and amortisation charge for the year/production for the year

Figure 136: Sector average DD&A 2002-2011: 3-yr avg. c.$9/boe vs. avg. nearer $4/boe 2002-2004



Source: Deutsche Bank, company data

Figure 137: Company DD&A per boe – 3 year average '09-11 vs. the sector average

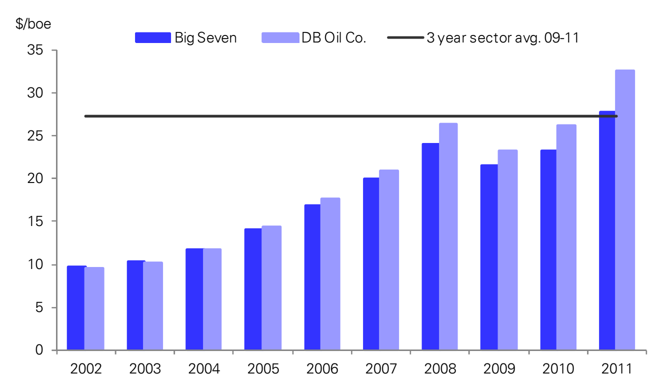


Source: Deutsche Bank, company data

Technical costs: Technical costs include exploration expenses, DD&A and production costs i.e. it is the entire cost excluding any marketing costs, involved in producing a barrel of oil (finding, developing, producing, etc).

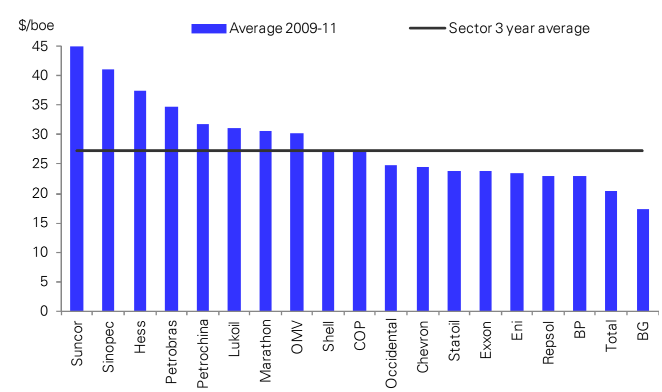
Technical costs = exploration costs + DD&A costs + lifting costs/annual production

Figure 138: Sector average technical costs 2002-2011: 3-yr avg. c.$27/boe vs. avg. nearer $11/boe 2002-2004



Source: Deutsche Bank, company data

Figure 139: Company technical costs per boe – 3 year average '09 -11 vs. the sector average



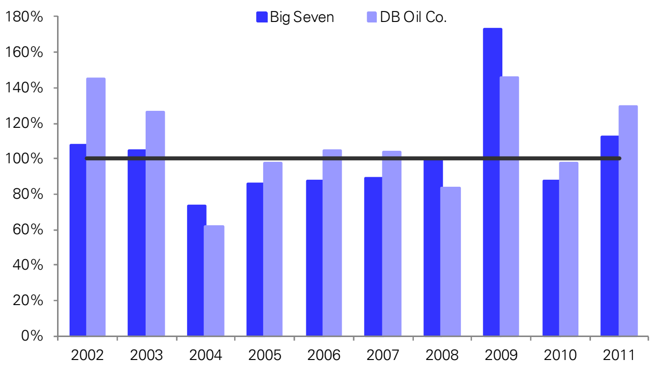
Source: Deutsche Bank, company data

Reserve replacement ratio: This is defined as the company's ability to replace production with reserve additions in the year under review. The reserve replacement ratio can be shown excluding (i.e. organic growth) or including acquisitions.

Reserve replacement ratio = Movement in reserves (revisions & reclassifications + improved recovery + extensions and discoveries) /Total production for the year

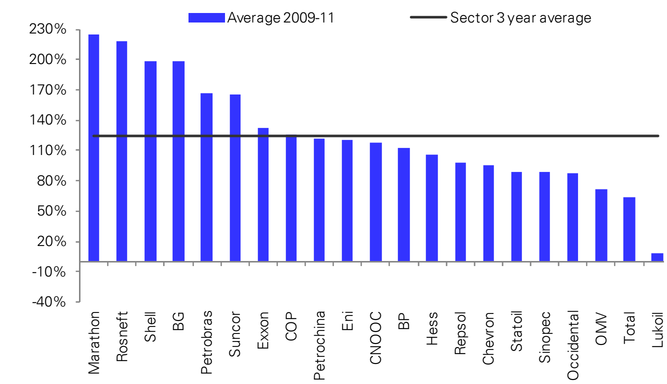
For RRR inclusive of M&A also include acquisitions and disposals in calculation of movement in reserves

Figure 140: Average RRR excluding acquisitions – '09 benefitting from FID on Gorgon & addition of oil sands



Source: Deutsche Bank, company data

Figure 141: Company organic 1P RRR – 3 year average '09-11 vs. the sector average

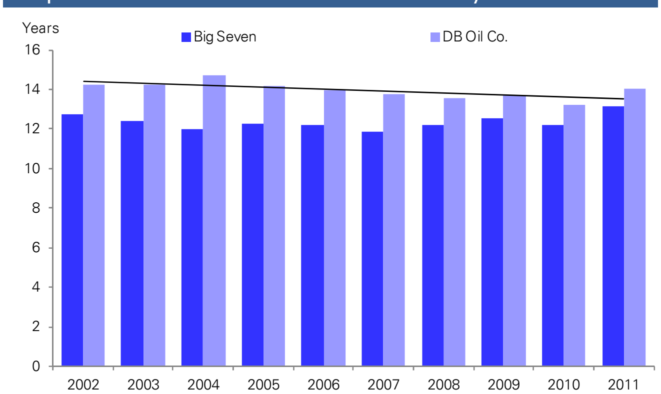


Source: Deutsche Bank, company data

Reserve Life: This is the number of remaining years of 1P reserves and is calculated as remaining reserves over annual production. It indicates how many years a company can continue to produce from its existing reserves should it find no additional reserves and maintain the same rate of production. Despite much pessimism regarding reserve life, as the below chart shows, the average in 2011 is not very dissimilar to the average 10 years ago. It is also worth noting that these reserve lives are only based on 1P reserves, while most companies have significant volumes of 2P reserves, which are considered by the industry a more accurate representation of sustainability.

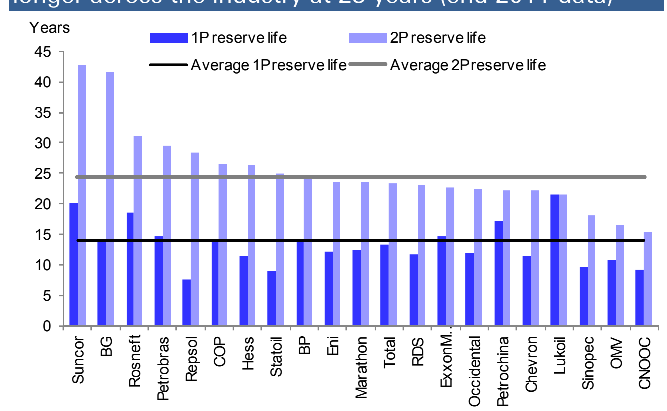
Reserve Life = Total 1P reserves/annual production

Figure 142: Average 1P reserves life (years) 2002-11 – despite concerns it has remained relatively stable



Source: Deutsche Bank, company data

Figure 143: On a 2P basis, resource lives are c.10 years longer across the industry at 23 years (end 2011 data)



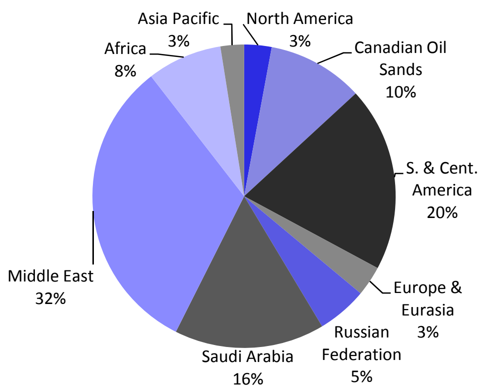
Source: Deutsche Bank, company data

All of the above FAS69 indicators are used by the market to assess the efficiency and profitability of each company. However, it should be noted that these measures are not always the most meaningful. For example, finding costs relate to exploration expenditure incurred in that year and usually have nothing to do with the actual reserves booked in that year given it normally takes up to 3 years before FID is taken on a discovery and the reserves are booked. Similarly, development costs incurred in a single year by and large do not relate to the majority of the reserves booked in that same year e.g. F&D costs at RDS appear very high over the last number of years as it invested heavily in capex intensive, long lead-time projects such as the oil sands, LNG and GTL where only limited reserves were booked prior to start-up.

Reserves - Where and what?

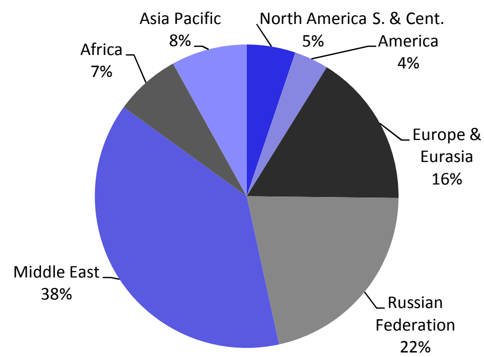
It is the nature of life that all things most highly sought are the hardest to find…and oil is no different. Located predominantly in 'unfriendly' countries or in technically challenging locations or located in vast quantities in 'friendly' countries but in difficult to extract/process forms, oil reserves are not to be had easily.

Figure 144: Oil reserves around the world – 1,653 billion barrels at end of 2011



Source: Deutsche Bank, BP Statistical Review

Figure 145: Gas reserves around the world – 7,361 TCF at end of 2011



Source: Deutsche Bank, BP Statistical Review

As illustrated above, close to 50% of the world's oil reserves are located in the Middle East, a region which has suffered repeated geopolitical tensions and instability throughout the years. Saudi Arabia alone with its 265 billion barrels is the world's largest holder of oil reserves and consequently the largest producer (along with Russia) and exporter of oil in the world. c70% of reserves are held by OPEC member countries.

50% of the world's oil reserves are located in the Middle East

It is worth noting that all reserves estimates for OPEC countries are issued by the countries themselves who do not issue any detail on wells or any detailed data hence these estimates could be subject to manipulation (particularly when we consider that OPEC production quotas are tied to its members reserves and that the level of reserves in a country can enable that country to gain access to bigger loans at lower interest rates). It is also worth noting that the definition of reserves varies from country to country e.g. in the US only reserves that are being produced are classified as proven while in Saudi Arabia all known fields are classified as proven, while Venezuela includes non-conventional oil (bitumen) in its reserve base.

So how much oil has been extracted?

While the use of oil is age old, commercial production only truly commenced in the 1860s following Drake's drilling success in Pennsylvania. Since then some 50,000 oil fields have been discovered and oil production has increased exponentially; in 1859 total annual production in the US was a mere 2,000 barrels, within 47 years this figure was 127m bbls, and in 2011 a total of 2.9bn bbls were produced in the US. While it is impossible to accurately state what total initial, global reserves were (given new fields are discovered every year and reserves estimates are changed as new technology is developed which enables additional reserves to be classified as commercial), using Wood Mackenzie data on all identified fields globally we estimate that 59% of commercially recoverable reserves have already been produced and consumed, albeit the denominator is not static and will be influenced by prevailing commercial conditions (i.e. price), technical developments and new discoveries/extensions.

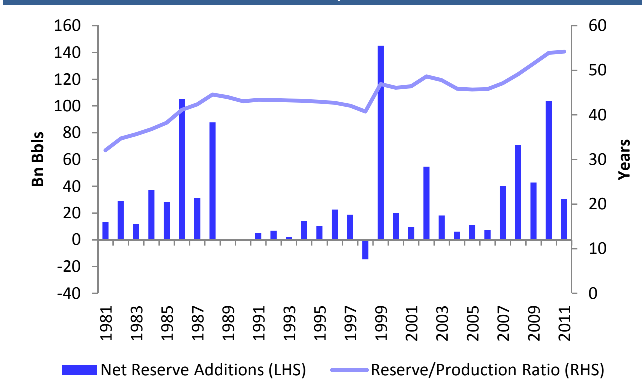
Wood Mackenzie data suggests that c59% of presently commercially recoverable reserves from developed assets has already been produced.

Figure 146: Top 25 Global Oil Fields (ordered by Life-of Field Commercially Recoverable Reserves)

Field Name	Country	Discovery	Start up	Rec Reserves (mmbbl)	Rem Reserves (mmbbl)	Peak output ('000 b/d)	Main Field Participants
Ghawar	Saudi Arabia	1948	1951	120,189	50,365	5,641	Saudi Aramco
Greater Burgan	Kuwait	1938	1946	44,500	14,536	2,416	KOC
Safaniyah	Saudi Arabia	1951	1957	40,000	23,837	1,900	Saudi Aramco
Samotlorskoye	Russia -West Siberia	1961	1969	22,285	3,529	3,027	TNK-BP Holding
Shaybah	Saudi Arabia	1968	1998	13,346	10,850	750	Saudi Aramco
Zuluf	Saudi Arabia	1965	1973	20,000	15,954	1,455	Saudi Aramco
Romashkinskoye	Russia -Volga-Urals	1943	1945	19,687	3,260	1,081	Tatneft
Cantarell	Mexico	1976	1979	16,653	1,499	2,136	Pemex
Khurais Area	Saudi Arabia	1958	1963	16,653	15,933	1,427	Saudi Aramco
Northern Fields	Kuwait	1955	1960	14,542	10,581	905	KOC
ADCO Contract Area	UAE	1954	1963	16,234	1,127	1,531	ADNOC, BP, XOM, RDS, Total,
Kirkuk	Iraq	1927	1934	15,962	1,906	1,400	North Oil (NOC)
Abqaiq	Saudi Arabia	1941	1946	15,000	3,353	1,056	Saudi Aramco
Ahwaz	Iran	1959	1959	14,535	3,734	1,082	NIOC
Marun Fields	Iran	1964	1965	14,181	2,285	1,369	NIOC
Prudhoe Bay Unit	US (Alaska)	1968	1977	12,238	1,023	1,540	BP, XOM, COP, Chevron
Gachsaran	Iran	1928	1940	13,750	3,359	921	NIOC
PDVSA Maracaibo	Venezuela	1916	1920	13,530	424	1,423	PDVSA
Lagunillas	Venezuela	1926	1926	13,140	157	238	PDVSA
AFK Group	Saudi Arabia	1940	1960	8,538	6,239	476	Saudi Aramco
PDO Contract Area	Oman	1956	1967	11,751	3,091	846	PDO
Rokan PSC	Indonesia	1940	1954	12,238	795	963	Chevron
PDVSA Eastern Fields	Venezuela	1933	1933	11,800	115	537	PDVSA
Agha Jari	Iran	1936	1939	11,800	1,635	1,023	NIOC
West Qurna 1	Iraq	1973	1976	11,638	11,638	1,350	South Oil (SOC)

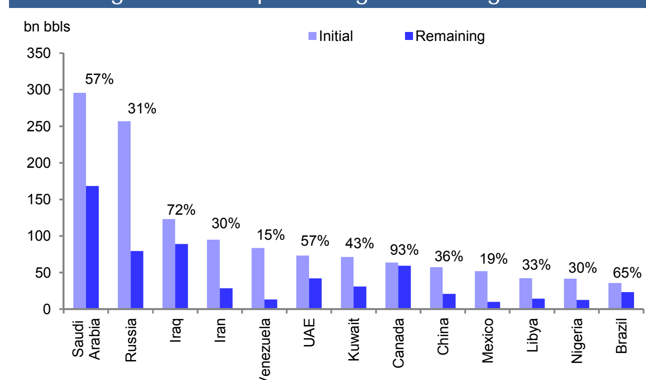
Source: Wood Mackenzie, Deutsche Bank

Figure 147: Net difference between annual reserves additions and annual consumption.



Source: BP Statistical review, Deutsche Bank

Figure 148: Top countries by reserves – initial reserves, remaining reserves & percentage remaining



Source: Wood Mackenzie

Another way of looking at it is to consider the net difference between annual reserve additions and annual consumption i.e. are we discovering sufficient reserves every year to replace oil consumed during the year. As the above graph (Figure 147) illustrates, with the exception of a few years we have witnessed *net* reserves additions (note that 1999 was boosted by the addition of Canadian oil sands to global reserves in our figures). And despite consumption also increasing, the global R/P ratio has been steadily rising.

What is Peak Oil?

Peak Oil refers to the point at which world oil output will reach a maximum, irretrievably declining thereafter.

Peak Oil refers to the point at which world oil output will reach a maximum, irretrievably declining thereafter. The last 100 years of worldwide GDP growth and associated improvement in living standards has been built on the ready supply of relatively cheap energy - i.e. oil. The idea that it will all shortly end is inherently alarming and hence Peak Oil proponents have until recently at least, found willing listeners to their conclusions. Economists on the other hand, have long argued that Peak Oil arguments are flawed, stimulating lively debate between the two parties.

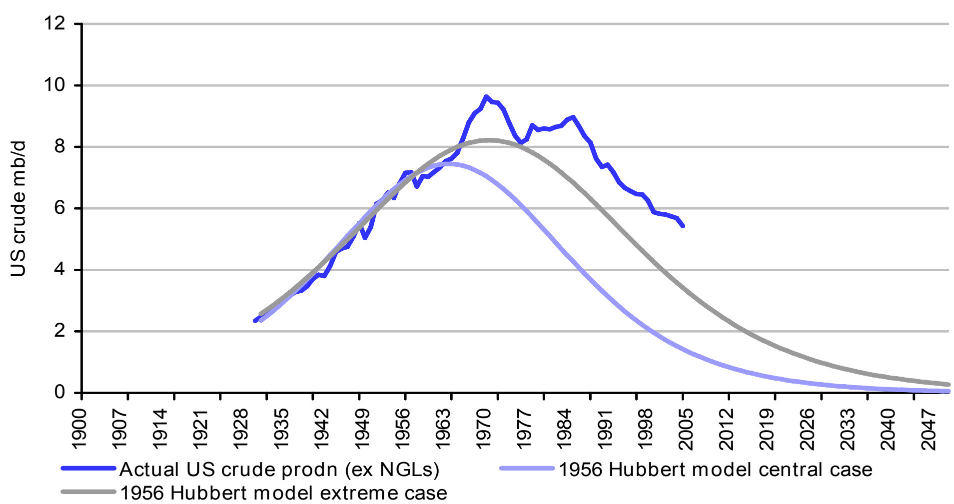
Dr M. King Hubbert – the father of Peak Oil

Dr M. King Hubbert – the father of Peak Oil

Dr. M. King Hubbert was a geophysicist who worked for Shell in the 1950s. He is credited with having correctly forecast the 1970 peak in US oil production, 14 years before the event. This impressive achievement gives credibility to his method, which is then applied by Peak Oil proponents to the world at large. Hubbert's method was not complicated; he assumed that US oil production would follow an exponential rise but would be constrained by the fact it is a finite resource. This results in the 'logistic' curve, which resembles a bell curve and is also used to model population growth. We show his predictions (1970 was actually an extreme scenario in his range of forecasts) for US oil production versus actual below:

Despite Hubbert's success with his US oil peak forecast, it was merely an extreme scenario out of several. His central forecast was actually for a US oil peak of 7.4mb/d in 1963, whereas the real peak was of 9.6mb/d in 1970. Most people do not refer back to the 1956 paper Hubbert wrote and so are unaware that Hubbert's central forecast was off by almost 50% (8 years until the peak instead of 14). Whether reviewing Hubbert's original forecasts, or simply looking at all the forecast 'Peaks' that have failed to materialise (the first was for 1940, made by the USGS in 1918), it is clear there are some fundamental problems with the methods employed by the Peak Oil camp.

Figure 149: Actual US crude production and Hubbert's forecasts (1900-2009)



Source: Deutsche Bank, US DOE, 'Nuclear energy & the fossil fuels' – M. King Hubbert 1956.

A critical weakness - simple economics ignored

Peak oil fails to take account of oil prices, technology, the inaccuracy of reserve estimates and non-conventional oil

The common ground between many Peak Oil forecasts is that they assume a fixed amount of oil remains to be recovered in the world. This may be intuitively reasonable but fails to take account of oil prices, technology, the inaccuracy of reserve estimates and non-conventional oil – all of which have a huge impact on the world's ultimately recoverable reserves (URR).

- **Oil prices matter**. The amount of oil left in the world is less important than one might think. What matters is the amount that is *economically recoverable*. As oil prices rise this figure increases, because investments in new wells, infrastructure or other measures that extend the field's life become NPV positive at higher oil prices. A key failing in traditional Peak Oil analysis is that it failed to connect the dots between increasing oil scarcity, higher oil prices and more reserves becoming economic.
- **Technology matters**. Even without oil price rises, technology progresses and reserves that weren't economic at say $40/bbl become economic with the introduction of new equipment and procedures. Horizontal drilling, 3D and multi-azimuth seismic, increased reliability of equipment; all of these have helped drive up economically recoverable oil reserve estimates.
- **How much was there to start off with?** It depends on who you ask. The problem is that this figure is not known with any degree of accuracy; credible estimates of this figure vary from 1.9 trillion bbls (Campbell, 2002) to 4.4 trillion bbls (USGS high end estimate, 2000).
- **There is more to oil than conventional.** Oil sands, heavy oil and the potential of shales/tight oil are not included in most Peak Oil analysis, yet these represent vast sources of resource potential; c.1.0 trillion bbls in oil sands/heavy oil and an estimated 1.5-2.0 trillion bbls in shale/tight oil. A timely case study is provided by the tight oil revolution in the US which has begun to see US onshore liquids production reverse a long established decline trend moving back to growth in 2012 (not captured by the time scale for Figure 149). This trend is expected to continue at a rate of c0.5mb/d p.a. through to 2020, which if achieved would represent a sustained deviation from the trajectory for US production anticipated by Peak Oil adherents. Furthermore, the industry is now looking at the potential of tight oil accumulations in other geographies including Russia, Argentina and Canada. We cover the advent of tight oil later in this note. Gas represents another huge resource that equates to over 1.0 trillion boe, but again is usually excluded from Peak Oil literature.

There are other criticisms of the traditional Peak Oil arguments, including the fact that it is quite clear that very few fields or basins have delivered a bell curve production profile, and it seems very unlikely that the world's production profile will either; economics suggests a long tail as more and substitutes become economically viable.

So when will a peak occur and does it matter?

In 2006 Exxon stated that it believed there will be no peak for at least 25 years. The IEA forecasts a peak between 2025 -'50. Still some way away, so is there no need to worry?

There will be a peak, and it will probably be within the lifetime of most people that read this text

There will be a peak, and it will probably be within the lifetime of most people that read this text. But what matters is less the precise date at which such a peak occurs than how the inevitable (but likely gradual) transition to an energy supply mix in which crude oil represents a declining proportion of primary energy consumption is managed. Relying purely on market forces, IOCs and OPEC countries to ensure a smooth transition seems like a recipe for turmoil. Rather, governments need to help the process. For example governments could:

- Much more aggressively promote more energy efficiency measures and lifestyles by appropriate tax schemes and other incentives.
- Encourage a step change (by say an order of magnitude) in investment by companies, including the IOCs, into alternative energy sources.

Oil & Gas Taxation

Concessions & contracts – An overview

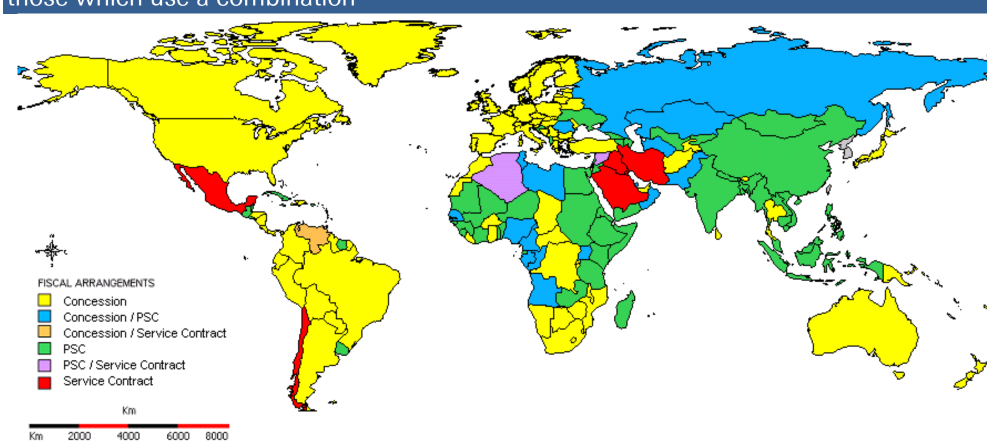
The sheer scale and value of the oil and gas industry together with its strategic importance has meant that governments have long seen the extraction of hydrocarbons as an important potential source of revenue. As such, oil & gas taxation is a very important part of today's industry with government-take invariably representing the single largest portion of an oil & gas project's cash flows. Moreover, most producing countries have established separate and distinct tax legislation laying down the specific fiscal terms that are to be applied in calculating the revenues and taxable profits of their upstream hydrocarbon industry.

Two main systems – tax & royalty or production sharing arrangements

While no two countries are likely to have identical fiscal legislation, as a general rule there are just two major fiscal arrangements used in the taxation of oil and gas producing activities; those which are concession based and as such focus on a tax and royalty system; and those which are contract based and as such represent a defined contractual arrangement between the resource holder and the contractor, most commonly in the form of Production Sharing Contract (PSC) or, in certain limited cases, a Buyback Contract (which is effectively a contract for services). As a general rule of thumb, oil production in OECD countries or countries that have a long history of oil production tend to work on the basis of concessions (US, UK, Venezuela, the UAE, etc) whilst those in the developing world tend to be based on PSCs or contracts for service. In several cases both types of arrangement will be applied.

There are just two major fiscal arrangements used in the taxation of oil and gas producing activities – those based on a concession and those on a contract

Figure 150: Distribution of global tax systems between concession, PSC, buyback and those which use a combination



Source: Wood Mackenzie; Deutsche Bank

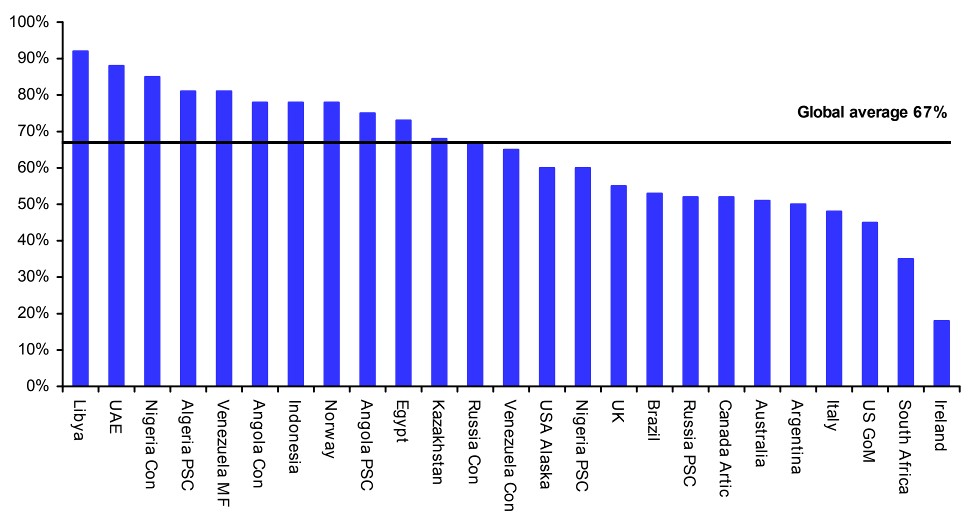
In determining the type of system used **resource holders** are typically trying to strike a balance between maximizing state take through both tax and/or profit share while still attracting additional prospective investment. For the **operating company or contractor**, the objectives are to maximize its return and protect its investment yet equally to ensure a stable fiscal environment that will allow for more predictability when assessing future cash flows. With this in mind, it is perhaps of little surprise that concession systems with their broader terms should be those most commonly found in OECD-member countries whilst in developing countries government-endorsed contracts are more typical.

Tax take varies – but the global average is estimated at 67%

The division of NPV between government and contractors sees material variation, but globally government take averages c67%.

Many other factors will, however, also apply to a contractor's willingness to invest not least the extent of the resource base, the technical challenges associated with extraction, the importance of the oil industry to the economy, competition, political stability/ethos and so on. As a consequence, government take varies significantly from country to country as illustrated by the chart below. For example in Ireland with its narrow resource base and limited prospectivity the modest level of government take at 18% is designed to incentivise exploration and development. This contrasts with, say, the 90% plus rate of take now typical in Libya, a known hydrocarbon province whose highly prospective basins offer significant opportunity for the discovery of meaningful onshore reserves. We highlight a 2007 study by Wood Mackenzie estimating that the weighted average government take globally was c67% of the industry's pre-tax NPV (or 72% if NOC equity is included). And despite a number of changes to tax terms subsequent to this study, primarily in concession rather than PSC regimes, we believe that the broad conclusion on the division of value and the ranking of countries continues to provide a useful reference point.

Figure 151: Government take of project pre-tax NPV in selected countries (%)



Source: Wood Mackenzie; Deutsche Bank

Regressive or progressive?

Regressive or progressive?

Quite aside from the absolute level of tax take attributable to the government at a particular oil price, fiscal systems also vary in their allocation of upside to higher oil prices or downside to lower prices between the resource holder (i.e. government) and the contractor (i.e. IOC).

In a **progressive tax system**, government share of a project's NPV rises at times of increasing prices so exposing it to oil price upside yet similarly falls at times of declining prices. In doing so, the resource holder benefits disproportionately from an increase in the value of its resource that is associated with rising prices whilst the risk-taking contractor obtains some downside protection on its investment in the face of declining prices. This contrasts with a **regressive tax system** in which the government's percentage share of project NPV falls at a time of rising oil prices but rises as prices fall.

In general, concession systems tend to be regressive to neutral with the resource holder capturing a smaller share of overall value as the oil price appreciates. By contrast, production sharing contracts tend to be progressive with the resource holder entitled to a greater share of project value given an appreciating oil price.

Concession regimes tend to be regressive – leaving them vulnerable to change

Importantly, this difference between the two systems has had significant consequences in recent years as governments have looked to capture a greater share of the upside from higher oil prices. Unsurprisingly, the regressive to neutral bias of concession regimes has meant that, since 2002, the vast majority of the unanticipated increases in taxation terms governing *existing assets* have been in concession-based regimes with governments as diverse as those in the UK and Venezuela implementing material increases in tax. This is not to say that the terms applicable to *new* PSCs have not tightened. Indeed, the terms of most PSCs negotiated today are less generous than they were, say, 5-10 years ago as they are now structured to reflect a $100/bbl world as the norm; however, in the case of a new PSC the contractor has at least agreed to the terms upon entering the contract. But we note that where an existing production/development asset is situated within a PSC regime, the nature of the contractual obligation with the attendant legal protections for the contractor have generally prevented terms being changed retrospectively.

The fiscal terms governing Concessions have been far more vulnerable to change than PSCs as the oil price has risen.

Figure 152: Tax changes impacting since 2002 impacting existing production/development assets have focused on concession regimes

Country	Tax form	Change
UK	Concession	Increased tax take by adding a supplementary tax (on post 1993 fields) to standard CT. ST introduced at 10% in 2002, but increased to 20% in '06 and 32% in '11.
Venezuela MF	Concession	Increased tax rate on marginal fields by increasing royalty to 33% and tax to 50%
Venezuela Faja	Concession	Increased tax on heavy oil projects raising royalty to 16.7% and tax to 50%
Bolivia	Concession	Introduced royalty rate of effective 50% from 18% and state granted equity share
Russia	Concession	Introduced export duty at 90% on oil prices over $27/bbl
Russia PSC	PSC	Altered terms reducing cost oil and seeing payment of special dividend
Argentina	Concession	Introduced tax capping export price at $42/bbl
Alaska North Slope	Concession	Introduced sliding scale supplementary tax on prices over $40/bbl
Canada (sands)	Concession	Introduced sliding scale royalty on prices over $55/bbl
US GoM	Concession	Raised royalty to 18.75% from 12% on all fields in late-2007
Australia	Concession	Proposals to bring onshore/near-shore projects under Federal tax regime (from State regime) via additional profits-based tax applied after State royalty.

Source: Deutsche Bank

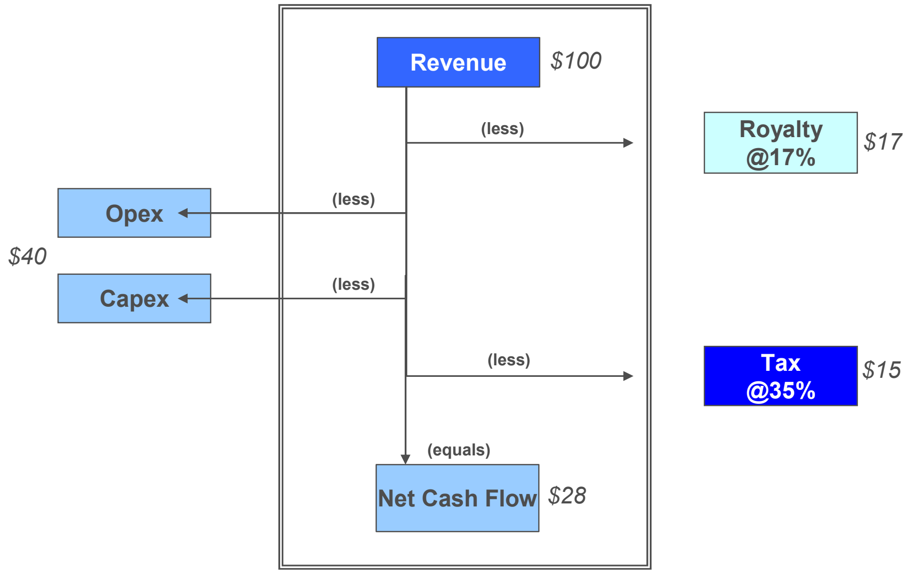
However, in a concession regime a government must balance the relative ease with which it can alter terms in order to capture more of the economic rent with the need to encourage incremental investment, whether in existing assets, Greenfield development or exploration. As a consequence, tougher headline tax rates have often been sweetened with more generous tax-breaks on capital investment or exploration.

Tax & Royalty Concessions

At its most basic, concessions or tax & royalty regimes describe a system where the oil industry is granted the rights to prospect for resource within a defined onshore or offshore acreage. The concession holder takes ownership of all minerals found on that acreage, but pays a percentage of their value upon extraction to the government together with a modest annual fee to retain the acreage. This is typically through the payment of a royalty on the revenue base (e.g. 18.75% in the US Gulf of Mexico) and the payment of tax at the determined corporate rate on profits (e.g. 35% in the US Gulf of Mexico). Consequently, as the oil price rises, government's share of the barrel remains broadly constant, with full upside accruing to the contractor.

Concessions or tax & royalty regimes describe a system where the oil industry is granted the rights to prospect for resource within a defined onshore or offshore acreage.

Figure 153: Schematic depicting tax and royalty calculation in a concession and Net Cash Flow to the operating company



Source: Wood Mackenzie; Deutsche Bank

Overall, government take under a concession is generally easy to tabulate. It will vary depending upon royalty rate, corporation tax rate and the rate at which capital expenditure can be recovered against profits i.e. the tax depreciation schedule. This latter point is important as in times of rising costs the pace of capital recovery against profits may be such that capex cannot be recovered until several years after it is incurred. For reference the main components of taxation in several key geographies.

Figure 154: Summary tax terms in major concessions

	Royalty rate	Corp. tax rate	Depreciation	Other tax rate
UK	None	20%	Year incurred	32% supplementary tax
US GoM	18.75%*	35%	7 year MACR System	n.a.
Norway	None	28%	Six years with 30% uplift available over 4 year period	50% hydrocarbon tax
Russia	'MET' - variable	20%	Varies	Up to 60% export tax
Nigeria Concession	0-20%	n.a.	5 year straight line with uplift	55-85% Petroleum Profits Tax
Australia	10.0-12.5%	30%	10 years	40% PRRT
Venezuela	30%	50%	Varies	Several indirect taxes; price-linked Windfall tax
Argentina	12.0-15.0%	35%	Unit of production	Export duty liable
Canada Oil Sands	1-40%	15%	4 years	10% state tax

*Source: Deutsche Bank * Increased to 18.75% from 16.7% for lease sales from 2008 onwards*

Outside royalty and corporation tax, the rise in the price of crude oil in recent years has seen the introduction of several sources of additional taxation as governments have looked to capture a greater share of the value of the resource base. Not least amongst these have been export taxes in Russia (60% tax on all revenues over $25/bbl) and Argentina (no upside over $42/bbl to the concession holder), sliding scale royalties in Canada and Alaska (whereby royalty rates rise at higher oil prices) and the introduction of supplementary petroleum taxes in the UK and Norway (now a 32% increment to corporation tax in the UK and 50% in Norway).

Don't forget reserve bookings!

There is, however, one final key point regarding concession systems. This is that, under SEC reserve reporting requirements, even if 99.9% of the revenues realised from the production of a company's working interest in a field is to be paid away as royalty and tax, the company is still entitled to book all of the barrels to which it is entitled as reserves (with the exception of the US where royalty barrels may not be consolidated). As we shall see, this stands in stark contrast to the rules for PSCs whereby only the barrels to which it will be entitled at the year-end oil price qualify as proven reserves.

Production Sharing Contracts (PSCs)

Where under a concession system the concession holder has the economic right to all of the oil produced within the concession but is liable to pay tax and royalty on the proceeds, in a production sharing contract the mineral resource remains the property of the state. As such, the PSC agreement lays down the terms under which the barrels produced from a development project will be allocated between the resource holder and contractor i.e. the contractors entitlement to the resource produced. Amongst others, these terms will typically indicate how the oil produced will be allocated to cover the capital and operating costs of the project (so called 'cost oil') and in what proportions the remaining 'profit' oil will be allocated between contractor and state.

In a PSC agreement a contract lays down the terms under which the barrels produced from a development project will be allocated between the resource holder and contractor

PSCs – Progressive yes, but not loved by stock market investors

In an era when the major international oil companies are being asked to take increasing political, financial and technical risk by developing resources in often remote and hostile environments, PSC agreements make considerable sense. For the oil companies, they provide the sanctity of an internationally recognised legal contract and the comfort that the early revenues will, in large part, be applied to recovering invested capital until pay-back is achieved, thereby underpinning a healthy level of return on investment and minimizing economic downside. For the host nation, they allow a valuable, but often difficult to extract, resource to be monetized, exposing them to upside risk from oil markets but without risk to the state balance sheet. Indeed, there can be little doubt that without agreements of this nature much of the oil now arising from Angola and Nigeria's deepwater, the Caspian region or more hostile environs in Russia would not be in production.

Cost recovery generally a priority

Under most PSCs, a significant proportion of the revenues achieved from the sale of the oil or gas produced are available for cost recovery. For example in Angola, Azerbaijan and Malaysia amongst others, 50% of annual revenue is available to facilitate cost recovery by the contractor with that amount drawn on termed 'cost oil' (i.e. a maximum of this proportion of revenues may be used to recoup sunk-costs prior to any split of the proceeds between the contractor and the State). And to the extent that these 'cost oil' barrels do not cover all the costs incurred to date, unrecovered costs may be carried forwards to subsequent periods, often accruing interest or some other form of value uplift. Importantly, at times of industry cost inflation, this emphasis on cost recovery upon the commencement of revenues can be protective of project economics for the contractor at the expense of the state.

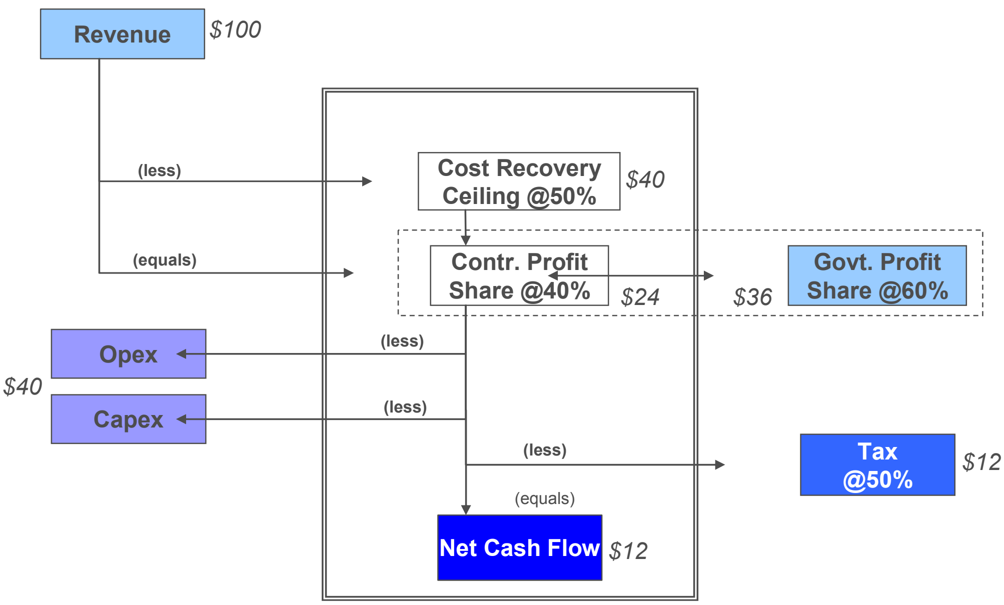
Under most PSCs, a significant proportion of the revenues achieved from the sale of the oil or gas produced are available for cost recovery

The remaining revenue, termed 'profit oil', is then allocated between the state and the contractors in accordance with the terms of the contract, the contractors taking their equity share of the profit oil, albeit this will then generally be subject to corporation tax.

A simple example of a PSC

This is illustrated by the schematic below which shows a $100 revenue project with costs of $40. Under the terms of the agreement up to 50% of revenues can be allocated for cost recovery (although in this example only $40 is required as 'cost oil' to recoup the costs incurred) with the balance of revenues (the 'profit oil') allocated between contractor and state in a hypothetical 40/60 ratio. The contractor is then liable for corporation tax at a hypothetical 50% on its share of the profit oil. As can be seen in our example all of the $40 costs are recovered with the contractor retaining some $24 of remaining $60 of revenues. On this a further $12 is then paid as taxation, the result being that of the net revenues of $60 the state achieves an income of $48 and the contractor $12.

Figure 155: Schematic depicting a PSC calculation and Net Cash Flow to the operating company



Source: Wood Mackenzie; Deutsche Bank

Trigger points – PSCs use various schemes

In most PSCs the allocation of profit will alter as certain contractual 'trigger points are attained'

Key within the PSCs is the allocation of profit oil between state and contractor. In most PSCs this allocation will alter as certain contractual 'trigger points' are attained. Invariably these trigger points will differ from contract to contract. In general, however, the variables used to determine the allocation of barrels tends towards four or so generic types. These are IRR based, production based, those based on a fixed share of profits (pre or post tax) and those based on the ratio of revenues to costs (the so called R-factor). Each of which is discussed below with the different PSC structures adopted by various different geographies also highlighted in the subsequent table.

IRR based PSCs: IRR based contracts are structured such that, depending upon the internal rate of return that the project has achieved, the share of profit oil barrels will alter. As with most PSCs they typically allocate a higher share of revenues to the contractor through the early phases of a project (to facilitate payback of sunk capital) but a greater share to the state as the contractors' capital is recouped and the rate of return on the project rises. Indeed, as their name suggests, changes in the allocation of barrels between state and contractor (trigger points) tend to be associated with the achievement of different internal rates of return. Countries which commonly use IRR-based contracts as a mechanism for determining share include Angola, Russia, Kazakhstan, and Azerbaijan, amongst others. In our opinion, the advantages of IRR based contracts are that they are generally geared towards rewarding the contractor first and directed at the achievement of an acceptable level of return. As such they are very protective of a company's upfront capital investment (particularly at times of cost inflation). The disadvantage, however, is that once that return has been achieved the change in barrel allocation tends to be quite severe. From the host country perspective, depending on the proportion of initial revenues that are available for cost recovery this can mean that the state receives little by way of revenue through the early years of a project. This has led to conflicts between state and contractor, particularly where cost increases have been evident (e.g. Sakhalin and Kashagan).

- **Production based PSCs.** These contracts generally tend to be written around cumulative production, with changes in total oil or gas produced driving the change in allocation (e.g. Nigeria Deepwater, Malaysian offshore, Egypt, etc). In some cases they may, however, be based on the absolute volume of daily production planned (e.g. Qatar). From the contractors' perspective the returns from production based contracts are particularly sensitive to shifts in the oil price as the tax take lacks a progressive link to this variable – upward moves in prices can be very positive, but likewise returns can deteriorate in the event of a downward shift. However, from the states' perspective the profitability of these contracts is less sensitive to upwards changes in the oil price than IRR based contracts because the change in allocation is based upon time to produce rather return achieved. Again, the State's delayed exposure to oil price rises can result in conflict (i.e. Nigeria DW).
- **R-Factor (revenue) based PSCs.** PSCs of this nature are based around trigger points that come into effect as certain ratios of revenue to cost are attained. As a consequence they are quite sensitive to the impact of rising oil prices, an event that is almost certain to ensure that trigger points are more rapidly attained. At the same time, however, because revenue allocation will almost certainly remain biased towards the contractor as long as the revenue/cost ratio is low they afford good cost protection at times of industry cost inflation. Examples of countries that tend towards R-factor based contracts include Yemen, Qatar and Libya.
- **Fixed share PSCs.** Although PSCs of this nature share profits between the state and the contractor, in reality because the allocation of profit oil is fixed they have much in common with tax and royalty arrangements. For the contractor, the advantage is that recovery of cost oil is given a priority - again providing protection at times of rising cost. That aside, given that the government's share of profit oil is fixed, they are not dissimilar to a concession. Examples of a fixed-share PSC include many of those written in Indonesia.

For companies and investors, hitting trigger points impacts several key metrics

Given that most PSCs are written to maximize the State's take from its resource base yet at the same time limit the contractors downside but incentivise their commitment to a project, the use of 'trigger points' for the allocation of resource makes considerable sense. However, the change in the allocation of production barrels between contractor and state holds several implications for company reporting. This is particularly true at times when the oil price is appreciating. Not least amongst these are the impact on reported growth and the contractor's entitlement to book reserves especially under contracts where the change in profit oil allocation is triggered by the contractors' IRR or revenue/cost ratio.

Growth may ostensibly falter and reserves ostensibly fall

The issue here is that in the face of a rising oil price the contractor will find that, because the oil produced is worth more, it recoups its capital and hits the contractual trigger points more rapidly than would have been the case at a lower oil price. As such, its entitlement to crude oil under the contract terms will almost certainly decline. Thus

Figure 156: International PSCs: Broad terms on a collection of PSC's compared- watch out for the type, terms on cost oil recovery, the movement in share from high to low and capex uplift, amongst others

Country	Angola	Nigeria DW	Azerbaijan	Malaysia
Example	Block 17	Bonga	ACG	MLNG
Royalty	None	0-12% (depth dependent)	None	10%
Capex uplift	50%	50% for tax purposes	LIBOR plus 4%	None
Cost Oil	Capex over 4 years	Capex over 5 years	Approved capex	Over 10 years
Cost recovery ceiling	55% revenues	100% revenues	50% revenues post opex	50% oil, 60% gas revenues
Profit oil split	IRR based	Production based	IRR based	Production based
Max (contractor/state)	75/25 @ IRR <15%	80/20 @ < 350mb	70/30 @ <16.75%	<2.12TCF 50/50
Min (contractor/state)	20/80 @ IRR >30%	40/60 @ >1500mb	20/80 @ >22.75%	>2.12 TCF 30/70
Tax rate	50%	50%	25%	38%
Companies	XOM, TOT, BP, CVX	RDS, TOT, XOM, ENI	BP, STL	RDS
Comments	Good cost protection but the switch in barrels is very marked as IRR moves	Good on costs and recovery. Move in rates is also quite favourable.	Huge swing on very small recovery boost in IRR	Stable but contracts tend to be finite with reversion to state.

Country	Russia	Qatar	Khazakstan	Indonesia
Example	Sakhalin II	Qatargas 1	Karachaganak	Offshore Mahakam
Royalty	6% revenues	None	None	20% FTP
Capex uplift	None	None	None	17% credit
Cost Oil	Capex over 3 years with c/f	Straight line at 20%	Capex over 5 years	Capex depreciated
Cost recovery ceiling	100% revenues	65% condensate revenues	60% revenues	100% post FTP
Profit oil split	IRR based	Production based	IRR based	Fixed (post tax)
Max (contractor/state)	90/10 @ <17.5%	65/35 @ <38kboe/d	80/20 @ <0%	15/85 Oil (fixed)
Min (contractor/state)	30/70 @ > 24%	10/90 @ > 80kboe/d	20/80 @ > 20%	30/70 gas (fixed)
Tax rate	32%	35%	30%	48%
Companies	RDS, XOM	TOT, RDS, XOM	ENI, BG, TOT, XOM, CVX	TOT, ENI, CVX
Comments	The state stood to receive next to nothing. Very favourable for contractor	Not very generous but lower tax	OK on recovery but low share of profit oil	Good recovery but not very generous share

Country	Egypt	Trinidad	Algeria	Libya
Example	West Delta Deep	North Coast Marine	In Amenas	NC186
Royalty	Paid by state oil company	None	10-20% but state may pay	None
Capex uplift	None	None	None	None
Cost Oil	20-25% costs p.a. recoverable	All costs	6 years straight line	
Cost recovery ceiling	From 40% of domestic revenues, 30% on LNG	Max 80% revenues less 25mboe	Revenue remaining after state has taken its share	Recovered from 35% production.
Profit oil split	Production based	Cumulative production but also with a view on price	IRR based but also with an oil price factor	Payback and production based
Max (contractor/state)	LNG 60/40; Domestic<150mmcf/d 60/40	>$2mmcf/d and <60mmcf/d 47/53	IRR<10% split 80/20	From 100% of IOC allocation (35% pre costs)
Min (contractor/state)	LNG 60/40; Domestic >900 mmcf/d 80/20	>$2mmcf/d and >450mmcf/d 19/81	IRR>14% split 10/90	From 30% of IOC allocation (35% pre costs)
Tax rate	40%	50%	30% but typically met by the state	None
Companies	BG, Petronas	BG, ENI	BP, Statoil	Repsol, Total, OMV, Occi
Comments	Share of profits into LNG is largely fixed. Low cost recovery reduces capex effect	If production stable little change in barrel take	Harsh terms, steady flow but limited IRR available	

Source: Deutsche Bank, Wood Mackenzie

although payback is accelerated with strong potential positives for both the project's IRR and NPV, the contractors' share of the barrels produced declines and in some cases rapidly.

Growth may ostensibly falter and reserves ostensibly fall

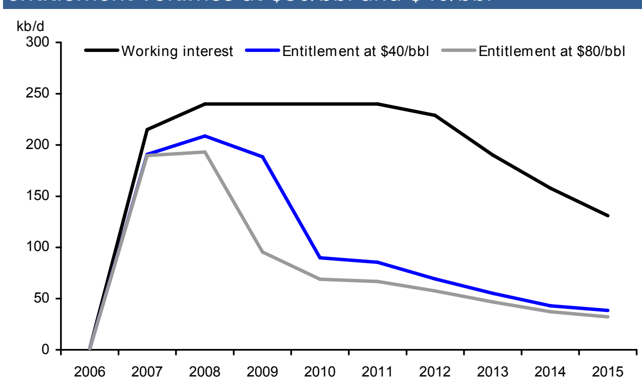
The issue here is that in the face of a rising oil price the contractor will find that, because the oil produced is worth more, it recoups its capital and hits the contractual trigger points more rapidly than would have been the case at a lower oil price. As such, its entitlement to crude oil under the contract terms will almost certainly decline. Thus although payback is accelerated with strong potential positives for both the project's IRR and NPV, the contractors' share of the barrels produced declines and in some cases rapidly.

Equally, because fewer barrels will be required for the contractor to be 'paid' its share of value under the production sharing contract, in accordance with SEC reserve accounting requirements its contractual entitlement to reserves is also reduced. This represents another key feature of PSCs, namely that under SEC rules, reserve bookings suffer in a rising oil price environment.

Value up, barrels down – an Angolan illustration

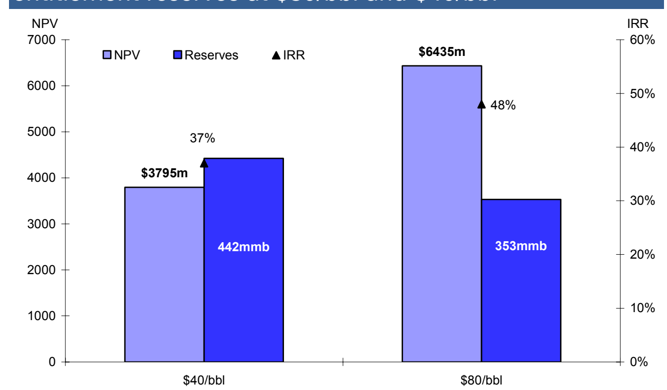
This is well illustrated by the following diagrams which depict the contractors working interest and entitlement share to production barrels in a typical Angolan PSC at different oil prices together with the different NPV's, IRRs and entitlement to reserves. What it emphasizes is that whilst the faster recovery of capex and profit share at $80/bbl oil results in both a higher NPV (c$2.6bn increase) and IRR (c11% increase) than at $40/bbl, reported production and reserves are both significantly reduced.

Figure 157: Angola's Dalia project – Working interest and entitlement volumes at $80/bbl and $40/bbl



Source: Wood Mackenzie; Deutsche Bank

Figure 158: Angola's Dalia project – NPV, IRR and entitlement reserves at $80/bbl and $40/bbl

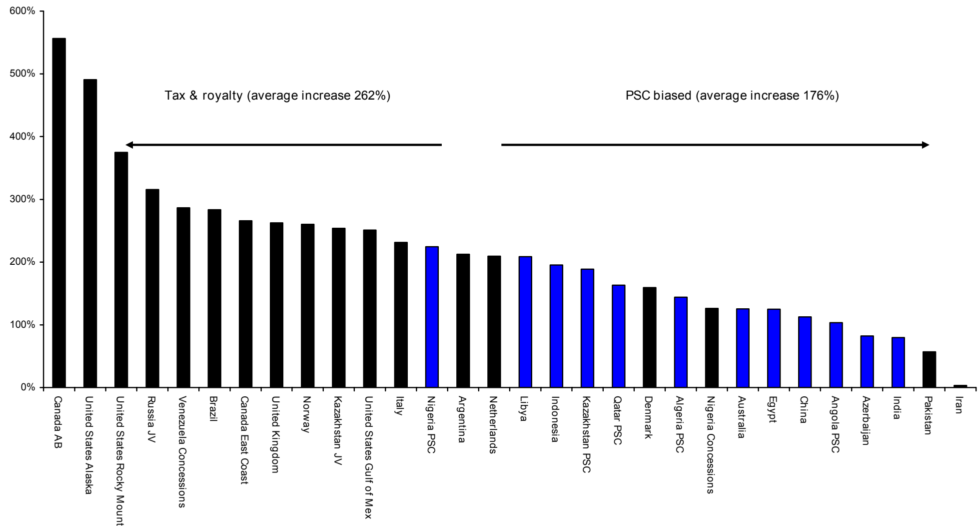


Source: Wood Mackenzie; Deutsche Bank

Consider value not reported barrels

Ultimately, the increase in project value for the contractor (and thus shareholder) should be seen as the key determinant of corporate value and, as the previous example illustrated, value for the contractor has increased at the higher oil price. However, in a stock market where reported production is seen as representative of a company's growth potential and reserves an indicator of business sustainability, the apparent deterioration in both these metrics is not particularly helpful. For even though overall value may have increased, investor perception is that production is declining and reserves faltering – neither of which is likely to be perceived as a positive.

Figure 159: Average % increase in contractor NPV in various regimes based on $75/bl vs. $25/bl oil (Black = Tax & Royalty, Blue = PSC)



Source: Wood Mackenzie; Deutsche Bank

Ceteris paribus – concessions are more geared to price

Moreover, with a greater proportion of the value now accruing to the resource holder, the strong (and accurate) perception is also that the oil company has signed away much of its exposure to the rise in oil prices. As illustrated by the above diagram which depicts the increase in value evident under various different tax regimes given a change in oil prices, for the contractor the upside from a movement in the oil price is certainly greater in concessions than under PSCs. What this does of course overlook is our earlier comment on government behaviour under progressive and regressive tax regimes. Allocate too much of the upside to the contractor, and it will not be long before governments elect to capture their fair share through the introduction of some form of windfall tax.

The upside from a movement in the oil price is certainly greater in concessions than under PSCs

Working through an IRR based PSC

As an example of how different oil prices affect the cash flows, IRR and barrel share of an IRR-based PSC we have taken Wood Mackenzie's assumptions around the Angolan Dalia field and, through building two models one at $60/bbl oil and the other at $40/bbl tried to explain the mechanics and the different outcomes (note that it is not the absolute oil price which matters in these worked examples, but rather the directional impact on entitlement production, cash flow, unit NPV and IRR for a given change in price).

Shown in the Figures overleaf, our models work from the assumptions depicted in the below table together with Wood Macs estimates of capex and opex. The table below details the workings and mechanics of the calculations.

Fewer barrels but greater NPV and a higher IRR

The results emphasise the very different production profiles of the two price outcomes. Most particularly, at $60/bbl the decline in entitlement production is almost as dramatic as the ramp up. However, even allowing for this the cash flow per barrel generated is substantially higher. Most significantly, both the NPV and the IRR of the project are significantly higher at the higher oil price. Thus while barrels may be lower, it is important to remember that at higher oil prices under IRR based PSC's companies create greater value.

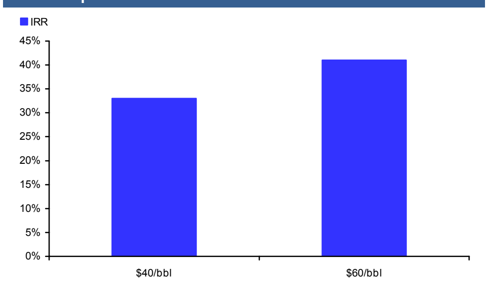
Barrels may be lower, it is important to remember that nevertheless at higher oil prices under IRR based PSC's companies create greater value

Figure 160: Angolan Deepwater PSCs: Broad terms (Block 17)

Term	Details
Development license	Typically 25 years from license grant
Signature bonuses:	Non-recoverable
Capex uplift	40% of capex (i.e. $1.4bn for $1bn of spend).
Cost oil	A maximum of 55% of revenue in the period. Excess cost is carried forward.
Cost recovery	Opex plus capex uplifted at 40% but amortised over 4 years straight line
Profit oil split	IRR based as follows
Order of recovery	Capital cost with uplift, operating costs, exploration costs
IRR <15%	25% state/75% contractor
IRR < 25%	40% state/60% contractor
IRR <30%	60% state/40% contractor
……IRR < 40%	80% state/20% contractor
……IRR > 40%	90% state/10% contractor
Corporate tax	50% of profit oil
Foreign oil company share	Their interest (%) in the post tax profit oil

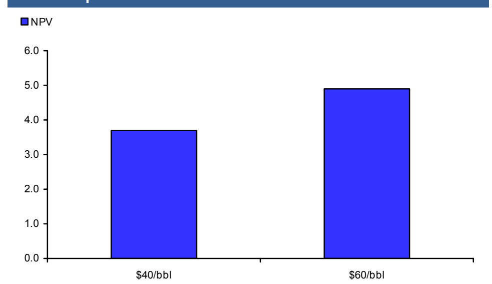
Source: Deutsche Bank, company data

Figure 161: Dalia: IRR at different oil price assumptions



Source: Wood Mackenzie; Deutsche Bank estimates

Figure 162: Dalia; NPV's at different price assumptions.



Source: Wood Mackenzie; Deutsche Bank estimates

Figure 163: Angola's Dalia - Estimated entitlement share and breakdown of contributing components at $60/bbl

	Gross output b/d	Capex $m	Uplift (40%)	Available for recovery	OPEX	Revenue $m	Cost Oil Limit	Available to recover in year	Cost Oil recovered	Cost oil c/f	Cost Oil Barrels kb/d	Profit oil ($m) (C-F)	Profit Oil share (% split)	Profit oil barrels (kb/d)	Entitle-ment barrels (kb/d)	Estimate of IRR %	Cash-flow per barrel ($)
NOTE			A	B		C	D	E	F	G	H	I	J (per M)	K	L (H+K)	M	N
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2004	0.0	700.0	980.0	245.0	0.0	0.0	0.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2005	0.0	900.0	1260.0	560.0	0.0	0.0	0.0	805.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2006	90.0	1300.0	1820.0	1015.0	91.1	1872.5	1029.8	1911.1	1029.8	881.2	49.5	842.6	75%	30.4	79.9	n.a	
2007	225.0	328.0	459.2	1129.8	156.5	4681.1	2574.6	2,167.5	2167.5	0.0	104.2	2513.6	75%	90.6	194.8	-0.2%	-4.3
2008	225.0	273.2	382.4	980.4	160.4	4681.1	2574.6	1,140.8	1140.8	0.0	54.8	3540.3	68%	114.9	169.7	24.8%	24.2
2009	225.0	215.4	301.5	740.8	164.4	4681.1	2574.6	905.2	905.2	0.0	43.5	3775.9	30%	54.4	98.0	31.5%	24.1
2010	225.0	176.6	247.3	347.6	164.4	4681.1	2574.6	512.0	512.0	0.0	24.6	4169.1	20%	40.1	64.7	34.0%	22.0
2011	220.0	0.0	0.0	232.8	161.9	4577.1	2517.4	394.7	394.7	0.0	19.0	4182.4	20%	40.2	59.2	35.9%	19.8
2012	210.0	0.0	0.0	137.2	157.0	4369.1	2403.0	294.2	294.2	0.0	14.1	4074.8	20%	39.2	53.3	37.0%	24.8
2013	199.1	0.0	0.0	61.8	151.7	4142.3	2278.3	213.5	213.5	0.0	10.3	3928.8	20%	37.8	48.0	37.7%	24.5
2014	165.3	0.0	0.0	0.0	135.0	3438.1	1890.9	135.0	135.0	0.0	6.5	3303.1	20%	31.8	38.2	38.0%	24.2
2015	137.2	0.0	0.0	0.0	121.2	2853.6	1569.5	121.2	121.2	0.0	5.8	2732.4	20%	26.3	32.1	38.3%	23.7

Source: Deutsche Bank, Wood Mackenzie

Notes

A) Uplifts capex at 40% (i.e. multiplies by 1.4x) as per Angolan terms.

B) Capex available for recovery. This is 25% of the uplifted capex of the year plus 25% of that of each of the previous three years i.e. 4 year straight line recovery.

C) Revenue is the number of barrels produced multiplied by the oil price ($60/bbl Brent) less a 5% discount for quality and location.

D) Cost oil limit. This is calculated by multiplying total revenues by 55% - the maximum permissible recovery factor.

E) Available to recover are the total costs that have been incurred (OPEX and uplifted Capex) that could be recovered in the year. It is equivalent to OPEX plus capex available for recovery in the year PLUS any un-recovered capex from the previous yearcarried forwards

F) The cost oil actually recovered. This is either the maximum available cost oil or the 'available for recovery' capex and opex in that year

G) Carried forwards capex is that eligible for recovery in prior years but which could not be recovered due to insufficient cost oil being available.

H) The value of cost oil in barrels per day i.e. cost oil divided by the price per barrel.

I) Profit oil – Gross revenues less those absorbed by cost oil

J) Profit oil split. This is dictated by the IRR and we believe is assessed on a quarterly basis. As prefigure 49, initially the split runs 75% contractor/25% state. But with the IRR (column N) rising rapidly, the split quickly falls.

K) This is the profit oil x the appropriate share expressed in barrels of production per day (i.e. revenues/oil price/0.365)

L) Entitlement barrels. This is the sum of the cost oil received (Column H) and that paid as profit oil (column K).

M) IRR %. This is our estimate of the return of the project per year. Although not shown here (we couldn't fit the columns on) it represents the implied return from the revenues received in total less the costs incurred after taxation at 50%

N) Cash flow per bbl – The cash flow achieved after tax at 50%. Thus revenue less costs less tax divided by total barrels of entitlement (kb/d * 365)/

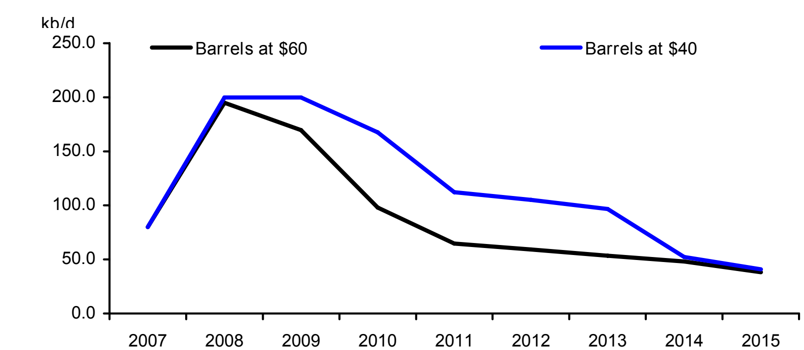
Figure 164: Angola's Dalia - Estimated entitlement share and breakdown of contributing components at $40/bbl

	Gross output b/d	Capex $m	Uplift (40%)	Available for recovery	OPEX	Revenue $m	Cost Oil Limit	Available to recover in year	Cost Oil recovered	Cost oil c/f	Cost Oil Barrels kb/d	Profit oil ($m) (C-F)	Profit Oil share (% split)	Profit oil barrels (kb/d)	Entitle-ment barrels (kb/d)	Estimate of IRR %	Cash-flow per barrel ($)
NOTE			A	B		C	D	E	F	G	H	I	J (per M)	K	L (H+K)	M	N
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2004	0.0	700.0	980.0	245.0	0.0	0.0	0.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2005	0.0	900.0	1260.0	560.0	0.0	0.0	0.0	805.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2006	90.0	1300.0	1820.0	1015.0	91.1	1248.3	686.6	1911.1	686.6	1224.5	49.5	561.7	75%	30.4	79.9	n.a.	
2007	225.0	328.0	459.2	1129.8	156.5	3120.8	1716.4	2,510.8	1716.4	794.4	123.8	1404.3	75%	75.9	199.7	-16.8%	-4.9
2008	225.0	273.2	382.4	980.4	160.4	3120.8	1716.4	1,935.1	1716.4	218.7	123.8	1404.3	75%	75.9	199.7	10.5%	15.7
2009	225.0	215.4	301.5	740.8	164.4	3120.8	1716.4	1,123.9	1123.9	0.0	81.0	1996.8	60%	86.4	167.4	21.6%	16.0
2010	225.0	176.6	247.3	347.6	164.4	3120.8	1716.4	512.0	512.0	0.0	36.9	2608.8	40%	75.2	112.1	25.7%	15.9
2011	220.0	0.0	0.0	232.8	161.9	3051.4	1678.3	394.7	394.7	0.0	28.5	2656.7	40%	76.6	105.1	28.6%	14.8
2012	210.0	0.0	0.0	137.2	157.0	2912.7	1602.0	294.2	294.2	0.0	21.2	2618.5	40%	75.5	96.7	30.4%	16.9
2013	199.1	0.0	0.0	61.8	151.7	2761.5	1518.8	213.5	213.5	0.0	15.4	2548.0	20%	36.7	52.1	31.0%	16.8
2014	165.3	0.0	0.0	0.0	135.0	2292.1	1260.6	135.0	135.0	0.0	9.7	2157.0	20%	31.1	40.8	31.3%	15.0
2015	137.2	0.0	0.0	0.0	121.2	1902.4	1046.3	121.2	121.2	0.0	8.7	1781.2	20%	25.7	34.4	31.5%	14.5

Source: Deutsche Bank, Wood Mackenzie

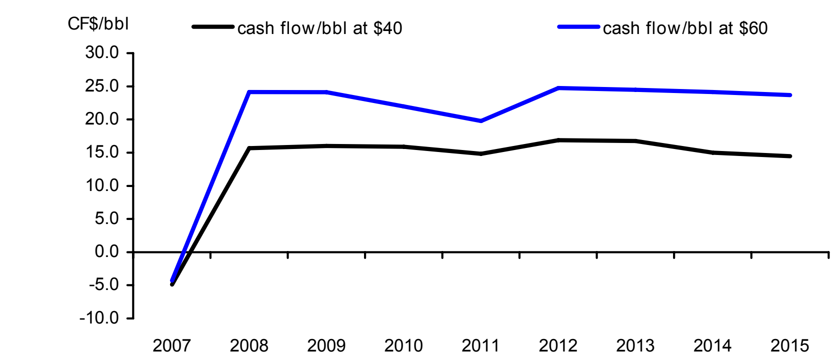
Notes: The same table but tabulated at $40/bbl Brent instead of $60. The key differences are depicted in the charts below. Note how lower revenues lead to an increase in the time taken to recover cost oil and so detract from the IRR. With the IRR staying lower for longer, profit share favours the contractor for a far longer period with the 20% trigger point taking far longer to reach. Yet despite higher barrels, cash flow per barrel is markedly lower than at $60.

Figure 165: Kb/d under different oil price scenarios ($60 vs. $40/bbl)



Source: Deutsche Bank

Figure 166: Cash flow per bbl under different price estimates ($60 vs. $40)



Source: Deutsche Bank

Buy Backs

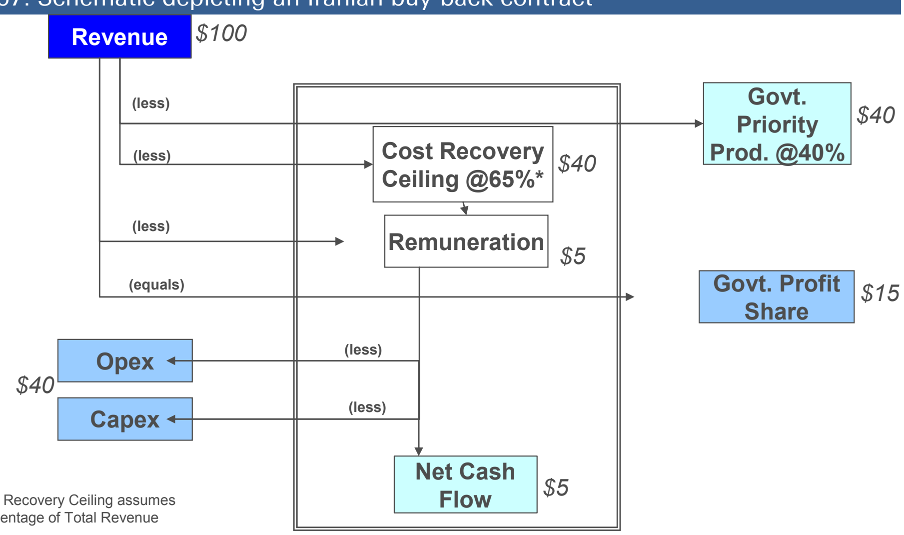
In almost every major oil producing territory, hydrocarbon taxation takes the form of either a concession or production sharing contract. There is, however, one major exception: Iran. In addition, we note that Mexico has introduced a limited number of service contracts to allow some level of inward investment without disturbing sensitivities about foreign ownership of reserves,

Due to constitutional restrictions and Iran's suspicions of foreign investors in the oil and gas sector, the concept of 'buy backs' or service contracts was introduced as a controlled and workable vehicle for foreign investment. Buy backs are essentially service contracts in which the Iranian National Oil Company, NIOC, subcontracts certain aspects of its responsibilities to a foreign party. No other form of direct investment in the oil gas industry is allowed by foreign persons or companies under current regulations.

Buy backs are essentially service contracts in which the Iranian National Oil Company, NIOC, subcontracts certain aspects of its responsibilities to a foreign party.

Although inward investment into Iran has since been constrained by US-led sanctions, the participation of the international majors in such contracts and their willingness to accept returns capped around the mid-teens is testimony to the level of competition in the sector for access to quality assets.

Figure 167: Schematic depicting an Iranian buy-back contract



Note: *Cost Recovery Ceiling assumes percentage of Total Revenue

Source: Wood Mackenzie; Deutsche Bank

Under a buy back contract the foreign investor will not own any part of the Iranian oil or gas field. The contractor is the designated operator for design, construction, commissioning and start up of all facilities and this responsibility passes to NIOC immediately after start up. The foreign partner provides all the capital for the project and is compensated for its costs and awarded an agreed level of profit. The details of the development programme are contained in the field Master Development Plan, which clearly states the work to be performed and the agreed capital cost for such work.

Cost Recovery

Illustrated by the schematic above, under the contract the contractor is compensated for all capital and operating costs and bank charges incurred in fulfilling the specifications of the Master Development Plan. Costs due for recovery are amortised over an agreed number of years (generally five to ten years) from the date of first production. Any costs, which cannot be recovered in any given period, are carried forward and recovered with interest in subsequent periods. If the actual field costs are greater than anticipated then the extra cost is borne solely by the contractor and the additional costs are not eligible for cost recovery.

The result is a contract in which the contractor essentially takes significant risk for the return of what has over time become an ever more modest level of reward. Upside is often negligible with several companies in recent years suffering significant write-downs as a consequence of industry inflation increasing costs to the point of non-recovery (Statoil in particular comes to mind). Looking forward, with considerable uncertainty now presiding around future investment in Iran and many of the contracts currently in place coming towards an end, we think Iranian buy backs are likely to become an even less significant feature of company portfolios for some years to come.

Oil & Gas Taxation – Some Key Terms

Production Sharing Contract (PSC): A contract between a resource holder and (generally) an oil company where the oil produced is shared between the resource holder and contractor (oil company) in a pre-arranged manner.

Tax & Royalty regime (concession): A regime under which an oil company is granted a concession to prospect for and extract hydrocarbons. From the revenues generated the concession holder will typically pay a pre-agreed royalty on revenues together with corporation tax on profits.

Cost Oil. Share of barrels produced that is used to pay back the contractor for its capital investment in the project and/or the operating expenses incurred in the year. Typically the resource holder will allow cost oil to be recovered from c.50-60% of project revenues. Once the upfront capital costs have been recovered (generally high in the first years of a project coming on-stream), anything left over is termed profit oil. Capital or operating costs that remain un-recovered in any one year are typically carried forwards for recovery in subsequent years.

Profit Oil: The oil available for distribution to the partners in the project in line with their equity (or working interest) share. Profit oil is invariably that available after costs (capital and annual operating) have been recovered.

Capex uplift. The % increase granted by the state on capex spend for recovery against costs. For example, in Angola's Block 17 capex is uplifted for recovery against revenues at a rate of 50% i.e. on capital spend of $1.0bn, the contractor will be able to recover $1.5bn against cost oil. The allocation of uplift pays heed to the time that it might take to recover capex invested in a project given restrictions on cost recovery (as a % of revenues) and the time taken from breaking ground to first oil in a development project.

Trigger points (our terminology). The conditions laid out in the PSC contract, the attainment of which lead to changes in the allocation of profit oil share between the state and the contractor.

Working interest: The contractor's percentage interest in the project as a whole. Thus if a company has a 40% interest in a project producing 100kb/d its working interest in that project would be 40kb/d.

Entitlement share: The number of barrels of profit oil which the contractor is entitled to from the project in any one year. This will typically represent the contractor's share of cost oil and its equity entitlement to profit oil. Depending on the nature of the PSC terms, the entitlement share will alter over the life of the project as costs are recovered and the oil available for distribution as profit alters following the attainment of trigger points. As an illustration, if a company has a 40% equity interest in a project producing 100kb/d, the profits from which are distributed 50% government and 50% contractor after 10kb/d has been allocated for cost recovery, its share of entitlement barrels would be 22kb/d (i.e. 40% of the 10kb/d of cost oil and 40% of the 45kb/d available to the contractors as profit oil). Note this compares with the 40kb/d in which the contractor has a 'working interest'.

IRR based PSC. A PSC whose trigger points are determined by the internal rate of return achieved from the date of onset. As the returns from a project move beyond pre-defined levels, so the share of profit oil will alter in favour of the host nation. Common examples include those in Angola, Azerbaijan, Kazakhstan and Russia amongst others.

Production based PSC. A PSC whose trigger points are determined by the achievement of particular levels of production. In some production contracts the production element refers to the cumulative number of barrels produced. In others, the level of daily production achieved. In either case, as the trigger levels are attained, the share of profit oil between the state and the contractor alters. Common examples include those in the Nigerian Deepwater, Qatar, Malaysia, India and many others.

R-factor (and R-factor based PSC). A PSC whose trigger points are determined by the ratio of total revenues to total costs. Typically the contract will stipulate that as revenues meet certain multiples of costs so the share of profit oil between the state and the contractor alters. Common examples include Algeria, Qatar (often mixed with production) and the Yemen.

Fixed share PSC. A PSC which stipulates at the onset the division or post tax or pre-tax profits from the project between the state and the contractor. In effect, these contracts have economics that are similar to those of a tax and royalty regime. Indonesia represents a good example of a fixed share PSC.

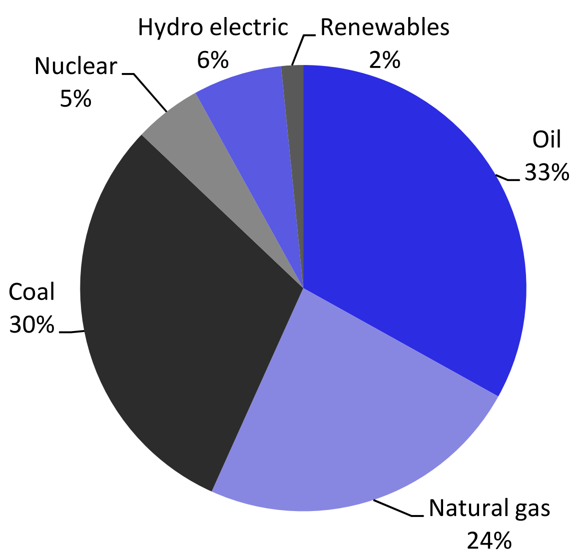
World Oil Markets

Fundamentals, physical and financial

Oil remains the world's most important source of energy

For many years, oil has been the world's most important source of energy, meeting 33% of global energy needs in 2011 (natural gas 24% and coal 30% are its nearest rivals). This has resulted in the oil becoming the world' largest traded commodity, whether measured by value or volume. Indeed, the physical crude oil market would be worth some USD3.3 trillion per year were we to assume a constant reference price of USD100/bbl applied to 2012 global demand of c.90mb/d. Unsurprisingly for a market of this global reach and physical/financial size the price reflects the interaction of myriad considerations around supply/demand fundamentals and risk factors. Furthermore it is probably fair to assert that in recent times the market has become increasingly complex, not least due to the role of financial investors, leading to debate about the relationship between the commodity prices and physical fundamentals. In this section we examine the various different components of oil markets and how they ultimately impact the oil price.

Figure 168: World Primary Energy Consumption by fuel in 2011



Source: BP Statistical review 2010

Key exchanges and benchmarks

The main traded benchmarks for oil are Brent (traded on ICE) and WTI (traded on NYMEX)

The main international exchanges for the trading of oil and oil products (both physical and financial) are the New York Mercantile Exchange (Nymex) and the Intercontinental Exchange (ICE, formerly the International Petroleum Exchange in London). Both exchanges trade spot contracts for immediate delivery and future contracts for delivery at a later date, providing hedging, speculating and price discovery opportunities. Given the large number of crudes and the difficulty in following them all, two benchmark crudes are widely used; West Texas Intermediate (WTI) on Nymex and Brent crude on ICE. While these are used as indicative oil prices, most other crudes will trade at a discount or premium depending on their gravity and sulphur content (refer to section on crude for detail on gravity and API and refining for detail on the 'heavy-light spread'). Turning to products, the key pricing benchmarks are US RBOB gasoline, US heating oil and European gasoil.

Nymex WTI: WTI is the largest exchange-traded commodity, with traded volumes often being four times that of Brent. However, WTI is primarily consumed by refineries situated in the US mid-continent and as a consequence price is very dependent upon regional supply/demand dynamics, something that has become increasingly apparent in recent years with the renaissance of North America supply driving WTI to a substantial price discount to comparable seaborne crudes. As such, WTI is a relatively weak barometer of prevailing fundamentals in seaborne crude markets meaning that very little of the world's physical volumes are actually priced against it. Nonetheless, in recognition of the liquidity of the contract and the importance of the US as the largest global consumer of crude, WTI remains an important and closely watched point of reference. Another interesting point to bear in mind with WTI is that it is settled physically with delivery taking place at Cushing, Oklahoma.

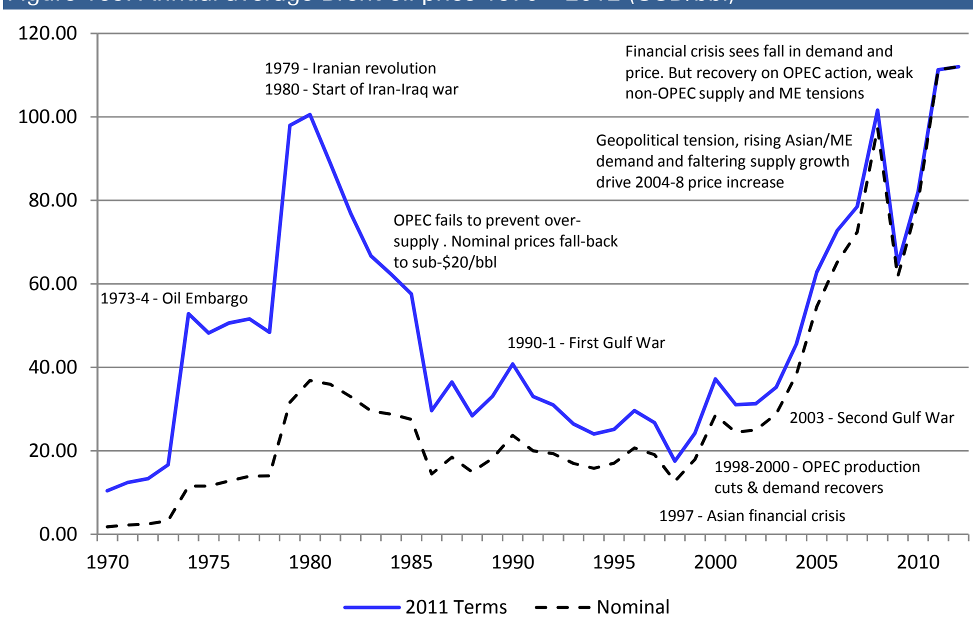
ICE Brent: Brent futures are tied to the North Sea physical market and comprise four key crude streams: Brent, Forties, Oseberg and Ekofisk (BFOE). Unlike WTI, Brent is settled financially (i.e. there is no physical delivery upon contract expiry). Instead, the value upon expiry is equivalent to the Brent Index, which is set on a daily basis by the exchange and is the weighted average of all trades in the physical market for the month in question for each of the four crude streams. Brent is a far more complex financial instrument than WTI in that not only is it comprised of futures and a physical forward market (BFOE), there is also a physical spot market, Dated Brent. This sets the price for most of the global physical market and as such is of huge importance. The value of Dated Brent is set every day at 16:30GMT and is assessed by Platt's as the value of the cheapest crude in the BFOE group on that day.

The oil price

The nominal price of oil has fluctuated significantly throughout the years, from the lows of USD2.5/bbl seen in the 1940-70's to the highs in 2008 of near USD150/bbl. However, looking through day-to-day price movements, 2012 set a new high for the annual average oil price, despite the lingering effects of the financial crisis.

2012 represent the highest ever annual average oil price at $111/bbl.

Figure 169: Annual average Brent oil price 1970 – 2012 (USD/bbl)



Source: BP Statistical Review of World Energy 2011, Deutsche Bank

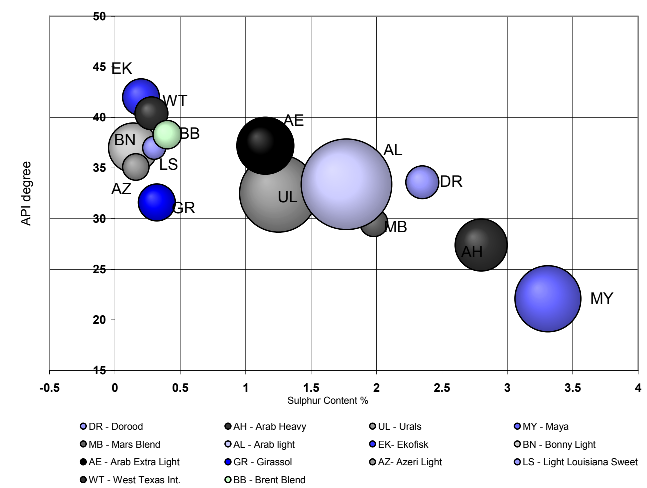
Different crudes; different prices

The pricing of different crude lends varies according to physical characteristics and specific S/D dynamics.

It is worth noting that although crude is supplied into a fungible market, different price points exist in physical markets for the various crude blends to reflect differences in their chemical characteristics (which influences the value of the resulting product slate) and in some cases localised supply/demand dynamics. Typically the various crude blends will trade in a well defined range relative to one-another, although in periods where the supply/demand characteristics of a given crude alter, the price premium/discount will correspondingly move.

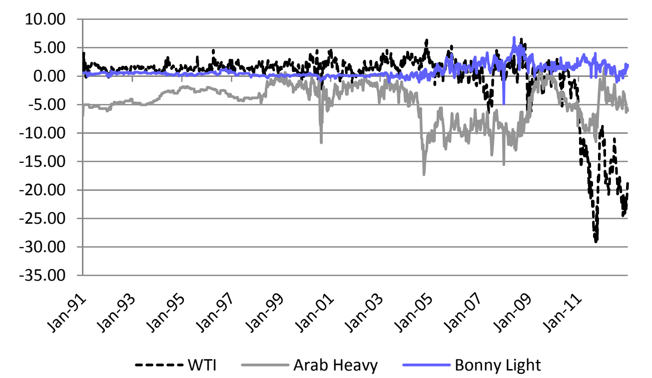
The clearest recent example of how localised supply/demand trends can cause deviation in the relative pricing of crude blends is provided by the recent evolution in the price of WTI relative to other grades. The recent growth in onshore US production driven by the emergence of a series of tight oil plays has fundamentally altered supply/demand dynamics at the pricing point for WTI (a surfeit of supply relative to refining capacity) leading the price of WTI to decline relative to other crudes to accommodate the cost of transporting the crude to alternative refining centres. We consider the growth in US onshore supply in the Unconventionals section of this report.

Figure 170: Quality (API & sulphur content) and relative quantity (bubble size) of various crude blends (2006)



Source: Deutsche Bank, ENI World Oil & Gas Review

Figure 171: Trading premium/discount of various crude blends relative to Brent ($/bbl)



Source: Bloomberg Finance LLP, Deutsche Bank

What factors determine the price of crude?

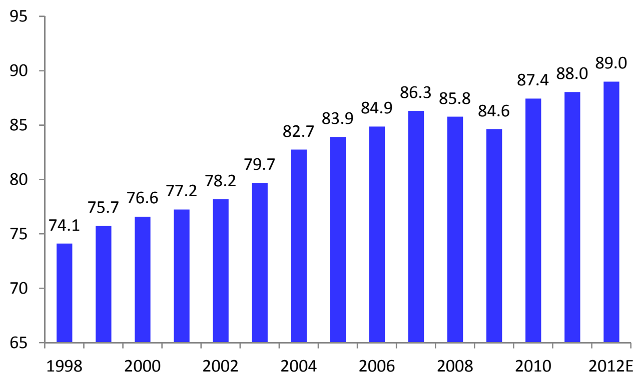
Returning to our main point, there are many factors which affect the oil price; the most important being supply and demand fundamentals. In addition, the strength of the US dollar, given that oil is traded in this currency, and of course geopolitics and OPEC action/rhetoric are important factors. We also note that the growth of commodities as a financial asset class for investors has added a further angle to the oil price debate, particularly around the role of speculation in price formation. Other factors that impact the oil price include inventory levels, oil product markets and OPEC spare capacity. We now consider a number of these factors.

Oil Demand

Crude demand has seen a 1.3% CAGR since 1990

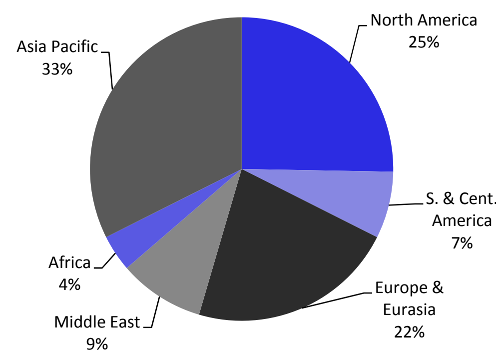
Demand for oil has experienced sustained growth worldwide over the past 15 years, with 2008/9 the exception. In 2009, the level of world demand is estimated to have stood near 84.6mb/d, down from a peak of 86.3mb/d in 2007, reflecting the impact of the financial crisis. However, demand has recovered and for 2012 is expected to be some 3% above the 2007 pre-crisis peak.

Figure 172: World oil demand, 1998-2012e (mb/d) – A 1.3% CAGR in global demand



Source: BP Statistical Review of world Energy, 2012

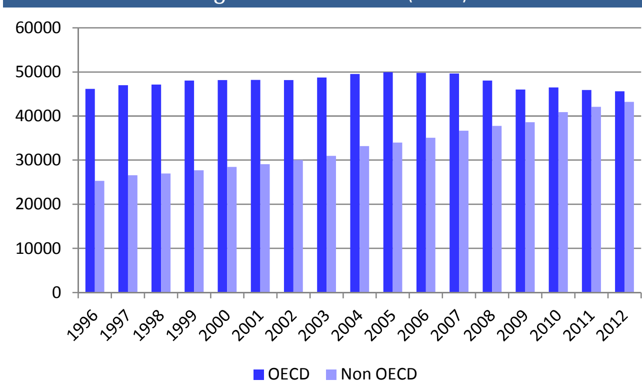
Figure 173: Regional breakdown of world oil demand 2009 (%)



Source: BP Statistical Review of world Energy, 2012

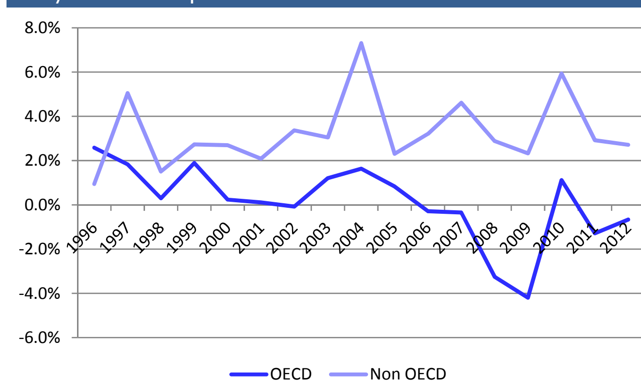
Demand growth over this period has been driven primarily by non-OECD where a c3% 1996-2012E CAGR compares to stagnation in OECD demand. Indeed, we note that in absolute terms non-OECD demand is close to surpassing that of OECD and should do so within the next 3 years based on our projections.

Figure 174: Absolute crude demand from non-OECD is close to over-taking OECD demand (kb/d)



Source: BP Statistical Review of World Energy, 2012

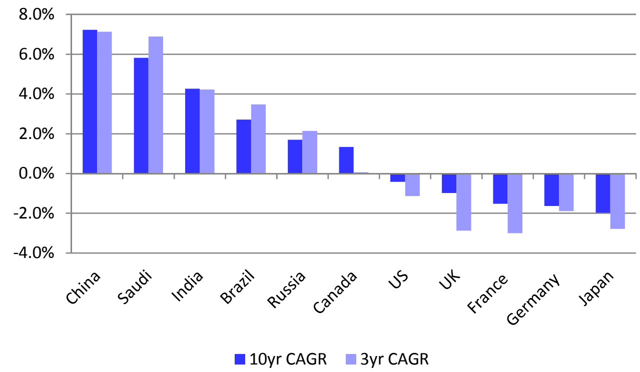
Figure 175: Non-OECD demand growth has averaged a fairly stable 3% p.a. in stark contrast to declines in OECD



Source: BP Statistical Review of World Energy, 2012

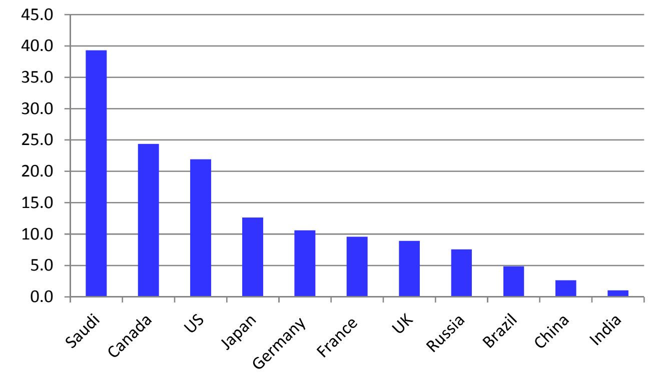
The divergence of growth rates between non-OECD and OECD is placed into sharp relief when we consider the demand evolution from the key consuming countries. China, India and Brazil in particular have seen strong demand growth driven by rapid industrialisation and a strong GDP-Oil Demand growth multiplier. Saudi and Russia have also seen strong demand growth, with domestic consumption supported by rising export revenues given their status as the largest exporters of crude/product. It is worthy of note that despite the pace of demand growth sustained for 15 years by China, India and Brazil, the per capita consumption in each of these countries remains materially below the 10bbls/capita average of the largest EU consuming nations. This hints at the structural underpinning for continuing strong growth rates from these countries.

Figure 176: Avg. growth rate of oil demand – non-OCED nations have been key drivers over last 10 years



Source: BP Statistical Review of World Energy, 2012

Figure 177: 2011 Oil consumption bbls/capita/p.a. – China, India & Brazil have low per capita demand despite growth



Source: BP Statistical Review of World Energy 2012, CIA World Fact book

Looking forward, the IEA forecasts (*IEA Medium Term Oil Market Report 2012*) that global oil demand will rise by 1.3% CAGR – essentially in-line with the trailing 15 year average growth rate – between 2012 and 2017 assuming an average c3.9% p.a. GDP growth rate over this period. Striking, however, is the mix, with non-OECD expected to account for all of the incremental demand, expanding at a 2.9% CAGR over the period to 2017 to account for 53% of global demand. By contrast OECD is expected to continue to stagnate with demand declining at a 0.4% CAGR to 2017 (around 200kb/d).

China looks set to consolidate its position as the second largest oil consumer worldwide.

Within these projections China is expected to see the strongest growth, at a 3.5% CAGR – admittedly below the c7% of the past 10 years as the pace of GDP growth moderates and the GDP/Oil demand multiplier softens given some liquids-for-gas substitution, a focus on energy efficiencies and a gradual maturation of the shape of economic activity. Nonetheless 400kb/d p.a. of expected growth should see China consolidate its position as the second largest consumer of crude at approaching 11.3mb/d by 2017. And despite stagnant demand growth, the US is expected to comfortably retain its position as the largest consumer of crude at c18.7mb/d by 2017.

Clearly implicit in these estimates is a decline in the energy intensity of GDP growth is decreasing. From the perspective of the OECD oil demand is expected to decline despite modest GDP growth, largely driven by greater efficiencies in transportation demand, which constitutes the largest constituent (c75%) of demand. We have already noted some of the key trends likely to see moderation in the GDP/Oil multiplier in China.

Product demand by sector

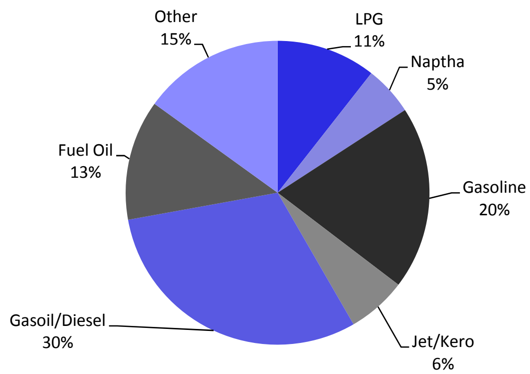
The three principal energy-generating uses for oil are transportation, power generation and heating. However, oil is also used for alternative non-energy, or process functions e.g. as a raw material in the petrochemicals industry. Non-transportation uses are commonly referred to as "stationary uses".

Transportation fuels will account for the majority of growth in world oil demand.

Transportation fuels (gasoline & diesel) account for the majority of oil demand in both OECD and non-OECD countries, and similarly are expected to be the greatest driver of future demand growth. Fuels for transport include motor gasoline, kerosene (jet fuel) and gas/diesel oil. Gasoline is the most commonly used transportation fuel in North America whilst diesel is more dominant in Europe.

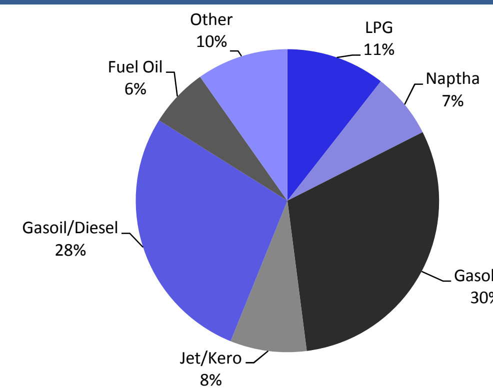
The composition of oil demand by sector is by no means uniform across all countries. Mature economies are characterised by well-developed distribution infrastructures, service-based industries and high levels of private vehicle use. Consequently, gasoline and distillate form the bulk of end-product demand in these countries. In particular, the US uses the highest volume of gasoline worldwide, accounting for 45% of world demand.

Figure 178: Total Non-OECD end-product demand breakdown



Source: IEA Annual Statistical Supplement, 2012

Figure 179: Total OECD end-product demand breakdown



Source: IEA Annual Statistical Supplement, 2012

Another strong regional trend is seasonality in end-product demand. This effect is most apparent in countries in the northern hemisphere. Heating oil experiences particularly strong demand during the winter season, while gasoline demand is strong during the summer 'driving season' in the US.

Climate influences oil demand, particularly in the northern hemisphere.

Factors influencing demand

The two key determinants of oil demand are price and income (GDP per capita). The responsiveness, or elasticity, of oil demand to changes in these factors is also an important consideration.

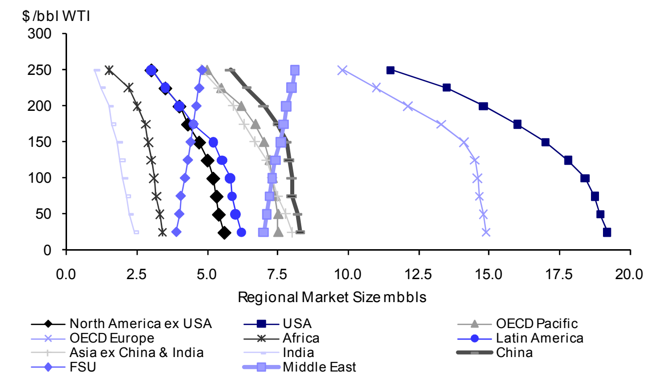
Price: Oil demand and price theoretically have an inverse relationship, although in practice, this does not always hold true i.e. through the boom years of 2004-2008, global oil demand and crude oil prices increased simultaneously. However, this is most likely a function of increased income resulting from economic growth (notably in China) rather than an indication that oil demand and prices have moved to an inelastic relationship. When oil prices remained over $100/bbl for a number of months in 2008 at a time where the world economy came under significant pressure, we started to see demand destruction, particularly in the US and OECD Europe. The figure below illustrates estimated crude oil demand elasticity at a range of different oil prices across a number of regions, and illustrates the inverse relationship between oil demand and oil prices i.e. demand is lower at higher oil prices. A notable exception to this is fuel oil which is one of the only components of crude to have high price elasticity due to the fact that it is easily substituted with natural gas or coal for these products. As a result, it loses market share to these substitutes in times of high oil prices.

In theory, oil demand and price have an inverse relationship.

Transportation fuel, by contrast, is relatively price inelastic as no readily available substitute exists as yet i.e. it is a captive market. However, changes in spot crude prices do not tend to pass through immediately to retail prices as a result of government policy. Firstly, a large tax component in the retail price helps to cushion volatility arising from raw material price fluctuations. Secondly, retail prices are capped or managed by the government in many countries e.g. China, Mexico and Argentina. These controlled retail price regimes support demand growth by insulating consumers from price increases. However, as 2008 showed there is a price at which even demand for transportation fuel starts to decline. Miles driven in the US fell by almost 4% y-o-y in 2008 as consumers cut back on gasoline consumption, with many selling second cars and/or changing their less efficient SUVs for smaller, more energy efficient (often hybrid) cars.

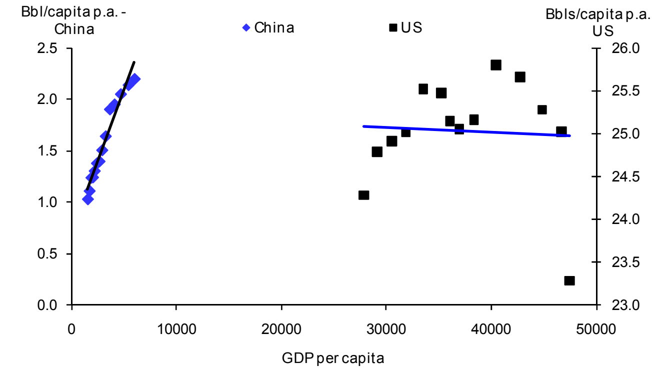
...whilst transport fuels are relatively price inelastic.

Figure 180: Price elasticity - Regional estimated demand at a range of different oil prices



Source: Deutsche Bank estimates

Figure 181: Income elasticity of oil demand in China vs. the US



Source: IMF, BP Statistical Review of World Energy, June 2009

Income: Historically, the main driver of demand growth has been income (or GDP). Strong economic growth, as measured by rising GDP per capita, boosts levels of oil demand, as industry is developed and people start to consume more energy-intensive products such as motor vehicles and domestic appliances. This is visibly the case for China's appetite for increasing volumes of oil in recent years.

Conversely, mature economies have lower income elasticity as these countries have gravitated towards service-based economies, which typically have less intensive energy demands. Mature economies are increasingly outsourcing energy-intensive activities to emerging economies such as China which reinforces the differential in income elasticity. The figure above illustrates that for a given change in GDP per capita, growth in demand for oil is much higher in China compared to the US. The relatively steep slope of the line representing China demonstrates this higher income elasticity. As a result, it appears that the strong growth trend in emerging economies will amplify growth in oil demand.

Oil Supply

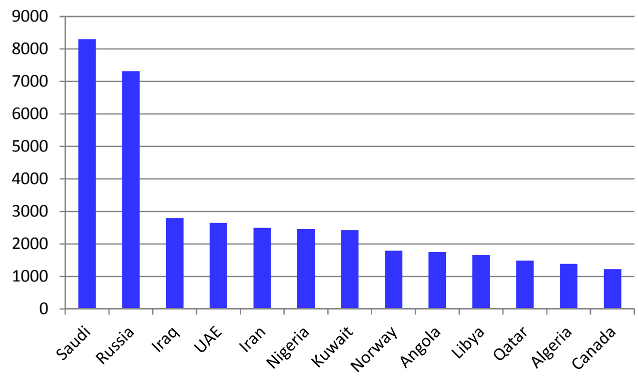
OPEC controls 75% of global reserves and contributes 43% of production.

With OPEC controlling c75% of total global oil reserves, it goes without saying that a significant portion (c43% in 2011) of the world's oil supply is derived from its member countries. The graph below shows the world's largest exporters of oil in 2011 and clearly indicates how dependent the world is on Middle Eastern and OPEC crude oil. As illustrated, the US is the world's single largest importer, although given Canada and Mexico are two of the US' largest suppliers, it is not North America but Asia Pacific that is the largest regional importer. On the export side, Saudi Arabia and the Middle East are the largest net exporting country/region respectively.

Non OPEC ex-FSU supply has declined by an average 0.2% p.a. since 2000. The emergence of Tight Oil growth in US production is expected to reverse this trend

In its Medium-Term reference scenario (*IEA Medium Term Oil Markets Review 2012*) the IEA forecasts that non-OPEC supply will grow at a 1.6% CAGR between 2012 and 2017 (c850kb/d p.a.) – a significant improvement on the 0.8% CAGR achieved since 1998. Growth is centred on US (GoM production recovery and onshore tight oil), Canada (oil sands) and Brazil (Santos Basin). Critically, this rate of forecast non-OPEC supply growth is close to being sufficient to fully accommodate the IEA's projected demand growth over the period, such that the 'Call' on OPEC to balance the market is expected to remain fairly static until 2017.

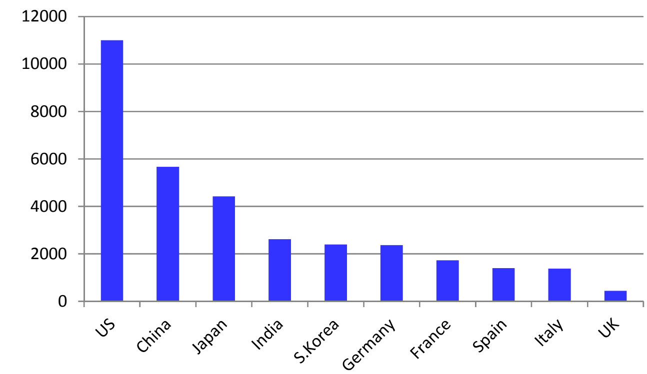
Figure 182: World's largest net exporters in 2011*- Saudi Arabia & Russia dominate



Source: BP Statistical Review of World Energy, 2012

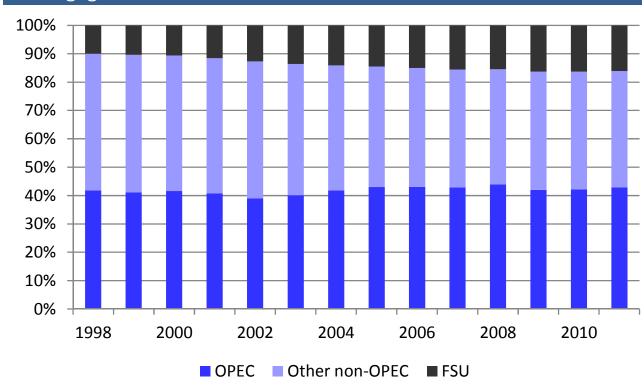
** Note that 2010 data is used for Libya to look through the 2011 production downturn*

Figure 183: World's largest net importers in 2011 – the US by far the largest importer of crude oil



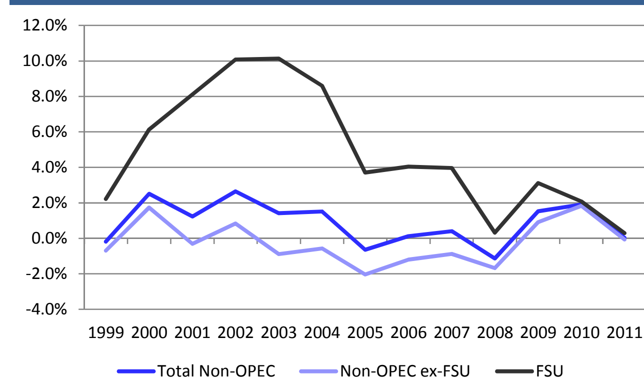
Source: BP Statistical Review of World Energy, 2012

Figure 184: Global production mix – FSU has exhibited strong growth, but other non-OPEC has declined



Source: BP Statistical Review of World Energy, 2012

Figure 185: Non-OPEC Production growth rates – 0.2% decline CAGR from non-OPEC ex-FSU (+0.8% incl FSU)



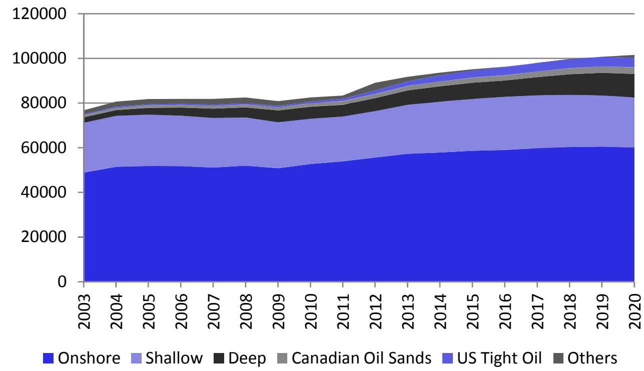
Source: BP Statistical Review of World Energy, 2012

It is important to note that this observation represents a significant change from the IEA's 2010 forecast that non-OPEC production would remain static and hence that OPEC would have to materially increase production in order to accommodate demand growth. If correct, this emergence of supply growth potential outside of OPEC clearly has the potential to profoundly impact the market balance. So, what has changed? Substantially all of the IEA's more positive view on the evolution of non-OPEC supply is attributable to the emergence of rapid production growth and forward potential in various onshore US 'tight oil' plays. We return to this in detail in the Tight Oil section of this report,

Looking more broadly at the long-term potential for supply growth, the trend toward a greater proportion of oil production coming from unconventional sources, such as deepwater, oil sands and tight oil, looks set to continue. As the figure below illustrates, deepwater production is estimated to account for 10% of global oil supply in 2020 (from the current 6%) while the oil sands in Canada could contribute up to 4% of global oil supply by 2020 (from today's 2%). US tight oil could rise to 4% by 2020 (versus c1% today).

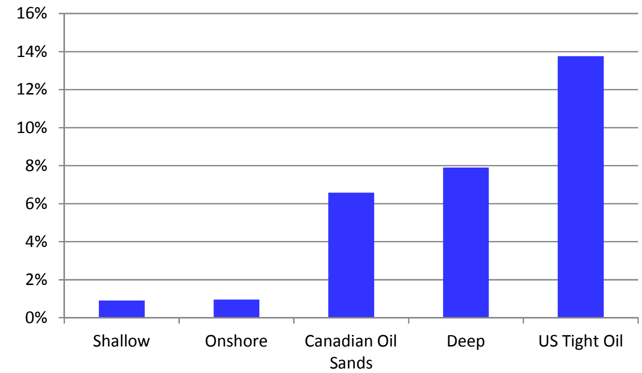
Moreover, as the figure below shows, future oil production is expected to be increasingly heavy and sour, in large part owing to growing production at the Canada oil sands and Venezuela's Orinoco.

Figure 186: Unconventional oil production looks set to grow in importance (production, kbd)



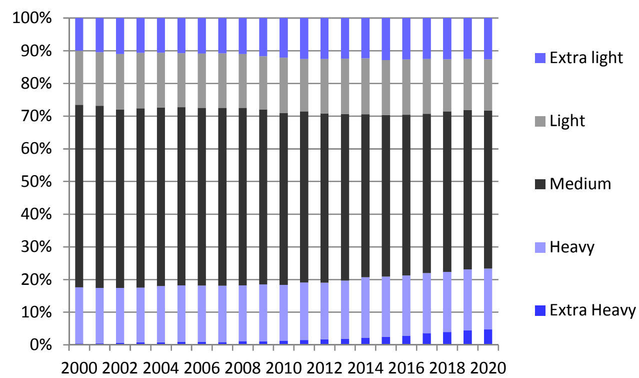
Source: Wood Mackenzie GOST

Figure 187: Expected 2012-2020 CAGR from various source of crude oil supply



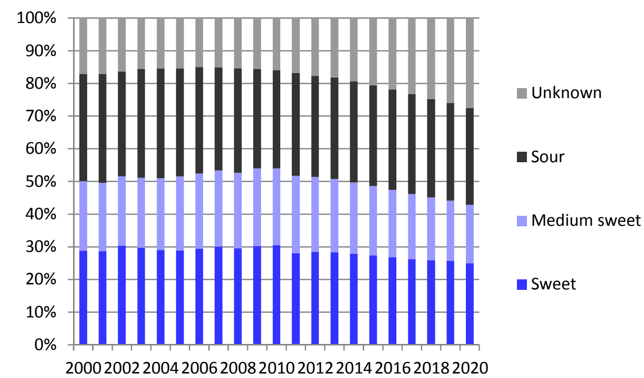
Source: Wood Mackenzie GOST, Deutsche Bank estimates

Figure 188: Crude oil production look set to become increasingly heavy....



Source: Wood Mackenzie GOST

Figure 189: ....and increasingly sour



Source: Wood Mackenzie GOST

Inventories

Another fundamental consideration impacting oil prices is the level of crude and product inventories. There are two relevant points to consider. First, absolute inventory levels can act as a buffer to smooth any fluctuations in supply and demand. Second, inter-period inventory movements may provide an indicator of a tightening or loosening in the supply/demand balance.

In addition to supply & demand, the relative of health of crude/product inventories can have an influence on price.

Crude/product inventory may be held in state controlled locations as an explicit buffer against supply shocks (for instance the US SPR) or privately controlled by companies operating in the trading/refining part of the product supply chain for normal commercial purposes. In the latter instance, the host government may mandate that private companies maintain a minimum inventory level to ensure that a strategic buffer is maintained, but that the inventory cost is borne privately.

The world's largest crude storage capacity is unsurprisingly in the US. The US Strategic Petroleum Reserve (SPR) was started in 1975 following the supply shock caused by the 1973-4 oil embargo in order to mitigate future supply oil disruptions. Maintained by the US Department of Energy (DOE), the SPR is the largest emergency supply in the world with current capacity to hold 727mbbls of crude oil (theoretically 38 days of supply at current consumption levels). Elsewhere, Japan also has significant inventory capacity (583mbbls held in a mix of state/private stockpiles), China has begun to expand its SPR targeting capacity of some 685mbbls by 2020, whilst in the EU the 27 member states require that oil companies keep a specified minimum level of crude and oil products (typically 90 days consumption) in inventory as opposed to having a separate, state controlled SPR.

The timeliest information is published weekly by the Energy Information Administration (EIA, part of the DOE) with inventory data for crude, crude products and refinery utilisation in the USA. And although this data is only for the US, it is closely watched by the market as an indicator of current capacity/tightness in the market. Another widely watched report is contained in the IEA's monthly Oil Market Report 'OMR' that reports crude and product inventory levels across OECD countries. The advantage of this data is that it covers a wider group of countries, but its shortcoming is a lag of 2 months in reporting estimated data.

In short, obtaining a timely and accurate picture of global inventories is essentially impossible given the lack of publically available information in many geographies and time lags in those countries where the data is available. Nonetheless, even recognising the limitations of the data, it can provide useful insights to market fundamentals.

Where inventory data is available, heed has to be paid when interpreting the data to both normal fluctuations which reflect the seasonality of demand and to the level of inventory relative to demand. As a consequence it is common to analyse inventory levels on the basis of 'forward days cover' (i.e. the ratio of the inventory being analysed to the forward demand, expressed as days) and to compare the resulting estimate to the seasonal norm (say the trailing 5 year average for the comparable point in the year.

OPEC Spare Capacity

OPEC is the 'lender of last resort' to oil markets and hence its level of available but unutilised productive capacity is an important factor for the oil market.

Another factor in analysing market fundamentals is the level of spare productive capacity held by OPEC. The assumption is that all countries outside of OPEC are price takers and therefore acting as independent agents seek to maximise revenue simply by maximising their level of production. By contrast, as an oligopoly of 12 states OPEC believes that it controls a sufficient proportion of global supply for its production decisions to have an influence on price. As a result, OPEC will seek to finesse its level of production in order to best maximise its revenues.

The consequence is that the OPEC membership are the only countries to maintain a structural buffer between production capacity and production. As such the group is seen as the 'lender of last resort' to the crude markets. Where OPEC's spare capacity is low the market may be seen as vulnerable to any unexpected supply outage, particularly in times of elevated geopolitical tension, and as a result this is likely to prove supportive for the crude price. By contrast, when spare capacity is high the crude price is likely to be softer, and certainly less responsive to fears around supply outages. Furthermore, in such a situation the OPEC membership may become more fractious given the incentive that exists for individual countries to cheat on production quotas to enjoy a 'free-ride' on the actions to support price from the other members. In such a situation any perceived lack of cohesion within the group can of itself prove sufficient to undermine price.

The level of spare capacity within OPEC has fluctuated over-time in response to trends in demand growth, non-OPEC supply and investment in expanding its own productive capacity. However, over time the level of spare capacity has averaged around 5% of global crude demand.

It is, however, important to note that spare capacity is far from equally distributed across the OPEC membership with over 75% held by the main adherents – Saudi, Kuwait and UAE. (*For more detail on OPEC, including a summary of current and historical spare capacity please refer to the OPEC section of this report).*

Product Prices

The relative supply/demand dynamics and hence price of oil products can influence the price of crude

At first glance, one would assume that the price of crude drives the price of crude products. However, the reverse is often the case. At times of tight refining capacity, product price increases can lead to an increase in the price of crude as the market assumes that demand for crude will increase as companies seek to take advantage of high product prices. Likewise when significant spare refining capacity is evident, or when inventories of oil products are high, this can lead to a decline in the crude price.

Physical vs. Financial

Oil is not a solely physical market. The size of the financial market exceeds that of the physical market.

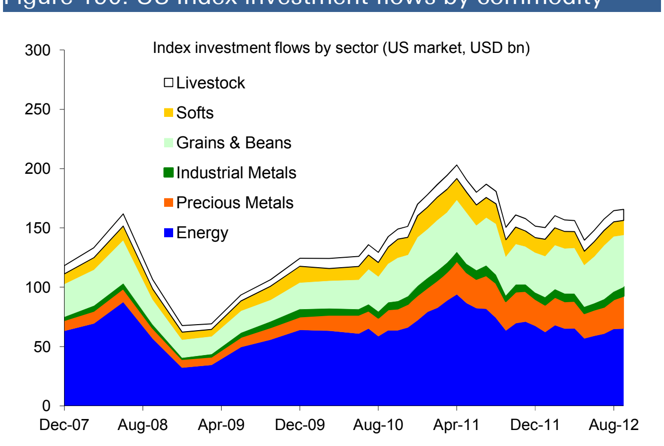
All of the factors discussed above are considered as the underlying fundamental drivers of the oil market. However, oil prices on the screen often may appear not to reflect these fundamentals due to the impact of financial factors. The size of financial market for crude is considerable and drastically outsizes the physical market, with less than 1% of Nymex contracts for example actually going to physical delivery. Thus the financial market can have a significant impact on the oil price, essentially setting the outright price (or flat-price) for crude even though financial contracts are cash settled. Physical settlement, however, ensures that the value of the crude futures contract at expiry is in effect equal to the price at which demand sets in.

The **physical market** for both crude and oil products consists of many small markets depending on the quality and region. There is a market for almost every blend or grade of crude produced globally be that Nigeria's Bonny Light, Russia's Urals or Peru's Loreto. In products there are a multitude of different specs depending on regional environmental requirements and refining complexity. Physical contracts actually take delivery of crude upon expiry with many large commercial traders able to store the physical commodity.

In contrast, the **financial market** is generally settled in cash or traders can roll their position to the next delivery month or simply by settling the position. As described above, there are 5 key internationally traded benchmark contracts (Nymex WTI, RBOB gasoline and heating oil in the US and ICE Brent and European gasoil in Europe) and two main markets (Nymex and ICE) on which they are traded.

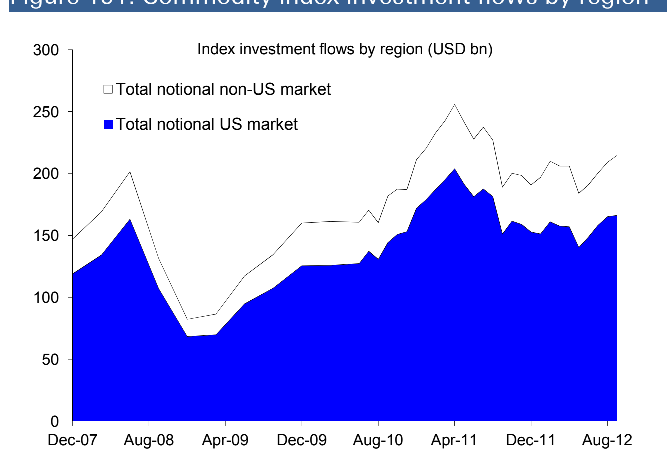
As illustrated below, the level of assets invested in commodity based indexed investment products (based on data sourced from the CFTC) has, after growing rapidly until the 2008 financial crisis, staged a recovery from 2009 lows. With c$65bn presently invested in energy-based US indexed investment products alone, the importance of the non-physical sector of the oil market seems clear.

Figure 190: US Index investment flows by commodity



Source: CFTC Monthly Index Investment Data

Figure 191: Commodity index investment flows by region



Source: CFTC Monthly Index Investment Data

A number of different types of investors invest in the commodities market, employing various different strategies to trade the commodity. Below we detail the key players, strategies used and also the main 'tools' used by the market to analyse trends in commodities markets.

Key players in financial commodities markets

Commercial: These are the producers (both upstream and refiners) and consumers (i.e. airlines, shipping companies) of crude and crude products. Typically trade in the physical market and might use financial instruments to hedge exposure thereby optimising portfolio and pricing.

Mainstream (institutional and retail investors): Trade in the financial market profiting from either short-term volatility (typically hedge funds) or longer-term moves (pension funds).

Traders/Commodity Trading Advisors (CTA): Traders try to profit from price discrepancies between different regions and commodities or try to anticipate future price moves by trading in a range of financial instruments. CTA's typically trade both physical long and short. CTAs advise others on the value of financial products (future, options, etc).

Key strategies used in financial commodity markets

Outright: This is taking a position directly in the future/OTC swap contract, whether it be in a long or short position. The price of the outright contract is the most important reference when discussing oil trading, with the front month contract closing price being quoted as the price of crude. It tells us how the market values the price of crude today (and via the forward curve, in the future).

Options: There are two main types of options calls (right to buy) and puts (right to sell) that give the holder the right to buy or sell the underlying (crude or crude contract) at an agreed price on an agreed date. There are many complex trading strategies that use these instruments. Options pricing is also a useful indication of how the market values the chances for a move up or down in the price of the underlying.

Time-spreads: In the futures market, it is not just one contract that is traded. Each traded commodity has a strip of one month contracts that extend out for 8 years in the future (see the forward curve below). One of the most common trading activities is to trade the relative price strength/weakness between different contracts. The shape of the curve is very important and is indicative of market expectations of supply/demand over the future months. Under "normal" market conditions, the forward curve would be expected to slope upward (called contango) reflecting the cost of storage, insurance and the greater level of uncertainty around future supply i.e. market is expected to be tighter further out. However, as described below, the curve can for various reasons flip into backwardation (downward sloping). An example of a trading strategy in a backwardation or tightening market would be to sell the prompt contract and buy the cheaper deferred contract in a bet that the price will continue to rise as the deferred contract nears expiry.

Arbitrage: Traders try to take advantage of the relative strengths and weakness between regions, buying in the region that is expected to perform and selling in the region that is expected to underperform i.e. it is a relative trade. It also sometimes explains a lot about the relative strength in one region vs. the other.

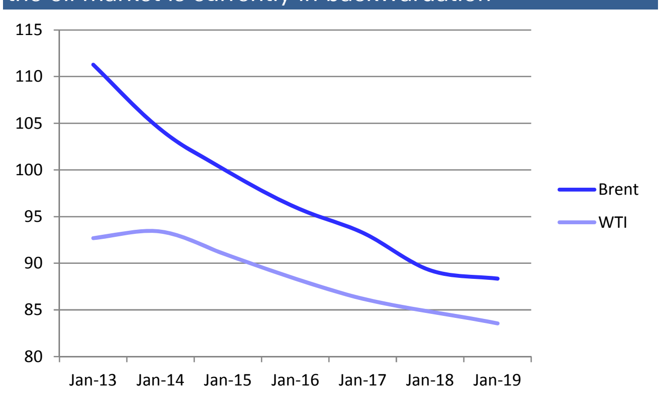
Inter-commodity: Crude is not traded in isolation and is in fact of limited use without being turned into oil products. Thus the relationship between crude and oil products is crucial in energy markets. For example, from a commercial point of view, if diesel is trading at a strong premium to gasoline, refiners can adjust their yield to optimise diesel production and thus maximise the margin obtained per barrel of crude processed. From a financial point of view, if an investor doesn't want to take a direct position in crude, a position can be taken in a product. This can indirectly impact on crude prices i.e. if the market sees the open position in say gasoline contracts increasing (indicative that expects an increase in demand) it will assume that refiners will need to process more crude to produce gasoline. This can lead to open long positions in crude subsequently increasing.

Other: Finally if investors do not want to take an outright position in the commodity they can invest in funds or indices that that do. **Exchange Traded Funds** (ETF) are investment vehicles that invest in commodities (or indeed in other assets) and subsequently issue shares that are traded similar to company shares on the market. **Commodity Indices** are exactly what the name implies, an index of specific commodity prices (spot or futures) into which people can invest e.g. Deutsche Bank's own DBLCI (Deutsche Bank Liquid Commodity Index) which tracks crude, heating oil, aluminium, gold, corn and wheat prices.

Key data points in financial commodity markets

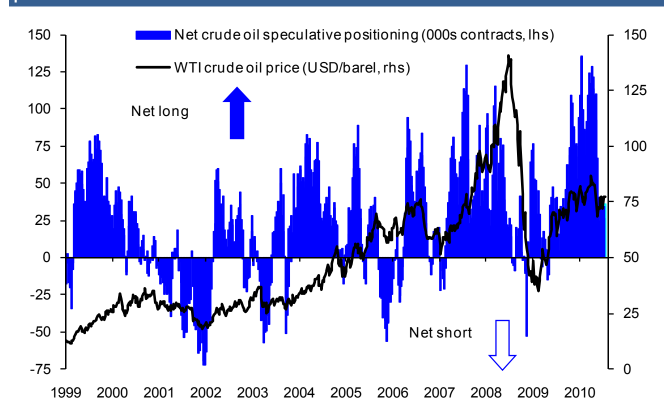
The forward curve: As levels of financial involvement in oil trading have increased, the importance of the futures curve has increased as an indicator of market sentiment (albeit it has not always necessarily proved itself to be a good predictor of the actual forward price). The shape of this curve reflects expectations of supply/demand over the next 12 months. An upward 'contango' curve indicates that the market expects higher prices in the future, implying that demand is expected to be higher relative to supply in the future, that spare capacity may become more limited in the future or that the current market is well supplied but is expected to be tighter in the future. A downward sloping 'backwardation' curve, where the front month commands a premium over the future month's contracts, suggests current demand is outpacing current supply, with the expectation that the imbalance will become less pronounced in the future. Stripping out any expectations regarding supply and demand, a contango curve is considered 'normal' as the costs of carry will always be included, thereby increasing the price of future months. However, recent years have seen the oil futures curve move into backwardation suggesting that the market is increasingly comfortable about the medium-term supply/demand balance.

Figure 192: The forward curve – downward sloping thus the oil market is currently in backwardation



Source: Bloomberg Finance LP, data as of 30 July 2010

Figure 193: Weekly CFTC data shows the net open/long position in crude contracts



Source: CFTC

CFTC data: While the futures curve incorporates overall market sentiment in relation to the underlying supply/demand, further insight is given by the weekly publication by the Commodities and Futures Trading Commission (CFTC) published at 15.30 (Eastern Time) every Friday, which shows the speculative long and short position as well as weekly open interest data. Open interest refers to the number of open futures or options contracts that are yet to be closed through either an offsetting transaction, delivery or exercise, with options positions counted in futures equivalent terms. This gives a snapshot of what direction the market expects crude to trade i.e. a net long position suggests the market is bullish the crude price. In recent years, market volatility has seen the CFTC make changes to improve visibility in the data reported e.g. it has subdivided the 'non-commercial' component to give a clearer idea of the level of participation of large money managers in the crude market.

World Gas Markets

In a state of flux

Natural gas is the world's third largest source of primary energy, but its markets tend to be regional rather than global

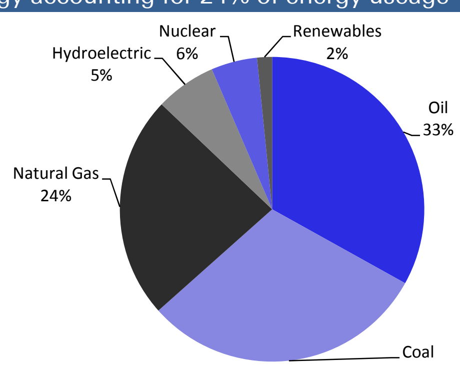
Natural gas is the world's third largest source of primary energy, accounting for 24% of total energy use in 2011 and with growth in its consumption having comfortably outpaced that of crude oil on a 3, 10 and 20 year view. In the medium-to-long-term we continue to see an attractive demand backcloth for gas, not least as increasing environmental pressures and favourable pricing relative to substitutes (in certain markets) provide strong incentives to both private industry and governments to opt for gas over coal or oil as the source for energy generation.

However, despite its importance and unlike crude oil, gas is not produced into a globally fungible market owing primarily to high capital cost barriers (and political challenges) which have prevented a global transportation network being built to facilitate an active spot market. The global gas market is therefore primarily regional in nature with its growth having been largely dependent on piped supply and point-to-point long-term contractual agreements, the exception being the US where a fully liberalised spot market does exist. More recently, the rapid growth of the LNG market has provided a bridge between stranded supply and distant markets, although accounting for just 10% of global supply and with the majority of this gas also supplied on a long-term contracted basis the emergence of a fully liberalised and price efficient global gas market remains a fairly distant prospect.

The debate in gas markets around supply, demand and price is currently dominated by a number of issues, including: (1) the extent to which the complete change in the US supply/demand picture with the growth in shale gas, and resultant collapse in US prices will begin to impact gas pricing in other regions, (2) the potential for a shale gas revolution in other markets, (3) whether the gradual breakdown in traditional oil-linked contract structures in Europe is terminal and what are the medium-to-long-term consequences, (4) the rapid growth in Asian demand for LNG.

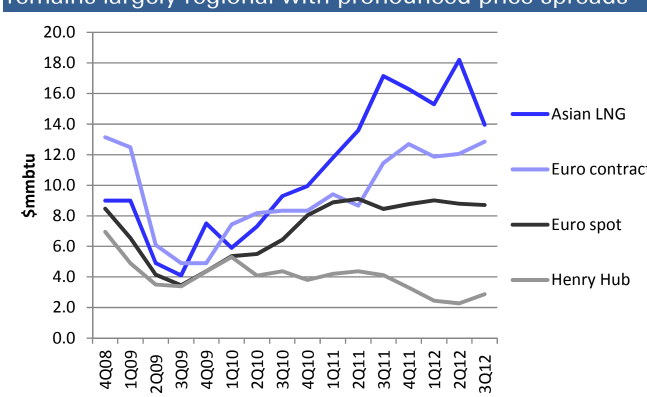
In this section of the report we first consider the main global trends in gas markets before looking in more detail at the specific characteristics of the three main regional markets: US, Europe and Asia.

Figure 194: Gas is the third largest source of primary energy accounting for 24% of energy useage



Source: BP Statistical Review of World Energy, 2012

Figure 195: But despite its global importance the market remains largely regional with pronounced price spreads



Source: Deutsche Bank

Global Gas Demand

Demand

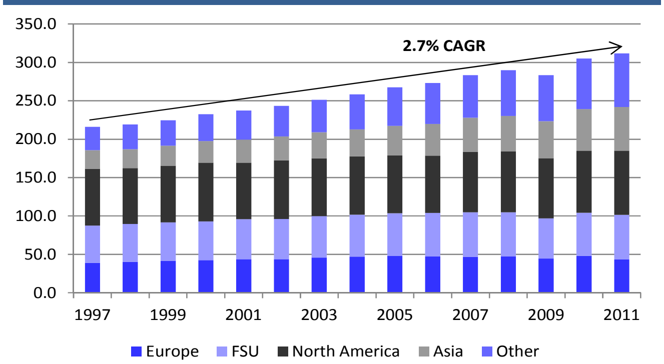
Global gas demand has seen a 2.7% CAGR since 1996.

Global demand for natural gas has expanded by a 2.7% CAGR since 1997. Growth has been registered in every year except 2009, when consumption in Europe fell by 6% in the wake of the financial crisis, albeit demand recovered strongly in 2010/11 and globally now stands 7% above the pre-crisis peak.

Compared to its main competing sources of energy, growth in natural gas consumption materially outpaced oil across 2000-2010. The IEA expect this trend to continue, forecasting a 2.0% CAGR in global gas demand between 2010 and 2020. However, growth in gas lagged coal across 2000-10, and whilst the delta is expected to narrow in coming years, coal consumption is forecast by the IEA to continue to grow more rapidly through to 2020, albeit the trend reverses thereafter. There is a clear difference here between OECD (where coal is expected to decline as policy decisions lead to growth in gas) and non-OECD (where despite expected strong growth in gas consumption, industrialisation trends drive a faster pace of growth in coal). Future trends in gas demand (especially relative to coal) remain intimately linked to political decisions.

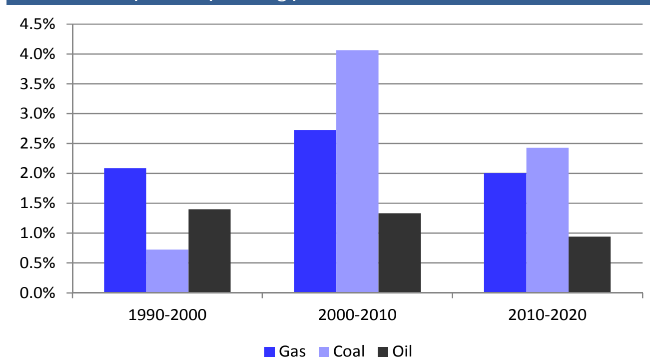
Considering regional demand trends, North America remains the largest consumer of gas, although the IEA expect consumption from non-OECD to grow at a multiple of almost 3x OECD over the 10 years to 2020. Asia and specifically China is the driving force with an expected 10% p.a. growth rate over this period.

Figure 196: Global Natural Gas Demand – 312bcf/d of demand in 2011



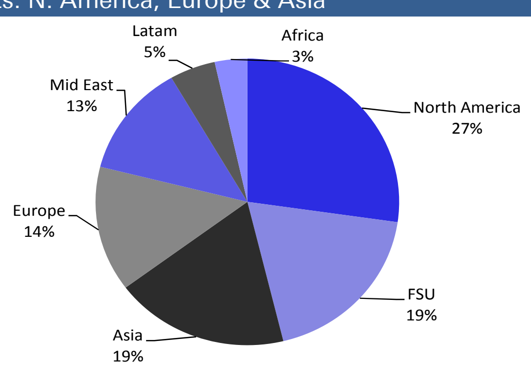
Source: BP Statistical Review of World Energy, 2012

Figure 197: Actual and forecast demand CAGR for key sources of primary energy



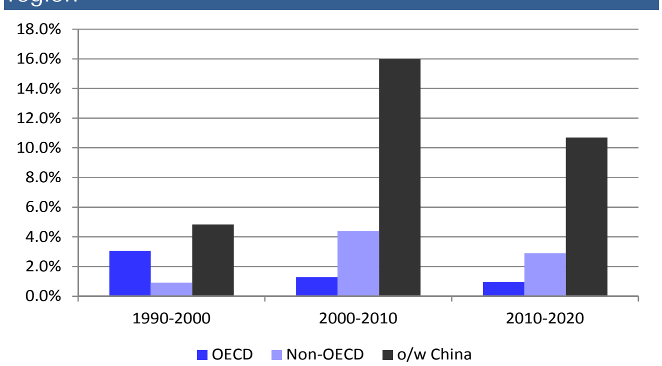
Source: IEA World Energy Outlook 2012

Figure 198: 2011 Gas Demand by region – Three key markets: N. America, Europe & Asia



Source: BP Statistical Review of World Energy, 2012

Figure 199: Actual and forecast gas demand CAGR by region



Source: IEA World Energy Outlook 2012

The largest gas consuming countries are the US and Russia. Albeit Russia is a net exporter of gas to Europe whilst the US, despite advances in domestic supply, remains a modest net importer. The two main import markets for gas are Europe (relying on Russia, North Africa, Norway and LNG) and Asia (China, Japan, South Korea and India among others relying on LNG imports at the margin).

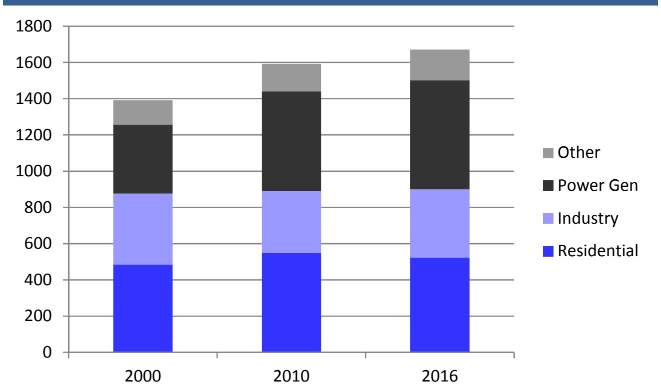
End Uses

The principal uses of gas are for electric power generation, industrial sector processes (such as refrigeration, process heating/cooling), residential/commercial uses (primarily heating, air-conditioning and ventilation) and other uses (including as a feedstock in chemicals processes).

Focusing on OECD markets for which we posses data on consumption by sector, Power generation (34%) and residential/commercial (34%) account for the bulk of consumption. Since 2010 Power Generation has been the main driver of consumption, expanding at a 3.7% CAGR over this period compared to 1.2% for residential and -1.3% for industry. Looking forward, the IEA forecast that the pace of OECD demand growth for gas in power gen will slow to a c1.5% CAGR, albeit this is likely to prove very dependent upon government policies, not least around the cost of carbon.

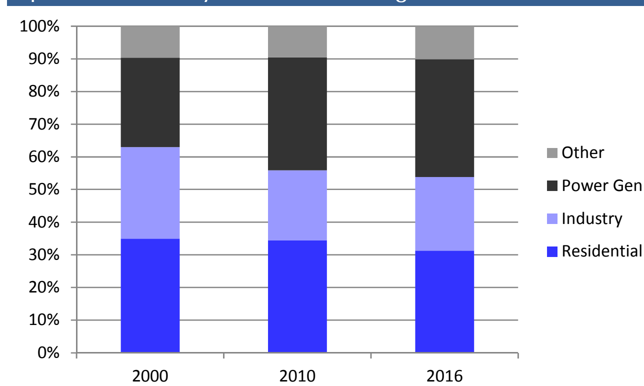
When considering the demand for gas, particularly in power generation, it is important to note the potential for substitution with other energy sources – namely coal and fuel oil. Whilst demand from residential/commercial users is likely to be less price responsive (at least in the short-term), a certain amount of power generation and industrial users have the ability to make short-term switching decisions between fuel sources depending upon which is most economical at any given time. A clear example is this is playing out at the present time – cheap US gas prices have seen switching from coal to gas, as a result thermal coal prices have been depressed, but this in turn has stimulated increased demand for coal in Europe where gas prices are higher than in the US.

Figure 200: OECD Natural gas demand by sector – power and residential dominate



Source: IEA Medium Term Oil & Gas Market Report, 2011

Figure 201: OECD Natural gas demand growth by sector – power is the key driver of OECD growth

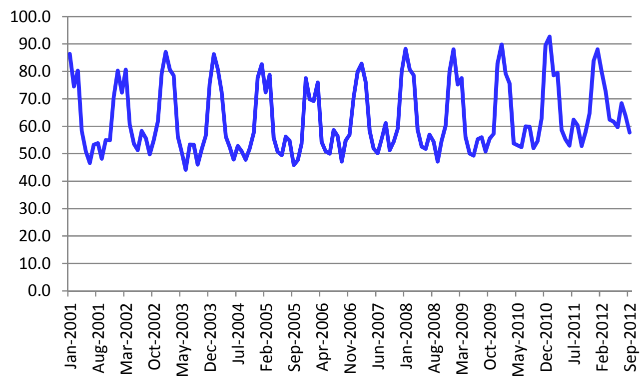


Source: IEA Medium Term Oil & Gas Market Report, 2011

Demand Seasonality & Storage

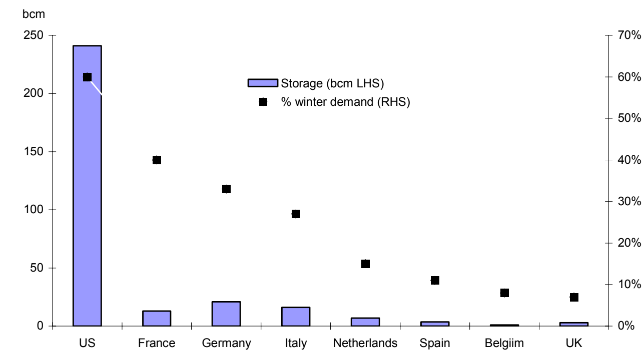
To a greater extent than oil, gas demand is affected by the weather, inter-fuel competition and storage. As clearly illustrated in the chart below, demand for gas usually peaks during the colder winter months due to increased residential demand for heating. In addition, there is a mini-peak in demand during the summer months due to increased electricity generation demand for use in air conditioning.

Figure 202: Seasonality of US gas demand (bcf/d)



Source: EIA Natural Gas Monthly data

Figure 203: US storage facilities dwarf those of Europe making the US the 'sink' for excess supply



Source: IEA World Energy Outlook 2009

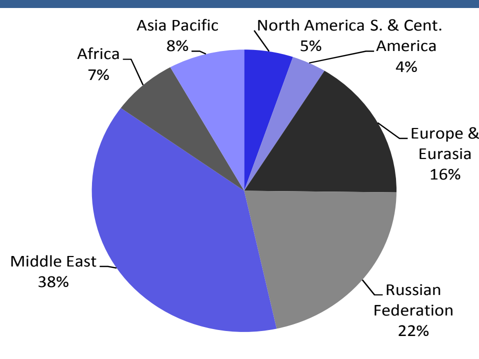
As a consequence, storage facilities are important for smoothing the peaks and troughs in demand. Storage facilities tend to be depleted salt caverns (or other aquifers) which have been converted to store natural gas. The US holds by far the most gas storage capacity globally (241bcm or 8500bcf), with most other regions having well below 40% of winter demand storage capacity, albeit efforts are being made to grow storage capacity. Storage levels may have an impact on the commodity's price. Similar to oil inventories, the EIA publishes a 'Weekly Natural Gas Storage report' which indicates the volume of gas held in storage in the US that week, in addition to week-on-week movements.

Global Gas Supply

Reserves

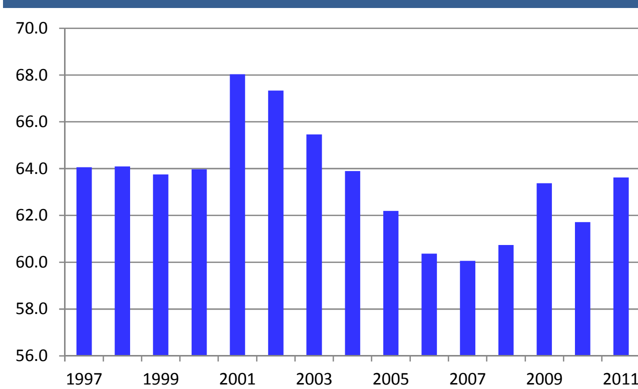
Proven global natural gas reserves stand at 1200bn/boe (208Tcm) according to the 2011 BP Statistical Review, some 25% below those of oil (inclusive of the oil sands).

Figure 204: Regional disposition of natural gas proved reserves 2011



Source: BP Statistical Review of World Energy, 2012

Figure 205: Natural Gas Proved Reserves R/P ratio (years)



Source: BP Statistical Review of World Energy, 2012

Commercial gas reserves have risen by almost 25% over the last decade, in part because oil companies have begun to search for gas in its own right, but also because less gas is being flared. However, the increase in absolute reserves has simply kept pace with expanding demand such that the R/P ratio has remains broadly static at around 60-65 years since 1990.

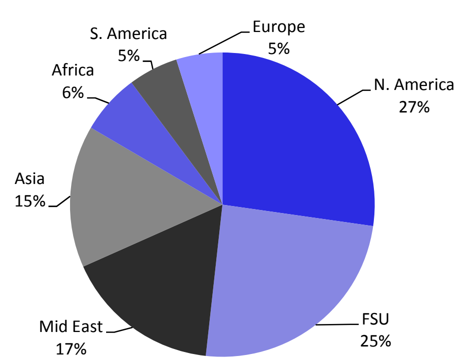
The current supply mix

The key sources of global supply are North America (USA, Canada), FSU (Russia, Turkmenistan), the Middle East (Iran, Qatar, Saudi) and Asia (Indonesia, Malaysia, Australia).

There is a regional mismatch between the demand for and supply of natural gas. Whilst the needs of North America are presently broadly balanced, the other two key consuming regions are materially short gas. Europe derives c65% of its consumption from imports (30% from LNG, 70% from pipeline – primarily Russia and North Africa), whilst Asia derives c20% of its consumption from imports, albeit this percentage is significantly higher in some key centres of demand (i.e. Japan and South Korea) and is set to grow in China.

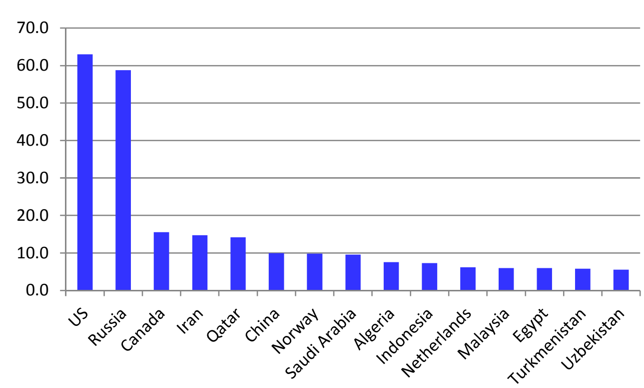
Looking in greater detail at those countries making a net contribution to the global gas market, the most important sources of incremental supply are: Russia (piped gas to Europe and LNG to Asia via Sakhalin), Qatar (LNG exports primarily to Europe and Asia), Norway (piped gas to Europe), Canada (piped gas to the US), Algeria (piped gas to Europe and LNG) and Indonesia/Malaysia (LNG exports to Asia).

Figure 206: Natural gas supply by region



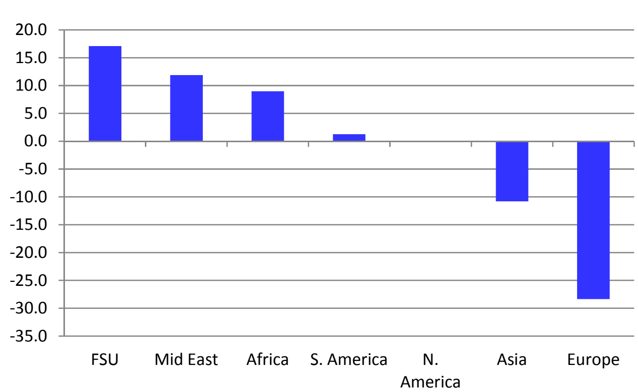
Source: BP Statistical Review of World Energy, 2012

Figure 207: Net gas supply by country (bcf/d)



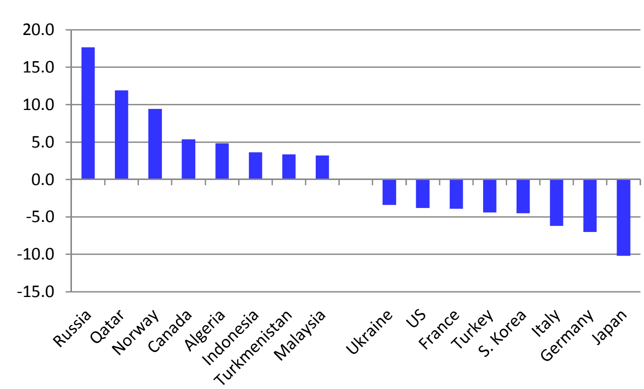
Source: BP Statistical Review of World Energy, 2012

Figure 208: Net imports/exports by region (bcf/d)



Source: BP Statistical Review of World Energy, 2012

Figure 209: Major net importers/exporters (bcf/d)



Source: BP Statistical Review of World Energy, 2012

Sources of supply growth

However, the supply picture is not static, and to support the IEA's forecast 2.0% 2010-20 global gas demand CAGR the sources of expected supply growth are relatively concentrated, as illustrated by the table below.

Figure 210: IEA estimates for key sources of 2010 to 2020 gas supply growth (sources of likely *net* supply growth shaded)

Country	Production (bcm p.a.)				Comment
	2010	2020	Change	%	
US	604	747	143	24%	Expected growth driven by shale gas production. Should drive one of most important trends in global gas markets as the US transitions from being a net importer to modest net exporter.
China	95	175	80	84%	Significant supply growth driven increasingly by CBM/tight gas in second half of decade. But domestic supply growth lags demand expansion.
Qatar	121	177	56	46%	Majority of 2010-20 growth has already occurred by end-2012. No current plans for incremental Greenfield capacity. Any further growth to 2020 likely to be modest and focused to de-bottlenecking existing LNG facilities.
Australia	49	102	53	108%	The second major source of net supply growth after the US. Growth driven by a series of Greenfield LNG start-ups impacting from 2015.
Russia	657	704	47	7%	Growth to satisfy domestic market, but also some net supply growth to Europe. Longer-term export expansion options via Arctic LNG and piped gas to China.
Turkmenistan	46	84	38	83%	Increased pipe exports to China.
Saudi	81	107	26	32%	Domestic focus.
Nigeria	33	58	25	76%	Domestic demand and potential for increase in LNG exports via Brass or NLNG T7, but low level of visibility.
Brazil	15	32	17	113%	Domestic focus.
Azerbaijan	17	30	13	76%	Expected export of piped gas to Europe from the Shah Deniz II project. Awaiting sanction.
Canada	160	171	11	7%	Potential net export growth via East Coast LNG exports from a series of nascent opportunities.
Mozambique	n.a.	n.a.			Potential LNG exports commencing at decade end

Source:IEA World Energy Outlook 2012, Deutsche Bank

The IEA expect gas demand to see a 2% CAGR through to 2020 with US, Australia and Russia the key sources of net supply growth to satisfy this demand.

The key supply-side trends to watch for over the next decade are:

- **US/Canada:** The extent to which LNG export licences are granted to accommodate the potential for further tight/shale gas led production growth.

- **China:** Whether ambitious government targets for domestic supply growth (50bcm from CBM and 60-80bcm from shale gas by 2020) are achievable and, if not, to what extent China's thirst for imports will increase.

- **Australia:** Whether the host of Greenfield projects scheduled to commence between late-14 and 2018 commence on time or suffer delays.

- **Russia:** (1) The extent to which Russian plans to monetise Arctic gas via LNG (Yamal LNG) come to fruitition. (2) The extent to which negotiations with the Chinese for piped exports progress.

- **Mozambique:** Whether plans to monetise the significant resource base firm sufficiently quickly to see LNG exports by end-decade.

The emergence of Shale Gas

A key change in the supply-side during the past decade has been the emergence of shale/tight gas as a viable source of production. We examine this process in greater detail in the Unconventionals section of this note; however for completeness two important points regarding the implications for global gas supply need to be made.

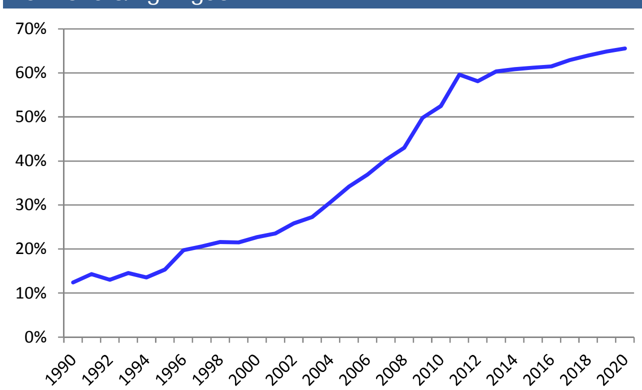
The last decade has seen a revolution in US gas supply/demand dynamics with the rapid growth of tight & shale gas.

First, the emergence of shale/tight gas has, thus far, been a primarily US phenomenon. The remarkable thing is the speed with which supply from this source has come to represent the most important constituent of US supply – from c20% in 2000 to c50% in 2010 and an expected 65% in 2020. Thus far the impact on global gas markets has been to displace the need for imports. Longer-term the impact will be more direct as US LNG exports commence from c2016 – something unthinkable just 5 years ago. Please refer to the LNG section of this note for a fuller discussion of the potential for US LNG exports.

Second, the existence of shale/tight gas resource is clearly not limited to the US. A recent EIA report flagged material potential in China, Argentina, Mexico and South Africa among others, in addition to more limited potential in Europe. For the time-being, this potential remains untapped whether due to restrictive politics (Europe) and/or some combination of geographical location, insufficient exploratory activity conducted to date, more challenging geological conditions, or an insufficiently developed local service market and infrastructure. It does not seem unreasonable to believe that this resource opportunity will be exploited, but over what timeframe could we begin to observe an impact on global gas markets? The impact by 2020 seems likely to be relatively modest; China is at the forefront of efforts to mature its shale gas resource base, but even here activity is today only in the exploration/appraisal phase. So the period to 2020 is likely to be about better defining the global opportunity with the physical impact on gas markets beginning to be felt in the 2020-2030 timeframe.

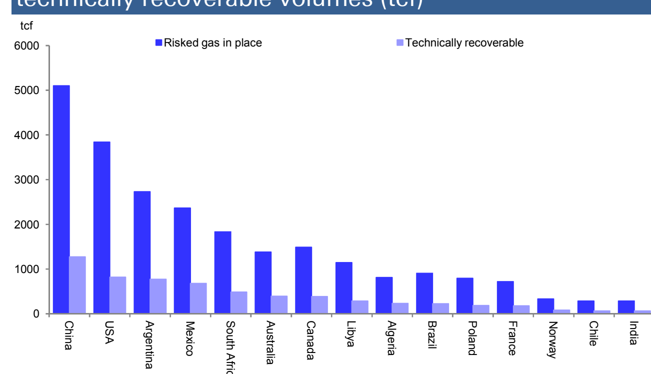
The questions for the next 10 years are: (a) to what extent US gas will be exported to global markets, and (b) whether other regions will also see a supply revolution.

Figure 211: Proportion of US domestic gas supply derived from shale/tight gas



Source: EIA

Figure 212: EIA estimates for shale gas in place and technically recoverable volumes (tcf)



Source: EIA

LNG – A growing conduit for supply

Because of the challenges associated with transporting gas over large distances and limitations on storage the major centres of production have tended to be within piping distance of the major demand centres. However, as indigenous production not least in Europe starts to decline so the delivery of gas in liquid form as LNG from often stranded or displaced sources is set to become more prevalent. LNG has evolved from acting as a conduit for around 5% of global supply in 2000 to c10% by 2012 and could grow to approaching 15% by 2020. A detailed overview of the process by which LNG is produced and the value chain may be found in the LNG section of this note.

Gas Pricing - US

Global context

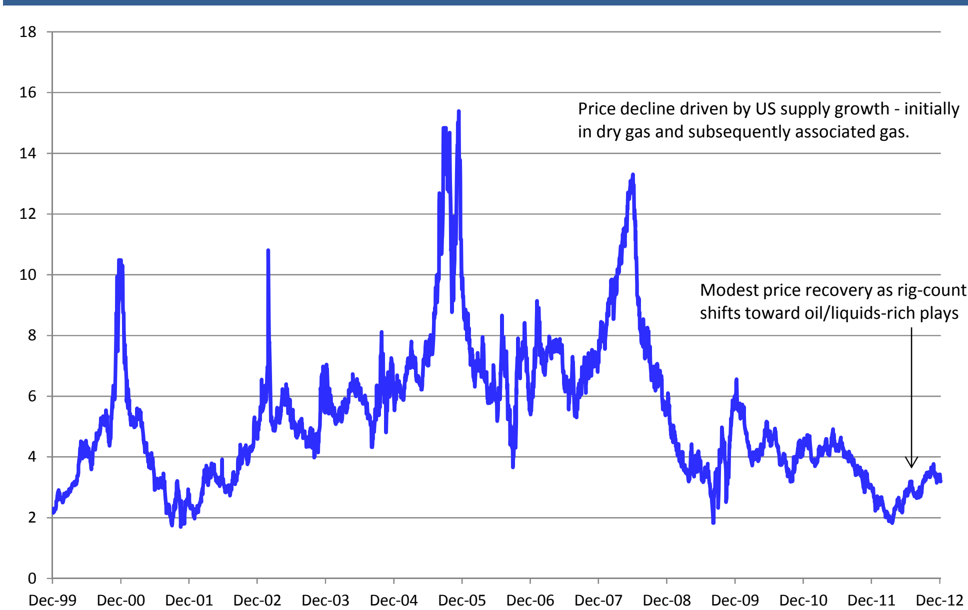
As already explained, gas is not produced into a globally fungible market owing primarily to high capital cost barriers (and political challenges) which have prevented a global transportation network being built to facilitate an active spot market. Gas markets have therefore tended to function on the basis of piped supply and point-to-point long-term contracts. And whilst LNG, which facilitates inter-regional trade, is growing, it is still just 10% of global supply and with the majority of this gas also sold under long-term agreements. In fact, of the main markets only the US and to a lesser extent the UK are transparent and for the main part, liberalised. And whilst the post-financial crisis supply overhang in Europe is seeing a shift toward spot the market remains opaque. So, although at the most basic level natural gas is priced based on energy content and proximity to consuming markets, pricing mechanisms vary considerably across the world.

US gas - Henry Hub represents the only fully liberalised market

US gas is sold into a fungible market with Henry Hub the benchmark price point.

All gas sold in the US whether piped gas or LNG is traded on both the spot and futures market in much the same way as crude. All gas is priced against Henry Hub (HH), which is an actual physical interconnection point on the natural gas pipeline in Louisiana where gas is typically delivered. Spot and future prices set at Henry Hub are denominated in US$/mmbtu and are generally seen as the primary price set for the North American natural gas markets, although the physical distance from Henry Hub will impact on prices around the country e.g. West Coast prices normally trade at a discount to Henry Hub whilst those located near to the major centres of demand on the Eastern Seaboard trade at a premium. Around 80% of gas sold in the US is via the "bid-week process". This process occurs on the three days leading up to and ending on the NYMEX contract's expiration, which occurs on the third-last business day each month. The NYMEX natural gas contract expiration price is indicative of the price bid-week deals should be conducted at.

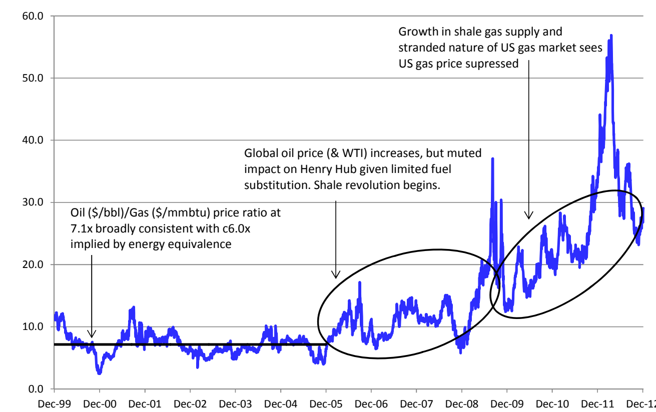
Figure 213: US Henry Hub gas price ($/mmbtu)



Source: Datastream, Deutsche Bank

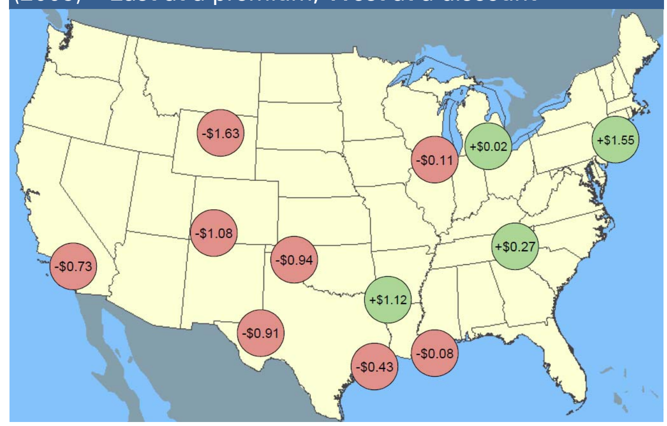
The US gas price has been under structural pressure during the past 5 years as the rapid growth in domestic production (shale/tight gas) allied to the current inability to export gas has driven the North American market from a state of under supply to self-sufficiency. And whilst we see the economic floor for gas prices in the region of a $4-$6/mmbtu marginal cost (see the Tight & Shale Gas section of this report), the growth in associated gas from oil/liquids-rich sources (where gas is essentially a by-product) has, during the past 1-2 years pushed prices to below marginal cost.

Figure 214: US Henry Hub gas price vs. the oil price ratio – energy equivalence breaks down as gas supply rises



Source: Datastream, Deutsche Bank

Figure 215: Indicative gas price differentials within the US (2009) – East at a premium, West at a discount



Source: Wood Mackenzie, Deutsche Bank estimates

Over-supply should constrain price upside, but could cultivate new sources of demand

The key debate around the US gas market is to what extent suppliers will be successful in seeking to exploit the low price of US gas relative to both the energy-equivalent price for crude oil (WTI presently trading at c30x the gas price versus equivalence at c6x) and the price of gas in other non-linked regional markets. There are two sources of demand to consider.

The growth in US supply and resultant price collapse has the potential to stimulate new sources of domestic gas demand in transportation, power and chemicals.

First, domestic demand for gas is likely to be witness structural change in the medium-to-long-term (beyond simple short-term fuel switching) through a combination of: (1) Revitalised demand from the US chemicals industry as cheaper feedstock leaves US facilities more competitively positioned on the global cost curve. (2) Demand for gas in transportation, whether via CNG (Compressed Natural Gas), LNG in the long-haul truck fleet or GTL (gas-to-liquids). And (3) Influencing the coal Vs gas decision in constructing Greenfield power generation capacity. In each case these are sources of potential demand that will take time to cultivate given both investment lead-times and the need for investors to be very confident that low US gas price can be sustained such that the rationale for some capital intensive investment opportunities is sound.

Second, there are presently applications pending for permits to export c153mtpa of gas from conversion of Brownfield re-gas facilities together with a further 55mtpa of gas from Greenfield facilities. To date just 18mtpa has been approved. We consider this debate in more detail, including an assessment of the economics, in the LNG section of this report.

Gas Pricing - Europe

A market built on long-term oil indexed contracts, but in transition

The European gas market is dominated by long-term oil indexed contracts.

The European gas market developed on the basis of long term oil (or oil product) indexed contracts. The long-term contract structure developed not only to provide the supplier with clear line-of-sight on end-demand to support the capital-heavy investment decisions (i.e. trans-national pipelines and in some cases large offshore production facilities) when the market was in its infancy, but also to give the utility buyers (making their own investment decisions around power gen capacity) security of supply. Oil-indexation developed in the absence of a functioning spot market for gas to allow the contract price of the gas to fluctuate, albeit in-line with the price (and hence supply/demand dynamics) of a competing source of primary energy.

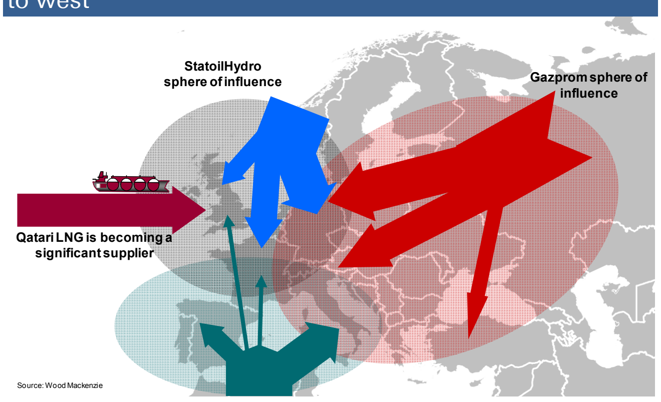
Gas sold under long-term contract continues to represent the majority of the European gas market; however a combination of relatively recent factors is altering the structure of the market (and the contracts themselves). The causes and symptoms are multiple and inter-linked, but simplifying the situation: a demand slump in the wake of the 2008 financial crisis combined with increased LNG imports (primarily from Qatar) has seen a situation of over-supply, a more active spot-market, and spot prices below long-term oil indexed contract prices. As a consequence, the gas buyers have been actively seeking to renegotiate the terms of their purchase arrangements to re-base the price paid for gas to something closer to the spot price.

The starting point: the structure of the physical market for gas in Europe

Europe is a net importer of gas with Russia, Norway, Algeria and LNG the keynet importers.

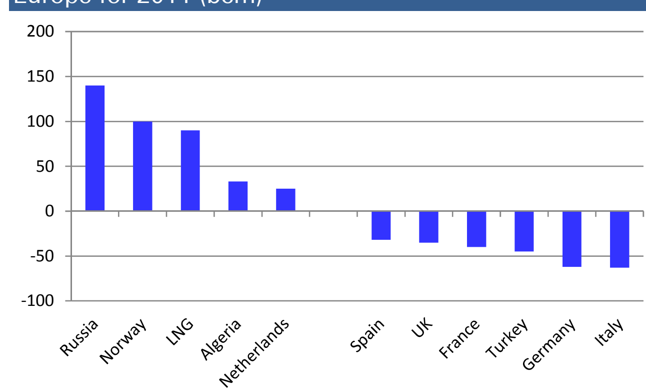
While the US has an extensive, interconnected pipeline system, Europe's pipeline infrastructure is designed to allow gas to flow from the key suppliers in the North, East and South (Norway, Russian and Algeria) to the key demand hubs in the centre South and West (Germany, France, UK Netherlands, Spain and Italy). As a result, and combined with the contract structure, the system effectively impedes the free movement of gas around Europe.

Figure 216: Majority of gas piped into Europe flows east to west



Source: Wood Mackenzie

Figure 217: The key sources of net supply and demand in Europe for 2011 (bcm)



Source: BP Statistical Review of World Energy, 2012

A base-line long-term contract structure

There is no established format or content for long term contracts; each is bespoke, tailored to the needs to both the seller and the buyer. However, as a general rule long term gas contracts are indexed to a basket of oil product prices, lagged by between three to nine months. The contract nature means that external visibility on pricing is poor although, theoretically, prices should track those of crude (given product price fluctuations are normally in line with oil price fluctuations). We present below our understanding of the typical structure of a long term contract (although the precise percentages will vary).

Figure 218: Summary key points in European long-term gas contracts

Term	Description
Gas Year	1 October - 30 September
Duration	Varies from contract to contract but typically 25-30 years.
Off-take	Varies from contract to contract but : *Annual*: Buyers will have a minimum and maximum contracted quantity for a given year. This may typically span c80% to 120% of the contracted volume. *Daily*: Daily average volumes can fluctuate between 60% to 110% of the delivery obligation
Nomination	Many long term contract customers can nominate volumes to be delivered a close as 24 hours in advance of delivery. Newer contracts may have less flexibility.
Take-or-pay	If consumers take less than the 80% minimum in a gas year, they must make a (partial) pre-payment for the difference between the volumes taken and minimum volumes permissible under the contract. They will catch-up on these volumes over the remainder of the contract.
Make-up volumes	Where a customer has made a pre-payment for volumes but not taken they may be entitled to take between 50-80% of these 'pre-paid' volumes over the next 5 gas years (a general proxy and varies from contract to contract and is often negotiable between both parties).
Contract pricing	LT contract gas prices are typically linked to a basket of competing fuels such as gas oil, fuel oil, coal etc as determined by the contract. Each customer's gas price is set at the start of each quarter and will be based on 3-9 month rolling average product prices with a one month lag e.g. Q1 gas price could be based on average product prices between 01 June to 30 Nov weighted by end market (residential, industrial, power).

Source: Deutsche Bank

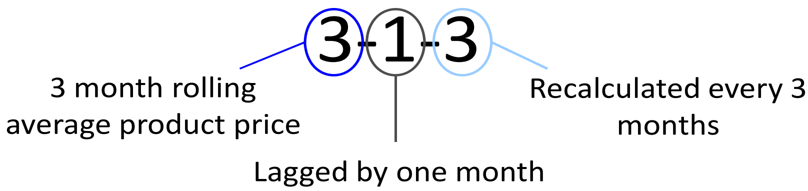
Determining the gas price under long term oil indexed contracts is as noted above, not simple. There are so many nuances within each individual contract that two consumers purchasing gas from the same field may actually be paying different gas prices depending on the terms they've negotiated. However, as a general rule, pricing under long term gas contracts comprises a number of the following main components:

- **Base price** per unit of gas and competing fuels as agreed at start of contract: this is the minimum base price of gas and competing fuels agreed between the producer and the consumer at the start of the contract to ensure that the producer is guaranteed a minimum gas price in order to make a return on the project. This may also be referred to as the P-zero or P0.
- **Indexation** to competing fuels: long term gas pricing is effectively determined by pricing the gas relative to its main competing fuels such as gasoil, fuel oil and coal. In order to do this the price is normally set at the start of a quarter and is based on historic prices for the relevant competing fuels.
- **Weighting**: the formula will be weighted based on what the consumer typically uses the gas for e.g. if the customer is a big utility which sells most of its gas to the residential sector where the main competing fuel is gasoil, the price of gasoil will have a greater weighting in determining the gas price for this customer. This is one of the elements that can be negotiated and changed during price reviews depending on how the consumers business has evolved.
- **Capacity charge**: use of pipeline capacity and the processing plants is also added on to the end sale price.

