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Industry Update

9 September 2010

Oil & Gas for Beginners

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 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. Almost three 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 13 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 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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Table of Contents

Table of Contents (Cont'd)

Table of Contents (Cont'd)

Table of Contents (Cont'd)

Table of Contents (Cont'd)

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

Source: Deutsche Bank

Figure 2 contd: A brief history of oil

			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%
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			Oil price shock	Iraq on verge of civil war, heightened 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
2009-2010			Price collapse	Global financial crisis precipitates a decline in oil demand and oil prices collapse to lows of $33/bbl. Fiscal stimulation and a return to growth eventually see oil prices stabilise around $70-80/bbl but world remains over-supplied in both oil and gas.

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, ConocoPhilips 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 there existed a wealth of alternative supplies.

- **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.

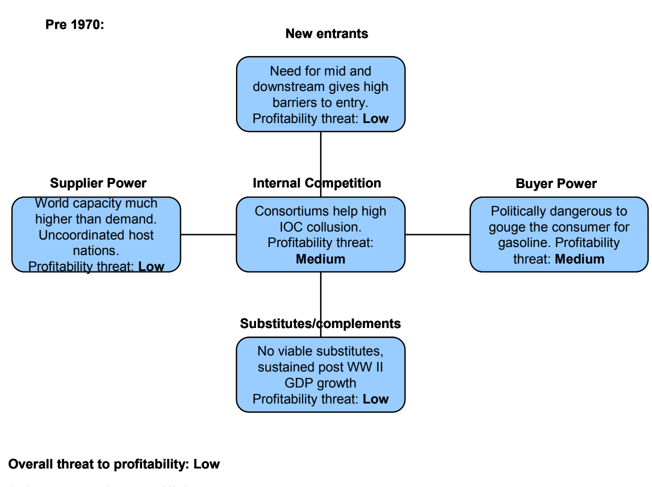
Prior to 1970 the IOCs held the bulk of industry power, almost uninterrupted. The period from 1970 to 1979 was pivotal in the evolution of power from western oil companies towards resource holding nations, and we have seen another surge in this theme in recent years.

Classical analysis suggests recent shifts are structural

Classical analysis suggests recent shifts are structural

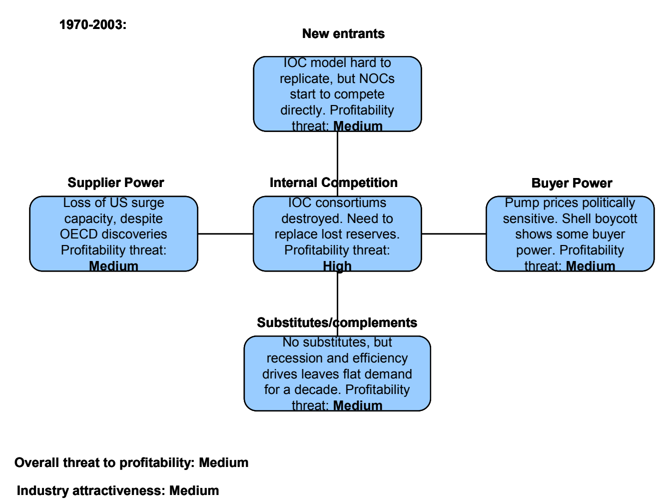
Time will tell whether recent adverse changes (from an IOC perspective) in contract terms and field ownership are cyclical blips that will reverse (as has occurred several times in the past), or not. The classic approach to analysing an industry's profitability (by breaking down the threats to that profitability)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

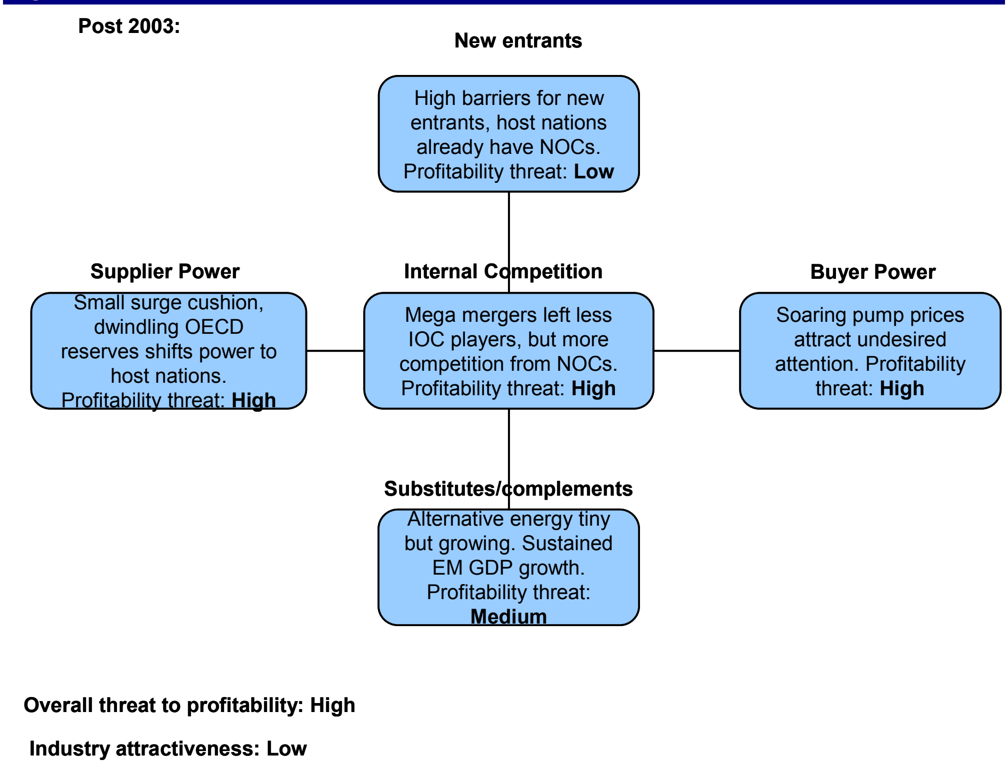


Source: Deutsche Bank

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.

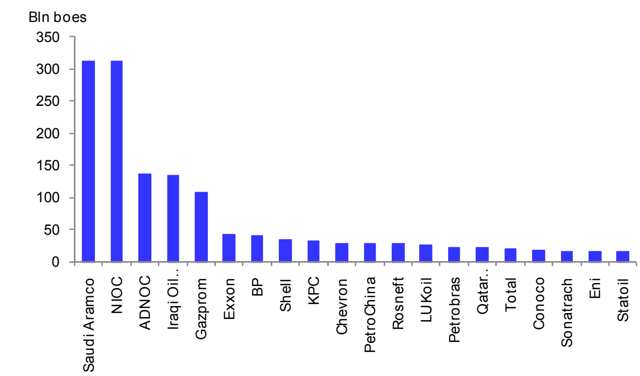
IOCs and NOCs

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

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).

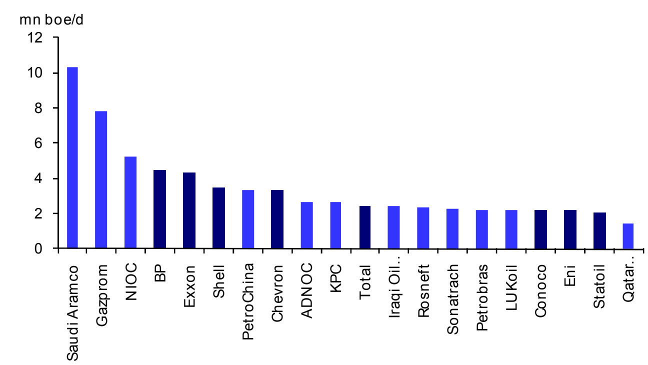
The fundamental difference in the reserve holdings between these two groups of industry players is clear in the left hand chart below:

Figure 6: IOC and NOC oil and gas reserves (billion boe) end 2009



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 2009 (million b/d)

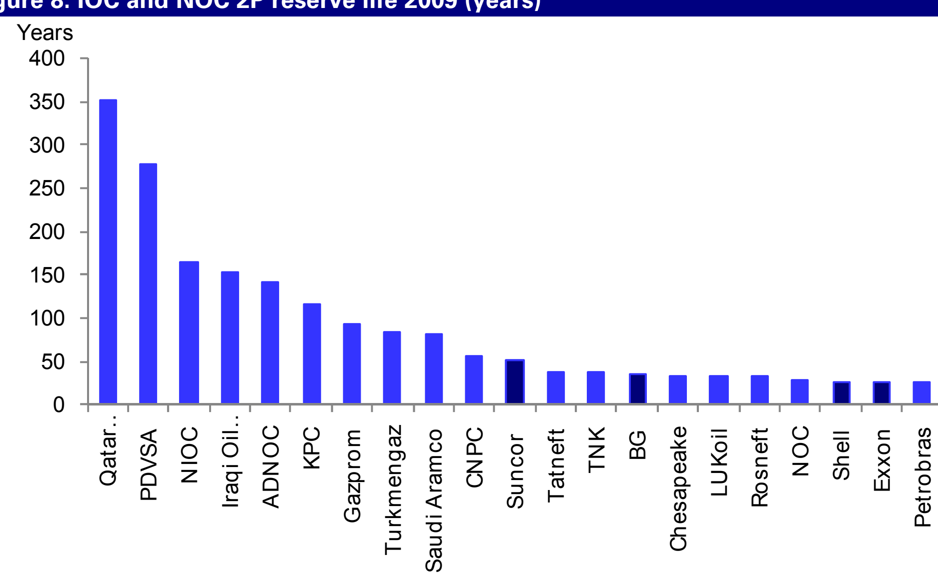


Source: Wood Mackenzie, Deutsche Bank estimates

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 2P reserve life 2009 (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 Exxon, Chevron, Shell and BP

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.

2000s – power moves further towards the resource owners. Since 2003 oil prices have risen from just above $20/bbl to just below $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. That said, those that can grow their business from non-conventional production will likely eventually find themselves at an advantage relative to those that persist with the 'old' conventional oil IOC model.

The International Oil Companies

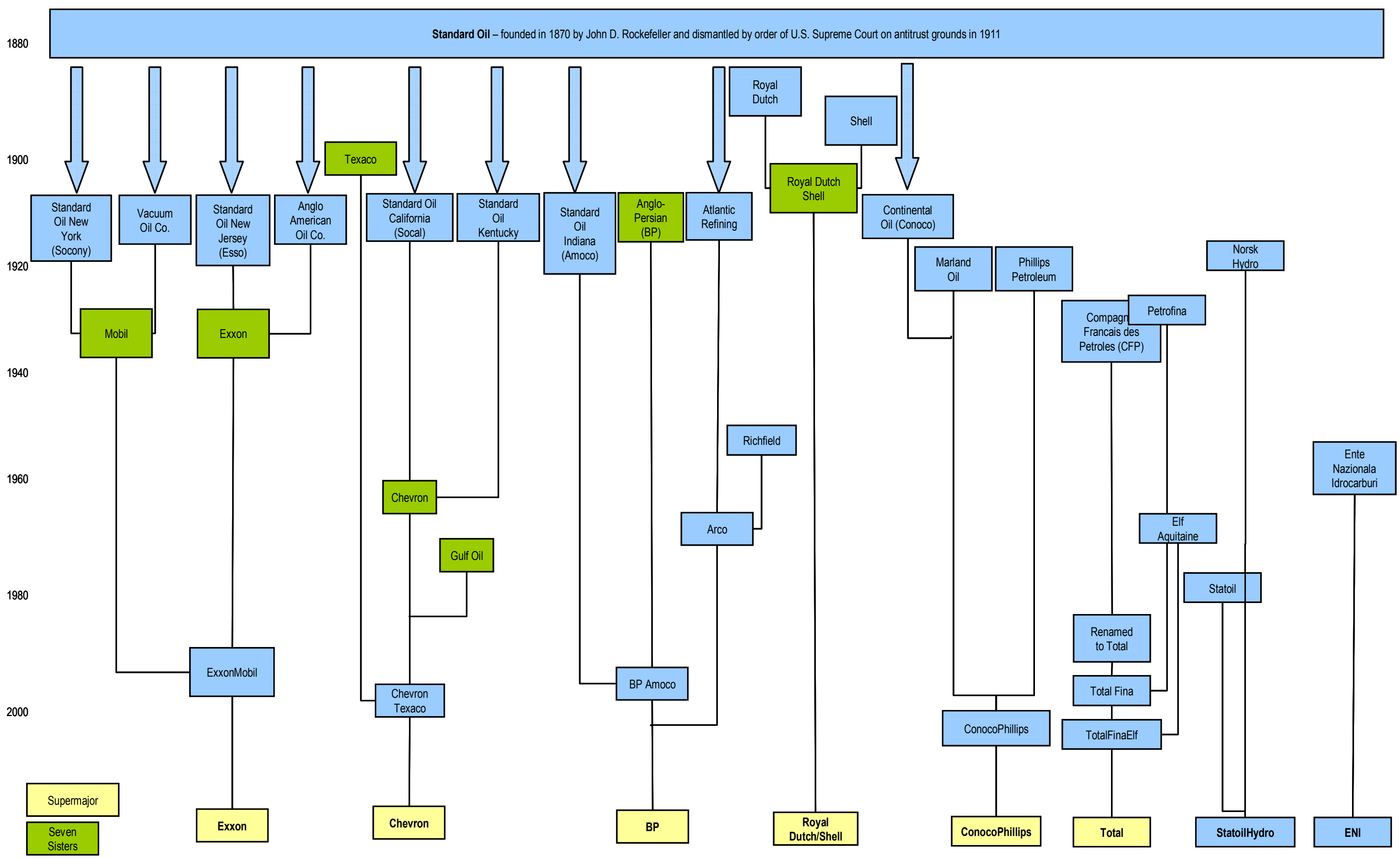
Exxon, is a direct descendent of Standard's heart; Standard Oil New Jersey

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.

Figure 9: The major IOCs family tree



Source: Deutsche Bank

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 oilfiled, 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 ten years; 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.

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.

ConocoPhillips 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.

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 six largest IOCs – Exxon, Chevron, RD/Shell, BP, ConocoPhillips and Total.

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

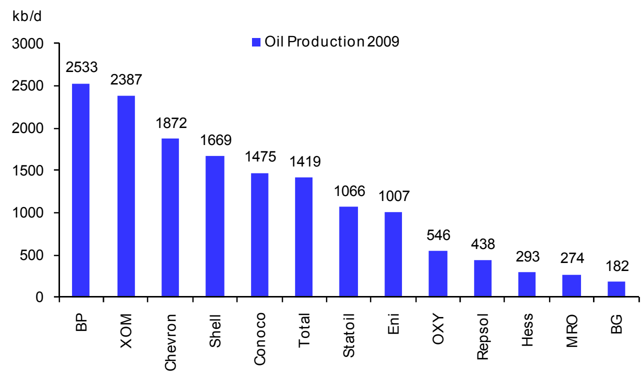
The other two IOCs in the previous figure are Statoil and Eni:

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.

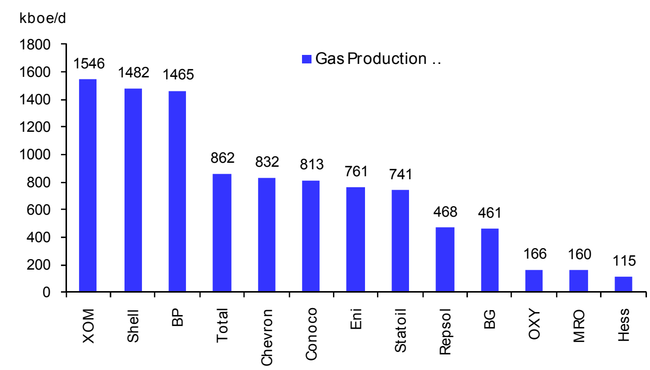
The IOCs Compared

Figure 10: 2009 Oil Production by company



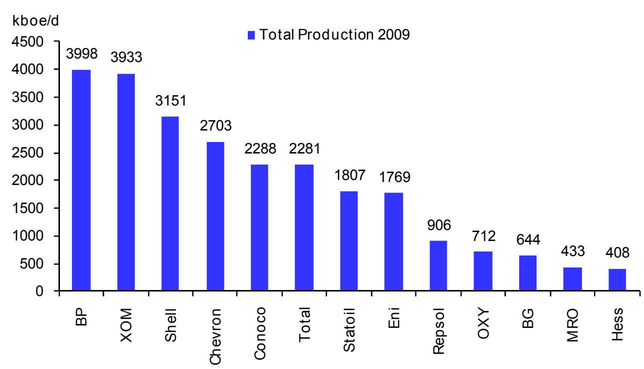
Source: Company data, Deutsche Bank estimates

Figure 11: 2009 Gas Production by company



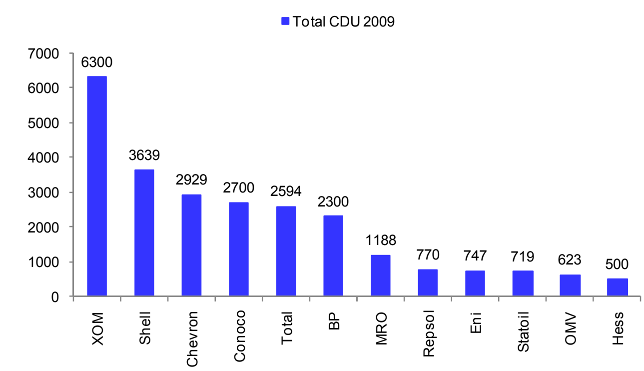
Source: Company data, Deutsche Bank estimates

Figure 12: 2009 Total Production by company



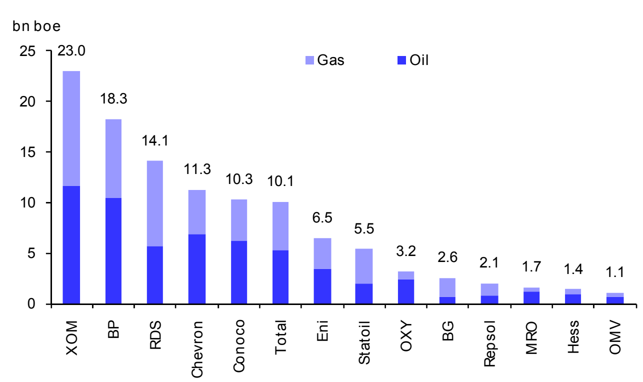
Source: Company data, Deutsche Bank estimates

Figure 13: 2009 Refining Capacity by company



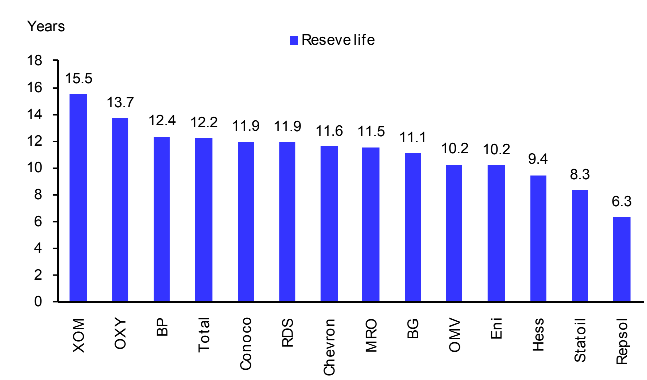
Source: Company data, Deutsche Bank estimates

Figure 14: 2009 1P reported reserves by company



Source: Company data, Deutsche Bank estimates

Figure 15: Reserve Life by Company 2009



Source: Company data, Deutsche Bank estimates

Figure 16: Western Majors – Production by Geography 2012E

Country	Exxon	BP	Shell	CVX	Total	Conoco	Eni	Repsol	Statoil	OCY	BG	MRO	Hess
Canada	7%	1%	7%	2%	0%	17%	-	-	2%	0%	-	9%	-
US (Alaska)	3%	4%	-	1%	-	12%	1%	-	-	-	-	3%	-
US (Deepwater GOM)	2%	9%	7%	3%	1%	1%	2%	4%	2%	-	-	8%	11%
US (GOM Shelf)	1%	-	0%	3%	-	-	1%	-	-	-	-	1%	-
US (Lower 48)	6%	11%	4%	13%	2%	24%	0%	-	2%	41%	8%	25%	15%
Total N.America	**18%**	**25%**	**18%**	**23%**	**3%**	**54%**	**5%**	**4%**	**6%**	**41%**	**8%**	**46%**	**26%**
Argentina	0%	3%	0%	1%	2%	-	-	43%	-	7%	-	-	-
Bolivia	-	0%	-	-	1%	-	-	10%	-	0%	3%	-	-
Brazil	-	-	1%	1%	-	-	-	1%	4%	-	3%	-	-
Colombia	-	1%	-	1%	0%	-	-	1%	-	4%	-	-	-
Ecuador	-	-	-	-	-	0%	1%	1%	-	-	-	-	-
Peru	-	-	-	-	-	-	-	3%	-	-	-	-	-
Trinidad & Tobago	-	6%	-	2%	0%	-	1%	17%	-	-	10%	-	-
Venezuela	-	0%	0%	2%	2%	-	1%	7%	1%	-	-	-	-
Total S.America & Caribbean	**0%**	**10%**	**2%**	**7%**	**6%**	**0%**	**2%**	**82%**	**5%**	**11%**	**16%**	**0%**	**0%**
Croatia	-	-	-	-	-	-	1%	-	-	-	-	-	-
Denmark	-	-	4%	1%	-	-	-	-	-	-	-	-	2%
France	-	-	-	-	1%	-	-	-	-	-	-	-	-
Germany	2%	-	1%	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	0%	-	-	-	-	-	1%	-	-	-	-
Italy	-	-	1%	-	-	-	8%	-	-	-	-	-	-
Netherlands	7%	-	8%	0%	1%	-	-	-	-	-	-	-	-
Norway	6%	2%	4%	0%	10%	8%	5%	-	60%	-	1%	13%	8%
Spain	-	-	-	-	-	-	-	0%	-	-	-	-	-
UK	3%	5%	5%	2%	7%	6%	3%	-	0%	-	15%	6%	7%
Total Europe	**18%**	**7%**	**23%**	**4%**	**19%**	**14%**	**17%**	**0%**	**61%**	**0%**	**16%**	**18%**	**17%**
Azerbaijan	2%	7%	-	3%	1%	-	-	-	6%	-	-	-	4%
Kazakhstan	3%	-	0%	12%	-	-	7%	-	-	-	17%	-	-
Kirgizstan	-	-	-	-	-	-	-	-	-	-	-	-	-
Russia	1%	17%	5%	-	1%	2%	1%	-	1%	-	-	-	5%
Turkmenistan	-	-	-	-	-	-	1%	-	-	-	-	-	-
Total FSU	**6%**	**24%**	**5%**	**15%**	**1%**	**2%**	**8%**	**0%**	**7%**	**0%**	**17%**	**0%**	**10%**
Bahrain	-	-	-	-	-	-	-	-	-	3%	-	-	-
Iran	-	-	-	-	0%	-	0%	-	-	-	-	-	-
Iraq	4%	9%	2%	-	0%	-	3%	-	0%	5%	-	-	-
Oman	-	-	6%	-	1%	-	-	-	-	9%	-	-	-
Qatar	21%	0%	7%	-	9%	3%	-	-	-	21%	-	-	-
Saudi Arabia	-	-	-	4%	-	-	-	-	-	-	-	-	-
Syria	-	-	1%	-	1%	-	-	-	-	-	-	-	-
United Arab Emirates	6%	4%	3%	-	8%	-	-	-	-	2%	-	-	-
Yemen	0%	-	-	-	4%	-	-	-	-	4%	-	-	-
Total Middle East	**32%**	**13%**	**20%**	**4%**	**24%**	**3%**	**4%**	**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	OCY	BG	MRO	Hess
Nigeria	6%	-	10%	8%	10%	3%	7%	-	2%	-	-	-	-
Algeria	-	3%	-	-	2%	2%	8%	6%	7%	-	-	-	5%
Egypt	-	5%	2%	-	-	-	18%	-	-	-	25%	-	-
Libya	-	-	-	-	3%	3%	10%	8%	1%	4%	-	13%	6%
Tunisia	-	-	-	-	-	-	1%	-	-	-	6%	-	-
Total N.Africa	**6%**	**8%**	**12%**	**8%**	**15%**	**7%**	**43%**	**14%**	**10%**	**4%**	**32%**	**13%**	**10%**
Angola	8%	7%	-	7%	13%	-	10%	-	11%	-	-	2%	-
Chad	1%	-	-	1%	-	-	-	-	-	-	-	-	-
Congo	-	-	-	1%	4%	-	5%	-	-	-	-	-	-
Equatorial Guinea	2%	-	-	-	-	-	-	-	-	-	-	21%	15%
Gabon	-	-	1%	-	2%	-	-	-	-	-	-	-	-
Total W.Africa	**11%**	**7%**	**1%**	**9%**	**19%**	**0%**	**15%**	**0%**	**11%**	**0%**	**0%**	**23%**	**15%**
Australia	2%	2%	2%	3%	-	2%	1%	-	-	-	4%	-	-
Bangladesh	-	-	-	6%	-	-	-	-	-	-	-	-	-
Brunei	-	-	5%	-	0%	-	-	-	-	-	-	-	-
China	-	0%	1%	1%	-	4%	0%	-	-	-	-	-	-
India	-	-	-	-	-	-	0%	-	-	-	5%	-	-
Indonesia	1%	2%	-	10%	9%	7%	1%	-	-	-	-	-	6%
Malay/Thai JDA	-	-	-	-	-	-	-	-	-	-	-	-	13%
Malaysia	5%	-	8%	-	-	-	-	-	-	-	-	-	-
Myanmar	-	-	-	1%	2%	-	-	-	-	-	-	-	-
New Zealand	-	-	1%	-	-	-	-	-	-	-	-	-	-
Pakistan	-	1%	0%	-	-	-	3%	-	-	-	-	-	-
Philippines	-	-	1%	1%	-	-	-	-	-	-	-	-	-
Thailand	0%	-	-	8%	2%	-	-	-	-	-	3%	-	3%
Timor Leste/Australia JPDA	-	-	-	-	-	4%	1%	-	-	-	-	-	-
Vietnam	-	0%	-	-	-	1%	-	-	-	-	-	-	-
Total Asia Pacific	**8%**	**5%**	**18%**	**31%**	**12%**	**18%**	**6%**	**0%**	**0%**	**0%**	**12%**	**0%**	**23%**
Group Production '10E (kboe/d)	**3,985**	**3,967**	**3,201**	**2,706**	**2,384**	**2,349**	**1,843**	**896**	**1,811**	**645**	**665**	**400**	**408**

Source: Deutsche Bank estimates

The major NOCs

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

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.

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 312bn 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.2mboe/d and combined reserves of 134bn 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 267bn boe.

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 22bn boe.

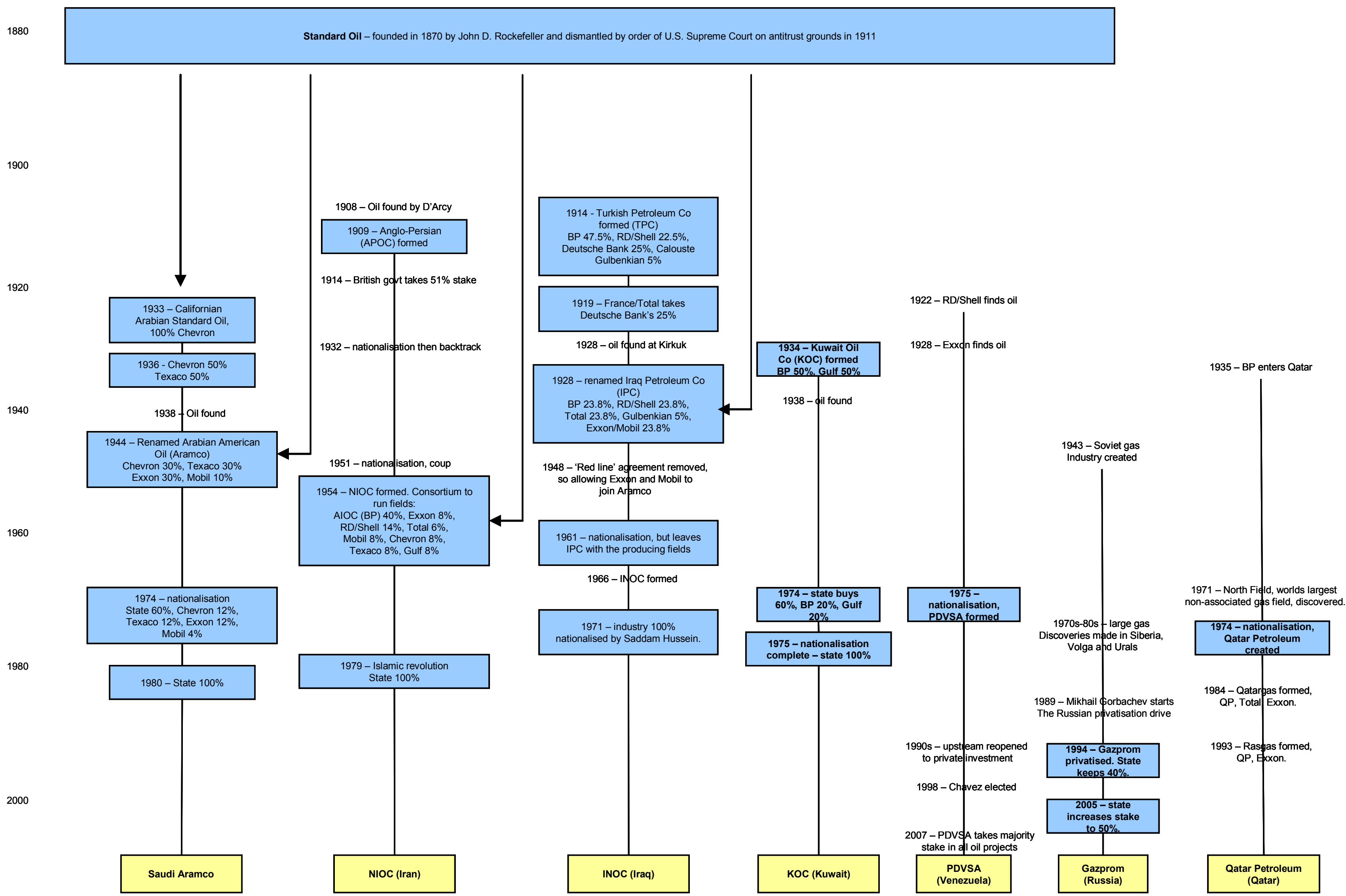
Pemex (Mexico) can trace its history back to the country's nationalisation of the industry in 1938. It is state owned and has a monopoly over all Mexican upstream and downstream operations. Pemex is hamstrung by the fact that much of its revenues go direct to the government and the technology and skills 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

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

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.

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

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'

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 major 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 the 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.

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 major 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 3.22mb/d, its current production capacity is little more than 2.4mb/d. By contrast although Algeria has a production quota of only 890kb/d, it regularly produces nearer 1.2mb/d.

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. Having considered the supply position the organisation will then determine whether it needs to supply more or less crude to the market.

Figure 20: OPEC's ingredients

Member	Production Quota July 2005	Production May 2010 (mbbl/d)	Production capacity '10 (mbbl/d)	% OPEC total	Spare capacity '10 (mbbl/d	% OPEC total	Official Reserves (bn bbls/d)	Reserves as % those globally	Petroleum exports as % GDP 2009
Saudi Arabia	9.10	8.25	12.00	34%	3.75	61%	264.1	21%	48%
Iran	4.11	3.75	4.00	11%	0.25	4%	137.6	11%	25%
Iraq	n.a.	2.24	2.60	7%	0.36	6%	115	9%	57%
UAE	2.44	2.29	2.70	8%	0.41	7%	97.8	8%	39%
Kuwait	2.25	2.29	2.65	8%	0.36	6%	101.5	8%	53%
Qatar	0.73	0.82	0.90	3%	0.08	1%	27.3	2%	42%
Nigeria	2.31	2.00	2.20	6%	0.20	3%	36.2	3%	35%
Libya	1.50	1.54	1.70	5%	0.16	3%	43.7	3%	55%
Algeria	0.89	1.24	1.40	4%	0.16	3%	12.2	1%	30%
Venezuela	3.22	2.25	2.40	7%	0.15	2%	99.4	8%	24%
Angola	1.90	1.89	2.10	6%	0.21	3%	13.5	1%	77%
Ecuador	0.52	0.47	0.50	1%	0.03	0%	3.8	0%	22%
TOTAL	**30.42**	29.03	35.15	100%	6.12	100%	952.1	76%	42%

Source: Deutsche Bank, OPEC, BP Statistical Review

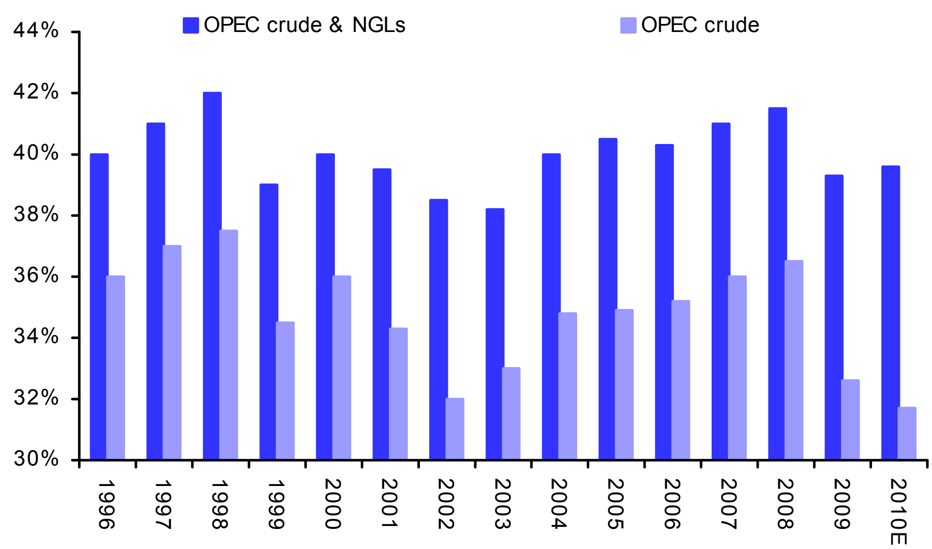
Should less supply be required it will set a production ceiling for the organisation as a whole with each member state agreeing a reduction in its current level of production (and vice versa). In this way OPEC seeks to ensure that the market is adequately supplied. Importantly, member countries must 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 (77% in 2009) 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 2009, oil production by OPEC members (including Angola) is estimated to have accounted for around 29mb/d or 34% of world demand for crude oil and natural gas liquids (although NGLs are outside the organisation's quota system). Where all countries outside OPEC operate at full capacity, it is purely within OPEC that spare oil production capacity resides (and this predominantly in Saudi Arabia).

Figure 21: OPEC – recent years have seen its share of world crude production falter as OPEC members have sought to support oil prices



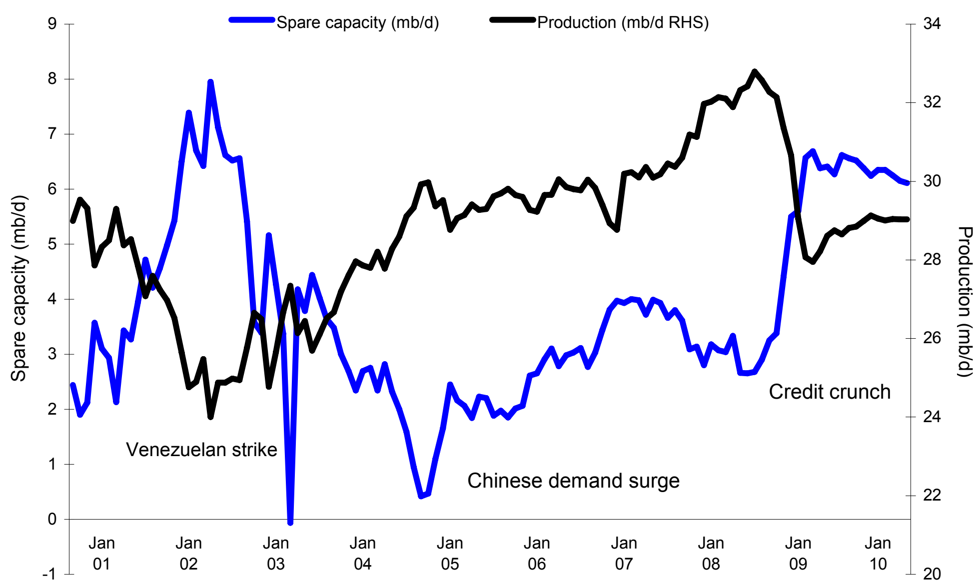
Source: Deutsche Bank, OPEC, BP Statistical Review

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.

The diagram below 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. However, 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 has moved back towards levels not seen since 2002 at which time the global economy was similarly facing much more challenging economic conditions. Looking forwards, it would seem reasonable to anticipate that, with some 5-6mb/d of spare capacity, oil prices are unlikely to quickly retrace their 2008 highs. However, given uncertainties around the stability of some 8mb/d of supplies from Iran, Nigeria and Iraq, geopolitical tensions will continue to prove an important concern.

Figure 22: OPEC production and spare capacity – getting longer



Source: Deutsche Bank, OPEC, BP Statistical Review

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, however, with crude oil prices showing some good recovery from their lows of the recent economic downturn the Organisation has declared itself comfortable with an oil price range of between $70-80/bbl. Important here no doubt is the fact that with oil exports on average accounting for over 40% of OPEC members' GDP, an oil price of at least $50-60/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 WTI it trades at a typical 5-10% 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 most particularly at Total, Chevron, ENI and Exxon 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 (2010E)

Country	BP	RDS	XOM	CVX	Total	COP	ENI	Repsol	Hess	OXY	BG	Statoil	MRA
Saudi Arabia				3%*									
Iran		0%					1%						
Iraq												1%	
Kuwait				3%*									
UAE	7%	8%	12%		17%								
Venezuela	1%	1%		5%	4%		2%	3%				2%	
Nigeria		14%	16%	12%	13%	4%	9%					3%	
Angola	7%		8%	8%	12%		14%					9%	
Algeria					1%	1%	7%	2%	5%			1%	
Qatar		0%	2%		4%					10%			
Libya		0%			7%	6%	14%	7%	8%	1%		1%	19%
Ecuador						1%	2%	4%					
As % Oil	15%	23%	38%	31%	58%	12%	49%	16%	13%	11%	0%	17%	19%
As % Group	**10%**	**12%**	**23%**	**21%**	**34%**	**5%**	**28%**	**8%**	**7%**	**1%**	**0%**	**9%**	**11%**
Group Oil Prodn kb/d	*2533*	*1641*	*2387*	*1846*	*1389*	*954*	*1056*	*449*	*293*	*491*	*189*	*1070*	*243*
Total Prodn kboe/d	*3967*	*3201*	*3985*	*2706*	*2384*	*2349*	*1843*	*896*	*408*	*645*	*665*	*1811*	*400*

*Source: Deutsche Bank * Partitioned zone (assumed 50% Kuwait and 50% S Arabia)*

In the beginning …..

A brief summary

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

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

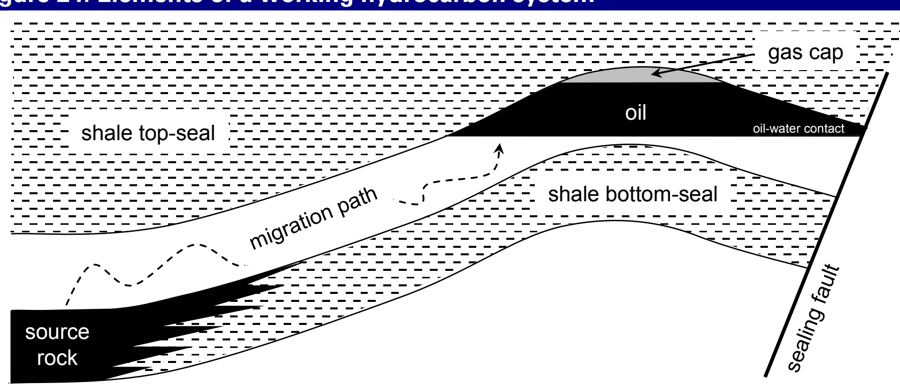
At its simplest, the deposition of organic matter from plants and micro-organisms in waters with little if any oxygen, or at a rate faster than that at which they could be consumed, led to the establishment of layers of organic matter and very fine silt particles on the sea bed which were subsequently 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 three 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.

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

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 considerable number of factors need to have aligned 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.

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** underliess 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.

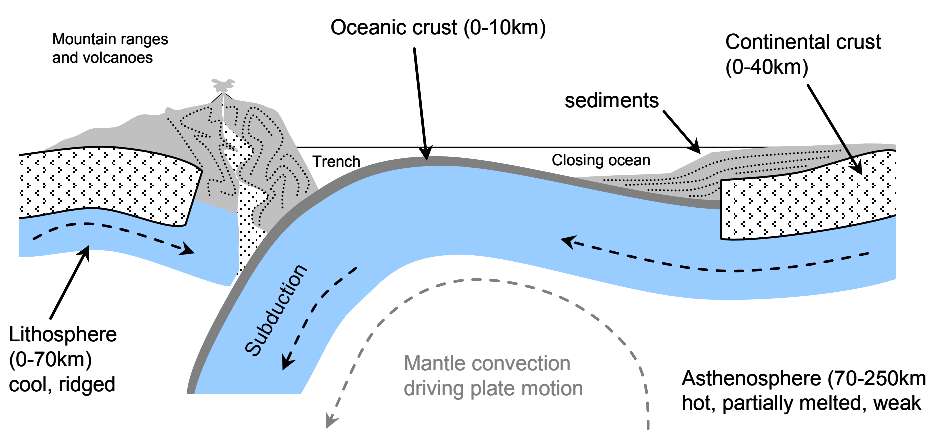
As they drift, the plates interact at their margins - new crustal material being created at mid-ocean ridges, and destroyed in subduction zones. These subduction zones are marked by deep ocean trenches and high mountain ranges. Across geologic time '**plate-tectonic drift**' has opened and closed oceans,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

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

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**.

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

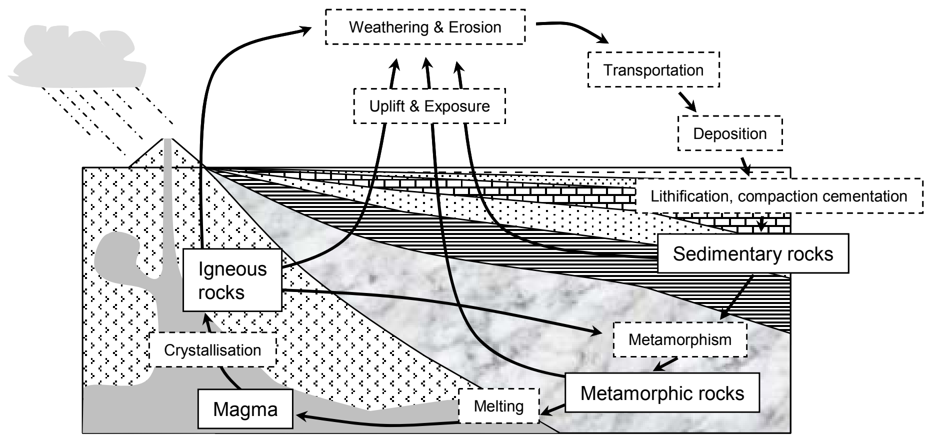
Rocks are divided according to their process of origin into 3 major groups: igneous, sedimentary and metamorphic.

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).

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.**

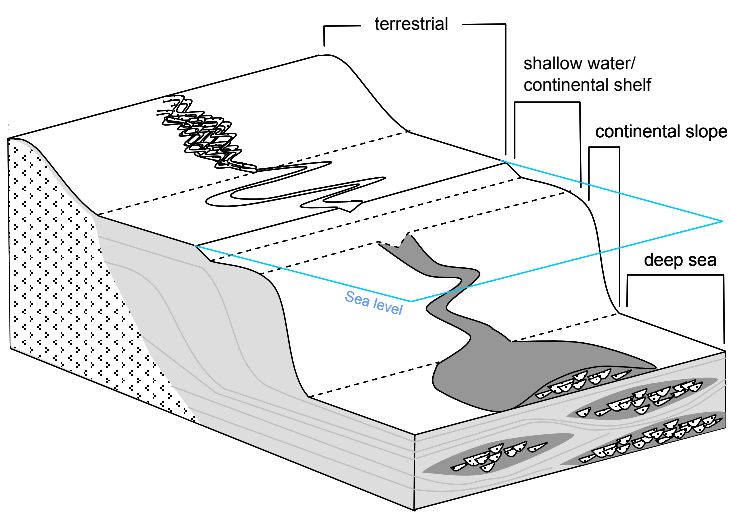
- In this context, one of the exploration geologist's principle tasks is to develop and apply models that help predict the distribution of reservoir units within a background of mud.

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.

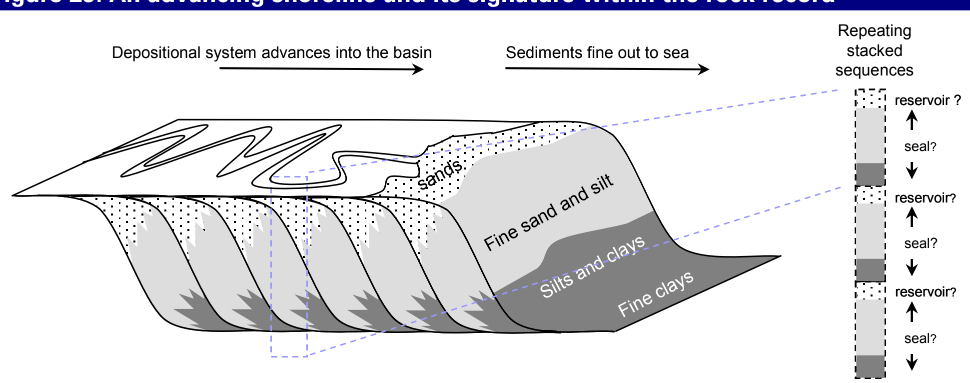
A seaward shift in the system (**progradation/regression**) is typically marked by coarser sediments such as beach sands overstepping finer sediments such as continental slope silts and muds. At the same time, exposure and erosion of the old beach-line is likely to release large volumes of sand into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

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

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.

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.

Source

- A 'source rock' is needed to generate the hydrocarbons

Reservoir

- A suitable 'reservoir' interval is needed to bear the hydrocarbons

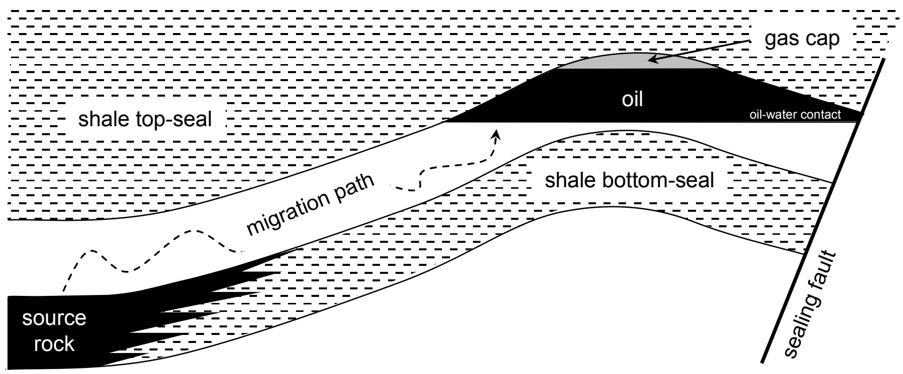
Trap

- A 'trap' is needed to contain the hydrocarbons

Dynamic

- All three elements must occur within a 'dynamic' system where each can interact

Figure 30: Elements of a working hydrocarbon system



Source: Deutsche Bank

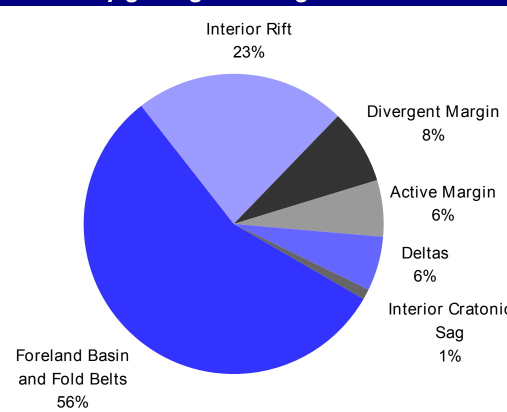
The exploration for and appraisal of oil and gas is an exercise in risk management. The risk associated with a prospect can be represented by an assumed '**probability of geologic success**' (Pg) - defined as the product of the probabilities of the 4 elements above.

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

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

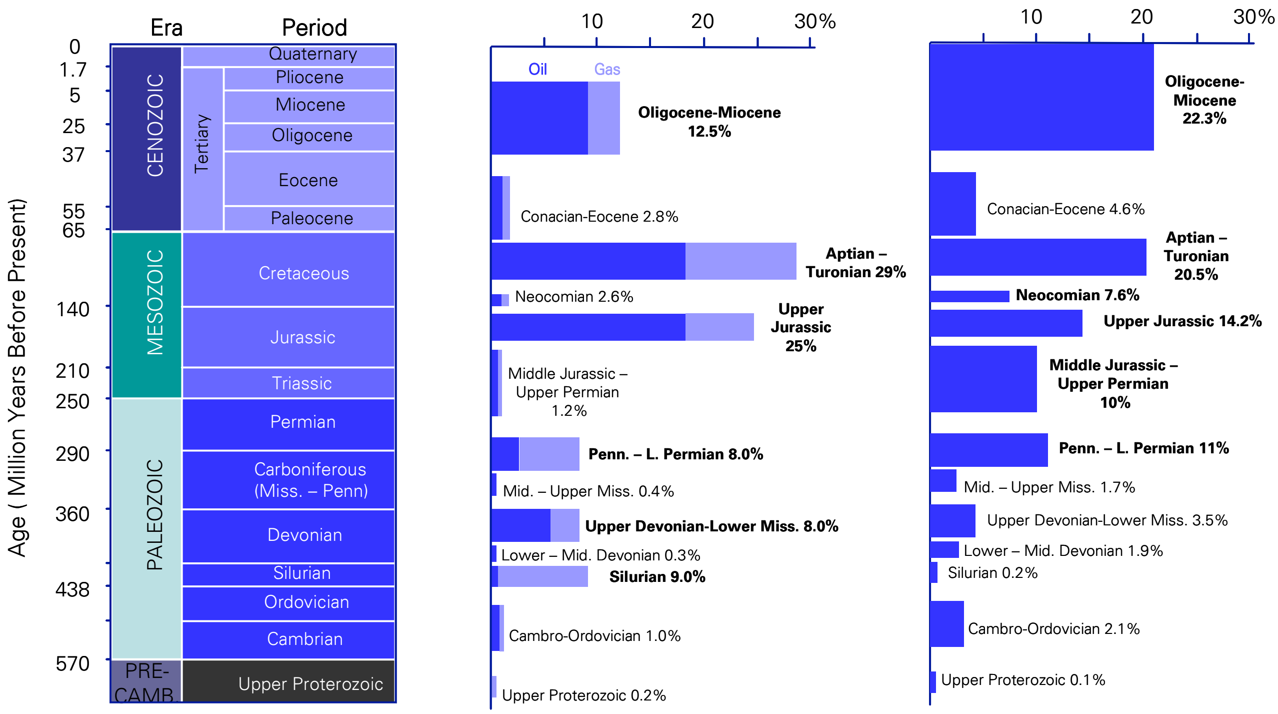


Source: Deutsche Bank

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

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.

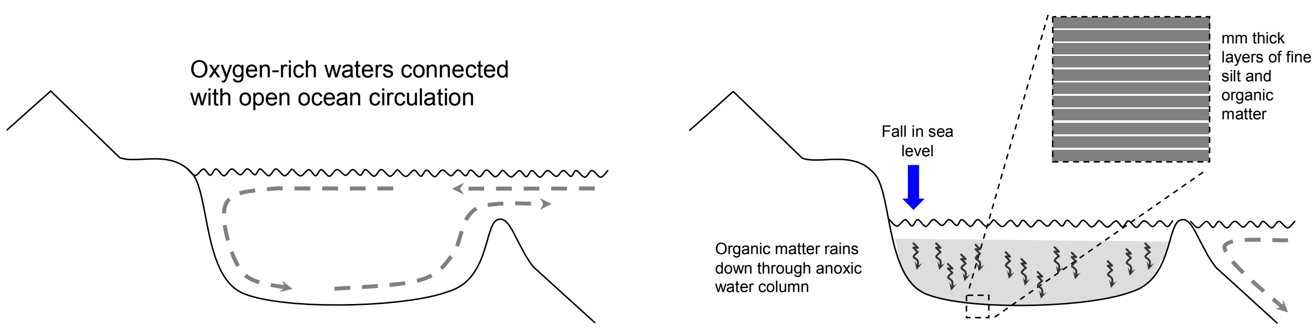
These organic-rich sediments are fine grained (deposited within low energy environments), dark in colour and are often referred to as **sapropels**.

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.

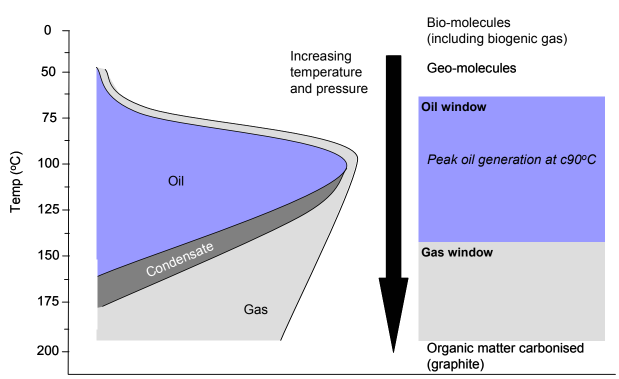
Source rock maturity… the 'oil window'

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.

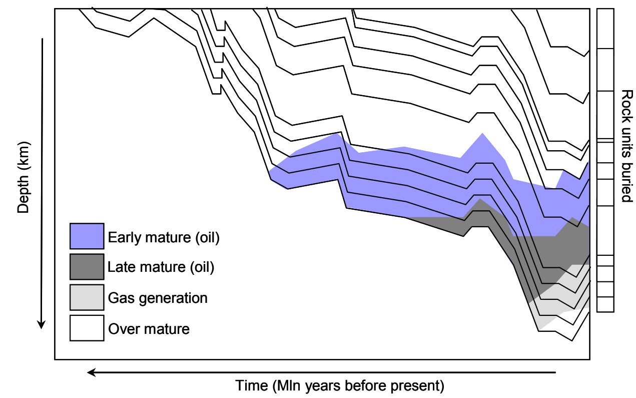
At higher temperatures, oil molecules are converted into lighter hydrocarbons, producing gas. Above 500°F (260°C), the source becomes '**over mature**' – hydrocarbon chains are broken down and organic material is carbonized.

Figure 34: Burial and the transformation of organic material



Source: Deutsche Bank

Figure 35: Schematic basin burial history and maturity window plot



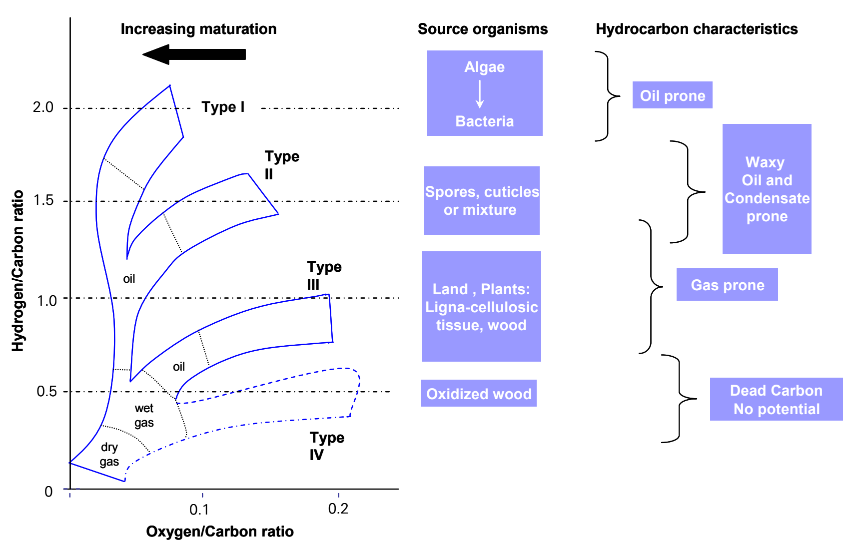
Source: Deutsche Bank

Finally, it has been observed that higher temperatures and greater burial depths are required for generation within younger rocks compared with older rocks.

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 mater 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. 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.

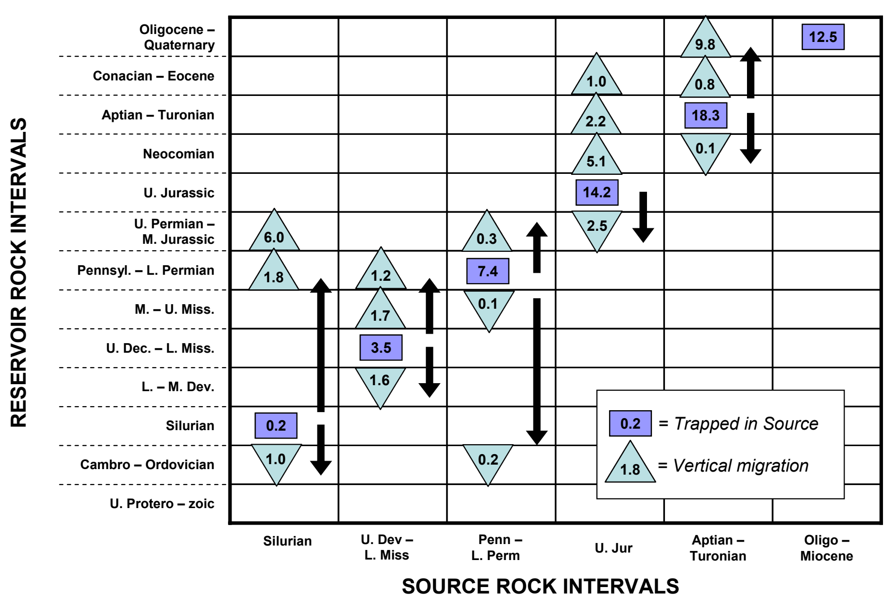
- **Secondary migration** - movement of oil/gas through carrier rocks or reservoir rocks outside the source rock, or movement through fractures within the source rock.