All the different elements vary dramatically from contract to contract and indeed within a single contract but we try to illustrate above how indexation works in a European gas contracts.

Figure 219: Indexation to product prices made simple

How product prices feed into LT contract gas prices



- There are many variances on this such as 6-1-3, 9-1-3 or 9-1-1 etc. However the referencing remains consistent.
- In determining the gas price for a quarter there are different periods of time lag by product e.g. there could be a gasoil 6-1-3 and a fuel oil 3-1-3 due to the fact that gasoil is more seasonal than fuel oil.
- Example: One of the pricing elements in a LT contract is a 6-1-3 gasoil.

To determine the price for Q4 one would take the average gasoil price for the 6 months between 01 March to 31 August
One excludes September in order to allow for the one month lag
One needs to recalculate every 3 months

Source: Deutsche Bank

The emergence of a more active spot market(s)

UK NBP is a fully functioning spot market for gas. Other European hubs are gradually developing as effective markets.

Spot pricing in Europe remains in its relative infancy. At present the UK is the European country with the most active gas trading market. NBP (National Balancing Point) is the virtual equivalent to US Henry Hub for pricing and delivery of natural gas futures contracts. It is the most liquid trading point in Europe and essentially determines the price domestic UK consumers pay for their gas.

Turning to Continental Europe, the combination of a series of disputes between Russia and the Ukraine which reduced gas supply to Europe (2005/06, 2007/08 and Jan 2009), coupled with the de-linking of spot/oil-linked contract prices, has led to a push toward developing more effective spot markets. The over-supply of gas in Europe – the cause of the spot/contract price disconnect – has provided the liquidity to facilitate the emergence of more active spot markets.

Beyond NBP, the key hubs in Europe are TTF (Netherlands), ZEE (Belgium), PEG (France), PSV (Italy), CEGH (Austria) and NCG/Gaspool (Germany). The exchanges that provide the market place for these hubs are, respectively, ICE (UK), Powernext (France), EEX (Germany) and APX-Endex (Netherlands/Belgium). To place these hubs into context, the Oxford Institute of Energy Studies in a recent paper (*'Continental European Gas Hubs: Are they fit for purpose?*' June 2012) divided the markets between: (1) Trading Hubs (NBP/TTF) – virtual trading points which already provide reliable markets. (2) Transit Hubs (ZEE and CEGH) – physical locations that facilitate gas flow rather than trading. And (3) Transition Hubs (PEG, PSV, NCG) – virtual trading points which are growing but have yet to reach maturity as markets.

So the spot market is becoming more active, but to expect a full move to spot pricing in Europe seems unrealistic in the near term for a number of reasons. First, existing long-term contract structures tie buyers/sellers into agreements often for many more years. Second, infrastructure limitations will impede market development – the majority of pipelines in Europe flow east to west (from Norway/Russia to rest of Europe) and do not have the ability to reverse flow or link the key centres of consumption. That said, surplus re-gas capacity (c150mtpa with c60% utilisation) is supportive. Finally, Europe is short gas storage facilities thus limiting the capacity of the market to smooth periods of high/low demand. Despite noting these limitations, as the volume of gas sold into spot markets gradually increases, investments are made to increase the flexibility of infrastructure and storage capacity is expanded, we do believe that the spot market will gain greater importance.

This debate also has important political and security of supply overtones. Although Europe is oversupplied in the near-term, Wood Mackenzie has estimated (*'How will new sources of supply and infrastructure impact the European market'* April 2012) that due to declining indigenous production, rising demand and contract roll-over, around 200bcm p.a. of new supply may be required by 2025. With the majority of this supply likely to come from capital intensive infrastructure-led developments some form of long-term contract is likely to remain the bedrock of the market; however, the evolution of an active spot market to providing a clear and reliable price signal that incentivises the required private investments is seen by many as necessary.

The evolution of long-term contract structures

The death of oil indexation? The recent emergence of a disconnect between spot and contract gas prices in Europe has led to gas buyers lobbying for changes to contract pricing terms with some degree of success.

Although long-term oil indexed contracts, as explained above, rest of a number of pre-agreed parameters for duration, volume and pricing, they should not be seen as static. In most cases there are provisions for buyer/seller to seek revisions to pricing terms if the indexed price begins to fundamentally deviate from market realities. Such 're-openers' are typically allowed every 3 years, should the situation require. With European spot gas prices having traded at an often substantial discount to the indexed contract price since 2009 the profitability of the large gas buyers has been adversely affected. As a consequence, gas-buyers have since 2009 actively pursued their right to adjust the pricing terms of pre-existing contracts.

This lobbying for adjustment to existing contract terms has achieved some degree of success as key producers have ceded ground in recognition of the current pressure on gas buyers borne of lower sales prices and contractual purchase obligations, albeit the approach taken by the gas sellers has varied.

- **Gazprom** has sought to retain the explicit link to oil prices and has instead focused on lowering the P-zero (starting point for indexation). That said, our understanding is that some concessions have been made on the method of indexation, allowing at least some weighting to spot in some cases. Buyers continue to agitate for improved price terms and it remains to be seen whether Gazprom will be forced to cede more ground over coming years.

- **Statoil** has, by contrast, been more active in allowing a move toward spot as a reference point for the price indexation in some of its sales contracts – an implicit acknowledgement that European spot gas markets are functioning more efficiently. Albeit we understand that the quid pro quo for this change in pricing structure has been a reduction in the customers' volume flexibility.

It is open to debate who will benefit most from these changes. Certainly a move to spot as the basis for indexation should benefit the buyers in the near-term. However, it also leaves the producers' more favourably geared to the likelihood that the European supply/demand balance will tighten in the medium-term.

Finally, what about the structure of the next generation of supply agreements? As noted above, we think that long-term agreements will remain an important component of the market. However, the nature of these agreements may change, with Statoil's Nov-12 agreement to supply Wintershall with 45bcm over 10 years BUT referenced to spot gas prices an early way-marker.

Gas Pricing – Asia & LNG Markets

Oil parity and S-curves

The marginal molecule of gas is supplied to Asia from LNG markets. Long-term agreements for LNG supply are typically priced with reference to oil/products.

Not surprisingly, gas sold in Asia is priced in a different manner to both Europe and the US. Given the lack of any material domestic gas production in the region, it has tended to offer a premium, oil linked gas price in order to attract international gas to its shores (note that LNG represents c.90% of gas imported in Asia Pacific). In the past, oil linked S-curves were used, however, as gas markets tightened between 2004-2008, contracts were increasingly signed at or near oil price parity in order to attract gas away from both the US and Europe although more recently, some reversion to 'S' type formulas has become evident, and more recently some allowance for Henry Hub to enter the indexation formula in recognition of the potential evolution of the US as an LNG exporter.

- **S-curve:** In the past, LNG sold under long term contract into Japan (world's largest importer of LNG) has typically been priced under an oil price linked formula, the price outcome of which was similar in shape to that of an S-curve. On the basis that the price of crude had, and would likely continue to trade within its historically defined range this formula invariably comprised a constant, usually $1-3/mmbtu, together with an oil price linked multiplier which was to be applied within a defined range of oil prices, typically $15-35/bbl. Should the oil price fall outside this range the contract also provided an interim formula whereby a lower multiple would be applied to the oil price. At the upper end of the inflection point (e.g. over $35/bbl in our example) this typically afforded the buyer some protection from a temporary surge in oil prices whilst at the lower inflection point (under $15/bbl) it provided the seller with some form of downside protection.
- **Oil parity:** this is when gas is priced on an energy equivalent basis with crude i.e. 17% of the price of crude (thus at $100/bbl, gas is priced at $17.24/mmbtu). In most cases, the price achieved is less than the price of crude in BOE terms, however, in 2008/09 when gas markets were at their tightest, a number of cargos in East Asia achieved oil parity. Even the 14-15% long term contract prices signed since the highs of 2008 remain significantly ahead of terms signed in the past. Unlike the S-curve, contracts signed at oil parity provide no protection to the buyer from a surge in oil prices or to the seller should the price of crude oil collapse.

LNG pricing is covered in much greater detail in the LNG section of this note.

For reference, the tables below summarise oil & gas reserves, production and consumption by country.

Figure 220: Oil & Gas reserves, production and consumption by country (A to M)

	Oil					Gas				
Countries	Reserves	Production	CAGR	Consumption	CAGR	Reserves	Production	CAGR	Consumption	CAGR
	Bn Bbls	kb/d	2001-11	kb/d	2001-11	Tcf	Bcf/d	2001-11	Bcf/d	2001-11
Algeria	12.2	1728.6	1.0%	344.5	5.7%	159.1	7.5	0.0%	2.7	3.2%
Angola	13.5	1746.4	8.9%							
Argentina	2.5	606.9	-3.1%	609.2	3.7%	12.0	3.8	0.4%	4.5	4.1%
Australia	3.9	483.7	-4.4%	1002.8	1.8%	132.8	4.4	3.3%	2.5	1.5%
Austria				257.3	-0.2%				0.9	1.0%
Azerbaijan	7.0	930.7	11.9%	79.6	0.1%	44.9	1.4	11.4%	0.8	0.8%
Bahrain						12.3	1.3	3.6%		
Bangladesh				103.9	2.6%	12.5	1.9	6.4%	1.9	6.4%
Belarus				179.9	2.1%				1.8	1.6%
Belgium & Luxembourg				677.5	0.6%				1.6	0.9%
Bolivia						9.9	1.5	12.5%		
Brazil	15.1	2192.9	5.1%	2652.7	2.7%	16.0	1.6	8.1%	2.6	8.4%
Brunei	1.1	165.9	-2.0%			10.2	1.2	1.2%		
Bulgaria				74.4	-1.9%				0.3	-0.4%
Canada	175.2	3521.6	2.8%	2293.2	1.3%	70.0	15.5	-1.5%	10.1	1.7%
Chad	1.5	113.7								
Chile				326.9	3.7%				0.5	-3.2%
China	14.7	4089.7	2.1%	9757.7	7.2%	107.7	9.9	13.0%	12.6	16.9%
China Hong Kong				363.3	4.1%				0.3	0.1%
Colombia	2.0	930.0	4.0%	252.7	1.1%	5.8	1.1	6.0%	0.9	4.0%
Czech Republic				192.6	0.8%				0.8	-0.6%
Denmark	0.8	224.2	-4.3%	172.8	-1.5%	1.6	0.7	-1.7%	0.4	-2.0%
Ecuador	6.2	508.6	2.0%	226.1	5.1%				^	
Egypt	4.3	735.1	-0.3%	709.5	2.8%	77.3	5.9	9.3%	4.8	7.3%
Eq. Guinea	1.7	251.9	3.6%							
Finland				221.4	0.1%				0.3	-1.3%
France				1724.2	-1.5%				3.9	-0.4%
Gabon	3.7	245.0	-2.0%							
Germany				2362.3	-1.6%	2.2	1.0	-5.2%	7.0	-1.3%
Greece				343.5	-1.6%				0.4	8.6%
Hungary				141.8	0.1%				1.0	-1.6%
India	5.7	858.4	1.7%	3472.6	4.3%	43.8	4.5	5.7%	5.9	8.7%
Indonesia	4.0	941.7	-3.8%	1430.5	2.3%	104.7	7.3	1.8%	3.7	2.0%
Iran	151.2	4321.1	1.2%	1824.4	2.7%	1168.6	14.7	8.7%	14.8	8.1%
Iraq	143.1	2798.1	1.0%			126.7	0.2	-3.9%		
Israel				239.6	-0.8%				0.5	
Italy	1.4	110.2	2.5%	1486.1	-2.5%	3.1	0.7	-5.8%	6.9	0.9%
Japan				4417.9	-2.0%				10.2	3.6%
Kazakhstan	30.0	1840.7	7.8%	212.4	3.1%	66.4	1.9	7.7%	0.9	1.2%
Kuwait	101.5	2865.4	2.8%	438.5	5.2%	63.0	1.3	2.1%	1.6	4.4%
Libya	47.1	479.1	-10.3%			52.8	0.4	-4.0%		
Lithuania				55.4	0.1%				0.3	1.8%
Malaysia	5.9	573.0	-1.5%	608.3	2.4%	86.0	6.0	2.8%	2.8	1.2%

Source: Deutsche Bank

Figure 221: Oil & Gas reserves, production and consumption by country (M to Z)

	Oil					Gas				
Countries	Reserves	Production	CAGR	Consumption	CAGR	Reserves	Production	CAGR	Consumption	CAGR
	Bn Bbls	kb/d	2001-11	kb/d	2001-11	Tcf	Bcf/d	2001-11	Bcf/d	2001-11
Mexico	11.4	2937.8	-1.9%	2027.2	0.4%	12.5	5.1	3.2%	6.7	5.1%
Myanmar						7.8	1.2	5.9%		
Netherlands				1052.0	1.3%	38.9	6.2	0.3%	3.7	-0.5%
New Zealand				148.3	1.2%				0.4	-4.2%
Nigeria	37.2	2457.4	0.8%			180.5	3.9	10.3%		
Norway	6.9	2039.3	-5.0%	252.8	1.2%	73.1	9.8	6.5%	0.4	0.7%
Oman	5.5	891.0	-0.7%			33.5	2.6	6.6%		
Pakistan				408.3	1.1%	27.5	3.8	5.6%	3.8	5.6%
Papua New Guinea						15.6				
Peru	1.2	152.7	4.5%	203.1	3.4%	12.5	1.1		0.6	
Philippines				256.3	-2.9%				0.3	
Poland				565.6	3.0%	4.3	0.4	1.0%	1.5	2.9%
Portugal				240.4	-2.8%				0.5	7.2%
Qatar	24.7	1722.6	8.6%	237.6	12.6%	884.5	14.2	18.5%	2.3	8.1%
Rep. of Congo	1.9	295.4	2.4%							
Republic of Ireland				142.2	-2.4%				0.5	1.6%
Romania	0.6	88.0	-3.8%	187.1	-1.2%	3.8	1.1	-2.1%	1.3	-1.8%
Russia	88.2	10280.3	3.9%	2961.0	1.7%	1575.0	58.7	1.4%	41.1	1.5%
Saudi Arabia	265.4	11160.6	2.0%	2855.7	5.8%	287.8	9.6	6.3%	9.6	6.3%
Singapore				1192.3	5.4%				0.8	25.5%
Slovakia				77.7	1.4%				0.6	-1.0%
South Africa				547.3	1.6%				0.4	
South Korea				2397.5	0.6%				4.5	8.4%
Spain				1391.6	-0.6%				3.1	5.8%
Sudan	6.7	453.0	7.6%							
Sweden				305.2	-1.1%				0.1	5.9%
Switzerland				234.5	-1.7%				0.3	0.4%
Syria	2.5	332.2	-5.4%			10.1	0.8	5.2%		
Taiwan				951.0	0.1%				1.5	7.8%
Thailand	0.4	345.1	6.1%	1080.0	3.1%	9.9	3.6	6.5%	4.5	6.5%
Trinidad & Tobago	0.8	135.9	0.1%	34.4	2.7%	14.2	3.9	10.2%	2.1	6.6%
Tunisia	0.4	77.6	0.9%							
Turkey				694.1	0.9%				4.4	11.1%
Turkmenistan	0.6	215.8	2.9%	108.1	2.7%	858.8	5.8	2.5%	2.4	7.2%
Ukraine				277.0	-0.2%	33.0	1.8	1.0%	5.2	-2.5%
UAE	97.8	3322.1	2.7%	671.0	5.6%	215.1	5.0	1.4%	6.1	5.2%
UK	2.8	1099.7	-7.8%	1542.2	-1.0%	7.1	4.4	-8.1%	7.8	-1.8%
USA	30.9	7841.3	0.2%	18835.5	-0.4%	299.8	63.0	1.6%	66.8	0.9%
Uzbekistan	0.6	86.1	-6.6%	91.2	-3.7%	56.6	5.5	0.9%	4.8	-0.1%
Venezuela	296.5	2720.3	-1.4%	832.0	3.0%	195.2	3.0	0.5%	3.2	1.1%
Vietnam	4.4	328.2	-0.6%	357.7	6.8%	21.8	0.8	15.6%	0.8	15.6%
Yemen	2.7	228.4	-6.7%			16.9	0.9			
Other countries	7.3	1102.3	1.2%	5621.3	2.3%	75.7	5.3	5.8%	9.5	6.9%

Source: Deutsche Bank

Oil & Gas Products

What is crude oil?

Crudes differ in a large number of chemical and physical properties

Not all crude oil is the same. Breaking it down to its most simple form, crude oil consists of lots of carbon chains and molecules all of differing lengths. It is not a homogenous material and its physical appearance varies from a light, almost colourless liquid to a heavy black/brown sludge. The number of hydrocarbons, in addition to the heat at which the hydrocarbons formed, will determine the density and hence the classification of the oil. Density (light/medium/heavy) is classified by the American Petroleum Institute (API). The less dense the oil, the higher the API gravity, hence high gravity oils are known as 'light' crudes and low gravity oil are 'heavy' crudes. Equally, all oils contain sulphur to some degree which is released on combustion as sulphur dioxide. Oils containing a higher percentage of sulphur are known as sour, and those with lower sulphur levels are known as sweet.

Figure 222: Simple depiction of the structure of the different components that comprise crude oil. Importantly, not all chains are the same*

C-C-C-C (LPG)

C-C-C-C-C-C (naphtha)

C-C-C-C-C-C-C-C-C (gasoline)

C-C-C-C-C-C-C-C-C-C-C-C-C (diesel)

CH_3 - (C-C-C-C-C-S-C-C-C-C-C-C-C-C) - CH_3 (long chain bunker fuel)

CH_3-(CH_2)n-CH_3 Bitumen

*Source: Deutsche Bank *Chain lengths are for illustrative purposes only rather than an accurate depiction of length and molecular form*

Definitions

Light crude usually has an API gravity between 35 and 40 degrees

Light crude usually has an API gravity between 35 and 40 degrees. It has a lower wax content and fewer long chain molecules, hence lower viscosity and as such is easier to pump and transport. This historically has meant lower operating (both production and refining) costs to exploit resources of light crude and hence higher demand by oil companies to gain access to these resources. The majority of refined oil (in all its forms such as petrol, heating oil) to date has been produced from light oil and both the London (Brent) and New York (WTI) oil prices -- the two key international benchmarks -- are for light crude, indicating the dominance of light crude in the global market to date.

Heavy crude usually has an API between 16 and 20 degrees. Physical properties that distinguish heavy crudes from lighter ones include higher viscosity, with a consistency ranging from that of heavy molasses to a solid at room temperature. These oils can often contain high concentrations of sulphur and several metals, particularly nickel and vanadium. These are the properties that make them difficult to pump out of the ground or through a pipeline and interfere with refining. In general, diluents are added at regular distances in pipelines carrying heavy crude to facilitate the flow.

Sweet crude contains less than 0.5% sulphur.

Sweet crude contains less than 0.5% sulphur. High quality, low sulphur crude oil is commonly used for processing into petrol and is in high demand. "Light sweet crude oil" is the most sought-after version of crude oil as it contains a disproportionately large amount of gasoline (petrol), kerosene, and high-quality diesel.

What is API gravity? The American Petroleum Institute gravity, or API gravity, is a measure of how heavy or light a petroleum liquid is compared to water. If its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids. For example, if one petroleum liquid floats on another and is therefore less dense, it has a greater API gravity. Although mathematically API gravity has no units (see the formula below), it is nevertheless referred to as being in "degrees". API gravity is graduated in degrees on a hydrometer instrument and was designed so that most values would fall between 10 and 70 API gravity degrees. The formula for API is as follows. Note that the specific gravity (SG) of a liquid is its density relative to water.

API Gravity = 141.5/SG at 60°F – 131.5

Sour crude contains impurities such as hydrogen sulphide and carbon dioxide

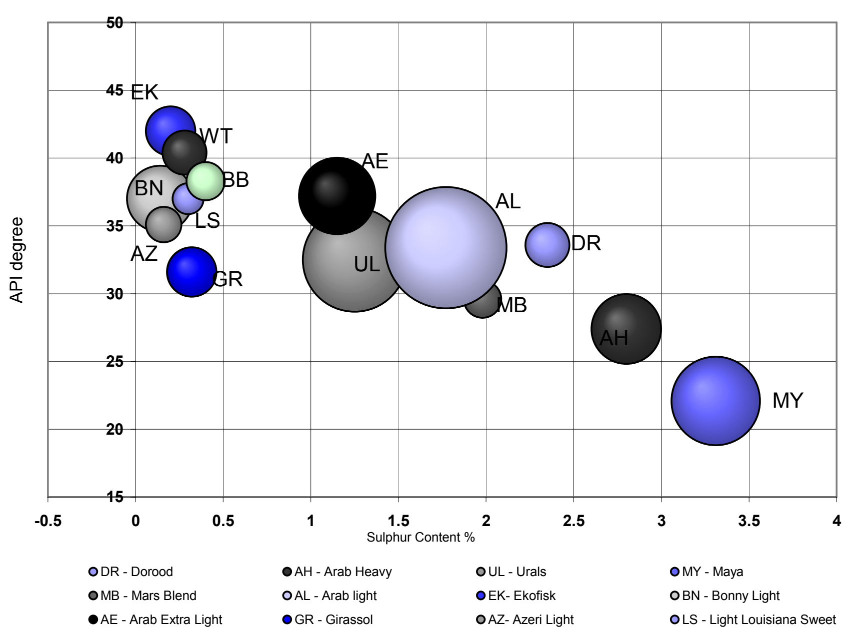
Sour crude contains impurities such as hydrogen sulphide and carbon dioxide. When the total sulphide level in the oil is >1% the oil is called 'sour'. The impurities need to be removed before the lower quality crude can be refined, thereby increasing the cost of processing. This results in higher costs to produce transport and other fuels than those made from sweet crude oil.

Acidity is measured via a total acid number (TAN) index. Acidity above a certain level poses problems for refiners as it can lead to corrosion of the refinery equipment. Special equipment can be installed to handle higher acid crudes or the problem can be addressed via blending but this too has a logistical element to it. Acidity has not played a major role in oil markets to date but with more unconventional sources of oil being explored this could be an important factor going forward.

Key global crude blends & resultant product slates

The figure below shows the different API and sulphur content of some familiar crude blends

Figure 223: Quality and Production volumes of crude oil 2006

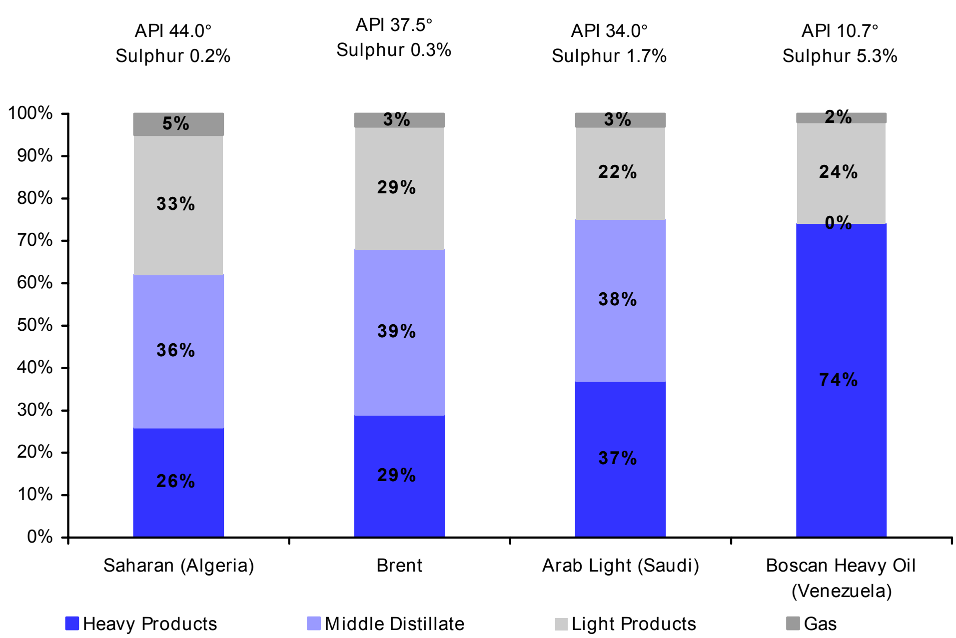


Source: Deutsche Bank estimates, and ENI World Oil and Gas Review

The chart above highlights higher volumes of production in light but sour blends indicating that the need for refineries to de-sulphurise crude. For example both Urals and Arab Light (light sour blends) and Maya (heavy sour blend) are now produced in much higher volumes than Brent Blend or West Texas Intermediate.

The diagram below illustrates the typical refining slate of a number of different crude oils. Clearly heavier crude blends result in a much heavier product slate. In general both heavy and sour crudes trade at a discount to lighter/sweeter crudes due to higher processing costs and the relative availability of refining capacity to process heavier/sourer grades.

Figure 224: Typical refining output of crude oil for selected blends



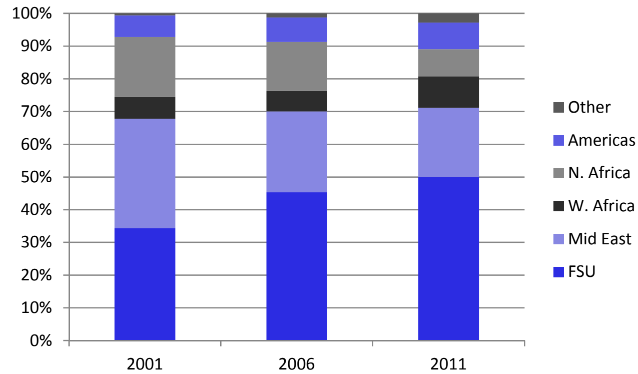
Source: Wood Mackenzie

Trends in the crude oil slate

In Europe, the slate of crude available has evolved in recent years as oil production in the North Sea has begun to decline. As this supply is replaced, the dominant trend has been growth in supply from FSU from c30% to c50% of the total c13mb/d of imports. With a greater proportion of supply from the heavier and sourer Russian Urals blend European refiners have had to invest in processing and desulphurising capabilities.

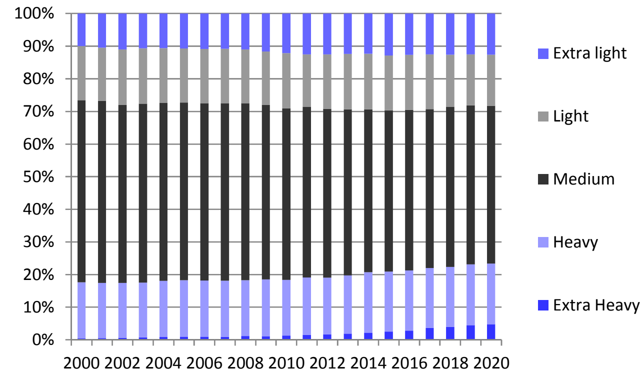
In North America, the crude slate is undergoing a period of change with two trends. First, the resurgence in light/sweet domestic production due to the growth in output from tight oil plays. This growth is seeing the ongoing displacement of heavier imports. As a consequence, recent investments in upgrading capabilities at Gulf Coast refineries now appear less necessary. Second, continued growth in the output from the Canadian Oil sands. A relatively small number of US refineries are appropriately sited and configured to take advantage of this feedstock and hence stand to make strong margins.

Figure 225: European crude imports (mb/d)



Source: Deutsche Bank, BP Statistical report

Figure 226: Looking forward the global crude slate is expected to become somewhat heavier



Source: Wood Mackenzie GOST

As noted, heavy investment has been made by refineries (refer to section on refineries) in order to process and desulphurise heavy and/or sour oil. The introduction of Auto-Oil I and II in Europe and similar legislation in most other countries (designed to reduce the environmental impact of acid rain) has meant that the level of sulphur permitted in gasoline and diesel has significantly decreased over the last number of years.

Figure 227: Gasoline and Diesel Maximum sulphur level

	Gasoline (ppm sulphur)				Diesel oil (ppm sulphur)			
Country	2000	2005	Current	Started from	2000	2005	Current	Started from
EU	150	50	10	2009	350	50	10	2009
USA	300	90	30	2006	500	500	15	2006
Canada	320	30	30	2005	500	500	15	2006
Australia	800	150	50	2008	1500	500	10	2009
Japan	100	50	10	2007	800	50	10	2007
China	800	500	150	2010	2000	500	350	2010

Source: Deutsche Bank

Refining Overview

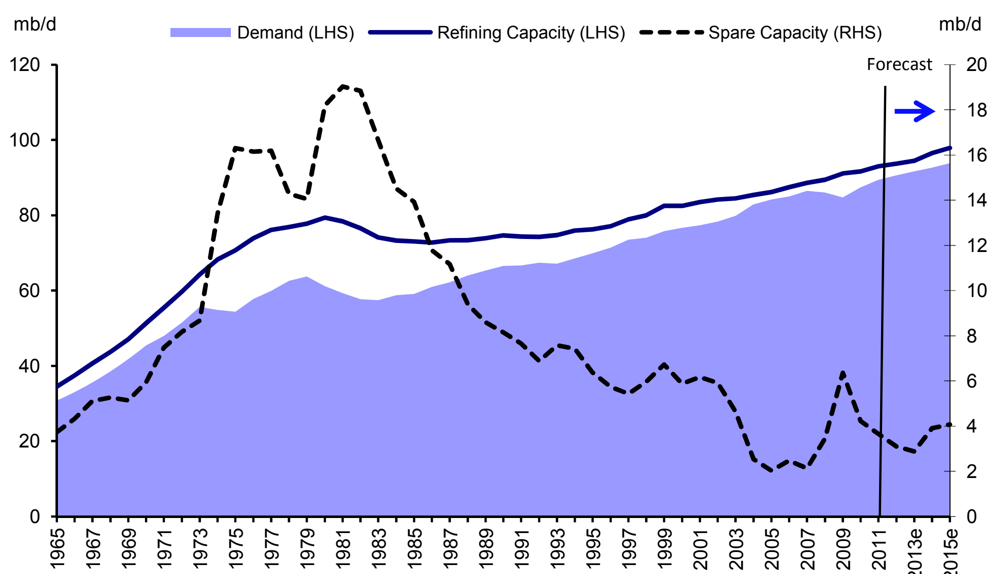
The Black Sheep of the family

Refining has long been the least favoured child of the integrated oil company's portfolio. Low return, low growth, capital intensive, politically sensitive and environmentally uncertain - the industry has perhaps appropriately been described by one leading refiner's CFO as one of the world's least attractive industries. Yet as an important link between upstream production and end consumer markets, refining has long been perceived as a necessary evil by the integrated oil companies and one that, if managed tightly with limited capital investment, can generate both healthy returns on invested capital and strong cash flows.

Refining has long been the least favoured child of the integrated oil company's portfolio.

Of course it wasn't always like this. Through much of the twentieth century as demand for oil products grew strongly refining afforded the oil exploration companies the opportunity to benefit from that growth while securing demand for their upstream production. However, akin to the western hemisphere's petrochemical industry, the oil price shock of the early 1970s served to hasten an already impending slowdown in underlying demand growth for refined oil products in the developed world (see chart below), following which years of overcapacity helped to ensure that returns remained well below re-investment levels. A similar reaction was once again evident through the financial crisis of 2008/09 with demand falling by some 1.3mb/d in 2009 which resulted in a significant increase in refining spare capacity as illustrated in the figure below.

Figure 228: Refining supply and demand and apparent 'spare' capacity 1965-2015E



Source: BP Statistical Review; DB estimates

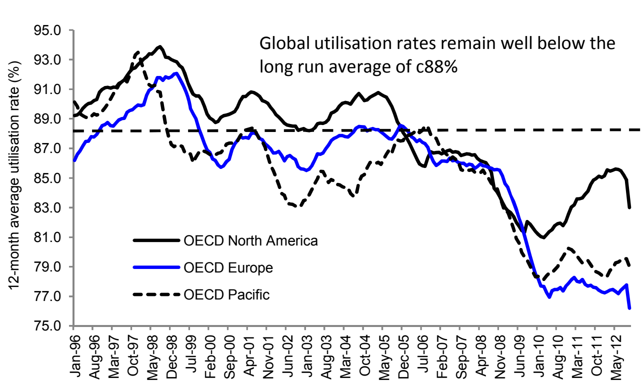
The 'Golden Age of Refining' more of a Golden Moment?

Through the period of 2004-2008 refining profitability experienced something of a renaissance. Continued steady demand growth combined with western refiner's ongoing reluctance to invest in new capacity resulted in a reduction of much of the surplus supply with the resulting improvement in capacity utilization, particularly in the US, leading to periods of market tightness and much improved profitability. With gross margins significantly improved this led to comments of a new "golden era" for refining.

Recently refining profitability has, however, seen something of a renaissance

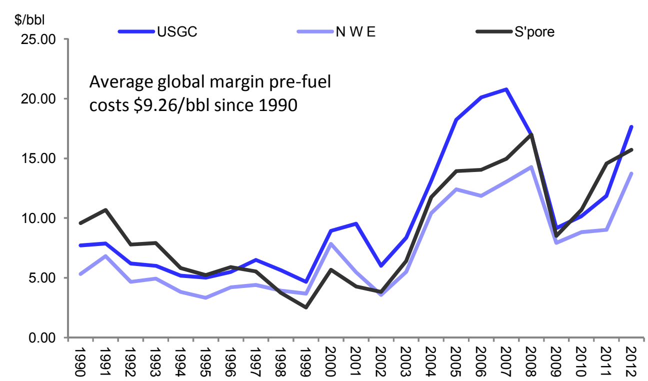
However, the financial crisis of 2008/09 sent the golden era to an early grave, with refining margins in 2009 dropping sharply to pre-2004 levels. Weak demand, a sharp increase in existing spare capacity (with the risk that new capacity additions currently under construction will further exacerbate the situation) and increased supply of both bio-fuels for blending and NGL production all put downward pressure on margins. Subsequent recovery has been impressive not least in North America where the industry is benefitting from both low energy costs (natural gas) and the material disconnect that has emerged subsequent to the tight oil revolution between land-locked WTI and water-borne Brent. This has offered certain North American refiners a material competitive advantage through lower feedstock costs (not least those in PADD2 – see later). The overall improvement in industry margins has, however, come on the back of notably lower utilisation rates. In Europe in particular, deteriorating oil product demand combined with limited capacity closures has meant that utilisation rates have barely recovered from those seen through the depths of the 2008 downturn.

Figure 229: OECD refinery utilization rates 1995-2012



Source: IEA

Figure 230: Global refining margins by region



Source: BP Trading Indicators

Various factors have clearly played an important role in the dramatic improvement and subsequent collapse in gross refining margins in recent years. These are discussed in some detail over the following section. In brief, however, they include:

The impact of rising crude oil prices on conversion margins

Refining at its simplest is about the separation of the different components of the crude oil barrel.

As we shall see, refining at its simplest is about the separation of the different components of the crude oil barrel. However, not all of the outputs have the same market value. Gasoline and diesel for example sell at a premium to heavy fuel oil for power generation. Moreover, where the market price of these transport fuels typically advances with a rise in the price of crude oil given a lack of substitutes, in the case of heavy fuel oil the availability of energy alternatives (coal, natural gas, etc) serves to cap price improvements even at higher crude oil prices. As a consequence, those refiners that have invested in the process equipment to CONVERT lower value products to higher value products stand to gain from an improvement in conversion margins. This is illustrated by the table overleaf which depicts the benefits to Total from a conversion plant inaugurated in 2006 for production of diesel from heavy fuel oil.

The light-heavy spread

Theoretically, the prices of different crude oils should reflect variances in their composition and the different value of the product slate that emerges from their distillation. However, because not all refineries can process heavier, sour blends, at times of tightness in crude oil markets or if the supply of light, sweet crude oil is restricted, those refiners that cannot process heavy, sour crudes will likely bid up the value of lighter sweeter blends. This phenomenon is further augmented by the fact that

Figure 231: Total's Gonfreville hydrocracker – summarizing the economics

Input	Amount	Price ($/T)	Cost ($m)	Output	Amount	Price ($/T)	Value ($m)
Heavy Fuel Oil	1.8mtpa	250	-450	Diesel	1.3 mtpa	580	754
Domestic Fuel Oil	0.7mtpa	550	-413	Naphtha	0.2 mtpa	530	106
	2.5mtpa		-863	Kerosene	0.4 mtpa	620	248
				Other	0.5 mtpa	550	275
							1383
				OPEX Costs (@$5/bbl)			-90
				Input Costs			-863
				Upgrade value (gross)			430
				Upgrade value/bbl			*$23.5/bbl*

Source: Deutsche Bank estimates

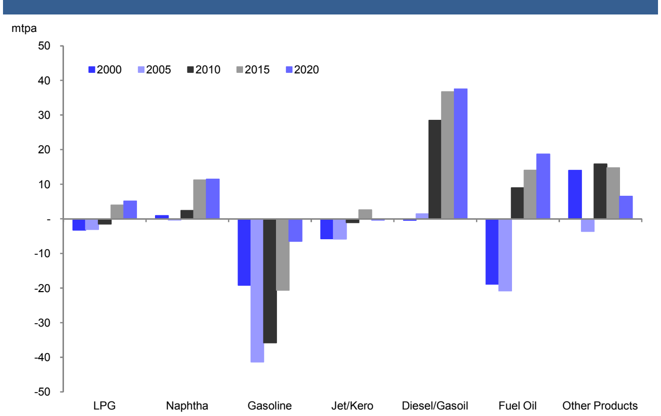
Theoretically, the different price of different crude oils should reflect variances in their composition and the different value of the product slate that emerges from their distillation

the marginal OPEC barrel tends to be heavier and more sour. As such, an increase in the 'call' on OPEC will tend to drive increased production of heavy, sour barrels. Whilst this may provide the market with the crude it needs, it will do little to alleviate the challenges faced by those refiners which cannot process these heavy, sour barrels thereby further exacerbating the spread between light and heavy. Clearly, the above also implies that at times of market oversupply the first barrels to be withdrawn from the market will equally tend to be OPEC heavy. Thus where in tight product markets the heavy-light spread tends to widen, in slack product markets the spread will narrow.

Product imbalances

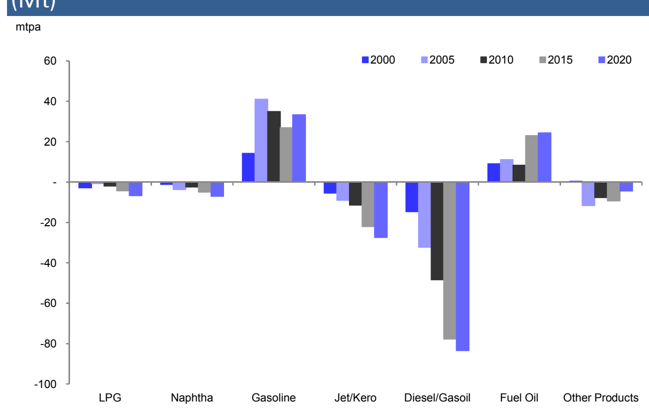
Although refining capacity globally may be in surplus, there are clear regional differences in capacity utilization. Moreover, whilst it is possible through investment to alter the products emerging from the refining process, ultimately the product slate cannot be tailored to exactly meet the needs of the market. Indeed, given the age of many refineries in the western world considerable rigidity exists within the refining system. Environmental concerns also limit the scope for investment in new build. As such, while a regional market may be long overall capacity, it may be unable to fully meet the local demands for a particular refined product.

Figure 232: North America – Future product balances (Mt)



Source: Wood Mackenzie Balancing the World

Figure 233: North West Europe – Future product balances (Mt)



Source: Wood Mackenzie Balance the World

This is particularly true of gasoline in both the US market and Europe. Thus where the US market is significantly short of gasoline, the European market produces substantially more than is required. Of course, this European excess can be sold into the US. However, in order to do so prices in the US market need to be sufficient to justify the cost of shipping. This 'transport premium' suggests that so long as the US market remains short of gasoline US prices will be better as should US refining margins. By contrast, Europe's need to export not only means that refining margins will be lower. It also suggests that the health or otherwise of European margins is likely to be critically dependent upon the health of markets elsewhere, not least the US.

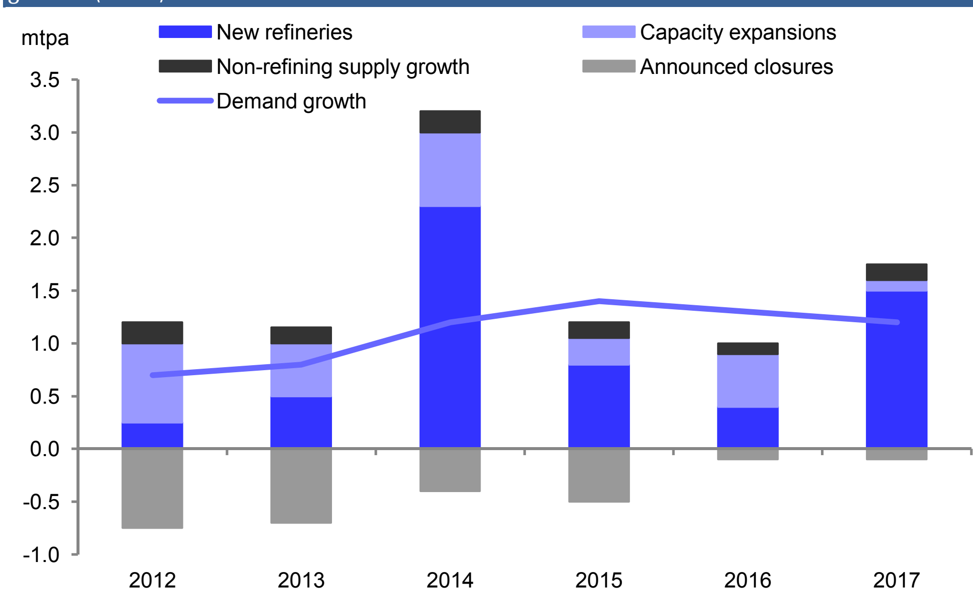
Conclusion: refining profitability the sum of many parts

Ultimately it is not just fluctuations in supply markets that has driven the improvement and subsequent deterioration in refining profitability in recent years. It is also the structural shift in oil prices, different rates of demand growth for the end-products of the refining process and the growing product imbalances between different regional markets. Add to these the increased environmental and regulatory specifications applied to oil products nowadays, most significantly transport fuels all of which require investment and add barriers to the simple flow of products between one region and another, and it seems clear that there is much more at play here than a simple shift in the demand supply balance.

The curse of the investment cycle

Following the improvement to profitability during the so called golden moment of refining, on looking at current planned refineries around the world, the industry appears to have invested in more capacity than is actually needed, something it has done in the past. Current capacity addition plans are significant (even net of known planned closures) and despite incremental demand growing at a faster pace than incremental supply, the existing oversupply situation means the world still looks oversupplied by c6mb/d in 2015. No doubt in this environment some of these plans will be deferred whilst others will be pushed out. However, if all were to proceed the oversupply situation looks like it will persist for many years to come. Further capacity closures most significantly in mature ex-growth OECD markets are undoubtedly going to be required.

Figure 234: Planned global refining capacity additions and annual expected demand growth (mb/d)



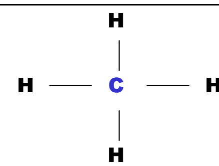
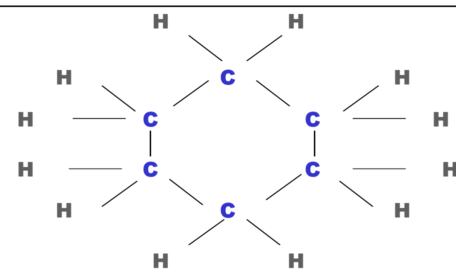
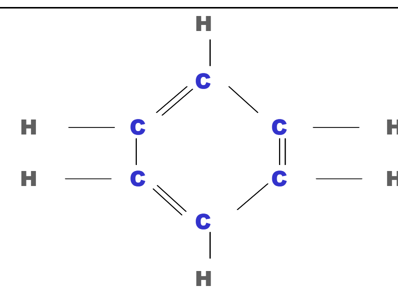
Source: IEA Medium Term Outlook; Wood Mackenzie; Deutsche Bank

What is Refining?

Refining is a process of converting crude oil into usable products. Crude oil is a mixture of hundreds of different types of hydrocarbons with carbon chains of different lengths. These can be separated through refining. The shortest chain hydrocarbons are gases (under five carbon atoms); chains containing five to 18 carbon atoms are liquids; and chains of 19 or more carbon atoms generally form solids at room temperature.

Refining is a process of converting crude oil into usable products.

Figure 235: Types of Hydrocarbons in Crude Oil

Paraffins The lightest of all carbon chains, they have very few carbon atoms (C_1 to C_4). These are very stable and are ingredients of natural gas and LPG. These consist of straight or branched carbon rings saturated with hydrogen atoms. (General formula: C_nH_{2n+2})	 Methane, CH_4
Naphthenes Naphthenes consist of carbon rings, sometimes with side chains, saturated with hydrogen atoms. (General Formula: C_nH_{2n}). They are found in all fractions of crude oil except the very lightest. Single-ring naphthenes (monocycloparaffins) with five and six carbon atoms predominate, with two-ring naphthenes (dicycloparaffins) found in the heavier ends of naphtha.	 Cyclohexane, C_6H_{12}
Aromatics Aromatic hydrocarbons are compounds that contain a ring of six carbon atoms with alternating double and single bonds and six attached hydrogen atoms. All aromatics have at least one benzene ring (a single-ring compound characterized by three double bonds alternating with three single bonds between six carbon atoms) as part of their molecular structure. The most complex aromatics, polynuclears (three or more fused aromatic rings), are found in heavier fractions of crude oil.	 Benzene, C_6H_6

Source: Deutsche Bank,

What do refineries make?

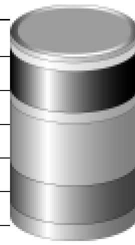
Oil refining produces a wide variety of products that can be seen in use around us every day: gasoline for motor vehicles; kerosene; jet fuel; diesel and heating oil to name just a few. Petroleum products are also used in the manufacture of rubber, nylon and plastics.

A typical product yield or a refinery's **product slate** (the proportion of refined products obtained by refining one barrel of crude) obtained from a complex refinery in Western Europe is shown in the figure below. This yield reflects both the refineries configuration but, because all crude oils differ in their hydrocarbon composition, also the type of crude oil that is processed.

The initial product yield can be improved by further processing the oil products using more sophisticated refining units to crack, unify and/or alter the hydrocarbons (see the "How does a refinery work?" section below).

Refinery yields also tend to vary slightly over the year as refiners respond to both the regular seasonal swings in product demand (more heating oil in the winter, more gasoline in the summer) and irregular movements in product prices (the best and most flexible refineries can quickly alter their output to produce the highest priced mix).

Figure 236: Typical Western Europe Product Yield



Product	Western Europe (%)
Petroleum Gas	3
Naphtha	6
Gasoline	21
Kerosene	6
Gasoil/ Diesel (aka middle distillates)	36
Fuel Oil	19
Others (residuals, lubricants)	9

Source: Deutsche Bank

The stream of oil products

The basic building block of the oil and gas sector, hydrocarbons, contain a lot of energy. Fuel products from the refining process take advantage of this attribute. The only difference between each oil product is the length of the carbon chains it contains. As mentioned previously, this determines its physical state (gas, liquid, solid) and also its application. The main refinery outputs can be summarized as follows:

- **Petroleum gas** is the lightest hydrocarbon chain, commonly known by the names methane, ethane, propane and butane. It is a gas at room temperature, easily vaporised and is used for heating, cooking and making plastics. It is often liquefied under pressure to create liquefied petroleum gas (LPG) supplied by pipeline, in filled tanks or in large bottles.
- **Naphtha** is a light, easily vaporised, clear liquid used for further processing into petrochemicals (in western Europe and Asia in particular), as a solvent in dry cleaning fluids, paint solvents and other quick-drying products. It is also an intermediate product that can be further processed to make gasoline.
- **Gasoline** is a motor fuel that vaporises at temperatures below the boiling point of water i.e. it evaporates quickly if spilt on the ground. Gasoline is rated by octane number, an index of quality that reflects the ability of the fuel to resist detonation and burn evenly when subjected to high pressures and temperatures inside an engine. Premature detonation produces "knocking" (backfiring), wastes fuel and may cause engine damage. Previously a form of lead was added to cheaper grades of gasoline to raise the octane rating, but with the environmental crackdown on exhaust emissions, this is no longer permitted. New formulations of gasoline designed to raise the octane number contain increasing amounts of aromatics and oxygen-containing compounds (oxygenates). Cars are now also equipped with catalytic converters that oxidise un-reacted gasoline.
- **Kerosene** is a liquid fuel used for jet engines or as a starting material for making other products.
- **Gasoil or diesel distillate** is a liquid used for automotive diesel fuel and home heating oil, as well as a starting material for making other products.

- **Lubricating oil** is a liquid used to make motor oil, grease and other lubricants. It does not vaporise at room temperature and varies from the very light through various thicknesses of motor oil, gear oils, vaseline and semi-solid greases.
- **Heavy gas or fuel oil** is a liquid fuel used in industry for heat or power generation and as a starting block for making other products. Heavy grades of fuel oil are also used as 'bunker oil' to fuel ships. However, because most of the contaminants of oil (sulphur, metals, etc) have very high boiling points they tend to concentrate in the heavy fuel oil. Together with a heavy fuel oil's low hydrogen to carbon ratio, this makes it the most polluting fraction of oil.
- **Residuals** (or resid) are solids such as coke, asphalt, tar and waxes. They are generally the lowest value products in the barrel but can also be used a starting material for making other products.

How does a refinery work?

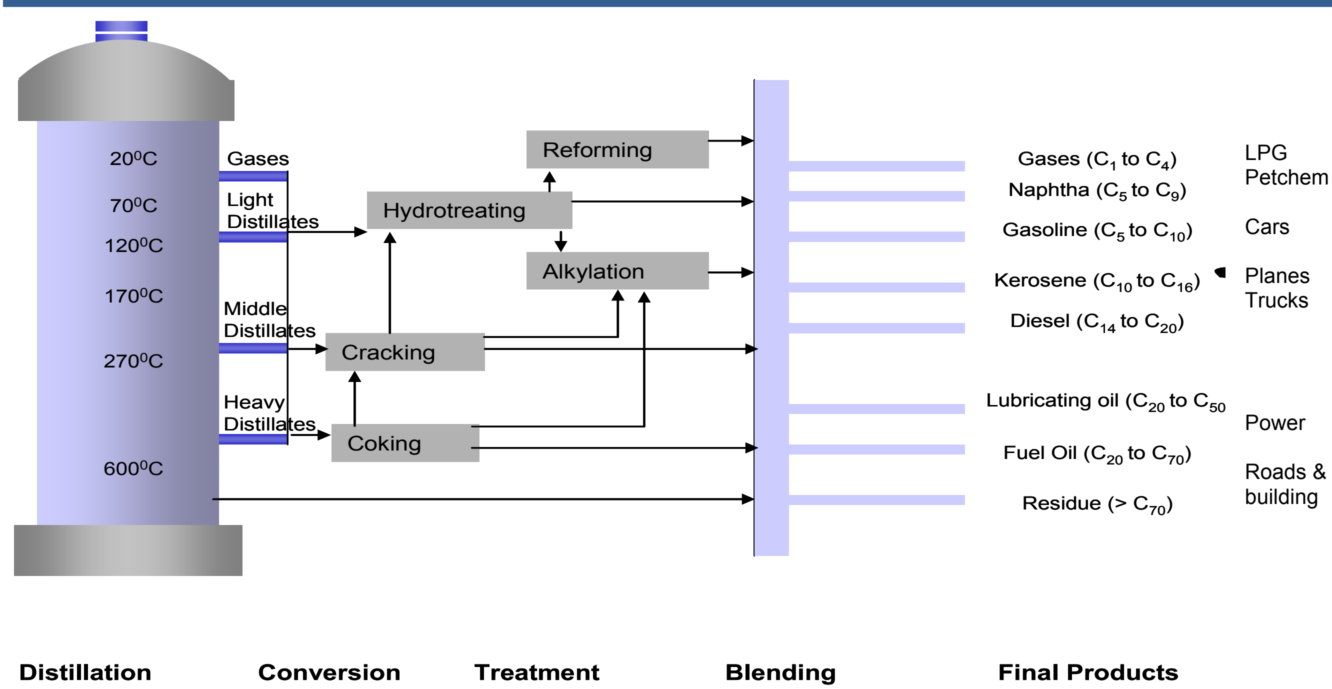
The function of a refiner is to convert crude oil into finished products required by the market in the most efficient, and therefore profitable, manner. How this is done will vary widely from refinery to refinery, depending upon the location of the site, the configuration of the refinery, crude oil processed and many other factors.

The function of a refiner is to convert crude oil into finished products required by the market in the most efficient, and therefore profitable, manner

Overall, however, there are four major refining steps taken to separate crude oil into useful substances:

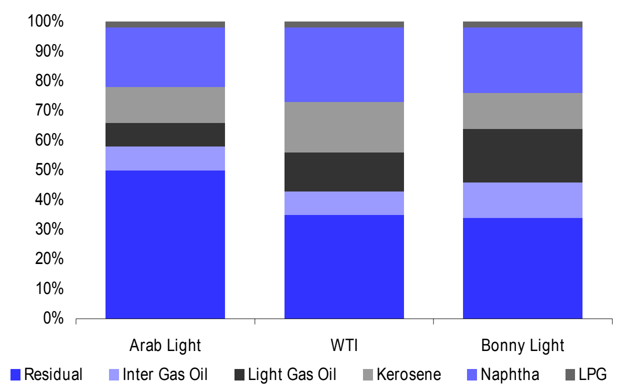
- Physical separation through crude distillation
- Conversion or upgrading of the basic distillation streams
- Product treatment to purify and remove contaminants and pollutants
- Product blending to create products that comply with market specifications

Figure 237: The oil refinery crude distillation process – fractionation through blending



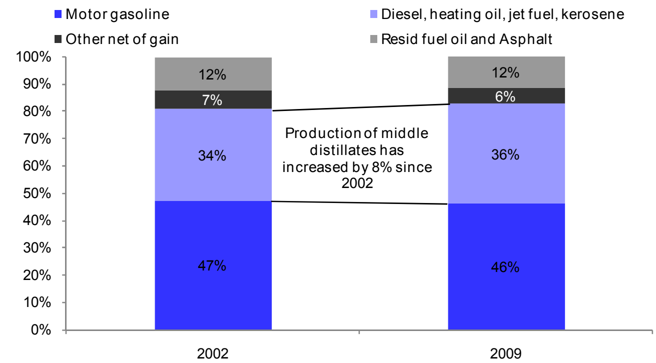
Source: Deutsche Bank

Figure 238: Product yields from simple distillation of different crude stream



Source: Deutsche Bank, EIA

Figure 239: Average US refinery yield – complexity improves the product slate



Source: Deutsche Bank, EIA

Crude Distillation (also known as 'Topping' or 'Skimming')

Distillation or fractionation is a process by which crude oil is separated

Distillation or fractionation is a process by which crude oil is separated into groups of hydrocarbon compounds of differing boiling point ranges called "fractions" or "cuts". It uses the property of differing boiling points of different sizes of carbon chains in the crude oil — the longer the chain, the higher the boiling point. Two types of distillation can be performed:

- **Atmospheric distillation**: This takes place at atmospheric pressure when the crude is heated to 350-400°C. The liquid falls to the bottom and the vapour rises, passing through a series of perforated trays (sieves). The lighter products, liquid petroleum gases (LPG), naphtha, and so-called "straight run" gasoline, are recovered at the lowest temperatures. Middle distillates namely jet fuel, kerosene and distillates (home heating oil and diesel fuel) come next. Finally, the heaviest products, such as, residuum or residual fuel oil are recovered.
- **Vacuum distillation:** To recover additional heavy distillates from this residue, it may be piped to a second distillation column where the process is repeated in vacuum conditions. Called vacuum distillation this allows heavy hydrocarbons with boiling points of 450°C and higher to be separated without them partially cracking (breaking down) into unwanted products such as coke and gas.

Conversion (or upgrading)

Unlike distillation, which maintains the chemical structure of the hydrocarbons, conversion alters their size and/or structure

Unlike distillation, which maintains the chemical structure of the hydrocarbons, conversion alters their size and/or structure. Using several processes to improve the natural yield of products achieved through simple distillation, upgrading enables refiners to more closely match their output with the requirements of the market. Thus where, for example, the output from a light crude oil would include around 25 percent gasoline but 40 percent residuum, after further processing in a sophisticated refinery the product slate can be altered to something nearer 60 percent gasoline, and 5 percent residuum, far more in line with the demand from end markets. The following are the major types of conversion processes:

- **Cracking**: Cracking processes break down heavier hydrocarbon molecules (high boiling point oils) into lighter products such as petrol and diesel, using heat (thermal) or catalysts (catalytic).

- **In thermal cracking** the hydrocarbons are heated, sometimes under high pressure, resulting in decomposition of heavier hydrocarbons. Thermal cracking may use steam cracking, coking (severe form of cracking - uses the heaviest output of distillation to produce lighter products and petroleum coke), visbreaking (mild form of cracking -quenched with cool gasoil to prevent over-cracking, used for reducing viscosity without affecting the boiling point range).
- **In catalytic cracking** the heavy distillate (gasoil) undergoes chemical breakdown under controlled heat (450-500°C) and pressure in the presence of a catalyst, a substance which promotes the reaction without itself being chemically changed, such as silica. Fluid catalytic cracking (FCC) uses a catalyst in the form of a very fine powder, which is maintained in an aerated or fluidized state by oil vapours. Feedstock entering the process immediately meets a stream of very hot catalyst and vaporizes. Hydrocracking uses hydrogen as a catalyst.

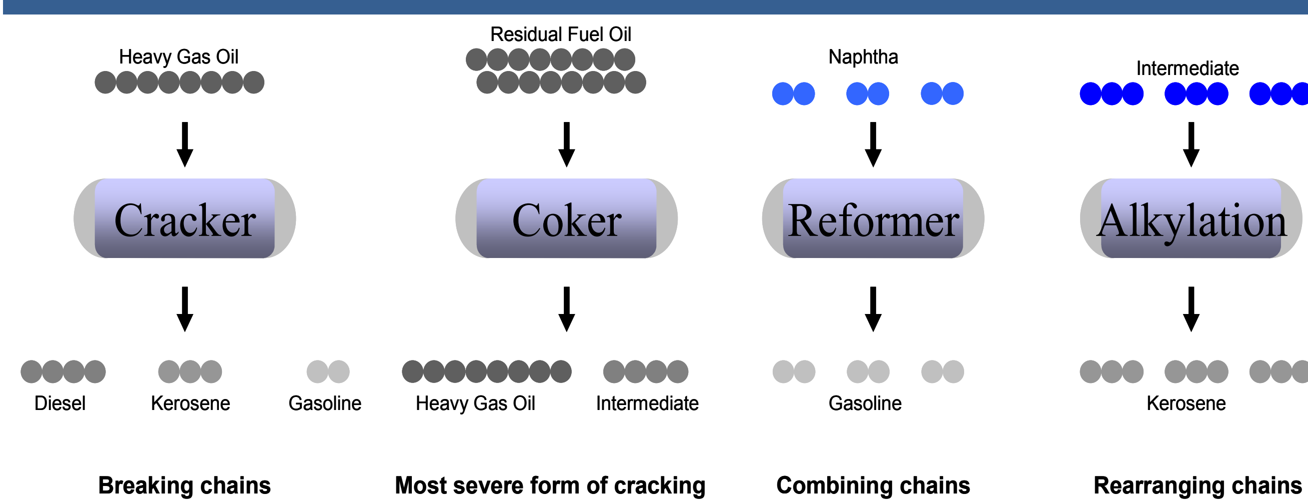
Figure 240: Catalytic cracking – FCC is used to produce gasoline whilst hydro-cracking is used to increase distillate yields

	FCC	Hydrocracker
Gas	5%	3%
LPG	14%	6%
Naphtha	1%	7%
Gasoline	45%	4%
Kerosene	1%	40%
Gasoil	23%	38%
Residue	8%	2%
Coke	5%	0%

Source: Deutsche Bank

- **Unification**: This process combines the lighter hydrocarbons to create heavier hydrocarbons of desired characteristics. Alkylation is one such process and uses a catalyst such as sulphuric acid to convert lighter hydrocarbons into alkylates, a mixture of high-octane hydrocarbons used to blend with gasoline.
- **Alteration**: This uses processes such as isomerization and catalytic reforming for "re-arranging" the chemical structure of hydrocarbons. Catalytic reforming uses a catalyst to produce higher-octane components under controlled temperatures and pressure. The process also produces hydrogen, which is used to remove sulphur from refinery streams.

Figure 241: Pictorial representation of major refining processes



Source: Deutsche Bank, http://science.howstuffworks.com/oil-refining5.htm

Treatment

A number of contaminants are found in crude oil. As the fractions travel through the refinery processing units, these impurities can damage the equipment, the catalysts and the quality of the products. There are also regulatory limits on the contents of some impurities, such as sulphur, in products. Treatment includes processes such as dissolution, absorption, or precipitation to remove/separate these undesirable substances. **Desalting** (dehydration) is used to remove impurities such as inorganic salts from crude oil. **Catalytic hydro-treating** is a hydrogenation process used to remove 90% of contaminants such as nitrogen, sulphur, oxygen, and metals from liquid petroleum fractions.

Treatment includes processes such as dissolution, absorption, or precipitation to remove/separate these undesirable substances

Formulating and Blending

Blending involves the mixing and combining of hydrocarbon fractions, additives, and other components to produce finished products with specific performance properties. Additives including octane enhancers, metal deactivators, anti-oxidants, anti-knock agents, gum and rust inhibitors, detergents, etc., are added during and/or after blending to provide specific properties not inherent in hydrocarbons.

Figure 242: Summary of main downstream processes

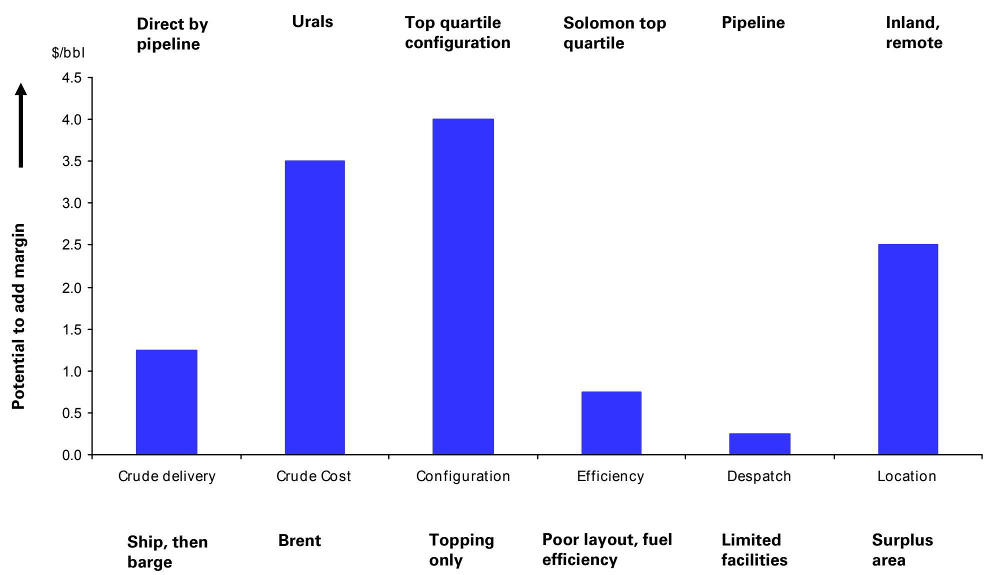
Process Name	Action	Method	Purpose	Feedstock (s)	Product (s)
Distillation					
Atmospheric distillation	Separation	Thermal	Separate fractions	Desalted crude oil	Gas, gasoil, distillate, residual
Vacuum distillation	Separation	Thermal	Separate fractions	Atmospheric tower residual	Gasoil, lube stock, residual
Conversion – cracking					
Catalytic cracking	Decompose	Catalytic	Upgrade gasoline	Gasoil, coke distillate	Gasoline, petrochem feedstock
Coking	Polymerize	Thermal	Convert vacuum residuals	Gasoil, coke distillate	Gasoline, petrochemical feedstock
Hydro-cracking	Hydrogenate	Catalytic	Convert to lighter HCs	Gasoil, cracked oil, residual	Lighter, higher-quality products
Steam cracking	Decompose	Thermal	Crack large molecules	Atm tower heavy fuel/ distillate	Cracked naphtha, coke, residual
Vis-breaking	Decompose	Thermal	Reduce viscosity	Atmospheric tower residual	Distillate, tar
Conversion - unification					
Alkylation	Combining	Catalytic	Unite olefins & iso-paraffins	Tower isobutane/ cracker olefin	Iso-octane (alkylate)
Polymerizing	Polymerize	Catalytic	Unite two or more olefins	Cracker olefins	High-octane naphtha, petrochemical stocks
Conversion - alteration					
Catalytic reforming	Alteration/ dehydration	Catalytic	Upgrade low-octane naphtha	Coker/hydro-cracker naphtha	High oct. reformate/ aromatic
Isomerization	Rearrange	Catalytic	Convert straight chain to branch	Butane, pentane, hexane	Isobutane/ pentane/ hexane
Treatment and Blending					
Desalting	Dehydration	Absorption	Remove contaminants	Crude oil	Desalted crude oil
Hydrodesulfurization	Treatment	Catalytic	Remove sulphur, contaminants	High-sulphur residual/ gasoil	Desulphurized olefins
Hydrotreating	Hydrogenation	Catalytic	Remove impurities, saturate HCs	Residuals, cracked HCs	Cracker feed, distillate, lube
Sweetening	Treatment	Catalytic	Remove H2S, convert mercaptan	Untreated distillate/gasoline	High-quality distillate/gasoline

Source: Deutsche Bank, www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html

Key variables impacting refinery performance

Whilst all refineries concentrate on converting crude oil into oil products, the net profit margin of one refinery relative to another can vary markedly. Clearly, given the potential for refiners to introduce different processes to alter their output slate, refinery configuration, or complexity, has a major role to play here. As illustrated by the schematic below, configuration is, however, only one of several factors that can play a significant role in determining the refining margin achieved by one refinery relative to another. Other important factors include the type of crude oil processed (sweet/sour), location, crude delivery method and overall efficiency (although for a cost based industry this is a surprisingly modest performance differentiator). Each of these is discussed over the following pages.

Figure 243: Several factors impact on a refiners net margin not least configuration, the crude slate and, perhaps surprisingly, location.



Source: Wood Mackenzie; Deutsche Bank

Configuration and complexity

A "complex" refinery refers to a refinery with secondary heavy oil upgrading units downstream of atmospheric distillation

A simple refinery (also known as a skimmer or topper) is one which in essence is focused on crude oil distillation with very little investment in equipment to upgrade the distillate streams. In contrast a "complex" refinery refers to a refinery with secondary heavy oil upgrading units downstream of atmospheric distillation. These secondary units include catalytic crackers, catalytic hydro-crackers, and fluid cokers. The advantages of adding complexity to refineries include:

- **Value of the product slate**. Simple refining configurations have a more rigid product yield or production pattern than the more complex refineries due to the lack of conversion units. Adding conversion units imparts the ability to produce a product slate which comprises a higher percentage of more highly value outputs, not least LPG, light distillates (gasoline, naphtha) and middle distillates (diesel for transport and home heating) whilst reducing the percentage of low value fuel oil, the selling price of which is constrained by lower cost substitutes such as coal and natural gas.

- **Choice of crude.** Complex refineries have far greater flexibility around their choice of crude feedstock and therefore are well placed to benefit from the use of lower priced crude feedstocks, which often sell at a discount that is greater than that implied from their molecular composition. This flexibility is a function of the investment they are likely to have made to remove sulphur (hydro-treaters) and to break down the lower value fractions at the bottom of the barrel (cracking). By contrast, a simple refinery is far more dependent upon light, sweet oil as a feedstock.
- **Fuel specifications**. Complex refineries are far better positioned to produce high-quality, refined products which are in line with frequently changing fuel specifications.

Having said this, while complexity certainly adds to a refiner's ability to realise a higher gross profit margin, the additional capital associated with the investment mean that it need not necessarily achieve a similar improvement in RoCE..

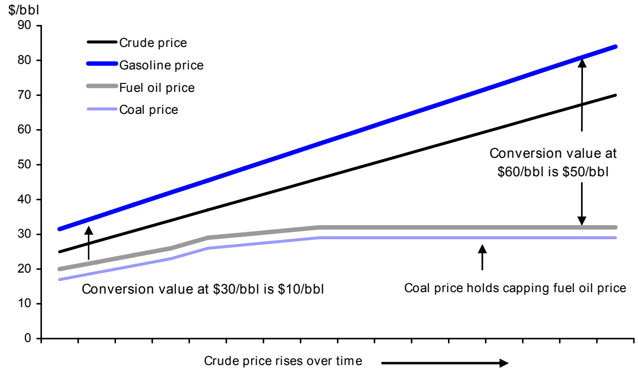
Equally, it is possible for refineries to be highly complex yet for that complexity to be directed towards making products which are now in surplus and therefore poorly rewarded. This is particularly true in Europe where a number of refineries invested in earlier years in upgrading equipment (predominantly FCCs) to increase gasoline yields. However, with the European market moving towards diesel, and gasoline production now in surplus they find themselves dependent upon export markets for sales. Moreover, because a gasoline cracker cannot be converted to one focused on diesel, repositioning the refinery would require not only the construction of a new and expensive hydro-cracker, but would also necessitate the idling or scrapping of a valuable piece of upgrading equipment.

High oil prices are good for complex refiners.

The economics of conversion are dramatically improved at high oil prices,

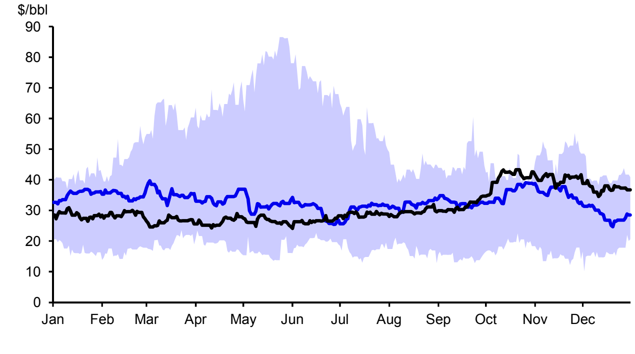
The importance of complexity should not, however, be underestimated particularly at high oil prices. This is because the economics of conversion are dramatically improved at high oil prices, a feature which reflects the widening price differential between transport fuels and heavy fuel oil at high oil prices and with it the so called 'crack spread' (discussed later). For while the absence of effective substitutes means that transport fuels rise in price as the price of crude oil increases, demand for fuel oil from its power generation end markets is largely capped by the availability of cheaper substitutes, namely coal and natural gas. Consequently those companies with the ability to upgrade or 'crack' fuel oil achieve a far better value uplift. This is illustrated in the two charts below, one of which depicts the 'theoretical' drag effect of coal on fuel oil prices and the other the substantial improvement in conversion margins for those companies cracking fuel oil to make diesel in recent years (the shaded area representing the historic norm).

Figure 244: Conversion margins expand as lower value fuel oil prices are capped by substitutes



Source: Deutsche Bank estimates

Figure 245: The result is a significant rise in conversion margins (diesel/fuel oil here) for complex refiners

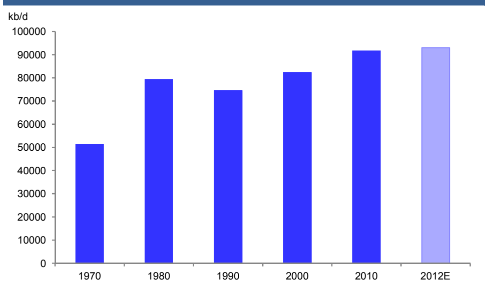


Source: Bloomberg Finance LP, Deutsche Bank estimates

Refining is getting more complex

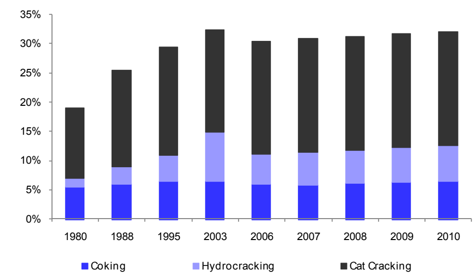
Not surprisingly, with limited underlying growth in product demand the bias of investment in the US and Northern Europe in recent years has been towards increasing the complexity of refineries rather than expanding capacity. In the US, for example, no new refineries have been built since 1980 although improvements in process design and the removal of bottlenecks has seen capacity creep of around 1% p.a. Complexity has, however, increased significantly. The European trend is depicted below with an evident bias towards investment in diesel biased hydro-crackers.

Figure 246: Refining capacity on the increase since the 1990's



Source: BP statistical review; Deutsche Bank

Figure 247: But refining infrastructure has become more complex



Source: Wood Mackenzie, BP, Deutsche Bank estimates

Measuring Complexity – The Nelson Complexity Factor

There are several measures of complexity. The most recognised is the Nelson Complexity Index (NCI)

There are several measures of complexity. The most recognised is the Nelson Complexity Index (NCI) which represents a standard measure to ascertain refinery complexities. Developed by Wilbur L Nelson in 1960, this captures the proportion of secondary conversion unit capacities relative to primary distillation or topping capacity. It is an indicator of not only the investment intensity or cost index of the refinery but also the value addition potential of a refinery. Nelson assigned a factor of one to the primary distillation unit. All other units are rated in terms of their costs relative to the atmospheric distillation unit. The complexity of a single refinery reflects the sum of the following equation for all the major refinery processes: (Complexity Factor x Unit Capacity)/CDU capacity). In the below example it tabulates as 3537/817=4.3

Figure 248: Complexity calculation: Worked Example

Ulsan Refinery	Change Capacity*	Complexity Factor	
	A	B	A*B
Crude Distillation	817	1	817
Vacuum Unit	79	1	79
Semi-regen Reformer	20	3.4	68
Continuous-regen reformer	50	5.8	290
Cat Cracker	45	12	540
Residue Hydrocracker	27	12	324
Mild Hydrocracker	54	7	378
Residue Hydrotreating	27	6	162
Alkylation	5	9	45
MTBE	5	9.1	45.5
BTX	28	15	420
Bitumen production	5	1.5	7.5
Hydrotreating (Naphtha)	76	1.2	91.2
Hydrotreating (Distillate)	159	1.7	270.3
			3537.5

Source: Deutsche Bank, * Oil and Gas Journal

The NCI typically varies from about two for hydro-skimming refineries, to about five for cracking refineries, and over nine for coking refineries. A related term to NCI is EDC or Equivalent Distillation Capacity. The calculation of EDC is a two-step process. The first step is the multiplication of the capacity of each unit in the refinery with the Nelson's complexity factor and the second is the sum of these products to arrive at the EDC for the refinery in total.

Figure 249: Typical Western Europe Product Yields: Simple vs. Complex

Product	Simple Refinery	Complex Refinery
Liquid Petroleum Gas	4%	6%
Naphtha	10%	10%
Gasoline	14%	26%
Kerosene	17%	16%
Gasoil/ Diesel (aka middle distillates)	20%	23%
Fuel Oil	35%	19%

Source: Deutsche Bank

Choice of Crude – Heavy, sour, sweet and light

We have already discussed the different properties of various crude oils emphasizing that the two key differences are:

- whether a crude is heavy or light, with light crude oils containing a greater proportion of more valuable, shorter chain, hydrocarbons such as gasoline and naphtha; and
- whether a crude is sweet or sour, indicating the degree of sulphur evident in the crude, with sweet crude oils containing less sulphur and thus requiring less processing equipment and cost to extract the sulphur in order to meet product specifications.

Crude oil prices reflect the different refining value of the distillate slate

Crude oil pricing reflects these differences with light sweet crudes such as Brent or WTI trading at a significant price premium to heavy, sour blends such as Russian Urals or Mexican Maya. Theoretically the difference in price should be reflective of the different value of the product slate produced by the simple distillation of each. In other words, if the value of the product slate obtained from the crude distillation of Brent is $4/bbl higher than that from the distillation of Urals, it would seem reasonable to expect Urals to trade at a $4/bbl discount.

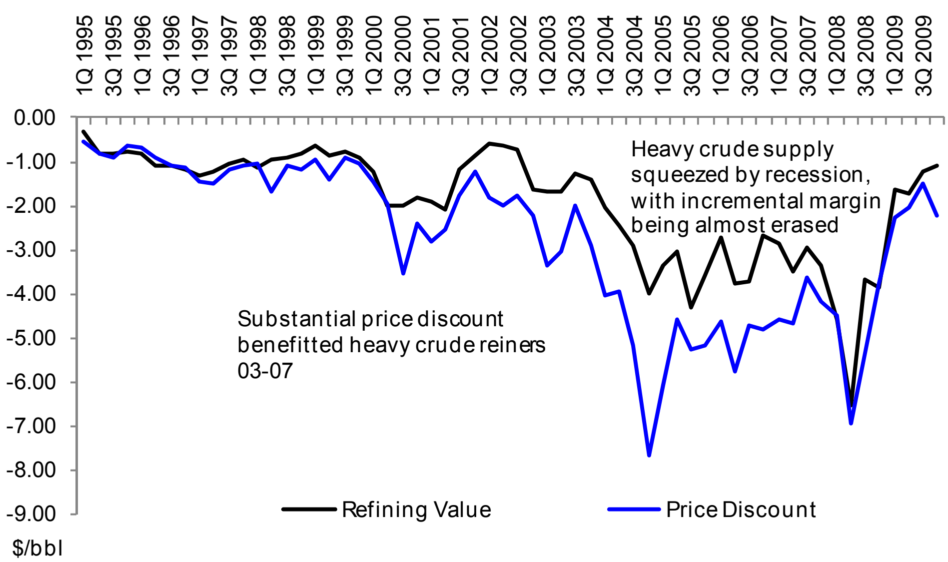
In tight markets a processing premium can emerge

This is broadly what happens in practice. However, because the refining system is heavily geared towards the processing of a lighter, sweeter barrel, at times when product demand is high or light crude supply is constrained, those refiners who are unable to process heavier or more sour crudes will find themselves having to compete for the available light barrels. The result is that the discount between the price of heavy and light crude oils expands to reflect the scarcity of the light barrel, moving to levels which reflect more than the simple difference between the two crude’s underlying components and processing costs.

Put simply, the refiner capable of processing a heavy crude oil will find that it is effectively receiving a ‘profit’ premium for its ability to do so.

This phenomena is well illustrated by the below chart. This depicts both the different value of the product slate emerging from processing a barrel of Urals crude oil relative to Brent and the actual price discount at which Urals trades relative to Brent. As explained earlier, in a perfect market, one would expect the price discount of Urals to reflect purely the underlying difference in value of its product stream. This was the case through much of the late 1990s before tightness through the middle of the last decade saw the discount expand with Brent trading at a premium to Urals that was more than justified by its higher value product yield. As markets moved into oversupply through the financial crisis in late 2008 so this position subsequently reversed.

Figure 250: The theoretical discount at which Urals should trade to Brent based on the refining value of the product slate compared with the actual price discount



Source: Wood Mackenzie

In a heavier world this premium is likely to occur more frequently

For refiners who are capable of processing the heavier, more sour barrel this price premium clearly represents a profit opportunity. Moreover, in a world in which the supply of crude oil is becoming tighter and the barrel of crude oil heavier, this premium is likely to emerge more frequently placing a greater value premium on refineries capable of processing heavy, sour blends. In particular, given that the marginal OPEC barrel is heavy, at times when OPEC is producing towards capacity the heavy-light spread is likely to broaden (and vice versa as is clear from quota cuts in 2009). In large part this is reflected by the Saudi's decision to build to new high conversion facilities in Saudi Arabia at Jubail (one with COP, the other Total) as it seeks to add value to the heavy oil arising from new fields such as Manifa and Safinayah.

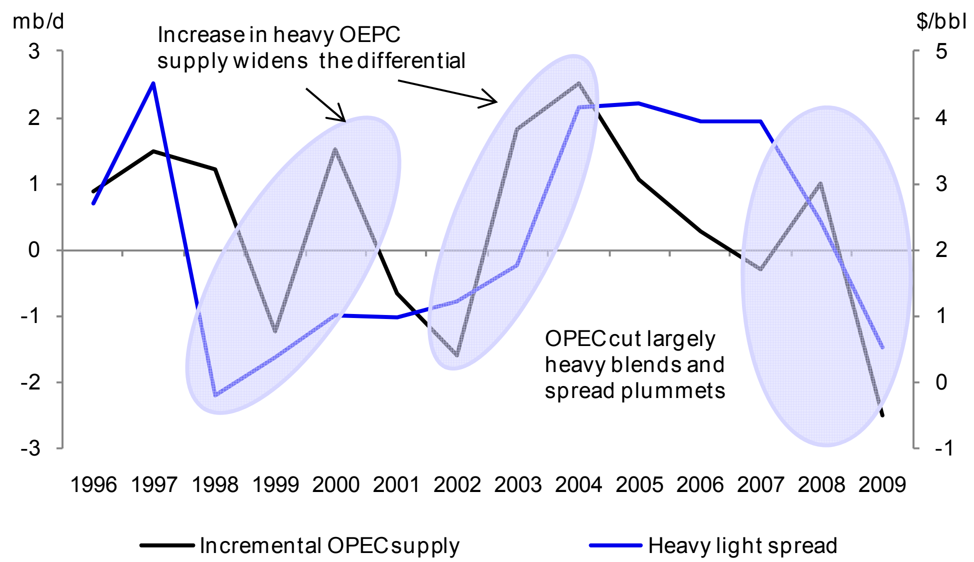
An ability to process heavy oil adds flexibility and value

Away from the actual benefits to refiners of being able to gain from the heavy-light spread, refiners capable of running heavy blends also gain from the greater flexibility of their system to use a far wider range of crude oils for processing. This leaves them in a far better position to benefit from temporary differences that may emerge between the price of different crude oils in the marketplace or to buy the occasional distress cargo at a discount price.

Warning: Complexity and processing heavy oil need not be the same

As a final point, it is often assumed that complexity and the ability to run a heavy, sour crude are the same thing. It is, however, important to emphasise that they are not. Complexity is about investment in a wide range of processes to upgrade distillate, some of which may be associated with desulphurization or upgrading low value fuel oil. There are, however, plenty of complex refineries which are unable to process a heavy, sour barrel. Equally, it should be appreciated that the higher profitability of a complex refiner is not necessarily a function of its ability to buy lower priced crudes. As we have shown, much of the time the heavy light discount is purely a function of the difference in the refining value of the two crude streams. What is, however, key to profitability is the ability to convert lower value products to those of a higher value and so to gain from the conversion premium.

Figure 251: OPEC production has had a clear influence on the heavy light spread – the marginal OPEC barrel is a HEAVY barrel



Source: Wood Mackenzie

Location

Location is probably the third most important determinant of a refinery's ability to capture profit

Away from configuration and crude supply, location is probably the third most important determinant of a refinery's ability to capture profit. Location, and with it likely competition, affects crude freight costs, product despatch costs, product price realisations as well as labour and environmental legislation compliance costs.

The basic technical division lies between coastal and inland plants. Coastal plants will often have low crude supply costs and will be able to access export markets cheaply. However, inland refiners may be closer to areas of high demand (important given that product distribution costs are generally higher than the carriage of crude) and may be specifically configured to relatively isolated markets. To the extent that they dominate a local market or are sole supplier to a local market, reduced competition means that they can be very well placed to capture a significantly higher margin. This has been in particular evidence in the US over the past two years where inland refineries in the PADD2 area (Mid West but see later) have benefitted significantly from low input costs in a regional market which is short refining capacity.

Other factors

Away from the above, other factors that are important determinants of refinery profitability include:

- **Plant reliability and efficiency**. Given the relatively high fixed costs associated with running a refinery, reducing unscheduled downtime is a very important determinant of profitability. This is particularly the case for high added value, high cost units such as crackers. Efficiency is reflected in a range of parameters such as scale economies or the physical layout of the refinery. In general, refineries nowadays will be shut for a major maintenance overhaul once every 5 years with the timing of that shutdown generally planned to take place during periods when the relevant market is particularly slow (late summer, early autumn is frequently chosen being the end of the driving season but ahead of the impending winter build in fuel oil). However, unplanned maintenance shutdowns can be very expensive given the refinery is likely to face a total loss of contribution through the entirety of the closure.

- **Crude delivery**. Largely dependent upon location, the source of fuel delivery to a refinery can make a meaningful difference to the effective price paid by the refinery for each barrel of crude that it receives. In general, plants located near an export port or within access of a main oil pipeline will have delivery costs per barrel which are lower than that for a refinery which is supplied by road tanker or rail. As an example, when OMV connected its Schwechat refinery to the Druzbha Russian via pipeline it indicated it could reduce its fuel costs by as much as $1.50-2.00/bbl of delivered crude.

- **Speciality product capacity:** Refinery speciality products such as lube base oil, aromatics, solvents and anode grade coke often offer higher margins than bulk fuels. Manufacturing margins for these products often contribute significantly to downstream results. For example, the high margins achieved by Conoco's UK Killingholme refinery on anode coke probably make it one of the most profitable refineries in Europe. High margins can often also be obtained on other speciality products, but the small volumes involved limit the impact on the bottom line.

- **Petrochemical integration.** Refineries forming part of a larger petrochemical complex have greater flexibility in optimising the use of many of the intermediate product streams as well as benefiting from lower transfer costs and shared operating costs. Depending on transfer pricing between the refinery and petrochemical complex, this integration can add significantly to the refining margin. TOTAL's Antwerp refinery is an example of a fully integrated petrochemical refinery whilst Exxon's excellence in downstream profitability owes much to the close integration of its refining and petchem operations.

- **Operating costs.** Costs are chiefly dependent on fuel usage, labour costs, efficiency, economies of scale and the degree of investment in automation. Manpower per unit of capacity is a key benchmark since labour costs are a large element of operating costs. However, as the price of crude oil has risen in recent years one of the most significant components of costs has been that of fuel. In general, refineries use some 7-9% of their feedstock as fuel to run the refinery. Energy efficiency has consequently become a far more important component of costs and initiatives designed to improve fuel savings have delivered much greater payback than may have been the case a few years ago.

In general, refineries use some 5-7% of their feedstock as fuel to run the refinery.

Regional balances and market structure

Within regional refining markets product imbalances are frequently evident.

Through investment in conversion units, refiners are able to go a long way towards meeting the underlying market demands for the different product streams arising from the crude oil barrel. Invariably, however, the molecular composition of the crude barrel means that it is not economically possible to perfectly match the output from the refinery with the demands of the local regional market. As a consequence, within regional refining markets product imbalances are frequently evident.

Importantly, these product imbalances together with regulatory restrictions and fuel specifications also have an important role to play in refining profitability. To the extent that a local market is short a particular product, refiners will be able to charge a premium for that product – the premium being largely equal to the transport cost for an external source of supply. Similarly, where a product is long the refiner may reduce price to try and encourage sales or incur a transport cost to export. In aggregate, however, whilst refining markets may be tight regionally, product flows ensure that tightness in any one regional market tends not to be sustained. In other words, looked at globally, today's refining market is not short of supply.

US balances suggest that it will continue to deliver above global-average margins

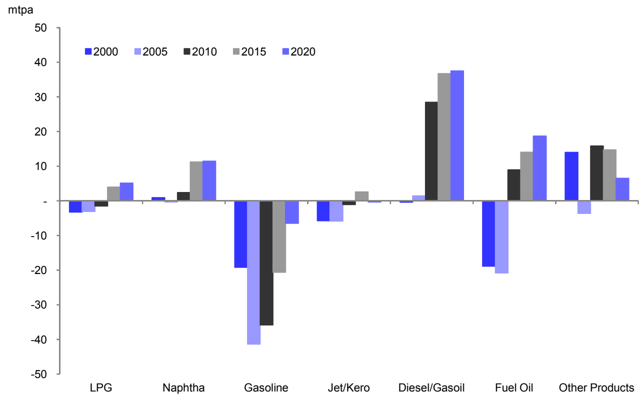
The charts overleaf depict Wood Mackenzie's estimates of current product balances across four major regional markets and how they are expected to move over the course of the next decade. The charts serve to emphasise that, where the US market is now short across almost every major product group, significant surpluses exist in other regional markets with Europe, for example proving an important supplier of gasoline to the US. Several simple observations can be made.

- The US market is now tight across most major product categories, in particular gasoline and therefore import dependent. Given that the US authorities are unlikely to sanction the build of a new grass roots refinery in the US market for environmental reasons, capacity growth is likely to be modest (c1% p.a.) and depend on companies' ability to de-bottleneck plant (capacity creep). As such, in the absence of a major deterioration in demand US margins can sensibly be expected to be higher on average than those in other regional markets.
- The European market is significantly long gasoline, with some surplus fuel oil and naphtha and is thus export dependent. Given its maturity, demand growth is likely to prove modest and with the exception of fuel oil, these imbalances more likely to increase than subside. Overall, European margins thus tend to be lower than those in the US – something that is unlikely to change. Europe's export bias also clearly means that its health is dependent upon continued good demand in other regional markets.
- Although modestly long diesel and jet fuel, Asia is currently a significant net importer of oil products particularly of fuel oil much of which is supplied from Europe. It is also the fastest growing of the three main regions and expected to see an increasing deficit in naphtha (petrochemicals), fuel oil (space heating) and, in time, gasoline.

Capacity utilization by region

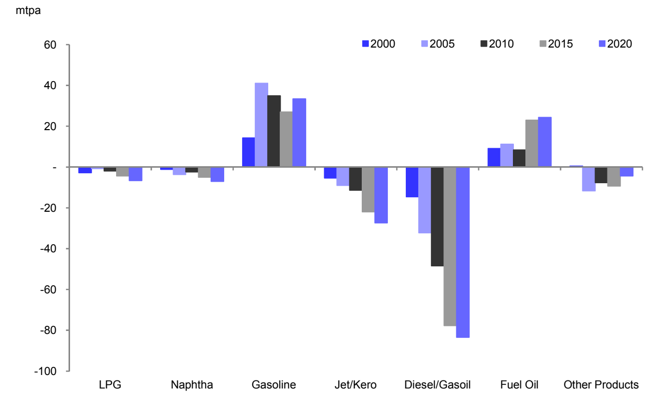
This difference in product balances is also well reflected by refinery utilization rates across the different regional centres. Utilisation fell dramatically across all regions in 2009 due to the financial crisis which precipitated a decline in demand across all regions. Despite some improvement in demand (and a corresponding uplift in refining margins) outside the US, which is benefitting from a feedstock driven renaissance, utilisation rates remain low at present given that over-supply remains prevalent in global refining capacity. This is especially evident in ex-growth Europe.

Figure 252: US – Future product balances (Mt)



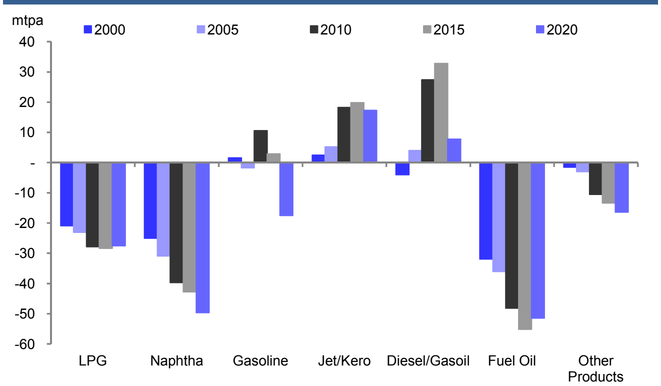
Source: Wood Mackenzie

Figure 253: North West Europe – Future product balances (Mt)



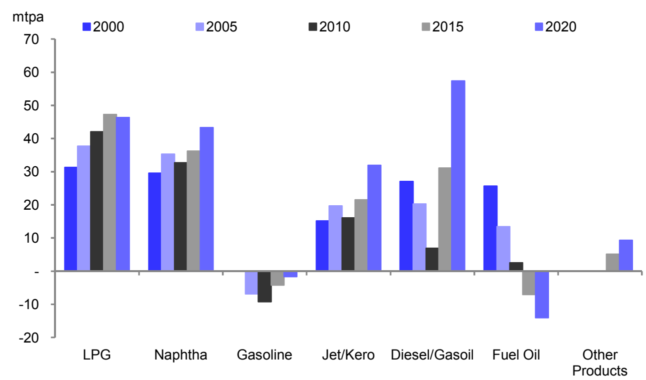
Source: Wood Mackenzie

Figure 254: Total Asia – Future product balances (Mt)



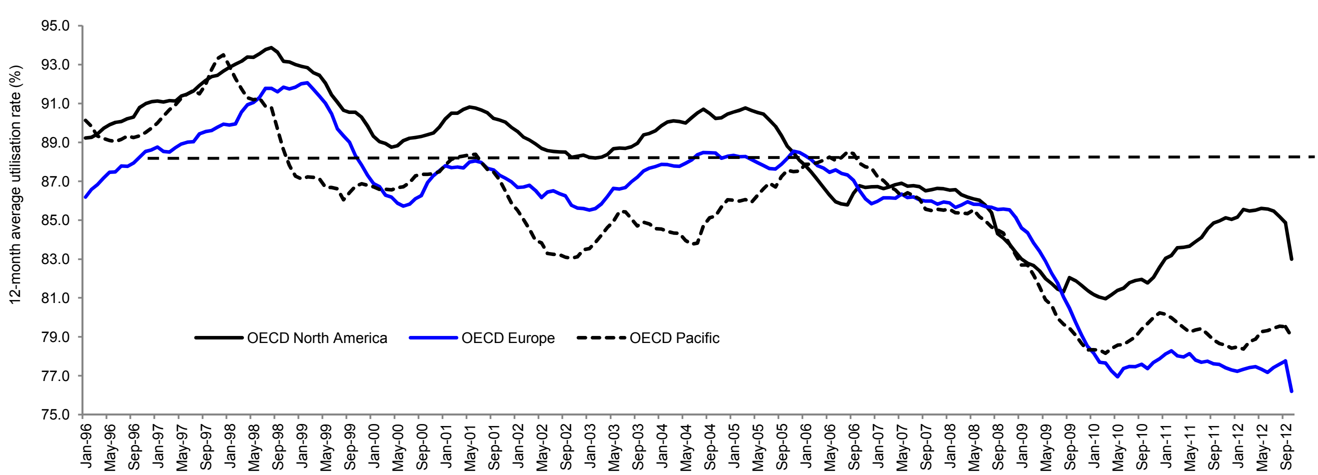
Source: Wood Mackenzie

Figure 255: Middle East – Future product balances (Mt)



Source: Wood Mackenzie

Figure 256: Regional capacity utilization rates 1995-2012 (%)



Source: IEA OMR, Deutsche Bank

Measuring Refining Profitability

Just as the stock market looks to the daily oil price as an indicator of upstream profitability, so it focuses on 'refining margins' as a guide to the health of downstream returns. These volatile margins are merely the subtraction of the daily crude price from a basket of oil products. They represent only the additional revenue that can be generated from turning a barrel of crude into something useful – not the costs, or therefore, the profit, of doing so.

'Crack spreads' depict the gross margin per barrel

Given crude oil and oil product prices are readily visible in most of the major regions of the world, it is possible to calculate the gross refining profit or margin that a refiner is likely to be achieving at any moment in time. Indeed, several newswires (e.g. Reuters) and oil agencies (e.g. Platts) publish daily or weekly gross margins for the major regional refining centres, namely the US Gulf Coast, North West Europe (or Amsterdam, Rotterdam, Antwerp ***aka ARA***) and Singapore. Called 'indicator' margins or 'crack spreads' these depict the gross margin per barrel that a regional refiner operating with either a simple or complex refinery configuration typical of that area and running a single crude widely processed in the region is likely to be achieving.

Because all refineries are different these published margins are, as their name suggests, no more than an indicator. They do, however, afford a strong view of refining profitability at any one time and the trend in margins (up or down).

Calculating crack spreads

In calculating these indicator margins or crack spreads, simple assumptions are made about the output of the local refinery. Thus, for example, the most commonly quoted Gulf Coast 3-2-1 crack spread assumes that for every three barrels of oil, two barrels of gasoline and one of low value heavy fuel oil are produced (or one barrel of crude gives 0.67 barrels of gasoline and 0.33 barrels of fuel oil). From this it is easy to calculate the gross refining margin.

Consider the following. The price of crude oil per barrel is $100 whilst the wholesale price of gasoline is $3.00/gallon and that of fuel oil $1.75/gallon. Given that there are 42 gallons in a barrel the crack spread calculates at $8.68/bbl as illustrated by the below calculation.

0.67 x one barrel of gasoline + 0.33 x one barrel of fuel oil – one barrel of crude oil

or

[(0.67*3.00*42) + (0.33*1.75*42)] - $100.00 = ($84.42 + $24.255) - $100.00 = $8.68

Other spread ratios can be used to reflect the refining complexity of the refinery or region. For example, where light crude is refined and there is a higher demand for heating oil the appropriate ratio may be 2-1-1. Similarly a refinery that yields significant amounts of residue might be 6-3-2-1 (gasoline, distillate and residue).

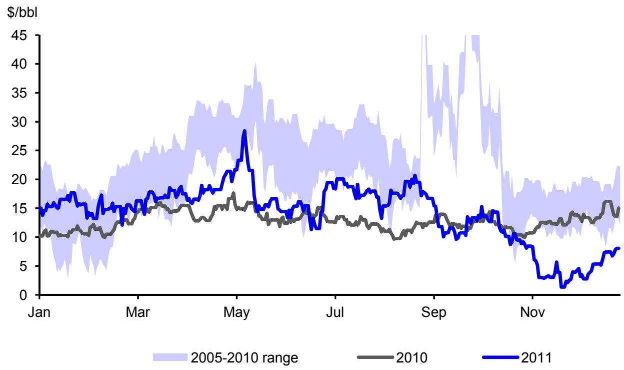
Product cracks

Beyond indicator margins or cracks, one can also look at product cracks. These give a strong view of the value of conversion. Most common here are gasoline and diesel fuel oil cracks which depict the value uplift of converting a barrel of heating oil to more highly valued gasoline or diesel.

The following charts depict complex and simple gross refining margins in the three main refining centres over the course of the past several years together with gasoline/fuel oil crack spreads in the US and Europe.

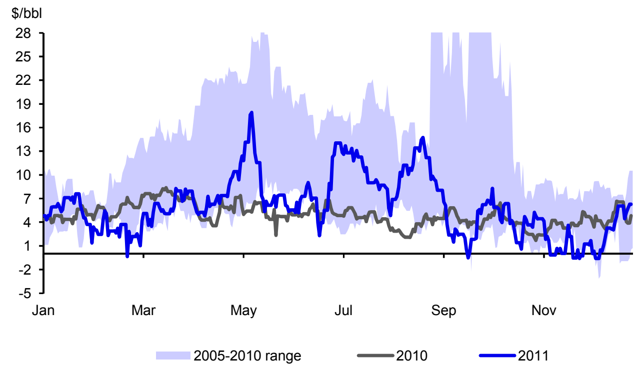
US margins ($/bbl)

Figure 257: US Gulf Complex



Source: Deutsche Bank estimates, Bloomberg Finance LP

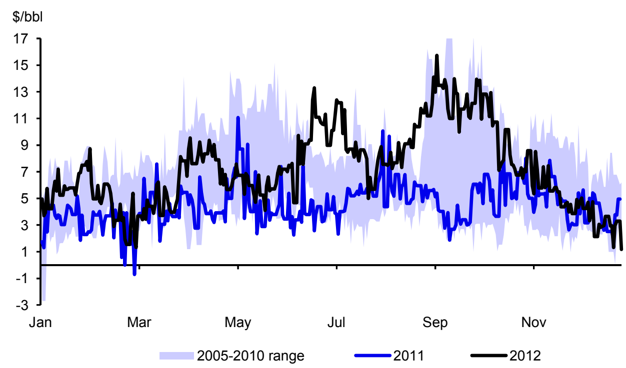
Figure 258: US Gulf Simple (3-2-1)



Source: Deutsche Bank estimates, Bloomberg Finance LP

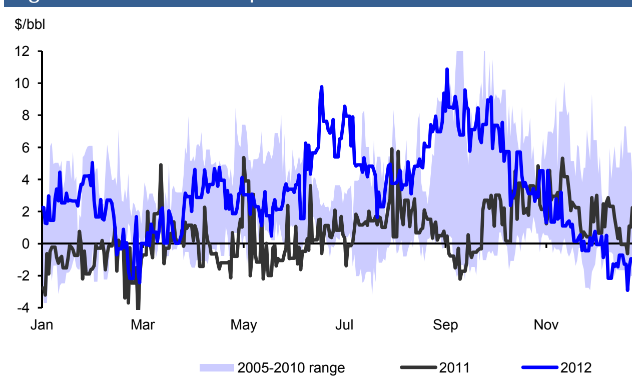
NWE margins ($/bbl)

Figure 259:NWE Complex



Source: Deutsche Bank estimates, Bloomberg Finance LP

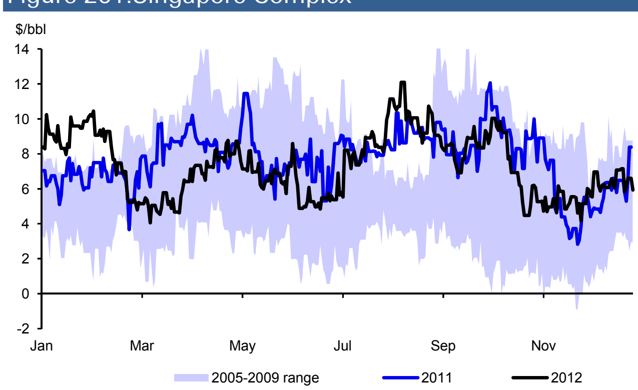
Figure 260: NWE Simple



Source: Deutsche Bank estimates, Bloomberg Finance LP

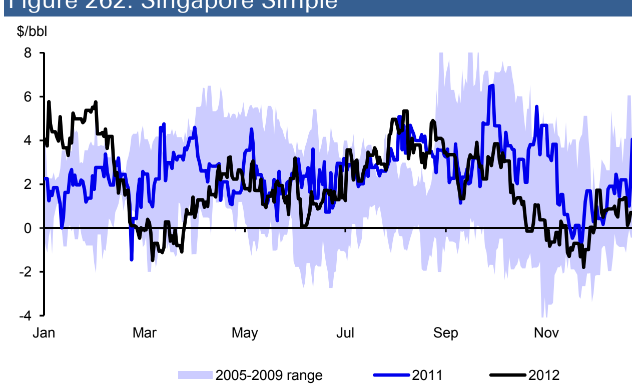
Asian margins ($/bbl)

Figure 261:Singapore Complex



Source: Deutsche Bank estimates, Bloomberg Finance LP

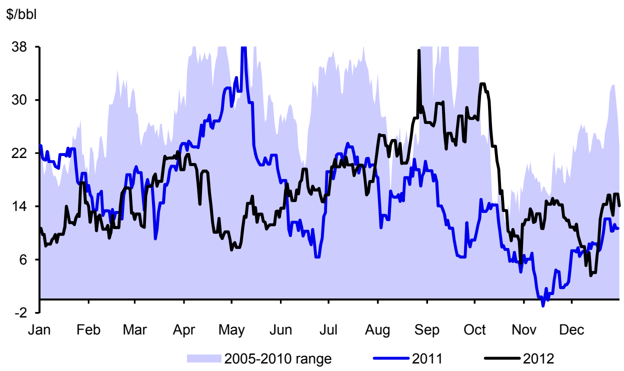
Figure 262: Singapore Simple



Source: Deutsche Bank estimates, Bloomberg Finance LP

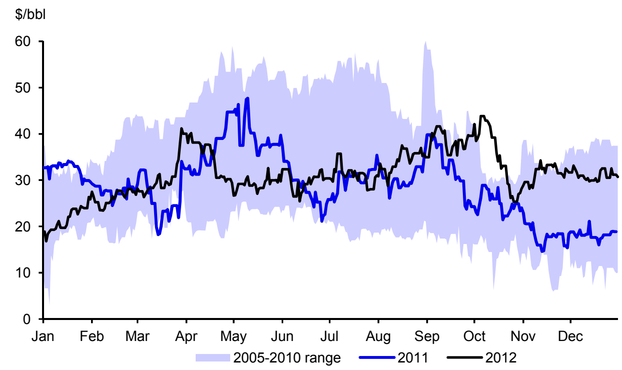
Gasoline/fuel oil crack spreads US/Europe

Figure 263: US Gasoline/Fuel Oil



Source: Deutsche Bank estimates, Bloomberg Finance LP

Figure 264: Europe Gasoline/Fuel Oil



Source: Deutsche Bank estimates, Bloomberg Finance LP

What drives refining margins?

As secondary derivative, refining margins ultimately represent the dynamic outcome of a host of different drivers. Beyond the factors discussed over the preceding pages (location, complexity, crude feedstock, etc) over which companies have some good degree of control, refining margins are heavily influenced by a multitude of external influences. Not least amongst these are:

As secondary derivative, refining margins ultimately represent the dynamic outcome of a host of different drivers

- **Demand**. As with most products, demand is key to profitability. Strong demand and inventories are likely to come under some downwards pressure and refineries kept active. Faltering demand and the likely build in inventories will result in price weakness as buyers become less concerned about the availability of supply and refiners look to shift volume.
- **Inventories**. Through their influence on perception, inventories can have a powerful impact on refining margins. Low stock levels and the market starts to worry about shortages, bidding up gasoline. High stock levels and the surplus begins to weigh equally heavily upon forward prices.
- **Seasonality.** Because demand for the different outputs from a refinery varies through the course of the year so too do gross refining margins. In particular, from late winter through to late spring focus moves towards the production of gasoline for the US and European driving seasons, which officially starts in the US on Memorial day (31 May). This tends to be a period of relatively high refinery activity and, with production biased towards expanding gasoline demand, margins tend to strengthen. However, as gasoline demand starts to fall off towards the end of summer, margins have a tendency to weaken before refining activity picks up, the focus now being on the production of heating oil for winter in the Northern hemisphere.
- **Maintenance activity.** Time and time again maintenance activity has proven a significant influence on refining margins. With significant capacity down, refining tightness is often accompanied by declining inventories. The result tends to be an improvement in product prices and with them margins. Appreciating maintenance timelines can provide valuable insights into the likely direction of margins.
- **Crude Oil Price Prospects.** As the heavy-light spread becomes a more important influence on refining profitability, so too does understanding

dynamics in oil markets. Tight crude markets and the heavy light premium is likely to expand as simple refiners pay up for light oil. Equally, if crude oil is tight due to geopolitical supply concerns but demand in domestic markets weak, one would expect refining margins to be squeezed (and vice versa).

- **Gasoline differential US/Europe**: As an import dependent gasoline market, the scope for arbitrage opportunities from Europe to the US can impact gasoline prices and with them refining margins on both continents. For example, tight US markets tend to pull in product from overseas, so placing pressure on US prices but improving the supply demand balance and pricing in Europe. Weak US prices and the opportunities for exports and price arbitrage fall away, with surplus European gasoline placing added pressure on European gasoline prices and refining margins.
- **Specification and regulation**: To the extent that specification changes can place a temporary restriction on production as refiners struggle to produce on-spec product or distribute it, specification changes can impact refining margins meaningfully. This was particularly evident in the US market in mid-2006 as changes in the specifications for diesel and the removal of MTBE as an oxidant in gasoline impacted supply.
- **Inter-fuel substitution:** This is of particular relevance to fuel oil pricing. Given that fuel oil competes in power markets with gas and coal, the price which the market is willing to bear will depend heavily on that of its alternatives. Falling coal or gas prices and fuel oil prices are likely to deteriorate taking down the margins of simple refineries in particular.
- **Weather:** Unpredictable as it is, the weather and weather forecasts can play a huge role in the level of refining margins. Key here are perceptions of what the demand and/or supply consequences of periods of extreme weather might be. For example, after the events of 2004 and 2005 when hurricanes resulted in the closure of significant US refining capacity, the fear of hurricanes in the US plays an important part in market psychology through the summer months. Similarly, forecasts of a cold winter will help heating oil prices in the run-up to winter whilst forecasts for a mild winter will tend to undermine them.

Petroleum Administration for Defence Districts (PADDS)

The United States is divided into five ‘Petroleum Administration for Defence Districts’, or PADDs. These were created in 1942 during World War II under the Petroleum Administration for War to help organize the allocation of fuels derived from petroleum products, including gasoline and diesel (or "distillate") fuel. Although the Administration was abolished in 1946 these regions are still used today for data collection purposes. The five PADD Districts are:

- PADD I (East Coast) is composed of the following three sub-districts A (New England); B (Central Atlantic); and C (Lower Atlantic).
- PADD II (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee, and Wisconsin.
- PADD III (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, and New Mexico, and Texas.
- PADD IV (Rocky Mountain): Colorado, Idaho, Montana, Utah, and Wyoming.
- PADD V (West Coast): Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington

Refining Industry Structure

The global refining industry continues to be dominated by the integrated oil majors

The global refining industry continues to be dominated by the integrated oil majors with companies such as Exxon, Shell, BP, Chevron and Total retaining very substantial distillation capacity (broadly 25% of total supply). However, as these companies have sought to bring their refining exposure more in line with their marketing position in regional markets and reduce overall exposure to refining in mature western markets, so a significant number of sizeable independents have emerged.

Shifting to the independents

This has been most evident in the United States where companies, not least Valero, have built strong and broadly spread portfolios of assets through selective acquisition over a number of years. Indeed, within the US market the independents now account for comfortably over half of national crude distillation capacity. Similarly, within Europe a significant independent refining sector now exists although many of the existing companies tend to have relatively modest refining capacity available to them. Several are also focused on emerging markets, not least PKN, MOL and OMV.

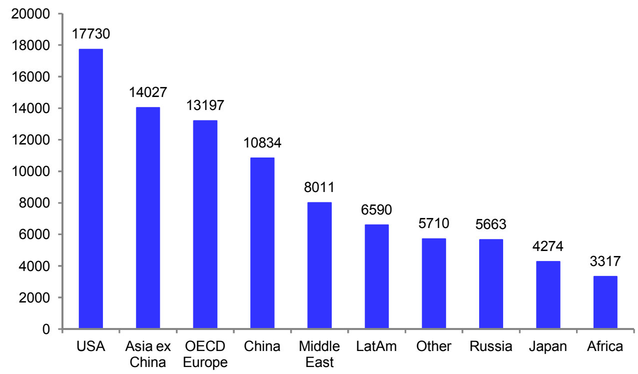
Looking forwards, the western integrated majors continue to downsize their refining portfolios through the sale of non-strategic assets on a piecemeal basis most particularly in mature European markets where excess capacity combined with an outlook of static to falling demand mean investment is likely to be focused and very disciplined. This process is expected to continue as the majors seek to upgrade their portfolios whilst containing absolute capex, the investment $ is being concentrated in their most advantaged assets.

Asia and the Middle East will gain share

Longer run, with oil demand in much of the OECD essentially static, new capacity is likely to centre on those markets which offer volume growth (essentially Asia) or which are advantaged by virtue of access to raw materials (essentially the Middle East). Little surprise then that it is in these markets that many of the planned capacity increases are anticipated over the next five or so years as companies seek to both meet the needs of the local market but also benefit from the growth on offer.

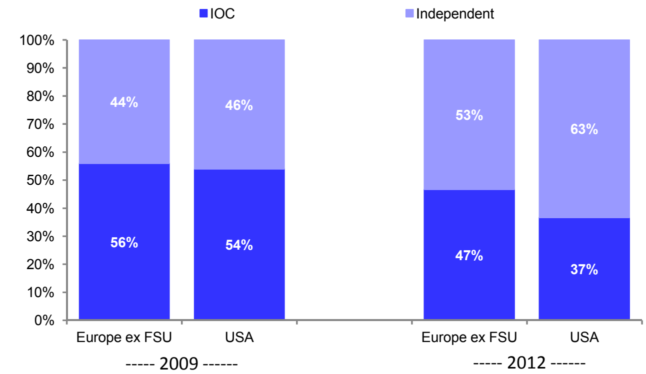
Summary statistics – Capacity and players 2012

Figure 265: Global refining capacity by region 2011 (kb/d



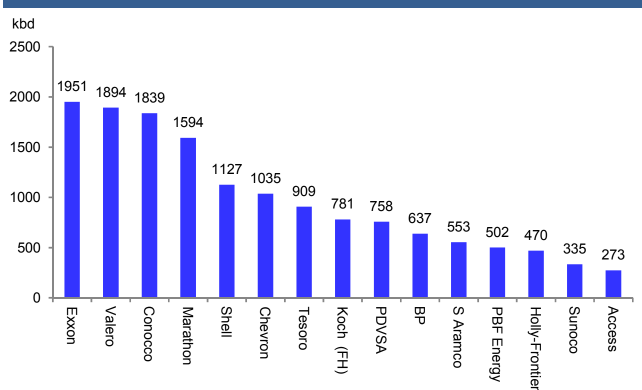
Source: BP Statistical Review; Deutsche Bank

Figure 266: Share of refining capacity in mature markets is shifting from integrated to independent (%)



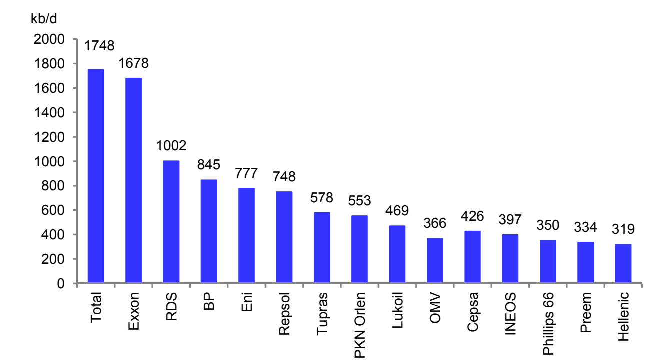
Source: EIA, Deutsche Bank

Figure 267: Major US refiners 2012 – CDU capacity (bpd)



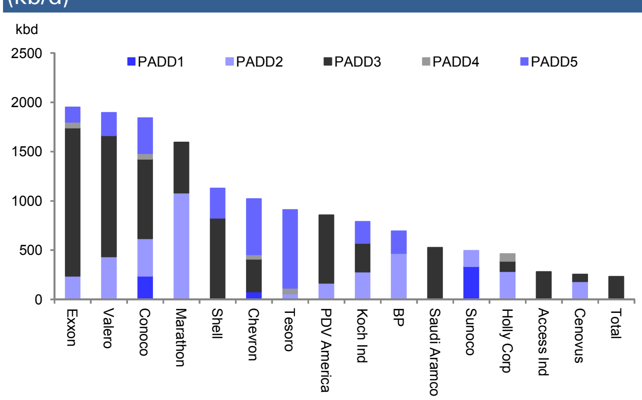
Source: EIA, Deutsche Bank *Assumes BP disposals completed

Figure 268: Major European refiners – CDU capacity (bpd)



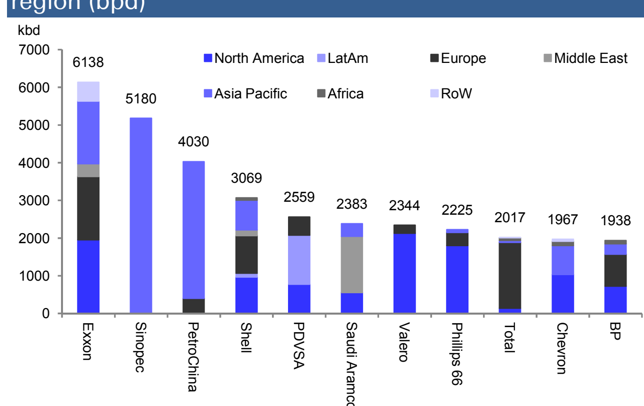
Source: Wood Mackenzie, Deutsche Bank

Figure 269: Major US refiners – CDU capacity by PADD (kb/d)



Source: EIA, Deutsche Bank

Figure 270: Major refiners – CDU capacity globally by region (bpd)



Source: Company data, Deutsche Bank estimates

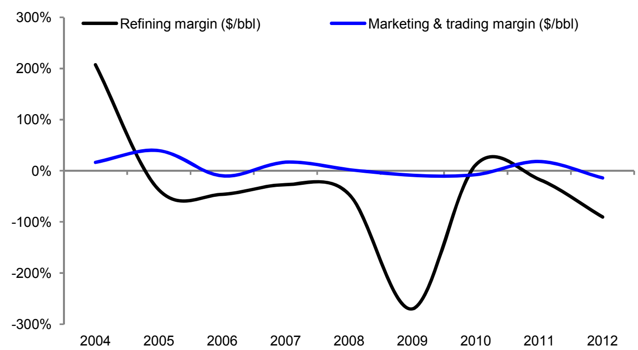
Marketing

Stability in a cyclical world

Marketing, or the wholesale and retail sale of fuel products, is the final step in the integrated chain and the oil industry's main point of contact with the end-market consumers of its products and, consequently, its public face. Profits tend to be much less volatile than those of its refining activities and as such lend stability to the financial performance of an oil company's downstream operations. Indeed, marketing is probably the single aspect of an oil company's operations that, excluding short term fluctuations, are largely insensitive to commodity price volatility.

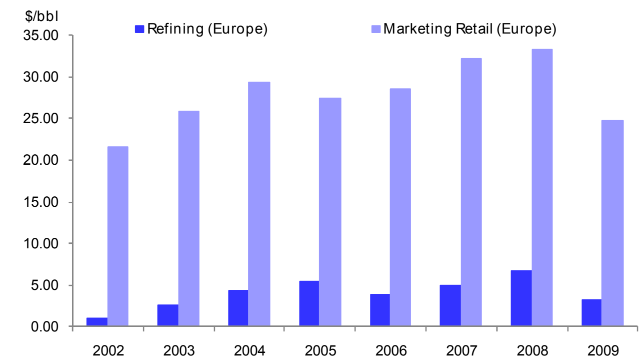
Marketing, or the wholesale and retail sale of fuel products, is the final step in the integration chain

Figure 271: Change in European marketing (retail) margins and refining margins y-o-y % (2004-2012)



Source: Wood Mackenzie, BP

Figure 272: Absolute gross retail margins are higher and less volatile than those achieved in refining

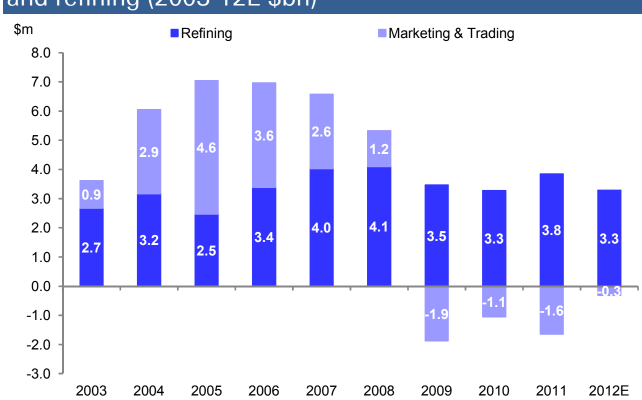


Source: BP Statistical Review; Deutsche Bank

Profits are sizeable

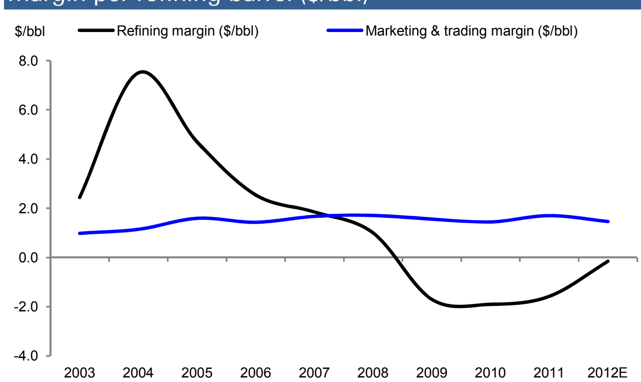
Perhaps it is because of this stability that the absolute scale of the marketing profits achieved by the majors is easily overlooked. Despite the fact that net margin tends to be very thin as a percentage of revenues (at somewhere between 1-2% of sales), given the huge volumes of product moving through an integrated oil company's marketing network, the absolute level of profit is substantial. This is well illustrated by reviewing Shell's downstream performance, the marketing profits of which have consistently stood at in excess of $3bn net per annum. As evidenced by the analysis, profit performance per barrel has also been far more robust than that of the refining activities.

Figure 273: RDS; Oil products net profit split - marketing and refining (2003-12E $bn)



Source: RDS; Deutsche Bank estimates

Figure 274: RDS Net margin per marketing barrel vs. net margin per refining barrel ($/bbl)



Source: RDS; Deutsche Bank estimates

Securing end markets

Profit and cash flow aside, the key role of marketing is to secure end markets for an integrated oil company's refined products and so act as the engine of refining output growth. Moreover, through providing a route to market and customer access, marketing helps to ensure that at times of faltering demand an integrated oil company will be able to place its refined products and the refinery maintain its rate of utilization. In effect, the marketing network serves to pull through refined product.

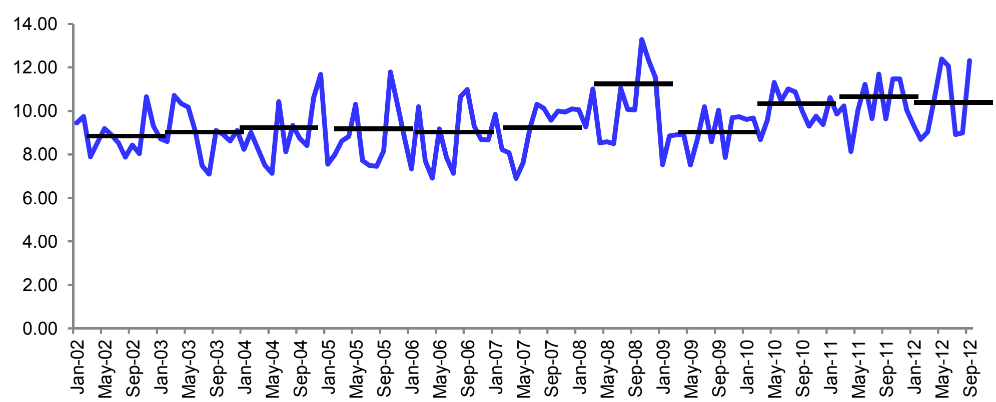
The key role of marketing is to secure end markets for an integrated oil company's refined products and so act as the engine of refining output growth

Equally, marketing typically represents the first step of downstream entry into a new market. Again, once a market presence and sufficient base demand are established, refining can follow and with it demand for upstream crude oil. In what is essentially an ex-growth industry, marketing therefore represents one of the few low-risk opportunities for an integrated company to build share in an emerging or developing market and to actually drive above average industry growth for its range of oil products.

Profits and seasonal trends

In general disclosure of marketing profits is poor, almost all companies presenting a single profit result for their refining and marketing operations, with the industry arguing that the two are inextricably linked by their integration. Equally likely, this obfuscation reflects a sensible desire to shield the absolute level of profit achieved 'at the pump' from the prying eyes of consumer groups and government (one can just imagine the headlines were any individual company to inform the general public that it achieved an operating profit from fuel marketing of around $5bn at a time when pump prices were high). Having said this industry bodies such as the EIA do disclose gross marketing margins, calculated by deducting tax and refinery prices from those achieved at the retail pump. Quarterly marketing margins per barrel are also released by certain of the IOCs not least Chevron.

Figure 275: European marketing margins (retail) – overall steady but not without short term noise (gross margin €cents – unleaded 95 Gasoline)



Source: Wood Mackenzie

Marketing profitability does, however, fluctuate both with the commodity price and by season. Typically at a time of rising oil prices marketing margins will be squeezed as the marketer takes time to push through increases in the cost of refined product. Equally, however, at times of falling oil prices, marketing prices tend to prove very sticky most especially at the retail end, with margins expanding as input costs fall (the so called 'parachute' effect). Seasonally, the run up in refined product prices as the driving season approaches tends to see a seasonal fall in gross marketing margins. However, as the summer driving season moves towards an end, marketing margins generally tend to expand. Thus, while marketing profits are relatively stable over a longer time period (say a year) short term volatility can be considerable.

One other important development in recent years has been the entry into fuels retailing of the supermarket chains, most significantly in Europe. These have tended to see fuel retailing as something of a loss leader (i.e. a means of attracting customers to the grocery door through the use of predatory pricing). The result has been both a meaningful loss of share for the IOCs and a reduction in industry profitability as a whole.

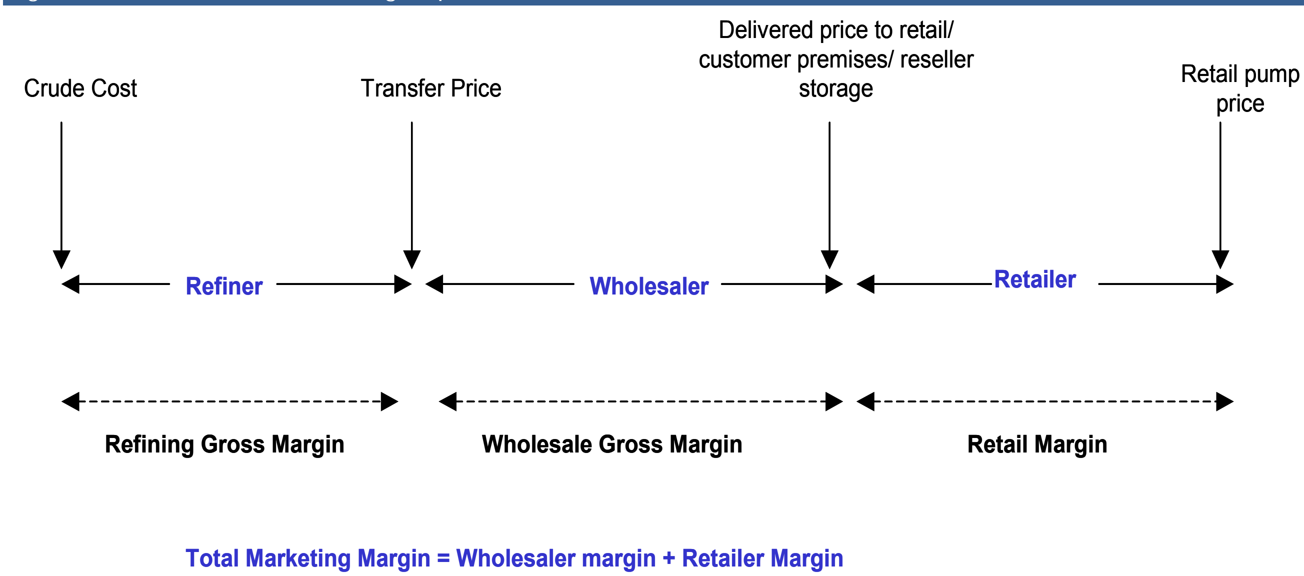
The wholesale/retail chain

Oil companies market petroleum products to a wide variety of trade sectors, both at the wholesale and retail level.

Oil companies market petroleum products to a wide variety of trade sectors, both at the wholesale and retail level. At the wholesale level, they typically supply to retail service stations, industrial and commercial customers, oil distributors and other oil companies. Retail sales typically occur through either own branded service stations (COCO: Company owned, company operated), or through a franchise network, where the franchisee is required to adhere to strict standards (as said, retail marketing IS the public face of the oil company).

Given little differentiation between one supplier's product offering and another's, marketing margins tend to be very fine on a per unit basis, with volume and throughput absolutely key to profitability and return. For example, in Europe, the gross margin achieved per litre of throughput at a retail station is typically around €0.09cents – or around 5-10% of the value of the sale excluding government excise duty. As such, marketing operations are highly operationally geared with control of costs absolutely central to profitability. Given the need for volumes and throughput, well located retail outlets are key as is the product offering.

Figure 276: Wholesale/ Retail margin split



Source: Deutsche Bank

The degree of ownership/ control of the supply chain will determine the extent to which a typical refiner can access the total marketing margins. The marketing margin also depends on the type of the product and the channel of sales. For example, specialized products such as lubricants command the highest unit margins though volumes are small. Similarly retail fuel marketing enjoys higher gross margins than industrial/ commercial marketing, but volumes are lower. Moreover, retail marketing requires higher capital investment.

Another critical variable impacting marketing margins is the geography in which the company operates. There are countries which impose restrictions on pump prices or subsidise retail fuel to shield customers from price inflation, e.g. Argentina, China, Indonesia and India. Thus while strong economic growth in these territories may feed product growth, achieving profitable growth can be a significant challenge. In the OECD retail and wholesale prices are, however, determined by the market although the absolute price may be very heavily influenced by government taxation (see overleaf).

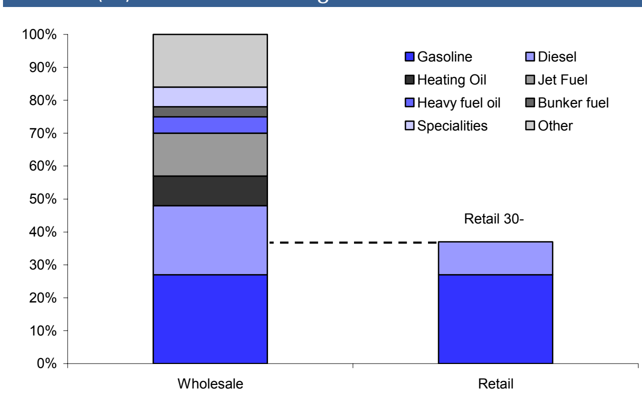
Retail; the smaller volume but higher value component

Overall, around 30-40% of marketing volumes tend to arise through service stations in retail end markets. However, in revenue terms the significantly greater value of the products sold through the retail channel (gasoline and diesel) relative to those sold via wholesale suggests that closer to 50% of revenues are likely to arise in retail markets.

Overall, around 30-40% of marketing volumes tend to arise through service stations in retail end markets

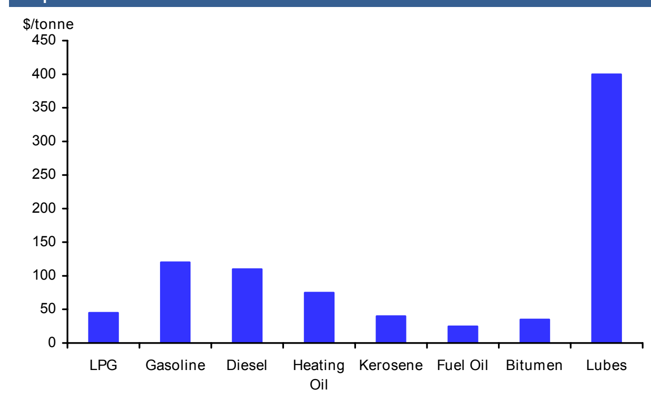
As companies have striven to improve returns so they have sought to increase the retail offering of their service stations, driving incremental revenues and gross margin from their non-fuel activities. Perhaps ironically, these activities have achieved faster growth than almost any of the companies' other activities although contribution in general remains very modest.

Figure 277: Illustrative split of marketed products by volume (%) and those through the retail chain



Source: Wood Mackenzie; Deutsche Bank

Figure 278: Illustrative split of net contribution per tonne of product sold



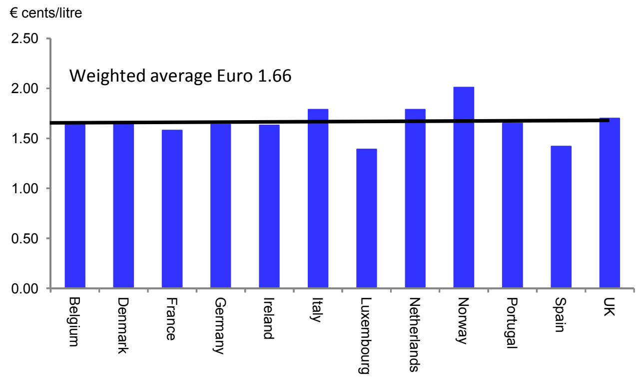
Source: Wood Mackenzie; Deutsche Bank

Removing capital, containing costs

More significantly, however, in recent years most of the major oils have endeavoured to take capital out of their marketing operations either by selling down parts of their portfolio – typically in markets where they are under-represented and unlikely to be able to achieve the critical mass and thus economies of scale necessary to achieve a healthy return on capital - or by seeking to expand the proportion of dealer owned, company branded sites. With growth in mature western markets unlikely to accelerate and competition for sales expected to remain intense, these initiatives to strip costs and to contain capital investment are unlikely to change.

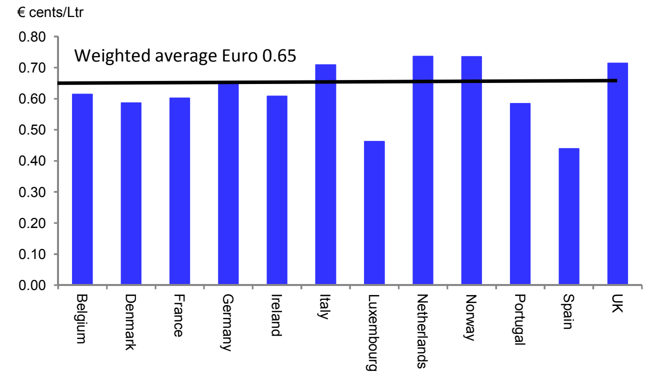
What's in a litre of fuel? European Retail Data

Figure 279: Retail prices by Country (2012)



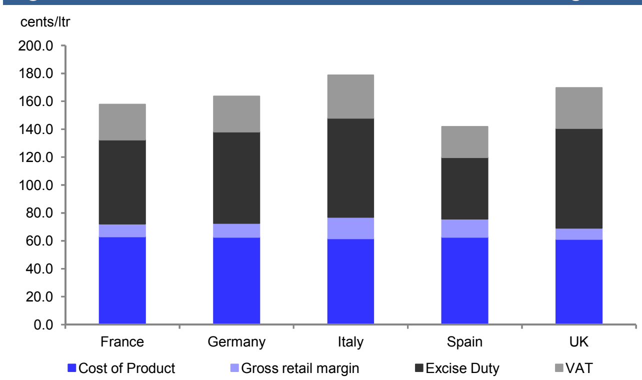
Source: OPAL, Deutsche Bank

Figure 280: Excise duty by country (2012)



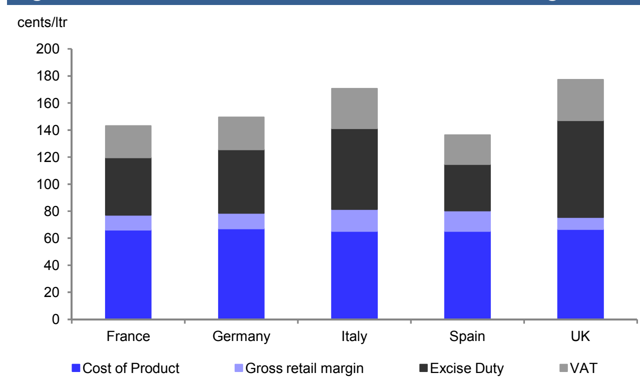
Source: OPAL, Deutsche Bank

Figure 281: What's the cost? Gasoline (2012 averages)



Source: OPAL, Deutsche Bank % Is proportion represented by taxation

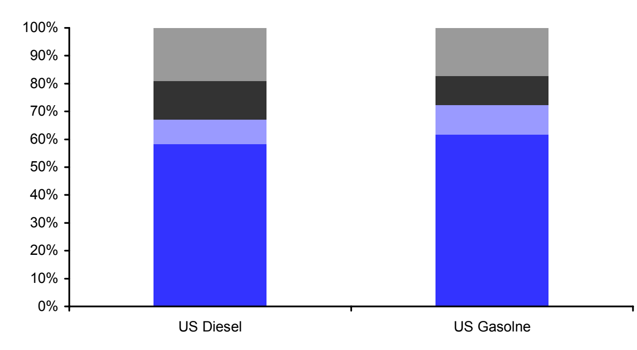
Figure 282: What's the cost? Diesel (2012 averages)



Source: OPAL, Deutsche Bank % Is proportion represented by taxation

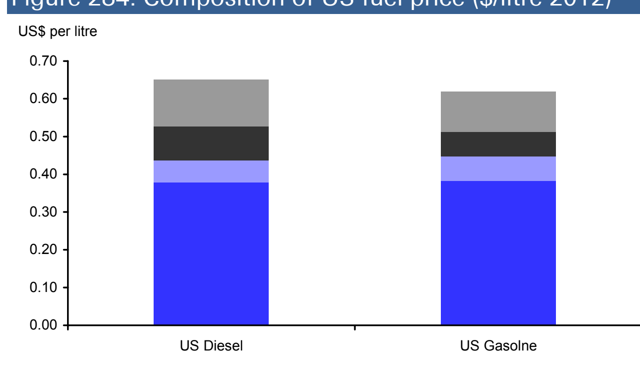
What's in a litre of fuel? US Retail Data

Figure 283: Composition of US fuel price (% 2012)



Source: EIA, Deutsche Bank

Figure 284: Composition of US fuel price ($/litre 2012)



Source: EIA, Deutsche Bank

Biofuels

What are biofuels?

Some market context

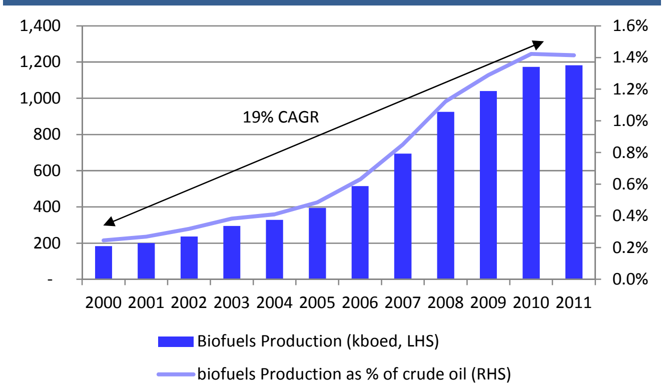
Biofuels are fuels made or processed from vegetation from which energy can be extracted (known as biomass sources can include corn, wood and sugar cane).

Biofuels contribute c1.2mboed of supply – around 0.5% of global primary energy consumption.

Biofuels currently comprise only a small part of energy supply at a modest 0.5% of 2011 total primary energy consumption and a volume equivalent to 1.4% of crude oil production. Placing this in context, renewable energy (ex nuclear) represented c8% of global primary energy consumption in 2011 with hydro and wind the leading sources. USA and Brazil are comfortably the largest producers of biofuels.

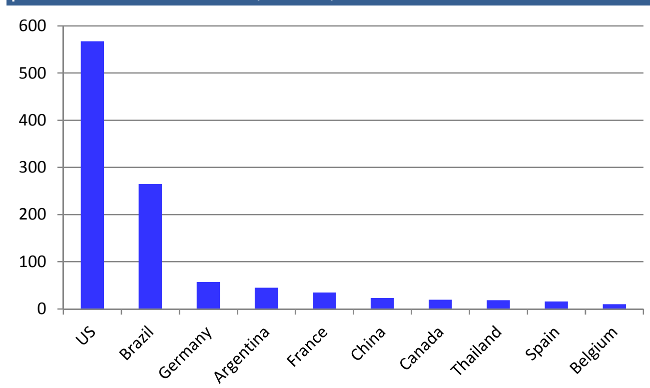
Growth rates for biofuel production have been impressive with a 19% CAGR over the past decade (albeit falling to 9% across the past 3 years). Looking forward, the IEA anticipate that biofuels production will grow at a c6% CAGR to 2020 to reach a volume of c2.4mboed (compared to c1.2mboed today).

Figure 285: Biofuels production how seen a 19% 2000-2011 CAGR to stand at 1200kboe



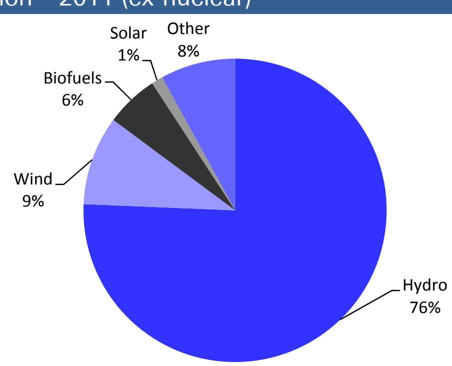
Source: BP Statistical Review of World Energy, 2012

Figure 286: US & Brazil are comfortably the largest producers of biofuels (kboed)



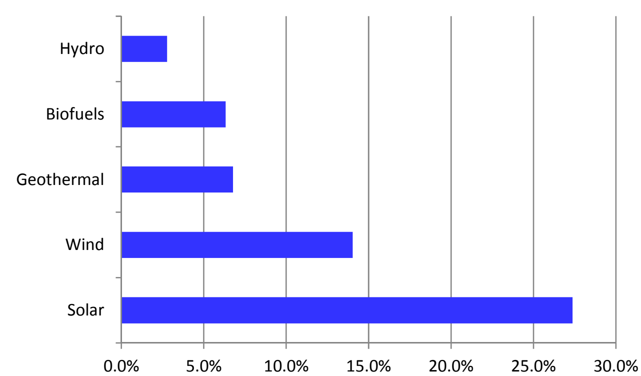
Source: BP Statistical Review of World Energy, 2012

Figure 287: The key sources of renewable energy production – 2011 (ex-nuclear)



Source: BP Statistical Review of World Energy, 2012

Figure 288: IEA estimated 2010-20 GAGR for renewable energy usage by source



Source: IEA World Energy Outlook 2012, New Policies Scenario

What are biofuels

Biomass energy is effectively derived from living or recently living organisms and is carbon based, composed of a mixture of organic molecules including hydrogen, nitrogen amongst others. While fossil fuels are in fact ancient biomass, they are not considered "biomass" as they contain carbon that has been 'out' of the carbon cycle for a very long time, thus their combustion disturbs the Co2 content in the atmosphere.

Whilst biofuel technology is still relatively yound, there are already 2 recognised generations of technology, with fuel from algae an emerging third generation.

Biofuels are distinguished as either first or second generation biofuels.

- **First generation biofuels.** These are biofuels produced using conventional technology and by and large use food crops (such as sugar, corn) as the source of biomass. The two most notable first generation biofuels are bioethanol and biodiesel. Other first generation biofuels include butanol, alcohol and biogas.
- **Second generation biofuels.** Second generation biofuels make use of more advanced technology such as gasification and liquefaction processes to convert biomass into biofuel. Moreover they are use non-food crops such as stalks of wheat as feedstock. Many are only at an early stage of development and they are not yet in widespread use. Examples include biohydrogen, biomethanol and Fischer-Tropsch (FT) diesel.

Why use biofuels?

Bio-fuels are a potentially more environmentally friendly substitute for fossil fuels and this is naturally where their strengths lie. We visit the counter-arguments to this claim later in this section, however the advantages may be summarised as:

- **Carbon neutrality.** Carbon generated from biofuel consumption has been absorbed from atmospheric carbon dioxide by the original organism as it grows. This means that net carbon emissions should equal zero, assuming that biomass is replenished to its sustainable level. Bioethanol, for example, produces 65-70% less carbon emissions than conventional gasoline.
- **Security of supply.** Use of biofuels reduces reliance on oil imports. This is becoming increasingly important because of the volatility of oil prices and frequent tensions with oil producing nations. However, although increasing use of biofuels is predicted, estimates still suggest contribution to overall consumption will remain moderate (only 9% of total by 2030).
- **Biodegradability.** Biofuels are not harmful in the event of a spillage unlike the majority of fossil fuels.
- **Political support.** The use of biofuels is welcomed by the agricultural sector as biofuels provide an extra market for farming products. In countries where the farming industry has strong lobbying powers, this is a clear political benefit.

Where are biofuels produced and used?

Agricultural products used in biofuels are grown across the world in varying forms. In the US, for example, corn and soybean are grown mainly whilst in Europe, flaxseed and rapeseed are more common. In Brazil, where use of biofuels is already widespread, sugar cane is the favoured crop and in India, the plant jatropha is used primarily.

Brazil has been using bioethanol since the 1970s.

The US recently surpassed Brazil as the world's primary producer of bioethanol. However, Brazil still remains a significant producer of bioethanol, which makes up 45% of the fuel used in cars in the country. This is largely a consequence of the government initiative 'Proálcool' established in 1975 to encourage oil substitution. Today, more than 60% of new cars sold in the country are capable of running on pure bioethanol.

In Europe also, biofuels have experienced increasing popularity. Sweden, for example, has a well-established biofuel vehicle network and in Germany, biodiesel is available at filling stations across the country.

The policy & legislative framework

Targets have been introduced to encourage the penetration of biofuels within the energy mix, but in the EU greater awareness is emerging of the relative merits of different sources of biofuel.

Regulation continues to play an important role in the advancement of biofuel use. An emphasis has been placed on initiatives which provide direct targets within a specific timescale. The international body that has overseen these current trends is IEA Bioenergy, established in 1978 by the International Energy Agency (IEA). IEA Bioenergy facilitates the development of biofuels by providing a platform for information exchange between countries with national biofuel programs.

Legislation is integral to the effective regulation of the biofuels industry. The industry has witnessed a gradual switch from fiscal incentives based on tax subsidies to regulation-dominated measures which mandate minimum biofuel blend ratios. Part of the reason for this change has been to remove the burden of providing subsidies on tax revenues.

European Union

At present, the Biofuels Directive (2003) and the Renewable Energy directive (2009) set the principal policy framework for biofuels in the EU. The directives established a non-binding target of deriving 10% of transportation fuel from renewable sources by 2020, a target which remains in place. However, a proposal published in Oct-12 will limit the contribution of food-crop based biofuels to 5%, which implies no growth from current levels, to reflect environmental and social concerns around 1st generation biofuels (i.e. the impact on food prices and uncertainty about net greenhouse gas emission savings). Instead the EU will seek to incentivise 2nd/3rd generation biofuels that do not create additional demand for land (and hence minimise the impact on food prices) and which deliver targeted net greenhouse gas savings. The Biofuels directive is complemented by the EU Directive of Taxation on Energy which grants biofuels special exemption from fuel taxation in member states. There is no consistent set of tax incentives across member countries to encourage uptake of biofuels.

United Kingdom

The key directive currently in place in the UK is the Renewable Transport Fuel Obligation (RTFO) mandated that 5% of all transport fuel must be from a renewable source by 2010, primarily achievable by blending with fossil fuels (given all existing vehicles are already capable of running on a 5% blend). Current government policy is to amend the RTFO to fall into line with the EU proposal to incentivise 2nd/3rd generation biofuels. The UK formerly provided a £0.20/litre tax reduction in excise duty on biofuels, but this ceased in April 2010.

United States

The Alternative Motor Fuels Act 1988 provided the foundation for widespread production of motor vehicles capable of operating on alternative fuels such as bioethanol. This has been formalised more recently under the Energy Policy Act 2005 which introduced the Energy Independence and Security Act 2007 which calls for 15.2bln gallons of biofuels to be used annually by 2012, rising to 36bln gallons by 2022 (from 4.7bln gallons in 2007). Most cars in the US already run on blends of up to 10% ethanol, whilst part of the car pool is capable of running on 85% (E85). More recently we note the Open Fuel Standard Act 2011 requires that 50% of automobiles made in 2014, 80 in 2016 and 95% in 2017 be manufactured to have the operation to operate on non-petroleum based fuels, including ethanol and biodiesel. In the US, biofuels receive a simple tax rebate of $1.00 per gallon for biodiesel. The tax credit which used to apply to ethanol expired in Jan-2012.

Bioethanol

Bioethanol is an alcohol-based fuel made through the fermentation of crops such as barley, wheat, corn or sugar cane. It is the most commonly used biofuel worldwide. The US and Brazil represent the major markets for bioethanol, together accounting for 72% of worldwide production.

Flexible fuel vehicles (FFVs) will help to increase the popularity of bioethanol.

Principally, it is used in blends with gasoline as a substitute for pure gasoline. As a fuel additive, it reduces the carbon monoxide emissions of conventional combustion engines to promote cleaner burning. Low blends of bioethanol and gasoline, typically comprising 5-10% bioethanol, can be used in conventional engines without modification. The development of flexible fuel vehicles (FFVs) has assisted the growing popularity of higher blends, with FFVs capable of running on an 85% bioethanol mix (E85) after relatively simple modifications. Rubber seals and aluminium parts must be replaced with materials that resist the corrosive properties of bioethanol. However, while the market is growing FFVs are not currently in widespread use.

Production – several stages

The bioethanol production process consists of the following stages: processing, fermentation, distillation and dehydration.

- **Processing.** The processing stage of corn can be distinguished as either wet or dry corn milling. In wet corn milling, corn is first soaked in water before processing. In this case, one bushel (56 pounds) of corn yields approximately 31.5 pounds of starch which is then further processed into 2.7 gallons of bioethanol. In dry corn milling, the corn kernel is ground into flour before processing and the bioethanol is then evaporated off. Under dry corn milling, one bushel of corn yields approximately 2.8 gallons of bioethanol and a by-product of 17 pounds of distiller's dried grains (DDGS), which can be used as an animal feed. Although dry corn mills are less expensive to construct than wet corn mills, they are more expensive to operate.
- **Fermentation.** Sugars are fermented to produce bioethanol, water and carbon dioxide. Sugarcane yields approximately 8 units of fuel energy per unit of energy expended whilst corn is relatively inefficient, yielding only 1.34 units for every unit of energy used.
- **Distillation.** Water is removed from the fermented product, purifying this to 95-96% bioethanol for use as a fuel. This is known as hydrated ethyl alcohol.
- **Dehydration.** Further purity can be attained through dehydration, which removes remaining traces of water to produce anhydrous bioethanol with purity of 99.5-99.9%.

Issues – there are several

ETBE has replaced MTBE as a gasoline additive.

Bioethanol is used as an oxygenate additive to promote cleaner burning of standard gasoline. The gasoline blend, which is known as ETBE (ethyl tertiary butyl ether), contains 47% bioethanol. It has replaced MTBE (methyl tertiary butyl ether) as a standard oxygenate additive largely because MTBE has been shown to contaminate groundwater and is thought to cause cancer. Two key issues surround ETBE blending:

- **Octane.** ETBE circumvents the problem of 'knocking' caused by conventional gasoline. Knocking occurs when gasoline prematurely combusts in an engine without the spark plug triggering the ignition. This produces an audible sound, hence the name. Octane is a measure of how well a fuel can resist knocking, which can cause engine damage. The addition of bioethanol to gasoline enhances a fuel's octane rating therefore reducing the occurrence of knocking.

- **Reid Vapour Pressure (RVP).** RVP is a measure of the pressure required to prevent a substance from evaporating. The evaporation of gasoline is clearly harmful and restrictions have been placed on the permitted RVP of finished gasoline. Bioethanol evaporates extremely easily and therefore has a high RVP rating. In order to meet permitted RVP levels, molecules which evaporate easily must be removed from the gasoline stream. However, these molecules tend to be rich in octane hence the net octane effect of blending bioethanol with gasoline can be negative.

The bioethanol market

The US is the leading bioethanol market worldwide, accounting for c.55% of world production in 2009 at which point bioethanol represented c.4% of all vehicle fuel consumed in the US. The US is currently a net importer of ethanol (largely from Brazil) a situation which is likely to remain given demand growth rates and tax incentives to promote the construction of more stations capable of supplying bioethanol.

The US is the world's primary producer of bioethanol.

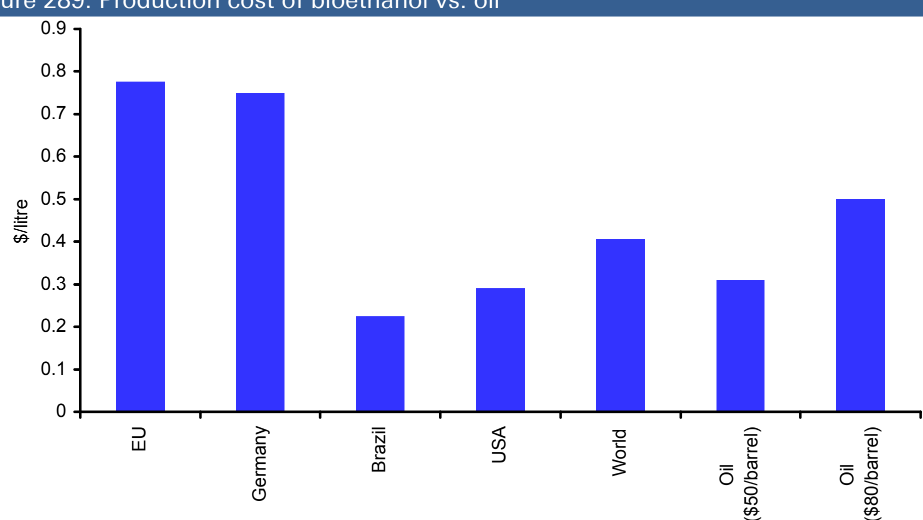
By contrast, the EU produced only 5% of the world's supply of bioethanol in 2009. Demand is currently in excess of supply and presently, this situation is being met by imports. The demand dynamics for bioethanol will be determined by the level of blending ratio requirements. Forecasts indicate that excess demand will persist after the introduction of these requirements even under conservative demand estimates.

Pricing

In theory, the price of bioethanol is equal to gasoline prices adjusted for any applicable tax subsidies. However, this model is too naïve as the price of bioethanol should be based on its own supply and demand dynamics, since bioethanol and gasoline are not perfect substitutes. Its price should also vary with the capacity utilisation rates of bioethanol, with increasing rates driving prices upwards. Based on production costs, bioethanol is unable to compete with conventional fuels. Global production costs exceed €0.25-0.40 per litre whilst those of conventional gasoline are only $0.31 per litre at $50 per barrel. These figures suggest that a tax credit is necessary for bioethanol to be competitive. However, even in the absence of one, bioethanol has been cost-competitive in Brazil where it has benefited from raw material cost advantages and economies of scale. Note also that production costs exclude by-products, some of which generate additional value e.g. DDGS.

Bioethanol is more expensive to produce than conventional gasoline.

Figure 289: Production cost of bioethanol vs. oil



Source: Deutsche Bank

Biodiesel

Biodiesel is the most common biofuel in Europe.

Biodiesel is a fuel made from biological sources, such as vegetable oils or animal fats, blended with distillates such as diesel. It is far less flexible than bio-ethanol as it has fewer sources and applications. In spite of this, biodiesel is the most common biofuel in Europe where the market has experienced rapid development. In 2005, Europe was responsible for the production of 1 billion gallons of biodiesel, equal to 85% of world production, with Germany the leading market.

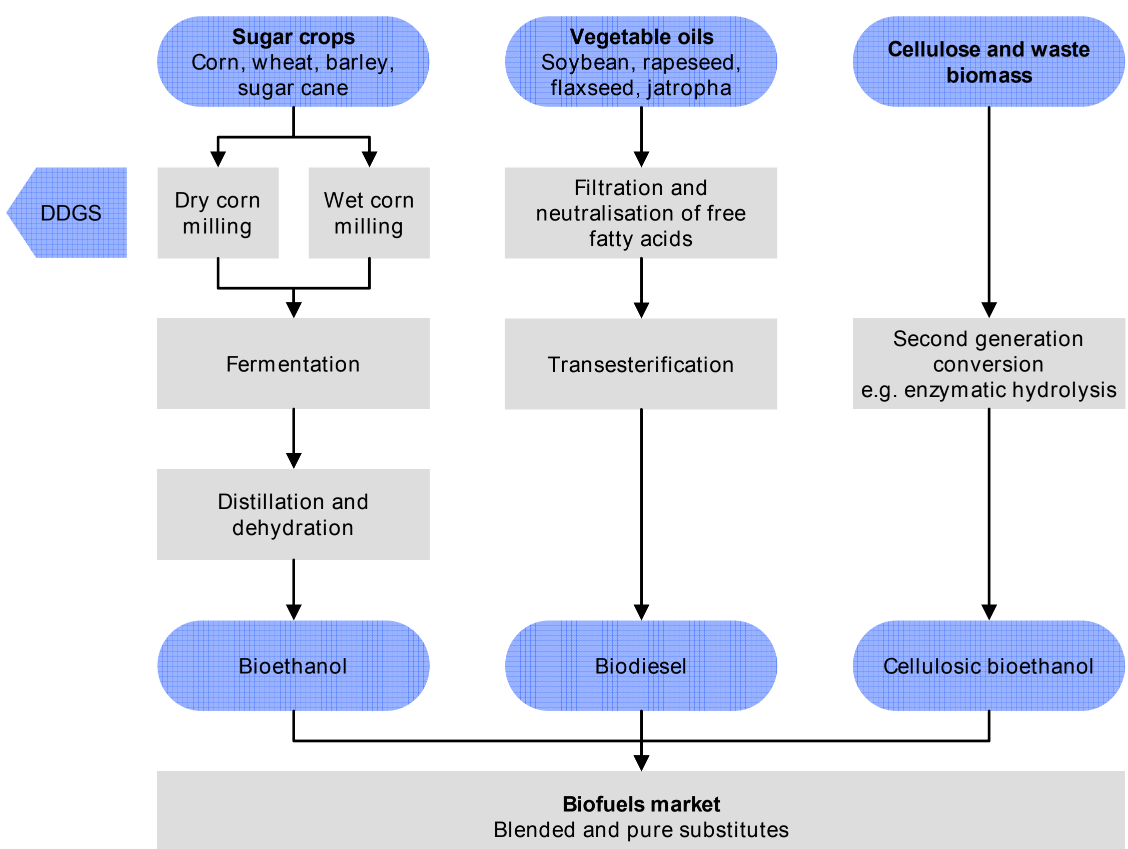
In the US, the industry is at a relatively early stage of development, producing 700 million gallons of biodiesel in 2008 (up from 2 million gallons in 2000). The preferred source of biodiesel in the US is soybean oil which constitutes c.90% of US vegetable oil production. It is possible to use low blends of biodiesel fuel in unmodified diesel engines. However, in the UK for example, engine warranties only cover the use of 5% biodiesel blends (B5).

Biodiesel – The production process

The key process in biodiesel production is transesterification.

Biodiesel production uses the process of trans-esterification, also known as alcoholysis. Prior to this, the raw material must undergo purification through filtration to remove impurities and water. Any free fatty acids must also be neutralised. Trans-esterification is based on the reaction between a vegetable oil containing glycerides and a short-chain alcohol such as methanol. This converts vegetable oil into fatty acid methyl esters (FAME) with a by-product of glycerol. One gallon of biodiesel can be produced from 7.5 pounds of vegetable oil.

Figure 290: The overall production process



Source: Deutsche Bank

Issues -

Biodiesel has both technical limitations and advantages. It experiences difficulties in cold weather in comparison to other refined products. One measure of fluid performance in cold weather is the cold filter plugging point (CFPP), the temperature at which a standard fuel filter will clog. Biodiesel has a high CFPP, indicating that it requires special handling in cold weather. A quality-related issue also arises because of the by-production of glycerol. Glycerol can potentially clog mechanical filters, causing engine damage and eventual breakage.

It is also possible to identify technical advantages. Biodiesel contains no elements of sulphur and are well-suited to ultra low sulphur diesel (ULSD) specifications which limit sulphur content in diesel fuel to 15 ppm. In addition, sulphur is not required as a lubricant, allowing blends of any level of biodiesel to operate in non-FFV engines.

The biodiesel market

In Europe, there have been announcements of substantial capacity additions and European biodiesel production capacity reached some 21mln tonnes in 2008. The global market structure is highly fragmented comprising oil majors, agribusinesses, independents and pure-play biodiesel producers. In contrast, the vegetable oil industry is highly consolidated, with integrated firms dominating the supply of raw materials to the biodiesel industry.

Pricing

As in the case of bio-ethanol, the theoretical price of biodiesel should be equal to the price of diesel, in particular ULSD, plus any existing tax credit. Part of the tax credit will be shared with the retailer in order to accommodate blending margins. Similarly to bioethanol pricing, the supply and demand dynamics of biodiesel are more realistic determinants of its price.

Criticisms of biofuels

A range of criticisms is directed towards the use of biofuels, some justifiable and others less so. Much of the concern surrounding biofuels has wide-ranging political implications. This will inevitably play an important role in determining the viability of biofuels as a fossil fuel substitute.

Use of crops for fuel rather than food is likely to be an important political issue.

- **Increasing food prices.** There is concern that the widespread use of biofuels will lead to production of 'fuel crops' rather than 'food crops'. Crops grown for fuel are likely to be extremely unpopular politically given the scarcity of food supplies in certain regions across the world. The limited availability of land also provides an additional constraint. The combination of additional demand for biofuels and scarcity of land is likely to increase the price of raw materials such as corn and vegetable oils thereby exerting cost pressures on food prices as evidenced through much of 2008. Note, however, that grain surpluses in some countries are unable to be sold in any case. Furthermore, demand for crops does not solely originate from biofuel producers; for example, China's increasing dependence on agricultural imports is an important demand factor.
- **Environmental impact.** The cultivation of crops specifically tailored for biofuel use may be damaging to the existing ecosystem, and may also decrease global biodiversity. Use of high blend fuels, such as E85, would require volumes of bioethanol that are far from feasible under existing systems.

- **Greenhouse gas emissions.** A widely cited benefit of biofuels is carbon neutrality. However, the agricultural techniques used in the cultivation of the input crop plus the production process require use of fossil fuels, thereby reducing the net benefit of biofuel use.
- **Cost.** The European Commission has stated that biofuels are an "expensive way of reducing greenhouse gas emissions". This is certainly true of its transportation and storage costs. Bioethanol has two undesirable properties: it is corrosive and hydrophilic, in other words, it is naturally attracted to water. The first property means that bioethanol will dissolve conventional pipelines used in transportation. Use of corrosion-resistant materials is considerably more expensive than those used in a conventional refined product pipeline. The second property implies that any water collected in transportation will make bioethanol unusable. Bioethanol must therefore be stored separately from gasoline throughout transportation and prior to blending, entailing further costs.

Long-term developments in biofuel

Market developments

The European biofuels market offers high growth potential.

Following the switch from fiscal to regulation-dominated government programs with mandatory blending requirements, blending markets are likely to represent the primary engine of growth in the biofuels industry. Geographically, the EU offers high growth potential because of the relative infancy of the industry in the region. Growing excess demand is unlikely to be met by imports because of the common external tariff currently in place. Consequently, EU biofuel production levels should exhibit high growth rates. Strong volume growth in the bioethanol industry will also require adaptation of existing transportation and storage techniques. This will provide an opportunity for infrastructural developments.

Cellulosic bioethanol

Cellulosic bioethanol is made through the fermentation of cellulosic feedstock such as wood, grasses i.e. it can use non edible parts of plants. Wide-scale production of cellulosic bioethanol will deliver major efficiency gains as its raw biomass is cheaper and also does not necessarily have a competing use as a food resource.

Second generation conversion technologies are key to progress.

Production of cellulosic bioethanol requires second generation conversion technologies. Specifically, enzymatic breakdown, known as hydrolysis, is one necessary stage of production. Although the technology does exist, it is far from being cost-effective. Therefore, cellulosic feedstock is not yet a viable alternative to corn. Projected estimates place a 10 to 30 year timescale of development before it can be introduced as a viable substitute. Within the US target of 36 billion gallons of ethanol production by 2022, 16 billion is targeted from cellulosic ethanol.

Biobutanol

Biobutanol is a type of biofuel that can be used as a substitute for bioethanol. It offers several advantages over bioethanol:

- It does not suffer from high RVP.
- It is hydrophobic and non-corrosive.
- It has a higher energy yield than bioethanol.

- However, biobutanol is relatively costly at its current price of around $0.85 per gallon. Given that it does not receive a subsidy, it is not yet a cost-competitive fuel. Further development will be necessary to drive production costs down.

Third generation biofuels

The latest focus on so called third generation biofuels focuses on algae. This large and loosely defined group of plants produce a significant proportion of the planet's oxygen and are an integral element of many food chains. Certain types of algae (namely the diatoms and cyanobacteria collectively known as "microalgae") have been found to contain proportionately higher levels of fat (lipids). Some researchers prefer the Chlorophycae (green algae) which produce starch instead of lipids.

A key element of the driven behind algae as a commercial feedstock is the yield per hectare. The table below shows the significant difference between algae and other traditional fuel crops.

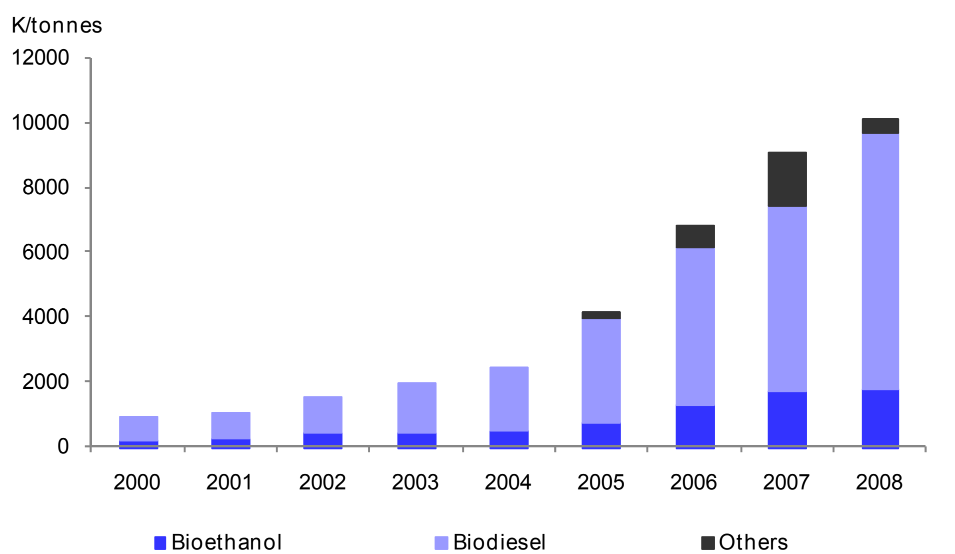
Figure 291: Comparison of yields for typical oil crops

Crop	Yield (litres of oil per hectare)
Algae	100,000
Palm	5,950
Coconut	2,689
Castor	1,413
Sunflower	952
Soy	446

Source: Oligae.com

Much of the early work with algae was undertaken using open pond systems, thus relying heavily on the hardiness of the algae and being subject to the variability of conditions. Results were mixed. Later studies have tried using closed systems (such as photo bioreactors) which can be more carefully controlled, allowing the introduction of potentially higher yielding strains, The disadvantage of such an approach is, of course, increased cost. Oil can be harvested from algae using a variety of different techniques including chemical, enzyme, dry pressing, ultrasonic or osmotic processes.

Figure 292: Biofuel consumption in the EU, 2000-2008 (ktonne per annum)



Source: European Biomass Association Statistics

Petrochemicals

Petrochemicals are non fuel compounds derived from crude oil and natural gas which take advantage of the reactivity of the carbon molecule

Petrochemicals are non fuel compounds derived from crude oil and natural gas which take advantage of the reactivity of the carbon molecule and its ability to create a diverse range of polymers which have very different properties. All organic chemistry is based upon hydrocarbons (carbon-based molecules) and derivatives of oil or natural gas and organic chemicals account for approximately 85% of all substances produced in the chemical industry - from basic plastics through to complex pharmaceuticals. For many of these, petrochemicals form the basic building blocks from which they are formed, with the oil and gas industry consequently playing a fundamental role in the provision of these essential molecules. As such, the chemical activities of the oil companies mean that by volume and revenues they are amongst the largest chemical companies across the globe with Exxon and Shell firmly established amongst the world's top-10 chemical companies by revenues.

Part of the integrated chain

Historically, the oil and gas industry's involvement in the petrochemical industry stems from its desire to add further value to certain of the product side-streams arising from the refining of both crude oil and natural gas. Beyond providing incremental revenues, as the versatility of petrochemicals became evident and new end markets appeared, petrochemicals also offered the major oil companies important new avenues for growth, something that remains the case today.

The feed-stocks for most petrochemical plants are provided by large refineries and include petroleum gases, naphtha, kerosene and light gas oil. Natural gas processing plants are also a source of feedstock providing methane, ethane and liquid petroleum gases or LPGs. As a consequence the petrochemical plants that take these feed-stocks are typically built next to the refineries from which they are sourced. Indeed, in recent years closer integration between refining and petrochemical plants has become an increasingly important source of operating efficiency (and is something that, for example, Exxon excels at and which, in part, explains its excellent relative profitability).