  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

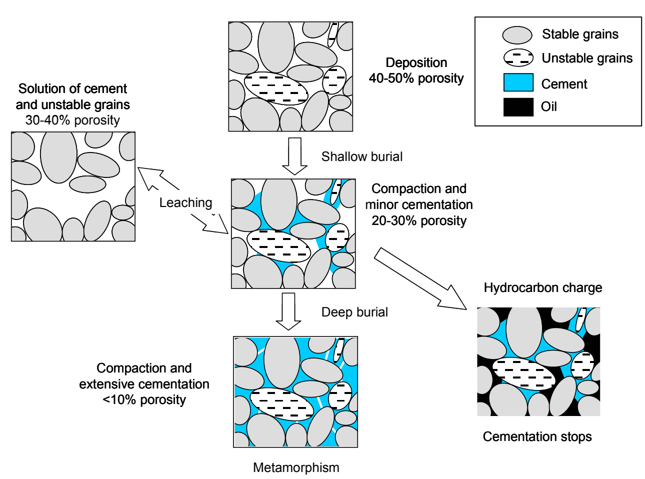
Key for high quality reservoir formation is the combination of porosity and permeability

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** refering 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

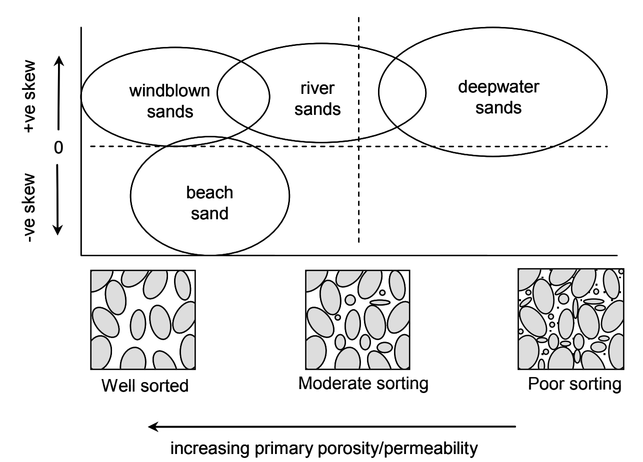
Although porosity is independent of grain-size, it is strongly a function of the degree of grain-size uniformity (sorting) within a sediment – porosity decreasing as sorting becomes poorer. Sorting is again an expression of the environment in which the sands were deposited.

Figure 38: Evolution of porosity with burial



Source: Deutsche Bank, Selley, 1985

Figure 39: Grain sorting and depositional environment



Source: Deutsche Bank, Bjorlykke, 1989

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.

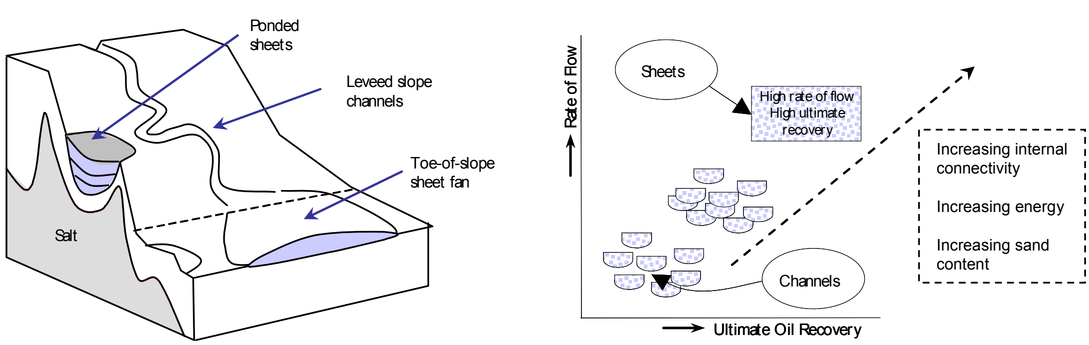
Sands within such a system are delivered down the continental slope by 'turbidity current' – the deposits of which are referred to as 'turbidites'

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.

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

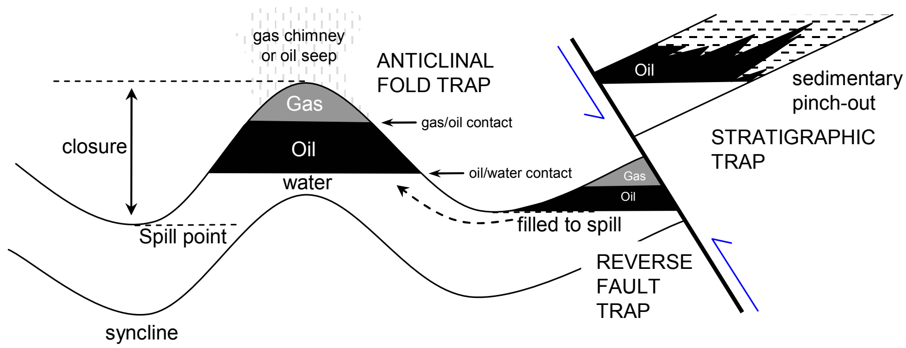
The trap and seal

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

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.

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

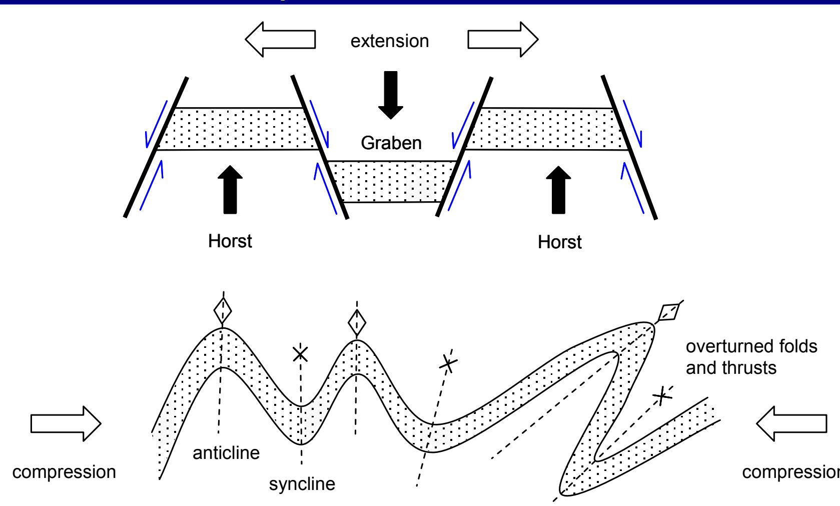


Source: Deutsche Bank

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)



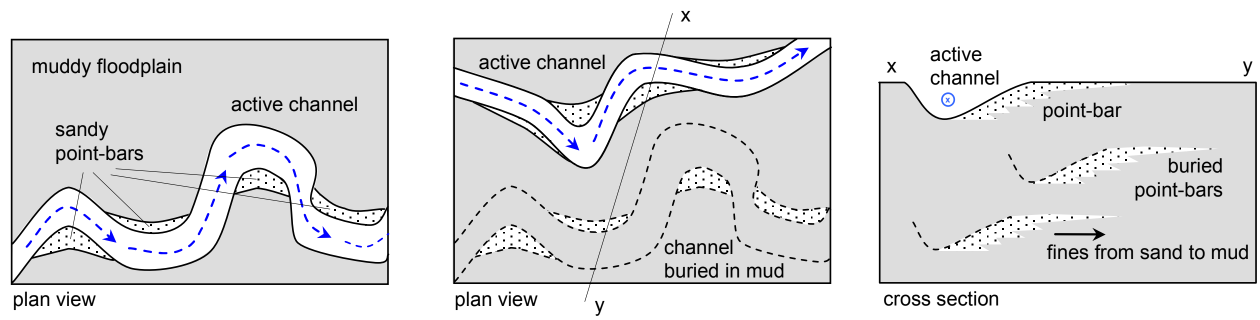
Source: Deutsche Bank

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.

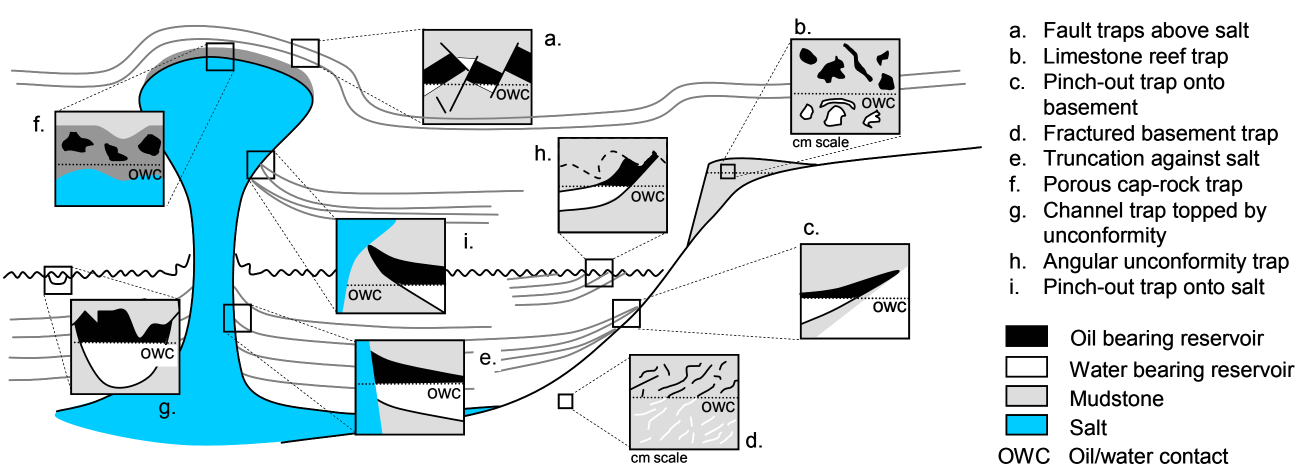
Figure 43: Stratigraphic trap formation via lateral facies changes (plan-view and cross section)



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 asigned 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

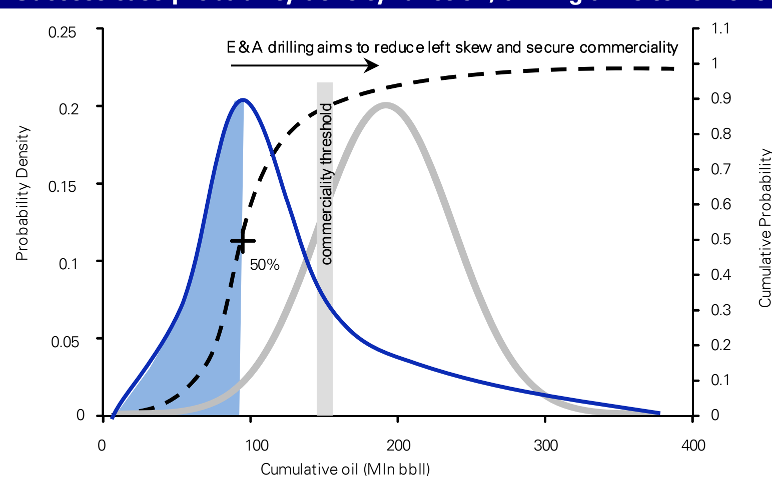
The data would then be presented for a prospect as P10, P50 and P90 resource estimates. In the success case, these equate respectively to at least 10%, 50% and 90% probabilities that the resource quantities identified will equal or exceed the resource estimate.

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.

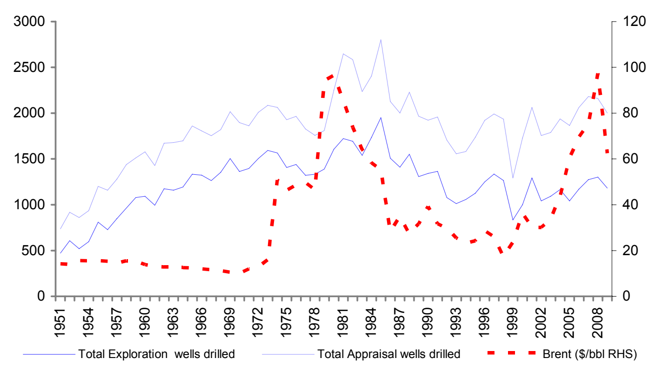
Hydrocarbon basins typically follow a lifecycle of licensing-exploration-development-decline-abandonment. The maturity of a basin is important for a variety of reasons, including:

- 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.

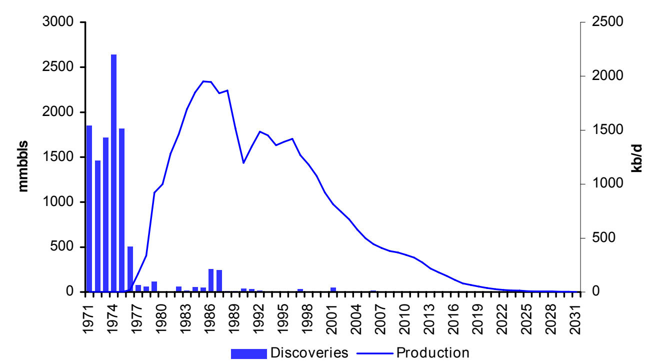
Host governments usually auction leases for exploration acreage at regular intervals and occasionally will commission seismic surveys of the acreage under offer to provide some basic information to prospective bidders. Assuming the acreage is of interest to the industry, bids will all be submitted by 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 - 2010



Source: Deutsche Bank, Wood Mackenzie

Figure 47: North North Sea (UK) discoveries and production, 1971-2031



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.

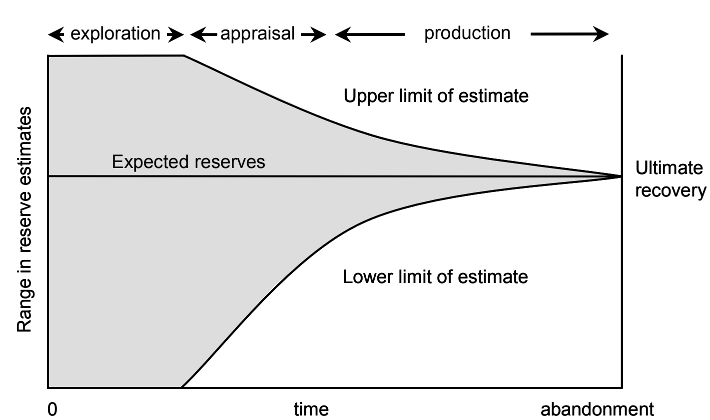
Development – put the infrastructure in place

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 maximise 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

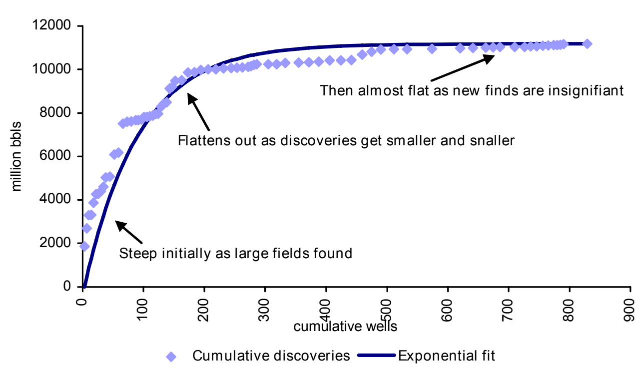


Source: Deutsche Bank

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

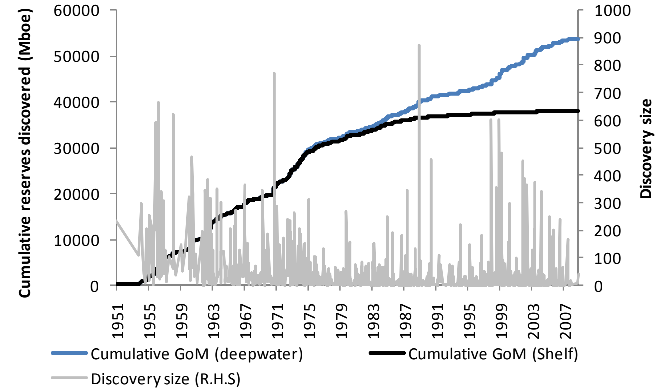
A creaming curve is a plot of cumulative discoveries versus cumulative wells, as shown in the following left hand figure (Northern North Sea). The reserves growth curve shown for the Gulf of Mexico on the right (cumulative discoveries by year) is often also labeled as a creaming curve, which is not strictly correct. However it is accepted by most as such; it has a similar shape and tells broadly the same story.

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 an initial steep rise as the 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.

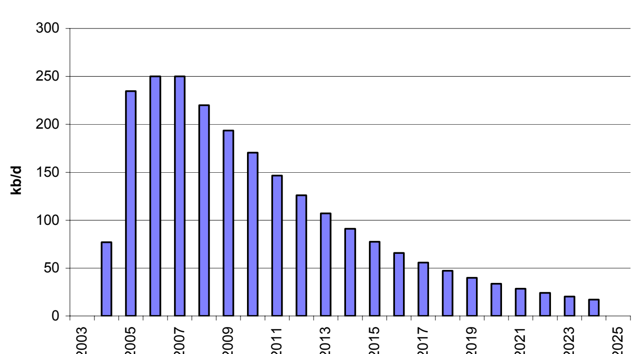
Oil and gas fields have quite different production profiles; oil tends to peak quickly, gas has a longer plateau

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

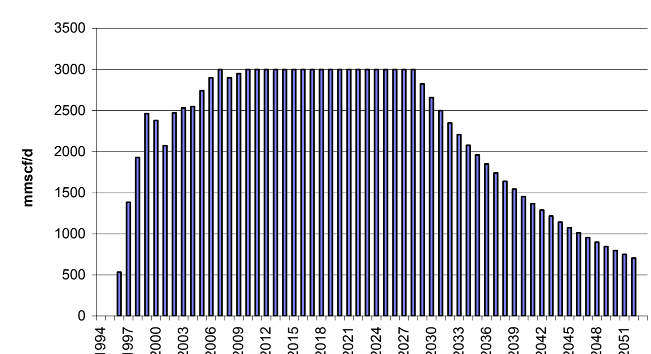
Oil and gas fields have quite different production profiles; oil tends to peak quickly, plateau for a relatively short time then deliver a long tail of decline. A non-associated gas field will usually have a long plateau of 20 years or more, as with the Troll field shown below.

Figure 51: Kizomba A oil production (Angola)



Source: Deutsche Bank, Wood Mackenzie

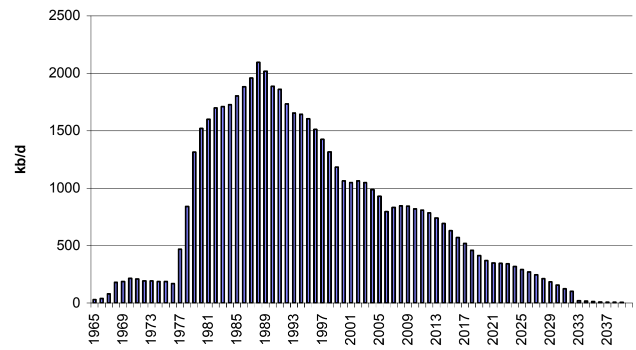
Figure 52: Troll gas production (Norway)



Source: Deutsche Bank, Wood Mackenzie

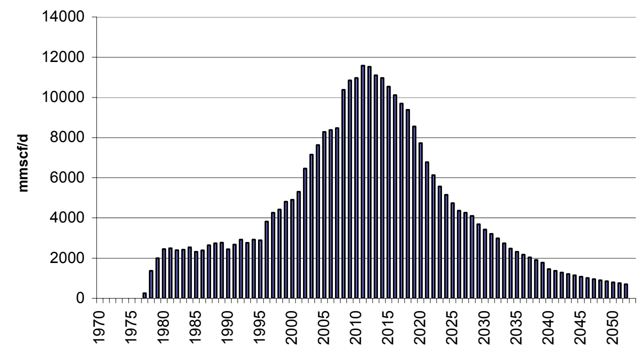
When these profiles are aggregated at the basin level, for oil a similar profile to individual fields is sometimes seen, i.e. a relatively steep rise followed by a long decline. However, for gas the basin production profile can take various forms depending upon the mix of associated and non-associated 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

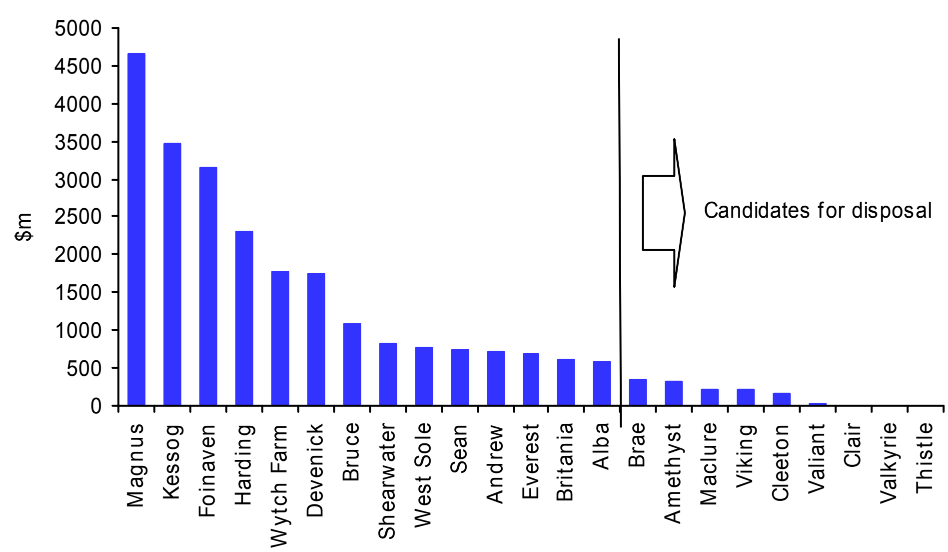
Figure 54: Norway gas production 1970-2050E



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 been 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.

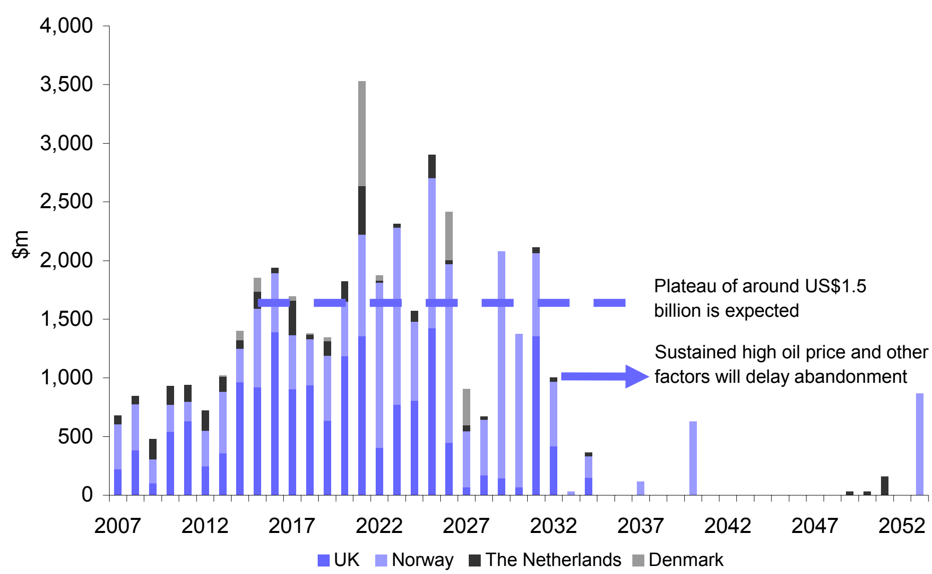
Abandonment. At some point the cost of extracting any remaining oil will not be justified by commodity prices, and the field will need to be abandoned. Onshore this usually entails plugging the wells with cement and steel plugs, and returning the land to its original condition. Offshore the dismantling 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

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

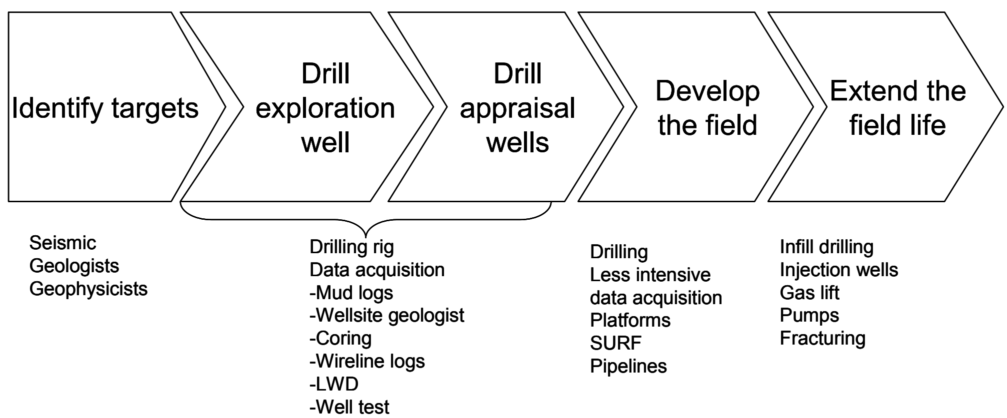
Little changed

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.

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.

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

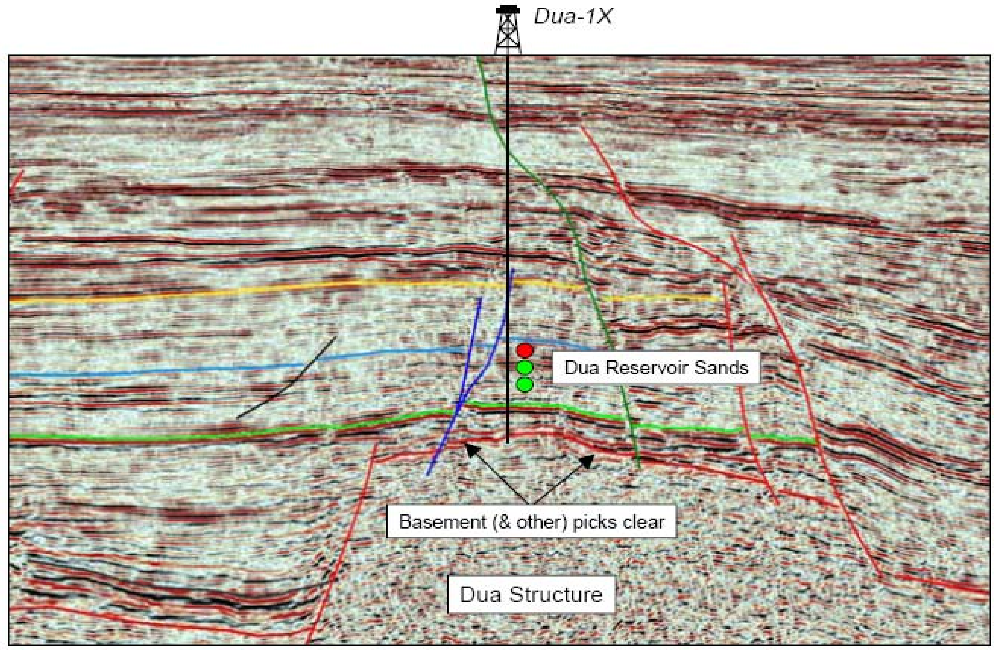
First step - where to look?

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.

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.

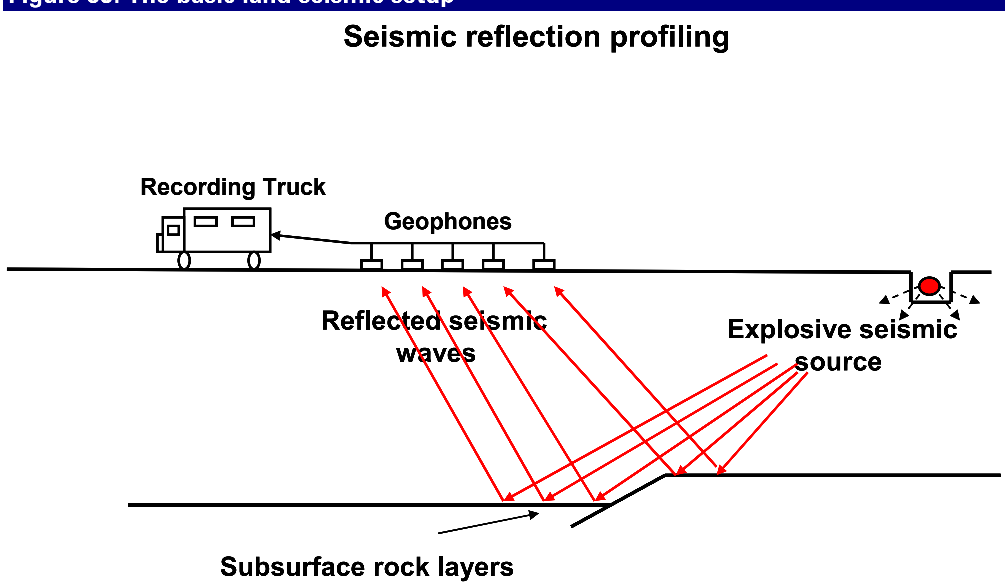
Figure 58: Picking a prospect using a modern-day seismic



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 (by the sudden release of highly compressed air). 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 (which can number in the hundreds) 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
The 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.

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

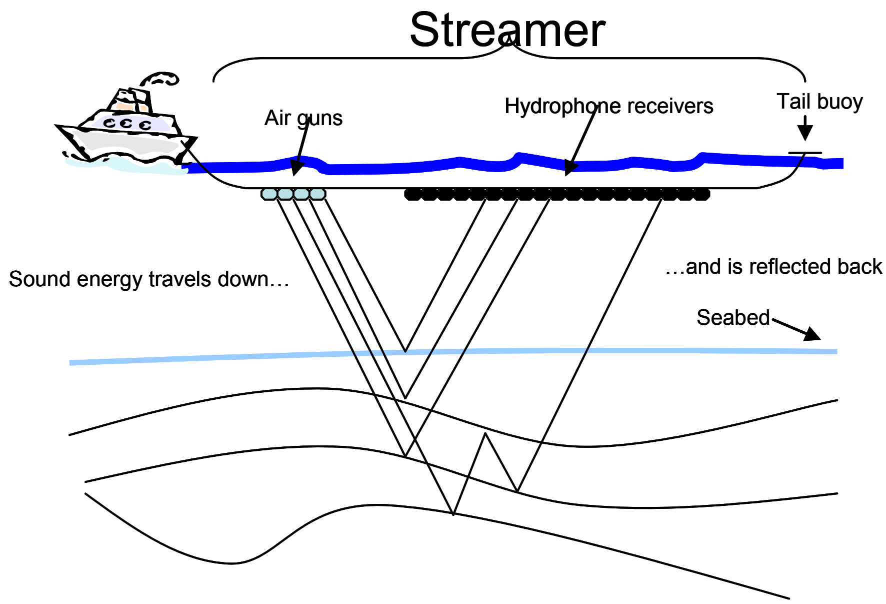
Results are in time, not depth. Seismic processing results in a picture that is scaled in time, rather than depth. Estimates of velocity of sound in rock can be made to try and convert the seismic image to depth (rather than time), but this is inaccurate and can result in the estimated depth of an identified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

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. 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.

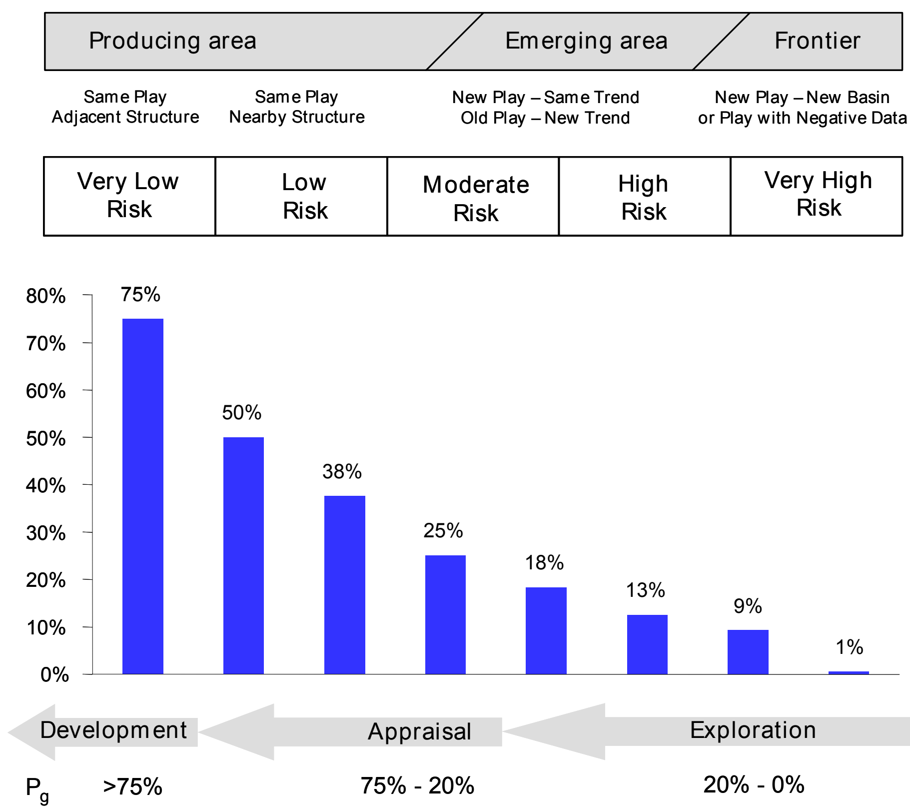
Exploration for, and appraisal and development of, oil and gas is an exercise in risk management.

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 coinside 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.

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

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

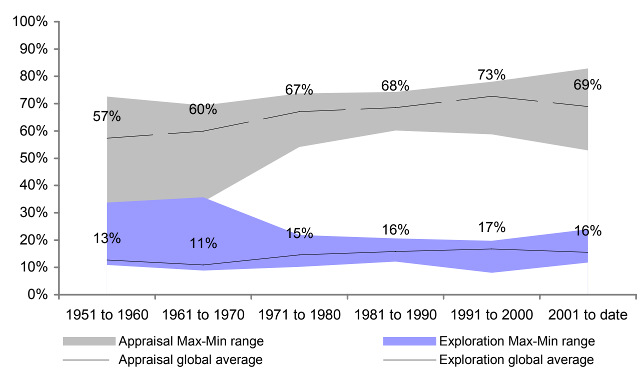
Following the identification of a prospect on seismic, key steps in the reduction of uncertainty include drilling or '**spudding'** the first exploration well often termed the **'wild cat'**, and testing that well – testing providing tangible evidence on which meaningfull recoverable reserve estimates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

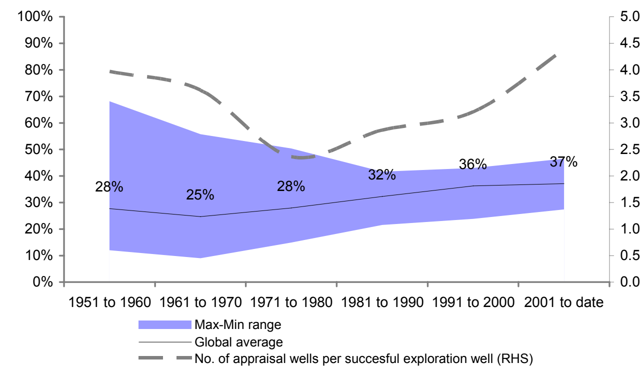
- Commercial exploration success rates rising from 13% to 16%; averaging 15%
- Appraisal success rates rising from 57% to 69%; averaging 66%
- Combined commercial E&A success rising from 28% to 37%; averaging 31%

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



Source: Deutsche Bank, Wood Mackenzie

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

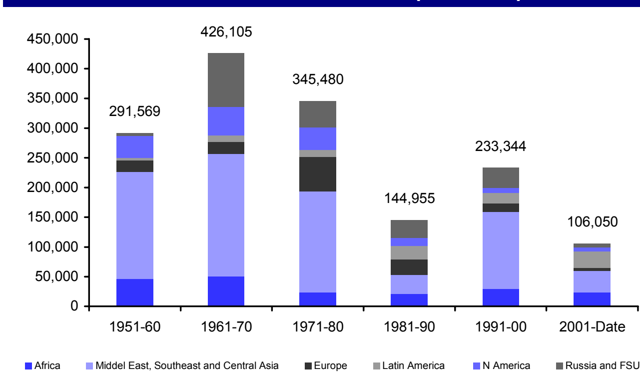


Source: Deutsche Bank, Wood Mackenzie

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.

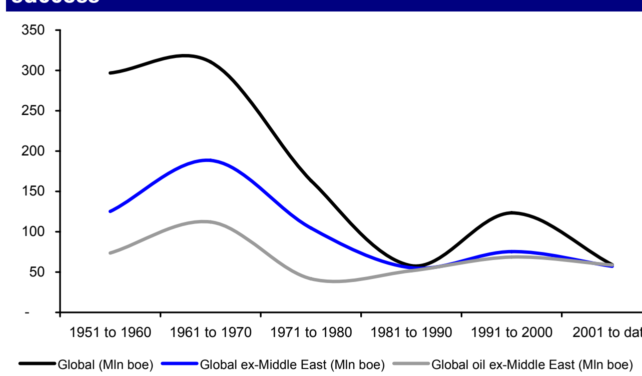
However, at the same time, the number of appraisal wells required to bring this volume to development has almost doubled (*see above*).

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

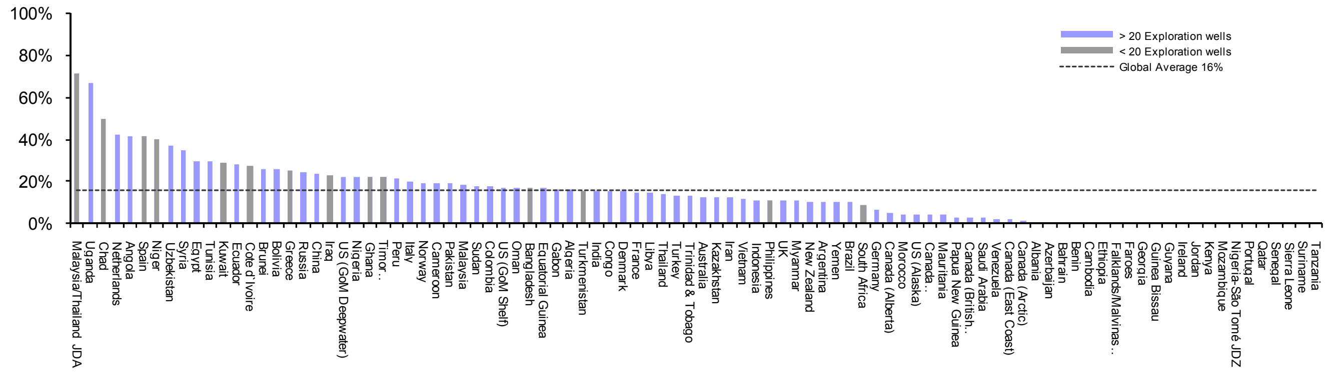


Source: Deutsche Bank, Wood Mackenzie

Country-by-country analysis… statistically inexact

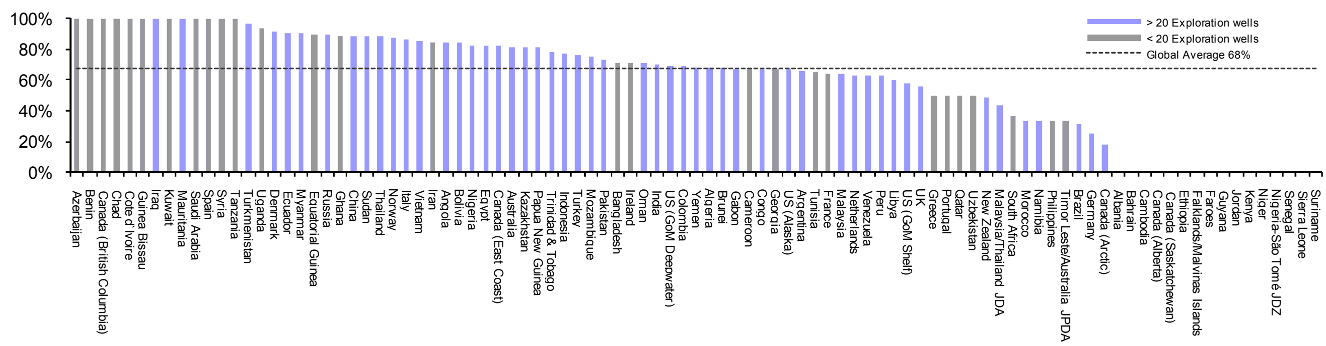
This global/regional analysis can be broken down on a country-by-country basis, however the statistical significance of the data breaks down; a material number of countries emerging as high or low outliers, but with very few wells drilled (*see below*).

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



Source: Wood Mackenzie, Deutsche Bank ** 11,036 wells*

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



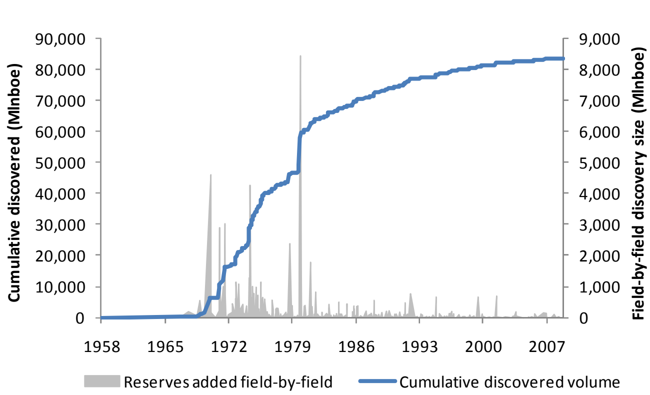
Source: Wood Mackenzie, Deutsche Bank ** 7,513 wells*

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

These static levels of E&A 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.

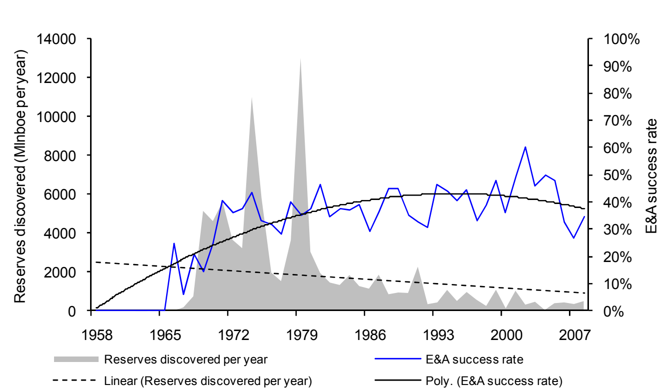
In basins with long exploration histories there is clear evidence that as more wells are drilled, and more data gathered, E&A success rates do increase through time (*see below*). However, as a basin matures the materiality of yet to be discovered volumes falls; large basin-opening finds replaced by 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

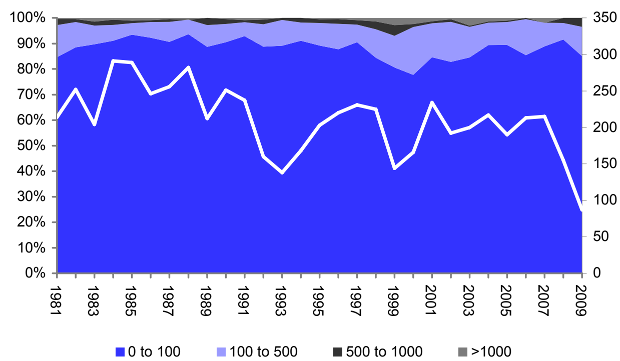
E&A drilling data also highlights the challenge of accessing material exploration volumes:

- Since 1981, 89% of the upstream industry's commercially successful exploration wells have identified fields of 100 Mln boe or less. These discoveries collectively 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.

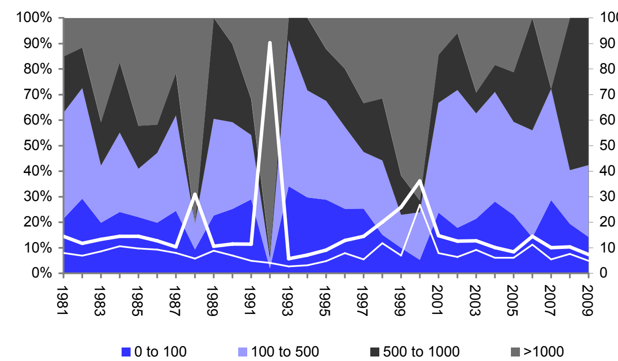
For the smaller players, although the 60 Mln boe discovery-size base-line remains material, growth resulting from this exploration success and perhaps subsequent development inevitably forces them into more challenging prospectivity/frontier areas; where, although the materiality of the prize is larger,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

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



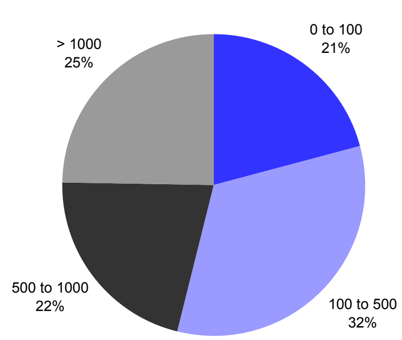
Source: Deutsche Bank, Wood Mackenzie

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



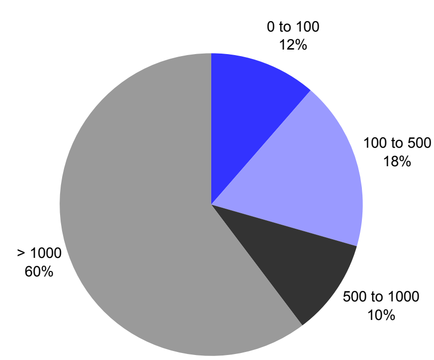
Source: Deutsche Bank, Wood Mackenzie

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

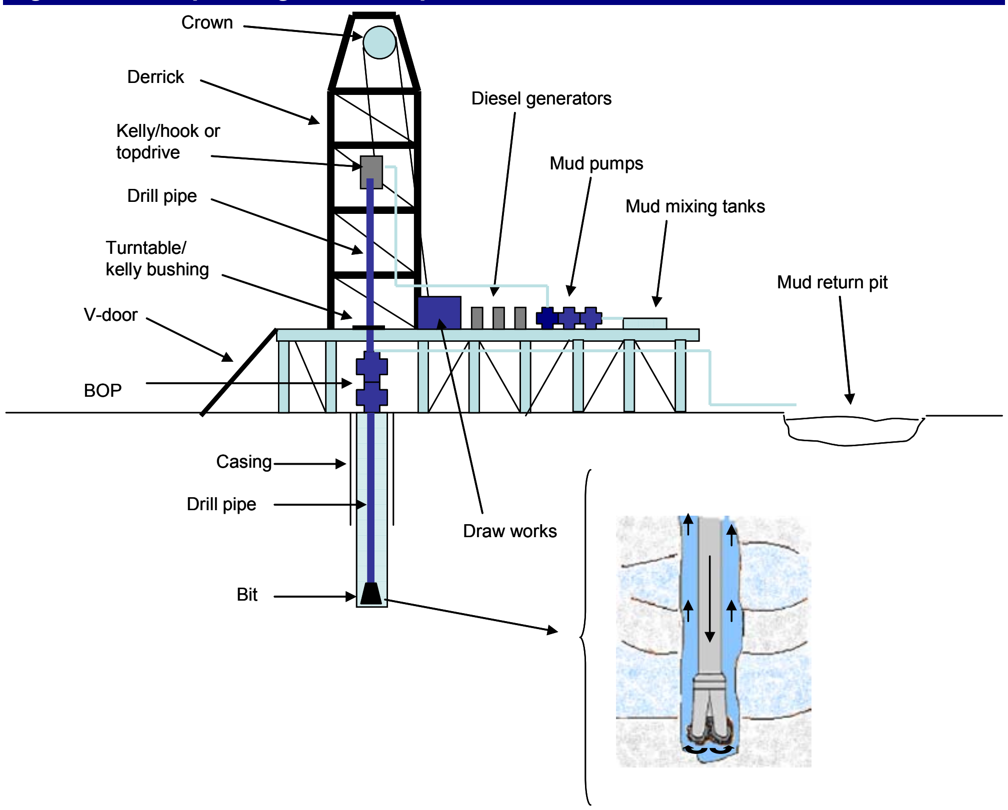
Up until the early 1900s well bores were 'drilled' by cable-drilling, Rotary drilling is the technique used by oil rigs around the world today.

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 (in theory) any gas or 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-base 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.

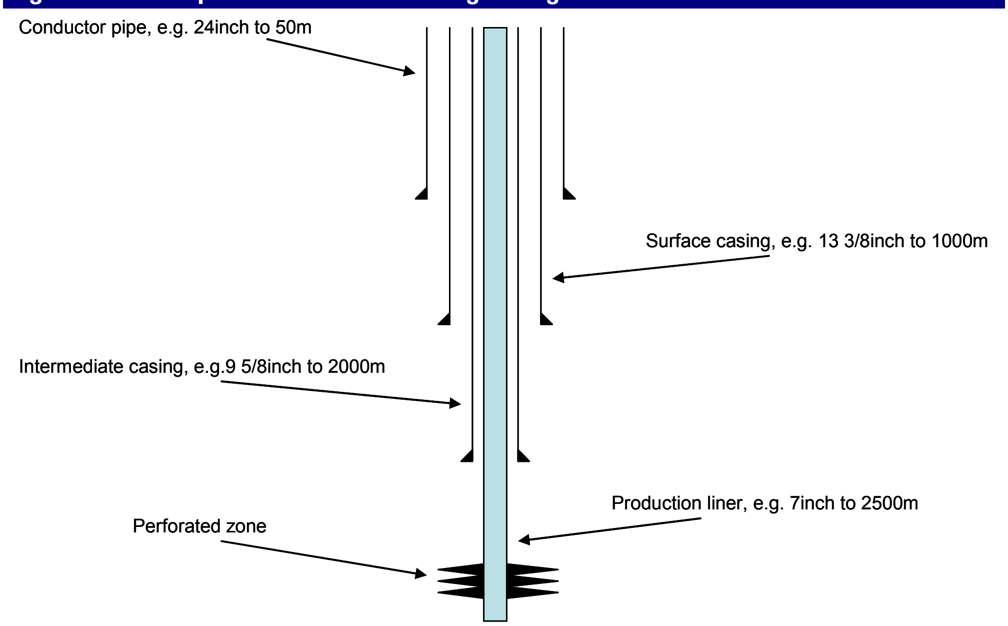
The BHA can include several optional elements that make it more complicated – mud motors for directional drilling (as discussed briefly above). MWD (measurement-whilst-drilling) sensors to provide real-time direction and torque measurements or even LWD (logging-whilst-drilling) instruments that can record 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

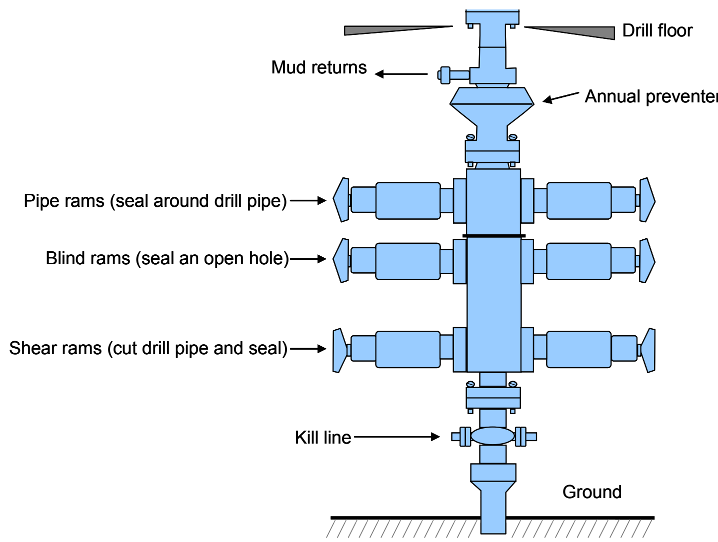
Cementing. The diameters quoted above are just generally used diameters around the world, but various other diameters are also in common use. To 'set' the casing it is first lowered into the well, then the drill-pipe is lowered (without a drill bit on the end) down inside the casing to the bottom, and 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.

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

BOPs. BOP stands for blow-out-preventor 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.

Figure 76: A blow-out preventor (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.

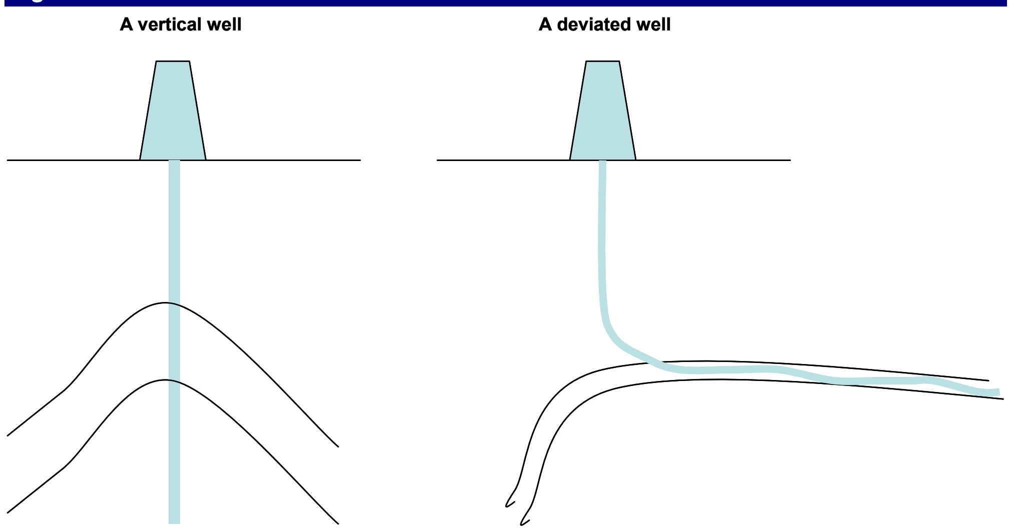
Directional wells

Identifying a potential reservoir trap and drilling straight down into the top of it is an intuitively obvious strategy. In this case 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 be able to 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 technically 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, targets can usually be hit with precision.

Figure 77: Vertical and deviated wells



Source: Deutsche Bank

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.

Drilling in the sea is more complicated than on land

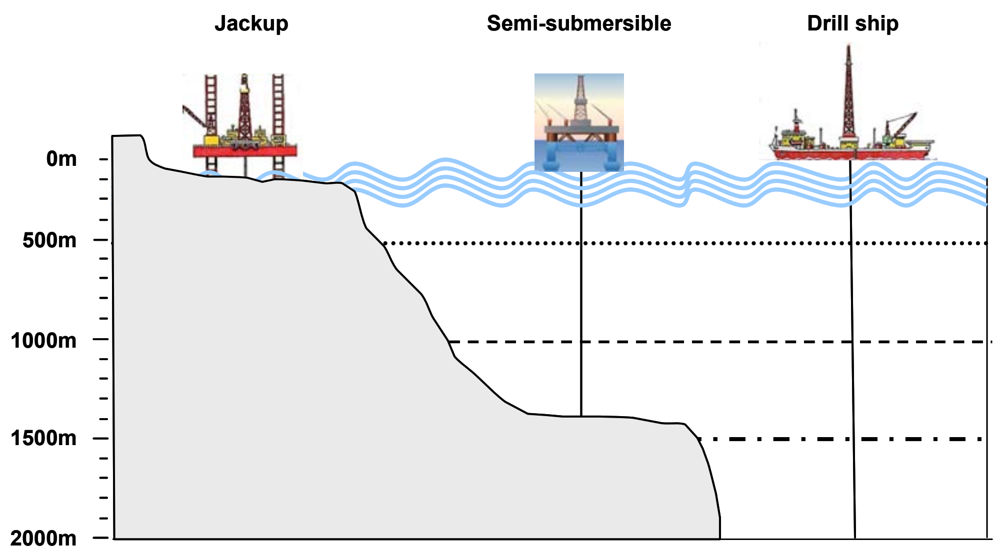
Drilling in the sea is more complicated than on land; the lack of stability (for floaters), the corrosive environment, the more cramped conditions and the more difficult support logistics all dictate this.

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 '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 simply stand on retractable legs (usually three) and hence provide a stable platform from which to drill.

Figure 78: Offshore rigs



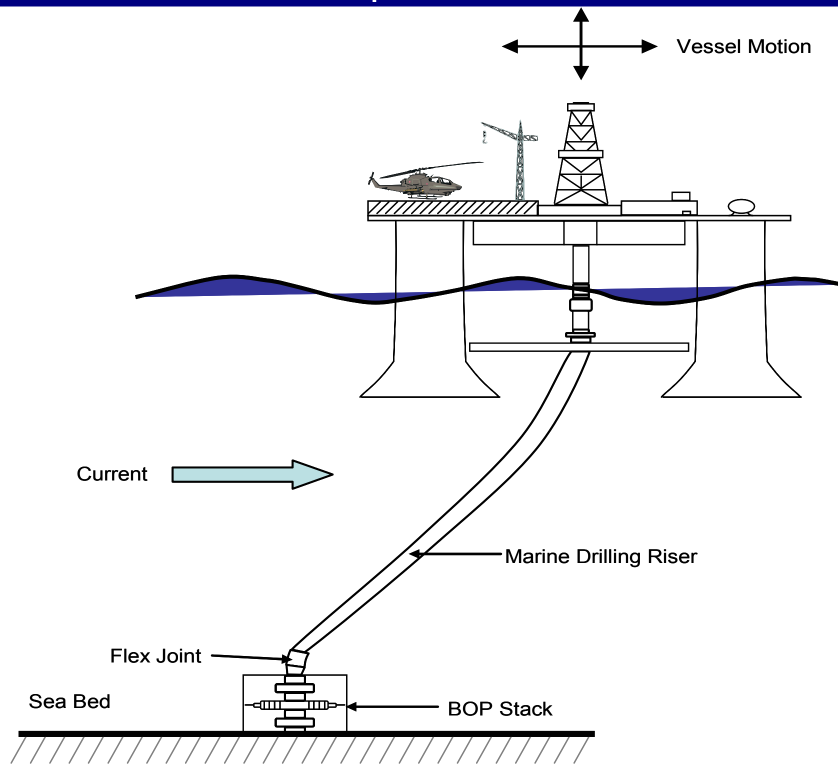
Source: Deutsche Bank

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 water depth. 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 at the drilling location, the legs are lowered to the seabed, and then the hull (upon which all the drilling equipment is installed) is jacked up the legs, so raising itself out of the water.

Unlike Jackups. **Floaters** are not limited to 400ft water depths as they do not rely on standing on long 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, but the main technical challenges versus jackups is the floating nature of the platform. The problem is that the rig will move up and down with swell and 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, which would make drilling a decent well problematic. The solution involves using a large hydraulic system known as a wave-motion-compensator. 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 doghouse for their specialist 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:

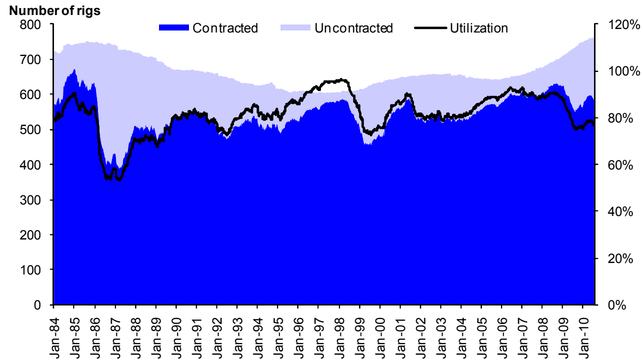
- Catering – supply of food and onboard catering staff and cleaners
- Supply vessels – to supply fuel, food, water, chemicals, drill pipe, casing, cement and act as an offshore storage facility when deck space becomes tight.
- Supply vessels – used to act as emergency support for evacuation in bad weather 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 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.