The petrochemical portion of the oil & gas industry is chiefly concerned with the manufacture of base chemicals and plastics

Very simply, there are three main stages in the conversion of refinery feedstock through to final product. The first of these is the manufacture of base chemicals (see below). These are produced in high volumes in large facilities. Base chemicals are then converted into various 'intermediate' products (for example, ethylene glycol). Lastly, these intermediates are either further processed or converted into goods and 'effects' used directly by consumers or industry. The petrochemical portion of the oil & gas industry is chiefly concerned with the first of these three stages; the manufacture of base chemicals together with their subsequent conversion into the more basic plastics (polyethylene and polypropylene).

Olefins and aromatics.

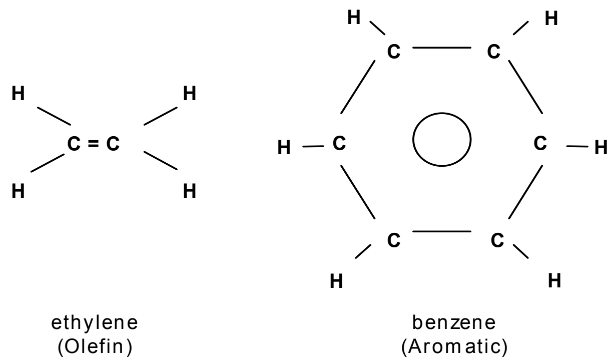
Base chemicals can be broadly classified into two groups: olefins and aromatics. Olefins have chains of carbon atoms as their 'backbone' whereas aromatics contain a ring of carbon atoms at the core of the molecule.

Figure 293: Base chemicals

Olefins	Aromatics
ethylene (2 - carbon chain)	benzene (6 - carbon ring)
propylene (3 - carbon chain)	toluene
butadiene (4 - carbon chain)	xylene

Source: Deutsche Bank

Figure 294: The molecular structure of ethylene and benzene

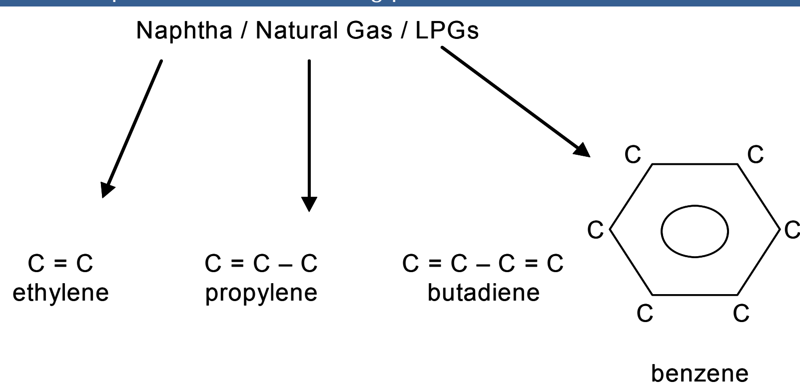


Source: Deutsche Bank

The olefin plant (cracker)

An olefin plant takes long chained carbon molecules and 'cracks them' (splits them up) into smaller chains such as C_2 (a chain consisting of two carbons), C_3 & C_4. The two cracking methods used are thermal cracking (high temperature) and cat cracking (use of catalysts), both of which are very energy intensive.

Figure 295: End products of the cracking process



Source: Deutsche Bank

Naphtha and natural gas/LPGs (liquefied petroleum gases rich in ethane, propane and butane) are the major feedstocks in olefin production. Naphtha is the dominant feedstock in Europe while natural gas/LPG is predominant in the US. Naphtha is essentially a crude form of gasoline and is obtained from the fractional distillation of crude oil, part of the oil refining process. Broadly, the principal feedstocks consumed in the main producing regions are:

Figure 296: Typical regional feedstocks

Region	Key feedstock
Europe	Naphtha
US	Mainly natural gas with some naphtha
Middle East	Natural gas
Japan	Naphtha
Asia (excluding Japan)	Mainly naphtha with some natural gas

Source: Deutsche Bank

Only about 7% of naphtha (part of the gasoline pool) is actually used by the chemical industry,

Only about 7% of naphtha (part of the gasoline pool) is actually used by the chemical industry, the rest is consumed by the fuel industry. Consequently, the price of naphtha virtually replicates that of gasoline, with the price being determined by the demand for transport fuels. As a result chemical producers are often subject to wild variations in feedstock costs. Similarly, in developed economies, like the US, consumption of natural gas by the chemical industry is dwarfed by utility and energy demand. Therefore, natural gas-based crackers are also subject to volatile feedstock cost swings.

As shown below, cracking naphtha, ethane, propane or butane produces different proportions of the base chemicals ethylene, propylene, butadiene and aromatics. Ethylene and, increasingly, propylene are the two most significant outputs. Ethane, propane and butane are the most the important constituents of natural gas and LPG. It should be noted that the bias of the US industry towards the use of ethane and NGLs as feedstock has offered them significant competitive advantage subsequent to the build in cheap shale gas and NGL's associated with the shale gas/tight oil revolution.

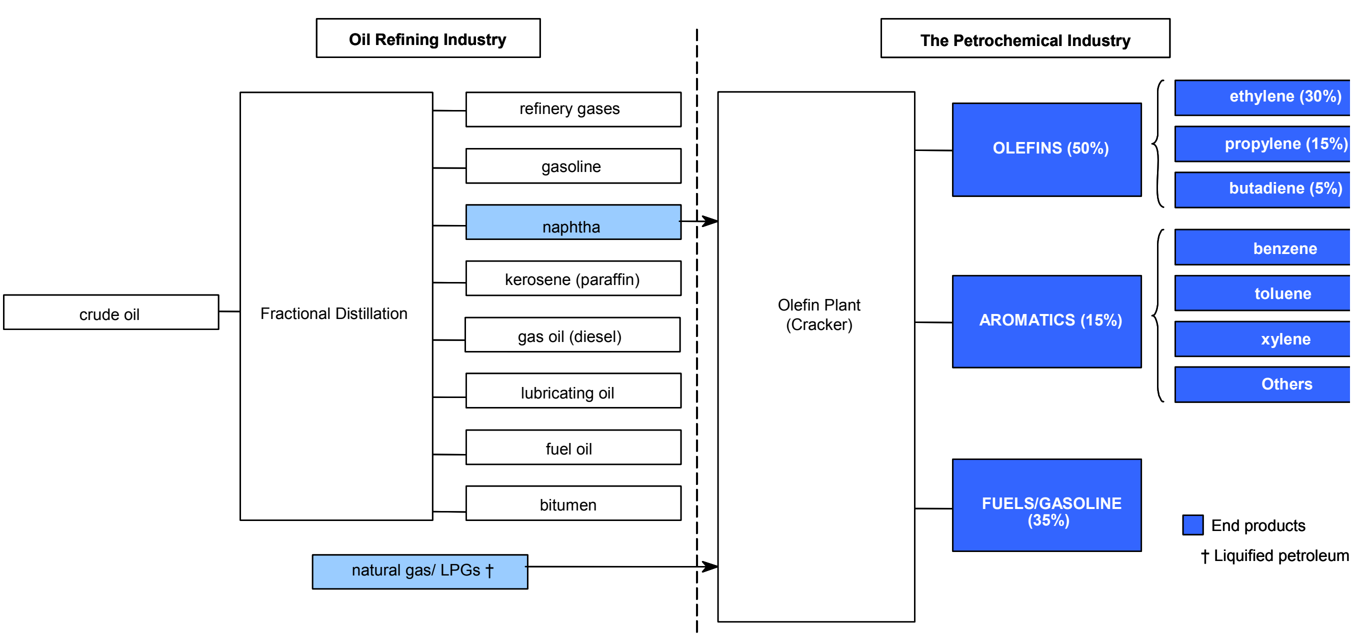
Figure 297: Percentage of base chemicals produced by feedstock

	Ethane (%)	Propane (%)	Butane (%)	Light naphtha (%)	Full-range naphtha (%)	Gas oil (%)
Ethylene	82	44	42	29	25	25
Propylene	2	21	15	14	13	8
Butadiene	3	4	4	4	5	5
BTX	1	5	5	14	11	11
Others	13	26	35	39	44	47

Source: Business Briefing: Oil and Gas Processing Review 2006

The operations and economics of the participants in the olefin industry are heavily influenced by the availability and cost of upstream feedstock. This in turn is often determined by the proximity and relationship of 'local' refining operations or upstream reserves.

Figure 298: Simple flow chart depicting refinery input to an olefins plant



Source: Deutsche Bank

Petrochemical Industry profitability

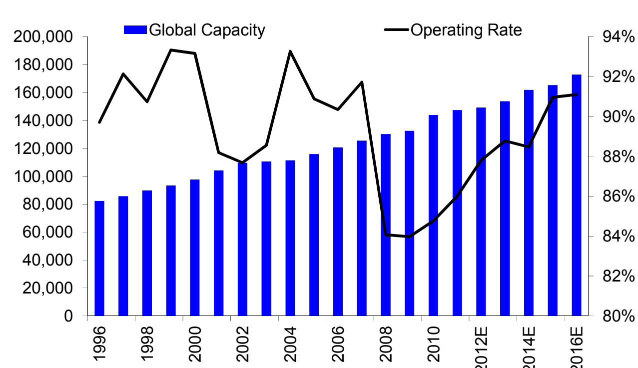
The petrochemical industry exhibits significant cyclicality.

Akin to most capital intensive industries, the petrochemical industry exhibits significant cyclicality. In large part this represents its continuing fragmented structure whereby the largest five producers control less than 25% of global ethylene capacity, together with the fact that the different industry participants add capacity in line with their own needs and strategies rather than in a coordinated manner. periods of supply tightness and slack fluctuate, with product prices and margins varying accordingly.

Feedstock costs are key

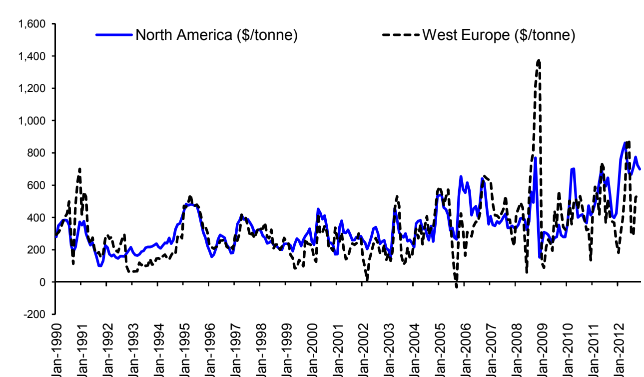
Central to profitability across the cycle are therefore the different cost structures of the players involved, together with their proximity to consumer end markets. Plant scale, integration and cost efficiency all have a key role in determining relative profitability. However, the sheer weight of feedstock cost as a percentage of end product value (c70% in Europe but only 15% in the Middle East) means that, ultimately, access to low cost feedstock represents a competitive advantage. This has led to the substantial growth of the petrochemical industry in the Middle East where the region's rich abundance of gas reserves, in particular ethane, has seen the emergence of substantial capacity over the past two decades, with Middle Eastern producers today representing a rapidly growing 15% or so of industry capacity. Illustrated below, this provides Middle Eastern producers with an unassailable cost advantage despite their remoteness from most of the major demand centres. Indeed, it is cheaper to produce polypropylene in the UAE and export it Germany than it is to sell from a locally based plant.

Figure 299: Global ethylene operating rates to 2015E



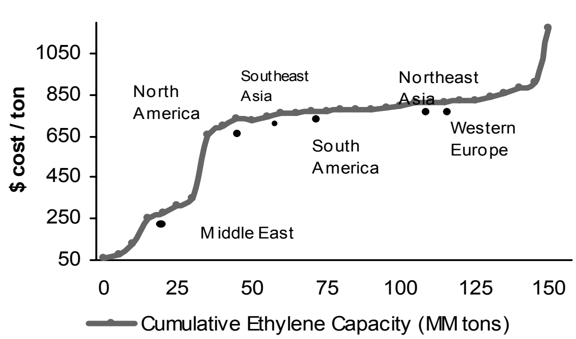
Source: Deutsche Bank, CMAI

Figure 300: Ethylene margin ($/tonne) 1990 – 2012



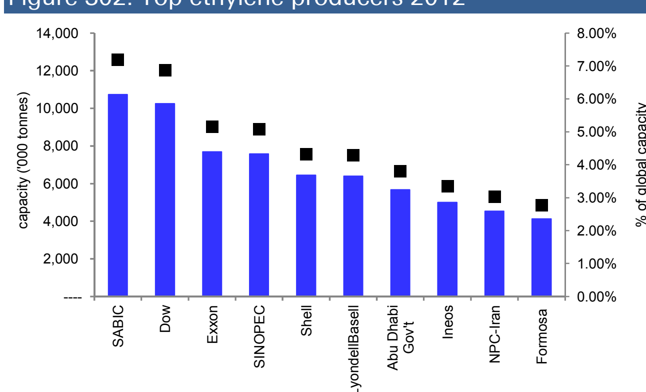
Source: Deutsche Bank, CMAI

Figure 301: Global chemicals cost curve (ethylene)



Source: Deutsche Bank, CMAI

Figure 302: Top ethylene producers 2012



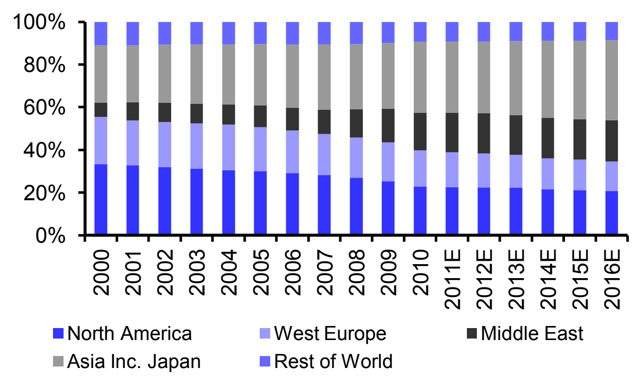
Source: Deutsche Bank, CMAI

The emergence of the Middle East – altering strategies

For the oil and gas majors this shift in the petrochemical industry's power base has impacted significantly on the strategies that they have adopted towards their petrochemical operations. Not surprisingly investment in new capacity in the mature, lower growth markets of Europe and the US, the heartland of the petrochemical portfolios of the western oil majors, has been substantially curtailed with the focus in these markets very much on improving efficiencies, taking costs out and ensuring a disciplined focus on a narrower set of chemical activities.

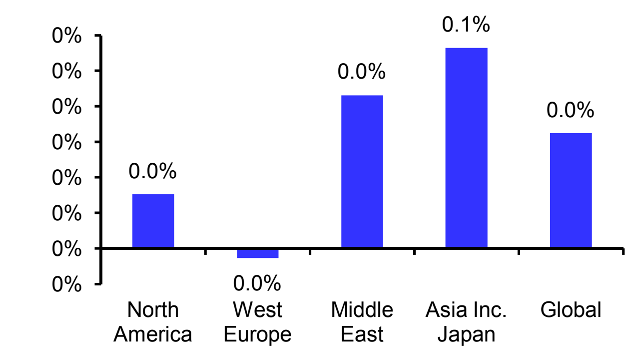
Consequently, to the extent that the oil industry continues to invest in petrochemical capacity its focus has been to build facilities that are close to the major demand centres (e.g. Shell in Nanhai, China and Total in Daesan, Korea) or in those Middle Eastern countries with an advantaged supply of feedstock (e.g. Total in Algeria and Qatar). Indeed, companies such as BP have gone so far as to exit the industry in all markets but for those where it perceives it has a sustainable competitive advantage (in BP's case the polyester chain i.e. PTA).

Figure 303: Regional share of global ethylene capacity



Source: Deutsche Bank, CMAI

Figure 304: CAGR in ethylene capacity by region (2010 – 16E)



Source: Deutsche Bank, CMAI

An ever diminishing part of the integrated company

Looking forward, petrochemicals will no doubt remain an important activity for the integrated industry. However, with chemical investment facing ever more rigorous hurdles and the profitability from existing production centres almost certain to remain under pressure, the expectation has to be that this source of the integrated oil company's earnings will continue to decline. Indeed the majority of integrated companies have ceased to report petchems earnings separately highlighting the fact that this area is no longer considered a major source of earnings, growth or investment

Olefin and Aromatic Building Blocks and their Chains

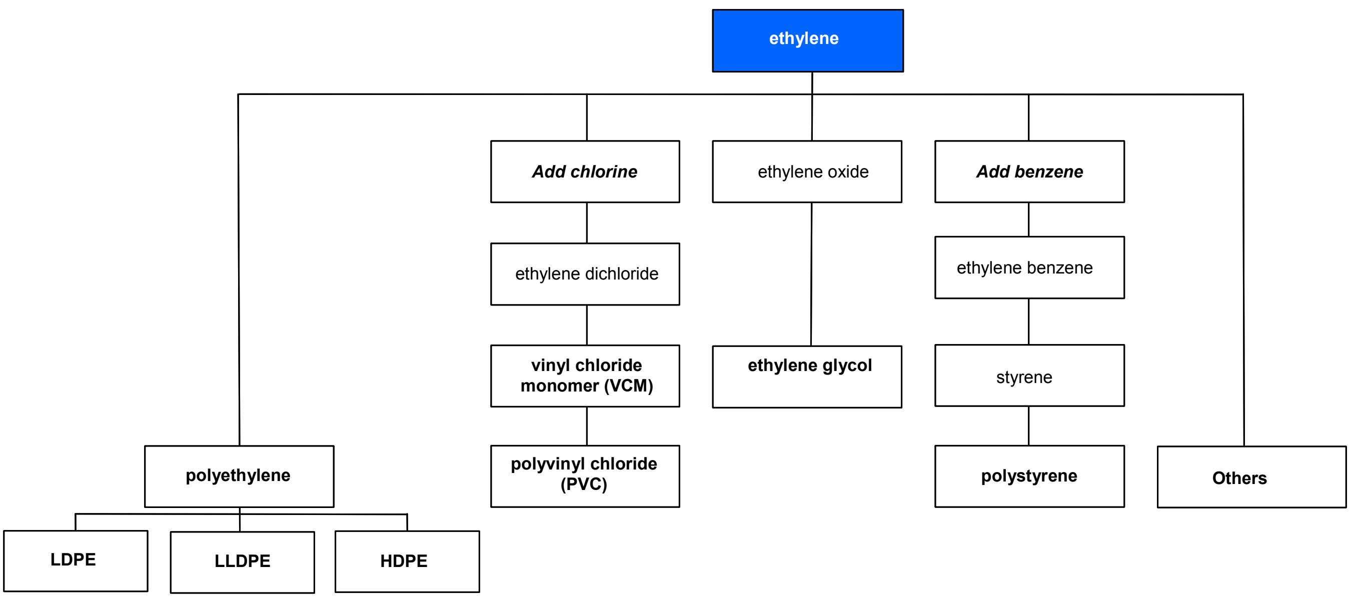
Over the following pages we summarily discuss the major petrochemical building blocks. It is these often highly reactive first derivatives produced in the upstream petrochemical cracker that form the basis of today's plastics industry and the starting point for almost all organic chemistry.

Ethylene – C_2 Olefin

Ethylene is the petrochemical industry's key building block. It is the substance from which approximately 60% of other organic chemicals are derived. It contrasts with ethane in that triple rather than single bonds exist between the two carbon molecules (i.e. C_2H_2 cf C_2H_6).The production economics and output of an ethylene production facility are largely determined by the choice of feedstock (raw material). Within Western Europe naphtha is generally used as the raw material of choice, whereas in the US most plants use natural gas due to its ready availability. Natural gas fed facilities also produce a far higher proportion of ethylene (approximately 80%), although the proportion of co-products produced (propylene and butadiene and so on) is much less, when compared to a naphtha cracker. The capital investment required for natural gas fed units is generally lower.

Ethylene demand growth reflects global GDP and chemical demand due to its position as a major petrochemical building block. Long-term growth is typically between 1-1.5x GDP.

Figure 305: A simple flow chart of ethylene and its derivatives



Source: Deutsche Bank

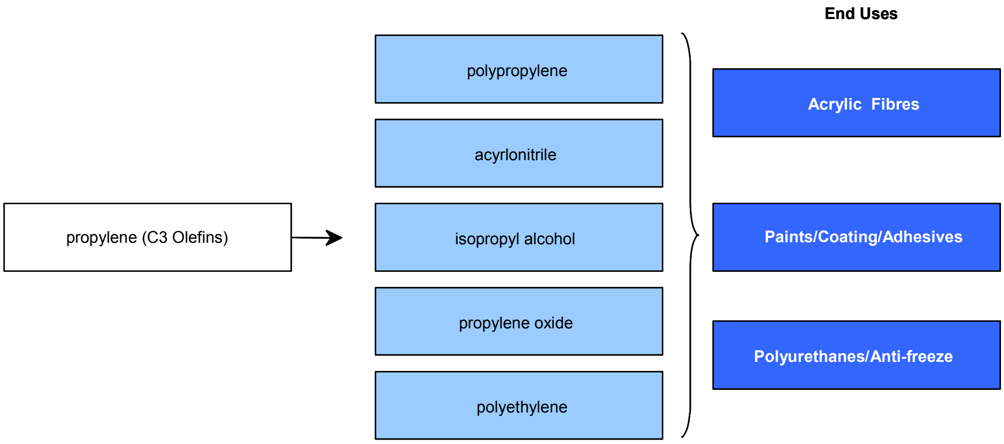
Propylene – C_3 Olefin

In Europe, propylene is produced mainly as a by-product of ethylene. In the US, oil refineries provide a second major source. The crude propylene stream created in a refinery can be "cleaned up" for use as a gasoline component. Thus, when gasoline values are much higher than chemical values refineries will retain the propylene stream while when gasoline values are low they will separate and market this merchant product.

There are two principal grades of propylene: chemical grade (from crackers or refineries) and polymer grade (from crackers only). There is a third source of propylene, from the dehydrogenation of propane gas, but it accounts for only a small proportion of global propylene production currently.

Propylene does not have many direct applications in the consumer market but is used extensively as an intermediate product in the chemical chain, for example in the production of fibres, textiles, injection moulded plastics and paints among others. Long-term growth is more than 2x GDP.

Figure 306: The polypropylene chain

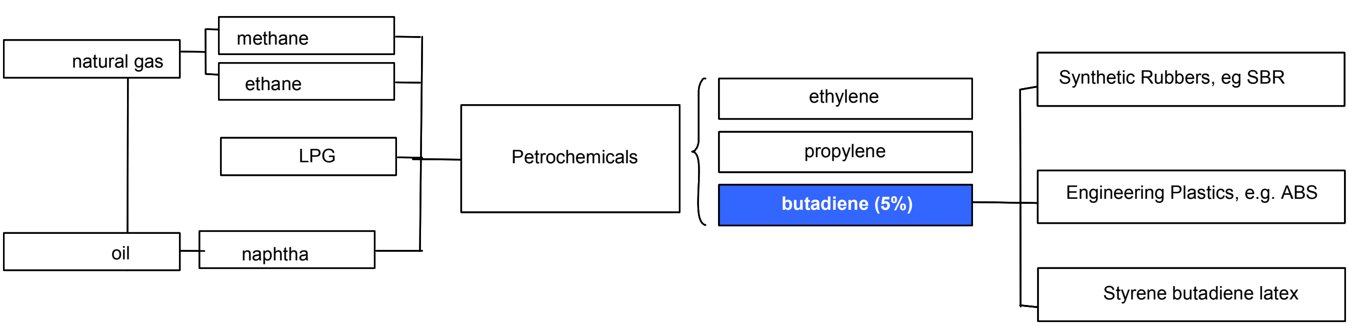


Source: Deutsche Bank

Butadiene – C_4 Olefin

Butadiene, a colourless gas at room temperature (liquid a few degrees below freezing point), is a by-product of the cracking process (that produces ethylene primarily). Approximately 5% of the base chemicals produced in the cracking process are in the form of butadiene (a molecule with four carbon atoms). The raw materials are again natural gas or naphtha. The main use of butadiene is as an intermediate in the manufacture of various forms of rubber, latex and plastics. The largest customers for butadiene include Goodyear Tire & Rubber, Firestone Synthetic Rubber & Latex, DuPont Nylon, Dow Chemical, Lanxess, Michelin North America and Ameripol Synpol.

Figure 307: Production process of butadiene



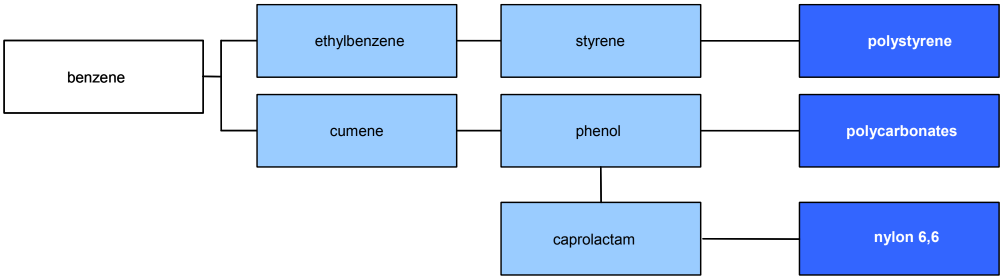
Source: Deutsche Bank

Benzene – C_6 Aromatic

Benzene can be derived from petroleum based sources or coal. Petroleum sources include refinery streams, pyrolysis gasoline (a by-product of ethylene manufacture in cracking naphtha, gas oil or LPG) and toluene. Coal-derived benzene is obtained from the light oil resulting from coke-oven operations. Some of this light oil is processed by petroleum refiners for benzene recovery.

Demand for benzene is predominately driven by styrene production - styrene is used to make polystyrene used in insulation, moulding and packaging). However, it is also influenced by a variety of other products such as nylon (via cyclohexane), resins (for wood treatment), CD/DVD (via polycarbonate), acrylics (through cumeme, phenol and acetone) and furniture and auto components (via aniline into polyurethane). As a result of this wide mix benzene demand is typcically in line with GDP growth.

Figure 308: The benzene chain



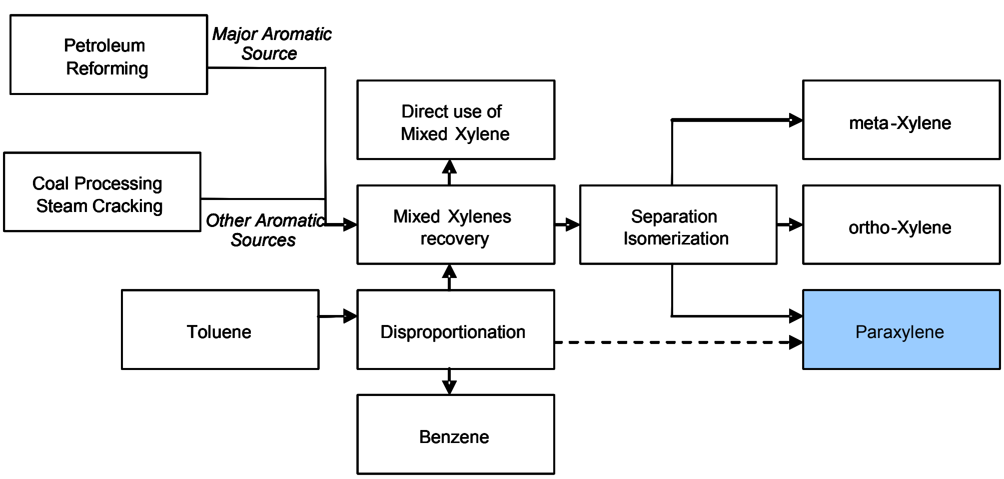
Source: Deutsche Bank

Paraxylene – C_8 Aromatic

Paraxylene (PX) is a colourless liquid and is the most commercially important xylene. The main use for paraxylene is as a raw material for polyester (fibre and resin). It is almost entirely used as an intermediate into polyester (via PTA and DMT). Polyester continues to see strong growth driven by new applications for the resin (PET) and this is anticipated to drive demand growth for paraxylene at an average of 1.5x GDP.

Paraxylene is most commonly separated from the mixed xylene stream that results from the refining of naphtha. However, it can also be produced through toluene disproportionation which involves toluene with a limited amount of C_9 aromatics being combined with a hydrogen rich recycle gas, preheated and passed through a catalyst bed. The liquid from this process is then fractionated to recover the benzene product and the mixed xylenes.

Figure 309: The production of paraxylene



Source: SRI

The Major Plastics or Polymers

Polymerisation – The Manufacture of Plastics (polymers)

Polymerisation is the linking of individual molecules or 'monomers', such as ethylene, into long chains or 'polymers' such as polyethylene. This happens in the presence of pressure and a catalyst. There are five commonly used polymerisation processes, each with their own merits and downsides. They are:

- **Bulk/Gas-Phase Polymerisation.** This is one of the most common (and modern) production methods and is used in the manufacture of polyethylene and polypropylene. There is no solvent or dilutant in this process, merely the monomer (e.g. ethylene) and a catalyst. As a result there are significant environmental benefits from using this method. It is also less energy intensive per quantity of polymer produced. Attempts are being made to make rubber-type polymers by such methods, such as EPDM/SBR.
- **Solution Polymerisation**. The monomer is dissolved in a solvent and the resultant polymer is also soluble. The polymer can be used directly from this process, but solvent extraction can be difficult and expensive.
- **Slurry Polymerisation**. In this process the polymer is produced as a slurry or paste from a solvent-based system. Solvent removal can also be a problem with this method.
- **Suspension Polymerisation**. This process is used when both the monomer and polymer are insoluble in the solvent but the catalyst is soluble. Energy is required to prevent the original monomer and polymer sticking together.
- **Emulsion Polymerisation**. This high cost method is used in the manufacture of special latex polymers.

Although common usage tends to apply the generic term 'plastics' to everything, there are in fact numerous types of plastics with a variety of characteristics suitable for a wide range of applications. Plastics can be divided into two main categories - thermoplastics and thermosets. Thermoplastics soften on heating and then harden again when cooled. They can therefore often be re-moulded or extruded and, increasingly, even recycled. Thermosets never soften once they have been moulded.

Figure 310: Common types of plastic

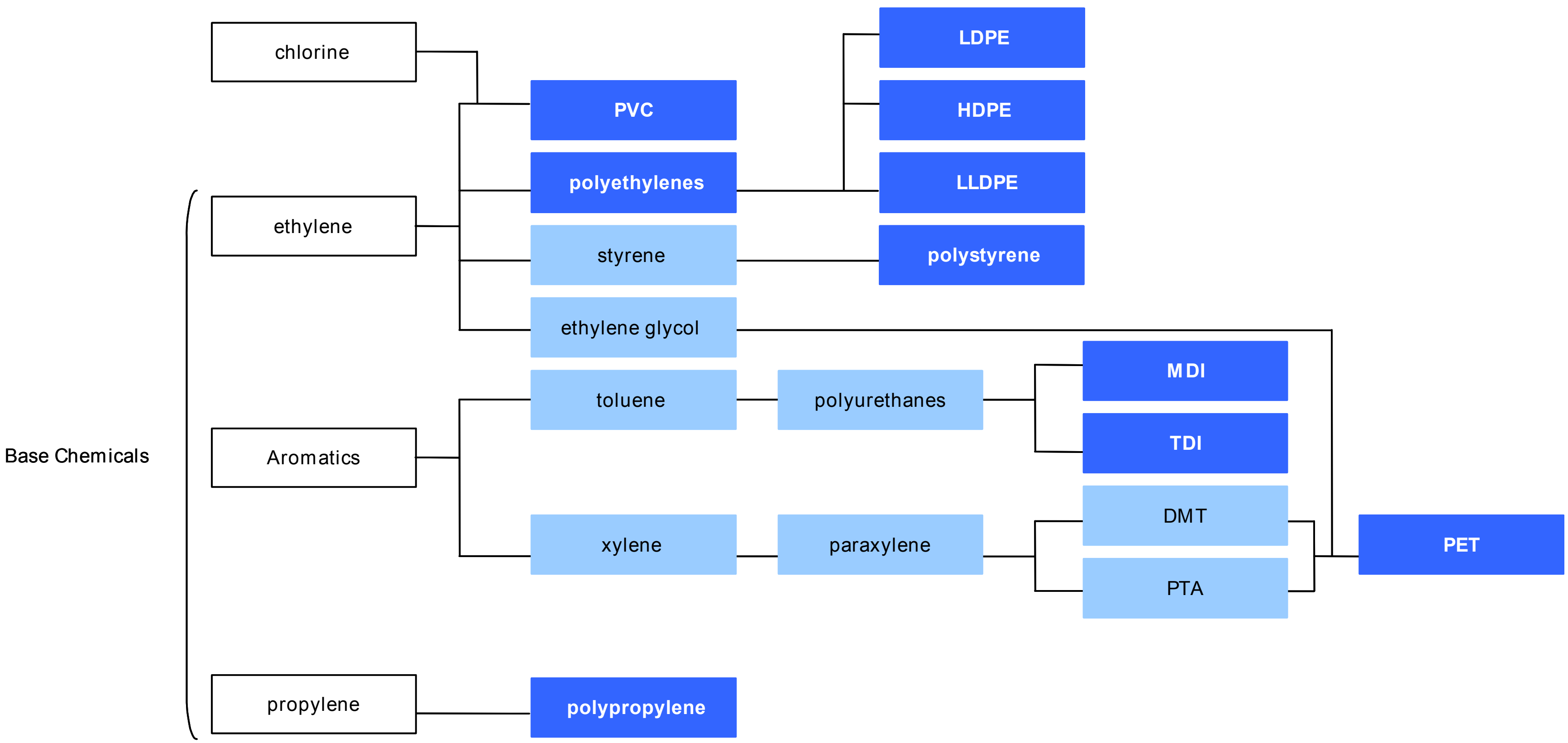
Thermoplastics	Thermosets
HDPE	MDI
LDPE	TDI
LLDPE	Epoxy
PET resins	Phenolic resins
polypropylene	
polystyrene	
polyvinyl chloride (PVC)	

Source: Deutsche Bank

Polyethylene (PE)

Around 57% of all ethylene produced globally is polymerised to form polyethylene (PE), the most widely used plastic. It is produced in three different forms (HDPE, LLDPE and LDPE) each of which have different properties giving it a wide range of applications. HDPE and LLDPE are often manufactured in the same production facilities. Production can 'swing' from the manufacture of one to the other. LDPE production facilities are dedicated to that product alone. The different ‘grades’ of each polyethylene are produced using different combinations of pressure, temperature or additives. High density polyethylene (HDPE) is a rigid plastic. It is mainly used for rigid packaging items such as detergent or milk bottles, crates or car fuel tanks. Linear low density polyethylene (LLDPE) is a tough plastic which has other monomers such as butane or octane added to it. It is mainly used in the manufacture of films for plastic bags, sheets, plastic wraps and heavy-duty applications, for example, agricultural film. LDPE was the first grade of polyethylene, produced in 1933 by ICI, made at high temperature and pressure. It is a more flexible plastic than HDPE, is and its main uses are in carrier bags, films and 'squeezable' applications such as toothpaste tubes

Figure 311: Polymers: simplified flow diagram of the product pathways Involved in their production



Source: Deutsche Bank, industry sources

Long-term HDPE grows at around 1.5x GDP. LLDPE is experiencing stronger demand growth than both HDPE and LDPE, at around 2.0x GDP. LLDPE is gradually replacing LDPE in a range of applications. It has the advantage of a wider range of properties and a more flexible manufacturing process.

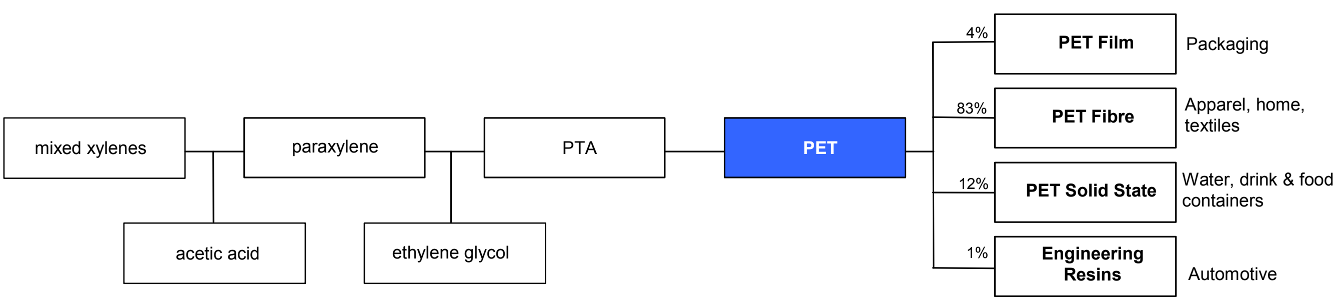
Polypropylene

Polypropylene (PP), which is produced in several grades, has a wide range of applications across the industrial, automotive and domestic sectors from injection moulding (car dashboards and toys) to fibres. Although less tough than LDPE, it is much less brittle than HDPE. This allows polypropylene to be used as a replacement for engineering plastics, such as ABS. Polypropylene has very good resistance to fatigue, so that most plastic hinges, such as those on flip-top bottles, are made from this material. Polypropylene demand is growing more rapidly than that of polyethylene, driven by the discovery of new applications such as the substitution of ABS and other engineering plastics. In the coming five years we anticipate growth of on average 4.5% pa while long term growth tends to be 1-1.5x GDP.

Purified Terephthalic Acid (PTA)

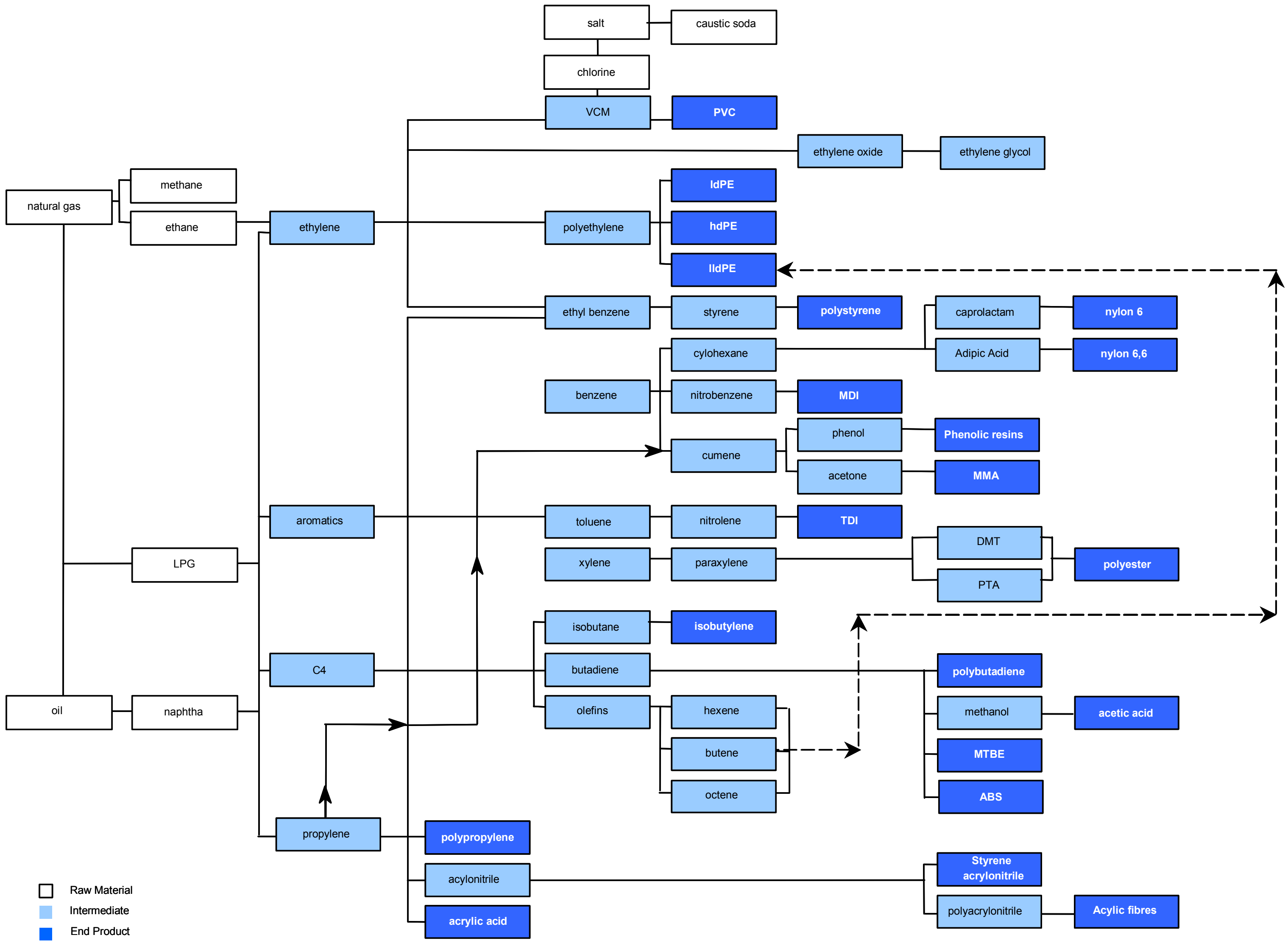
Purified terephthalic acid is a white, water-insoluble powder obtained from the oxidation of paraxylene with the solvent acetic acid. It is used primarily in the manufacture of polyester (either resin called PET or fibre). PTA is also known at TPA (terephthalic acid). Demand growth in PTA is expected by DB to remain relatively strong out to 2015, averaging 4% pa, although we also anticipate this will be outpaced by growth in capacity of 6% over the same period so pressuring margins. The industry's leading producer is BP.

Figure 312: Production and end uses of PTA



Source: SRI

Figure 313: Organic chemistry - simplified flow diagram of the derivatives from petrochemical production



Source: Deutsche Bank and SRI

Conventionals & Unconventionals

Conventionals

LNG

Deepwater

NGLs and Condensates

Unconventionals

Canada's Oil Sands

Gas-to-Liquids

Coal Bed Methane

Shale and tight Gas

Tight Oil

Liquefied Natural Gas (LNG)

Overview

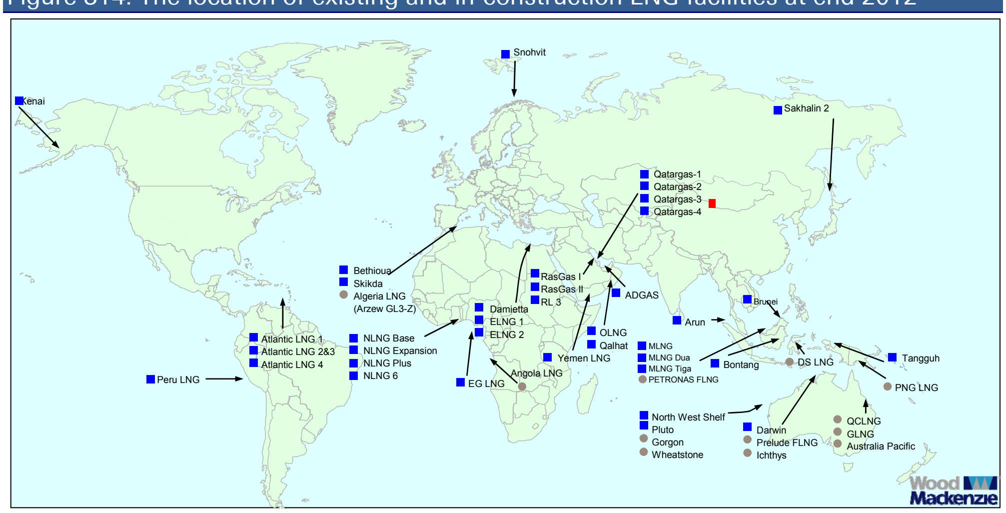
Liquefied natural gas (LNG) is produced when natural gas (predominantly methane) is cooled to a temperature of -162°c at atmospheric pressure and condenses to a liquid occupying about a 600th of the volume of natural gas. It is a process that is typically used in order to transport natural gas from a stranded and remote location of origin to a consuming region where to do so by pipeline would prove uneconomic either because of distance (typically 1500km or more) or for technical reasons (i.e. the need to cross deepwater). The process is very capital intensive, requiring substantial upfront investment. As a result, in order to prove economic conventional onshore LNG projects require a large gas resource (at least 5tcf) with the LNG produced generally being pre-sold under long term (20 year) take or pay contracts using an agreed price formula. Importantly, as the major consuming markets of the East (China, India, etc) shift from the use of fuel oil towards natural gas, demand for LNG is growing at an estimated 4-6% per annum. In 2012 LNG capacity at the world's forty or so producing facilities stood at an estimated 240 million tonnes per annum and represented around 10% of global gas consumption. By 2020, production is expected to stand at around 370mtpa from over fifty facilities, a 10-year CAGR of 5%. Major producing countries include Qatar, Nigeria, Indonesia and Australia whilst the major IOCs involved in the production and marketing of LNG include Shell, BG, Exxon, Chevron and Total.

Liquefied natural gas (LNG) is produced when natural gas (predominantly methane) is cooled to a temperature of -162°c at atmospheric pressure

A brief history

Relative to both oil and piped gas, the LNG industry is still in its infancy. Efforts to liquefy gas for storage commenced in the early 1900s but it wasn't until 1959 that the world's first LNG ship carried a cargo from the US to the UK, proving the potential for LNG to be transported. Five years later the UK began importing 1mtpa of LNG from Algeria under a 15 year contract with gas sourced from Algeria's huge Saharan gas reserves, so establishing the Algerian state oil company Sonatrach as the world's first major LNG exporter. This was followed by the 1969 start up of Alaska's Kenai facility, the output from which was sold under long term contract to Japan's Tokyo Gas and Tokyo Electric and shortly after, in 1970, the start-up of Libya's Marsa El Brega facility, with LNG sold into southern European markets.

Figure 314: The location of existing and in-construction LNG facilities at end 2012



Source: Wood Mackenzie; Deutsche Bank

Yet it was OPEC's creation and the oil price shock of 1973 that provided real impetus for the emergence of LNG as significant industry in its own right. With the oil-dependent industrial economies of Japan and Korea facing substantial increases in their energy costs they turned increasingly to LNG to meet their growing energy requirements. Not only were these countries large potential buyers. They were also happy to sign long term 20-year, take or pay contracts under an agreed pricing formula in order to obtain security of supply. With demand underwritten this encouraged the development of liquefaction facilities by countries in the region with substantial gas reserves not least Indonesia and Malaysia. And as trade in the Pacific Basin developed, so several Middle Eastern states looked towards LNG as a means of monetizing oil-associated gas, much of which had previously been flared, often offering development terms which, today, seem very generous. Indeed, it is legacy positions in these assets that continue to form the back bone of Shell and Total's LNG profitability today.

The LNG market today

Today, international trade in LNG centres on two geographic regions. These remain discrete with their own demand/supply balances although they are increasingly becoming linked by Middle Eastern supply.

Today, international trade in LNG centres on two geographic regions.

- The Atlantic Basin involving trade in Europe, northern and western Africa and the America's eastern sea board.
- The Asia Pacific Basin involving trade in South Asia, India, Russia and Alaska.

OECD Asia's historic dependence upon imported gas as a source of energy has meant that, today, the Pacific Basin dominates the LNG market with the Asian market accounting for around 60% of overall LNG demand. Indeed, contrary to expectations at the start of the last decade at which time declining US natural gas production suggested that North America would become a major LNG importer, the Asian market looks certain to retain its dominance. Whilst in large part this reflects the North American market's new found ability to meet indigenous demand from the growth in supply of tight and shale gas it also illustrates the emergence of China and India as significant buyers of LNG under long term contracts, with these geographies alone now expected to account for around 25% of world demand by 2020 and the Pacific Basin in aggregate nearer 75% of global LNG demand.

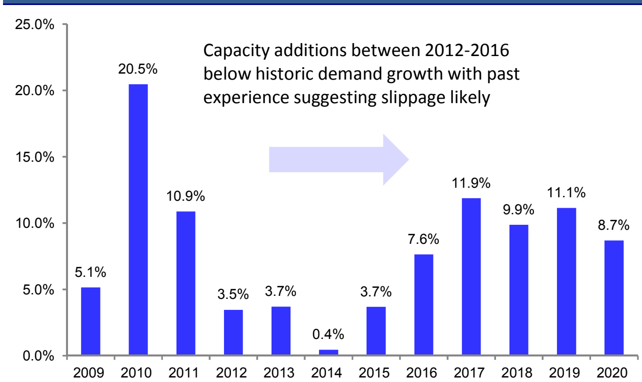
North American unconventional gas alters the Atlantic Basin outlook

The loss of North America as a major LNG demand growth opportunity does, however, hold significant implications for global LNG markets long term. As illustrated below, where in May 2007 North American LNG demand had been expected to reach over 100mtpa by 2020 the successful development of unconventional gas in that region means that in reality LNG imports by the end of this decade will quite likely account for under 2% of global demand. As a consequence, much of the LNG that was developed to supply the North American market, not least from Qatar, has had to seek an alternative home. Short term this clearly added to the over-supply already evident as industrial demand collapsed following the 2008 global economic downturn.

Longer term, however, not only has the development of unconventional sources of gas supply reduced the outlook for growth in LNG from double digit rates to a more likely 5-7%. It has also raised questions on both the economic viability of future non-US green-field Atlantic Basin developments and whether North America itself will in time prove to be a major source of LNG for export and as a consequence undermine supply-side economics. For with North American shale production costs low and much of the infrastructure required to build a US LNG export terminal already in place across America's Eastern Seaboard, as long as US gas prices stay in a $4-6/mmbtu range US sourced LNG looks is likely to prove competitive with that sourced from alternative Greenfield supply centres. As such outside the US, future Atlantic Basin LNG developments appear likely to be limited in number unless built as expansions of existing facilities or with a specific view for sale under long term contract into European end markets. Rather the majority of new supply developments will likely locate nearer to the end user customers in the Pacific Basin.

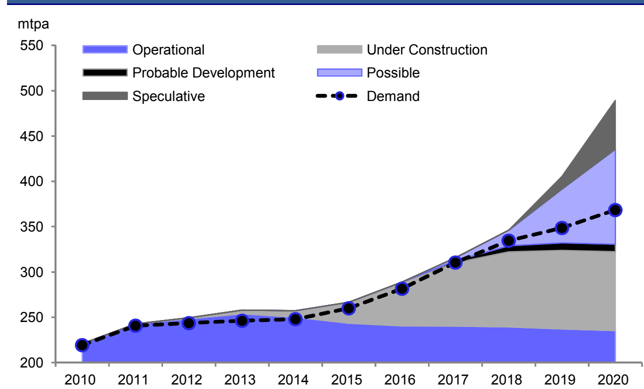
Growth should remain robust but contract and spot pricing will vary with the cycle. Having said this the industry is, however, almost certain to remain prone to its own very notable supply/demand cycles. Given that the most recent downturn in LNG markets marked a confluence of negative demand factors coinciding with the 2008-11 start-up of some 80mtpa of new supply (40% of existing capacity) these are unlikely to be as extreme as was the case over the 2008-11 period. That the US is no longer a viable end market for LNG also suggests that future sales will increasingly be made on a point to point basis with a specific end-user user in mind. Although this should contain the pace at which new facilities are developed in the future, as with most capital intensive industries with long (4-5 year) construction cycles the addition of new supply will invariably be lumpy - something which has been only too evident in the LNG industry in recent years. The consolation is that with the construction costs of an LNG facility at least three times what they were a decade ago and the US no longer a viable economic home for surplus gas, the willingness of the industry's portfolio players to pay the price required to secure the supply of LNG for potential arbitrage across regional markets is likely to be severely contained. Absent the unexpected emergence of a major deep and liquid gas trading hub outside Europe, the likelihood of an excessive capacity build out should consequently be much diminished.

Figure 315: After the surge in capacity across 2009-11 additions thru 2015 are modest with risk of delay



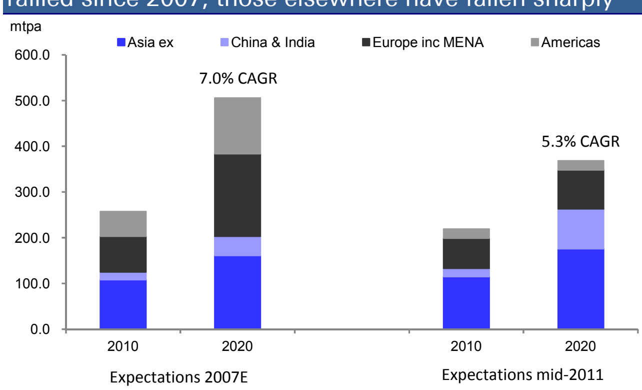
Source: Deutsche Bank

Figure 316: Globally demand is contained by supply through 2015 before building strongly as projects come on



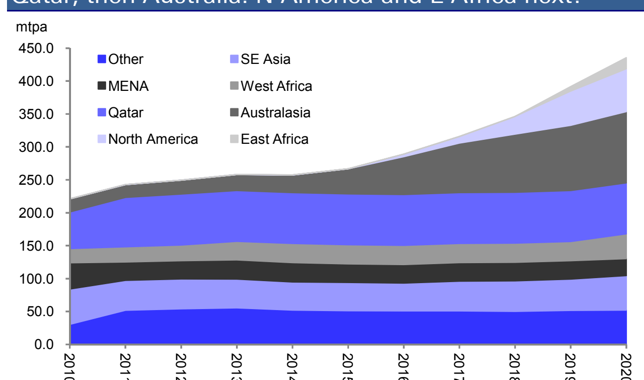
Source: Deutsche Bank

Figure 317: Whilst expectations for Asia demand have rallied since 2007, those elsewhere have fallen sharply



Source: Wood Mackenzie

Figure 318: Supply comes in waves – West Africa, then Qatar, then Australia. N America and E Africa next?



Source: Wood Mackenzie

Atlantic Basin vs. Pacific Basin

Same molecule, different demand growth, different pricing

Given the ubiquitous nature of the LNG molecule the distinction between Atlantic and Pacific Basins may seem an odd one. Yet because of the different demand growth profiles of the two regions (PB +7%, AB +2%) and the different price formulae under which contracts supplying the two markets have been signed the distinction is important most particularly for those companies that can divert cargoes between the two basins.

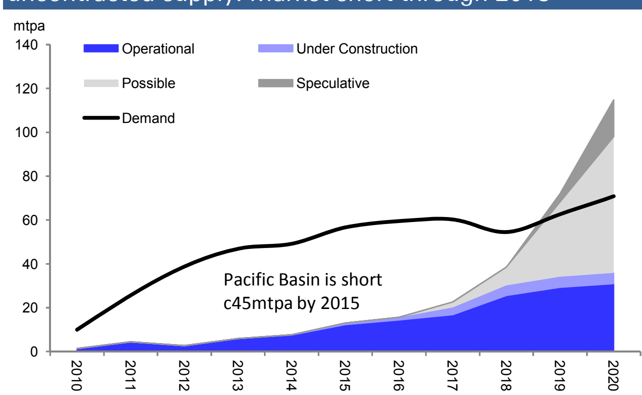
In part the distinction again owes much to the now extant expectation that North America would prove a significant demand centre for LNG. For with most of the LNG sold into the Pacific Basin pegged to the price of crude oil yet that for sale into the Atlantic Basin struck on the basis of the US Henry Hub or UK NBP price, spot prices between the two regions can, and do, show significant discrepancy. Moreover, because most Atlantic Basin demand centres have alternative indigenous sources for gas, predominantly via pipeline, and trading hubs on which spot gas can be traded the potential for the arbitrage of volumes between one market and the other exists.

Consequently, at times when the Pacific Basin market is short gas, LNG volumes with flexible destination clauses have the potential to be diverted from the Atlantic Basin – assuming Asia is willing to pay the required price premium. Similarly, at times when the Pacific Basin is long gas it has the potential to flow to Europe and the US where it can either displace often more expensive pipeline gas (Europe) or be held in storage (North America). Thus where the global market for LNG can appear in balance, within the two basins themselves significant supply demand imbalances can exist (illustrated below).

Qatar adds a further dimension

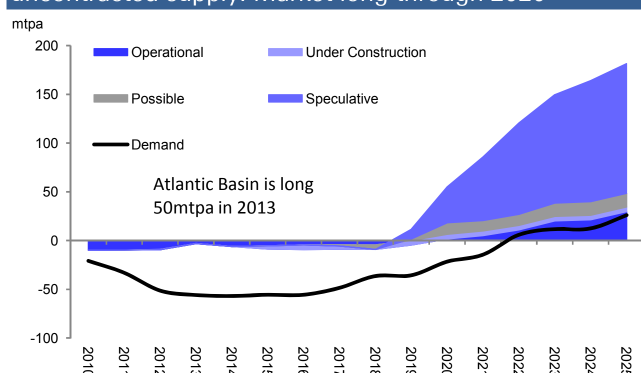
Looking at LNG supply/demand globally over the next few years and as depicted in Figure 316 the market appears broadly in balance. Yet as illustrated below whilst globally the market in aggregate may appear in equilibrium this masks significant discrepancies within the two basins - the Pacific seemingly c45mtpa short supply and the Atlantic similarly long. Unsurprisingly, the consequence of this mismatch has been the emergence of regional price signals encouraging the flow of cargoes from West to East. Importantly, at the time of writing these signals have been further augmented by the strategies of the dominant player in flexible markets, namely Qatar, which has limited the flow of 'spot' volume under its control and currently delivered into Europe as it seeks to term out a proportion of its flexibility at favourable long term contract prices.

Figure 319: The Pacific Basin – Uncontracted demand vs. uncontracted supply. Market short through 2018



Source: Deutsche Bank

Figure 320: The Atlantic Basin - Uncontracted demand vs. uncontracted supply. Market long through 2020



Source: Deutsche Bank

LNG - The process and the chain

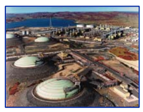
Conceptually, the LNG process is relatively straightforward. It involves a sequence of stages, which may be undertaken by one or more companies dependent in part upon the extent to which they wish to be integrated across the 'LNG chain'.

Figure 321: The LNG Chain – for every 1mtpa of LNG supplied under a 20 year contract 1.1TCF of gas is required

Upstream

Supplies gas to a liquefaction plant

~1.1 tcf of gas required per mmtpa for a 20 year project



Liquefaction

Plant train size typically ranges from 3 mtpa to 5 mtpa with new plants now up to 7.8 mtpa

Trains require approx 150 mmcfd (gross) of gas per mtpa

~11% feed gas consumed in process

Shipping

Typical new ship capacity 138,000 m^3 or 145,000m^3 with some (XOM Q-Max) 200,000 m^3 +

138,000 m^3 ship delivers ~2.85 bcf of gas (gross) or c60,000t LNG

~0.15% 'boils off' per day

Re-gas

Send-out capacity of new plants ranges from 400 mmcfd to over 1 bcf/d

Storage for at least one ship's worth of LNG

1-2% of gas consumed as fuel

Source: Wood Mackenzie

These commence with the upstream production of gas either onshore or offshore, the gas being piped to a 'midstream' liquefaction plant (the equivalent of a large refrigerator) located on the coastline. Here the gas is processed to remove impurities such as water, carbon dioxide and hydrogen sulphide as well as any associated liquids and longer chain carbon molecules before being cooled by a series of compressors in a liquefaction facility. (For reference the US industrial gas major, Air Products, accounts for around 90% of the worldwide market for compressors with its Mixed Component Refrigerants (MCR) process. The balance of the market is largely based on the Phillips' Cascade process, originally developed for Alaska's Kenai plant). Once liquefied, the LNG is loaded into storage before being transferred to purpose built ships and transported to an end market (e.g. US) or customer (e.g. Tokyo Electric Power or TEPCO). Upon arrival the liquefied gas will normally be transferred to an onshore storage facility where it will be held in liquid form before being passed through a re-gasification plant as, and when, it is required either for use in power generation by the dedicated contractor (e.g. TEPCO) or for sale into the local grid.

Costs of LNG Production

LNG is a very capital intensive process requiring substantial upfront capital investment for the development of a typically sizeable resource base

LNG is a very capital intensive process requiring substantial upfront capital investment for the development of a typically sizeable resource base. As such the return profile from an LNG project is very different to that from a conventional oil or gas development, the internal rate of return on projects generally being relatively modest but the absolute potential for value creation very large and the development costs per barrel of resource relatively modest. Although improvements in technology and the ever larger scale of projects had seen the underlying cost per tonne of capacity decline over the past decade, industry cost inflation has resulted in a substantial rise in the cost of all elements of the chain pushing the costs for a green field LNG development to levels not seen for several years. All told liquefaction capacity alone has broadly quadrupled in cost over the past decade rising from c$300m/mtpa to c$1.3bn/mtpa today.

Importantly, because of the absence of large liquid end markets and the absolute level of capital required to develop an LNG facility supply is seldom added on a speculative basis. Rather the project sponsors will seek to secure end demand for at least 75-80% of any schemes output before committing to build. In this respect the LNG market is very different to that for oil and, indeed, pipeline gas. Historically, this attribute has tended to limit the extent of overbuild at any one point in the cycle. As discussed earlier it does, however, mean that at times when several separate projects are competing for end market demand contract pricing will tend to erode.

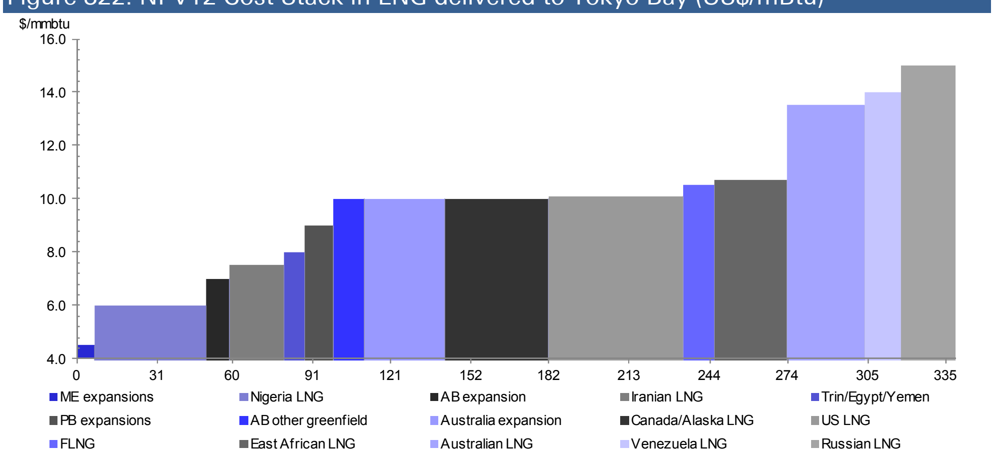
Depreciation per unit of production is the key cost

Given the capital requirements, the most significant cost component of LNG production is the depreciation charge per unit of output. In an integrated project this can run as high as $3/mmbtu. Again, this tends to vary quite significantly depending upon whether the project is a new, green field development requiring significant investment in infrastructure (jetties, land reclamation, storage tanks, utilities, etc) or the brown field addition of a further liquefaction train, the economics of which are invariably very attractive. For many projects commercial viability is also often very dependent upon whether there is an associated stream of more highly valued LPG or condensate from which to drive valuable additional revenues. As to variable operating costs these tend to be relatively modest at around $0.30/mmbtu, the major energy requirements of liquefaction being provided by the supply of gas (as indicated earlier for every 10mmbtu of LNG produced roughly 1mmbtu is consumed internally as energy).

Cost stack curves

When assessing the relative profitability and costs of a different project one commonly used method is to look at the estimated cost of delivering a unit of LNG into a defined end market through a re-gas facility (Tokyo Bay in Japan in the below example). Through adding the likely costs of re-gas and shipping to those for the production of an mmbtu of gas. The resulting 'cost stack' profile provides some insight into how the various LNG projects around the world compare with each other on a cost basis. Shown in the diagram below, this also helps to emphasise the improved economics arising from the build of additional liquefaction trains on existing sites, as evidenced with ELNG, ALNG, NLNG 6 and Qatar II as well as the importance of liquids (key to the profitability of most Qatari projects). Most significant, however, in the below chart is the fact that as industry costs have risen so the economics of the more recent projects have deteriorated relative to their predecessors with the Australian projects proving especially expensive given contractor constraints and additional environmental costs.

Figure 322: NPV12 Cost Stack in LNG delivered to Tokyo Bay (US$/mBtu)



Source: Wood Mackenzie data; Deutsche Bank

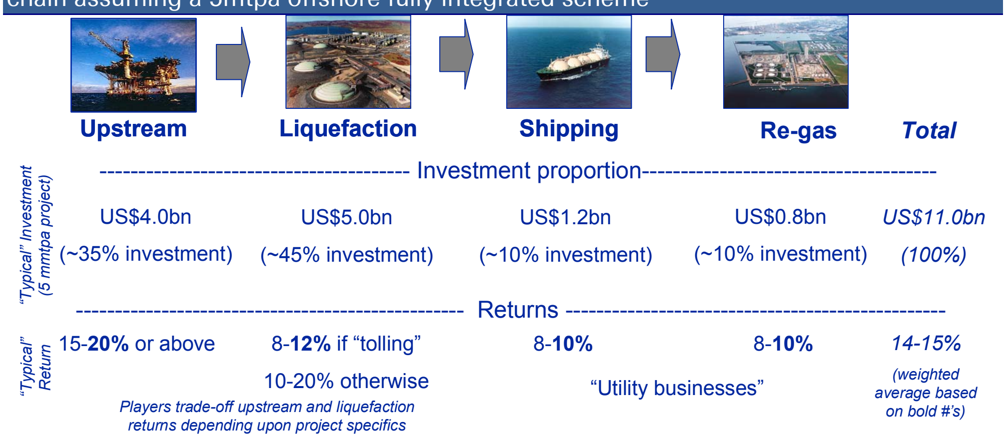
LNG – returns across the chain

Given the different nature of the various activities along the chain and the levels of investment required, the return profile of each activity varies. In most instances the majority of the value associated with the gas molecule is either captured in the upstream or, depending upon the fiscal regime, within the liquefaction plant itself. This contrasts with the more typical cost of capital type returns associated with re-gasification and shipping, a return profile that reflects their utility nature. Not surprisingly, given the superior returns available from the upstream and liquefaction elements of the chain, it is within these two areas that the major oil companies have tended to invest.

In most instances the majority of the value associated with the gas molecule is either captured in the upstream or, depending upon the fiscal regime, within the liquefaction plant itself

Historically, the long-term bias of Asian buyers and their desire to ensure security of supply meant that they would invest in the utility-type assets necessary to transport the liquid gas and re-gasify it once it had come to port. For the major oils this meant that to a large extent they could avoid investment in those parts of the chain that tended to offer utility type returns and concentrate their capital investment in the higher added value upstream and liquefaction activities.

Figure 323: Indicative returns and investment proportions and returns across the LNG chain assuming a 5mtpa offshore fully integrated scheme



Source: Wood Mackenzie

Globalisation – driving integration across the chain

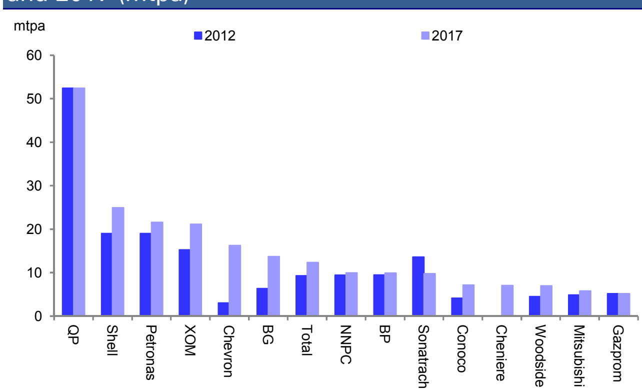
However, the opening of a multitude of new geographic end-markets in recent years with dislocated (or regional/local) pricing has driven a change in integration across the LNG chain as well as the price basis of supply. In particular, the existence of a deep liquid, traded gas market in North America with visible pricing and substantial storage capacity encouraged significant growth in spot markets. Safe in the knowledge that providing they had access to re-gas capacity LNG could always be sold into the US market at the prevailing Henry Hub price, a greater bias towards trading and price opportunism has emerged amongst the major players. Those wishing to gain from the profit opportunities arising in a world in which the price in one gas market need not be the same as another have thus pushed down the LNG chain, investing in re-gas and shipping and committing themselves to the 15-20 year contractual purchase of LNG, often from their own facilities in order to underwrite the construction of a new LNG plant and with it the monetization of their upstream resource.

In part, this change in market structure has increased the risks associated with the LNG business through raising both market risk and the investment capital required to establish access and distribution. This has become all the more so given the secular change in North American gas supply arising post the revolution in 'unconventional' supply and the consequent 'step-down' in the underlying US natural gas price. It has, however, also opened up new market opportunities for those willing to commit to the long-term contractual purchase of LNG for subsequent marketing (or 'merchanting') across the globe. Consequently, several of the major IOCs and some specialist players (e.g. the UK's BG Group and France's GDF-Suez) have built sizeable 'merchant' portfolios committing to buy LNG under 20-year contracts and then placing that LNG with dedicated end users either through back-to-back contracts or via the direct sale into a traded gas market (i.e. UK/US) using re-gas facilities to which they have secured access (either via lease or ownership). As a consequence, we estimate that around 25-30% of LNG deliveries globally are now effectively made on a 'spot' or 'short term' basis, the LNG buyer (or merchanter) effectively re-marketing LNG bought into their own portfolio.

NOC resource holders push down the chain

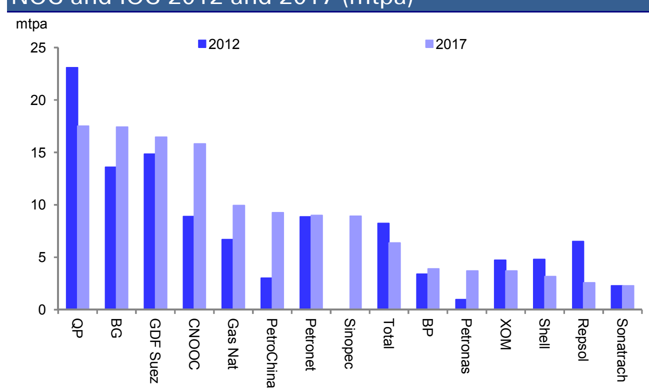
Similarly, several of the major NOCs have also shown their desire to push into downstream markets as they seek to capture the full value of their upstream resource. This has proven especially true of the Qatari's, whose involvement in downstream markets suggests that, from a standing start, they are now the world's largest producer of LNG. Importantly, of Qatar's 77mtpa in excess of 20mtpa remains available for diversion to different geographic markets depending largely upon price. It is this substantial flexible portfolio that for the present at least has afforded the Qatari's considerable influence in spot markets.

Figure 324: Liquefaction capacity by NOC and IOC 2012 and 2017 (mtpa)



Source: Wood Mackenzie

Figure 325: LNG contracted for potential remarketing by NOC and IOC 2012 and 2017 (mtpa)



Source: Wood Mackenzie

Pricing of LNG

As a contract business with terms negotiated individually between supplier and purchaser the pricing structure of one LNG contract is almost certain to differ in some way from that of another. Pricing is also complicated by the absence in all but the UK and North America of deep, liquid, traded markets for natural gas, a feature of gas markets that has meant pricing between regions is dislocated and in certain situations open to arbitrage.

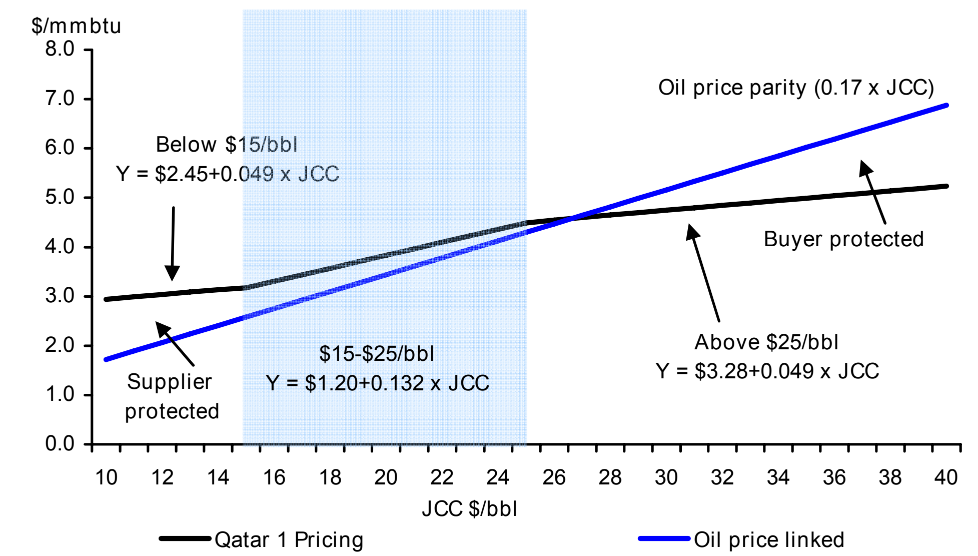
Traditionally, however, with the LNG market dominated by Asian purchasers the main pricing mechanisms have tended to be similar with the price paid per unit of delivered gas indexed (typically with a six-nine month time lag) against either crude oil or a basket of energy alternatives in a manner that broadly reflects its energy equivalence. Thus Japan uses a mixture of imported crude oils otherwise known as the Japan Crude

Cocktail or JCC whilst the typical proxy for sales to European buyers is likely to be an energy index comprising oil, oil products and coal.

Traditionally oil-indexation and 'S' curves have dominated price formulae

Moreover, in order to provide the seller with some protection on the downside and the buyer relief against upward spikes in the oil price, Asian and western European contracts have also tended to have in-built caps and collars. As a consequence, relative to an oil or energy index, the LNG price curve has tended to look a little like the letter S with pricing steady at both low and high oil prices but rising in an almost linear fashion in between as illustrated by the figure below depicting our understanding of initial contract prices for supply of gas from Qatar Gas 1 to certain Japanese customers following that plant's commissioning in the mid 1990s.

Figure 326: Historically, Japan and European LNG supply contracts have been priced with caps and collars creating an 'S' type price curve



Source: Deutsche Bank

Contract pricing will also reflect the outlook for new supply ....

Beyond individual customer/supplier relationships and negotiations, the shape of the price curve and the price equation itself will also clearly depend on the strength or otherwise of the forward market for supply at the time that the contract was signed. Thus at times when the supply outlook is tightening and limited new projects are seeking commitments from new customers, contract prices will tend to strengthen with the percentage of the oil price paid for each unit of gas moving closer to, if not above, its energy equivalent cost assuming oil as an energy proxy (16-17% of the prevailing oil price effectively representing the energy equivalent of an mmbtu of natural gas relative to a barrel of oil). Equally, however, given a loose market or competition between a greater number of planned schemes for long term customers contract prices will almost certainly weaken as resource holders prove willing to accept a lower price for planned supply in order to monetise their gas resource.

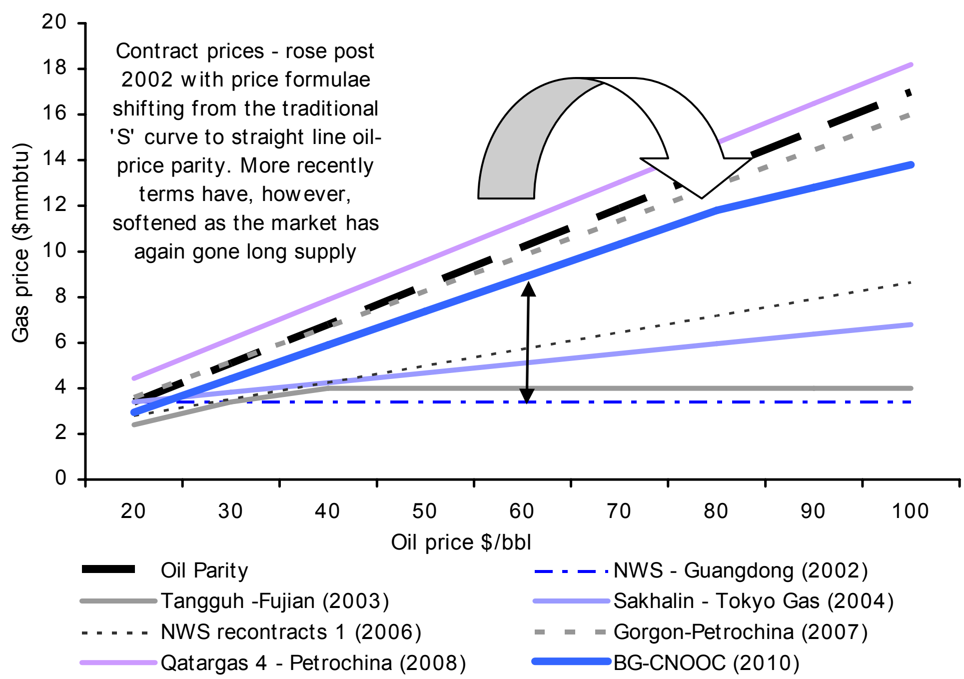
That the pricing of LNG is sensitive to the prevailing supply/demand outlook is clearly illustrated in the figure overleaf. This depicts the different price terms achieved for supply contracts from a number of Asian projects initiated over the past decade. Evident from this is that as markets tightened over the 2002-8 period so too did the gradient of the price line, with the LNG seller achieving a higher % of the prevailing oil price for every unit of gas to be sold under contract.

More recently, however, as the supply/demand balance has softened so too have the terms achievable for the sale of LNG under long-term contract fallen from their 2008 peak with long term contract pricing at the start of 2013 understood to be running at c14.85% of the prevailing JCC price plus a nominal $1/mmbtu for transport.

… with pricing also subject to adjustment to reflect the market changes

Importantly, it is also worth noting that many Asian contracts tend to be subject to price review every five or so years with any downwards or upwards adjustments typically reflecting the price dynamics then prevailing in the contractually agreed destination end-market.

Figure 327: Contract price terms fluctuate along with the cycle



Source: Deutsche Bank

North America – changing the basis of price

Where pricing under Asian and European contracts has historically been linked to that for crude oil, the emergence through the noughties of the US as an end market for LNG saw the emergence of contracts using the market-derived Henry Hub gas price as the basis for contract pricing, buyers paying a fixed percentage (typically 85-90%) of the prevailing Henry Hub price for delivered gas. Not only did this added greater transparency to LNG pricing. With the US a potential home for almost any LNG cargo, at a time of increasing tightness in the market for the supply of LNG it also set something of a floor for price negotiations in the rest of the world.

Given the collapse in the US gas price and the rise in industry development costs, the use of Hub pricing as a basis for new LNG contracts had ground to a standstill. However, the more recent emergence of the US as a potential source of LNG exports has re-opened discussion between buyers and sellers on the use of the US Henry Hub gas price in long term contract pricing. With US gas prices well below the energy equivalent oil-linked price buyers have called for the introduction of Hub-plus pricing in long term price formulae irrespective of whether the gas is US sourced or not.

Assuming North American prices remain at a substantial discount to those attainable elsewhere and US facilities gain approval for export it would thus seem likely that some form of linkage to Hub will in future be introduced. Indeed, it is of note that towards the end of 2012 both BP and BG Group signed Henry Hub-plus contracts (believed to be Hub plus $6-8/mmbtu) for the supply of gas to Asian customers even though that gas need not be US sourced (in BP's case it very clearly is not). Thus where at the start of 2013 it is less than clear to us how significant a source of future LNG supply the North American market might become, its impact on pricing is already beginning to be felt.

US exports – a potentially significant new supply source

Starting with Cheniere's mid-2010 application to seek a license for the export of LNG from US shores, the past few years have seen a dramatic increase in applications for the export of US gas as LNG to both FTA (free trade agreement) and non-FTA markets. As we enter 2013 around twenty applications have been received requesting the export of up to 215mtpa or 29bcf/d of gas, over 40% of current US gas supply (c68bcf/d).

What will be the permitted export volumes?

Yet whilst US utility appetite for the build out of export facilities appears very substantial, far less clear is quite how great the permitted volumes of gas for export will be. For where the US would certainly appear to contain more than enough shale gas resource to export substantial volumes of LNG, less obvious is the extent to which a dramatic increase in exports could disturb the prevailing domestic gas price. Politically, there is also the important question of whether the US should seek to retain its energy advantage for the benefit of its own industries and people.

Figure 328: Main LNG export schemes for which an export application has been made both FTA and non-FTA

Project (filing date)	Location	Sponsor	Capacity mtpa*	Capacity bcf/d	For FTA countries	Approval status	Non-FTA countries	Approval status
Brownfield								
Sabine Pass	Gulf Coast	Cheniere	18.0	2.20	Yes	Yes	Yes	Yes
Freeport	Gulf Coast	Freeport LNGI	10.4	1.40	Yes	Yes	Yes	No
Lake Charles	Gulf Coast	BG/Southern	15.0	2.00	Yes	Yes	Yes	No
Cove Point	Maryland	Dominion	7.4	1.00	Yes	Yes	Yes	No
Cameron	Gulf Coast	Sempra	13.0	1.70	Yes	Yes	Yes	No
Freeport Expansion	Gulf Coast	Freeport LNG	11.0	1.40	Yes	Yes	Yes	No
Elba	South Georgia	Southern	4.0	0.50	Yes	Yes	n/a	n/a
Excelerate Liquefaction	Gulf Coast	Excelerate	10.0	1.38	Yes	Yes	n/a	n/a
Gulf LNG Liquefaction	Gulf Coast	Gulf LNG LLC	11.5	1.50	Yes	Yes	n/a	n/a
Golden Pass	Gulf Coast	Exxon/QG	18.0	2.2	Yes	Yes	n/a	n/a
Cheniere Marketing	Gulf Coast	Cheniere	16.0	2.1	Yes	Pending	Yes	No
Main Pass Energy	Gulf Coast	FMR	21.0	3.22	Yes	Pending	n/a	n/a
Total brownfield			**153.6**	**20.48**				
Greenfield								
Jordan Cove	Oregon	Fort Chicago	9.0	1.2	Yes	Yes	Yes	No
Gulf Coast LNG export	Gulf Coast	Sempra	21.0	2.80	Yes	Pending	Yes	No
Oregon LNG	Oregon	Oregon LNG	9.0	1.25	Yes	Pending	NO	No
CE FLNG LLC	Louisiana	Cambridge Energy	8.0	1.07	Yes	Yes	Yes	No
Pangea Energy	South Texas	Daewoo/Statoil	8.0	1.09	Yes	Pending	Yes	No
Total greenfield			**55.0**	**7.42**				
Total (main ex 0.4bcf/d)			**208.6**	**27.90**				

*Source: EIA; Deutsche Bank *mmtpa based on 135mscf/d providing 1mtpa of capacity*

Thus, where most of those applications filed have been approved for the export of gas to countries with which the US has an existing free trade agreement (of which only Chile, Mexico and South Korea offer material export potential) only first to apply Cheniere has so far received Department of Energy (DoE) and Federal Energy Regulatory Commission (FERC) approval for the export and construction of up to 18mtpa of LNG to both FTA and non-FTA countries. Following the release by the US DoE in late 2012 of an independent study that saw positive net benefits for the US of increased LNG exports it is, however, likely that further non-FTA approvals will be forthcoming albeit most likely in a limited and controlled manner. The EIA has separately suggested it could see c. 25mtpa of US export capacity in place by 2027.

Even if all were approved there are also clear questions on the absolute level of buyer interest in the supply that is available. For where on the face of it sourcing gas from the US at a relatively low price may appear compelling, by the time shipping and liquefaction costs have been included the price differential is substantially reduced.

This is illustrated by the tabulations below. Based on selected Henry Hub gas prices these assess the likely delivered price by the time that the costs to liquefy (the fixed capacity charge) and ship the LNG, amongst others, are incorporated. Include these and the price differential is nowhere near as great as may at first appear. Thus where at $4/mmbtu sourcing US gas may look a compelling proposition by the time the full costs of delivery to Asia have been incorporated, at over $10/mmbtu, the price differential is far less material.

Figure 329: US CIF pricing based on most recent Cheniere's contracts ($/mmbtu)

Hhub price	**2.00**	**3.00**	**4.00**	**5.00**	**6.00**	**7.00**
Energy cost (15%)	0.30	0.45	0.60	0.75	0.90	1.05
Capacity charge	3.00	3.00	3.00	3.00	3.00	3.00
FOB cost	5.30	6.45	7.60	8.75	9.90	11.05
Shipping via Cape inc fuel*	2.51	2.51	2.51	2.51	2.51	2.51
CIF cost	**7.81**	**8.96**	**10.11**	**11.26**	**12.41**	**13.56**

*Source: Deutsche Bank *Were product to travel via the Panama Canal once opened in 2014 the charter saving would be c$1.00. We assume however that much of this will be offset by the toll charged to use the Canal. Separately, we note that current spot shipping rates would equate to a $2.00 increment on the costs indicated above ie at today's spot rates the effective cost of delivered LNG would be $11/mmbtu.*

Equally, where the broadening of supply sources and use of a non-oil proxy for price are both attractive features, committing to supply off-take does not come without significant risks and complications. Not least amongst these from our perspective are the following:

- **Price:** At a conceptual c.$10/mmbtu delivered cost (split $4.6/mmbtu gas, $3/mmbtu liquefaction and $2.5/mmbtu shipping), US sourced LNG may look an attractive supply option. But as the recent history of US gas prices has shown the commodity can be notoriously volatile.
- **Political risk:** Energy and energy independence are emotive subjects in US politics. Consequently, there must be buyer concern that US politicians might change their view on exports and act to rescind the export licenses that have been granted. Importantly, the terms of Cheniere's license specifically grant the US authorities this option.
- **Dry gas:** That US gas is dry and therefore of a lower calorific value than that used in many importing countries means that many Asian buyers would require the gas to be further treated with NGL's added to increase calorific value. Beyond complicating delivery requirements at c$0.4/mmbtu 'spiking' adds further to cost.
- **Capacity cost.** The US looks set to operate on a capacity basis with the liquefaction of LNG being undertaken by a utility, and the cost of the liquefaction process covered by the offtaker's commitment to pay an annual capacity charge over an

extended contract period – whether or not the economics of exporting work. At c$150m p.a. for each mtpa of committed liquefaction capacity the financial commitment required is, consequently, not modest. Moreover, those contracting will also have to have access to shipping, adding further to their committed cost.

Ultimately, none of these risks are likely to prove insurmountable. Yet they do appear sufficiently large to suggest that, where US sourced gas may come to represent an important portfolio option for many, buyers will be reluctant to leave themselves overly dependent upon this one market. To the extent that pricing of contracts outside North America shifts towards the use of Henry Hub as a price proxy this may, ultimately therefore, prove a far more attractive buyer's option.

Cargo flexibility – FOB and DES (or CIF)

Price and the sourcing of supply asides, contract prices are generally stated after the allowance of a negotiable charge for re-gas, location and trading, and an agreed cost for shipping. Contracts may be defined as free on board (FOB) or delivery ex-ship (DES also known as cost, insurance, freight or CIF).

- **Free on Board**. For FOB contracts, shipping will be organized by the buyer and the contract price paid will exclude the costs of shipping. Importantly, FOB contracts have no destination clause and as such no restrictions on where the cargo may be delivered. This flexibility represents a potential advantage to the buyer particularly if the LNG purchased is being taken into a portfolio for subsequent marketing.

Free on Board - shipping will be organized by the buyer

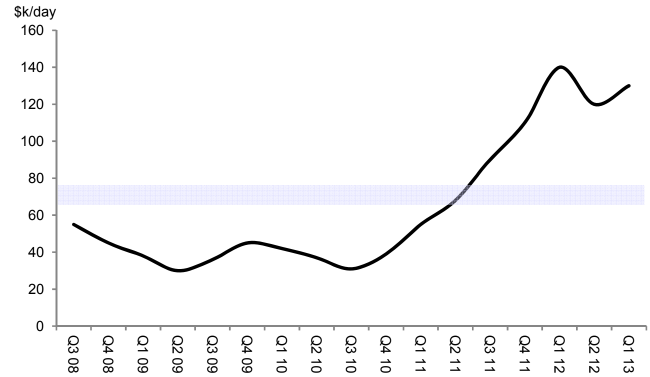
- **Delivery ex-Ship**. DES cargoes are generally written with a specific destination in mind. As such, they afford less flexibility than a FOB contract. Although the destination can be altered by mutual agreement, because the shipment will likely have to fit in with the supplier's pre-arranged shipping schedule and the use of its fleet of ships, altering the destination is likely to prove challenging particularly if it requires extending the number of shipping days required. Overall, contracts with a DES clause thus offer less scope for the purchaser to realise arbitrage opportunities through cargo re-direction.

DES cargoes are generally written with a specific destination in mind

Shipping of LNG

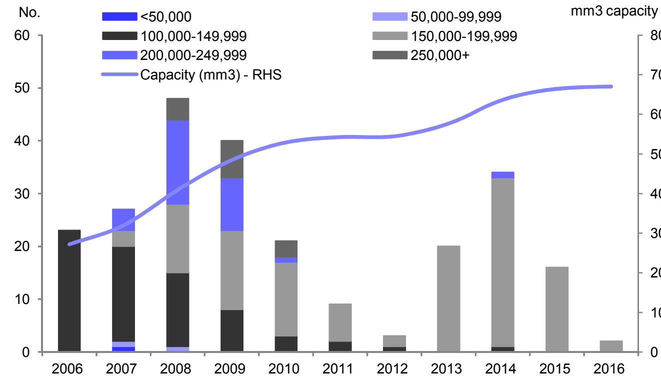
With the LNG market expected to show continued growth over the coming years demand for shipping is expected to expand significantly. A substantial recent increase in new builds suggests, however, that shipping availability is unlikely to be a limiting factor in the development of the LNG trade. Moreover, not only is the fleet expanding, shipping capacities are also increasing with the average new vessel size moving from c.138,000m^3 (c55kt LNG) today to nearer 170,000m^3 (c.70kt LNG) and beyond (the latest orders for the Qatari projects involve ships called the Q-Max with a capacity of some 260,000m^3 or c105kt LNG). Of today's fleet around 60% are based on a membrane design which incorporates multiple tanks with linings made from nickel steel. Of the remaining 40%, the vast majority incorporate a spherical design which features a containment tank that sits on supports on the hull of the ship. Given advances in the membrane design which allow for larger ships to be produced at lower cost, the vast majority of ships under construction today are of the membrane variety. Note that with 0.15% of the LNG cargo typically 'boiling-off' per day, today's shipping fleet is largely gas-fuelled and that a 15-20 day charter from Africa to the US will consume 2-3% of the cargo.

Figure 330: Freight rates at end 2012 were almost twice the long run average at c$130k/d



Source: Deutsche Bank; Fearnley Shipping

Figure 331: The build in capacity suggests that shipping should only prove a temporary bottleneck



Source: Deutsche Bank; Wood Mackenzie GLO

Charter rates fluctuate with the shipping cycle

In general, shipping rates are fixed with shipping provided either by the LNG project consortium's own fleet or via vessels chartered from dedicated shipping companies (e.g. Golar, Teekay, Bergesen, etc). There is however a spot market in ships, the charter prices of which tend to fluctuate with the supply cycle. Indicative rates for delivery into the US and elsewhere from various geographic points are shown in the figure below. Although the major oil companies do own their own ships or lease ships under long term charter, their shipping fleets have historically been relatively modest. As mentioned earlier this reflected their desire not to invest in assets with utility type returns. The emergence of a more global market in LNG and with it increasing opportunities for price arbitrage has, however, seen some build in the shipping fleets of the IOC majors, not least BG, BP and RDS.

Figure 332: Freight rates ($/ mmbtu) at end 2012 for 145,000m3 charter ship at $125k/day – almost twice the mid-cycle average of c$70k/day

Exporter/Destination	Trinidad	Nigeria	Algeria	Norway	Qatar	Australia	Malaysia	Russia
US Gulf	0.87	2.16	1.76	1.83	3.67	4.41	4.83	5.67
US East Coast	0.74	1.85	1.40	1.50	3.26	4.20	4.41	5.23
UK	1.33	1.47	0.58	0.63	2.41	3.49	3.52	4.32
Spain	1.43	1.37	0.28	1.12	1.94	2.99	3.03	3.81
India	3.24	2.45	1.97	2.92	0.55	1.35	1.30	2.10
China	4.41	3.36	3.26	4.26	1.93	1.07	0.80	0.72
Japan	4.80	3.73	3.63	4.65	2.27	1.32	0.93	0.44
Argentina	1.60	1.65	2.05	2.69	3.02	3.11	3.22	3.66
Chile	2.44	2.45	2.85	3.52	3.73	2.95	3.15	3.13

Source: Deutsche Bank

Re-gasification of LNG – facilitating access

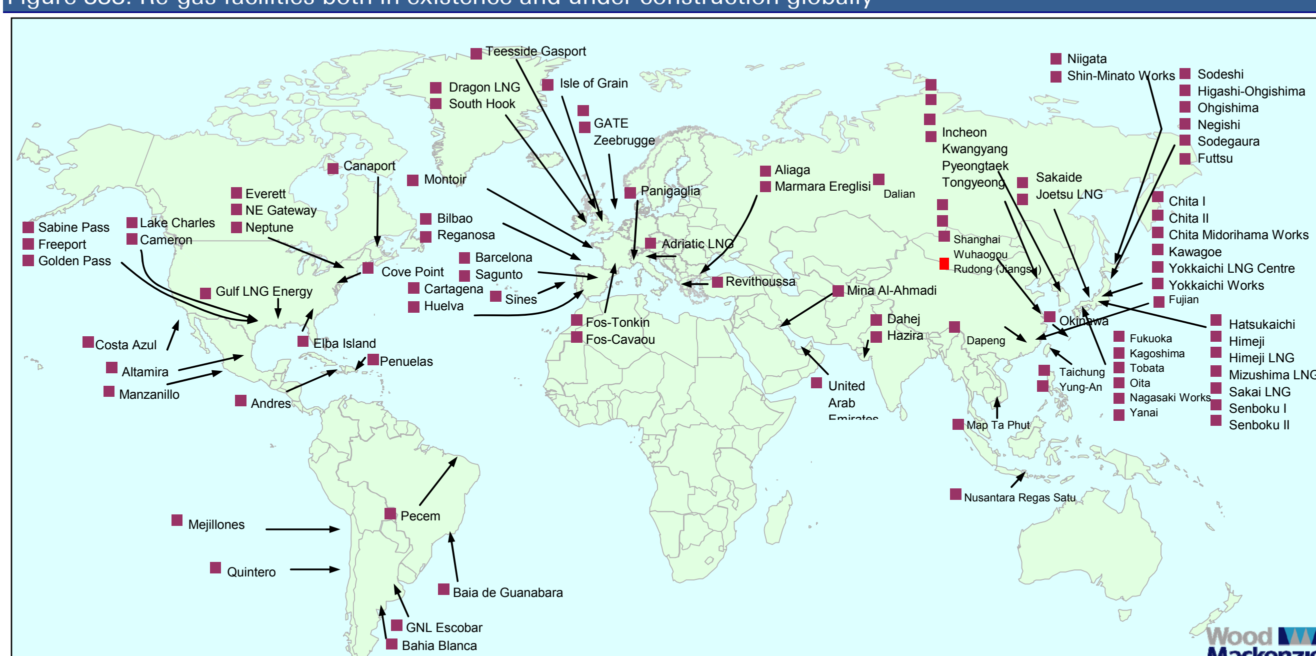
Re-gas capacity rights afford access to new markets

Given the utility nature of the re-gas business, investment in re-gasification facilities was for a long time eschewed by the integrated oil companies. To the extent that facilities were required they were either constructed by the consumers of gas or specialist utility companies. The opening of new markets for LNG not least the US, UK, China and India has, however, placed added importance on having re-gas capacity rights in order to access these new and emerging markets. Indeed, the establishment of new re-gas facilities in a multitude of new markets as countries seek alternative sources of gas supplies has proven one of the key drivers of incremental LNG demand growth. Moreover, through owning access rights in a multitude of different national markets, those companies involved in the marketing of LNG enhance their access to selected markets and have been able to:

- Take advantage of price discrepancies in different regional markets through diversion of cargoes (i.e. arbitrage price);
- Reduce dependence on any single market for the sale of their contracted gas;
- Argue for higher prices from customers given a range of end-market options;
- Negotiate more favourable terms of supply from upstream producers through maximizing the price achievable for the resource holder's gas.

In general, re-gas assets outside of the United States are likely to be owned either in full or in part by the companies with capacity rights. Local market regulators may, however, insist that a proportion of any facility's capacity remains available for all to use (i.e. grants open access rights) in order to ensure competition. By contrast, in the United States most of the facilities in existence at present are owned and operated by pipeline companies. Although these facilities are also termed 'open access', with firm capacity rights granted to companies that have subscribed to pay committed reservation fees for an agreed period (typically 20 years), the majority of facilities are in effect closed. These fees broadly cover the financing costs of the facility plus a return on capital that is regulated by the Federal Energy Regulatory Commission (FERC).

Figure 333: Re-gas facilities both in existence and under construction globally



Source: Wood Mackenzie

Floating LNG (FLNG) – Exactly what it says on the tin

Conventional LNG projects involve an onshore liquefaction plant where the raw gas is processed, liquefied and stored prior to loading onto LNG tankers for transport to overseas markets. However, for certain types of gas resource – be it because of scale or location – processing via an onshore facility is often not possible either by virtue of the economics or because the gas discovery is too remote.

One solution to these issues is clearly to take a page out of the oil industries books and, akin to the FPSO, seek to develop mobile facilities located on a ship. Floating LNG (FLNG) thus seeks to place the liquefaction plant on a floating vessel. At present there are no operating FLNG facilities and the technology remains unproven on a commercial basis. In May 2011 Shell, however, took the first final investment decision on its 3.6mtpa Prelude. Constructed in Korea by Technip and Samsung, with whom Shell signed an agreement for the delivery of up to 8 modules over the next 20 years, Prelude is expected to be the first commercially operating FLNG facility upon its anticipated delivery in 2017.

There are several reasons why FLNG is proposed as an alternative to conventional land-based liquefaction facilities. These include:

- Potentially lower costs than conventional projects
- No requirements for trunklines from offshore fields to an onshore liquefaction facility as the FLNG vessel is anchored directly above the fields
- An ability to monetize remote or smaller fields that would remain stranded using conventional methods
- Potentially lower environmental impacts given no onshore plant footprint

However there remain several challenges to FLNG that are also discussed later in this report, but include:

- Technology is unproven, there are currently no operating FLNG projects
- Technical challenges associated with liquefying gas on a moving vessel such as sloshing in storage tanks
- Willingness of buyers to accept unproven and challenging technology when contracting
- Limited economies of scale – FLNG cannot be expanded to multiple trains as easily as land-based facilities

Figure 334: Small scale vs Large scale LNG

	Small Scale FLNG	**Large Scale FLNG**
Target field size	0.5 - 2tcf	2 - 5tcf
Facility size	1-1.5mmtpa	2-4mmtpa
Motivation for development	Monetise reserves too small for conventional LNG Generally regarded as quicker and cheaper than convetional LNG	Demonstrate LNG capability Monetise reserves too remote for conventional LNG Generally not regarded as cheaper or quicker than conventional LNG
Key Australian players	Flex LNG, Golar LNG	Shell, GDF SUEZ

Source: Deutsche Bank

Ultimately the success of FLNG has yet to be proven. Success at Prelude, however, and we would expect FLNG to become an increasingly significant basis for LNG production.

Existing LNG facilities and facilities planned 2013-18

Figure 335: LNG facilities – Onstream and planned 2013-18

Project	Location	Start up	Trains	Capacity	Value resides	Upstream Participants	Liquefaction Participants
Adgas	Abu Dhabi	1977	3	5.6	Liquefaction	ADNOC	BP 10%; Total 5%; Mitsui 15%
Algeria LNG	Algeria	1964	18	19.9	Integrated	Sonatrach	
Angola LNG	Angola	2012	1	5.0	Liquefaction	ENI (13.6%), Chevron (36.4%), BP (13.6%), Total (13.6%), Sonagas (22.8%)	
Arun	Indonesia	1978	6	9.0	Upstream	Exxon 100%	Tolling
APLNG	Australia	2016	2	9.0	Integrated	Conoco (42.5%); Origin (42.5%); Sinopec (15%)	
Atlantic LNG 1	Trinidad	1999	1	3.3	Integrated	BP 70%; Repsol 30%	BP 34%; BG 26%; Repsol 20%
Atlantic LNG 2 & 3	Trinidad	2002	2	6.8	Upstream	BP 44%; Repsol 19% BG 18%	BG 33%; BP 43%; Repsol 25%
Atlantic LNG 4	Trinidad	2006	1	5.2	Upstream	BP 49%; Repsol 21%; BG 14%; Chevron 10%	BP 38%; BG 29% Repsol 22%
Bontang	Indonesia	1977	8	22.2	Upstream	Total 38%; Inpex 38%; CVX 17%; ENI 4%; BP 1%	Tolling
Brunei	Brunei	1972	5	7.2	Shared	NOC 49%; Shell 49%; Total 2%	NOC 50%; Shell 25%; Mitsubishi
QGC LNG	Australia	2014	2	8.5	Integrated	BG (93.75%), CNOOC (5%), Tokyo Gas (1.25%)	BG (93.75%), CNOOC (5%), Tokyo Gas (1.25%)
Damietta	Egypt	2005	1	5.1	Upstream	BP/BG/Petronas/NOC (mixed)	Union Fenosa 80%;
Darwin	Australia	2006	1	3.2	Integrated	COP 57%; ENI 12%; Santos 11%; Inpex 11%	
EG LNG	Eq. Guinea	2007	1	3.7	Upstream	Marathon 64%; Nobel 34%	Marathon 60%; GE Petrol 25%; Mitsui 8.5%
ELNG	Egypt	2005	1	3.6	Upstream	BG 50%; Petronas 50%	BG 36%; Petronas 36%;
ELNG 2	Egypt	2005	1	3.6	Upstream	BG 50%; Petronas 50%	BG 38%; Petronas 38%
GLNG	Australia	2014	2	7.8	Integrated	Santos (30%) Petronas (27.5%); Total (27.5%); KOGAS (15%)	
Gorgon LNG	Australia	2014	3	15.0	Integrated	Chevron (50%), Exxon (25%), Shell (25%)	
Ichthys	Australia	2017	2	8.5	Integrated	Inpex (70%); Total (30%)	
Kenai	Alaska	1969	1	1.5	Upstream	COP 70%; Marathon 30%	
Marsa El Brega	Libya	1971	1	3.7	Integrated	NOC 100%	
MLNG	Malaysia	1983	3	8.1	Shared	Shell 50%; Petronas 50%	Petronas 90%
MLNG Dua	Malaysia	1995	3	7.8	Shared	Shell 50%; Petronas 50%	Petronas 60%; Shell 15%; Mitsubishi 15%
MLNG Tiga	Malaysia	2003		7.4	Shared	Shell 28%; Petronas 25%; Nipon Oil 48%	Petronas 60%; Shell 15%; Nippon 10%
NLNG (Bonny) 1-6	Nigeria	1999	6	22.2	Liquefaction	Shell 17.5%; Total 13%; ENI 8%	Shell 26%; Total 15%; ENI 10%
North West Shelf 1-5	Australia	1989	5	16.2	Integrated	Woodside; BHP; BP; Shell 17% each; CNOOC 22%	
Oman LNG	Oman	2003	2	7.1	Liquefaction	NOC 100%	NOC 51%; Shell 30%; Total 6%
Peru LNG	Peru	2010	1	4.5	Integrated	Pluspetrol 27%, Hunt Oil 25%, Repsol 10%	Hunt Oil 50%, Repsol 20%, SK 20%, Marubeni 10%
PNG LNG	Pap New Guinea	2014	2	6.6	Integrated	Exxon (33.2%), Oil Search (29%), Santos (13.5%), PNG Gov (19.2%)	
Pluto LNG	Australia	2011	1	4.8	Integrated	Woodside 90%, Kansai 5%, Tokyo 5%	Woodside 90%, Kansai 5%, Tokyo 5%
Prelude LNG	Australia	2017	1	3.6	FLNG	Shell (70%); Inpex (30%)	
Qalhat LNG	Oman	2006		3.4	Liquefaction	NOC 100%	NOC 66%; Shell 11%; Union Fenosa 7%
Qatar Gas 1	Qatar	1999	3	9.7	Liquefaction	Total 20%; XOM 10%	Total 10%; XOM 10%

Source: Wood Mackenzie data; Deutsche Bank k

Figure 336 (Continued): Existing LNG Facilities, capacities and major upstream and mid-stream participants

Qatar Gas 2	Qatar	2009	2	15.6	Liquefaction	Total 8.4%, QP 67.5%, XOM 24.2%	
Qatar Gas 3	Qatar	2010	1	7.8	Liquefaction	QP 70%; Conoco 30%	
Qatar Gas 4	Qatar	2011	1	7.8	Liquefaction	QP 70%; Shell 30%	
Ras Gas 1	Qatar	1999	2	6.6	Integrated	QP 63%; XOM 25%	
Ras Gas 2	Qatar	2004	3	14.1	Integrated	QP 70%; XOM 30%	
RL 3	Qatar	2010	2	15.8	Integrated	QP 70%; XOM 30%	
Sabine Pass	USA	2015	4	18.0	Liquefaction	Cheniere 100% capacity	
Sakhalin	Russia	2009	2	9.6	Integrated	Gazprom 50%, Shell 27.5%, Mitsui 12.5%, Mitsubishi 10%	
Snohvit	Norway	2007	1	4.2	Integrated	Statoil 34%; Total 18%; Hess 3%; GdF 12%	
Tangguh	Indonesia	2009	2	7.6	Upstream	BP, Nippon Oil, CNOOC, Mitsubishi, Talisman	Tolling (Gov Indonesia)
Wheatstone	Australia	2016	2	8.9	Integrated	Chevron 72%; Apache 13%; Shell 6%; KUFPEC 7%	
Yemen LNG	Yemen	2009	2	6.6	Liquefaction	Total 50.6%, Hunt Oil 22%; SK 12.2%; Kogas 7.7%, Hyundai 7.5%	

Source: Wood Mackenzie data; Deutsche Bank ***Some useful LNG conversion factors***

1 million tonnes LNG = 49.74bcf = 51.69mmbtu = 1.41bcm = 8.59mboe in gas form

1 metric tonne LNG = 2.193 cubic metres LNG (m^3) = 77.5 cubic feet LNG in liquid form

1mtpa LNG = 49.7bcf natural gas = 136mscf/d natural gas = 23kboe/d

LNG - The IOCs Portfolios and Positions

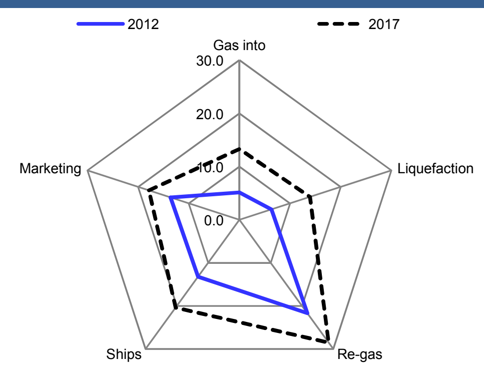
Over the following pages we depict the relative positions of the major international oil companies in the markets for LNG

Over the following pages we depict the relative positions of the major international oil companies in the markets for LNG. In doing so we have used Wood Mackenzie data to assess their position across all aspects of the LNG chain in 2012, as well as the anticipated position by 2017. Importantly, the charts emphasize that, for those with resource, the bias of their investment focus remains its monetization. Investment in downstream markets is, however, evidently becoming a more important feature with some market participants (BG Group) clearly focused on building a strong presence in this area of the chain.

Shell the clear leader – but watch Chevron

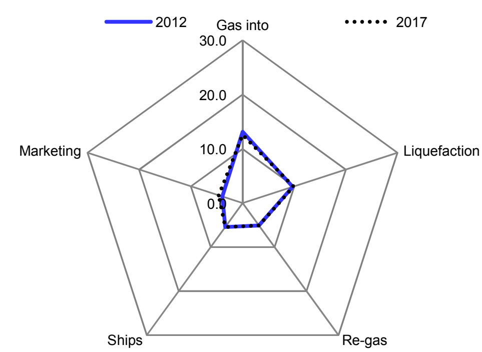
Given its long history of involvement in LNG most significantly in Asia, Shell looks set to remain the undisputed industry leader. Total's long history in LNG combined with recent excellent success at accessing new gas resource suggests that its business should see accelerated growth - a statement that also holds true for Exxon which benefits significantly from its strong presence in Qatar. The most significant shift however is that for Chevron which as it seeks to monetise its abundance of Australian resource is expected to see a near 17mtpa addition of capacity by 2017.

Figure 337: BG Group – Well rounded growth throughout



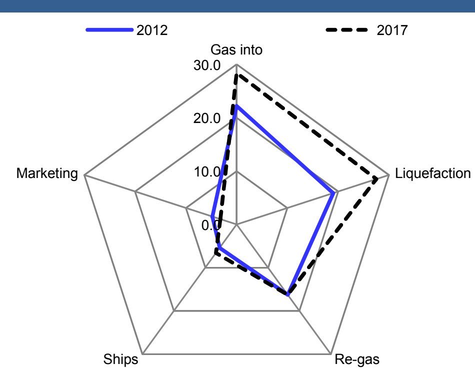
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 338: BP – No progress envisaged through 2017



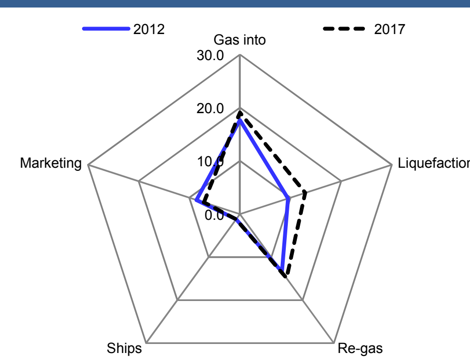
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 339: Shell – Big push upstream, trading static



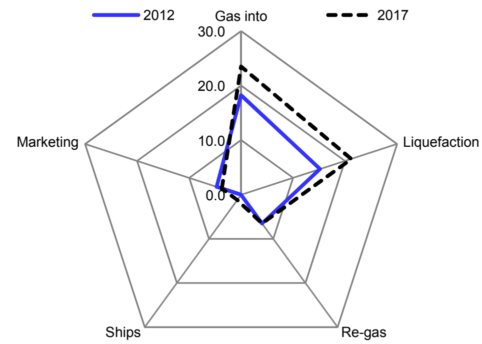
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 340: Total – Upstream progress but slowing



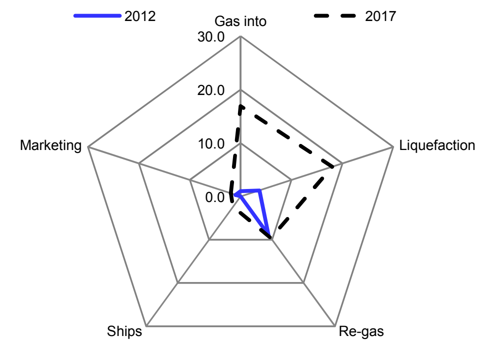
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 341: Exxon – Steady growth, no trading



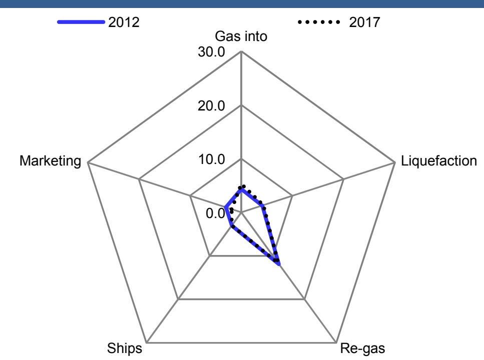
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 342: Chevron – From nowhere to major player



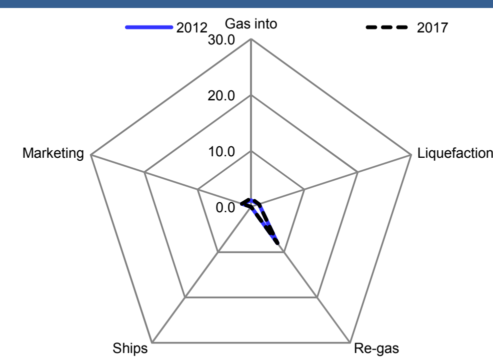
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 343: ENI – Too early for Mozambique



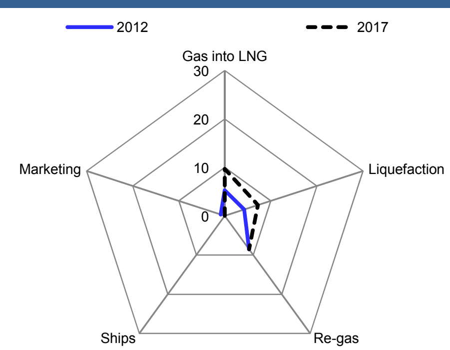
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 344: Statoil – No progress over 2012



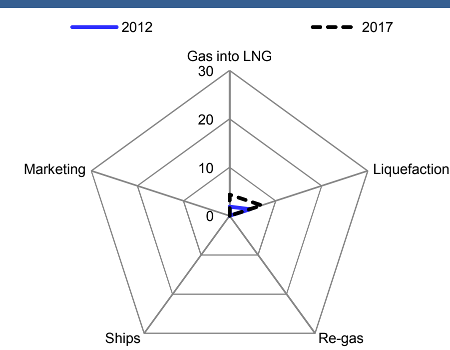
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 345: Conoco – Modest expansion through APLNG interests



Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

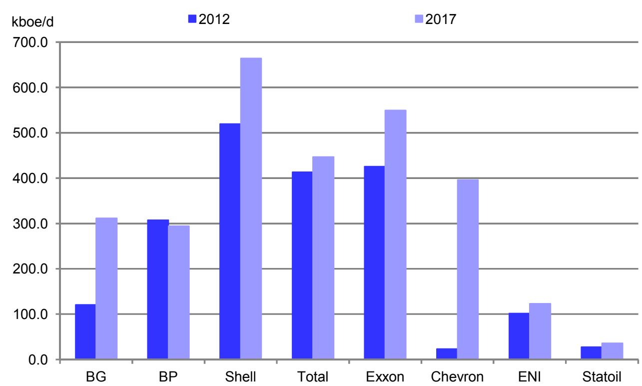
Figure 346: Woodside – Australian leader but still modest in a global context



Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

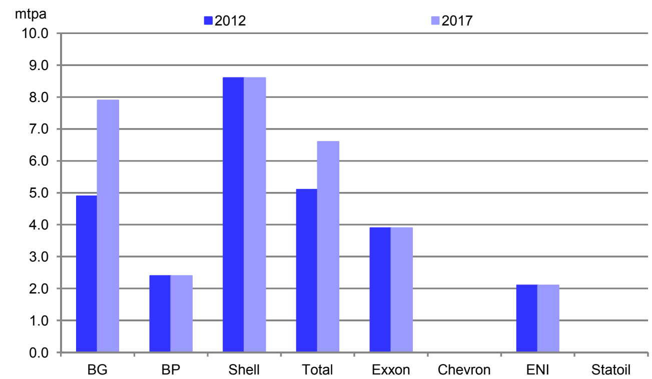
Comparing and contrasting the LNG majors – Side by Side

Figure 347: Gas into LNG in kboe/d – Shell leads but Chevron and BG are the huge movers



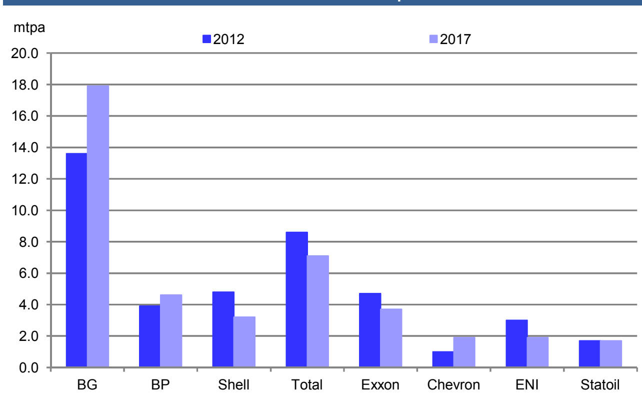
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 348: Re-gas capacity ex US (mtpa) – the broader, the greater the options for access. Shell, Total and BG



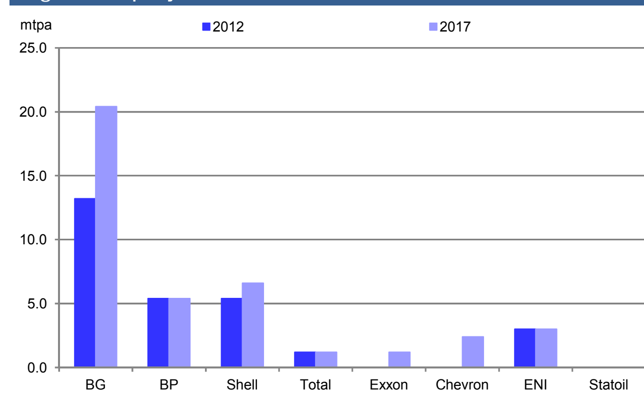
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 349: Marketing volumes (mtpa) – Only BG grows as Sabine Pass volumes start to impact



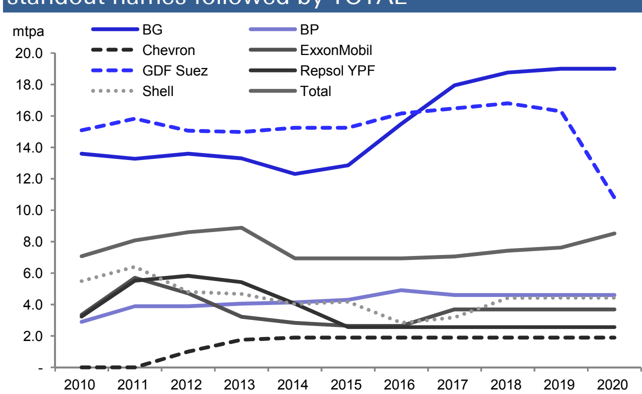
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 350: Shipping capacity (mtpa) – Excludes ships aligned to projects but BG the stand out trader



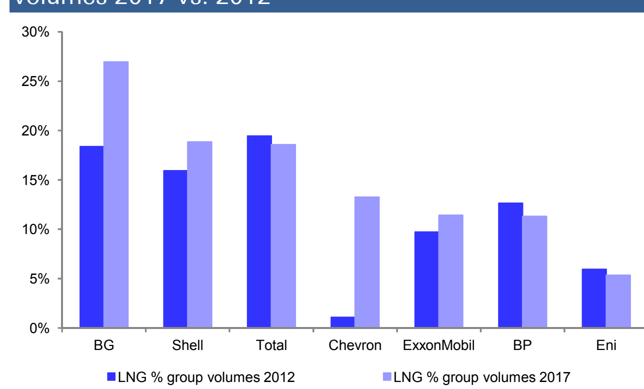
Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 351: Portfolio LNG: BG and GDF remain the standout names followed by TOTAL



Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Figure 352: The LNG majors: LNG production as % group volumes 2017 vs. 2012



Source: Deutsche Bank; Wood Mackenzie data; all numbers in mtpa

Deepwater

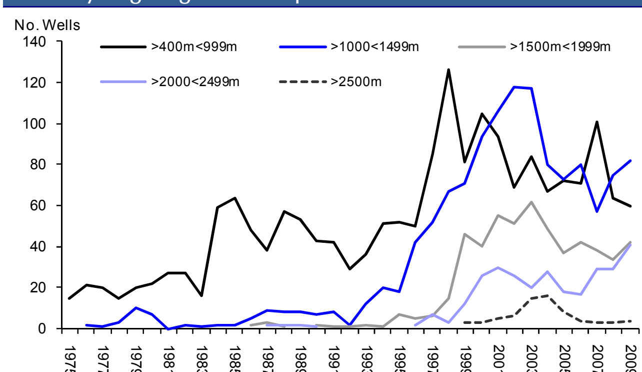
Peering into deepwater

Deepwater refers to oilfield exploration and development in water depths greater than 1000m. The cut off is arbitrary and chosen by us

Historically, the deepwater has incorporated offshore exploration at water depths of over 400m. In truth, however, it could be argued that the deepwater is still evolving with the boundary shifting as the industry has become ever more adept at pushing the absolute depth of the waters in which it can drill. Thus where drilling at around 1000m's offshore Nigeria in the mid to late 1990s was perceived as cutting edge, today drilling at depths of towards 2000m's could almost be described as commonplace. This is perhaps well illustrated by the below charts which depict the number of exploration and appraisal wells drilled annually at depths of over 400m. Evident from these is the progressive build in depth, with E&A drilling moving from depths of 400ms to nearer 1000ms by the early 1990s and then towards 2000m's at the start of the last decade.

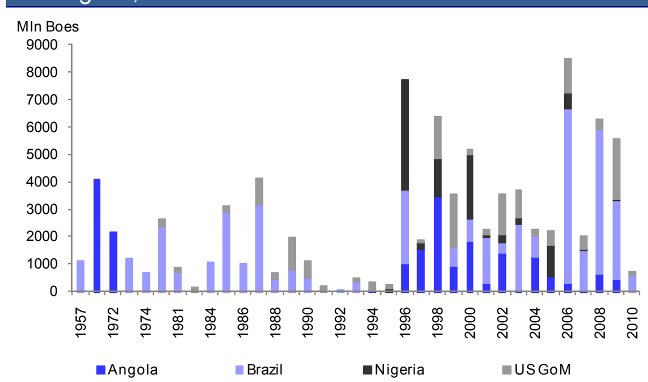
Developing these fields has been crucial to the world's oil supply, has provided diversification away from OPEC, given the IOCs a major new play to focus on and has driven step changes in oil service company capabilities. Three areas currently dominate the world's deepwater; the US GoM, Brazil and West Africa (Angola and Nigeria).

Figure 353: Global deepwater wells 1975-2010 – the industry is going ever deeper



Source: Wood Mackenzie data; Deutsche Bank

Figure 354: Deepwater discoveries, US GoM, Brazil, Angola and Nigeria, 1957-2010

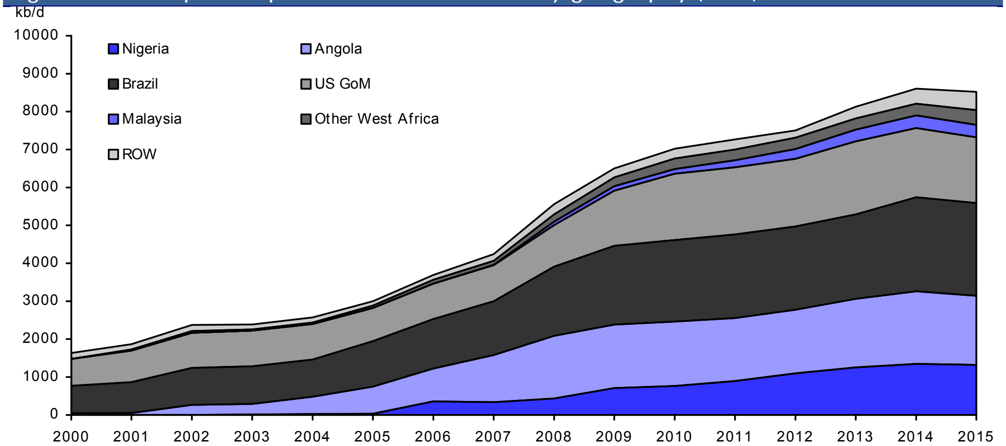


*Source: Wood Mackenzie; Deutsche Bank *includes all discoveries in depths of water over 1000 metres where recoverable oil resource is greater than 50mbbls*

Brazil and the US GoM have been producing from deepwater fields since the early 1990s, in line with the fact that deepwater fields were discovered in these regions some 12 years before the West African discoveries, as shown in the right hand figure above. More recent growth has seen worldwide deepwater production rise to an expected 8mb/d in 2013, a four-fold increase on the production levels at the start of the decade. West Africa has been the engine of this growth, with Angola and Nigeria being by far the dominant contributors.

- The surge in deepwater production witnessed since 2000 is mainly due to the exploration efforts of the IOCs in Angola and Nigeria from 1996 onwards.
- Although 2004/05 were disappointing years for deepwater exploration by recent standards, the discovery of Brazil's 5-8bn Tupi field by Petrobras in '06 is the largest DW discovery ever. This was followed by further large discoveries (Jupiter and Iara) and more recently Zaedyus in French Guyana.
- The US GoM also continues to surprise with several discoveries each year, although the average DW discovery size in the region is c.265mmbbls versus an average range of 375-721mmbbls found in Brazil, Angola and Nigeria.

Figure 355: Deepwater production 2000-2015e by geography (kb/d)



Source: Wood Mackenzie, Deutsche Bank estimates

Technically tough

Notwithstanding the increased interest in developing deepwater resources, DW remains at the high risk, complex end of the oil field development spectrum. The technical challenges are numerous and range from simply having a rig able to hold its station in 2000m of water to ensure subsea valves, pumps, electrical and hydraulic equipment can work non-stop for 20+ years at close to 0˚C whilst under 3000psi of external pressure. The technically challenging nature of deepwater operations has led to some high profile disasters (most recently the US GoM Macondo oil spill disaster); numerous E&C companies came close to bankruptcy in the early 2000s due to ill-advised bids on platforms, FPSOs and SURF installations, Petrobras watched in dismay as its flagship P36 platform sank in 2001 (the largest platform in the world at the time) and delays to other flagship projects have occurred all too frequently.

The leading source of industry barrel growth

2010 production of c.7mb/d is only c.8% of worldwide consumption, however from the IOCs perspective the deepwater is far more important that this statistic might suggest

However, despite these risks the success of the industry's exploration initiatives and reserves growth has meant that the deepwater has become an increasingly important source of barrel growth and not just for the IOCs involved. Illustrated in the table below, data from Wood Mackenzie suggests that of the three main sources of global oil production (onshore, shallow water and deepwater), it is the deepwater which has been the key driver of production growth over much of the past decade. Moreover, in a global oil market that is expected to increase its production capacity by around 2% on average over the period to 2015, supply from the deepwater is expected to advance by closer to 9% with barrels sourced from depths of over 400m estimated to account for almost 10% of global supply by 2015 compared with only 2% in 2000. As such, from a supply and consequently oil price perspective, continued development of the DW would appear to be absolutely central to the oil industry's ability to meet the anticipated growth in demand of an energy hungry world.

Figure 356: The deepwater is the fastest growing source of forecast oil production

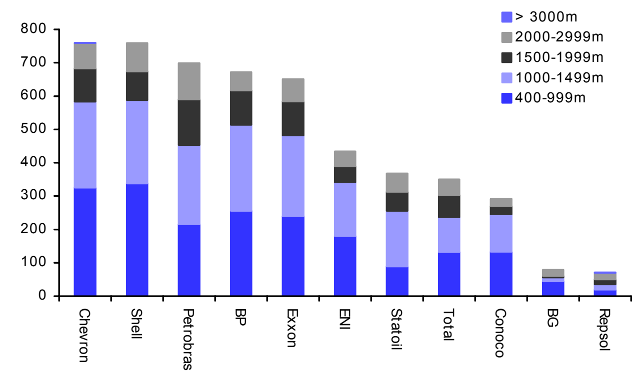
	2000	2010	2015	2020	10-yr CAGR	CAGR 10-15	CAGR 10-20
Onshore	49702	54362	64850	66959	1%	4%	2%
Shallow	21391	20241	23187	21756	-1%	3%	1%
Deep	1724	5388	7501	10490	12%	7%	7%
Other/YTF	1747	2362	-723	2144	3%	-179%	-1%
Total	74564	82354	94814	101349	1%	3%	2%

Source: Wood Mackenzie; Deutsche Bank YTF = yet to find

Perhaps surprisingly, from a geographic perspective the source of these barrels is also very concentrated. Illustrated below deepwater oil production is, in effect, dominated by production from just four main regions namely the US GoM, Brazil, Angola and Nigeria with the four estimated to account for over 90% of current deepwater output. Equally, while the emergence of new deepwater territories is expected to see new sources of production emerge, not least from West Africa, their impact on the overall deepwater market is likely to remain relatively modest, with the major four regions accounting for a still substantial 86% of estimated 2015 deepwater production. For the Governments of these four countries the deepwater has proven, and is likely to remain, a very important source of tax revenues.

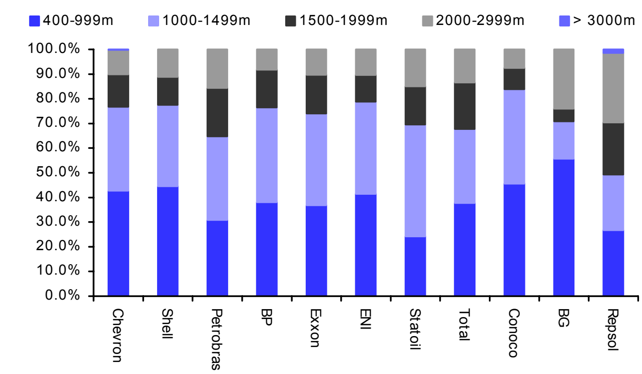
Clearly the deepwater has been an important source of reserves growth and oil production. Equally apparent is that it has very much been the major oils that have been responsible for much, if not all, of the exploration activity undertaken.

Figure 357: Number of IOC operated wells at depths of >400m 1975 - 2010



Source: Wood Mackenzie; Deutsche Bank

Figure 358: Analysis of the percentage of total wells driven by depth (IOC's only)



Source: Wood Mackenzie; Deutsche Bank

Illustrated above, we show both the absolute number of deepwater (>400m) wells drilled by the major IOCs graded by depth together with the distribution of those wells. Evident from this is that despite the often very different portfolios of the companies, their deepwater experience relative to absolute scale is similar both in terms of the number of E&A wells drilled and the range of depths to which they have drilled. Thus, with the exception of Total which is disadvantaged by its more limited exposure to the US GoM, each of the super majors has typically drilled between 650-750 deepwater wells, over 60% of which have been at depths of over 1000m. Relative size would also not appear to have proven a disadvantage compared to relative depth, Repsol for example appearing to have been involved in the drilling of more well at depths of >1000m than near all of its peers.

The deepwater accounts for c11% of IOC reserves…

More importantly, however, the international industry's success at discovering and developing resources has meant that the deepwater now accounts for a material proportion of most of the larger companies reserve bases and upstream asset values. Based on Wood Mackenzie data we estimate that the deepwater now accounts for around 11% of the major Western companies' 2P reserves. Evident is that in absolute terms BP accounts for more deepwater barrels than any of its super-major peers predominantly as a consequence of its dominance in the US GoM. As a percentage of its overall resource base its exposure to the deepwater is around twice the average at 18%. BG's success in Brazil has resulted in a very significant increase in its exposure with an estimated 46% of its 2P reserves base located in the deepwater, something which has similarly increased the deepwater exposure of Repsol relative to its peers. Interesting also is the relative under-representation of both Shell and Exxon, the deepwater accounting for a relatively modest c7% of each company's 2P reserves base not least given the typically greater breadth of these companies' upstream portfolios.

Figure 359: Reserves (WoodMac 2P entitlement) by Deepwater province (2012)

	US GoM	Brazil	Angola	Nigeria	Malaysia	Deepwater	Total portfolio	% deepwater
BP	2986	208	1122			4316	21173	20%
Shell	1822	165		842	171	3000	30546	10%
Exxon	662		1142	621		2425	39135	6%
Chevron	1471	321	699	669		3160	25768	12%
Total	127		1391	532		2050	16598	12%
BG		4631				4631	10037	46%
ENI	392		611	282		1285	13404	10%
Statoil	653	484	642	60		1839	16489	11%
Repsol	144	527				671	3555	19%
Conoco	217				293	510	16196	3%
Total	**8474**	**6336**	**5607**	**3006**	**464**	**23887**	**192901**	**12%**

Source: Wood Mackenzie; Deutsche Bank

…but nearer 17% of upstream value

What is also clear, however, is that whilst the deepwater may only account for 11% on average of the major IOCs upstream reserves, the value of the deepwater barrel is significantly greater than that of the average portfolio barrel. In part this no doubt reflects the greater technical and geological risks associated with their recovery together with the higher capital costs associated with DW development relative to the onshore and shallow water. Illustrated below, using Wood Mackenzie data and a long run (2014) oil price of $100/bbl we estimate that on average the deepwater accounts for 19% of the companies' upstream portfolio value with the average barrel worth an estimated $15/bbl against a portfolio average of nearer $9/bbl (and this despite the strong development bias of those barrels located in Brazil and the consequent dilutive effect of their markedly lower average value).

As with reserves what is immediately evident is the much greater exposure of BP's upstream value to its success in the deepwater, predominantly as a consequence of its weighting towards the US GoM. At 28% of estimated upstream value BP's exposure to the deepwater is almost twice the average, reflecting the company's strategy of concentrating on dominating major production basins and its deepwater expertise. BG's recent success in Brazilian deepwaters also means that BG now has greater deepwater exposure than any of its peers whilst Repsol's is also well above average. Otherwise, Conoco is notable for its very limited deepwater exposure with the deepwater also accounting for a below average proportion of Shell and Exxon's upstream value.

Figure 360: Value ($m) by deepwater province*

Company	US GoM	Brazil	Angola	Nigeria	Malaysia	Total DW value	Upstream Value	DW as % Total
BP	46564	2516	20851			69931	196313	36%
Shell	26314	3436		12566	1665	43981	285586	15%
Exxon			18709	13529		32238	291629	11%
Chevron	19777	6434	7117	17080		50408	258032	20%
Total	2357		21872	9937		34166	147815	23%
BG		31211				31211	71256	44%
ENI	5743		7765	3944		17452	131364	13%
Statoil	8021	6829	12564	3374		30788	127451	24%
Repsol		5642				5642	23045	24%
COP	1893				2851	4744	114849	4%
Total	**110669**	**56068**	**88878**	**60430**	**4516**	**320561**	**1647340**	**19%**
Average barrel value ex PB	***13.06***	***8.85***	***15.85***	***20.10***	***9.73***	***13.42***	***8.54***	***157%***

*Source: Wood Mackenzie; Deutsche Bank *Assumes an oil price of $100/bbl escalating at 2% from 2015.*

NGLs and condensates

A valuable by-product

Condensates and natural gas liquids (NGLs) are a valuable by-product from gas production. As gas is produced and travels down a pipeline (or even as it travels up the well), within a short distance it will cool down to a point where the heavier hydrocarbons (C4 to C11+) it contains will liquefy and the gas will become a mixture of gas and condensate, also known as 'wet gas'.

Condensate and NGLs are very similar, with the main difference being that condensates contain longer chain hydrocarbons

The wet gas is passed into a vessel known as a field separator which separates out the wet gas into gas and 'condensate'. This is a simple process (an expansion vessel) and invariably some hydrocarbons heavier than methane (C1) or ethane (C2) remain in the gas. These residual liquids are recovered by a dedicated gas processing plant and are known as 'natural gas liquids', or NGLs. Condensate and NGLs are very similar, with the main difference being that condensates contain slightly longer chain hydrocarbons. The two are often blended together and contain hydrocarbons ranging from C2-C11+, i.e. including ethane, butane, propane, pentane and other hydrocarbon compounds, including gasoline-range molecules.

Its all oil from a supply/demand perspective

When people talk about world oil production, they are nearly always referring to crude AND NGL/condensate production. The BP statistical review rolls the figures into one number and the IEA monthly oil report also discusses world oil supply with NGLs included. This makes sense, since like crude oil, NGLs and condensates ultimately end up satisfying liquid hydrocarbon demand. From a processing perspective NGLs can be thought of as just another blend of crude, and indeed sell for roughly 70% the price of Brent on a per barrel basis.

NGLs are an important part of the industry; they account for c.7% of world 'oil' supplies, 70% of ethylene feedstock and c.10% of US motor gasoline requirements.

The main constituents of condensates and NGLs are:

- **Ethane (C_2H_6):** mainly used as feedstock for ethylene production – the building block for the bulk of the worlds plastics.
- **Propane (C_3H_8):** is readily liquefied by compression and cooling and used as a fuel and chemical feedstock. It can be found in cigarette lighters, portable stoves and lamps.
- **Normal Butane (C_4H_{10}):** is also easily liquefied at room temperature by compression. It is used as a gasoline additive, fuel and as chemical feedstock. Propane and butane are also known as liquid petroleum gas, or **LPG**.
- **Iso-butane (C_4H_{10}):** is used in the manufacture of MTBE (methyl tertiary butyl ether), a high octane additive for reformulated gasoline, as a petrochemicals feedstock and more recently as a refrigerant (replacing freon).
- **Natural Gasoline:** a gasoline blending component used as a refinery intermediate feedstock, crude diluent and as a petrochemical feedstock.

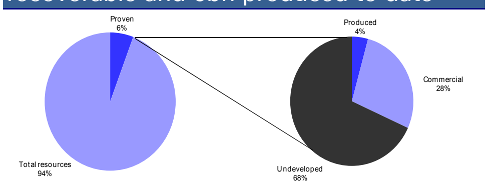
Canada's Oil Sands

A huge unconventional resource

An estimated 170bn barrels of recoverable oil lie in the sand, water and clay of Northern Alberta.

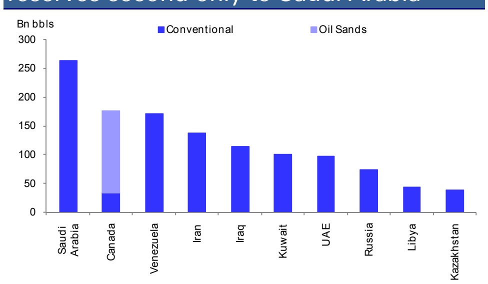
Canada's oil sands represent the largest single undeveloped, discovered, oil resource globally. All told, an estimated 170bn barrels of recoverable oil lie in the sand, water and clay of Northern Alberta. These reserves are second in size only to Saudi Arabia and 50% greater than those of Iraq. Moreover, with an estimated total resource of as much as 2.5 trillion barrels, huge potential exists for technological improvements to further enhance the extent to which this resource can ultimately be recovered.

Figure 361: Of 2.5trillion bbls, 143bn are recoverable and 6bn produced to date



Source: BP Statistical Review, Wood Mackenzie

Figure 362: Oil sands mean Canada has reserves second only to Saudi Arabia



Source: BP Statistical Review June 2010

Three locations, two principle extraction techniques

Oil sands represent heavy and thick deposits of bitumen-coated sand. They are found in three different deposits in northern Alberta; Athabasca; Peace River and Cold Lake, which extends into neighbouring Saskatchewan (see map). In contrast with conventional crude oil which flows naturally or is pumped from the ground, the bitumen from oil sands must be mined or recovered in situ (i.e. the bitumen will be extracted in place rather than mined and extracted subsequently). The Athabasca deposit which is the largest of the three has the highest concentration of developments, a feature which in large part reflects the fact that it is the only one shallow enough to be suitable for surface mining. This can be done at depths of up to 75 metres. However, at depths of greater than this mining becomes uneconomic and alternative 'in-situ' methods are required. Two methods of in-situ extraction are used; steam assisted gravity and drainage (or SAGD) and cyclic steam stimulation (CSS). Of these, SAGD's higher recovery rates mean it is by far the most frequently used. Of the current reserves base 80% are expected to require in-situ extraction.

This is not crude oil – it is low value bitumen

Compared with conventional production methods, the oil sands are very capital intensive and expensive to extract requiring significant energy. This is particularly true of the in-situ processes which require a mscf of natural gas for every barrel of bitumen recovered. The bitumen produced is also not suited to the North American refining market, its very low API (under 10°) requiring specialist refineries. Consequently it sells at a substantial ~$25/bbl discount to WTI. Most of the current mines therefore have invested in expensive upgraders. This second and separate process takes the bitumen and upgrades it to create a lighter product with similar characteristics to conventional crude oil. Dependent upon location the resulting synthetic crude oil or syncrude as it is commonly termed, should theoretically sell at a similar price to WTI.

Given all of this it is perhaps surprising that the oil sands should be of such interest to producers. However, in an era of high prices and political uncertainty Canada represents a haven of stability. Moreover, the fiscal terms available have proven by and large attractive and largely stable with the Alberta authorities encouraging investment. This and the outlook for production are discussed further in the Countries section.

Figure 363: Canada's Alberta – Home to the oil sands and the location of the three key deposits

Source: Wood Mackenzie

Methods of Extraction – Mining

About 10% of the Athabasca oil sands, accounting for an area of c.3,400km^2, are covered by less than 75 metres (250 feet) of overburden making them readily accessible for mining. The overburden consists of 1 to 3 metres of water-logged muskeg on top of 0 to 75 metres of clay and barren sand, while the underlying oil sands are typically 40 to 60 metres thick and sit on top of relatively flat limestone rock.

The oil sands are mined using truck and shovel methods

The oil sands are mined using truck and shovel methods, 100 ton power shovels lifting the sands into 400 ton trucks for transport to an ore preparation plant. Here the untreated oil sands are crushed and mixed with hot water and caustic soda to create a slurry before moving on to an extraction facility where it is agitated. The combination of hot water and agitation releases bitumen from the oil sand and, by allowing small air bubbles to attach to the bitumen droplets, the bitumen floats to the top of the separation vessels as a froth which can be skimmed. After further treatment to remove any remaining water and fine solids, the bitumen is diluted with lighter petroleum (typically naphtha or paraffin) to allow it to flow (this can require as much as 40% dilution) after which it can be transported by pipeline as low value, 'dilbit' for upgrading.

Overall, around 90% of the bitumen can be recovered from sand with about two tons of tar sands required to produce one barrel (roughly 1/8 of a ton) of oil. Separate to the extracted bitumen, the remaining tailings are then thickened by dewatering before being returned for reclamation with the warm water recovered re-entering the extraction process. The diluted bitumen or dilbit is then transported via pipeline to an associated upgrader. At the present time, all of the Alberta mining projects except Exxon's Kearl have associated upgraders.

Figure 364: Mining Canadian Oil sands projects – existing and planned

Project	Status	Start-up	Reserves (mmbls)	Peak (kb/d)	Main Participants	Method
Suncor Mine	Onstream	1967	2,975	280	Suncor Energy* (100%)	Mining with Upgrader
Syncrude	Onstream	1978	6,850	405	Syncrude JV (See note below)	Mining with Upgrader
AOSP	Onstream	2003	3,600	285	Shell* (60%), Chevron (20%), Marathon (20%)	Mining with Upgrader
Horizon Project	Onstream	2008	4,300	130	Canadian Natural Resources* (100%)	Mining with Upgrader
Kearl Ph 1	Onstream	2013	4,260	300	Imperial Oil* (71%), ExxonMobil (29%)	Mining no upgrader
Planned						
Fort Hills	Probable	2017	1,750	165	Suncor Energy (41%)*, TOTAL (39%) Teck (20%)	Mining with Upgrader
Joslyn	Probable	2018	875	100	Total* (38%), Suncor (37%), Oxy (15%), (Inpex 10%)	Mining with Upgrader

*Source: Wood Mackenzie Pathfinder. * denotes operator Note Syncrude JV comprises COST (36.74%), Imperial Oil (25%), Suncor Energy (12%), ConocoPhillips (9%), Nexen (7.23%), Murphy Oil (5%), Nippon Oil (5%)*

Methods of Extraction – In-situ

At depths of greater than 75 metres the mining of oil sands is no longer economic

At depths of greater than 75 metres the mining of oil sands is no longer economic. Alternative approaches which involve heating the subsoil to enable the bitumen to flow are then used. At the present time there are two main in-situ methods used, SAGD and CSS although alternatives using either solvents instead of steam (Nexen's VAPEX) or in-situ combustion (ISC), which uses oxygen to promote combustion and generate heat, are also being trialed.

Steam Assisted Gravity and Drainage (SAGD)

The gravity drainage idea was originally conceived by Dr. Roger Butler, an engineer for Imperial Oil around 1969. However, it wasn't really until the development of directional drilling that the economics associated with SAGD improved to the point that it became financially viable. SAGD involves drilling two parallel horizontal oil wells in the oil sand formation. The upper well injects steam and the lower one collects the water that results from the condensation of the injected steam and the crude oil or bitumen. The injected steam heats the crude oil or bitumen and lowers its viscosity which allows it to flow down into the lower wellbore. The large density contrast between steam on one side and water/hot heavy on the other side ensures that steam is not produced at the lower production well.

SAGD involves drilling two parallel horizontal oil wells in the oil sand formation. The upper well injects steam and the lower one collects the water that results from the condensation of the injected steam and the crude oil or bitumen

The water and crude oil or bitumen is brought to the surface by several methods such as natural steam lift where some of the recovered hot water condensate flashes in the riser and lifts the column of fluid to the surface, by gas lift where a gas (usually natural gas) is injected into the riser to lift the column of fluid, or by pumps such as progressive cavity pumps that work well for moving high-viscosity fluids with suspended solids.

SAGD tends to result in the recovery of around 60% of the original oil in place (OOIP).

Cyclic Steam Stimulation

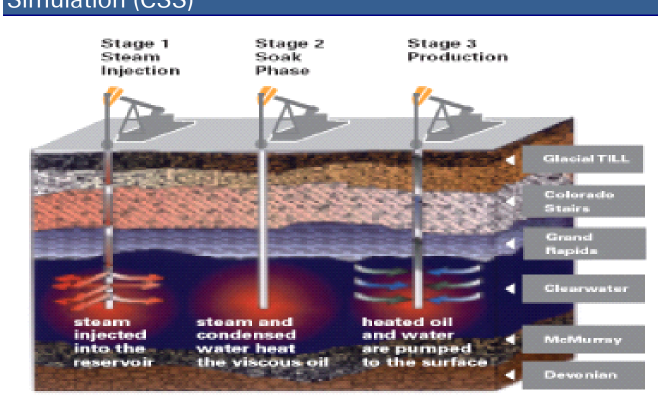
CSS is a common enhanced oil recovery technique, accidentally discovered by Shell while it was doing a steam flood in Venezuela and one of its steam injectors blew out and ended up producing oil at much higher rates than a conventional production well in a similar environment.

Also known as the Huff and Puff method, CSS consists of three stages: injection, soaking and production. Steam is first injected into a well for a certain amount of time to heat the oil in the surrounding reservoir to a temperature at which it flows. This persists for many weeks with the steam 'soaking' the subsoil sands before the process is halted. At this time the wells are turned into producers, at first by natural flow (since the steam injection will have increased the reservoir pressure) and then by artificial lift. Production will decrease as the oil cools down, and once production reaches an economically determined level the steps are repeated again.

CSS consists of three stages: injection, soaking and production.

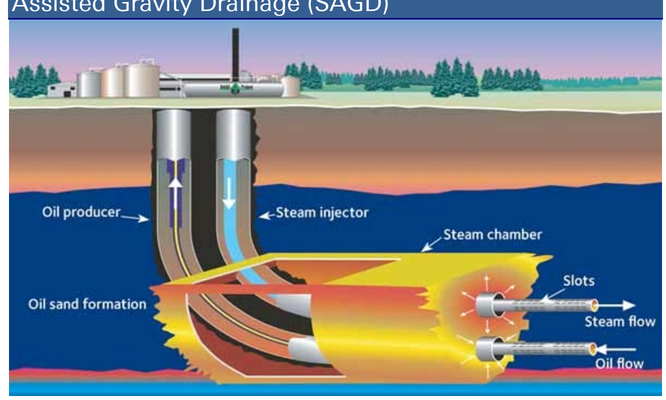
The process can be quite effective, especially in the first few cycles. However, it is typically only able to retrieve approximately 20% of the OOIP. As a result, it has given way to the use of SAGD as a preferred method of extraction with only three founding projects now using CSS as their primary means of extraction Cold Lake, Peace River and Primrose/Wolf Lake.

Figure 365: Diagrammatic representation of Cyclic Steam Simulation (CSS)



Source: Courtesy of Shell

Figure 366: Diagrammatic representation of Steam Assisted Gravity Drainage (SAGD)



Source: Courtesy of Shell

Figure 367: Main SAGD/CSS Canada Oil sands Projects and start up dates (all Athabasca except those shaded)

Project	Status	Start-Up	Reserves (mmbbls)	2013 kb/d	Partners	Method
Primrose/Wolf Lake	Onstream	1983	880	120	CNRL* (100%)	CSS/SAGD no upgrader (peak 120kbd)
Cold Lake	Onstream	1986	1,000	150	Imperial Oil* (100%)	CSS no upgrader (peak 190kbd)
Peace River	Onstream	1986	620	8	Shell* (100%)	CSS no upgrader (peak 50kbd)
Hangingstone	Onstream	1999	270	7	Japan COS 75%; Nexen 25%	SAGD no upgrader (peak 30kbd)
Foster Creek *	Onstream	2001	1788	120	Cenovus Energy* (50%), COP (50%)	SAGD no upgrader (peak 245kbd)
Christina Lake *	Onstream	2002	1700	80	Cenovus Energy* (50%), COP (50%)	SAGD no upgrader (peak 240kbd)
MacKay River	Onstream	2002	540	30	Suncor Energy* (100%)	SAGD no upgrader (peak 70kbd)
Suncor SAGD	Onstream	2004	3625	175	Suncor Energy* (100%)	SAGD with upgrader (peak 345kbd)
Tucker	Onstream	2006	347	17	Husky Energy* (100%)	SAGD with upgrader (peak 17kbd)
Surmont	Onstream	2007	1130	27	ConocoPhillips* (50%), Total (50%)	SAGD no upgrader (peak 136kbd)
Jackfish	Onstream	2008	900	55	Devon 100%*	SAGD no upgrader (peak 105kbd)
Long Lake	Onstream	2008	1375	48	CNOOC* (100%),	SAGD with upgrader (peak 100kbd)
Kai Kos Dehseh	Onstream	2012	900	20	Statoil* (60%), PTT (40%)	SAGD no upgrader (peak 80kbd)
Sunrise	Development	2014	3000	n.a.	Husky Energy* (50%), BP (50%)	SAGD with upgrader (peak 200kbd)
Kirkby	development	2014	460	n.a.	CNRL (100%)	SAGD no upgrader (peak 85kbd)

*Source: Wood Mackenzie Pathfinder. *Encana and COP established a JV with COP taking an upstream interest in the Encana fields but offering scope for upgrading of bitumen at two COP facilities ^ CAPEX costs are shown in 2010 terms*

Upgrading

The bitumen output from the oil sands needs to be upgraded if it is to find a market.

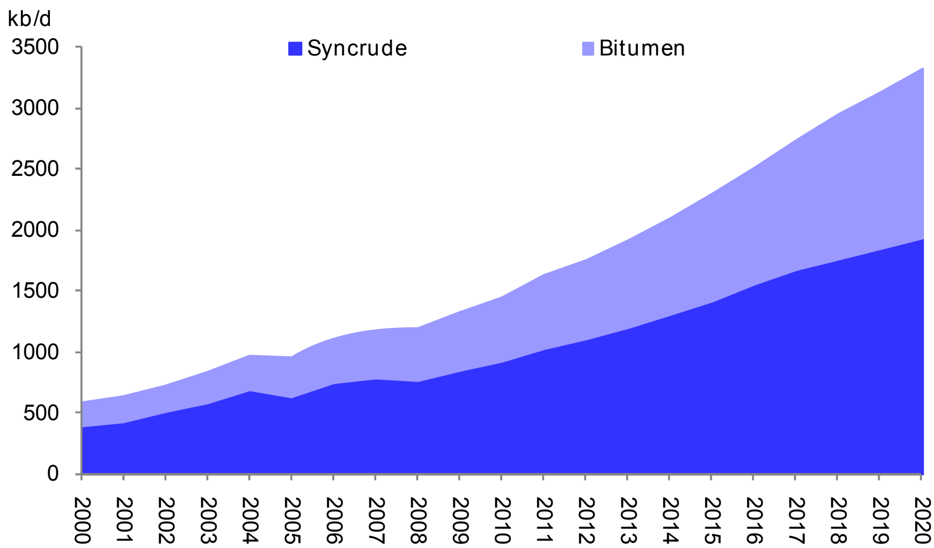
Because of limited demand for bitumen itself in North America, the bitumen output from the oil sands needs to be upgraded if it is to find a market. Consequently, many of those involved in the production of the tar sands have invested in complex upgrading refineries designed to break down the long chain bitumen carbon molecules into shorter, lighter chains more representative of crude oil. In the first stage of the upgrading coking or hydro-cracking is used to break up the heavy hydrocarbons. The second stage, hydro-treating, uses hydrogen to remove impurities, namely sulphur. Depending upon the technology chosen and the capex spent upgraders can be designed to produce differing API crudes with different sulphur content.

The scale of the cost should not, however, be underestimated. In 2007 when making a regulatory application to build a new 400kb/d upgrader, Shell indicated that the total project would cost as much as $27billion i.e. $67,500/flowing bbl. This compares with the estimated $25,000/flowing barrel cost of a green-field refinery. In 2008 Statoil withdrew its application for an upgrader on its Leismer project. It initially planned to spend $4bln on an 80kb/d upgrader, increasing this capacity to 243kb/d in subsequent phases for a total cost of $16bln. However, it subsequently found the costs to be too prohibitive. More recently, Suncor has estimated a cost for its 245kb/d bitumen upgrader at c$18bn or c$75,000/flowing barrel. The development is on hold.

Because the majority of the large mining projects have associated upgraders, around 70% of the oil sands production is sold in North American markets as synthetic crude oil or syncrude. This can readily be refined within North American markets. Nonetheless, as production from often smaller SAGD developments builds, so the volume of untreated diluted bitumen is also expected to increase significantly.

This represents both an opportunity for refiners but also a potential threat to the tar sands industry. To the extent that investment in expensive cokers and hydrocrackers is made across North American refineries, it represents a good opportunity to capture a significant proportion of the value of the tar sands barrel. This is a strategy that companies such as BP are looking towards as a way of benefiting from the growth in production from Canada's oil sands. However, if this investment is not made, the resulting surplus in bitumen production is almost certain to see an increase in the discount to WTI at which dilbit currently sells, so placing further potential pressure on the economics of an already very costly process.

Figure 368: Expected output of syncrude and bitumen from Canada's Oil Sands 2000-2015E



Source: Wood Mackenzie GOST

Costs – The highest marginal cost barrel on the globe

Although there are no exploration or finding costs associated with oil sands production, the energy intensity of the projects combined with the sheer scale of the facilities required for the production of bitumen means that the fixed capital and variable operating costs of their production are amongst the highest in the world.

Cost inflation in recent years has been dramatic

Before the global economic crisis gathered pace in 2008, the pace of growth in activity in the oil sands drove dramatic cost inflation in the industry with the estimates for expenditure on many projects at least doubling from first inception. In particular, with so many companies looking to expand production the local labour force has been overwhelmed with the population of Fort McMurray, the unofficial centre of the industry, growing annually at a rate of just below 10%. This exorbitant cost inflation coupled with the global economic crisis and the subsequent crash in oil prices in 2009 saw a significant decline in the number of final investment decisions taken on oil sands projects in Canada. Even with some level of cost deflation since then, Wood Mackenzie still estimates that the breakeven oil price required for a SAGD project is $65/bbl, while mining projects require nearer $90-100/bbl (discounted at 15%).

The very heavy, upfront capital costs associated with doing business in the oil sands are thus a notable feature that not surprisingly, weighs very heavily on the internal rates of return that these projects can achieve. However, because of the very large reserves associated with most developments, at around $7-8 per upgraded barrel the DD&A cost is not dissimilar to that seen in many other parts of the oil industry.

The DD&A charge is, however, as nothing when compared with the variable operating costs associated with extracting an oil sands barrel. At comfortably over $30 per upgraded barrel there can be little doubt that the oil sands represent amongst the highest marginal cost barrels in the world. Not least amongst these costs are those for natural gas given that for every barrel produced under the SAGD process at least 1mscf of gas will be required. Indeed, even an upgraded mined barrel requires around 0.75mscf per bbl of production given the energy requirements of the upgrader (0.5mscf/bbl). Add to this the costs associated with diluting the bitumen for transport and the pipeline costs themselves, and it soon becomes very clear that the oil sands need high crude prices to prove economic. Given the significant discount at which WTI currently trades to waterborne crudes given the growth in tight oil production not least in the Bakken region, the economics of oil sand developments now appear ever more challenged.

On average, the full costs for a mined, upgraded barrel runs at around $30/bbl with the more recent projects looking at something nearer $40/bbl

Using Wood Mackenzie data for full cycle project costs to estimate the fixed and variable costs per barrel of production over a range of different projects we show below the estimated average capex/bbl and opex/bbl costs for a broad selection of producing SAGD and mining projects. Highlighted in the table below the analysis emphasises not only the very high opex costs per barrel produced for both forms of production but also the clear difference in capex and opex cost between the different extraction methods.

Figure 369: Oil sands opex and capex costs for varying type projects

$/bbl costs for varying sands projects	DD&A	Opex
Mined with upgrader	10.35	30.11
Mined without upgrader	7.84	16.89
SAGD no upgrader	6.06	17.46

Source: Deutsche Bank

The analysis emphasizes that on average, the full production costs for a mined, upgraded barrel runs at around $40/bbl placing them amongst the most expensive barrels produced globally. Of this the variable component stands at over $30/bbl with costs ranging between $27/bbl (Suncor) at the low end and $33/bbl at the high (AOSP). For SAGD projects the upfront capital costs are notably more modest with DD&A running at a just $5.0-7.5/bbl given the scale of the resource base against nearer $10/bbl for those from a mined barrel with upgrader. Equally, at an average $17.50/bbl the opex costs of production are notably lower than those of an upgraded mine ($30/bbl). The benefit of lower costs is however likely to be more than ceded at the present time by the excess discount at which Canadian bitumen trades relative to SCO leaving the non-integrated projects more vulnerable to the vagaries of regional price movements across the oil price cycle.

Gas to Liquids (GTL)

An expensive alternative to LNG

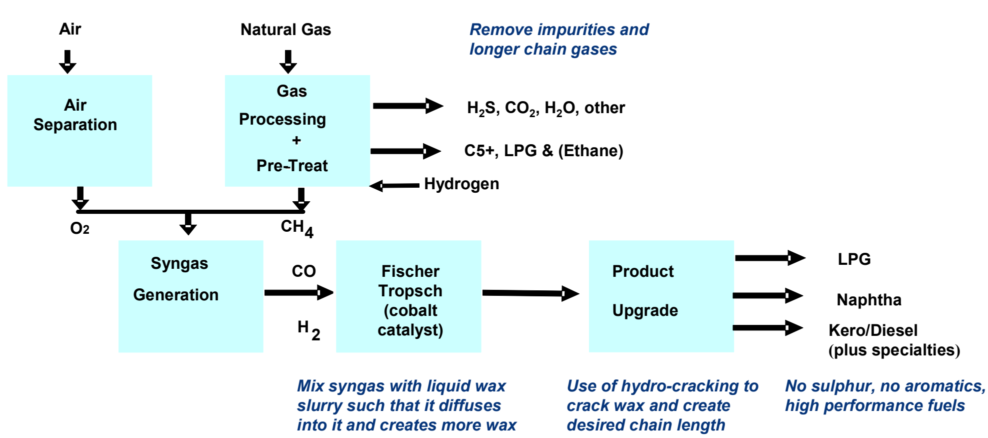
Gas-to-liquids technology represents a means of converting natural gas into liquids

Gas-to-liquids technology represents a means of converting natural gas into liquids. Energy and capital intensive, the process offers the potential to convert large reserves of stranded gas to higher value, high purity, synthetic liquids namely diesel, naphtha and lubricant base oils which can be transported to consuming markets. Based on a catalytic chemical reaction called the Fischer-Tropsch process, the chemical process at its most basic represents the addition of single carbon molecules to create carbon chains, the lengths of which can, to some extent, be determined by altering the conditions through the conversion process. Because of the very high associated costs, GTL is unlikely to prove economic at oil prices below $40/bbl. However, at high oil prices the process creates far greater value than the main alternative for gas monetisation, LNG. At this time, only two companies, SASOL and Shell have technology proven to work on a commercial scale.

Background

In the 1920s, two German scientists Franz Fischer and Hans Tropsch sought to discover an alternative source of liquid fuels in petroleum-poor but coal-rich Germany. They discovered that by combining carbon monoxide with hydrogen (collectively entitled syngas) in the presence of either an iron or cobalt catalyst at high pressures and temperatures, they could create longer chain, liquid, carbon molecules (synthetic petroleum) which could be used as fuel. Moreover, the fuel produced contained no sulphur, aromatics or other impurities all of which enhanced engine performance. For countries in need of transport fuels but lacking access to crude oil, their process became an important alternative source of supply. Indeed, by the time of World War II Germany was producing over 125kd/d of synthetic fuels from 25 plants. Similarly, the process was used by South Africa to meet its energy needs during its isolation under Apartheid, with the South African energy company, SASOL, becoming the global leader in the commercial application of Fischer-Tropsch technology for the production of high quality diesel fuels albeit predominantly using coal as a source of carbon.

Figure 370: The GTL process –straightforward addition chemistry removes the need for a refinery. But very commercially and technologically challenging



Source: Deutsche Bank

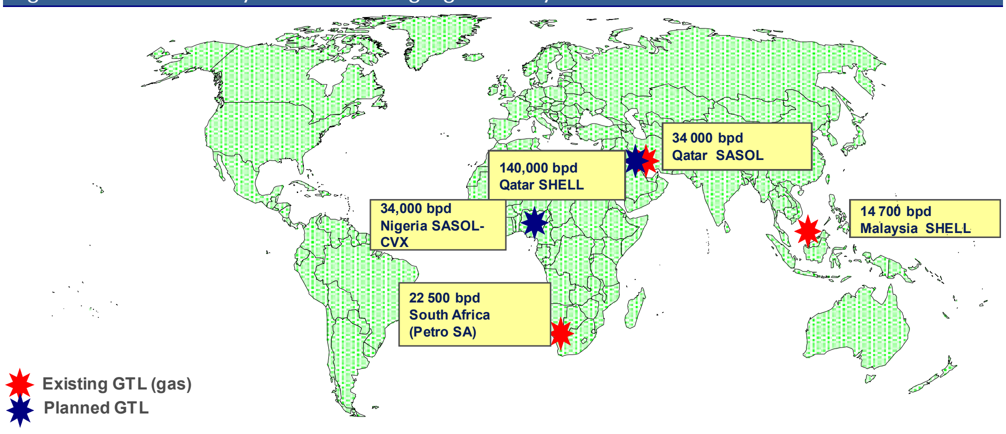
Today, GTL represents the potential for those countries with substantial, low cost, stranded gas resources to monetise their gas and diversify their sources of revenue by producing high value, transport fuels and lubricants rather than LNG or other low value-added, methane based chemicals such as methanol and fertilisers.

Commercial GTL plants are limited

The commercialisation of GTL remains very much in its infancy

Although it is now almost 90 years since the discovery of the Fischer-Tropsch process, the commercialisation of GTL remains very much in its infancy. To date, only four plants are operating commercially, three of which are relatively small scale namely Petro SA's 22.5kb/d in South Africa, Shell's 14.7kb/d Bintulu plant in Malaysia, SASOL's 34kb/d Oryx facility in Qatar. Only Shell's recently commissioned 140kboe/d Pearl GTL facility could be described as world scale.

Figure 371: GTL today: Still an emerging industry

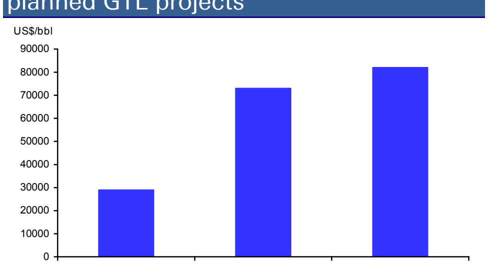


Source: Deutsche Bank

The low number of GTL plants reflects several factors:

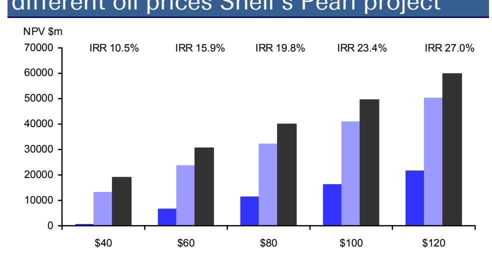
- **Capital costs:** The capital costs associated with constructing GTL facilities remain substantial. In part this reflects the inability of companies to find benefit from improved reactor economics. Given the extremely explosive and challenging conditions under which these operate, increasing reactor capacity has proven very difficult. Consequently, projects operate in batch mode, each unit having a capacity of around 8kb/d using Shell's 'fixed bed' technology or 17kb/d using SASOL's slurry process (but which produces a lower value end product slate). To build a commercial plant with significant output is thus extremely expensive with Shell's Pearl GTL plant costing an estimated $80k per barrel of capacity.

Figure 372: Costs per b/d of the three planned GTL projects



Source: Deutsche Bank

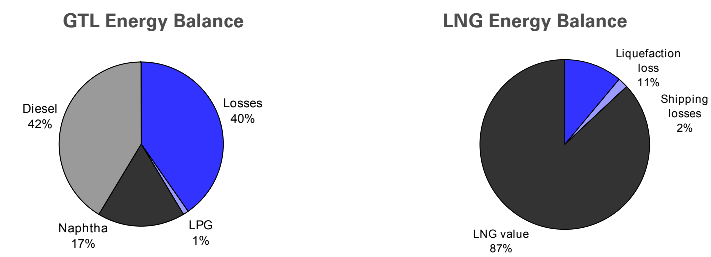
Figure 373: Estimated IRR (%) and NPV at different oil prices Shell's Pearl project



Source: Deutsche Bank

- **Energy intensity:** GTL is a very energy intensive process. Overall, roughly 40% of the energy value of the natural gas used in the process is lost, with extensive associated production of carbon dioxide. For example, Shell's Pearl GTL facility is expected to require 1.6bcf/d of gas or the oil equivalent of 270kboe/d to create 140kb/d of oil products. This contrasts with the production and shipping of LNG, the major alternative for stranded gas, which results in energy usage of a far less material 13% during the liquefaction process and through 'boil-off' during shipping to its final destination, and an oil refinery's consumption of around 7-9% of its crude oil feedstock.

Figure 374: About 40% of the gas entering the GTL process is consumed within it relative to only 13% for LNG.



› **A GTL plant incurs:**

- **Carbon losses of around 30%, due to the extensive production of carbon dioxide and water. Optimal carbon efficiency of ~75 % may be achieved (depending upon slate)**
- **Energy losses of over 40%, which is primarily associated with the production of synthesis gas, which is energy intensive. The process "looses" significant energy in its generation of water, a major by-product. Optimal energy efficiency of ~65 % could be achieved**

Source: Wood Mackenzie; Deutsche Bank

- **Technology:** With the exception of Shell, SASOL and Chevron (through access to SASOL's technology via the SASOL-Chevron JV), none of the major oil and gas companies has technology that has been proven on a commercial scale. Although Exxon, BP and Conoco all claim to have GTL technology, it is unclear at this time whether their technology is sufficiently advanced to be capable of applying to a large scale, commercial facility. This has been emphasised following decisions by Conoco and Marathon in recent years to abandon planned Qatari GTL projects and Exxon's more recent 2007 decision not to proceed with a planned 154kb/d GTL facility, again in Qatar. In part this doubtless reflects the rising capital costs associated with these ventures. However, it is also almost certainly indicative of the huge technical risks associated with operating and constructing a world-scale GTL facility, using technology that is often unproven. This was highlighted in 2007 when SASOL's Oryx plant suffered significant start-up teething problems despite SASOL's industry leading expertise in GTL and CTL (Coal to liquid) markets.

Figure 375: GTL plants on stream and planned

Name	Company	Location	Start-up	Capacity (b/d)	Comment
Mossgas	Petro SA	South Africa	1993	22,500	Producing
Sasolburg	SASOL	South Africa	1993	2,500	Producing
Bintulu	Shell	Malaysia	1993	14,700	Producing
Alaska	BP	USA	2002	300	Pilot
Oklahoma	Conoco	USA	2002	400	Pilot
Oryx	SASOL	Qatar	2007	34,000	Producing
Pearl GTL	Shell	Qatar	2012	140,000	Producing
Escravos	SASOL-Chevron	Nigeria	2014	34,000	In development

Source: Deutsche Bank

- **Oil price:** Because of the substantial capital costs of the process and its poor energy efficiency, GTL is rarely economic unless the price of crude oil is high and gas feedstock very lowly priced. Based on our estimates a new full cycle, integrated GTL plant being considered today would require an oil price north of $40/bbl just to break even and an oil price nearer $60/bbl to achieve a return nearer typical industry standards – and this assuming a gas feedstock cost of c$1/mmbtu. Push the cost of gas to nearer $4/mmbtu and we estimate breakeven would rise to nearer $80-90/bbl.

There are positives

GTL represents a substantial opportunity for those countries with substantial gas resources at their disposal to establish a very profitable and value creating revenue stream

Yet despite the costs and the technical challenges, at high crude oil and product prices GTL represents a substantial opportunity for those countries with substantial gas resources at their disposal to establish a very profitable and value creating revenue stream. Although the breakeven costs are high, because of the absolute scale of the investment and the resource being monetised at oil prices above US$40/bbl the NPV of the project is substantial assuming that the cost of the gas feedstock is low.

For the resource holder GTL also offers the potential to reduce dependence upon international gas prices and gain greater exposure to higher value oil products, not least diesel and lubricants, so diversifying risk. Equally, for the integrated oil company, the high quality of the output slate offers the opportunity to market a high performance, differentiated fuel that because of its purity (no sulphur, no metals) burns more cleanly and with limited particulate emissions.

Figure 376: Difference between product slate of a refinery and Qatari GTL projects – with no low value fuel oil produced the GTL slate is of far greater value

	Traditional Crude Slate	Shell GTL slate	Sasol GTL slate
Raw material	Crude oil	Natural Gas	Natural Gas
	↓	↓	↓
Process	Refinery		
	↓	↓	↓
	Product slate	Product slate	Product slate
LPG	3%	3%	3%
Naphtha	7%	28%	26%
Gasoline	27%	0%	0%
Middle distillate	40%	54%	71%
Fuel oil	21%	0%	0%
Lubricants/waxes	2%	15%	0%

Source: Deutsche Bank

An uncertain future at this time

GTL's future role in energy markets is thus likely to depend heavily on the direction of future oil and gas prices and the extent to which technology can bring down the associated capital costs. In the near term, however, its role in energy markets is likely to be determined more than anything by the success or otherwise of Shell's Pearl project – the initial outlook for which we would say has been more than encouraging. As Pearl's reliability is proven we would expect interest in future GTL developments to increase not least in gas rich provinces such as onshore US and east Africa will increase. Ultimately, however, with unconventional oil production expanding we suspect that GTL will very much retain an important but niche role in hydrocarbon liquids production.

Coal Bed Methane

Exactly what it says on the label

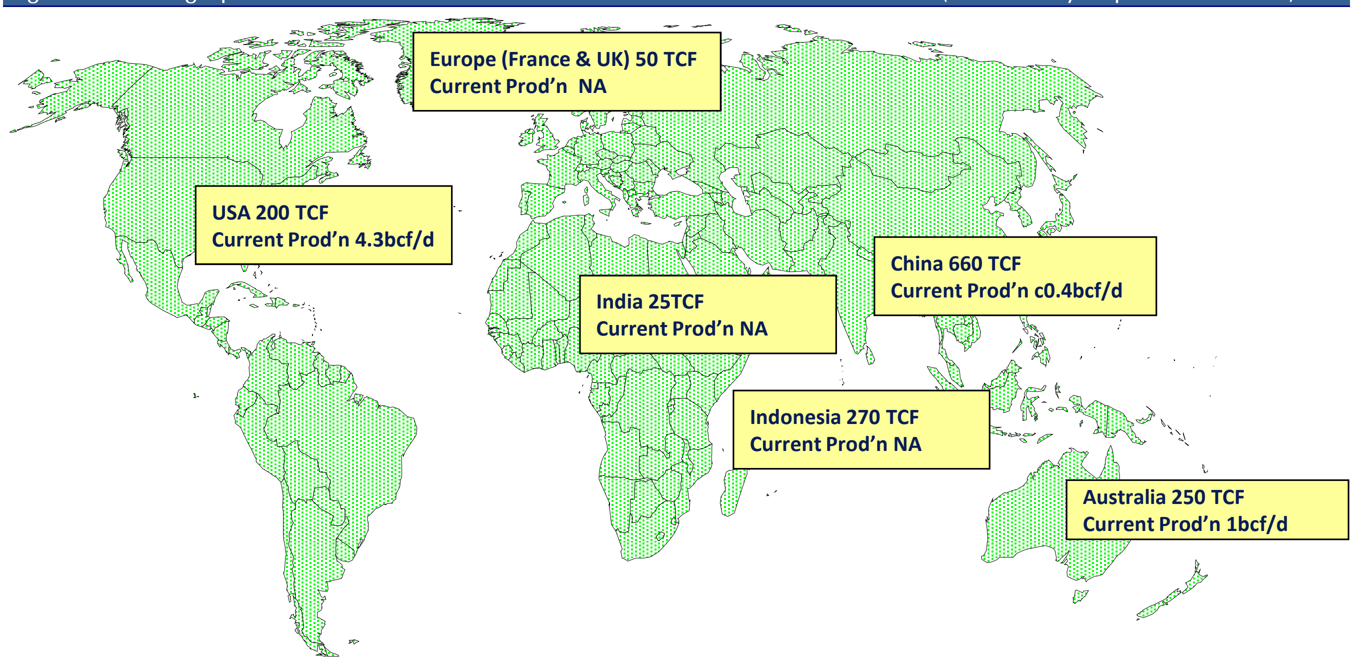
Coal bed methane (CBM) is simply methane found in coal seams

While natural gas is perhaps most commonly associated with oil, it also occurs with coal. Coal bed methane (CBM, also referred to as coal seam gas) is simply methane found in coal seams. It is generated either from a biological process as a result of microbial action or from a thermal process as a result of increasing heat with the depth of the coal. Whereas in a natural gas reservoir such as sandstone the gas is held in the void spaces within the rock, methane in coal is retained on the surface of the coal within the micropore structure. Often a coal seam is saturated with water, with methane held in the coal by water pressure. Release this pressure and it allows methane to dissociate and so escape from the coal.

A substantial resource

During coalification large quantities of methane rich gas are generated and stored within coal on its internal surfaces. Because the coal has such a large internal surface area it can store surprisingly large volumes of gas – perhaps six or seven times those of a conventional gas reservoir of equal rock volume. Moreover, much of the coal and thus methane lies at shallow depths making wells easier to drill, whilst exploration costs are low given that the location of many of the world's coal reserves are well known.

Figure 377: Geographical location of coal bed methane resources around the world (Gas-initially-in-place estimates)



Source: Wood Mackenzie Unconventional Gas Tool, Deutsche Bank estimates

Although scientific understanding of, and production experience with, coal bed methane is in the early stages, it is believed to represent a very substantial resource of natural gas. In the US alone, US Geological Society estimates suggest that as much as 700TCF of CBM resources are in place, of which perhaps near 200TCF could prove economically recoverable. Australia is another country with considerable CBM resources (c.250TCF) that has seen a lot of interest by IOC's in recent years, particularly for CBM to LNG projects. Perhaps most interesting, however, is China where estimates suggest some 660TCF of commercial CBM gas reserves. Given considerable support for the sector production of an estimated 0.5bcf/d is somewhat ambitiously targeted to rise towards 3bcf/d by 2015. Given the country's growing appetite for gas we suspect there will be significant investment in developing its CBM resource in future years.

Extracting CBM

The focus of most extraction techniques is to reduce the pressure of the coal stream and the water within it

Several methods exist for extracting CBM. The focus of most extraction techniques is, however, to reduce the pressure of the coal seam and the water within it, predominantly by the release of water and fracturing of the coal seam. Since CBM travels with ground water in coal seams, extraction of CBM involves pumping available water from the saturated coal seam in order to reduce the water pressure that holds gas in the seam. CBM has very low solubility in water and readily separates as pressure decreases, allowing it to be piped out of the well separately from the water. Water moving from the coal seam to the well bore encourages gas migration toward the well.

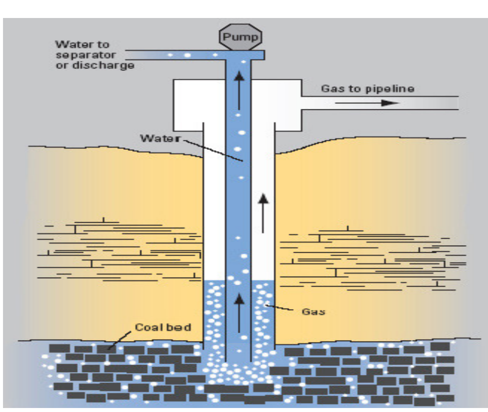
As illustrated below, the production profiles of CBM wells are typically characterized by a 'negative decline' in which the gas production rate initially increases as the water is pumped off and gas begins to desorb and flow. Both production and ultimate recovery rates from each well are highly variable due to the heterogeneous nature of coalbeds. On average a typical CBM well recovers anything between 0.2 and 7BCF of gas, with production rates varying from less than 1mscf/d to up to 7mscf/d.

The extraction of CBM gas requires drilling significantly more wells than would be typical for a conventional gas project due to considerably lower permeability in the reservoir which limits flow rates. For example, the conventional Pluto gas project in Australia requires a total of 7 wells (flow rates of c.120mscf/d per well) compared to some 1500 wells for the Fairview/Roma CBM project (flow rate of 1mscf/d per well). While this would seem cost prohibitive at first glance, the fact that CBM is found in shallow, onshore beds means the wells are typically faster and less complicated to drill than those for many conventional projects. Indeed in Australia rigs are now truck mounted for ease of logistics, a move that has resulted in the cost per CBM well falling from more than A$5mln to nearer A$1mln. Moreover, production and processing facilities for CBM gas are relatively simple, and thus more cost beneficial when compared to those of conventional gas facilities.

Environmental pros and cons

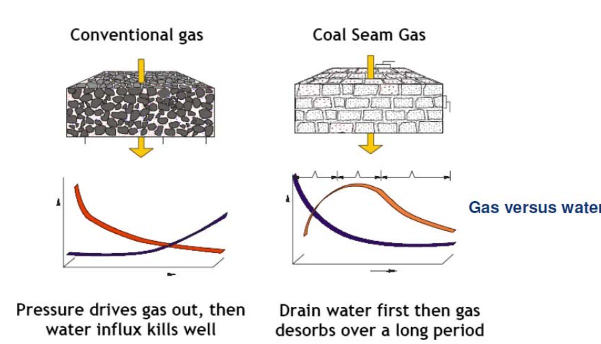
CBM does, however, produce very large volumes of high salinity water, the disposal of which represents a significant challenge given the toxic impact of salt water on vegetation. More positively, however, through capturing methane that may otherwise find its way to the earth's atmosphere it holds the potential to significantly reduce global methane emissions.

Figure 378: Extracting Coal Bed Methane/CSG



Source: EIA

Figure 379: Conventional gas production profile vs. CSG



Source: Wood Mackenzie

Tight & Shale Gas

Huge potential resource

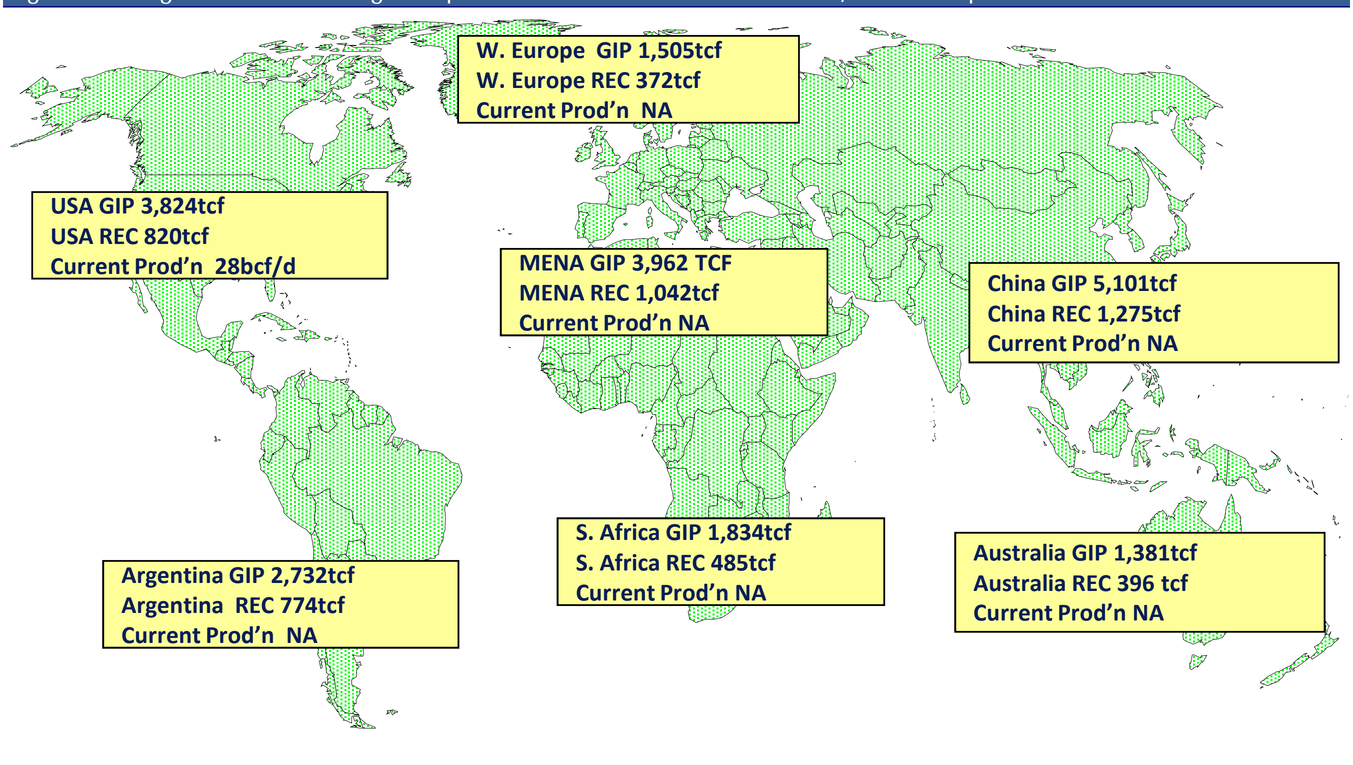
Tight gas is gas that is trapped in reservoirs that have low porosity and permeability

Recent years have seen a huge surge in interest in developing tight and shale gas reserves, particularly in the US. Not only are these resources by and large based in energy hungry OECD countries (i.e. access to both resource and end-market), improvements in technology that have improved productivity and reduced costs coupled with a steadily increasing gas price has rendered the exploitation of these vast resources economic. Moreover, a drive to reduce dependence on volatile oil producing regions and increase consumption of more environmentally friendly sources of energy has also stood in favour of the development of these unconventional gas resources. So what exactly is tight gas or shale gas?

Tight gas is gas that is trapped in reservoirs (often sandstone) that have low porosity and permeability (typically less than 0.1millidarcy). It is known as a non-conventional resource since simply drilling a conventional well through the middle of such reservoirs will not result in enough gas production to make the well economic.

Shale gas is similar to tight gas, the key difference being that the rock is shale. Shale is the earth's most common sedimentary rock, rich in organic carbon but characterised by ultra-low permeability. In many fields, shale forms the seal that retains the hydrocarbons within producing reservoirs, but in a handful of basins shale forms both the source and reservoir for natural gas.

Figure 380: Tight and Shale Gas gas-in-place reserves – at an estimated 26,000 TCF represents a vast resource

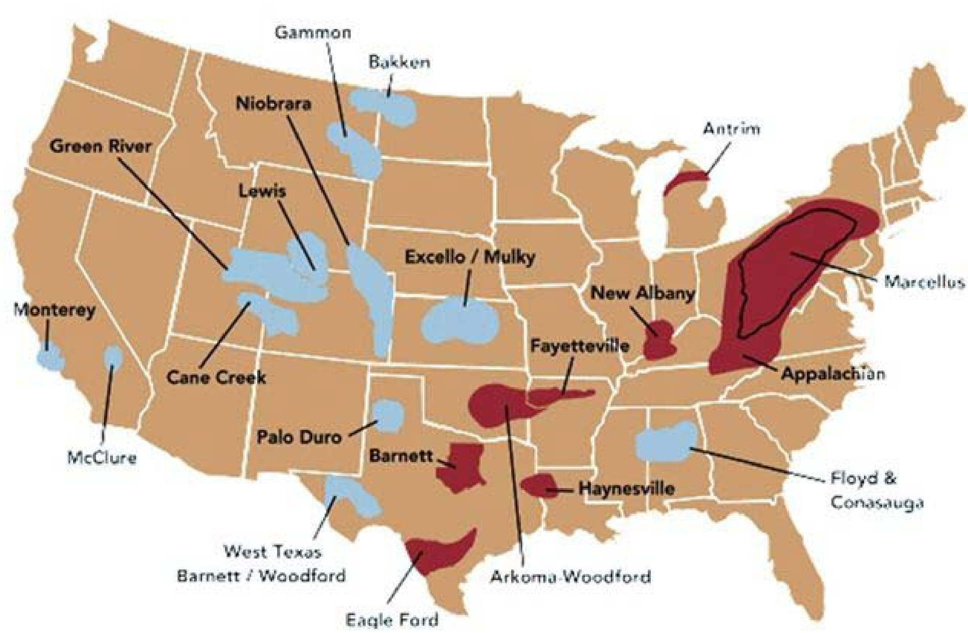


Source: Wood Mackenzie Unconventional Gas Tool, Deutsche Bank estimates

Global resources of tight and shale gas are believed to be vast with the EIA estimating almost 26,000TCF of initial gas to be in place across the major regions of the globe. However, despite this vast global resource base its development saw little attention until North American gas prices started to appreciate. In short, steadily increasing US gas prices combined with new production techniques resulted in a source of supply hitherto seen as uneconomic, becoming highly profitable. In particular new extraction techniques including horizontal drilling, multi-lateral well completions, reservoir fracturing and acidising were all combined to drive a stark increase in well productivity. Important within the improvements was also the evolution in the 1990s from using large volumes of sand based propellant during fracturing (i.e. expensive) to slick-water fracturing which uses greater volumes of water and far less propellant.

The implementation of these new techniques has revolutionised gas production in North America. From a position of steady decline, robust production growth - first from tight gas and then from 2005 onwards in the US shales - has turned a picture of steadily declining supply into one of healthy growth. According to EIA estimates shale gas today accounts for around 24bcf/d of supply or just over 1/3rd of US gas production (66bcfd). This compares with shale production as recently as 2005 of just 2bcf/d.

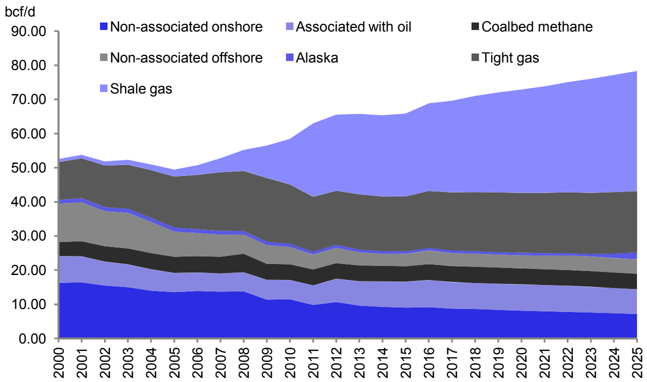
Figure 381: Major unconventional oil & gas plays in the United States



Source: Wood Mackenzie data; Deutsche Bank

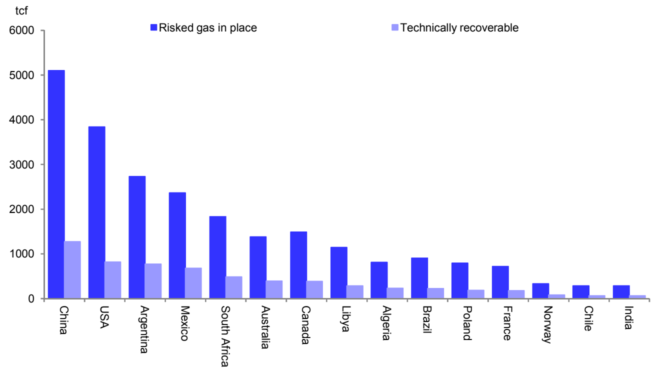
Yet despite this clear production renaissance in North America, globally the emergence of shale gas as a source of supply remains very much in its infancy. In part this no doubt reflects the more limited knowledge and potentially greater complexity of the shale reservoirs in many other territories. At least as significant at this time however is the existence in the US of a vast and very well developed service industry, not least the significant availability of rigs and down-hole service teams, together with land rights whereby the land owner also owns the sub-soil rights and as such is thereby incentivised through the agreement of a royalty payment to allow access to his land. These features together with the greater acceptance by the local population in many of the producing regions of the oil & gas industry in general have all contributed to the dramatic acceleration in shale gas production.

Figure 382: At 40bcf/d Shale (24bcfd) and tight gas (16bcfd) have come to dominate US natural gas supply



Source: EIA data; Deutsche Bank

Figure 383: EIA estimates for shale gas in place and technically recoverable volumes – big potential



Source: EIA Deutsche Bank

Globally other regions are, however, slowly opening up. In Argentina considerable potential for the development of shale gas (and perhaps more importantly oil) is envisaged not least in the Neuquen Basin whilst in China the Government has highlighted the exploitation of its vast shale gas resources as a key future energy source with the production of at least c6bcf/d of shale gas targeted (very optimistically in our view) by 2020. Given limited infrastructure, service sector availability and resistance from the local population often on environmental grounds (not least in Europe) progress towards the development of significant supply is, however, likely to prove far more protracted than has been the case to date in North America.

Extracting the gas

Both tight and shale gas are typically difficult to extract given the rock's low permeability. However, once flowing the gas tends to flow 'clean' i.e. without any liquid content. As with CBM, tight and shale gas production is characterised by a high initial flow rate (referred to as the initial production or IP rate) after which production tends to decline steeply with the remaining gas produced very slowly over time. Expected ultimate recovery (EUR) of the gas in place is typically only 20%, much lower than conventional gas plays. However, recovery rates are continually improving with advances in completion and horizontal drilling. IP and EUR rates can vary widely by play with shale plays in the US Barnett for example averaging at a 30 day IP rate of 2.4msc/f and an EUR of 2.7BCF per well compared to up to 20mscf/d in the Haynesville with EURs of up to 7.5BCF.

Figure 384: Comparing the major US shale plays plays

	Haynesville T1	Marcellus NE	Fayetteville	Woodford	Barnett core
IP (mscf/d)	9.33	5.9	2.48	3.9	2.25
EUR (bcf)	7.26	4.9	2.25	4.4	2.7
Production start up	2008	2008	2006	2006	1998
Rec gas (tcf)	34	84	5	10	19
Depth	3,500m	2,000m	1,000m	2,500m	2,000m
Year 1 decline	62%	65%	64%	68%	66%
Terminal fade	10%	7%	8%	9%	12%
Well cost (D&C) $m	10.6	6.6	3.2	5	3.0
Recovery factor	23%	25%	38%	35%	28%
2012 production bcf/d	5.60	3.80	2.80	0.90	4.80

Source: EIA; Wood Mackenzie; Deutsche bank

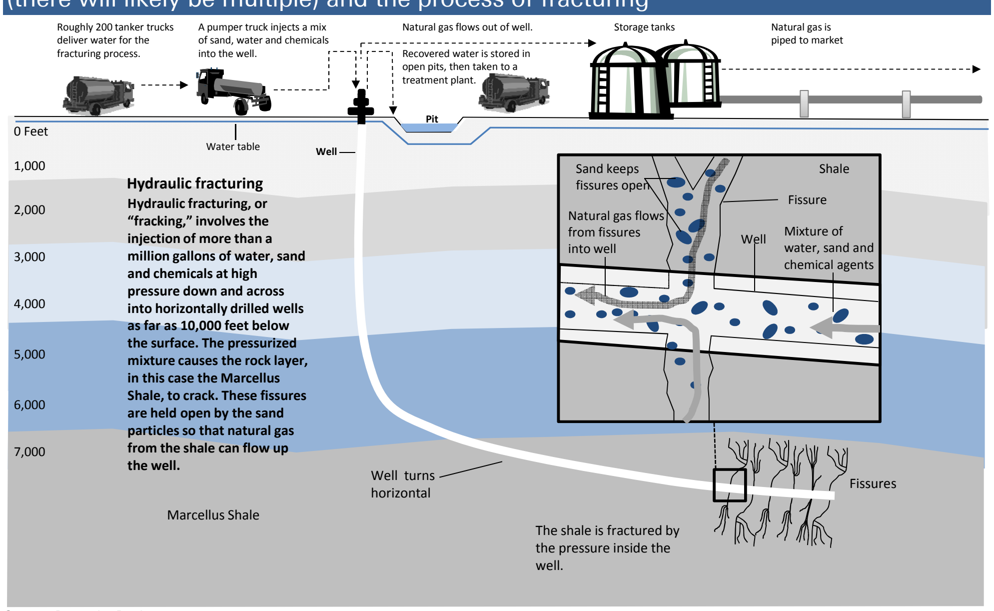
Vertical drilling is typically used in the initial or pilot-testing phases of an emerging shale/tight play given the lower cost of coring and drilling vertically. However, once the play is deemed to be commercially viable based on early testing, almost without exception wide-scale development is undertaken using horizontal drilling (explained below). Drilling is typically conducted on what are called pads which are established across the lessor's acreage on the basis of pre-determined acreage spacing, the objective being to maximise the recovery potential of the gas for the minimum cost.

Each pad can effectively be viewed as a hub from which several horizontal wells covering the pre-determined area will be drilled in multiple directions. Not only does this reduce the above ground impact of drilling out an area environmentally. By reducing the need to constantly move rigs, crew and services it also significantly enhances well economics. Pad spacing in most plays is often set at 160 acres but can be tighter depending upon recovery rates, resource penetration and the perceived economics of narrowing the spacing.

In most cases, a successful well requires hydraulic stimulation. When completing a well, an operator will commonly perform numerous staged fracture jobs along the lateral leg of the wellbore – that which is in direct contact with the producing zone. At each frac stage, fluid and proppant (grains of synthetic materials or sand used to prop pore-space open) are hydraulically pumped into perforations that are 'punched' into a section of the formation. After each stage, a plug is set and the process is repeated moving up the wellbore.

While the theoretically ideal completion would involve the maximum possible smaller frac stages – so as to contact the maximum amount of rock in the wellbore – that quickly becomes cost-prohibitive. While every gas play is different and completion methods can vary widely between operators, lateral lengths of 3000 to 6000 feet with fracs performed every 500-700 feet are typical across most plays.

Figure 385: Diagram depicting the process of drilling a single horizontal well from a pad (there will likely be multiple) and the process of fracturing



Source: Deutsche Bank

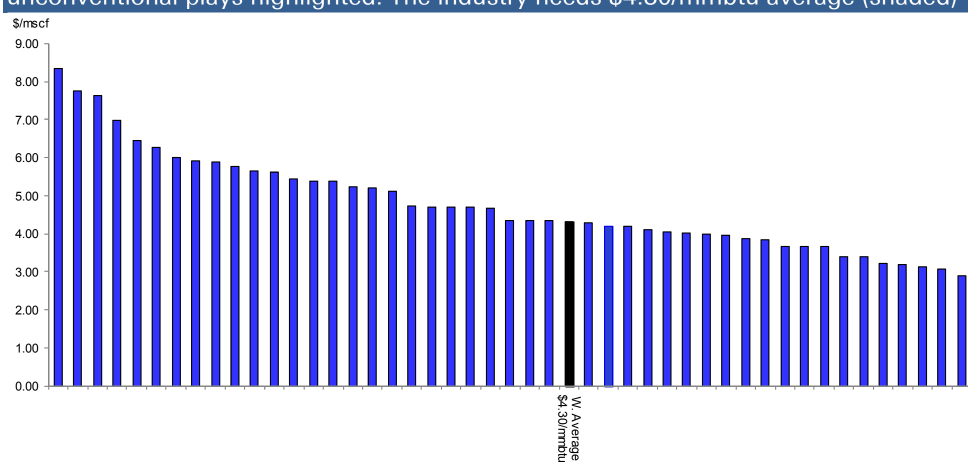
Economics – quick out, low depth, at current gas prices

Through the early years of the US shale revolution improvements in fracturing and drilling technology drove considerable economies. Ultimate recovery and initial production rates improved steadily whilst ever more efficient practices, not least the move to pad drilling, helped drive down drilling and completion costs.

As these initial experience benefits have been realised however so too the cost curves associated with shale gas production have become increasingly sticky. Breakevens across the different plays have essentially stabilised with the weighted average breakeven price for most North American plays suggesting that on average the North American industry needs around $4-4.5/mmbtu to earn a 10% return on investment. Faced with a $2-3/mmbtu headline price it thus comes as little surprise that rig utilisation should have collapsed over the past two years with supply growth moderating significantly.

Having said this it should be recognised that there is considerable variation across the different plays. Dependent upon depth (well cost), location (discount to Hub), initial production rate (initial cash flow), total organic content, permeability and expected ultimate recovery (volume monetised) breakevens vary considerably. Illustrated below and based on Wood Mackenzie data we estimate that whilst the weighted breakeven may be around $4.30/mmbtu, the range of breakevens varies from $3-$9/mmbtu depending upon play. Moreover, within the individual plays the economics can be dramatically different. As ever the quality of the acreage is absolutely key to the profitability of any single company's holding.

Figure 386: Estimated Hub price required to deliver a 10% IRR with major US unconventional plays highlighted. The industry needs $4.30/mmbtu average (shaded)

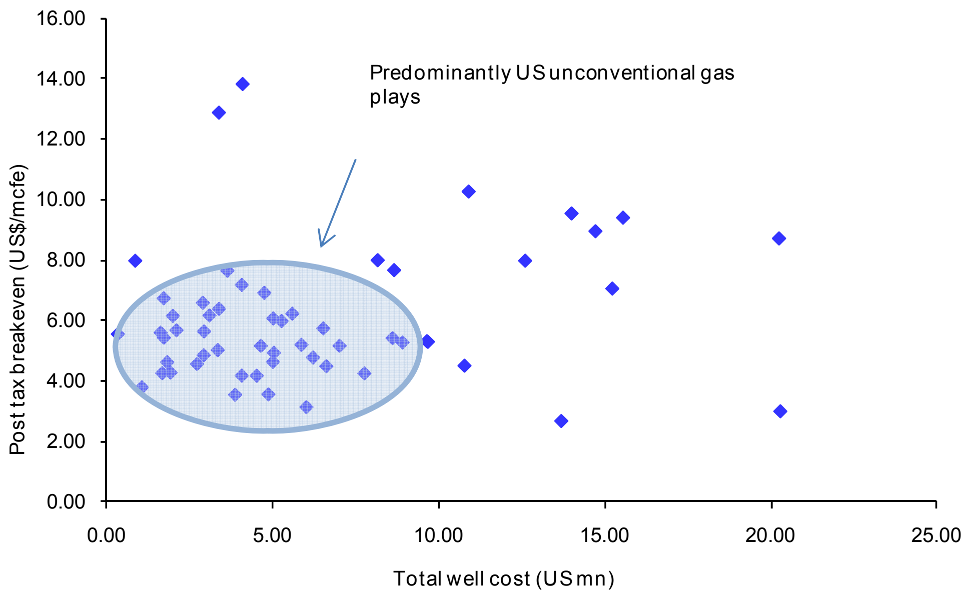


Source: Wood Mackenzie; Deutsche Bank

North America – at least a ten year experience advantage to the RoW

Outside North America however the shale industry remains very much in its infancy. While drilling costs have fallen considerably in the US (for example average well costs in the Barnett have fallen from near $7-8mln per well in the 1980's to today's $2-3mln per well) we cannot extrapolate this performance to the rest of the world, particularly Europe where it currently costs between $20-25mln to drill a single well. Not only are the plays geologically more challenging, but Europe also has a number of other impediments such as limited supply of key services, lack of necessary infrastructure, language barriers, border controls (you can't simply shift a rig from one country to the next as you can from state to state) and stricter environmental regulation and land access rights (Europe is geographically smaller and more built up vs. the location of unconventional gas reserves in the US). All of these factors have done little to enhance the economics of shale activity and have only served to compound often disappointing drilling results. Below we present Wood Mackenzie's most recent assessment of well costs and breakeven prices around the world. This highlights the challenging economics of developing unconventional gas plays outside the US in most other regions.

Figure 387: Well costs vs. breakeven prices for shale



Source: Wood Mackenzie Unconventional Gas Tool

Despite the high costs involved, large industry players continue to commit both financial and human capital towards evaluating the potential of international unconventional gas assets. After some considerable early interest in European potential, much of which has subsequently faded given poor well results (not least in Poland) but also environmental opposition the industry has recently shown particular interest in China, South Africa, Argentina and Australia all of which are known to contain very significant untapped resource. We expect increased investment in the evaluation of these resources over the coming years.

Environmental pros and cons

As with CBM there are a number of environmental considerations with tight/shale gas. While gas is environmentally cleaner to burn than oil, there are concerns over the impact current extraction techniques (in particular fraccing) could have on the surrounding environment. These concerns have led to blanket bans on the practice in several European countries, most notably France.

The main concerns include the mishandling of solid toxic waste, a deterioration in air quality, the contamination of ground water from use of chemicals and the migration of gases and hydraulic fracturing chemical to the surface. In the UK shale gas activity in Lancashire is believed to have been responsible for minor earthquakes. Although the industry has done much to improve its operating standards and assure the public of the safety of its operations, the potentially negative impact not least on potable water supplies in urban areas remains a significant threat to the industry's ongoing license to operate.

Some technical lingo

Horizontal drilling: in a horizontal well, a vertical well is deviated to drill laterally so as to expose the wellbore the maximum amount of the shale formation as possible. This is well suited to tight/shale gas exploitation as in many instances the naturally occurring fractures in the rock are oriented vertically so a horizontal well effectively intersects there pre-existing fractures thereby increasing potential production rates.

Fraccing: a procedure used to improve reservoir effective permeability. Fluid (such as water or acid) and propellant (such as sand) are pumped at high pressure into the reservoir. The result being that the reservoir rock fractures with the propellant effectively wedged inside the fractures thus keeping them open and allowing the gas to flow (also known as fracturing).

Pad: A hub from which the drilling of multiple wells, potentially across a 360 degree area and on several different horizons (levels), will be conducted. Pad drilling both reduces the environmental footprint of the shale industry and facilitates better economics by containing multiple well activities from a single site.

Laterals: The sideways (lateral) extension of the horizontal well.

Proppant: Grains of synthetic materials or sand used to prop pore-space open

Well spacing: The distance in acreas between drilling pads. This may typically start at 160 acres and depending upon recovery and shale content narrowed over time.

IP: The initial production rate i.e. the rate at which the gas flows when first produced. Measured in mmscf/d and often over the first 30 days of production

EUR: Expected ultimate recovery, namely the total volume of gas that is expected to be recovered in bcf over the life of the well

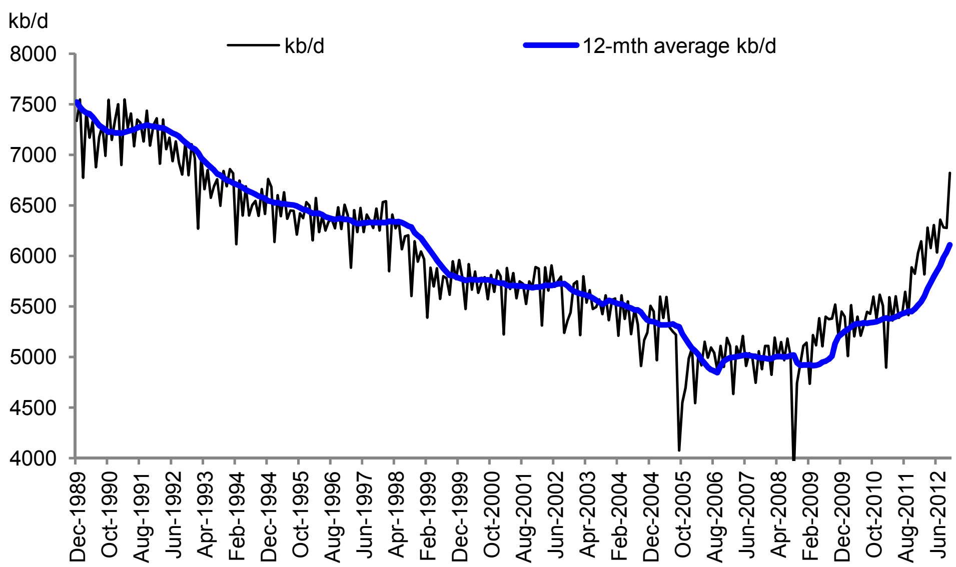
TOC: Total organic content. A measure of the quantity of shale rock which is comprised of hydrocarbons

Tight Oil

Changing the fundamentals of oil supply

In much the same way that the application of horizontal drilling and fraccing technologies have transformed the supply of natural gas in North America, so too is their application having similar impact on North American oil production. Some four decades after oil production in the US peaked, volumes are again strongly rising so reversing what had been seen as an inexorable decline. But what is tight oil and how significant is its potential for growth both in the US and globally?

Figure 388: US oil production 1990 to end 2012 – an inexorable decline transformed by the application of technology



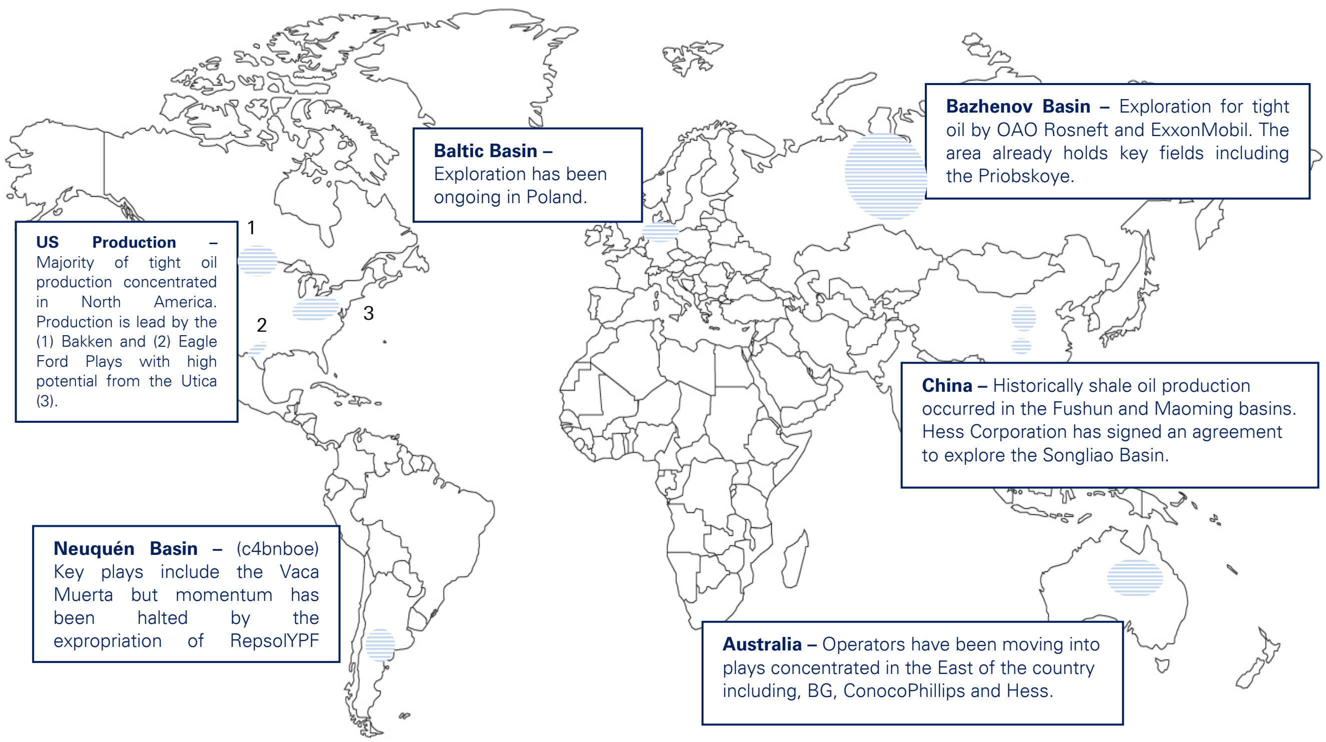
Source: EIA; Deutsche Bank

As with tight gas, tight oil refers to hydrocarbons that are typically captured in rock sequences (including sandstone and limestone) characterised by low permeability and porosity (<0.1mD). These rocks were created from compression of mineral substances including clay, quartz and carbonates. The oil contained within these reservoir rocks typically will not flow to the wellbore at economic rates without assistance from technologically advanced drilling and completion processes.

Tight oil has been labeled as a non-conventional resource as conventional extraction methods will not yield sufficient rates of hydrocarbon flows to make production economically viable. However, it is important to note that the characteristic exhibited by most tight rocks of acting solely as a reservoir (rather than also as the source as is the case for shale gas) categorises it closer to conventionals rather than unconventional resources. Geographically, tight plays are commonly found in onshore areas.

Shale oil & gas is a subset of tight hydrocarbons. The key factor for differentiation is that its reservoir rock, shale, also acts as the source rock for the oil. Shale is the earth's most common, sedimentary rock type, featuring high-clay content and forming a laminated, fissile structure through a process of extended compression.

Figure 389: Global tight oil key regions



Source: Deutsche Bank, Wood Mackenzie, Australian Government GA,

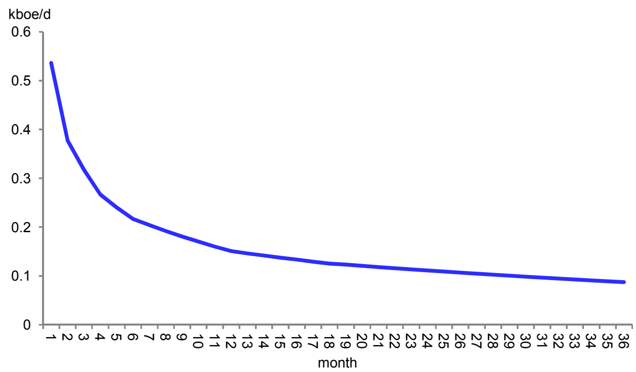
Extraction Process

The nature of the reservoir rock dictates the rate at which tight oil can be extracted. Conventional extraction techniques involve the drilling of vertical wells directly into expected "sweetspots" in the reservoir. However, under this method, extraction of hydrocarbon deposits in tight rock is not economically sustainable due to their low flow rates. Horizontal drilling and hydraulic fracturing are two alternative techniques that have been developed and combined to convert tight oil production into a profitable process. The application of horizontal drilling and hydraulic fracturing techniques on an industrial scale began in the 1980s and 1950s respectively.

The primary stages of horizontal drilling are identical to conventional techniques. A vertical well is drilled from a well pad typically 100x100m in area. Once the well has reached a specified depth above the target reservoir, dubbed the "kickoff point", it is common practice for the vertical segment to be cased in several layers of steel and cement not least to prevent seepage into the water table. Once the vertical shaft is secured, drilling is resumed at an angle such that the reservoir is ultimately accessed horizontally (technically termed the 'kick point'). It is essential that the surface area of the well exposed to the reservoir is maximised. Once the horizontal segment has been constructed, hydraulic fracturing is commenced. High-explosive, directional charges are detonated into the tight rock creating primary fractures. This process is followed by the pumping of fraccing fluid at high-pressure into the well to shatter the rock structure and extend the primary fractures - artificially creating permeability in the rock. The fraccing fluid is a solution of 99% water and 1% chemical additives. Sand or ceramic beads are mixed into the solution in order to prop the fractures open. After each frac, a plug is set and the process is repeated along the wellbore. As a reference point, the wells in the Bakken have a horizontal segment with a typical length ranging between 4,500 to

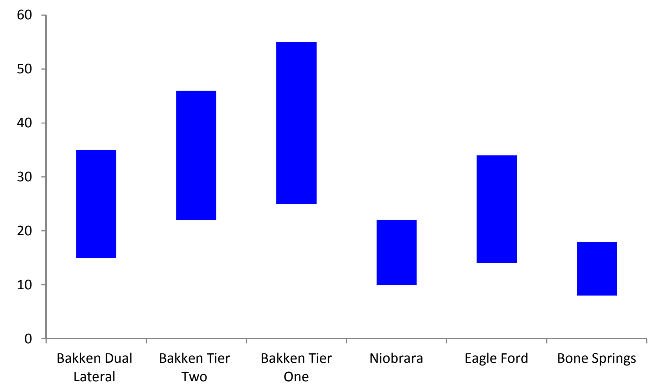
10,000 feet with 15 to 36 fracs. Tight oil extraction is characterized by a high initial flow rate followed by an exponential decline that is represented by a steep type curve. Because the liquid produced has to have low viscosity to flow it tends to be medium to light oil or very light condensate and natural gas liquids (NGLs)

Figure 390: Type curve: Bakken flow rates (kboe/d) through the first 36 months of production



Source: Deutsche Bank, Wood Mackenzie

Figure 391: Range of fracs undertaken across the key tight oil plays



Source: Deutsche Bank, Wood Mackenzie

For operators, the fortunate characteristic of high potential plays to be “stacked” in a set planes that form a series of geological tiers has lead them to develop and utilise multilateral drilling techniques that initiates horizontal drilling at numerous levels from a single vertical well or “mother well”. The method minimises operational costs and time consumption thereby increasing productive efficiency. The technique has an additional bonus of a smaller surface footprint.

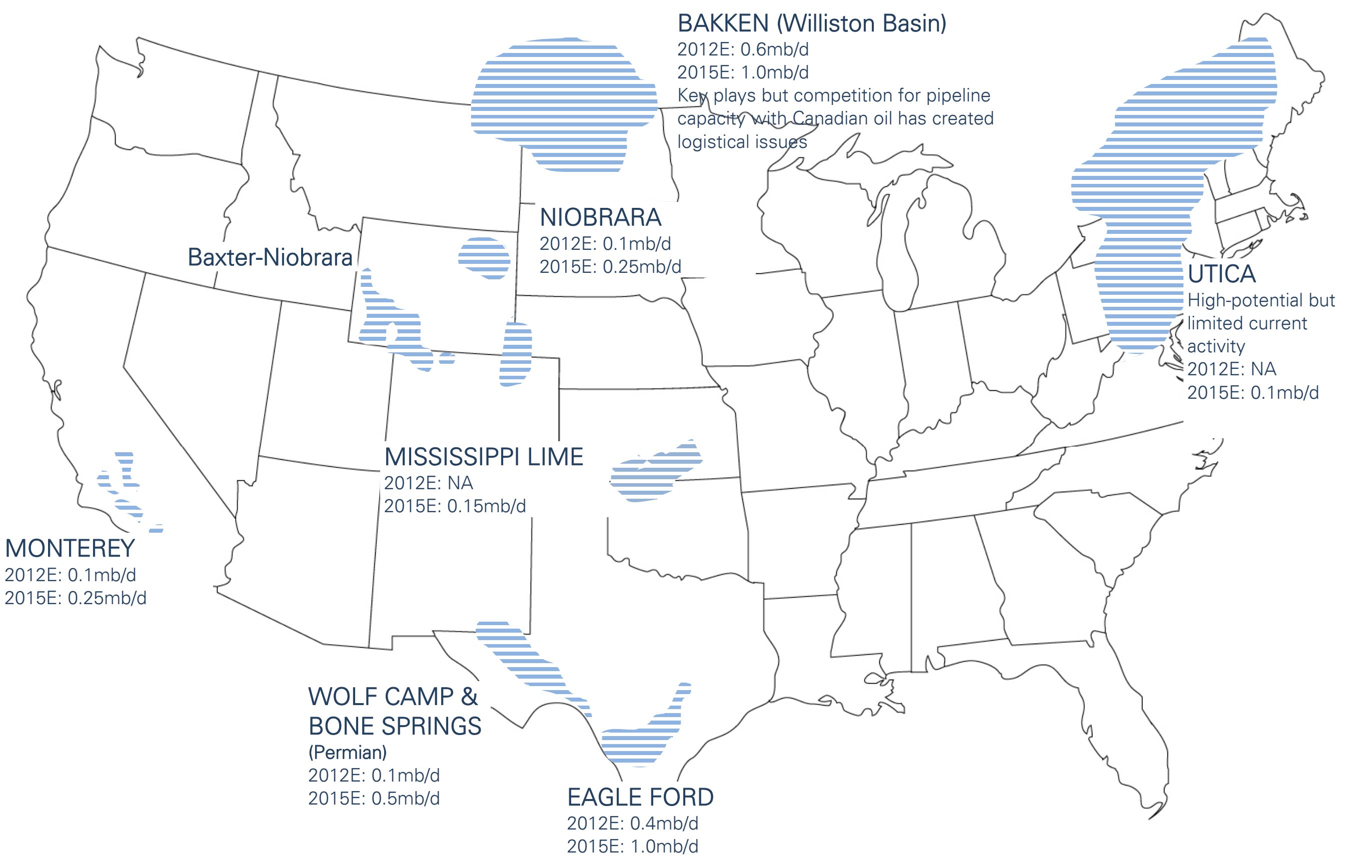
US at the Forefront

The proliferation of exploration projects in unconventional resources has been such that a compression has been observed in the spread between global unconventional and conventional resources. The lion’s share of the exploration has been confined within the borders of the United States due to an alignment of three key conditions:

- A **supply surge** in shale gas was initiated on the back of inflationary gas fundamentals that peaked at over $13/mmbtu in 2008. The fractionalised nature of physical markets limited outflow from production regions and a localised glut was formed in the Mid-Con that eroded prices until they eventually bottomed at c.$2/mmbtu in 2012. This sequence left operators scrambling towards liquids as they attempted to substitute away from gas thereby developing tight. In 2010, the gas rig count fell by 60% and 92% in the Rocky Mountain and Permian regions respectively.
- The US has traditionally held a **trade deficit** in energy with imports in Q3 2012 at c350kb/d. This disequilibrium in the internal economy has sustained R&D into alternative liquids giving the US a technological edge in tight oil production.
- The US oil industry has an extensive and adaptable **services sector** in place, which functions alongside the core industry due to an aggressive period of outsourcing in the mid-1990s by oil companies chasing efficiency and reductions in price risk exposure. The flexibility that these private, service firms have developed lubricated the transition process of oil producers into an increasingly unconventionals- heavy portfolio.

The majority of US, unconventional hydrocarbon reserves are located within the Inland Corridor which runs down the centre of the North American continent. The oil plays across the US have been categorised into 6 regions: West Coast, Rocky Mountains, Mid-Continent, Southwest, Gulf Coast and Northeast. The EIA highlights 8 plays of particular interest in the US: Monterey, Niobrara, Bakken, Austin Chalk, Eagle Ford, Avalon/Bone Springs, Spraberry and Woodford. It is important to note that the magnitude of the reserves in a play does not necessitate a correlation with production. Crucial production hubs including the Eagle Ford and the Bakken do not have access to the largest resources.

Figure 392: US Tight oil – Key plays in the Lower 48



Source: Deutsche Bank

Production

US tight oil production has increased dramatically over the last 5 years and the trend in the Lower 48 is expected to continue. Wood Mackenzie estimates that production will reach 1.5mb/d and 4.1mb/d by 2012 and 2020 respectively. The trend is likely to be driven by underlying growth in the prolific Bakken and Eagle Ford plays. These estimates are conservative with considerable upside existing from the Bone Springs, Three Forks Sanish, Utica, and Niobrara plays. On the back of unconventionals growth, total US oil production is expected to continue upwards at an average rate of 400-500kb/d per annum up until 2020. The growth will be distributed at a 60:40 ratio between light and medium crude types.

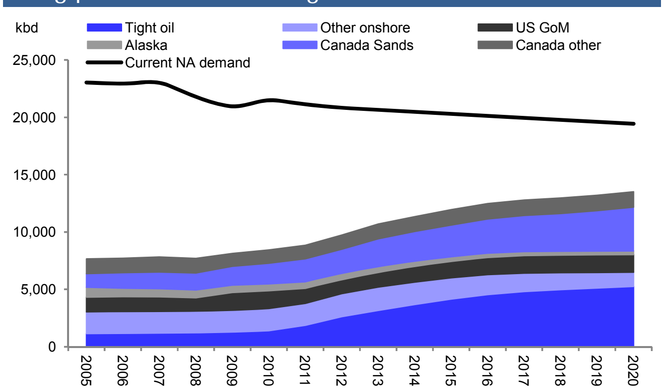
The Bakken in the Rocky Mountain Region and the Eagle Ford in the Gulf Coast are expected to produce 0.6mb/d and 0.4mb/d respectively by end-2012. The Bakken alone will produce an estimated 1mb/d by 2015. Potential productive capacity for unconventionals is huge with an estimated 630,000 new wells required to bring all US shale gas and tight oil reserves onstream. To place this into perspective, the total number of new wells drilled in 2010 was 37,000 across all types of hydrocarbons.

Figure 393: Key US tight oil potential

Play	Basin	Region	Area square miles	Untested area (%)	Area with potential (%)	Av. EUR (mbbl/well)	No. of potential wells	TRR** (mbbl)
Monterey/Santos	San Joaquin	West Coast	2520	98	93	0.5	27584	13709
Niobrara	Denver-Julesburg	Rocky Mountain	20385	97	80	0.05	127451	6500
Bakken	Williston	Rocky Mountain	6522	77	97	0.55	9767	5372
Austin Chalk	Gulf Coast	Gulf Coast	16078	72	61	0.13	21165	2688
Eagle Ford	Gulf Coast	Gulf Coast	3200	100	54	0.28	8665	2461
Avalon/Bone Springs	Delaware	Permian	1313	100	78	0.39	4085	1593
Spraberry	Midland Basin	Permian	1085	99	72	0.11	4636	510
Woodford	Andarko	Mid-Continent	3120	100	88	0.02	16375	393
Total							**219729**	**33226**

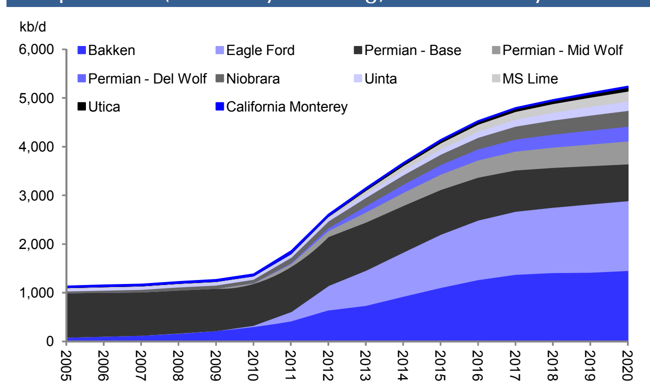
Source: Deutsche Bank, *As at 1.1.2010

Figure 394: N American Total oil production forecasts – rising production and falling demand



Source: Deutsche Bank

Figure 395: Tight oil production forecasts for key plays – The potential (takeaway allowing) for >5mbd by 2020



Source: Deutsche Bank

The Utica basin has attracted recent interest due to its capacity to become a significant production hub. It is an expansive play that underlies the pre-developed Marcellus in the Appalachian basin and stretches across Ohio, New York, Pennsylvania, Maryland, Kentucky, Tennessee, Virginia and West Virginia. Despite the attention, with fewer than 60 wells concentrated in Ohio providing limited empirical evidence, uncertainty surrounds the true potential of the play. Regardless, the per acre prices being paid for land in the Utica exceeds the historical prices of other high-potential plays in their equivalent stage of development.

It is important to be wary of the fact that although the potential of tight oil appears very material, it is still just that - potential. The unexplored areas are large and there is a high standard deviation in performance, hydrocarbon composition and costs between each well.

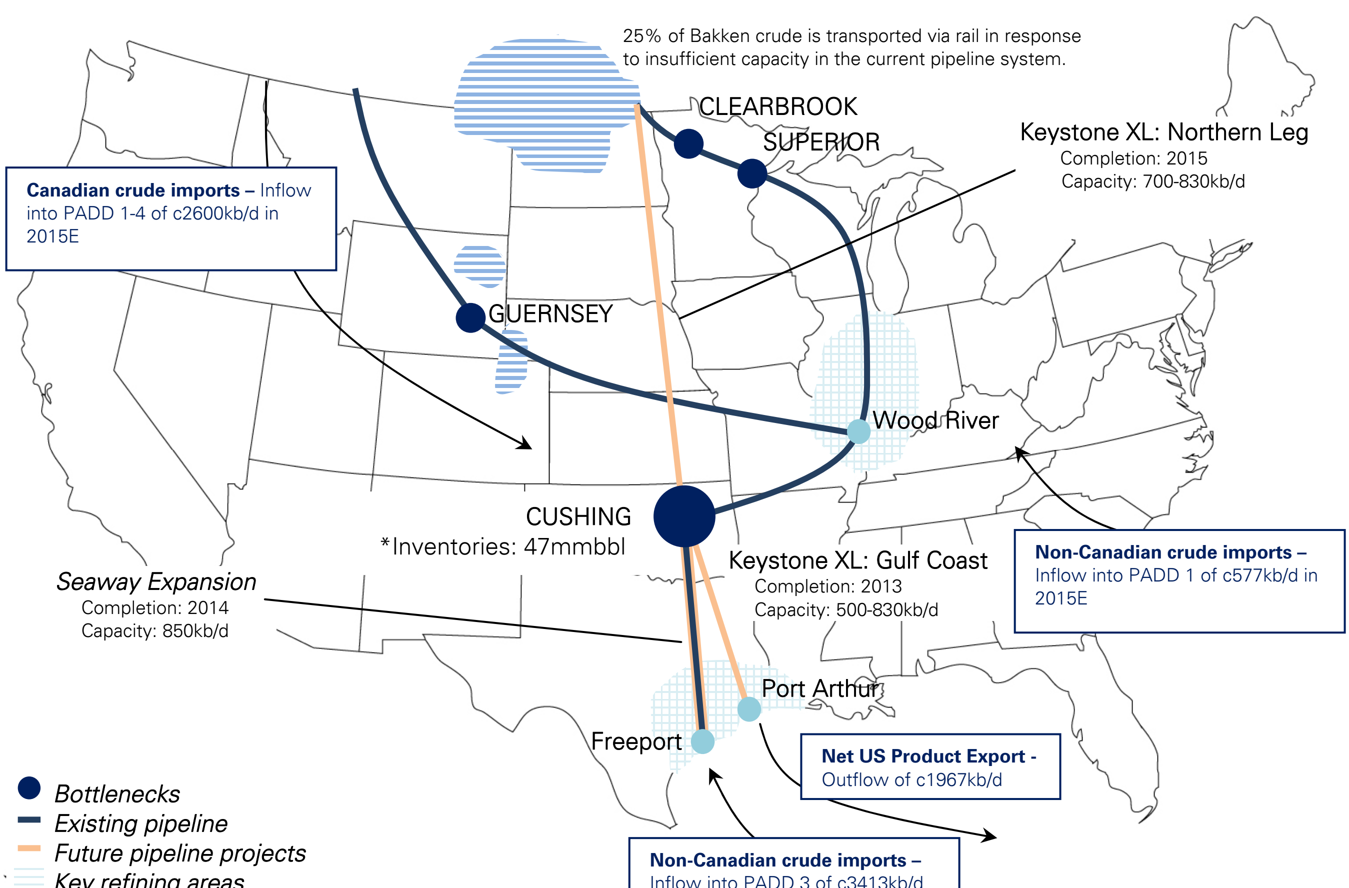
In the short-to-medium term, we expect US crude to follow a similar story to natural gas. A supply surge driven by tight oil and Canadian crude combined with persistent transportation constraints will place downwards pressure on oil fundamentals, eroding operator activity in marginal plays and thereby reducing production.

As with any hydrocarbon extraction process, production in tight oil is inevitably linked with environmental conflict. Production is partially or completely banned in Australia, France, South Africa, Germany, Bulgaria, the US and Ireland. In the US Vermont is the only state to ban fraccing despite having no hydrocarbon industry.

US Logistics and Infrastructure

The ability to access end-markets from the point of production is a crucial issue for the hydrocarbon industry. The unprecedented tight oil boom that has unfolded in the North has reversed the internal dynamics of US oil flow. Increased oil production from unconventional resources in the Bakken and Canada have been held back by a series of downstream pinch points at Superior, Clearbrook, Guernsey and Cushing on its way to the refineries concentrated along the Gulf Coast. Of these, the largest bottleneck has formed at Cushing, Oklahoma – the storage and futures delivery hub where WTI price is marked.

Figure 396: US Tight oil – Key evacuation routes in the US



Source: Deutsche Bank

Operators in the Williston basin (Bakken) are attempting to overcome the logistical limitations by partially diverting crude to Pad II refineries. In addition, transportation by rail has been identified as a medium-term alternative. As things stand at the end of 2012, approximately 25% of Bakken crude is being transported by carriage to St James. The increasing weight being placed on rail contributes to risks in the supply chain and thus adds to volatility in regional prices through exposure to exogenous factors including the weather. In the medium-term, the pressure on railways is likely to mount as Bakken crude is squeezed out of trunk pipelines by Canadian crude volumes that will continue to increase.

In response to the shortfalls, a plethora of pipeline construction and expansion projects have been proposed. Many of these will either be too minor to correct the current market imbalance or they will not be constructed due to legal and financial difficulties. There are two major pipeline projects that have drawn particular attention in the recent period.

- The Seaway Pipeline connecting Cushing, Oklahoma, to Freeport on the Gulf coast has historically transported oil inland to satisfy Mid-con demand. However, in accordance with mounting pressure on the utilisation of Texan refinery capacity, the direction of flow was reversed for the first time in H1 2012 with takeaway capacity of 150kb/d. This was expected to be increased by early 2013 to 400kb/d through the addition of further pump stations. Seaway reversal project is likely to be a temporary measure due to the high rate of growth of oil production. On the other hand, the Seaway expansion project is a medium-to-long term solution, which aims to increase the capacity of the route by laying a sister-pipeline alongside taking gross capacity to 850kb/d on its anticipated start up in 2014. The pipeline project is co-owned by North-South Enbridge and Enterprise.
- The c750kb/d Keystone is a trunk, trans-national pipeline that transports oil from Alberta, Canada to Cushing. Plans have been proposed to extend the existing pipeline in its Northern and Southern legs through the Keystone XL project. As of June 2012, the Keystone XL: Gulf Coast (the more relevant for domestically produced crude) has been granted 1 of 3 permits required to construct the entire southern section. The Keystone XL: Northern Leg and Texas Lateral projects have also been proposed but there are likely to be numerous legal barriers to overcome before a green light is given.
- The TransMountain expansion and the Northern Gateway pipeline projects are two alternative pipeline projects that have estimated completion dates further down the line.

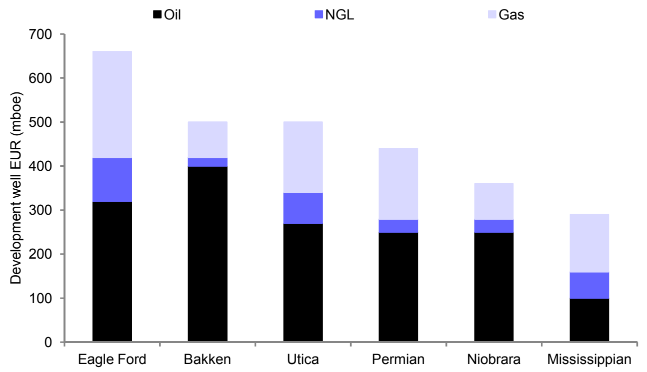
Economics

One might have thought that it was relatively simple to calculate the average breakevens for the different tight oil plays. In reality, however, the truth is anything but a statement that reflects:

a) The impact that infrastructure constraints can have on pricing and consequently the discount at which local product trades relative to the WTI marker

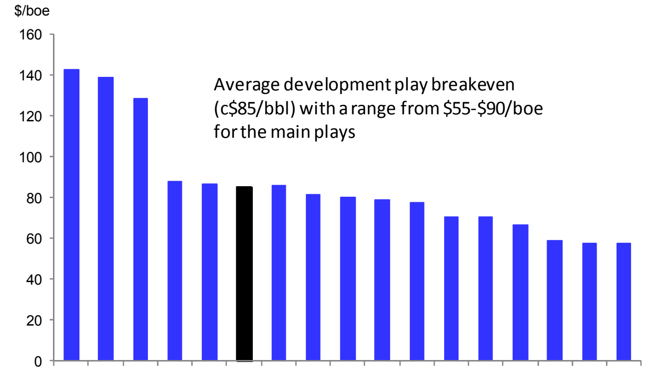
b) The heterogeneity of acreage within the different plays. Not all acreage is born equal. Dependent upon location well production can differ significantly both in terms of absolute flow rates and mix of hydrocarbons produced.

Figure 397: Typical estimated ultimate recovery by hydrocarbon type across six plays



Source: Wood Mackenzie data; Deutsche Bank

Figure 398: Estimated breakeven range across six plays together with development well breakeven



Source: Wood Mackenzie data; Deutsche Bank

c) The proportionate production mix (oil, NGL and gas) of the different basins and plays within those basins. In short in laying down a breakeven assumption one needs to assume a price for oil, gas and the discount at which NGL's will trade.

Having said this assuming a fixed discount rate for NGL's relative to WTI (c40%) and a long term gas price of c$4/mmbtu together with typical current discounts to WTI across the different plays it is possible to estimate a range of breakevens. Illustrated in the figures above, analysis by Wood Mackenzie across the different plays for both the acreage as a whole and a typical development well (which we note will not include associated corporate and admin costs nor those for acreage gathering) suggests a WTI breakeven figure of towards $70-75/bbl for the Bakken with most of the plays breaking even at around $60-65/bbl. Interestingly, this assessment concurs with an analysis of rig activity, the data over the past several years suggesting that demand for rigs tends to falter as the WTI price moves towards $80/bbl.

In the near term it would seem reasonable to anticipate that as learning efficiencies build and connectivity improves some reduction in breakevens should be expected. However, on the basis that we would expect most E&P companies to target their most productive acreage first over the long run breakevens must be expected to rise.

Active Companies

Although recent years have seen a considerable increase in interest from the IOCs in the tight oil opportunity, at the present time the arena continues to be dominated by the smaller US E&Ps. With limited barriers to entry and the potential to prove up additional onshore provinces in North America we would expect this to remain the case. No doubt the majors will look to build up their acreage and production portfolios. However, having very significantly overpaid for access to the North American shale gas plays, we would expect this to arise through lease activity rather than asset acquisitions.

Illustrated below we detail the main players across five emerging US plays not least the Bakken and the eagle Ford. Evident from this is that the key operators in the Bakken play are Continental, EOG and Marathon whilst in the Eagle Ford, EOG, Murphy oil and Petrohawk hold significant acreage. Equally apparent (and as discussed above) is that, with the exception of Exxon whose acquisition of unconventionals leader XTO in 2007 established it as a major shale gas and tight oil player, the IOCs are by and large under-represented across the main US plays.

Figure 399: US Tight Oil Plays and Corporate Presence – E&P dominates and will likely continue to do so

Country	Austin Chalk	Bakken	Bone Spring	Eagle Ford	Niobrara
Anadarko	X		X	X	X
Apache	X				
Chesapeake			X	X	X
CNOOC				X	X
ConocoPhillips		X			
Devon Energy			X		
EOG		X	X	X	X
ExxonMobil		X			
Hess Corporation		X			
KNOC				X	
Marathon		X		X	X
Mitsui & Co				X	
Murphy Oil				X	
Petrohawk Energy (BHP)				X	
Plains E&P (FMR)	X				
SM Energy		X		X	X
Statoil		X			

Source: Deutsche Bank

A look outside the US

Unconventional reserves are evenly distributed across the world. Areas of particular potential include the Neuquén, Baltic, Georgina and Bazhenov basins in Argentina, Eastern Europe, Australia and Russia respectively. Developments in many of these areas are held back by technological and capital constraints. A developed base in human & operating capital, infrastructure and technology are critical in supporting the production. They require significant investment and the process can be accelerated through cooperation with IOCs. Three countries are of particular interest:

- The majority of Argentina's tight oil resource lies in the sandstone Neuquén basin. Although the basin can single-handedly reverse the production decline seen in the last decade, the technology is not available to the domestic oil industry. The short-to-medium term realisation of this resource potential is unlikely due to the negative business environment that operators will experience. The industry has remained suppressed due to a $42/bbl fixed price and the expropriation of YPF assets from Repsol will further feed the fire that will drive off foreign firms that could have plugged the technological shortfall.
- The Russian oil major OAO Rosneft has estimated that the Bazhenov basin in Western Siberia holds 13.2 billion barrels of tight oil. In anticipation, Exxon has announced a JV with Rosneft to explore several plays in the basin with the aim of making an accurate assessment of the reserves. Expectation is high with hopes that tight oil developments will revive Russian crude production.
- China is unique in that it is one of the few countries that have the ability to recreate the tight oil success story that has been experienced in the United States. China has significant tight oil reserves and exploration had begun as early as the 1950s although production has been limited. The Hess Corporation has been operating in China since 2010 and it is currently engaged in a tight oil exploration project in the North-west of the country. Overall, there is very little IOC exposure within the Chinese hydrocarbon industry.

The Countries – Non-OPEC

Argentina

Australia

Azerbaijan

Brazil

Canada Oil Sands

Kazakhstan

Mexico

Norway

Russia

United Kingdom

US Alaska

US Gulf of Mexico

Argentina

Although not a major oil producer, Argentina has been an important source of oil and gas production for several of the international majors, albeit a status dramatically undermined by the 2012 expropriation of 51% of Repsol's interest in YPF. A mature hydrocarbon province, in 2012 the country produced some 609kb/d of oil and 3.5bcf/d (628kboe/d) of natural gas from reserves which, at the end of 2012 were estimated by Wood Mackenzie to stand at some 2.4bn barrels of oil and 11.8TCF of gas. Sadly the economic crisis of 2002 and subsequent government price controls served to materially undermine investment in the industry, not least the development of the country's significant natural gas reserves. As a result, production has been steadily declining for the last decade, which allied to strong demand growth, itself a function of the price controls, has seen shortages emerge and a rapidly growing reliance on government subsidised LNG imports. Ironically whilst production slumped, 2011 witnessed a series of discoveries by YPF in the Neuquen Basin pointing to a potentially vast shale oil/gas resource opportunity. However, rather than incentivise private investment in this transformational opportunity through more favourable end pricing, the government decided to take direct control via the effective re-nationalisation of YPF. It remains to be seen whether a State controlled YPF will be able to meet the technical and financial challenges of monetising this resource potential. The leading producer in Argentina is YPF, followed by BP (through its 60% interest in Pan American Energy) and Total.

Key facts

Liquids production 2012E	609**kb/d**
Gas production 2012E	**628kboe/d**
Oil reserves 2012E	2.4bn bbls
Gas reserve 2012E	11.8TCF
Reserve life (oil)	11.9 years
Reserve life (gas)	10.4 years
GDP 2012E ($bn)	$475billion
GDP Growth 2012E (%)	2.6%
Population (m)	41.0m
Oil consumption 2011(mb/d)	609kb/d
Oil exports 2011 (mb/d)	80kb/d
Fiscal regime	T&R
Marginal (domestic) tax rate	45.9%
Top 3 fields (2012E)	
Cerro Dragón Area	141kboe/d
Loma la Lata Area	123kboe/d
Cuenca Marina Austral	116kboe/d
Top 3 Producers (2012E)	
YPF	430kboe/d
BP	134kboe/d
Total	73kboe/d

Source: Wood Mackenzie data

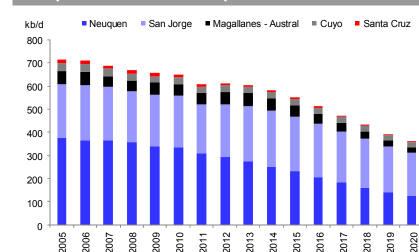
Broad geology and topology

Argentina comprises eighteen sedimentary basins, five of which are currently producing hydrocarbons. Of these the most significant oil and gas producing basin is the Neuquen, the source rocks for which were created in the Lower Cretaceous. Neuquen accounts for around 45% of the country's oil production and over 58% of gas. Outside the Neuquen, the San Jorge Basin is an important source of oil and includes the country's largest single producing asset, the BP operated Cerro Dragon field whilst the Austral Basin, located in the far south of the country (Tierra del Fuego), has proven an important source of natural gas. Of the thirteen non-producing basins, the larger have been explored albeit with limited success. The most recent development is the discovery of potentially material shale oil/gas resource in the Jurassic aged Vaca Muerta formation.

History and regulation

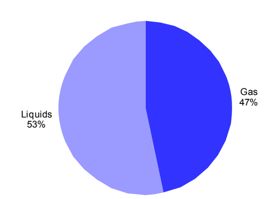
The development of Argentina's hydrocarbon industry was, for much of its history, associated with the state. Oil was first produced in the San Jorge basin in 1907 but by 1922 the state had established Yacimientos Petroliferos Fiscales (YPF) as the national oil company to oversee all aspects of the industry. Shortly thereafter private companies were prohibited by law from developing the country's resource base. This largely remained the state of affairs until the mid-1980s when, in an attempt to boost the dwindling fortunes of the national industry, the so called 'Houston Plan' was launched. Designed to attract new entrants into the Argentine hydrocarbon market and reinvigorate production, this incorporated the licensing of a significant number of blocks under service contracts, the terms of which required the successful explorer to both offer YPF at least a 50% participating interest and to sell YPF any crude oil produced at a 20-30% discount to the international price. Although the plan brought some significant new investment to the sector, with the Argentine economy continuing to struggle in 1991 the Government elected to de-regulate the industry and restructure the state company with a view to its subsequent privatization. Consequently, under 'Plan Argentina', the previous service contracts were converted to tax/royalty

Liquids Production profile kb/d



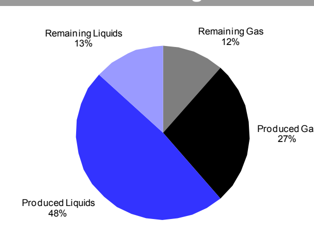
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

concessions and the owners given the right to dispose of their crude oil as they pleased. Most significantly, however, the state set about the sale of a number of YPF's interests, divesting not only YPF's non-core activities but also a total of some 1.3bn barrels of reserves associated with both its marginal fields and some of its core producing assets. Then in June 1993 45% of YPF was successfully floated. Subsequent share disposals eventually saw the Government reduce its holding to 15% before, in January 1999, it agreed to sell its remaining interest to Repsol for some $2bn. Repsol thereafter made a $13.4bn offer for the rest of the company.

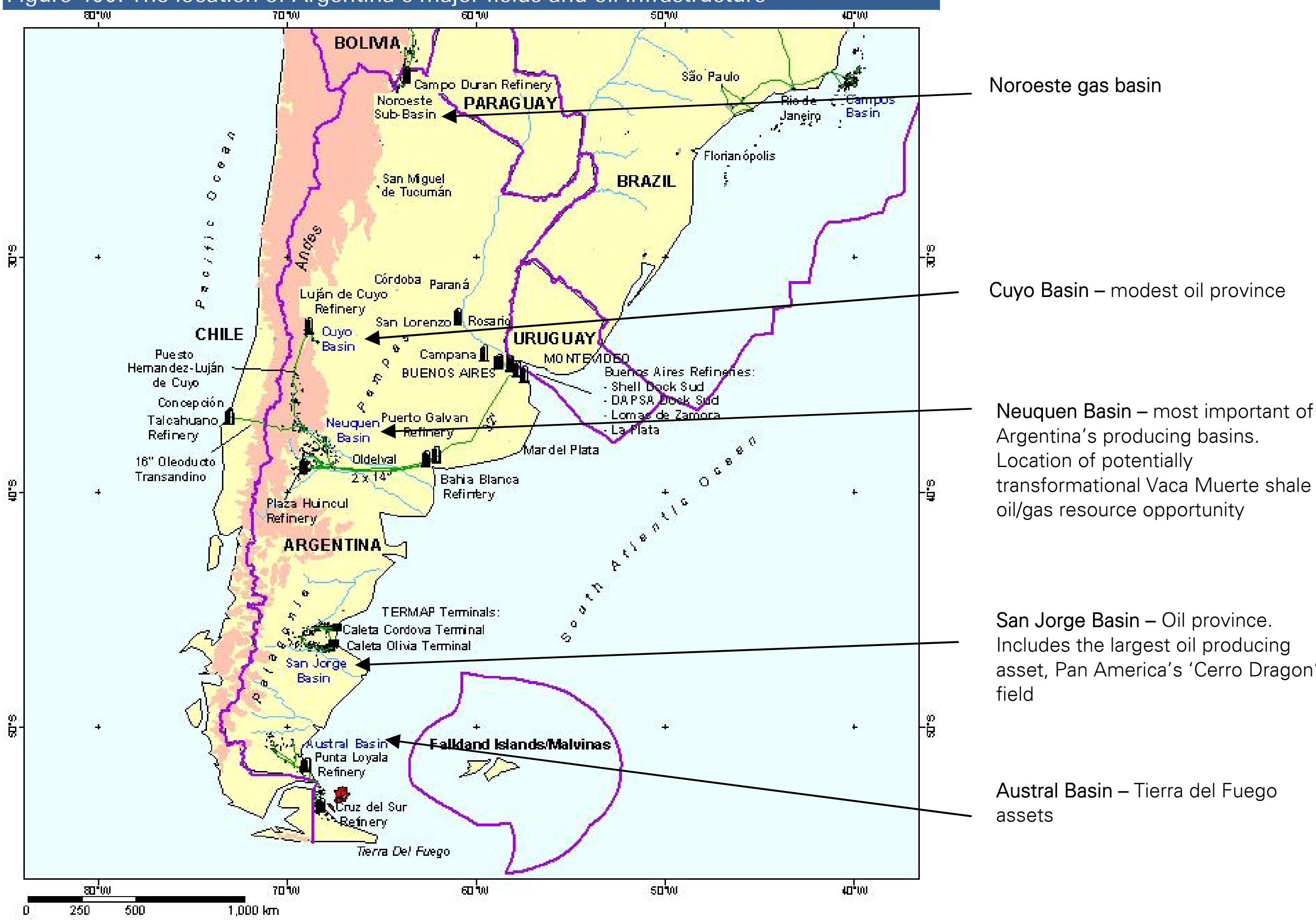
Yet where the sale of YPF saw the state's direct involvement in the upstream industry come to an end, the currency and economic crisis of 2002 resulted in it introducing regulatory measures which have had a debilitating effect on industry profitability and investment. Importantly, prior to the economic crisis of 2002 and the devaluation of the peso hydrocarbon prices in Argentina were not regulated. Rather they were determined on the open market. However, with the value of the peso collapsing against the US$ and energy prices effectively spiralling out of control, in March 2002 the Government introduced an export tax on crude oil. Initially set at 20% the rate was subsequently raised in 2004 to 45% and further adjusted in 2007 in order to cap the maximum oil price at $42/bbl where oil prices exceed the reference WTI oil price of $60.90/bbl. Most significant, however, has been the government's regulation of domestic gas prices with the previous $-based, market determined price frozen at its March 2002, pre-devaluation, peso equivalent. For the producers this implied a 65% price cut, the price of gas at the well-head effectively falling to the equivalent of c.$0.40/mscf. Although in 2004 the government and industry agreed to implement staged price increases (the government at the same time introducing a 20% export tax on gas) and later introduced a mechanism for producers to directly negotiate a price with industrial users ("Gas Plus"), progress to date has been slow in the extreme. The result is that the blended average price paid by residential, industry and utilities is today little over $2/mcf. Moreover, as demand from the economy for lowly priced gas has increased, so domestic gas production has stagnated through a lack of investment, thereby pushing Argentina from a position of gas self sufficiency to one of import dependence. Export contracts with Chile have been curtailed, contracts for the supply of gas from Bolivia extended, and since 2010 LNG imports have grow rapidly to the extent that the State company, Enarsa, projects the need for 83 cargos in 2013 (up from 56 in 2012 and 0 in 2009). With the customer paying a blended average $2/mcf, domestic production declining, and the government subsidising the 20% of demand (and rising) that is now satisfied by imports costing $10/mcf or higher, this is clearly a dysfunctional situation for an ostensibly resource rich country.

Against this backdrop 2011/12 saw two significant and arguably linked developments in Argentina's hydrocarbon industry. First, YPF commenced E&A activities aimed at delineating the shale oil/gas potential of the Vaca Muerta formation in the Neuquen Basin. Initial success resulted in Repsol guiding in Feb-12 that the defined contingent resource was already 1.5bn/boe and that the gross contingent plus prospective resource opportunity could reach 21bn/boe (6bn/bbls liquids, 15bn/boa gas). Against Argentina's current 2P resource base and declining production trajectory this new discovery clearly has transformational potential, but would require substantial investment, which in turn would require much more accommodative prices than $2/mcf. Furthermore, this disclosed resource potential related to just one basin, with the apparent potential for an unconventional hydrocarbons in a series of other basins.

Second, in April 2012 the Argentine President took the populist decision to effectively re-nationalise YPF via the forced expropriation of 51% of Repsol's interest for nil compensation (prior to this the YPF shareholding structure consisted of Repsol c57%, Argentine private investors 25% and a float of c18%). In essence the government was using the production declines as justification to take control of the shale opportunity.

This has a number of consequences. First, Repsol is pursuing various legal routes to secure compensation from the Argentine state. Second, the YPF balance sheet alone would seem ill placed to independently fund a prompt development of the shale opportunity and hence it should be expected that over time YPF will seek financial or technical partners to offer support.

Figure 400: The location of Argentina's major fields and oil infrastructure



Source: Wood Mackenzie; Deutsche Bank

Licensing

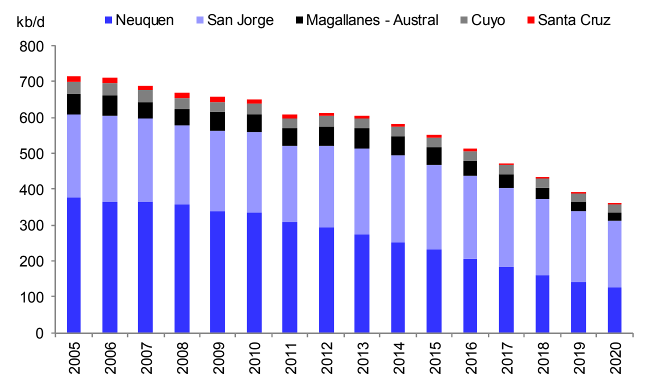
At present the upstream sector in Argentina is regulated at the federal level by the State Secretariat for Energy. The regulatory framework and fiscal terms are established by the Hydrocarbon Law (1967) and subsequent amendments. A new Hydrocarbon Law has been mooted to create a new upstream regulator and cede greater power to the provinces, however progress does not appear to have been made.

Production of Oil and Gas

Argentina's oil fields are, by and large, mature. This coupled with reduced investment following the economic crisis in 2002 has meant that oil production, which in 2009 stood at 683kb/d, has been declining in recent years, a trend which is expected to continue. Similar to the previously aforementioned 'Gas Plus' programme, the government has also introduced an equivalent 'Petroleo Plus' programme to encourage oil production growth and oil reserve replacements. Production of gas which, in 2009 ran at 4.2bcf/d has also suffered as a consequence of faltering investment post the

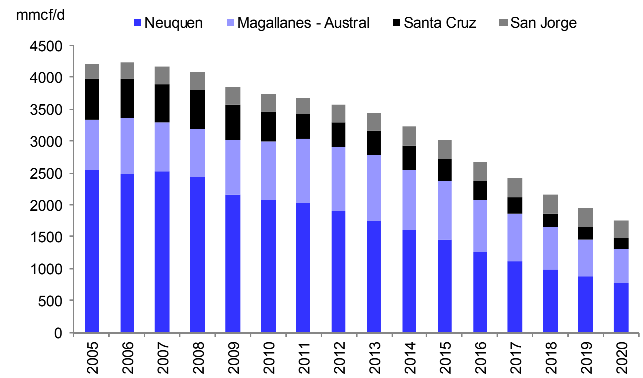
2002 crisis. Unless the economics around gas pricing improve further investment is likely to mean that gas production will continue to decline. This is despite the existence of both significant 2P and technical reserves. For the reasons already noted, the pressure to increase domestic gas prices to incentivise investment can only be seen to be increasing. As to the producers, as illustrated by the charts below, production of both oil and gas is dominated by YPF whose largest producing asset, Loma La Lata accounts for 16% of the country's gas production. BP's position reflects its 60% interest in Pan American Energy which operates the country's key oil producing asset, the 100kb/d Cerro Dragon field in the San Jorge Basin.

Figure 401: Argentina Liquids production 2005-20E (kb/d)



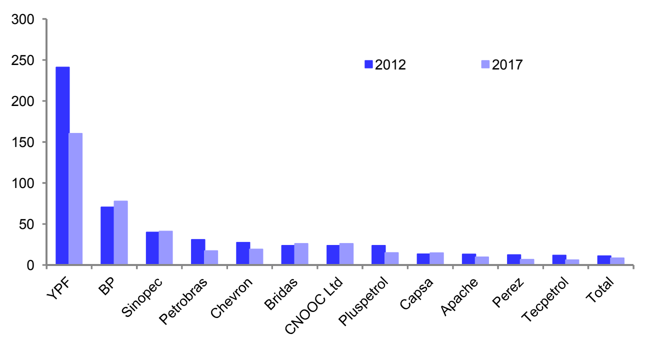
Source: Wood Mackenzie

Figure 402: Argentina: Gas production 2005-20E (mscf/d)



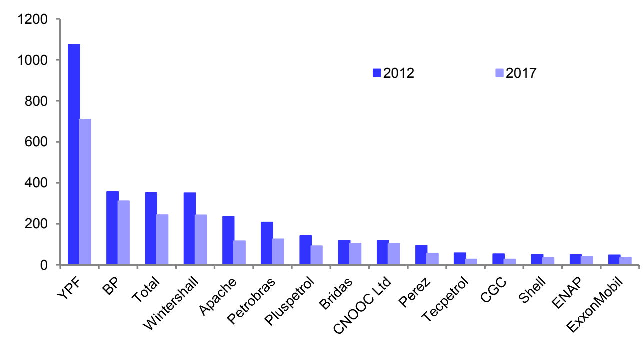
Source: Wood Mackenzie

Figure 403: Argentina: Major liquid producers 2012/17E



*Source: Wood Mackenzie * through Pan American Energy*

Figure 404: Argentina: Major gas producers 2012/17E



Source: Wood Mackenzie

Reserves and resources

At the end of 2012 Wood Mackenzie estimates suggest that Argentina had 2P oil reserves of 2.4bn bbls and gas reserves of 11.8TCF. Oil reserves are principally located within the San Jorge Basin with Pan American's Cerro Dragon field accounting for around 33% of those of the entire country. Gas reserves are by contrast concentrated in the Neuquen (not least at Loma la Lata) and Austral Basins (Cuenca Marina Austral). Looking forward, given the maturity of the Argentine producing basins, the prospect for reserve growth would appear to rest on the exploration, appraisal and development of the nascent shale oil and gas technical/prospective resource opportunity.

Pipeline and infrastructure

Argentina's centres of oil production and consumption are connected by a series of pipelines which are owned and operated by the major producers, not least YPF. Most significant is the 220kb/d, 1500km Oldelval pipeline which runs east from the producing fields in the Neuquen Basin towards refineries on the eastern seaboard with subsequent connections to Buenos Aires. Otherwise Neuquen produced oil is piped north to YPF's 120kb/d Cuyo oil refinery. Similarly, oil produced in the San Jorge Basin is transported via an extensive pipeline network to ports on the South Atlantic at Caleta Cordova and Caleta Olivia. These have a loading capacity of some 220kb/d.

For gas, a domestic transmission system which comprises over 8000km of trunk lines carries gas from the main producing basins towards Buenos Aires. These are operated by two main distribution companies which are owned by a consortium of producers. Simplistically, Transportadora de Gas del Norte or TGN, operates the pipelines in the north of the country carrying gas from the Noroeste and Neuquen Basins while the Transportadora de Gas del Sur or TGS looks after those in the south carrying gas from the San Jorge and Austral Basins as well as gas from the Neuquen.

In addition to the domestic transmission system, there are also a number of international pipelines for the transit of gas to and from Argentina. Perhaps ironically, several of these were established to monetize surplus Argentine gas by supplying purpose built power generation facilities in Chile and Brazil. Latterly the Bolivia-to-Argentina gas infrastructure has been expanded to facilitate rising imports, not least from Bolivia's Margarita gas field. We detail below some of the more significant pipelines.

Figure 405: Selected pipelines

Name	Length (km)	From	To	Capacity mcf/d	Purpose
YABOG	440	Bolivia	Arg	495	Gas to Argentina
Methanex	50	Austral	Chile	71	Feed stranded gas to plant
GasAndes	459	Neuquen	Santiago	353	Domestic market
Gas Atacama	925	Noroeste	N.Chile	265	Power generation
Gasoducto del Pacifico	537	Loma La Sata	Chile	124	Power generation
TGM	440	Neuquen	Brazil	530	Power generation

Source: Wood Mackenzie, Deutsche Bank

Crude oil blends and quality

Argentina's principle export blend is Medanito (API 34.9 degrees, sulphur 0.48%) which is sourced from the Nequen Basin and exported from Bahia Blanca on the East Coast. Beyond this the country also exports two heavier blends. Of these, Escalante comes from the Nequen Basin and has an API of 24.1° but, at 0.19%, is very low in sulphur. The other, Canadon Seco from the San Jorge Basin is more sour (0.62%) but slightly lighter than Escalante at c26° API.

Broad fiscal terms

Following the introduction of 'Plan Argentina' in 1991, Argentina moved to a tax & royalty regime. Historically, the fiscal system was relatively generous. Key fiscal components included the payment of a tax deductible royalty on the wellhead value of the hydrocarbons produced, typically at 12%, provincial sales tax of 1-2% on hydrocarbons sold in the domestic market and profit tax at 35% (after deduction of royalty and provincial tax). As such, the marginal tax rate ran at roughly 44%. However, following the economic crisis of 2002 the government introduced an additional export tax on crude oil exports. Initially intended for a period of five years, the tax has subsequently been increased twice and extended to 2011. At present, the tax operates on a sliding scale whereby 25% tax is payable at oil prices below $32/bbl and increases to whatever level necessary to cap the maximum oil price achievable by oil producers at $42/bbl. This effectively means that at a WTI price of $80/bbl, the marginal tax rate on crude oil exports is thus around 90%. Separately, since May 2004 an Export Tax of 20% has been payable on gas exports.

Refining

According to Wood Mackenzie Argentina's eight operating refineries have 640kb/d of refining capacity. With domestic demand rising, utilization rates have also increased to stand around 90% - likely close to sustainable levels. Most of the capacity is located near Buenos Aires. YPF dominates the sector through ownership of three refineries with a total capacity of c330kb/d, most significantly the 190kb/d La Plata refinery located near the capital.

It should be noted that Argentina effectively controls product prices at the retail pump a feature which again significantly limits the profitability of the domestic oil market. We note that pump prices have been allowed to increase significantly in recent years, but nonetheless the price of fuel at the pump in Argentina remains some below comparable prices in neighbouring countries such as Chile and Brazil.

LNG

With domestic gas production declining, the state owned company, ENARSA, has constructed re-gas capacity to facilitate LNG imports. Two facilities are presently operational, the 3.8mtpa Bahia Blanca GasPort located 600km southwest of Buenos Aires and the 3.8mtpa GNL Escobar facility located 48km north of Buenos Aires. There are proposals to add further capacity, including a third 3.8mtpa facility named GNL Puerto Cuatreros.

Argentina Notes

Australia

Predominantly a gas province, Australia's gas reserves are estimated to have stood at 147Tcf at the end of 2012, the highest in Asia Pacific and tenth largest globally. Ideally located to act as a supplier to the gas hungry Asian market, development of its vast gas reserves is continuing apace using LNG technology. Gas production has increased by 40% over the last decade as the country has established itself as a leading global LNG producer. In addition to its large conventional gas reserves, its considerable coal seam gas reserves offer great potential for the development of coal bed methane and represent what should prove an increasingly important source of production growth in future years. In terms of liquids, production peaked at 737kb/d in 2000 and has since been in decline currently standing at around 400kb/d. Major IOC producers in Australia include BHP, Woodside, Santos, Shell, and ExxonMobil with Chevron and BG Group set to grow very significantly from a currently limited base.

Basic geology and topology

Australia lays claim to some 48 sedimentary basins, of which around 20 are found offshore, with hydrocarbons found in rocks formed during several geological periods. The majority of the country's reserves are found in either the Gippsland Basin off the south east coast or the prolific Carnarvon Basin on the North West coast. The latter is Australia's most important hydrocarbon province accounting for two-thirds of the country's gas reserves, not least by virtue of the resources contained in the North West Shelf and the Greater Gorgon Area.

The bulk of the country's liquid reserves are gas-associated with some modest oil produced in central Australia's Cooper/Eromanga Basin. The Bass Strait in the Gippsland Basin, which since the 1970's has been one of Australia's main associated liquids regions, is expected to remain an important oil region in the future, despite production peaking in 1985.

Regulation and history

Australia's oil and gas industry is young relative to some of its peers. Oil production commenced in the early 1960's following the discovery of significant liquids in the Gippsland Basin. In 1969 the gas market took off with the start of production from Exxon's interests in the Bass Strait and the subsequent discovery of significant resource in the Cooper Basin. This was followed by material discoveries in the offshore Carnarvon Basin, not least the 1984 discovery of the North Rankin Field, the gas from which formed the basis of the North West Shelf LNG projects and its current 17mtpa of LNG capacity.

Beyond production of hydrocarbons from conventional sources, coal seam gas (CSG) production has increased steadily since 1995 with the start-up of the Fairview field in the Bowen Basin. Indeed, since 2001, production has been strong enough to supply a significant proportion of Queensland's gas consumption. Furthermore with several CSG to LNG projects planned, CSG is expected to secure an increasing source of gas supply.

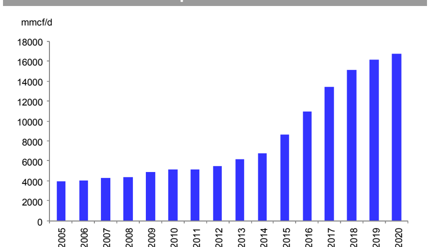
Regulation of exploration and production in Australia is shared between the Commonwealth Federal Government and the State/Territory Governments. The State Governments are responsible for all production within their state, both onshore and up to three nautical miles offshore. All remaining acreage (i.e. further than three nautical miles offshore and within Australia's territorial waters) is regulated by the federal government. The latter is governed by the Offshore Petroleum Act 2008.

Key facts

Liquids production 2013E	439kb/d
Gas production 2013E	1.03mboe/d
Oil reserves 2013E	3bn bbls
Gas reserve 2013E	147TCF
Reserve life (oil)	19 years
Reserve life (gas)	66 years
GDP 2012E ($tn)	$1.5trillion
GDP Growth 2012E (%)	3.3%
Population (m)	22.7
Oil consumption (mb/d)	1.02mb/d
Fiscal regime	Tax & Royalty
Top Gas Projects (2012E)	
NWS Gas Project	2,804mmcf/d
Bass Strait	550mmcf/d
Cooper Basin	255mmcf/d
Top 3 Gas Producers (2012E)	
Woodside	800mmcf/d
BHP	740mmcf/d
RDS	460mmc/d

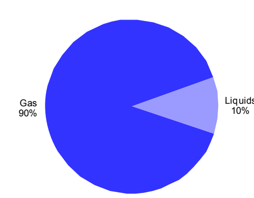
Source: Wood Mackenzie; IMF; EIA

Gas Production profile mmcfd



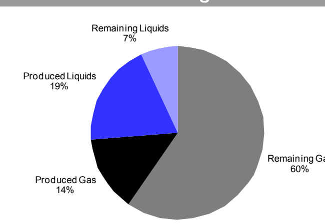
Source: Wood Mackenzie data

Remaining reserves split %



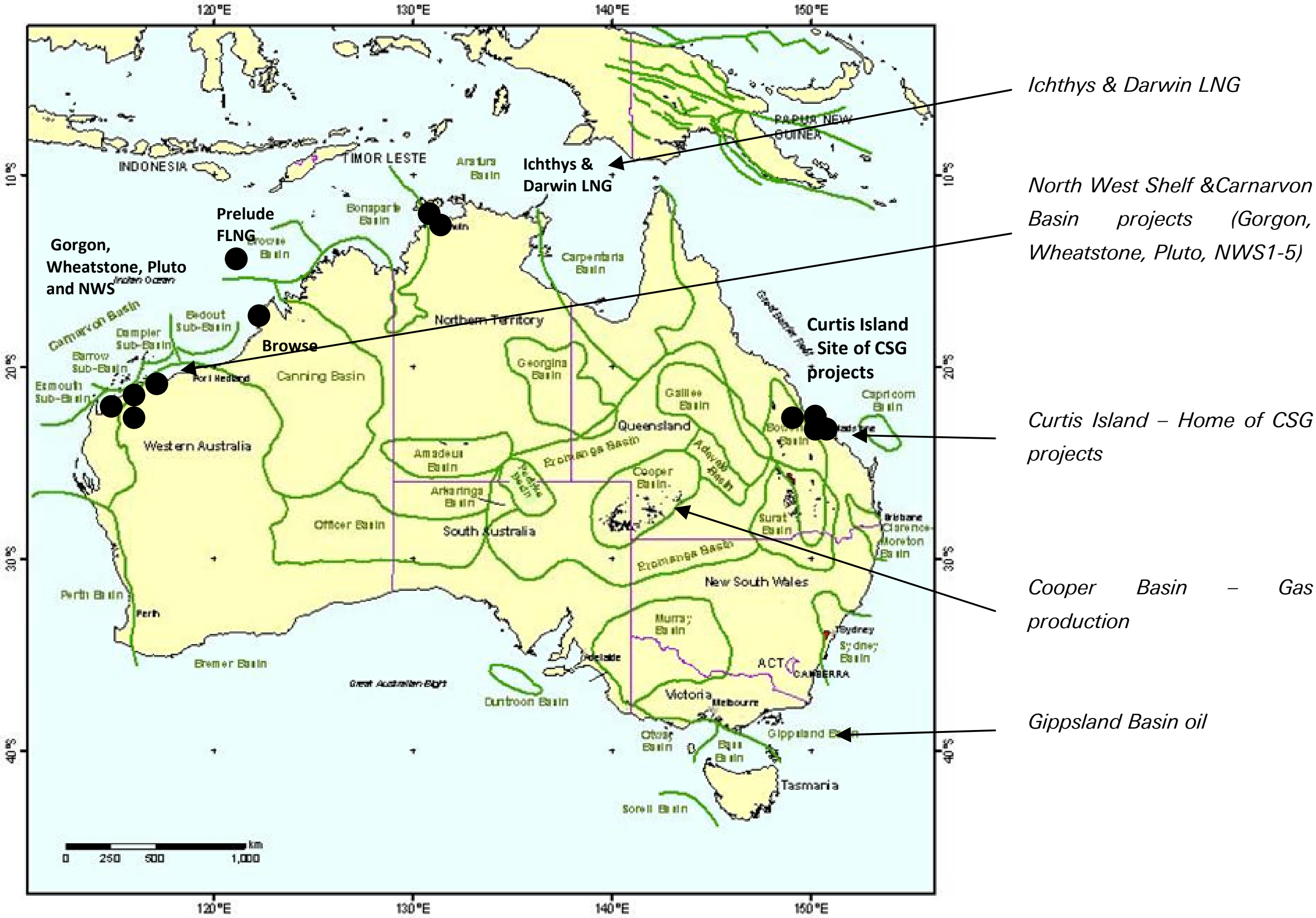
Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Figure 406: Australia: Main regions and oil and gas basins



Source: Wood Mackenzie,

Licensing

In federal waters, permits for available exploration are allocated annually based upon a work programme bidding system in which details of the minimum amount of work and estimated expenditure p.a. are disclosed. Exploration permits are granted for six years, with the first three typically being mandatory. Thereafter, the permit may be surrendered provided that the work programme has been fulfilled. In the past the Foreign Investment Review Board could demand that development projects have at least a 50% state interest. This requirement was, however, abolished in 1988 and oil & gas development may proceed with 100% foreign equity. Upon successful discovery, the permit holder has two to four years to consider applying for either a production license (for life of field) or a retention license. Retention licenses last five years but can be extended for a further five years if the operator can demonstrate the discovery is likely to be commercialized within the following fifteen years.

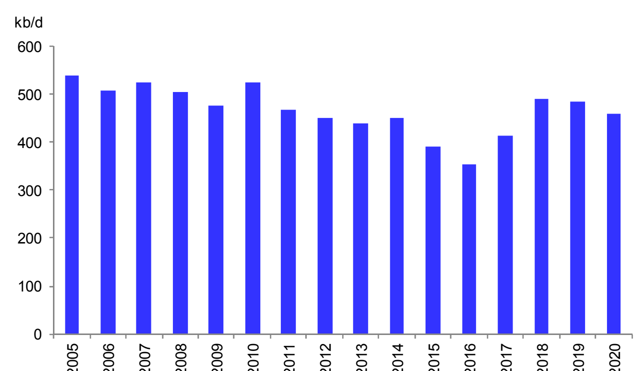
Onshore licensing, which comes under State jurisdiction, is administered by the relevant State Authority thus licensing legislation can vary considerably. Although some States conduct formal annual licensing rounds, in general exploration blocks can be applied for at any time. The table below illustrates the various licensing details across states.

Production of Oil & Gas

Increasingly, Australia's gas production is set to be used for sale into export markets as LNG. At present, LNG production arises from three projects producing c.25mtpa, namely Darwin LNG (Conoco, ENI), Pluto (Woodside) and, more significantly the five train 17mtpa North West Shelf Venture, (NWSV) which is owned by a consortium of six companies (Woodside, Shell, BP, Chevron, Japan Australia LNG and BHP Billiton). Through 2017 an explosion in commercial LNG production is, however, anticipated with some 60mtpa of LNG capacity added as a number of LNG projects complete construction. As a consequence gas production by 2020 is set to broadly treble from the current 5.5bcf/d towards 17tcf/d. Important within this growth will be the increasing contribution anticipated from coal seam gas (CSG) predominantly as a feedstock for LNG which by 2020 is expected to account for towards 20% of domestic production. Key national gas producers include Woodside and BHP Billiton, both of which have significant interests in both LNG and domestic gas production. The build in their LNG presence over the coming years suggests however that by 2020 gas production in Australia will be dominated by Chevron and Shell.

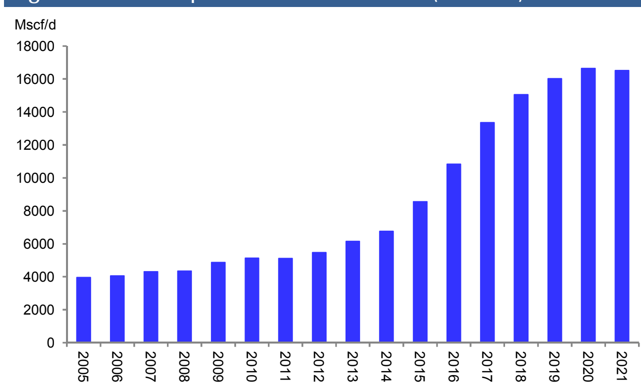
Conversely, liquids production has been in steady decline reflecting the maturation of production from the Bass Strait. Over the next decade production should however stabilize at c450kb/d as production of gas-associated condensate builds with the commissioning of the country's LNG facilities and offsets the decline from tradition sources of production.

Figure 407: Liquids production 2005-20E (kb/d)



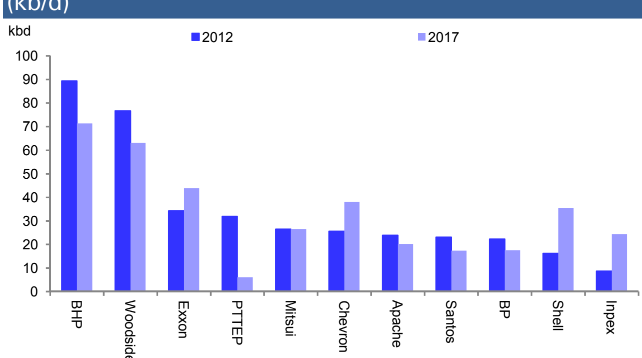
Source: Wood Mackenzie

Figure 408: Gas production 2005-20E (mmcfd)



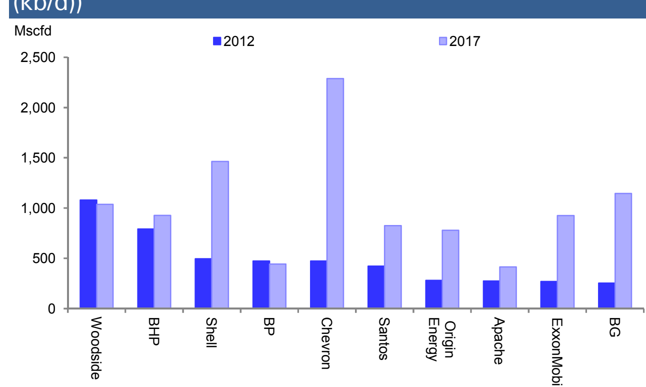
Source: Wood Mackenzie

Figure 409: Liquids production by company 2012 & 2017 (kb/d)



Source: Wood Mackenzie

Figure 410: Gas production by company 2012 & 2017 (kb/d))



Source: Wood Mackenzie

Reserves and resources

Australia's total remaining gas reserves are estimated at approximately 4.2 billion barrels of liquids and 147Tcf of gas. According to the Australian Bureau of Agricultural and Resource Economics (ABARE) total reserves have increased three-fold over the past twenty years. As stated previously, the majority of the estimated recoverable conventional reserves reside off the west and north-west coast of Australia in the Carnarvon Basin. The principal onshore gas reserves are encountered in the coal seams of the Surat and Bowen Basins which together account for towards 20% of total gas reserves. Given the youth of Australia's gas industry and the fact that is remains relatively under-explored, exploration efforts could yield further reserve increases in the future, not least from tight and shale gas.

Pipelines and infrastructure

Australia has extensive gas infrastructure reflecting the sheer scale of Australia's land mass and the distance between the main sources of production and delivery. Over 11,000km of pipeline have a combined capacity of c3bcfdmmcfd. These essentially connect production centres in the Cooper, Surat and Bowen basins with the major conurbations on Australia's eastern seaboard.

Crude oil blends and quality

Australian crude is typically light with an API ranging from 36°-59°.The crude is quite sweet with a sulphur content ranging between 0.01% and 0.1% with the blend from the Gippsland Basin having an API of 42° and a sulphur content of 0.1%.

Broad fiscal terms

The Australian oil & gas industry essentially operates as a tax & royalty concession albeit one of the more complex. Upstream licenses outside state/federal boundaries are taxed depending on locality and mainly comprise Petroleum Resource Rent Tax (PRRT) and corporation tax resulting in a marginal tax rate of c60%. Following the introduction of changes to minerals taxation in late 2012 upstream projects within state boundaries are now also liable to PRRT but with the royalty paid to the state treated as an allowable expense. Thus:

- Offshore fields suffer PRRT, with the exception of the North West Shelf gas project. Under the PRRT system, companies pay no royalty but are subject to a 40% profits related tax after on profits after deduction of development, operation, and exploration costs together with interest. Importantly, as a consequence PRRT only becomes liable once all development expenditure has been recovered.
- For onshore or near-onshore fields under State jurisdiction the royalty rate applies. In most states the royalty rate is around 10% with all of the royalty collected by the State Government. As of 2012 the upstream component of these projects is also liable to PRRT but after the deduction of royalty.

In 2011 Australia also introduced a tax for carbon emissions. Initially set at $23/tonne this will escalate at 5% p.a. through after which an emissions trading scheme is expected to be introduced. The allocation of permits reflecting its importance to the Australian economy and the global nature of its competition, means that the LNG industry is expected to pay only a proportion of this tax.

Refining

As Australia's liquids production has faltered so too has its mature and aging refining industry come under increasing stress. Recent years have seen the closure of several refineries (Shell Clyde -85kb/d, Caltex Kumell -124kbd) reducing capacity at the remaining five refineries to 540kbbl/d. With Australia's demand for crude oil and products now at over 1mb/d the country remains dependent upon the import of products in order to meet its demand requirements. Small and uncompetitive, further restructuring of its refining base is likely to prove inevitable.

Figure 411: Australian Refineries

Name	Location	Owners	CDU capacity (kb/d)
Altona	Melbourne, Victoria	ExxonMobil	78
Bulwer Island, Brisbane	Brisbane, Queensland	BP	90
Geelong	Geelong, Victoria	Shell	130
Kwinana	Kwinana, Perth	BP	138
Lytton	Brisbane, Queensland	CVX (50%), Other (50%)	104

Source: Wood Mackenzie

LNG

Currently the world's fifth largest LNG exporter, Australian LNG exports have risen by almost 50% over the last decade as its production capacity has built out. The continued build illustrated below is expected to see The three existing LNG facilities are the North West Shelf Venture (NWSV) and Darwin LNG. As stated earlier the NWSV is the larger of the two projects with a combined capacity of 16.3mtpa. Growth in LNG is expected to come from new projects currently under construction as detailed below. Pluto which aims to monetise some 4.8TCF of gas reserves via a 1 train 4.8mtpa facility is due to come on-stream in 2011, while the giant Gorgon project is expected on-stream in 2014. This is expected to monetise some 43TCF of gas reserves via a three-train LNG facility with total capacity of 15mtpa.

Moving onshore, CSG to LNG is expected to be a significant driver of growth in the near term with a number of projects such as BG's Curtis LNG and Santos' GLNG targeting first production from late 2014. We outline below the key existing, under construction and planned LNG projects below.

Figure 412: Key gas projects: on-stream and planned

	Project	Basin	Gas Reserves TCF	Liquid reserves Mbbls	Capacity (mtpa)	Start up	Main IOCs (*operator)
On-stream	North West Shelf	Carnarvon	16.9	443	17.4	1989	Woodside*, BHP, BP, Chevron, MIMI, Shell (all 16.7%)
	Darwin LNG	Bonaparte	3.0	214	3.6	2006	COP* (57%), Santos (12%), INPEX (11%), Eni (11%).
	Pluto	Carnarvon	4.8	62	4.8	2012	Woodside* (90%), Kansai (5%) and Tokyo Gas (5%)
Under Construction	Gorgon	Carnarvon	36.6	244	15.6	2014	Chevron* (47.3%), Exxon (25%), Shell (25%)
	Curtis	Surat	9.6	-	8.5	2014	BG (93.8%)*, CNOOC (5%), Tokyo Gas (1.3%)
	GLNG	Bowen/Surat	9.0	-	7.8	2015	Santos (30%)*, Petronas (27.5%), Total (27.5%)
	Australia Pacific	Bowen/Surat	12.4	-	9.0	2016	COP (37.5%)*, Origin Energy (37.5%), Sinopec (25%)
	Wheatstone	Carnarvon	11.0	169	8.9	2016	Chevron* (72.14%), Apache (13%), RDS (6.4%)
	Ichthys	Browse Basin	11.8	500	8.4	2017	INPEX* (76%), Total (30%)
	Prelude	Browse basin	2.8	110	3.6	2017	Shell (70%)*, Inpex (30%)
Planned Offshore (CBM)	Browse	Browse	14.7	417	12.0	2019+	Woodside (31%)*, Shell (27%), (BP 17%) CNPC (10.6%),
	Greater Sunrise	Bonaparte	5.1	226	4.0	2021+	Woodside (33.4%)*, Shell (26.6%), COP (30%)

Source: Wood Mackenzie

Australia - notes

Azerbaijan

Azerbaijan is one of the oldest oil producing regions in the world. Onshore oil production peaked at just under 500kb/d in the early 1940s but following decades of production, reserves of only an estimated 300 mboe suggest the onshore is now largely spent. However, in the offshore significant prospectivity and reserves remain, much of which is associated with a single PSC - BP's 700kb/d Azeri Chirag Guneshli (ACG) contract. Similarly, in gas markets the giant, BP-operated, 34Tcf Shah Deniz gas-condensate field offers significant potential for expansion from its current production rate of c.135kboe/d assuming new export routes can be agreed upon and a pipeline constructed. At end 2012 Azeri 2P reserves stood at some 7.1 billion barrels of oil and 45Tcf (7.8bn boe) of gas.

Basic geology and topology

From a hydrocarbon perspective, the geology of Azerbaijan is dominated by a single sedimentary basin, the South Caspian. Believed to be one of the most prolific oil provinces in the world, the petroleum geology of the basin owes its attractiveness to high quality reservoir sands, rich source rocks and the development of large anticlinal traps. This combination has served to create numerous large, productive fields containing sweet (less than 1% sulphur), light (around 34 degree API) oil. While 150 years of extraction means that much of the onshore has now been largely depleted, substantial potential is believed to remain in the offshore in water depths of up to 1000m, as demonstrated by Total's 11tcf 2011 Absheron discovery. Offshore Azerbaijan is however a difficult reservoir system not least given the 6,000 metre sub-sea depths of the reservoir systems. As such, formation pressures and temperatures tend to be very high with mud volcanoes a frequent phenomenon. Not only does this make drilling very technically challenging; it also means the reservoirs are vulnerable to collapse.

History and regulation

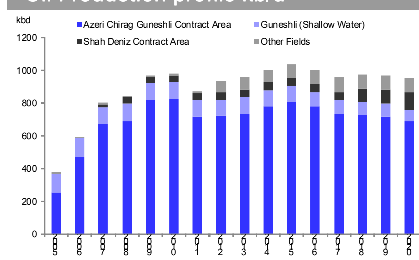
Azerbaijan is one of the oldest oil-producing nations and has played a significant role in the development of today's oil industry. In 1823, the world's first paraffin factory was built in the capital city of Baku, followed in 1846 by the drilling of the world's first oil field and in 1863 the world's first Kerosene factory. Indeed, the country was also the home to the world's first offshore oil field, Neft Dashlary, located in the shallow waters of the Caspian. Built on stilts some 50km off the Azeri coast, oil is still being produced from these offshore fields today. By the end of the late nineteenth century at 200kb/d Azerbaijan was the world's leading oil producer and Baku the heart of the global oil industry. Volumes peaked in 1941, at which time Azerbaijan produced around 475kb/d or 70% of the Former Soviet Union's total oil output. Although production recovered to around this level sometime after the Second World War, the growing maturity of the country's onshore oil provinces combined with a lack of facilities for drilling deeper offshore resulted in a steady decline in output and proven reserves. Indeed, despite the discovery of four substantial oil fields not least Guneshli (1979), Chirag (1985) and Azeri (1987), the Azeri national oil company SOCAR lacked the technology and finance necessary to develop these let alone further extend its exploration activities. Consequently, in 1991 the Azeri Government decided to open its doors to the international oil companies (IOCs) inviting them to tender for the development of its resource base. This resulted in the 1994 signing of the Azeri Chirag Guneshli (ACG) contract between the state oil company SOCAR and several international oil companies. It also saw a general land grab with several exploration licenses awarded to a host of international oil companies.

Key facts

Oil production 2012E	**0.9 mb/d**
Gas production 2012E	**0.3mboe/d**
Oil reserves 2012E	7.1bn bbls
Gas reserve 2012E	45TCF
Reserve life (oil)	20.7 years
Reserve life (gas)	47.1 years
GDP 2012E ($bn)	$71.billion
GDP Growth 2012E (%)	3.9%
Population (m)	9.2m
Oil consumption (mb/d)	0.8m/d
Oil exports (mb/d)	0.82mb/d
Fiscal regime	IRR-based PSC
Marginal tax rate	70%-90%
Top 3 fields (2012E)	
ACG	720kboe/d
SW Guneshli	203kboe/d
Shah Deniz	183kboe/d
Top 3 Producers (2012E)	
Socar	361kboe/d
BP	136kboe/d
Statoil	63kboe/d

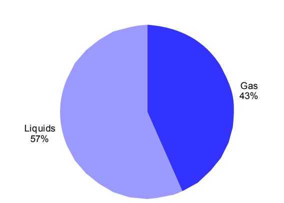
Source: Wood Mackenzie data; EIA

Oil Production profile kb/d



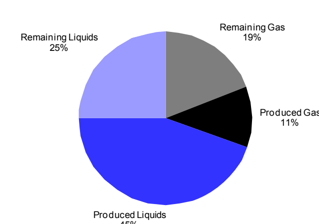
Source: Wood Mackenzie data

Remaining reserves split %



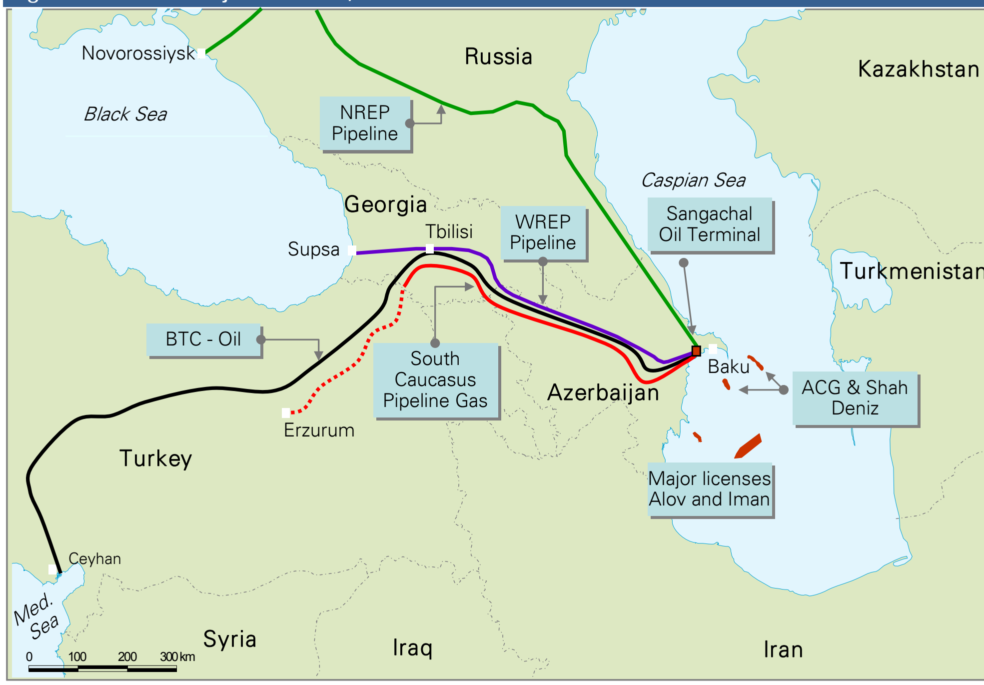
Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

Figure 413: Azerbaijan – Fields, infrastructure and licenses



Source: Courtesy of BP

Licensing

Azerbaijan has only ever conducted one open licensing round – that in 1991 for the Azeri field. Since that time contract negotiations have been direct with the national oil company SOCAR (State Oil Company of the Azeri Republic) which retains a 10% direct interest in the main producing fields. In the onshore, the maturity of the area has meant that the licenses on offer have typically been for enhanced oil recovery from existing fields, with little interest shown by the major IOCs. Strong perception of the prospectivity of the region meant however that subsequent to the signing of the ACG contract competition for licenses was high with significant signature bonuses paid. Licensing peaked in 1997 when 7 licenses were awarded. However, disappointing exploration results have meant that in subsequent years licenses have been relinquished more frequently than awarded. More recently two giant gas/condensate discoveries, Umid (6tcf and 230mboe condensate) and Absheron (c11tcf of gas & 350mboe of condensate), have driven renewed the exploration interest.

Production of Oil & Gas

Following the strong recovery in oil production associated with the ramp of BP's ACG fields, Azeri production is now expected to stabilise at around 1mb/d before declining slowly from mid-decade. A lack of new oil discoveries in recent years suggests, however, that absent the delivery of gas-associated liquids, Azeri production is unlikely to move beyond 1mb/d for the foreseeable future. This clearly represents something of an issue for the country. Dependence upon a single asset is also true of gas production given the overwhelming dominance of Shah Deniz albeit mitigated to some degree by the Absheron discovery. Key here, however, will be the determination of an export route and the funding of any future export project not least the signing of commercial gas sales contracts. At the present time, the most likely route will involve two pipeline consortia with 16bcma (1.5bcfd) of gas carried from Azerbaijan to and through Turkey via the Trans-Anatolian (TANAP) pipeline before connecting to either the planned 1300km Nabucco West pipeline which would carry the gas from the Turkish Bulgarian border to Austria's Baumgarten Hub or the competing Trans Adriatica Pipeline (TAP) which would take the gas to Italy. Of the delivered gas 6bcm is earmarked for Turkey with the balance expected to be delivered into Europe.

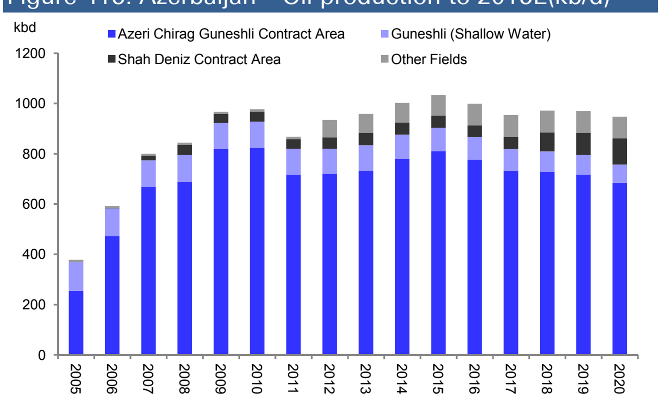
Figure 414: Azerbaijan International Operating Company members (BP operator)

Name	Stake	Narrative
BP	35.79%*	Operator. Gained status 6/99 post merger with founder member Amoco
Chevron	11.27%	Acquired through Unocal
SOCAR	11.65%	State oil company
Inpex	10.96%	Acquired from Lukoil for $1.35bn in '02 after others declined pre-emption rights
Statoil	8.56%	Entered as part of the BP/Statoil JV
Exxon	8.00%	
TPAO	6.75%	
Itochu	4.30%	
ONGC	2.72%	In Sep'12, Hess agreed to sell this along with 2.36% BTC pipeline to ONGC for $1bn

*Source: Wood Mackenzie, BP, Deutsche Bank *Operator*

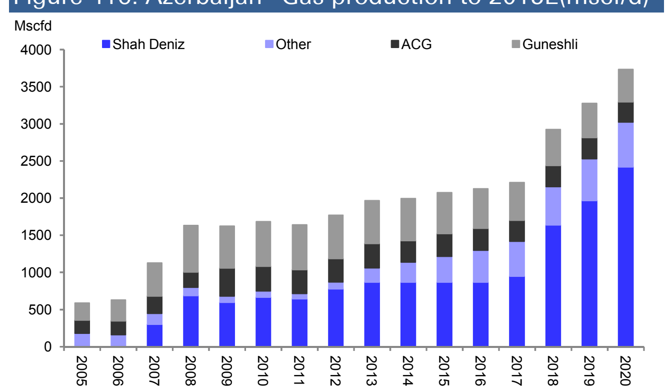
Initially, the ACG development was to be managed by a joint operating company comprising those companies that had signed up for the 1994 PSC, the Azerbaijan International Operating Company or AIOC. However, following its acquisition of Amoco in 1998, BP sought and was granted the role of operator. With a 36% interest in the PSC BP is thus the leading international producer in Azerbaijan, a position that is further cemented through its 25.5% leading interest in the Shah Deniz PSC. Other Shah Deniz shareholders include Statoil, which retains responsibility for marketing the gas, Total (10%) and Lukoil (10%)).

Figure 415: Azerbaijan – Oil production to 2015E(kb/d)



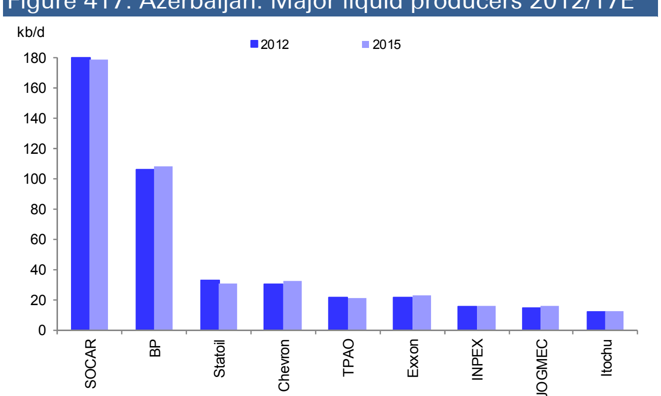
Source: Wood Mackenzie

Figure 416: Azerbaijan –Gas production to 2015E(mscf/d)



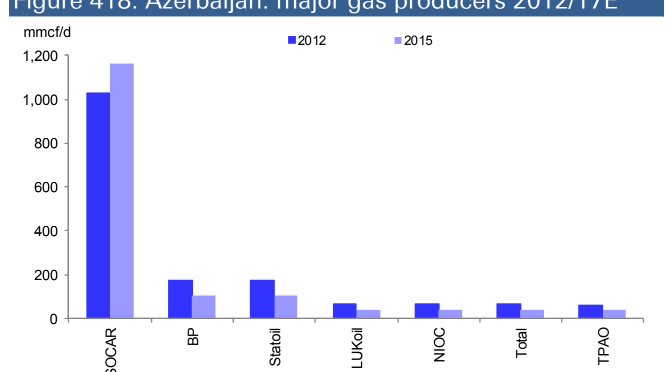
Source: Wood Mackenzie

Figure 417: Azerbaijan: Major liquid producers 2012/17E



Source: Wood Mackenzie

Figure 418: Azerbaijan: major gas producers 2012/17E



Source: Wood Mackenzie

Reserves and resources

At the beginning of 2012 estimated reserves of liquids stood at 7.1bn barrels of which 5bn were associated with the ACG fields. Similarly, gas reserves are estimated at 45Tcf, most of which are associated with Shah Deniz. It is, however, of note that following the success of the Absheron and Umid discoveries a further 15TCF or so of technical resource is estimated to lie in place.

Pipelines and Infrastructure

Historically, of the 350-400kb/d of Azeri oil and products not intended for domestic consumption, 100-150kb/d had typically been exported via rail to Black Sea ports in Georgia with the balance reaching the Black Sea for export through three main pipeline routes.

- The Baku Tbilisi Ceyhan (BTC) pipeline which runs 1760km from the ACG fields to the port of Ceyan, Turkey. The pipeline has a capacity of 1.2mb/d with the potential to be increased to 1.6mb/d with additional pump stations. Crude oil from Turkmenistan is also transported following signing of transportation agreement in July 2010 with the pipeline also expected to offer access to crude produced at Kashagan.
- The Western Route which runs from Baku to Supsa on Georgia's Black Sea Coast is 830km in length. Total capacity is 155kb/d although the facility has been running at utilisation rates well below this since coming back on-line late 2008 following extensive repairs.
- The Northern route from Baku to Novorossiisk on Russia’s Black Sea coast. Extending for 1346km and operated on the Azeri side by AIOC (and Transneft from the Russian border) this has a capacity of 160kb/d. At c40kbd utilisation has in recent years been well below nameplate.
- The South Caucasus pipeline or SCP, commenced operations in Dec 2006 with the start-up of Shah Deniz and transports gas to the Turkish/Georgian border. The 690km pipeline runs through Azerbaijan and Georgia and into Northern Turkey where it connects to the national network. The current capacity, 720mmcfd, being insufficient is expected to increase to 2,000mmcfd.

Crude oil blends and quality

With production dominated by the output from the giant ACG PSC the main oil blend is Azeri light. This is a light, sweet oil with under 1% sulphur and a 34 degree API.

Broad fiscal terms

Hydrocarbons in Azerbaijan are produced under production sharing contracts with the share of profits dependent upon the internal rate of return achieved by the project. Profits are calculated and shared between the state and the members of the PSC after the recovery of capex and operating costs, the first 50% of profits being available for cost oil recovery. (Note that capex not recovered in the year in which it is incurred can be carried forwards at LIBOR plus a 2-4% margin). Given the scale of the investment and the absolute level of capital returned the trigger points for a change in the profit share between contractor and state are relatively fine. Thus, using the ACG contract as an example, at its minimum hurdle rate (16.75% IRR) profits are shared 70/30 in favour of the contractors, a split which moves to 20/80 in favour of the State once the maximum 22.75% IRR has been achieved. The consequence of these terms is a very sharp fall in consolidated entitlement barrels for the AIOC partners as the different trigger points are attained. With the exception of the ACG PSC profits are also liable to corporation tax at 20% although half of the contractor's share of corporation tax is typically paid on their behalf by SOCAR. For the ACG fields corporation tax is, however, liable at 25% and with the full liability paid by the AIOC consortium.

Refining

Azerbaijan has two major refineries both of which are owned by the state oil company SOCAR and located near Baku. Detailed below, these are in very poor condition and, estimated to be running below 40% of the capacity. SOCAR is currently investing significantly to improve output although it is doubtful that they will ever achieve nameplate capacity.

Figure 419: Azerbaijan major refineries

Name	Location	Nominal Capacity	Focus
Azerneftyag	Baku	239kb/d	Fuel and lubes
Heidar Aliyev	Baku	203kb/d	Fuel and coke

Source: O&G Journal; Deutsche Bank

Azerbaijan Notes

Brazil

Success in the deepwater off its Atlantic coastline, not least the prolific Campos and Santos basins, has seen Brazil's emergence as a major oil producer in recent years with massive growth potential through to 2020 driven by the development of a series of multi-billion barrel discoveries in the pre-salt Santos Basin. From 2.2mb/d in 2012, Wood Mackenzie forecast that liquids production could exceed 5mb/d by 2020, thereby positioning Brazil as a major oil exporter. However, timely delivery of this potential requires significant challenges to be overcome, not least the need for Petrobras, as operator, to add over 20 FPSO units in the Santos basin pre-salt play by decade-end. Current 2P reserves are estimated to be 31bn barrels of oil and 18TCF of gas although this will likely prove conservative given the potential for follow-on exploration activity. Accounting for over 90% of output, Brazil's production is dominated by the 50% Government controlled Petrobras, although as the Santos and Campos discoveries are developed the volume contribution of IOC's, including BG, Statoil, Repsol, Sinopec and Galp will begin to expand. Large tracts of unlicensed and unexplored acreage exist in Brazil's most prolific basins, which has led the Government to recently develop a new regulatory framework to strengthen the role of the State and raises questions about future IOC access to Brazil's most prospective pre-salt opportunities. Pending full approval of this new framework (there remains an ongoing dispute around the division of royalties) no new offshore licenses have been awarded since 2007. This is expected to change in 2013 with the 11th license round possible around mid-year, whilst the much anticipated first round of licensing for the pre-salt region could occur toward year-end.

Key facts

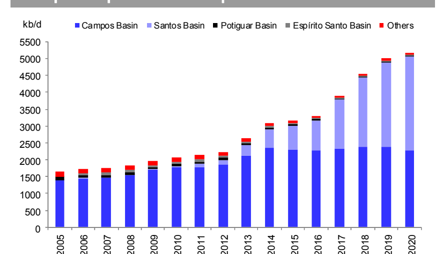
Liquids production 2012E	2.2mb/d
Gas production 2012E	0.25mboe/d
Oil reserves (2P) 2012E	31.4 bn bbls
Gas reserve (2P) 2012E	18.1 TCF
Reserve life (oil)	38 years
Reserve life (gas)	33 years
GDP 2012E ($tn)	$2.4trillion
GDP growth 2012E (%)	1.5%
Population 2012E	196.5m
Oil consumption 2011E (b/d)	2.8mb/d
Oil exports 2011E (mb/d)	na
Fiscal regime	Royalty & IT
Marginal tax rate (concession)	40-65%
Top 3 Liquids fields (2012E)	
Marlim Sul Area	300kb/d
Roncador	297kb/d
Marlim Area	202kb/d
Top Producer (2012E)	
Petrobras	2.2mboe/d
Statoil	44kboe/d
Shell	40kboe/d

Source: Wood Mackenzie, EIA, IMF

Basic geology and topology

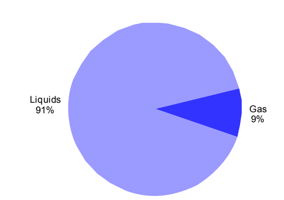
Brazil has some 29 onshore and offshore sedimentary basins. These were in large part laid down through the Cretaceous period with the coastal sedimentary basins evolving alongside their West African counterparts as the African and South American tectonic plates separated. The oil and gas plays are mostly confined to the country's eastern seaboard where salt-related structures are prominent and serve as important hydrocarbon traps. To date, the most significant discoveries have been those in the deepwater off the coast of Rio de Janeiro not least in the Campos, Espirito Santo and, more recently, the pre-salt of the Santos Basin. In the most important producing basin to date, the Campos, water depths extend up to 3,400m with the hydrocarbon-bearing reservoirs residing a further 2,800m below the seabed. Reservoir temperatures are, however, relatively cold which has meant that the oil tends to heavy (sub-30°API) and, as such, more challenging to extract.

Liquids production profile kb/d



Source: Wood Mackenzie

Remaining reserves split %

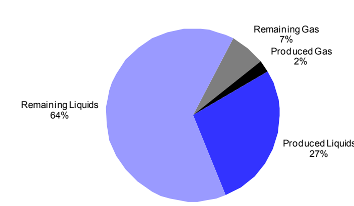


Source: Wood Mackenzie

Regulation and History

Akin to so many South American countries Brazil's oil and gas history reads as a litany of swings between nationalism and open access to private enterprise. Not least amongst these was the 1953 creation of the state company Petroleo Brasileiro SA (Petrobras) which, upon its establishment, was granted a monopoly over the exploration, production, refining and transportation of oil as well as its import and export, a position which it retained until 1997, when a new Petroleum Law was introduced. This removed Petrobras' monopoly rights, removed mandatory state participation and introduced a new era of concession agreements under which other companies could prospect for and produce oil under the auspices of a new National Petroleum Agency (the Agenca Nacional de Petroleo, or ANP). Following its formation, the ANP signed concession agreements with Petrobras permitting it to retain the vast majority of its acreage (around 7% of Brazil's sedimentary basins) but requiring it to prove up the commercial potential of retained exploration blocks within a three year period. To the extent that such commitments were not fulfilled, or Petrobras licenses

Initial versus remaining reserves



Source: Wood Mackenzie

extended, this acreage together with any new acreage being opened up (not least in the Atlantic margin) has been made available to the industry as a whole through a series of annual licensing rounds.

However, following the discovery of huge resources in the pre-salt, the Government has reassessed how the sector is structured, in 2009 proposing new legislation for the pre-salt or for areas deemed to be of 'strategic importance'. Under this new regime, which importantly will not apply to either pre-existing licenses or to future licenses outside of these strategic areas, three key changes will occur. First, a new state-run agency, Petro-sal, will be created to administer the PSAs, take a non-investing stake in licensed blocks and to receive the State's share of profit oil from each PSA. Second, the fiscal terms will evolve from a Concession to a Production Sharing structure with the government profit share a key biddable factor. Third, Petrobras will be the sole operator and will be required to carry a minimum 30% interest in new blocks that are offered to outside investors with the government, at its discretion, able to award Petrobras 100%.

Importantly, concurrent with the new legislative proposals, outlined above, in 2010 the government transferred the rights to c5bn/bbls of unlicensed pre-salt reserves to Petrobras in return for Petrobras shares, a process conducted in parallel with a Petrobras rights issue, designed to strengthen its capital position ahead of the pre-salt development phase. Following this transaction the direct Brazilian State interest in Petrobras' common stock is 50.24% with other State entities owning c8.38%.

Figure 420: The location of Brazil's major basins and refining infrastructure

c90% of Brazil's oil production and 50% of gas production from the Campos and Espirito Santo basins

Santos Basin - massive resource base and production growth potential via the pre-salt discoveries, including BMS-9 (Sapinhoa, Carioca), BMS-11 (Lula, Iara) plus Franco and Libra.

Source: Wood Mackenzie

Licensing

Following the opening of the market to international participants and the establishment of the ANP in 1997, Brazil has conducted licensing rounds on an annual basis, the 10th round having taken place end 2008. Given exploration success in the Campos Basin these have at times attracted significant interest and large signature bonuses (not least $260m in the 2nd Round in 2000). However, interest in the latest licensing round was more muted with only onshore blocks on offer. Contracts are awarded via competitive tender with signature bonuses being paid for the rights to a license between the bidding companies and the ANP in its role as the federal representative. In any license award the operator must have a minimum 30% interest whilst the minimum participation is 5%. Under the 1998 Model Concession Contract exploration licenses are for a 3-year period with a minimum work obligation defined, although a license extension will be granted as long as hydrocarbons have been discovered and an additional work programme agreed. Similarly, acreage surrounding discoveries will be allowed to be retained so long as an Evaluation Plan has been agreed. This will likely involve an appraisal programme and associated timescales. Assuming commerciality is declared, a Plan of Development will need to be submitted within 180 days for approval wherein a Development area, or multiple development areas, are defined by the ANP and acreage outside this area relinquished. Concession contracts generally last for 30 years with extensions possible, assuming the asset is still productive and the application is made one year before expiry. The long-awaited 11th round is likely to take place during 2013.

As already noted, a new licensing structure has been proposed solely for the areas which the Brazilian Government deems to be ‘strategic’ (for instance the pre-salt). Under this structure Petrobras will take a minimum 30% stake, fiscal terms will be PSA based and companies will bid based on government profit share. The precise structure of this new regime for the strategic areas has yet to be fully defined. There are suggestions that a first license round could commence in late-2013.

Production of Oil and Gas

Brazil’s c2.2mb/d of liquids production is concentrated in the offshore, the onshore basins producing little more than 100kb/d. The most important oil producing basin is the Campos, from which production first commenced in 1977 and which, following several major discoveries, now accounts for c75% of output. However, offshore discoveries in the pre-salt Santos Basins (e.g. Lula) will drive the majority of Brazil’s massive growth potential (toward 3.9mb/d in 2017 and 5mb/d in 2020). Production from Santos basin could rise from c0.1mb/d in 2012 to 1.4mb/d by 2017 and 2.8mb/d by 2020.

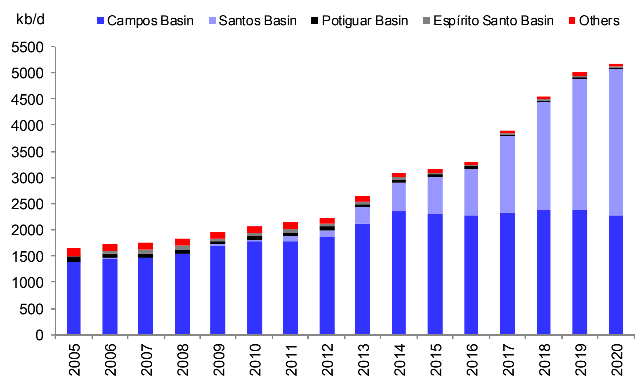
Figure 421: The changing shape of Brazil’s liquids production (kb/d)

10 Largest fields in 2012				10 Largest fields in 2017			
		2012E	2017E			2012E	2017E
Marlim Sul Area	Campos	300	223	Lula	Santos	82	606
Roncador	Campos	297	362	Roncador	Campos	297	362
Marlim Area	Campos	202	125	Sapinhoa	Santos	0	241
Barracuda Area	Campos	125	60	Marlim Sul Area	Campos	300	223
Marlim Leste Area	Campos	119	62	Cernambi	Santos	5	185
Jubarte	Campos	115	145	Franco	Santos	0	162
Lula	Santos	82	606	Jubarte	Campos	115	145
Albacora Area	Campos	75	39	Marlim Area	Campos	202	125
Peregrino	Campos	73	95	Papa-Terra	Campos	0	109
Cachalote	Campos	70	67	Baleia Azul	Campos	25	107

Source: Wood Mackenzie, Deutsche Bank

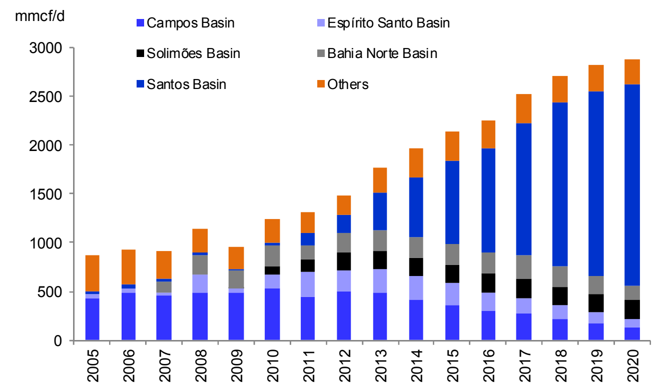
In general, production of gas has been associated with oil production with few non-associated gas fields developed. Despite the country's growing demands for gas, poor infrastructure has, however, meant that around half of the gas produced is either flared or re-injected. Overall, gas production is less concentrated than that of oil with significant volumes coming from the Espirito Santo, Campos and Camamu-Almada basins. The Santos basin is the source of growth with the Mexilhao field on-stream in 2011 and a fairly significant ramp anticipated in coming years due to volumes associated with the developed of pre-salt oil fields. Wood Mackenzie project that volumes will grow from 1.4bcf/d in 2012 to 2.9bcf/d by 2020.

Figure 422: Brazil Liquids production 2005-20E (kb/d))



Source: Wood Mackenzie

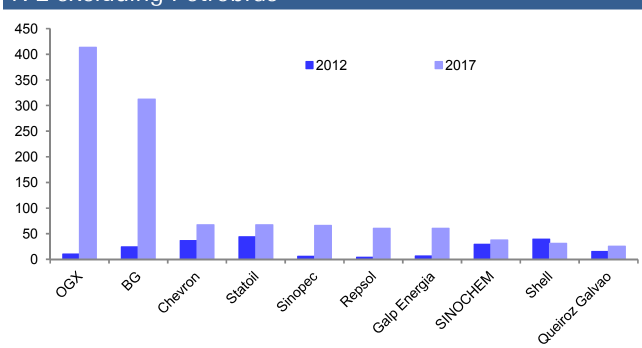
Figure 423: Brazil gas production 2005-20E (mscf/d)



Source: Wood Mackenzie

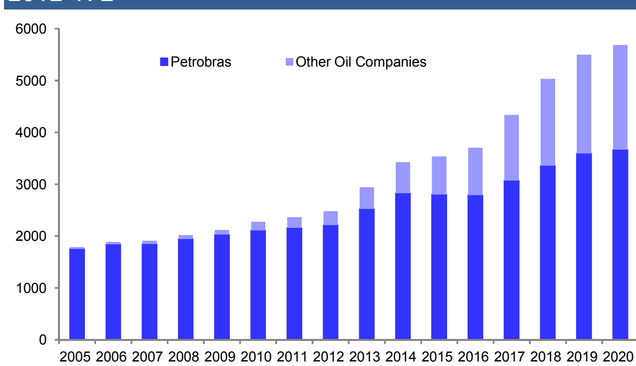
Production is dominated by Petrobras which accounts for comfortably over 90% of both oil and gas volumes. Although Petrobras' dominance is unlikely to change, the start up of several additional fields in the Campos, and, more importantly, the Santos will see the Brazilian offshore become a more important part of the IOC major's portfolios.

Figure 424: Brazil: Major hydrocarbon producers 2012-17E excluding Petrobras



Source: Wood Mackenzie,

Figure 425: Petrobras: hydrocarbon production in Brazil 2012-17E



Source: Wood Mackenzie

Reserves and Resources

At the end of 2009 Wood Mackenzie estimates suggest that Brazil had 2P reserves of 31.4bn barrels and 18TCF of natural gas. In the past, the majority of reserves were located in the deepwater of the Campos basin; however, significant exploration success in the Santos basin means this region has grown in importance in recent years. Today Wood Mackenzie estimates that c. 62% of commercial reserves are situated in the

Santos basin, with a further 33% located in the Campos basin. With exploration efforts continuing on the Santos basin we would anticipate reserves growth to continue over the coming years.

Pipelines and Infrastructure

The deepwater bias of Brazilian oil production has meant that most of its production is associated with FPSOs. Pipeline infrastructure is, as a consequence, relatively limited with production tending to be tanker loaded and shipped directly to coastal terminals and refineries located around the major conurbations of Rio and Sao Paolo. In the Campos Basin there is a pipeline system linking the shallow water fields to onshore processing facilities, whilst in the deepwater there is a relatively new 818kb/d pipeline gathering crude from the Marlim Leste, Marlim Sul and Roncador fields. Otherwise, pipeline systems do connect the remote onshore basins with the major centres of demand (production is, however, modest).

Similarly, gas infrastructure is relatively under developed, covering mainly the urban centres of Rio and Sao Paolo. Brazil has two major international pipelines, the 1200mscf/d Bolivia to Brazil pipeline (BBPL) and the Transportadora de Gas del Mercosur (TGM) pipeline carrying gas from the Nequen province in Argentina to a 600MW power station in southern Brazil at Uruguaiana. In 2009 Brazil started importing LNG via two re-gas facilities. The rapid growth in associated gas production linked to the development of the Santos Basin is likely to see greater investment in the domestic gas network in coming years, with current plans calling for the gas to the piped to shore (or re-injected) as opposed to exported via FLNG.

Crude Oil Blends and Quality

Brazil's continuing import dependence and Government policies designed to contain exports have meant that, to date, the export of crude oil has been limited to that quantity of heavy oil that the country's internal refining system was unable to process. The main crude stream is Marlim, from the field of the same name, which is a sweet (<1%), heavy (20°API) crude. As noted, Brazil's production growth will be driven by the pre-salt Santos Basin where the mains discoveries are somewhat lighter (Lula, Sapinhoa and Franco all 28-30°API). With production of oil now expanding beyond the capacity of the country's refining system and, indeed, its internal needs, exports are expected to increase significantly.

Broad Fiscal Terms

Brazil's existing fiscal regime operates on the basis of tax and royalty concessions with no obligatory state participation in project equity. Federal tax is collected through three particular means namely royalty; special participation tax (SPT); and corporation tax (CT). Of these royalty, is typically 10% of gross revenue (but can be less dependent upon agreement with the ANP), while CT stands at 34% and is calculated after the deduction of royalty, SPT and capital allowances (which run on a less than generous 10-20 year asset life schedule).

Dependent upon the scale of the producing asset, Special Participation Tax (SPT) can be a far more meaningful component of tax take. Chargeable on a sliding scale in accordance with an ANP defined production schedule, the rate depends upon the location of the field (onshore, offshore and depth), the rate of production (0-60kb, 61-90kb/d, 91-120kb/d, etc) and the year of production (lower tax in year one and full rates by year four). Because most of Brazil's fields are relatively modest (i.e. under 50kb/d) SPT tends to be low (sub 10%). However, on the larger fields the rate of SPT on production over 140kb/d can run at 40% (albeit that, as a staged tax, the rate of the production between 0 and 140kb/d will be taxed at a lower level thereby reducing the average SPT rate). Importantly, SPT is struck after all costs, including depreciation, but before corporation tax.

Federal taxes aside, there are also several indirect taxes. These are typically levied on the cost of capital equipment and services and, taken together, can add significantly to that cost, much to the detraction of project economics. Of the numerous taxes that exist the most significant are the *Imposto de Importacao* or II which, at 11-18%, is an import tax levied on the value of externally sourced equipment and *state value added tax* (ICMS) which, at around 18% is levied on the value of all goods and services bought (although this can be recouped further down the value chain as ICMS is subsequently charged by the enterprise for the oil that it sells in the domestic market).

Importantly, the Brazilian government has recently legislated for a new fiscal regime to cover future licenses awarded in 'strategically important' areas, such as the pre-salt. These changes have no impact upon any existing licenses, including those in the pre-salt. The precise terms of the new regime are yet to be published pending a first licence round which may take place in late-2013. However, the salient points are that new licenses in these strategic areas will be PSC based and that the state share of profit oil will be a key biddable factor. We would anticipate that greater clarity around the terms will emerge during 2013.

Refining and Downstream markets

Brazil is estimated to have around 2.1mb/d of refining capacity spread across 13 refineries of which 8 are located close to the major centres of demand and production in Rio de Janeiro and Sao Paolo. Of these 11 are operated by Petrobras. Petrobras has announced ambitious plans to expand the country's refining capacity and several projects are already underway (or in planning) that could add c.1.2mb/d of new capacity. The projects include the 230kb/d Abreu e Lima refinery due in two phases spanning 2014-15 and the first phase of the Comperj project. Of the existing 13 refineries, over 60% is associated with the county's five largest facilities not least the 365kb/d Paulina facility.

Figure 426: Brazilian refineries with over 200kb/d of capacity

Name	Location	Nominal Capacity	Operator
Paulinia (REPLAN)	Sao Paolo	365kb/d	Petrobras
Landulpho Alves (RLAM)	Bahia	280kb/d	Petrobras
Duque de Caixas (REDUC)	Rio de Janeiro	242kb/d	Petrobras
Henrique Laje Refinery (REVAP)	Sao Paolo	251kb/d	Petrobras

Source: Wood Mackenzie

LNG

Despite its significant reserves, as an importer of natural gas at this time Brazil has sought to diversify its current dependence for gas on other LatAm states. Consequently, Brazil started importing LNG at the start of 2009 after commissioning two regasification terminals, one located in the northeast of the country (PECEM, 7mcm/d) and the other near the major southeastern markets (Baia de Guanabara, 20mcm/d). In 2009, Petrobras signed an MOU with a number of its Santos basin partners (BG Group, Repsol and Galp) to investigate the potential of developing pre-salt gas reserves using floating LNG technology. However, it now seems that the first phase of the development of the Santos Basin will see associated gas re-injected or delivered by pipeline to the domestic market.

Canada – Oil Sands

Located in three principle deposits in Alberta, Canada's oil sands are believed to represent the world's largest single petroleum deposit with estimated reserves in place of up to 2.5 trillion barrels of which some 48 billion barrels are deemed recoverable at this time. Production in 2012 is estimated at 1.8mb/d or roughly half of Canada's total oil production. On the back of planned investment of $120bn over the next eight or so years this is, however, expected to rise to over 4.3mb/d by 2020 leaving Canada as the world's 6th largest oil producer with the sands representing close to three-quarters of the country's oil production. Key producers in 2012 included Suncor (404kb/d), Canadian Natural Resources (256kb/d) and Exxon Mobil (141kb/d).

Broad geology and topology

Covering the north eastern part of the Western Canadian Sedimentary Basin the oil sands of Alberta were established by streams which flowed from the Rockies and brought sand and shale which filled ridges running through Alberta and Saskatchewan. The area eventually became an inland sea with the remains of plants and animals buried over time in the sea bed. As these became more and more deeply buried they gradually cooked becoming liquid hydrocarbons which migrated upwards until they reached large areas of sandstone near the surface in the Athabasca region. With the shorter carbon chains fed on by bacteria the hydrocarbons concentrated as bitumen creating an oil sand composed 70% sandstone/clay, 10% water and 20% bitumen.

History and regulation

Bitumen seepages were first noticed by the Athabasca River as early as the 18th century and in the early 1900s wells were sunk in the area in search of conventional oil. However, commercial operations did not begin until the 1960s since which time most of the prospective land has been licensed. The first commercial project, which involved opencast mining of the sands, was launched by Suncor in Athabasca in 1965 with first production commencing two years later. This was followed in 1972 with the start up of the world's largest oil sands operation, Syncrude. Following this it was not until the start up of Shell Canada's Athabasca Oil Sands Project (AOSP) some 25 years later that a further project came onstream. Today twenty five projects are producing with a further seven or so under development or in planning. Given the weight of development and interest in the sands it comes as little surprise that in recent years the local economy has boomed and the costs of project development have spiralled. This has significantly impacted upon the future economics of projects in the planning or development stage, with the final investment decision on many projects postponed or cancelled during the oil price crash of 2008/09.

Development and production of the oil sands is governed by the terms of the Oil Sands Conservation Act of 1983 (OSCA) and the Alberta Environmental Protection and Enhancement Act (AEPEA). Amongst others these Acts are designed to ensure the orderly and economic development of the sands and to assist the government in controlling pollution from their development.

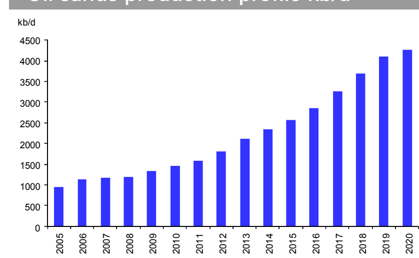
Importantly, in drafting the legislation the Canadian authorities sought to ensure that all areas of potential conflict were encompassed. Thus the AEPEA consolidates former legislation on chemical contamination, agriculture, hazardous substances, land conservation and reclamation, clean air and water and other environmental issues. In doing so it has added considerable clarity to the legal conditions and requirements under which the sands can be developed and extracted. The legislation also guarantees the public's participation in decisions affecting the environment providing them with increased access to information.

Key facts

Key facts	
Oil sands production 2012E	1.8mb/d
Canada oil 2012E ex sands	1.7mb/d
Oil sands reserves 2012E	48bn bbls
Canada O&G 2012E ex sands	33bn boe
Reserve life (oil sands)	73 years
Canada reserve life (gas)	23 years
Canada GDP 2012E	$1,77bn
Canada GDP Growth 2012E (%)	1.9%
Canada Population (m)	34.8mn
Canada Oil consumption (2011)	2.3mb/d
Canada Oil exports (2011)	1.3mb/d
Fiscal regime (concession)	Tax & royalty
Marginal tax rate (concession)	49%
Top 3 Oil Sands fields (2012E)	
Syncrude	353kb/d
Suncor	265kb/d
AOSP	225kb/d
Top Producer (2009E)	
Suncor	404kb/d
CNR	256kb/d
XOM	141kb/d

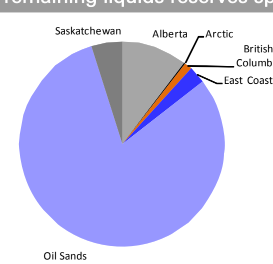
Source: Wood Mackenzie, EIA, IMF

Oil sands production profile kb/d



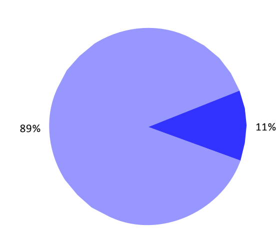
Source: Wood Mackenzie

Canada remaining liquids reserves split



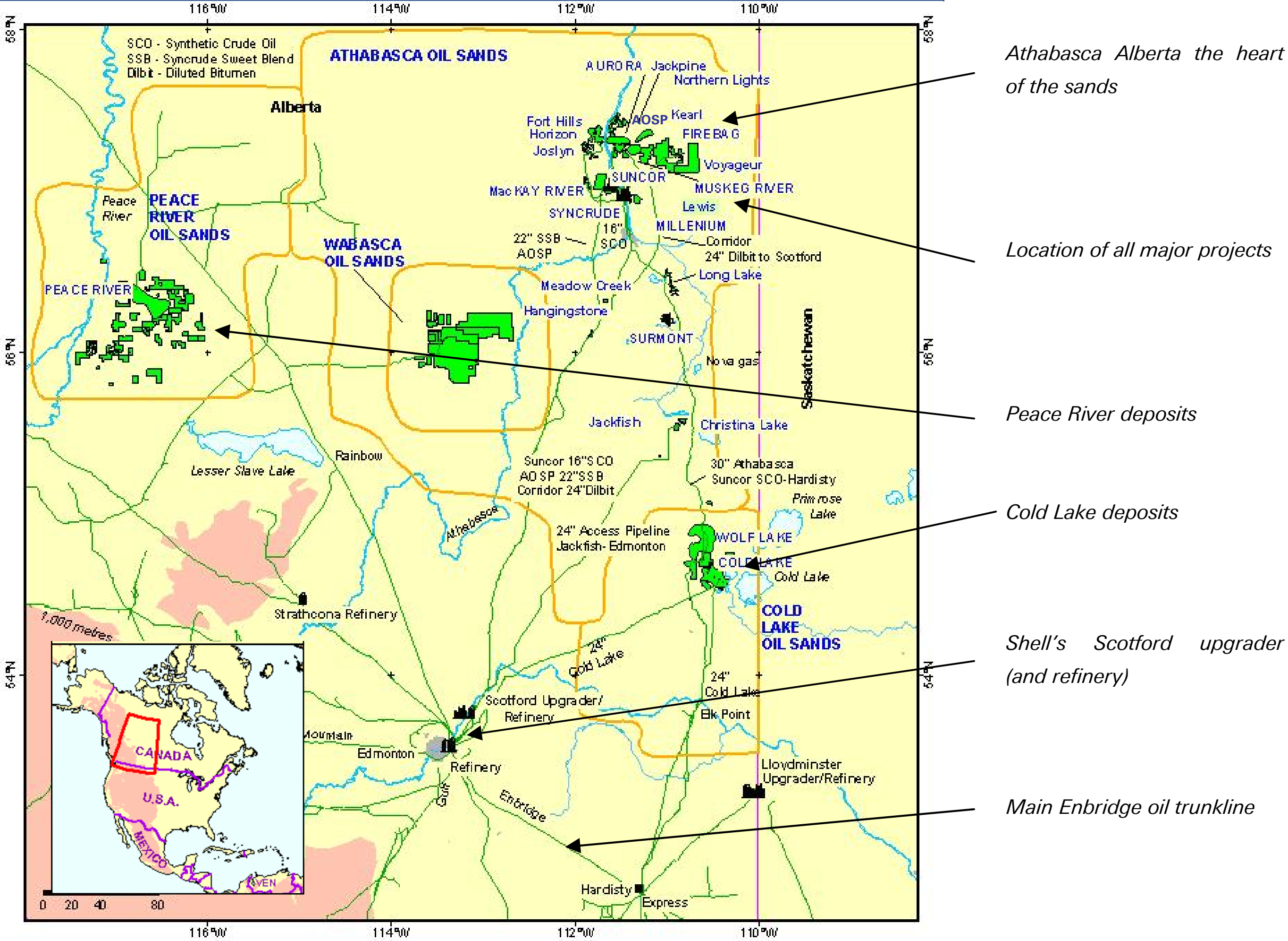
Source: Wood Mackenzie

Oil sands initial versus remaining reserves



Source: Wood Mackenzie

Figure 427: Key Athabasca sands Projects and Infrastructure



Source: Wood Mackenzie; Deutsche Bank

Licensing

Canada's oil sands are concentrated in three main regions, Athabasca which accounts for 77% of licensed acreage, Peace River (12%) and Cold Lake (12%). Of the licensed acreage around 40% contains commercial projects.

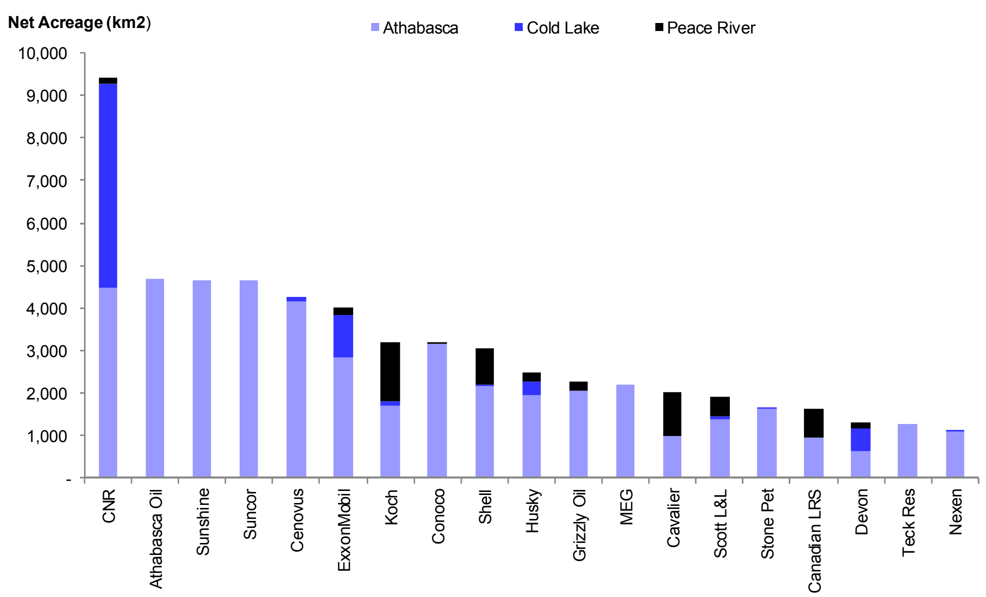
The body responsible for awarding Oil Sands Leases (OSLs) is the Alberta Energy and Utilities Board (AEUB). The Board must grant approval before any oil sands operation can commence. Leases have been awarded across all potential regions since operations began in the 1960s. At present, active licences are concentrated in two oil sands areas, Athabasca and Cold Lake, with the majority in Athabasca. The AEUB issues two types of oil sands licences:

- **Permits.** These are awarded for a five-year period with only minimal evaluation commitments. They can be converted to leases if desired.
- **Leases.** These are awarded for a primary fifteen-year term but can be extended, provided that evaluation commitments have been met.

Licences are issued through either public or private awards. The majority tend to be publicly awarded, taking the form of a public offering. These are held every two weeks and are co-ordinated by the Department of Energy. The process is based on a competitive sealed bid auction system, similar to petroleum and natural gas offerings. Lands available for bidding are published eight weeks before the auction takes place. In contrast, private awards are made based on private requests for oil sands rights. In many cases, these are an extension of an existing petroleum and natural gas agreement. The private sales price is calculated by the Department of Energy and it is non-negotiable; the minimum price requirement is the greater of CDN$2000 or CDN$500 per hectare. In order to access the minerals, a surface lease must also be acquired from the landowner.

A wide range of companies currently hold OSLs. The Super-majors, US and Canadian independents, and specialist Canadian oil sands companies are particularly well represented. As illustrated below, with over 9,000km^2 of land under license Canadian Natural Resources controls a leading share of acreage with significant tracts of land under license in both the Athabasca and Cold Lake areas.

Figure 428: Land under license in Athabasca, Cold Lake and Peace River



Source: Wood Mackenzie; Deutsche Bank

Production of oil & gas

As the oil price climbed and access to resource particularly in fiscally stable regions of the world decreased so interest in the development of Canada's oil sands surged. After several decades of fairly static levels of production, a steady flow of new project developments looks set to drive consistent healthy growth in production. Based on Wood Mac estimates, from 2012 production of around 1.8mb/d is expected to rise at a 11% CAGR towards 4.3mb/d by 2020, split roughly equally between production sourced from mining and from SAGD. Plans are, however, vulnerable to slippage given both tight labour and supply markets but also, as a consequence of the growth in Bakken tight oil production and infrastructure limitations, increasing uncertainty on product pricing

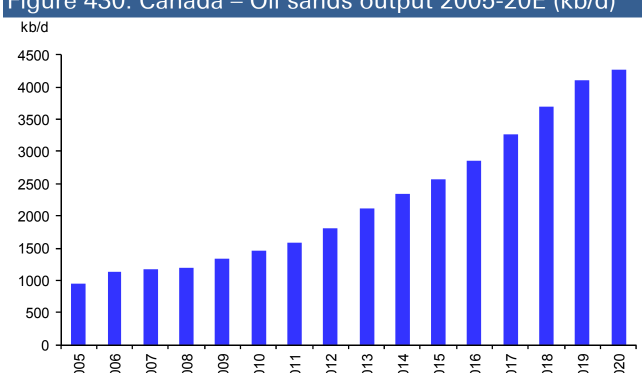
(*Note*: *For a description of the different production techniques (mining, SAGD and Cyclic Steam) please see the Industry section on non-conventional oils).*

Figure 429: Canada Oil sands Projects and start up dates (all Athabasca except those shaded)

Projects	Status	Start up	Reserves (mmbbls)	Peak Prod (kb/d)	Main Participants	Method
Suncor Mine Project	Onstream	Oct-67	2,878	289	Suncor* (100%)	Mining with upgrader
Syncrude Project	Onstream	Nov-78	6,714	600	COS (36.74%), Imperial (25%), Suncor (12%),	Mining with upgrader
Primrose/Wolf Lake	Onstream	Jan-83	840	120	CNR* (100%)	CSS & SAGD with upgrader
Cold Lake	Onstream	Nov-86	976	190	Imperial Oil* (100%)	CSS, LASER
Peace River	Onstream	Nov-86	552	50	Shell* (100%)	CSS
Pelican Lake (CNRL)	Onstream	Jan-96	349	78	CNR* (100%)	Primary
Hangingstone	Onstream	Jan-99	244	33	Japan Canada Oil Sands* (75%), Nexen (25%)	SAGD
Seal (Shell)	Onstream	Jan-01	23	12	Shell* (100%)	CSS & SAGD
Foster Creek	Onstream	Nov-01	1,948	245	Cenovus* (50%), Conoco (50%)	SAGD, VAPEX,SAP
Pelican Lake (Cenovus)	Onstream	Jul-02	215	55	Cenovus* (100%)	Primary
Christina Lake	Onstream	Oct-02	1,692	238	Cenovus* (50%), Conoco (50%)	SAGD, VAPEX,SAP
MacKay River	Onstream	Nov-02	528	70	Suncor* (100%)	SAGD
Seal (Murphy)	Onstream	Jan-03	89	28	Murphy Oil* (100%)	Primary (CSS)
AOSP	Onstream	Apr-03	3,479	370	Shell* (60%), Chevron (20%), Marathon (20%)	Mining with upgrader
Seal (Penn West)	Onstream	Jan-04	51	16	Penn West Exploration* (55%), China Invest(45%)	Primary
Suncor SAGD Project	Onstream	Mar-04	3,589	343	Suncor* (100%)	SAGD with upgrader
Tucker	Onstream	Nov-06	185	17	Husky* (100%)	SAGD
Orion	Onstream	Sep-07	54	6	Shell* (100%)	SAGD
Great Divide Project	Onstream	Oct-07	144	16	Connacher Oil & Gas* (100%)	SAGD
Surmont	Onstream	Oct-07	1,096	136	Conoco* (50%), Total (50%)	SAGD
Jackfish	Onstream	Nov-07	845	105	Devon* (100%)	SAGD
Long Lake	Onstream	Mar-08	1,336	102	Nexen* (65%), CNOOC Ltd (35%)	SAGD with upgrader
MEG Christina Lake	Onstream	May-08	2,031	232	MEG* (100%)	SAGD
Horizon Project	Onstream	Sep-08	4,231	298	CNR* (100%)	Mining with upgrader
Kai Kos Dehseh	Onstream	Sep-10	891	80	Statoil* (60%), PTTEP (40%)	SAGD
Kearl	Development	Jan-13	4,260	300	Imperial Oil* (70.96%), ExxonMobil (29.04%)	Mining
Sunrise	Development	Jan-14	2,844	200	Husky* (50%), BP (50%)	SAGD
CNRL Kirby	Development	Mar-14	460	85	CNR* (100%)	SAGD
MacKay River (PetroChina)	Development	Aug-14	1,300	115	PetroChina* (100%)	SAGD
Fort Hills Mine	Probable	Jan-17	1,750	164	Suncor* (40.80%), Total (39.20%), Teck (20%)	Mining with upgrader
Joslyn SAGD/MINE	Probable	Jan-17	874	100	Total* (38%), Suncor (37%), Occidental (15%),	Miniing

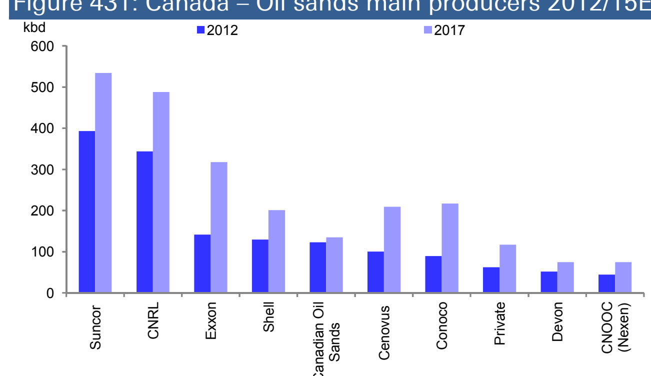
Source: Wood Mackenzie, Deutsche Bank

Figure 430: Canada – Oil sands output 2005-20E (kb/d)



Source: Wood Mackenzie

Figure 431: Canada – Oil sands main producers 2012/15E



Source: Wood Mackenzie

By company, at the present time Suncor (0.4mb/d), Canadian Natural Resources (0.3mb/d), Exxon (0.1mbd), Shell (0.1mb/d) and Canadian Oil Sands Trust (0.1mb/d) are the leading producers, accounting for almost 60% of anticipated output in 2015. However, as new entrants develop facilities production is expected to become far less concentrated. By 2020 under current plans around ten companies will be producing over 100kb/d with the production share controlled by the big five falling to nearer 50%.

Reserves and resources

Although in-place reserves of Canada's oil sands are estimated to be as much as 2.5 trillion barrels of oil, plans established to date allow for the commercial recovery of around 55 billion barrels of which 48 billion barrels have yet to be produced. However, as recovery rates improve and, more significantly, further developments are established we would expect the estimate of commercial reserves to increase substantially.