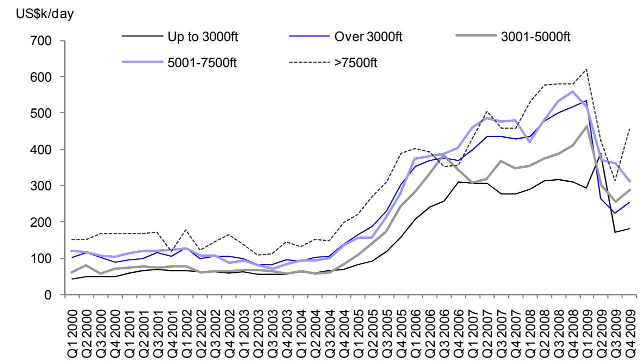
Drilling day rates behave as economists would expect; as demand outstrips supply so day rates quickly rise, and as soon as there is too much supply rates collapse. The high oil price environment of the last few years has led to a surge in demand for all classes of rigs, and has driven up day rates to record levels

Figure 80: Worldwide offshore fleet (jackups, semis, drillships). Contracted vs. subcontracted 1984-2010



Source: Deutsche Bank, ODS Petrodata

Figure 81: Deepwater and intermediate semisub day rates, 2000-2009



Source: Deutsche Bank, ODS Petrodata

The same drivers behind day rates tend to also drive the rest of the service industry supply/demand balance and so when drilling day rates rise, so usually does the cost of all the other associated services – supply boats, helicopters, cementing, mud, wireline logging etc.

IOCs will usually have many rigs working for them, all on different day rates and with different contract ending dates. When we see a large increase in day rates as in the last few years, it therefore takes time to fully impact the cost base of the IOCs, as the portfolio of rig contracts slowly but surely rolls over to the higher day rate environment. Similarly, in the event of a day rate collapse (if drilling companies build too many new rigs for example), the lower day rates on offer will take a year or two to feed through to the IOC bottom line.

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 well-sites will almost always have a geologist working on site (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.

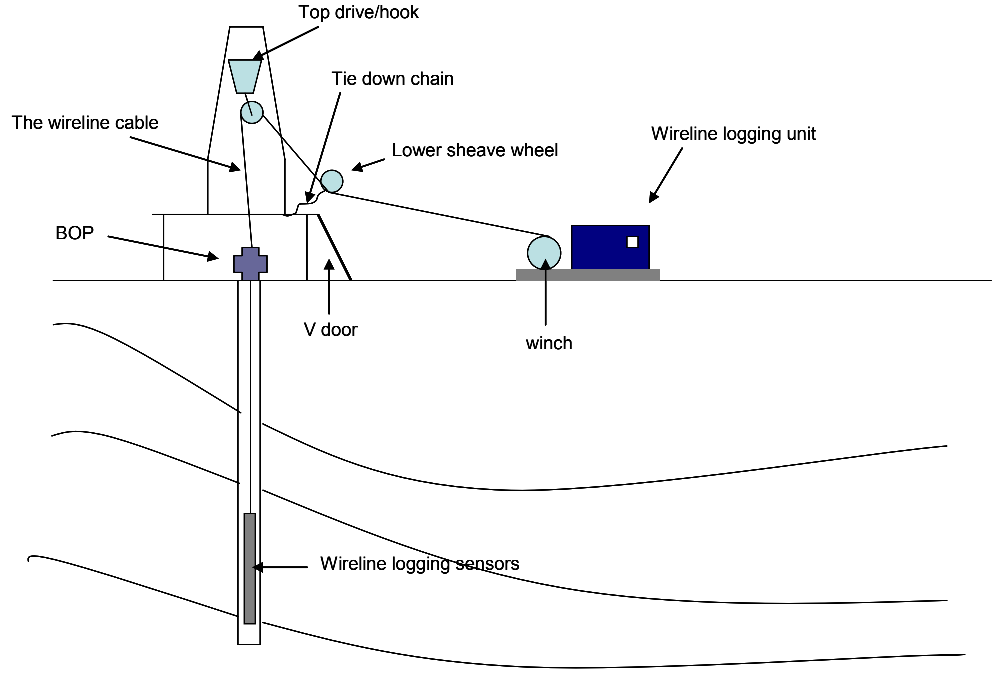
Coring – ideal but expensive
The best way to asses the formation that has been drilled through is to have physical samples. This can be achieved by 'coring', a process where a special drill bit and tubes inside the bottom hole assembly allow a continuous core to be taken whilst drilling. The downsides 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.
- Its 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) wireline log was born.

Figure 82: A typical land wireline logging setup



Source: Deutsche Bank

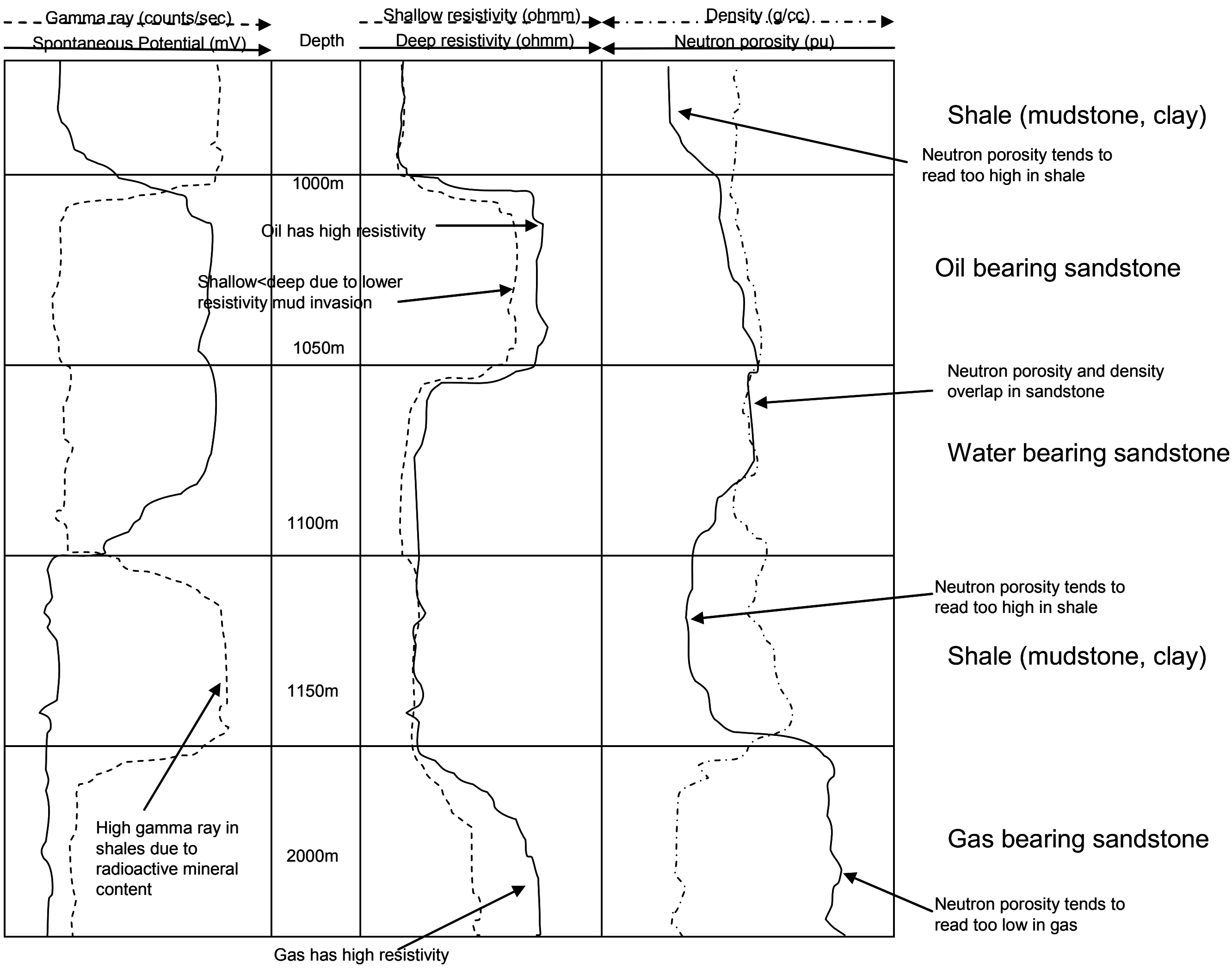
Wireline logging involves the lowering of instruments to the bottom of a well, then pulling them up slowly with a winch, whilst recording in high resolution the information provided

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 wireline 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 83: 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 wireline 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

'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.

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.

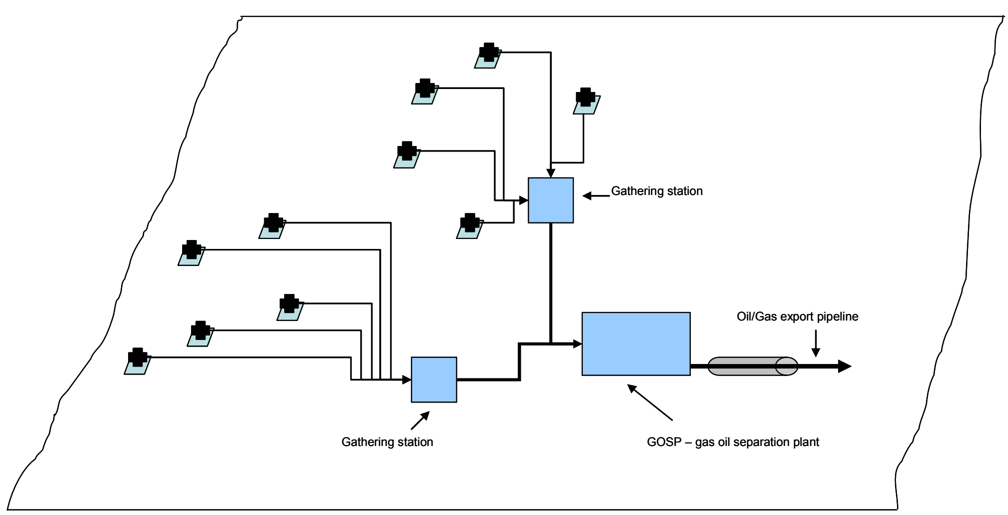
Development wells can be complex, with long horizontal sections to tap thin beds, and even multiple branches spurred off from a single surface well to target several areas of a reservoir from one set of surface production equipment. Fracturing and acidising of the reservoir may be used to help maximise 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 (if required) 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 amount of oil production.

Onshore – oil is usually straight-forward…

Figure 84: 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 an energy wastage standpoint, but also because flaring gas is a material 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.

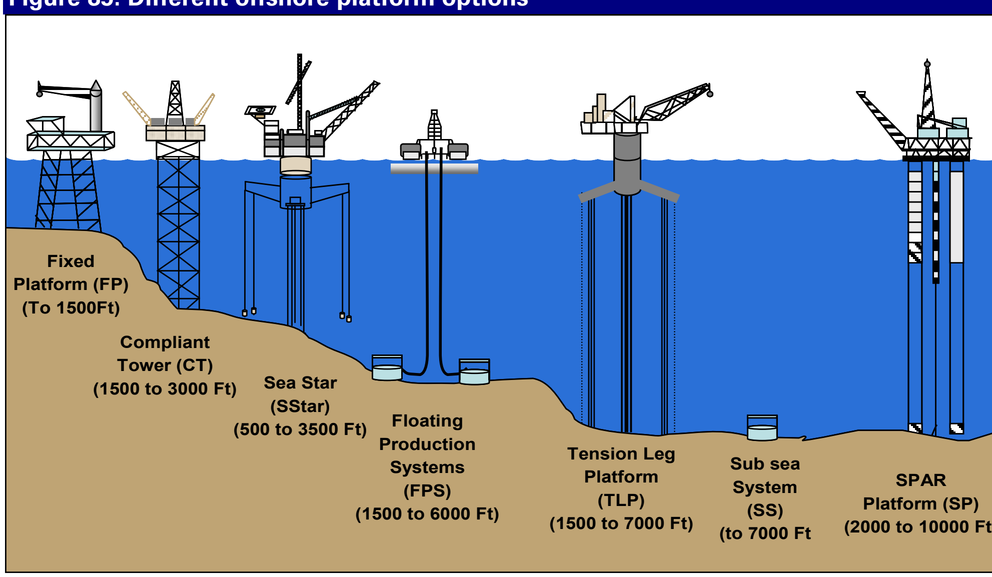
Offshore – as usual, deeper is tougher

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 85: 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.

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

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 oil 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 the producing fields (in the event of hurricanes for example). FPSOs are the most common solution to deepwater developments off the West African coast, and have also been used extensively by Petrobras in developing their deepwater Brazilian fields. The connection between the wells and the FPSO is either via rigid pipes (risers), flexible pipes or a combination of the two.

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

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 relatively cheap to fabricate, but have limited deck area and tend to have relatively large vertical movement in rough seas, so as with FPSOs limiting deck access to wells for maintenance.

TLP stands for 'tension leg platform'

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. This allows a portable rig to be installed on the TLP deck with direct access to problematic wells, without interrupting production of the remaining wells.

SURF – the plumbing

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 platform. This is usually done via small diameter rigid and flexible pipes that are installed by a specialist installation company (such as Acergy or Technip) and such hardware is collectively known as 'SURF' – subsea, umbilicals, risers and flowlines.

Subsea units are production units that sit on the sea bed, feeding oil or gas from a well through a flowline to a manifold, which collects the hydrocarbons from numerous wells. Each manifold is connected to an umbilical and a riser. The former is a pipeline which carries hydraulic, power and communication cables, which enables the operator on the surface facility to control valves on the manifold. The latter is the piping through which oil or gas travels to reach the surface.

Subsea completions - bypass the platform altogether?

SURF infrastructure can be spread over a wide area, and indeed several West African fields are tied back via subsea pipelines over 10kms to central platforms. 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.

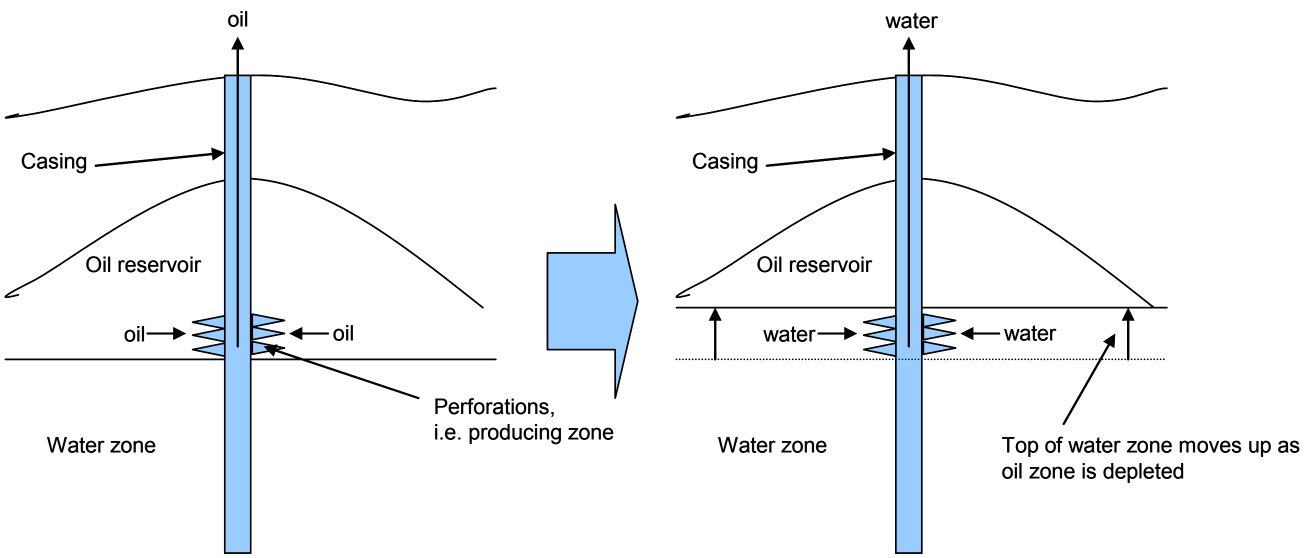
For oil however, long subsea tiebacks are more difficult. The cold seabed temperatures make the oil more viscous, to the extent that some grades simply will not flow without extremely powerful pumps and/or commingling with a solvent – but of course without a platform nearby such solutions imply that long power cables and chemical injection lines need to be laid from shore, so reducing project feasibility and economics.

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 86: 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.

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 % of the in-place volumes, this is expressed as a **recovery factor**. A central focus within development is to maximize this factor.

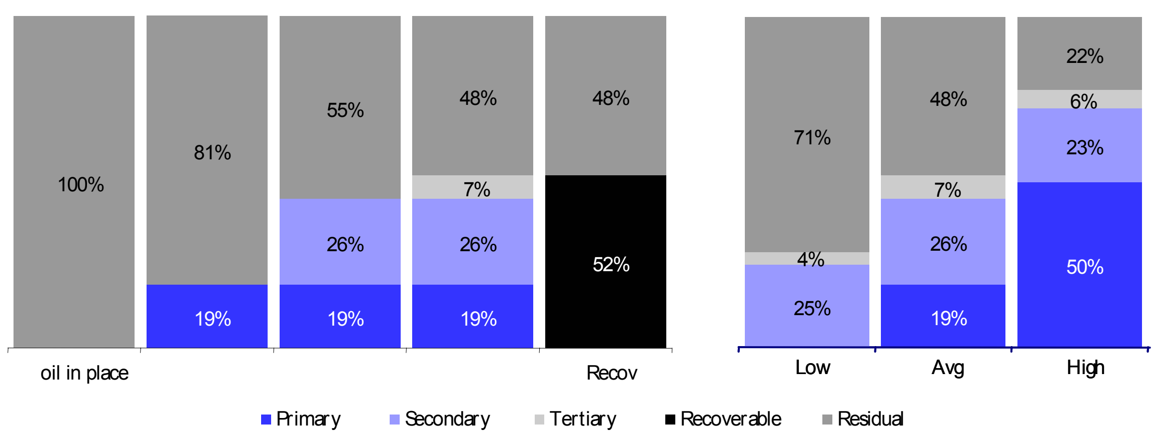
Three forms of recovery are recognized:

- **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.
- **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 an oil 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 recovery scenarios around this 'average'.

The relative buoyancy of gas means that recovery factors are materially higher – see below.

Figure 87: Typical primary, secondary, tertiary cumulative recovery factors and low-high range



Source: Deutsche Bank and Company data

Secondary and tertiary recovery are together refered 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 grain fabric of the rock and expansion of the pore fluids when the reservoir pressure drops.

Primary recovery rates typically ranges between 25% and 40

In practice, most primary recovery is via a combination of these drive 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 a maximum of 75%. For gas, gravity drainage, water drive and depletion drive can deliver recovery in excess of 80%.

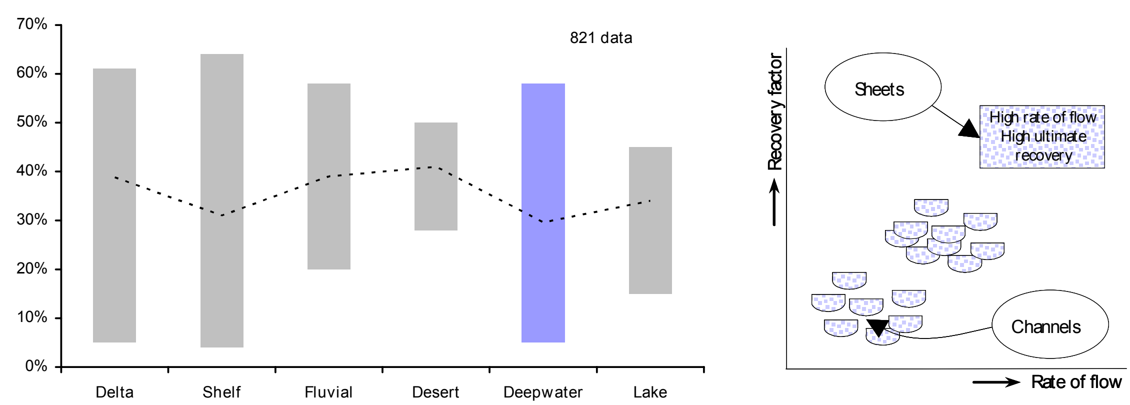
Depositional controls on recovery factor

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 88: 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 hydrocarbon recovery by maximizing displacement efficiency in a cost efficient way. Below we briefly summarize the principle EOR mechanisms which are currently employed.

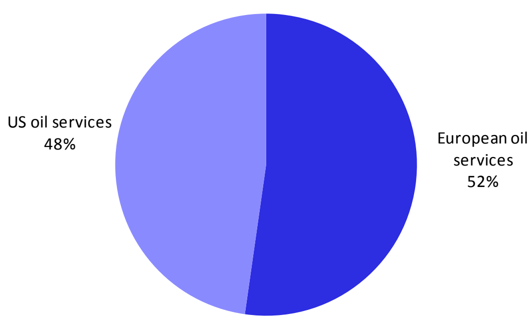
- **Thermal EOR** is principally employed within accumulations of heavy oil – this being heated to reduce its viscosity and increase its mobility. Common techniques include steamflood and cyclic steam injection - see section on oil sands.
- **Miscible liquid flooding** uses the principle that some fluids 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 greater 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 or dispersions 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?

The oil services sector provide the assets and/or staff (with varying degrees of complexity and intellectual capability) across various points of the life cycle of oil and/or gas. Their clients will include the integrated oil companies, national oil companies, the independents, refiners and petrochemical companies. The oil services span the entire oil and gas supply chain and will therefore cater for a variety of companies that do not necessarily fall into the aforementioned client base. They will often sub-contract to each other various parts of the project whether it be engineering, procurement, installation and/or construction. Of course the supply chain will ultimately lead to the owner/operator. It is important to note that every client relationship will comprise personnel from both sides—i.e., the work will never fully be outsourced.

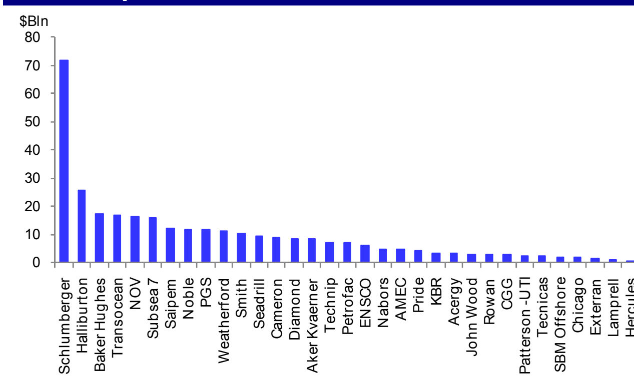
Put simply the capital expenditure of the aforementioned client base will drive the backlog of an oil service company. Backlog is defined as the aggregate value of the company's contracts (existing and recently awarded) at a specific point in time. Backlog will in turn drive a service company's revenue as projects that can have a shelf life of between 3 months to five years through to completion. The rate at which a contract crystallises into revenue and ultimately profit will depend on the nature of the contract, and we expand on this in the next section.

Figure 89: Market cap split between the US and European oil service sectors



Source: Deutsche Bank, Bloomberg Finance LP

Figure 90: US and European oil service companies market cap ($bn)



Source: Deutsche Bank

Although there is some overlap, the US service companies tend to offer drilling and completion services (e.g. mud logging, supply vessels, pressure pumping etc) and the Europeans focus predominantly on engineering & construction and seismic activities. A fully integrated E&C company will participate in the engineering design, construction and installation (including commissioning) of an oil and gas development effectively being involved from start to finish.

Making sense of it all

As illustrated in the previous chapter on "Getting it out", the oil life cycle can be broadly split into several themes: 1) Exploration and appraisal, 2) Developing the field 3) Production management 4) Managed decline and decommissioning. Though each segment requires a certain level of capital intensity, a key common denominator is the heavy reliance on skilled personnel. This is typically a combination of staff from the operator(s) and contractor(s). The relationship between operator and service contractor is multilayered and very complex, with the role of the operator often being one more of project management and funding while the contractor is responsible for implementing the majority of the work. We illustrate below, the key global players within the service industry, highlighting their involvement across the different parts of the oil and gas chain.

Oil Service companies - Europe

Figure 91: The oil service chain by company in Europe

			Abbot Group	Acergy	Aker Solutions	Amec	CGG Veritas	Expro Intl	Fred Olsen	Heerema	Lamprell	Maire Tecnimont	Maritime Industrial Services
Identifying targets	Seismic	Onshore seismic					■						
		Offshore Seismic					■						
Exploration and Appraisal Drilling	Exploration and appraisal: drilling services	Onshore Drilling	■										
		Shallow water drilling	■						■				
		Deepwater drilling							■				
		Ultra deepwater drilling							■				
	Exploration: associated well head services	Surface servicing						■					
		Surface equipment	■		■								■
		Subsurface servicing						■					
		Subsurface equipment and products						■					
	Exploration: Energy construction services	Newbuilds	■								■		■
		Upgrades	■								■		■
		Others	■								■		■
Develop the field	Engineering & Construction Services	Onshore/offshore operations and maintenance (OPEX)		■	■	■				■			
		Deepwater SURF		■	■					■			■
		Deepwater facilities			■	■				■	■		■
		Shallow water SURF/Facilities		■	■	■				■			■
		Frontier Developments			■	■							
		LNG			■							■	
		Re-gas terminals										■	
		Refining & petrochemicals			■							■	
		Onshore facilities & Infrastructure	■		■	■							■
		Gas to liquids											
		Heavy Oil Sands: extraction				■							
		Heavy Oil Sands: refining											
	Non oil and gas	Power				■							
		Process and others			■	■							

Source: Deutsche Bank

Figure 92: The oil service chain by company in Europe (cont'd)

			Petrofac	PGS	Saipem	SBM Offshore	Seadrill	Subsea 7	Technip	Tecnicas Reunidas	TGS-Nopec	Wellstream	Wood Group
Identifying targets	Seismic	Onshore seismic		■							■		
		Offshore Seismic		■							■		
Exploration and Appraisal Drilling	Exploration and appraisal: drilling services	Onshore Drilling			■								
		Shallow water drilling			■		■						
		Deepwater drilling			■		■						
		Ultra deepwater drilling					■						
	Exploration: associated well head services	Surface servicing											■
		Surface equipment					■						
		Subsurface servicing									■		■
		Subsurface equipment and products											■
	Exploration: Energy construction	Newbuilds				■							
		Upgrades				■							
		Others				■							
Develop the field	Engineering & Construction Services	Onshore/offshore operations and maintenance (OPEX)	■		■			■					■
		Deepwater SURF			■	■		■	■			■	■
		Deepwater facilities			■	■			■			■	■
		Shallow water SURF/Facilities			■	■		■	■			■	■
		Frontier Developments	■		■								
		LNG			■				■	■			
		Re-gas terminals								■			
		Refining & petrochemicals			■				■	■			■
		Onshore facilities & Infrastructure	■		■	■			■	■			■
		Gas to liquids											
		Heavy Oil Sands: extraction											■
		Heavy Oil Sands: refining							■				
	Non oil and gas	Power								■			
		Process and others											

Source: Deutsche Bank

Oil Service companies - US

Figure 93: The oil service chain by company in the US

			Baker Hughes	Bechtel	Cameron	Chicago Bridge & Iron	Diamond Offshore	FMC Technologies	Fluor	Foster Wheeler	Halliburton	Helmerich Payne	J Ray Mcdermott
Identifying targets	Seismic	Onshore seismic	■								■		
		Offshore Seismic	■								■		
Exploration and Appraisal Drilling	Exploration and appraisal: drilling services	Onshore Drilling					■					■	
		Shallow water drilling					■						
		Deepwater drilling					■					■	
		Ultra deepwater drilling					■					■	
	Exploration: associated well head services	Surface servicing	■								■	■	
		Surface equipment	■		■			■			■	■	
		Subsurface servicing	■								■		
		Subsurface equipment and products	■								■		
	Exploration: Energy construction services	Newbuilds											■
		Upgrades											■
		Others											■
Develop the field	Engineering & Construction Services	Onshore/offshore operations and maintenance (OPEX)		■									
		Deepwater SURF				■				■	■		■
		Deepwater facilities			■			■	■				■
		Shallow water SURF/Facilities	■			■			■	■	■		■
		Frontier Developments											
		LNG		■		■			■	■			■
		Re-gas terminals		■		■			■	■			
		Refining & petrochemicals		■		■			■	■			
		Onshore facilities & Infrastructure				■			■				■
		Gas to liquids				■			■	■			
		Heavy Oil Sands: extraction							■				
		Heavy Oil Sands: refining											
	Non oil and gas	Power											
		Process and others											

Source: Deutsche Bank

Figure 94: The oil service chain by company in the US (cont'd)