Pipeline and infrastructure

The bitumen extracted from oil sands is very viscous and heavy. As such, before it can be refined it needs to be further processed or upgraded into a form of synthetic crude oil (SCO) that is less viscous and of an API that allows it to be processed by a more conventional refinery. This either takes place in the Alberta region or at a more distant upgrading refinery, the bitumen being mixed with condensates as a diluent (to form 'dilbit') or with synthetic crude oil (to create 'syndbit') so that it can meet the density and viscosity requirements for pipeline transportation. Currently there are six principle upgraders with c1.3mb/d bitumen capacity operating in Alberta.

Figure 432: Upgraders in Athabasca

Company	Capacity	Location	Company	Capacity	location
Suncor	350kbd	Mildred Lake	CNRL Horizon	135kbd	Fort McMurray
Syncrude	350kbd	Mildred Lake	Nexen Long Lake	72kbd	Long Lake
Shell AOSP	255kbd	Scotford	Husky	82kbd	Fort McMurray

Source: Deutsche Bank

Whether in the form of synthetic crude oil or diluent, bitumen produced from the oil sands is pumped either to Edmonton or Hardisty. Once here it is shipped through one of the main trunklines to markets in Canada and the United States. Most significant is the Enbridge mainline which, with a capacity of 2.5mb/d runs from Edmonton through to the Great Lakes region and on to the United States where it connects with US liquids infrastructure. Of the other main export lines, the 1260km Express pipeline has the capacity to carry 280kb/d of Canadian crude to Montana, Wyoming and Utah whilst the Platte with capacity 150kb/d runs 1490km carrying crude to Colorado, Kansas and Illinois. Transcanada's Keystone pipeline which came onstream in mid-2010 carries Canadian crude from Hardisty, Alberta to markets in the American Midwest at Wood River and Patoka in Illinois, and at Cushing, Oklahoma a total distance of 3,460km. If implemented the Keystone XL expansion to Houston, Texas and other Gulf Coast areas and increase the capacity to 1.1mb/d. Otherwise, the Alberta Clipper Pipeline, which came on-line in 2010, runs 1,607km carrying crude from Hardisty, Alberta to lake Superior, Wisconsin. Its 450kb/d initial capacity will likely expand to 800kb/d.

Crude oil blends and quality

Although several 'syndbit' and 'dilbit' blends are marketed, the streams tend to be relatively small. More recently, blending of product from several suppliers has seen the establishment of a new crude stream entitled 'Western Canada Select'. Blended at Hardisty, volumes at present total around 500kb/d a figure that will likely expand as new projects come on stream. Lloyd blend serves as a marker for bitumen prices.

Broad fiscal terms

All licenses in Canada are governed by concession terms and have been structured to encourage investment and maintain the growth in the development of the State's tar sands base. Taxation comprises royalty, federal tax and provincial tax and, once the costs of a project have been recovered and an agreed return achieved, the marginal rate of tax (government take) in 2009 calculates at around 48% or around 33% on projects that are yet to cover costs.

Royalty: Royalties on oil sands are structured to allow recognition of the financial viability of the project. From 2009, royalty is payable at a minimum rate of 1% on all production at a WTI oil price of under $55/bbl rising to 9% in a straight line at oil prices of $120/bbl and above. However, from 2009 once a project has achieved payout (including a return equivalent to that of the Government of Canada Long Bond Rate) royalty is payable at 25% of net revenues (net revenues equalling revenue from the sale of bitumen or SCO less opex less capex and less the return allowance) at oil prices of below $55/bbl rising to 40% at oil prices of $120/bbl and above. As such, royalty and taxation tends to be very modest through the early years of a project's life.

Tax. Beyond royalty, tax is payable at both the federal and provincial level, with the effective rate of federal tax incorporating full allowance for provincial taxes paid. Given that provincial tax in Alberta currently stands at 10%, federal tax is currently payable at an effective rate of 20% rather than its 30% nominal rate. Moreover, federal tax is scheduled to fall to a nominal rate of 25% by 2012, declining by around 0.5% per annum over the next three years. This should mean a further decline in the effective rate paid on the oil sands. Assuming no change in the 10% rate of Alberta's provincial tax, the effective rate of federal tax by 2012 should stand at 15% implying a marginal rate of tax on a project paying full royalties of 43.8% or circa 26% on projects that have not yet achieved payout at oil prices below $55/bbl.

Canada Notes

Kazakhstan

Predominantly an oil province, Kazakhstan accounts for the lion's share of reserves in the Caspian Sea and is the second largest FSU producer after Russia. At 1.7mb/d the country has achieved growth in oil production of around 10% per annum since beginning of this century and growth from the country's 27 billion barrel oil reserve base is expected to continue at around 8% into the medium term driven primarily by the expected 1H13 start-up of the first phase of the long-awaited Kashagan development. Kazakhstan's resource base rests on three giant fields, Kashagan, Tengiz and Karachaganak. At almost 40TCF the country also has substantial reserves of natural gas, albeit the majority is associated and export routes are at present very limited. Production is dominated by the state oil company KazMuniGaz (KMG) while the major IOCs with a position in Kazakhstan include CVX, XOM, Eni, Shell, Total and XOM.

Basic Geology and topology

In many respects the geology of Kazakhstan reads as though the country is one giant oil field. Over 60% of Kazakhstan's 2.7 million square kilometers are occupied by some 15 sedimentary basins of varying sizes, the most prolific of which, the Precaspian, lies to the west of the country around the Caspian Sea. Accounting for around 85% of the country's remaining 2P reserves the Precaspian includes the giant fields of Kashagan, Karachaganak and Tengiz all of which have been found in its pre-salt mega-sequence. The Precaspian aside, Kazakhstan's more important producing basins include the Mangyshlak which lies to the south west of the country and extends into Uzbekistan and Turkmenistan, and the North Ustyurt which lies in-between the Precaspian and Mangyshlak to the west of the country.

History and regulation

For many years Kazakhstan represented the smallest of the three main Soviet production areas. Although first commercial production commenced in 1911, with significant production coming from Azerbaijan and Russia there was little need to develop Kazakhstan's reserves. However, the discovery and development in the 1960s of two major fields in the Mangyshlak Basin combined with declining Azeri output saw all of this change. By the mid-1970s Kazakhstan had become an important source of Soviet oil with production of around 500kb/d. Yet, faced with significant technical challenges, not least the depth and complexity of the larger reservoirs in the Precaspian Basin, output struggled to move beyond this level and it was only upon the introduction of the major IOCs in the 1990s that Kazakh production started to make progress again as the major Karachaganak and Tengiz fields commenced production.

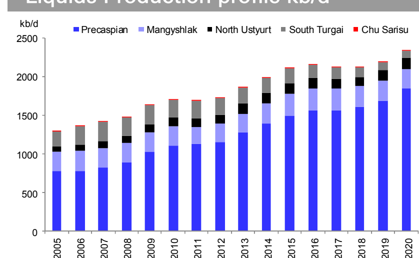
Oil & gas activities are overseen and regulated by the Ministry of Energy and Mineral Resources. However, the state plays a direct role in the country's day to day activities in hydrocarbons through the national oil company KazMunaiGas (NC KMG). NC KMG holds direct interest in each of the key fields – 16.8% in Kashagan, 20% in Tengiz, 10% in Karachaganak. In addition, primarily through its subsidiaries – most notable being a 58% controlling stake in the listed KazMunaiGaz E&P (KMG E&P) – NC KMG holds material stakes, and in some cases acts as operator, for a multitude of other fields. Moreover, through KazTransOil (KTO) and KazTransGaz (KTG) the national company has a near monopoly on the transport infrastructure for both oil and gas. Through a joint venture company with Gazprom (KazRosGaz) it is also responsible for the trading and export of Kazakh natural gas. Oil & gas production aside, NC KMG's key functions include its participation in the strategic planning and development of the country's

Key facts

Oil production 2012E	**1.7mb/d**
Gas production 2012E	**0.35mboe/d**
Oil reserves 2013E	22bn bbls
Gas reserve 2013E	39TCF
Reserve life (oil)	33 years
Reserve life (gas)	52 years
GDP 2012E ($bn)	$200 billion
GDP Growth 2012E (%)	5.5%
Population (m)	16.7m
Oil consumption (mb/d)	0.26m/d
Oil exports (mb/d)	1.4mb/d
Fiscal regime	T&R and PSC
Marginal (corporate) tax rate	60% & 84%
Top 3 fields (2012E)	
Tengizchevroil	707kboe/d
Karachaganak	381kboe/d
CNPC AktobeMunaiGas	189kboe/d
Top 3 Oil Producers (2012E)	
KazMunaiGas	492kboe/d
Chevron	395kboe/d
Exxon	177kboe/d

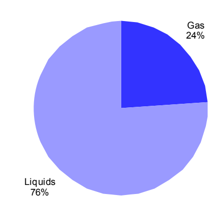
Source: Wood Mackenzie; EIA data

Liquids Production profile kb/d



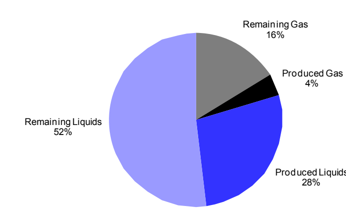
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

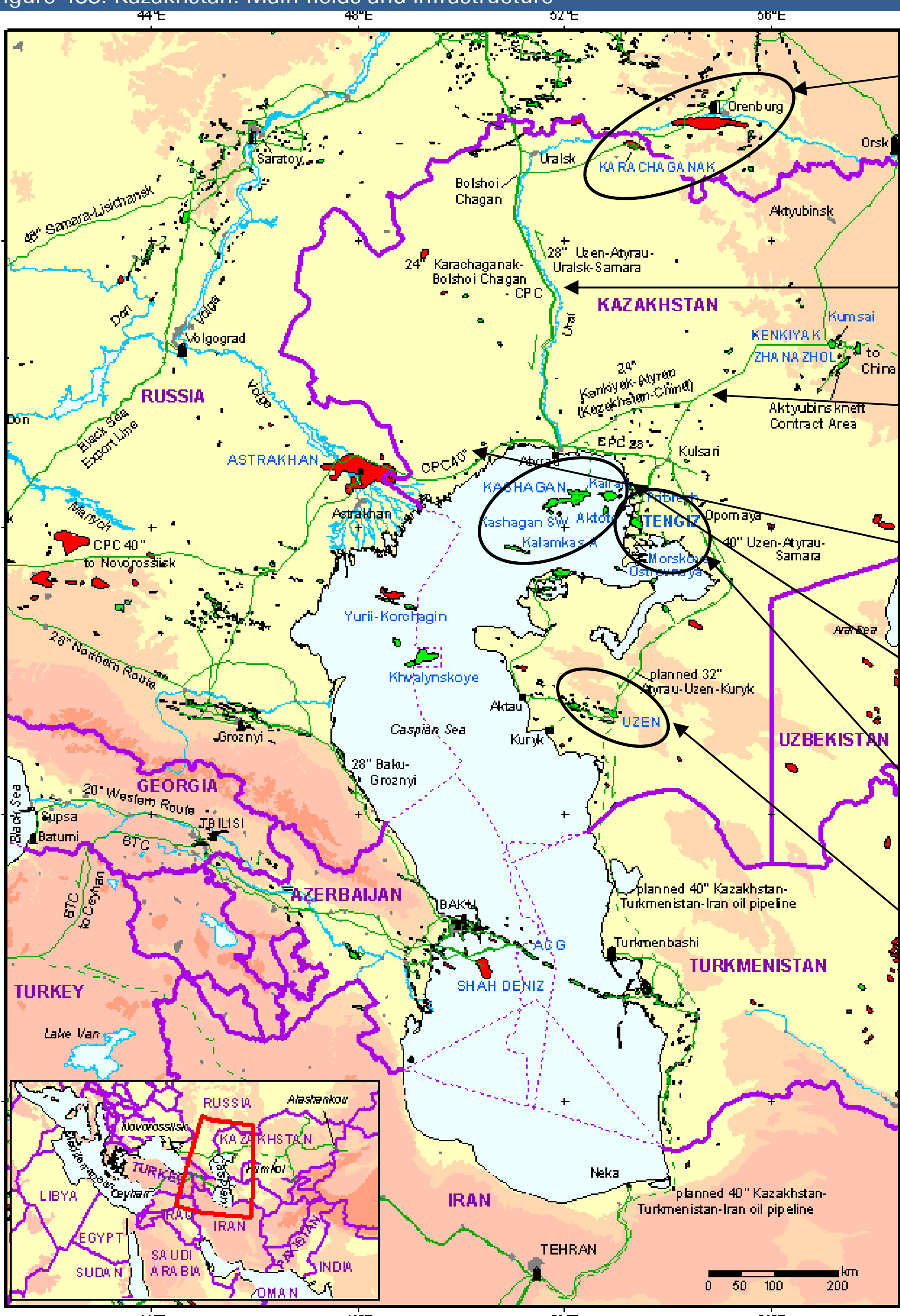
Initial versus remaining reserves



Source: Wood Mackenzie data

hydrocarbon resources base and in overseeing the conduct of tenders amongst potential contractors. Following legislation laid down in 2005, the Government has also mandated that KMG will be entitled to a 50% shareholding in all future offshore PSCs, with its share of any costs carried through the exploration phase. It is also of note that the Government has become increasingly assertive in its dealings with western companies, not least through its negotiation of a greater equity interest for KMG first in Kashagan and, more recently, in Karachaganak.

Figure 433: Kazakhstan: Main fields and infrastructure



Source: Wood Mackenzie

Karachaganak *gas-condenstate field. Hydrocarbons processed at Russian Orenburg facility. Majority of gas re-injected with liquids exported via CPC or Atyrau-Samara pipeline. Output c250kb/d liquids & c750mmcf/d gas*

Atyrau-Samara pipeline *– capacity to evacuate c350kb/d of crude to Russia*

Kazakhstan-China pipeline *– capacity to evacuate c250kb/d of crude to China. World's longest crude oil pipeline*

CPC pipeline *evacuates crude to Black Sea Novorossiysk terminal. Capacity of 600kb/d with expansion plans to 1.4mb/d*

Kashagan *first phase scheduled to start-up during 1H13 with c300kb/d liquids capacity*

Tengiz Area *c600kb/d current liquids output. Exported primarily via CPC pipeline*

Uzen Area *c100kb/d current liquids output*

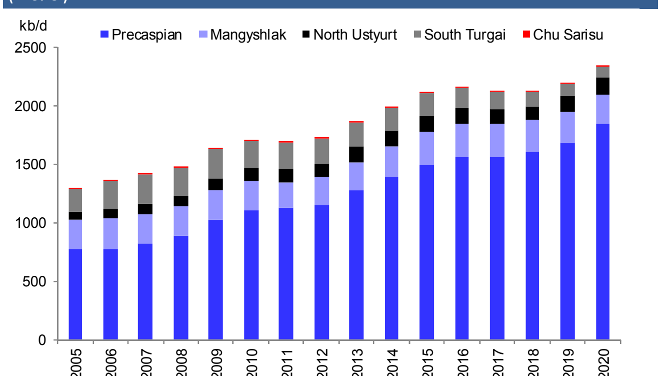
Licensing

Since opening up to foreign investment in 1991 Kazakhstan has seen significant licensing activity with almost 400 active licenses currently in place. There is, however, no formal structure to licensing rounds. Companies tend to negotiate direct with either the state or KazMunaiGaz entering into production sharing agreements or joint ventures. The law establishes a limit of 6 years for an exploration contract with the option of a two year extension. There is no defined term for production contracts.

Production of Oil & Gas

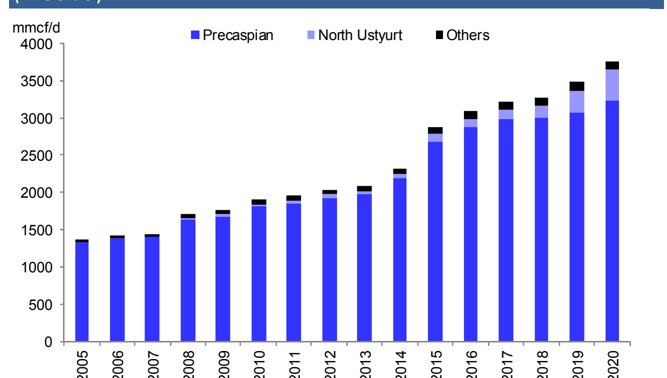
With additional phases of production scheduled at both Karachaganak and Tengiz and the planned start up of the giant Kashagan development, oil and gas production in Kazakhstan is expected to increase substantially over the coming years. Assuming that work proceeds in line with current expectations, oil production is expected to reach around 3mb/d by the end of the decade. Similarly, gas production is expected to see a substantial increase rising to at least 4bcf/d although, dependent upon the signing of additional commercial agreements and infrastructure build, gas production could prove to be significantly higher. Importantly, despite the considerable number of hydrocarbon producing areas within the country over 70% of oil and 65% of gas production is expected to arise from the major fields of Kashagan, Karachaganak and Tengiz. Key IOCs operating in Kazakhstan include Chevron which has interests in both Tengiz and Karachaganak, Exxon (Tengiz and Kashagan) and ENI (Karachaganak and Kashagan). Combined these three companies are expected to account for over 33% of the country's anticipated production on a working interest basis by 2015.

Figure 434: Kazakhstan Liquids production 2005-20E (kb/d)



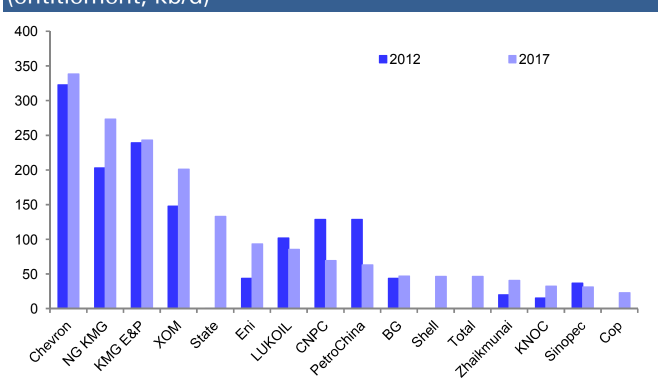
Source: Wood Mackenzie

Figure 435: Kazakhstan: Gas production 2005-20E (mscf/d)



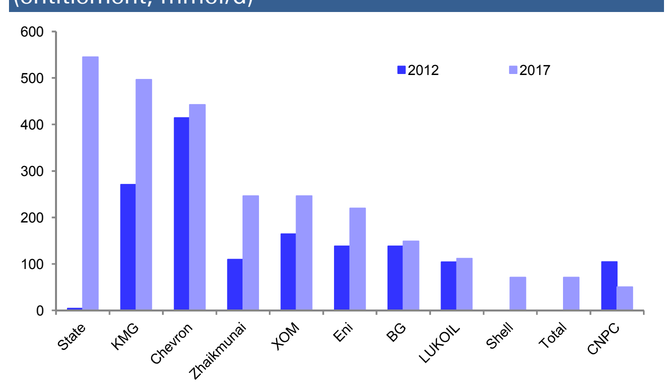
Source: Wood Mackenzie

Figure 436: Kazakhstan: Major liquid producers 2012/17E (entitlement, kb/d)



Source: Wood Mackenzie

Figure 437: Kazakhstan: Major gas producers 2012/17E (entitlement, mmcf/d)



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data estimated 2P reserves in Kazakhstan at the end of 2012 included 21.9bn barrels of oil and liquids and some 39TCF (6.9bn/boe) of natural gas. Of these over 70% (20.7bn boe) were associated with Kashagan (9.0bn boe), Tengiz (6.5bn) and Karachaganak (5.2bn). Given existing production this suggests a 2P reserve life of over 38 years. Moreover, these reserve estimates are almost certain to understate actual reserves given the scale of the technical resource known to exist at each of the three large fields.

Pipelines and infrastructure

As an essentially land-locked market the establishment of adequate export infrastructure has been central to the development of Kazakhstan's hydrocarbon base. Although upon independence, significant infrastructure was in place, it had largely been laid down with a view to transporting oil and gas to and from Russia. Much was also in a poor state of repair. Since independence, infrastructure development has consequently focused on establishing new export routes to supply Kazakh oil to both western and eastern markets and ensuring the major new fields were connected to these and already existing export routes. Significant investment has also been made in upgrading what was an aging system.

Oil Infrastructure

Shown in the diagram below the major pipelines include the following:

- **CPC**: Central to Kazakhstan's needs has been the development of the 1500km CPC (Caspian Pipeline Consortium) pipeline. Largely financed by a consortium of the major IOCs (whose equity interests afford them access), the pipeline has been running well above its nominal capacity of 600kb/d due to the use of drag reducing agents. The capacity is expected to be expanded in three stages to 1.4mb/d by 2015/16. CPC runs from the shores of the Caspian to Russia's Black Sea port of Novorossiysk. It has substantially reduced Kazakhstan's dependence on the Russian Transneft system and provided much of the capacity required to export oil from Tengiz and Karachaganak. The expansion is required to accommodate the output of Kashagan.
- **Kazakhstan-China:** Looking to the east, CNPC completed the Kazakhstan-China oil pipeline in 2009. This c.3000km pipeline was built in three phases. With the final phase of the Kenkiyak-Kumkol connecting section completed, oil started to flow to the Xinjiang-Gansu province in northwest China in 2010. The overall capacity is 250kb/d with plans to increase to 420kb/d.

These two major export routes aside, the key export line is the **Atyrau-Samara** pipeline which connects the Kazakh and Russian systems. This pipeline currently has a capacity of 350kb/d. Expansion plans have previously been mooted, but there is limited visibility.

The long-term potential exists to develop a major new pipeline, the **KCTS** to connect oil field (most significantly Kashagan) to the Caspian port of Kuryk from where oil would be transported by ship to Baku before being transported through the BTC to southern Turkey. A decision on this pipeline is likely to be key to any decision to proceed with subsequent development phases at Kashagan. Initial plans suggest capacity could be 600kb/d.

Figure 438: Major oil pipelines: existing and in development

*Source: Courtesy of ENI, * K-C pipeline was completed late in 2009.*

Pipelines aside, Kazakhstan may have the potential to export up to 340kb/d of oil by rail (although actual volumes are seen as much lower) and 240kb/d by ship from the port of Aktau (again actual volumes have been lower). Shipping facilities may in the long-term be expanded to provide a link to Baku and the BTC pipeline (as part of the potential KCTS pipeline).

Figure 439: Export routes for Kazakhstan's main producing fields

Field	Export routes
Tengiz	CPC to Novorossiysk
	Atyrau-Samara to Russia (and on through Transneft) – Limited export at present
	Rail potential
Karachaganak	To CPC through the Bolshoi Chagan-Atyrau pipeline – 150kb/d
	Atyrau-Samara to Russia (and on through Transneft) - 66kb/d by 2012
	Rail potential
	Orenburg processing plant - 80kb/d condensate processing
	Orenburg processing plant - 8bcm rising to 16 bcm in 2012.
Kashagan	Phase 1 likely to be a mix of CPC (preferred), Atyrau-Samara K-C pipeline and rail. Phase 2 will require new capacity, potentially including KCTS and shipping to Baku.

Source: Deutsche Bank

Gas Infrastructure

Kazakhstan's gas infrastructure was predominantly designed with a view to transporting large volumes of Turkmen and Uzbek gas across the country to Russia. Little thought was given to the collection and forward distribution of domestic gas production, much of which was associated with Kazakh oil production. As a consequence, Kazakhstan's gas infrastructure is largely underutilized with many of the pipelines in a poor state of repair and connections between areas of production and consumption limited. Operation of domestic pipelines is managed by KaxTransGaz, a subsidiary of KazMunaiGaz, which intends to construct new pipelines for the collection and export of Kazakh gas. At the current time, Kazakhstan remains, however, very dependent upon Gazprom for access to international markets. With this in mind, in 2002 the state company KazMunaiGas established a joint venture marketing company with Gazprom and Rosneft (now sold). Named KazRosGaz, this 50/50 JV with Gazprom provides Kazakhstan with access to the Russian gas pipeline system so enabling it to realize some international income from domestic production albeit at relatively low prices.

Crude oil blends and quality

Clearly to the extent that Kazakh oil is fed into the Russian pipeline system it suffers from being blended with often heavier Urals product, undermining its end market price. However, product that emerges through the CPC pipeline is sold as 'CPC blend' a light (43.3° API), sweet (0.6% sulphur) blend of Caspian oil.

Broad fiscal terms

Overall, taxation in Kazakhstan is complicated. Most contracts in Kazakhstan currently operate as joint ventures paying royalty and tax although both Karachaganak and Kashagan are structured as PSCs. For tax and royalty regimes, recent years have seen a significant increase in Government take not least through the introduction of Rent Tax, a progressive tax whose % take alters with the price of oil.

Joint Ventures (tax & MET): Subsequent to the changes under 2009 tax law, JVs now find themselves subject to several different forms of Government take. These include a Mineral Extraction Tax (MET) which varies between a minimum of 5% on gross revenue for production under 5kb/d to a maximum of 18% on production over 200kb/d; Excess Profit Tax (which is levied on profits at a rate of between 10% and 60% once cumulative income exceeds 1.25x cumulative tax); Corporation Tax of 20% in 2009 (from 30% in 2008), 17.5% in 2010 and 15% thereafter; and finally Rent Tax on Exported Oil which is levied on the gross revenues less transport costs at a rate that commences at 7% on oil prices of $40/bbl to a maximum of 32% at an oil price of above $180/bbl. The result is that at high oil prices Government take can be as high as 86% of gross income.

PSCs: Similarly, under PSCs the trigger points established under the country's IRR based contract system are such that as returns move from under 12% to beyond 20% the Government's share of a projects net profits rises from 30% to 90%. This is after payment of corporation tax and significantly limits the scope for the holders to make exceptional returns. Cost oil allowances are, however, relatively generous running at an estimated 60-70% of revenues although capex uplift is not available.

Refining

The refining sector in Kazakhstan comprises several small (c10kb/d) facilities together with three relatively large (150kb/d), strategically located, state controlled facilities; one in the North at Pavlodar, which uses Russian crude as feedstock, one in the west at Atyrau and one in the south at Shymkent. Both Atyrau and Shymkent have access to domestic crude oil. KMG plans to invest in a modernisation programme to facilitate improved utilisation, an upgraded product slate and adherence to European product emissions standards. Production is sufficient to meet the country's demand requirements which in 2009 stood at around 230kb/d.

Mexico

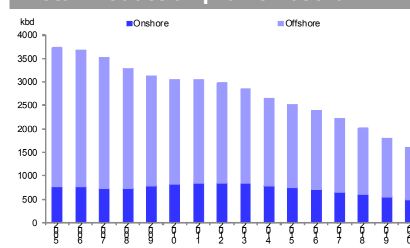
The maturation of prolific fields, foremost the Cantarell complex, has drawn Mexico's hydrocarbon production into sustained decline. With oil production estimated at 2.9mb/d in 2012, Mexico is still the seventh largest producer in the world; a position that is likely to be usurped as fields mature and reserves shrink from current levels of 11bn bbls. Gas production is at 4.5bcf/d and shares the declining trend in reserves which have fallen to 13Tcf. Regardless, Mexico holds huge production potential and fortunes may be reversed by the Chicontepec field and deep-sea areas that are estimated to hold up to 130bn bbl. However, exploitation is only feasible with the technical and financial backing of IOCs that are currently restricted by constitution to minor contractual roles. The interaction between fiscal pressure and strong, nationalistic sentiment will determine the course of Mexico's oil industry. The market is monopolised by the state-owned company, Pemex.

Key facts

Oil production 2012E	2.9mb/d
Gas production 2012E	4.48bcf/d
Oil reserves 2012E	11.14 bn bbls
Gas reserve 2012E	13.3 Tcf
Reserve life (oil)	10.2 years
Reserve life (gas)	8.1 years
GDP 2012E ($bn)	1207 bn
GDP Growth 2012E (%)	3.6 %
Population (m)	112m
Oil consumption (mb/d)	2.02 mb/d
Oil exports (mb/d)	1.48 mb/d
Service Contracts	MSC Terms
Extraction tax rate	10%-20%
Top 3 fields (2012E)	
Ku-Maloob-Zaap	953.98 kboed
Cantarell	582.69 kboe/d
Litoral de Tabasco	413.12 kboe/d
Key Oil Producer	
Petróleos Mexicanos (PEMEX)	2.9mb/d

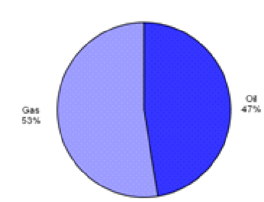
Source: Wood Mackenzie, EIA, IMF, BP

Total Production profile kboe/d



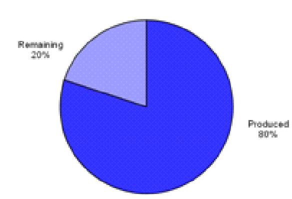
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data, BP Statistical Review 2011

Basic geology and topology

Mexico has eleven sedimentary basins, the majority of which were formed under compressional stress in the Mesozoic period, extending down the present-day East coast. Hydrocarbon reserves are concentrated predominantly on the Eastern seaboard bounded to the West by the Sierra Madre Oriental Mountains. To date, output has been constrained to five basins, of which the Sureste which contains the prolific Campeche sub-basin, is the most significant with a 94% share of oil production. The region is characterised by faulted, asymmetric anticlines and reservoirs formed in a range of sequences between the Lower Palaeocene to Upper Jurassic periods. Aside from Sureste, the Burgos Basin is the largest source of non-associated gas holding 92% of production.

Regulation and history

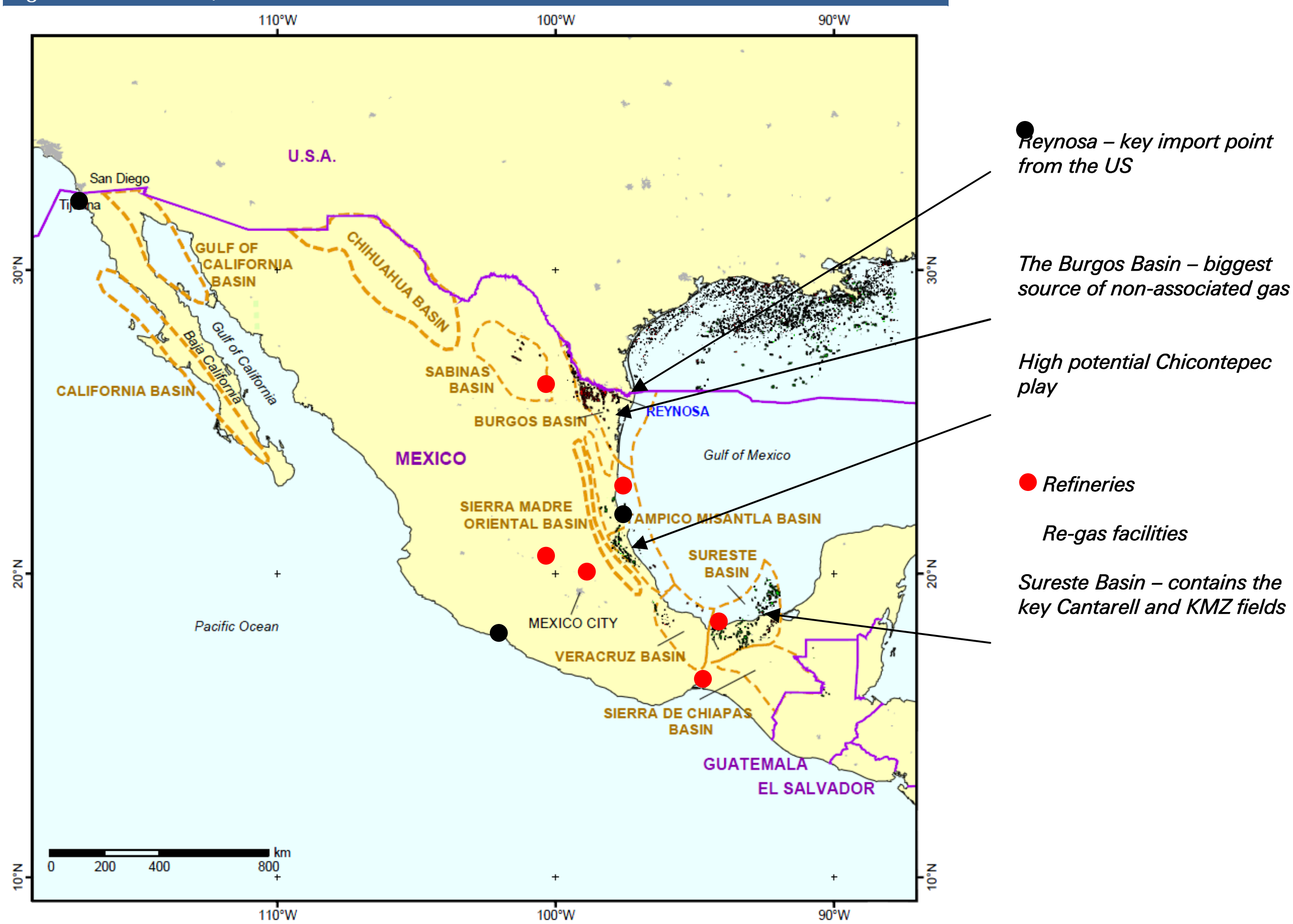
Contrary to the experiences of neighbouring Latin American nations, the legislation in the hydrocarbons industry has been enduring in the underlying themes set out in the original 1917 Constitution. All ownership of natural resources is assigned to the state under Article 27. In 1938 the expropriation of the entire portfolio of oil and gas assets in Mexico led to the institutionalisation of the 100% state-owned Petroleos Mexicanos (Pemex). The corporate structure of Pemex is divided into four subsidiaries: PEP (upstream operations), PGPB (downstream gas), Pemex Refinación (downstream oil) and Pemex Petroquímica (petrochemicals). Pemex has been granted exclusive rights to exploit Mexico's hydrocarbon reserves and therefore has held a monopoly position across all stages of the oil and gas production chain over the last century. Of late, there have been a series of notable amendments to Article 27 which have broken the completeness of the Pemex monopoly.

Natural Gas Law: Alterations to the Regulatory Law in 1995 allowed for private sector companies to operate in certain downstream functions of natural gas and to participate in service contracts throughout the hydrocarbons industry. This combined with contract regulation under the Public Works law dictates the interaction of private firms in the Mexican oil market.

Energy Reform: A series of bills were introduced in 2008, which gave Pemex the ability to offer service contracts with attached incentives. A key evolution for IOC participation, the 2008 reform was initiated in the face of a marked decline in oil production, led by the Cantarell field entering the latter stages of maturity. An additional change induced by the reforms was the overhaul of the Pemex's financing and budget structure, increasing autonomy. The firm is now permitted to access money markets without approval from central government and, through a process of gradual adjustment, can commit 100% of surplus revenue to projects of its choice.

A key development in 2012 has been the election of Pena Nieto on July 1st as the President-elect of Mexico. Nieto who heads the Institutional Revolutionary Party (PRI) has labelled the hydrocarbons industry as his "signature issue" and has expressed strong desire for what is effectively, partial liberalisation, opening the door to foreign investors. In order to do so he must amend the Constitution. Whether such plans are feasible is another issue as the PRI failed to gain a majority in both the Senate and the lower house and a two-thirds majority is required to make an amendment to the constitution.

Figure 440: Mexico; location of main field and infrastructure



Source: Deutsche Bank

Licensing

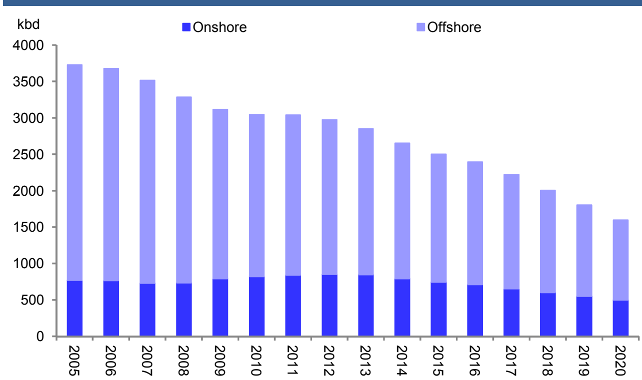
Activity in Mexico's oil industry has historically been ring-fenced from foreign participation. The industry was tentatively opened up to foreign investment for the first time in 2003 through the initiation of a public bidding process for packaged groups of service contracts coined Multiple service contracts (MSC). There were two rounds of bidding on MSCs based on the Burgos and Sabinas basins. Before the third round occurred in 2006, the MSC was rebranded as the Financed public works contract (FPWC). A total of 20 companies have divided ownership of the 11 contracts that have been issued across the 3 rounds with maturities of either 15 or 20 years. In 2011, the first-incentive-based service contracts dubbed Integrated E&P Contracts (IEC) were awarded with generic maturities of between 20 to 35 years.

IECs are performance-based with an incentive component that increases the value of remuneration depending on a variety of factors including application of new technology, efficiency and speed. To date there have been two rounds of bidding for IECs and in total 7 have been issued with Cheiron Holdings Ltd, Schlumberger, Petrofac, Monclova Pirineos Gas and APC registering successful bids. The current production of fields under IECs is 19kb/d of liquids and 25mcf/d of gas (under 1% of the total in both cases).

Production of Oil & Gas

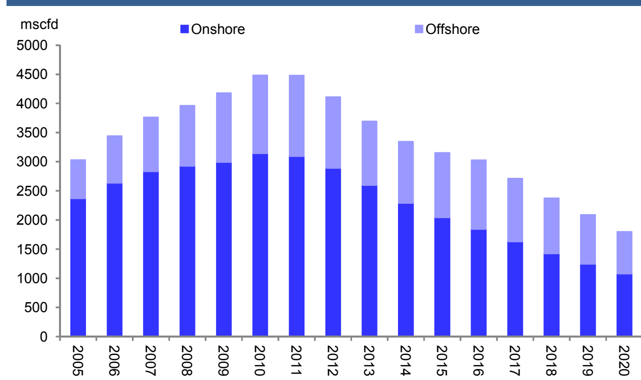
Mexico's liquid production is currently concentrated along the East coast and 71% is derived from offshore fields. Oil production in Mexico first commenced with the tapping of the Ebano oil field in 1904. Production soared and soon after, a new set of fields dubbed the Golden Lane region was in operation in the Tampico-Misantla Basin, central Mexico. Reaching a primary peak in 1921, a sustained period of steady production decline followed until 1974 when the trend reversed. With the Cantarell field coming online in 1979, Mexican production reached its secondary peak of 3.8 mbd in 2004. Since the 1980s, the Cantarell field has dominated the industry forming 63% of total Mexican production at one point.

Figure 441: Mexico liquids production, 2000-2020E (kb/d



Source: BP stat review; Wood Mackenzie

Figure 442: Mexico gas production, 2005-2020E (mmcf/d)



Source: BP stat review; Wood Mackenzie

In recent years, the spotlight has shifted very much to the Ku-Maloob-Zaap fields with an estimated production of 0.9mbd in 2012. In the same year, the rapidly maturing Cantarell produced only 0.5mbd, down from a peak of 2.1mbd in 2004. In terms of future outlook, the share of onshore production is forecast to increase with the development of the Chicontepec field in the Burgos Basin. In 2012, Pemex's total production of liquids was 2.9mb/d.

Figure 443: Key Fields in Production

Fields	Remaining Reserves (mbbl)*	Production 2012E (kb/d)	Production 2015 (kb/d)
Ku-Maloob-Zaap	4,041	923	830
Cantarell	1,680	533	385
Litoral de Tabasco	1,250	339	322
Samaria-luna	1,080	281	224
Chicontepec	841	66	115

*Source: Wood Mackenzie. * As at 1.1.2012; Proven plus Probable; total liquid*

Reserves and Resources

Wood Mackenzie estimates that commercial reserves in Mexico amount to 11.1bn barrels and 13Tcf for liquids and natural gas respectively. In the last decade, the majority of accessible reserves have been located in the North East Marine Region with the current proportion at 44%. The prominent Cantarell and KMZ fields in the region constitute 15% and 36% of Mexico's total reserves

The dispersion of natural gas reserves are greater across Mexico with the Northern, Southern and South West Marine Region holding 38%, 27% and 24% respectively. To date, the largest natural gas fields is the Litoral de Tabasco, which forms 18% of total reserves. The fields in the Burgos Basin combined, hold 16%.

There is high expectation regarding Mexico's oil resource potential with Wood Mackenzie estimating a short 10bn additional barrels of oil. In addition it is hypothesised that undiscovered reserves in the deep-sea regions and Chicontepec field could contain up to 30bn and 102bn barrels respectively.

Pipelines and infrastructure

The long-term objective set by Pemex to minimise costs through efficiency gains has resulted in the majority of crude transportation being conducted through a 28,200km pipeline network that is concentrated along the Eastern seaboard. The North West and Western regions are isolated from the network and hence are serviced by trucks. There are three major pipeline networks. The first stretches north-east and joins the Cadereyta and Ciudad Madero Refineries to the southern fields. The second network connects the central Salamanca and Tula refineries to the Tampico-Misantla and Veracruz basins. The third brings crude from the offshore fields in Campeche and onshore fields in the southern region to the Minátitlan refinery, Salina Cruz refinery and Coatzacoalcos port.

The gas pipeline system includes 11,500km and 28,000km of transmission and distribution pipelines respectively. 2800km of transmission pipelines are privately owned. There are 14 major cross-border pipelines into the US with key import junctions at Reynosa and Ciudad Juarez. The north-east grid is connected to the south via the Natural Gas Trunk line System. Again the North West region is isolated and hence as an alternative, the area is entirely reliant on gas imports from the US.

Crude Oil Blends and Quality

Mexico commercially exports four blends of crude oil: Maya, Olmeca, Isthmus and Altamira. The core crude export is heavy, fairly sour and has a relatively high metal content. The Maya blend which forms just under 90% of exports has an API gravity of 22° with a sulphur content of 3.4%. The majority of Maya is produced from the Cantarell and KMZ oil fields.

Figure 444: Summary of main crude blends and characteristics

Crude Oil	Gravity (°API)	Sulphur (%)
Maya	21.8	3.33
Olmeca	39.3	0.8
Isthmus	32.5	1.5

Source: The International Crude Oil Market Handbook 2009, Energy Intelligence Research

Broad Fiscal Terms

As of 2007, 40% of national tax revenue was levied from hydrocarbon production. The batch of reforms passed in 2007, (effective circa 2008) dictates the current fiscal terms, the majority of which are directed at Pemex. Ordinary Hydrocarbons Duty (OHD) is the core tax instrument and is levied at a fixed rate of 71.5%, under conditionality, on the value of annualised oil and gas production. A large set of taxes are deductible from the OHD. Royalties and exceptions apply to high-growth and marginalised fields.

The only method of participation by foreign investors in Mexico's oil industry is through FPWCs and IECs. Payment for activity by the contractor is based on unit prices with reimbursements in cash made available under a monthly schedule. Contractors are liable for corporate income tax (CIT) although these are permitted to be registered into expenses. CIT is sequenced to gradually adjust between a range of 28% to 30% between 2008 to 2014 with rates finally being fixed at 28% from 2014 onwards. Under the new IECs, the remuneration package consists of a fixed-fee per barrel and cost recovery component. A minimum work commitment is also required.

Refining and downstream markets

Mexico has a total of six crude oil refineries with a distillation capacity of 1.54 mbd. All refineries are incorporated into the pipeline network. Utilisation has been high in the last two decades fluctuating between 85% to 90% of capacity. Geographically, the refineries are located in proximity to production complexes in the south and the south-east of Mexico. In 2011, a 150,000 bd expansion project to the Minatalan refinery was completed and the Salamanca refinery is also scheduled for expansion in order to increase processing volume of Maya crude. Outside of Mexico, Pemex owns a 50% share of Deer Park refinery in Texas through a joint venture with Shell.

The build out of re-gas capacity in recent years has seen Mexico establish access to some 15.6mtpa of nominal re-gas capacity. Deliveries into Manzanilla are committed from the Peru LNG facility whilst those into Tampico and Altamira are fed on a more speculative basis often through spot or short term contracts with gas into Altamira essentially fed by supplies from the portfolios of Shell and Total which were the previous facility owners and have commitments to supply not least from Nigeria..

Figure 445: Refineries & re-gas facilities in Mexico

Operator	Refinery	Location	Capacity (Kb/d)
Pemex	Cadereyta	Monterrey	275
Pemex	Ciudad Madero	Veracruz	190
Pemex	Minatitlán	Tabasco	185
Pemex	Salamanca	Guanajuato	245
Pemex	Salina Cruz	Oxaca State	330
Pemex	Tula	Hidalgo State	315

LNG re-gas

Location	Name	Owner/cap holder	Capacity (Kb/d)
Baja	Costa Azul	Sempra, Shell, Gazprom	7.6mtpa
Tampico	Altamira	Vopak, Enagas	3.8mtpa
Manzanilla	Manzanilla	CFE	3.8mtpa

Source: Deutsche Bank

Mexico – Notes

Norway

Norway is a relatively mature hydrocarbon province having commenced oil production in the early 1970s. Nevertheless, helped by the State's generally conservative approach to the development of the country's natural resource base and a resurgence in exploration success – notable discoveries include play opening success in the Barents Sea and the giant Johan Sverdrup discovery in the North Sea – Norway retains substantial hydrocarbon reserves estimated by Wood Mackenzie at end 2012 to stand at 11.2bn bbls of oil (2P) and 81TCF of gas (2P). Production is entirely offshore. 2012 oil production was 2.1mb/d of which circa 1.75mb/d was exported, making Norway the world's eighth largest net oil exporter. 2012 gas production was 1.9mboe/d. The Norwegian state holds a significant interest in the nation's oil production both directly, through the State Direct Financial Interest (SDFI), and indirectly through its 67% interest in Statoil. IOCs with a strong presence in Norway include Statoil, Exxon and Total.

Basic geology and topology

All of Norway's oil reserves are located offshore on the Norwegian Continental Shelf. This can be divided into three main areas namely the North Sea, the mid Norwegian Shelf and the Barents Sea. The bulk of Norway's oil production occurs in the central and northern sections of the North Sea where hydrocarbons reside in two reservoir horizons created during the Jurassic and Lower Tertiary. In the central North Sea these are dominated by the Central Graben which contains, amongst others, the giant Ekofisk field. In the northern North Sea the Viking Graben dominates. Major fields include Troll, Oseberg and Sleipner.

Moving further north, the mid Norwegian Shelf has traditionally been perceived as a gas prone province. To date most of the exploration has concentrated on the Haltenbanken area and, with the geological knowledge of the Shelf still limited, expectations around exploration remain relatively high. Similarly, the Barents Sea which contains the most northerly acreage in the Norwegian sector remains highly prospective. Enthusiasm toward this frontier region had waned following some disappointing results beyond the Snohvit and Goliat discoveries; however significant recent successes (Skrugard in 2011 and its twin Havis in 2012) have reinvigorated interest in the province.

Regulation and history

The rights to Norway's natural resources are administered by the NPD (Norwegian Petroleum Directorate). The NPD's primary function is to ensure that exploration and production is carried out in accordance with Government legislation, to ensure safety regulations are adhered to and to serve as advisor to, amongst others, the Ministry of Petroleum and Energy.

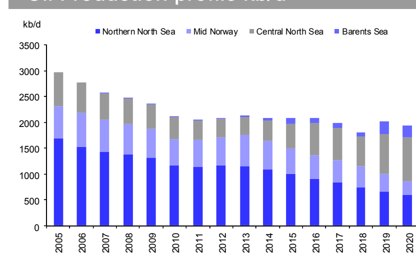
Importantly, the State plays a dominant role in the Norwegian Petroleum Industry and has taken a direct interest in all licenses awarded since the second licensing round in 1969. Initially these interests were held through the state owned oil company, Statoil, which was established in 1972 to explore, transport market and refine petroleum products. However, in 1985 the Norwegian state established the aforementioned SDFI at which time the majority of Statoil's interests were split between it and the SDFI. Subsequently, in 2001 the State underwent a further major restructuring of its interests. An 18% interest in Statoil was listed on the Oslo and New York exchanges via an IPO while management of the State's remaining assets was transferred to a new state-owned company, Petoro, the purpose of which was to create a commercial portfolio that would maximize the value of the holdings for the nation as a whole. At the same time, a new company called Gassco was established with responsibility for operation of the gas pipeline network and treatment facilities for the benefit of all companies wishing to use the gas network. Statoil retains responsibility for the marketing and sale of State hydrocarbons.

Key facts

Oil production 2012E	2.1 mb/d
Gas production 2012E	1.9mboe/d
Oil reserves 2012E	11.2 bn bbls
Gas reserve 2012E	81 TCF
Reserve life (oil)	14.5 years
Reserve life (gas)	19.7 years
GDP 2012E ($bn)	$500bn
GDP Growth 2012E (%)	3.1%
Population (m)	5.03
Oil consumption (2011)	253 kb/d
Oil exports (mb/d)	1.75 mb/d
Fiscal regime	Tax & royalty
Marginal tax rate	78%
Top 3 Oil & Gas fields (2012E)	
Troll	654 kboe/d
Ormen Lange	396 kboe/d
Åsgard	374 kboe/d
Top 3 Oil & Gas Producers (2012E)	
Statoil	1352 kboe/d
Norway State DFI	1114 kboe/d
ExxonMobil	311 kboe/d

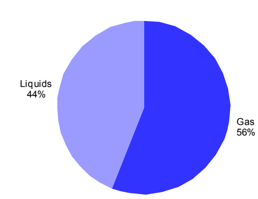
Source: Wood Mackenzie; EIA

Oil Production profile kb/d



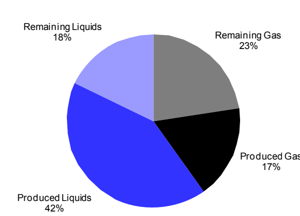
Source: Wood Mackenzie data

Remaining reserves split %



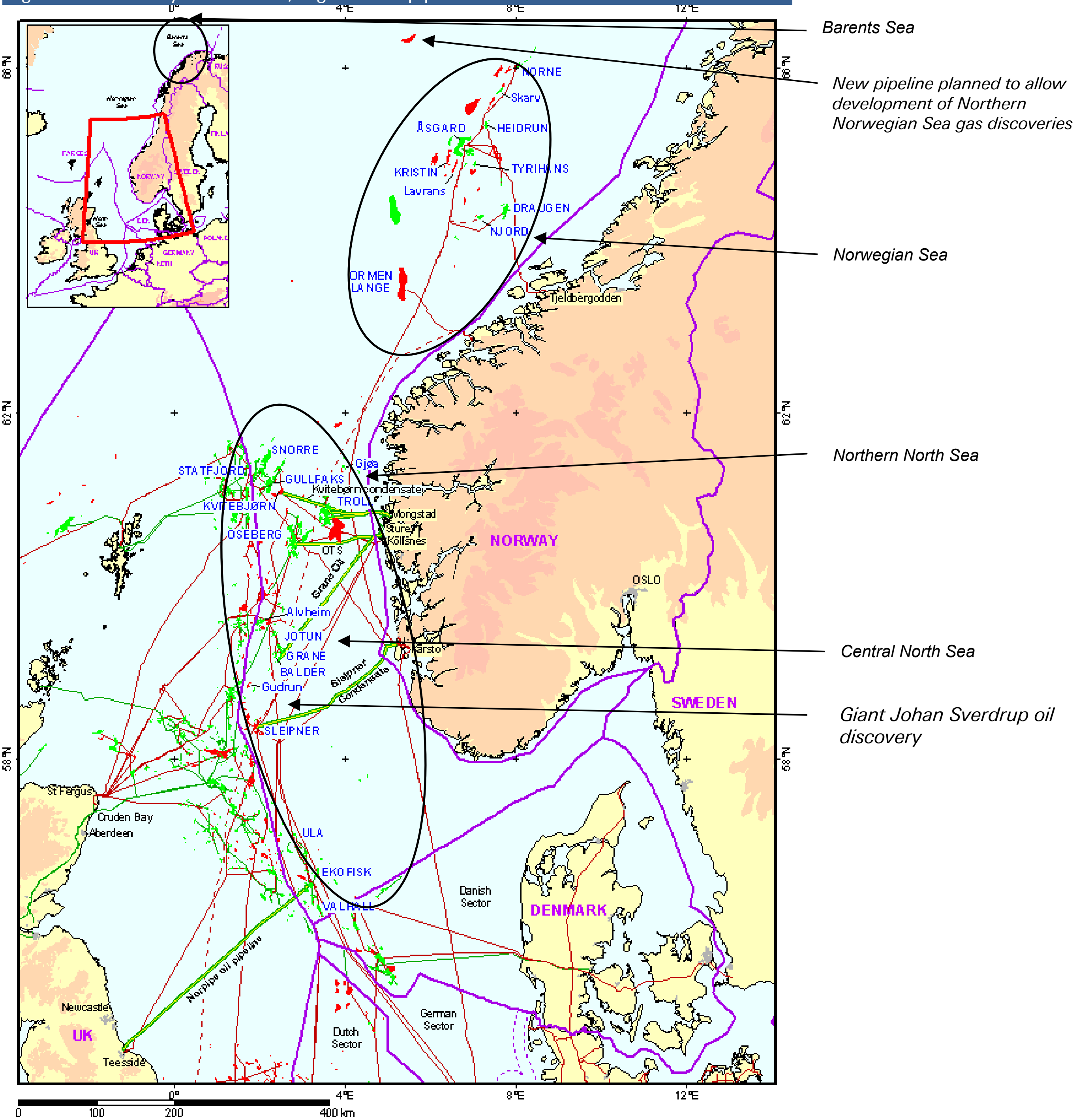
Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

Figure 446: Norway: Main fields, regions and pipelines



Source: Wood Mackenzie

Licensing

First licensing in the Norwegian sector took place in 1965. The licensing of **frontier** acreage continues today on a biannual basis with the ‘21st Round’ concluded in April 2011 and the ‘22nd Round’ set to complete in mid-2013. Two types of regular license exist. An **exploration** license is normally granted for three years, need not be exclusive and requires the payment of a largely nominal annual rent. It entitles to holder to conduct various geological surveys and some limited drilling. In contrast a **production** license entitles the holder to undertake exclusive geological studies and exploration under a pre-defined work programme which generally lasts from 2-6 years. Following this the holder may retain areas covering discoveries for up to 30 years.

In 1999, the Norwegian authorities have introduced a second licensing scheme entitled the Awards in Pre-defined Areas (or APA). Occurring annually, this seeks to award open acreage in more mature parts of the shelf, the intention of the authorities being to reduce fallow acreage and maximize the use of existing infrastructure. Exploration may extend for up to three years. However, at the end of this period the holder must either 'drill or drop'. Similarly, by the end of the fourth year the license holder must either decide to proceed with an application for a Plan of Development and Operation (PDO) or relinquish the acreage. Assuming that this application is successful, the license holders are allowed to retain half their initial license for a further 15 years during which time the plan may be executed and they may lift the oil or gas to which they are entitled.

In 2010, Norway and Russia agreed to end a protracted dispute over the shared Barents Sea border between the two countries, by clearly defining their borders, exclusive economic zones and rights to their assigned portions of the continental shelf. This was ratified in 2011. As a consequence, some 54,000 square miles of the formerly disputed zone is now allocated to Norway and becomes available for the government to license for oil/gas exploration. This is widely considered to be a highly prospective frontier region and hence we would anticipate interest from the industry as acreage is made available.

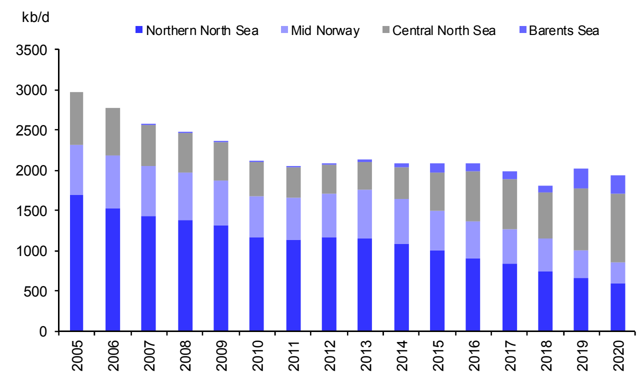
Production of Oil & Gas

Norwegian oil production rose strongly through the 1980s and into the 1990s, peaking at around 3.3mb/d in 2001 since when it has steadily declining to the current 2.1mb/d. Production is concentrated in the North Sea which accounts for c.1.5mb/d. As existing field continue to mature we would expect the production base to continue to decline. However, a series of near-term start-ups including Goliat and Skarv and the medium-term potential of recent discoveries in the Central North Sea (Johan Sverdrup) and Barents Sea (Skrugard/Havis) suggest that the pace of decline will be arrested and that production should stabilise at around 2.0mb/d out to 2020. The significance of the Sverdrup discovery cannot be overstated. In what is a mature province E&A success has unlocked a potential resource base of1.7-3.3bn/boe with production likely to commence in the 2018/19 time-frame.

In contrast to liquids, gas production has shown sustained growth in recent years positioning Norway as the world's second largest gas exporter after Russia. Overall, gas production in 2012 was c.4TCF. Growth is expected to be sustained through to the latter part of this decade supported by a number of start-ups including Skarv (2012) and Aasta Hansteen (2017). The Aasta Hansteen development is significant as the associated Polarled pipeline will open-up the potential commercialisation of other discoveries in the previously stranded Northern Norwegian Sea.

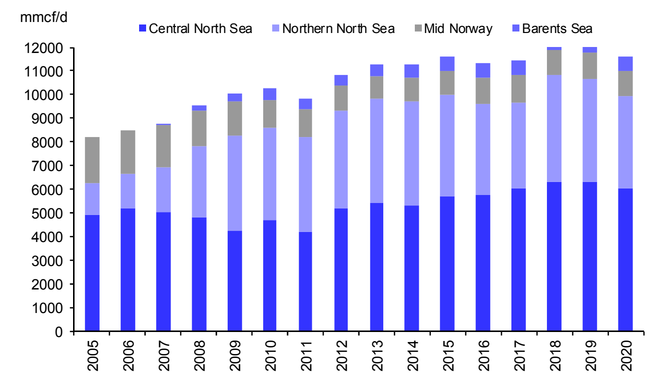
In 2012 the largest producing oil fields in Norway were Ekofisk (184kb/d), Asgard (172kb/d), Troll (161kb/d), Grane (130kb/d) and Snorre (101kb/d). The largest producing gas fields were Troll (2.8bcf/d), Ormen Lange (2.1bcf/d), Aasgard (1.1bcf/d), and Sleipner (0.7bcf/d). The major end-markets for Norway's gas exports are UK, Germany and France.

Figure 447: Norwegian liquids production 2005-20E (kb/d)



Source: Wood Mackenzie

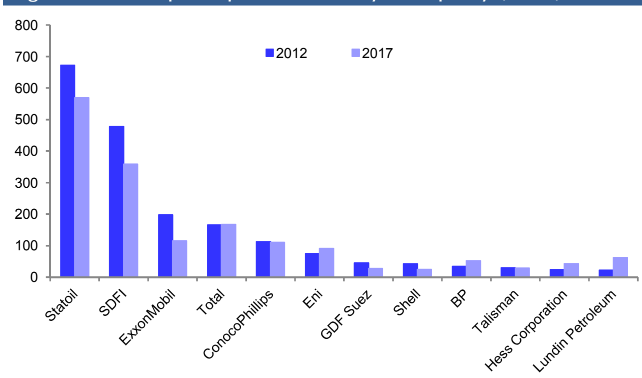
Figure 448: Norwegian gas production 2005-20E (mscf/d)



Source: Wood Mackenzie

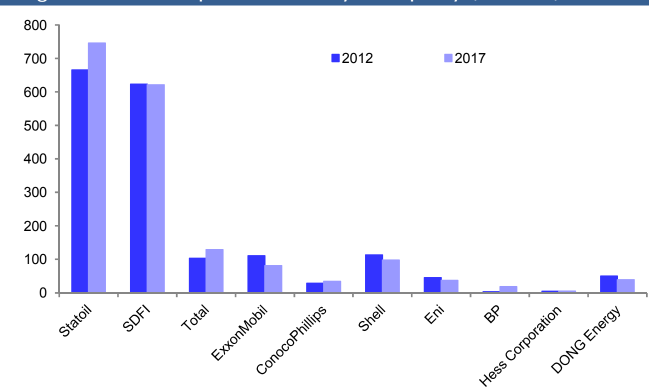
From a company perspective it comes as little surprise that in 2012 Statoil was the country's main producer. Exxon and Total represent the international players with the greatest absolute exposure to Norway's upstream.

Figure 449: Liquids production by company (kb/d)



Source: Wood Mackenzie

Figure 450: Gas production by company (kboe/d)



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data, 2P reserves in Norway at the end of 2012 include some 11bn bbls of oil and 81TCF of gas. Of these an estimated 72% are located in the North Sea. In recent years, reserve growth has tended to arise through additions to existing fields rather than new discoveries. Nevertheless, despite its maturity Norway remains highly prospective with the NPD estimating total undiscovered resources of some 16bn boe shared by North Sea (5.3bn boe), Norwegian Sea (4.9bn boe) and Barents Sea (5.9bn boe). The Barents in particular has been a source of significant excitement inspired by the Skrugard (2011) and Havis (2012) discoveries. New discoveries aside, with an average field recovery factor estimated by the NPD at 42%, significant potential also remains for reserve additions through improved recovery techniques and field developments.

Pipelines and infrastructure

Norway's crude oil transport pipelines are all located in the North Sea and carry the crude oil to shore. Key pipelines include the Norpipe system which links Ekofisk with the UK at Teeside and the Oseberg Transportation System, Troll Oil System and Grane Oil Pipeline, all of which connect facilities in the northern North Sea to the Norwegian mainland at Mongstad and Sture. Similarly, the country has established a significant number of gas pipelines both to connect the offshore fields to the Norwegian mainland as well as to other European markets. The most significant infrastructure development over the next 5 years is likely to be the c900bcf/y Polarled pipeline which will link the stranded discoveries of the Northern Norwegian Sea to the processing facilities at Nyhamna.

Figure 451: Selected international gas pipelines

Name	length (km)	Fields	Destination	Volume
Langeled	1200	Ormen Lange	Easington	750bcf/y
Frigg	350	Frigg	St Fergus	510bcf/y
Zeepipe 1	814	Sleipner	Zeebruge	460bcf/y
Franpipe	830	Troll/Sleipner	Dunkerque	530bcf/y
Europipe	716	Asgard	Dunkirk	700bcf/y

Source: Deutsche Bank

Crude Oil Blends and Quality

Norwegian oils are in the main light, sweet blends. The most important blend is Ekofisk which has an API of 37.8 and 0.3% sulphur content i.e. very similar to the UK's Brent. Variations in crude quality are not expected to prove significant going forwards.

Broad Fiscal Terms

All licenses in Norway are granted as tax and royalty concessions. The main tax components are corporation tax of 28% and a special tax levied on hydrocarbon production of 50%. The resulting 78% effective tax rate makes Norway one of the highest tax regimes globally. However, whilst the rate of tax is high, tax allowances are relatively generous. Capex is amortizable against income on a six year straight line basis with a 30% value uplift available for tax purposes (which is recoverable over four years). Furthermore, in an effort to incentivise exploration, since 2005 the tax system has allowed companies to recoup tax losses associated with unsuccessful exploration in the following tax year even where the company has no profit stream to offset. As a result, the State is assuming a greater degree of exploration risk and exploration biased companies without material Norwegian profit streams to shelter have been attracted.

Refining and downstream markets

Norway had some 336kb/d of refining capacity in 2012 through two major refining facilities; the Exxon owned and operated 116kb/d Slagen plant and the Statoil operated 220kb/d Mongstad facility (21% of which is owned by Shell). Norway produces more petroleum products than it consumes and is thus a net exporter of c80kb/d of finished products as well as crude oil. Not surprisingly, Statoil (46%), Shell (27%) and Exxon (20%) dominate the Norwegian downstream product markets.

LNG

To date LNG has not played a significant role in natural gas exports from Norway and in this respect the commissioning of Statoil's 4.1mtpa Snohvit facility at the end of 2007 was intended to open new markets for Norwegian gas. Fed by a cluster of gas discoveries in the Barents Sea in the early 1980s the development of an LNG project was seen as the only feasible option for the monetization of some 6TCF of gas. Completion of the project was, however, not without its delays and disappointments not least a very substantial increase in cost. Snohvit now accounts for around 4% of Norway's gas production. The potential for installation of a second liquefaction train has long been mooted; however following mixed E&A results it was decided during 2012 that an expansion would not proceed at the present time.

Norway – Notes

Russia

Russia holds the world's eighth largest reserves of oil and by far the largest reserves of natural gas. Proven reserves at the end of 2012 stood at 96 billion barrels of oil and 1575Tcf of natural gas and this before considering the huge potential for resource addition in the offshore Arctic and Bashenov shales. Production is concentrated in four main regions and, at c.10.3mb/d and 59bcf/d, Russia is the largest non-OPEC producer of oil and the world's largest producer (and exporter) of natural gas. After several exceptional 'recovery' years during which oil volumes increased at a staggering 6-7% p.a, output growth is now expected to moderate to around 1% p.a. Production is dominated by Russian national companies (Rosneft and Gazprom) with the Russian state exerting influence over a resource base that it increasingly regards as 'strategic' through both legislation and indirectly through its majority interests in Gazprom (50%), the national gas company, and Rosneft (75.16%), the country's largest oil company. With the exception of BP, which post its sale of TNK-BP to Rosneft for $26.7bn will hold a 19.75% interest in that company, and subsequent to Conoco's sale of its 20% interest in Lukoil, foreign ownership in Russia is limited.

Broad geology and topology

Russia's oil and gas provinces are formed around two ancient and stable tectonic plates or 'cratons', the East European craton to the west of the Ural Mountains and the East Siberian craton to the east. Fourteen oil and gas provinces are defined, each of which is synonymous with Russia's major geological regions and each of which is quite different to the other in terms of maturity and oil quality. To date, production has concentrated on four of these, most significantly West Siberia and the Volga-Urals, but also Timan-Pechora and the now largely depleted North Caucasus. Looking ahead, increased activity in the Far East around Sakhalin Island, the Russian Arctic and, as infrastructure is laid down, East Siberia will likely see these gain in significance.

History and regulation

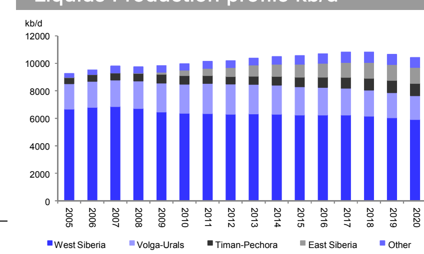
Russian oil exploration and production was first initiated around the borders of the Caspian Sea in the 1860s. Over the subsequent 150 years, exploration has, however, been extensive with only the most hostile environments such as East Siberia and the Arctic remaining relatively poorly explored. In total over 2300 oil and gas fields have been discovered. Initially industry activity was concentrated in the North Caucasus. However at the end of the 1920s the focus shifted towards the Volga-Urals and Timan-Pechora and, by the end of the Second World War, a series of large discoveries led to the Volga-Urals becoming known as the 'Second Baku', replacing Azerbaijan as the main oil producing region in the Soviet Union. By 1960 85% of total Soviet production of 2.4mb/d arose in the Volga-Urals. Output from this region peaked in 1975 at 4.6mb/d but with exploration technology improving, industry activity had already moved towards more challenging but highly prospective regions, not least West Siberia. Here a series of huge discoveries including TNK-BP's 21bn bbl Samatlor field and the giant gas fields of Zapolyarnoye (107tcf), Urengoiskoye (267tcf) and Yamburgskoye (211tcf) saw the heart of Russia's oil industry shift again. Yet, after peaking at 11.3mb/d in 1988, the break-up of the Soviet Union and with it the collapse of State financing led to a major decline in drilling activity. By the late 1990s production had fallen back to just 6mb/d – a level not seen for 25 years. Yet, as the oil price has risen and Russia's economy has stabilized, so an increase in drilling activity together with the introduction of advanced recovery techniques have helped drive a dramatic upturn in production.

Key facts

Liquids production 2013E	10.4mb/d
Gas production 2013E	11.4mboe/d
Oil reserves 2013E	96bn bbls
Gas reserve 2013E	1575tcf
Reserve life (oil)	25.3 years
Reserve life (gas)	74 years
GDP 2012E ($bn)	$1.95trillion
GDP Growth 2012E (%)	3.7%
Population (m)	141.9m
Oil consumption (mb/d)	2.96m/d
Oil exports (mb/d)	7.5mb/d
Fiscal regime	T&R and PSC
Marginal (corporate) tax rate	68%&86%
Top 3 O&G fields (2012E)	
Zapolyarnoye	1,686kboe/d
Yamburgskoye	1,546kboe/d
Urengoiskoye	1,464kboe/d
Top 3 O&G Producers (2012E)	
Gazprom	8,307kb/d
Rosneft	2,621kb/d
Lukoil	1,959kb/d

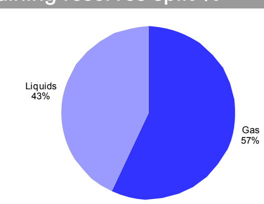
Source: Wood Mackenzie; EIA data

Liquids Production profile kb/d



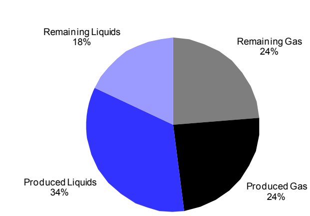
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

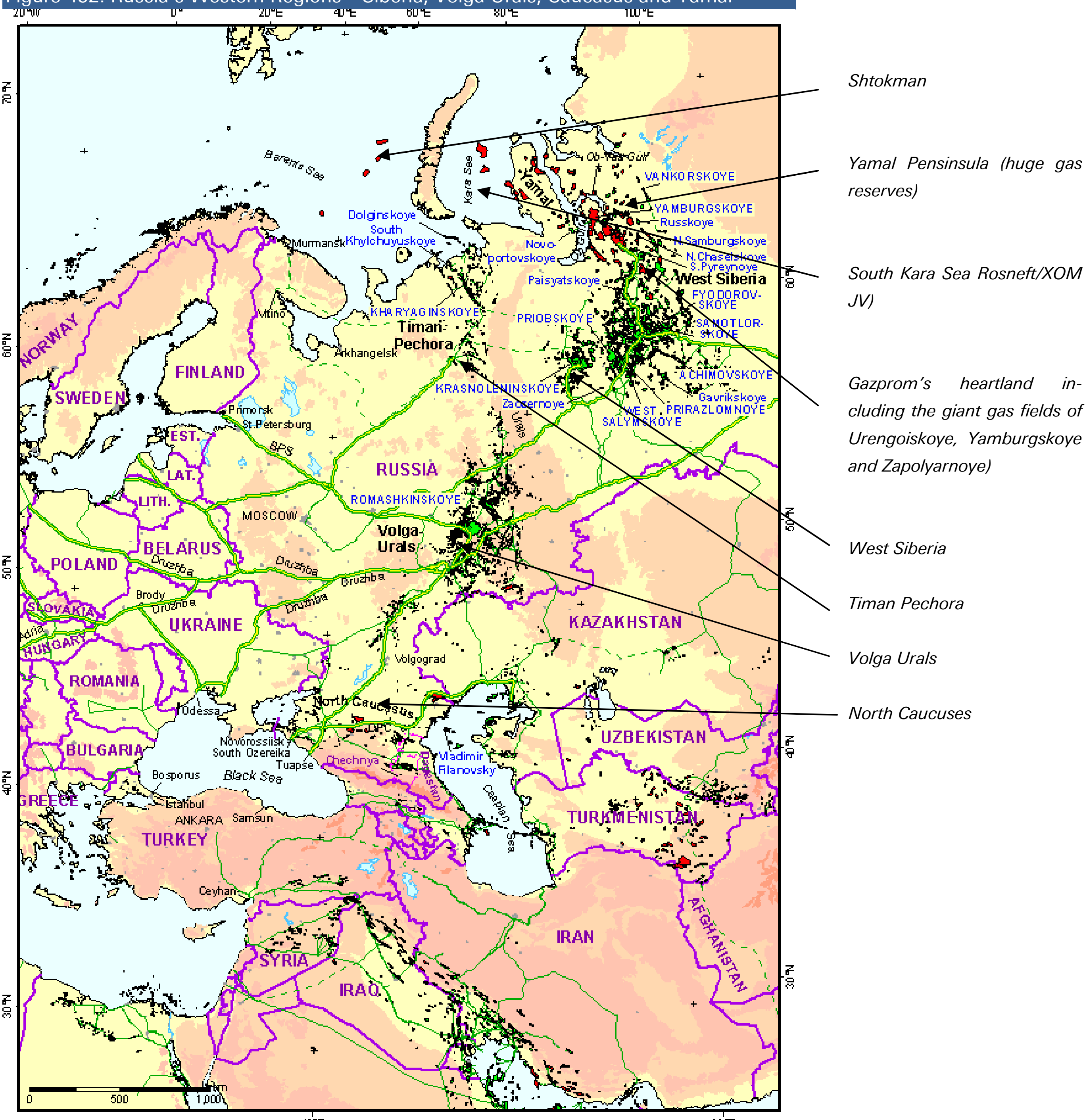
Initial versus remaining reserves



Source: Wood Mackenzie data

In Russia the State is the owner of all subsurface resources. Overseen by the Ministry of Resources, a myriad of laws define permitted activities and the state's authority. Key amongst existing hydrocarbon legislation is the 'Law on the Subsurface'. This provides the basic legal framework for investment in the development of all natural resources and defines the regulation of licenses.

Figure 452: Russia's Western Regions – Siberia, Volga Urals, Caucasus and Yamal



Source: Wood Mackenzie

Amended several times since its 1992 introduction, the law awards the federal government full authority for tendering resources and for the issuance and withdrawal of licenses. It is, however, of note that the Subsurface Law is continuously reviewed with the most recent review resulting in introduction of the "Strategic Investments Law" in 2008 which restricts foreign investors buying an interest in or acquiring control over strategic assets (see overleaf).

Indeed, under the guidance of President Putin the state's growing desire to use its mineral wealth for strategic and political ends had served to add considerable uncertainty around foreign investment in Russia. Starting with the 2004 dissolution of the country's then largest oil company, Yukos, for alleged tax evasion, the state has sought to recapture control over significant resources that were licensed to foreign companies under earlier administrations, often through the assertion of questionable claims of license infringement (for example the dilution of Shell's interest in the Sakhalin II PSA and the 'negotiated' purchase of BP's interest in the giant Kovytka field). The result has been the concentration of production in the hands of the state, culminating most recently through Rosneft's buy-out of the joint venture partners in TNK-BP, a move which sees its hydrocarbon production rise towards 5mboe/d from nothing but a decade ago.

Licensing

As indicated, licensing is controlled by the Ministry of Natural Resources. Licenses are awarded by way of tender and the payment of a bonus although under an amendment to the Subsurface Law in 2000, the winner of a tender may now be chosen for the national security of Russia. At present, licenses may be assigned to joint ventures in which the license holder has a 50% share. Licenses typically allow a five year period for exploration with production licenses granted for a twenty year period (although applications for extensions were commonly granted). Following amendments to the law in 2000 licenses are now granted for production over the life of the field. The introduction of the Strategic Investments Law in 2008 means foreign investors now face restrictions when buying an interest in or acquiring control of strategic assets (where control is defined as holding >10%). Whilst there are a number of restrictions, the most important are:

- Companies operating strategic assets should be registered in Russia.
- If, whilst operating under an exploration licence, a foreign investor (or entity in which foreign investors participate) discovers reserves which are subsequently deemed strategic, the Russian government has the right to refuse to grant a licence for the development of the resources found.
- If a strategic deposit is found on a combined exploration and production licence, the Russian government has the right to terminate the right to use the subsoil plot.

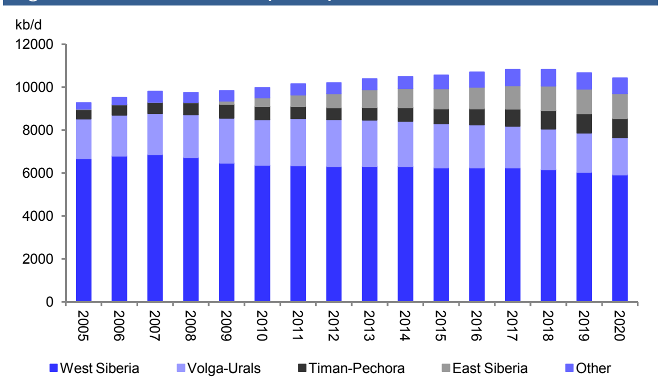
Production of oil & gas

Having recovered strongly through the early years of the current decade production of both gas and oil in Russia is expected to continue to grow over the next few years, albeit at a much slower rate. According to Wood Mackenzie estimates, oil production is expected to rise to 10.8mb/d by 2017 and gas to over 70bcf/d. For oil production to continue to expand beyond this period will, however, require substantial investment, much of the improvement in recent years coming from enhanced recovery at existing fields rather than greenfield investment. Historically, several super giant fields contributed significantly to oil output. For example, in 1980 Samatlor's 3mb/d of production accounted for almost 40% of Russia's production. However, with many of these in decline production today is far more widespread. Key fields include Rosneft's Priobskoye (c770kb/d), Samatlor (475kb/d) and Vankor (350kb/d). Russia's oil production is dominated by state companies Rosneft (c3.9mb/d) and Gazpromneft (0.8mb/d) together with national companies Lukoil (1.7mb/d) and Surgut (1.1mb/d).

Despite already huge production, gas volumes are expected to grow at a compound 3-4% through 2017 rising to an estimated 73bcf/d. Moreover, gas production is far more concentrated with the three largest fields (Zapolyarnoye, Yamburgskoye and Urengoiskoye) accounting for over 40% of current production. With production from the last two of these now in decline, recent years have seen Gazprom invest substantially to develop new giant fields not least Bovanenkovskoye on the Yamal Peninsular and which is expected to produce c13bcf/d by end decade.

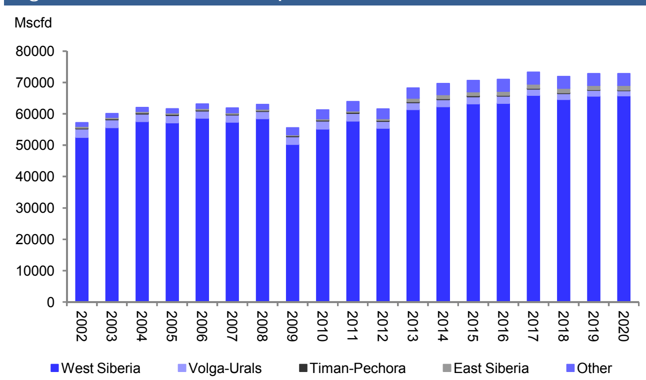
Gas production is dominated by state controlled Gazprom, which by law has the right to any gas fields deemed of strategic importance (provided no development licence has been granted), a monopoly over piped gas exports and domestic supply. Gazprom also retains a monopoly over Russia's gas transport network the Unified Gas Supply System (UGSS). Although other companies produce gas in Russia, not least Novatek, their prospects are heavily dependent upon their relationship with Gazprom given its monopoly of gas infrastructure and domestic supply.

Figure 453: Russia – Liquids production 2005-20E (kb/d)



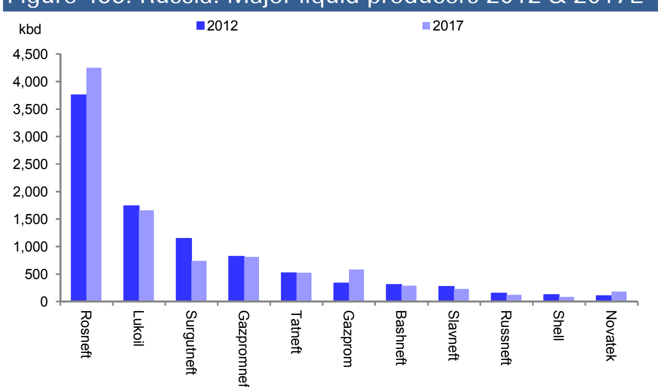
Source: Wood Mackenzie

Figure 454: Russia: Gas production 2005-20E (mscf/d)



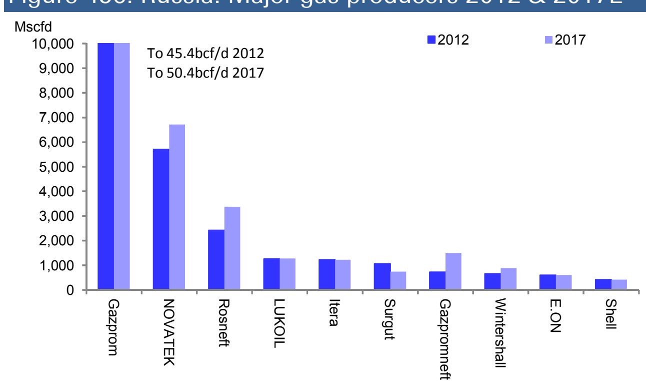
Source: Wood Mackenzie

Figure 455: Russia: Major liquid producers 2012 & 2017E



Source: Wood Mackenzie Assumes completion of Rosneft TNK-BP

Figure 456: Russia: Major gas producers 2012 & 2017E



*Source: Wood Mackenzie *Assumes completion of Rosneft TNK-BP*

Reserves and resources

Based on Wood Mac estimates Russia held estimated 2P reserves of oil at the end of 2012 of 96bn bbls. The country has the world's 8th largest bank of conventional oil reserves and, at 1575tcf (c.272bn boe), by far the largest reserves of natural gas – nearly twice those of the next largest country, Iran. Moreover, the USGS estimates that yet to find gas reserves stand at over 1,000tcf of gas and 60bn bbls of liquids. By region, around 78% of the country's 2P reserves base is in West Siberia with around 2-9% of reserves located in each of the Volga-Urals, East Siberia (largely Kovytka) and the Barents Sea (Shtokman). By field, the most significant reserves reside within those detailed in the following table.

Given the scale of Russia's resource opportunity and the capital that will be required to extract it but also the more limited technical competence of the Russian majors, the Russian state has more recently encouraged the establishment of joint ventures between Rosneft and the IOC majors as it seeks to exploit its resource endowment. Following the failure of a planned alliance in the Arctic waters of the South Kara Sea between BP and Rosneft, an alliance was subsequently signed between Exxon and Rosneft. This gave Exxon a 30% interest in highly prospective Arctic acreage and was followed by later deals between Rosneft and both ENI and Statoil. Similarly, Rosneft has more recently established an alliance with Exxon that will seek to assess the potential of Russia's huge tight oil reserves not least those in West Siberia's Bashenov shale formation. Given similar properties to the tight oil reserves of the Bakken it is estimated that the Bashenov formation could contain as much as 365bn barrels of recoverable liquids resource.

Figure 457: Major oil and gas fields and remaining reserves (1/1/13)

Oil			Gas		
Name	Region	Reserves (Mbbl)	Name	Region	Reserves (TCF)
Priobskoye North	West Siberia	6,004	Bovanenkovskoye	West Siberia	106.7
Samotlorskoye	West Siberia	3,356	Zapolyarnoye	West Siberia	67
Romashkinskoye	Volga-Urals	3,152	Yamburgskoye	West Siberia	60.2
Vankorskoye	East Siberia	2,742	Urengoiskoye	West Siberia	48.1
Priobskoye South	West Siberia	2,189	Kharasaveiskoye	West Siberia	37.1
Astrakhanskoye	Precaspian	2,180	Kovyktinskoye	East Siberia	37.1
YuganskNG	West Siberia	2,069	Kruzenshternovskoye	West Siberia	23.9

Source: Wood Mackenzie; Deutsche Bank

Pipeline and infrastructure

With 220,000km of pipelines, Russia has extensive pipeline infrastructure albeit that much of it is in need of investment. Virtually all of this is owned and operated by Government controlled entities. Pipelines for oil are operated by Transneft, gas by Gazprom and oil products by Transnefteprodukt. Including rail and ports Russia is believed to have a current export capacity of 10.6mb/d. Of this 4.0mb/d (38%) is represented by the main Druzhba pipeline, 4.6mb/d (43%) by ports in the Baltic (predominantly 1.5mb/d at Primorsk) and Black Seas (largely Novorossiysk 1mb/d). At 1.2mb/d (11%) rail makes up much of the balance.

Oil infrastructure: The original design capacity of the Russian oil pipeline system was for 13mb/d but bottlenecks limit the overall capacity. The main export pipeline today is the 4mb/d **Druzhba**. This has a total length of almost 4,000km and connects oil produced in West Siberia and the Urals to markets in western Russia and Europe. Other key pipelines providing access to western export markets include the **Baltic Pipeline System** which has a capacity of 1.5mb/d and connects oil from West Siberia and Timan Pechora, amongst others, to the Baltic port of Primorsk and the 1.4mb/d **Caspian Pipeline Company (or CPC),** which although predominantly for Kazakh exports from the Caspian Sea also carries Russian oil to the Black Sea port of Novorossiysk. Looking east Stage 1 of the **East Siberia to Pacific Ocean Pipeline (or ESPO)** connects fields in West and East Siberia with Chinese and Pacific markets. Initial capacity of 1mb/d is expected to rise to 1.6mb/d on completion of Phase 2 which connects to Kozmino Bay, north of

Vladivostok on the Sea of Japan in late 2013**.** A separate 300kb/d spur line running to Daquing in China is expected to be completed around the same time.

Gas infrastructure: Russia has the world's largest network of gas pipelines, collecting and distributing some 24tcf of gas per annum both for the domestic market and for sale into Europe. Many are, however, in need of investment with annual leakages estimated at a huge 800mscf/d. Key international pipelines include **Blue Stream (**owned jointly with ENI) which runs under the Black Sea exporting up to 1.4bcf/d of gas from Russia to Turkey, the **Soyuz** system which carries gas from the Orenburg processing plant on the border with Kazakhstan into Europe, **Northern Lights** which carries gas from West Siberia and Timan Pechora into the Baltic states, the 46bcf/d **Brotherhood System** which starts at the giant fields of West Siberia and carries gas through the Ukraine into Europe and the 3.2bcf/d **Yamal Pipeline** which carries gas across Belarus and into Poland from the Yamal Peninsula and for which a second pipe (Yamal 2) is planned. Several international projects are also under development. The **Nord Stream** pipeline will carry 5.3bcf/d of gas across the Baltic Sea to Germany is under the first phase of its development and potentially, should a second phase proceed, extend transportation to the UK. Gazprom has also been considering extending its gas network to China with gas potentially coming from Kovytka or the Sakhalin fields. **South Stream** will carry 3.0bcf/d from Beregovaya through the Black sea to Varna, Bulgaria where it will split in two; one leg will connect through Serbia and Hungary to Austria while the other leg will run through Greece and the Ionian Sea to Italy.

Evidently, most of Russia's gas pipelines today are directed at Europe with eastern-facing infrastructure still largely in its infancy and requisite of very substantial capex if it is to be laid down. Several plans are, however, in pace to carry gas from both West and East Siberia to Asian markets including the proposed 2.9bcf/d **Altai** pipeline which would carry gas from West Siberia to the East, and the proposed 3.3bcf **Kovytka-Chayandinskoye** which would connect two huge East Siberian gas deposits to Asia.

Crude oil blends and quality

With almost all oil in Russia entering the Transneft network, which does not have a quality bank, the vast majority of Russian oil is sold as Urals Blend. This has a typical API of 31.8 and relatively high sulphur content (1.35%). In an attempt to retain value some producers do, however, export higher product via rail. This lighter (35.6 API), sweeter (0.46% sulphur) oil is sold as Siberian Light.

Broad fiscal terms

Fiscal terms in Russia tend to be based on a concession/tax and royalty system. Although projects operating under PSCs do exist (Exxon's Sakhalin 1, Shell's Sakhalin 2 and Total's Kharyaga), future use is likely to be limited in the extreme. As such, we focus solely on the general tax terms surrounding concessions.

Simplistically, the standard fiscal regime in Russia includes three main fiscal components; a mineral extraction tax (MET), corporation tax and, if the oil is exported, an export tax.

- MET in effect represents a royalty payable by the producer on the **volume** of extracted resource, the tax receipts being shared between the federal and regional governments in an 80/20 ratio. MET varies depending on whether the resource is oil, condensate or gas. For oil, the calculation of duty involves some adjustments for the oil price and changes in the Rouble rate of exchange against the US$. As a proxy, however, the rate of oil MET, whilst being a absolute rouble amount per tonne of oil produced, typically runs at around 15-17% of the well head price. On gas MET is also set at a fixed rate determined annually with a higher rate pertaining to Gazprom. (c$19/mcm in 2013) and on condensate at 17.5% of the well-head price. Importantly, and in order to incentivise development, regions such as the Arctic and East Siberia are entitled to certain exemptions from MET with the scale of the relief dependent upon the perceived complexity of developments in the region (with developments in the Arctic for example receiving the greatest relief). This system of relief has also been applied to hard-to-recover oil categories; an initiative which it is hoped will help support the development of tight oil formations such as the Bashenov shale, amongst others.

- Export duties were introduced in January 2003 and revised upwards significantly in 2004. They apply to oil and are calculated on a sliding scale rising from 0% at a price below $15/bbl to 60% at an average price above $25/bbl. The duty payable is calculated on the average official Mediterranean and Rotterdam price from the middle of month 1 to the middle of month 2 with the calculated rate then applied from the start of the following month.
- Beyond these two taxes, companies are liable to corporate tax at a standard rate of 20%.

The consequence of Russian export tax is that at oil prices of over $25/bbl the effective marginal rate of tax per $/bbl increase in the price of crude is around 68%, with the total rate (i.e. including MET) nearer 90%. In general, at prices of over $40/bbl export tax represents a major financial incentive to convert crude to products (gasoline, diesel, etc) before exporting.

Refining

Russia has some 40 refineries with a total distillation capacity of 5,663kb/d. Although a dozen or so have a capacity of over 250kb/d many of the refineries are old and inefficient. Utilization rates, whilst improving, remain relatively low at an estimated 80%, with around 4.6mb/d of oil products produced. The refining system is also relatively simple producing large volumes of fuel oil (around 40% of output) but only limited gasoline (20% of output). Furthermore, with almost 25% of refining capacity located around Moscow but under 10% in the all important West Siberian region, crude oil needs to travel significant distance before conversion adding to costs. Outside these two areas 40% of capacity is located in the Volga Urals and 10% the North Caucasus. Given that Russian product demand runs at c2.9mb/d, the refining sector is a major exporter even at its depressed rates of utilisation. In particular it is an important source for Europe of diesel.

LNG

Despite its substantial gas resources, Russia's proximity to Europe has meant that its main and most economical export routes have been via pipeline. Through Gazprom the state has, however, exhibited a growing interest in diversifying its supply options through the construction of LNG facilities. The Shell-led Sakhalin II project on the East coast of the country represents the country's first commissioned LNG facility. With an initial capacity of 9.6mtpa, the two trains of the project commissioned in 2009. Sakhalin aside, and following the indefinite postponement of the Shtokman LNG project, Russia is looking to the development of LNG capacity on the Yamal Peninsula and at Vladivostok. Of these the proposed 15mtpa Yamal LNG, which will be operated by Novatek and in which Total has a 20% interest appears to be the most advanced with the companies anticipating a final investment decision in late 2013 or 2014.

Russia - Notes

United Kingdom

The UK is a mature hydrocarbon province having commenced oil production in the early 1970s. Both liquids and gas production are believed to have peaked in 1999 and 2001 respectively and have subsequently declined by a compound annual rate of 7%. Nevertheless, the UK is the second largest hydrocarbon producer in the EU. Looking forward, Wood Mackenzie anticipates that production will enjoy a mini-recovery though to 2015/16 supported by a number of start-ups after which the decline trend resumes. However, the performance of the UK asset base has consistently disappointed such that confidence in this period of growth is low. The UK now a net importer of both oil and gas. Wood Mackenzie estimates end-2012 recoverable reserves of 5.7bn bbls of oil (2P) and 18.4TCF of gas (2P). Production arises from a huge number of often modest fields, is largely offshore and, in 2012, ran at around 1.1mb/d of oil and 0.8 mboe/d of gas. Major IOCs with a strong presence in the UK include BP, Shell, Total, COP and XOM.

Basic geology and topology

The bulk of the UK's reserves are located offshore in the UK continental shelf (UKCS). This can broadly be divided into five main hydrocarbon provinces namely the Central North Sea, Northern North Sea, Southern Gas Basin, West of Britain and Atlantic Margin. Akin to Norway the vast majority of production is concentrated in the central and northern sections of the North Sea where hydrocarbons reside in two reservoir horizons created during the Jurassic and Lower Tertiary eras. In the Central North Sea these are dominated by the Central Graben and in the Northern North Sea by the Viking Graben. Further to the south, off the east coast of England, lie the substantial gas deposits of the Southern Gas Basin, whilst to the north west of Shetland the relatively unexplored/developed Atlantic Margin has seen a number of significant finds in the more recent past from Palaeocene reservoirs including Foinhaven, Schiehallion and Lochnagar. Although UK activity is predominantly offshore, some modest onshore activity takes place at Wytch Farm on the coast of southern England.

Regulation and history

Spurred by the Groningen gas discovery in the Netherlands, initial offshore exploration in the UK concentrated on the Southern Gas Basin with the first gas discovery in British waters (West Sole) made in 1965. However, following the discovery of Norway's Ekofisk field in the North Sea, attention shifted with first oil being discovered in the Arbroath field in 1969. This led to the substantial development of the North Sea and with it the establishment of significant infrastructure. After peaking at 2.9mb/d oil production is, however, now well into decline and despite increased exploration activity, results have generally been disappointing. Consequently, development from here is likely to become increasingly dependent upon maximizing recovery from existing areas of production and maturing technical discoveries, not least some significant heavy oil deposits (such as Bressay/Mariner).

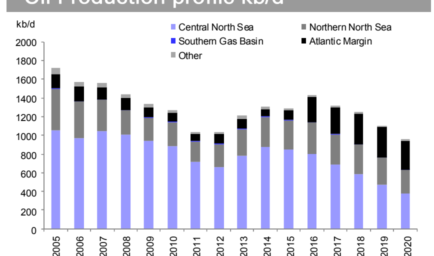
Given an outlook of long-term decline the challenge for the UK authorities must be to stimulate continued investment in what is a mature province and so extend the life of both the region and the current infrastructure. Clearly this ambition has not been helped in recent years by the imposition of significant tax increases, particularly given that the offshore bias of the UK and hostile North Sea environment means that it is already a high cost oil province. Regulation of the UK industry, which is overseen by the Department of Energy & Climate Change, has in recent years thus focused on ways of increasing activity and reducing 'fallow' acreage.

Key facts

Liquids production 2012E	1.1 mb/d
Gas production 2012E	0.9 mboe/d
Oil reserves 2012E	5.7bn bbls
Gas reserve 2012E	18.4 TCF
Reserve life (oil)	9.8 years
Reserve life (gas)	7.9 years
GDP 2012E ($bn)	$2.4trillion
GDP Growth 2012E (%)	-0.4%
Population (m)	63m
Oil consumption (mb/d)	1.6m/d
Oil exports (mb/d)	NIL
Fiscal regime	Tax (CT & SCT)
Marginal tax rate	62%
Top 3 Oil and Gas fields (2012E)	
Buzzard	172kboe/d
Alwyn Area	89kboe/d
Sean	60kboe/d
Top 3 Oil and Gas Producers (2012E)	
BP	212kboe/d
Shell	177kboe/d
Total	127kboe/d

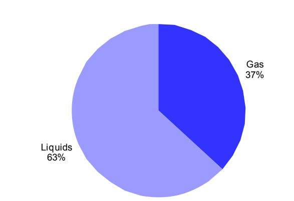
Source: Wood Mackenzie; EIA

Oil Production profile kb/d



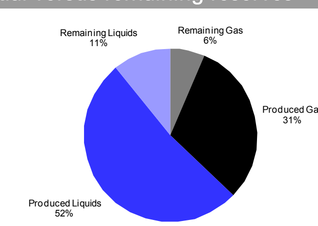
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

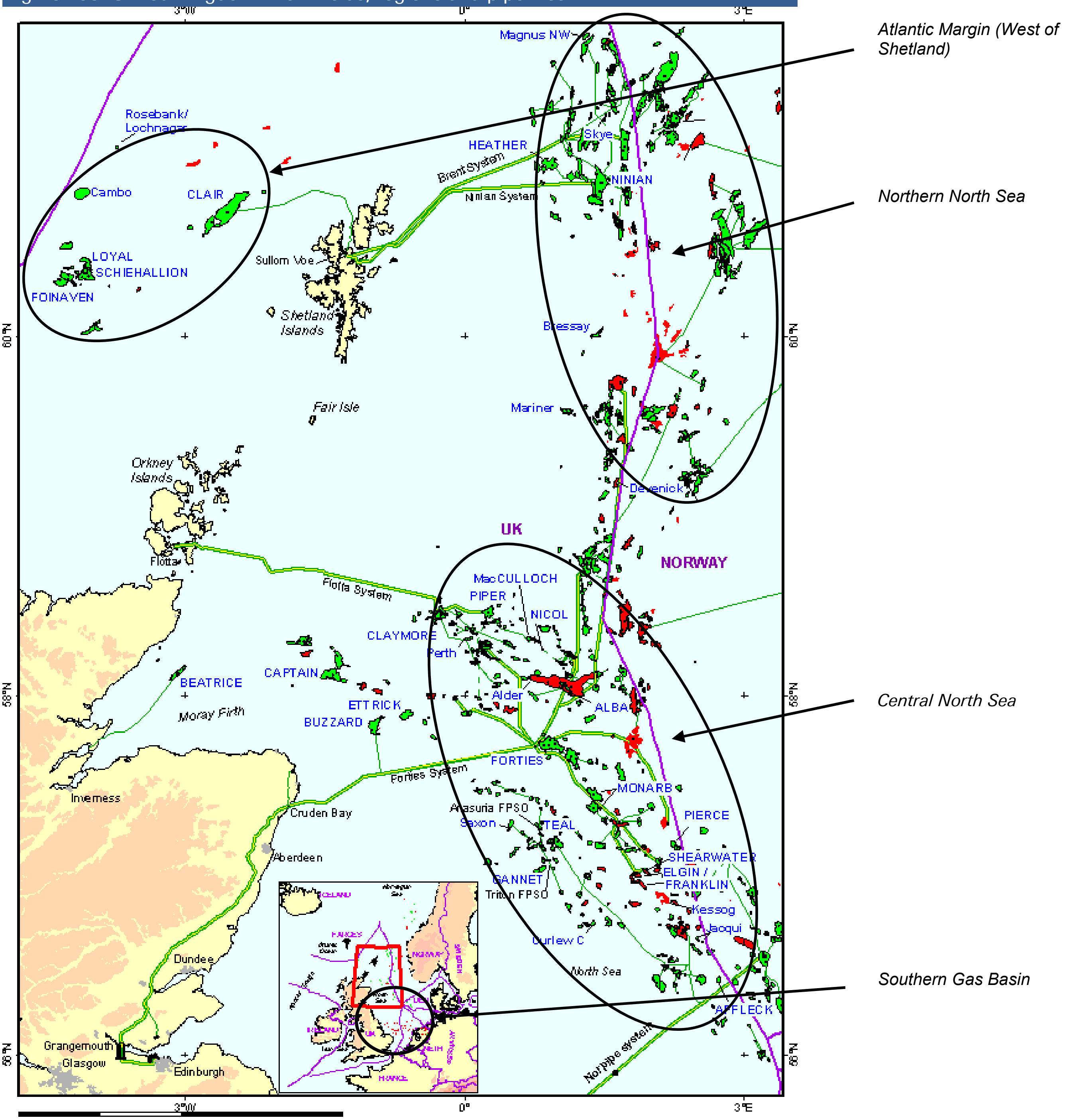
Initial versus remaining reserves



Source: Wood Mackenzie data

The UK Government no longer holds a direct interest in the country's oil and gas production (the old, state owned, British National Oil Corporation or BNOC, having been privatized as Britoil through an IPO under the Conservative Thatcher government in the early 1980s before being acquired by BP in 1988). However, Corporation Tax & Supplementary Tax income from UK oil and gas production at c£7bn p.a. represents around 1/6th of UK Corporation Tax receipts.

Figure 458: United Kingdom: Main fields, regions and pipelines



Source: Wood Mackenzie

Licensing

The UK regulatory framework comprises a licensing system that is administered by the Department of Energy and Climate Change (DECC) previously known as BERR and before that DTI. The regulations contained within the 1934 Petroleum (Production) Act and 1964 Continental Shelf Act govern how applications for licences must be made and by whom. For regulatory purposes, the UKCS is divided into quadrants of 1° longitude by 1° latitude. Each quadrant is numbered and contains 30 blocks, each with an area of 250 square kilometres. Divisions of blocks into part-blocks occur when the block is partially relinquished. Licence holders are required to pay an application fee in addition to a licence fee, which is calculated for each square kilometre included in the licence area, for the initial term, and then subsequent payment for each year in the further term.

Six types of what are termed 'Seaward Production Licenses' are available of which the most important are the 'Traditional', 'Frontier' and 'Promote'. It is of note that in recent years license periods have been reduced as the authorities have sought to both increase exploration activity and prevent acreage from becoming 'fallow'.

- **Seaward Production Licence (Traditional).** This enables the holder to explore and exploit the reserves in the area awarded in the form of an Offshore Licensing Round. The license runs for an initial 4 years at which point half the acreage must be relinquished with the option to extend on the balance for a further four years. All acreage not covered by a development plan must be relinquished at the end of the second term.
- **Seaward Production Licence (Promote).** In February 2003, DTI introduced the Seaward Promote License. This is awarded in the same way as the traditional license but has a lower rental fee and expires within two years if a work programme is not in place.
- **Seaward Production Licence (Frontier Six Years).** Introduced in the 22nd round in 2004 as a way to encourage activity in frontier areas, these licenses have a longer initial term of six years. For the first 3 years rental is set at 10% of the Traditional License rental at the end of which 75% of the acreage must be relinquished. The Licensees then have a further three years in which to complete a work programme at the end of which a further 50% must be relinquished.
- **Seaward Production Licence (Frontier Nine Years).** Introduced before the 26th round in 2010, companies were able to apply for Frontier Licenses in the West of Shetland and West of Scotland sector. This is similar to Six Year Frontier licence as above but the initial term set to nine years with first mandatory relinquishment of 75% at the end of sixth year and 50% of the remaining at the first initial term end in the ninth year.

Production of Oil & Gas

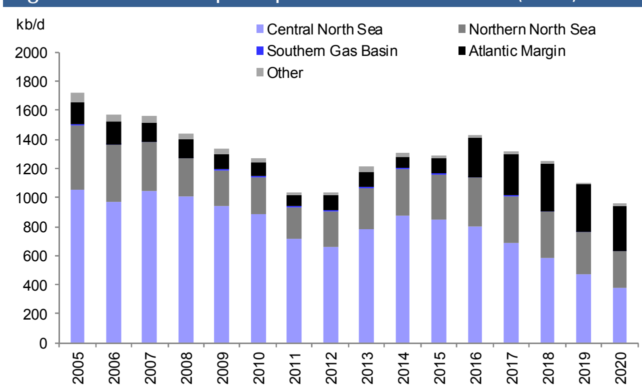
UK liquids production peaked in 1999 at c2.5mbd, since when a steady decline has seen production fall to an estimated 1.1mbd, despite the start-up of the c200kb/d Buzzard field in 2007. Looking ahead to 2017 a period of improved production is now expected with scope for a mini-peak of 1.4mb/d in 2016 supported by a number of start-ups including Golden Eagle, Catcher, Jasmine, Kraken and the Schiehallion redevelopment. However, this is likely to prove temporary, and despite the start-up of the Bressay/Mariner heavy oil development in the latter part of the decade production is set to move back on to a declining trend beyond 2016.

Turning to gas, a peak was seen in the 1999-2001 period at around 10bcf/d since when production has declined precipitously to just 4.5bcf/d in 2012. In much the same way as for oil, a number of relatively modest start-ups (plus a recovery from the Elgin-Franklin field) are expected to see production stabilise if not slightly improve through to 2015, after which point the declines look set to resume.

In the face of such dramatic declines, almost 40% of industry infrastructure could be at risk of decommissioning by 2020 unless significant investment is encouraged. Time is of the essence. In this context the 2011 increase in the Supplementary Tax charge (from 20% to 32%) could not have come at a more inopportune time. Perhaps in belated recognition of this a series of initiatives to encourage investment were introduced it the 2012 budget (see below). Activity remains price dependent.

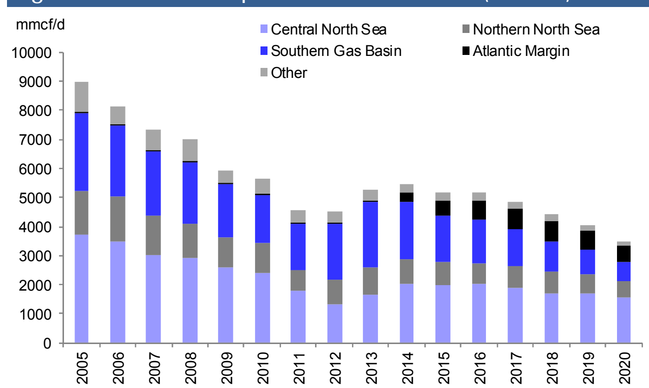
The pace of decline is also reflected in the production profiles of the major players – BP, Exxon, Shell, Total and Conoco, each of whom is expected to witness a c5-25% reduction in their annual rate of UK production over the next four or so years.

Figure 459: UK: Liquids production 2005-20E (kb/d)



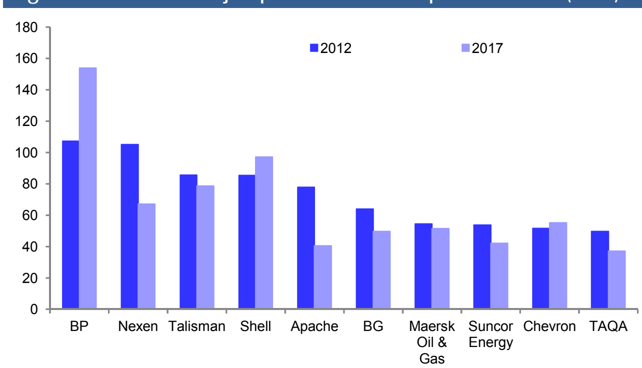
Source: Wood Mackenzie

Figure 460: UK: Gas production 2005-20E (kboe/d)



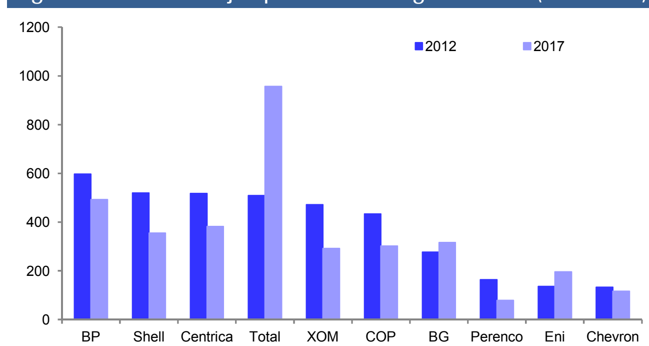
Source: Wood Mackenzie

Figure 461: UK: Major producers of liquids 2012E (kbd)



Source: Wood Mackenzie

Figure 462: UK: Major producers of gas 2012E (mmscf/d)



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data, estimated 2P reserves in the UK at the end of 2012 included some 5.7bn bbls of oil and 18.4TCF of gas. Of these the vast majority reside in the North Sea. Wood Mackenzie further estimates that stranded technical reserves of circa 2.1bn bbls and 8.3TCF of gas have been discovered but as yet have no defined path to development. Separately, the UK's DECC has suggested yet-to-find reserves (mid range estimate) of up to a further of 5.5bn of oil and 20TCF of gas may exist in UK albeit that, with an average discovery size of 15mbbls over the past six years, such numbers seem a little optimistic.

Pipelines and infrastructure

Over the past thirty years a substantial network of pipelines has been laid down in the UKCS. This infrastructure has played a key role in allowing for the economic development of a host of relatively modest oil and gas deposits. At present there are thirteen pipelines serving the North Sea but twenty five in the Southern Gas Basin and Irish Sea. Details of the more significant pipelines are depicted in the table below with graphics for those in the North Sea shown on the UK map.

Figure 463: Main Gas and Oil Pipelines

Pipeline	Operator	From	To	Length km	Capacity kb/d
Oil pipelines					
Brent System	TAQA	Brent	Sullom Voe Terminal	153	1000
Flotta System	Talisman	Piper	Flotta Terminal	209	560
Forties System	BP	Forties	Cruden Bay	169	1150
Ninian System	BP	Ninian	Sullom Voe Terminal	159	875
Norpipe Oil Pipeline	Conoco	Ekofisk I	Teesside (Oil) Terminal	350	810
Gas pipelines					
CATS	BP	Everest	Teesside (Gas) Terminal	404	1650
FLAGS	Shell	Brent	St Fergus (Shell)	451	1100
Frigg UK System	Total	Frigg UK	St Fergus (Total)	134	1170
LOGGS	Conoco	Valiant N	Theddlethorpe	119	1200
SAGE	ExxonMobil	Beryl	St Fergus (SAGE)	327	1150
SEAL Gas Export	Total	Elgin	Bacton(Shell)	468	1235
UK - Continent Gas	Interconnector (UK)	Bacton	Zeebrugge	235	1940
UK - Ireland Gas	Bord Gais Eireann	Brighouse	Loughshinny	289	80

Source: Wood Mackenzie; Deutsche Bank

Crude Oil Blends and Quality

There are multiple different crude streams in the UK, however, the two key blends are Brent and Forties both of which are light, sweet oils. Brent has an API of 38 and 0.4% sulphur content while Forties has an even lighter API of 41.7 albeit slightly higher sulphur (0.5%). This is despite the addition to the Forties Blend of lower (32/1.4%) oil from the Buzzard field.

Broad Fiscal Terms

All licenses in the UK are based on concessions. For fields approved after 16 March 1993 the main tax components are: (1) UK Corporation Tax (CT), which despite being reduced for industry in general on a series of occasions since the 2007 Budget (from 30% in 2007 to 24% for the 2012/13) has been held at 30% for the oil & gas industry, and (2) a special additional 'Supplementary Corporation Tax' or SCT. Introduced in the 2002 Budget at a 10% rate this charge was increased to 20% in 2006, albeit at the same time the Government did increase the writing down allowance (WDA) on eligible capex to 100% from 25% previously. In 2011, SCT was again increased, this time to 32% and as such, today's effective UK tax rate runs at 62%. In the 2012 budget a series of measures/proposals were made to encourage investment. These included a commitment to provide greater certainty on decommissioning tax relief (necessary to encourage activity around mature assets) and allowances for very deep fields (targeted at encouraging investment in the West of Shetland region). Royalties were abolished in 2003 following implementation of SCT.

For those fields approved prior to 16 March 1993, an additional tax entitled Petroleum Revenue Tax or PRT is also liable. This is charged at a rate of 50% on the profits of the field after various allowances have been made but before the payment of CT and SCT. In effect this means the marginal rate of taxation on pre-1993 fields today runs at 81% although the nature of the available allowances means that, unless the field was over 100mbbls, PRT would probably not be liable.

Refining and Marketing

In 2012 the UK had nine operational refineries with an aggregate 1.7mb/d of refining capacity. At 326kb/d ExxonMobil operates the single largest refinery at Fawley in southern England although Total (218kb/d), Phillips 66 (210kb/d), Essar & Valero have significant positions. Shell (sale of Stanlow), Petroplus (bankruptcy) and Chevron (sale of Pembroke) have all recently exited UK refining. Overall the UK is a net exporter of oil products with significant excess refining capacity of around 200kb/d, mainly in fuel oil and gasoline. In the downstream, the broad spread of refining activity means that markets are fiercely competitive, a feature that is further compounded by the presence of the major superstores as fuel retailers. According to Wood Mac data for 2011, Exxon and BP lead the products market with c14% apiece followed by Shell (11%) and Total (8.5%).

LNG

With the UK no longer able to produce enough natural gas to meet its needs, LNG looks set to play an increasing role in bridging the production gap over the coming years. At present, four LNG re-gas facilities operate in the UK with total capacity of c.38MTPA. Indeed, at an aggregate c5bcf/d of current capacity and a projected LNG import requirement of around 2.5bcf/d, 50% of capacity is likely to remain idle.

Figure 464: LNG re-gas facilities

Name	Location	Capacity	Holders	Onstream
Isle of Grain	Isle of Grain	14.8mtpa/1,960mmcf/d	BP/Sonatrach/Centrica/GDF Suez	Yes
South Hook	Milford Haven	15.6mtpa/2,061mmcf/d	QP/XOM	Yes
Teeside Gasport	Teesport	3.1mtpa/400mscf/d	Excelerate Energy	Yes
Dragon LNG	Milford Haven	4.6mtpa/614mmcf/d/d	BG/Petronas	Yes
Port Meridian	East Irish Sea	3.7mtpa/484mmcf/d	To be decided	End 2014

Source: Wood Mackenzie, Deutsche Bank

US Alaska

Given its 30 plus years history of oil production, Alaska is in many respects a mature oil province. However, with much of its land and arctic waters as yet unexplored the region remains one that is believed to have substantial prospectivity, with as much as 50 bn bbls of yet-to-find oil suggested to exist both onshore and offshore by the USGS and the BOEM. At this time both oil and gas production are, however, in decline although with c600kb/d of oil produced in the state in 2012 it continues to account for c7% of total US liquids production. In 2012 Wood Mackenzie estimates that 2P oil reserves stood at 3.7bn barrels. At 32TCF gas reserves are also substantial although 95% of these are associated with Arctic fields that, as yet, have no route to market.

Basic geology and topology

To date hydrocarbon exploration and production has focused on two main areas, the predominantly gaseous Cook Inlet and the Alaskan North Slope (ANS), which borders the Arctic Ocean and accounts for near all of the state's oil production. Formed during the Triassic and Jurassic, the ANS lies within the Arctic-located Colville River Basin and it is this basin which is the source of its hydrocarbons including those of the giant Prudhoe Bay and Kuparuk fields. Some 500km further south, the gas producing Cook Inlet Basin in the Gulf of Alaska also derives its hydrocarbons from source rock laid down during the Jurassic. More recently, Shell initiated exploration activity in both the Chukchi and Beaufort Seas both of which hold significant prospectivity.

History and regulation

Alaska has a long history of oil exploration, with seepages of oil first noted by the Russians prior to their sale of the lands to the US in 1867. Indeed, such was its confidence that the US Government set aside land as a potential national source of oil for the country's naval fleet (the National Petroleum Reserve-Alaska or NPR-A) in the 1920s. However, despite considerable exploration through the early 20th century initial finds were modest and, given the distance from consumer end-markets, invariably uneconomic. This all changed in 1957 with the discovery of the Swanson River oil field on the Kenai Peninsula, a discovery which resulted in a period of intense and often successful activity in the Cook Inlet not least Unocal's 1959 discovery of the Kenai gas field. By the end of the 1960s interest in the Cook Inlet was, however, waning and, following ARCO's 1968 discovery of the 10bn bbl Prudhoe Bay oil field (America's largest ever) on Alaska's North Slope, attention switched to this arctic area. Other major fields including Kuparuk (second largest ever US field) were discovered shortly thereafter. The remote and hostile location of the ANS meant, however, that in order to get the oil to market a reliable system was needed to transport the crude oil to the Lower 48 refineries. After much debate and opposition not least from environmental groups and native Alaskans, the 1287km Trans-Alaska Pipeline System (TAPS) was decided upon to transport crude oil from Prudhoe Bay to the port of Valdez in Prince William Sound. Built at a cost of US$8bn, the pipeline was completed in mid-1977 with a nominal capacity of 2.1mb/d (although the rate of flow today is well below 1mb/d).

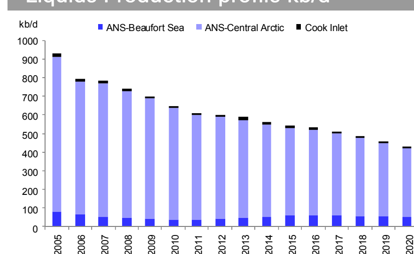
Alaskan oil & gas leases are mainly state owned with activity governed by either the State or the Federal Government. Leasing is overseen by the US Department of Natural Resources with the Alaskan Oil & Gas Conservation Commission responsible for overseeing the below-ground operations of the industry. Importantly, the Federal Government also owns significant blocks of land namely the aforementioned NPR-A which at 23 million acres is the largest piece of undeveloped federal land in the US and the 19 million acre Arctic National Wildlife Refuge (ANWR). Discussed later, these two

Key facts

Liquids production 2013E	**0.6 mb/d**
Gas production 2013E	**0.1mboe/d**
Liquids reserves 2012E	3.7 bn bbls
Gas reserve 2012E	32 TCF
Reserve life (liquids)	17.4 years
Reserve life (gas)	293 years
US GDP 2012E	$15.7 trillion
US GDP Growth 2012E	2.2%
US Population (m)	314.3
US Oil consumption (2011)	18.8 mb/d
US Oil exports (mb/d)	n.a.
Fiscal regime	Tax & royalty
Marginal tax rate	c.64%
Top 3 Oil & Gas fields (2012E)	
Prudhoe Bay	331kboe/d
Kuparuk	118kboe/d
Colville	74kboe/d
Top 3 Oil & Gas Producers (2012E)	
Conoco	217kboe/d
BP	150kboe/d
Exxon	109kboe/d

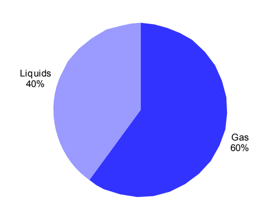
Source: Wood Mackenzie data; EIA

Liquids Production profile kb/d



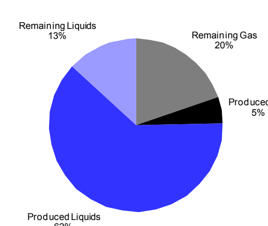
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

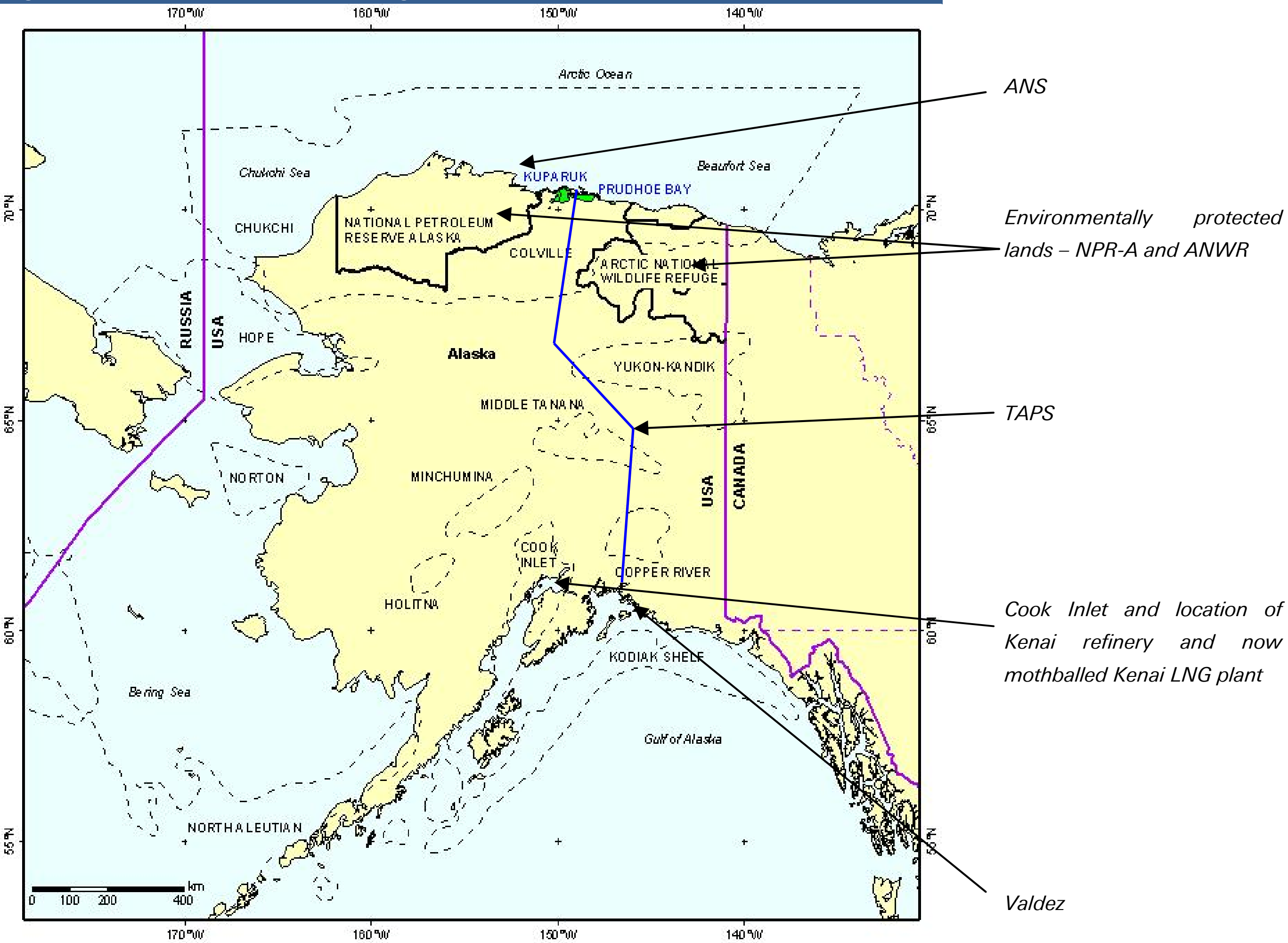
Initial versus remaining reserves



Source: Wood Mackenzie data

tracts of largely untouched wilderness are estimated by the USGS to potentially contain over 30 billion barrels of recoverable oil. Not surprisingly, the industry has long expressed considerable interest in their development.

Figure 465: Alaska: Key basins and regions



Source: Wood Mackenzie

Because of the environmental sensitivity of the area oil & gas operations are strictly monitored with stringent controls set by the environmental agency. Perhaps surprisingly, on the North Slope this has meant that all drilling activity is carried out during a three month winter window at which time ice is thick enough to prevent damage to the permafrost. Pipelines must either be buried or lifted on stilts so as not to interfere with migration routes. Severe penalties are in place to counteract any environmental damage from water run-off to oil spills.

Licensing

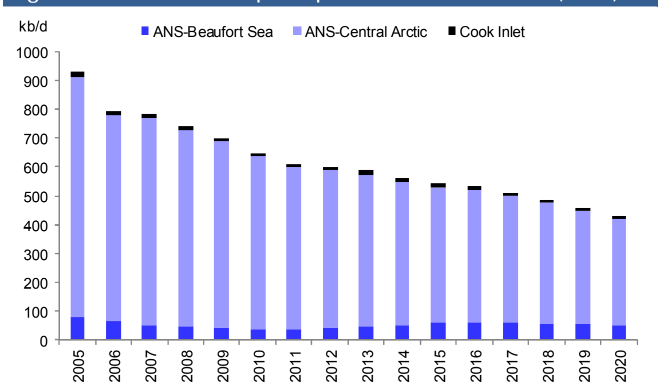
Licensing in Alaska takes two main forms, area wide leasing and exploration leasing. Every two years the state issues a five year oil and gas leasing program. This sets out the schedule for area wide sales for the North Slope, Cook Inlet and Beaufort Sea with an announcement of the lease available made 90 days prior to the sale and detailing the terms and bidding method. The most common bidding method is a cash bonus per acre although past sales have also seen royalty rates and profit share used as a bid variable.

Where the leasing program typically focuses on mature areas, Alaska's exploration licensing is designed to encourage exploration in frontier areas. As such, portions of the ANS and Cook Inlet which are covered by the lease program are off limits to the exploration license program. Licensing begins in April of each year with the commissioner outlining areas for exploration. Applicants then have 60 days to submit proposals and bids to the Department of Natural Resources. The most common bid used by the State is the cash bonus and, where competing bids exist, the bidder committing to the highest exploration expenditures will be awarded the license.

Production of Oil & Gas

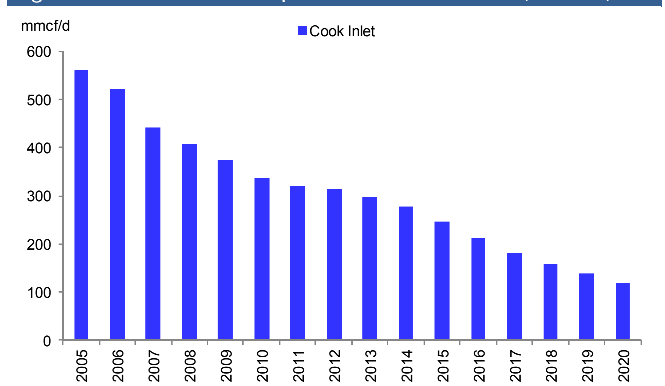
After peaking at over 2mb/d in 1988, oil production in Alaska has been on a declining trend for much of the past decade with oil production from the Cook Inlet in particular now in its twilight years (production peaked at 230kb/d in 1970). Alaskan oil production is concentrated on the ANS and this is likely to remain the main source of oil for many years to come. Key ANS fields are Prudhoe Bay (c330kboe/d), Kuparuk (c120boe/d) and Colville (c70kboe/d). Prudhoe Bay has now been in production for over 30 years in part due to the tie-back of satellite fields but predominantly as a consequence of the use of enhanced recovery techniques (which have seen over 50% of the original oil in place extracted). With no gas pipeline system in place and flaring strictly prohibited, North Slope gas reserves are substantial but have yet to be commercialized. This is, however, a clear objective for the majors involved (namely Conoco, Exxon and BP), likely by way of an LNG project, but unlikely to happen until the fiscal terms around any future production are sufficiently robust to allow for the construction of a pipeline to the south for its export. Current Alaskan gas production thus centres on the Cook Inlet, much of which was used as feedstock for the Kenai LNG plant prior to its mothballing in Nov'11.

Figure 466: Alaska: Liquids production 2005-20E (kb/d)



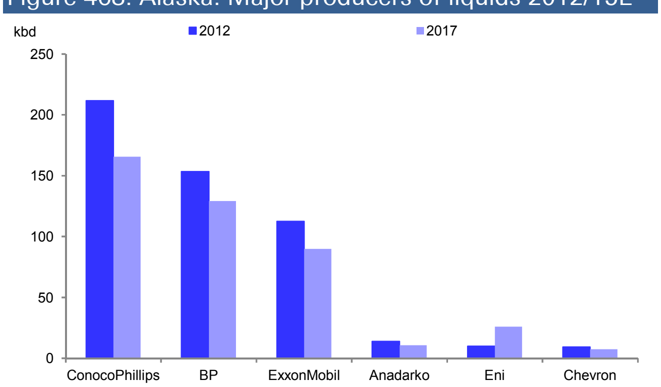
Source: Wood Mackenzie

Figure 467: Alaska: Gas production 2005-20E (mscf/d)



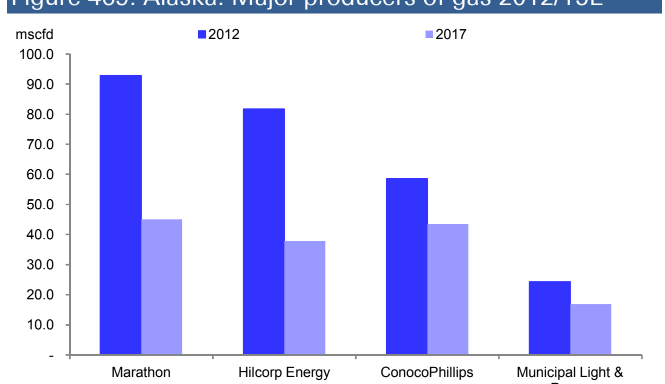
Source: Wood Mackenzie

Figure 468: Alaska: Major producers of liquids 2012/15E



Source: Wood Mackenzie

Figure 469: Alaska: Major producers of gas 2012/15E



Source: Wood Mackenzie

Reserves and resources

At the end of 2012 Wood Mackenzie estimates that liquid reserves on a 2P basis stood at 3.7bn barrels with around 65% of these associated with Prudhoe Bay and Kuparuk. Compared with initial liquids recoverable reserves of 17bn barrels this clearly illustrates the maturity of existing production. Similarly, the Cook Inlet estimated remaining reserves of c205mboe compared with an initial recoverable reserve of over 10x that figure. In this respect Alaska thus looks a very mature play.

However, with some 32TCF of proven ANS gas reserves as yet untapped, gas production remains a substantial opportunity for the players involved if appropriate fiscal structures can be established to incentivise investment. Some 36bn barrels of viscous heavy oil overlying the main producing zones at Prudhoe Bay and Kuparuk also offer substantial potential should economic technologies for their development emerge.

Perhaps more significant, however, is the perceived prospectivity of two as yet untapped tracts of protected Arctic wilderness, each of which is estimated by the USGS to contain between five and twelve billion barrels of potentially recoverable oil, and that of the relatively shallow Arctic waters of the Chukchi and Beaufort Seas.

- **ANWR**. Lying on the shores of the Arctic Ocean to the east of Prudhoe Bay, the Arctic National Wildlife refuge represents 19 million acres of untouched wilderness. Its Coastal Plain, which accounts for 8% of the total acreage, is also regarded by many geologists as having greater potential for petroleum discoveries than any other onshore area. However, to date only limited exploration drilling has taken place and the lands remain subject of an intense debate between the industry and environmental groups with no clear resolution on an opening of the Coastal Plain achieved.
- **NPR-A**. In 1923 President Harding set aside this 23 million acre tract of land to provide emergency supplies for a US navy that was, at that time, switching from the use of coal to oil to power its ships. Located to the west of the 430m barrel Alpine field, several lease sales have taken place over the years and borne successful exploration results, confirming earlier positive results by the US Navy and military. Despite both the Clinton and Bush Administrations opening up tracts exploration has, however, been limited with license awards prevented by the environmental agencies.
- **Chukchi Sea**. First drilled in the late 1970s by Shell, at which time gas was discovered, the USGS has estimated potential resource of towards 30bn bbls of oil & gas. After an absence of some 30 years Shell recommenced exploration in summer 2012 having re-acquired key licenses for $2.1bn in 2008. To date Shell's programme has, however, been thwarted by exogenous events, not least increased environmental concerns post the 2010 offshore Deepwater Horizon disaster but more recently issues associated with the harsh weather environment. Following a series of unfortunate events, not least the 2012 loss of control of its Kulluk drilling rig, at the present time it remains unclear whether Shell will be permitted to continue with its exploration programme.

Pipelines and infrastructure

Alaska's oil and gas infrastructure centres on the two main areas of production. For the ANS the key oil pipeline is clearly the aforementioned Trans Alaska Pipeline System (TAPS or Ayelaska Pipeline) with all fields in the region linked into TAPS by series of field pipelines and gathering systems. These were upgraded by BP following its embarrassing decision to close the entire Prudhoe Bay production area in 2006 after the integrity of the pipeline was found to be in question. TAPS runs through to Valdez in the south of the state from which oil is transported to the US west coast for refining. Within the Cook Inlet producing area, 100km of gas pipeline links the producing fields with the Kenai LNG facility. Otherwise, gas produced is largely transported to Anchorage through the Marathon/Chevron-owned Cook Inlet Gas Gathering System (CIGGS). Cook Inlet oil production is either transferred through pipeline or tanker to the Kenai refinery some 100km south of Anchorage, with the products produced largely feeding the needs of the Alaskan market.

As yet, whilst there has been much discussion around the monetisation of ANS gas, the infrastructure to transport gas from the ANS is not in place. Consequently, the gas produced is either used as fuel or recycled. Nevertheless, given the scale of the resource base (31TCF) it is the clear desire of the producers involved (BP, COP, Exxon) to lay down infrastructure. Initially, this was expected to be by way of a pipeline connecting the fields to the large US market. Following the shale gas revolution more recent discussions have, however, focused on the potential for a multi-train c20mtpa LNG facility for start up late next decade.

Crude oil blends and quality

With all North Slope oil transported through the TAPS pipeline there is only one Alaskan Blend, ANS. With an API of 32° and around 1% sulphur this is both heavier and more sour than benchmark WTI.

Broad fiscal terms

Alaska operates as a tax and royalty concession. The tax regime is, however, complicated by the application of state taxes in addition to the typical elements of royalty (normally 12.5% but can vary by field) and federal corporate income tax (which is charged at 35% on profits after royalty and state taxes). The basic rate of State Income Tax applied in Alaska runs at 9.4% with a further 2% being charged as a property tax on the tax book value of the producing assets. Moreover, from April 2006 the state introduced a new mechanism for calculating the main state tax. Entitled Profit-sharing Production Tax this replaced the former severance tax and contains a progressive element. Simplistically, this is charged at 25% of the production tax value (which in crude terms is equal to the well head revenue less royalty and allowable costs including depreciation) increasing by 0.25% for every $1/bbl increase in the price of oil over $40/bbl up to a maximum of 75%. At $60/bbl oil PPT would thus run at 30% with a company typically receiving around 30 cents per US$ of revenues.

Refining

Alaska has six refineries, albeit five are simply topping plants that remove the lighter, higher value transportation fuel from the crude oil. The Kenai Refinery (72kb/d) owned by Tesoro, is Alaska's key refinery and is located 100km south of Anchorage. It is fed with oil produced in the Cook Inlet and its output is used to supply the local market, most particularly the jet fuel requirements of Anchorage International Airport.

Figure 470: Alaska Refineries

Company	Location	Capacity (bpd)
Flint Hills Resources Alaska Llc	North Pole	220,157
Tesoro Alaska Petroleum Co	Kenai	72,000
Petro Star Inc	Valdez	55,000
Petro Star Inc	North Pole	19,700
ConocoPhillips Alaska Inc	Prudhoe Bay	15,000
BP Exploration Alaska Inc	Prudhoe Bay	6,935

Source: EIA, Deutsche Bank

LNG

Given its remote location and the distance of gas from potential markets, Alaska is home to one of the first ever LNG plants. Constructed in 1969 and owned by Marathon (30%) and Conoco (70%) Kenai LNG is a 1.5mtpa nameplate facility located on the southern shores of the Cook Inlet. Conoco became 100% owner by acquiring 30% stake from Marathon in 2011 following which the plant has been mothballed.

US Alaska - Notes

US Deepwater Gulf of Mexico

At 1.2mbd the US Deepwater Gulf Of Mexico is the largest single oil producing region in the US accounting for around 18% of 2012 US liquids and gas production. After three difficult years during which exploration and production was materially impacted by the after effects of the Deep Water Horizon (DWH) tragedy, not least the implementation of a six month moratorium on drilling and changes to the permitting process, activity levels are recovering strongly. Production is expected to build towards 1.7mb/d by end decade. Moreover given the discovery of new hydrocarbon horizons, prospectivity remains material with the region's favourable tax terms, amongst others, acting as an incentive for exploration and investment. Significant infrastructure exists tying together a very broad number of fields at water depths that are frequently in excess of 1500m and transporting the produced hydrocarbons back to shore. At end 2012 2P oil reserves were estimated by Wood Mackenzie to stand at 10.8bn bbls of oil and 9.9TCF of gas.

Basic Geology and topology

The GoM Basin originated in the Late Triassic during a major rifting episode which continued into the Middle Jurassic at which time the westerly advance of the sea resulted in the formation of extensive salt deposits. These impermeable salt deposits played a critical role in the migration and entrapment of hydrocarbons in the northern Gulf. Several major fault trends exist in the basin and one of the more unusual features of the GoM is the distribution of petroleum resources throughout the sequence of layers of the basin i.e. hydrocarbons exist on many levels and were established through many different periods of time (Pliocene, Miocene, Paleogene. etc). Moreover, each of these is large enough to qualify as a major oil province in its own right.

Regulation and history

While interest in exploration and production in the shallow waters of the Gulf Shelf commenced as early as the 1930s, it was not until the mid-1970s that leases on tracts of acreage at a water depth of over 500m started to carry favour. However, by the start of the 1990s many companies had scaled back their activities for one or other reason and industry interest was waning, many nicknaming the Gulf area the 'Dead Sea'. Despite this, leasing incentives, new seismic technology and more efficient deepwater production equipment resulted in increased interest in deepwater acreage, interest that was further encouraged by better than expected performance at Shell's Auger field upon its start up in 1994. With oil prices firming and fiscal incentives on offer in the form of deepwater royalty relief, activity increased significantly with the industry pushing even further offshore and into acreage at water depths of over 1600m (the ultra-deep). This push into ever deeper water combined with the opening of new plays and horizons (e.g. Chevron's 2006 'Jack' find in paleogene) suggests that the US Deepwater GoM is likely to retain its prospectivity for many years to come with the US Geological Society estimating that the region has c90bn boe of yet-to-find resources.

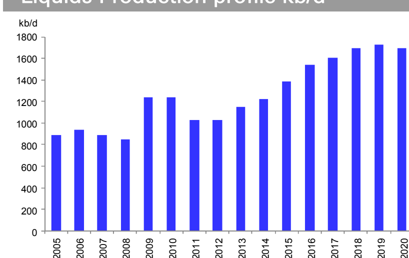
Historically, coastal states took responsibility upon themselves for leasing offshore GoM blocks to the oil companies. However, a dispute between the coastal states and the federal government over rights to revenues soon ensued. This ultimately led to the establishment in 1982 of the Minerals Management Service (MMS), a bureau of the Department of the Interior (DoI) whose purpose was to oversee the development of the US Outer Continental Shelf (OCS) and collect and distribute the bonuses, rents and royalties from the producing and leasing companies. Subsequent to the April 2010 DWH disaster, and with a view to improving regulatory, operating and safety standards

Key facts

Liquids production 2013E	1.2 mb/d
Gas production 2013E	0.4 mboe/d
Oil reserves 2012E	10.8 bn bbls
Gas reserve 2012E	9.9 TCF
Reserve life (Liquids)	25.6 years
Reserve life (gas)	13.4 years
US GDP 2012E	$15.7 trillion
US GDP Growth 2012E	2.2%
US Population (m)	314.3
US Oil consumption (2011)	18.8 mb/d
US Oil exports (mb/d)	n.a.
Fiscal regime	Tax & royalty
Marginal tax rate	35% - 46%
Top 3 GoM fields (2012E)	
Thunder Horse	121kboe/d
Shenzi (GC 654)	89kboe/d
Tahiti (GC 640)	87kboe/d
Top 3 Producers (2012E)	
BP	246kboe/d
Shell	192kboe/d
Chevron	113kboe/d

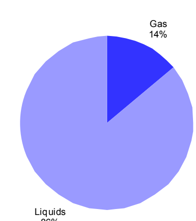
Source: Wood Mackenzie data

Liquids Production profile kb/d



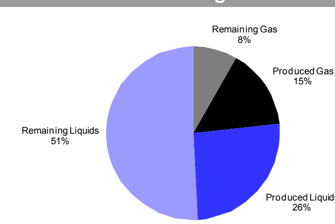
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

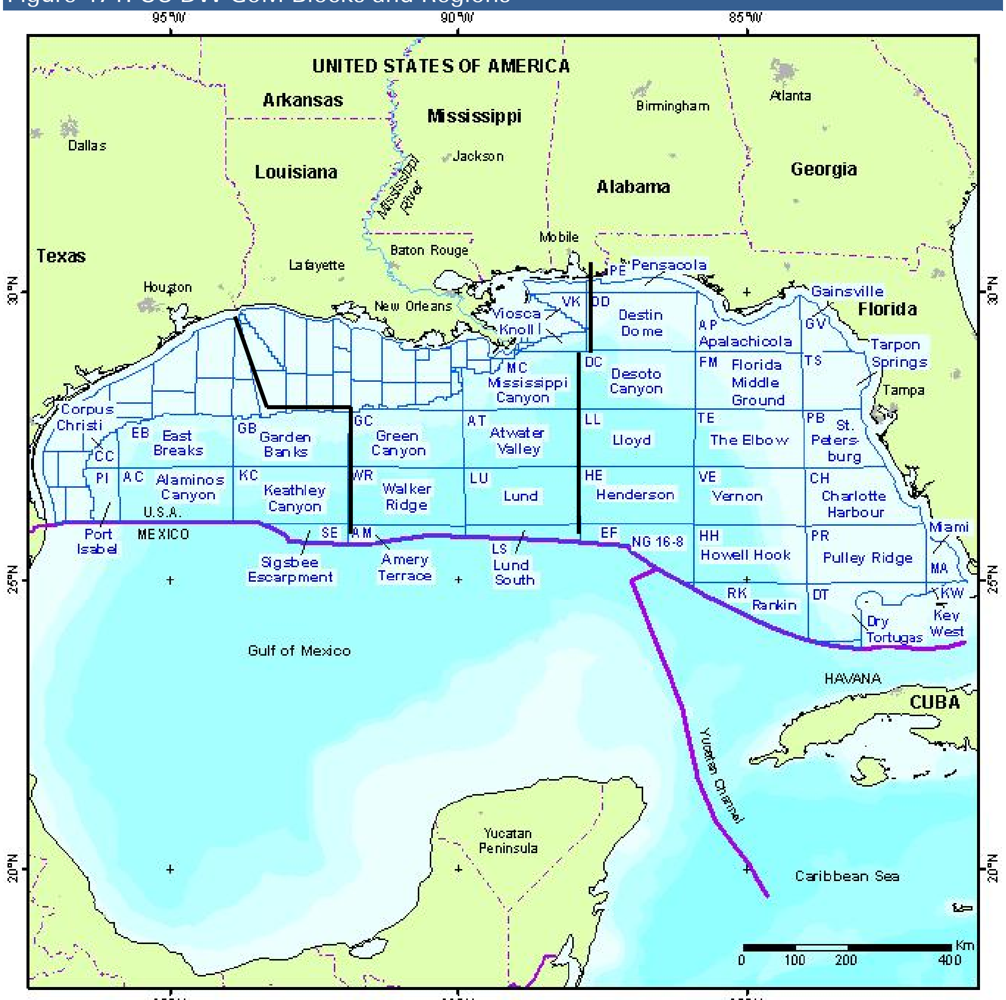
Initial versus remaining reserves



Source: Wood Mackenzie data

but also removing the potential for conflicts of interest within an organisation that was responsible for regulating the companies that paid for its keep, the MMS was reorganised as the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) with responsibility for revenue collection passed to a separate body, the Office of Natural Resource Revenue (ONRR). This was followed in late 2011 by BOEMRE's dissolution and the establishment of two new DoI bureaus; the Bureau of Ocean Energy Management (BOEM) with responsibility for lease allocation and the Bureau of Safety and Environmental Enforcement (BSEE) with responsibility for all field operations including permitting and offshore regulation. These bodies aside several other agencies have some form of jurisdiction over hydrocarbon exploration and production (not least the Environmental Protection Agency (EPA) and US Coast Guard).

Figure 471: US DW GoM Blocks and Regions



Source: Wood Mackenzie

Licensing

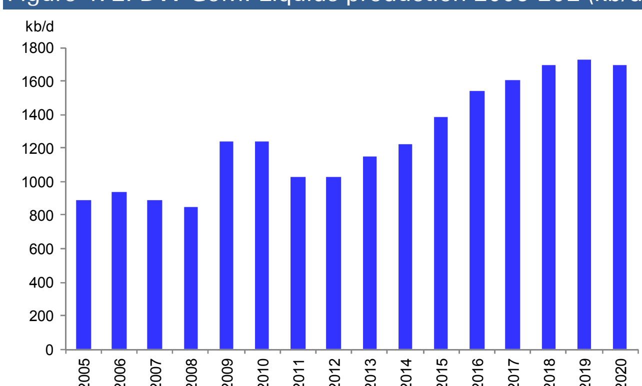
As stated, today the BOEM administers the allocation of leases on the US deepwater GoM with leases issued by public sales on a closed cash bid basis to an approved bidder who offers the highest gross bonus. Lease sales are generally undertaken twice a year with sales in the OCS Central Gulf Region (see map) taking place in the spring and those in the Western region the autumn. Due to environmental concerns and restrictions, not least an order banning all oil & gas activity within 100 miles of the Florida coastline and 15 miles of that in Alabama, lease sales involving eastern Gulf acreage have been far less frequent. Approximately six months before a lease sale the MMS issues a provisional list of leases available with the final list, which includes details of minimum bid levels and royalty rates, issued a month before the sale. Bids can be made any time up to the day preceding the sale with the successful bidder liable to pay the non-refundable cash bonus upon final award as well as an annual lease rental fee (c$7.50/acre). Lease terms vary dependent upon water depth which at this time stand at 5 years for depths of under 400m, 8 years for between 400-800m and 10 years for depths beyond 800m. There is no mandatory work obligation although, unless otherwise agreed with BOEM, the lease must be relinquished if production has not commenced by the end of the term or, in the case of an 8-year lease, drilling has not commenced by the end of the fifth year. Once production starts the lessee is entitled to retain the lease until production ceases.

Production of Oil and Gas

Given hurricanes (not least Ivan in 2004, Katrina in 2005 and Gustav in 2008) and the DWH moratorium, GoM production has in recent years failed to deliver on its potential. Nonetheless, as activity rebuilds and production from existing facilities is restored the outlook for volume growth is very positive. Growth is expected to be augmented by the start-up over the 2014-7 period of a host of new developments not least Chevron's Big Foot (c50kb/d) and St Malo (c45kb/d, Anadarko's Lucius (c50kb/d), Shell's Mars B (100kb/d), Cardamom Deep (40kb/d) and Appomattox (100kbd) and Exxon's Hadrian (c90kb/d). It is however of note that overall outside a few significant facilities (Thunder Horse, Atlantis, Tahiti, Shenzi and Great White) production in the region is fragmented with over 100 fields contributing to the region's overall profile. Similarly, the production of gas is very fragmented with only ten fields producing more than 50mscf/d.

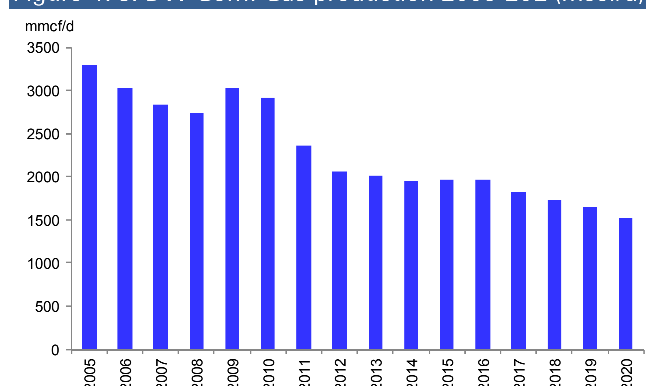
With so many small fields it is perhaps surprising that GoM production should be concentrated in the hands of a relatively small number of producers, BP, Shell, Chevron, BHP Billiton and Anadarko dominating in 2012. Further out, BP's substantial exploration success from acreage that was acquired through the mid 1990s, when companies such as Shell started to look elsewhere, shows through in its expected substantial increase in production. Buoyed by the start up of the new projects in 2009, its oil output dwarfs that of its competitors.

Figure 472: DW GoM: Liquids production 2005-20E (kb/d)



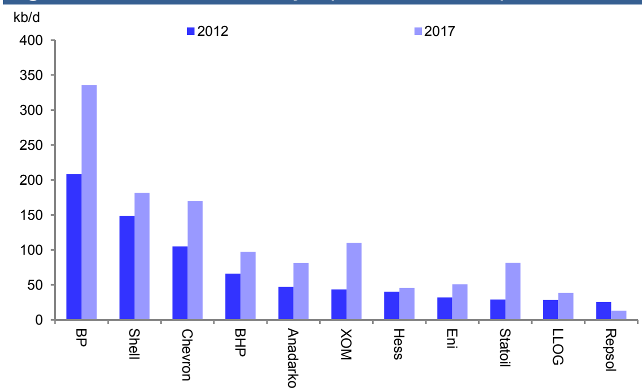
Source: Wood Mackenzie

Figure 473: DW GoM: Gas production 2005-20E (mscf/d)



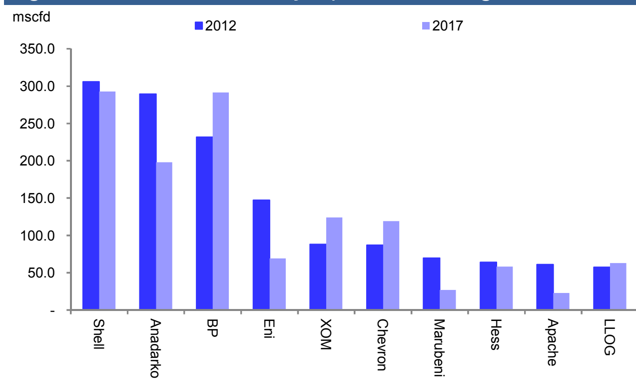
Source: Wood Mackenzie

Figure 474: DW GoM: Major producers of liquid 2012/17E



Source: Wood Mackenzie

Figure 475: DW GoM: Major producers of gas 2012/17E



Source: Wood Mackenzie

Reserves and Resources

Based on Wood Mackenzie data, estimated 2P liquid reserves in the US DW GoM at the end of 2012 stood at some 10.8bn bbls and gas 9.9TCF. The majority lie in the central Gulf. The substantial prospectivity of the region is, however, reflected by BOEM data which suggests undiscovered resources stood at around 48.4 billion bbls of oil and 219.5 TCF of gas i.e. twice the level of reserves that have been produced to date. Amongst the companies BP leads, its interest in existing and future developments accounting for almost 23% of the 2P reserves estimate followed by Shell with 14%.

Pipelines and Infrastructure

Over the past 40 years an extensive network of platform and pipeline infrastructure has been developed in the GoM. This includes both field-specific pipelines and shared gathering systems such as the Mardi Gras Oil & Gas Transportation system. Hub facilities established on the edge of the Gulf Shelf in the 1970s and 1980s also provide important processing points. The reluctance of the US Government to sanction offshore loading in the US GoM and its strict no-flare policy suggest, however, that at some point the development of major deepwater infrastructure will be necessary. Following years where the use of FPSOs was prohibited for environmental reasons, in 2008 the MMS finally approved the use of an FPSO by Petrobras for the development of its Cascade-Chinook project, the production from which commenced in late 2012.

Crude Oil Blends and Quality

Crude oil from the US GoM tends to be slightly heavier and more sour than WTI. The principle marker is Mars Blend which with an API of 28 and sulphur content of 2.28% serves as a price barometer for imported sours such as Arab and Kuwait Medium.

Broad Fiscal Terms

As a tax and royalty concession, taxation in the US GoM is comprised of two key elements namely royalty and federal corporate income tax. There is no state corporation tax for federal OCS areas. Historically, in order to encourage drilling in the deepwater, royalty rates varied by water depth with additional tax relief granted on a set volume of production (entitled the royalty suspension volume or RSV). Details of the tax rates and relief volumes are depicted in the table below. Effective from Nov 2007, royalty rates on new leases have been set at a fixed 18.75% irrespective of location.

Figure 476: US GoM tax , royalty and deepwater royalty relief

Water Depth	Royalty rate (%)	DWRR RSV mboe	Tax rate (%)
<200m	18.75	0	35
200-400m	18.75	0	35
400-800m	18.75	5	35
800-1600m	18.75	9	35
1600-2000m	18.75	12	35
>2000m	18.75	16	35

Source: Deutsche Bank

Where taxation in the US is by global standards very generous, recovery of capital expenditure is less so. In general, capital costs are recovered over a period of seven years under a convention entitled the Modified Accelerated Cost Recovery System or MACRS. This provides for a depreciation schedule with pre-stipulated rates of depreciation namely 14.3% in year 1, 24.5% in year 2, 17.5% in year 3, 12.5% year 4, 8.9% in each of years 5-7 and a final 4.5% in year 8.

LNG

Infrastructure and the Gulf Coast's significance to US natural gas production have seen its emergence as a major gas hub with the region a key entry point for the import of LNG through the establishment of re-gasification facilities. These are regulated by the Federal Energy Regulatory Commission (FERC) which oversees and approves developments and dictates the tariffs that may be charged for capacity usage. The shale revolution has, however, left many of these facilities essentially redundant for imports and as such multiple applications have been presented for Gulf facilities to be converted to LNG export terminals. To date only that for Cheniere's Sabine Pass has been cleared for export to FTA and non-FTA geographies with first production from its 18mtpa of planned capacity envisaged by late 2015. For further details see the LNG unconventionals section of this report.

Figure 477: Gulf Coast re-gas (on-stream) & LNG facilities (planned)

Name	Status	Capacity mscf/d	Capacity mtpa	Liquefaction (mtpa)	Status
Lake Charles	On-stream	1800	13.6	15.0mtpa	FTA
Freeport	On-stream	1550	12.1	10.4mtpa	FTA
Sabine Pass	On-stream	4000	30.1	18mtpa	FTA & non-FTA
Cameron LNG	On-stream	1500	11.3	13.0mtpa	FTA
Golden Pass	On-stream	2000	15.1	18.0mtpa	FTA
Gulf LNG Energy	On-stream	1300	9.8	11.5mtpa	FTA

Source: FERC, Wood Mackenzie, Deutsche Bank

Refining

Not surprisingly given the significance of Texas, Louisiana and the GoM to US oil production both today and in the past, the US Gulf Coast is home to the vast majority of US refining capacity. In total 40 refineries with an estimated 45% or 7.8mb/d of current US refining capacity (17.1mb/d) are located in these two states, many in close proximity to the Gulf Coast. Moreover, with an average capacity of c200kb/d the region is home to many of the largest refineries globally. Given the tight oil revolution in the US and consequent access to advantaged feedstock this has positioned the Gulf Coast as a major export centre for oil product sales into the Atlantic Basin. However, this concentration of capacity also leaves the refining market in the US vulnerable to the US Gulf hurricane season, most notably in 2005 when Hurricane Rita resulted in significant damage to a number of coastal refineries, pushing up oil product prices globally.

Figure 478: Major US Gulf Coast Refining Assets

S.No	US Rank Size	Company	State	Location	Barrels per day
1	14	Motiva Ent (Shell/Aramco JV)	Texas	Port Arthur	600,000
2	1	Exxon	Texas	Baytown	560,500
3	2	Exxon	Louisiana	Baton Rouge	502,500
4	3	Marathon Petroleum (MPC)	Louisiana	Garyville	490,000
5	4	CITGO	Louisiana	Lake Charles	427,800
6	5	BP (Sold to MPC)	Texas	Texas City	400,780
7	7	Exxon	Texas	Beaumont	344,500
8	11	Deer Park (Shell 50%, Pemex 50%)	Texas	Deer Park	327,000
9	13	Premcor	Texas	Port Arthur	290,000
10	15	Flint Hills Resources LP	Texas	Corpus Christi	284,172

Source: EIA, Deutsche Bank

US Deepwater GoM - Notes

Major OPEC Producers

Angola

Iran

Iraq

Kuwait

Libya

Nigeria

Saudi Arabia

UAE

Venezuela

Qatar

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Angola

Although Angola's admission to OPEC membership in 2007 with a 1.9mb/d quota raised some uncertainties over future production growth, the pace of investment to date has remained largely unhindered. Discovery in the deepwater of over 12 billion barrels, together with recent pre-salt success, suggests strong resource and production potential over the medium and long term. Following the recent start-up of BP's PSVM (150kb/d) and the continuing ramp of Total's 240kb/d Pazflor, liquids production of 2.0mb/d in 2012 is expected to rise towards 2.2mb/d by 2014. Export revenues should be further augmented by the now-imminent start-up of the country's first LNG facility with nameplate capacity of some 5.2mtpa. Key producers include Chevron, BP, Total, Exxon, Statoil and Eni, together with state oil company Sonangol.

Basic geology and topology

The evolution of Angola's coastal basins stems from the separation of the African and South American tectonic plates through the Early Cretaceous period. This separation saw the establishment of several major salt basins on Africa's Atlantic margin, of which Angola straddles three: the Congo, the Kwanza and the yet-to-be-explore, Namibe. Key to current production is the Lower Congo Basin, which contains the entire Cabinda enclave as well as key producing deepwater blocks 14-18, which lie in water depths of 1200-1500m. Yet it is in the pre-salt Kwanza Basin that most of the exploration excitement now resides, not least following the Cameia discovery by Cobalt of an estimated 2.3bn recoverable barrels in Block 21. Geologically analogous to Brazil's prolific Campos and Santos basins, the award of new licenses across a swathe of the Kwanza's deepwater acreage is set to prove the focus of significant exploration activity by the majors with first exploration planned from late 2013.

Regulation and History

Oil was first noticed in certain parts of Angola as long ago as the 18th century. However, it was not until the late 1950s that discoveries demonstrated Angola's commercial potential both onshore and in the shallow waters of the Cabinda enclave. Following the award of a concession license by the then-Portuguese authorities to the Cabinda Gulf Oil Company, or CABGOG (today Chevron), the still-ongoing extraction of Cabinda's estimated 5 billion barrels of recoverable reserves was to prove the mainstay of Angolan production for the better part of the next four decades.

Yet perhaps ironically, it was Angola's independence from Portugal in 1975 and its ensuing civil war that helped spur greater interest in the exploration of the country's offshore basins. With onshore exploration severely curtailed in the face of the onshore hostilities, the new state oil company Sociedade Nacional de Cobustiveis de Angola (Sonangol) looked towards opportunities on the country's Atlantic coastline as it sought to encourage exploration interest from the international oil companies. Offshore activity pushed ahead as Sonangol licensed sizeable tracts of acreage, first in Angola's shallow waters to the south of Cabinda in 1980 and then in the deeper waters some 100km offshore a decade later. Importantly, it is the exploration success in the deepwater that has been central to Angola's growth as an oil-exporting nation. In total, discoveries to date in the offshore have delivered over 12 billion barrels, not least those in Exxon-operated Block 15 (3bn barrels) and Total-operated Block 17 (3.5bn barrels).

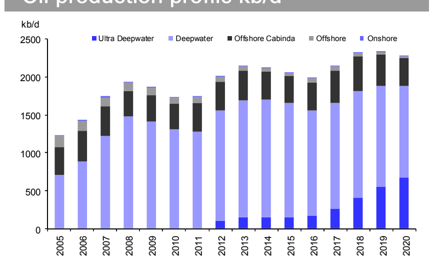
In early 2007 OPEC announced that it had accepted Angola's application to join OPEC, and in January 2008 the country became a full member with its initial production quota set at some 1.9mb/d. Whether this serves to contain Angola's planned production

Key facts

Oil production 2012E	2mb/d
Gas production 2012E	0.08mboe/d
Oil reserves 2012E	11.5bn bbls
Gas reserve 2012E	8.4TCF
Reserve life (oil)	15.6 years
Reserve life (gas)	45.5 years
GDP 2012E	$115bn
GDP Growth 2012E (%)	6.8%
Population (m) (July 2009E)	20.2m
Oil consumption (2010)	74kb/d
Oil exports (mb/d) (2010)	1.8mb/d
Fiscal regime	Offshore-PSC, Onshore-T&R
Marginal tax rate (concession)	73.8%
Top 3 fields (2012E)	
Dalia	240kboe/d
Cabinda Area A	232kboe/d
Pazflor	180kboe/d
Top Producers (2012E)	
Sonangol EP	188kboe/d
Chevron	184kboe/d
BP	178kboe/d

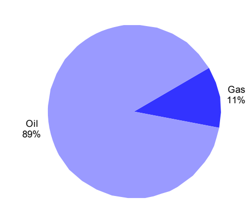
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



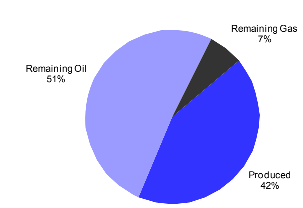
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

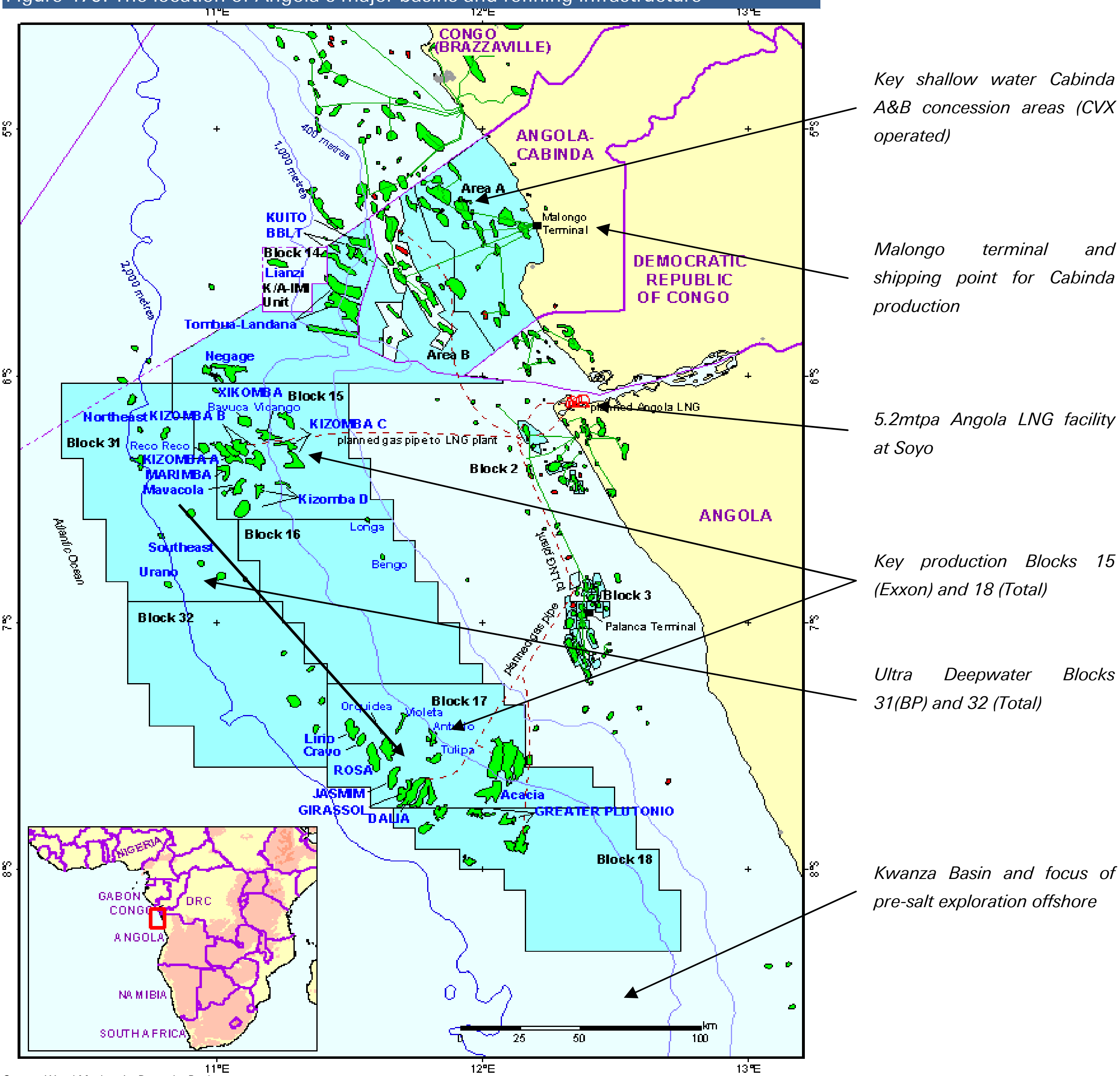
Initial versus remaining reserves



Source: Wood Mackenzie

growth will clearly depend upon many factors, not least the extent to which global oil demand continues to expand. It does, however, add a greater element of uncertainty to the timing of several investments, the start-up of which are presently expected by Wood Mackenzie to see the country's production rise to nearer 2.3mb/d by 2018.

Figure 479: The location of Angola's major basins and refining infrastructure



Source: Wood Mackenzie; Deutsche Bank

Licensing

The principal laws relating to the licensing and production of hydrocarbons in Angola were laid down in 1978. These established the state oil company Sonangol and gave it exclusive rights to the country's hydrocarbon resources as well as the authority to contract foreign companies to undertake work on its behalf. Initially, the offshore shelf areas in Angola's shallow waters were sub-divided into 13 blocks of 4000km² each for licensing. This was followed in 1990 by the delineation of seventeen separate blocks, 14 through 30, again of around 4,000 km^2 running along the whole of Angola's deepwater shelf and in 1999 the creation of four ultra deepwater blocks (31-34) running to the west of Blocks 15-18. In 2006 Angola relicensed several relinquished territories in the shallow and deepwater. This was followed by the 2008 round in which Angola offered three ultra-deep water blocks in Lower Congo basin and several blocks in the Kwanza basin. However, this round was delayed due to presidential elections in 2008 and was later launched pre-salt round in 2010. Through various licensing rounds Sonangol has set in place a series of production-sharing contracts for the exploration and production of oil. The only exception is the award of Blocks 9 and 20 to Cobalt in 2010, which was done under a risk-service agreement. License awards depend upon the signature bonus offered, with Sonangol often taking an equity interest in the awarded block. This interest is typically carried through the exploration phase.

The much-awaited Kwanza Basin award was announced in January 2011 by inviting 13 companies to submit their bids. Repsol and ConocoPhillips entered Angola in this round while the rest were all existing explorers in Angola. The most sought-after blocks, 19 and 20, were awarded to BP and Cobalt, but significant acreage and blocks were also captured by Statoil, Total, Repsol, ENI and Conoco as detailed below.

Figure 480: Exposure to Angola Pre-Salt

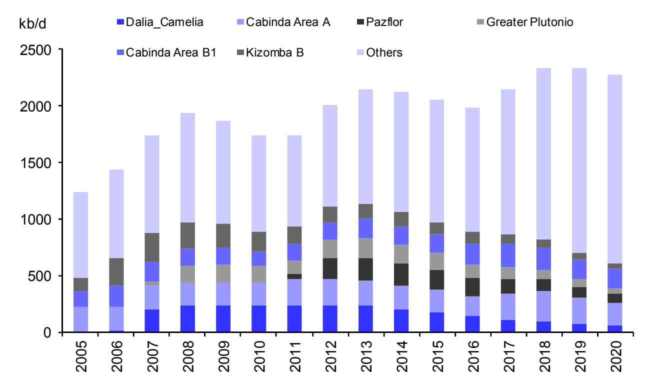
Position	Block	Acreage (Km2)	Operator	BP	Cobalt	COP	Eni	XOM	Maersk	Repsol	Statoil	Total	Sonangol
Shallow	Block 8	4801	Maersk						50.0%				20.0%
	Block 9	4810	Cobalt		40.0%								20.0%
Deep	Block 19	4850	BP	50.0%									40.0%
	Block 20	4900	Cobalt	20.0%	40.0%								30.0%
	Block 21	4887	Cobalt		40.0%								20.0%
	Block 22	5180	Repsol							30.0%	20.0%		50.0%
	Block 23	5237	Maersk						50.0%				20.0%
	Block 24	4778	BP	50.0%									50.0%
	Block 25	4825	Total	15.0%							20.0%	35.0%	30.0%
Ultra Deep	Block 35	4831	Eni				30.0%			25.0%			45.0%
	Block 36	5028	COP			30.0%							50.0%
	Block 37	5353	COP			30.0%				20%			50.0%
	Block 38	6298	Statoil					15%.0			40.0%	15.0%	30.0%
	Block 39	7800	Statoil					15.0%			40.0%	15.0%	30.0%
	Block 40	7588	Total	15.0%							20.0%	35.0%	30.0%
Net Acreage (Km2)				**7656**	**5839**	**3114**	**1449**	**2115**	**5019**	**3832**	**9158**	**6459**	**27654**
Total Blocks				**5**	**3**	**2**	**1**	**2**	**2**	**3**	**5**	**4**	**15**
Operated				**2**	**3**	**2**	**1**	**0**	**2**	**1**	**2**	**2**	**0**

Source: Deutsche Bank, company datra

Production of Oil and Gas

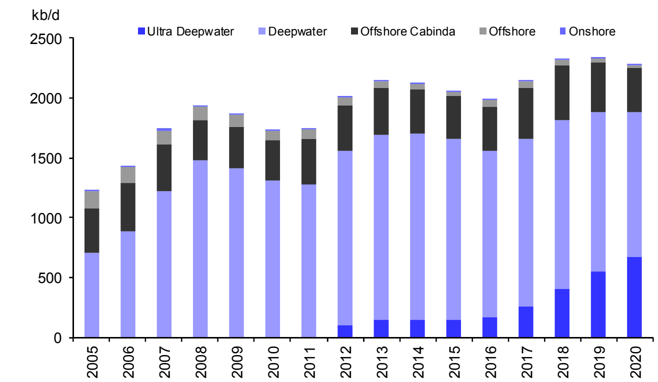
In 2012 oil production in Angola was estimated at 2.0mb/d. This has the potential to expand notably with current development plans suggesting a production peak by 2018 of some 2.3mb/d, subject to OPEC quota restrictions. Evidenced below, the key producing blocks are Exxon-operated Block 15, which produced c0.4mb/d in 2012 and Total's Block 17 (the so-called 'Golden Block') with peak production of 0.7mb/d anticipated by 2015. First production from BP's ultra-deepwater Block 31 commenced in late 2012 with that from Total's Block 32 seen following in 2016.