			Jacobs Engg	KBR	Nabors	Noble Drilling	Precision Drilling	Pride Intl	Schlumberger	SNC Lavalin	Transocean	Weatherford
Identifying targets	Seismic	Onshore seismic							■			
		Offshore Seismic							■			
Exploration and Appraisal Drilling	Exploration and appraisal: drilling services	Onshore Drilling			■		■	■				
		Shallow water drilling			■	■		■			■	
		Deepwater drilling			■	■		■			■	
		Ultra deepwater drilling			■	■		■			■	
	Exploration: associated well head services	Surface servicing						■	■			■
		Surface equipment			■			■	■			■
		Subsurface servicing			■			■	■			■
		Subsurface equipment and products			■			■	■			■
	Exploration: Energy construction services	Newbuilds										
		Upgrades										
		Others										
Develop the field	Engineering & Construction Services	Onshore/offshore operations and maintenance (OPEX)	■							■		■
		Deepwater SURF										
		Deepwater facilities		■								■
		Shallow water SURF/Facilities		■								
		Frontier Developments										
		LNG		■								
		Re-gas terminals										
		Refining & petrochemicals	■	■						■		
		Onshore facilities & Infrastructure										
		Gas to liquids										
		Heavy Oil Sands: extraction	■	■						■		
		Heavy Oil Sands: refining								■		
	Non oil and gas	Power										
		Process and others										

Source: Deutsche Bank

Oil Service companies - Asia

Figure 95: The oil service chain by company in Asia

			China Petroleum	Chiyoda	Consolidated Contractors Co	Daewoo	Dubai Dry Docks	GS Engineering and Construction	Hyundai	JGC
Identifying targets	Seismic	Onshore seismic	■							
		Offshore Seismic	■							
Exploration and Appraisal Drilling	Exploration and appraisal: drilling services	Onshore Drilling	■							
		Shallow water drilling	■							
		Deepwater drilling	■							
		Ultra deepwater drilling	■							
	Exploration: associated well head services	Surface servicing								
		Surface equipment								
		Subsurface servicing								
		Subsurface equipment and products								
	Exploration: Energy construction services	Newbuilds				■	■		■	
		Upgrades				■	■		■	
		Others				■	■		■	
Develop the field	Engineering & Construction Services	Onshore/offshore operations and maintenance (OPEX)	■							
		Deepwater SURF	■						■	
		Deepwater facilities	■			■		■		
		Shallow water SURF/Facilities	■			■		■	■	
		Frontier Developments								
		LNG		■	■			■	■	■
		Re-gas terminals		■	■				■	
		Refining & petrochemicals	■		■			■		■
		Onshore facilities & Infrastructure			■	■			■	■
		Gas to liquids		■					■	■
		Heavy Oil Sands: extraction								
		Heavy Oil Sands: refining	■	■	■					
	Non oil and gas	Power								
		Process and others								

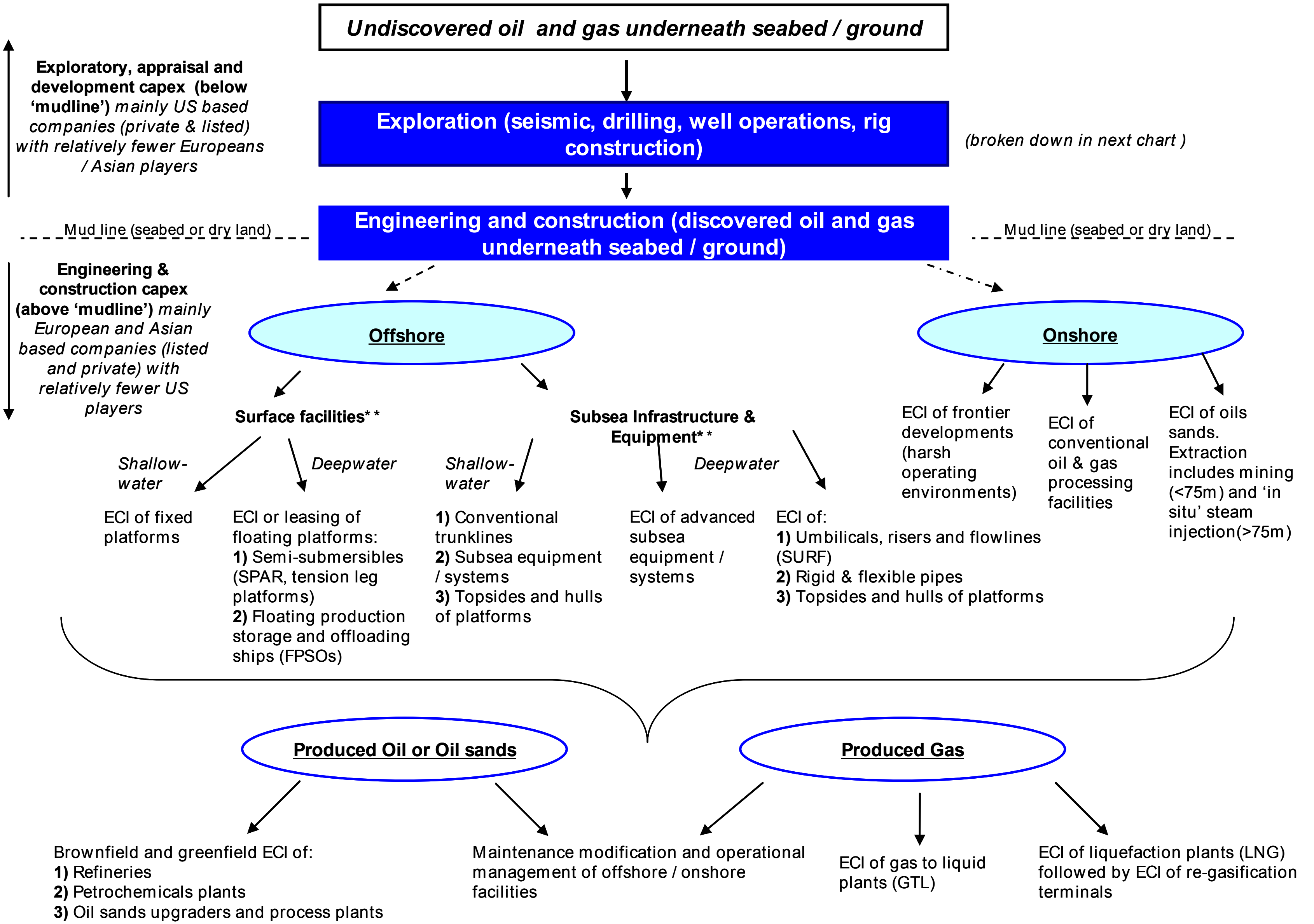
Source: Deutsche Bank

Figure 96: The oil service chain by company in Asia (cont'd)

			Keppel Corp	Modec	SK Engineering and Construction	Samsung	Scomi Group	Sembcorp	Worley Parsons	Yantai Raffles
Identifying targets	Seismic	Onshore seismic								
		Offshore Seismic								
Exploration and Appraisal Drilling	Exploration and appraisal: drilling services	Onshore Drilling								
		Shallow water drilling								
		Deepwater drilling								
		Ultra deepwater drilling								
	Exploration: associated well head services	Surface servicing					■			
		Surface equipment								
		Subsurface servicing								
		Subsurface equipment and products					■			
	Exploration: Energy construction services	Newbuilds	■		■	■		■		■
		Upgrades	■		■	■		■		■
		Others	■		■	■		■		■
Develop the field	Engineering & Construction Services	Onshore/offshore operations and maintenance (OPEX)			■					
		Deepwater SURF		■					■	
		Deepwater facilities		■		■	■	■	■	
		Shallow water SURF/Facilities		■		■	■	■	■	
		Frontier Developments								
		LNG							■	
		Re-gas terminals							■	
		Refining & petrochemicals			■				■	
		Onshore facilities & Infrastructure				■		■	■	■
		Gas to liquids								
		Heavy Oil Sands: extraction							■	
		Heavy Oil Sands: refining							■	
	Non oil and gas	Power								
		Process and others								

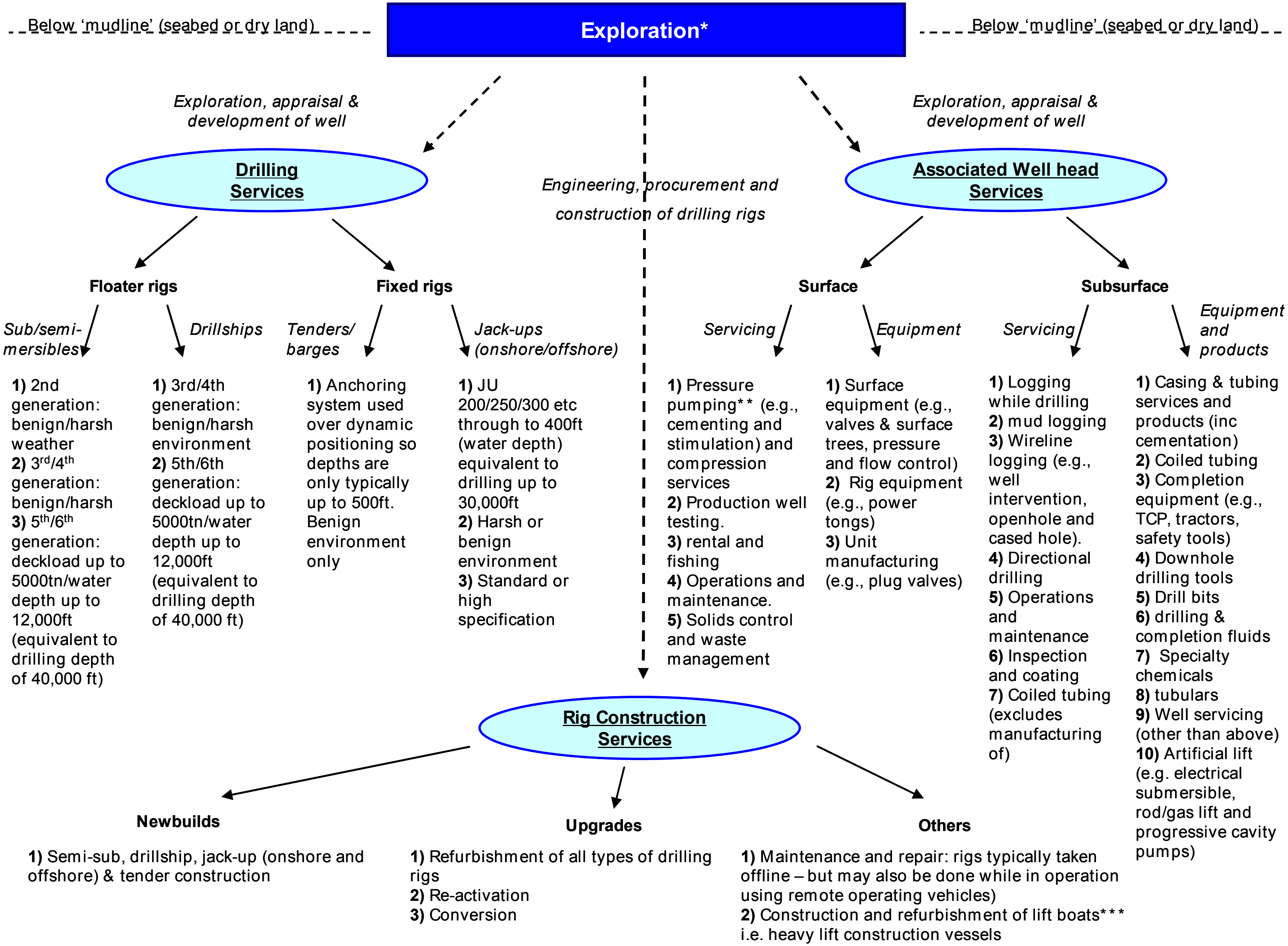
Source: Deutsche Bank

Figure 97: Backbone functions of the service sector across the oil life cycle



Source: Deutsche Bank, *ECI is engineering, construction and installation; **Installation phase completed using various heavy lifting/pipe-laying/inspection vessels (owned or leased by E&C company) also known as lift boats

Figure 98: Backbone functions of the service sector within exploration based activities

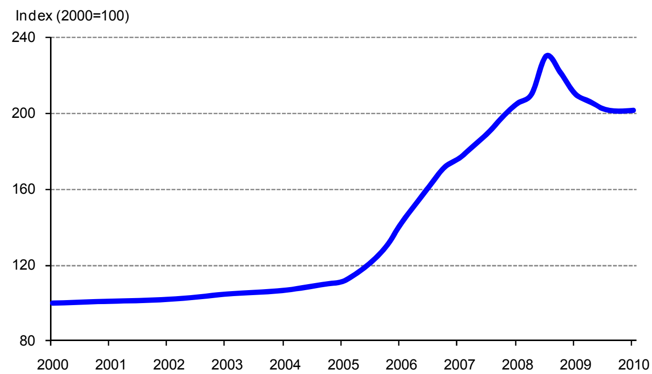


Source: Deutsche Bank, *Note we have excluded seismic operations; **we have placed this within 'surface' activities but can arguably be placed in 'subsurface' (servicing) also; ***'lift boats' are different to 'rigs' in that they are used for E&C type operations within the offshore segment (see figure18). Underlying driver for this market will therefore not be exploration but offshore E&C; for simplicity we have included lift boats here as they are typically built by the same companies that construct rigs

A word on costs...

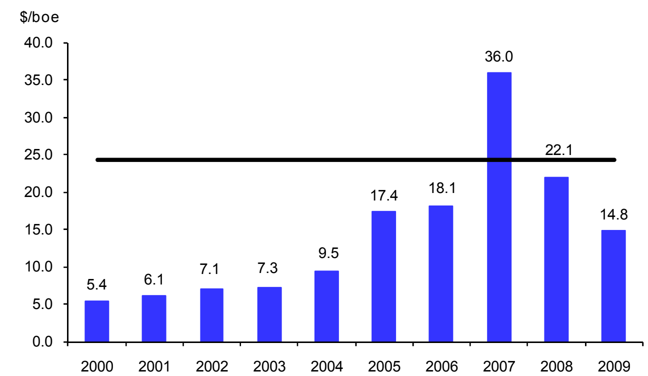
The cost of the various field operations described above has been very much in the limelight over the last few years. Stories of the over-heated services market in Canada or of capital over-spend on complex projects such as ENI's Kashagan or Statoil's Snoevhit LNG facility have abounded. Indeed, a glance at average finding and development costs at the IOCs or at CERA's cost index highlights that between 2004 and 2008 capex costs in the oil and gas industry more than doubled. Put another way, CERA estimates that costs rose by c.12% pa between 2000 and 2008, while our analysis of company data suggests an increase of 19% in finding and development costs over the same period.

Figure 99: IHS/CERA upstream capital cost index – 2000 to Q1 2010



Source: CERA, Deutsche Bank estimates

Figure 100: Industry average Finding and development costs 2000-2009



Source: Company data, Deutsche Bank estimates

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

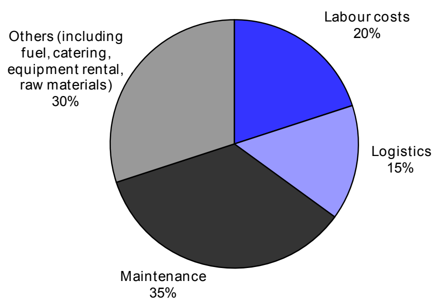
In order to understand the drivers of this increase we must first understand exactly what are the costs incurred in extracting a barrel of oil. Excluding taxation (which we consider later on) the three key cost components are exploration, capital and operating costs.

- **Exploration –** the cost of finding resources. Also referred to as finding costs, it includes signature bonuses, seismic and exploration and appraisal drilling. 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 can comprise such things as the project FEED (front end engineering and design), procurement of equipment, construction of facilities, drilling, vessel/rig purchase and engineering and project management costs. In terms of accounting, capital costs are effectively the equivalent of FAS 69 development costs and can be capitalised on the balance sheet and depreciated over time in line with production.
- **Operating Costs –** these are essentially the day-to-day operating expenses and comprise such costs as consumables (e.g. fuel, gas and chemicals used in the extraction of gas and/or gas), aircraft to fly staff to/from the rig, catering on the rig, transportation and other logistics and day-to-day maintenance of the rig/vessel. 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, as a result of limited company disclosure and more significantly the very disparate nature of the producing locations (onshore, offshore, arctic, desert, etc) this industry is not one that lends itself easily to analysis. As illustrated below, given the disparate nature of costs both by geography (e.g. Australia vs. US GoM vs. Middle

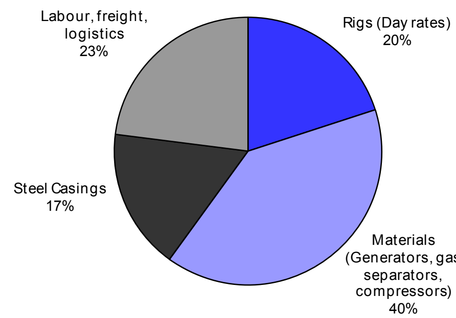
East) and type of development (deepwater vs. shallow water vs. onshore), trying to get a good overview or even compare projects is nigh on impossible.

Figure 101: Average OPEX split in Europe



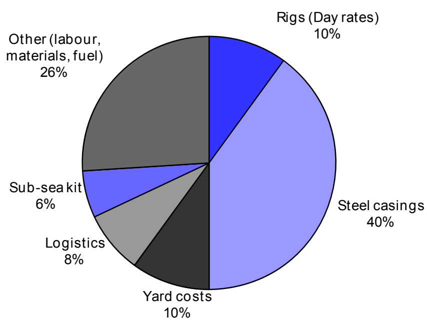
Source: RDS, Deutsche Bank estimates

Figure 102: Average OPEX split in US onshore



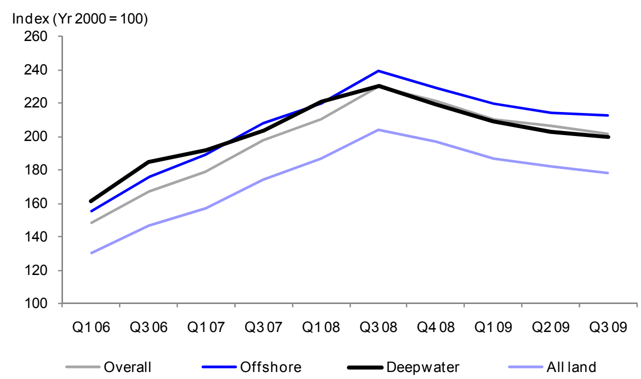
Source: RDS, Deutsche Bank estimates

Figure 103: Average OPEX split in US offshore



Source: RDS, Deutsche Bank estimates

Figure 104: CERA capital costs index by project type



Source: CERA, Deutsche Bank estimates

As such we present below our assessment of the key drivers of both capital and operating costs and how the various components may have contributed to the sharp increase in costs over the last few years. We then present our analysis based on Wood Mackenzie data of what it actually costs to extract a barrel of oil.

So what drove the increase in costs?

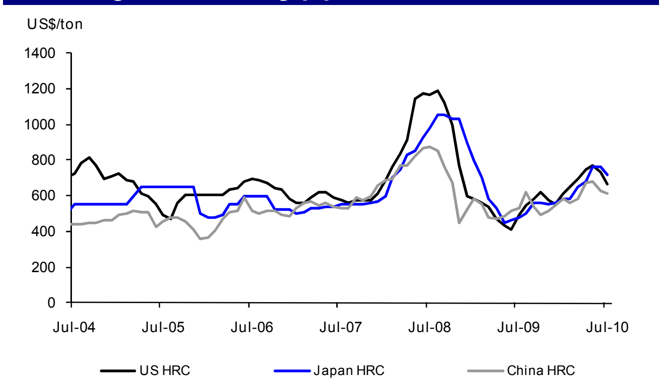
We believe the following factors constitute the key drivers of the oil and gas industry cost base and were pivotal between 2004-09 in the rise and fall of the cost of producing oil.

- **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%.
- **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.

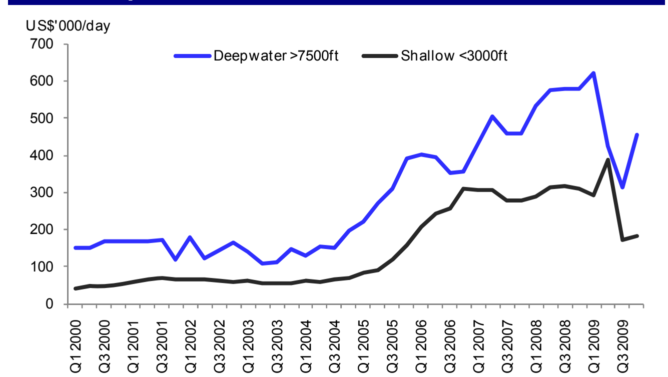
- **Tight services industry –** this surge of interest in developing projects such as the Canadian oil sands or in the deepwater meant the services industry has grappled to keep up with demand. Deepwater rig rates rocketed through the 2004 – 2008 period as illustrated below, while a number of oil sands projects were postponed due to an overheated services market in Alberta.
- **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. This resulted in increased demand and competition for services/consumables and thus higher prices.

Figure 105: Steel prices surged on high demand increasing the cost of rig/pipe construction



Source: CRU, Deutsche Bank estimates

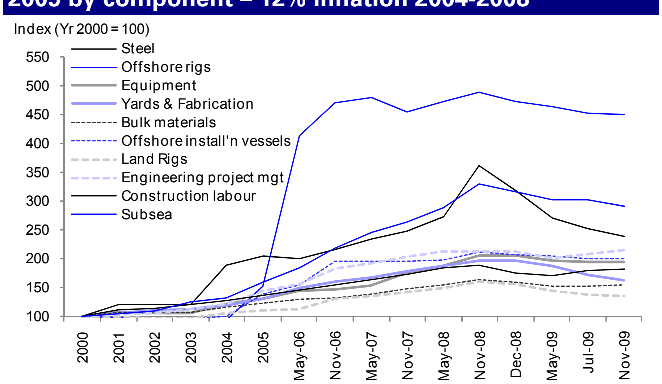
Figure 106: Rig rates skyrocketed since 2004 particularly in the deepwater



Source: Baker Hughes, Deutsche Bank estimates

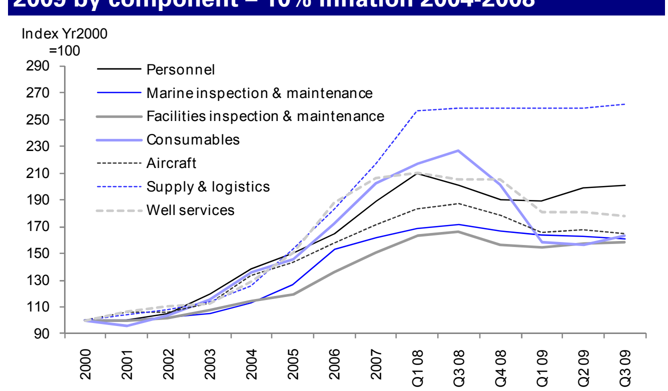
- **Service contracts –** through the period of 2004-2008 there was a shift in service contracts from lump-sum to cost plus. Cost plus increased from c.26% of contracts signed in 2005 to nearer 30% in 2007. This meant that service companies were better able to pass through cost increases in consumables, labour rates etc.

Figure 107: CERA upstream Capital costs index 2000-end 2009 by component – 12% inflation 2004-2008



Source: CERA

Figure 108: CERA upstream OPEX costs index 2000-end 2009 by component – 10% inflation 2004-2008



Source: CERA

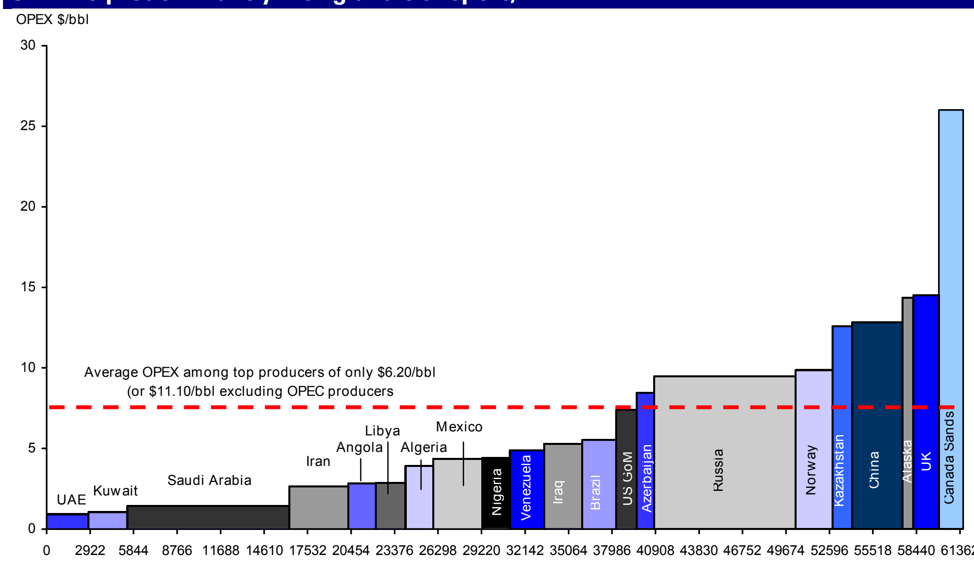
- **Commodities –** the price of consumables such as fuel, gas and chemicals used in producing oil and gas, the price of steel (as shown above), even global food prices such as corn, rice, wheat (this would impact on catering costs in rigs) all rocketed through the period on increased demand from a number of sectors.

- **Foreign exchange –** the majority of budgets and expenses in the oil and gas industry are in US$. Fluctuations in the value of the US$ can have an impact on industry costs.

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



Source: Wood Mackenzie GEM, Deutsche Bank estimates

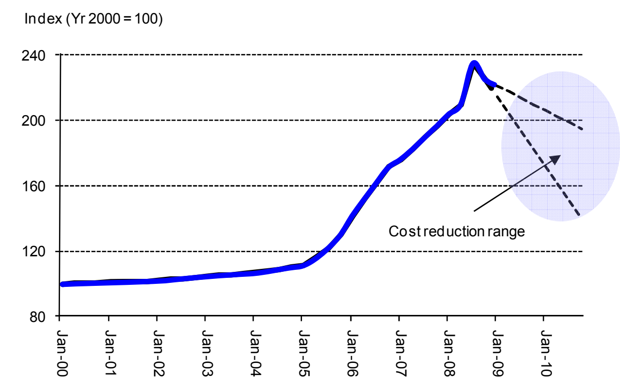
Of course, the above only focuses on the operating costs associated with extracting a barrel of oil from different geographic territories. Add in the capital costs associated with exploration and development (c$20/bbl globally), taxation (average 67% rate globally) and expected return on investment (c15%) 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 the US GoM, Brazil, Nigeria and Angola suggests that at present an average oil price of over $60/bbl is required for projects to deliver an above cost of capital return to the partners. This is not dissimilar to the $70/bbl suggested by OPEC as being 'fair'.

Where to from here?

While costs have fallen somewhat since the peaks of 2008, they have by no means fallen to the extent that industry hoped for back in early 2009 when oil prices were near $40/bbl. As the chart below illustrates, in a 'blue sky' scenario, some companies were anticipating a return to 2005 cost levels. However, flash forward a year and we see that capital costs only fell a modest 12% from the peak, while opex costs declined by an even more modest 8%.

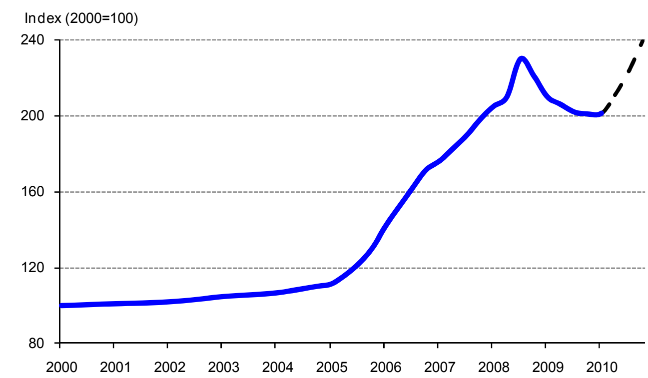
Moreover, CERA believes that cost deflation has *bottomed out* and that costs will in fact start to increase from here, surpassing the 2008 peak as early as end 2010.

Figure 110: Companies had hoped for costs to decline to 2005 levels



Source: CERA

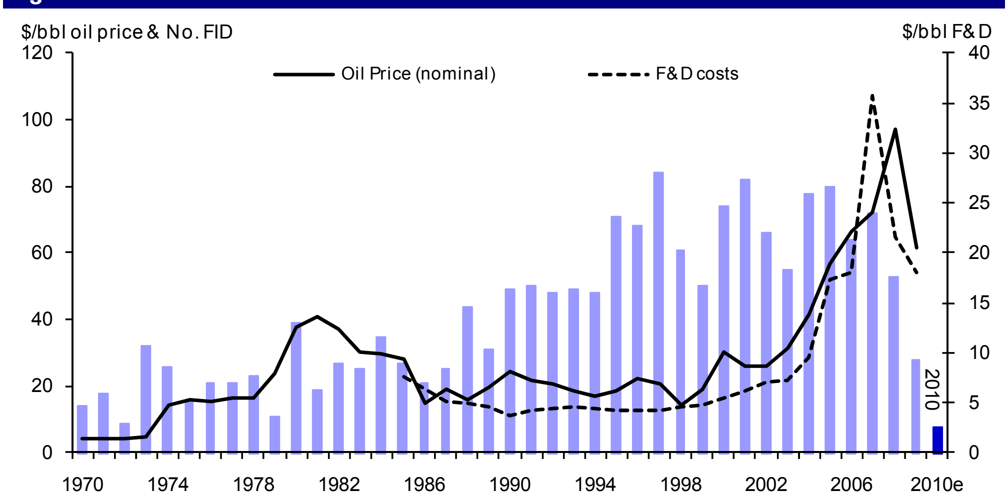
Figure 111: Harsh reality – declined only a modest 12% and are already on the increase



Source: CERA

Quite where costs may move to from here is obviously open to debate. Key however will remain both tightness in the services market but also, as importantly, the view of the major oil companies (both NOC and IOC) on quite where the oil price is likely to trade on a sustainable basis over the longer term. With many companies typically using a $60-80/bbl price band in their investment decisions, any further sharp spikes in cost would almost certainly see a reduction in industry investment decisions, thereby driving a reduction in investment decisions and service sector demand.