Figure 481: Angolan oil production 2005-20E by Block (kb/d)



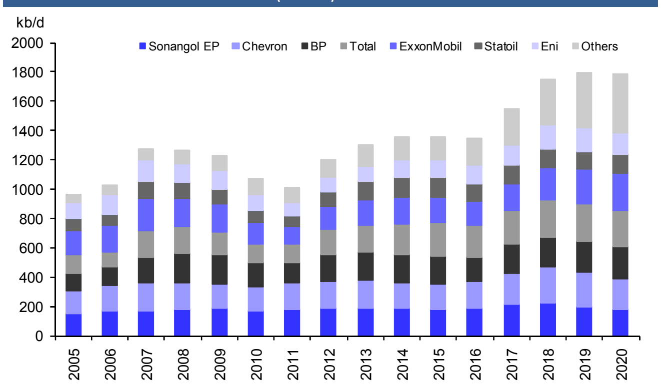
Source: Wood Mackenzie

Figure 482: Angolan oil production 2005-20E by location (kb/d)



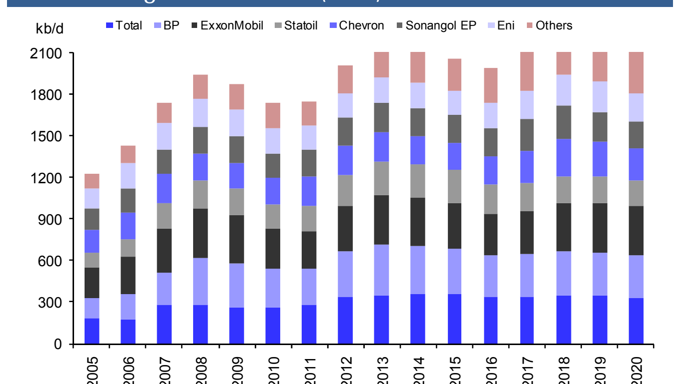
Source: Wood Mackenzie

Figure 483: Angolan oil production 2005-20E by company on an entitlement basis (kb/d)



Source: Wood Mackenzie

Figure 484: Angolan oil production 2005-20E by company on a working interest basis (kb/d)



Source: Wood Mackenzie

Historically, Chevron's dominance of the shallow water offshore Cabinda concession positioned it as Angola's leading producer. While the Cabinda concession remains a significant producer of crude (owned 39.2% Chevron, 10% Total, 9.8% ENI and 41% Sonangol), the success of Total, BP and Exxon in developing Angola's deepwater is expected to see each of these generating over 350kb/d of working interest production in the near to medium term. Note, however, that as a consequence of the PSC structure of Angola's deepwater licenses, entitlement production will be significantly lower. Crude oil aside, there is currently no production of sales gas in Angola. Following the 2013 delayed start-up of Angola LNG, some 125mscf/d of sales gas is, however, expected to be processed for domestic markets.

Reserves and Resources

Remaining Angolan reserves of oil at the end of 2012 stood at an estimated 12bn barrels with some 80% of this associated with the deep and ultra-deepwater Blocks 14, 15, 17, 18, 31 and 32. With considerable exploration work continuing, reserves growth is expected to be meaningful over the next several years. Angola has estimated proven and probable reserves of gas in its offshore licenses of around 8TCF, much of which is committed to export via LNG. Possible reserves are estimated at up to 26TCF.

Pipelines and Infrastructure

Oil and gas infrastructure in Angola is limited. In large part this reflects the offshore and deepwater bias of the country's production, which has resulted in most developments loading production directly onto tankers from FPSOs. Pipelines are, however, in place to carry shallow-water Cabinda production to onshore terminals at Malongo for loading onto ships or internal transport by rail to Sonangol's Luanda refinery.

At present there is no sales gas in Angola and all new oil developments in Angola are approved subject to the understanding that no gas will be flared but rather stored or re-injected for oil recovery and production of LNG.

Crude Oil Blends and Quality

Several different blends of crude oil emerge from Angola reflecting its bias towards deepwater facilities, which operate using an FPSO to load crude directly onto tanker for export. Most Angolan oil is light (c30°) and sweet (<1% sulphur) with the notable exceptions being crude from B17's Dalia (23.7°API) and B14's Kuito (c20°API). The most significant and well-known blend is Cabinda, which is a mix of all the crude produced in the offshore Cabinda A concession. This light sweet oil trades at a modest 2-3% discount to Brent.

Broad Fiscal Terms

The tax structure applicable to production licenses in Angola varies depending upon whether the operated fields are in the shallow-water Cabinda concession, to which tax and royalty terms apply, or the offshore, which is subject to production-sharing contracts, or PSCs.

Cabinda (tax and royalty): Government take in the concession areas typically arises through three main sources: Royalty, which is charged at 20% on gross revenues, Petroleum Revenue Tax (IRP) which is charged at 65.75% on revenues net of DD&A, royalties, surface rental charges and finally Taxa de Transacca de Petroleo (TTP) at 70%. This is charged before corporation tax but after a production allowance (which increases by 7% per annum and is estimated at c$30/bbl in 2013). For the purposes of TTP, an investment allowance or uplift equating to 50% of capital spend is also allowable.

Figure 485: Change in Angolan Deepwater terms upon re-licensing

License	Block 15 Initial)*	Block 15/06 relicense	Block 17 initial	Block 17/06 re-license
Signature bonus	$35m	$900m	$6m	To be decided
Cost oil limit	50%	50%	55%	50%
Uplift	145%	130%	150%	130%
Profit shares (IRR/contractor share)				
IRR	<15%/75%	<15%/70%	<15%/75%	<15%/70%
IRR	15-25%/65%	15-20%/60%	15-25%/60%	15-20%/60%
IRR	25-30%/45%	20-30%/40%	25-30%/40%	20-30%/40%
IRR	>30%/25%	>30%/20%	>30%/20%	>30%/20%

Source: Sonangol; Deutsche Bank

Deepwater: Angola's deepwater blocks are subject to production sharing contracts. Terms between these may vary by block. In general, however, Angolan PSCs are structured as IRR-based profit sharing contracts. In most PSCs, 50% of revenues are available for the recovery of cost oil with the remaining profit oil divided between state and contractor in proportions that vary dependent upon the project's quarterly-measured IRR (%), the resulting profits being taxed at a rate of 50%. Importantly, in determining cost oil, capex is uplifted by as much as 50% and is depreciated for tax purposes on a four-year straight line basis. It is of note that in the more recent licensing rounds, the terms applicable to the PSCs awarded have deteriorated somewhat for the contractors, with capital uplift reduced and the trigger points for a change in the share of profit oil based on lower project IRRs.

Refining and Downstream markets

Angola presently has one refinery based in Luanda with a capacity of c65kb/d, although processing capacity is currently nearer 40kb/d. The refinery was 56%-owned by Total, but following its successful bid for Block 17/06, Total passed its equity interest to Sonangol as part of its signature bonus payment. While this single refinery meets most of the country's requirements for oil products, in 2006 Sonangol agreed a deal with Sinopec whereby Sinopec agreed to finance the construction of a new 200kb/d refinery at Lobito in Southern Angola. Plans are currently on hold.

LNG

The Angola LNG project took Final Investment Decision (FID) in late 2007 and is expected to see the start-up of a 5.2mtpa LNG facility at Soyo in the north of the country in Q2 2013. This will be operated by Chevron, which has a 36.4% interest in the project, the other equity holders being Sonangol (22.8%), Total (13.6%), Eni (13.6%) and BP (13.6%). The project will use the associated gas that is currently being flared or re-injected into oil reserves. Whilst the initial plan on taking FID was that the LNG produced would be delivered to the Pasaguola re-gas facility in the US, the changed market environment means that the LNG produced will now be marketed by Angola LNG as an entity in its own right.

Angola - Notes

Iran

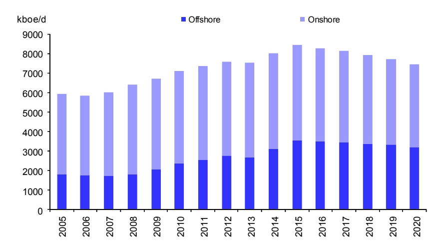
Whilst Iran has consistently ranked as the fourth-largest oil-producing nation in the world, behind Saudi Arabia, Russia and the US, and the second-largest within OPEC, the last year has seen production levels severely curtailed due to the impact of US-led sanctions. Whilst crude production ran at c3.8mb/d between 2009 and 2011(a sub-set of 4.3mb/d total liquids production), this has now been curtailed to stand at just 2.7mb/d in Dec-12, the reduction primarily impacting exports, which have fallen to around c1.0mb/d. Clearly Iran's production potential is higher. Proven liquids reserves of 151 billion bbls (9% of the world total) imply a reserves life of over 125 years. Unfortunately, such growth requires massive investment and the participation of the IOCs, and this is not presently occurring, in large part due to the current array of UN resolutions and US/EU sanctions imposed to stymie Iran's apparent ambition of developing ballistic missiles. However, the issue of under-investment runs deeper than sanctions imposed during the past two years and includes a relatively unattractive fiscal regime (buybacks), the 1995 Iran-Libya Sanctions Act (that prevents US company investment), years of turmoil in the leadership of the oil ministry and the general inefficiencies associated with a massive state-controlled oil company. With none of these issues likely to change in the short term, Iran's production aspiration of 5 million b/d by 2015 looks unobtainable. Main IOCs with legacy exposure to Iran include Eni and Statoil.

Key facts

Oil production 2012E	3.0mb/d
Gas production 2012E	2.8mboe/d
Oil reserves 2012E	151.2 bn bbls
Gas reserve 2012E	1168.6 TCF
Reserve life (oil)	89.4 years
Reserve life (gas)	190.7 years
GDP 2012E	$483.8bn
GDP Growth 2012E (%)	-0.0%
Population (m)	76.1m
Oil consumption (2011)	1.8mb/d
Oil exports (2010)	2.2mb/d
Fiscal regime	Buybacks
Marginal tax rate	n/a
Top 3 fields (2012E)	
South Pars	1922kboe/d
Ahwaz	972kboe/d
Marun	559kboe/d
Top 3 Producers (2012E)	
NIOC	6378kboe/d
Petro Pars	11kboe/d
CNPC	7kboe/d

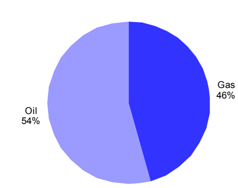
Source: Wood Mackenzie, EIA, IMF

Oil Production profile kb/d



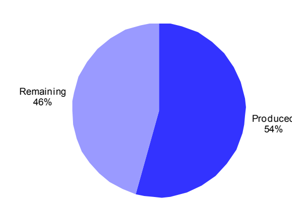
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

Basic geology and topology

Two areas dominate Iran's hydrocarbon production; the Arabian and Zagros basins. Both basins contain a high proportion of giant and super giant oil and gas fields, and numerous smaller reservoirs and prospective structures. The Arabian basin extends roughly South West from Iran's Gulf Coast and goes on to include the bulk of the famous fields in Iraq, Kuwait and Saudi Arabia. The Zagros Basin lies onshore, to the North East of Iran's Gulf coast and contains reservoirs formed by tectonically-induced folding when the Arabian and Iranian plates collided. Most of Iran's oil and gas reserves are contained within five sedimentary rock sequences; the Dalan, Kangan, Khami Group, Bangestan Group and Asmari. All of these are typified by limestones and dolomites and generally have quite poor primary permeability, but in many cases benefit significantly from the presence of fractures that allow very high effective permeabilities and flow rates.

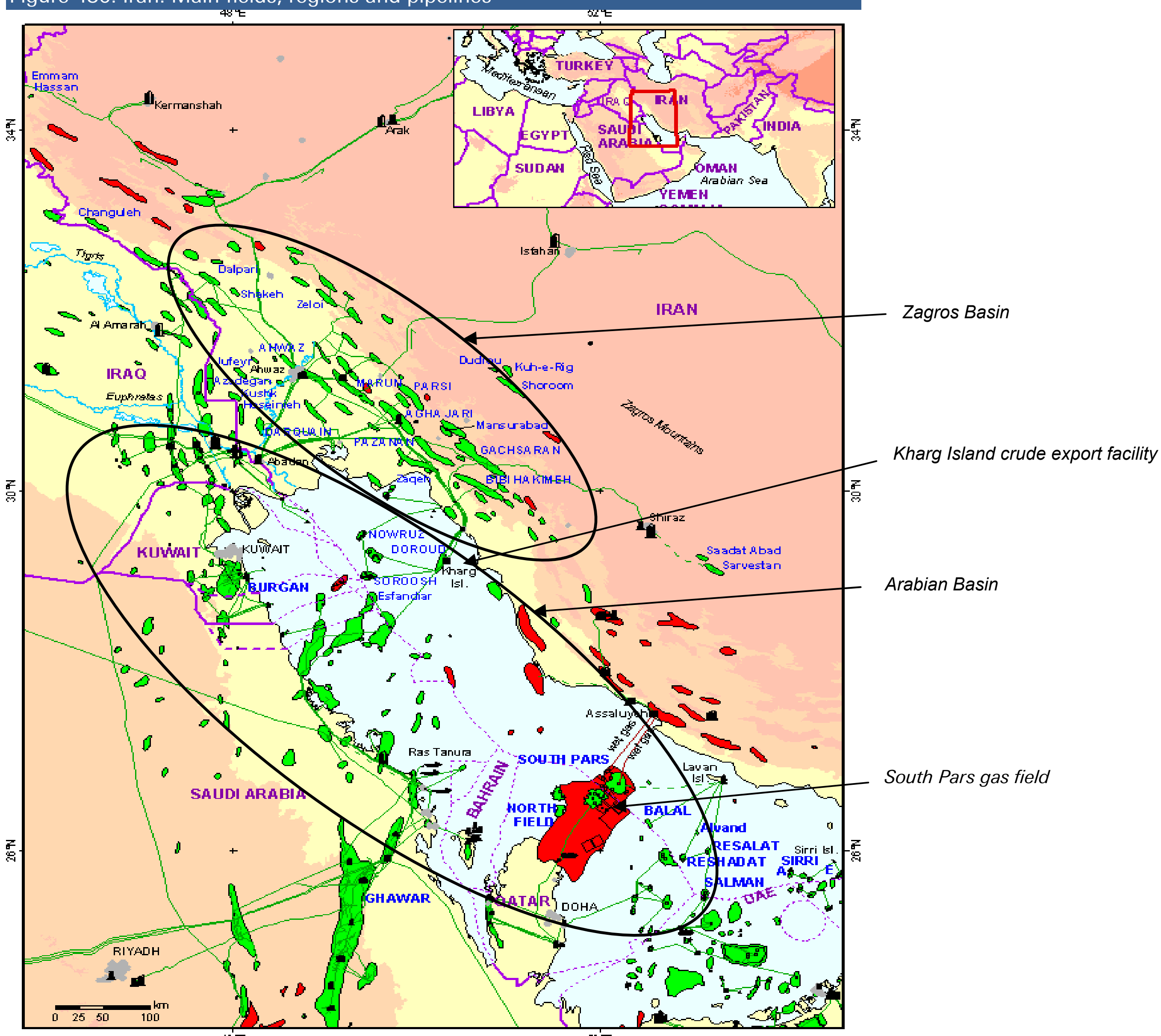
Regulation and history

Iran's oil industry started over 100 years ago when in 1901 William D'Arcy negotiated a large concession. The subsequent 1908 oil discovery heralded the birth of both Middle East oil production and BP. By 1950 the Iranians' experience with AIOC (later to become BP) and perception of the profit share was so poor that the prime minister nationalized the entire industry. This was soon followed by a coup in which the Shah assumed full power and effectively returned control of the oilfields to a consortium of Western companies, albeit officially reporting to the newly created state oil and gas company – NIOC (National Iranian Oil Company). The 1979 Islamic Revolution handed full control of all fields and assets to NIOC.

Despite this, Iran's legal regime is mature and stable, with even the 1979 Islamic Revolution leaving most laws intact. The current concept of buyback contracts dates back to the 1974 Petroleum Act, when Iran passed laws that made foreign ownership of oil reserves illegal but allowed payment for services. The Ministry of Oil has full control of the oil and gas industry in Iran and is backed by the 1987 Oil Act that provides the required framework. The Ministry is responsible for the ultimate approval for license awards, project approvals and the running of state oil company NIOC. Unfortunately the hydrocarbon laws and Iranian constitution are subject to different interpretations, and this ambiguity, particularly over what foreign investments are allowed, has been a contributing factor to investment delays. For example one reasonable interpretation of the existing text is that no foreign investment of any kind is allowed in the hydrocarbon sector.

As a result of Iran's apparent efforts to produce sufficient fissile material to produce a ballistic missile and non-compliance with international efforts to monitor its nuclear programme, the country is subject to numerous international sanctions. With respect to the oil industry, the most notable effect is to prevent investment in the country and to block a large part of Iran's crude exports.

Figure 486: Iran: Main fields, regions and pipelines



Source: Wood Mackenzie

Production of Oil & Gas

Oil production at Iran's first discovery (Masjid-e-Suleiman, 1908) began in 1914. A sequence of giant reservoir discoveries started in the late 1920s and production steadily increased, despite a blip due to the aborted 1951 nationalisation attempt, until a peak of 6mb/d was achieved in 1974. Saddam Hussein's first major impact in the region was not the invasion of Kuwait, but the unannounced military attack on Iran in 1980 that saw the start of the eight-year Iran-Iraq war. This war caused significant damage to both countries' oil and gas infrastructure, and indeed Iran's production was only 3mb/d, half its 1974 peak, by the time the war ended.

Iran's crude oil production was c.3.7mb/d in 2011, but reflecting the impact of newly imposed sanctions limiting crude exports, crude production had fallen to closer to 2.7mb/d by end 2012. The EIA anticipates that the FY13 average could fall to around 2.5mb/d. In addition to crude production, the giant South Pars gas field provides an NGLs production stream of c.0.6mb/d, taking total liquids production to c.4.3mb/d in 2011. The largest oil producer is the giant onshore Ahwaz field (c.973kb/d). This field, together with nine other giant fields (all but one of which lie in the onshore Zagros basin) have supplied c.90% of Iran's cumulative oil production to-date.

Production growth since the late 1990s has come mainly as a result of IOC investment under the buyback contract regime, starting with Sirri A&E (Total) in 1995 and continuing with Soroosh-Norwruz (Shell), South Pars 2&3 (Total), South Pars 4&5 (Eni), Darquain (Eni), and Doroud (Eni & Total) amongst others. Without these buyback contracts, Iran would have likely at best posted flat production from the late 1990s onwards, and the fact that additional contracts are not being signed in the current environment leaves the future production profile at significant risk. The main legacy fields are mature and well past peak production, with underlying decline rates of around 7% or more. As with buyback contracts, NIOC plans to implement further secondary recovery projects on its major declining fields but is struggling in the face of delays in project awards, not least as current US sanctions effectively disbar IOC involvement.

Figure 487: Key liquids fields in production

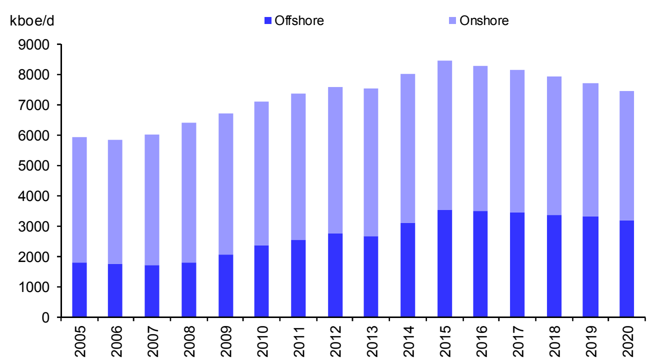
Fields	Remaining Reserves (mmbbl)*	Production 2012 kb/d	Production 2015 kb/d
South Pars**	6,060	538	760
Ahwaz***	3,734	949	800
Gachsaran	3,359	448	428
Marun Fields	2,566	533	408
IOOC Fields	1,939	392	386
Karanj-Parsi	1,750	247	260

*Source: Wood Mackenzie. * As at 1.1.2012; Proven plus Probable; total liquid. **South Pars includes fields 1-18*** Ahwaz and Ahwaz Area fields*

Historically Iran's gas production was associated with onshore oil fields; however, non-associated gas fields have been developed from 1983 onwards. A significant increase in gas production occurred from 2002 onwards as Iran began to develop the giant South Pars field (a field that straddles the Iran/Qatar border, the Qatari-named 'North Field' feeding gas to a series of independent LNG and GTL projects) assisted by IOCs operating under the buyback contract structure.

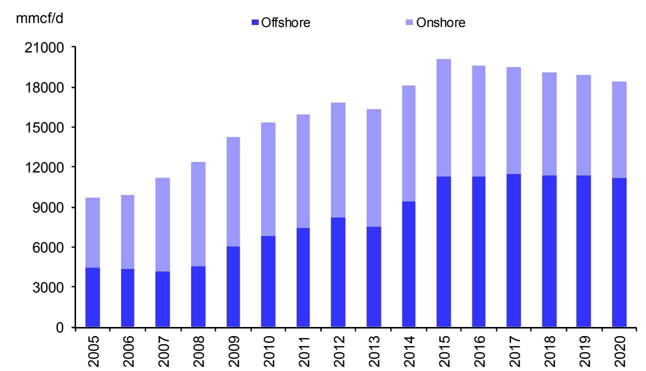
IOCs have made investments in Iran over the last ten years, but a combination of sanctions and high oil prices, allied with the buyback contract model, means that the current IOC exposure by production is insignificant.

Figure 488: Iran liquids production, 2005-2020E (kb/d)



Source: Wood Mackenzie; Deutsche Bank

Figure 489: Iran gas production, 2000-2020E (mmcf/d)



Source: Wood Mackenzie; Deutsche Bank

Reserves and Resources

Iran's stated proven oil reserves are at 151 bn bbls. The offshore Arabian basin and the onshore Zagros basin contain over 90% of these reserves.

Although Iran is one of the world's leading oil producers, it retains a high potential for major new discoveries. This is supported by the rate of new, giant oil and gas discoveries that have been made over the last 10-15 years, which include Khayyam field, Ferdowsi oil layer, Forouz gas field, Azadegan, Kushk, Housseineh and Anaran. However, the appraisal and development path for these assets is unclear given the presently reduced role of international firms in the wake of sanctions. All these finds have been in the established producing region of the Zagros basin and suggest that there is a high probability of further discoveries. There is also significant potential for new discoveries in the less explored basins of Iran, such as in the offshore Persian Gulf and the Main Central Basin, but again this is likely to require collaboration with international companies, which is severely limited at present.

Iran has the second-largest gas reserves in the world after Russia. With the massive South Pars field's 500TCF (Iran's share) of 2P reserves largely untapped as yet, Iran has a gas reserves life of over 190 years. As with oil, there is plenty of scope, from a resource perspective, to increase production, but commercial and political considerations provide obstacles that for the time being appear insurmountable.

Pipelines and infrastructure

Iran has a well-established and extensive oil pipeline infrastructure that links its oil fields to its nine refineries and export facilities throughout the country. Its pipeline infrastructure consists of five (13,500km) crude oil trunk pipelines and a 44,000km gas pipeline network. The oil pipeline network is used to export oil and serve refineries in Iran and is complemented by multiple international projects under appraisal. The majority of Iran's export pipeline network is used for transporting oil from the producing fields in the Zagros Basin for export at the Kharg Island terminal. The terminal has a capacity of 4mb/d and is the loading point for almost all of Iran's exported oil.

A high-profile new oil pipeline project has been for the import of oil produced in the Caspian region (Kazakhstan, Turkmenistan and Azerbaijan). The imported crude is consumed in the Northern industrialized areas of Iran, and equivalent amounts are sold from the Kharg export island in the South, where Iran's own oil is produced – it is hence a swap arrangement. Wood Mackenzie records that after shipping 90kb/d in early 2010, this arrangement was halted.

Besides pipeline network, Iran has 20mbbl oil storage capacity in Karg Island, where most of the exports are made, together with a loading capacity of 5mbbl/d. Lavan Island, the second-largest terminal, has a 5mbbls storage capacity with 200kb/d loading capacity.

Iran's regional gas supply network is dominated by two regional transmission lines, the Iranian Gas Trunk lines IGAT-1 and IGAT-2. The pipelines IGAT-1 and IGAT-2 have a capacity of 1.6bcf/d and 2.6bcf/d respectively. They form the primary trunk lines carrying gas from the Zagros fields to the main industrial areas and population centers of northern Iran. Further IGAT-3 with initial capacity of 3.0bcf/d carries gas from South Pars to Qazvin in northern Iran with further expansion in pipeline to connect Astara, Turkey. IGAT-4 with 3.9bcf/d, serving mainly domestic markets, carries gas from South Pars fields to Saveh, northern demand centres. The constructed IGAT-5 and IGAT-6 are ready to transport gas from South Pars 6-8 and South Parts 9-10 respectively with the former will carry gas to Agha Jari field for re-injection while the later to the Bid Boland gas processing plant, Khuzestan. IGAT-7 was constructed in 2010 will transport gas from Assaluyeh to Iranshahr through Baluchistan to the Pakistan border for export.

Crude Oil Blends and Quality

Iran exports oil as a series of blends, with Iran Heavy and Iran Light making up around 90% of the total. Iran Heavy is a typical Middle Eastern, medium-gravity, high sulphur crude, while Iran Light is comparable in quality to Arab Light. The outlook for Iranian crudes is a trend towards heavier and sourer grades over time as lower quality crude is produced from newly developed fields that replace falling production from legacy assets.

Figure 490: Summary of main crude blends and characteristics

Crude Oil	Gravity (°API)	Sulphur (%)
Doroud	36.0	2.40
Foroozan Blend	29.7	2.34
Iran Heavy	30.2	1.77
Iran Light	33.1	1.50

Source: The International Crude Oil Market Handbook 2007, Energy Intelligence Research

Broad Fiscal Terms

All contracts for Iranian production and exploration must be negotiated with NIOC, which in turn must seek final approval from the Ministry for Oil. Foreign companies can invest only via buyback contracts, the first of which was awarded to Total in 1995. Buyback contracts stipulate that the foreign company (or 'contractor') must fund and execute all appropriate exploration and development and then recoup a fixed, pre-agreed return (in the form of barrels of oil) from the subsequent production, assuming the production is successful enough to do so. Each buyback contract goes out to tender and companies must bid their best offer in terms of the lowest return they will accept. A key part of the buyback contract is the Master Development Plan document, where exact details of what will be done, and how much it will cost (the Capital Cost Allowance) are recorded and committed to. Prior to more stringent sanctions which have effectively shut down foreign investment in Iran, investment was already being disincentivised with the combination industry-wide cost escalation and the need to commit to a certain capex level elevating the risk of being unable to make a decent return. There was a proposal to alter the buyback model so that the Capital Cost Allowance is not finalised until late in the tender process; however, such changes do not tend to occur quickly in Iran.

Refining and downstream markets

Iran has a total refining capacity of 1.7mb/d split among nine refineries. Although there are plans to add seven more refineries, only three progressed beyond the initial stage and after making slow progress wood Mackenzie notes that the lack of funding has seen production essentially cease. As with other areas of the Iranian oil and gas industry the poor terms on offer have dissuaded many E&C firms from bidding for such work, thus such growth plans seem vastly over-optimistic at present.

Figure 491: Main refineries in Iran

Operator	Refinery	Capacity (Kb/d)
National Iranian Oil Company	Abadan Refinery	360
National Iranian Oil Company	Arak Refinery	170
National Iranian Oil Company	Bandar Abbas Refinery	320
National Iranian Oil Company	Isfahan Refinery	370
National Iranian Oil Company	Tabriz Refinery	110
National Iranian Oil Company	Tehran Refinery	250

Source: Wood Mackenzie

A surprising statistic is that at one point as much as 40% of the country's total gasoline consumption was met by imports, although this has been considerably reduced (to 50kb/d in 2011) by converting petrochemical facilities to produce gasoline and improving the existing refineries. The planned refinery capacity expansion was aimed at increasing gasoline production by upgrading the refineries' ability to process heavier crudes; if such plans could actually be implemented then indeed Iran would cease to be a net importer of gasoline. Perhaps a more appropriate place to look for explanations is not the lack of refining capacity, but rather subsidized gasoline prices.

To control imports, which grew by more than 30% p.a. between 2000 and 2006 on the back of a huge surge in fuel demand (c.10% p.a. growth in the period), the government introduced gasoline rationing in 2007 and from late-2010 introduced a programme to reduce subsidies.

LNG

The huge South Pars gas field is an obvious candidate for Iran to enter the world as a major supplier of LNG. Four projects have been variously suggested: Pars LNG (10.5mtpa supplied from South Pars phase 11), Iran LNG (10.5mmtpa supplied from South Pars phase 12), Persian LNG (16mmtpa supplied from phases 13 and 14) and North Pars LNG (20mtpa). However, in each case work had not progressed beyond the MOU or planning phase and, in the face of sanctions, is indefinitely suspended.

Quite aside from sanctions, the LNG projects are bedevilled by inflexible contract structures; no IOC wants to take on fixed returns for pre-agreed capital costs when it is clear that capital costs are currently extremely volatile. Furthermore, no international E&C firm wants to submit a binding bid for building an LNG plant (where they are obliged to use a high percentage of local content) without a massive cushion for potential cost overruns being built in.

Iraq

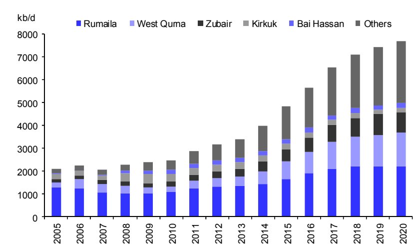
Iraq has the world's fifth-largest proven petroleum reserves. However, only a fraction of its known fields are in development, reflecting a legacy of conflicts, sanctions and, more recently, internal political problems, which have constrained investment since the early 1980s. According to the BP Statistical Review of World Energy, total estimated oil reserves are around 143 billion barrels, in accordance with Iraqi Federal Government's 2010 disclosure excluding Kurdistan. The potential for reserve additions, through appraisal and further exploration, is considered high given large areas of the country remain relatively unexplored and broad regions, particularly in Western Iraq, remain undrilled. Yet despite its huge potential, current production (3.1mb/d) is mostly derived from Iraq's four main oil fields. When thinking about the oil industry in Iraq, it is increasingly useful to consider the autonomous region of Kurdistan and the remainder of Iraq as two distinct entities. In Iraq, 2 licensing rounds in late-2009 saw 12 Technical Service Contracts awarded to various international consortia with a combined plateau production potential of 11.7mb/d. Reflecting an array of challenges including security issues, insfrastructure constraints, a limited services sector, bureaucracy, political uncertainty and less-than-appealing fiscal terms, progress toward this target has been slow. As a consequence, a number of original licensees have looked to exit or have taken positions in Kurdistan in direct opposition to the desires of the Oil Ministry. Reflecting these ongoing challenges Wood Mackenzie forecast 2017 volumes of circa 5.5mb/d (ex Kurdistan). Turning to Kurdistan, the challenges facing the industry appear more political than technical. The Kurdistan Regional Government (KRG) has attracted significant interest from international oil companies, licensing over 40 blocks covering a mixture of development opportunities, appraisal and frontier exploration. However, the authority of the KRG to issue these licenses is a point of contention with the Federal Iraqi goverment. And with contraints over the evacuation of crude from Kurdistan, this issue has manifested itself in a dispute over the division of export revenues. It remains unclear how this issue will be resolved and what the impact on the pace of development of the oil industry in Kurdistan will be.

Key facts

Oil production 2012E	3.1mb/d
Gas production 2012E	0.2mboe/d
Oil reserves 2012E	143.1 bn bbls
Gas reserve 2012E	126.7 TCF
Reserve life (oil)	125 years
Reserve life (gas)	335 years
GDP 2012E	$131bn
GDP Growth 2012E (%)	10.2%
Population (m)	33.6m
Oil consumption (2011)	0.7mb/d
Oil exports (mb/d) (2011)	2.4mb/d
Fiscal regime	Service Contract & PSC
Marginal tax rate	Various
Top 3 fields (2012E)	
Rumaila	1300kboe/d
West Qurna	377kboe/d
Zubair	300kboe/d
Top Producer (2012E)	
INOC	2.2mb/d

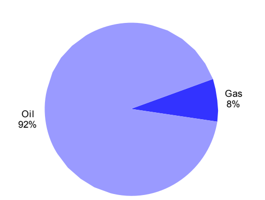
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



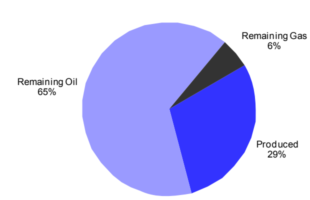
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

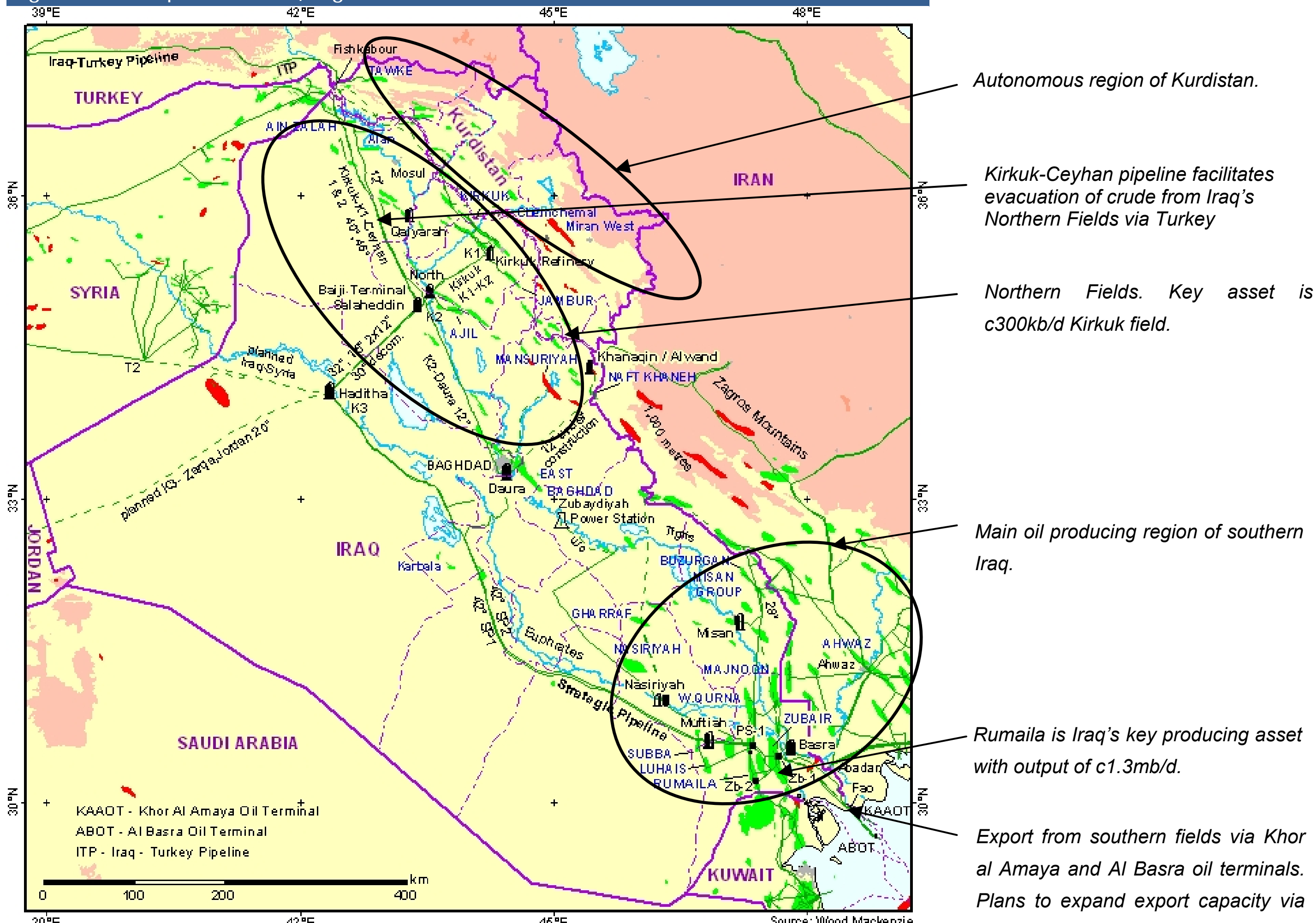
Basic geology and topology

Iraq's geology can be split into two main areas. The northern oil fields are situated in the Zagros basin, while those that lie in the central and southern parts of the country are located in the Arabian basin. These two basins are characterised by a high proportion of giant oil and gas fields, as well as a multitude of smaller pools and prospective structures. The country's reserves are composed of source rocks that are principally Jurassic to early middle Cretaceous in age. To date there have been more than 47 productive reservoirs identified across Iraq, the most successful being the Yamana reservoir in the south, which contains the giant Rumaila, West Qurna and Zubair fields, and the Asmari reservoir in the north, which contains the Kirkuk oil field.

Regulation and history

Historically, Iraq's oil industry has been plagued by political instability, manifested primarily in wars. Subsequent to Iraq's invasion of Kuwait in 1990, the UN comprehensively embargoed Iraq of all trade save that approved by the UN for humanitarian goods, leading to the 'Oil-for-Food' programme in 1996. Under this programme, Iraq was allowed to export oil to buy food, medicine and other humanitarian goods and to pay for war reparations. These sanctions continued until the Second Iraqi War in 2003, but have since been lifted.

Figure 492: Iraq: Main fields, regions and basins



Source: Wood Mackenzie

Despite almost a decade having passed since the start of the 2003 Iraqi War, the regulatory structure of the Iraqi oil sector post-Saddam is still evolving, not least due to an inability to reconcile the viewpoints of the KRG and Federal Iraqi governments.

Legislation governing the country's future hydrocarbon industry has been subject to detailed ongoing political negotiations, and numerous deadlines for the completion of the Oil and Gas Law have already passed. The Council of Ministers did reach an agreement on a draft Federal Oil and Gas Law (covering the whole of Iraq including Kurdistan) in February 2007; however, this bill has never been enacted. There have been a number of subsequent initiatives proposed to deliver and legislate a draft oil law that is acceptable to both parties, but without evident progress at the time of writing.

There are essentially two points of contention. First, under the terms of the Iraq Constitution, the KRG assert their right to exclusive jurisdiction over oil and gas resources in the Kurdistan region. For licenses awarded prior to the Constitution coming into force (2006), the KRG believe that this right is explicitly provided for, whilst the Federal Government argues the contrary. And, with respect to subsequent rights over the oil industry, the Constitution omits the issue of petroleum jurisdiction from the list of specified federal powers, which is consequently interpreted by the KRG to be a regional power. Reflecting this viewpoint, the KRG passed its own oil law in 2007, which the Iraqi Oil Ministry has declared to be "illegal and illegitimate".

Second, as a consequence of the above, when the KRG announced the launch of oil exports in 2009, the Iraqi Government initially withheld payments to Kurdistan (the payment mechanism for all crude exported from Iraq sees revenue remitted to the Federal Government). Whilst there was a partial resumption of payments in 2011, there is now dispute over the level of reimbursement to be made and no visibility over the payment schedule. This is set to become a growing issue as the value of Kurdistan's oil production moves to the point of equivalency with the 17% of the federal Iraqi budget (the vast majority of which is derived from oil), which it is entitled to receive under the Constitution.

The consequence of the above is that one effectively needs to think about the Iraqi oil industry today as two separate regions. At a federal level, the as-yet-unsanctioned Hydrocarbon Law defines a regulatory role for the Ministry of Oil, which includes licensing, whilst an operational role for the Iraqi State will be undertaken by an independent Iraqi National Oil Company (INOC). Within Kurdistan, the Ministry of Natural Resources administers all petroleum operations, including licensing.

Licensing

The nationalisation of the Iraqi oil industry in 1975 pushed all IOC's (primarily US and UK companies) out of the country. Prior to this they held approximately a three-quarter share of the Iraq Petroleum Company (IPC), including Iraq's entire national reserves. In light of the UN sanctions of the 1990s and the subsequent war in 2003, foreign participation in Iraq was very limited with only a small number of companies (BP, Shell, Anadarko) signing contracts for the provision of technical services. However, in 2009 the country proceeded with its first licensing round in years in which it sought to award a number of service contracts. However, the first round in June 2009 saw only one contract awarded; that for the giant Rumaila field. The low service fees on offer deterred many companies from accepting 'winning' bids. Subsequent licensing rounds have seen Technical Service Contracts (TSCs) awarded on 12 further fields including Zubair, West Qurna, Majnoon and Halfaya. A gas-focused license round was held in 2010 awarding three development contracts, whilst the latest licence round, held in 2012, focused on the award of exploration acreage although only 3 of 12 blocks on offer were awarded. There is no visibility on when further license rounds may be held. It is worth noting that due to a variety of challenges (already referred to), a number of companies have subsequently sought to exit from their interest in these TSCs (i.e. Statoil) or have looked to diversity by also taking acreage in Kurdistan (i.e. Exxon, Total).

Licensing activity has been more intense in the self-governed Kurdistan region, where Wood Mackenzie estimates that over 50 licenses have been awarded since 2007, in addition to a number of pre-existing licenses. These licenses have been awarded via direct negotiation between participants and the KRG as opposed to open competitive tenders. Whilst these awards initially attracted a series of small/mid-tier independents, since 2011 the international majors have begun to take a more prominent role, with Exxon, Chevron, Total and Repsol all present. As already outlined, the legitimacy of the KRG to issue these licenses remains a point of significant contention between the federal and regional governments. In this context, the award of 6 blocks in Kurdistan to ExxonMobil in late 2011 may be seen as a watershed. Exxon is a participant in Iraq via the West Qurna field, and hence in also moving into Kurdistan became the first company to operate in both regions, in direct contravention of the wishes of the federal government. Total has subsequently followed suit.

Production of Oil and Gas

Commercial production in Iraq commenced in 1927 and gradually increased throughout the 1960s and 70s, peaking at approximately 3.5mb/d in 1979. However, despite the fact that it started producing oil more than 75 years ago, Iraq's oil production potential has yet to reach a level commensurate with its reserves. Internal political problems and regional conflicts have constrained production capacity and crippled the infrastructure for the last 25 years. Production was disrupted in 1980 by the Iran-Iraq War, in 1991 by the Gulf War and again in 2003 by the War on Iraq. Subsequent to the 2003 war, and following the award of a number of TSCs in 2009, production has been increasing, with liquids volume of c3.1mb/d in 2012 representing the highest level since the late 1970s.

Figure 493: Iraq's key oil fields and production

	Initial Reserves (mb)	Remaining Reserves (mb)	Start-up	Production 2005 (kb/d)	Production 2012 (kb/d)	Production 2015 (kb/d)
Rumaila	30674	16728	1954	1277	1300	1650
West Qurna One	14932	13866	1976	200	377	500
West Qurna Two	13227	13227	2013	Nil	145	250
Kirkuk	23821	4492	1934	242	282	242
Zubair	9413	7375	1950	150	300	550

Source: Wood Mackenzie

Historically, approximately two-thirds of total production arose in the southern fields. At present, c.75% of Iraqi oil production comes from just four fields: Rumaila, Zubair and West Qurna in the south and Kirkuk in the north. Rumaila production has been recovering since the award of a TSC to BP in 2009 and now stands at c1.3mb/d, the highest level since 2000. The situation is similar at both West Qurna and Zubair. However, daily production at Kirkuk of around 280kb/d is only a fraction of its pre-war level of 700kb/d. The production terms of recent production awards would suggest the government is targeting production of near 11.7mb/d by 2020, although a combination of challenges (including security issues, insfrastructure constraints, a limited services sector, bureaucracy, political uncertainty and less-than-appealing fiscal terms) render this objective extremely ambitious. We note Wood Mackenzie is only forecasting near 7mb/d for 2020.

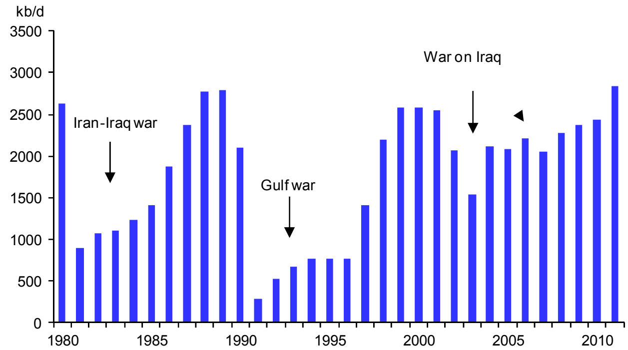
Figure 494: Key TSCs awarded in 2009 licensing round

Project	Comm'l Reserves	Current output	Plateau Production	Remun'n Fee	Sig Bonus	Original Partners
	mln boes	kboe/d	kboe/d	$/bbl	$mln	
Rumalia	16825	960	2850	2.00	500	BP 38%, CNPC 37%
Zubair	3805	182	1200	2.00	100	Eni 33%, OXY 23%, KOGAS 19%
West Qurna I	8115	270	2325	1.90	100	Exxon 60%, Shell 15%
West Qurna II	5519	0	1800	1.15	150	Lukoil 85%, Statoil 15%
Majnoon	6280	42	1800	1.39	150	Shell 60%, Petronas 40%
Halfaya	2405	10	535	1.40	150	CNPC 50%, Petronas 25%, Total 25%
Gharraf	1126	0	230	1.49	100	Petronas 60%, JAPEX 40%

Source: Wood Mackenzie, Deutsche Bank estimates

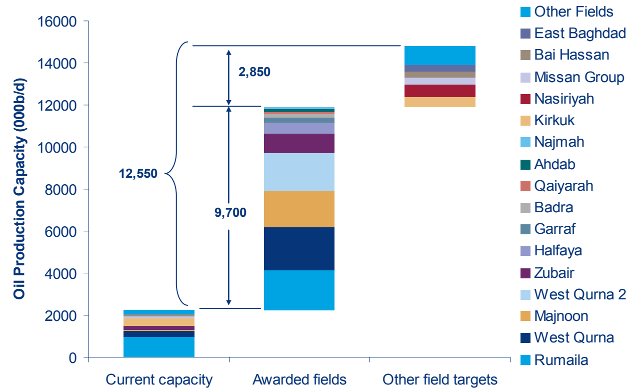
The majority of Iraq's gas production is associated gas except Kormor, which produces c.280msf/d non-associated gas; thus, its profile has tended to follow that of oil production. Production currently stands near 1000mscf/d, but the government aims to increase this to more than 6000mscf/d with about 50% of this intended for export. Ultimately Iraq could have potential to supply gas to Europe, although this remains a discussion for the long term. Near-term efforts are focused on reducing the scale of flaring with, Wood Mackenzie estimating that between 800-1000mscf/d of gas is currently flared.

Figure 495: Iraqi oil production over the last 30 years (kb/d)



Source: Wood Mackenzie; Deutsche Bank

Figure 496: Prospective Iraqi production as capacity starts to increase

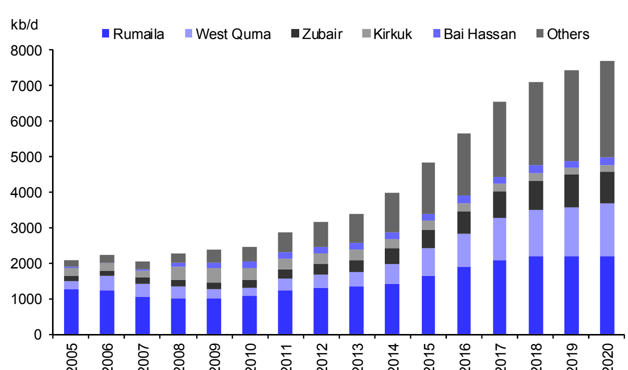


Source: Wood Mackenzie; Deutsche Bank

Iraq has not been subject to OPEC's formal production agreements for more than a decade. It is unlikely that this will change in the near term. Once its exemption is lifted (which is likely given the level of capacity additions it is targeting), Iraq is likely to demand a significantly higher quota than that which previously applied given the level of funds required by the country to rebuild basic infrastructure such as roads, schools, hospitals, etc. We note that in the 1990's when Iraq was subject to production quotas, its 3.14mb/d quota represented some 14% of OPEC's then total production. We also note informal comments from OPEC suggesting that a move to bring Iraq back within the quota system would not occur until production was c5mb/d – likely not until 2017+.

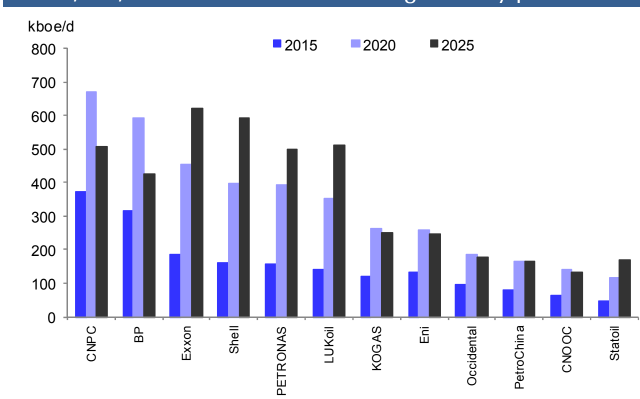
From a company perspective, all of Iraq's current production is controlled by the Ministry of Oil via its two operating units the North (NOC) and the South (SOC) Oil Companies. As detailed above, a number of service contracts were awarded to various Western companies in 2009 including BP, RDS, Eni, Statoil and Exxon. Wood Mackenzie production forecasts suggest that by 2017 CNPC, BP and Exxon will be the top three foreign producers in the country.

Figure 497: Iraqi oil production 2005-2020E(kb/d)



Source: Wood Mackenzie, Deutsche Bank

Figure 498: Working Interest Production by company – CNPC, BP, Exxon and Shell to emerge as key producers



Source: Wood Mackenzie, Deutsche Bank

Reserves and Resources

In global terms, with reserves standing at 143bn bbls of oil and 127TCF of gas, Iraq's oil reserves are the world's fifth largest. Of these, 80% are contained within the southern Arabian basin and the remainder in the north. However, for reasons described above, large volumes of oil remain undeveloped and Iraq has the lowest reserves to production ratio of the major oil-producing countries (125 years). Iraqi officials have stated in the past that they believe up to 350bln bbls will ultimately be discovered. This is consistent with early studies which showed that in addition to proved reserves, a further 214bln bbls of 2P reserves are estimated to be held in Cenozoic and Mesozoic formations.

Key fields for development in forthcoming years include those recently awarded under the 2009 licensing round such as Majnoon, Halfaya and Gharraf, which together should contribute an additional c.1.1mb/d to oil production by 2020.

Figure 499: Potential new fields in Iraq

	Recoverable Reserves (mb)	Remaining Reserves (mb)*	Start-up	Current Production (kb/d)
Majnoon	15854	15714	2002	75
Halfaya	4940	4933	2006	71
Gharraf	1100	1100	2012	0
Nasiriyah	864	855	2009	6
Bai Hassan	3230	2084	1960	199

*Source: Wood Mackenzie *Commercial reserves that are deemed to be recoverable*

In the past, exploration has concentrated on oil; hence almost all of Iraq's gas reserves are classified as technical as they lack commercial development plans. Hence approximately 70% of Iraq 127TCF estimated gas reserves is associated gas, with the main non-associated gas fields contained within seven fields (Kormor, Chemchemal, Khashm al-Ahmar, Jaria Pika, Mansuriyah, Siba and Akkas). With the exception of Komor, it is thought none of these are in production. As with oil, the potential for growth in Iraq's gas reserves is believed to be very high given the limited extent of exploration activity. Iraq's yet-to-find reserves potential is estimated by Wood Mackenzie to stand at about 260TCF – split 60/40 between non-associated and associated reserves.

Pipelines and Infrastructure

Iraq has a long established and extensive oil pipeline system, which links its oil fields to refineries and export facilities throughout the country. However, the various wars in Iraq throughout the years (both Gulf Wars and the 2003 War on Iraq) have had a significant impact on the condition of Iraq's infrastructure. In 2009 the Iraq Transition Assistance Office estimated the cost of reconstructing, rehabilitating and expanding Iraq's oil infrastructure to support 6mb/d of production capacity at US$100billion. Yet even this would be insufficient to accommodate the country's production targets for c.12mb/d oil production.

Figure 500: Iraq's main pipelines

Pipeline	Operator	From	To	Length (km)	Diameter (inches)	Capacity (kb/d)
ITP Kirkuk-Ceyhan (40")	IOM	Kirkuk	Ceyhan	986	40	1100
ITP Kirkuk-Ceyhan (46")	IOM	Kirkuk	Ceyhan	986	46	500
Strategic Pipeline SP-1	IOM	Fao	Al Basrah	52	48	800
Kirkuk (K1)-T2	IOM	Kirkuk	Tripoli	460	30	580

Source: Wood Mackenzie

The main pipelines that provide the potential capacity to supply the domestic market and to deliver crude for export are detailed above. In total Iraq has design pipeline capacity of some 9mb/d although actual usage is nowhere near this level. At present most of Iraq's oil is exported by sea through key ports Khor al Amaya (100kb/d) and Al Basra on the south coast near Basra. A major project was completed in 2007 to increase capacity at Al Basra, which now has design capacity of 3mb/d, albeit operating capacity remains at 1.7mb/d given the condition of the pumping equipment and pipeline infrastructure. Further investment is planned in new export terminals with a FEED contract awarded in 2009 to study increasing export capacity in southern Iraq to 5mb/d by 2014. The first phase of this project was completed in 2Q12 including new pipeline linking to two new Single Point Moorings, each with 900kb/d capacity. The second and third phases are both scheduled for end-2013.

Gas infrastructure within Iraq is limited, a factor that has contributed to the lack of progress to date in the development of gas reserves. The country has two gas plants; one in the north and one in the south. In late 2011, Basra Gas Company was established with Shell, Mitsubishi and Iraq's South Gas Company as partners to buy gas from the government and sell the processed gas to domestic markets. Besides this, there could be future prospects for LNG exports with FLNG potential suggested, although this should not be expected until beyond 2020.

Crude Oil Blends and Quality

Iraqi crudes vary greatly in quality with gravity ranging from 15˚ API to more than 40˚ API. Sulphur is also varied (0.1% to 4%). Under the terms of UN sanctions, Iraq exported only two blends in significant volumes, produced primarily in Kirkuk and Rumaila. However, since the lifting of the sanctions, Basra blend has been exported without restriction, and it is expected that exportation of further blends will increase as production gradually intensifies.

Figure 501: Main crude streams and loading points

Crude Oil	Loading Point	Gravity (°API)	Sulphur (%)
Basra Blend	Mina al-Bakr	34.4	2.10
Kirkuk	Ceyhan/Botas, Turkey	35.8	2.06

Source: Wood Mackenzie

Broad Fiscal Terms

Prior to the draft Federal Oil and gas law of 2007, Iraq's fiscal terms were characterised by two forms of contract: PSCs and DPC (Development and Production contracts). These have by and large been superseded by a range of Technical Service Contracts, which were awarded in the 2009 licensing round. Key features of these contracts include 1) the payment of a signature bonus (this ranged between $100mln and $500mln) although this is recoverable over 5 years with interest; 2) All capital and operating costs required to develop the field must be paid by the contractor albeit this is recoverable via the service fee; 3) The service fee includes the recovery of all costs incurred plus an agreed remuneration fee per bbl. Only 50% of the revenues generated from incremental production (i.e. gross production less baseline production at the start of the contract) are available in any one year to pay the service fee, with any excess entitlement simply carried forward until it is paid in full. The remuneration per barrel fee was a biddable item during the licensing round and it varies from $1.15/bbl to $2/bbl (though this will be adjusted according to project profitability). Finally, taxable income (which is the remuneration fee received) is subject to corporation tax of 35%. Perhaps most importantly, however, neither costs nor service fees are recoverable until a 10% increase in 'baseline' production has been achieved.

The Kurdistan region continues to operate under a separate R-factor type PSC fiscal regime. This incorporates royalty (10%), cost recovery and profit oil. The terms for cost recovery vary from as low as 36% in a low-risk field to almost 50% in a frontier development. Profit oil share due to the contractor varies as illustrated in the following table. There is a long, ongoing dispute between the Iraqi government and the regional government in Kurdistan as to the validity of these contracts; however, with no resolution in sight in the near term, companies operating in Kurdistan continue to operate under these PSC contracts.

Figure 502: Kurdistan PSC fiscal regime – cost recovery and profit oil

Model Regime	Cost Recovery	Profit oil to Contractor
Low Risk	36%	30%-13%
Medium Risk	39%	35%-15%
High Risk	41%	38%-16%
Frontier	50%	40%-20%

Source: Wood Mackenzie

Refining and Downstream markets

As with infrastructure, refineries have been subject to much sabotage over the years. Currently the sector has not been able to meet domestic demand for refined products like gasoline, kerosene and diesel, and at the start of 2007 the government liberalised the fuel import market to increase imports to meet local demand; however, domestic operating capacity remains insufficient to meet growing domestic demand.

At present total refining capacity at Iraq's 12 oil refineries is 772kb/d although effective capacity is nearer 500kb/d. The main refineries include Daura (185kb/d), Baiji (310kb/d) and Basrah (180kb/d). A plan unveiled by the Iraqi Oil Minister in June 2010 indicates that Iraq plans to become a large net exporter of oil products within five years. To achieve this, Iraq is inviting IOCs to build a total of four new refineries with total capacity of 750kb/d. We understand that there is a FEED process ongoing, but timing and participation are unclear at this stage.

LNG

At present Iraq has no LNG facilities. However, with the potential to significantly increase its gas reserves, Iraq will likely look to promote the viability of both LNG and GTL technology to provide the prospect of realising value from its significant gas resource base. In 2004, Shell announced that it had received approval from the Iraqi Oil Ministry to assist in the development of a gas master plan. In November 2011 Shell (44%) and Mitsubushi Corp (5%) formed a JV with Iraq's Southern Oil Company (51%) to establish the Basrah Gas Company (BGC). This will gather a growing c0.7bcf/d of gas from the Rumaila, Zubair and West Qurna 1 fields that is currently flared and seek to process it for use predominantly in Iraq as a source of energy for power but potentially in the future for export from a possible floating LNG facility. To achieve its objectives, significant infrastructure – not least pipelines, liquids stripping plant and power generation capacity – will need to be established.

Kuwait

Kuwait is one of the richest nations in the world on a per capita basis, due primarily to its significant accumulated oil wealth. With 2P reserves of 102bn bbls, it is the fourth-largest oil producer in the Middle East with oil revenues accounting for around 90-95% of total export earnings and around 40% of GDP. Current production is approximately 2.9mb/d, broadly consistent with sustainable production capacity. The government plans to increase production capacity to 4mb/d by 2020. Although international companies have not held production licenses in Kuwait since the industry was nationalised in 1975, in the late 90s the government offered certain re-development rights under 'Project Kuwait', but no contracts were awarded.

Basic geology and topology

Kuwait lies in the prolific Arabian basin, which contains some of the world's largest and richest oil and gas accumulations. Predominantly an oil province, the principal reservoirs in Kuwait comprise Cretaceous carbonates and sandstones, although oil has more recently been produced from Jurassic formations. The principal reservoir is the Cretaceous Burgan Sandstone, which has world-class permeability and contains the majority of Kuwait's giant oil fields. Source rock in Kuwait is Jurassic to Cretaceous in age, and fields are dominated by oil, with relatively low gas content. Major oil plays include Burgan, Minagish, Umm Gudair and the Northern Fields.

Regulation and History

Oil was first discovered in Kuwait in 1938 by the Kuwait Oil Company, a joint venture between the Anglo-Persian Oil Company (now BP) and Gulf Oil (now Chevron) with production starting in earnest following World War II. Nationalised in 1975, the State's constitution was amended to forbid any future foreign ownership of Kuwait's vast hydrocarbon resources. Since then, the only foreign participation has been in the Partitioned Zone and through service contracts, which have been signed with IOCs at various interjections to assist Kuwait rebuild its upstream infrastructure. IOC's including BP, Shell, and Chevron have maintained a presence in Kuwait through these service contracts. The partitioned or neutral zone is an area of land between Saudi Arabia and Kuwait with significant reserves (estimated at some 5 billion barrels), which are shared 50:50 between the two countries. Current production from this region net to Kuwait is c270kb/d. To date Kuwait has awarded licences under concession terms in the neutral zone only to Japanese-owned Arabian Oil Company (AOC) in the offshore and to Aminoil onshore. However, both companies were eventually replaced by KOC as operator.

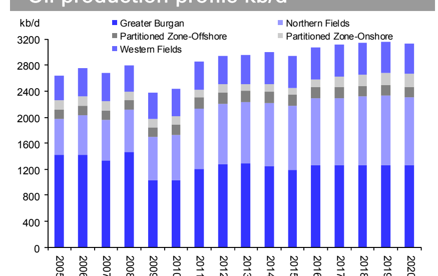
Oil and gas activities are primarily the responsibility of the Supreme Petroleum Council (SPC), which sets oil and gas strategy and oversees the operations of the Kuwait Petroleum Corporation (KPC). However, the state plays a direct role in the day-to-day activities of the hydrocarbon sector through the Minister of Oil, who is responsible for providing the legislation that governs the industry, in addition to being the chairman of KPC and sitting on the board of SPC. The issue of potential participation by foreign companies is a very contentious point – such that despite 'Project Kuwait' having been mooted in the late 90s (and three bidding consortia approved in 2003), no further progress has been made.

Key facts

Oil production 2012E	2.9mb/d
Gas production 2012E	0.2mboe/d
Oil reserves 2012E	101.5bn bbls
Gas reserve 2012E	63TCF
Reserve life (oil)	95 years
Reserve life (gas)	166 years
GDP 2012E	$174.6bn
GDP Growth 2012E (%)	6.3%
Population (m)	3.8m
Oil consumption 2011 (b/d)	436kb/d
Oil exports 2011 (mb/d)	1.8mb/d
Fiscal regime	OSA, Royalty, IT
Marginal tax rate	55%
Top 3 Oil fields (2012E)	
Greater Burgan	1,282kb/d
Northern Fields	929kb/d
Western Fields	439kb/d
Top Producer (2012E)	
KOC	2.9mb/d

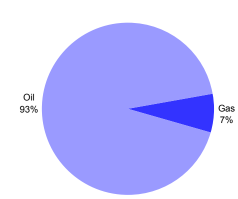
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



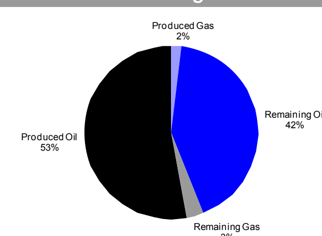
Source: Wood Mackenzie

Remaining reserves split %



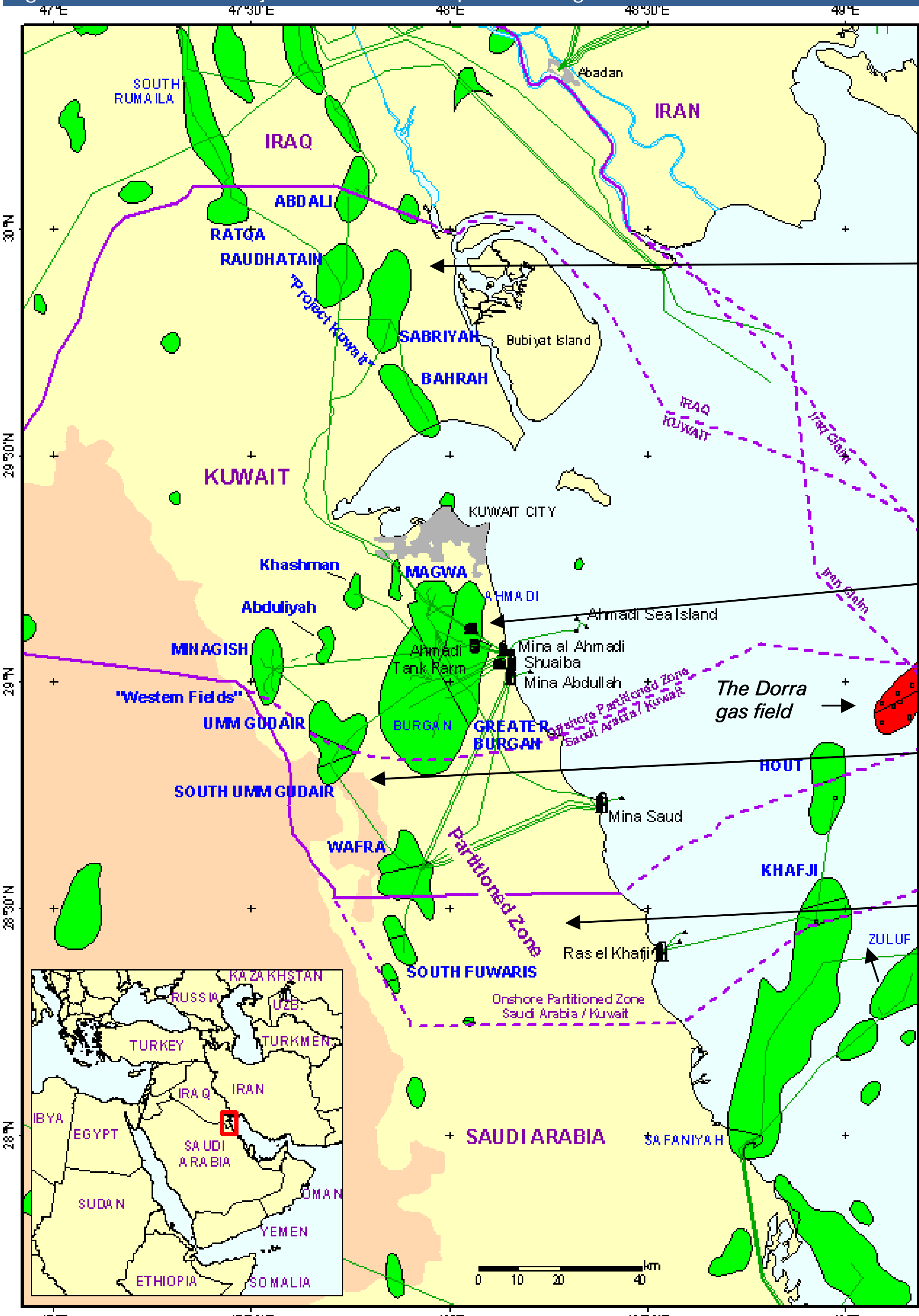
Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Figure 503: Kuwait – major oil fields and export/refining facilities



Source: Wood Mackenzie; Deutsche Bank

Licensing

The possibility of lifting the ongoing ban on awarding foreign companies upstream licences was mooted under the proposed 'Project Kuwait'. Under this structure, first proposed in 1997, licenses could be awarded for the Northern Fields with the objective of lifting production. However, this proposal was never ratified by Parliament and as a result no contracts have been awarded.

The intention of 'Project Kuwait' was to offer 25-year licenses to increase both the country's reserves and production capacity with the help of IOCs, via 'Operating Service Agreements' (OSA). Unlike PSA's, the structure of OSA agreements would allow the Kuwaiti government to retain full ownership of oil reserves, control over oil production levels, and strategic management of the ventures. Foreign firms would be paid a "per barrel" fee, along with allowances for capital recovery and incentive fees for increasing reserves, in their role as service provider/contractor.

There were three major consortia competing for projects: **Chevron** (along with Total, Sibneft and Sinopec); **ExxonMobil** (along with Shell, ConocoPhillips, and Maersk); and **BP** (along with Occidental, ONGC/Indian Oil Corp.).

Legislation facilitating Project Kuwait was introduced in early 2005 and approved by the Finance and Economic Committee, but with amendments limiting its scope to four of the five original fields (Bahra was excluded). Final action on the bill by the full parliament is still pending and is subject to much political opposition. Parliamentary approval for Project Kuwait has not been helped by suggestions that current reserve estimates may be materially overstated (see section on reserves). This has fuelled opposition MPs to call for production to be kept within 1% of official reserve estimates to ensure that oil is available for future generations. Even taking the c.100bn/barrel figure, the 1% limit would restrict Kuwait's production to less than 3mb/d, increasing the difficulty of efforts to pass the Project Kuwait legislation.

Production of Oil and Gas

Kuwait was one of the founding members of OPEC and remains a leading producer today. However, growth in global demand, coupled with supply constraints in other countries, has meant that Kuwait has produced above its official level for the last few years. Oil production in 2011 was 2.9mb/d (including liquids) and gas 0.2mboe/d, making Kuwait the 9th largest producer of oil in the world. Output is split equally between shallow wells and high-pressure wells. Key commercial fields include:

Figure 504: Key commercial oil fields

Field	Recoverable Reserves (mbbl)	Remaining Reserves (mbbl)	Start-Up year	Production 2012 (kb/d)	Production 2015 (kb/d)	Production 2020 kb/d
Greater Burgan	45,679	15,226	1946	1,282	1,186	1,257
Northern Fields	16,534	11,744	1960	929	989	1,054
Offshore PNZ	3,693	1,179	1961	174	168	157
Onshore PNZ	2,609	976	1954	118	112	202
Western Fields	6,133	3,511	1961	439	491	465

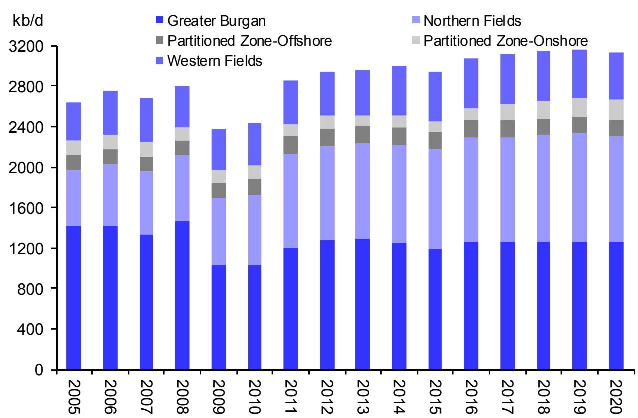
*Source: Wood Mackenzie * PNZ is the Partitioned Neutral Zone*

Unlike many other OPEC members, Kuwait's production history has been relatively stable. Kuwait is generally considered a voice of "moderation and stability in production policy" in OPEC, and applies the same principles at home (as demonstrated in its production targets detailed below). Production has only ever been disrupted due to external causes including Iraq's invasion in 1990 and an explosion at Raudhatain oil field in 2002, which destroyed two gathering centres. Each time, Kuwait has acted quickly to repair the damage to infrastructure and reinstate production levels. Furthermore the country is intent on stabilising both production and reserves to sustain the industry for future generations. The stated production targets of the country designed to achieve sustainable production levels include:

- Increase production from fields outside the Greater Burgan area to reduce demand on this field and preserve its long-term capacity;

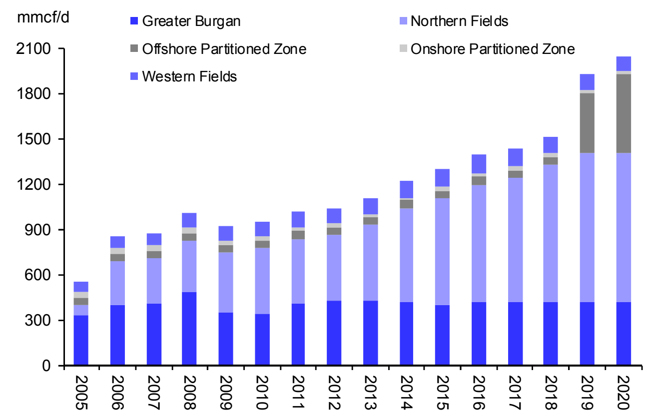
- Achieve total production capacity of 4.0 million b/d by 2020 and develop 15% spare capacity above expected demand;
- Replace production and add 8 billion barrels of incremental reserves by utilisation of modern technology to enhance oil recovery;
- Develop the expertise within KOC to deal with the more sophisticated reservoir management challenges expected in the future.

Figure 505: Kuwait oil production 2005-20E (kb/d)



Source: Wood Mackenzie

Figure 506: Kuwait gas production 2005-20E (mmcf/d)



Source: Wood Mackenzie

Historically, Kuwait has relied heavily on the super-giant Burgan field for the majority of its production capacity. However, since the end of the Gulf War, Kuwait has aimed to reduce this reliance and to manage production in such a way as to maximise future production. Current government plans suggest Burgan will be used as a swing producer to meet the country's needs and commitments. Key to this strategy is the development of the Northern Fields (Raudhatain, Sabriyah, Bahrah, Ratqa and Abdali) through Project Kuwait (as detailed above). The development of the Northern Fields is planned to be via OSA; however, the long and protracted discussions regarding the terms of the OSA have led to recurring delays in the tender process. If the Northern Fields eventually are successfully developed, the Kuwaiti government may choose to seek further international investment in the western fields to the same effect.

Gas production in Kuwait is associated with oil production. Consequently, Kuwait has little scope for major increases in its gas production. However, large-scale non-associated gas was discovered at Umm Niqa and in deeper reservoirs under Raudhatain, Sabriya, Bahrah and Dhabi in the Northern Fields, with reserves estimated to be near 35TCF. As part of the Northern Gas Project, KPC aims to achieve c.1,000mmcf/d through three separate production and processing plants. Phase 1 came onstream in 2008 with capacity of 175mmcf/d, although actual production has been reported to be well below this level, calling into question the aspiration of achieving 1,000mmcf/d by 2015.

Reserves and Resources

Kuwait ranks sixth in the world in terms of its oil reserves. Total estimated oil reserves in 2011 were 102bn/bbls according to EIA and BP Statistical Survey 2012. Kuwait has several super-giant fields including Greater Burgan, Raudhatain, Sabriya and Minagish all of which contain large remaining volumes of incremental recoverable oil for which no firm development plans exist. The reserve base is dominated by Greater Burgan, which accounts for an estimated 47% of Kuwait's total oil reserves.

In 2006, the published level of reserves came into question, following a leaked memo from the KOC which stated that reserves actually stood at approximately half the declared level. Kuwait has signalled its intent to defend its stated reserve level; however, if the lower figure is confirmed, reserve life would drop from 95 years to c.45 years. This would further decrease (to approx 30 years) were production levels increased to the government's 4mb/d target.

Given the majority of Kuwait's oil fields have been producing for more than 60 years, field maturity is becoming an issue. One aspect of Project Kuwait would be to gain access to expertise in Enhanced Oil Recovery (EOR) techniques. Agreements to assist in developing EOR have already been reached with Chevron, ExxonMobil and Japan National Oil Corporation (JNOC).

Kuwait's total gas reserves are estimated at c.63TCF, the majority of which was associated gas until the discovery of Umm Niqa (35tcf) in 2005. Until this discovery the Dorra field (7tcf), located in the offshore Partitioned Zone, was Kuwait's only significant non-associated gas field. Due to the field's location, close to the disputed border between Iran and the Partitioned Zone, the Dorra field has yet to be developed.

Pipelines and Infrastructure

Given Kuwait's long history of oil production and exports, the country correspondingly has an established, if somewhat aging, network of oil and gas pipeline infrastructure that links the country's oil fields to its refineries and export terminals. Most of Kuwait's onshore oil is gathered from individual wellheads and transferred directly to one of the dedicated gathering centres. It is then piped to the Central Mixing Manifold (CMM) for blending at the Burgan field, prior to transfer to the Ahmadi tank farms. Significant portions of Kuwait's infrastructure were damaged during the Gulf War and again following a major explosion at the Raudhatain field. This damage was quickly repaired and capacity reinstated to normal levels.

Kuwait's position on the western coast of the Arabian Gulf means that export of crude oil to world markets is relatively easy. Kuwait has four export terminals, all located on the Arabian Gulf coast. The main export terminal is centred around Mina al-Ahmadi (2.7mb/d) which exports both crude and refined products. Shuaiba (733kb/d) and Mina Abdallah (1.5mb/d) and Mina al Zour (1.0mb/d) are also significant export terminals.

Prior to the development of the first LPG plant at Ahmadi in the late 1970's, the majority of Kuwait's gas production was flared. Today, however, Kuwait's associated gas is collected via a network of pipelines and processing facilities. Gas is separated from oil at the gathering centres situated across the major fields and then piped to LPG plants situated at Ahmadi and Shuaiba. The offshore Partitioned Zone produces large volumes of gas (capacity of 300mmcf/d) which is then piped to offshore facilities at Khafji and Hout and then to Mina Saud. The bulk of Kuwait's LPG production is exported to the Asian market

Crude Oil Blends and Quality

Kuwait's crudes are generally of low to medium gravity (19-35° API) with moderate to high sulphur content (1-4%). The plans to increase production by developing the Northern Fields, which contain significant volumes of heavy crude, could see the characteristics of Kuwaiti crude change in coming years. With this in mind, Kuwait Oil Company (KOC) has sought to upgrade almost 80% of its oil production facilities in the southeast to be able to handle sour crude.

Figure 507: Main crude streams and loading points

Crude Oil	Loading Point	Gravity (°API)	Sulphur (%)
Kuwait Blend	Mina al Ahmadj	32.4	2.55
Khafji (PNZ)	Ras al Khafji	28.5	2.85
Walfra (PNZ)	Mina Saud	24.2	4.00

Source: Wood Mackenzie

Broad Fiscal Terms

Since the Gulf War, foreign companies have operated in Kuwait under service agreements with KOC. These contracts have taken the form of straight payment for services provided. The proposed OSA contracts are expected to have the following fiscal characteristics, although these are of course subject to change pending any final decision on Project Kuwait:

- State participation has not been specified, but it is expected that the state will not take an equity position.
- No royalty was levied under the terms of the model OSA
- Two fees per barrel will be paid on field production – an 'old' fee will be paid based on the agreed production profile and a 'new' fee paid on anything above this agreed base line. Both the old fee and the new fee are expected to be biddable items in the OSA.
- The IOC consortium will be responsible for funding 100% of capex; however revenues remaining after the payment of production fees are available to the contractor to recover capital and operating costs. Cost recovery will not be subject to an amortisation schedule as the IOC will have no legal title to the assets.
- Any remaining IOC revenue is subject to income tax, which although generally 55%, may be revised down to 25% under the terms of the OSA.

Refining and Downstream markets

Kuwait National Petroleum Company (KNPC) is responsible for all refining and gas processing activities in Kuwait and operates all three of Kuwait's refineries. These refineries have a total operating capacity of around 930kb/d and are all situated in the south east of Kuwait.

Figure 508: Kuwait Refining capacity

Operator	Refinery	CDU Capacity (kb/d)
Kuwait National Pet Co (KNPC)	Al Shuaiba	215
Kuwait National Pet Co (KNPC)	Mina Abdullah	275
Kuwait National Pet Co (KNPC)	Mina Al Ahmadi	440

Source: Wood Mackenzie

Kuwait has outlined plans to construct a 615kb/d oil refinery at Al Zour. The plant has been designed so that it can produce up to 330kb/d of low sulphur fuel oil for thermal power generation. The Al Zour project may see contracts awarded in 2013 with the intention of beginning production around 2018. The aging Shuaiba refinery will be decommissioned on completion of the project bringing total refining capacity in Kuwait to 1.2mb/d. We note that Al Zour was originally mooted in 2007, but was cancelled in 2009 in the wake of the financial crisis only to be re-approved in 2011.

LNG

With much of Kuwait's gas reserves associated with oil fields, Kuwait depends on imported gas to meet the country's demand. Kuwait (through KPC) has, since 2009, received LNG cargos via a regasification vessel at Mina al Ahmadi with a peak capacity of 600mmcf/d.

Libya

Libyan crude oil production had, for much of the past 20 years, fluctuated within a 1.5-1.7mb/d range. But with the 2011 civil war leading to the temporary abandonment of production facilities and associated infrastructure and an exodus of foreign workers, production briefly slumped to sub-100kb/d and the FY11 average to c400kb/d. However, with the Gaddafi regime ousted, production levels rapidly recovered during the latter stages of 2011 and through early-2012 to something close to pre-conflict levels. With elections to a transitional General National Congress held in July 2012 and an interim PM selected in Octover 2012, the political focus in now on drafting a new constitution ahead of a proposed referendum and then elections later in 2013. During this ongoing period of transition toward a democratically elected government, the key posts of both Oil Minister and head of the Libyan NOC are filled, but this is clearly a time of uncertainty for the oil industry. Operationally we expect production to continue to inch back to pre-civil war levels, albeit with an element of unreliability, not least due to ongoing security concerns. Strategically the hope must be that the country becomes open to much greater inward investment and new growth opportunities, and we note that the Oil Ministry has unveiled a 2mb/d 2015 target. The industry will remain a priority for the government, not least because it accounts for >90% of export earnings and c25% of GDP. However, we do not expect real clarity on the future structure of the industry in Libya (i.e. contract terms, governing institutions, etc.) until after elections are held. Libya has a disclosed 47 billion barrels of proven oil reserves, making it the largest in Africa. Key IOCs operating in Libya include Eni, ConocoPhillips, Total and Repsol. BP among others has positioned in frontier exploration acreage.

Basic geology and topology

Libya comprises five large distinct basins: Sirte, Ghadames, Murzuk, Kufra and the offshore Pelagian Shelf. Sirte is the most significant in terms of hydrocarbon discoveries and production, containing c.80% of the country's total reserves and accounting for 65% of total production. However, while each basin is believed to contain significant reserves, all are under-explored relative to onshore Sirte, particularly the Kufra basin due to its remoteness from infrastructure and markets. Reservoir rocks are primarily late Cretaceous in age and it is generally thought that oil generation commenced in the Middle Eocene era, coming to a halt in the late Oligocene.

Regulation and History

From regaining its independence from Italy in 1951 until his fall in 2011, Libya was governed by Colonel Gaddafi and his 'green book', which combined socialist and Islamist theories and rejected parliamentary democracy and political parties. In theory, the General People's Congress (GPC) was established by Qaddafi to serve as an intermediary between the populace and the leadership of the country. However, in reality Qaddafi exercised the real and only authority. This authoritarian reign saw Libya 'expelled' from the international investment community following accusations of international terrorism, with the US Government in 1986 ordering US companies including Occidental and the Oasis Partnership (Conoco, Marathon and Hess) to exit Libya. Rehabilitation in 2003-04 saw sanctions lifted, US companies return, four new licensing rounds held and crude production increase from c1.4mb/d toward 1.7mb/d.

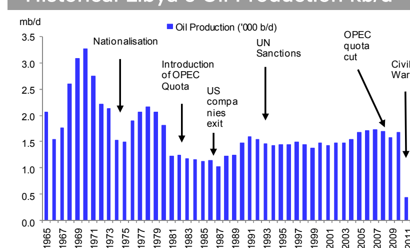
The 2011 civil war saw the Gaddafi regime ousted. Initially a 'National Transition Council' assumed power until this was replaced by the elected General National congress in mid-2012. Having selected a Prime Minster and Government, an important part of the remit of this interim body is to draft a new constitution to be approved by a referendum during 2013. New elections will then be held, likely in 2H13.

Key facts

Liquids production 2012E	1.5mb/d
Gas production 2012E	0.2mboe/d
Oil reserves 2012E	47.1bn bbls
Gas reserve 2012E	53 TCF
Reserve life (oil)	89 years
Reserve life (gas)	119 years
GDP 2012E	$85.1bn
GDP Growth 2012E (%)	NM
Population (m) (July 2012E)	6.6m
Oil consumption (2010E)	270kb/d
Oil exports (2010E)	1.5mb/d
Fiscal regime	PSC/concession
Marginal tax rate	78.5%
Top 3 oil fields (2012E)	
Agoco	297kb/d
Waha	268kb/d
El Sharara	200kb/dd
Top 3 Producers (2012E) – Entitlement	
NOC	648kboe/d
Eni	134kboe/d
Marathon	45kboe/d

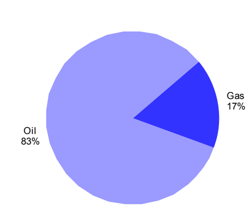
Source: Wood Mackenzie, EIA, IMF

Historical Libya's Oil Production kb/d



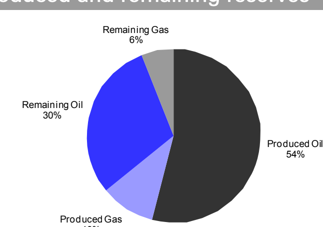
Source: Wood Mackenzie data

Remaining reserves split oil & gas %



Source: Wood Mackenzie data

Produced and remaining reserves

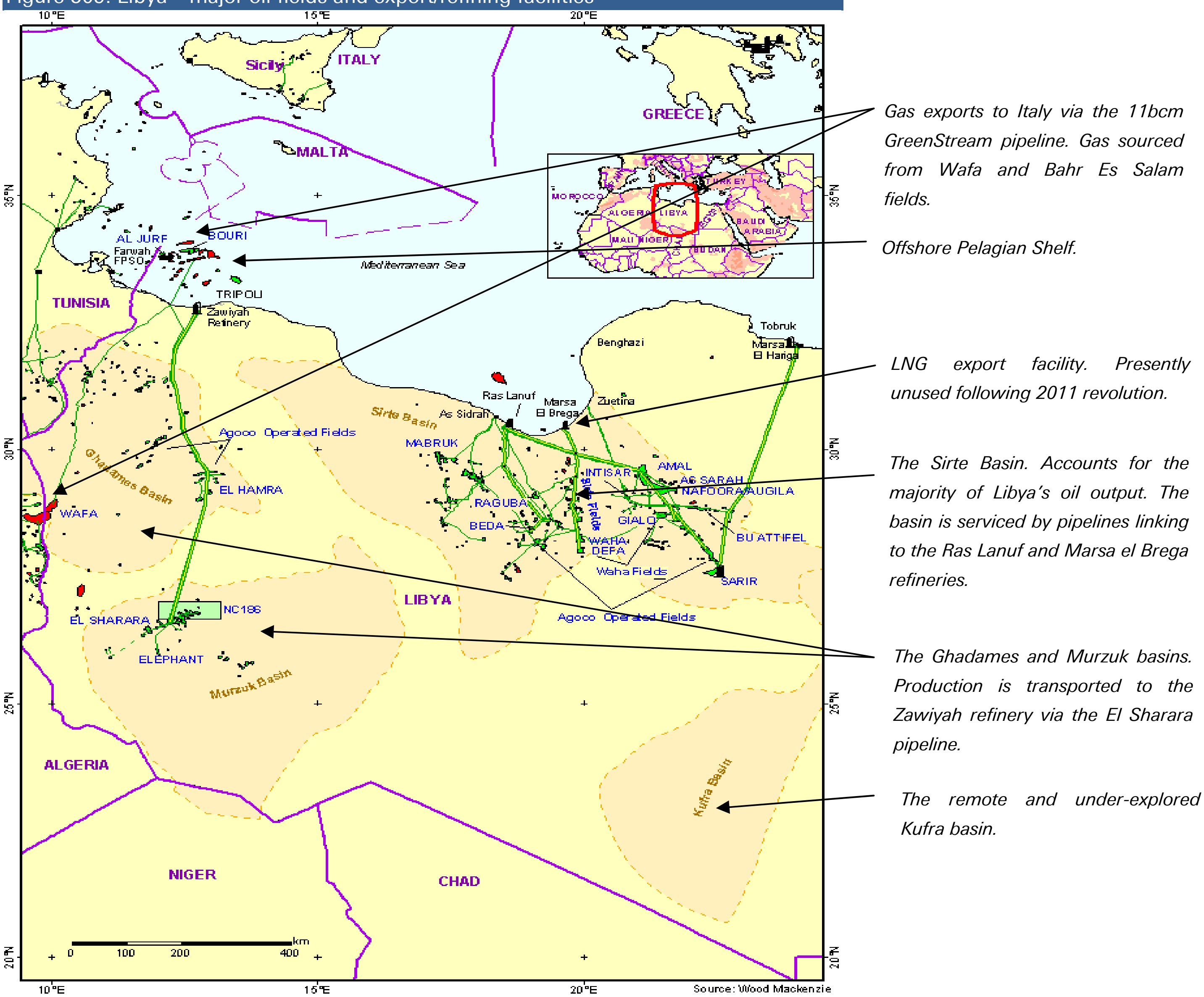


Source: Wood Mackenzie data

The Western fields

Libya's national oil company (NOC) has been the primary player in the country's hydrocarbon industry since nationalisation in 1974. NOC operates Libya's major oil and gas fields through its smaller subsidiaries Agoco, Waha and Sirte oil, which together account for over 60% of total Libyan oil production. Since 2006, NOC has also been responsible for all licensing, fiscal terms and negotiations with the IOCs regarding contracts. This follows years of frequent changes in 'who' actually holds responsibility for the regulation of the country's hydrocarbon industry. Over the years, the baton has passed from the Petroleum Commission to the Ministry of Petroleum to the Secretariat of Petroleum. However, the removal of the Energy Minister in 2006 saw NOC assume the role. Following the revolution, a new Oil Minister and NOC Chairman have been appointed. It remains to be seen to what extent the structure of the industry, its governing institutions and regulation/terms will alter following the proposed agreement of a constitution and new elections.

Figure 509: Libya – major oil fields and export/refining facilities



Source: Wood Mackenzie

Licensing

Libya has been awarding licences to the international oil community since 1955. Initially licenses were awarded under a concession (tax and royalty) regime; however, following the 1969 revolution Libya effectively nationalised the oil industry and, from 1974, put in place Exploration and Production Sharing Agreements (EPSAs). Licences are no longer awarded under the concessions regime and Libya has gradually converted concessions to the terms of EPSA either as they expire or via negotiation. EPSAs have terms lasting 30-35 years, including an initial period of 5 years of exploration where the contractor bears 100% of exploration costs, after which if no commercial hydrocarbons are found, the contract will be terminated. The terms of the EPSAs have been amended four times since their introduction, the latest being EPSA IV which was introduced in 2004-5 (see fiscal section for details of the terms of EPSA IV).

Following the lifting of sanctions, licensing in Libya recommenced in earnest in 2005. Four licensing rounds under the EPSA IV terms have been held. The most recent in December 2007 was the first to focus on natural gas assets. Separate agreements have also been reached with the super-majors Shell and BP, with a focus on exploration. Importantly, the first two rounds generated very high levels of interest and saw companies outbid one another, resulting in extremely high levels of production (up to 93%) going to NOC before any costs or remuneration can be recovered by the contractor (under EPSA IV contracts NOC participation is a biddable factor). More recent licensing rounds have also been characterised by high non-recoverable signature bonuses, high spending and an increased focus on the number of wells or seismic each company commits to drill/perform.

Following the 2011 revolution it is unclear when the next licensing round may be conducted, how the process will be managed and what terms may be on offer. However, subject to terms we would anticipate a high level of interest from international oil companies.

Production of Oil and Gas

Libya, a member of OPEC since 1962, is one of the largest oil producers in Africa after Nigeria, Angola and Algeria. And, despite recovering from the impact of the 2011 revolution, 2012 liquids production averaged c.1.5mb/d – just 0.3mb/d shy of 2010 levels. Placing Libya's liquids production into an historical context, we note that from a peak of 3.3mb/d in 1970, the combination of a lack of foreign investment, poor management and sanctions pushed volumes down to little over 1mb/d through the majority of the 1980s. Production improved a little in 1990s to average around 1.4mb/d, but it has only been in recent years since the lifting of sanctions (2004) and new EPSA IV license rounds that volumes have begun to show any meaningful improvement.

Libya's liquids production is dominated by the Sirte basin (65% in 2012), which has been producing since 1961, and the Murzuq basin (25% in 2012). From a company perspective, production is dominated by NOC, although on an entitlement basis Eni (c80kb/d in 2012), Total (c40kb/d in 2012), Repsol (c35kb/d in 2012), Occidental (10kb/d in 2012) and, by virtue of a 16.33% interest each in the Waha Oil company, ConocoPhillips (c45kb/d in 2012) and Marathon (c45kb/d in 2012) have a notable presence in the country.

As already noted, Libya's interim administration has indication an aspiration of growing production to 2mb/d by 2015. A key medium-term focus is likely to be focusing on exploration outside of the more mature onshore Sirte basin.

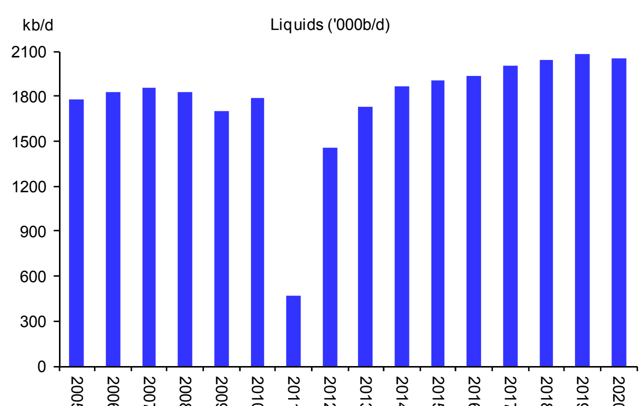
Figure 510: Key commercial oil fields

Field	Recoverable Reserves (mbbl)	Remaining Reserves (mbbl)	Start-up	Production 2012 (kb/d)	Production 2015 (kb/d)	Production 2020 kb/d
Agoco	9536	3572	1963	297	367	404
Waha	13029	4480	1962	268	343	469
El Sharara	1657	793	1996	200	200	107
NC186	712	528	2003	101	134	81
Elephant	660	417	2004	92	110	54
EPSA Area B	2227	349	1972	88	83	45
Sirte	4800	1087	1961	74	106	111
EPSA Area D (WLGP)	866	660	2004	70	78	78
Bouri	921	435	1988	45	65	72

Source: Wood Mackensie

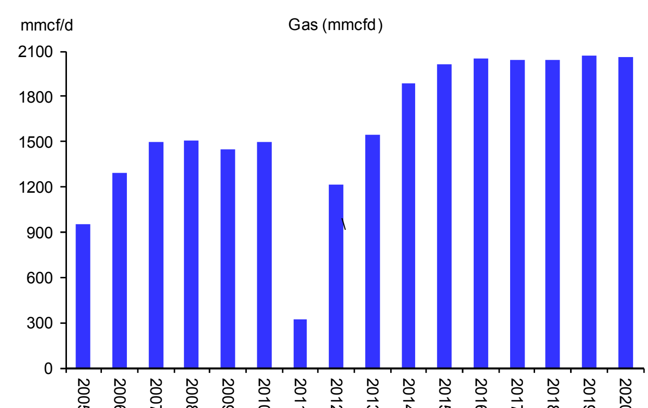
Gas production has grown substantially since 2000 to a level approaching 1.5bcf/d. Central to this growth has been the Western Libyan Gas Project (WLGP), a 50/50 joint venture between Eni and NOC. The fields supporting this project produce c1bcf/d, of which c.0.8bcf/d is exported to Italy via the 11bcm Greenstream pipeline. Domestic demand has also been increasing, and satisfying this is a high-priority for the country. Given a disclosed reserve base of 53TCF, the long-term potential to support rising domestic demand and increased exports would seem to exist, albeit there are no firm plans at present.

Figure 511: Libya - Oil production 2005-20E (kb/d)



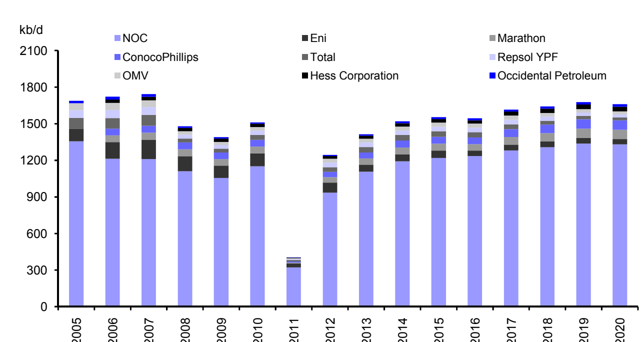
Source: Wood Mackenzie

Figure 512: Libya - Gas production 2005-20E (mmcf/d)



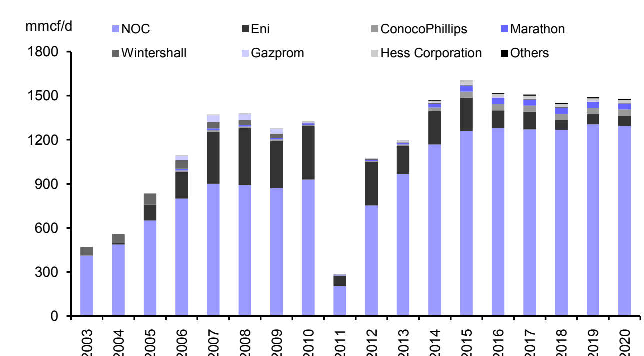
Source: Wood Mackenzie

Figure 513: Libya –Oil production by company 2005-20E



Source: Wood Mackenzie

Figure 514: Libya –Gas production by company 2005-20E



Source: Wood Mackenzieie

Reserves and Resources

With estimated oil reserves of c.47.1billion barrels, Libya holds the largest proven oil reserves in Africa. More than 78% of proved reserves are located in the Sirte basin, with the balance being shared equally between the remaining basins. The country remains relatively under-explored with only 25% of acreage covered by exploration agreements with oil companies. The post-sanction re-opening from 2004 led to a flurry of interest from the international oil community, and whilst the near-term outlook is somewhat uncertain following the revolution, meaningful potential to grow the resource base via exploration would seem to exist. As to gas, an estimated 53TCF of reserves make Libya the fourth-largest holder of gas in Africa.

Pipelines and Infrastructure

Libya has a well established pipeline transportation system which connects the bulk of its oil production, situated in the Sirte basin, to refineries and export terminals on its Mediterranean coastline. These include pipes to the Marsa El Hariga terminal and the Tobruk refinery and to the Zueitina and Ras Lanuf terminals. Further pipelines link the Murzak and Ghadames basins to the Zawiyah terminal and refinery near Tripoli. However, following years of sanctions, Libya's infrastructure is in need of significant maintenance and upgrading in order to retain the integrity of existing systems.

As with oil, Libya's gas infrastructure is also well established. Pipelines, which are primarily operated by NOC and its subsidiaries, bring gas to the main power plant and to the LNG plant at Marsa El Brega. Operated by ENI, Libya also exports gas to mainland Europe via the 11bcm GreenStream pipeline which runs from Mellitah to Sicily and represents the export link of ENI's West Libya Gas Project (which connects the NC41 and Wafa gas fields to the Mellitah processing plant). The NOC has previously expressed ambition to significantly improve the gas infrastructure.

Figure 515: Libya – Key domestic oil pipelines

Pipeline	Operator	Length km	Capacity kb/d	Utilisation %
Intisar A-Zueitina	Occidental	220	1000	15
Dahra-As Sidrah	Waha Oil Company	138	823	20
Nasser-Brega	Sirte Oil Company	171	805	20
Sarir-Marsa El Hariga	Agoco	509	505	50
Amal-Ras Lanuf	Agoco	273	420	25

Source: Wood Mackenzie

Crude Oil Blends and Quality

Libya's crudes are generally of high quality, being predominantly light (26-43° API) and sweet (0-2%). The Bouri blend is the heaviest and sourest with an API of 26.3° and 1.91% sulphur content. In total, almost 60% of current production is light and sweet and Wood Mackenzie forecast this to increase to 75% by 2020. The country exports nine different blends, the main ones being:

Figure 516: Main crude streams and loading points

Crude Oil	Loading Point	Gravity (°API)	Sulphur (%)
Zueitina	Zueitina	41.5	0.31
Es Sider	Es Sider	36.3	0.44
El Sharara	Zawiyah terminal	43.1	0.07

Source: Wood Mackenzie

The lighter, sweeter grades are generally sold to Europe, with the heavier crudes often being exported to Asian markets. The majority of Libyan oil is sold on a term basis to various companies, including major European IOCs and refiners.

Broad Fiscal Terms

While a small number of Libya's oldest producing assets continue to operate under vintage concession terms, the majority of recent discoveries are governed by Exploration and Production Sharing Agreements (EPSAs).

- **Concessions:** Under all concession agreements the NOC is the majority stakeholder with 51% in the license. Concessions do not involve payment of any signature bonus and are subject to royalty and other production taxes. Royalty is typically 16.67% of the value of the recovered crude and is a deductible operating expense for tax purposes. The corporate tax rate for concessions is not fixed and will vary depending on the level of profitability. In simple terms, tax is the residual so as to give the contractor a guaranteed remuneration of 6.5% of gross revenues. From 2007, the former government was re-negotiating concession contracts to bring them in line with EPSA IV.
- **PSAs:** Libya's EPSAs are fundamentally different in structure to other PSAs in that the government takes a large share of production 'off the top'. The percentage of production the contractor seeks in order to recover costs and for remuneration (the production allocation) is the primary biddable parameter in the award of EPSA IV licenses. The subsequent profit-oil split is determined by NOC for each licence and will depend typically on production rates and the payback ratio. High levels of competition in the first EPSA IV round resulted in IOC production shares of 10-20%, which dropped as low as 7% in the second licensing round i.e. NOC receives 93% of production before any contractor costs (or remuneration) can be recovered, implying the contractor is unlikely to recover its costs for many years. In addition to the signature bonus and cost elements discussed above, EPSA IV also features production bonuses of USD1m upon first production, USD5m once 100mboe have been produced and USD3m for each additional 30mboe thereafter.
- As noted, under the former government there was a migration of concession contracts (and indeed older EPSA contracts) toward EPSAIV terms. This process was linked with license extensions. For instance, in 2007 Occidental renewed a soon-to-expire licence on terms which, whilst less favourable, included a 30-year licence extension. Likewise, in 2008, Eni migrated six contracts to less-favourable EPSA IV terms, but extended rights until 2042.
- The possible structure of any new licenses that may be awarded in the future under the post-Gaddafi legislature is, at this point, uncertain.

Refining and Downstream markets

Libya has five domestic refineries with a total capacity of around 380kb/d. The plants are well utilised and, with output of c360kb/d, produce broadly thrice the level of product that is required by the domestic market leaving scope for exports:

Figure 517: Main Libyan refining capacity

Operator	Refinery	CDU Capacity
NOC	Ras Lanuf	220kb/d
NOC	Zawiyah	120kb/d
NOC	Tobruk	20kb/d

Source: Wood Mackenzie

Under US sanctions, Libya was unable to import refinery equipment, hence subsequent to sanctions being lifted a programme of upgrading the capacity was commenced. Prior to the fall of the Gaddafi regime there were plans to expand the capabilities of the three main refineries (Ras Lanuf, Zawiyah and Tobruk) and to construct a new refinery at Sebha. It now is unclear how Libya's downstream investment plans will evolve. Libya's former interest in Tamoil, with its 3000 service stations across Europe was sold to a venture capital fund for $5.4bn in 2007.

LNG

In 1970 Libya became the third country to export LNG following the construction of the 3.2mtpa Marsa El Brega facility. However, gas supply constraints together with technical limitations saw production substantially reduced. In 2005 NOC concluded a deal with Shell to redevelop the facility with exploration and development of the feedstock from five blocks in Sirte Basin. Following the civil war, the plant is no longer operational and the future of any rejuvenation project is unclear.

Libya - Notes

Nigeria

Often referred to as 'Africa's slumbering giant', Nigeria has been plagued for decades by widespread corruption, kidnappings, murders, pipeline sabotage, prolonged protests, refinery explosions, all inflicted by a few dissident groups. A member of OPEC since 1971, Nigeria should have gained significantly from its related oil & gas wealth. Yet, with over $400bn of government income squandered or stolen since independence from Britain in 1960, over 85% of the population continues to live on under $2/day. Little surprise the populace should often violently voice its dissatisfaction, especially in key oil-producing regions. Efforts are being made to incentivise greater national participation in the industry and to better distribute Nigeria's wealth. A long-mooted Petroleum Industry Bill (PIB), now five years in the making, is intended to overhaul industry regulation, taxation and structure. However, progress remains frustratingly slow, with the resulting uncertainty deterring IOC investment. Consequently, despite reserves of 37 bn bbls and 180Tcf of gas suggesting the potential for strong production growth, the outlook is flat at best. Nevertheless, even with its current problems, Nigeria is the largest oil producer in Africa, accounting for approximately 3% of global crude supplies. Major IOCs include Exxon, Shell, Chevron, Total and Eni.

Basic geology and topology

While there are a number of hydrocarbon basins in Nigeria, the Niger Delta located in the south of the country is by far the most prolific and important. Approximately 85% of Nigeria's remaining commercial reserves are located either onshore or in the shelf areas of the Niger Delta, while the remaining reserves are in the offshore deepwater. The delta contains numerous fields of varying degrees of importance, including a high number of undeveloped marginal fields, which to date have not proved economically interesting. Nigeria's reserves comprise source rocks that are principally Cretaceous to Miocene in age, and these yield a light, waxy, paraffinic crude.

Regulation and History

Similar to most of its OPEC compatriots, Nigeria's oil industry was nationalised in the 1970's, a move cemented upon creation of the Nigerian National Petroleum Corporation (NNPC). However, in contrast to other OPEC nations, Nigeria remained open to foreign investment, and today the majority (95%) of its major oil and gas projects are funded through JVs with IOCs where NNPC is the major shareholder. The remaining contracts are PSCs, again with the oil majors, which are confined to deepwater projects.

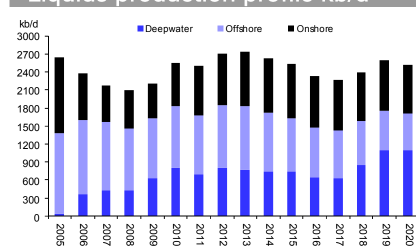
Nigeria's security and political problems stem primarily from tensions between Nigeria's many different ethnicities (over 250 ethnic groups comprise its population of 165m) and between federal and state governments. The dominance of the Muslim population in the north together with its control of the military has meant that it was this population that set the political agenda, effectively ruling over the oil-rich but ethnically divided Christian south. The emerging tensions, most particularly in the oil-rich Niger Delta, have led to high levels of corruption as one group tries to forcefully gain power over another and more importantly lay claim to the country's natural resources. Through the Movement for the Emancipation of the Niger Delta (MEND) the Ijaw group in particular is known for pursuing a violent agenda in an attempt to declare the Niger Delta a Republic and gain control over its oil reserves (and undoubtedly the vast wealth that goes with it). Since November 2009, a fragile ceasefire has been in place on government promises that local companies will have greater control over natural resources. Disruptions are, however, a regular occurrence with the illegal tapping of pipelines or 'bunkering' accounting for towards 200kb/d of the country's production.

Key facts

Oil production 2012E	2.3mb/d
Gas production 2012E	0.7mboe/d
Oil reserves 2012E	37bn bbls
Gas reserves 2012E	181TCF
Reserve life (oil)	44years
Reserve life (gas)	117years
GDP 2012 ($bn)	$273bn
GDP growth 2012 (%)	7.1%
Population 2012 (m)	165m
Oil consumption 2011E (b/d)	286kb/d
Oil exports 2011E (mb/d)	2.3mb/d
Fiscal regime	PSC, JV Concession
Marginal tax rate	66%-85%
Top 3 Oil fields (2012E)	
OML 67	239kb/d
OML 130 (Akpo, Egina & Preowei)	175kb/d
OML 127 (Agbami-Ekoli)	159kb/d
Top Producers (2012E)	
NNPC	1001kb/d
Exxon	267kb/d
Chevron	245kb/d

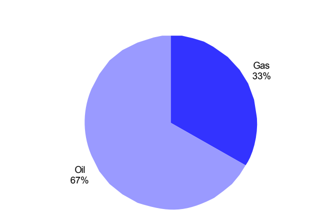
Source: Wood Mackenzie, EIA, IMF

Liquids production profile kb/d



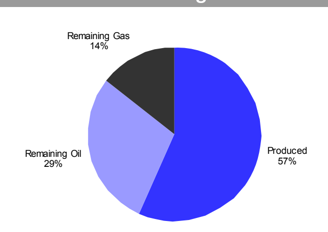
Source: Wood Mackenzie

Remaining reserves split %



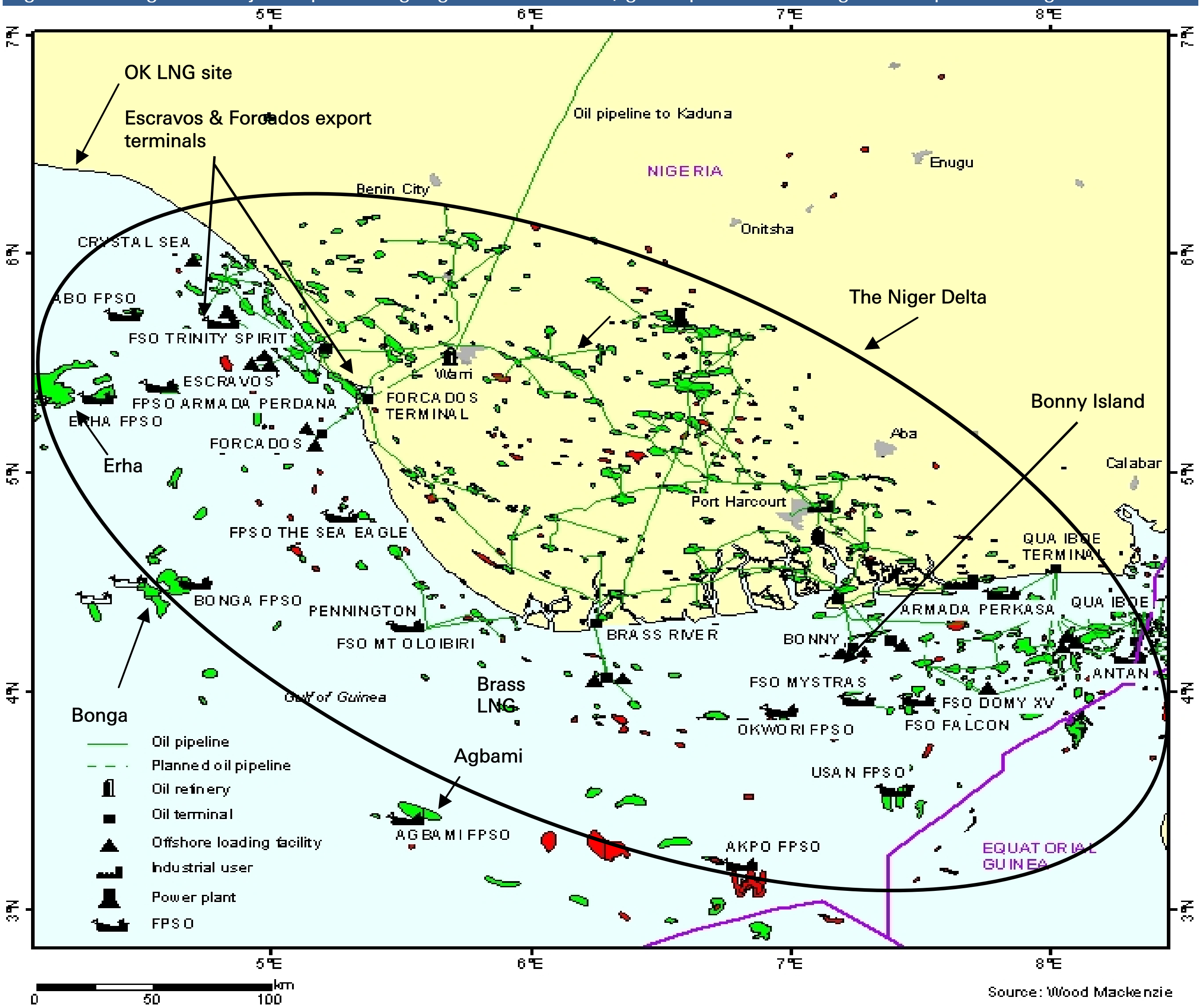
Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Figure 518: Nigeria – major oil producing regions of the Delta, gas exploration acreage and export/refining facilities



Source: Wood Mackenzie

Licensing

Whilst the exact nature of licensing will likely change should the PIB pass into law, the broad thrust of the licensing is likely to remain largely unchanged. At the present time licenses are awarded via formal licensing rounds that are held on an adhoc basis. Licenses awarded in Nigeria fall into three categories;

- **Oil exploration licence (OEL)** – non-exclusive licence to explore by surface geological and geophysical methods for a limited time period.
- **Oil prospecting licence (OPL)** – exclusive rights of surface and subsurface exploration. The maximum duration of these licences is 10 years.
- **Oil mining licence (OML)** – exclusive rights to explore, produce and transport petroleum from the leased field (subject to relevant legislation). The duration is about 20 years but may be extended for a negotiated period. These leases are operated under three types of contract: joint venture, PSC and service contract.

Onshore prospects take the form of joint venture contracts which are governed by a tax and royalty regime. NNPC is always the majority shareholder (60% interest in all JVs, except the Shell-operated JV which is 55%), and costs and revenue are shared in proportion to each party's holding. The deepwater projects are taxed under PSC regimes and NNPC does not ordinarily participate with an equity interest (please see the Fiscal section for further details).

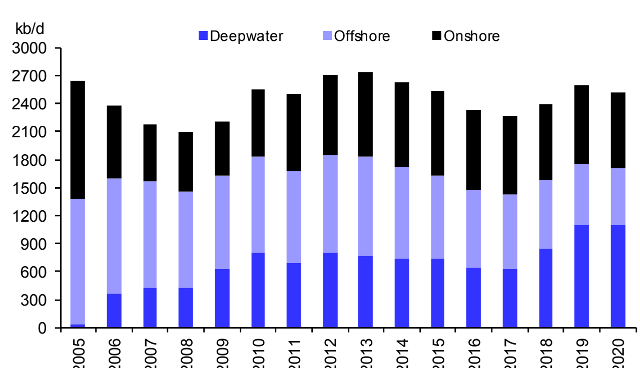
One further area of interest is the Joint Development Zone (JDZ), an offshore area shared by Nigeria, Sao Tome and Principe. Under a 45-year treaty signed in 2001, the countries agreed to divide future revenues from hydrocarbons 60% to Nigeria and 40% Sao Tome and Principe. To date licences for the blocks are awarded under PSC terms with some modest discoveries of oil & gas made from limited exploration.

Production of Oil and Gas

Including some 0.4mb/d of condensates, liquids production in 2012 was an estimated 2.7mb/d, and gas production 4.2bcf/d with hydrocarbons accounting for 95% of the country's export revenues and 80% of government revenues. Since production commenced 50 years ago, onshore developments have dominated, particularly in the mangrove swamps of the Delta, with production gradually moving offshore to the shallow waters of the Gulf of Guinea. The deepwater era kicked off in 2005 with the start-up of Shell's Bonga, and has continued with the development of Erha (XOM), Agbami (CVX), AKPO (Total) and Usan (Sinopec).

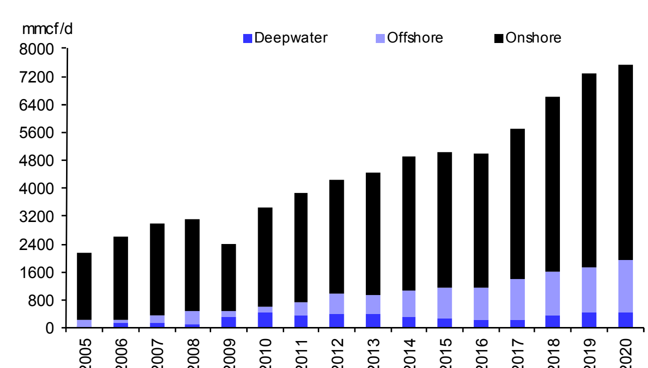
As stated onshore and shallow water developments have been subject to consistent disruption and sabotage, via both the actions of various civil groups and the simple theft of large volumes of crude oil. As a consequence, onshore/shallow water production has been relatively volatile over much of the past decade with as much as 200kb/d of oil stolen from the system via the illegal hotwiring of pipelines. Consequently, the migration of production towards the deepwater has to a large extent insulated the industry from such attacks although even in the deepwater attacks on facilities have been made by various militia (e.g Bonga in 2008). This, together with the Nigerian state's clear desire to encourage greater local ownership of its production, has encouraged the oil majors to divest significant tracts of their onshore portfolios in recent years, not least Shell and Total. We expect the shift in production towards the deepwater through the end of the decade to continue both in absolute terms and decidedly within the portfolios of the major IOCs. What the pace of that shift will be, however, is almost certain to be determined by the fiscal terms that are ultimately decided upon in the PIB.

Figure 519: Nigeria Liquids production 2005-20E (kb/d)



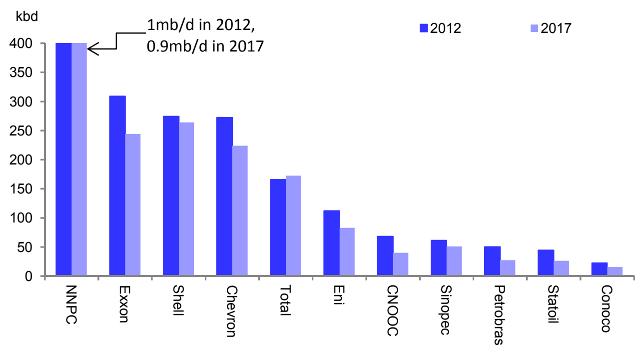
Source: Wood Mackenzie; Deutsche Bank

Figure 520: Nigeria gas production 2005-20E (mmcf/d)



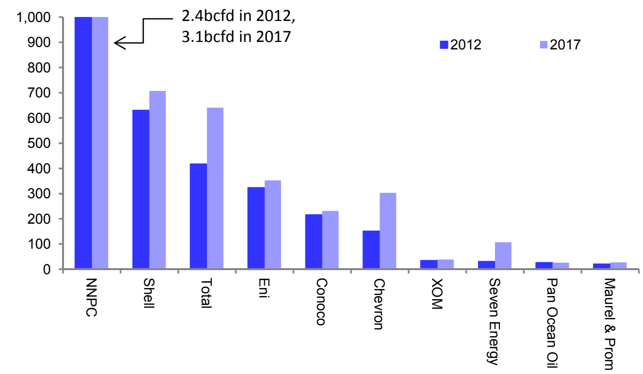
Source: Wood Mackenzie; Deutsche Bank

Figure 521: Nigeria: Major oil producers 2012/17E



Source: Wood Mackenzie; Deutsche Bank

Figure 522: Nigeria: Major gas producers 2012/17E



Source: Wood Mackenzie; Deutsche Bank

While there are of course significant challenges to deepwater projects, such as tough economics and smaller oil deposits, the potential benefits from these projects are significant. Over the life of a deepwater contract, at the present time the estimated contractor take achieved per barrel from a deepwater PSC is more than double that achieved from an onshore barrel under a tax and royalty scheme. This disparity in take does, however, raise certain questions, not least the extent to which future OPEC quota reductions will be sought from the deepwater in light of the clear tax benefits to Government of retaining onshore production. In addition, with Nigerian capacity already ahead of its official OPEC quota, there must be some questions on the timing of start-up for future deepwater developments.

In natural gas, given limited demand from national markets, the majority of Nigeria's 4.2bcfd of commercial production is currently used to feed the 6 LNG trains at Bonny LNG with under 1bcf/d of production used for the generation of local power. Whilst this is notably reduced from the 2.2bcfd that was being flared in 2005, it remains well above the Nigerian authorities' target of an end to flaring by 2008. Looking ahead, gas production is expected to grow significantly should the country achieve its ambitions of building out its LNG capacity, introducing additional national power capacity and exporting increased volumes of gas via the now built West Africa Gas Pipeline. Most likely, however, progress will be limited. Of the IOC majors Shell and Total represent the dominant producers.

Reserves and Resources

With total estimated oil reserves just over 37 billion barrels, Nigeria has one of the largest resource bases in Africa. Recently, however, the pace of reserve growth has moderated despite the region's significant prospectivity as exploration has slowed in light of both the challenges associated with onshore work and the uncertainties engendered over the outlook for profitability by the PIB. Resource growth has been further complicated by NNPC's parlous financial condition, a function of the fact that it does not have control over its revenues but rather is dependent upon allocation by the Government. To circumvent the problem, all the oil majors (with the exception of ENI) have undertaken JV projects with NNPC under alternative funding arrangements.

Natural gas reserves are estimated at 180TCF, which makes Nigeria the ninth-largest natural gas reserve holder in the world and the largest in Africa. Very little of Nigeria's exploration to date has had the objective of discovering gas for development, hence there is likely to be significant potential to grow gas reserves through exploration and investment in technology. Government plans to significantly raise earnings from natural gas exports by developing reserves, a target which will require substantial, $-multi-billions of investment, has, however, so far made little progress.

Pipelines and Infrastructure

Near term, the question of infrastructure is vital for Nigeria given repeated guerrilla attacks and the impact this has had on the country's production levels and the onshore investment climate. In total, there are c.3000km of pipelines in the delta, connecting over 275 flow-stations to five export facilities. Each of the major operators has its own dedicated pipeline network and it is not feasible for production to be switched from one network to another in the event of either a pipeline or terminal disruption. Pipeline integrity is a key issue and much of the JV budget is spent on pipeline rehabilitation given both the age of the network and sabotage.

Over two-thirds of total oil production passes through one of Nigeria's five main export terminals: **Escravos (490kb/d), Forcados (350kb/d), Brass River (200kb/d), Bonny (475kb/d) or Qua Iboe (460kb/d).** Most of these terminals have been affected in one way or another over the last several years, whether by protests or by outright attack.

For a country with such significant gas reserves, Nigeria's gas infrastructure is notably underdeveloped, with a high percentage (40%) of gas being flared. While Nigeria has for a number of years been working to end flaring, the deadline was pushed out to 2012 from the original 2008. Meanwhile poor contractor performance and funding issues suggest that there is still little chance of this target being achieved. In 2009, the government published its "Gas Master Plan" which promotes the construction of new gas-fired power plants to utilise the flaring gas and generate much-needed electricity supply. At the present time key completed gas projects include the West Africa Gas Pipeline (WAGP) with capacity of 470mscf/d. Opened in 2010 this currently exports 200Mscf/d of gas from Nigeria to Ghana, Benin and Togo. It is owned by a consortium which includes NNPC (25%), Chevron (36.7%) and Shell (18%), amongst others.

Crude Oil Blends and Quality

Nigeria has a total of 19 marketed crude blends, the most important of which are highlighted in the following table. These are essentially all sweet, light crudes. While Bonny Light is arguably the main proxy for Nigeria's crudes, Forcados blend is considered one of the best gasoline-producing blends in the world.

Figure 523: Main crude streams and loading points

Crude Oil	Loading Point	Gravity (API)	Sulphur (%)
Bonny Light	Bonny Terminal	33.6	0.14
Brass River	Brass River Terminal	34.6	0.22
Escravos	Escravos Terminal	34.2	0.15
Forcados	Forcados Terminal	30.4	0.18

Source: Wood Mackenzie

Broad Fiscal Terms

Licences in Nigeria are governed by two main fiscal regimes depending on whether the project is on the Delta (largely onshore) or in the deepwater. In an effort to incentivise the development of projects in the deepwater, the PSC terms pertaining to these are invariably far more attractive than those for the onshore/shallow water JVs given there is no required minimum NNPC stake, cost recovery is at a minimum of 80% and the tax rate is only 50% compared to 85% onshore. However, more recently there have been early indications from the Nigerian authorities that the Deepwater PSC terms could be subject to review, and it is anticipated that a series of changes to taxation will most likely be included in any final version of the Petroleum Industries Bill (PIB).

Figure 524: Key fiscal characteristics for JV and PSC

	Onshore JV	1993 Deepwater PSC	2005/6 Deepwater PSC
Minimum NNPC stake %	60	n/a	n/a
Minimum bid round bonus ($m)	n/a	25	50
Cost recovery ceiling (%)	n/a	100	80
Investment Uplift (%)	5	50	50
Royalty/Production charge (%)	20	0	8
Petroleum Profit Tax (%)	85	50	50
State share of profit oil	n/a	20%-60%	30%-75%

Source: Wood Mackenzie

Oil aside, the government is making concerted efforts to ensure that there is a favourable investment climate in the country's gas sector. Investors in the gas sector (both associated and non-associated) benefit from a broad range of fiscal incentives, including zero royalty rate, a tax rate of only 30%, the ability to offset expenditure on gas infrastructure against oil revenues and an initial tax free period of 5 years, which can be extended by a further 2 years.

Less than certain at the present time, however, is the extent to which all of the current fiscal terms will be overturned by any final version of the PIB. As things stand fiscal terms certainly look set to deteriorate – most particularly in the deepwater. Looking at the proposals as they currently stand suggests changes include the following

- Corporation tax will be levied on all upstream profits be they from oil or gas at 30%. At present only gas earnings are subject to CT
- Nigeria's Petroleum Profits Tax (PPT) will be removed and instead a Nigerian Hydrocarbon Tax (NHT) introduced. This will be levied at 50% for onshore and shallow water fields (cf 85% currently) but 25% for deepwater fields (cf 50% currently).
- All Upstream companies will have to pay an additional 10% of post-tax income towards a Petroleum Host Communities Fund (PHCF). There is some confusion with the current drafting of the PIB as to whether this would be tax deductible or not.
- Royalties will be increased for all forms of production albeit on a volume dependent sliding scale. Onshore royalties will be a maximum of 22%, shallow water 20% and deepwater a maximum of 18.5%. Royalties of up to 12.5% will also be payable on gas and condensate production. Moreover for all production types a second type of sliding-scale royalty which is price dependent will be introduced. This would equate to 12-18% on oil and 0-10% on gas.

The implication of the above is that marginal take in the Deepwater at high oil prices would rise towards 70% from c54% currently but that marginal tax on the onshore would fall towards 82% from c86% currently.

Refining and Downstream markets

Put simply, Nigeria's downstream market is in disarray. Although its four refineries have capacity of 445kb/d, internal disruption combined with limited investment has served to significantly undermine performance with utilisation rates frequently collapsing. As a consequence the country suffers frequent fuel shortages, necessitating the import of petroleum products (which are then sold at a subsidised price to the domestic market). The country currently imports 85% of its domestic need of 286 kb/d. The main refineries are highlighted in the table below:

Figure 525: Nigeria: Refining capacity vs. throughput

Operator	Refinery	CDU Capacity	Utilization (2011)
Port Harcourt Refining Company	Port Harcourt I	60	15%
Port Harcourt Refining Company	Port Harcourt II	150	15%
Warri Refining & Petrochem Co	Warri	125	42%
Kaduna Refining & Petrochem Co	Kaduna	110	22%
Total CDU		445	

Source: Wood Mackenzie, NNPC

LNG & GTL

Until the late 1990's, the sole focus of development in the Delta was crude oil production, with the majority of associated gas being flared. However, following the 1999 start-up of Nigeria (Bonny) LNG, much gas is now diverted to LNG projects or re-injected to improve oil production.

LNG in Nigeria is highly profitable, with gas currently transported to the liquefaction plant at a nominal cost of an estimated c$2/mmbtu. As such, the value of the LNG project resides largely with the liquefaction plant – much to the benefit of Shell, Total and ENI. Capacity utilisation has, however, frequently been affected by issues on the Delta, not least the sabotage of pipelines and consequent a lack of gas although more recently the 2010 start up of Shell's 1bcf/d Gbaran Ubie project has eased the previously frequent feedgas constraints.

Given tax incentives, a huge reserve base and its favourable location for European markets, it is little surprise that significant plans for future LNG capacity should be in place. Following the 2008 start up of a sixth train, capacity at Bonny LNG rose to 22mtpa. A seventh train has long been planned but, despite the clear advantages of expansion at an existing site, politics have to date prevented its build with priority given instead to the development of a separate, 10-mtpa two-train plant at Brass. Progress on this has however faltered, hampered again by politics and corruption together with access to gas and general rise in industry capital costs. As such, despite several years of discussion, FID on Brass in the near term appears a very unlikely prospect.

Figure 526: Nigeria Major LNG Projects

Project	Start-up	Trains	Capacity (mta)	Equity Holders
NNLNG (Bonny)	1999	1-5	17	NNPC (49%), Shell (25.6%), Total (15%) ENI (10.4%)
NNLNG (Bonny)	2008	6	5	NNPC (49%), Shell (25.6%), Total (15%) ENI (10.4%)
NNLNG (Bonny)	2020+	7	8	NNPC (49%), Shell (25.6%), Total (15%) ENI (10.4%)
Brass LNG	2020+	1-2	10	NNPC (49%) Eni (17%), Conoco (17%), Total (17%)

Source: Wood Mackenzie

GTL has also proven a possible means by which to utilise the associated gas. Chevron is working on the Escravos GTL project, which will convert 325 mmcf/d into 33kb/d of liquids. Due to a number of delays and cost overruns, start-up has been pushed to 2013.

Nigeria – Notes

Qatar

From its roots as a British protectorate known mainly for pearling, Qatar is today a global leader in gas markets. With some 12% of the world's natural gas reserves and some of the largest LNG projects in the world, this OPEC member has established itself in recent years as the world's leading LNG player with 77mtpa of capacity. However, absent the lifting of its moratorium on the further development of the giant North Field (the world's largest non-associated gas field), gas production from here will likely stabilise at c20bcf/d whilst liquids production, which had seen rapid NGL-driven growth, is expected to decline from its current 1.7mb/d as many of Qatar's oil fields enter decline. Major IOCs present in Qatar include RDS, ExxonMobil and Total.

Broad geology and topology

Qatar comprises seven key sedimentary basins from an oil and gas perspective. These are further broken into 16 exploration blocks which (with the exception of Block 2) all reside offshore. Among the exploration areas, the Qatar Arch is the most important for both oil and gas production. Comprising the mammoth Shell-discovered North Field with some 900TCF of natural gas resource, the Qatar Arch accounts for some 77% of Qatar's total liquid reserves, with the Western and Eastern Gulf Basins holding a more modest 13% and 10%, respectively. Important oil fields include Al-Shaheen, Dukhan and Idd El Shargi North Dome, which are operated by Maersk, Qatar Petroleum (QP) and Occidental, respectively.

History and regulation

Oil was first discovered in Qatar in 1940 when BP and the Qatar Petroleum Company discovered the Dukhan field with production commencing in 1949. Following a peak in production in 1973, activity fell in response to OPEC production quotas at which time Qatar started to look more aggressively towards the development of its gas resource base, not least the huge North Field, which had been discovered by Shell in 1971. Development of the immense gas reserves in the North Field did not, however, begin until 1984 with Phase 1 coming onstream in 1991. This was developed for the domestic gas market while subsequent developments have mainly been for the export market (via LNG or the Dolphin pipeline).

Oil production underwent something of a renaissance in 1994 as the IOCs and QP applied EOR techniques to improve production with production subsequently improving by c5% pa. Growth in recent years has been further supported by the increased production of NGL's associated with the country's build-out of its LNG and GTL facilities. However, a lack of exploration success, combined with the Kingdom's self-imposed moratorium on any future North Field-sourced gas projects, suggests that both oil and liquids production will now likely move into steady decline.

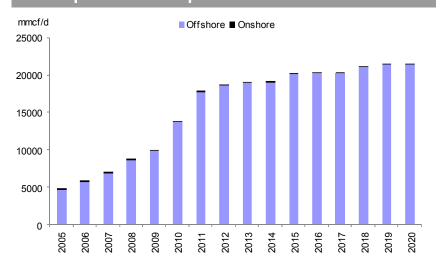
Qatar is unusual in that it has no dedicated petroleum law. Instead all exploration and production activities are regulated by the terms of Production Sharing Contracts (PSCs). These in turn are negotiated, awarded and administered by QP, which is also the designated authority to oversee all production and exploration operations on behalf of the government. Recent years have seen a number of licenses awarded in under-explored areas, or for earlier discoveries that may now be commercialised with modern technology. However, there has been little in the way of new discoveries in the last decade.

Key facts

Liquids production 2012E	1.7mb/d
Gas production 2012E	3.13mboe/d
Oil reserves 2012E	24.7 bn bbls
Gas reserve 2012E	884.5 TCF
Reserve life (oil)	40 years
Reserve life (gas)	129 years
GDP 2012E	185bn
GDP Growth 2012E (%)	6.0%
Population (m) (2012E)	1.8m
Oil consumption (2011)	238kb/d
Oil exports (mb/d)	1.4mb/d
Fiscal regime	PSC, tax and royalty
Top 3 liquid fields (2012E)	
Al Shaheen (Block 5)	311 kb/d
Dukhan (Block 9)	257 kb/d
Dolphin Upstream	182 kb/d
Top Oil Producers (2012E)	
Qatar Petroleum	650kb/d
ExxonMobhil	138kb/d
Maersk Oil & Gas	131kb/d

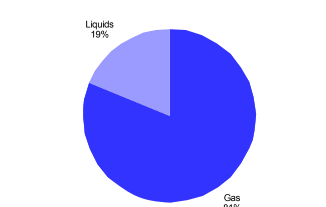
Source: Wood Mackenzie, EIA, IMF

Gas production profile mmcfd



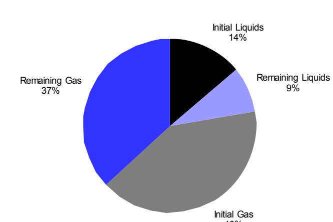
Source: Wood Mackenzie

Remaining reserves split %



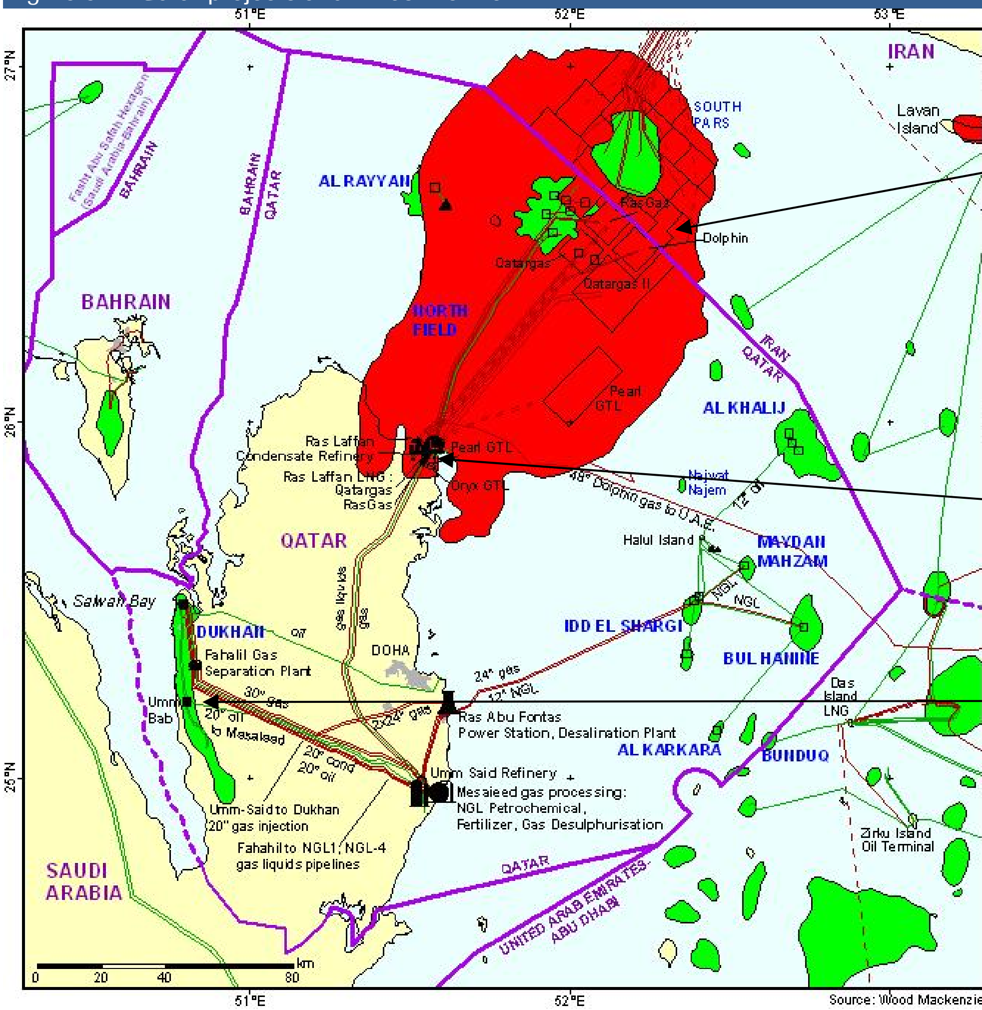
Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie, BP Statistical Review 2010

Figure 527: Qatar projects and infrastructure



The giant North Field which straddles Qatari and Iranian territory is the world's largest non-associated gas field with some 900Tcf of reserves

Ras Laffan – home of Qatar's LNG, GTL and chemicals production

Main oil producing fields

Source: Wood Mackenzie

Licensing

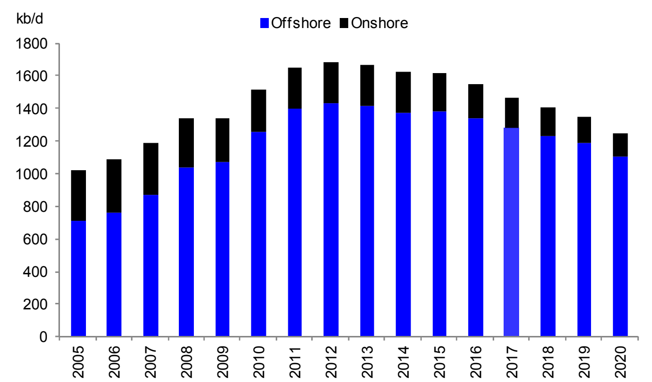
Qatar Petroleum directs and administers the allocation of licenses in Qatar. Unlicensed blocks are available for international oil company participation via direct negotiation with QP. Of the 16 established exploration blocks, nine are currently unlicensed and QP typically offers a selection of these blocks to IOCs in an annual bid round or on an adhoc basis. The bidding criteria include a work programme (seismic and three wells) and a signature bonus (generally around $2million). In terms of gas, between 1991 and 2009, a total of 11 development blocks were awarded. Seven of these are for the production and export of LNG (Qatargas and RasGas), one is for a large-scale 140kb/d GTL project (Pearl) and three are assigned to meet domestic demand.

Production of oil & gas

Although Qatar is a significant oil-producing state and member of OPEC, key to its success has been the monetisation of its huge gas resource. Recent years have seen the build-out of some 77mtpa of LNG capacity and the establishment of two world-scale GTL projects. Consequently, gas production has rallied from around 3bcf/d at the start of the last decade to nearer 19bcf/d currently. From here, however, gas production growth is expected to stabilise. Key players in gas production in Qatar include ExxonMobil through its involvement with state company Rasgas, and Shell, Total, Conoco and Occidental, largely through their developments with Qatar Petroleum.

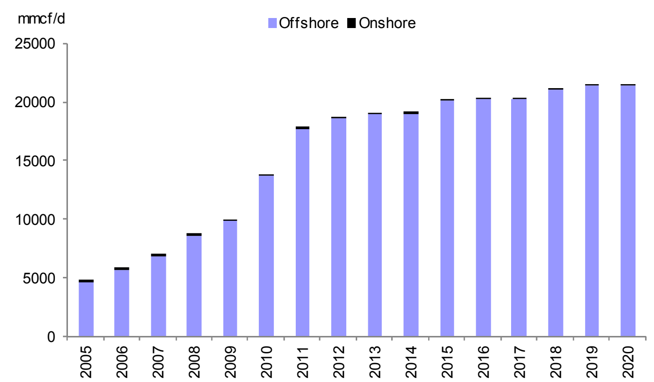
At 0.8mb/d Qatari oil production has now moved into slow but steady decline. Overall liquids production has, however, gained materially from the build in NGL production associated with its gas-based developments. As with gas, ExxonMobil, Occidental and Total are key IOC players while Maersk Oil & Gas also has significant production.

Figure 528: Liquids production to 2005- 2020E (kb/d)



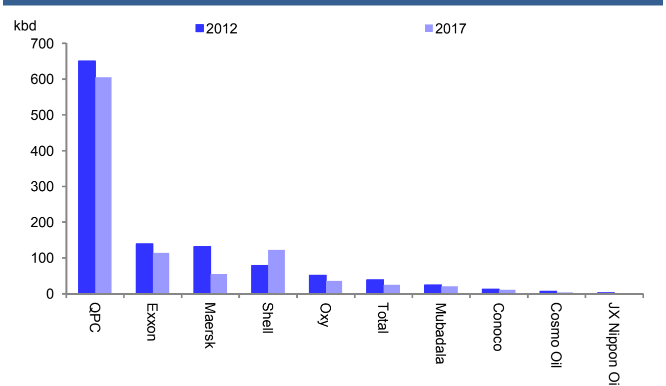
Source: Wood Mackenzie

Figure 529: Gas production to 2005- 2020E (mmcfd)



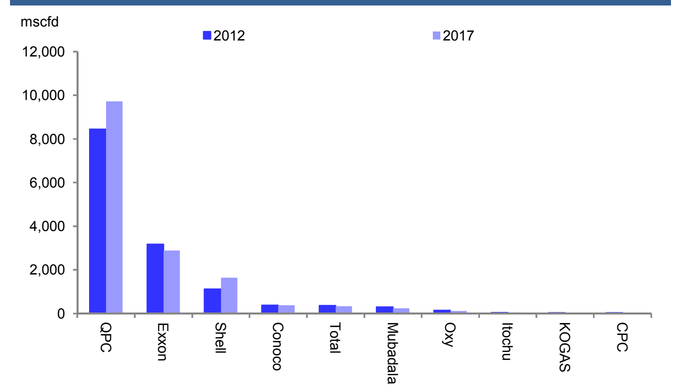
Source: Wood Mackenzie

Figure 530: Liquids production by company 2012 and 2017 (kb/d)



Source: Wood Mackenzie

Figure 531: Natural gas production by company 2012 and 2017 (Mscf/d)



Source: Wood Mackenzie

Pipelines and infrastructure

Qatar's network of pipelines transports oil produced both onshore and offshore to processing and offloading facilities at the Halul Island terminal, located 80 kilometres from the east coast of Doha, and to the Mesaieed terminal on the Qatari peninsula south of Doha. Similarly, the gas pipeline network transports gas produced to processing plants and LNG export facilities located at Ras Laffan. The Dolphin project (developed by Total and Occidental) also includes the country's only export gas pipeline, a 350km sub-sea pipeline to transport gas from Ras Laffan to Abu Dhabi.

Crude oil blends and quality

Despite the fact that Qatar's importance lies in its vast gas reserves, it is a net exporter of liquids consuming only 15% of the 1.6mb/d of liquids it produces. Qatari crude is typically light with an API ranging from 26°-44°. The crude is quite sour though with a sulphur content ranging between 1% and 3.2%. Key blends for export are Al Shaheen (29°API, 1.27% sulphur) and Dukhan (40.9°API, 1.27% sulphur) from the country's largest oil fields.

Broad fiscal terms

The majority of upstream licenses in Qatar operate under a PSC regime (the Bunduq field is the only concession; this operates under the UAE's tax & royalty regime). The principle characteristics of these contracts are:

- Signature bonus: typically between $2 million and $5 million.
- Cost Recovery: the contractor can recover costs from a negotiated percentage of production ranging from 20% to 65%. The only exception is Qatargas, where cost recovery is based wholly on a share of the liquids stream (65% for the first seven years and 25% thereafter). All legitimate operating and capital costs are recoverable; opex in the quarter in which it is incurred and capex via depreciation (typically 5% per quarter).
- Profit sharing: profit oil split is determined based on the rate of production and an R-factor as shown below:

Figure 532: Profit Oil Splits

Prod'n b/d	R Factor							
	<1.0		1.0-1.5		1.5-2.0		2.0-2.5	
	Govt %	Contr %	Govt %	Contr %	Govt %	Contr %	Govt %	Contr %
<15	70	30	74	26	77	23	80	20
15-30	74	26	78	22	80	20	83	27
30-45	78	22	81	19	83	17	86	14
45-60	82.5	17.5	84	16	85	15	88	12
>60	85	15	86	14	87	13	90	10

Source: Wood Mackenzie

Contractors are also liable for Qatari Income Tax at the prevailing rate (currently 35%) though this is paid on the contractor's behalf by the government out of its share of production.

Liquefaction revenue streams are taxed separately under a tax and royalty scheme. We outline below our understanding of the terms for the key projects:

Figure 533: Selected gas projects

Projects	Royalty on dry gas produced	Royalty on condensate	Tax on profits	Issue date
Qatargas 2	40%	18%	35%	Jun 2002
Qatargas 3	45%	18%	35%	Jul 2003
Qatargas 4	45%	18%	35%	Feb 2005
Rasgas	35%	9%	35%	1993
Rasgas II	40%	18%	35%	March 2001

Source: Wood Mackenzie

LNG & GTL

As the world's third-largest holder of gas reserves, and given its position as the world's leading LNG exporter, it is no surprise that seven of Qatar's 11 gas development blocks are dedicated to the production and export of LNG. However, this was not always the case. Even though the North Field was discovered in 1971, it was not decided to develop it until the late 1980's as an offset to declining production. Since the 1996 start-up of Qatargas, most of Qatar's gas production is now diverted into LNG. In 2009 following the start-up of Qatargas2 and RasGas3, Qatar accounted for 18% of global supply. This is set to increase to 24% following the start-up of three further trains in 2010/11.

LNG in Qatar is highly profitable, with Wood Mackenzie estimating that a FOB breakeven gas price of zero is required on all projects with the exception of Qatargas 1 (and at $1.93mmbtu this remains modest). This is due to the significant high value liquids associated with the gas, the relatively low upstream cost of production, the scale of the projects and the sharing of some common facilities with other LNG projects. Moreover, in recent years Qatar has signed a number of long-term oil indexed gas supply contracts which means that the economics of LNG projects in Qatar are very attractive.

The main LNG projects (both onstream and under-construction) are detailed below. These should drive growth of 13%pa in gas production out to 2015. However, beyond that given the moratorium, there is little visibility on what longer-term growth could look like.

Figure 534: Qatar: Key gas projects: on-stream and planned

Project	IOC*	BCF Gas Reserves	Mb Liquid reserves	Capacity (mtpa)	Start up
Qatargas 1	XOM 10%, TOT 10%	7457	211	9.7	1996
Qatargas 2	XOM 24.2%, TOT 8.4%	22084	729	15.6	2009
Qatargas 3	COP 30%	11888	322	7.8	2010
Qatargas 4	RDS 30%	12327	349	7.8	2011
Rasgas	XOM 25%	6147	182	6.6	1999
Rasgas II	XOM 30%	17206	429	14.1	2004
Rasgas 3	XOM 30%	21947	605	15.6	2009
Pearl GTL	RDS 100%	11753	818	12.5**	2011

*Source: Wood Mackenzie, Deutsche Bank *Qatar Petroleum major shareholder in all projects excluding IOC interest ** Pearl capacity = 120kb/d condensate and 140kb/d end GTL products.*

Qatar has also established a number of options and agreements to monetise its vast gas reserves using gas-to-liquids technology. While the majority have been placed firmly on the backburner by QP while the moratorium is in place, Sasol did start-up production at its Oryx GTL plant (34kb/d GTL liquids capacity) in 2007 albeit production has suffered a number of technical difficulties has yet to consistently deliver full design capacity. Pearl GTL, operated by Shell, came onstream in 2011 and following ramp through 2012 is expected to start producing at nameplate from early 2013. It aims to monetise some 15TCF of gas and condensates from the North Field over the next 25 years. Pearl's production, when ramped up to full capacity, is expected to consist of 120kb/d of condensate output and 140kb/d of end GTL products via two 70kb/d GTL trains. Given the extent of the country's gas reserves, further GTL and LNG projects are likely to be sanctioned post the moratorium.

Qatar – Notes

Saudi Arabia

Saudi Arabia is currently the largest producer of oil in the world and home to the world's largest oil field, Ghawar. As one of the founding members of OPEC and its all-important 'swing' producer, Saudi Arabia has been the dominant force in the global oil industry since the late half of the 20th century. Economically, the country is heavily dependent on its vast hydrocarbon resource base. Official oil reserves estimates at the beginning of 2012 stood at 265bn/bbls and gas reserves at 288TCF. Production in the country is almost entirely conducted by Saudi Aramco, the state-owned organisation. The company has a monopoly over upstream operations and responsibility for most downstream activities in the country. For much of the last decade, total oil production levels have remained at or around 8–10mb/d, fluctuating in response to global demand and OPEC production quotas. In 2011, crude oil output averaged 9.3mb/d (excluding NGLs, which accounted for 1.4mb/d) rising to 9.9mb/d in 2012. This stands some way below estimated crude production capacity of 12.5mb/d. Total gas production stood at 1.4mboe/d, consisting largely of associated gas.

Basic geology and topology

The majority of Saudi Arabia's reserves are located in the Arabian Basin. Another sedimentary basin, the Red Sea, borders Saudi Arabia but to date, no commercial discoveries have been made in the region. The Arabian Basin covers a large part of the eastern half of the country and is situated upon the northeastern margin of the Arabian plate. The country's principal reservoirs are composed of source rocks that are predominantly Jurassic, Permian and Cretaceous in age. The Basin itself consists of a high proportion of giant and super-giant oil and gas fields, in addition to a multitude of smaller pools.

Regulation and history

The principal regulatory body is the Ministry of Petroleum and Mineral Resources, established in 1960 to conduct general policy related to oil, gas and minerals. This now entails the supervision of Saudi Aramco and its affiliates through observing and monitoring all upstream, midstream and downstream activities. Saudi Aramco must also report to the Saudi Arabian government via the Supreme Council of Petroleum and Minerals Affairs. This was formed with the aim of outlining the company's broad policy objectives. Members are drawn from both the government and the private sector.

The presence of oil in Saudi Arabia had long been predicted prior to any exploration. Discoveries in neighbouring Bahrain provided an early indication, encouraging several oil companies to pursue a licence to explore the country. In 1933, Standard Oil of California (SOCAL, later Chevron) was awarded a concession to explore large areas of the country in return for the provision of loans to the government. SOCAL subsequently set up CASOC (Californian Arabian Standard Oil Company), in partnership with the Texas Oil Company, to operate the concession. Exploration drilling began in the Dammam Dome and oil was discovered in 1937 in the same area. CASOC was renamed Aramco (Arabian American Oil Company) in 1944, and shareholding was later enlarged to incorporate Standard Oil of New Jersey and Socony Vacuum (later Exxon and Mobil respectively).

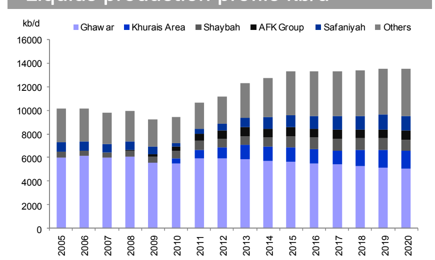
From 1968 onwards, the Saudi Arabian government began to increase its stake in the ownership of Aramco. This came to fruition in early 1976 when the government assumed full control of the company. However, it was not until 1988 that the company was established under its present name, Saudi Aramco. This event marked the completion of the process to nationalise Aramco.

Key facts

Liquids production 2012E	11.1mb/d
Gas production 2012E	1.4mboe/d
Oil reserves 2012E	265 bn bbls
Gas reserve 2012E	288 TCF
Reserve life (oil)	65years
Reserve life (gas)	96years
GDP 2012E	657bn
GDP Growth 2012E (%)	6.0%
Population (m) (2012E)	28.8m
Oil consumption (2011)	2.8mb/d
Oil exports (mb/d)	8.3mb/d
Fiscal regime (concession)	Income tax & royalty
Marginal tax rate (concession)	80%-88%
Top 3 liquid fields (2012E)	
Ghawar	5,938kb/d
Khurais Area	915 kb/d
Shaybah	750 kb/d
Top Liquid Producers (2012E)	
Saudi Aramco	11,053kb/d
Chevron	118kb/d

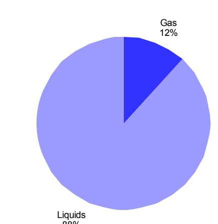
Source: Wood Mackenzie, EIA, IMF

Liquids production profile kb/d



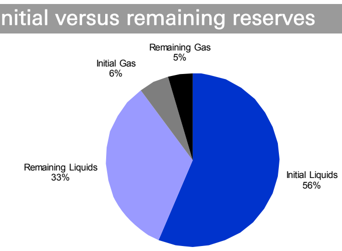
Source: Wood Mackenzie

Remaining reserves split %



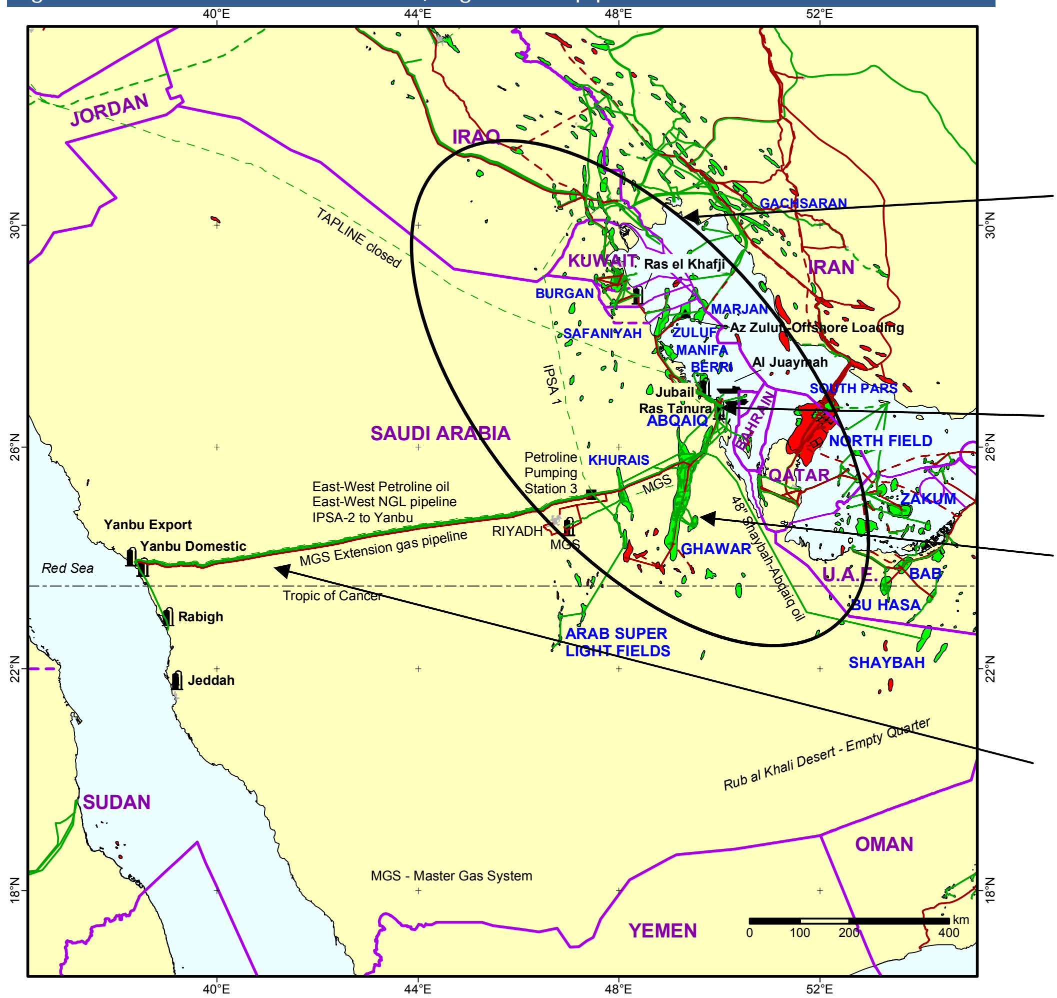
Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Figure 535: Saudi Arabia: Main fields, regions and pipelines



Source: Wood Mackenzie

Licensing

Since the nationalisation of Aramco in 1976, no oil exploration licences have been granted to foreign companies to operate within Saudi Arabia. Foreign participation is limited to the Partitioned Zone, a 3500 km² region lying between Saudi Arabia and Kuwait. Both nations share sovereignty over the area and accordingly, the petroleum resources of the zone are divided equally between the two.

A 60-year concession for the Saudi share of the onshore Partitioned Zone was awarded to Getty Oil in 1949. Following various acquisitions, Getty Oil now exists in the form of Saudi Arabian Texaco, a subsidiary of ChevronTexaco. The onshore concession is jointly operated with the Kuwait Oil Company, which holds the Kuwaiti interest in the licence. The Saudi Arabian part of the concession was due to expire in 2009; however, negotiations were concluded in 2008 for extending the concession to 2039. The Saudi offshore concession was previously operated by a Japanese-owned subsidiary called the Arabian Oil Company. This agreement expired in 2000 and was not subsequently renewed. The concession is now operated by Aramco Gulf Operations Company (AGOC), a subsidiary of Saudi Aramco.

In 2003, Shell and Total were awarded gas exploration contracts for the South Rub' Al Khali region ('the Empty Quarter'). This marked the first foreign involvement in the Saudi Arabian gas sector since nationalisation. Further contracts were awarded in 2004 to Lukoil, Sinopec and ENI/Repsol to explore areas across the country totalling 120,000 km². This follows from the Natural Gas Initiative, launched in the late 1990s with the aim of attracting foreign oil companies into the country to explore for and produce non-associated gas. However, exploration results have been disappointing with Total, Repsol and Eni all apparently withdrawing.

Production of Oil and Gas

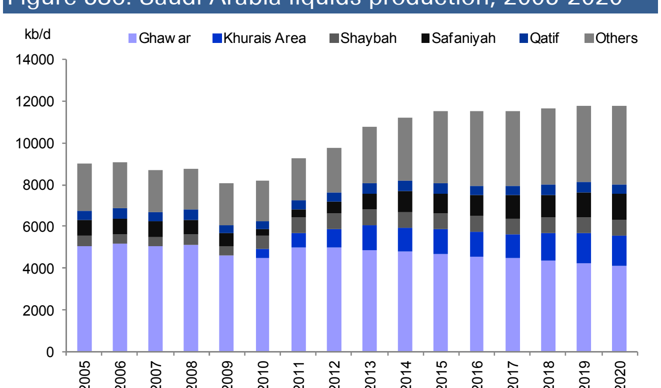
The discovery of Ghawar in 1948 and subsequent development of new and existing fields led to sustained growth in oil production until the 1970s. However, weakness in global demand and the introduction of OPEC production quotas in 1983 constrained Saudi output thereafter. It is only in recent years that production has, at times, returned to its historical peak of circa 10 mb/d achieved in 1980.

For much of the last decade, crude output has remained between 8 and 9 mb/d. Crude production exceeded 9mb/d in 2006 and remained near this level until 2008/09 when OPEC introduced quota cuts to prevent the oil market becoming oversupplied following a meltdown in oil demand during the global economic crisis. Saudi suffered much of this quota-led reduction, reducing its volumes by c1.5mb/d between Sept-08 and Feb-09. However, production has subsequently recovered, with the geopolitical situation in Libya (2011) and Iran's sanctions (2012) seeing Saudi production move above 10mb/d for the first time in circa 30 years during the middle of 2012.

Production is heavily dominated by Ghawar, the largest oil field in the world. This single oil field accounted for 5.9mb/d of liquids, over 50% of Saudi production and an estimated 6.7% of total world production.

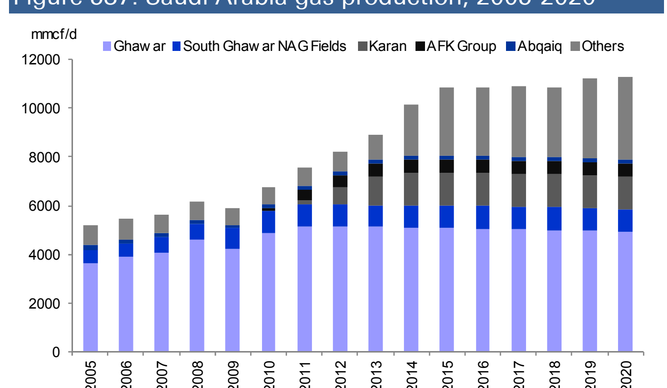
Gas production in Saudi Arabia has considerable potential though only a small portion of this has been realised to date. In 2011, gas production stood at 7.6bcf/d but while significant additional potential exists, installation of the appropriate facilities is still required at most existing crude oil fields. Current production of gas is split evenly between associated and non-associated gas and therefore remains fairly dependent on the global oil market. After efforts to bolster gas production via the Natural Gas Initiative proved disappointing, Saudi Aramco increased its own gas exploration efforts which resulted in successful discoveries of non-associated gas at Arabiyah, Hasbah, Karan. These assets are expected to drive strong production growth over coming years to meet growing domestic gas demand. Karan commenced production in 2011.

Figure 536: Saudi Arabia liquids production, 2005-2020



Source: Wood Mackenzie

Figure 537: Saudi Arabia gas production, 2005-2020



Source: Wood Mackenzie

Capacity expansion plans

The IEA places Saudi's end-2012 sustainable crude oil production capacity at c12.0mb/d. Prior to the financial crisis and the meltdown in global oil demand, Saudi had plans to grow it capacity toward 15mb/d; however these plans were put on hold. Given the visible roster of crude development projects, the IEA anticipate that Saudi capacity will remain in a range of 11.9-12.3mb/d through 2017. Saudi's only major growth project is the 900kb/d offshore heavy crude Manifa field, the first phase of which is due to start up in late 2013 or early 2014, although this is likely to simply offset declines elsewhere. Other projects focus on the rehabilitation and upgrading of existing assets, such as the Safaniya field. Spare capacity stood at c2mb/d at end-2012, which is likely seen as a comfortable level, not least given the near-term potential for supply growth from onshore US and Iraq. However, Saudi Aramco continually revises its five-year operation plans in line with market conditions and should it be required, we suspect that the prior plan to grow to 15mb/d could be refreshed.

Reserves and resources

Saudi Arabia has the largest remaining reserves of oil in the world; at 265 billion barrels, this is twice the volume of the next-largest conventional oil reserve base in the world. As of end 2012, it is thought that around 40% of initial commercial reserves have been produced and that c.1.9% of remaining reserves are produced annually. The reserve base is concentrated in only ten fields, dominated by the super-giant fields Ghawar and Safaniyah, the world's largest oil field and offshore oil field, respectively. Ghawar alone contains around 67 billion barrels of remaining reserves. These figures include the substantial volume of NGLs present in the country; initial NGL reserves were c.33 billion barrels of which some 24 billion still remain.

Saudi Arabia has the fourth-largest gas reserves in the world. Wood Mackenzie estimates initial commercial reserves of 188TCF, the majority of which is associated gas. Only a relatively small proportion of this figure has been used, however, and remaining reserves are estimated to be 148TCF. Further potential for discovery also still remains; Wood Mackenzie estimates that an additional 74TCF of technical reserves exists.

Pipelines and infrastructure

Saudi Arabia has an extensive network of oil and gas pipelines, linking the country's oil and gas fields to processing facilities, refineries and export terminals. Oil is transferred via flowlines to a Gas-Oil-Separation-Plant (GOSP) where basic processing is carried out. The product is then sent to a major stabilisation facility, such as Abqaiq, for final separation from gas. Saudi Aramco owns and operates nearly 340 pipelines covering a total length of 14 000 km. These are located in three distinct geographical areas, namely the Northern, Southern and East-West areas.

The major pipeline in the country is the Abqaiq-Yanbu Pipeline (Petroline). The Petroline extends from the Abqaiq facility in eastern Saudi Arabia to the Yanbu export terminal on the Red Sea coast, covering a length of 1200 km. It has capacity of around 5 mb/d, mainly transporting Arabian Light and Super Light blends. Saudi Aramco does not currently operate any major international pipelines. The Trans-Arabian Pipeline (Tapline) and Iraq Pipeline to Saudi Arabia (IPSA) are no longer in use, although the latter is reported to have been converted into a gas pipeline in 2003. There are three main export terminals in Saudi Arabia – Ras Tanura, Al Juaymah and Yanbu. The Ras Tanura complex is the largest offshore loading facility in the world, with capacity of over 6 mb/d. Along with several other smaller terminals, these facilities have estimated total export capacity of between 14 and 15 mb/d.

The gas infrastructure in Saudi Arabia is based on the Master Gas System (MGS), an integrated gas distribution network feeding gas to the industrial cities of Yanbu and Jubail. The MGS was brought onstream in 1982, initially relying upon associated gas from Ghawar. It has been gradually upgraded since that time to incorporate non-associated gas. Saudi Aramco is presently investing in the Wasit Gas Plant, which will process up to 2.5bcf/d of non-associated gas from the Arabiyah and Hasbah fields. This project is expected to be completed during 2014.

Security concerns continue to surround the Saudi infrastructure network, especially following statements made by Al-Qaeda to target the region. In 2006, Saudi security prevented an attempted suicide bomb attack at the Abqaiq facility. The infrastructure does, however, remain well protected. 5000 guards are directly employed by Saudi Aramco and government assigned military security forces stand at around 20 000.

Crude oil blends and quality

Oil in Saudi Arabia tends to be of low to medium gravity (28-40° API) and contains moderate to high levels of sulphur (1-4%). The country produces and exports five main crude blends, ranging from Arab Heavy to Arab Super Light. Arab Light is by far the most significant, accounting for approximately 60% of crude output by volume. Unsurprisingly, the primary source of Arab Light is the Ghawar oil field.

Both Arab Extra Light and Arab Super Light represent a comparatively small proportion of overall output, with 2012 production levels of 1250 kb/d and 1000 kb/d, respectively. Yet although light, premium grade crude currently dominates production, Arab Heavy has gained a more prominent role in Saudi Aramco's production through completion of a major investment plan ended in 2008. The 2013 start-up of the Manifa field will continue this trend.

Figure 538: Summary of crude blends and characteristics

Crude Oil	Gravity (° API)	Sulphur (%)
Arab Heavy	28.7	2.79
Arab Medium	31.8	2.45
Arab Light	32.7	1.95
Arab Extra Light	38.4	1.16
Arab Super Light	50.6	0.04

Source: The International Crude Oil Market Handbook 2006, Energy Intelligence Research

Broad fiscal terms

The only active contract in Saudi Arabia is the concession agreed with ChevronTexaco in the onshore Partitioned Zone. The main elements of this concession are royalty and income tax. Under the terms of the concession, a 20% royalty is levied and the contractor must pay income tax at a rate of 80% on all profits. Furthermore, the concession specifies a Domestic Market Obligation (DMO) under which the government has the right to purchase 20% of production from the area at a 5% discount.

Historically, terms for gas exploration contracts have been unattractive to foreign investors. Vastly improved terms were offered under the Natural Gas Initiative to encourage international oil company participation in gas focused exploration in the Empty Quarter. In summary, the IOCs taking direct equity stakes (albeit terms focus exclusively on gas and condensate since commercial discoveries classified as oil automatically revert to the ownership of Saudi Aramco); royalty payments would not have to be made on gas and NGL although condensate would be subject to a royalty on gross revenues of 20%; net income would be subject to a Natural Gas Investment Tax

(NGIT) charged at a flat rate of 30% up to a threshold, after which the tax rate rises incrementally up to 85%; and corporate income tax levied at a rate of 30% would be allowed as credit against NGIT liabilities. However, these points are somewhat academic with exploration having seemingly proven disappointing and a number of the participants apparently exiting their contracts.

Refining

Saudi Arabia has a total of eight refineries across the country, two of which are joint ventures devoted to exports. The Yanbu refinery is operated in partnership with ExxonMobil and the refinery at Jubail in partnership with Shell. The remaining six are operated solely by Saudi Aramco for the domestic market including the Khafji refinery which processes oil from the offshore concession in the Partitioned Zone. The key refinery units are listed below:

Figure 539: Refinery units

Operator	Refinery	Capacity (kb/d)
Saudi Aramco	Jeddah	60
Saudi Aramco Shell	Jubail (export)	305
Saudi Aramco	Khafji	30
Saudi Aramco	Rabigh	425
Saudi Aramco	Ras Tanura	525
Saudi Aramco	Riyadh	120
Saudi Aramco	Yanbu (domestic)	255
Saudi Aramco Mobil	Yanbu (export)	365

Source: Wood Mackenzie

Four major refinery projects are presently underway or in the planning phase:

- **400kb/d Yanbu Greenfield project**: In 2006, ConocoPhillips signed an MOU to build a proposed 400kb/d full-conversion refinery in Yanbu designed to process heavy crude and produce transportation fuels for export. Conoco withdrew from the project in 2010, but Aramco has nonetheless progressed with the development with Sinopec as a partner. Then unit is expected to be completed in mid-2014.
- **400kb/d Jubail Greenfield project**: Separately, Saudi Aramco established a joint venture with Total to build a refinery of similar capacity and complexity in Jubail. The project is scheduled to start operation in 2013.
- **400kb/d Ras Tanura expansion**: Elsewhere, a 400kb/d capacity expansion project at Ras Tanura expected to come on-stream in 2013.
- **400kb/d Jazan Greenfield project:** Aramco is planning a new 400kb/d facility to take a diet of Arabian Heavy and Arabia Medium crude and produce gasoline and ultra-low sulphur diesel. The Aramco plans call for a 2016 completion.

United Arab Emirates

A confederation of seven Arab states, in 2012 the United Arab Emirates (UAE) is estimated to have produced some 3.2mb/d of crude oil (2.7mb/d) and condensates (0.5mb/d) from reserves, which at the end of 2011 stood at 98bn barrels. Abu Dhabi, the largest Emirate, dominates the UAE's oil and gas industry, accounting for all but 70kb/d of output and 92 billion barrels of the proven reserve base. It is followed by Dubai with 4 billion barrels; Sharjah (1.5 billion) and Ras al Khaimah (100 million). In its efforts to increase its profile in the region, the UAE intends to increase its oil production capacity to 3.5mb/d by 2017 from an estimated level of 2.7mb/d (excluding NGLs) currently. Key IOCs participating in the UAE include BP, Exxon, Total and Shell.

Basic geology and topology

The Eastern Gulf Basin underlies a large proportion of the offshore area of the western Emirates (Abu Dhabi, Dubai and Sharjah). The basin is bound to the south and east by the Ras Al Khaimah Basin and to the west and northwest by the Qatar Arch. The onshore and eastern offshore regions of the UAE comprise the Rub Al Khali Basin and the Ras Al Khaimah Basin. The UAE's petroleum prospects are largely derived from prolific source rocks developed in the Permian, Late Jurassic and Early Cretaceous eras.

Regulation and history

The UAE is a federation of seven states, with specific powers delegated to the UAE Federal Government but others reserved for the individual Emirates. The executive branch, otherwise known as the Federal Supreme Court, consists of the rulers of the seven Emirates and is the highest constitutional authority establishing federal policy and sanctioning federal legislation. However, there is no governing petroleum legislation in any of the constituent states of the UAE. E&P operations are generally governed by concession agreements with IOCs although within the various Emirates there are specific laws that provide some fundamental guidelines for the industry. In Abu Dhabi, the Supreme Petroleum Council (SPC) has overall policymaking responsibility for the industry as well as management control over the state oil company, the Abu Dhabi National Oil Company (ADNOC). In Dubai, the industry is effectively regulated through agreement with Dubai's sole oil producing entity, the state-run Dubai Petroleum Establishment. Elsewhere, the Sharjah Petroleum Council develops and administers oil and gas policy in Sharjah and has the authority to oversee the exploration and production activities of the international companies operating there.

Overall, UAE production is dominated by three companies that operate in Abu Dhabi and whose origins can be traced to the grant of concessions for that country's onshore territories in 1939 and offshore in 1955. Initially, IOCs owned and operated UAE's production. Entry to OPEC in 1967, however, and subsequent nationalization in 1974 saw their equity interest diluted and the national oil company, ADNOC, granted a 60% equity interest. Of these three key companies, ADCO, the largest, operates the onshore concessions originally awarded to BP and Shell in 1939 (the concession on which expires in 2014) whilst ADMA-OPCO operates the offshore concessions obtained by BP and Total in the 1950s. The third, ZADCO, operates the giant offshore Upper Zakum field, which the main shareholders of ADMA elected not develop given its development cost at the time (1973).

Figure 540: Ownership of Abu Dhabi's main oil producing companies

	ADNOC	BP	Total	Inpex	Shell	Exxon	Partex	Remark
ADMA	60.0%	14.7%	13.3%	12.0%	-	-	-	Contract expires in 2018
ADCO	60.0%	9.5%	9.5%	-	9.5%	9.5%	2.0%	Contract expires in 2014
ZADCO*	60.0%	-	-	12.0%	-	28.0%	-	Contract expires in 2026

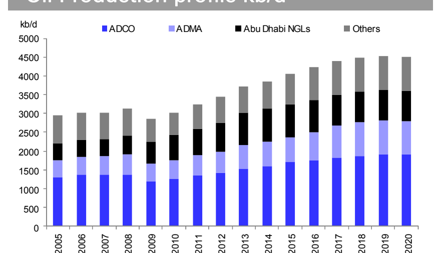
*Source: Deutsche Bank *Shares shown are those for the main Upper Zakum field*

Key facts

Liquids production 2012E	3.4 mb/d
Gas production 2012E	0.6 mboe/d
Oil reserves 2012E	98bn bbls
Gas reserve 2012E	215 TCF
Reserve life (oil)	78 years
Reserve life (gas)	180 years
GDP 2012E ($)	362bn
GDP Growth 2012E (%)	4.0%
Population (m)	5.5m
Oil consumption (mb/d)	671kb/d
Oil exports (mb/d)	2.8mb/d
Fiscal regime	Tax & Royalty
Marginal tax rate	65%-88%
Top 3 liquids fields (2012E)	
ADCO Contract Area	1,413kb/d
ADMA Contract Area	575kb/d
Upper Zakum	560kb/d
Top liquid producers (2012E)	
ADNOC	2,315kb/d
Exxon	291kb/d
BP	220kb/d

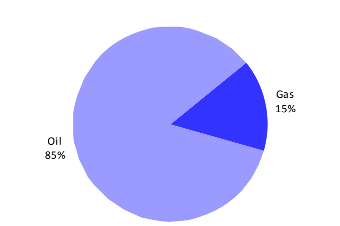
Source: Wood Mackenzie data; EIA; Deutsche Bank estimates

Oil Production profile kb/d



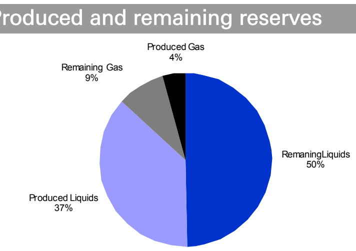
Source: Wood Mackenzie data

Remaining reserves split oil & gas %



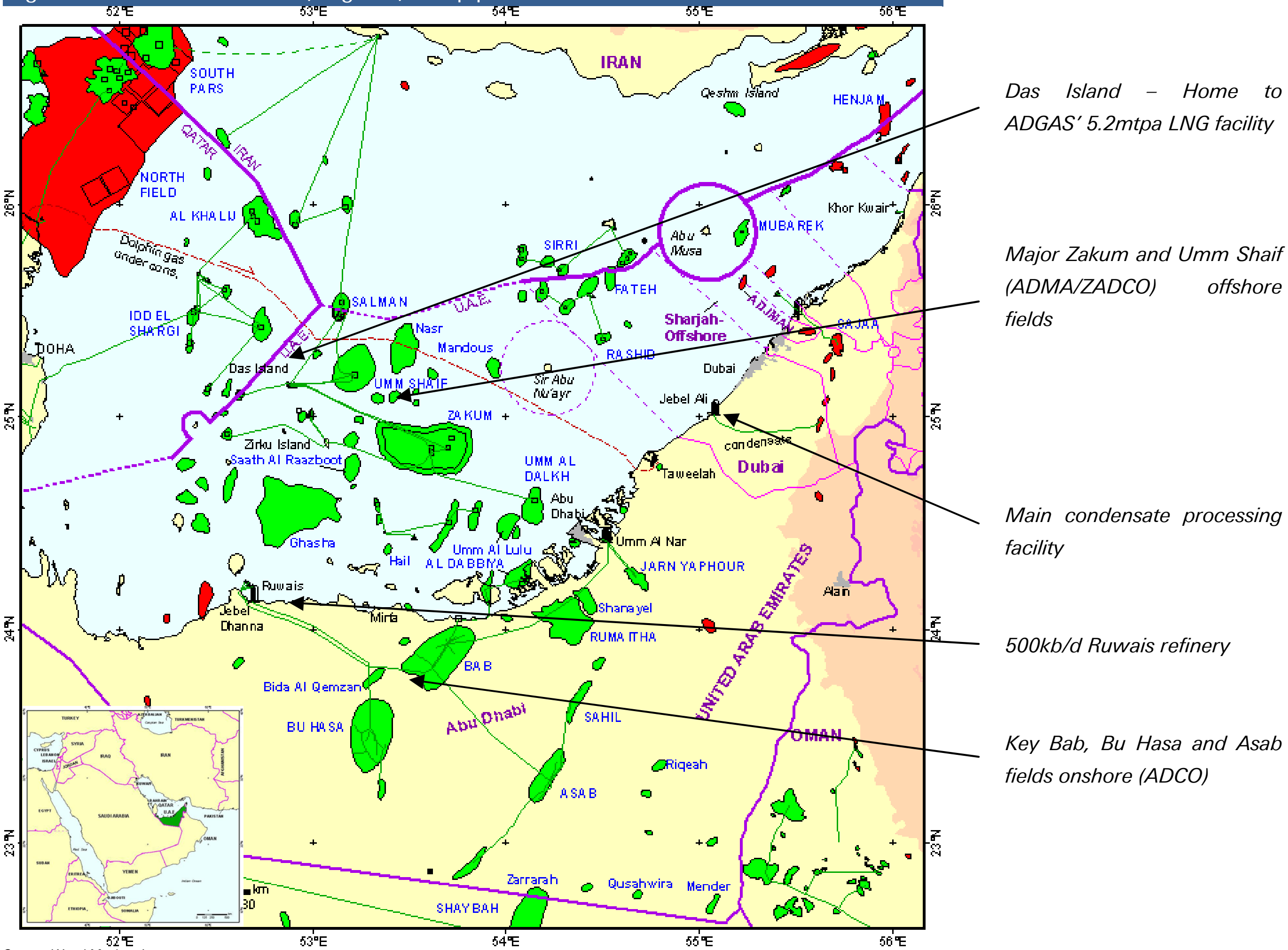
Source: Wood Mackenzie data

Produced and remaining reserves



Source: Wood Mackenzie data

Figure 541: UAE: Main fields, regions, and pipelines



Source: Wood Mackenzie

Licensing

Direct participation in the upstream oil and gas industry in the UAE occurs only in Abu Dhabi and Sharjah and with nearly all of their territories already awarded under concession agreements, licensing opportunities for oil production in the UAE have been relatively limited. In particular no new licences have been awarded in Abu Dhabi since the 1980's although in 2004 Exxon was granted a 28% interest in the Upper Zakum. This was followed by the award of a further two concessions in 2008; Occidental with the onshore Ramhan and Jarn Yaphour fields and ConocoPhilips with the onshore Shah sour gas project. More recently, OMV and Wintershall were granted rights to the Schuweihat gas condensate field with an estimated 2Tcf of wet gas.

Importantly, the concession rights to ADCOs territories are due to expire in 2014 and ADMA's in 2018. Both are thus likely to see discussion around contract extension over the next few years. The contract for Upper Zakum expires in 2026.

Production of Oil and Gas

Oil and liquids production in the UAE, which totalled an estimated 3.2mb/d in 2011 (of which 0.7mb/d represents NGL's) is dominated by a handful of giant fields, most of which were discovered in 1960/70s and which have been producing for several decades. This is illustrated by the following table which depicts the output and reserves of the UAE's major fields. Also implied from this is that, outside Abu Dhabi, only limited liquids are produced by the other Emirates namely 74kb/d in Dubai and 10kb/d in Sharjah. The main IOC producers include Total, BP and, through its position in Upper Zakum, Exxon.

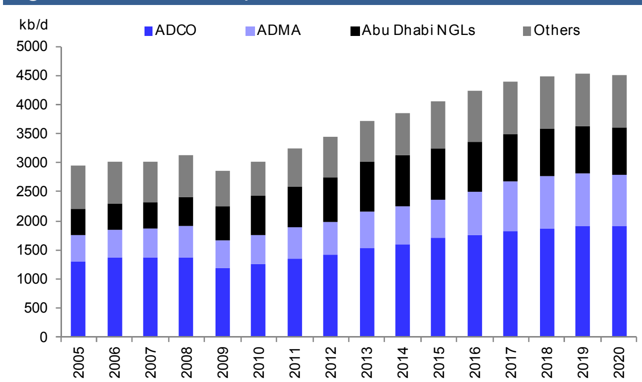
Figure 542: Key fields in Abu Dhabi

	Emirates	Operator	Discovery	Current Reserves (Liquids)	Prod 2012E (kb/d)	Prod 2015E (kb/d)
ADCO	Abu Dhabi	ADNOC	1954	21,114	1,410	1,700
ADMA	Abu Dhabi	ADNOC	1958	9,876	575	660
Abu Dhabi NGLs	Abu Dhabi	ADNOC	1900	7,045	760	870
ZADCO	Abu Dhabi	ADNOC	1964	6,707	25	40
Upper Zakum	Abu Dhabi	ZADCO	1964	3,788	560	630
Shah	Abu Dhabi	ADNOC	1966	400	0	50
Abu Al Bukhoosh	Abu Dhabi	Total	1969	23	20	20

Source: Wood Mackenzie, Deutsche Bank

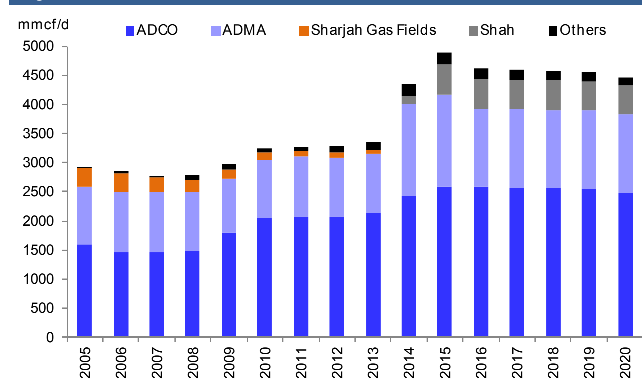
Abu Dhabi intends to increase production capacity from the current sustainable level of 2.5mb/d of oil to 3.5mb/d by 2017 by upgrading and expanding the country's existing fields and infrastructure. Following some delays, this now looks achievable if the present capacity expansion programme is successfully implemented.

Figure 543: UAE – Liquids Production 2005-20E (kb/d)



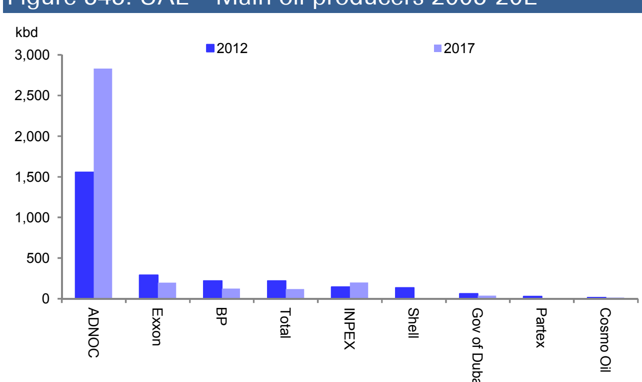
Source: Wood Mackenzie; Deutsche Bank

Figure 544: UAE – Gas production 2005-20E (mscf/d)



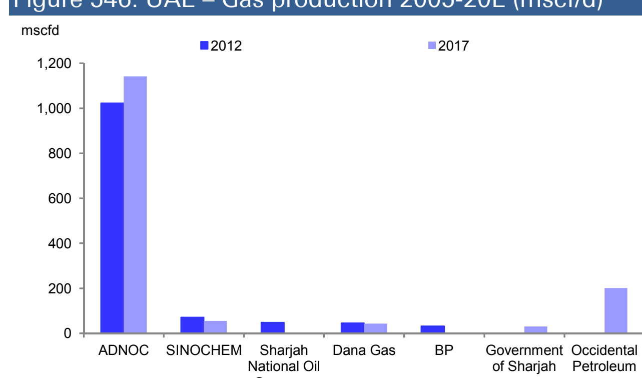
Source: Wood Mackenzie; Deutsche Bank

Figure 545: UAE – Main oil producers 2005-20E



Source: Wood Mackenzie; Deutsche Bank

Figure 546: UAE – Gas production 2005-20E (mscf/d)



Source: Wood Mackenzie; Deutsche Bank

In natural gas, despite significant reserves, strong domestic growth in demand and the need to use significant volumes of associated gas for oil recovery has seen the UAE move from being a net exporter to a net importer, with the emirate both sourcing some 2bcf/d from neighbouring Qatar through the $3.5bn Dolphin project but also via LNG imports in Dubai. Despite this the Emirate continues to honour LNG export contracts to long-term Asian buyers from its two LNG facilities (see below).

Reserves and Resources

At the end of 2011 proven oil reserves in the UAE stood at 97.8 billion barrels and were dominated by those of Abu Dhabi (92 billion). Reserves in the remaining Emirates are largely exhausted (Dubai and Sharjah) or undeveloped. In Abu Dhabi there is substantial scope for further upward revisions given production to date has concentrated on a small number of giant fields with appraisal work on other potential structures incomplete. In gas, the UAE is the world's fourth-largest holder with some 215TCF of proven reserves. The high sulphur content of several fields has, however, added considerably to the complexities associated with future production from this reserve base.

Pipelines and infrastructure

The oil infrastructure of the UAE is well established, especially in Abu Dhabi and Dubai. The offshore network focuses on oil export terminals at Das Island and Zirku Island which are fed by pipelines from the Umm Shaif and Zakum fields. Onshore, an extensive network of pipelines in Abu Dhabi connects with export terminals at Ruwais and Jebel Dhanna as well as feeding the regions two main coastal refineries at Ruwais and Umm Al Nar. More recently, plans have been laid to develop a 1.5mb/d pipeline to carry oil from the Bab field to the port of Fujairah on the eastern coast north of Oman so circumventing the need to run tankers through the Straits of Hormuz.

As with oil, gas infrastructure is also well established. In particular pipelines from the offshore Umm Shaif, Zakum and Abu fields feed the 5.6mpta Adgas LNG facility on Das Island whilst gas processing is concentrated at a 3bcf/d facility located near the Bab onshore oilfield.

Crude Oil Blends and Quality

UAE's crude streams are light and sweet compared with many other Middle Eastern producers. Moreover, many of the undeveloped fields also contain relatively light, sweet, oil. The key blend is that of Murban (40° API) which is sourced from the onshore fields of Bu Hasa, Asab and Bab. Elsewhere, oil from the major offshore fields, which is piped directly to storage facilities onshore, is sold under the respective field names.

Figure 547: Summary of crude blends and characteristics

Crude Oil	Gravity (°API)	Sulphur (%)
Murban Blend	39.6	0.7
Upper Zakum	32.9	1.8
Zakum	40.2	1.0
Umm Shaif	36.5	1.4

Source: The International Crude Oil Market Handbook 2007, Energy Intelligence Research

Broad Fiscal Terms

For the major operating concessions (ADCO, ADMA and ZADCO) the concessionaires are allowed to recover all capital costs and paid a fixed margin of $1/bbl post tax for every equity barrel that they produce. Otherwise, most contracts in the UAE are in the form of concession agreements, where contractors are liable to pay royalty and income tax. Although the contracts are relatively standard across the Emirates, tax and royalty levels vary. Royalty percentages are usually negotiable but stand at 20% for fields with production above 200kb/d (and as such apply to nearly all of the UAE's output). Income tax is payable on net profits at a basic tax rate of 55% although, again, on those fields producing over 200kb/d a higher 85% rate of income tax is applied. For most fields marginal government take thus runs at 88%. Note that capex is offsettable against profits on a 10-year straight-line basis.

Refining and Downstream Markets

With most of its crude exported, the refining capacity of the UAE's four oil refineries at around 710kb/d is modest relative to oil production. Capacity is dominated by the 425kb/d Ruwais refinery in Abu Dhabi. Otherwise, one further 85kb/d refinery resides in Abu Dhabi at Umm Al Nar, the others being located in Dubai (120kb/d at Jebel Ali) and Fujairah (120kb/d). .

LNG

The UAE operates one LNG plant. Built in 1977 the ADGAS facility on Das Island offshore Abu Dhabi has a current capacity of 5.6mtpa. It receives its feed gas from the ADMA operated offshore fields of Zakum and Umm Shaif, amongst others. The plant is owed 70% ADNOC, 15% Mitsui, 10% BP and 5% Total with its volume supplied in large part to TEPCO in Japan. However, to what extent production will continue beyond 2019 is uncertain given the growing domestic requirements for gas.

UAE – Notes

Venezuela

One of the founding members of OPEC, Venezuela is currently estimated to produce around 3.3% of world crude oil supply. With 297bn barrels of oil reserves, Venezuela has the largest reserves of conventional oil in the Western hemisphere. This figure has substantially increased with the inclusion of Orinoco belt extra heavy oil and bitumen reserves, which has further upside potential. Of the 2.2mb/d of oil produced, around 0.8mb/d is consumed domestically, with the balance exported, mostly to the US which receives c.1mb/d of Venezuelan crude and products (or c.8% of total US crude imports). Not surprisingly, oil production is key to the health of the Venezuelan economy, with oil exports accounting for more than three-quarters of total export revenues, about half of total government revenues and about one-third of total GDP. Equally, the national oil company Petroleos de Venezuela SA (PdVSA) is the country's largest employer. Major IOCs operating in the country include Total, Chevron, Shell, Repsol and Statoil.

Basic geology and topology

Venezuela occupies the northern coastal region of South America. Some 35% of the country is covered by sedimentary basins, all in northern Venezuela. There are five main sedimentary basins, all of which yield hydrocarbons. Two of these, the Maracaibo and Eastern Venezuela, are major oil and gas provinces, whilst the Falcon, Barinas-Apure and Margarita basins are far less important. The country's reserves are composed of source rocks that are principally Cretaceous to early Miocene in age. Key conventional fields include the Bolivar Coastal field which is one of the world's largest fields (over 35 billion barrels), El Furrial and Carito Mulata. Otherwise, the Orinoco Belt (Faja) with its four heavy oil projects (Petromonagas, Petrocedeno, Petroanzoategui and Petropiar) contains vast reserves of extra heavy oil and dwarves all other Venezuelan fields.

Regulation and History

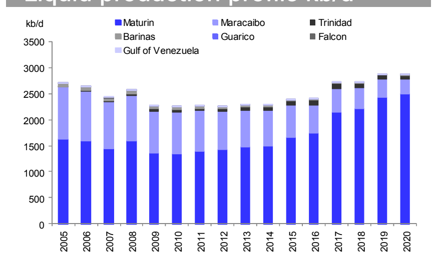
The role of the State has been and continues to be a key factor in Venezuela's oil production and a thorn in the side of many IOCs. Following the nationalisation of the oil industry in 1975, the state-owned PdVSA was created to control the exploration, production, refining, transport, storage and marketing of all hydrocarbons. Production, which peaked at 3.7mb/d in 1970, subsequently decline to an all-time low of 1.7mb/d in 1985 due to PdVSA's failure to invest sufficient funds in the industry. Eventually Venezuela launched 'La Apertura', an initiative to attract foreign investment back to the country. This included the creation of 32 Operating Service Agreements (OSAs) for the development of a series of so-called 'marginal fields' with 22 separate foreign oil companies, in addition to the creation of four 'Strategic Associations' or '*Faja*' to produce extra heavy crude in the Orinoco belt under 35-year licenses. At the same time, PdVSA embarked upon an aggressive investment programme itself with a view to sharply increasing production.

Under the Chavez administration (effective from 1998), Venezuela passed a new Hydrocarbons Law in 2001. This guaranteed PdVSA a majority share in any new projects and stipulated that all new projects would take the form of a joint venture with PdVSA as opposed to an OSA or Strategic Association. Initially, the OSA's and Faja were seen as exempt. However in 2005 the Venezuelan Government announced its intention to convert the terms of the OSAs to those implied under the 2001 Hydrocarbon Law, with PDVSA being granted a majority 60% share in each project. Completed in April 2006 this process saw the conversion of the 32 OSA's to joint ventures entitled 'Empresa Mixta', with several companies that failed to agree compensation effectively seeing their assets expropriated (notably ENI and Total).

Key facts	
Liquids production 2012E	2.2mb/d
Gas production 2012E	0.2mboe/d
Oil reserves 2012E	297 bn bbls
Gas reserve 2012E	195 TCF
Reserve life (oil)	363 years
Reserve life (gas)	460 years
GDP 2012E	$338bn
GDP Growth 2012E (%)	5.7%
Population (m) (2012E)	30.4m
Oil consumption (2011)	0.8mb/d
Oil exports (mb/d)	1.5mb/d
Fiscal regime	Concession
Marginal tax rate (concession)	68%-96.8%
Top 3 Liquids fields (2012E)	
Ceuta-Tomoporo	193 kb/d
Carito-Mulata	192 kb/d
El Furrial	174 kb/d
Top 3 Liquids Producers (2012E)	
PdVSA	1902 kb/d
Chevron	92 kb/d
CNPC	54 kb/d

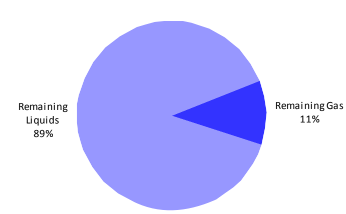
Source: Wood Mackenzie, EIA, IMF

Liquid production profile kb/d



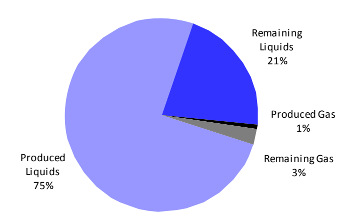
Source: Wood Mackenzie

Remaining commercial reserves



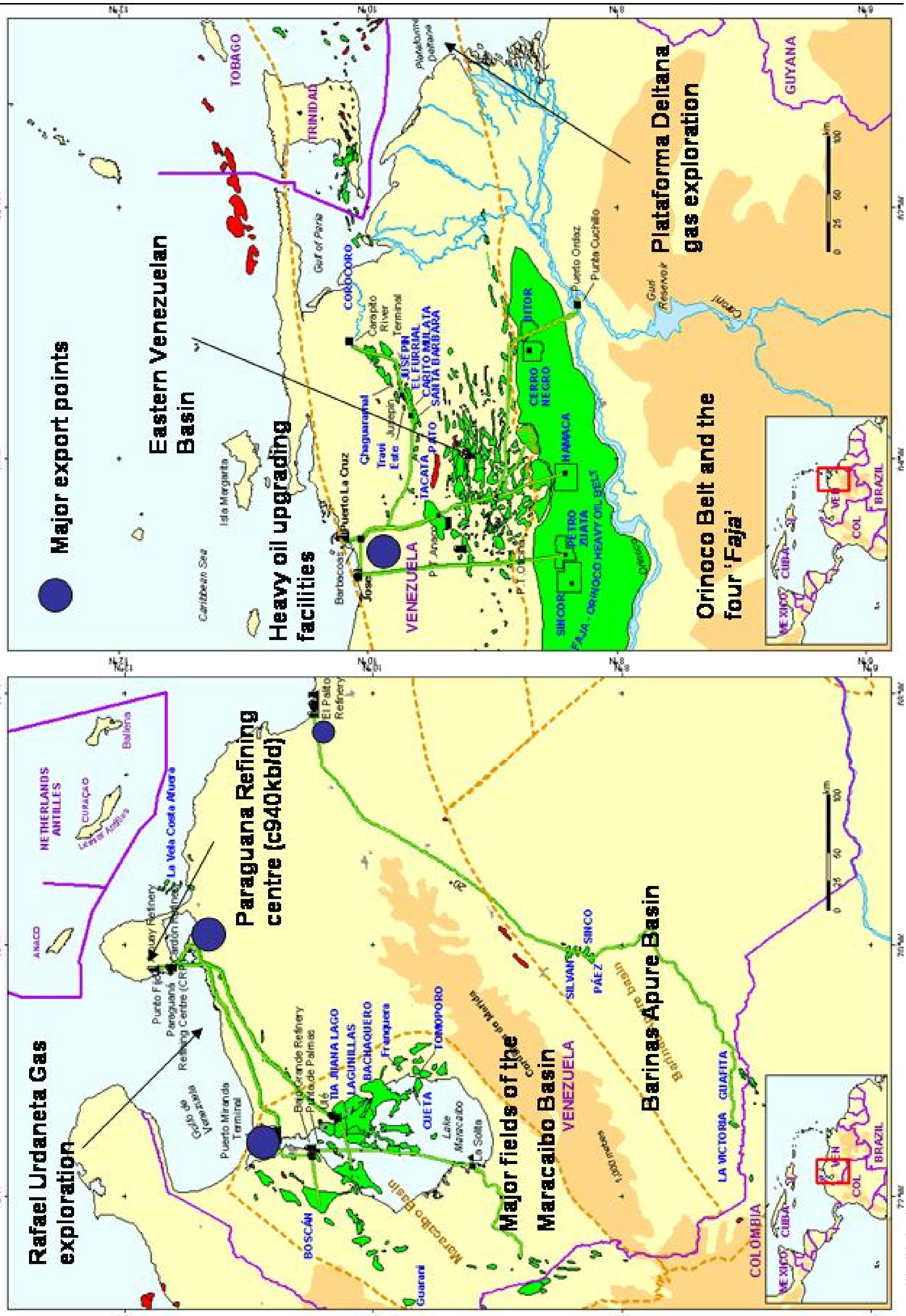
Source: Wood Mackenzie

Initial vs. remaining reserves



Source: Wood Mackenzie

Figure 548: Venezuela – major oil producing regions, gas exploration acreage and export/refining facilities



Source: WoodMackenzie

This trend towards nationalisation was repeated in 2007 when the authorities successfully pressured several IOCs to renegotiate the four Strategic Association contracts under the terms of the 2001 Hydrocarbon law. This again saw PdVSA assume a majority (60%) interest and encouraged ConocoPhillips and Exxon to exit the country. While some see this as a 'renationalisation' of the oil industry, others are confident that the government wants the IOCs to remain for their technical, commercial and management expertise. In the interim, Chavez has stated that NOCs from 'friendly' ally countries (such as Brazil, China, India, Iran, Russia) are more than welcome in the country. Whether these NOCs are willing or, indeed, able to take over such often complex projects remains open to debate.

Licensing

Following the conversion of all oil contracts to Empresa Mixta, licensing has been limited and largely on an adhoc basis. The most recent Carabobo Round took place in October 2008 and sought to attract international partners to help develop additional resource in the Orinoco heavy oil belt. Seven blocks with some 128bn bbls of oil in place were offered with three separate 200kb/d projects envisaged to monetise the resource. Ultimately, only two consortia emerged and were granted rights to take a 40% interest (60% PDVSA) in the development of two projects; PetroIndependencia which will develop the Carobobo 3 project and whose non-state equity is held, amongst others, by Chevron Mitsubishi and Inpex; and Petrocarabobo the non-state equity in which is held by Repsol, Petronas ONGC, Indian Oil Corp and Oil India. Both groups are expected to build a 200kb/d upgrader and with initial heavy oil production scheduled to commence around 2015 (the timelines for upgrader start-up remain less certain).

Carabobo aside several bi-lateral awards have been made on an adhoc basis most notably the Junin projects which again are designed to develop heavy oil acreage. The Junin licensing comprised several projects most notably ENI's Junin 5, a Junin 6 which comprises a consortium of Russian companies not least Gazprom, Rosneft, Surgut and Lukoil and Junin 4 and 8 with Chinese companies Sinopec and CNPC. Again as Empressa Mixta's PDVSA will hold a 60% controlling interest.

Whilst international access to Venezuelan oil has been limited since Chavez came to power, the development of non-associated gas fields was opened to private and foreign companies in 1998. Licensing rounds were held by the Ministry of Mines and Energy (MEM) in 2001 following the issue of the new Gas pricing policy. Under the licence the operator is required to complete a Minimum Exploration Programme (MEP) within five years or the license will be revoked. The licenses are for a period of 35 years (25 years in later licensing rounds). Following this initial licensing round, MEM entered directly into negotiations with a number of preferred bidders in 2002 for Plataforma Deltana (30TCF), in 2005 for Rafael Urdaneta (26TCF) and again in 2006 for Delta Caribe (12TCF). Licenses awarded in these rounds were granted on the basis of a signature bonus.

Production of Oil and Gas

In 2012, Venezuela was the world's eleventh-largest oil producer and the largest net oil exporter in the western hemisphere. Current production is estimated by Wood Mackenzie at some 2.3mb/d of oil and 1.2bcf/d of gas. The majority of production is exported and despite frequent political tensions with the USA, the US remains Venezuela's most important economic trading partner for oil exports. However, exports to USA are on the decline with exports of c950kb/d in 2011 as against 1.4mbd in 2006, a drop of c500kb/d.

The Maracaibo basin (c0.7mbd) has historically been the most important oil-producing basin in Venezuela. However, most of its oil fields are now mature and the basin has been surpassed both in terms of production and remaining reserves by the Maturin basin (c1.4mb/d). Key oil producing fields are detailed below:

Figure 549: Venezuela' s key oil producing fields

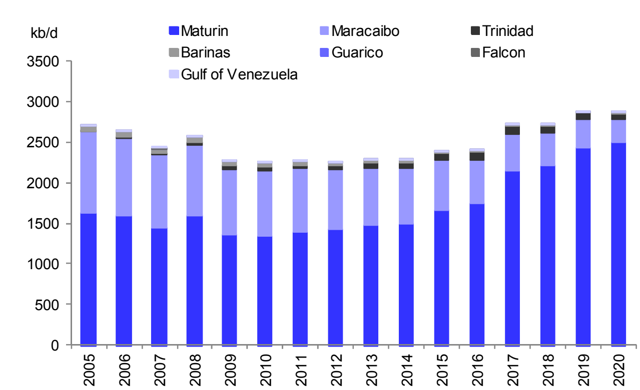
Fields	Initial Reserves	Remaining Reserves	Start up	Production in 2012	Production in 2015
	mmbbls	mmbbls	Year	kb/d	kb/d
Junin 2*	1707	1707	2012	1	200
Petropiar (Hamaca)*	1877	1401	2001	166	190
Petrocedeño (Sincor)*	1885	1354	2000	155	180
Ceuta-Tomoporo	1945	632	1957	193	178
Petrolera Sinovensa*	2168	2031	1980	130	145
Petromonagas (Cerro Negro)*	1438	1077	1999	132	145
El Furrial	3053	625	1986	174	141
Carito-Mulata	2283	499	1942	192	131
Petroanzoátegui (Petrozuata*)	1248	802	1998	100	107
PDVSA-Maracaibo Basin	13530	424	1920	145	103

*Source: Wood Mackenzie, *Extra Heavy oil producing fields in the Orinoco Heavy Oil belt*

Venezuela has a very chequered past in terms of production. The highs of the 1970's, when production reached 3.7mb/d, were followed by a post-nationalisation decline. Subsequent to the introduction of the 'Apertura', Venezuela regularly exceeded its OPEC quota in the guise of increasing production to meet increasing global demand. However, since the election of President Chavez, Venezuela has broadly adhered to the country's quota, recognising the importance of higher prices rather than increased production.

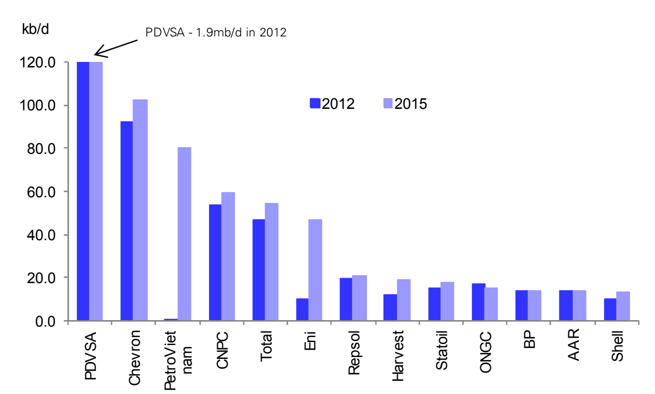
In 2002/3, a nationwide strike effectively shut down a large portion of the country's oil industry. Output fell sharply to 700kb/d for several months as Chavez dismissed almost half of PdVSA employees. Although production was returned to more normal levels on the strike's cessation, the loss of technical staff, together with consequent damage to the main producing reservoirs, has meant that production has never fully recovered to its pre-strike level. Despite official denials, questions remain on Venezuela's ability to produce in line with its stated production capacity of 3.3mb/d.

.Figure 550: Venezuela liquids production 2005-20E (kb/d)



Source: Wood Mackenzie

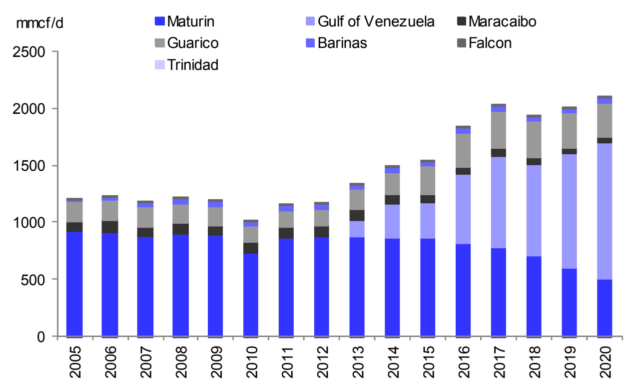
Figure 551: Venezuela oil production 2005-15E



Source: Wood Mackenzie

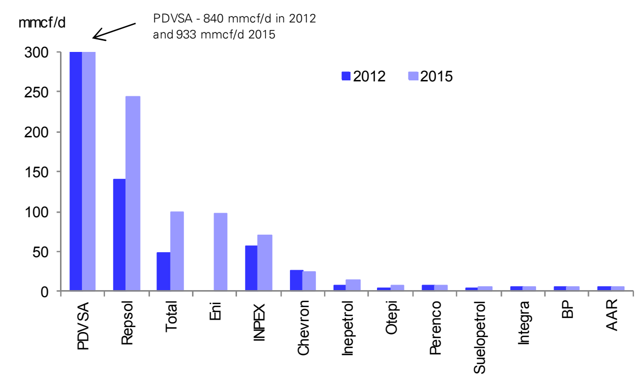
Gas production in Venezuela has always been tied to oil production, with the oil industry consuming up to 70% of output to enhance oil recovery. Total commercial gas production in 2011 was only 1.1bcf. However, more recently the Government has sought to boost gas production and in doing so allowed for improvements in gas pricing not least through the decision to provide for a competitive $3.69/mbtu gas price for the development of the c17Tcf offshore Perla field discovered in the shallow water Falcon Basin in 2009 (ENI, Repsol 50% each). Assuming the delivery of a planned 1.2bcf/d of production from Perla, gas production should consequently see strong growth through the end of the current decade.

Figure 552: Venezuela gas production 2005-20E (mmcf/d)



Source: Deutsche Bank, ** exited country in 2007

Figure 553: Venezuela: Major Gas producers 2012/15E



Source: Deutsche Bank, ** exited country in 2007

Reserves and Resources

With total estimated remaining reserves of oil at 297 billion barrels if its heavy oil barrels are included (or an estimated 18bn excluding the Faja), Venezuela has the largest proven reserves in the western hemisphere – with significant upside potential.

Oil aside, at 195tcf Venezuela also holds the largest gas reserves in South America. However, over 90% of these are associated gas, of which some 70% is injected to improve oil production. As mentioned earlier, recent license rounds (Plataforma Deltana, Delta Caribe) have now seen the country initiate programs to expand non-associated gas production.

Figure 554: Projects in Orinoco Belt

Grouping	Project	Start up	Oil (kb/d)	Ramp year	Partners
Active Projects	Petroanzoategui (Petrozuata)	1998	107		PdVSA (100)%
	Petromonagas (Cerro Negro)	1999	104.73		PdVSA (83.34%), Riosneft* (16.66%)
	Petrocedeno (Sincor)	2000	144		PdVSA (60%), Total(30.3%), Statoil (9.7%)
	Petropiar (Hamaca)	2001	131		PdVSA (70%), Chevron (30%)
Bilateral Agreements	Junin-2	2012	200	2015	PdVSA (60%), PetroVietnam(40%)
	Junin-4	2012	400		PdVSA (60%), CNPC (40%)
	Junin-5	2013	240	2020	PdVSA (60%), Eni (40%)
	Junin-6	2014	450		PdVSA (60%), Russian Consortium (40%)
Carabobo Bid Round	Carabobo-1	2013	400	2019	PdVSA (60%), Petronas (11%), Repsol YPF (11%), ONGC (11%), Indian Oil Corp (3.5%), Oil India (3.5%)
	Carabobo-3	2013	400	2019	PdVSA (60%), Chevron 34%), Japanese Consortium (5%)

Source: EIA, Wood Mackenzie, Deutsche Bank

Pipelines and Infrastructure

Venezuelan crude oil pipeline infrastructure is in excess of 3,400 kilometres and connects the major oil fields with refineries and export terminals on the Caribbean coast, Lake Maracaibo, San Juan and the Orinoco. Most of the existing system is owned by PdVSA, although a number of private companies have constructed pipelines in recent years to transport heavy oil from the Orinoco belt to Jose for upgrading. Key crude oil pipelines include:

Figure 555: Key Crude Oil Pipelines in Venezuela

Pipeline	Operator	From	To	Capacity (kb/d)
P.T. Oficina to Jose	PDVSA	P.T. Oficina	Jose Petrochemical Complex	800
Cerro Negro to P.T. Oficina	PDVSA	Cerro Negro	P.T. Oficina	600
Bachaquero-Puerto Miranda	PDVSA	Bachaquero	Puerto Miranda	480
P.T. Oficina-Puerto La Cruz	PDVSA	P.T. Oficina	Puerto La Cruz	470
Ule - Amuay	PDVSA	Ule	Amuay	380

Source: Wood Mackenzie, Deutsche Bank

Venezuela lacks adequate domestic natural gas infrastructure and it is estimated some $1.2 billion will need to be invested in pipelines over the next five years. At present there are two key pipelines linking the main gas field, Anaco, to both Puerto Ordaz and Puerto la Cruz, with total capacity of 850mmcf/d. The final phase of construction of the Central-Occidental Interconnection (ICO) pipeline completed in 2008. This 550mscf/d pipeline connects the central and western parts of the country, supplying gas for re-injection into oil fields in the west. The Gasoducto Transcaribeno pipeline (completed in 2007) links Venezuela to Columbia and Venezuela started importing gas from Columbia in 2008. The gas is primarily intended for enhanced oil production in the Maracaibo oil field. However, flow is expected to be reversed in 2013, by which time Venezuela hopes to have further developed its own domestic gas resources.

Crude Oil Blends and Quality

Venezuelan crude is predominantly heavy and sour. Its main export blend is BCF-17, a heavy (16° API) sour (2.5%) crude. A significant proportion of its output (c0.6mb/d) is also of synthetic crude produced from upgrading the extra heavy (9˚ API) crude from the projects in the Orinoco belt to syncrude with an API of nearer 26-36° in purpose built facilities. Syncrude, which cannot be sold on the open market, is sold for further upgrading in USA.

Outside these main crude blends, Venezuela also continues to market 100kb/d of Orimulsion, a blend of 70% bitumen, water and surfactant, which is used as boiler fuel in power plants. Orimulsion falls outside the country's OPEC quota given bitumen is seen as a non-oil hydrocarbon.

Broad Fiscal Terms

Venezuela operates through tax and royalty concessions. The 2001 Hydrocarbon Law now governs the fiscal terms applicable to all oil contracts. Both OSAs and Strategic Associations which applied to the majority of foreign operated contracts terminated throughout 2006-07. The corporation tax rate which is applied to all oil projects now stands at 50% and the royalty (which is deductible for tax purposes) is set at 33%. It should however be noted that for the heavy oil projects of the Orinoco Belt royalty is levied upon the value of the heavy oil blend (which tends to sell at a significant discount to WTI) rather than upgraded syncrude. No royalty is payable on upgrading. In 2008, the government introduced a 50% 'Wind Fall Tax' (WFT) on incremental revenues when the Venezuelan basket crude price exceeds USD70/bbl and 60% when it exceeds

USD100/bbl. However, this is deductible against income tax. The WFT was increased in April 2011 with a lowering of the basket oil price from $70/bbl to $40/bbl and the implementation of new rates. As such WFT is now understood to stand at 20% if the price of crude stands at between $40/bbl and $70/bbl, 80% for prices between $70/bbl and $90/bbl, 90% for $90/bbl and $100/bbl and 95% for above $100/bbl. It does not appear, however, to be liable on those projects which have yet to reach payback.

Refining and Downstream markets

In 2011 Venezuela's six domestic refineries had a total refining capacity of 1.3mb/d. The country's two largest refineries, Amuay at 635kb/d and Cardon at 305kb/d, which are located on the Paraguana peninsular to the north east of the Maracaibo Basin, together form the Paraguana Refining Centre (or CRP). These facilities aside production from the Barinas Basin is connected to the 130kb/d El Palito refinery near to Caracas on the Caribbean coast whilst production from the Eastern Venezuelan Basin feeds into the 195kb/d Puerto La Cruz refinery, again on the Caribbean coast line. In 2005, PdVSA announced plans to build three new refineries by 2009 and to upgrade facilities at El Palito and Puerto la Cruz, the result of which would have been the effective addition of c650kb/d to domestic refining capacity. However, no progress has been made to date due to ongoing fiscal issues

Importantly, the development of the Strategic Associations entailed the construction of four heavy oil upgrading facilities on the coast at Jose to the east of Caracas. These refineries process extra heavy oil piped north from the Orinoco belt and produce the Sincor, Petrozuata, Hamaca and Cerro Negro blends.

Separately, it is also of note that through its ownership of the US refiner, CITGO, amongst others PdVSA is actually one of the world's largest refiners with total distillation capacity including that in Venezuela itself of an estimated 3.4mb/d. The company has, however, indicated its desire to sell the CITGO business as well as other regional refining assets.

LNG

Despite its favourable location and significant gas reserves, Venezuela's attempts to establish an LNG industry have to date come to nothing. In 1994 and again in 2000, PdVSA signed agreements with Shell and Mitsubishi to develop gas reserves on the Paria Peninsula. These included the construction of an LNG export terminal (the Mariscal Sucre project). However, difficulties associated with securing a market for the gas saw these projects abandoned. In 2008, PdVSA published a plan that consolidated the proposals for Delta Caribe and the previous Mariscal Sucre project into a single three-train LNG project. The plan envisages the first two trains coming online by 2014, with the third following in 2020. Trains 1 and 2 are to be supplied from Plataforma Deltana fields and Mariscal Sucre area, respectively. Train 3 supply will largely be dependent on the exploration success of the Blanquilla and Tortuga blocks. With limited if any progress made to date, however, the realisation of its export plans looks unlikely in the extreme.

Venezuela – Notes

Section III: The Major Companies

The Europeans

BP

RDS

Total

ENI

Statoil

BG Group

OMV

Repsol

Galp Energia

Tullow

The US

ExxonMobil

Chevron

Conoco

Anadarko

EOG

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Rating
Buy

Europe
United Kingdom

Oil & Gas
Integrated Oils

Company
BP

Reuters	Bloomberg
BP.L	BP/ LN

Price at 16 Jan 2013 (GBP)	446.00
Price Target (GBP)	500.00
52-week range (GBP)	472.0- 415.50

Rebuilding

The traumas induced following the Deep Water Horizon tragedy have resulted in a much-slimmed-down BP. Having realized over $60bn from divestments to fund its liabilities, BP now appears far better positioned to return to sustainable growth. Focus is on driving cash flow for the benefit of shareholders with a concentration on internal opportunities that offer better return, together with greater emphasis on the drill bit to add value. In the downstream a more concentrated portfolio advantaged by location should provide significant cash, positioning E&P more favourably to invest for growth.

Upstream: The divestment of peripheral positions across a host of geographies means that relative to its peers, BP's upstream portfolio is narrower and more concentrated. The business retains a bias towards conventional oil and the deepwater with strong potential in high-margin plays, not least in the US GoM and Angola. Following the effective swap of its 50% interest in TNK-BP for a near-20% holding in Russia's Rosneft, BP has also rejuvenated its potential to benefit from Russian barrel and profit growth. In the near term, recovery in high-margin GoM barrels together with start ups in Angola and the North Sea are expected to drive production. Further out, BP will need to invest relatively heavily to mature its range of growth options.

Downstream: Following the divestment of c700kb/d of US refining capacity, BP's portfolio looks relatively well positioned. Its footprint is narrower than many of its super-major peers' and is concentrated on locations that in many cases offer competitive advantage. The impending completion of the significant upgrade of its 405kbd Whiting refinery in the US Midwest suggests a business that should now be capable of attaining double-digit RoCE across the cycle and with it support divisional FCF of c$4bn p.a.

Other: Outside refining BP's interests in chemicals are now essentially focused upon polyester chain, in which it has market-leading technology and capacity. In lubricants the build out of its Castrol brand over the past decade has also provided a separate stream of fairly robust profits growth.

Valuation & Risk: Our 500p price target reflects our view that BP will continue to trade at a st discount to peers ahead of the resolution of Macondo. We target a modest 8x 2013E P/E multiple – a c10% discount to our c9x 2013 sector target P/E multiple – and see scope for EPS upside from high-margin barrel delivery. Risks include an adverse court ruling on Macondo.

Forecasts and ratios

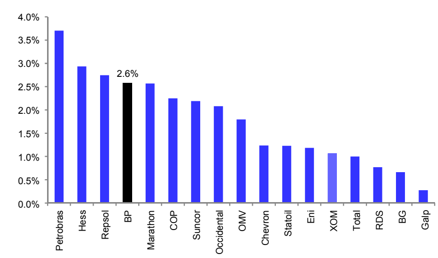
Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (USD)	1.09	1.15	0.91	0.96	1.03
P/E (x)	6.9	6.2	8.1	7.6	7.1
Dividend Yield (%)	0.9	3.9	4.6	5.2	5.5

Source: Deutsche Bank estimates, company data

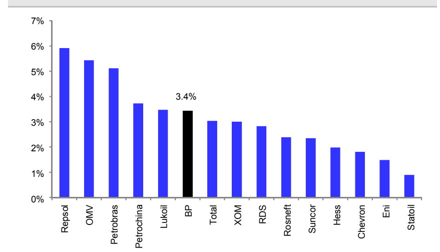
BP Production Profile 2010-15E

Upstream CAGR (2012-15E)	3.0%
Oil production (2012E)	2,295kb/d
Gas production (2012E)	1,284kboe/d
Oil Reserves (1P) 2011	10.6bn/bbls
Gas Reserves (1P) 2011	7.2bn/boe
Refining capacity	2,679kb/d
Marketing volumes	3,311b/d
Wood Mackenzie 2P(E) Total reserves	30.4bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.15%

Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)

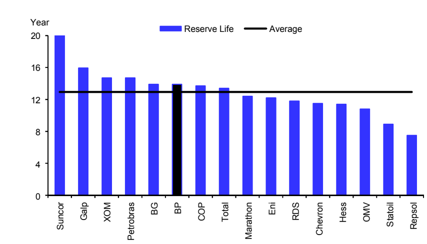


Figure 556: BP Asset Model from 1 January 2013 at $100/bbl and $4/mmbtu US gas

Upstream	Comments	Value ($ Million)	Value (GBP Million)	2 P Reserves	Value/2P Reserves	% of Total EV	GBP Value per Share
Algeria		2,212	1,383	297	7.4	1.0%	0.07
Angola		20,397	12,748	1549	13.2	9.3%	0.67
Argentina (sales value)		7,060	4,413	887	8.0	3.2%	0.23
Australia		8,487	5,304	1039	8.2	3.9%	0.28
Azerbaijan	*Key asset - upside in Shah Deniz*	16,271	10,169	1990	8.2	7.4%	0.53
Bolivia		312	195	83	3.8	0.1%	0.01
Brazil		2,244	1,402	204	11.0	1.0%	0.07
Canada Sunrise		2,696	1,685	1422	1.9	1.2%	0.09
Egypt	*Excludes large technical reserves*	3,957	2,473	1972	2.0	1.8%	0.13
India		791	494	269	2.9	0.4%	0.03
Indonesia		1,637	1,023	685	2.4	0.7%	0.05
Iraq		862	539	2519	0.3	0.4%	0.03
Norw ay		4,452	2,783	507	8.8	2.0%	0.15
Oman		221	138	1538	0.1	0.1%	0.01
Russia	*Assumes Rosneft valuation of TNK*	27,689	17,306	7774	3.6	12.6%	0.91
Trinidad		3,885	2,428	1188	3.3	1.8%	0.13
United Arab Emirates	*License set to expire*	872	545	262	3.3	0.4%	0.03
United Kingdom		10,004	6,252	953	10.5	4.5%	0.33
United States Alaska		8,555	5,347	1336	6.4	3.9%	0.28
United States Gulf Coast		447	280	533	0.8	0.2%	0.01
United States GoM ex Plains	*The BP heart*	44,312	27,695	2865	15.5	20.2%	1.45
US MidContinent		2,417	1,511	1284	1.9	1.1%	0.08
US Rocky Mountains		6,398	3,999	1299	4.9	2.9%	0.21
Sub-Total		**176,194**	**110,121**	**32,469**	**5.4**	**80.1%**	**5.78**
Refining							
Europe		7,152	4,470			3.3%	0.23
USA ex TC and Carson		6,836	4,273			3.1%	0.22
Rest Of World		1,590	994			0.7%	0.05
Sub-Total		**15,579**	**9,737**			**7.1%**	**0.51**
Marketing		11,035	6,897			5.0%	0.36
Refining & Marketing		**26,614**	**16,634**			**12.1%**	**0.87**
Chemicals		**9,000**	**5,625**			**4.1%**	**0.30**
Gas, Power & Renewables							
Liquefaction plants	*Liquefaction assets only*	2,769	1,731			1.3%	0.09
LNG contracts		3,574	2,234			1.6%	0.12
Renew ables (BP estimate - now w /off)		-	-			0.0%	0.00
Ships		1,750	1,094			0.8%	0.06
Sub-Total		8,094	5,058			3.7%	0.27
Total Enterprise Value		**219,901**	**137,438**			**100.0%**	**721**
Adjusted end-2012 Net Debt		19,098	11,936			8.7%	63
Net Asset Value		**200,803**	**125,502**			**91.3%**	**658**
Macondo costs (post tax) inc $7.5bn DT asset		(1,011)	(632)			(0)	(3)
Macondo Criminal & Civil excess		6,500	4,063			3.0%	21
NAV		**195,314**	**122,071**			**88.8%**	**640**
Market Capitalisation		**138,750**	**86,719**				**455**
Discount to NAV		**-29%**	**-29%**				**-29%**

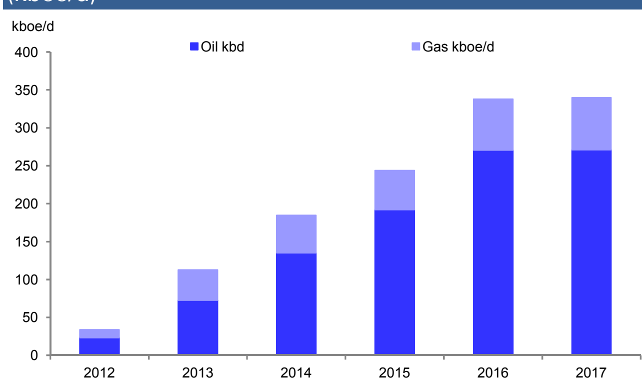
Source: Deutsche Bank

Figure 557: BP – Main Projects 2012-2015+ -

Name	Country	-- Reserves--		---- Peak----		Interest	PSC?	2012	2013	2014	2015	2016	2017
		Oil	Gas	Oil	Gas	%							
2012													
Block 31 PSVM*	Angola	520	0	160	0	26.7%	Yes	1	20	42	42	42	40
Block 15 Clochas	Angola	250	0	100	0	26.7%	Yes	10	25	23	20	18	16
Galapagos	US GoM	121	82	40	30	66.7%	No	12	20	22	22	22	18
Skarv*	Norway	180	2410	80	525	24.0%	No	1	31	28	25	23	21
Devenick*	UK	6	237	3	100	89.0%	No	10	0	0	0	0	0
2013													
Angola LNG	Angola	0	8250	0	875	13.6%	Yes		17	23	23	23	23
Na Kika Phase 3*	US GoM	n.a.	n.a.	25	90	50.0%	No			5	10	10	10
2014													
Kinnoul*	UK	45	24	35	20	77.0%	No			15	25	22	19
Sunrise	Canada	2840	0	60	0	50.0%	No			2	20	30	30
Chirag Oil*	Azerbaijan	n.a.	n.a.	140	0	36.0%	Yes			5	2	35	35
Mars B	US GoM	120	150	130	50	29.0%	No			10	30	35	35
CLOV	Angola	565	0	150	0	16.7%	Yes			10	25	25	25
2015+													
QUAD4*	UK	400	150			33.5%	No					35	43
Clair*	UK	700	150	110	30	28.6%	No					18	25
TOTAL								**34**	**113**	**185**	**244**	**338**	**340**
Of which													
Oil								*23*	*73*	*135*	*192*	*271*	*271*
Gas								*11*	*40*	*50*	*52*	*67*	*69*

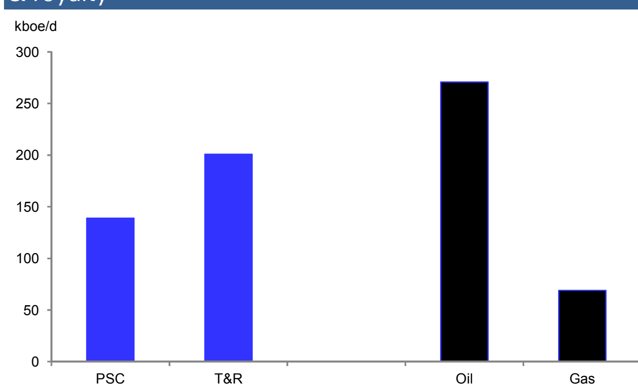
*Source: Wood Mackenzie, Deutsche Bank *=Operator*

Figure 558: Production growth by hydrocarbon type (kboe/d)



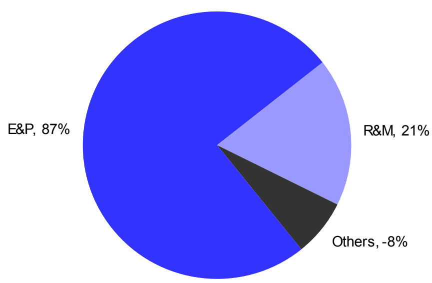
Source: Deutsche Bank

Figure 559: production growth by oil/gas and PSC or tax & royalty



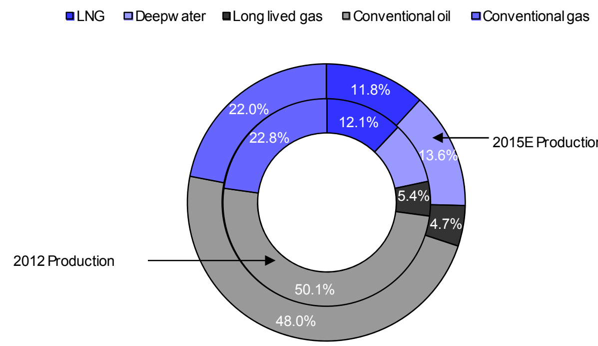
Source: Deutsche Bank

Figure 560: 2012E clean net income USD17,242m



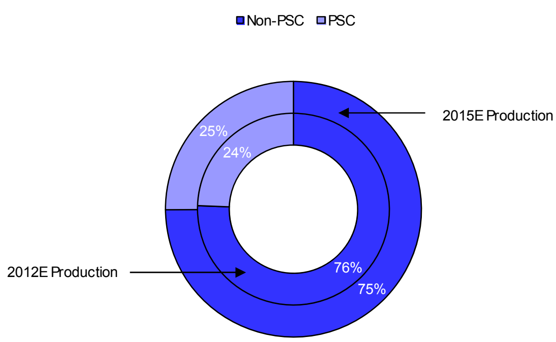
Source: Deutsche Bank

Figure 561: Trends in E&P Production



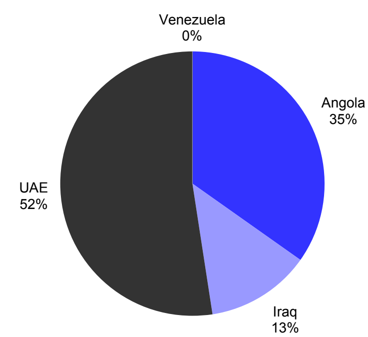
Source: Deutsche Bank

Figure 562: PSC exposure 12E-15E – essentially static



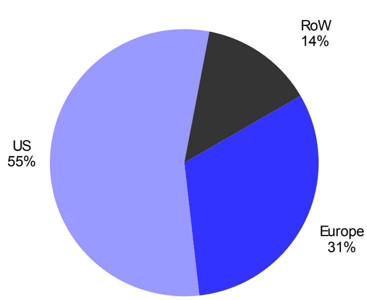
Source: Deutsche Bank

Figure 563: OPEC production 11% of total in 2012E



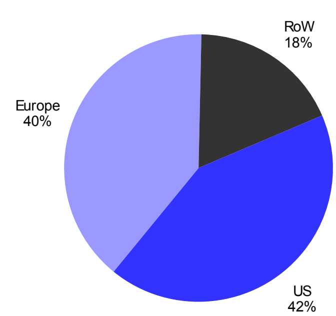
Source: Deutsche Bank

Figure 564: BP 2012 refining CDU 2,679kb/d



Source: Deutsche Bank

Figure 565: BP 2011 marketing by region



Source: Deutsche Bank

Rating
Hold

Europe
Netherlands

Oil & Gas
Integrated Oils

Company
Royal Dutch Shell plc

Reuters	Bloomberg
RDSa.L	RDSA LN

Price at 16 Jan 2013 (GBP)	2,166.00
Price Target (GBP)	2,475.00
52-week range (GBP)	2,331.50 - 1,970.50

Sustainable growth

Following the 2004 reserves debacle, Shell is a company transformed. Exploration success, whilst expensive, has afforded management the confidence that it can discover resource; the business has been simplified, driving savings and operational improvement; while Shell's strategic investments in growth areas - many of which are long-lived, geared to a high oil price and afford access to a substantial resource base - are now highly economically attractive. In the downstream, greater marketing exposure than its peers adds robustness. Resource depth and optionality, combined with a growing proportion of duration-type cash flows, position the business ahead of the peers for long-term sustainable dividend growth.

Upstream: Having committed to substantial capital and exploration spend, Shell now boasts one of the few truly global portfolios and holds a resource base that is deeper and broader and offers considerable optionality. Shell is the global IOC leader in LNG, technology leader in FLNG, a leader in the Canadian oil sands and is pioneering new uses of gas including GTL via its Pearl GTL project in Qatar. These long-term positions mean that Shell is well placed to enjoy sustained reserve and production growth and offers the potential for strong cash generation from a large suite of duration-type assets. Opportunities for investment are broad and sizeable.

Downstream: Downstream the emphasis remains on sustained cash generation and a focus on the growing markets of Asia Pacific. The company is a substantial European refiner but also has significant exposure to more profitable US markets, not least through its Motiva partnership with Aramco. In contrast with most of its peers, the company's downstream activities are more heavily weighted towards marketing, which historically has represented at least 50% of Oil Products' net income and adds greater robustness to the downstream portfolio. In Chemicals, US Shell's global portfolio positions it as a top 10 global petchem producer.

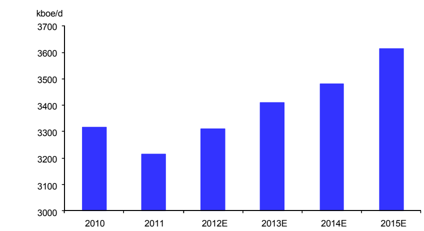
Valuation & risk: The most robust of the European majors, Shell deserves a premium multiple, in our view. We see fair value at 2475p assuming c4% forward dividend growth suggesting a fair multiple of c9x earnings. Downside risks include cost over-runs in Australia and unexpected downtime at Pearl GTL.; upside risk a stronger-than-expected exploration result in French Guiana.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (USD)	2.95	3.97	4.15	4.52	4.61
P/E (x)	9.9	8.7	8.4	7.7	7.5
DPS (USD)	1.68	1.68	1.72	1.80	1.88

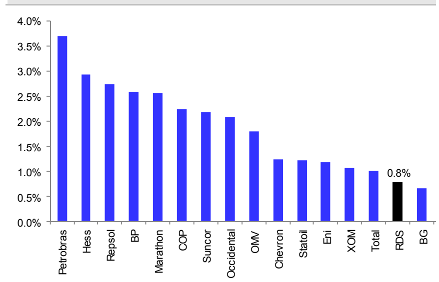
Source: Deutsche Bank estimates, company data

RDS Production Profile 2010-15E

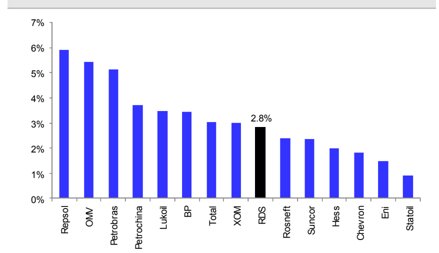


Upstream CAGR (2012-15E)	3.0%
Oil production (2012E)	1,640kb/d
Gas production (2012E)	1,669kboe/d
Oil Reserves (1P) 2011	6.0bn/bbls
Gas Reserves (1P) 2011	8.2bn/boe
Refining capacity	3,022kb/d
Marketing volumes	6,196b/d
Wood Mackenzie 2P(E) Total reserves	30.4bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.15%

Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)

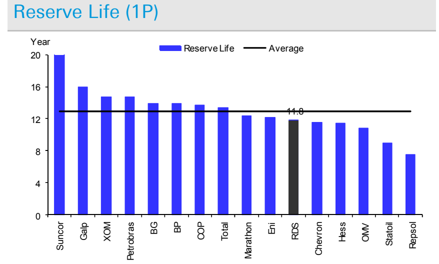


Figure 566: RDS Asset Model from 1 January 2013 at $100/bbl and $4/mmbtu US gas

Upstream	Comments	Value ($ Million)	Value (GBP Million)	2 P Reserves	Value/2P Reserves	% of Total EV	Value per Share (p)
Argentina		216	135	31	6.9	0.1%	2
Australia NWS/Domestic		12,421	7,763	2702	4.6	3.4%	122
Australia Gorgon		4,542	2,839	889	5.1	1.3%	45
Australia Prelude		3,578	2,236	862	4.2	1.0%	35
Brazil		3,017	1,886	134	22.6	0.8%	30
Brunei		11,236	7,023	866	13.0	3.1%	110
Canada	Muskeg and Jackpine only in the sands	26,045	16,278	4140	6.3	7.2%	256
China		663	414	98	6.8	0.2%	7
Denmark		4,652	2,908	328	14.2	1.3%	46
Egypt		1,073	670	218	4.9	0.3%	11
French Guiana		1,605	1,003	112	14.3	0.4%	16
Gabon		2,082	1,301	92	22.6	0.6%	20
Germany		1,778	1,112	175	10.1	0.5%	17
Indonesia		280	175	197	1.4	0.1%	3
Iraq		1,089	681	2419	0.5	0.3%	11
Ireland		1,586	991	67	23.6	0.4%	16
Italy		4,706	2,941	248	19.0	1.3%	46
Kazakhstan		11,483	7,177	1411	8.1	3.2%	113
Malaysia	Significant potential exploration upside	9,810	6,131	1472	6.7	2.7%	96
Netherlands Conc		21,787	13,617	1782	12.2	6.0%	214
New Zealand		1,298	811	119	10.9	0.4%	13
Nigeria	Huge value in NLNG	29,287	18,305	3722	7.9	8.1%	288
Norway		5,167	3,229	963	5.4	1.4%	51
Oman		16,357	10,223	1181	13.8	4.5%	161
Philippines		1,684	1,053	136	12.4	0.5%	17
Qatar		41,908	26,193	3691	11.4	11.6%	412
Russia		6,328	3,955	888	7.1	1.8%	62
UAE Abu Dhabi OPCO		-610	-381	58	-10.5	-0.2%	-6
United Kingdom		6,711	4,194	754	8.9	1.9%	66
United States Gulf Coast		553	346	3628	0.2	0.2%	5
United States Gulf of Mex Deep		25,214	15,759	1817	13.9	7.0%	248
US Conc MidContinent		390	244	169	2.3	0.1%	4
US Northeast		-1,218	-761	2611	-0.5	-0.3%	-12
United States Rocky Mount		413	258	835	0.5	0.1%	4
US Conc West Coast		7,663	4,789	367	20.9	2.1%	75
Venezuela Concessions		371	232	30	12.3	0.1%	4
Sub-Total		**265,179**	**165,737**	**39215**	**6.76**	**73.6%**	**2,606**
Refining							
Europe		8,102	5,064			2.2%	80
Africa		331	207			0.1%	3
Middle East		848	530			0.2%	8
Asia Pacific (ex Showa)		3,572	2,232			1.0%	35
USA		9,924	6,202			2.8%	98
Other Western Hemisphere		1,392	870			0.4%	14
Riazen (Brazil JV)		4,630	2,894			1.3%	45
Marketing		29,862	18,664			8.3%	293
Sub-Total		**58,660**	**36,663**			**16.3%**	**576**
Power and Others							
Ships		2,685	1678			0.7%	26
LNG Contracts - Downstream share		3,599	2250			1.0%	35
Gas and Power	*Largely regas. LNG in upstream*	3,184	1990			0.9%	31
Sub-Total		**9,468**	**5,918**			**2.6%**	**93**
Chemicals		**17,527**	**10954**			**4.9%**	172
Equity Interests							
Woodside	24% interest	6575	4110			1.8%	65
Showa Shell	35% interest	2333	1458			0.6%	23
Comgas	18% interest	529	330			0.1%	5
		9437	**5898**			**2.6%**	**93**
Total Enterprise Value		**360,271**	**225,169**			100.0%	**3,540**
Adjusted end-2012 Net Debt		22,980	14,362			6.4%	226
Net Asset Value		**337,291**	**210,807**			**93.6%**	**3,314**
Market Capitalisation		**222,871**	**139,294**				**2,190**
Discount to NAV		**-34%**	**-34%**				**-34%**

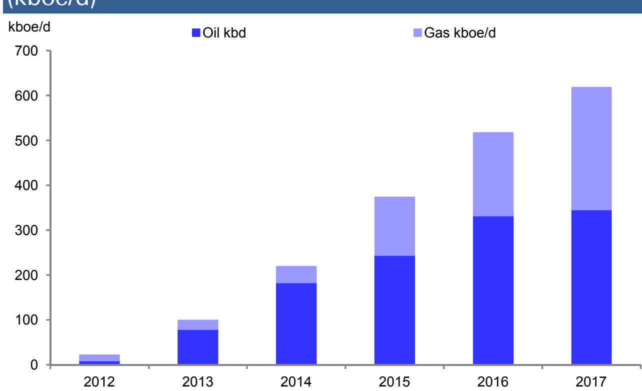
Source: Deutsche Bank

Figure 567: Royal Dutch Shell – Main Projects 2012-15+

Name	Country	-- Reserves --		--- Peak ---		Interest %	PSC?	2012	2013	2014	2015	2016	2017	NPV
		Oil	Gas	Oil	Gas									$m
2012														
Caesar Tonga	US GoM	205	200	50	50	22%	Yes	7	9	10	10	10	10	890
Gumusut Kapak	malaysia	530	285	125	60	33%	Yes	1	33	42	42	40	35	3850
Pluto LNG	Australia	60	4700	10	660	21%	No	13	20	23	23	23	23	-3600
Majnoon	Iraq	12600	5380	1000	-	45%	No	1	20	40	50	50	55	n.a.
2013														
BC-10 Phase 2	Brazil	150	0	35	-	50%	Yes		17	23	23	23	23	n.a.
Kashagan Phase 1	Kazakhstan	8195	4760	970	-	17%				26	49	60	60	-2680
Na Kika Phase 3	US GoM	n.a.	n.a.	25	90	50%	No			5	10	10	10	n.a.
2014														
Cardamom	US GoM	86	260	30	90	100%	No			32	40	50	45	n.a.
Corrib	Ireland	0	850	0	350	45%	No			1	27	24	21	-1315
Gorgon LNG	Australia	244	36600	18	2620	25%	No			6	43	95	110	10645
Mars B	US GoM	120	150	100	50	71%	No			10	30	35	35	n.a.
KBB	Malaysia	100	3000	10	600	30%	Yes			1	26	33	33	1330
2015														
QUAD4	UK	400	150			26%	No					35	43	n.a.
Clair	UK	700	150	110	30	28%	No					18	25	n.a.
Tempa Rossa	Italy	305	-	50	-	25%	No					11	15	2671
Prelude FLNG	Australia	110	2850	33	555	70%	No						60	2070
Wheatstone LNG	Australia	170	11000	21	1410	6%	No						15	5350
Total								**22**	**99**	**219**	**373**	**517**	**618**	
Of which														
Oil								*9*	*79*	*183*	*244*	*332*	*346*	
Gas								*13*	*20*	*36*	*129*	*185*	*272*	

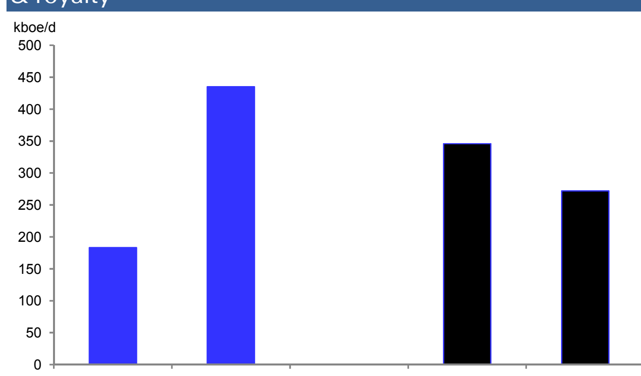
Source: Wood Mackenzie, Deutsche Bank

Figure 568: Production growth by hydrocarbon type (kboe/d)



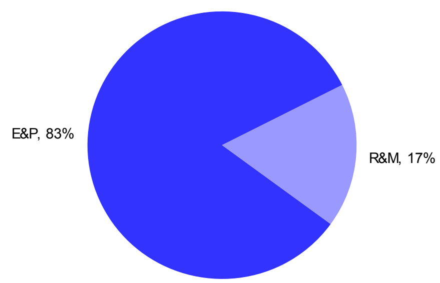
Source: Deutsche Bank

Figure 569: production growth by oil/gas and PSC or tax & royalty



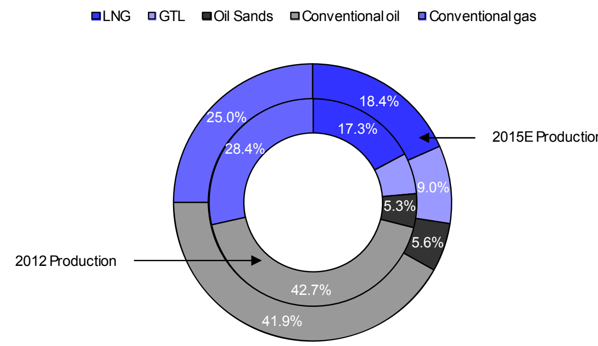
Source: Deutsche Bank

Figure 570: 2012E clean net income USD26,066m



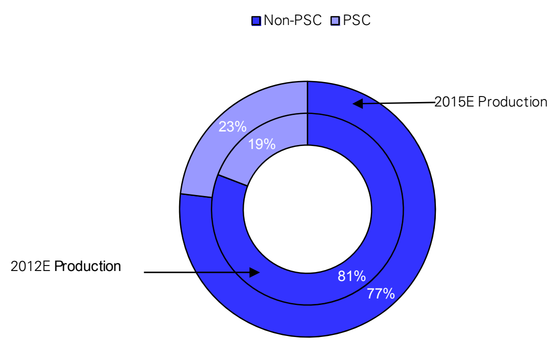
Source: Deutsche Bank

Figure 571: Trends in E&P Production



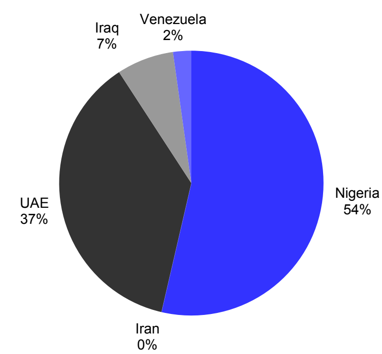
Source: Deutsche Bank

Figure 572: PSC exposure 12E-15E – on the increase



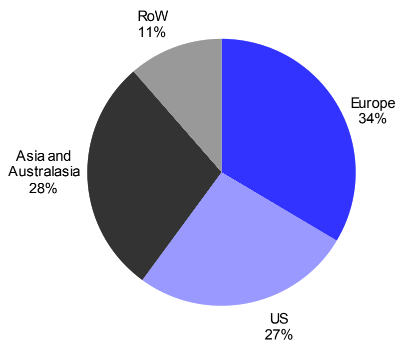
Source: Deutsche Bank

Figure 573: OPEC oil production 10% of total in 2012E



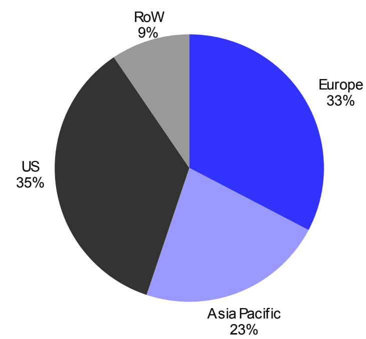
Source: Deutsche Bank

Figure 574: RDS 2012 refining CDU 3,022kb/d



Source: Deutsche Bank

Figure 575: RDS 2011 marketing by region



Source: Deutsche Bank

Rating
Buy

Europe
France

Oil & Gas
Integrated Oils

Company
Total SA

Reuters	Bloomberg
TOTF.PA	FP FP

Price at 16 Jan 2013 (EUR)	39.90
Price Target (EUR)	44.00
52-week range (EUR)	42.70 - 33.63

Repositioning

Having bulked up considerably following its mergers with Fina in 1999 and Elf in 2000, Total is currently focused on the build-out of positions that offer longevity in a number of new geographies. After several years of static production, a clutch of new projects - many of which are concentrated on duration-type assets - suggests a better outlook for growth. Downstream, Total's status as Europe's leading refiner by capacity is gradually being thrown off through both regional divestment and the build-out of positions overseas.

Upstream: Total's E&P portfolio continues to be characterized by its geographical and functional diversity, with significant plays in conventional onshore and shallow water but also the deepwater and, importantly, LNG. The company is the leading producer in West Africa and holds strong positions in the Middle East but is notable for its limited presence in the US market. Consistently strong on project execution, recent years have seen an increased emphasis on exploration and the establishment of new geographies for growth. Total's portfolio comprises a greater exposure to PSCs than most, with the higher proportion of production arising in OPEC territories.

Downstream: Although recent years have seen the divestment or closure of significant European refining capacity, Total's dominance of its home market means that at 1.8mb/d it retains the unenviable badge of being Europe's largest refiner with a c13% market share. However, an emphasis on European restructuring initiatives to reposition the business through partnerships in other territories, not least Saudi Arabia, should help support improved profitability. In Chemicals, the company retains a material bulk European business but also an enviable specialties business that achieves good profitability from its activities in adhesives and resins. .

Other: Whilst underwhelming to date, Total's 2010 acquisition of a 60% interest in the US quoted solar company Sun Power offers it a decent opportunity for renewable growth in both the US and European solar markets.

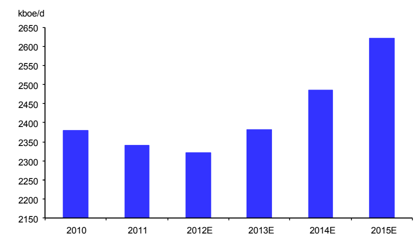
Valuation & risk: Standing at a discount to its 10-year sector P/E and yield relative ranges, we believe that exploration potential means Total's risk/reward is favourably disposed to the upside at current levels. Paying heed to the investment-driven, cash flow pressures we assign a 10% discount to our c9x 2013E sector target and set a €44/share price objective. Key risks include exploration disappointment and a delayed restart at Elgin-Franklin.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (EUR)	4.53	4.98	5.46	5.81	6.19
P/E (x)	8.8	7.8	7.3	6.9	6.4
DPS (EUR)	2.28	2.28	2.32	2.40	2.48

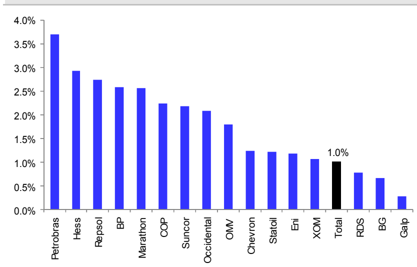
Source: Deutsche Bank estimates, company data

Total Production Profile 2010-15E

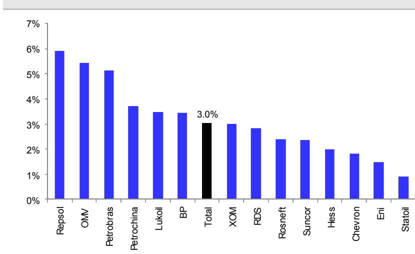


Upstream CAGR (2012-15E)	4.2%
Oil production (2012E)	1,381kb/d
Gas production (2012E)	900kboe/d
Oil Reserves (1P) 2011	5.8bn/bbls
Gas Reserves (1P) 2011	5.6bn/boe
Refining capacity	2,088kb/d
Marketing volumes	2,424b/d
Wood Mackenzie 2P(E) Total reserves	15.3bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.34%

Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)

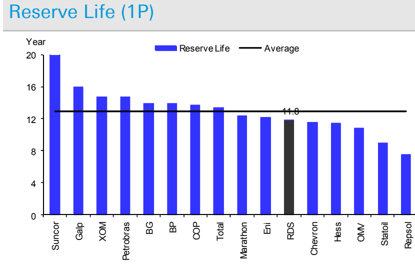


Figure 576: Total Asset Model from 1 January 2013 at $100/bbl and $4/mmbtu US gas

Upstream	Comments	Value ($ Million)	Value (EUR Million)	2 P Reserves	$ Value/2P Reserves	% of Total EV	EUR Value per Share
Algeria		219	165	374	0.6	0.1%	0.07
Angola		21634	16266	1604	13.5	11.8%	6.88
Argentina		1662	1250	259	6.4	0.9%	0.53
Australia		5030	3782	1063	4.7	2.7%	1.60
Azerbaijan		1998	1502	369	5.4	1.1%	0.64
Bolivia		1024	770	215	4.8	0.6%	0.33
Brunei		446	335	58	7.7	0.2%	0.14
China		805	605	206	3.9	0.4%	0.26
Canada Oil Sands		3247	2441	1568	2.1	1.8%	1.03
Congo Braz		4880	3669	477	10.2	2.7%	1.55
France		134	101	32	4.2	0.1%	0.04
French Guiana		892	671	62	14.3	0.5%	0.28
Gabon		2615	1967	207	12.7	1.4%	0.83
Indonesia		4675	3515	462	10.1	2.5%	1.49
Iraq		249	187	419	0.6	0.1%	0.08
Italy		2244	1687	222	10.1	1.2%	0.71
Kazakhstan		10112	7603	1189	8.5	5.5%	3.22
Libya		3182	2393	91	35.1	1.7%	1.01
Myanmar		2328	1750	211	11.0	1.3%	0.74
Netherlands		1120	842	64	17.5	0.6%	0.36
Nigeria		21112	15873	2284	9.2	11.5%	6.72
Norw ay		11031	8294	1685	6.5	6.0%	3.51
Oman		2412	1814	139	17.4	1.3%	0.77
Qatar		9196	6915	1620	5.7	5.0%	2.93
Russia		8133	6115	1565	5.2	4.4%	2.59
Thailand		2249	1691	152	14.8	1.2%	0.72
Trinidad		220	165	44	5.0	0.1%	0.07
Uganda		1227	923	371	3.3	0.7%	0.39
United Arab Emirates		640	481	255	2.5	0.3%	0.20
United Kingdom		9201	6918	747	12.3	5.0%	2.93
US Gulf Coast		624	469	370	1.7	0.3%	0.20
US GoM		2299	1729	126	18.3	1.3%	0.73
US Northeast		94	70	257	0.4	0.1%	0.03
Venezuela Concessions		3879	2917	544	7.1	2.1%	1.23
Yemen		5013	3770	804	6.2	2.7%	1.59
Sub-Total		**145877**	**109682**	**20115**	**7.3**	**79.4%**	**46.40**
Refining and Marketing							
Europe Refining		11643	8754			6.3%	3.70
Africa Refining		270	203			0.1%	0.09
Others Refining		1511	1136			0.8%	0.48
Europe Marketing		6818	5127			3.7%	2.17
Africa Marketing		1824	1371			1.0%	0.58
Others Marketing		914	687			0.5%	0.29
Sub-Total		**22979**	**17277**			**12.5%**	**7.31**
Chemicals		**6802**	**5114**			**3.7%**	**2.16**
Power & Others							
Pow er		215	162			0.1%	0.07
Re-gas value		1050	789			0.6%	0.33
LNG contracts		6187	4652			3.4%	1.97
Sun Pow er Inc	60% interest	566	425			0.3%	0.18
Sub-Total		**8018**	**6029**			**4.4%**	**2.55**
Total Enterprise Value		**183676**	**138103**			**100.0%**	**58.43**
Adjusted end-2012 Net Debt		21250	15977			11.6%	6.76
Net Asset Value		**162427**	**122125**			**88.4%**	**51.67**
Market Capitalisation		**124180**	**93368**				**39.50**
Premium to NAV		**-24%**	**-24%**				**-24%**

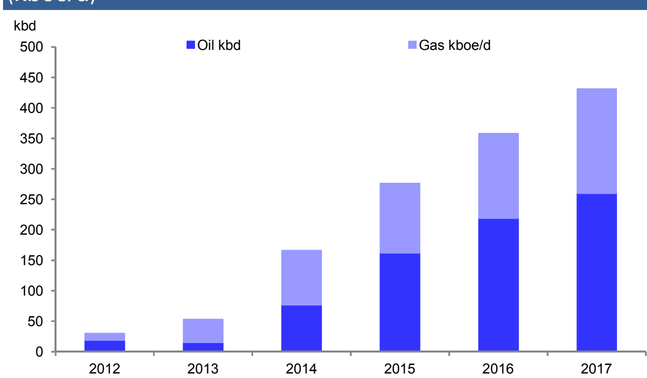
Source: Deutsche Bank

Figure 577: TOTAL SA – Main Projects 2012-15+

Name	Country	-- Reserves --		--Peak--		Interest %	PSC?	2012	2013	2014	2015	2016	2017	NPV
		Oil	Gas	Oil	Gas									$m
2012														
Usan	Nigeria	610	0	160	0	20%	Yes	18	0	0	0	0	0	5830
Bonkot South	Thailand	15	600	10	320	33%	Yes	10	18	18	18	18	18	n.a.
Sulige	China	0	2400	0	300	49%	Yes	1	3	10	18	25	25	680
Halfaya	Iraq	5100	0	475	0	19%	Yes	1	5	17	20	30	30	100
2013														
Kashagan Phase 1	Kazakhstan	8195	4760	970		17%	Yes		10	26	49	60	60	-2680
Angola LNG	Angola	0	8250	0	875	14.0%	Yes		17	23	23	23	23	n.a.
2014														
Lagan Tormore	UK	40	1300	5	435	80%	No			38	55	65	65	1340
CLOV	Angola	565	0	150	0	40%	No			24	60	65	60	5750
West Franklin	US GoM	100	590	35	225	46%	No			10	33	25	20	n.a.
2015														
GLNG	Australia	0	8000		1115	28%	No					8	25	-2800
Temokarstovskoye	Russia	700	150	110	30	49%	No					0	25	n.a.
Tempa Rossa	Italy	305		50		75%	No					33	38	2671
Ichthys	Australia	500	12000	100	1370	30%	No						15	6800
Block 32 Kaomba	Angola	610	0	2000	0	30%	yes					6	27	4300
total								**30**	**53**	**166**	**276**	**358**	**431**	
Of which														
Oil								*19*	*15*	*77*	*162*	*219*	*260*	
Gas								*11*	*38*	*89*	*114*	*139*	*171*	

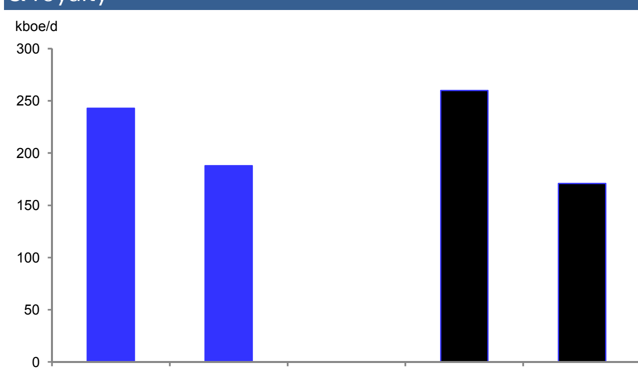
Source: Wood Mackenzie, Deutsche Bank

Figure 578: Production growth by hydrocarbon type (kboe/d)



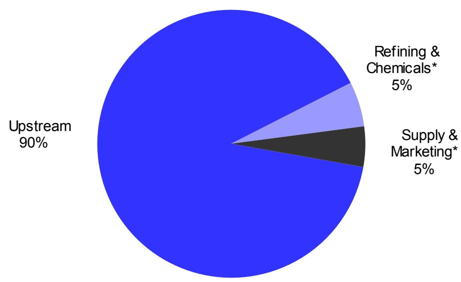
Source: Deutsche Bank

Figure 579: Production growth by oil/gas and PSC or tax & royalty



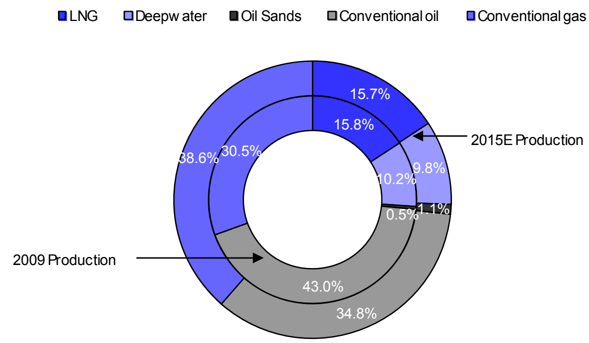
Source: Deutsche Bank

Figure 580: 2012E clean net income EUR12,397m



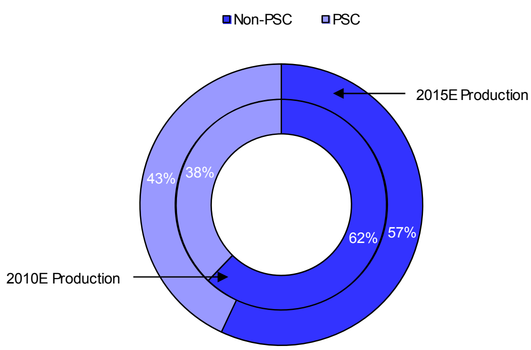
Source: Deutsche Bank

Figure 581: Trends in E&P Production



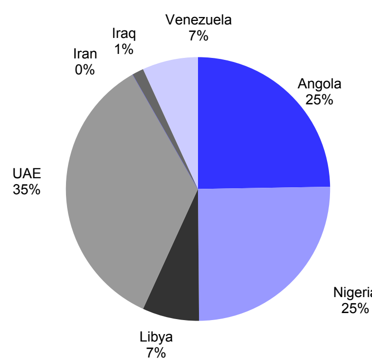
Source: Deutsche Bank

Figure 582: PSC exposure 12E-15E – on the increase



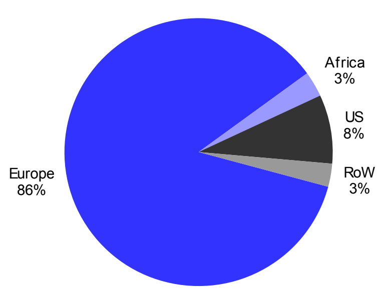
Source: Deutsche Bank

Figure 583: OPEC production 28% of total in 2012E



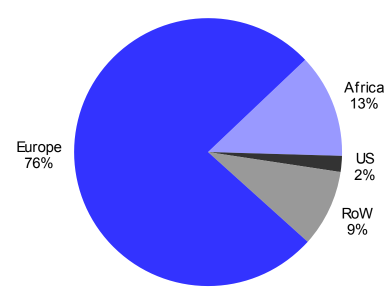
Source: Deutsche Bank

Figure 584: Total 2012 refining CDU 2,088kb/d



Source: Deutsche Bank

Figure 585: Total 2011 marketing by region



Source: Deutsche Bank

Rating
Buy

Europe
Italy

Oil & Gas
Integrated Oils

Company
ENI

Reuters	Bloomberg
ENI.MI	ENI IM

Price at 16 Jan 2013 (EUR)	19.31
Price Target (EUR)	21.00
52-week range (EUR)	19.33 - 15.25

Stronger Upstream

The past 2 years have seen Eni deliver material exploration success and make significant progress in simplifying the business and strengthening the balance sheet through divestment of much of its interest in both Snam and Galp. As a consequence, the investment story is cleaner, more upstream focused, and less encumbered by concerns around balance sheet or resource base. As we enter 2013 we look to improving operational momentum driven by a series of project start-ups. Earnings in the Italian-biased downstream (R&M and G&P) remain challenged, but are in our view finding a floor. Beyond completing its non-core divestments, we see Eni pursuing a stable strategy prioritizing development of its organic resource base and a focus on exploration. BUY.

E&P: As a series of development projects approach completion, Eni offers one of the sector's strongest volume and cash flow growth profiles over the next 3 years, on our estimates. Critical to sentiment are the Kashagan and Goliat projects. After a series of exploration successes, Eni's strategy appears very focused on organic opportunities. Key over coming years will be progress in maturing its 70% interest in the Area 4 gas discoveries offshore Mozambique.

G&P: Eni's Gas and Power segment has been simplified by the ongoing sell-down of its interest in Snam (from c50% to c20%) and partial divestment of its international pipelines. The remaining business is largely focused on Gas Marketing in Europe and in particular Italy. This business purchases gas under long-term oil-linked contracts and then sells to a mixture of industrial, power gen and residential customers. Profitability is under pressure from the de-linking of spot/contract prices and from much-reduced demand.

R&M: Eni is the leading refiner in Italy with five refineries, and it has a share of three further refineries in Germany and the Czech Republic. Its European 711kb/d refining capacity lags well behind the likes of Shell, Total or Exxon. Eni has the dominant position in Italian marketing.

Other: Eni has a small petrochemical division and also holds a 43% equity interest in Saipem, one of the world's leading oilfield engineering and construction firms, and a 33% interest in Galp Energia.

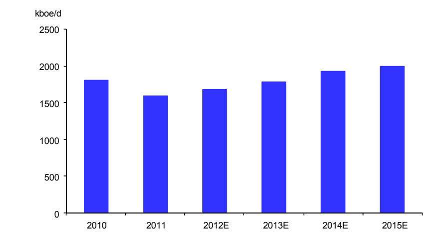
Valuation and Risk: Our €21/sh target is based on a blended average of our DCF/SOTP/PE valuations and implies a 9.1x target PE – in line with our sector target. Risks include oil price, asset reliability, political volatility and Italy.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (EUR)	1.90	1.88	2.16	2.31	2.43
P/E (x)	8.6	8.5	8.9	8.4	7.9

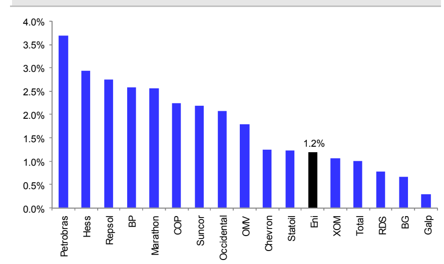
Source: Deutsche Bank estimates, company data

ENI Production Profile 2010-15E

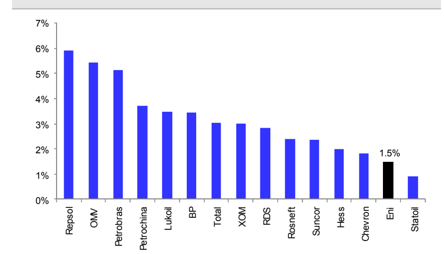


Upstream CAGR (2012-15E)	5.9%
Oil production (2012E)	883kb/d
Gas production (2012E)	805kboe/d
Oil Reserves (1P) 2011	3.4bn/bbls
Gas Reserves (1P) 2011	3.5bn/boe
Refining capacity	930kb/d
Marketing volumes	1,007kb/d
Wood Mackenzie 2P(E) Total reserves	10.8bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.74%

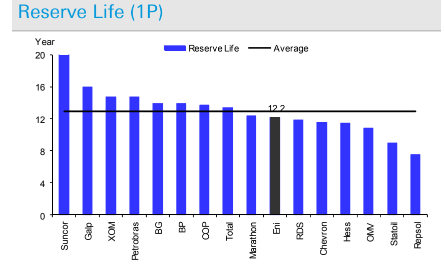
Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)



Eni - Net Asset Value and Breakdown at $100/bbl (long-run)

Figure 586: Eni - Net Asset Value by Asset

Upstream	Comments	Value ($ Million)	Value (EUR Million)	2 P Reserves	$ Value/2P Reserves	% of Total EV	EUR Value per Share
Algeria	*Growth from MLE/CAFC & El Merck*	10,336	7,951	706	14.6	7%	2.2
Angola	*Growth from Block 15/06 West & East*	9,101	7,001	915	9.9	6%	1.9
Australia		758	583	146	5.2	0%	0.2
Azerbaijan	*BTC pipeline*	387	298	0	0.0	0%	0.1
China		425	327	14	30.8	0%	0.1
Congo		4,558	3,506	474	9.6	3%	1.0
Croatia		155	119	26	6.0	0%	0.0
Ecuador		294	226	36	8.1	0%	0.1
Egypt		7,406	5,697	1,221	6.1	5%	1.6
India		129	99	12	11.2	0%	0.0
Indonesia		2,083	1,602	403	5.2	1%	0.4
Iran		123	95	1	88.3	0%	0.0
Iraq	*Zubair*	242	186	838	0.3	0%	0.1
Italy	*OECD Italy dominates…*	11,948	9,190	685	17.5	8%	2.5
Kazakhstan	*Kashagan & Karachaganak*	16,367	12,590	2,298	7.1	11%	3.5
Libya		7,903	6,079	1,059	7.5	5%	1.7
Mozambique	*Assumed 3x5mtpa Model & $1/boe for resource*	9,260	7,123	2,897	4.0	6%	2.0
Nigeria		5,950	4,577	1,371	4.3	4%	1.3
Norw ay		6,355	4,888	753	8.4	4%	1.3
Pakistan		830	638	100	8.3	1%	0.2
Russia	*SeverEnergia*	6,203	4,772	1,565	4.0	4%	1.3
Timor Leste Australia JPD		386	297	65	5.9	0%	0.1
Trinidad		272	209	39	7.0	0%	0.1
Tunisia		440	338	27			0.1
Turkmenistan		1,823	1,402	150	12.2	1%	0.4
United Kingdom		3,949	3,038	392	10.1	3%	0.8
US Alaska		2,102	1,617	247	8.5	1%	0.4
US GoM Deep		5,387	4,144	371	14.5	4%	1.1
US GoM Shelf		108	83	24	4.6	0%	0.0
US Conc Gulf Coast		62	48	34	1.8	0%	0.0
Venezuela	*Perla & Junin-5*	2,567	1,975	1,164	2.2	2%	0.5
Upstream		**117,909**	**90,699**	**18,032**	**6.5**	**77%**	**25.0**
LNG Contracts		328	253			0%	0.1
Australia Conc LNG	*Bayu Undan*	130	100			0%	0.0
Angola Conc LNG	*2013 start-up of ALNG*	2,433	1,872			2%	0.5
Egypt Conc LNG	*Damietta 1 via Union Fenosa Gas JV*	444	341			0%	0.1
Mozambique Conc LNG		184	141			0%	0.0
Nigeria Conc LNG	*Trains 1-6*	5,556	4,274			4%	1.2
Oman Conc LNG		405	312			0%	0.1
LNG		**9,480**	**7,292**			**6%**	**2.0**
Total Upstream		**127,389**	**97,992**			**83%**	**27.0**
Refining & Marketing	*7x mid-cycle EBIT*	1,138	875			1%	0.2
Chemicals		291	224			0%	0.1
Refining, Marketing & Chems		**1,429**	**1,099**			**1%**	**0.3**
Marketing & Transmission	*DCF valuation of Gas Marketing*	10,546	8,112			7%	2.2
Snam Equity Value	*MV of 20% interest*	3,376	2,597			2%	0.7
Gas & Power		**13,921**	**10,709**			**9%**	**3.0**
Galp Equity Value	*MV of 28.24% interest pre sell-down*	2745	2112			2%	0.6
Saipem Equity Value	*MV of 42.93% interest*	7,807	6,005			5%	1.7
Equity Interests		**10552**	**8117**			**0**	**2.2**
Total Enterprise Value		**153,291**	**117,916**				**32.5**
Adjusted end-2012 Net Debt	*Ex Snam and Saipem debt*	15,274	11,749				3.2
Net Asset Value		**138,017**	**106,167**				**29.3**

Source: Deutsche Bank

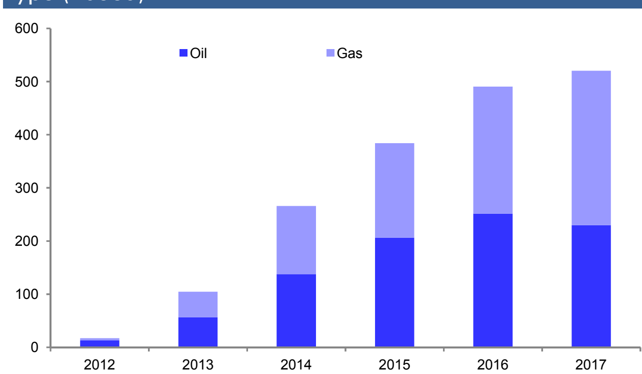
Eni – Main Projects 2012-15

Figure 587: Eni – Major Oil & Gas Projects by year – 2012-2015

			Reserves		Peak				Prod (kboed)						NPV
Project	Country	Launch	Oil	Gas	Oil	Gas	Equity	PSC	2012	2013	2014	2015	2016	2017	$m
			Mbbl	Mboe	kb/d	kboed									
2012															
Severenergia	Russia	2012	1327	4060	246	500	29.4%		9	22	53	91	147	189	5920
Kizomba Satellites	Angola	2012	253	0	100	0	20.0%	Yes	8	15	13	8	4	3	600
2013															
MLE/CAFC	Algeria	2013	276	293	42	60	75.0%	Yes	0	11	28	38	43	43	841
El Merk	Algeria	2013	442	0	127	0	12.3%	Yes	0	6	15	14	13	11	572
ALNG	Angola	2013	0	1423	0	172	13.6%	Yes	0	12	25	25	25	25	
Jasmine	UK	2013	245	319	51	49	33.0%		0	8	25	29	25	19	2997
Kashagan Ph-1	Kazak	2013	5822	501	296	78	16.7%	Yes	0	26	49	64	80	79	42
Junin-5 Phase 1	Venz	2014	1526	0	240	0	40.0%		0	4	12	20	28	30	2217
2014															
Perla	Venz	2014	0	1473	0	207	32.5%		0	0	9	9	9	20	552
Block 15/06 - W	Angola	2014	148	0	52	0	35.0%	Yes	0	0	10	21	24	10	570
Goliat	Norway	2014	195	45	88	21	65.0%		0	0	26	59	55	42	311
2015															
Block 15/06 - E	Angola	2015	383	0	90	0	35.0%	Yes	0	0	0	6	18	25	882
Hadrian	US	2015	576	121	102	25	25.0%		0	0	0	2	20	24	1996
Total (kboed)									**17**	**105**	**266**	**384**	**490**	**520**	
Of which: Oil									13	57	138	206	251	230	
Gas									4	48	128	178	239	290	

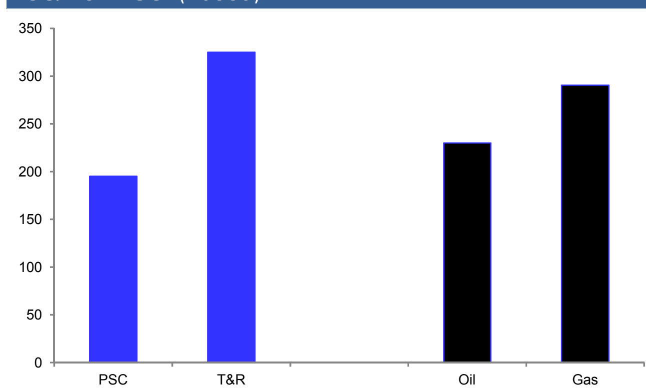
Source: Wood Mackenzie, Deutsche Bank

Figure 588: Identified production growth by hydrocarbon type (kboed)



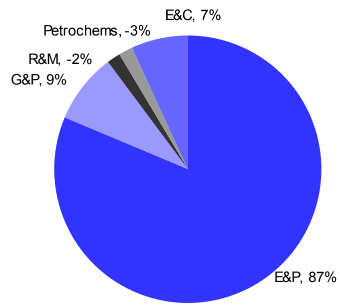
Source: Deutsche Bank

Figure 589: Identified 2017 Project Mix – Oil/Gas & PSC/Non PSC (kboed)



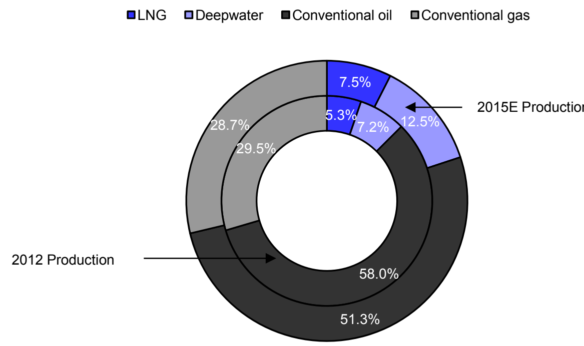
Source: Deutsche Bank

Figure 590: 2012E clean net income EUR7,750m



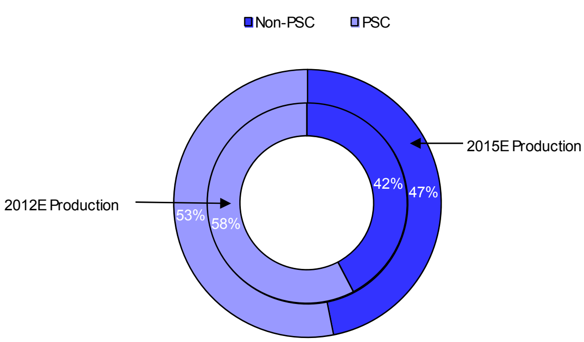
Source: Deutsche Bank

Figure 591: Trends in E&P Production



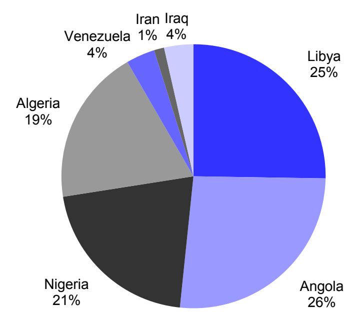
Source: Deutsche Bank

Figure 592: PSC exposure 12E-15E – on the increase



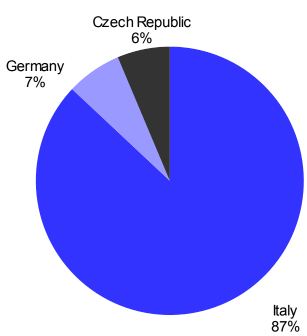
Source: Deutsche Bank

Figure 593: OPEC production 21% of total in 2012E



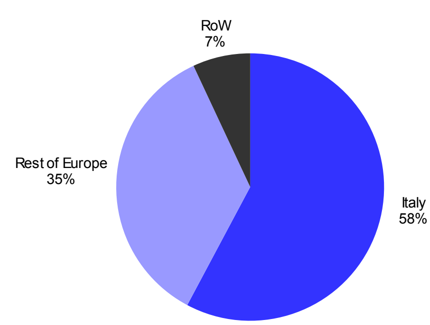
Source: Deutsche Bank

Figure 594: ENI 2012 refining CDU 930kb/d



Source: Deutsche Bank

Figure 595: ENI 2011 marketing by region



Source: Deutsche Bank

Rating
Hold

Europe
Norway

Oil & Gas
Exploration & Production

Company
Statoil

Reuters	Bloomberg
STL.OL	STL NO

Price at 16 Jan 2013 (NOK)	143.80
Price Target (NOK)	160.00
52-week range (NOK)	162.40 - 133.80

Securing future growth

The merger between Statoil and Norsk Hydro's oil and gas operations in 2007 created a major new upstream player, dominant on the NCS and able to compete for the world's largest projects. The company's key competitive strengths include hostile environment expertise, a history of technical leadership and a strong European gas sales position. With a portfolio long on mature North Sea assets, critical is generating new growth opportunities via exploration, direct access or acquisition. Statoil has been active on all three fronts, but most notably a change in exploration strategy, emphasizing "high-impact" frontier plays, has yielded material success and leaves the company with among the most visible of project rosters through to decade-end. Whist recognizing the long-term strengths, our Hold rating reflects valuation, a short-term hiatus in growth and perceived capex risk.

Upstream: Statoil's production is derived primarily from Norway (75% in 2011). Mature base assets on the NCS have spurred it to seek international opportunities, including GoM, Angola and Brazil, with the result that strong international growth has seen the NCS share slowly decrease. Statoil has adjusted its exploration strategy to focus on higher-impact frontier prospects, a move that has been successful in defining the next generation of growth opportunities. Statoil is considered one of the most geared companies to the oil price given its weighting to E&P and high but static Norwegian tax rate.

Natural Gas: Statoil is the second-largest supplier of gas to Europe after Gazprom, marketing its own gas production and that of the Norwegian state. Some 70% of its gas is sold under LT contracts, with the balance sold at spot prices. Importantly S/D pressures in European gas markets have recently seen Statoil ceding some ground to consumer demands for the spot gas price to form part of the price indexation mechanism in long-term contracts with the result that around 50% of Statoil's gas is now referenced to spot prices.

R&M: Statoil is a relatively small refiner and exited its position in marketing via the IPO and then sale of Statoil Fuel & Retail. As a result Statoil has very low downstream exposure versus the peer group.

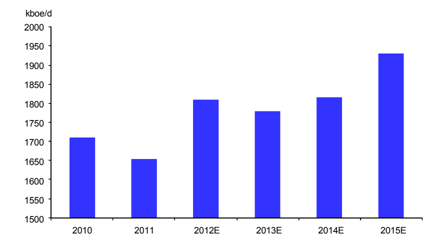
Valuation & Risk: Our NOK160 target represents the blended average of our DCF, SOTP and PE-based valuation approaches. Up/downside risks include oil price, exposure to European gas markets, exploration results and project execution.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (NOK)	12.4	18.4	17.2	17.3	16.7
DB EPS growth (%)	14.4	49.0	-6.5	0.6	-3.7
P/E (x)	10.7	7.6	8.3	8.3	8.6

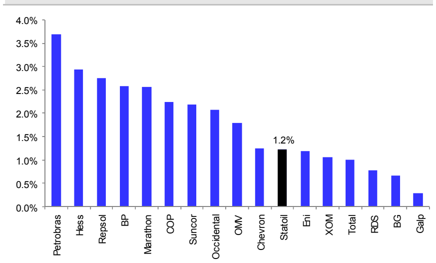
Source: Deutsche Bank estimates, company data

Statoil Production Profile 2010-15E

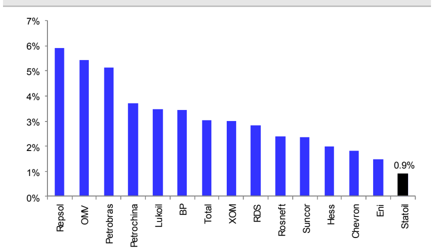


Upstream CAGR (2012-15E)	2.2%
Oil production (2012E)	983kb/d
Gas production (2012E)	824kboe/d
Oil Reserves (1P) 2011	2.3bn/bbls
Gas Reserves (1P) 2011	3.0bn/boe
Refining capacity	300kb/d
Wood Mackenzie 2P(E) Total reserves	15.1bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.21%

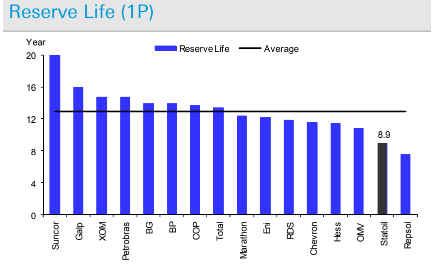
Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)



Statoil – Net Asset Value and Breakdown at $100/bbl (long-run)

Figure 596: Statoil – Net Asset Value by Asset

Upstream	Comments	Value ($ Million)	Value NOK Million	2 P Reserves	$ Value/2P Reserves	% of Total EV	NOK Value per Share
Norway		52567	302262	8253	6.4	40%	94.8
Angola		12387	71228	964	12.9	9%	22.3
Brazil Conc		7108	40870	473	15.0	5%	12.8
Brazil - Pao Da Acucar	*Recent Campos 33 discovery*	3150	18113	630	5.0	2%	5.7
Azerbaijan		7135	41023	1192	6.0	5%	12.9
US GoM		8419	48411	661	12.7	6%	15.2
Canada		3314	19057	655	5.1	3%	6.0
Nigeria		2733	15712	109	25.1	2%	4.9
Algeria		2383	13702	488	4.9	2%	4.3
UK		2138	12291	560	3.8	2%	3.9
Venezuela		1183	6805	126	9.4	1%	2.1
Ireland		1303	7492	54	23.9	1%	2.3
Tanzania - Block 2	*Lavani & Zafarani resource*	1126	6473	450	2.5	1%	2.0
Libya		598	3440	17	35.6	0%	1.1
Russia		408	2345	57	7.1	0%	0.7
US	*Onshore assets*	7233	41588	2808	2.6	6%	13.0
Subtotal		**113185**	**650812**	**17497**	**6.5**	**87%**	**204.1**
LNG Marketing - Contracts		2195	12623			2%	4.0
Norway Conc LNG		3547	20396	380		3%	6.4
Total Upstream Value		**118927**	**683831**	**17876**		**91%**	**214**
Other Divisions							
Marketing, Processing & Renewables	*DCF valuation of Gas supply/trading*	11650	**66987**			9%	21.0
Total Other Divisions		**11650**	**66987**			**9%**	**21.0**
Total Enterprise Value		**130577**	**750818**				**235.5**
Adjusted end-2012 Net Debt		6984	40157				12.6
Buyout of minorities (ex SF&R)		79	457				0.1
Net Asset Value		**123514**	**710204**				**222.7**

Source: Deutsche Bank

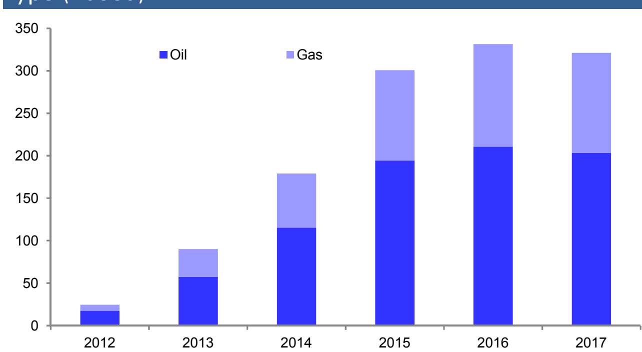
Statoil – Main Projects 2012-15E

Figure 597: Statoil – Major Oil & Gas Project by Year – 2012-15E

			Reserves		Peak				Production (kboed)						NPV
Project	Country	Launch	Oil	Gas	Oil	Gas	Equity	PSC	2012	2013	2014	2015	2016	2017	
			Mbbl	Mboe	kb/d	kboed									
2012															
Ceasar/Tonga Ph1	US	2012	205	34	48	8	23.6%		8	10	10	10	9	8	1159
Block 31 - PSVM	Angola	2012	520	0	158	0	13.3%	Yes	1	16	20	20	18	16	631
Kizomba Sat - Ph 1	Angola	2012	253	0	100	0	13.3%	Yes	7	15	14	12	11	10	399
Marulk	Norway	2012	21	51	8	17	50.0%		9	10	10	10	10	10	332
2013															
Skarv	Norway	2013	176	416	81	92	36.2%		0	33	41	40	41	40	475
2014															
CLOV - Block 17	Angola	2014	564	0	160	0	23.3%	Yes	0	0	15	35	35	35	1341
Corrib	Ireland	2014							0	6	15	20	20	17	
Jack/St Malo	US	2014	622	27	100	4	25.0%		0	0	8	20	25	25	817
Big Foot	US	2014	311	19	60	3	27.5%		0	0	2	10	10	10	906
Goliat	Norway	2014	195	45	88	21	35.0%		0	0	23	30	28	25	167
Gudrun	Norway	2014	96	41	69	29	75.0%		0	0	11	43	50	47	393
Valemon	Norway	2014	48	160	18	50	53.8%		0	0	11	49	60	58	378
2015+															
Mariner	UK	2015	325	0	65	0	65.1%		0	0	0	3	15	20	573
Total									**25**	**90**	**179**	**301**	**331**	**321**	
Oil									18	57	115	194	211	203	
Gas									7	33	64	106	121	118	

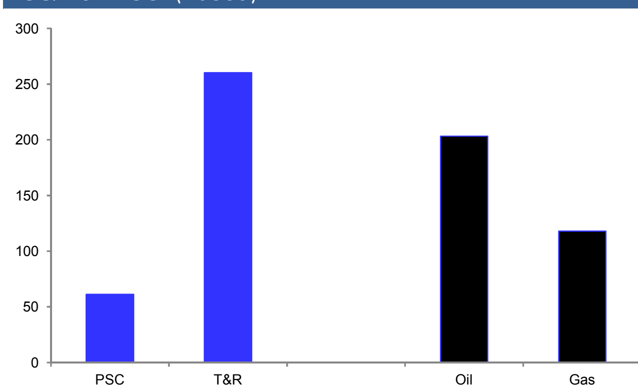
Source: Wood Mackenzie, Deutsche Bank

Figure 598: Identified production growth by hydrocarbon type (kboed)



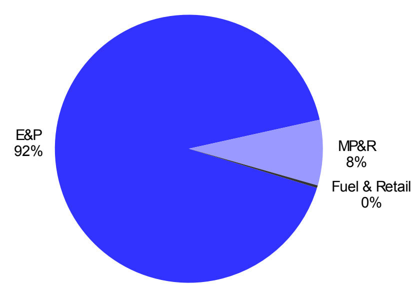
Source: Deutsche Bank

Figure 599: Identified 2017 Project Mix – Oil/Gas & PSC/Non PSC (kboed)



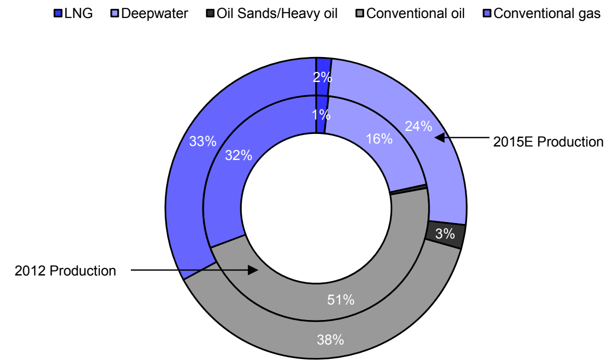
Source: Deutsche Bank

Figure 600: 2012E clean net income NOK54,754m



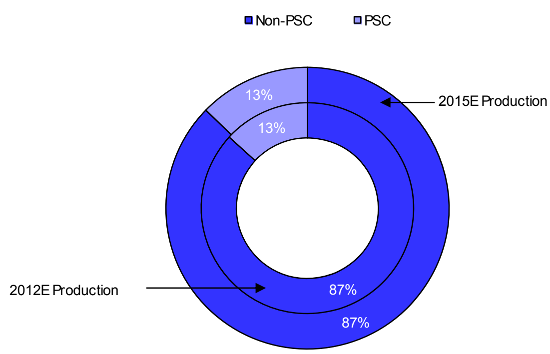
Source: Deutsche Bank

Figure 601: Trends in E&P Production



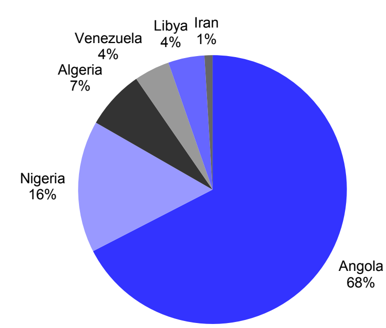
Source: Deutsche Bank

Figure 602: PSC exposure 12E-15E – staying flat



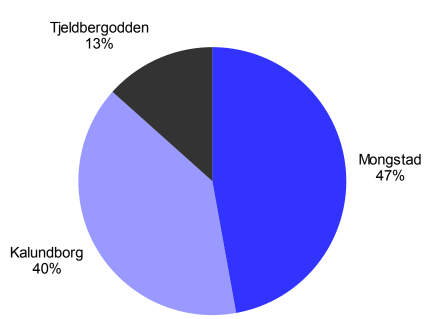
Source: Deutsche Bank

Figure 603: OPEC production 15% of total in 2012E



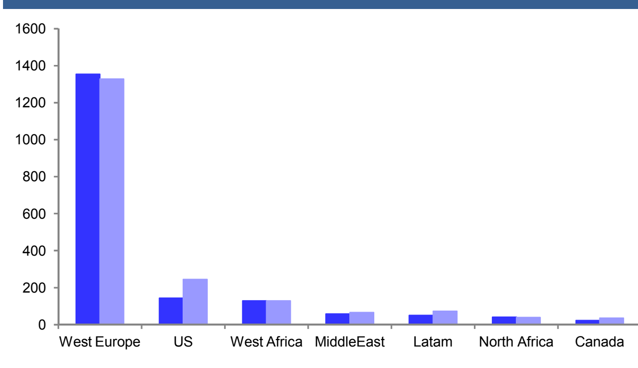
Source: Deutsche Bank

Figure 604: Statoil 2012 refining CDU 300kb/d



Source: Deutsche Bank

Figure 605: Statoil 2012 volumes by major region (kboed)



Source: Deutsche Bank

Rating
Hold

Europe
United Kingdom

Oil & Gas
Integrated Oils

Company
BG Group

Reuters	Bloomberg
BG.L	BG/ LN

Price at 16 Jan 2013 (GBP)	1,083.50
Price Target (GBP)	1,350.00
52-week range (GBP)	1,547.00 - 1,000.50

At a crossroads

For ten years a sector darling, recent production disappointments have removed significant gloss from BG's veneer. Midway through a major investment programme, concerns on the timely delivery of its substantial resource base have also undermined confidence in the former management's guidance on the potential for long-term growth. BG's competitive differentiation in growing LNG markets together with its very substantial resource position in Brazil argue, however, that this is a business which should be more than capable of outpacing its peers, most particularly on forward cash flow growth. The challenge is for the new management team to deliver on the businesses potential. Not broken. Just in need of some fine tuning.

E&P: In contrast to peers, BG's production remains concentrated on natural gas. The build-out of its c.6bn bbls of Brazilian resource over the coming decade will, however, see a significant shift in mix and with it a substantial increase in per-barrel margins. Profitability per barrel is likely to be further augmented by the start-up of some 200kboe/d net of Australian LNG production, near all of which is sold on an oil-linked basis. Whilst uncertainty around timely execution remains, BG's mix of long-duration gas and high-margin conventional oil suggests a portfolio that should be capable of outpacing peers with upside possible from continued exploration success.

LNG: Downstream, BG has established a leading, independent global marketing position in LNG and, following the start-up of new supply sources in the US and its own Australian QGC project, will have in excess of some 20mtpa of LNG to trade into markets that we expect to grow at 5-7% through the end of the current decade. This provides BG with a sustainable competitive advantage and leaves it well placed to take advantage of the ongoing dislocation in global gas prices across the different regional markets.

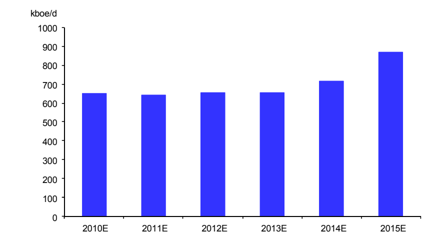
Valuation & Risk: Given that so much of the value is tied up in forward projects, our approach is to place the base business and driver of current earnings on a 10% discount to our 9x 2013E sector target multiple. To this we then add our estimate of the latent value of Brazil and Australia (c950p) at a 40% NAV discount - slightly above that pertaining to the sector (35%). This suggests a hybrid 12-month-forward valuation per share of c1350p Upside risks include clarity on base production come the Feb 2013 Strategy Day. Downside - delays to project delivery in Brazil and Australia.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (GBP)	77.33	81.83	89.15	98.85	121.18
P/E (x)	14.8	16.8	12.2	11.0	8.9
DPS (GBP)	13.66	14.83	16.54	18.55	23.19

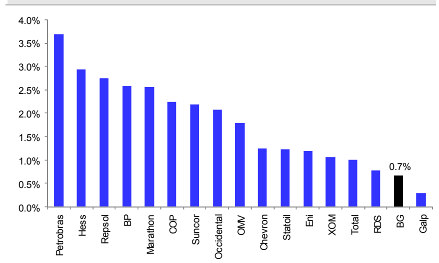
Source: Deutsche Bank estimates, company data

BG Production Profile 2010-15E

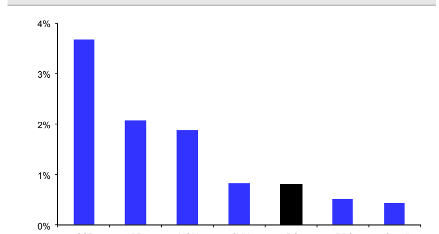


Upstream CAGR (2012-15E)	9.8%
Oil production (2012E)	184kb/d
Gas production (2012E)	472kboe/d
Oil Reserves (1P) 2011	1.1bn/bbls
Gas Reserves (1P) 2011	2.1bn/boe
Long lived assets % of Prod'n (2012E)	57%
LNG Contracted supply (2012E)	13.6mmpta
Wood Mackenzie 2P(E) Total reserves	9.8bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.32%

Sensitivity to $1/bbl move in oil



Sensitivity to $1/mmbtu move in H/Hub



Reserve Life (1P)

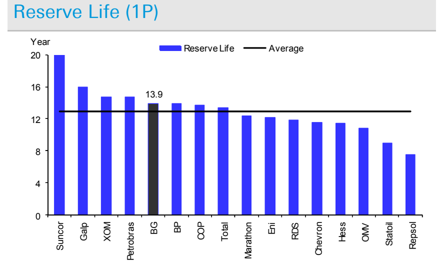


Figure 606: BG Group: NAV model at $100/bbl and $4/mmbtu US gas

Upstream	Value $ Million	Value GBP Million	2 P Reserves	Value/2P Reserves	% of Total EV	Value per Share
Algeria	49	31	105	0.47	0.0%	0.01
Australia domestic	455	285	121	3.77	0.4%	0.08
Bolivia	1,204	753	261	4.61	1.0%	0.22
Brazil Conc	50,518	31,574	5,349	9.44	41.9%	9.32
Egypt	3,955	2,472	818	4.84	3.3%	0.73
India	821	513	70	11.72	0.7%	0.15
Kazakhstan	6,068	3,793	1,110	5.47	5.0%	1.12
Norway	538	336	60	8.95	0.4%	0.10
Thailand	1,499	937	102	14.77	1.2%	0.28
Trinidad	1,536	960	590	2.60	1.3%	0.28
Tunisia	2,190	1,369	109	20.12	1.8%	0.40
United Kingdom	5,645	3,528	442	12.76	4.7%	1.04
US Haynesville	517	323	574	0.90	0.4%	0.10
US Marcellus Northeast	1,562	976	666	2.35	1.3%	0.29
Subtotal	**76,559**	**47,849**	**10,376**		**64%**	**14.12**
LNG Plant/midstream						
Egypt Concession LNG	635	397			0.5%	0.12
Trinidad Concession LNG	1,286	804			1.1%	0.24
TGGT Holdings (US) (50%)	606	379			0.5%	0.11
Australia QGC	15,004	9,378	1,642	9.14	12.5%	2.77
Kazakhstan - CPC pipeline	186	116			0.2%	0.03
Total Upstream value	**94,276**	**58,923**	**12,018**		**78%**	**17.39**
LNG contracts (ex QGC)	**20,040**	**12,525**			**16.6%**	**3.70**
LNG Import terminals						
Lake Charles, USA - Access rights only	0	0			0.0%	0.00
Elba Island, USA - Access rights only	0	0			0.0%	0.00
Dragon, UK	1,320	825			1.1%	0.24
Subtotal	**1,320**	**825**			**1.1%**	**0.24**
LNG Ships						
Own fleet	4,250	2,656			3.5%	0.78
Subtotal	**4,250**	**2,656**			**3.5%**	**0.78**
Transmission & Distribution						
Mahanagar Gas	277	173			0.2%	0.05
Subtotal	**277**	**173**			**0.2%**	**0.05**
Power Plants						
BG Italia Power S.p.A.(SERENE)	240	150			0.2%	0.04
Condamine	84	53			0.1%	0.02
Milford Energy Limited	14	9			0.0%	0.00
Subtotal	**338**	**212**			**0.3%**	**0.06**
Total Enterprise Value	**120,501**	**75,313**				**22.23**
Net Debt - end '12 cum QGC sale	8,194	5,121				1.51
Net Asset Value	**112,307**	**70,192**				**20.72**
Market Capitalisation	**60,984**	**38,115**				**11.25**
Premium to NAV	**-46%**	**-46%**				**-46%**

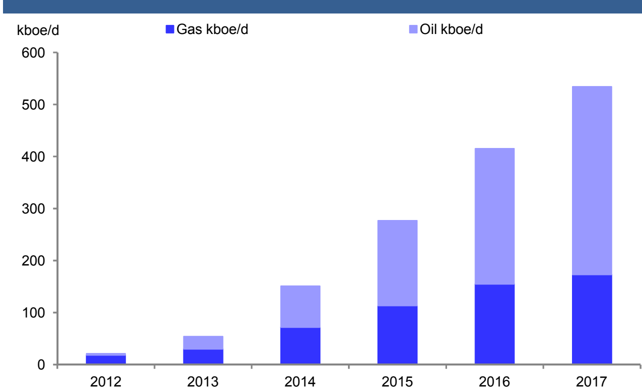
Source: Deutsche Bank

Figure 607: BG Group: Main Projects 2012-7E

Name	Country	---Reserves---		---Peak---		Interest %	PSC?	2012	2013	2014	2015	2016	2017	NPV
		Oil	Gas	Oil	Gas									$m
2012														
Gaupe	Norway	10	120	8	50	60%	No	5	8	8	7	5	3	1400
Bonkot South	Thailand	15	600	10	320	22%	Yes	8	12	12	12	12	12	n.a.
Margarita	Bolivia	60	4700	10	660	38%	No	8	12	12	17	17	17	-3600
2013														
Jasmine	UK	90	633	45	200	30%	No		4	18	22	23	19	n.a.
Sapinhoa 1	Brazil	350	150	120	175	30%			18	30	40	40	40	-2680
Lula NE	Brazil	n.a.	n.a.	25	90	25%	No			10	38	45	45	n.a.
2014														
Knarr	Norway	60	5	28	5	45%	No			15	15	10	8	305
Iracema Sul	Brazil	350	150	120	175	25%	No			5	20	35	35	-1315
Sapinhoa North	Brazil	450	200	150	195	30%	No			6	30	45	52	10645
QGC	Australia		9900		1270	73%	No			35	70	112	130	
2015														
Bream	Norway	45	0	40	0	40%	No				1	16	10	220
Iracema Norte	Brazil	525	200	150	210	25%	No				5	30	45	n.a.
Lula Alto	Brazil	525	200	150	210	25%	No					10	25	2671
Lula Sul	Brazil	525	200	150	210	25%						5	30	2070
Lula Central	Brazil	525	200	150	210	25%						5	30	
Lula Norte	Brazil	525	200	150	210	25%						5	30	
Jackdaw	UK	65	580	25	210	41%	No						3	850
TOTAL								**21**	**54**	**151**	**277**	**415**	**534**	
Of which														
Oil								*3*	*24*	*79*	*164*	*260*	*361*	
Gas								*19*	*30*	*72*	*114*	*155*	*173*	

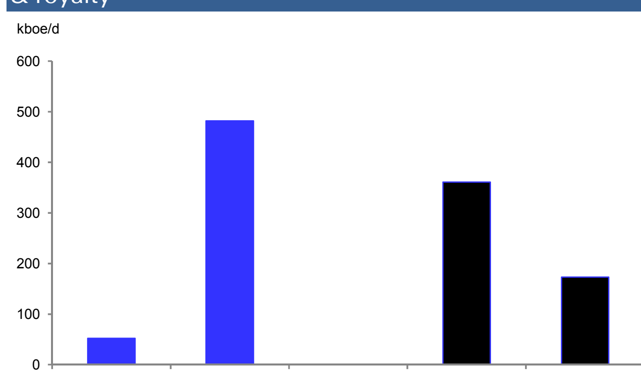
Source: Wood Mackenzie, Deutsche Bank

Figure 608: Production growth by oil and gas (kboe/d)



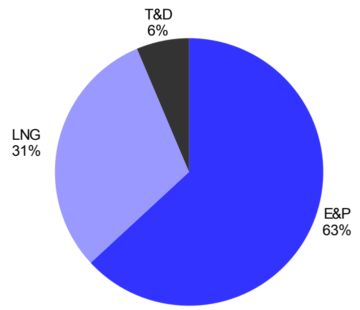
Source: Deutsche Bank

Figure 609: Production growth by oil/gas and PSC or tax & royalty



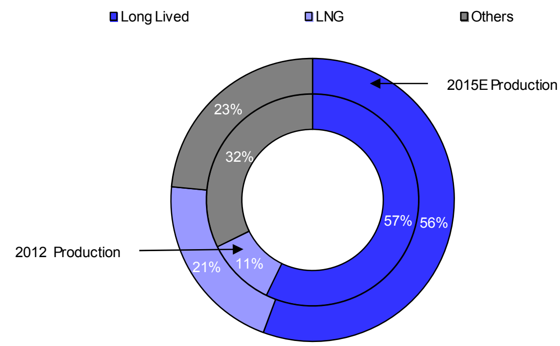
Source: Deutsche Bank

Figure 610: 2012E clean net income GBP3,126m



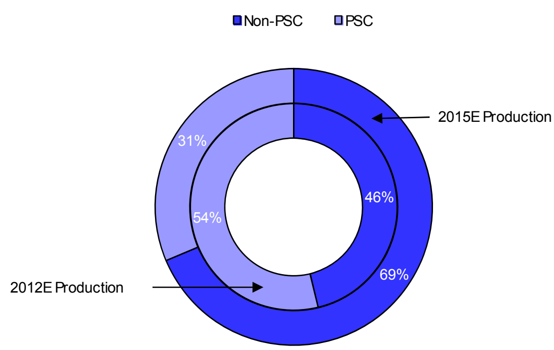
Source: Deutsche Bank

Figure 611: Trends in E&P Production



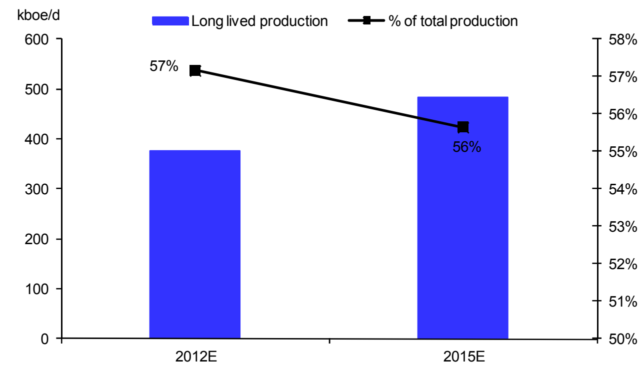
Source: Deutsche Bank

Figure 612: PSC exposure 12E-15E – in decline



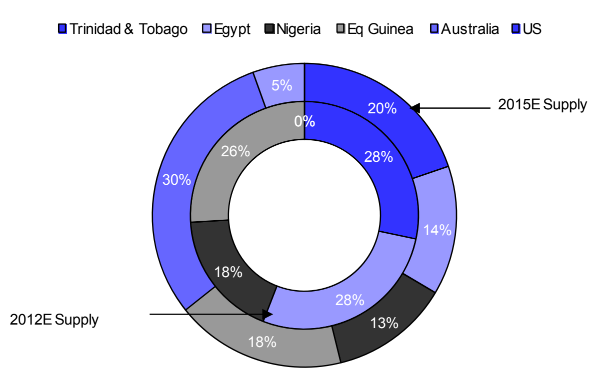
Source: Deutsche Bank

Figure 613: Long-lived assets (57% of total prod'n in 2012E)



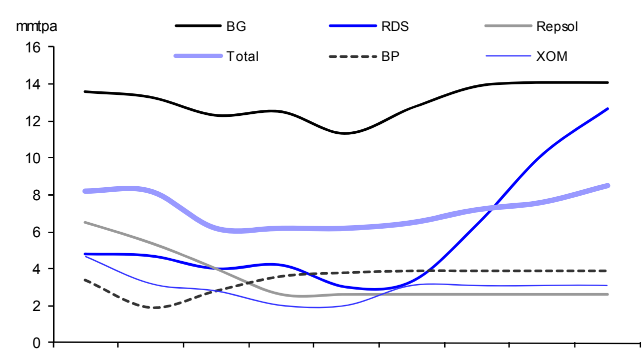
Source: Deutsche Bank

Figure 614: LNG contract schedule 12E and 15E



Source: Deutsche Bank

Figure 615: LNG contract volumes relative to peers



Source: Deutsche Bank

Rating
Hold

Europe
Austria

Oil & Gas
Integrated Oils

Company
OMV

Reuters	Bloomberg
OMVV.VI	OMV AV

Price at 16 Jan 2013 (EUR)	29.16
Price Target (EUR)	30.00
52-week range (EUR)	29.16 - 21.29

Evolving Upstream focus

Following the 2004 acquisition of Petrom, OMV established itself as the leading regional oil & gas company in central Europe, positioned to benefit from the premium rates of economic growth expected in the region. Following a number of failed forays to expand its downstream footprint, the company has unveiled a strategy that places upstream as its primary point of focus for future investment. This is welcome, but it will take time for the shift in emphasis to have an impact. Given its lack of scale versus the peers, exposure to weak refining markets and narrow resource base, we rate the shares Hold.

E&P: In 2004 OMV almost tripled its upstream production via the acquisition of 51% of Romania's Petrom, a move that transformed the company. Almost a decade later, the impact of the acquisition remains evident with 60% of production derived from Petrom (predominantly in Romania). In the core regions – Austria and Romania – OMV is focused on enhanced oil recovery to manage mature fields. A formerly disparate asset base outside of the core is now taking a more coherent shape under a new strategy, which aims to narrow the focus to countries with material potential, to make selective acquisitions/divestments to achieve this, and to build a functioning resource funnel that places an emphasis on exploration. The execution of this strategy is ongoing and it will likely be 2015/16 before the growth benefits become visible. Given its low marginal tax rate, OMV is among the most geared companies in the European integrated sector to oil prices.

R&M: With c450kb/d refining capacity and 20% retail market share in SEE/CEE, OMV is one of the leading players in the downstream in its core regions. Its crude slate is biased toward processing heavy crudes and producing middle distillates. The strategy is focused on modernising capacity and streamlining footprint to delivering improved returns. OMV has a c97% stake in Petrol Ofisi brining exposure to the growing Turkish market.

Gas: While gas currently accounts for only c.10% of operational earnings, this is a medium-term key growth division for OMV with a strategy predicated on integration with the proposed Nabucco West pipeline as the backbone.

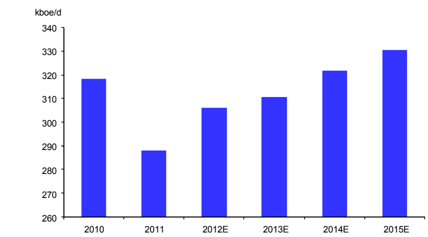
Valuation & Risk: Our €30 target is based on a blended average of our SOTP, DCF and PE valuations. Key up/downside risks include oil price refining margin volatility, exploration results, ME production disruption, scope for tax changes.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (EUR)	3.74	3.34	4.60	4.78	4.99
DB EPS growth (%)	87.4	-10.6	37.6	3.9	4.4
P/E (x)	7.3	8.4	6.3	6.1	5.8

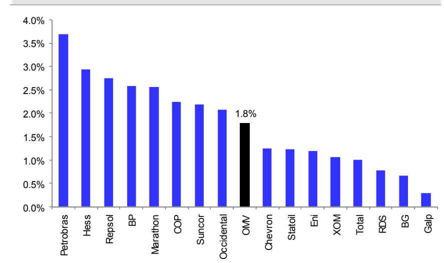
Source: Deutsche Bank estimates, company data

OMV Production Profile 2010-15E

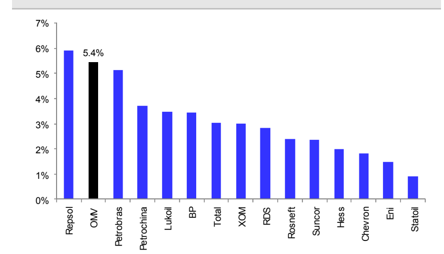


Upstream CAGR (2012-15E)	2.6%
Oil production (2012E)	162kb/d
Gas production (2012E)	806kboe/d
Oil Reserves (1P) 2011	628mn/bbls
Gas Reserves (1P) 2011	466mn/boe
Refining capacity	447kb/d
Marketing volumes	454kb/d
Wood Mackenzie 2P(E) Total reserves	1.3bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.32%

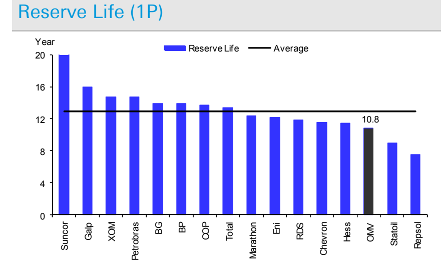
Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)



OMV – Net Asset Value and Breakdown at $100/bbl (long-run)

Figure 616: OMV – Net Asset Value by Asset

Upstream	Comments	Value ($ Million)	Value (EUR Million)	2 P Reserves	$ Value/2P Reserves	% of Total EV	EUR Value per Share
Austria		2831	2125	165	17.1	10.8%	6.52
Iraq PSC		154	116	75	2.1	0.6%	0.36
Libya PSC		2614	1962	82	31.9	10.0%	6.02
New Zealand		1275	957	69	18.5	4.9%	2.94
Norw ay		372	279	106	3.5	1.4%	0.86
Pakistan		252	189	37	6.8	1.0%	0.58
Tunisia		930	698	78	11.9	3.6%	2.14
UK		777	584	95	8.2	3.0%	1.79
Venezuela		34	26	2	15.1	0.1%	0.08
Yemen PSC		528	396	33	15.8	2.0%	1.22
Kazakhstan	*OMV's 51% Interest*	204	153	9	22.1	0.8%	0.47
Turkey		6	4	0	12.3	0.0%	0.01
Romania	*OMV's 51% Interest*	6627	4975	557	11.9	25.4%	15.26
Total Gem Upsteam Value		**16606**	**12466**	**1309**	**12.7**	**63.6%**	**38.24**
Refining and Marketing							
Europe Refining		2124	1594			8.1%	4.89
Europe Marketing	*Includes 99.3% Petrol Ofisi*	3493	2622			13.4%	8.04
Gas & Power		2358	1770			9.0%	5.43
Equity Interests							
Borealis	OMV's 36% interest	1513	1136			5.8%	3.48
Total Enterprise Value		**26093**	**19588**			**100.0%**	**60.09**
Adjusted end-2012 Net Debt		4724	3547			18.1%	10.88
Net Asset Value		**21368**	**16042**			**0.82**	**49.21**

Source: Deutsche Bank

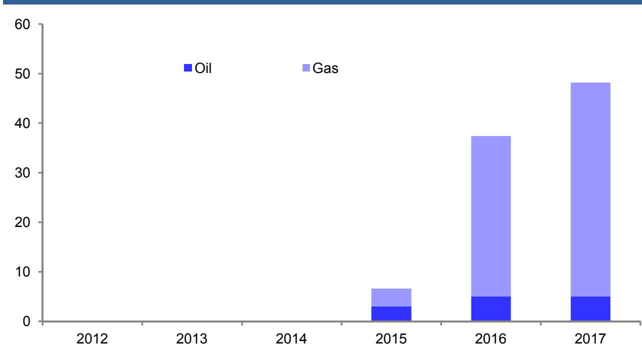
OMV – Main Projects 2012-15E

Figure 617: OMV – Major Oil & Gas Projects by Year 2012-15E

			Reserves		Peak				Prod						NPV
Project	Country	Launch	Oil	Gas	Oil	Gas	Equity	PSC	2012	2013	2014	2015	2016	2017	
			Mbbl	Mboe	kb/d	kboed									
2013															
2014															
2015															
Habban	Yemen	2015	98	0	28	0	44.0%	Yes	0	0	0	3	5	5	618
BinaBawi	Kurdis'n	2015					36.0%	Yes	0	0	0	4	32	43	429
Total									**0**	**0**	**0**	**7**	**37**	**48**	
Oil									0	0	0	3	5	5	
Gas									0	0	0	4	32	43	

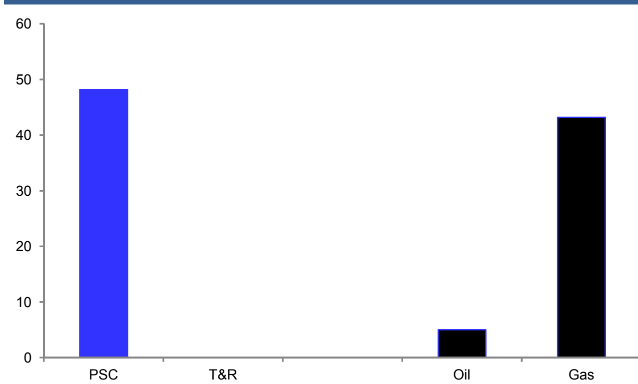
Source: Deutsche Bank

Figure 618: Identified production growth by hydrocarbon type (kboed)



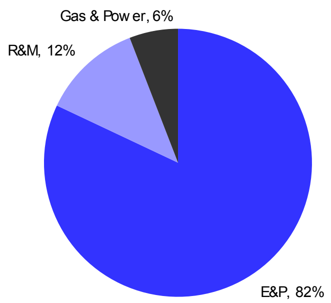
Source: Deutsche Bank

Figure 619: Identified 2017 Project Mix – Oil/Gas & PSC/Non PSC (kboed)



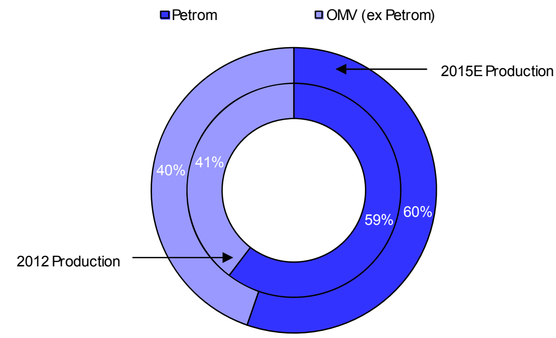
Source: Deutsche Bank

Figure 620: 2012E clean net income EUR637m



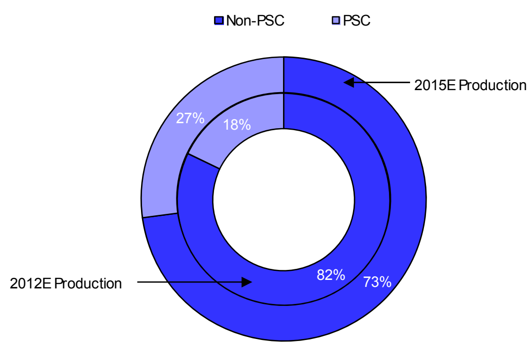
Source: Deutsche Bank

Figure 621: Trends in E&P Production



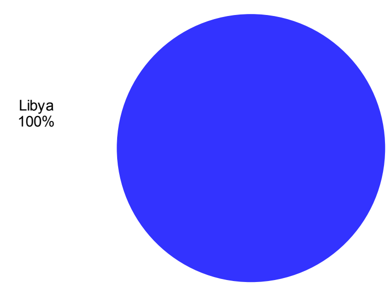
Source: Deutsche Bank

Figure 622: PSC exposure 12E-15E – on the increase



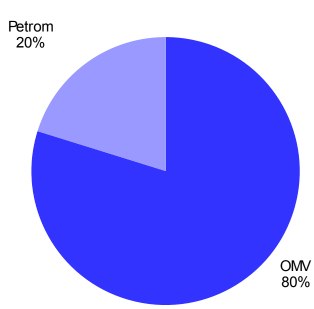
Source: Deutsche Bank

Figure 623: OPEC production 7% of total in 2012E



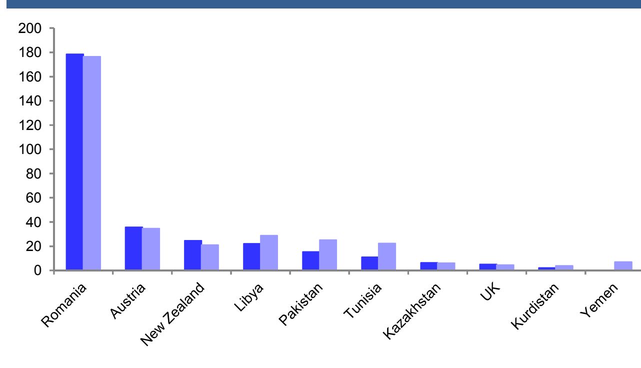
Source: Deutsche Bank

Figure 624: OMV 2012 refining CDU 447kb/d



Source: Deutsche Bank

Figure 625: OMV 2012 E&P production by region



Source: Deutsche Bank

Rating
Hold

Europe
Portugal

Oil & Gas
Integrated Oils

Company
Galp Energia

Reuters	Bloomberg
GALP.LS	GALP PL

Price at 16 Jan 2013 (EUR)	12.10
Price Target (EUR)	16.00
52-week range (EUR)	13.77 - 8.50

Developing Brazilian Resource

Since listing in 2006, exploration success in Brazil has been the primary driver of Galp's equity market performance and corporate strategy, including the 2011 sale of 30% of its Brazilian business to fund the development phase. With funding secured, Galp remains in the early stages of a transition from a 20k/d to a >250kb/d company as its Brazilian Santos basin resource base is developed over the remainder of the decade. Unsurprisingly, much of the investment debate now rests on assessing the inherent execution risk and the appropriate multiple of asset value on which the company deserves to trade at the current stage in its maturation. In the near term, key issues include the start-up of the next units offshore Brazil and the upgraded Sines refinery. Our stance reflects a view that execution risk will take time to unwind. Hold.

Upstream: From a single asset production stream generating c10kb/d from Angola, exploration success offshore Brazil has led to a development plan that should see Galp exceed 250kb/d by 2020. Elsewhere Galp has sought to expand its hopper of exploration acreage with notable success in the giant gas play offshore Mozambique, via a 10% stake in Area 4, and interests in blocks offshore Uruguay, Morocco and East Timor. The materiality of Brazil relative to the rest of the company (Brazil represents c60% of our Galp NAV) means that it is likely to remain the focus of the investment debate.

Downstream: In 2007 Galp launched an ambitious investment plan for its Sines refinery with the aim of increasing complexity and production of middle distillates in order to benefit from the structural shortage of middle distillates on the Iberian Peninsula. After delays, the facility should ramp up during 1Q13. However, a changing refining landscape since FID calls into question the level of margin uplift that was originally hoped for. Galp operates 330kb/d of refining capacity in Portugal, where it also has a strong retail presence.

Gas & Power: Galp is Portugal's largest supplier of gas, a key storage supplier and the largest marketer/distributor of gas. Profits have enjoyed a near-term boost as weak power demand has allowed Galp to divert contracted LNG cargos to higher-priced markets.

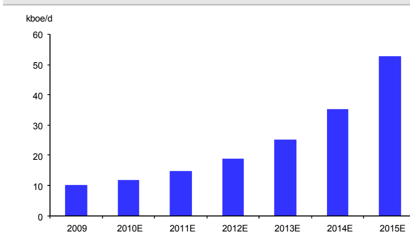
Valuation & Risk: We derive our €16/sh target by applying a 0.8x target multiple to our €19.8/sh NAV. Up/downside risks to our stance include oil prices, project execution, exploration results, exposure to Portugal and Brazil and the overhang from Eni's residual shareholding.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (EUR)	0.37	0.30	0.47	0.54	0.59
DB EPS growth (%)	43.5	-18.2	55.1	15.7	8.5
P/E (x)	34.3	47.3	25.8	22.3	20.5

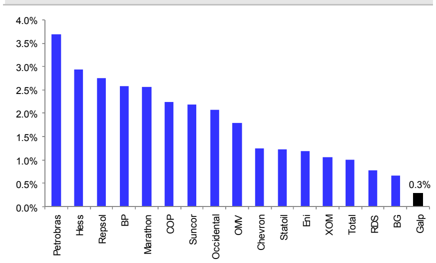
Source: Deutsche Bank estimates, company data

Galp Production Profile 2010-15E

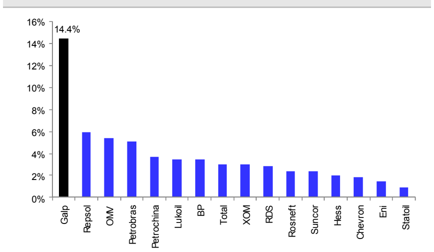


Upstream CAGR (2012-15E)	40.9%
Oil production (2012E)	17kb/d
Gas production (2012E)	25kboe/d
Oil and gas Reserves (1P) 2011	145mn/bbls
Refining capacity	310kb/d
Marketing volumes	211kb/d
Wood Mackenzie 2P(E) Total reserves	1.2bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.12%

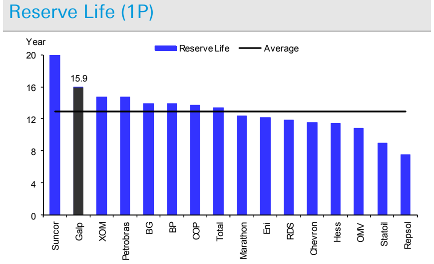
Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)



Galp – Net Asset Value and Breakdown at $100/bbl (long-run)

Figure 626: Galp – Net Asset Value by Asset

		($ Million)	(EUR Million)	Reserves	Reserves	Total EV	per Share
Angola		1376	1033	140	9.8	6%	1.25
Angola - blocks 14, 14K, 32 and 33	Technical reserve @30% success	454	341	62	7.4	2%	0.41
BMS-11	70% interest in Petrogal Brasil's 10% stake	10254	7698	1202	8.5	43%	9.29
BMS-24	70% interest in Petrogal Brasil's 20% stake	2225	1670	299	7.4	9%	2.01
BMS-8	70% interest in Petrogal Brasil's 14% stake	1018	764	103	9.9	4%	0.92
Congo		9	7	1	6.2	0%	0.01
Mozambique	3-train Area 4 LNG development	1370	1029	517	2.6	6%	1.24
Upsteam Value		**16706**	**12542**	**2325**	**7.2**	**70%**	**15.13**
Europe Refining		1645	1235			7%	1.49
Europe Marketing		1171	879			5%	1.06
Refining and Marketing		**2816**	**2114**			**12%**	**2.55**
Gas Supply & pow er	Based on 7.5x 2012 EV/EBITDA	1848	1388			8%	1.67
Gas Distribution	RAB end 2010	1732	1300			7%	1.57
Gas & Power		**3580**	**2688**			**15%**	**3.24**
Associates	5% CLH, gas pipelines, 49% stake in w indpow er	922	692			4%	0.83
Associates		**922**	**692**			**4%**	**0.83**
Total Enterprise Value		**24024**	**18035**				**21.76**
Adjusted end-3Q12 Net Debt	Inclusive of capital raise cash	1825	1370				1.65
Adjust for Petrolgal Brazil Minority	Deduct Sinopec interest in cash	863	647				0.78
Net Asset Value		**21336**	**16018**				**19.32**

Source: Deutsche Bank

Galp – Main Projects 2012-15E

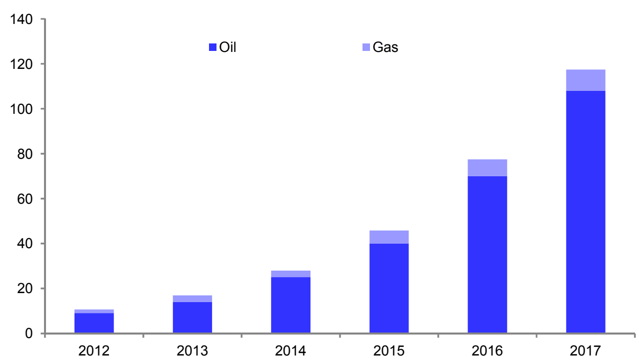
Figure 627: Galp – Major Oil & Gas Projects by Year 2012-15E

			Reserves		Peak				Production (kboed)						NPV
Project	Country	Launch	Oil	Gas	Oil	Gas	Equity	PSC	2012	2013	2014	2014	2016	2017	
			Mbbl	Mboe	kb/d	kboed									
2012															
2013															
Lula*	Brazil	2010	8223	681	1536	134	7.0%		11	17	23	28	48	83	3812
2014															
Cernambi*	Brazil	2014	1454	145	290	31	7.0%		0	0	5	18	30	35	1044
2015															
Total									**11**	**17**	**28**	**46**	**78**	**117**	
Oil									9	14	25	40	70	108	
Gas									2	3	3	6	8	9	

Source: Wood Mackenzie, Deutsche Bank

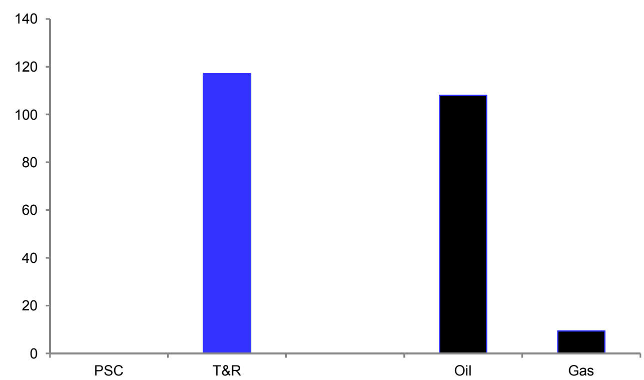
**Galp fully consolidates PetrogalBrazil which holds a 10% interest in Block BMS-11. Hence we reflect a 10% interest in the production estimates. The NPV estimate is net to Galp's 70% interest in PetrogalBrazil*

Figure 628: Identified production growth by hydrocarbon type (kboed)



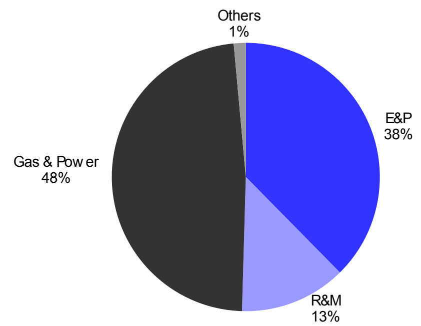
Source: Deutsche Bank

Figure 629: Identified 2017 Project Mix – Oil/Gas & PSC/Non PSC (kboed)



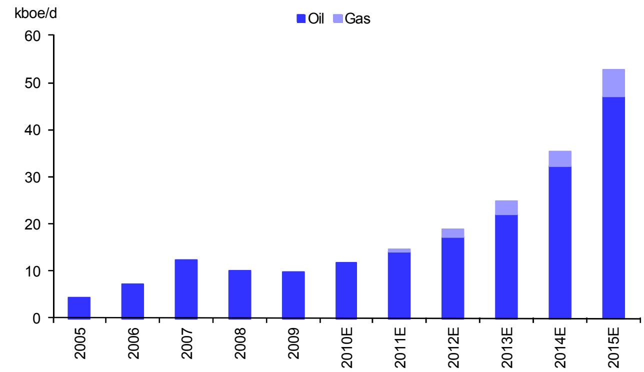
Source: Deutsche Bank

Figure 630: 2012E clean net income EUR388m



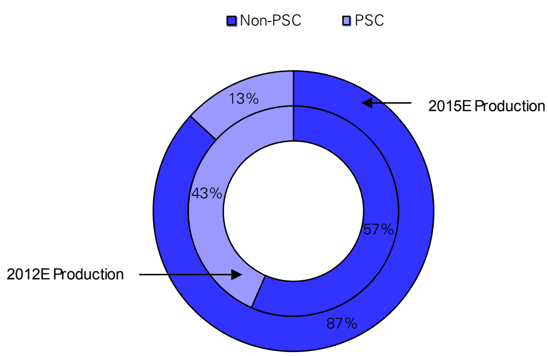
Source: Deutsche Bank

Figure 631: Trends in E&P Production



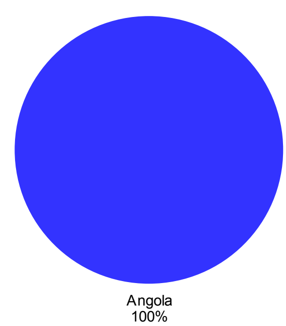
Source: Deutsche Bank

Figure 632: PSC exposure 12E-15E – diminishing



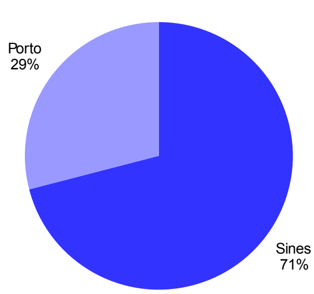
Source: Deutsche Bank

Figure 633: OPEC production 43% of total in 2012E



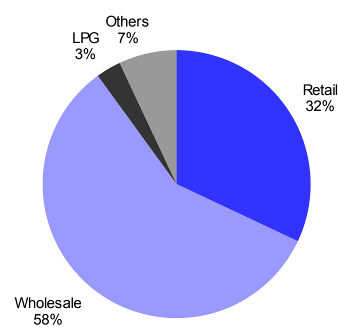
Source: Deutsche Bank

Figure 634: Galp 2012 refining CDU 310kb/d



Source: Deutsche Bank

Figure 635: Galp 2012 marketing by region



Source: Deutsche Bank

Rating
Hold

Europe
Spain

Oil & Gas
Integrated Oils

Company
Repsol

Reuters	Bloomberg
REP.MC	REP SM

Price at 16 Jan 2013 (EUR)	16.68
Price Target (EUR)	16.00
52-week range (EUR)	22.33 - 10.96

Operational momentum vs. valuation

The near-term investment debate continues to be dominated by the ramifications of the Argentine government's expropriation of Repsol's interest in YPF. First, we await clarity on whether the LNG business can be sold in order to strengthen the balance sheet and if so on what terms. Second, Repsol continues to seek compensation via various legal channels. Looking beyond these issues, we believe Repsol offers a period of strong production growth and an ongoing commitment to recycle a much greater proportion of upstream cashflow into exploration than its integrated peers. We are positive on the operational outlook, but find valuation up with events. Hold.

E&P: The positioning of Repsol's legacy upstream business (ex-Argentina) has been transformed during the past five years. The resource base and production outlook have been strengthened through a combination of exploration success (Brazil, Venezuela, Peru) and targeted acquisitions (US, Russia), whilst the capacity of the business to sustain itself has been addressed with a step-change in exploration activity leveraging a strategy of aggressively building frontier acreage. Latam assets remain core to Repsol's upstream, accounting for c70% of current production.

R&M: Repsol has c890kb/d of refining capacity situated in Spain and comprising five units. Investment in two units has seen c120kb/d of CDU capacity added and an upgrading of asset complexity to position them in the top quartile of European assets, although it remains to be seen whether these assets will ultimately enjoy the hoped-for margin uplift due to the changing dynamics in crude price spreads and product cracks. Repsol's R&M assets are well integrated, with Repsol having a c40% share in the Spanish retail market.

Other: Repsol has a presence in both the petrochemicals industry (where it is the market leader in Spain) and gas and power, where it owns 31% of Gas Natural (the Spanish gas utility). Repsol is engaged in a process to sell its LNG business.