Figure 112: Number of FID taken 1970 – 2010 YTD



Source: Wood Mackenzie Pathfinder, Deutsche Bank estimates

Such behaviour was more than evident through 2008/9 when as illustrated above the number of final investment decisions (FIDs) taken by the industry started to fall back. Although the trend has more recently been exacerbated by the economic downturn interesting in our view is that this reduction initially became evident at a time when the oil price was still strongly rising. For with project development costs moving to levels which, at $30-35/bbl plus, required a long term oil price that was above many companies' expectations the economics of many planned developments simply collapsed.

Costs may continue to rise. Ultimately, however, economics dictates that over the long run they must move in line with the oil price.

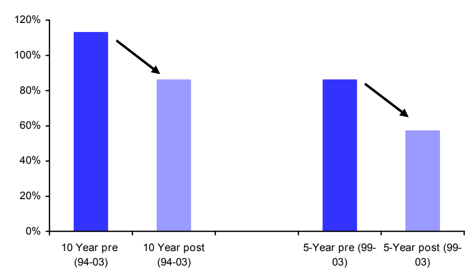
Oil & Gas reserves

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. Investor's responded by marking the shares down by 8%, so removing around US$15bn from the company's market value.

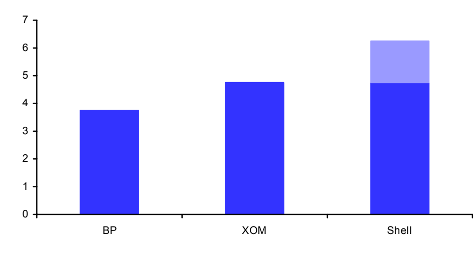
But where did the reserves go and how could almost 4 billion barrels of oil equivalent be there one day and not the next? Equally, how could a company of Shell's stature get its estimates so wrong? Amongst others, the answers largely came down to definitions of what can and cannot be considered a proven 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 113: Shell reserves replacement ratios pre & post restatement



Source: Shell

Figure 114: 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.

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, yet 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 the reserves estimate is so fundamental to the value of a company investors need to have confidence in the reserves 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.

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

What are reserves?

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.

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 or 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. Yet, they have also come under some considerable degree of criticism in recent years not least as technological developments within the industry for estimating the scale of recoverability have left them looking somewhat antiquated in their requirements.

SEC Reserves – Proven developed and proven undeveloped.

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.

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.

- **Proved oil & gas reserves.** These are estimated quantities of oil, gas and NGL's which geological and engineering data demonstrate with a **high degree of confidence** are recoverable from known **reservoirs** under existing economic conditions (i.e. prices and costs). Reservoirs are considered proved if economic production is supported by either actual production or conclusive formation tests. The area of a reservoir considered proved includes that portion outlined by drilling and defined by gas-oil/water oil boundaries and the immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons (i.e. how far do we conclusively know the oil bearing rock extends) should be used. Reserves that can be produced economically through improved recovery techniques can be included as proved when successful testing by a pilot project or operation of an installed programme is supportive of enhanced recovery in that SPECIFIC rock formation.

- **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 the 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 or FID has been taken, committing the company to the actual development of its acreage. The signing of an FID is thus a key indicator for investors and a potentially important indicator of the timing of reserve bookings.

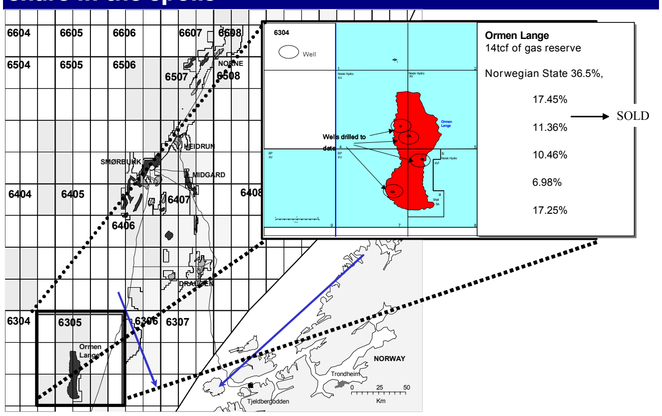
Room for manoeuvre

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 2003. 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 that the FID was signed these being Statoil, Shell, Norsk Hydro, Exxon and BP (BP has subsequently sold its position) and, with the final investment decision 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 the figure overleaf and despite the absence of any disputes between the partners over the field, these varied from an implied 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 c2bnboe by a more aggressive BP.

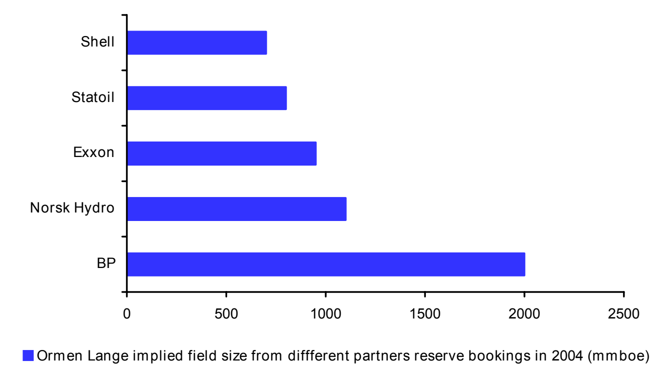
As stated, the point made here is not to say that one company is correct in its bookings and the other incorrect. The example does, however, illustrate that the SEC rules surrounding reserves replacement remain subject to interpretation. It also shows how reserves replacement estimates can be manipulated 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 115: Ormen Lange – Five partners initially set to share in the spoils



Source: Wood Mackenzie; Deutsche Bank

Figure 116: 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 off-shore 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 lead 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.

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).

- Companies now also have the option to disclose probable and possible reserves should they wish to do so. The definitions used by the SEC are in line with those of the SPE (see below).

Non-qualifying reserves under the SEC guideline
Importantly, the SEC also provides guidance on those reserve types that do not qualify for treatment as reserves.

- Oil, gas and NGL's the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors. This includes adjacent reservoirs to existing production that are isolated by major, potentially sealing faults until such a time as those reservoirs are penetrated and evaluated.

SPE definitions - Proven, probable and possible

SPE definitions - Proven, probable and possible

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, however, 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 expected to be recovered.

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

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

- **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. As described earlier, *proven developed reserves* are reserves that can be recovered from existing wells with existing infrastructure and operating methods. *Proven undeveloped reserves* require development.

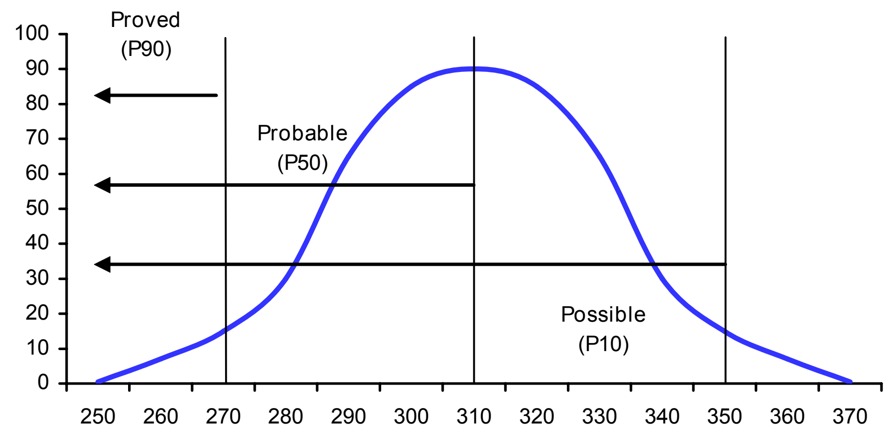
Proven plus Probable (2P) reserves have at least a 50% probability (or P50) that reserves recovered will exceed the estimate.

- **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, 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 below. 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.

Figure 117: SPE reserves: Diagrammatic view of the definitions of 1P, 2P and 3P



Source: Deutsche Bank

In addition to these three definitions of reserves, a further category exists for those reserves which for whatever reason are not deemed commercially recoverable at the present time namely contingent resources (or technical reserves). Thus **Contingent Resources** are those quantities of hydrocarbons which are estimated, on a given date, to be potentially recoverable from known 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 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 reserves are known to exist, the absence of a secure market means that they cannot be treated as recoverable.

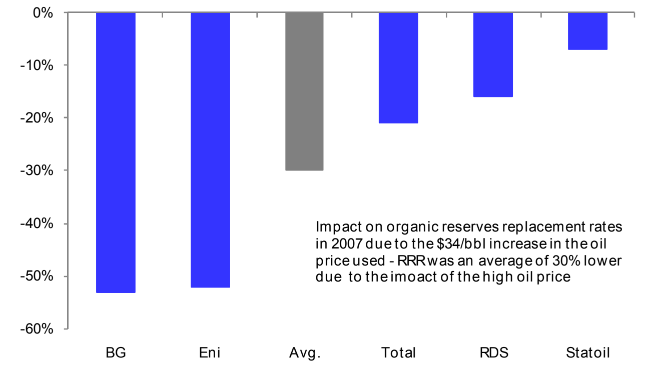
SEC and SPE – Some quirks.

Roughly speaking, reserves that companies may claim as proven under SEC rules correspond with 1P (or P90) reserves under SPE definitions. SEC rules do, however, add additional constraints, not least the two below.

The SEC guidelines require the use of the average of the closing market price of oil on the first day of each month as the basis for calculating proven reserves

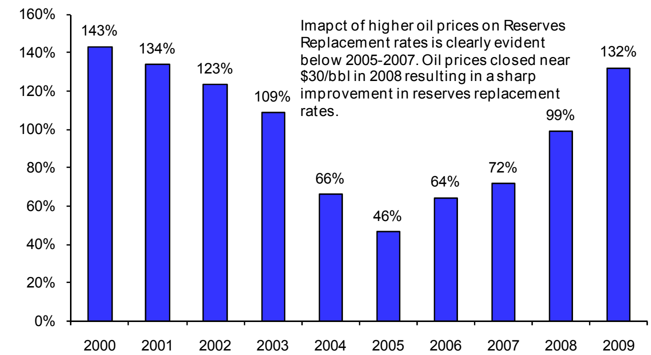
a) The SEC guidelines require the use of the average market price of oil on the first day of each month over a 12 month period as a basis for calculating proven reserves and future discounted cashflow whereas under SPE requirement long run budgeting assumptions are permitted. In the past the SEC used the closing oil price on the 31st December as the basis for calculating entitlement reserves. However, for those companies involved in profit sharing contracts (PSC's) this often had a meaningful impact on the reserves statement. This is because under PSC's the oil companies recover their capital costs through reserves and production entitlement to 'cost oil'. Clearly, the higher the oil price used to estimate their entitlement, the lower their entitlement to reserves. For those for whom PSC's are significant, the result of applying this guideline in a year when the price of oil has shifted markedly is to require a meaningful negative adjustment to reserves. For example, we estimate that the c. $34 shift in oil prices between 31 December 2006 and the same date in 2007 resulted in a potential c.30% reduction in reported reserves replacement ratios by the European majors. Similarly the very low year end oil price in 2008 ($30/bbl) meant that RR rates in 2008 were positively impacted, with the industry average increasing to just under 100%. The move to using an average oil price in determining entitlement should help to reduce the level of volatility in reserves bookings.

Figure 118: Impact on RRR as a result of the higher oil price used in determining entitlement



Source: Company data, Deutsche Bank estimates

Figure 119: Reserves replacement rates negatively impacted by use of y/e oil price amongst others



Source: Company data, Deutsche Bank estimates

b) SEC requirements dictate that only reserves recovered over the current license period can be included in recoverable reserves even though licenses are commonly extended. This contrasts with the SPE definition which allows inclusion of reserves recovered over the field life. The result is a more conservative, and potentially understated, estimate of future reserves under SEC guidelines.

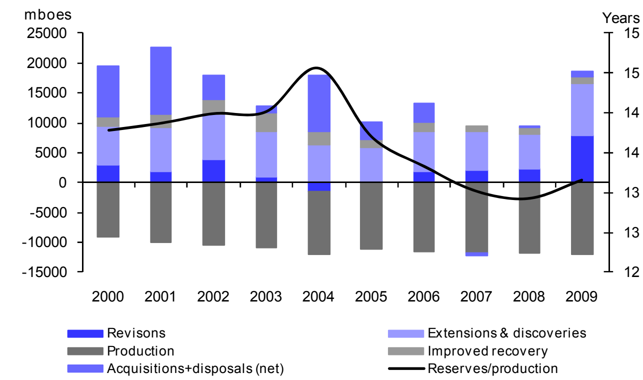
Reserve revisions

Because the estimation of reserves is inherently uncertain, it seems only natural that any statement of reserves is likely to be subject to revision as new information on the potential to recover oil from a 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.

- **Technical revisions or revisions of estimates:** Either positive or negative, 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 P1 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 i.e. recovery rates increase. 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.

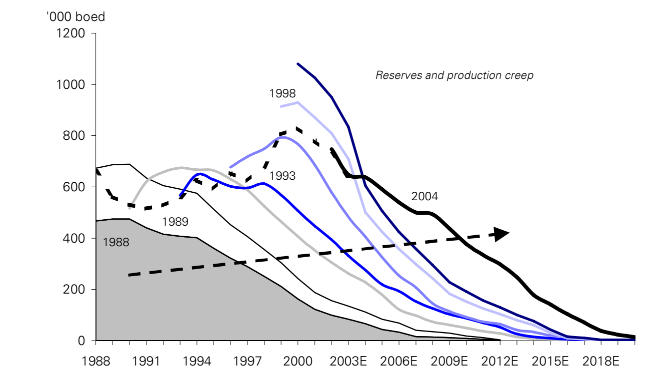
- **Acquisitions and disposals:** Shown separately, reserves movements on acquisitions and disposals highlight the reserves which have either been disposed of through the year or those acquired as asset parcels or through the purchase of another company.

Figure 120: Sources of industry reserve movements 2000-2009



Source: Company data, Deutsche Bank estimates

Figure 121: 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. For example we estimate that extensions and discoveries on average accounted for around 50% of the increase in reserves in the period 1990 to 2003 (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?

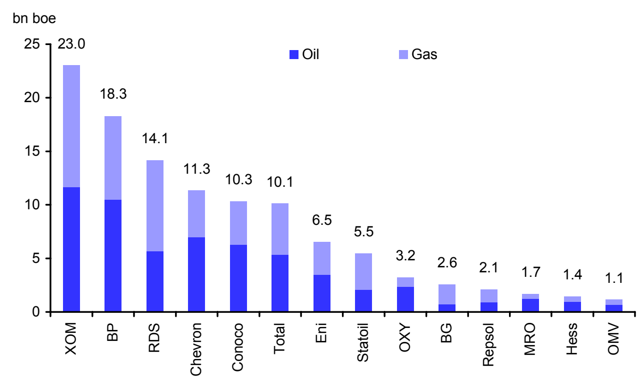
Reserves: What do they actually tell us?

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

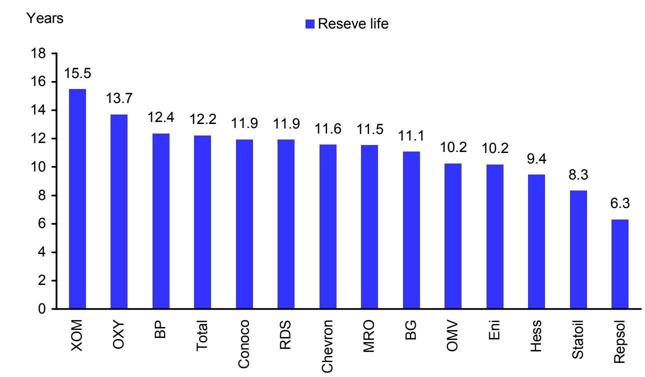
of potential production the greater the value of the company and the more sustainable the valuation. It should be noted that, for a growing business, to maintain proven reserves at a set number of years requires greater than 100% annual reserves replacement. Indeed, for a company growing at 1% annually 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 122: 2009 SEC 1P reported reserves by company



Source: Deutsche Bank, company data

Figure 123: 2009 Reserve Life by Company



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). This in turn 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 barrel of oil equivalent, finding and development (F&D) costs per barrel of oil equivalent 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.

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.

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 the 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 enterprises 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 cost relating to oil and gas 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 the year-end prices to year end reserve volumes
- 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.

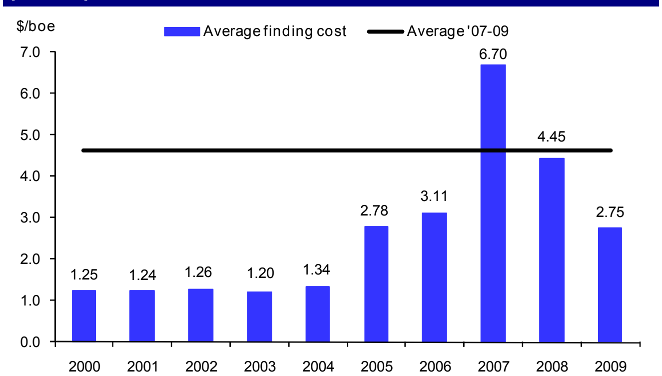
So how do analysts use FAS 69 information?

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 have risen considerably over the last few years as reserves replacement has come under pressure at a time of rising costs.

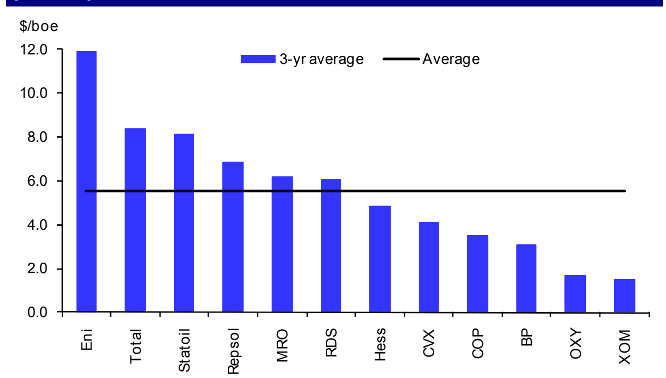
Finding costs = Total exploration costs divided by organic reserves additions (i.e. revisions, improved recovery & discoveries/extensions)

Figure 124: Industry average finding costs 2000-09 ($/boe)



Source: Deutsche Bank, company data

Figure 125: IOC finding costs 3-yr average 2007-09 ($/boe)

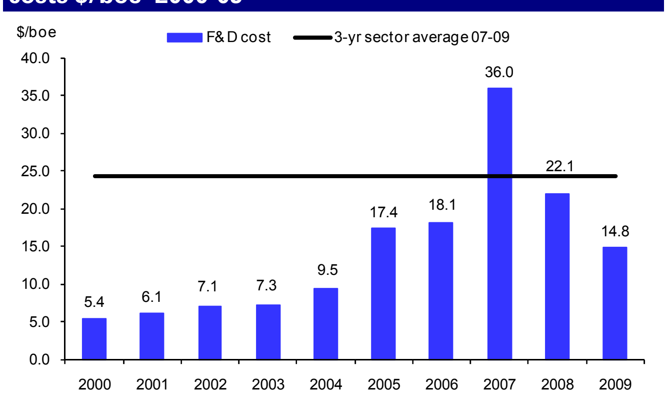


Source: Deutsche Bank, company data

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

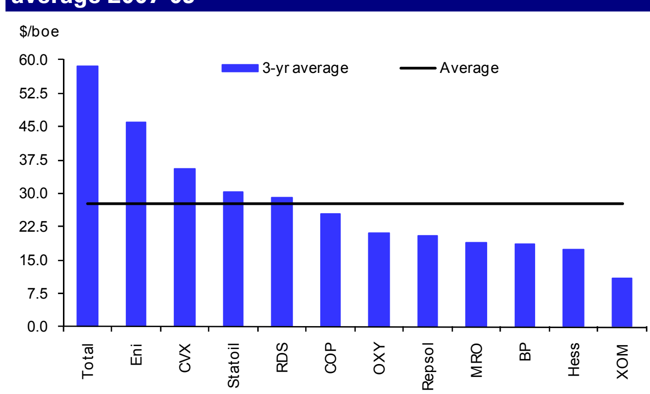
Finding & Development cost/bbl = Exploration plus development expenditure divided by organic reserves additions (i.e. revisions, improved recovery & discoveries/extensions)

Figure 126: Average industry finding & development costs $/boe '2000-09



Source: Deutsche Bank, company data

Figure 127: IOC finding & development costs 3-yr average 2007-09

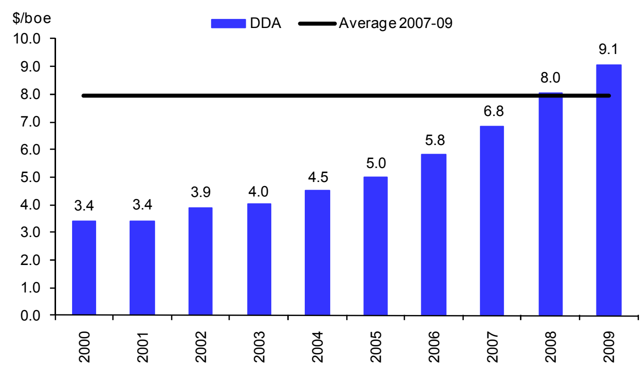


Source: Deutsche Bank, company data

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

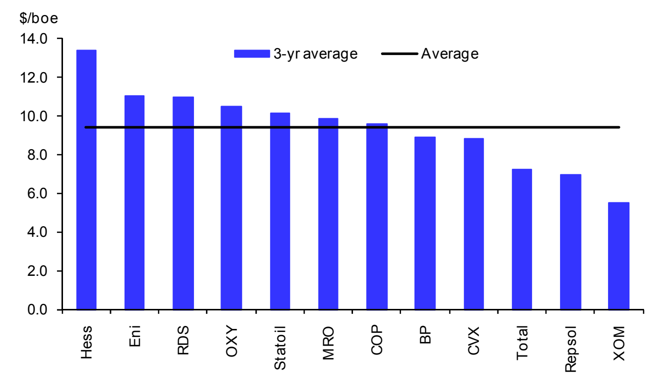
DDA = Depreciation, depletion and amortisation charge for the year/production for the year

Figure 128: Industry average. DDA $/boe 2000-09



Source: Deutsche Bank, company data

Figure 129: IOC DD&A 3-yr average. 2007-09 ($/boe)

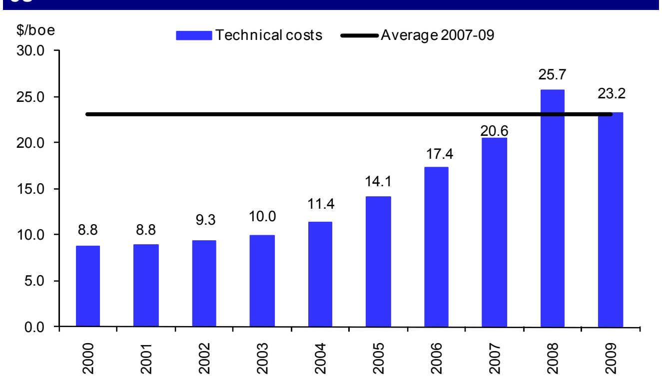


Source: Deutsche Bank, company data

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).

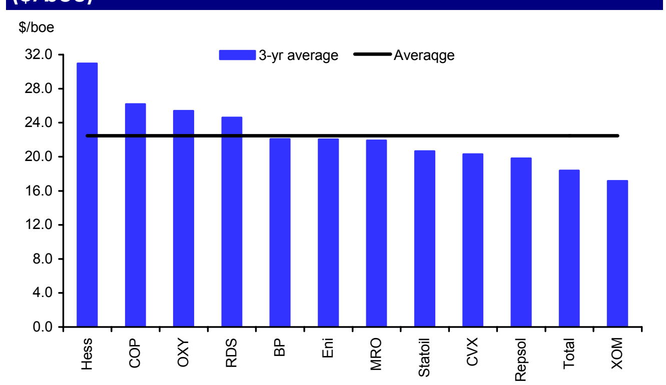
Technical costs = exploration costs + DD&A costs + lifting costs/annual production

Figure 130: Industry average technical costs $/boe 2000-09



Source: Deutsche Bank, company data

Figure 131: IOC technical costs 3-yr average 2007-09 ($/boe)



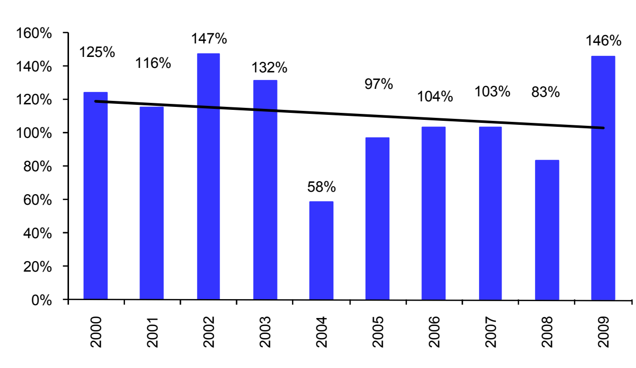
Source: Deutsche Bank, company data

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

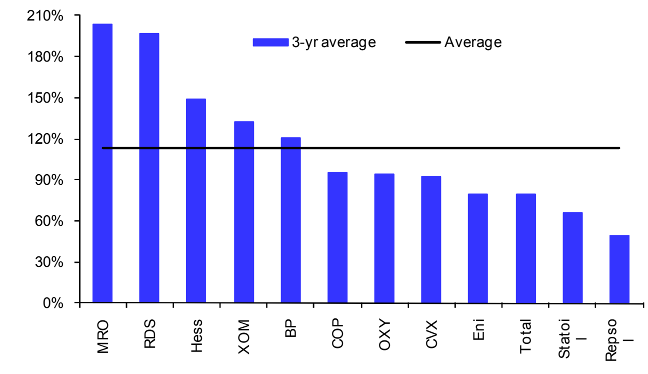
For RRR inclusive of M&A also include acquisitions and disposals in calculation of movement in reserves

Figure 132: Industry average reserve replacement % 2000-09 (Organic)



Source: Deutsche Bank, company data

Figure 133: IOC reserve replacement 3-yr average 2007-09 (Organic)

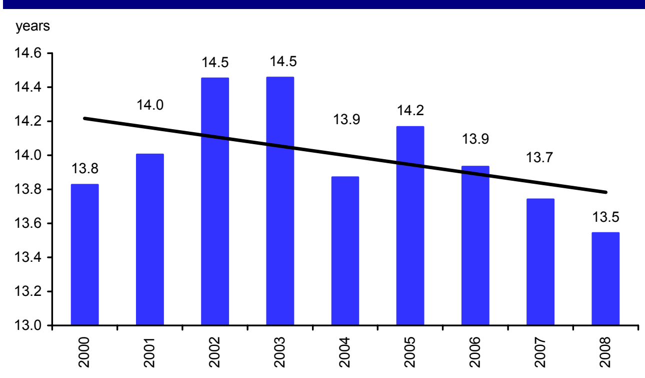


Source: Deutsche Bank, company data

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 2008 was 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.

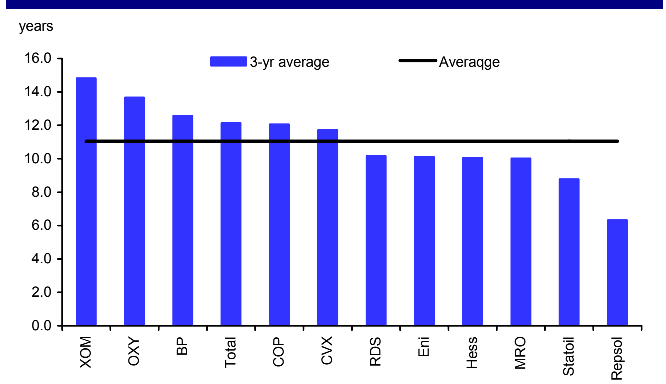
Reserve Life = Total 1P reserves/annual production

Figure 134: Industry average reserve life 2000-09 (years)



Source: Deutsche Bank, company data

Figure 135: IOC reserve life 3-yr average 2007-09 (years)



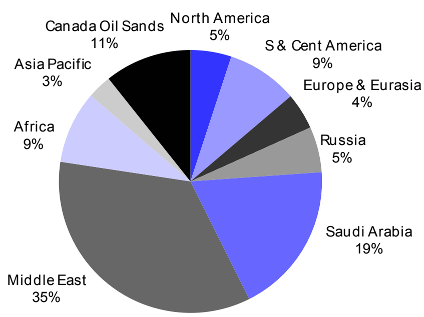
Source: Deutsche Bank, company data

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 can take 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 its giant oil sands and LNG projects where only limited reserves were booked.

Reserves - Where and what?

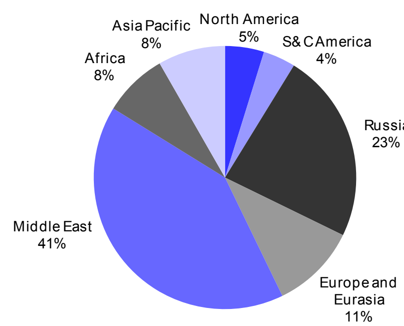
It is the nature of life that all things most highly sought are the hardest to find…and oil is no different. Located predominantly in 'unfriendly' countries or in technically challenging locations or located in vast quantities in 'friendly' countries but in difficult to extract/process forms, oil reserves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

Figure 136: Oil reserves around the world – 1,476 billion barrels at end of 2009



Source: Deutsche Bank, BP Statistical Review

Figure 137: Gas reserves around the world – 6,621 TCF at end of 2009



Source: Deutsche Bank, BP Statistical Review

As illustrated above, over 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 264 billion barrels is the world's largest holder of oil reserves and consequently the largest producer and exporter of oil in the world.