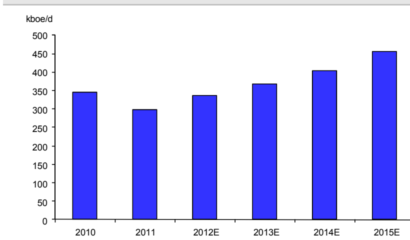
Valuation & Risks Our €16/sh target is based upon the blended average of our SOTP, DCF and PE-based inputs. Key risks include the oil price, the LNG sales process, Spain exposure, project execution and exploration results.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (EUR)	1.67	1.57	1.72	1.76	1.69
DB EPS growth (%)	70.7	-5.7	9.5	2.1	-4.0
P/E (x)	10.9	14.0	9.7	9.5	9.9

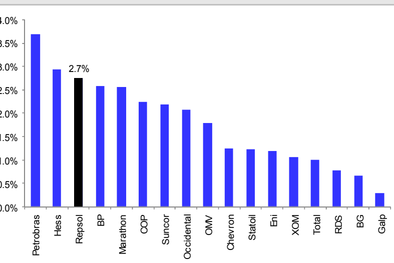
Source: Deutsche Bank estimates, company data

Repsol Production Profile 2010-15E

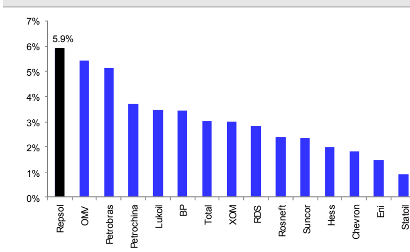


Upstream CAGR (2012-15E)	10.7%
Oil production (2012E)	143kb/d
Gas production (2012E)	193kboe/d
Oil Reserves (1P) 2011	1.0bn/bbls
Gas Reserves (1P) 2011	1.2bn/bbls
Refining capacity	998kb/d
Marketing volumes	759kb/d
Wood Mackenzie 2P(E) Total reserves	3.5bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.1.26%

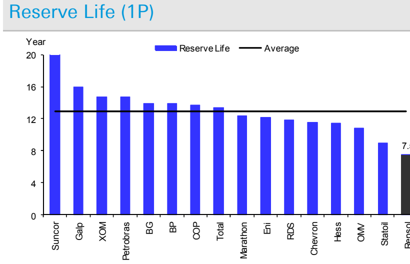
Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)



Repsol – Net Asset Value and Breakdown at $100/bbl (long-run)

Figure 636: Repsol – Net Asset Value by Asset

		Value ($ Million)	Value (EUR Million)	$ Value/2P Reserves	% of Total EV	EUR Value per Share
Algeria		397	305	2.5	1%	0.2
Bolivia		884	680	4.3	2%	0.6
Repsol Brazil	*60% of Asset Value RepsolSinopec EX CASH*	6477	4982	5.6	16%	4.1
Campos-33	*Assumes 1.8bn/boe gross discovery @$5/boe*	1890	1454	5.0	5%	1.2
Colombia		172	132	21.6	0%	0.1
Ecuador		3	2	0.2	0%	0.0
Libya		3132	2409	43.2	8%	2.0
Peru		2784	2142	4.3	7%	1.8
Spain		435	335	36.0	1%	0.3
Trinidad		2220	1707	3.4	5%	1.4
US GoM		2589	1992	18.6	6%	1.6
Venezuela	*incl Carabobo-1 and Perla*	1862	1432	2.2	5%	1.2
Total Upstream Value		**22845**	**17573**	**147**	**56%**	**14.4**
Liquefaction		1414	1088			0.9
Sales Contracts		1337	1028			0.8
Regas		860	661			0.5
Ships		1595	1227			1.0
Pipes		1797	1382			1.1
Finance Leases & Debt		-4692	-3609			-3.0
Total LNG Value		**2310**	**1777**		**6%**	**1.5**
Europe R&M		10913	8395			6.9
Other R&M		1046	805			0.7
LPG		771	593			0.5
Chemicals		1912	1471			1.2
Logistics		377	290			0.2
Downstream Asset Value		**15019**	**11553**		**37%**	**9.5**
Downstream DCF Valuation	*Value based on div DCF ex-debt*	**11828**	**9098**			**7.5**
Memo: 2013 EV/EBITDA			*5.4*			
Power		398	306		1%	0.3
Gas Natural	*30.01% interest*	3344	2572		8%	2.1
Total Gas & Power		**3741**	**2878**		**9%**	**2.4**
Total Enterprise Value	*Excluding any value for YPF*	**40724**	**31326**		**1**	**25.7**
Adjusted end-2012 Net Debt	*Ex-GNF, ex LNG Debt*	-9158	-7045			-5.8
Treasury Shares	*At current market value*	1020	784			0.6
BASE Case NAV - ex-YPF		**32585**	**25066**			**20.5**

Source: Deutsche Bank

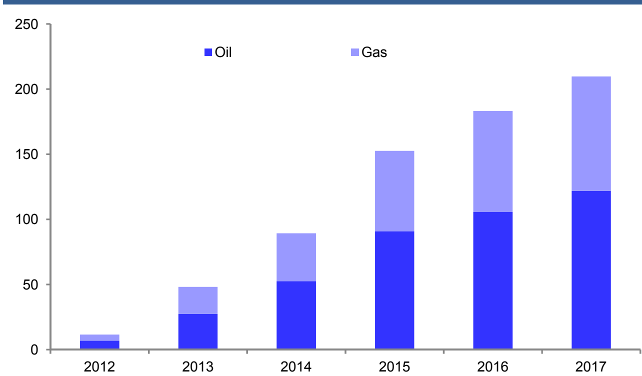
Repsol – Main Projects 2012-15E

Figure 637: Repsol – Major Greenfield Oil & Gas Projects by Year 2012-15E

			Reserves		Peak				Production (kboed)						NPV
Project	Country	Launch	Oil	Gas	Oil	Gas	Equity	PSC	2012	2013	2014	2015	2016	2017	
			Mbbl	Mboe	kb/d	kboed									
2012															
Mississippi Lime	US	2012					n/a		3	10	20	36	49	66	
Margarita	Bolivia	2012	119	490	21	91	37.5%		7	11	11	22	21	21	435
Alliance Oil	Russia	2012							2	7	9	11	11	11	
2013															
Sapinhoa	Brazil	2013	1756	134	250	20	15.0%		0	8	18	40	52	48	2906
Kinteroni	Peru	2013	78	345	9	28	53.8%		0	13	18	18	18	18	788
2014															
Perla	Venez	2014	0	1473	0	207	32.5%		0	0	6	12	17	23	552
Carabobo	Venez	2014	2612	0	400	0	11.0%		0	0	7	15	15	22	986
2015															
Total									**12**	**48**	**89**	**153**	**183**	**210**	
Oil									7	27	53	91	106	122	
Gas									5	21	37	62	78	88	

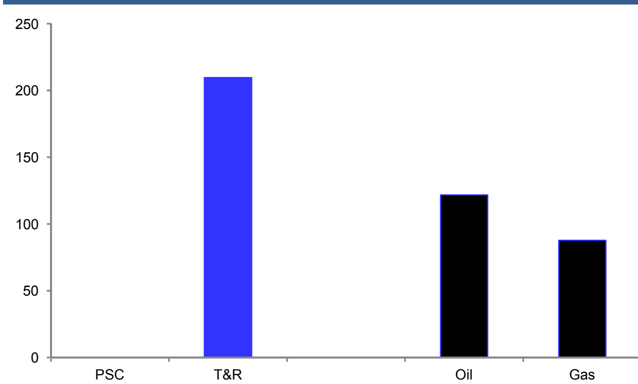
Source: Wood Mackenzie, Deutsche Bank

Figure 638: Identified production growth by hydrocarbon type (kboed)



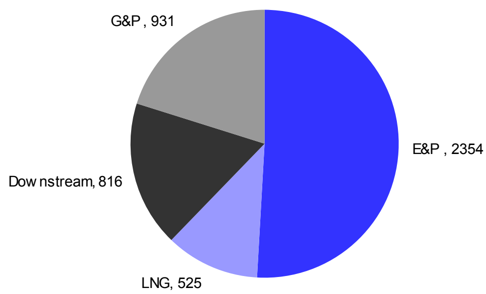
Source: Deutsche Bank

Figure 639: Identified 2017 Project Mix – Oil/Gas & PSC/Non PSC (kboed)



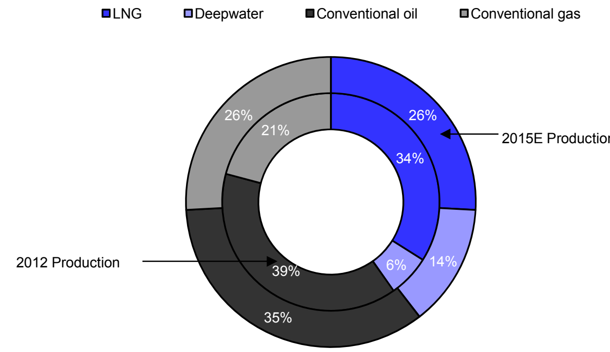
Source: Deutsche Bank

Figure 640: 2012E clean net income EUR1,888m



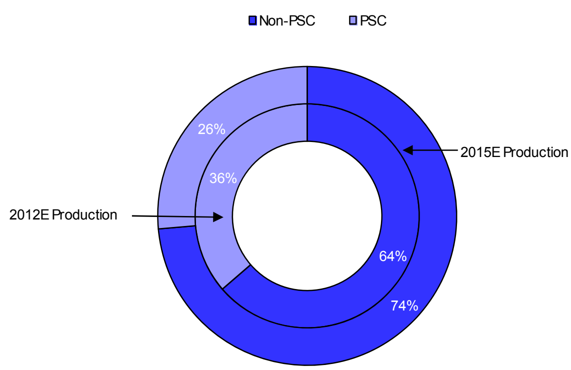
Source: Deutsche Bank

Figure 641: Trends in E&P Production



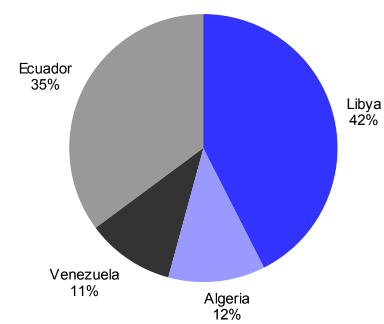
Source: Deutsche Bank

Figure 642: PSC exposure 12E-15E – diminishing



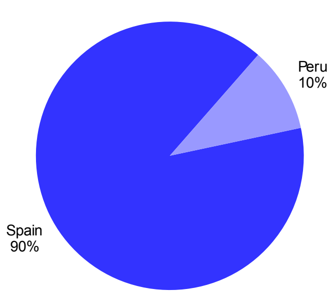
Source: Deutsche Bank

Figure 643: OPEC production 28% of total in 2012E



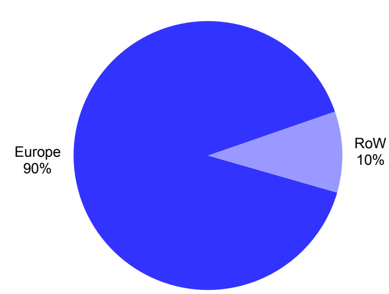
Source: Deutsche Bank

Figure 644: Repsol 2012 refining CDU 998kb/d



Source: Deutsche Bank

Figure 645: Repsol 2012 marketing by region



Source: Deutsche Bank

Rating
Hold

Europe
United Kingdom

Oil & Gas
Exploration & Production

Company
Tullow Oil

Reuters	Bloomberg
TLW.L	TLW LN

Price at 16 Jan 2013 (GBP)	1,180.00
Price Target (GBP)	1,105.00
52-week range (GBP)	1,601.00 - 1,150.00

Testing times

An unparalleled exploration opportunity is a key long-running theme in Tullow's investment case. However, in recent years this has been negated by mixed operational delivery and a demanding valuation, leaving the shares range-bound. We believe this trend is likely to continue - unsuccessful drilling in 4Q12 has seen the exploration halo slip slightly, meaning an extended run of exploration success and clear progress on key development projects in Ghana and Uganda will likely be needed to deliver sustained upward momentum.

Exploration: Since 2006, Tullow has been responsible for opening up material new hydrocarbon plays onshore Uganda and Kenya, and offshore Ghana and French Guiana. This implies a differentiating capability to add value, through a combination of proprietary in-house expertise and sustained investment levels across the exploration value chain. In 2012, Tullow spent cUS$25 per flowing barrel on exploration, compared to US$2-8/boe for the Euro integrateds. A similar intensity should be sustained in 2013 as Tullow drills up its East Africa rift acreage (Kenya, Ethiopia) and tests the French Guiana upside. Frontier wells offshore Mauritania and Mozambique should also spud this year, as well as the debut Norway drilling once the Spring Energy acquisition completes.

Development: Tullow has not been immune from a sector-wide inability to deliver against production targets, with the key Jubilee field only now approaching peak output after initial well-completion issues. The Uganda resource base (DBe on-stream 2017) was partly monetized through a US$2.6bn farm-out to Total and CNOOC in 2012, although a disagreement with the government over the development plan is weighing on sentiment. A similar cautious approach is being taken to the TEN cluster development (DBe on-stream c2016) offshore Ghana ahead of disclosure on capital cost.

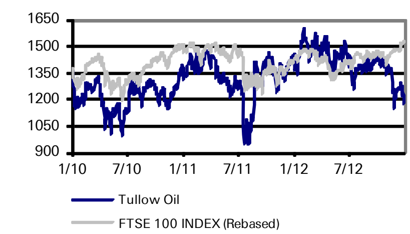
Valuation and risk: Tullow's premium rating, built on frontier exploration success and the market's willingness to value exploration on a P10 basis, has eroded recently on disappointing drilling results and concerns over key development assets. That said, the shares still trade at a premium to our risked exploration NAV (RENAV) of 1,031p (on US$110/bbl LT), falling to 792p on a futures/US$90/bbl pricing scenario. Our 1105p TP averages these two figures, and adds a premium to reflect the optionality of 2014+ drilling. Key upside and downside risks include outcomes in drilling new frontier wells, not least in French Guiana and Kenya.

Forecasts and ratios

Year End Dec 31	2010A	2011A	2012E	2013E	2014E
DB EPS (USD)	0.1	0.7	0.7	0.8	0.8
P/E (x)	234.9	29.5	28.8	23.3	22.7
DPS (USD)	0.09	0.19	0.21	0.23	0.26

Source: Deutsche Bank estimates, company data

Price/price relative

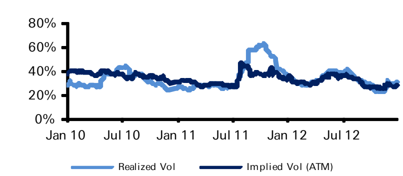


Performance (%)	1m	3m	12m
Absolute	-1.6	-17.2	-17.3
FTSE 100 INDEX	3.3	4.2	8.1

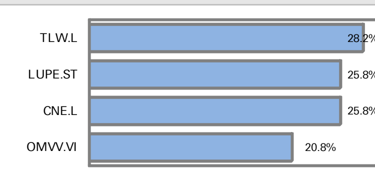
Stock & option liquidity data

Market cap (GBP)(m)	10,695.8
Shares outstanding (m)	913
Free float (%)	–
Option volume (und. shrs., 1M avg.)	984,211

Implied & Realized Volatility (3M)



Implied Volatility (3M, ATM) vs. Peers



*Weighted-avg. of index components
*Data as of 15-Jan-13

Figure 646: Net asset value breakdown at U$100/bbl long-run

	Comments	NAV (US$m)	NAV (£m)	2P reserves/ resources	NAV/boe (US$)	As a % of total NAV	NAV (p/sh)
UK							
CMS Area	Sale process commenced 4Q12	109	68	17	6	0.8%	7
Thames Area	Sale process commenced 4Q12	(63)	(39)	0	n/a	-0.5%	(4)
Netherlands							
Producing assets and infrastructure	Sale process commenced 4Q12	204	127	16	7	1.5%	14
Gabon							
Tchatamba		206	128	9	22	1.5%	14
Turnix		20	13	1	19	0.1%	1
Limande		59	37	4	16	0.4%	4
Echira		53	33	2	22	0.4%	4
Niungo		134	83	6	23	1.0%	9
Etame Marin (Etame, Avouma, Ebouri)		55	34	2	25	0.4%	4
Onal		109	68	6	19	0.8%	7
Obangue		19	12	1	26	0.1%	1
Tsiengui		19	12	1	26	0.1%	1
Oba		12	7	1	23	0.1%	1
Congo (Brazzaville)							
M'Boundi		135	84	7	20	1.0%	9
Eq Guinea							
Okume complex		396	246	15	26	2.9%	27
Ceiba		163	101	7	23	1.2%	11
Cote d'Ivoire							
CI-26 (Espoir and Acajou)		262	163	11	24	2.0%	18
Mauritania							
Chinguetti		(9)	(5)	1	n/a	-0.1%	(1)
Ghana							
Jubilee Phase 1 & 1a	Key producing asset, should ramp to FPSO capacity in 3Q13	4,056	2,519	156	26	30.2%	276
Bangladesh							
Lalmai/Bangora	Disposal process ongoing	36	22	14	3	0.3%	2
Pakistan							
Shekhan EWT	Disposal process ongoing	3	2	0	22	0.0%	0
Total producing assets		**5,978**	**3,713**	**275**	**22**	**44.5%**	**406**
Net debt		(1,001)	(622)			-7.4%	(68)
Other financials		(1,314)	(816)			-9.8%	(89)
Jubilee (Phase 1b)	Timing depends on Phase 1 & 1a performance	532	330	53	13	4.0%	36
Mahogany-East/Akasa/Teak development	Tie-back to Jubilee or stand-alone concept being considered	639	397	56	15	4.8%	43
TEN cluster liquids at 280mmbbls	PoD approval expected early 2013	1,683	1,045	132	15	12.5%	114
TEN cluster gas resources		261	162	108	3	1.9%	18
Uganda (discovered resource base	Significant uncertainty around development plan/value	1,441	895	340	5	10.7%	98
UK contingent gas resources		47	29	14	6	0.3%	
Shekhan (Kohat)		4	3	3	5	0.0%	0
Zaedyus (Guyane Maritime)	Assumes further appraisal proves up 400mmbbls resource	799	496	110	22	5.9%	54
Appraisal and development NAV (risked)		**5,406**	**3,358**	**818**	**7**	**40.2%**	**367**
Total risked NAV		**9,069**	**5,633**	**1,093**		**67.5%**	**616**
Total risked exploration		**4,375**	**2,718**	**1,212**		**32.5%**	**297**
Risked exploration NAV (RENAV)		**13,444**	**8,350**			**100.0%**	**914**

Source: Deutsche Bank

Figure 647: Tullow Oil – main projects 2013E – 2019E

Project	Country	Launch Year	Resources Oil (mmbbl)	Resources Gas (mmboe)	Peak Prodn Oil (kb/d)	Peak Prodn Gas (kboe/d)	Capex US$m	TLW %	PSC	Production (kboe/d) – working interest 2013	2014	2015	2016	2017	2018	2019	NPV
2014																	
Lake Albert development[1]	Uganda	2014	1,200	2	226	1	10,915	28.3%	Yes	0	1	2	4	29	44	64	2,721
2015																	
Jubilee Phase 1b[1]	Ghana	2015	150	0	38	0	1,750	35.5%		0	0	5	9	12	14	12	709
2016																	
TEN[1]	Ghana	2016	280	0	95	0	5,800	47.2%		0	0	0	38	45	45	33	1,979
2019																	
Mahogany-East, Akasa, Teak[1]	Ghana	2019	220	0	82	0	2,640	25.7%		0	0	0	0	0	1	4	852
Total											**0.8**	**7.2**	**50.1**	**86.1**	**103.1**	**113.0**	
of which	: Oil										0.8	7.0	49.9	85.8	102.9	112.8	
	: Gas										0.0	0.2	0.2	0.2	0.2	0.2	

1Development concept, volumes, schedule and capex for all these projects are current DB estimates ahead of formal development plans

Source: Deutsche Bank

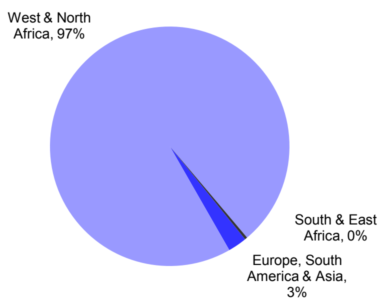
Figure 648: Tullow exploration programme at 1 Jan 2013

Location	Prospect/well	Net interest	NPV/boe (US$)	Timing	Target (mmboe)	GCoS	Unrisked (p/sh)	Unrisked as a % of total	Risked (p/sh)	Risked as a % of total
Uganda	Lake Albert licence exploration upside	28.3%	7.2	2013+	500	40%	70	7%	28	9%
Ghana	Sapele (DWT)	47.2%	15.0	Drilling	75	40%	36	4%	14	5%
Cote d'Ivoire	Calao	45.0%	12.2	2Q13+	150	30%	56	6%	17	6%
French Guiana	Zaedyus Deep	27.5%	22.0	2013+	100	33%	41	4%	14	5%
	Priodontes (Guyane Maritime)	27.5%	22.0	Drilling	300	33%	123	13%	41	14%
	Cebus (Guyane Maritime)	27.5%	22.0	3Q13+	150	33%	62	7%	20	7%
	Guyane Maritime exploration well (generic)	27.5%	22.0	2014+	300	33%	123	13%	41	14%
Mauritania	Scorpion (C-7)	36.0%	9.1	2Q13+	100	20%	22	2%	4	1%
	Caracol/Tapendar (C-10)	80.0%	9.1	3Q13+	100	20%	49	5%	10	3%
	Addax (C-1)	40.0%	9.1	4Q13+	100	20%	25	3%	5	2%
Kenya	Ngamia (Block 10BB) - contingent resource	50.0%	7.4	Discovery	51	75%	13	1%	10	3%
	Ngamia (Block 10BB) - Ngamia-1 updip	50.0%	7.4	Discovery	137	62%	35	4%	21	7%
	Ngamia (Block 10BB) - East & South	50.0%	7.4	3Q13+	76	39%	19	2%	7	3%
	Twiga South (Block 13T)	50.0%	7.4	Testing	59	50%	15	2%	7	3%
	Ekales (formerly Kongoni, Block 13T)	50.0%	7.4	1Q13+	73	50%	18	2%	9	3%
	Paipai (Block 10A)	50.0%	7.4	Drilling	121	10%	31	3%	3	1%
	Etuko (formerly Kamba, Block 10BB)	50.0%	7.4	1Q13+	160	34%	40	4%	14	5%
Ethiopia	Sabisa (South Omo)	50.0%	6.5	Drilling	70	17%	15	2%	3	1%
	Shimela (South Omo)	50.0%	6.5	3Q13+	60	17%	13	1%	2	1%
	Contingent well (South Omo)	50.0%	6.5	4Q13+	70	17%	15	2%	3	1%
Mozambique	Cachalote (Block 2)	28.0%	9.1	3Q13+	100	15%	17	2%	3	1%
	Buzio (Block 2)	28.0%	9.1	3Q13+	100	15%	17	2%	3	1%
Pakistan[1]	Kohat-1 (Kohat)	40.0%	5.0	Drilling	25	30%	3	0%	1	0%
	Kup (Kalchas)	30.0%	5.0	1Q13+	110	25%	11	1%	3	1%
Gabon	Perroquet (Kiarsenny)	50.1%	22.3	2Q13+	15	25%	11	1%	3	1%
	Crabbe (Kiarsenny)	50.1%	22.3	3Q13+	60	25%	46	5%	11	4%
	DE-7 (Assewe West)	24.3%	22.3	2Q13+	10	25%	4	0%	1	0%
Total					**3,172**		**932**		**297**	

1 Currently in our exploration model although Pakistan assets to be disposed in 2013 so may not be drilled

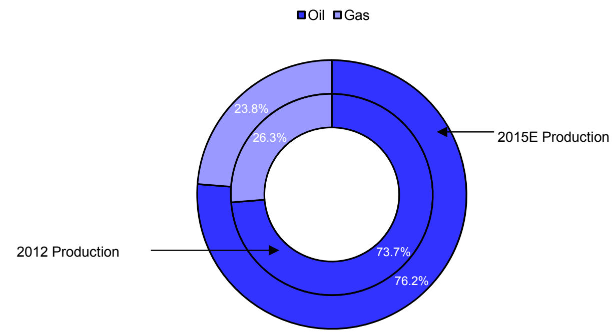
Source: Deutsche Bank

Figure 649: 2011 operating profit US$1,253m



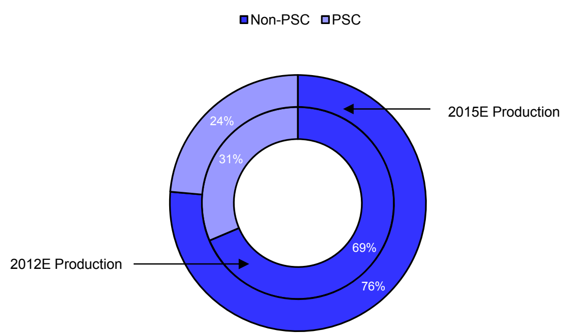
Source: Deutsche Bank

Figure 650: Trends in E&P production



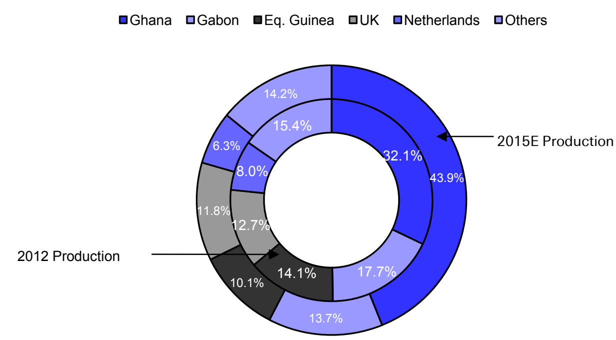
Includes Europe/SE Asia assets which are up for sale at 1 Jan 2013
Source: Deutsche Bank

Figure 651: PSC exposure 2012E-2015E – on the decline



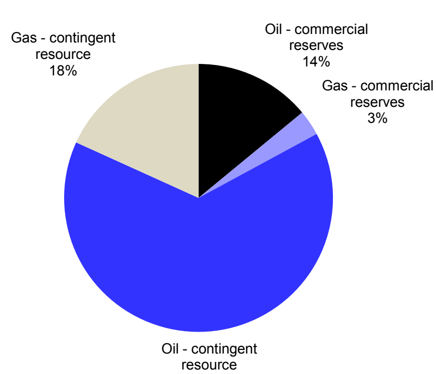
Assumes Uganda exports from 2017 onwards, which increases PSC exposure again
Source: Deutsche Bank

Figure 652: Production by country 2012-2015E



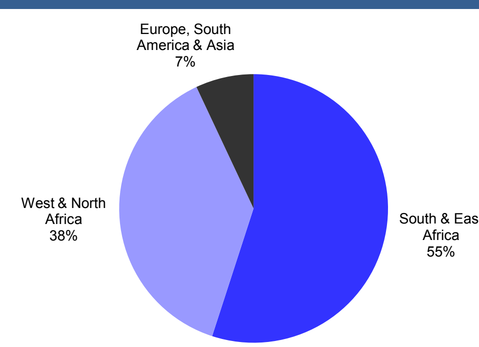
TEN assumed on-stream in 2016, Uganda exports from 2017
Source: Deutsche Bank

Figure 653: End 2011 reserves and resources (1.7 bn boe)



Uganda disposal completed early 2012 and reduced reserves and resources by c600mmboe
Source: Deutsche Bank

Figure 654: End 2011 reserves and resources (1.7 bn boe)



Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Integrated Oil

Company
ExxonMobil

Reuters	Bloomberg
XOM.N	XOM UN

The Big Unit

ExxonMobil has been the oil industry's leader ever since the days of Standard Oil (XOM is the legacy Standard Oil New Jersey). It is the world's largest company by revenue and the largest IOC by both production and reserves. Consistency of management and project execution, attention to returns and genuine integration characterize the business model. With its scale and attention to returns, this is not a volume growth leader. However major positions in West Africa, Russia, Canadian oil sands, Qatar and the Caspian are core drivers. Holding ExxonMobil offers quality assets/management in an uncertain economy.

Upstream: ExxonMobil's differentiation has been its excellent project execution track record. The company's strict capital discipline and adherence to a financial returns driven policy has seen impressive performance in the past with sector leading ROACE of 23%. Its reserve base is large, but relative to market cap, not the largest. The company has historically gained the biggest opportunities in low oil price environments, such as its XTO acquisition announced in Dec 2009. Under-appreciated strengths are Middle Eastern positioning (formerly Aramco partner, it dominates Qatar) and Russian understanding.

Downstream: ExxonMobil produces approximately 4.3mboe/d (2.2mb/d of oil), refines 5.1mb/d and sells 6.2mb/d. Although known for its Exxon and Esso service stations, its real advantage is in its wholesale network, integration, distribution, and "molecule management". ExxonMobil is the world's No.1 supplier of base stocks for lubricant and is a leader in marketing finished lubricants and specialty products, a legacy of the Mobil deal. The company holds world-scale positions in both base and specialty petrochemicals; no other oil does.

Valuation & Risk: Our NAV-implied valuation is $91 ($76 cash flows plus a 20% premium to reflect mgt strength); P/E methodology yields $101 (12x mid-cycle which is derived from ROCE estimate). The average yields our blended $96 PT. Key upside risks are rising commodity prices and refining margins but an expensive acquisition could put downward pressure on the stock.

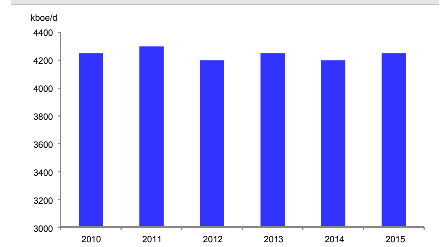
Forecasts and ratios

Year End Dec 31	2011A	2012E	2013E
FY EPS (USD)	8.22	7.80	8.57
P/E (x)	9.7	11.6	10.6
DPS (USD)	1.85	2.18	2.40
Dividend yield (%)	2.3	2.4	2.6

Source: Deutsche Bank estimates, company data

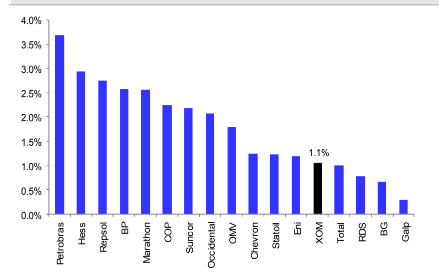
Price at 16 Jan 2013 (US$)	91.9
Price Target (US$)	96.0
52-week range (US$)	97.20-85.67

XOM Production Profile 2010-15E

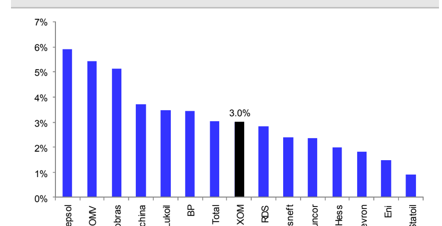


Upstream CAGR (2012-15E)	1.0%
Oil production (2012E)	2,237kb/d
Gas production (2012E)	2,113kboe/d
Oil Reserves (1P) 2011	12.2bn/bbls
Gas Reserves (1P) 2011	12.7bn/boe
Refining capacity	6,218kb/d
Marketing volumes	8,196b/d
Wood Mackenzie 2P(E) Total reserves	48.4bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.15%

Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)

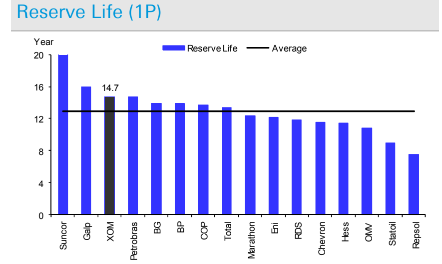


Figure 655: Asset Model from 1 January 2013 at $100/bbl and $4/mmbtu US gas

Upstream	Comment		Risked Value ($ million)	Absolute Value ($ million)	Risked 2 P Reserves	Absolute 2 P Reserves	Value/2P Reserves	% of Total EV	Value per Share	
Abu Dhabi			282	303	987	1,062	0.3	0.1%	0.06	
Angola PSC			9,441	15,735	742	1,237	12.7	2.6%	2.05	
Argentina			82	130	17	27	4.9	0.0%	0.02	
Australia			16,990	22,065	1,675	2,175	10.1	4.6%	3.70	
Azerbaijan			1,952	2,471	185	235	10.5	0.5%	0.42	
Cameroon			-	-	-	-	-	0.0%	0.00	
Imperial Oil (Canada)	Includes heavy oil, gas, downstream		25,921	24,928	3,896	4,190	6.7	7.0%	5.64	
Canada Mobil			6,583	7,397	413	464	15.9	1.8%	1.43	
Canada Heavy Oil	29.04% of Kearl (ExxonMobil Canada)		5,430	5,777	1,143	1,216	4.8	1.5%	1.18	
Western Canada			47	52	236	260	0.2	0.0%	0.01	
Chad			1,666	2,192	119	157	14.0	0.5%	0.36	
Equatorial Guinea			1,377	1,788	104	135	13.3	0.4%	0.30	
Germany			3,946	4,198	337	359	11.7	1.1%	0.86	
Indonesia			965	1,322	185	253	5.2	0.3%	0.21	
Iraq			447	699	1,312	2,051	0.3	0.1%	0.10	
Italy	BEB 50%		-	-	-	-	-	0.0%	0.00	
Kazakhstan			12,648	36,136	925	2,643	13.7	3.4%	2.75	
Malaysia			2,223	2,353	611	646	3.6	0.6%	0.48	
Netherlands			25,205	26,255	1,729	1,801	14.6	6.8%	5.48	
Nigeria	Includes infrastructure		7,284	20,812	618	1,766	11.8	2.0%	1.58	
Norway	Includes infrastructure		7,748	9,448	634	774	12.2	2.1%	1.69	Vast position in Qatar
Papua New Guinea			10,080	12,444	496	613	20.3	2.7%	2.19	
Qatar	Includes infrastructure		50,184	62,731	5,835	7,293	8.6	13.6%	10.92	
Russia			5,732	7,165	344	430	16.7	1.6%	1.25	
Thailand			126	153	10	12	13.0	0.0%	0.03	
United Kingdom	Includes LNG plant, infrastructure		2,115	2,783	210	276	10.1	0.6%	0.46	Large legacy US assets, but major hole in deepwater GOM
United States DWGOM			18,480	26,400	5,433	7,762	3.4	5.0%	4.02	
United States Alaska			4,539	5,673	1,194	1,492	3.8	1.2%	0.99	
United States Rocky Mount			3,705	4,309	1,614	1,877	2.3	1.0%	0.81	
United States MidContinent			3,701	4,304	1,714	1,993	2.2	1.0%	0.81	
US Conc West Coast	Includes infrastructure		12,692	14,588	2,305	2,649	5.5	3.4%	2.76	
United States Permian			8,361	9,722	564	656	14.8	2.3%	1.82	
US Gas Marketing			4,000	4,000	-	-		1.1%	0.87	
Venezuela			747	-	-	-		0.2%	0.16	
Yemen			67	90	4	5	17.6	0.0%	0.01	
Sub-Total			**254,765**	**338,421**	**35,593**	**46,508**	**7.2**	**68.9%**	**55.42**	
Implied per barrel of booked reserves		23,023	$11.1 /bbl							
Implied PER on 2008-11 average earnings $ M.		$27,106	9.4x	12.5x						
3P "Possible" Reserves			**13,692**					3.7%	2.98	
Upstream Sub-Total			**268,457**					**72.6%**	**58.40**	
Refining and Marketing										
Europe Refining			10,496					2.8%	2.28	
Europe Marketing			4,836					1.3%	1.05	World's largest and most diverse refining portfolio
North America Refining			33,791					9.1%	7.35	
North America Marketing	Excludes Imperial Oil		6,556					1.8%	1.43	
Japan Refining			3,838					1.0%	0.83	
Asia Refining			6,405					1.7%	1.39	
Asia Marketing			2,088					0.6%	0.45	
Latin America Refining			446					0.1%	0.10	
Latin America Marketing			1,130					0.3%	0.25	
Sub-Total			**69,585**					**18.8%**	**15.14**	
Implied PER on 2008-11 average earnings $ M.		$4,490	15.5x							
Gas, Power, Etc										
CAPCO	Majority stake in Hong Kong's		5,040					1.4%	1.10	Under-appreciated chemicals value
Sub-Total	biggest generator		**5,040**					**1.4%**	**1.10**	
Chemicals			**26,699**					**7.2%**	**5.81**	
Implied PER on 2008-11 average earnings $ M.		$3,641	7.3x							
Total Enterprise Value			**369,781**					**100.0%**	**80.44**	
Adjusted 3Q12 Net Debt			-631					-0.2%	-0.14	
Value before adjustments			**370,412**					**100.2%**	**80.58**	
Corporate Expenses			31,932					8.6%	6.95	
Pension Underfunding			25,672					6.9%	5.58	
Net Asset Value			**312,808**					**84.6%**	**68.05**	
Market Capitalisation			**417,959**						**90.92**	
Premium to NAV			**34%**						**34%**	
Implied PER on 2008-11 average earnings $ M.		$33,550	9.3x							
Memo:										
Number of Shares in Issue		**4,597**								

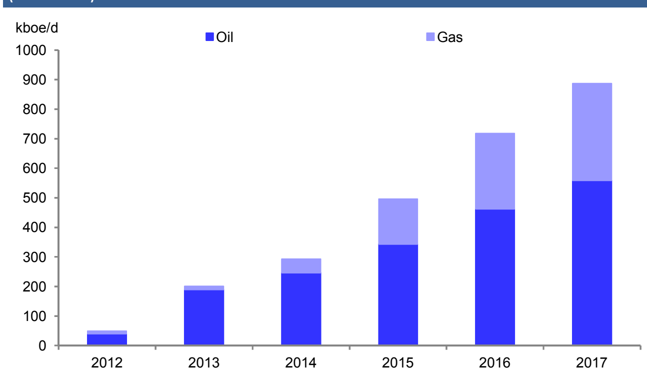
Source: Wood Mackenzie, Deutsche Bank

Figure 656: Exxon – Main Projects 2012-2015+

Name	Country	Recoverable		Peak		Interest	PSC?	Production						NPV
		Oil	Gas	Oil	Gas	%		2012	2013	2014	2015	2016	2017	$m
		Mbbl	Mboe	kb/d	kboed									
2012														
Kearl Initial Dev	Canada	4260*	0	170	0	100		8	101	105	106	120	130	-1513
Kipper/Tuna	Australia	31	103	15	29	40		1	2	4	7	10	10	-850
Turrum	Australia	n.a.	n.a.	20	33	50		9	12	11	20	27	27	n.a.
Kizomba satellites	Angola	253	0	100	0	40	Yes	8	38	35	30	27	23	3003
Usan	Nigeria			180	0	30		24	37	53	54	49	44	5831
2013														
Kashagan Ph 1	Kazakhstan	n.a.	n.a.	290	0	16.8	Yes	0	10	32	49	49	49	-2686*
2014														
Barzan	Qatar	569	2037	85	233	7		0	0	1	18	21	21	767
Greater Gorgon	Australia	244	6107	30	614	25		0	0	14	61	120	161	10642
Cold Lake Expansion	Canada	n.a.	n.a.	40	0	100		0	0	5	15	25	35	n.a.
Sakhalin-1 Arkutun	Russia	n.a.	n.a.	90	0	30	Yes	0	0	3	13	20	25	n.a.
CLOV	Angola	564	0	160	0	20	Yes	0	0	9	29	32	30	5748
PNG LNG	PNG	226	1495	30	157	33		0	0	20	51	62	62	14023
2015+														
Scarborough	Australia	0	1667	0	198	50		0	0	0	0	0	0	n.a.
Kearl expansion	Canada	n.a.	n.a.	110	0	100		0	0	0	5	40	70	n.a.
Hebron	Canada	840	0	130	0	36		0	0	0	0	0	14	1977
Mackenzie Gas	Canada	n.a.	n.a.	10	138	56		0	0	0	2	25	50	n.a.
Bosi	Nigeria	500	0	135	23	56	Yes	0	0	0	0	0	22	n.a.
Erha North Ph 2	Nigeria	200	0	60	0	56	Yes	0	0	0	18	34	34	n.a.
Hadrian North	US	558	42	100	17	50		0	0	0	5	36	46	7989*
Total								49	200	292	496	718	887	
Of which														
Oil								40	188	246	343	462	559	
Gas								9	12	46	153	256	328	

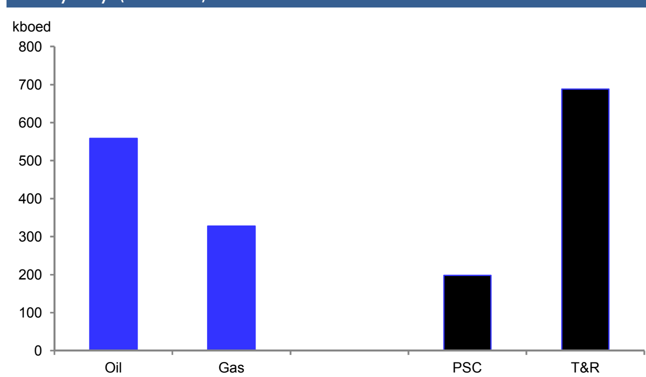
Source: Deutsche Bank

Figure 657: Production growth by hydrocarbon type (kboe/d)



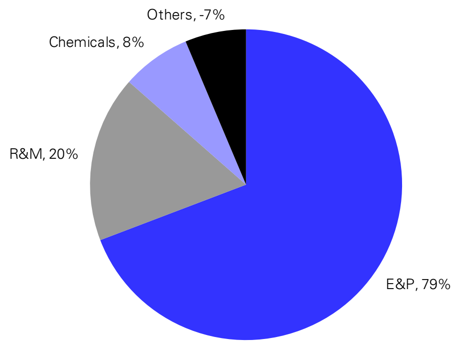
Source: Deutsche Bank

Figure 658: Production growth by oil/gas and PSC or tax & royalty (kboe/d)



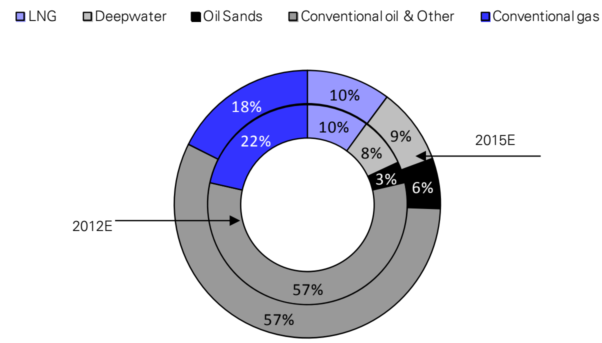
Source: Deutsche Bank

Figure 659: 2012E clean net income USD36,107m



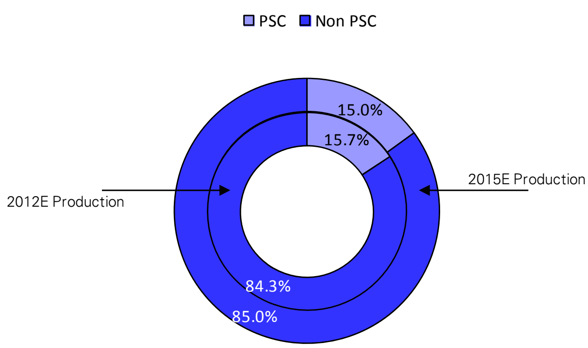
Source: Deutsche Bank

Figure 660: Trends in E&P Production



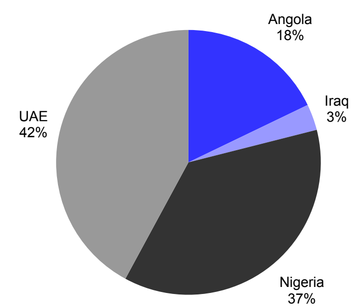
Source: Deutsche Bank

Figure 661: PSC exposure 12E-15E



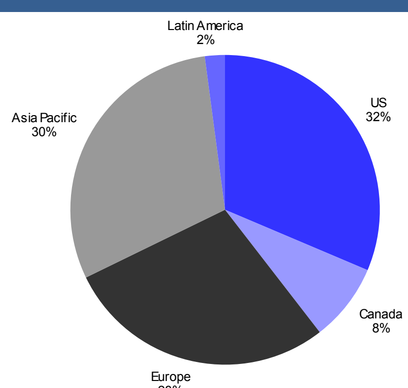
Source: Deutsche Bank

Figure 662: OPEC production 14% of total in 2012E



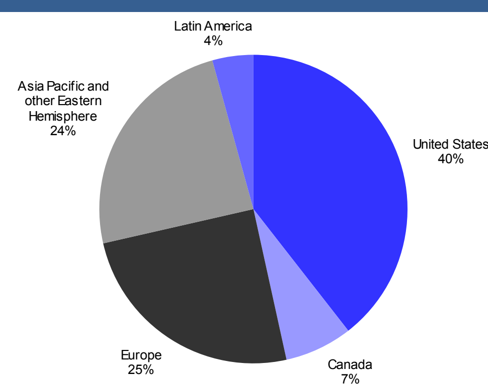
Source: Deutsche Bank

Figure 663: 2012 refining CDU 6,218 kb/d



Source: Deutsche Bank

Figure 664: 2011 marketing by region



Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Integrated Oil

Company
Chevron

Reuters	Bloomberg
CVX.N	CVX UN

Price at 16 Jan 2013 (US$)	115.31
Price Target (US$)	140.0
52-week range (US$)	118.02-96.41

Defensive with robust project queue

Chevron's earliest roots can be traced back to 1879 in Los Angeles with the discovery of oil at Pico Canyon. Following the 1984 acquisition of Gulf Oil, the 2001 merger with Texas and the 2005 acquisition of Unocal, Chevron is now one of the largest integrated oil companies in the world. We believe that US crude prices (WTI) will remain structurally discounted to international prices (Brent) on a long-term basis, which is positive for Brent-levered oil companies such as Chevron. Despite a mild medium-term growth outlook (around 1% pa production growth out to 2014E), Chevron's project portfolio is robust and long-term production growth should be solid. We rate Chevron a Buy.

Upstream: While its peers have been more focused on unconventional gas, Chevron has distinguished itself by focusing aggressively on the deepwater and huge LNG projects. It holds massive gas resources in Australia, with both Gorgon and Wheatstone LNG projects forming a big chunk of the company's growth profile from 2014E onwards, while we expect the company's portfolio to move from 30% gas production in 2010 to 35% in 2017.

Downstream: Chevron is a Pacific refiner with major California and Asia presence, a legacy of its deep history, namely Caltex, an outlet for Saudi oil. Including its share of affiliates, the company processes 1.8mb/d of crude and markets petroleum products worldwide.

Other: Chemicals are a small and relatively weak part of the investment case, and since 2010, its operations have been reported under the R&M business. Through its JV CPChem Chevron produces olefins and aromatics, and in February 2012, Chevron reached FID to significantly expand the capacity of its Singapore additives plant.

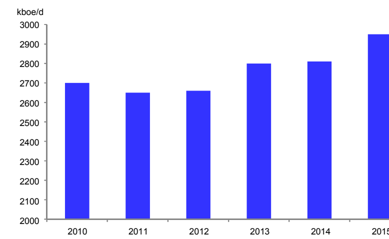
Valuation & Risk: We estimate NAV based on a bottom-up analysis of future cash flows and ROCE/WACC. Our P/E methodology is based on a target P/E of 11x (derived from ROCE/WACC) applied to a mid-cycle EPS estimate. The average results in our blended PT. Downside risks include over-spending and delays that could erode shareholder value.

Forecasts and ratios

Year End Dec 31	2011A	2012E	2013E
FY EPS (USD)	13.19	12.12	13.18
P/E (x)	8.7	9.5	8.7
DPS (USD)	3.09	3.51	3.72
Dividend yield (%)	3.1	4.1	4.3

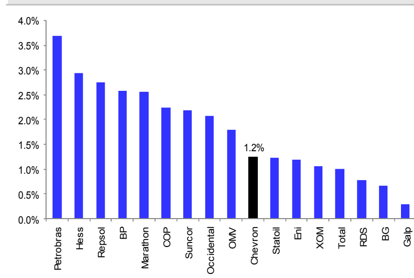
Source: Deutsche Bank estimates, company data

CVX Production Profile 2010-15E

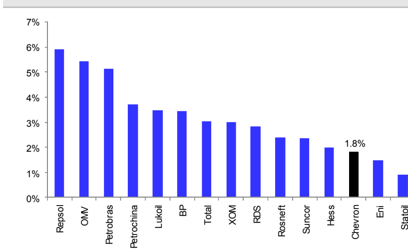


Upstream CAGR (2012-15E)	3.5%
Oil production (2012E)	1,793kb/d
Gas production (2012E)	875kboe/d
Oil Reserves (1P) 2011	11.2bn/bbls
Gas Reserves (1P) 2011	4.8bn/boe
Refining capacity	1,887kb/d
Marketing volumes	2,500kb/d
Wood Mackenzie 2P(E) Total reserves	29.7bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.11%

Sensitivity to $1/bbl move in oil



Sensitivity to $1/bbl move in refining



Reserve Life (1P)

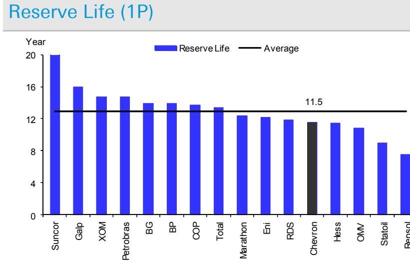


Figure 665: Asset Model from 1 January 2013 at $100/bbl and $4/mmbtu US gas

Upstream	Comment	Risked Value ($ Million)	Absolute Value ($ Million)	Risked 2 P Reserves	Absolute 2P Reserves	Value/ Risked 2P Reserves	% of Total EV	Value per Share
Angola		9,980	19,193	558	1,073	17.9	4.0%	5.1
Argentina		1,423	2,242	62	98	22.9	0.6%	0.7
Australia		44,939	58,363	4,369	5,674	10.3	18.0%	22.9
Azerbaijan		3,361	4,254	261	330	12.9	1.3%	1.7
Bangladesh		1,697	2,293	515	696	3.3	0.7%	0.9
Brazil		6,238	7,516	254	306	24.5	2.5%	3.2
Canada Newfoundland Labra		4,138	5,109	267	330	15.5	1.7%	2.1
Canada Oil Sands		7,841	8,761	623	696	12.6	3.1%	4.0
Chad		1,039	1,367	74	98	13.9	0.4%	0.5
China		3,740	4,156	308	342	12.1	1.5%	1.9
Colombia		438	504	32	37	13.7	0.2%	0.2
Congo Braz		1,959	2,544	179	232	11.0	0.8%	1.0
Denmark		1,786	1,861	103	107	17.3	0.7%	0.9
Indonesia		5,760	7,891	975	1,336	5.9	2.3%	2.9
Kazakhstan		17,213	49,181	1,257	3,593	13.7	6.9%	8.8
Myanmar		2,050	2,441	160	191	12.8	0.8%	1.0
Netherlands		254	265	17	18	14.7	0.1%	0.1
Nigeria		9,021	25,775	703	2,008	12.8	3.6%	4.6
Norway		109	133	7	9	15.6	0.0%	0.1
Philippines		1,697	1,907	121	136	14.1	0.7%	0.9
Saudi Arabia Partitioned		3,240	3,567	1,052	1,158	3.1	1.3%	1.7
Thailand		12,544	15,207	858	1,041	14.6	5.0%	6.4
Trinidad		559	588	221	232	2.5	0.2%	0.3
United Kingdom		4,342	5,713	323	425	13.5	1.7%	2.2
United States Alaska		528	659	51	63	10.4	0.2%	0.3
United States Gulf Coast		1,749	2,034	143	166	12.3	0.7%	0.9
United States DW Gulf of Mexico		18,719	28,798	1,169	1,799	16.0	7.5%	9.5
United States MidContinent		174	203	31	37	5.5	0.1%	0.1
United States Northeast		730	839	1,747	2,008	0.4	0.3%	0.4
United States West Coast		24,728	28,423	1,095	1,259	22.6	9.9%	12.6
United States Permian		8,267	9,613	886	1,030	9.3	3.3%	4.2
United States Rocky Mount		2,089	2,429	226	263	9.2	0.8%	1.1
Venezuela Strategic Assoc		3,186	9,103	499	1,426	6.4	1.3%	1.6
Vietnam		663	808	240	293	2.8	0.3%	0.3
Sub-Total		**206,200**	**313,735**	**19,386**	**28,507**	**10.6**	**82.4%**	**105.2**
Implied per barrel of booked reserves	11,315	$18.2	$27.7 /bbl					
Implied PER on 2008-11 avg earnings $ M.	$18,336	11.2x	17.1x					
3P "Possible" Reserves		**16,258**					**6.5%**	**8.3**
Upstream Sub-Total		**222,458**					**88.9%**	**113.5**
Refining and Marketing								
Europe Refining		1,730					0.7%	0.88
Europe Marketing		1,695					0.7%	0.86
North America Refining		11,605					4.6%	5.92
North America Marketing		1,275					0.5%	0.65
Asia / Africa Refining		2,460					1.0%	1.26
Asia Pacific / Latin America Marketing		2,641					1.1%	1.35
Sub-Total		**21,406**					**8.6%**	**10.92**
Implied PER on 2008-11 avg earnings $ M.	$2,193	9.8x						
Gas, Power, Etc								
GS Caltex, Ships etc		1,500					0.6%	0.77
Sub-Total		**1,500**					**0.6%**	**0.77**
Chemicals		**4,846**					**1.9%**	**2.47**
Implied PER on 2008-11 avg earnings $ M.	$148	32.8x						
Total Enterprise Value		**250,210**					**100.0%**	**127.65**
Adjusted 3Q12 Net Debt	-	8,977					-3.6%	-4.58
Value before adjustments		**259,187**					**103.6%**	**132.23**
Corporate Expenses		18,388					7.3%	9.38
NPV of eventual Ecuador litigation/arbitration liability		2,000					0.8%	1.02
Pension Underfunding		9,152					3.7%	4.67
Net Asset Value		**229,647**					**91.8%**	**117.16**
Market Capitalisation		**227,200**						**115.91**
Premium to NAV		**-1%**						**-1%**
Implied PER on 2008-11 avg earnings $ M.	$19,452	11.8x						11.81
Memo:								
Number of Shares in Issue	**1,960**							

Massive Australian position + resource

UCL deal bolstered leading Asian position ~13% of value

Tengiz is ~9% of total upstream value

Tremendous Nigerian position

Lots of resource, but surprisingly little development value yet

Large resource value relative to 2P reserves

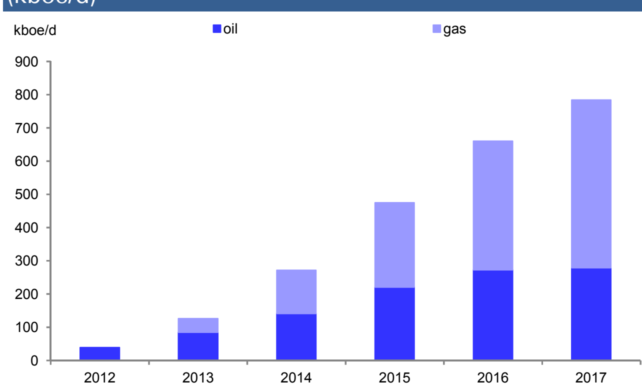
Source: Wood Mackenzie, Deutsche Bank

Figure 666: CVX – Main Projects 2012-2015+

Names	Country	Recoverable		Peak	Interest	PSC	Production						NPV
		Oil	Gas	Oil	%		2012	2013	2014	2015	2016	2017	
2012													
Angola LNG Plant	Angola	0	1383	175	36.4	Yes	1	21	46	63	63	63	5394
Usan	Nigeria	n.a.	n.a.	180	30	Yes	27	54	54	54	49	48	5831
Agbami 2	Nigeria	n.a.	n.a.	.	67.3	Yes	4	13	21	29	32	26	n.a.
Caesar/Tonga	US	205	33	46	20.3		8	9	9	9	8	8	4921
2013													
Chuandongbei	China	0	517	93	49	Yes	0	5	35	46	45	45	819
North Duri	Indonesia	n.a.	n.a.	17	100	Yes	0	1	5	11	15	17	n.a.
Escravos GTL	Nigeria	n.a.	n.a.	33	75		0	15	25	24	22	20	n.a.
Olero Creek	Nigeria	n.a.	n.a.	48	40		0	1	6	17	19	19	n.a.
Papa Terra	Brazil	380	0	140	37.5		0	7	33	49	53	53	4790
2014													
Gorgon LNG	Australia	244	6107	450	47.3		0	0	18	104	203	213	10642
Nemba ESR	Angola	n.a.	n.a.	16	39.2		0	0	1	4	6	6	n.a.
Lianzi	Angola	n.a.	n.a.	47	31.3	Yes	0	0	0.3	3	5	4	152
Big Foot	US	311	18	79	60		0	0	14	33	47	33	3296
Jack/St. Malo	US	622	26	177	50/51		0	0	3	21	35	59	3267
Tubular Bells	US	92	31	40-45	42.9		0	0	0.3	8	14	14	823
2015+													
Wheatstone LNG	Australia	169	1838	260	90/72*		0	0	0	0	28	123	5351
Clair Ridge (Ph 2)	UK	n.a.	n.a.	120	19.4		0	0	0	0	15	19	n.a.
Sonam Dev.	Nigeria	168	132	66	40		0	0	0	0	0	14	180
Total							**38**	**126**	**271**	**475**	**660**	**784**	**40575**
Of which													
Oil							*38*	*84*	*141*	*220*	*272*	*279*	
Gas							*0*	*42*	*131*	*255*	*388*	*505*	

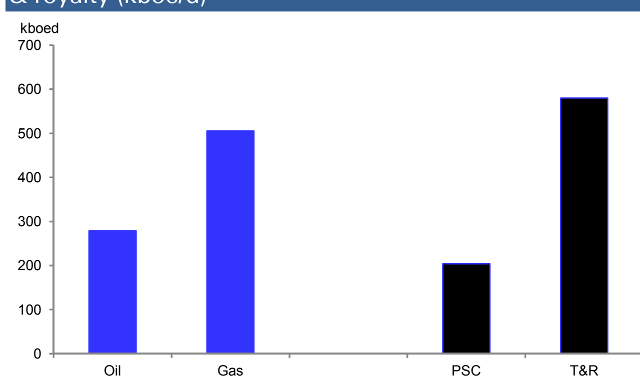
Source: Deutsche Bank

Figure 667: Production growth by hydrocarbon type (kboe/d)



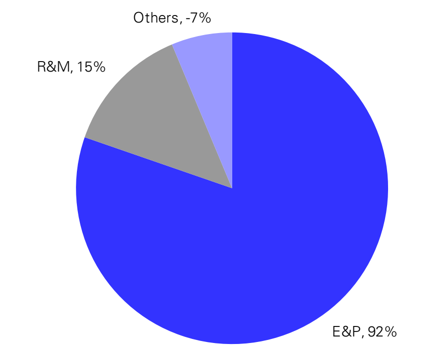
Source: Deutsche Bank

Figure 668: Production growth by oil/gas and PSC or tax & royalty (kboe/d)



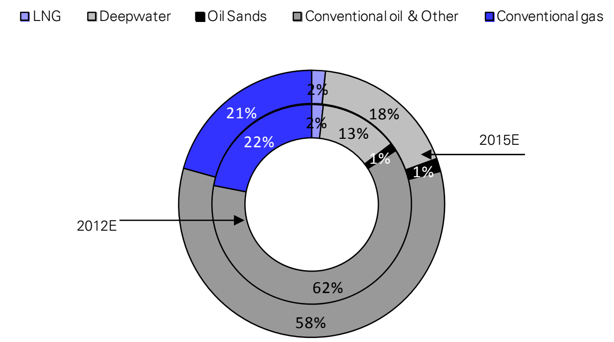
Source: Deutsche Bank

Figure 669: 2012E clean net income USD23,806m



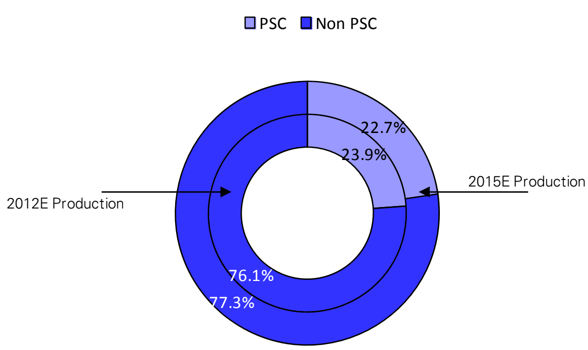
Source: Deutsche Bank

Figure 670: Trends in E&P Production



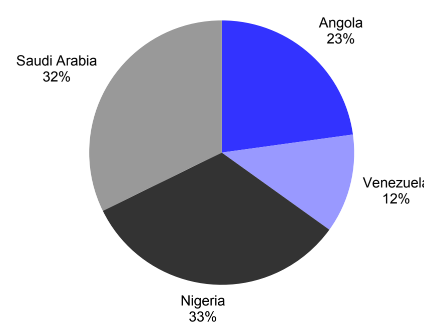
Source: Deutsche Bank

Figure 671: PSC exposure 12E-15E



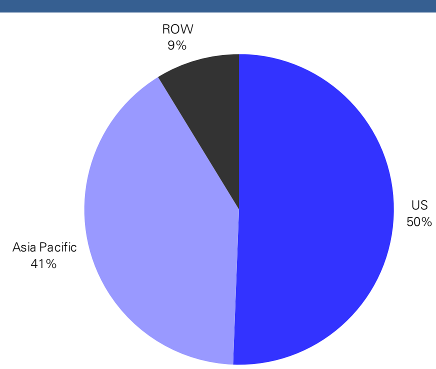
Source: Deutsche Bank

Figure 672: OPEC production 23% of total in 2012E



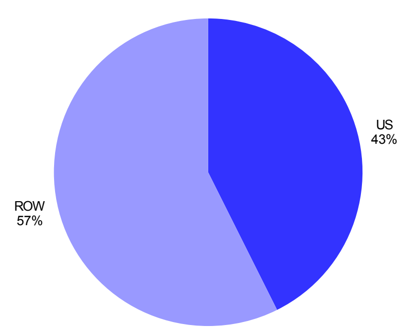
Source: Deutsche Bank

Figure 673: 2012 refining CDU 1,887kb/d



Source: Deutsche Bank

Figure 674: 2011 marketing by region



Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Integrated Oil

Company
Conoco

Reuters	Bloomberg
COP.N	COP UN

Price at 16 Jan 2013 (US$)	59.65
Price Target (US$)	62.0
52-week range (US$)	60.5-52.0

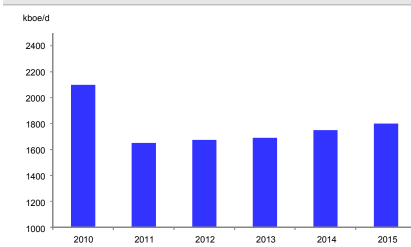
Streamlined

After a two-year restructuring, Conoco demerged its leading US position in refining to create Phillips 66 and positioned itself as a standalone upstream company effective May 1, 2012. Disposal of non-core upstream assets over the last two years has left a more streamlined and strategic asset base focused on North American unconventional/oil sands and Asian NGL.

Upstream: With a history of high levels of M&A activity (Burlington, Lukoil, Origin and a JV with Encana to name a few), the company reversed strategy and has announced $12bn of asset sales since the beginning of 2012, already exceeding the promise of $8-10bn by YE13, and has focused on returning cash to shareholders through buyback, especially in 2012. It is ConocoPhillips' goal to deliver 3-5% production CAGR in the long run.

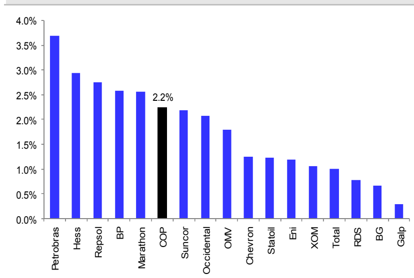
Valuation & Risk: We estimate adjusted net asset value based on a bottom-up analysis of future cash flows with ROCE/WACC, but apply a 10% discount. Our analysis of Return on Capital Employed (ROCE) over cost of capital yields a target P/E of 8.5x, which we apply to our mid-cycle EPS estimate. Averaging the two methods we arrive at our blended PT. Downside risks are in a failure to execute disposals, or worse, an unexpected acquisition that is larger than the $2bn guidance. More operational issues would also be a negative. Upside risks are in the form of more aggressive share buybacks vs. expectations and a future return to the shrink-to-grow strategy.

COP Production Profile 2010-15E

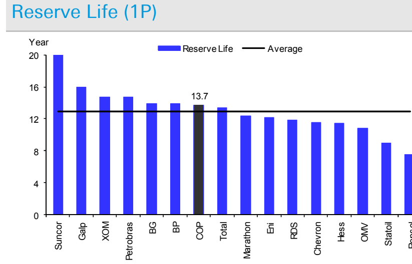


Upstream CAGR (2012-15E)	2.5%
Oil production (2012E)	978kb/d
Gas production (2012E)	731kboe/d
Oil Reserves (1P) 2011	4.9bn/bbls
Gas Reserves (1P) 2011	3.5bn/boe
Refining capacity	0kb/d
Marketing volumes	0b/d
Wood Mackenzie 2P(E) Total reserves	17.8bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.1%

Sensitivity to $1/bbl move in oil



Reserve Life (1P)



Forecasts and ratios

Year End Dec 31	2011A	2012E	2013E
FY EPS (USD)	8.63	6.12	5.95
P/E (x)	6.3	9.7	10.0
DPS (USD)	2.60	2.60	2.90
Dividend yield (%)	4.4	4.4	4.9

Source: Deutsche Bank estimates, company data

Figure 675: Asset Model from 1 January 2013 at $100/bbl and $4/mmbtu US gas

Upstream	Comment	Risked Value ($ Million)	Absolute Value ($ Million)	Risked 2P Reserves	Absolute 2P Reserves	Value/2P Reserves	% of Total EV	Value per Share
Australia		6,329	8,328	906	1,192	7.0	5.5%	5.15
Algeria		390	566	57	83	6.8	0.3%	0.32
Azerbaijan		172	218	-	-	-	0.1%	0.14
Canada Onshore (inc. Alberta)		1,924	2,115	1,565	1,719	1.2	1.7%	1.57
Western Canada (inc. Oil Sands)		18,178	19,976	2,551	2,803	7.1	15.7%	14.79
China		5,937	6,671	325	366	18.3	5.1%	4.83
Indonesia		4,023	5,667	353	497	11.4	3.5%	3.27
Kazakhstan		5,000	11,799	260	590	19.2	4.3%	4.07
Libya		148	1,478	259	471	0.6	0.1%	0.12
Malaysia		3,732	3,971	395	421	9.4	3.2%	3.04
Nigeria		1,373	3,924	227	528	6.1	1.2%	1.12
Norway		7,041	8,692	715	883	9.8	6.1%	5.73
Peru		-	-	-	-	NA	0.0%	0.00
Qatar		9,365	11,149	557	663	16.8	8.1%	7.62
Russia		96	119	8	9	12.6	0.1%	0.08
United Kingdom		5,175	6,993	334	451	15.5	4.5%	4.21
United States Alaska		10,824	13,701	1,055	1,336	10.3	9.3%	8.80
United States DW Gulf of Mexico		1,282	1,973	142	209	9.0	1.1%	1.04
United States Rocky Mount		7,969	9,267	1,245	1,447	6.4	6.9%	6.48
United States Gulf Coast		10,689	12,429	1,378	1,602	7.8	9.2%	8.70
United States MidContinent		1,348	1,568	166	194	8.1	1.2%	1.10
United States Permian		4,526	5,263	424	493	10.7	3.9%	3.68
Venezuela (arbitration)		2,000	4,512	-	-	-	1.7%	1.63
Sub-Total		**107,524**	**140,377**	**12,922**	**15,958**	**8.32**	**92.7%**	**87.46**
Implied per barrel of booked reserves	8,732	$12.3	$15.0					
Implied PER 2008-11 avg earnings $ M.	$8,081	13.3x	16.2x					
3P "Possible" Reserves		**8,463**					7.3%	6.88
Upstream Enterprise Value		**115,987**					**100.0%**	**94.35**
Adjusted 3Q12 Net Debt		17,381					15.0%	14.14
Value before adjustments		98,606					85.0%	80.21
Corporate Expenses		7,737					6.7%	6.29
Pension Underfunding		3,714					3.2%	3.02
Net Asset Value		**87,155**					**75.1%**	**70.90**
Market Capitalisation		**73,736**						**59.98**
Premium to NAV		**-15%**						**-15%**
Implied PER 2008-11 avg earnings $ M.	$11,443	6.4x						
Number of Shares in Issue	**1,229**							

Excluding Syncrude - sold to Sinopec for ~$4.7bn in Apr '10

For sale: expected proceeds ~$5bn vs. our original $2.85bn

For sale

North Sea and Alaska potentially for sale

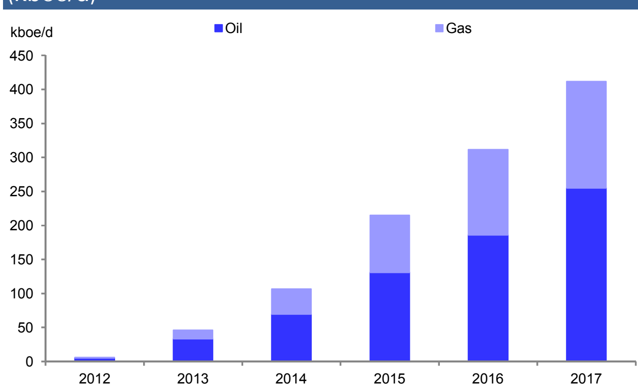
Source: Wood Mackenzie, Deutsche Bank

Figure 676: Conoco – Main Projects 2012-2015+

Name	Country	Recoverable		Peak	Interest	PSC?	Production					
		Oil	Gas		%		2012	2013	2014	2015	2016	2017
		Mbbl	Mboe	kboe/d								
2012												
Gumusut	Malaysia	417*	0	150	30.6	Yes	1	17	26	25	24	23
Jasmine	UK	93	106	95	37		1	6	11	14	17	14
Christina Lake D	Canada	n.a.	n.a.	40	50		4	10	18	20	20	20
APLNG JV	Australia	0	2063	293	37.5		1	3	8	18	35	70
2013												
Ekofisk South	Norway	n.a.	n.a.	n.a.	16.8	Yes	0	0.3	10	19	23	19
Alpine West	US	n.a.	n.a.	12			0	9	12	12	10	6
Petai-Pisagan	Malaysia	148	0	35			0	1	6	8	7	6
2014												
Surmont Phase 2	Canada	n.a.	n.a.	84	50		0	0	1	3	13	38
Christina Lake E	Canada	n.a.	n.a.	40	50		0	0	10	15	20	20
Foster Creek 1F	Canada	n.a.	n.a.	30	50		0	0	1	9	15	15
KBB - Kebabangan	Malaysia	102	514	103	30	Yes	0	0	1	26	31	31
Malikai	Malaysia	120	0	57	35	Yes	0	0	0	7	16	15
Eldfisk II	Norway	2713	428	75	35		0	0	3	23	24	23
2015+												
South Belut	Indonesia	0	17	5	23	Yes	0	0	0	1	1	1
Foster Creek 1G/H	Canada	n.a.	n.a.	95	50		0	0	0	0	6	23
Christina Lake F/G/H	Canada	n.a.	n.a.	120	50		0	0	0	15	30	40
Narrows Lake A/B	Canada	840	0	130	50		0	0	0	0	2	25
Clair Ridge	UK	n.a.	n.a.	120	24		0	0	0	0	19	23
Total							**6**	**46**	**106**	**215**	**312**	**411**
Of which												
Oil							5	33	70	131	186	255
Gas							1	13	37	84	126	157

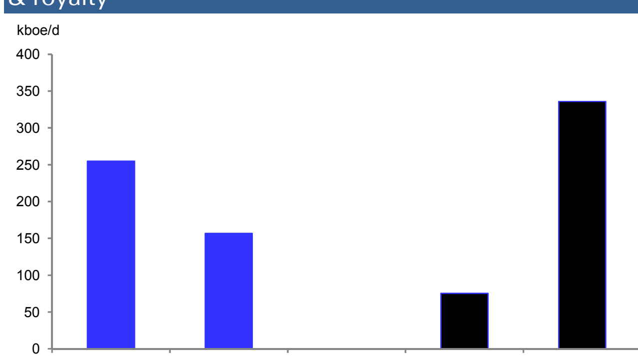
Source: Deutsche Bank

Figure 677: Production growth by hydrocarbon type (kboe/d)



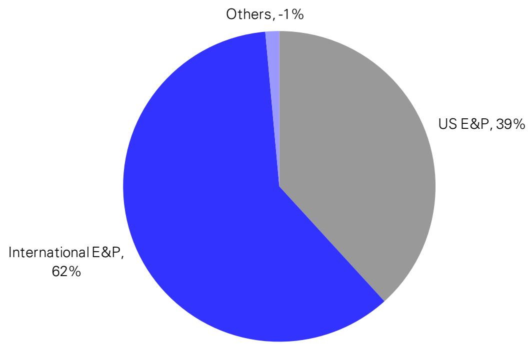
Source: Deutsche Bank

Figure 678: production growth by oil/gas and PSC or tax & royalty



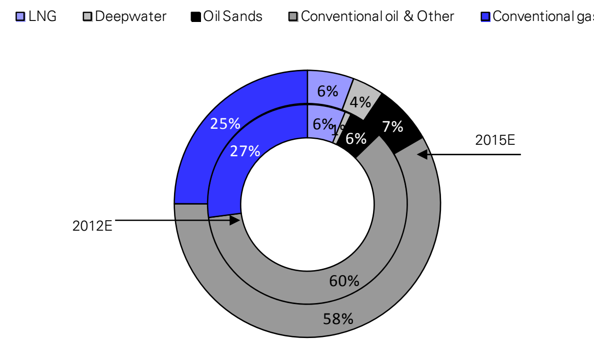
Source: Deutsche Bank

Figure 679: 2012E clean net income USD 7,681m



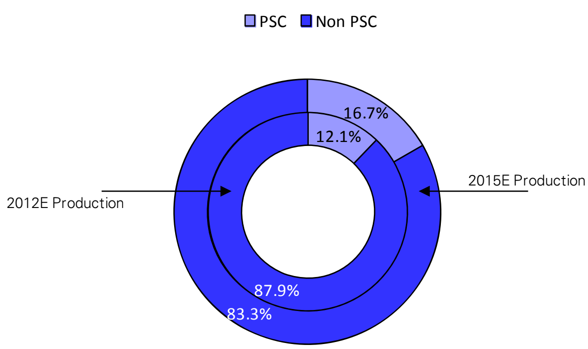
Source: Deutsche Bank

Figure 680: Trends in E&P Production



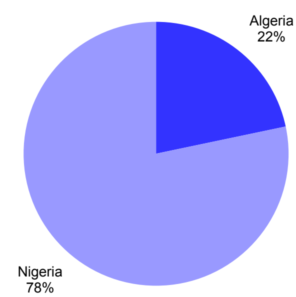
Source: Deutsche Bank

Figure 681: PSC exposure 12E-15E



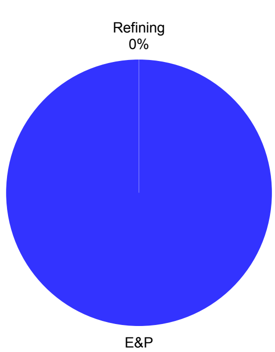
Source: Deutsche Bank

Figure 682: OPEC production 2% of total in 2012E



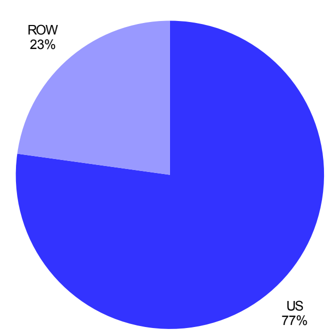
Source: Deutsche Bank

Figure 683: Refining business split out



Source: Deutsche Bank

Figure 684: 2011 marketing by region



Source: Deutsche Bank

Rating
Buy

North America
United States

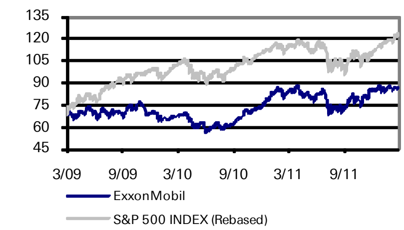
Industrials
Exploration & Production

Company
Anadarko

Reuters	Bloomberg
APC.N	APC UN

Price at 27 Mar 2012 (USD)	86.62
Price target	93.00
52-week range	88.00 - 68.03

Price/price relative

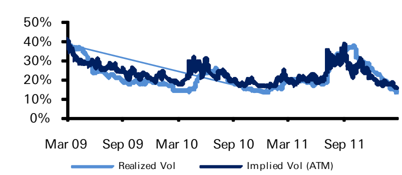


Performance (%)	1m	3m	12m
Absolute	-0.7	1.6	3.6
S&P 500 INDEX	3.3	11.6	7.5

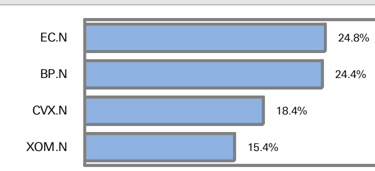
Stock & option liquidity data

Market Cap (USDm)	404,218.1
Shares outstanding (m)	4,666.6
Free float (%)	100
Volume (27 Mar 2012)	3,294,344
Option volume (und. shrs., 1M avg.)	4,209,486

Implied & Realized Volatility (3M)



Implied Volatility (3M, ATM) vs. Peers



*Weighted-avg. of index components
*Data as of 27-Mar-12

A Truly Diversified Global E&P, with a Nose for Exploration

Anadarko traces its beginnings to a subsidiary of Panhandle Eastern Corporation formed following the large natural gas discoveries made in the Anadarko Basin, the company's namesake, in 1959. It has since grown into one of the world's largest independent exploration companies with acreage in several premier basins, world-class offshore operating assets and interests in several high-impact exploration targets. APC's diversified asset position (onshore and offshore), accelerating operating momentum, and portfolio approach to exploration leave it uniquely positioned to capture/monetize resource, in our view. Given the undervalued nature of its quality assets, increasing scarcity of meaningful oil growth assets, and significant exploration exposure (tied to global crude benchmarks), we rate APC as a BUY.

Upside Potential: Anadako's differentiating factor has been its successful exploration track record as well as management's focus on realizing value from the asset base. The company's 2013 production trends appear positive with Wattenberg (domestic onshore liquids), Algeria (El-Merk ramp) and Jubilee remediation all drivers. Expect APC to return to trend-line production growth 5-7% while spending within cash flow in 2013 (this outlook is increasingly unique in the peer group). 2013 will likely see two significant realizations of NAV upside for the stock. In Brazil, APC is looking to finally progress the sale of this asset, which has been pending for ~12+ months. In Mozambique, look for APC to bring in a partner to support the development of the LNG project. The 2013 exploration calendar also looks exceptionally deep, with a number of major wells underway or planned in the Gulf of Mexico (Phobos, Raptor) and two wells in new basins (Kenya, South China Sea).

Valuation & Risks - We set our PT for Anadarko at $93. Our price target reflects our equal-weighted consideration of both target multiple (6x our 2013E EV/DACF) and NAV. The startup of new projects, better margin performance from the domestic onshore (less reliance on low margin natural gas for growth), and leverage to waterborne crude pricing (70% of crude production is indexed to waterborne prices) support a funding outlook where APC looks to be capable of fully funding our 2013 capex expectations within organic cash flow down at a $90/bbl (WTI & Brent). Beyond commodity price trends, the major risks include expectations surrounding the exploration portfolio and execution on major development projects.

Forecasts and ratios

Year End Dec 31	2011A	2012E	2013E
FY EPS (USD)	8.22	8.07	8.68
P/E (x)	9.7	10.7	10.0
Dividend yield (%)	2.3	2.7	3.0

Source: Deutsche Bank estimates, company data

Net Asset Value

Figure 685: Anadarko NAV by Asset

	Value ($/mm)	Resource mmboe	Implied $/BOE	Value $/shr
Proved Developed Reserves				
Proved Reserves	$24,929	2,539	$9.82	$49.76
Total Proved Developed (PDP)	24,929	2,539	9.82	49.76
Risked Resource (PUD /2P / 3P)				
Domestic Onshore				
Marcellus	$592	1,326	$0.45	$1.18
Eagleford	$1,414	574	2.46	2.82
Wattenberg - Horizontal	$4,977	609	8.17	9.93
Greater DJ (Outside Wattenberg)	$1,238	204	6.06	2.47
Permian	$1,574	430	3.66	3.14
Greater Natural Buttes	$3,012	1,184	2.54	6.01
Powder River Basin	$377	113	3.34	0.75
Haynesville	$--	530	--	--
Utica	$149	148	1.01	0.30
East Texas	$687	221	3.11	1.37
Deepwater GoM				
Development	$7,784	570	$13.66	$15.54
International				
Ghana (Jubilee + TEN)	5,251	561	9.35	10.48
Algeria	2,258	121	18.66	4.51
Brazil	4,547	538	8.45	9.08
Mozambique LNG	5,907	3,042	1.94	11.79
Kenya	85	150	0.57	0.17
Midstream				
WGP Ownership (~91%)	$5,915			$11.81
APC Midstream @ 7x EBIT	$1,890			$3.77
Capital				
Net Debt (Q312)	($11,609)			
Eagle Ford Carry	$591			
TPE Settlement	$1,800			
Tronox	($3,000)			
Total				($24.39)
Net Equity Value	$60,369			$120.00
MM Shares Outstanding, Including Dilution (Q312)				**501**

Source: Wood Mackenzie, Deutsche Bank

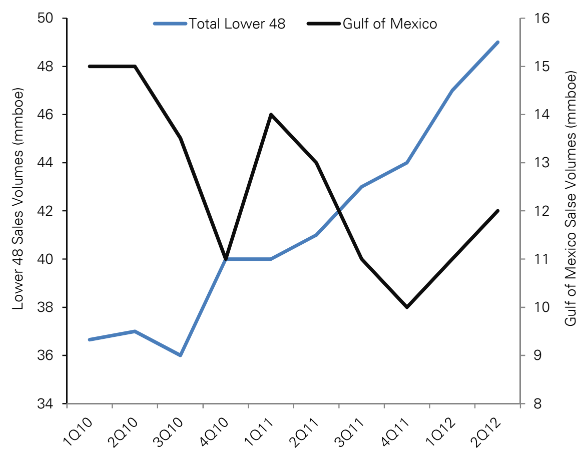
Figure 686: Pricing Assumptions

Futures	**Oil**	**Natural Gas**
2012	$95.30	$2.86
2013	$94.31	$4.03
2014	$92.04	$4.30
2015 and Beyond	$89.80	$4.50
Discount Rate	10%	

Source: Deutsche Bank

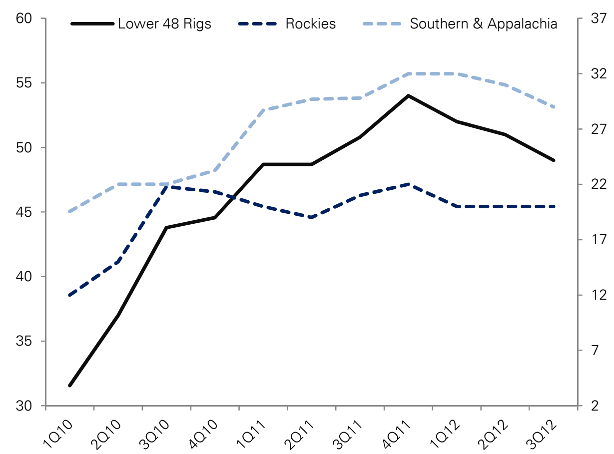
Quarterly Trends

Figure 687: Lower 48 vs. Gulf of Mexico Sales Volumes



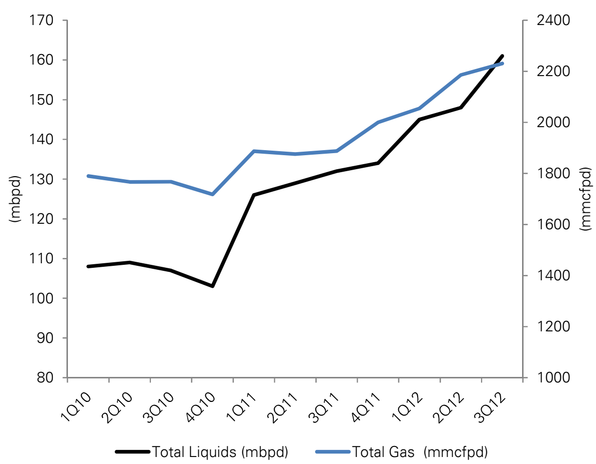
Source: Deutsche Bank

Figure 688: Lower 48 Rig Count Breakdown



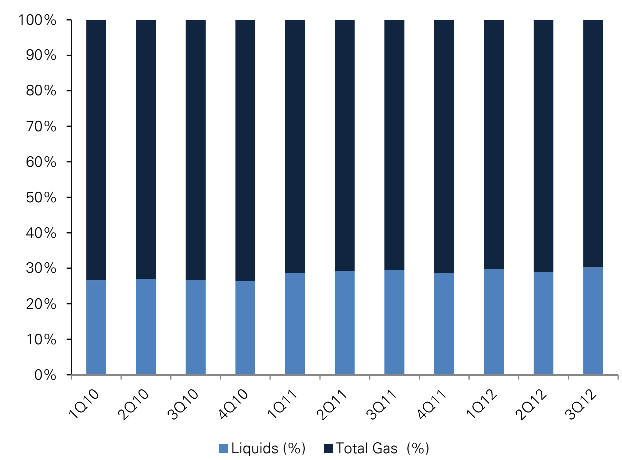
Source: Deutsche Bank

Figure 689: Lower 48 Production Volumes (per day)



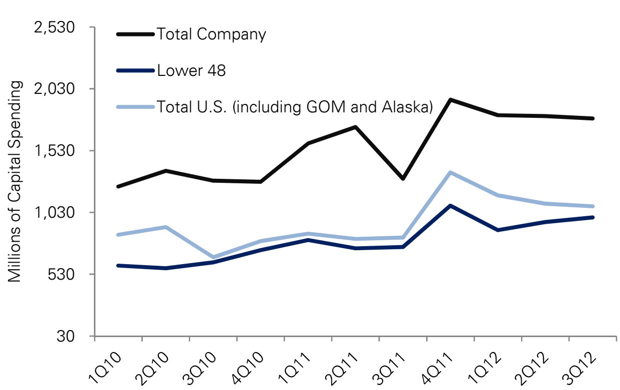
Source: Deutsche Bank

Figure 690:Lower 48 Volumes Mix



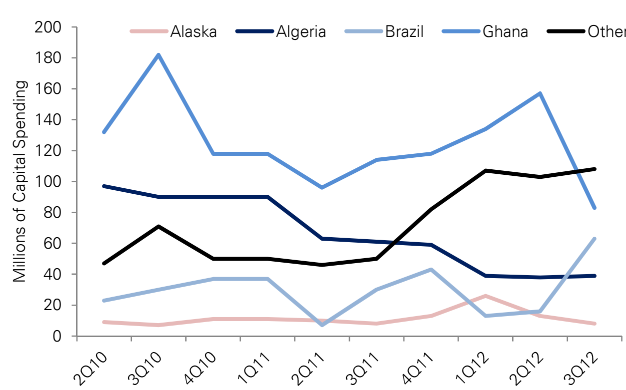
Source: Deutsche Bank

Figure 691: Capex Trends



Source: Deutsche Bank

Figure 692: Ex Lower 48 Capex Trends



Source: Deutsche Bank

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Rating
Buy

North America
United States

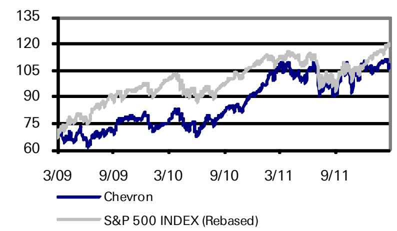
Industrials
Oil & Gas Exploration & Production

Company
EOG Resources

Reuters	Bloomberg
EOG.N	EOG UN

Price at 27 Mar 2012 (USD)	107.04
Price target	133.00
52-week range	111.19 - 89.88

Price/price relative

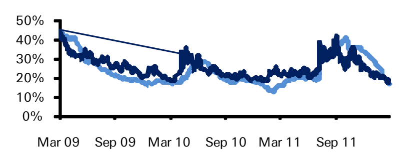


Performance (%)	1m	3m	12m
Absolute	-2.4	-0.9	0.2
S&P 500 INDEX	3.3	11.6	7.5

Stock & option liquidity data

Market Cap (USDm)	209,373.7
Shares outstanding (m)	1,956.0
Free float (%)	100
Volume (27 Mar 2012)	4,327,600
Option volume (und. shrs., 1M avg.)	1,803,276

Implied & Realized Volatility (3M)



First-Mover Advantage in U.S. Tight Oil

2012 marks the completion of what we see as a best-in-class operator's transition from a gas producer to a liquids producer. As one of the first entrants in the Bakken and Eagle Ford, EOG has amassed scalable resources in the most economic portions of these plays. Possessing the right assets and the operational know-how, we see EOG uniquely positioned to grow 2013+ liquids production by 20+%, further driving per-barrel margin expansion. Market concerns surrounding the cost of implementing the program have receded given EOG's successful execution in the Eagle Ford and the ability to deliver upside to Street growth expectations.

Eagle Ford and Beyond: With ~3,200 drillable locations in the Eagle Ford, EOG is the dominant operator in the region with multiple years of drilling inventory to support liquids growth. As the company continues to gain efficiencies and build upon its knowledge, EOG has attained the best-in-class Eagle Ford operator status. Down-spacing efforts in the region should provide additional upside to inventory and recoverable resources. The next leg for EOG involves finding and developing new resource plays (Permian, TMS) and secondary recovery, which should gain traction in 2013.

Management Change on the Horizon: After serving as Chairman and CEO since 1999, Mark Papa is expected to retire as CEO by mid-2013 and retain the Chairman role until YE'13. As a 30+ year veteran at EOG, Bill Thomas, the current President, is expected to assume the CEO position. Given Bill's tenure at EOG, we expect the same strategy going forward of finding and developing assets at an advantage to the industry, exemplified by the EOG's positions in both the Bakken and Eagle Ford.

Valuation & Risk: Our $133/sh target is derived via an equal weighted average of our $134 NAV at $90/$4.50 long term and 6.0x our 2013E DACF. Beyond the commodity exposure, downside risks include operational missteps in the Eagle Ford and Bakken, which would negatively affect liquids growth.

Forecasts and ratios

Year End Dec 31	2011A	2012E	2013E
FY EPS (USD)	13.19	13.10	15.23
P/E (x)	7.6	8.2	7.0
Dividend yield (%)	3.1	3.1	3.3

Source: Deutsche Bank estimates, company data

Net Asset Value

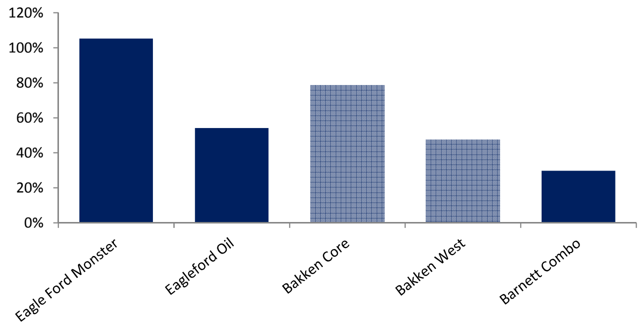
Figure 693: EOG Net Asset Value Summary

Net Asset Value

	Value ($/mm)	Resource mmboe	Implied $/BOE	Value $/shr
Proved Developed Reserves				
Developed	$13,291	1,043	$12.75	$49.35
Proved Undeveloped	5,432	1,011	5.37	20.17
Total Proved Reserve Value	$18,723	2,054	$9.12	$69.53
Risked Resource (2P / 3P)				
Liquids Assets				
Eagleford	$15,368	1,762	$8.72	$57.07
Barnett Combo	696	295	2.36	2.58
Bakken - Core	1,080	71	15.18	4.01
Bakken - Lite	579	128	4.52	2.15
Sanish - Three Forks	901	337	2.67	3.34
Niobrara	601	101	5.97	2.23
Leonard (Avalon / Bone Springs)	397	144	2.76	1.48
Horizontal Wolfcamp	655	138	4.74	2.43
Marmaton Sandstone (Mid-Cont)	89	33	2.66	0.33
Waskada (Spearfish)	240	20	12.00	0.89
Gas Assets				
Haynesville	$--	1,164	$--	$--
Bossier	31	964	0.03	0.11
Horn River	69	1,193	0.06	0.25
Marcellus	448	1,030	0.43	1.66
Remaining Barnett	203	1,017	0.20	0.76
Uinta	233	1,167	0.20	0.87
Other				
Argentina	300			1.11
Capital				
Cash	$581			
Debt	(5,012)			
Total				(16.45)
Net Equity Value	$36,182			$134.00
Shares Outstanding, Including Dilution				**269**

Note: Calculations are based on long term commodity prices of $90/bbl and $4.50/ mmbtu.
Source: Deutsche Bank

Figure 694: After-tax Single Well Internal Rate of Return



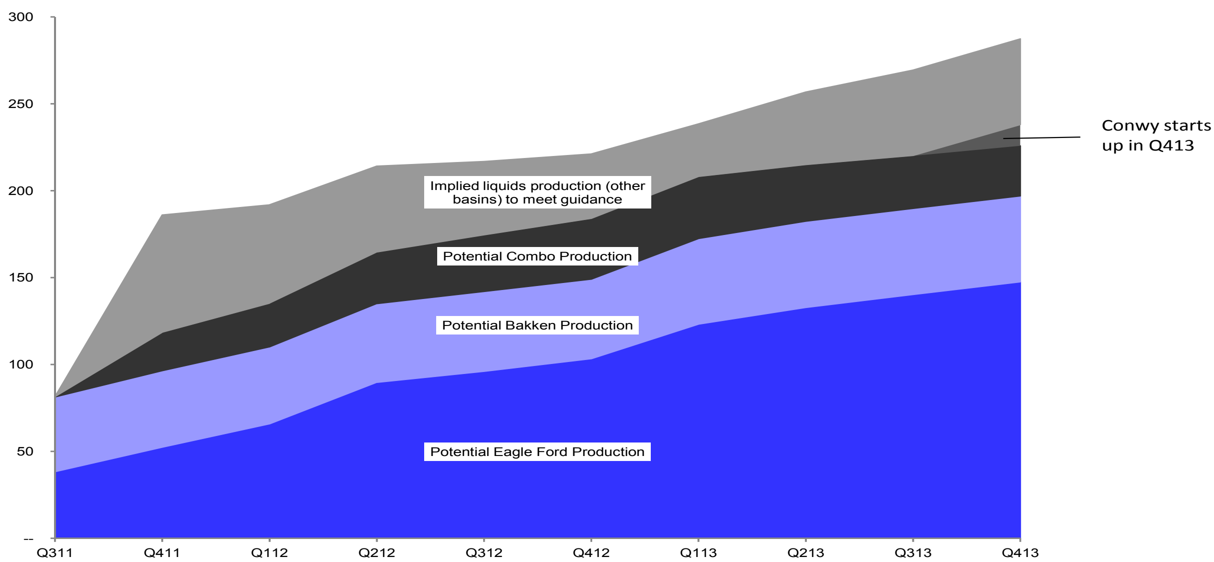
Note: Monster wells are defined by EOG as wells with IP rates of 2.5-4.8 mpd. Returns are calculated with commodity prices of $90/bbl and $4/mmbtu. Source: Deutsche Bank, Company Data

Figure 695: Major Eagle Ford Acreage Holders

Operator	Total Acres	Oil Window	Cond Window	Dry Gas Window
Marathon	230,000	149,500	57,500	23,000
EOG	644,000	572,000	26,000	46,000
ConocoPhillips	228,000	68,400	159,600	0
BHP	332,000	66,400	99,600	166,000
Pioneer	300,000	120,000	60,000	120,000
Anadarko	200,000	0	200,000	0
Murphy	201,800	141,260	20,180	40,360
Chesapeake	460,000	299,000	161,000	0
SM Energy	149,000	0	119,200	29,800

Source: Deutsche Bank, Company Data

Figure 696: EOG Production Forecast by Play (mbpd)



Source: Deutsche Bank, Company Data

Sector Investment Thesis

Outlook

In our recent sector review (*"Profiting from Big Oils Renaissance", Sept-11*), we argued that far from being structurally broken, the integrated model remained relevant, that the sector had been undergoing a period of strategic and operational transition, and that sentiment toward a materially undervalued group should begin to improve, driven by expected growth in volumes, cash and exploration activity. In this context 2012 proved disappointing, with confidence in operational delivery once again undermined by sharply reduced volume expectations. With this in mind, 2013-14 should prove a key staging-post for our thesis as the sector should show the first signs of operational rejuvenation. First, after a decade of stagnant volumes, we expect the delivery of modest production growth. Seeing is believing; but even allowing for 'normal' slippage we expect the group to return a sentiment-boosting uptick in volumes. Second, leveraging margin-accretive barrel growth we forecast a 13% expansion in OCF by 2014 at constant oil prices, driving an improvement in FCF and lowering the cash breakeven of the group. Third, with the Majors placing a greater emphasis on frontier exploration, we look to drilling activity to improve perceptions of sustainability. However, with market concerns deeply entrenched, a sector-wide re-rating will likely require a sustained period of improved performance. Recognising that each company stands at a different point in its evolution, we prefer to play this thesis on a bottom-up basis through preferred companies as opposed to a top-down sector call.

Valuation

We use several earnings and cash flow valuation techniques to value the oils. These include P/E relative, dividend yield, CROCI, discounted cash flow models, Free Cash Flow Yield and a cash-flow asset valuation based Sum-of-the-Parts. The absolute valuation of the sector presently appears attractive: (1) the group trades at an aggregate c35% discount to SOTP with asset disposals made across the past year suggesting that our asset valuation is conservative relative to the asset market. (2) the group trades at just 0.78x 2013e Net Capital Invested, c15% below the multiple consistent with our forecast for 2013 CROCI/COC and at odds with our assessment of potential returns on reinvestment. On a market-relative basis we observe that the 12-month-forward consensus PE of the sector stands at c0.75x for the market as compared to a trailing 7-year average of c0.8x. Furthermore, with the sector balance sheet robust and what we see as limited absolute downside, we regard the sector as defensive in the event of any market pullback. Aggregating our company target prices implies a 2013E sector target PE multiple of 9.0x and a sector target EV/NCI of 1.0x.

Risks

As ever, the key risk to our estimates is the outlook for commodity prices, crude oil in particular. Specifically, we note exposure to evolving expectations for economic growth in the key consuming countries and to expectations around the behaviour of OPEC, particularly in light of geopolitical tensions in the MENA region. Thus our forecasts are consequently vulnerable to moves in the price of crude about our $113/bbl 2013 oil price estimate. As a sector whose functional currency is the US dollar, a sharp fall in that currency would be counter to our current expectations and could significantly undermine asset values and the local currency value of dividend payments. Considering company-specific factors we note that equity value will be sensitive to perceived changes in economic/fiscal conditions in key countries of operation, to the physical risks inherent in an asset-intensive business, and to the risks borne of the environmental challenges directly associated with producing crude oil and gas.

Deutsche Bank Energy Coverage List

Companies by sub-sector and coverage analyst

Figure 697: Deutsche Bank – Global Drillers Coverage Universe & Analyst Contact List

Company	Reuters	Region	Country	Recom	Trading Currency	Last price	Target price	M Cap $m	Analyst	email
Aban Offshore Limited	ABAN.BO	Asia Pacific	India	Buy	INR	374.5	550	303	Harshad Katkar	harshad.katkar@db.com
China Oilfield Services	2883.HK	Asia Pacific	China	Hold	HKD	15.96	15.73	9510	David Hurd, CFA	david.hurd@db.com
Seadrill	SDRL.N	Europe	Norway	Hold	USD	38.67	37	19021	Michael Urban	michael.urban@db.com
Gulf Int'l Services	GISS.QA	GEM	Qatar	Buy	QAR	30.8	32.5	1258	Aleksandar Stojanovski	aleksandar.stojanovski@db.com
Diamond Offshore Drilling	DO.N	North America	US	Hold	USD	73.35	70	10389	Michael Urban	michael.urban@db.com
ENSCO International	ESV.N	North America	US	Hold	USD	61.82	58	14260	Michael Urban	michael.urban@db.com
Hercules Offshore	HERO.OQ	North America	US	Buy	USD	6.85	8	1089	Michael Urban	michael.urban@db.com
Nabors Industries	NBR.N	North America	US	Buy	USD	15.67	25	4626	Michael Urban	michael.urban@db.com
Noble Corp.	NE.N	North America	US	Buy	USD	39.87	47	10136	Michael Urban	michael.urban@db.com
Ocean Rig UDW	ORIG.OQ	North America	US	Buy	USD	15.87	25	2094	Michael Urban	michael.urban@db.com
Pacific Drilling S.A.	PACD.N	North America	US	Buy	USD	10.15	13	2202	Michael Urban	michael.urban@db.com
Patterson-UTI	PTEN.OQ	North America	US	Buy	USD	19.46	27	2970	Michael Urban	michael.urban@db.com
Pioneer Energy Services	PES.N	North America	US	Buy	USD	7.58	10	481	Michael Urban	michael.urban@db.com
Precision Drilling	PD.TO	North America	Canada	Hold	CAD	8.98	8	2607	Michael Urban	michael.urban@db.com
Row an Companies	RDC.N	North America	US	Hold	USD	34.21	32	4280	Michael Urban	michael.urban@db.com
Transocean	RIG.N	North America	US	Hold	USD	55.78	49	21001	Michael Urban	michael.urban@db.com
C.A.T. oil	O2C.DE	Russia	Russia	Buy	EUR	7.88	8	513	Tatiana Kapustina	tatiana.kapustina@db.com
Eurasia Drilling	EDCLq.L	Russia	Russia	Buy	USD	36.89	40	5418	Tatiana Kapustina	tatiana.kapustina@db.com

Source: Deutsche Bank

Figure 698: Deutsche Bank – Global Equipment & Services Coverage Universe & Analyst Contact List

Company	Reuters	Region	Country	Recom	Trading Currency	Last price	Target price	M Cap $m	Analyst	email
Bumi Armada Berhad	BUAB.KL	Asia Pacific	Malaysia	Hold	MYR	3.84	3.45	3696	Kevin Chong	kevin.chong@db.com
Ezra Holdings	EZRA.SI	Asia Pacific	Singapore	Hold	SGD	1.2	1.16	925	Kevin Chong	kevin.chong@db.com
Miclyn Express Offshore	MIO.AX	Asia Pacific	Australia	Hold	AUD	2.39	2.28	713	Wassim Kisirwani, CFA	wassim.kisirwani@db.com
WorleyParsons	WOR.AX	Asia Pacific	Australia	Hold	AUD	24	22.56	6312	Craig WongPan	craig.wongpan@db.com
AMEC Plc	AMEC.L	Europe	UK	Buy	GBP	1094	1350	5154	Sebastian Yoshida	sebastian.yoshida@db.com
Hunting	HTG.L	Europe	UK	Buy	GBP	824.5	1000	1952	Sebastian Yoshida	sebastian.yoshida@db.com
Petrofac	PFC.L	Europe	UK	Hold	GBP	1676	1600	9121	Sebastian Yoshida	sebastian.yoshida@db.com
Saipem	SPMI.MI	Europe	Italy	Buy	EUR	31.7	35	18577	Sebastian Yoshida	sebastian.yoshida@db.com
Schoeller-Bleckmann	SBOE.VI	Europe	Austria	Hold	EUR	74.63	80	1587	Matthias Pfeifenberger	matthias.pfeifenberger@db.com
Wood Group	WG.L	Europe	UK	Buy	GBP	826.5	870	4870	Sebastian Yoshida	sebastian.yoshida@db.com
Renaissance Services	RSC.OM	GEM	Oman	Buy	OMR	0.499	1	366	Aleksandar Stojanovski	aleksandar.stojanovski@db.com
Tenaris	TS.N	GEM	Argentina	Buy	USD	41.25	55	24338	Marcus Sequeira	marcus.sequeira@db.com
Baker Hughes	BHI.N	North America	US	Buy	USD	44.3	55	19758	Michael Urban	michael.urban@db.com
Basic Energy Services Inc	BAS.N	North America	US	Buy	USD	12.27	16	489	Michael Urban	michael.urban@db.com
Cameron International	CAM.N	North America	US	Buy	USD	58.9	76	14339	Michael Urban	michael.urban@db.com
Exterran Holdings	EXH.N	North America	US	Buy	USD	22.85	33	1519	Michael Urban	michael.urban@db.com
Exterran Partners	EXLP.OQ	North America	US	Buy	USD	22.57	39	1171	Michael Urban	michael.urban@db.com
Forum Energy Tech	FET.N	North America	US	Buy	USD	25.18	28	2253	Michael Urban	michael.urban@db.com
Halliburton	HAL.N	North America	US	Buy	USD	37.5	51	34792	Michael Urban	michael.urban@db.com
Key Energy Services	KEG.N	North America	US	Buy	USD	7.71	9	1179	Michael Urban	michael.urban@db.com
Oceaneering Int'l.	OII.N	North America	US	Buy	USD	59.88	58	6401	Michael Urban	michael.urban@db.com
RigNet Inc.	RNET.OQ	North America	US	Buy	USD	21.71	25	371	Brett Feldman	brett.feldman@db.com
Schlumberger	SLB.N	North America	US	Buy	USD	76.5	89	101785	Michael Urban	michael.urban@db.com
Weatherford International	WFT.N	North America	US	Buy	USD	12.37	20	9556	Michael Urban	michael.urban@db.com
Integra	INTEq.L	Russia	Russia	Sell	USD	0.352	0.3	68	Tatiana Kapustina	tatiana.kapustina@db.com
TMK	TRMKq.L	Russia	Russia	Buy	USD	15.8	18.8	3409	George Buzhenitsa	george.buzhenitsa@db.com

Source: Deutsche Bank

Figure 699: Deutsche Bank – Global Integrated Oil Coverage Universe & Analyst Contact List

Company	Reuters	Region	Country	Recom	Trading Currency	Last price	Target price	M Cap $m	Analyst	email
Origin Energy	ORG.AX	Asia Pacific	Australia	Hold	AUD	12.08	15.7	13941	John Hirjee	john.hirjee@db.com
PetroChina	0857.HK	Asia Pacific	China	Hold	HKD	11.14	11.28	262521	David Hurd, CFA	david.hurd@db.com
PTT	PTT.BK	Asia Pacific	Thailand	Hold	THB	336	335	31978	Thapana Phanich	thapana.phanich@db.com
Sinopec-H	0386.HK	Asia Pacific	China	Buy	HKD	9.19	9.06	103450	David Hurd, CFA	david.hurd@db.com
BG Group	BG.L	Europe	UK	Hold	GBP	1114	1350	59874	Lucas Herrmann	lucas.herrmann@db.com
BP	BP.L	Europe	UK	Buy	GBP	460.35	500	138877	Lucas Herrmann	lucas.herrmann@db.com
ENI	ENI.MI	Europe	Italy	Buy	EUR	19.29	21	93089	Mark Bloomfield	mark.bloomfield@db.com
Galp Energia	GALP.LS	Europe	Portugal	Hold	EUR	12.08	16	13344	Mark Bloomfield	mark.bloomfield@db.com
OMV	OMVV.VI	Europe	Austria	Hold	EUR	29.9	30	12985	Mark Bloomfield	mark.bloomfield@db.com
Repsol	REP.MC	Europe	Spain	Hold	EUR	16.82	16	28677	Mark Bloomfield	mark.bloomfield@db.com
Royal Dutch Shell Plc	RDSb.L	Europe	UK	Hold	GBP	2257	2475	226320	Lucas Herrmann	lucas.herrmann@db.com
Royal Dutch Shell plc	RDSa.L	Europe	UK	Hold	GBP	2203	2475	220905	Lucas Herrmann	lucas.herrmann@db.com
Statoil	STL.OL	Europe	Norway	Hold	NOK	144	160	81748	Mark Bloomfield	mark.bloomfield@db.com
Total SA	TOTF.PA	Europe	France	Buy	EUR	39.31	44	118707	Lucas Herrmann	lucas.herrmann@db.com
Dana Gas	DANA.AD	GEM	UAE	Buy	AED	0.51	1.05	916	Aleksandar Stojanovski	aleksandar.stojanovski@db.com
Ecopetrol	EC.N	GEM	Colombia	Hold	USD	61.8	64	127051	Marcus Sequeira	marcus.sequeira@db.com
MOL	MOLB.BU	GEM	Hungary	Buy	HUF	18900	25000	8973	Tatiana Kapustina	tatiana.kapustina@db.com
Petrobras	PBR.N	GEM	Brazil	Hold	USD	19.53	24	127380	Marcus Sequeira	marcus.sequeira@db.com
Petrobras Argentina	PZE.N	GEM	Argentina	Sell	USD	5.05	3.5	10197	Marcus Sequeira	marcus.sequeira@db.com
PGNiG	PGN.WA	GEM	Poland	Hold	PLN	5.66	5.4	10713	Tomasz Krukowski, CFA	tomasz.krukowski@db.com
Sasol	SOLJ.J	GEM	South Africa	Buy	ZAR	369.63	440	25633	Jarrett Geldenhuys	jarrett.geldenhuys@db.com
YPF Sociedad Anonima	YPF.N	GEM	Argentina	Hold	USD	15.01	13	5904	Marcus Sequeira	marcus.sequeira@db.com
Chevron	CVX.N	North America	US	Buy	USD	115.24	140	221133	Paul Sankey	paul.sankey@db.com
ConocoPhillips	COP.N	North America	US	Hold	USD	59.27	62	72803	Paul Sankey	paul.sankey@db.com
ExxonMobil	XOM.N	North America	US	Hold	USD	90.8	96	402961	Paul Sankey	paul.sankey@db.com
Hess Corporation	HES.N	North America	US	Buy	USD	57.66	70	19604	Paul Sankey	paul.sankey@db.com
Marathon Oil	MRO.N	North America	US	Buy	USD	33.08	40	23454	Paul Sankey	paul.sankey@db.com
Murphy Oil	MUR.N	North America	US	Hold	USD	61.33	68	11963	Paul Sankey	paul.sankey@db.com
Occidental Petroleum	OXY.N	North America	US	Hold	USD	82.58	80	66612	Paul Sankey	paul.sankey@db.com
Phillips 66	PSX.N	North America	US	Hold	USD	55.07	50	34010	Paul Sankey	paul.sankey@db.com
Suncor Energy	SU.TO	North America	Canada	Hold	CAD	33.74	36	51474	Paul Sankey	paul.sankey@db.com
Gazprom	GAZP.MM	Russia	Russia	Buy	RUB	148.42	170	112600	Pavel Kushnir	pavel.kushnir@db.com
Gazprom Neft	SIBN.MM	Russia	Russia	Buy	RUB	142.85	205	22281	Pavel Kushnir	pavel.kushnir@db.com
LUKOIL	LKOH.MM	Russia	Russia	Buy	RUB	2017.7	3000	50353	Pavel Kushnir	pavel.kushnir@db.com
Rosneft	ROSN.MM	Russia	Russia	Buy	RUB	262.44	300	91951	Pavel Kushnir	pavel.kushnir@db.com
Surgutneftegaz	SNGS.MM	Russia	Russia	Buy	RUB	28.703	45	33901	Pavel Kushnir	pavel.kushnir@db.com
TNK-BP	TNBP.MM	Russia	Russia	Buy	RUB	63.6	110	31557	Tatiana Kapustina	tatiana.kapustina@db.com

Source: Deutsche Bank

Figure 700: Deutsche Bank – Global Refining & Marketing Coverage Universe & Analyst Contact List

Company	Reuters	Region	Country	Recom	Trading Currency	Last price	Target price	M Cap $m	Analyst	email
BPCL	BPCL.BO	Asia Pacific	India	Sell	INR	434.05	300	5827	Harshad Katkar	harshad.katkar@db.com
Caltex	CTX.AX	Asia Pacific	Australia	Hold	AUD	19.14	16.5	5375	John Hirjee	john.hirjee@db.com
Essar Oil Ltd	ESRO.BO	Asia Pacific	India	Buy	INR	77.5	85	1965	Harshad Katkar	harshad.katkar@db.com
Formosa Petrochemical	6505.TW	Asia Pacific	Taiwan	Sell	TWD	85.1	73.1	27658	Alden Lin	alden.lin@db.com
GS Holdings Corp	078930.KS	Asia Pacific	Korea	Hold	KRW	67900	68000	6288	Shawn Park	shawn.park@db.com
HPCL	HPCL.BO	Asia Pacific	India	Sell	INR	362.85	265	2281	Harshad Katkar	harshad.katkar@db.com
IOC	IOC.BO	Asia Pacific	India	Hold	INR	348.95	275	15730	Harshad Katkar	harshad.katkar@db.com
IRPC PCL	IRPC.BK	Asia Pacific	Thailand	Hold	THB	4.28	4.2	2910	Thapana Phanich	thapana.phanich@db.com
NZ Refining	NZR.NZ	Asia Pacific	New Zealand	Hold	NZD	2.6	2.69	616	Grant Swanepoel	grant.swanepoel@db.com
Reliance Industries	RELI.BO	Asia Pacific	India	Buy	INR	898.95	1040	54237	Harshad Katkar	harshad.katkar@db.com
SK Innovation	096770.KS	Asia Pacific	Korea	Buy	KRW	164000	200000	14981	Shawn Park	shawn.park@db.com
S-Oil Corp	010950.KS	Asia Pacific	Korea	Hold	KRW	97400	113000	10853	Shawn Park	shawn.park@db.com
Thai Oil Pcl	TOP.BK	Asia Pacific	Thailand	Buy	THB	71	76	4865	Thapana Phanich	thapana.phanich@db.com
Grupa Lotos	LTSP.WA	GEM	Poland	Sell	PLN	40	21	0	Tatiana Kapustina	tatiana.kapustina@db.com
PKN Orlen	PKN.WA	GEM	Poland	Sell	PLN	50.4	32	6916	Tatiana Kapustina	tatiana.kapustina@db.com
Tupras	TUPRS.IS	GEM	Turkey	Hold	TRY	52.25	51	7425	Vedat Mizrahi, Ph.D	vedat.mizrahi@db.com
Alon USA	ALJ.N	North America	US	Hold	USD	17.67	16	1114	Paul Sankey	paul.sankey@db.com
Amyris	AMRS.OQ	North America	US	Hold	USD	3.29	4	195	Vish Shah	vish.shah@db.com
Calumet	CLMT.OQ	North America	US	Hold	USD	32.36	19	1871	Paul Sankey	paul.sankey@db.com
CVR Energy	CVI.N	North America	US	Hold	USD	49.99	50	4341	Paul Sankey	paul.sankey@db.com
Delek US	DK.N	North America	US	Hold	USD	31.3	25	1883	Paul Sankey	paul.sankey@db.com
El Paso Pipeline Partners LP.	EPB.N	North America	US	Hold	USD	40.82	41	8974	Curt Launer	curt.launer@db.com
HollyFrontier	HFC.N	North America	US	Buy	USD	44.26	45	8786	Paul Sankey	paul.sankey@db.com
Marathon Petroleum Corp	MPC.N	North America	US	Hold	USD	65.2	60	21228	Paul Sankey	paul.sankey@db.com
Northern Tier	NTI.N	North America	US	Hold	USD	24	25	2206	Paul Sankey	paul.sankey@db.com
NuStar Energy	NS.N	North America	US	Hold	USD	50.69	50	3726	Curt Launer	curt.launer@db.com
Tesoro Corporation	TSO.N	North America	US	Hold	USD	42.49	35	5815	Paul Sankey	paul.sankey@db.com
Valero Energy	VLO.N	North America	US	Hold	USD	36.76	30	19645	Paul Sankey	paul.sankey@db.com
Western Refining Inc	WNR.N	North America	US	Hold	USD	29.59	24	3160	Paul Sankey	paul.sankey@db.com

Source: Deutsche Bank

Figure 701: Deutsche Bank – Global Exploration & Production Coverage Universe & Analyst Contact List

Company	Reuters	Region	Country	Recom	Trading Currency	Last price	Target price	M Cap $m	Analyst	email
Aurora Oil & Gas	AUT.AX	Asia Pacific	Australia	Buy	AUD	3.44	4.2	1623	John Hirjee	john.hirjee@db.com
AWE Ltd	AWE.AX	Asia Pacific	Australia	Hold	AUD	1.195	1.55	679	John Hirjee	john.hirjee@db.com
Cairn India	CAIL.BO	Asia Pacific	India	Hold	INR	337.1	355	12006	Harshad Katkar	harshad.katkar@db.com
CNOOC Ltd	0883.HK	Asia Pacific	China	Hold	HKD	16.38	16.92	93248	David Hurd, CFA	david.hurd@db.com
Dart Energy	DTE.AX	Asia Pacific	Australia	Buy	AUD	0.155	0.55	129	John Hirjee	john.hirjee@db.com
Drillsearch	DLS.AX	Asia Pacific	Australia	Buy	AUD	1.475	2	572	Andrew Lewandowski	andrew.lewandowski@db.com
Karoon Gas	KAR.AX	Asia Pacific	Australia	Buy	AUD	5.31	8.8	1278	John Hirjee	john.hirjee@db.com
Kunlun Energy	0135.HK	Asia Pacific	China	Buy	HKD	16.7	17	17854	Eric Cheng, CFA	eric-ct.cheng@db.com
MIE Holdings Corp	1555.HK	Asia Pacific	Hong Kong	Buy	HKD	2.54	2.44	866	David Hurd, CFA	david.hurd@db.com
New Zealand Oil & Gas	NZO.NZ	Asia Pacific	New Zealand	Buy	NZD	0.87	1	287	Grant Swanepoel	grant.swanepoel@db.com
Nexus Energy Ltd	NXS.AX	Asia Pacific	Australia	Hold	AUD	0.17	0.2	240	John Hirjee	john.hirjee@db.com
Oil India Limited	OILI.BO	Asia Pacific	India	Buy	INR	561	560	6262	Harshad Katkar	harshad.katkar@db.com
Oil Search	OSH.AX	Asia Pacific	Australia	Buy	AUD	7.13	8.45	9991	John Hirjee	john.hirjee@db.com
ONGC	ONGC.BO	Asia Pacific	India	Buy	INR	337.5	340	53608	Harshad Katkar	harshad.katkar@db.com
PTT Exploration & Prod	PTTE.BK	Asia Pacific	Thailand	Buy	THB	162.5	185	18119	Thapana Phanich	thapana.phanich@db.com
Santos	STO.AX	Asia Pacific	Australia	Buy	AUD	11.78	15.25	11849	John Hirjee	john.hirjee@db.com
Senex Energy	SXY.AX	Asia Pacific	Australia	Hold	AUD	0.73	0.75	844	Andrew Lewandowski	andrew.lewandowski@db.com
Woodside Petroleum	WPL.AX	Asia Pacific	Australia	Buy	AUD	35.3	40.3	30579	John Hirjee	john.hirjee@db.com
Afren	AFRE.L	Europe	UK	Buy	GBP	135	165	2425	Phil Corbett	phil.corbett@db.com
Africa Oil	AOIC.ST	Europe	Sweden	Buy	SEK	47	70	1889	Phil Corbett	phil.corbett@db.com
Bowleven PLC	BLVN.L	Europe	UK	Hold	GBP	66.5	85	311	Phil Corbett	phil.corbett@db.com
Cairn Energy	CNE.L	Europe	UK	Buy	GBP	280.8	335	2693	Phil Corbett	phil.corbett@db.com
Essar Energy	ESSR.L	Europe	UK	Hold	GBP	133	175	2791	Lucas Herrmann	lucas.herrmann@db.com
Genel Energy	GENL.L	Europe	UK	Buy	GBP	800	1010	3557	Phil Corbett	phil.corbett@db.com
Lundin Petroleum	LUPE.ST	Europe	Sweden	Hold	SEK	164.5	165	8018	Phil Corbett	phil.corbett@db.com
Ophir Energy	OPHR.L	Europe	UK	Hold	GBP	540	495	3534	Phil Corbett	phil.corbett@db.com
Premier Oil Plc	PMO.L	Europe	UK	Buy	GBP	365.8	570	3126	Phil Corbett	phil.corbett@db.com
Salamander Energy	SMDR.L	Europe	UK	Buy	GBP	195	280	812	Phil Corbett	phil.corbett@db.com
Tullow Oil	TLW.L	Europe	UK	Hold	GBP	1165	1105	16871	Phil Corbett	phil.corbett@db.com
HRT Participacoes	HRTP3.SA	GEM	Brazil	Hold	BRL	4.73	6	535	Marcus Sequeira	marcus.sequeira@db.com
KazMunaiGas E&P	KMGq.L	GEM	Kazakhstan	Buy	USD	18.1	24	7626	Tatiana Kapustina	tatiana.kapustina@db.com
OGX	OGXP3.SA	GEM	Brazil	Sell	BRL	4.95	3.8	7838	Marcus Sequeira	marcus.sequeira@db.com
Pacific Rubiales	PRE.TO	GEM	Colombia	Buy	CAD	22.37	29	6826	Marcus Sequeira	marcus.sequeira@db.com
Petrominerales	PMG.TO	GEM	Colombia	Sell	CAD	9.32	7	1130	Marcus Sequeira	marcus.sequeira@db.com
Queiroz Galvao E&P	QGEP3.SA	GEM	Brazil	Buy	BRL	13.56	17	1766	Marcus Sequeira	marcus.sequeira@db.com
Access Midstream Partners	ACMP.N	North America	US	Buy	USD	35.29	41	4662	Curt Launer	curt.launer@db.com
Anadarko Petroleum	APC.N	North America	US	Buy	USD	77.55	93	38833	Stephen Richardson	stephen.richardson@db.com
Apache Corp.	APA.N	North America	US	Hold	USD	81.82	88	32646	Stephen Richardson	stephen.richardson@db.com
Bill Barrett Corp.	BBG.N	North America	US	Hold	USD	18	25	850	Ryan Todd	ryan.todd@db.com
Breitburn Energy Partners	BBEP.OQ	North America	US	Hold	USD	21.04	22	1697	Curt Launer	curt.launer@db.com
Canadian Natural	CNQ.TO	North America	Canada	Hold	CAD	29.95	32	33107	Paul Sankey	paul.sankey@db.com
Chesapeake Energy	CHK.N	North America	US	Hold	USD	17.82	20	13552	Stephen Richardson	stephen.richardson@db.com
Cimarex Energy	XEC.N	North America	US	Buy	USD	63.84	76	5548	Ryan Todd	ryan.todd@db.com
Cobalt International Energy	CIE.N	North America	US	Buy	USD	24.66	39	10025	Ryan Todd	ryan.todd@db.com
Concho Resources	CXO.N	North America	US	Buy	USD	89.2	112	9280	Ryan Todd	ryan.todd@db.com
Continental Resources	CLR.N	North America	US	Buy	USD	83.07	94	15280	Ryan Todd	ryan.todd@db.com
Devon Energy	DVN.N	North America	US	Hold	USD	54.28	64	21875	Stephen Richardson	stephen.richardson@db.com
Encana Corp	ECA.TO	North America	Canada	Sell	CAD	19.21	17	14251	Stephen Richardson	stephen.richardson@db.com
EOG Resources	EOG.N	North America	US	Buy	USD	126.79	133	34360	Stephen Richardson	stephen.richardson@db.com
EQT Corp.	EQT.N	North America	US	Buy	USD	59.5	74	8948	Stephen Richardson	stephen.richardson@db.com
Goodrich Petroleum	GDP.N	North America	US	Buy	USD	9.65	17	353	Ryan Todd	ryan.todd@db.com
Gran Tierra	GTE.TO	North America	Canada	Buy	CAD	5.31	7	1523	Marcus Sequeira	marcus.sequeira@db.com
Kosmos Energy	KOS.N	North America	US	Hold	USD	12.19	17	4552	Ryan Todd	ryan.todd@db.com
Magnum Hunter Resources	MHR.N	North America	US	Buy	USD	4.32	5	726	Ryan Todd	ryan.todd@db.com
Newfield Exploration	NFX.N	North America	US	Hold	USD	28.64	35	3878	Stephen Richardson	stephen.richardson@db.com
Noble Energy	NBL.N	North America	US	Buy	USD	106.62	114	19192	Stephen Richardson	stephen.richardson@db.com
Oasis Petroleum	OAS.N	North America	US	Hold	USD	35.69	35	3289	Ryan Todd	ryan.todd@db.com
Penn West Exploration	PWT.TO	North America	Canada	Hold	CAD	10.6	12	5207	Stephen Richardson	stephen.richardson@db.com
Pioneer Natural Resources	PXD.N	North America	US	Hold	USD	113.73	111	14216	Stephen Richardson	stephen.richardson@db.com
QEP Resources	QEP.N	North America	US	Buy	USD	29.81	37	5303	Stephen Richardson	stephen.richardson@db.com
Range	RRC.N	North America	US	Hold	USD	68.27	68	10893	Stephen Richardson	stephen.richardson@db.com
SandRidge Energy	SD.N	North America	US	Hold	USD	7.02	5	4128	Ryan Todd	ryan.todd@db.com
SM Energy	SM.N	North America	US	Hold	USD	56.92	62	3812	Ryan Todd	ryan.todd@db.com
Southwestern Energy	SWN.N	North America	US	Hold	USD	33.69	38	11746	Stephen Richardson	stephen.richardson@db.com
Ultra Petroleum	UPL.N	North America	US	Hold	USD	18.41	22	2815	Stephen Richardson	stephen.richardson@db.com
Whiting Petroleum	WLL.N	North America	US	Hold	USD	48.3	54	5744	Ryan Todd	ryan.todd@db.com
WPX Energy	WPX.N	North America	US	Hold	USD	14.58	19	2899	Stephen Richardson	stephen.richardson@db.com
Alliance Oil Company	AOILsdb.ST	Russia	Russia	Buy	SEK	54.65	99	1437	Tatiana Kapustina	tatiana.kapustina@db.com
Bashneft	BANE.MM	Russia	Russia	Hold	RUB	1860	2000	11393	Pavel Kushnir	pavel.kushnir@db.com
Novatek	NVTKq.L	Russia	Russia	Buy	USD	114.9	155	34865	Pavel Kushnir	pavel.kushnir@db.com
Tatneft	TATN.MM	Russia	Russia	Buy	RUB	220.35	265	16043	Tatiana Kapustina	tatiana.kapustina@db.com

Source: Deutsche Bank

Glossary

Abandonment	to cease work on a well that is non-productive/uneconomic
Acidisation	a process whereby acid is pumped at high pressure into a reservoir in an attempt to dissolve some of the rock and improve wellbore flow characteristics. Often used in conjunction with fracturing.
Acreage	the area over which a company has hydrocarbon exploration interests
Alkylation	refers to the alkylation of isobutane with olefins in the presence of a strong acid catalyst, which has the result of increasing the octane level and therefore the overall quality of the gasoline
Alteration	uses processes such as isomerisation and catalytic reforming to rearrange the chemical structure of hydrocarbons.
Annulus	the space between the drill string and the well wall, or between casing strings, or between the casing and the production tubing
Anoxic	an environment in which there is little or no oxygen. These are the conditions needed for organic matter build-up
Anti-clines	potential traps formed when strata deforms into the shape of a dome-like fold
API gravity	the American Petroleum Institute gravity is a measure of how heavy or light a petroleum liquid is compared to water. It is measured in degrees and the higher the API, the lighter the crude
Appraisal well	well drill after the field has been discovered, to appraise its content. Used particularly offshore to establish the optimum platform location.
Aromatic	a group of unsaturated cyclic hydrocarbons containing one or more structural carbon rings. They are highly reactive and chemically versatile.
Associated gas	natural gas associated with accumulation of oil. May be dissolved in the oil or may form a cap of free gas above the oil
Back off	to unscrew one piece of drill pipe from another. Also used to describe the process of using wireline conveyed small explosives to help unscrew a specific joint of pipe deep underground when a pipe is stuck and all other attempts to free it have failed
Back-Reaming	used during drilling to improve the condition of the hole. The drill pipe is run up and down over problem zones repeatedly whilst rotating the bit and circulating mud.
Backwardation	term used on the futures market to describe a downward-sloping forward curve. This indicates that the market expects lower prices in the future, i.e. demand is expected to be lower than supply in the future
Barge master	the supervisor of crane drivers and roustabouts on a rig
Barrel	the most commonly used unit of measurement for petroleum and its products (7.33 barrels = 1 ton or 6.29 barrels = 1 cubic metro). Represents 42 gallons of oil.
Bed	the geological term defining a stratum of any thickness and of uniform homogenous texture
Benzene	a liquid that is flammable and explosive, used to make ethylbenzene, phenol, cyclohexane (for nylon) and detergents
Biodiesel	a fuel made from biological sources, such as vegetable or animal fats, blended with distillates such as diesel
Bioethanal	alcohol-based fuel made through the fermentation of crops such as barley, wheat, corn or sugar cane
Biofuels	fuels made from or processed from biomass, e.g. bioethanol or biodiesel
Biomass	vegetation from which energy can be extracted, e.g. sugar cane, corn or soybean
Bit	a sophisticated cutting tool used in drilling. There are two main types of bit used in drilling oil/gas wells: rock bits and diamond bits.
Bitumen	naturally occurring near-solid hydrocarbon that is a mixture of organic liquids. Bitumen also results from the distillation process
Block	an acreage sub-division. Although varies from country to country, generally tends to be approximately 10 x 20 kms.
Blow down	condensate and gas are produced simultaneously from the outset of production
Blow out	occurs during drilling when reservoir pressure exceeds the ability of the well-head valves (BOP) to control it, resulting in uncontrolled ejection of wellbore fluid from the top of the well
Blow-out Preventor (BOP)	high pressure wellhead valve designed to seal the well quickly in the event of an uncontrolled flow of hydrocarbons
Borehole	the hole as drilled by the drill bit

Bottom-hole Assembly (BHA)	lower part of drill string from the bit to the drill pipe. Can consist of drill collars, stabilisers mud motors and a bit, amongst others. Provides weight for the bit to cut rock.
Bottoms up	circulation of drilling fluid in a well, so that mud from the bottom of the drill pipe is pumped back to surface
Breccia	rock composed of angular fragments of rocks or minerals in a matrix
Butadiene	a colourless gas at room temperature that is a by-product of the cracking process. Main use is as an intermediate in the manufacture of various forms of rubber, latex and plastics
Butane	a highly flammable, colourless and easily liquefied gas (see LPG). Butane gas is sold as bottled gas for fuel for cooking and it is also used as a feedstock for the production of base petrochemicals in steam cracking
Buy-back contract	used only in Iran; essentially a contract for services. The contractor is the designated operator for design, construction, commissioning and start-up of all facilities, and this responsibility passes to NIOC immediately after start-up. The foreign partner provides all the capital for the project and is compensated for its costs and awarded an agreed level of profit.
Call on OPEC	the level of oil demand that cannot be met by non-OPEC producers
Cap rock	impermeable rock overlaying a reservoir
Capex Uplift	the % increase granted by the state on capex spend for recovery against costs. The allocation of uplift pays heed to the time that it might take to recover capex invested in a project given restrictions on cost recovery (as a % of revenues) and the time taken from breaking ground to first oil in a development project.
Carbonate rock	a sedimentary rock that occasionally forms petroleum reserves. It is primarily composed of limestone or chalk or dolomite
Cased hole	hole in which casing has been set
Casing	the steel lining that supports the sides of the well and prevents the flow of fluid both from and into the well bore
Casing shoe	a reinforced section of casing placed on the bottom of the casing string that protects against damage
Catalyst	a substance that enables a chemical reaction to take place at a faster rate or under different conditions that otherwise possible
Catalytic hydro-treating	hydrogenation process used to remove c.90% of contaminants such as nitrogen, sulphur, oxygen and metals from crude oil fractions.
Catwalk	the working area in front of the V-door, upon which casing is usually placed before being pulled up to the drill floor
CDU	crude distillation unit. The basic building block of a refinery, where atmospheric distillation of crude occurs.
Cellar	the pit dug in the ground beneath the drill floor for land drilling, often lined with cement for larger wells
Cellulosic bioethanol	made through the fermentation of cellulosic feedstock, which encompasses almost any kind of organic feedstock. However, requires second-generation conversion technologies (e.g. enzymatic breakdown), hence not currently economically viable
Cementing	the filling of the space between the casing and the borehole wall with cement. This ensures the casing remains stationary and also prevents any leakage
Cetane number	a measure of diesel's tendency to self-ignite under pressure. Higher-cetane diesels self-ignite quicker, which gives more time for the fuel to fully combust and is hence more desirable than lower-cetane diesels.
Christmas Tree	an assembly of valves, spools and fittings for an oil well, named for its resemblance to a decorated tree. Its function is to prevent the release of oil/gas from an oil well and to direct and control the flow of formation fluids from the well.
Clastic rocks	sedimentary rocks composed of fragments of pre-existing rocks
Coal Bed Methane (CBM)	methane found in coal seams that is retained on the surface of the coal within the micropore structure. It is generated either from a biological process as a result of microbial action or from a thermal process as a result of increasing heat with depth of the coal.
Coker	an oil refinery processing unit that converts the residual oil into lighter hydrocarbon gases, naphtha, light and heavy gas oils and petroleum coke.
Cold filter plugging point (CFPP)	the temperature at which a standard fuel filter will clog
Commodities and Futures Trading Commission (CFTC)	an independent US agency that regulates commodity futures and options markets in the US. Its aim is to protect market users from fraud, manipulation and abusive practices and to encourage competition and efficiency in the futures markets.

Complexity	where a refiner invests in a wide range of processes to upgrade distillate
Condensate	hydrocarbons that are gaseous under reservoir conditions but that become liquid when temperature or pressure is reduced.
Contango	term used on the futures market to describe an upward-sloping forward curve. This indicates that the market expects higher prices in the future, i.e. demand is expected to be higher than supply in the future
Continental crust	dominated by granite rocks (rich in quartz and feldspar minerals). Relatively buoyant comparative to oceanic crust.
Contingent Resources	those quantities of hydrocarbons that are estimated to be potentially recoverable from known accumulation, but that are not yet commercially recoverable
Conversion	process that alters the size and/or structure of hydrocarbons, further upgrading the crude output in order to give a higher yield of more valuable products such as gasoline. See cracking, unification and alteration
Coring	drilling with a doughnut-shaped bit that allows a cylinder-shaped core of un-drilled rock to rise up inside the pipe above the bit. The core is then removed when the drill string is tripped out of the hole
Cost oil	share of barrels produced that is used to pay back the contractor for its capital investment in the project and/or the operating expenses incurred in the year. Typically the resource holder will allow cost oil to be recovered from c.50-60% of project revenues. Once the upfront capital costs have been recovered (generally high in the first years of a project coming on-stream), anything left over is termed profit oil. Capital or operating costs that remain un-recovered in any one year are typically carried forwards for recovery in subsequent years.
Cracking	breaking down heavier hydrocarbon molecules into lighter products using heat (thermal) or by the addition of catalysts (catalytic)
Creaming curve	a plot of the number of discoveries against the number of wells in a basin in order to estimate the quantity of ultimate basin reserves
Crude oil	a mixture of liquid hydrocarbons of different molecular weight, containing different levels of impurities such as sulphur, water
Cyclic Steam Stimulation (CSS)	consists of three stages: injection, soaking and production. Steam is first injected into a well for a certain amount of time to heat the bitumen in the surrounding reservoir to a temperature at which it flows. This persists for many weeks with the steam 'soaking' the subsoil sands before the process is halted. At this time the wells are turned into producers, at first by natural flow (since the steam injection will have increased the reservoir pressure) and then by artificial lift. Also known as Huff and Puff
Deepwater	refers to oilfield exploration and development in water depths greater than c.1000m (note this is an arbitrary figure chosen by Deutsche Bank)
Delivery ex-ship (DES) contracts	DES cargoes are generally written with a specific destination in mind and as such are less flexible than FOB contracts. While the destination can be changed by mutual agreement, this is likely to prove difficult to arrange given the shipment will have to fit in with the supplier's pre-arranged shipping schedule
Depositional Environment	the conditions under which a series of rock strata were laid down. Depositional environments can be divided into six subgroups: marine, lagoonal, deltaic (laid down by a river at its delta), alluvial/fluvial (laid down by a river), lacustrine (laid down under a lake) and aeolian (laid down by wind)
Depreciation, depletion and amortisation (DD&A)	the release of capitalised hydrocarbon assets to the income statement over their economic useful lives
Derrick	the tower-like structure that houses most of the drilling controls
Derrick man	the labourer that works at the top of the derrick and helps guide drill pipe to its correct position during drill pipe makeup. Sometimes replaced by electro-mechanical systems on more modern rigs.
Desalting	process used to remove/separate contaminants such as inorganic salts found in crude oil. Also referred to as dehydration
Development costs	costs of constructing and installing the facilities to produce and transport the oil and gas
Dewpoint	the pressure at which liquid comes out of solution in a gas condensate
Diagensis	any chemical, physical or biological change undergone by a sediment after its initial deposition that results in changes to the rock's original mineralogy and texture.
Directional drilling	the art of guiding the drill bit to a target that is not vertically below the drill floor. Downhole mud motors, special stabilisers, MWD and LWD sensors and telemetry (communications system) can all be used to increase accuracy.
Distillation	the process via which the various components of crude are separated into groups of hydrocarbon compounds on the basis of the difference in relative boiling points. Distillation can be atmospheric or vacuum. Also known as topping or skimming
Distillation margins	the gross profit from a CDU - equivalent to distilled product price minus crude cost

Doghouse	a metal shack used for storing equipment and working in
Downstream	includes oil refineries, petrochemical plants, petroleum product distribution, retail outlets and natural gas distribution companies.
Draw works	the winch that pulls on the steel cable that in turn raises and lowers the travelling block in the derrick
Drawworks	the large rotating drum that spools the drilling line in and out to raise the load on a drilling rig
Drill collar	heavyweight drillpipe that goes on the bottom of the drill string to provide weight-on-bit and stability
Drill pipe	pipe that connects drillfloor torque to the drill collars and ultimately the drill bit. Drill pipe is hollow to allow mud to circulate through it.
Drill string (drill pipe)	comprises lengths of drill pipe and drill collars that connect the drill bit with the drilling rig. The drill string is used to rotate the drill bit and to act as a conduit to circulate drilling mud to the cutting face
Driller	the person responsible for drilling a decent hole by constantly monitoring and adjusting drill pipe torque and weight-on-bit
Drilling fluid	see 'mud'
Drilling Rig	any kind of drilling unit (i.e. land, submersible, semi-submersible, jack-up or drill ship). Also incorporates the derrick and its associated machinery
Dry gas	natural gas composed mainly of methane with only minor amounts of ethane, propane and butane and little or no heavier hydrocarbons in the gasoline range
Dry hole	see duster
Duster	a well that fails to find any commercial oil or gas
Enhanced Oil Recovery (EOR)	Increases hydrocarbon recovery by maximising displacement efficiency in a cost-efficient manner. Methods include thermal EOR, flooding the reservoir with various substances or Microbial EOR.
Entitlement share	the number of barrels of profit oil to which the contractor is entitled from the project in any one year. This will typically represent the contractor's share of cost oil and its equity entitlement to profit oil. Depending on the nature of the PSC terms, the entitlement share will alter over the life of the project as costs are recovered and the oil available for distribution as profit alters following the attainment of trigger points. As an illustration, if a company has a 40% equity interest in a project producing 100kb/d, the profits from which are distributed 50% government and 50% contractor after 10kb/d has been allocated for cost recovery, its share of entitlement barrels would be 22kb/d (i.e. 40% of the 10kb/d of cost oil and 40% of the 45kb/d available to the contractors as profit oil). Note this compares with the 40kb/d in which the contractor has a 'working interest'.
Ethane	part of the methane series, this forms one of the main components of naturally occurring gas
Ethylene	a colourless gas with a slightly sweet odour. It turns from liquid into gas at -155˚F and in general has triple bonds between the two carbon molecules. It is flammable and explosive and is used to produce petrochemical products
EUR (expected ultimate recovery)	the volume of hydrocarbons that it is expected will be recovered from a shale oil or gas well over the well's life cycle.
Facies	a distinctive rock that forms under certain conditions of sedimentation, reflecting a particular process or environment.
Farm-in	a term used to describe when an oil company buys a portion of the acreage in a block from another company, usually in return for cash and for taking on a portion of the selling company's work commitments.
Fault	a fracture along which the rocks on one side are displaced relative to those on the other
Fault trap	created when a reservoir layer such as sandstone is faulted and juxtaposed against an impervious rock, which thus prevents the migration of hydrocarbons leading to oil or gas accumulations against the fault
Field	a geographical area under which an oil or gas reservoir lies
Final Investment Decision (FID)	the point at which sufficient field data has been obtained in order to determine whether there are sufficient proven reserves that are economically recoverable at a set oil price. In general companies book reserves only once a positive FID has been made.
Finding costs	the costs of exploration and appraisal programmes, i.e. how much did it cost the company to find each barrel of oil actually added to reserves in the year
Fischer-Tropsch process	a catalytic chemical reaction whereby single carbon molecules are added together to create carbon chains, the lengths of which can to some extent be determined by altering the conditions through the conversion process
Fishing	a procedure whereby drillpipe is used to retrieve items lost in the hole - e.g. a dropped spanner, clamp, wireline instruments or even other drillpipe. It can consume great amounts of time, can be dangerous and is universally hated (except by fishing consultants)

Flare	a vent for burning off petroleum products that cannot be produced or re-injected into the reservoir. Flaring is becoming increasingly prohibited in most countries due to the environmental impact it has
Floater	floating production units including floating platforms and FPSO's.
Flow rate	the rate at which hydrocarbons flow up through the oil well. The rate is expressed in terms of bbls/day for oil and SCF/day for gas
FPSO	Floating Production, Storage and Offloading system comprising a large tanker equipped with a high-capacity production facility. This system, moored at the bow to maintain a geo-stationary position, is effectively a temporarily fixed platform that uses risers to connect the sub-sea wellheads to the on-board processing, storage and offloading systems.
Fraction	that part of petroleum separated off from other parts at a particular boiling range
Fracturing (fraccing)	an EOR procedure to improve reservoir effective permeability. Fluid (sometimes acid) and propellant are pumped at high pressure into the reservoir. The reservoir rock fractures and the propellant wedges inside the fractures to keep them open once pressure is removed.
Free-on-board (FOB) contracts	LNG contracts where the shipping is organised by the buyer and the contract price paid will exclude the costs of shipping. FOB contracts have no destination clause and hence no restrictions on where the cargo may be delivered, i.e. the buyer can ship to the market where it will obtain the best price
Fuel Oil	liquid fuel used in industry for heat or power generation
Gas injection	process by which gas is re-injected into the reservoir either to conserve the gas for extraction at a later date or to maintain the pressure within the reservoir (known as gas lift)
Gasoil	liquid used for motor diesel fuel and for home heating oil
Gas-oil contact	the depth in a reservoir where gas sits on top of oil
Gas-oil ratio	the volume of gas at atmospheric pressure and temperature produced per unit volume of oil produced
Gasoline	light petroleum product; also known as petrol
Gas-to-Liquids (GTL)	using highly energy and capital intensive technology (see the Fischer Tropsch process), natural gas is converted into higher value, high purity, synthetic liquids, namely diesel, naphtha and lubricant base oils, which can then be exported to consuming markets
Geophone	an instrument that detects seismic waves passing through the earth's crust
GIIP	Gas Initially in Place in a reservoir refers to the total volumes of gas contained in a reservoir
Gross Refining margins	the gross margin made over and above the price of crude oil in the refining process
Guar	a bean that is used in fraccing as a thickening agent that helps to suspend the ceramic beads and sands in solution through the frac process. Largely grown in India and typically used in foods as the basis of a gel
Henry Hub	an interconnection point on the natural gas pipeline in Louisiana where gas is typically delivered. It is the pricing point for natural gas futures contracts in the US.
Hydrocarbon	an organic compound consisting only of carbon and hydrogen. The majority of hydrocarbons found naturally occur in crude oil, where decomposed organic matter provides an abundance of carbon and hydrogen
Hydrocarbon saturation	the percentage of the voids within a rock that are filled with oil/gas versus water
Hydrosulphurisation	used to clean products or inputs by reducing the sulphur content by using hydrogen under pressure over a catalyst. Also referred to as hydro-treating.
ICE	Intercontinental Exchange - see NYMEX
Igneous rocks	deliver both sand (which is the building block for most reservoirs) and clay (which forms seals)
Injection well	a well used for pumping water or gas into the reservoir
In-situ extraction	when mining the oil sands is no longer economic (generally at depths greater than 75m), the subsoil is heated to enable the bitumen to flow. There are two principal methods of in-situ extraction: Steam Assisted Gravity and Drainage and Cyclic Steam Stimulation
International Oil Company (IOC)	normally refers to a large, western, listed, integrated oil company, e.g. Exxon, Shell, Chevron, Total
IP rate (initial production)	rate at which a shale oil or gas well initially flows, typically over the first 30 days production.
Iron roughneck	an electro-mechanical device that spins two pieces of pipe together to a specified torque - safer and faster than using roughnecks, chain and tongs
Isomerisation	the transformation of a molecule into a different isomer
Jacket	the steel legs of an offshore platform - the legs are usually installed separately, and then the topside modules (accommodation, drilling etc) are installed
Jack-up	mobile self-lifting unit comprising a hull and retractable legs, used for offshore drilling operations

Kelly a hexagonal piece of pipe that screws into the top of the drill string and passes through the kelly bushing. Torque is passed from the rotary table to the kelly bushing, and so to the kelly and on to the drill pipe and bit. Not used if drilling is being undertaken with a top drive.

Kelly bushing an adaptor that sits on top of the rotary table, allowing the transmission of torque from the rotary table to the kelly, and hence drill pipe. Not used if drilling is being undertaken with a top drive.

Kerogen mixture of organic chemical compounds that make up a portion of the organic matter in sedimentary rocks. When heated to the right temperature in the earth's crust, some types of kerogen release hydrocarbons

Kerosene liquid fuel used for jet engines, tractors or as a starting material for making other products

Kick a 'kick' occurs during the drilling process when reservoir pressure exceeds borehole fluid pressure and so forces mud to be displaced out of the top of the well. An uncontrolled kick can lead to a blow out.

Knocking occurs when gasoline prematurely combusts in an engine without the spark plug triggering the ignition - the process of which produces an audible 'knocking' sound

Liquefaction plant plant that process natural gas to remove any impurities such as water or carbon dioxide before cooling the gas via a series of compressors, i.e. the equivalent of a large refrigerator. Also referred to as the LNG train

Liquefied Natural Gas (LNG) naturally occurring gas that has been cooled to a temperature of -162˚C at atmospheric pressure in order to condense the gas into a liquid that can be more easily stored, handled and transported.

Liquefied Petroleum Gas (LPG) propane and butanes liquefied under relatively low pressure and ambient temperatures. LPG is a gaseous fuel stored under pressure at refineries and sold in pressurised cylinders as bottled gas for domestic use

Logging whilst drilling (LWD) similar to MWD but provides more detailed measurement and can replicate wireline logging measurements.

Lubricating oil liquid used to make motor oil, grease and other lubricants

Marketing the wholesale or retail sale of fuel products

Measured depth (MD) the actual length of the borehole, irrespective of how deep it is vertically (see true vertical depth)

Measurement whilst drilling (MWD) uses sensors placed near the drillbit to acquire basic information such as mud pressure, temperature and torque, all of which aid in more efficient drilling and weight on the bit

Merchant portfolio whereby a company contracts to purchase a product under one contract and then sells the product to dedicated end users either through back-to-back contracts or by selling directly on the spot markets. Used in this document to describe BG's LNG portfolio

Metamorphic rocks result of the transformation of a pre-existing rock type that has been subjected to great heat and pressure, causing profound physical and/or chemical change

Middle Distillate refers to kerosene and all gasoils

Midstream the midstream sector processes, stores and transports commodities such as crude oil, natural gas and syncrudes

Mining where traditional mining techniques such as truck and shovel are used to extract the oil sands from the reservoir

Monkey board the platform near the top of the derrick where the derrickman works

Mousehole an opening to a tube beneath the drill floor usually used to store the kelly when it is not being used

Mud a mixture of base chemicals and additives used to carry cuttings from the drill bit, lubricate the drill bit and provide pressure that in theory prevents any oil or gas from blowing out

Mud logging equipment that continuously analyses and records the gas present in the mud returns from the well bore

Mud man the engineer responsible for ensuring the mud is in optimum condition to drill the well successfully

Multi azimuth type of seismic survey that gives a better picture of the target subsurface geology by using more than one energy source location.

Multi-client survey a seismic survey run by a seismic company on its own account, to provide speculative data that can be resold many times over to future clients, IF they happen to be interested in the acreage the seismic company has chosen to survey

Naphtha light, easily vaporised clear liquid used for further processing into petrochemicals and the gasoline fractions arising from the straight-run distillation of crude. Naphtha is used as a feedstock for catalytic reforming and for chemicals manufacture

National Oil Company (NOC) a state-owned or majority-state-owned oil company, often established as a result of large domestic reserves.

Natural Gas Liquid (NGL) liquid hydrocarbons found in association with natural gas

Neutral Zone	the territory between Saudi Arabia and Kuwait where production is shared 50/50 and is included in each country's respective OPEC quotas
Nipple up	the process of assembling and pressure testing the BOP
NYMEX	New York Mercantile exchange, along with ICE, are the two main exchanges where oil and gas and associated products are traded
Oceanic Crust	underlies the ocean and is dominated by basaltic rocks (rich in iron and magnesium-based minerals)
Octane	the level of gasoline's resistance to pre-ignition. The higher the octane, the better high-compression engines run. Gasoline with a low octane can cause knocking (see knocking)
OIIP/STOIIP	Oil Initially in Place refers to the total volume of oil contained in a reservoir, i.e. will be higher than the estimated recoverable reserves of oil in the same reservoir. Stock Tank Oil Initially in Place also refers to the in-place oil volume but is measured at the Earth's surface temperature and pressure
Oil sands	heavy and thick deposits of bitumen-coated sand
Oil window	range of temperatures in which oil matures. Generally said to begin at c.120˚F (50˚C), peak at 190˚F (90˚C) and end at 350˚F (175˚C)
Oil-water contact	the depth in a reservoir where oil sits on top of water
Olefin	a class of unsaturated hydrocarbons with the general formula of one carbon for every two hydrogens. Olefins are the 'ene' form of paraffins, i.e. ethylene is the olefin of the paraffin ethane.
OPEC	Organisation of Petroleum Exporting Countries
OPEC basket	mix of 12 different blends produced by OPEC member states used to determine the price band that OPEC wishes to see on world oil markets
Open hole	drilled hole in which casing has not been set
Paraxylene (PX)	a colourless liquid that is the most commercially important xylene. Main use of paraxylene is as a raw material for polyester
Peak oil	the hypothetical point at which oil output will reach a maximum, irretrievably declining thereafter
Perforated zone	see perforations
Perforations	holes that are blasted through casing by explosive shaped charges conveyed by either wireline or drillpipe. The holes provide a path for reservoir fluids to enter the casing, and then tubing to be produced at surface.
Permeability	the ease with which a fluid can pass though the pore spaces of a rock
Petrochemical	any organic chemical for which petroleum or natural gas is the ultimate raw ingredient
Petroleum Administration for Defence Districts (PADDs)	the US is divided into five PADDs, which were created during WW II to help organise the distribution of petroleum products
Petroleum gas	gaseous fossil fuel consisting primarily of methane but also containing significant volumes of ethane, propane and butane.
Platform	an offshore structure that is permanently fixed to the sea bed.
Play	a hydrocarbon play is when a set of circumstances combines to create the necessary conditions for the accumulation of oil and/or gas. A single play may contain a number of discoveries and prospects
Plugged	where a bore hole is sealed or plugged using cement
Polyethylene (PE)	a solid, wax-like material make by polymerising ethylene, which is the most widely used plastic. Applications include LLDPE/LDPE, which are used in packaging film, toys, electrical insulation, wire and cable coating, and HDPE which is used in moulded products, fibres, gasoline and man-made paper
Polymerisation	process of bonding monomers (single molecules) together through a variety of reaction mechanisms to form longer chains named polymers. This happens in the presence of pressure and a catalyst. There are five commonly used processes: Bulk/Gas-Phase Polymerisation, Colution Polymerisation, Slurry Polymerisation, Suspension Polymerisation and Emulsion Polymerisation
Polypropane (PP)	a thermoplastic resin that is translucent, readily coloured and maintains its strength after repeated flexing. Primary uses are food wrapping, yarn, fibre and moulded parts
Porosity	the fraction of a rock's bulk volume accounted for by void space between its constituent grains
Primary Recovery	recovery of oil/gas from a reservoir purely by using the natural pressure in the reservoir to force the oil or gas out
Product cracks	the gross margin being gained on different crude products. Primarily used to give a view on the value of conversion
Product slate	the proportion of refined products obtained by refining one barrel of crude
Production quotas	oil output that each OPEC member country agrees to produce up to, assuming no other restrictions in place and assuming the country remains in compliance

Profit Oil	the oil available for distribution to the partners in the project in line with their equity (or working interest) share. Profit oil is invariably that available after costs (capital and annual operating) have been recovered.
Profit Sharing Contract (PSC)	a contract between a resource holder and (generally) an oil company where the oil produced is shared between the resource holder and contractor (oil company) in a pre-arranged manner.
Progressive tax system	government's share of a project's NPV rises at times of increasing prices. PSC's increasingly are examples of a progressive tax system
Propane	normally a gas, but compressible to a liquid that is transportable (see LPG). It is commonly used as fuel for engines and home heating systems
Propellant	tiny particles used during fracturing to ensure that induced fractures remain open once pressure is removed
Propylene	a colourless gas that is flammable and explosive, produced mainly as a by-product of ethylene; used extensively as an intermediate product in the chemical chain, e.g. in the production of fibres, textiles, plastics and paints among other
Proved (1P) reserves	there is 'reasonable certainty' (90% confidence or P90) the reserves are commercially recoverable from known reservoirs under existing economic and operating conditions. Proven developed reserves are reserves that can be recovered from existing wells with existing infrastructure and operating methods. Proven undeveloped reserves require development.
Proved plus Probable (2P) reserves	probable reserves are unproven, but they are more likely than not (at least a 50% probability or P50) to be recoverable
Proved, Probable plus Possible (3P) reserves	possible reserves are unproven and are less likely to be recoverable (only 10% confidence or P10) than probable reserves
PSC - Fixed share	a PSC that stipulates at the onset the division of post-tax or pre-tax profits from the project between the state and the contractor. In effect, these contracts have economics that are similar to those of a tax and royalty regime. Indonesia represents a good example of a fixed share PSC.
PSC - IRR	a PSC whose trigger points are determined by the internal rate of return achieved from the date of onset. As the returns from a project move beyond pre-defined levels, so the share of profit oil will alter in favour of the host nation. Common examples include those in Angola, Azerbaijan, Kazakhstan and Russia amongst others.
PSC - Production	a PSC whose trigger points are determined by the achievement of particular levels of production. In some production contracts, the production element refers to the cumulative number of barrels produced. In others, the level of daily production achieved. In either case, as the trigger levels are attained, the share of profit oil between the state and the contractor alters. Common examples include those in the Nigerian Deepwater, Qatar, Malaysia, India and many others.
PSC - R-Factor	a PSC whose trigger points are determined by the ratio of total revenues to total costs. Typically the contract will stipulate that as revenues meet certain multiples of costs, so the share of profit oil between the state and the contractor alters. Common examples include Algeria, Qatar (often mixed with production) and Yemen.
Purified Terephthalic Acid (PTA)	a white, water-insoluble powder obtained from the oxidation of paraxylene with acetic acid. It is used primarily in the manufacture of polyester
Rat hole	hole in the drill floor used to store the kelly and kelly bushing when not in use
Recovery factor	the ratio of recoverable oil/gas reserves to the estimated oil/gas in place in the reservoir
Refining	the conversion of crude oil into finished products required by the market in the most efficient and profitable manner
Refining margins	also referred to as an indicator or crack spreads, this depicts the gross margin per barrel that a regional refiner with either a simple or complex refinery configuration typical of that area and running a single crude widely processed in the region is likely to be achieving
Reforming	the process by which the molecular structure of gasoline fractions is altered to improve the 'anti-knock' quality by increasing the octane level, thereby allowing greater performance from an engine.
Re-gasification plant	plant in which the chilled LNG is heated to the appropriate temperature to reconvert it to gas, after which it is used in power generation or sold into a national gas market for consumption
Regressive tax system	government's percentage share of the project NPV falls at a time of increasing oil prices. Concession systems tend to be regressive to neutral
Reid Vapour Pressure (RVP)	measure of the pressure required to prevent a substance from evaporating
Reserve life	number of remaining years of 1P reserves, calculated as remaining reserves over annual production
Reserve replacement ratio	a company's ability to replace production with reserve additions in the year under review
Reserves	volumes of oil and gas in a reservoir that are commercially producible. See also SEC reserves
Reservoir	hydrocarbons sitting between the mineral/rock grains in sandstone, and within voids in limestone

Residuals	solids such as coke, asphalt, tar and waxes that are 'left over' after distillation
Rig supervisor	the shift supervisor of a rig crew, to which all rig personnel report - eg the barge master and driller
Riser	Large-diameter steel pipe that connects the top of the well on the seabed with the rig
Rotary Table	a circular piece of equipment in the middle of the drill floor that can be rotated in either direction with great torque. The kelly bushing is mounted on top, and this imparts torque (i.e. rotation) to the kelly and hence drill pipe. It's always present but is not used if drilling is being undertaken with a top drive.
Rough neck	labourers that work on a rig - usually associated with handling pipe and equipment on the drill floor
Roustabout	a general labourer on a rig
Royalty	a cash payment or payment in kind to the resource holder
Sapropel	dark-coloured sediments that are rich in organic matter
Seal	typical mudstone and shale that overlies reservoir rock; the seal prevents the escape of hydrocarbons from the reservoir. Also referred to as 'cap'
SEC reserves	under SEC rules companies can account for only proved reserves. See Proved (1P) reserves.
Secondary Recovery	recovery of oil/gas from a reservoir by artificially enhancing the pressure in the reservoir by injecting water, gas or other substances into the reservoir
Sedimentary Rocks	the primary source of almost all oil and gas reserves. They are formed by the compaction of mineral grains that have been laid down as a result of terrestrial, wind or ocean currents.
Seismic survey	a technique used to obtain geophysical data by projecting sound waves below the surface to try to create an image of subsurface rock layers
Separator	a pressure vessel that separates produced fluids into oil, water and gas.
Seven Sisters	the seven IOC's that dominated the oil industry until the 1970's. Comprised Exxon, Mobil, Chevron, Texaco, RDS, BP and Gulf.
Shale oil	oil that is extracted by heat, from clays that are impregnated with oil (much like oil sands)
Source Kitchen	see source rock
Source Rock	hydrocarbons originate from organic matter that is deposited and preserved within sedimentary rocks. Any sediments that have high organic carbon content and produce hydrocarbons in significant amounts are known as source rocks
SPAR	floating production system, anchored to the seabed through a semi-rigid mooring system, comprising a vertical cylindrical hull supporting the platform structure.
Spill point	the structurally lowest point in a reservoir that can contain hydrocarbons
Spud	the operation of drilling the first part of a new well
Steam assisted gravity and drainage (SAGD)	involves drilling two parallel horizontal oil wells in the oil sand formation. The upper well injects steam and the lower one collects the water from any resultant condensation. The injected steam heats the crude oil or bitumen and lowers its viscosity, which allows it to flow down into the lower wellbore
Steam cracking	crackers that use steam to initiate the process of breaking down larger, heavier, more complex hydrocarbons
Straight-run	production resulting from the distillation of petroleum without chemical conversion, i.e. no adjustment to the molecular structure or size
Structural Traps	result from plate movements such as folding and/or faulting of the reservoir and cap rock. Typical examples are anti-clinal and fault traps, which are sometimes connected with salt domes.
Superposition	within a sequence of layers of sedimentary rock, the oldest layer is at the base, and the layers are progressively younger with ascending order in the sequence
SURF facilities	Sub-sea Umbilical Risers Flowlines – pipelines and equipment connecting the well or sub-sea system to a floating unit.
Swing	fluctuation in oil/gas demand. Resource holders with spare capacity (namely Saudi Arabia and Nigeria) are often referred to as swing producers as they have the capacity to increase production at times of increased demand
Syncrudes	Synthetic Crude is a liquid fuel obtained from coal, gas or heavy oil sands. Synthetic crude is created via CTL (Coal-to-Liquids), GTL (Gas to Liquids) and by upgrading bitumen found in oil sands
Tax & Royalty regime (concession)	a regime under which an oil company is granted a concession to prospect for and extract hydrocarbons. From the revenues generated, the concession holder will typically pay a pre-agreed royalty on revenues together with corporation tax on profits.
Technical costs	include exploration expenses, DD&A and production costs, i.e. it is the entire cost involved in producing a barrel of oil

Tension Leg Platform (TLP) fixed-type floating platform held in position by a system of tendons and anchored to ballast caissons located on the seabed. These platforms are used in ultra-deep waters.

Tertiary recovery methods of increasing recovery from oil/gas fields beyond that achieved by secondary recovery. These techniques are often referred to as Enhanced Oil Recovery (EOR)

Texas Railroad Commission the US forerunner to OPEC, created to regulate oil production

Thermoplastics plastics that melt to a liquid when heated and freeze to a brittle, very glassy state when cooled sufficiently, i.e. they can be re-moulded, extruded or even recycled

Thermosets polymer material that is set to a stronger form through the addition of energy (normally heat or through a chemical reaction). Unlike thermoplastics, thermosets never soften once they have been moulded

Tight gas gas that is trapped in reservoirs that have low porosity and permeability

Tongs vice-like large grips that clamp on to drill pipe and allow two pieces of pipe to be screwed together tightly via chain and pulleys on the draw works

Tool pusher the person in charge of drilling operations, to whom the driller and roughnecks report

Top Drive a large electric or hydraulic motor that is positioned on top of the drill pipe and can move up and down in the derrick. It transmits torque directly to the top of the drill pipe and simultaneously allows high pressure mud to be circulated, even if pulling the pipe out of hole - a feat that rotary table drilling cannot perform. It makes the rotary table, kelly bushing and kelly redundant.

Topsides the modules that are installed above the sea level on an offshore platform, e.g. accommodation, drilling package, power, mud pumps, separators

Torque a rotating force defined as the force applied to a lever, multiplied by the distance from the lever's fulcrum (turning point)

Total depth the bottom of the well

Transesterification based on the reaction between a vegetable oil containing glycerides and a short-chain alcohol such as methanol, which converts vegetable oil into fatty acid methyl esters (FAME). Also known as alcoholysis

Treating processes additional processes carried out at refineries prior to the petroleum products being marketed. Treating is used to 'clean up' products, e.g. the reduction of sulphur content in gasoline

Trigger points the conditions laid out in the PSC contract, the attainment of which leads to changes in the allocation of profit oil share between the state and the contractor.

True vertical depth (TVD) the vertical depth of a well, which in the case of a deviated hole can be much lower than the measured depth

Turbidites sands within a depositional environment that are delivered down the continental slope by turbidity current. (A turbidity current transports sand and mud within a current of turbid water, much like a snow avalanche transport snow within air)

Turntable rotating platform used to work the drill

Unconventional Oil/Gas generally refers to oil sands, gas-to-liquids, coal bed methane and tight gas, which all require advanced technology and in the past were considered un-commercial given the high development costs

Unification combines lighter hydrocarbons to create heavier hydrocarbons of desired characteristics

Uniformitarianism the principal developed by Charles Lyell stating that geological processes have not changed throughout the Earth's history

Upgrading the process by which the bitumen obtained from the oil sands is upgraded into shorter, lighter carbon chains more representative of crude. Hydro-cracking and hydro-treating are just two of the processes used to upgrade the bitumen

Upstream term commonly used to refer to the search for and the recovery and production of crude oil and natural gas

V-door something that all rig trainees must find the keys for (since time immemorial), which is problematic, as it is simply a metal ramp that allows pipe to be pulled up from the main deck of a rig to the drill floor

Vibroseis truck an alternative to explosives for generating seismic data. A vibroseis truck drops a steel pad from its underbelly, jacks itself up on the pad, then vibrates the pad to generate shock waves

Vis-breaking thermal cracking used to reduce the thickness of residual oils

Water cut the percentage of produced fluids that is water

Water flood an EOR method that involves pumping water down through injector wells to force oil towards the wellbore that otherwise would have not been produced.

Weight-on-bit the force that is allowed by the driller to be transmitted to the bit. This is controlled by the use of the 'brake' that slows (or halts) the descent of the traveling block in the derrick.

Well test	also referred to as a 'flow test', this refers to pumping oil and gas at controlled rates for a period of time in order to gain further information about the permeability, contents, and potential flow rates of the reservoir and its physical size
Wellhead	the part of an oil well that terminates at the surface where petroleum or gas can be withdrawn
Wet gas	geological term for a mixture of gas that contains significant amounts for liquid or condensable compounds heavier than ethane. Wet gas is generally derived from a reservoir that contains some amounts of water
Wildcat well	speculative drilling on unproven acreage. Also known as exploration well
Wireline logging	uses cables and downhole instruments to acquire measurements that provide strong indications of whether any oil/gas has been found
Working Interest	the contractor's percentage interest in the project as a whole. Thus if a company has a 40% interest in a project producing 100kb/d, its working interest in that project would be 40kb/d.

Source: Deutsche Bank

Appendix 1

Important Disclosures

Additional information available upon request

Disclosure checklist			
Company	Ticker	Recent price*	Disclosure
BP	BP.L	461.15 (GBp) 21 Jan 13	1,7,14,15,17,SD11
Royal Dutch Shell Plc	RDSb.L	2,263.68 (GBp) 21 Jan 13	7,14,17,SD11

*Prices are sourced from local exchanges via Reuters, Bloomberg and other vendors. Data is sourced from Deutsche Bank and subject companies

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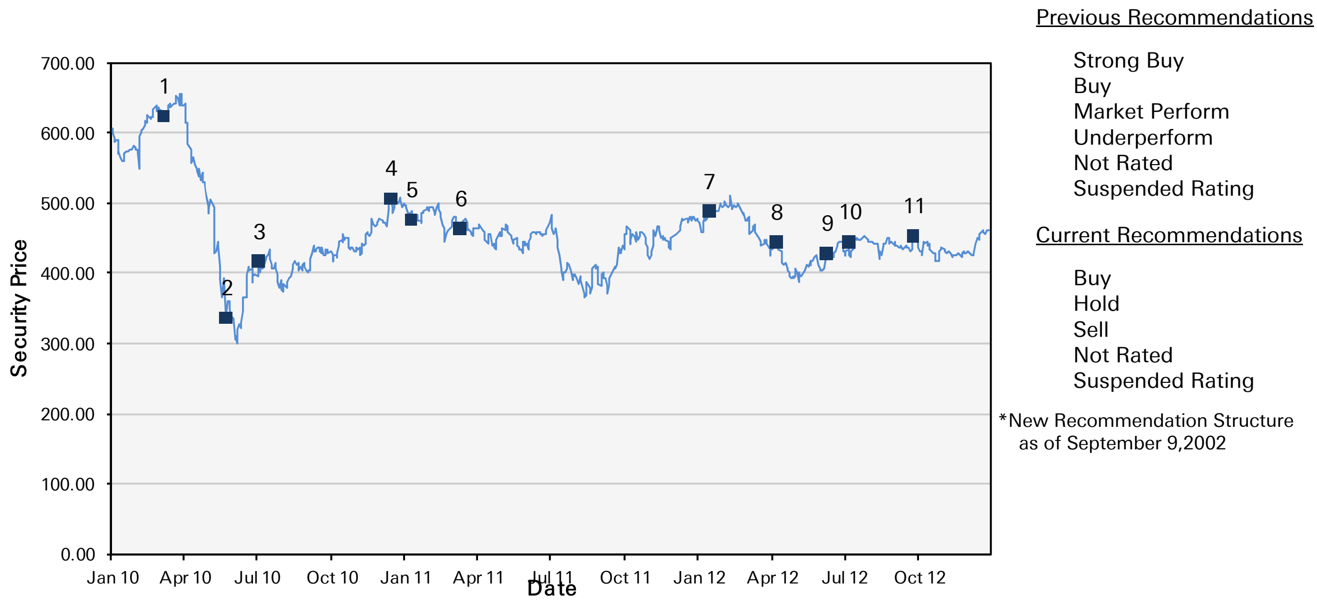
Historical recommendations and target price: BP (BP.L)

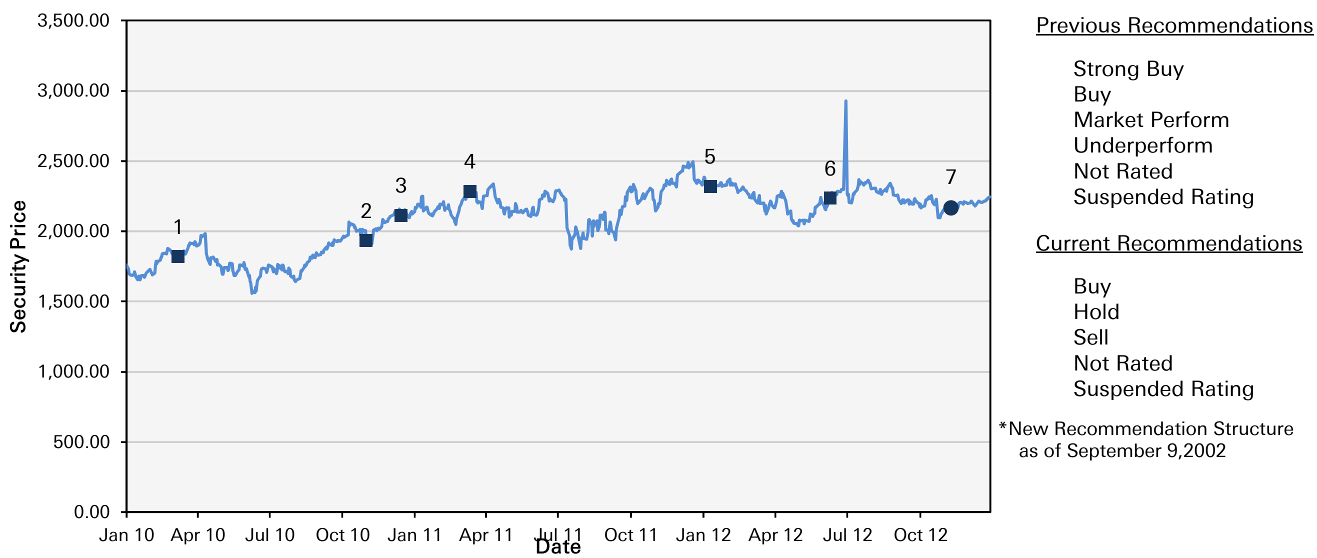
(as of 1/21/2013)



1.	31/03/2010:	Buy, Target Price Change GBP720.00	7.	07/02/2012:	Buy, Target Price Change GBP550.00
2.	17/06/2010:	Buy, Target Price Change GBP480.00	8.	01/05/2012:	Buy, Target Price Change GBP525.00
3.	27/07/2010:	Buy, Target Price Change GBP520.00	9.	03/07/2012:	Buy, Target Price Change GBP500.00
4.	07/01/2011:	Buy, Target Price Change GBP580.00	10.	31/07/2012:	Buy, Target Price Change GBP480.00
5.	02/02/2011:	Buy, Target Price Change GBP550.00	11.	19/10/2012:	Buy, Target Price Change GBP500.00
6.	04/04/2011:	Buy, Target Price Change GBP575.00			

Historical recommendations and target price: Royal Dutch Shell Plc (RDSb.L)

(as of 1/21/2013)



1.	31/03/2010:	Buy, Target Price Change GBP2,100.00	5.	02/02/2012:	Buy, Target Price Change GBP2,600.00
2.	24/11/2010:	Buy, Target Price Change GBP2,420.00	6.	03/07/2012:	Buy, Target Price Change GBP2,475.00
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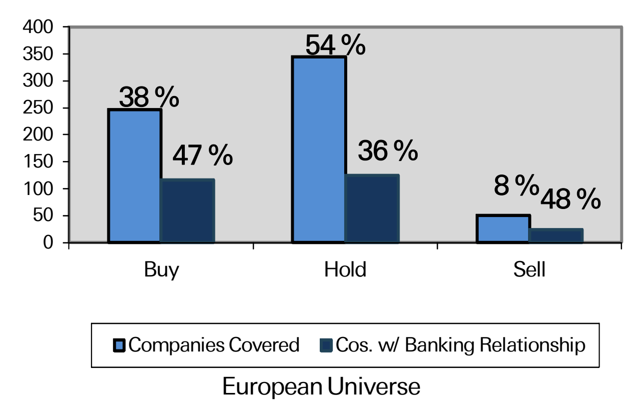
Equity rating dispersion and banking relationships



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