Over 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?

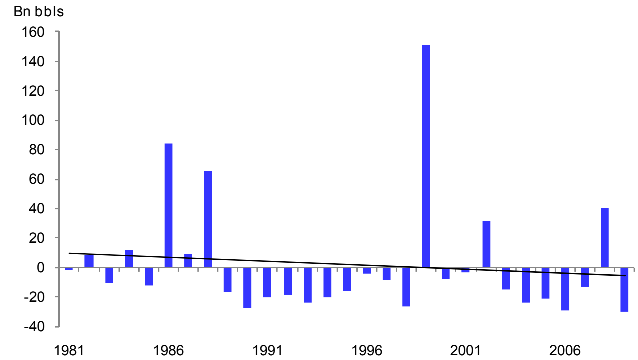
While the use of oil is age old, commercial production only truly commenced in the 1860s following Drake's drilling success in Pennsylvania. Since then some 50,000 oil fields have been discovered and oil production has increased exponentially; in 1859 total annual production in the US was a mere 2,000 barrels, within 47 years this figure was 127mbbls, and in 2006 a total of 2.5bn bbls were produced in the US. While it is almost 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), it is estimated that approximately 77% of the world's total recoverable oil has already been discovered of which 39% has already been produced and consumed. As illustrated below, an average 46% of initial reserves in the top ten reserve holders have been depleted since production commenced.

Figure 138: The world's largest oil fields

Field Name	Location	Start up (year)	Discovery (year)	Recoverable reserves (m bbl)	Remaining Reserves (mbbl)	Peak Production (kb/d)	Field Participants
Ghawar	Saudi Arabia	1951	1948	126201	64551	5573	Saudi Aramco
Greater Burgan	Kuwait	1946	1938	48372	20533	2416	KOC
Safaniyah	Saudi Arabia	1957	1951	36536	21044	1552	Saudi Aramco
North/South Rumaila	Iraq	1954	1953	24807	13283	1534	South Oil
Samotlor	Russia - West Siberia	1969	1961	21163	3432	3027	TNK-BP
Kirkuk	Iraq	1934	1927	19853	5098	1424	North Oil (NOC)
Cantarell	Mexico	1981	1976	17500	6,000	2,100	PEMEX
Romashkin	Russia- Volga-Urals	1945	1943	17125	1944	1081	Tatneft
Upper Zakum (UC)	UAE	1982	1964	16125	16125	650	ZADOC
Shaybah	Saudi Arabia	1998	1968	14698	13156	1000	Saudi Aramco
Abqaiq	Saudi Arabia	1946	1941	14348	3347	1056	Saudi Aramco
Gachsaran	Iran	1940	1928	14084	4686	921	NIOC
Kashagan	Kazakhstan	2009	2000	13600	13600	1800	ENI
Ahwaz Asmari	Iran	1959	1958	13597	4290	1082	NIOC
Lagunillas	Venezuela	1926	1926	13140	325	237	PDVSA
Manifa	Saudi Arabia	1964	1957	12800	12332	1100	Saudi Aramco
Marun	Iran	1965	1964	12173	2101	1344	NIOC
Khurais	Saudi Arabia	1963	1958	12082	11826	1075	Saudi Aramco
Prudhoe Bay Unit	US (Alaska)	1977	1968	12015	1266	1540	BP
Zuluf	Saudi Arabia	1973	1965	11899	8087	600	Saudi Aramco
Northern Fields	Kuwait	1960	1955	11692	7156	900	KOC
Rokan PSC	Indonesia	1954	1940	11651	1505	963	Chevron
Agha Jari	Iran	1939	1936	10933	1653	1023	NIOC
Fyodorov	Russia- West Siberia	1973	1971	10662	2241	723	Surgutneftegaz
Songli Historic	China	-	-	9894	0	1209	PetroChina
Bachaquero	Venezuela- West	1930	1930	8491	324	238	PDVSA
Qatif	Saudi Arabia	1946	1945	8385	7392	500	Saudi Aramco
Berri	Saudi Arabia	1967	1964	8381	3785	762	Saudi Aramco
Majnoon	Iraq	2002	1977	8259	8186	1250	NOC
Bu Hasa	UAE	1965	1962	8258	1796	n.a.	ADCO
Daqing Fields	China	1960	1959	7884	5375	1079	PetroChina
AFK Group	Saudi Arabia	2007	1940	7719	6019	500	Saudi Aramco
Sarir	Libya	1961	1961	7665	0	1175	LNOC
Tía Juana Lago	Venezuela	1929	1929	7360	216	115	PDVSA
Nahr Umr	Iraq	1998	1949	6789	6779	500	NOC
TUPI	Brazil	2010	2006	6500	6500	n.a.	Petrobras
Tengiz	Kazakhstan	1991	1979	6292	5300	669	Chevron
Abu Sa`fah	Saudi Arabia	1966	1963	6219	4613	300	Saudi Aramco
Azeri Chirag Guneshli	Azerbaijan	1997	1979	5400	4865	1105	BP
Bab	UAE	1959	1954	5343	5343	320	ADCO
Ahwaz	Iran	1971	1959	5340	4038	490	NIOC
NC Basin (Sinop) Historic	China	-	1961	5193	0	798	Sinopec
Dukhan	Qatar	1949	1940	5026	1518	375	QP
Zubair	Iraq	1950	1949	4931	3554	300	NOC
Priobskoye	Russia West Siberia	1988	1982	4778	3990	600	Rosneft
Mamontovskoye	Russia West Siberia	1970	1965	4597	670	689	Rosneft
Marjan	Saudi Arabia	1973	1967	4429	2862	300	Saudi Aramco
Lower Zakum	UAE	1967	1964	4202	1265	250	ADMA

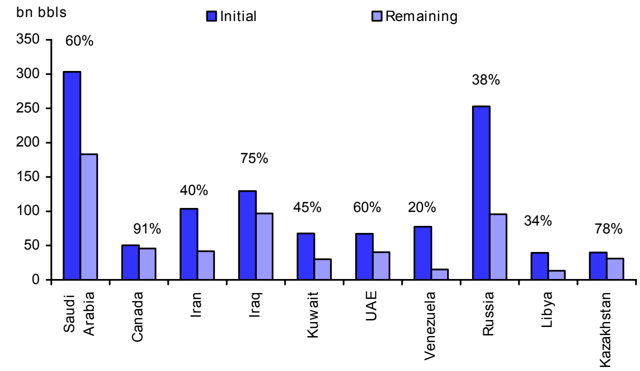
Source: Deutsche Bank, Wood Mackenzie

Figure 139: Net difference between annual reserves additions and annual consumption.



Source: BP Statistical review, Deutsche Bank

Figure 140: Top 10 countries by reserves – initial reserves vs. remaining reserves



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 illustrates, with the exception of a few years (notably 1999 where the Canadian oil sands are added to global reserves in our figures) global consumption outpaces reserves additions.

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, and several lively debates between the two parties have taken place.

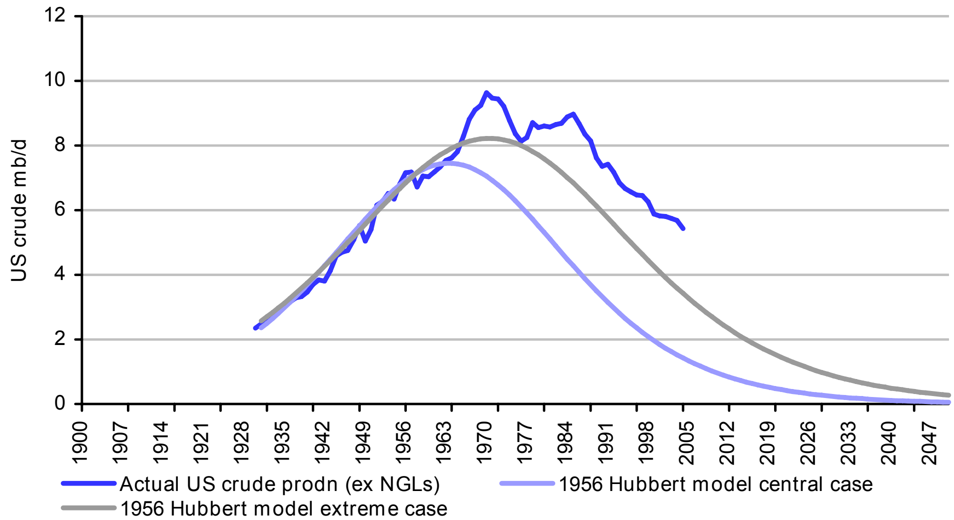
Dr M. King Hubbert – the father of Peak Oil

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 141: Actual US crude production and Hubbert's forecasts



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 shale oil are not included in most Peak Oil analysis, yet these represent vast reserves; c.1.0 trillion bbls in oil sands/heavy oil and an estimated 1.5-2.0 trillion bbls in shale oil. 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 more 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, and the IEA forecasts a peak between 2025-2050. 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. What matters is not when such a peak occurs but what will the mix of energy supply be in 100 years, and how painful the transition will be. 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.
- Provide substantial state funding for research into alternative energy.

With careful management of both the demand and supply side of oil and gas governments could help minimise the pain in the transition from the hydrocarbon age to a post hydrocarbon world. There are tentative signs that the process has started. The alternative is a much more dramatic change, which would likely only add to worldwide tensions.

Oil & Gas Taxation

Concessions & contracts – An overview

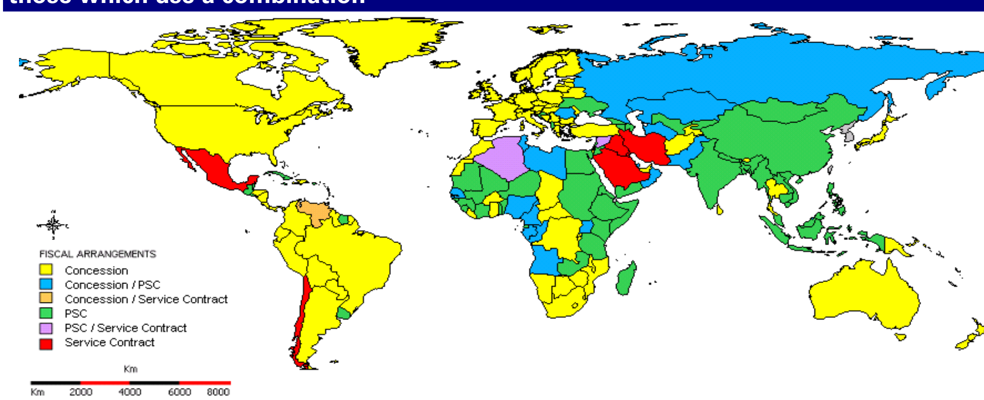
The sheer scale and value of the oil and gas industry together with its strategic importance has meant that governments have long seen the extraction of hydrocarbons as an important potential source of revenue. As such, oil & gas taxation is a very important part of today's industry with government-take 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.

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

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.

Figure 142: Distribution of global tax systems between concession, PSC, buyback and those which use a combination



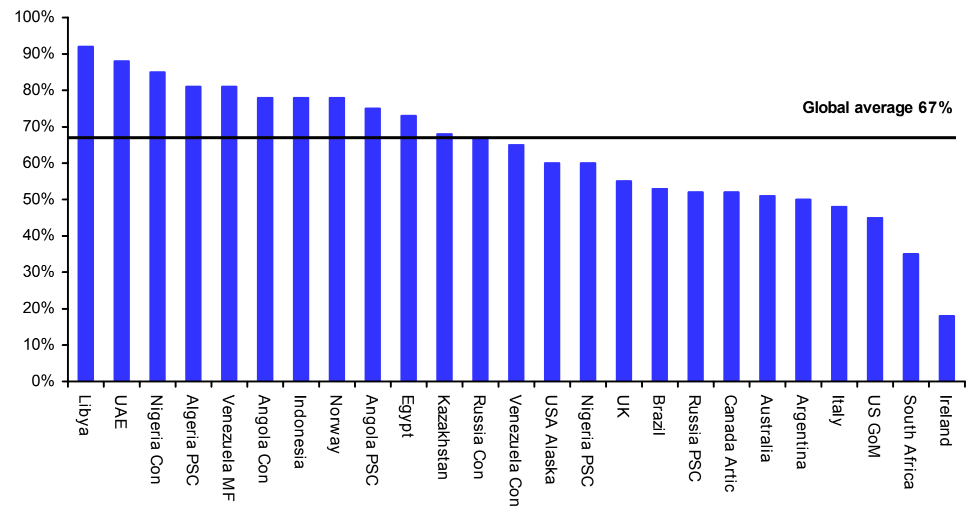
Source: Wood Mackenzie; Deutsche Bank

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%

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 ethos and so on. As a consequence, government take varies significantly from country to country as illustrated by the chart below. Thus 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. In a recent Wood Mackenzie study, the weighted average government take globally was estimated at 67% of the industry's pre-tax NPV (or 72% if NOC equity is included).

Figure 143: 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 oil 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 announced by governments 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, five years ago. However, in the case of a new PSC the contractor has at least agreed to the less favourable terms upon entering the contract. In a concession, for existing projects it has clearly not.

Figure 144: Broad tax changes since 2002 have focused on concession regimes

Country	Tax form	Change
UK	Concession	Increased tax take to 50% from 30% by adding supplementary tax on post 1993 fields
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

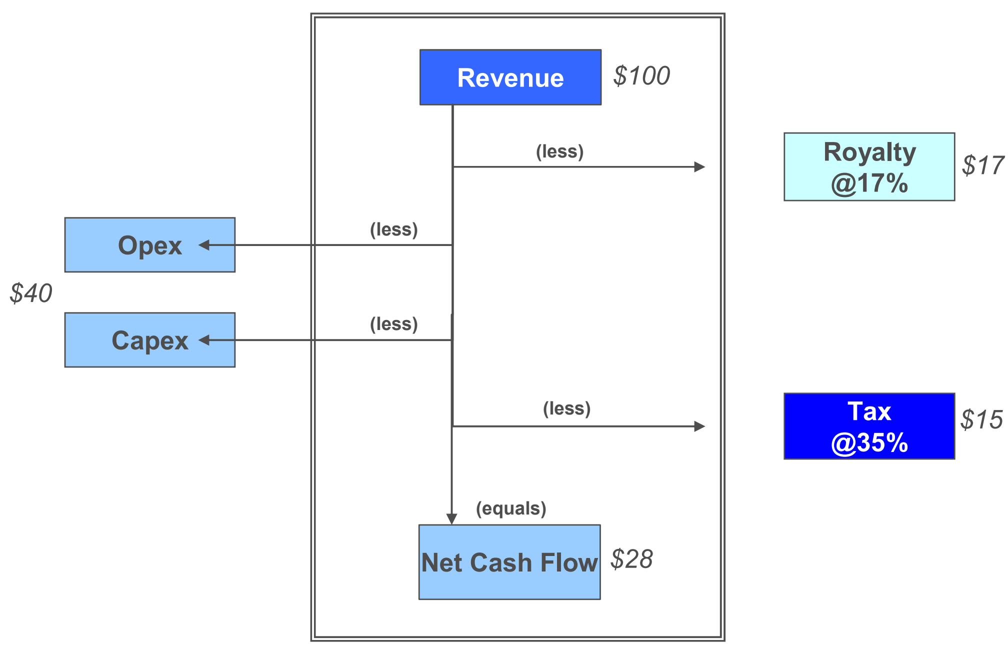
Source: Deutsche Bank

Tax & Royalty Concessions

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.

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 % 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.

Figure 145: Schematic depicting tax and royalty calculation in a concession



Source: Wood Mackenzie; Deutsche Bank

Overall, government take under a concession is generally relatively 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 in that, at 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 we show below the main components of taxation in several key geographies.

Figure 146: Summary tax terms in major concessions

	Royalty rate	Corp. tax rate	Depreciation	Other tax rate
UK	None	30%	Year incurred	20% supplementary tax
US	18.75%	35%	7 year system	n.a.
Norway	None	28%	Six years with 4 year uplift	50% hydrocarbon tax
Russia	Variable	24%	Varies	Up to 65% export tax
Nigeria Concession	0-20%	n.a,	5 year straight line with uplift	85% Petroleum tax
Australia	12.50%	30%	10 years	40% PRRT
Venezuela	30%	50%	Varies	Several indirect
Argentina	12%	35%	Unit of production	Export duty liable
Canada sands	1-40%	18%	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 (65% 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 20% 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)

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

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.

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 so providing them with a healthy level of return on investment and minimizing project 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 with limited downside to their own finances. 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.

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

Cost recovery generally a priority

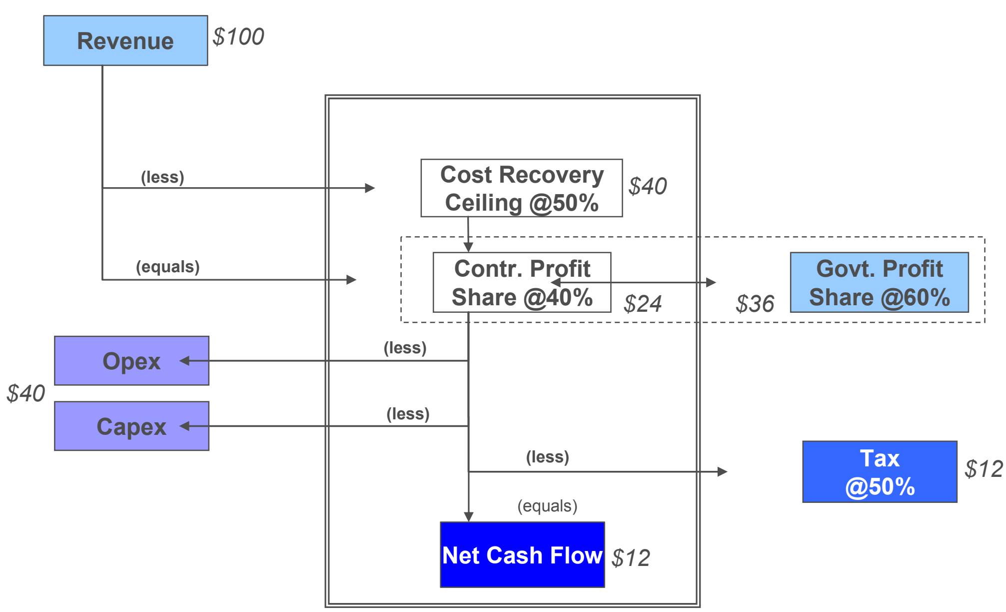
Under most PSCs, a significant proportion of the revenues achieved from the sale of the oil or gas produced are available for cost recovery. For example in Angola, Azerbaijan and Malaysia amongst others, 50% of revenues are available for cost recovery whilst up to 100% is available in some Nigerian deepwater projects. 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 very protective of project economics.

The remaining 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. This will 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 (the cost oil) with the balance of revenues (the profit oil) allocated between contractor and state in a 40/60 ratio. The contractor is then liable for tax at 50% on its share of the profit oil. As can be seen, at $40, all 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 147: Schematic depicting a PSC calculation



Source: Wood Mackenzie; Deutsche Bank

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

Trigger points – PSCs use various schemes

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 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. Equally, depending on the proportion of initial revenues that are available for cost recovery they 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 also 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). In our opinion, production based contracts are particularly profitable for the contractor given an upwards shift in the oil price (from that at the time the contract was written) but have the potential to be quite painful given a downward shift. In aggregate they are certainly 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 (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.

Figure 148: 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	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	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	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 screwed on share	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	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

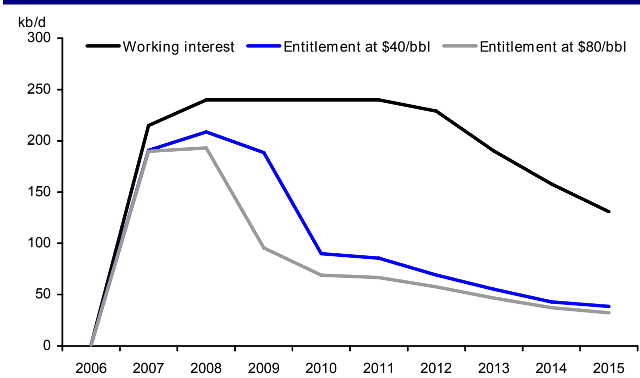
For companies and investors, hitting trigger points impacts several key metrics
Given that most PSCs are written to maximize the State's take from its resource base yet at the same time limit the contractors downside but incentivise their commitment to a project, the use of 'trigger points' for the allocation 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 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.

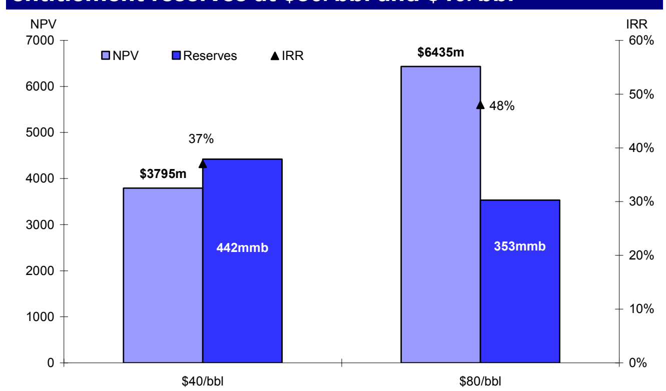
Value up, barrels down – an Angolan illustration
This is well illustrated by the following diagrams which depict the contractors working interest and entitlement share to production barrels in a typical Angolan PSC at different oil prices together with the different NPV's, IRRs and entitlement to reserves. 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 149: Angola's Dalia project – Working interest and entitlement volumes at $80/bbl and $40/bbl



Source: Wood Mackenzie; Deutsche Bank

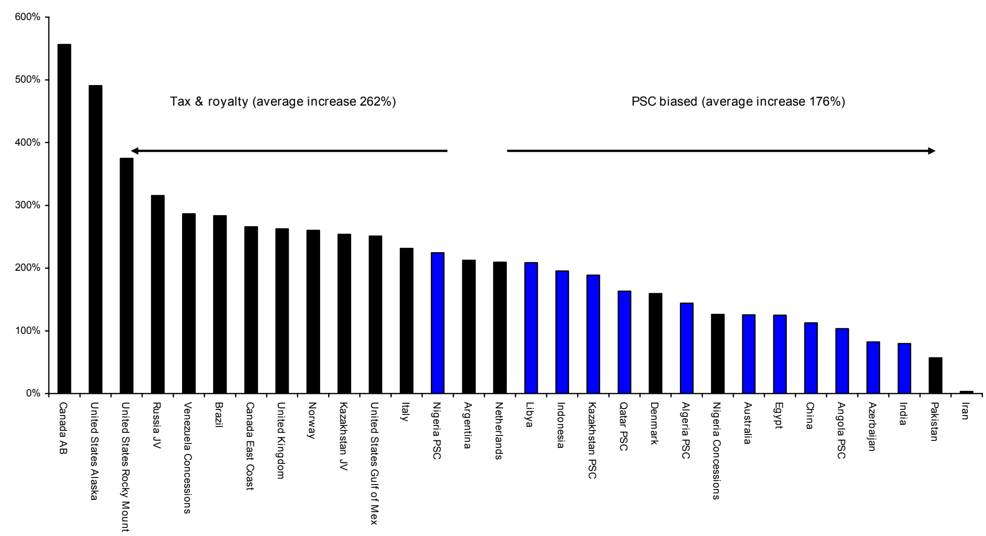
Figure 150: Angola's Dalia project – NPV, IRR and entitlement reserves at $80/bbl and $40/bbl



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



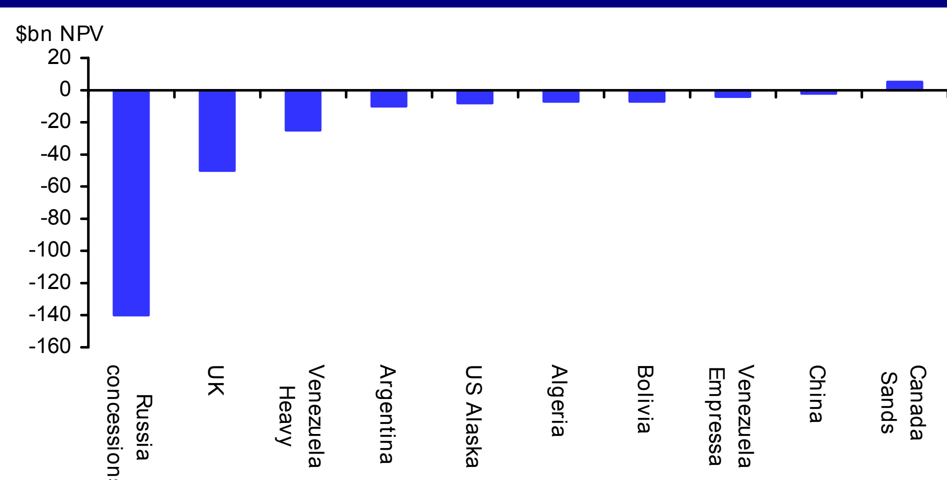
Source: Wood Mackenzie; Deutsche Bank

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

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 as illustrated by the below estimates of the value transfer through recent tax changes.

Figure 152: Estimated impact on upstream NPV of changes in tax legislation since 2001



Source: Wood Mackenzie

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.

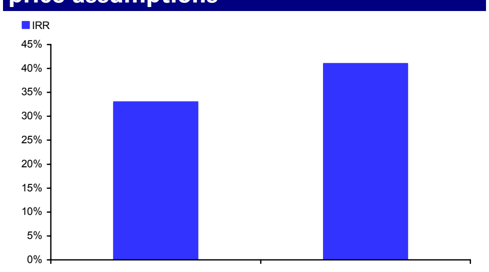
Shown in the Figures overleaf, our models work from the assumptions depicted in the below table together with Wood Macs estimates of capex and opex. The table below detail the workings and mechanics of the calculations.

Figure 153: 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

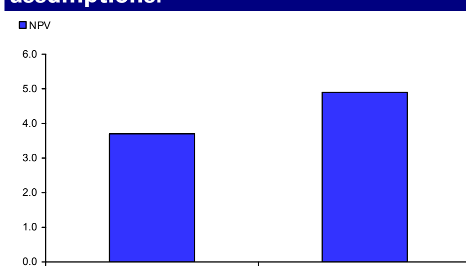
Source: Deutsche Bank, company data

Figure 154: Dalia: IRR at different oil price assumptions



Source: Wood Mackenzie; Deutsche Bank estimates

Figure 155: Dalia; NPV's at different price assumptions.



Source: Wood Mackenzie; Deutsche Bank estimates

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

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.

Figure 156: 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)/*

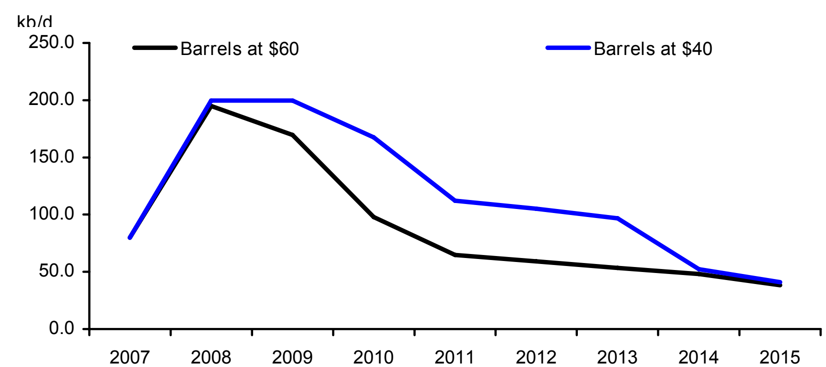
Figure 157: Angola's Dalia - Estimated entitlement share and breakdown of contributing components at $40/bbl

	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

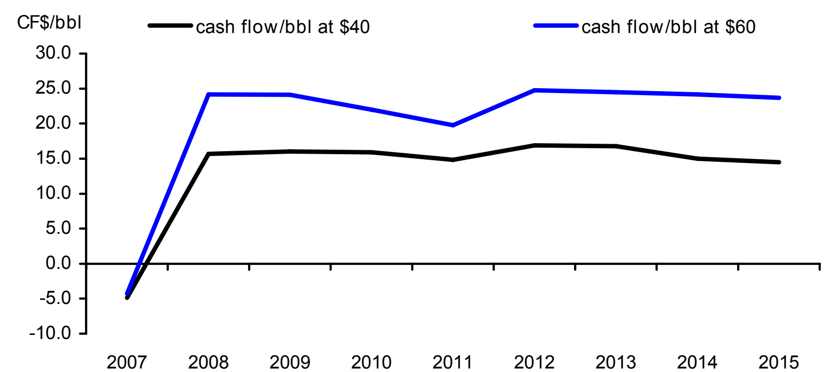
Notes: The same table but tabulated at $40/bbl Brent instead of $60. The key differences are depicted in the charts below. Note how lower revenues lead to an increase in the time taken to recover cost oil and so detract from the IRR. With the IRR staying lower for longer, profit share favours the contractor 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 158: Kb/d under different oil price scenarios ($60 vs. $40/bbl)



Source: Deutsche Bank

Figure 159: Cash flow per bbl under different price estimates ($60 vs. $40)



Source: Deutsche Bank

Buy Backs

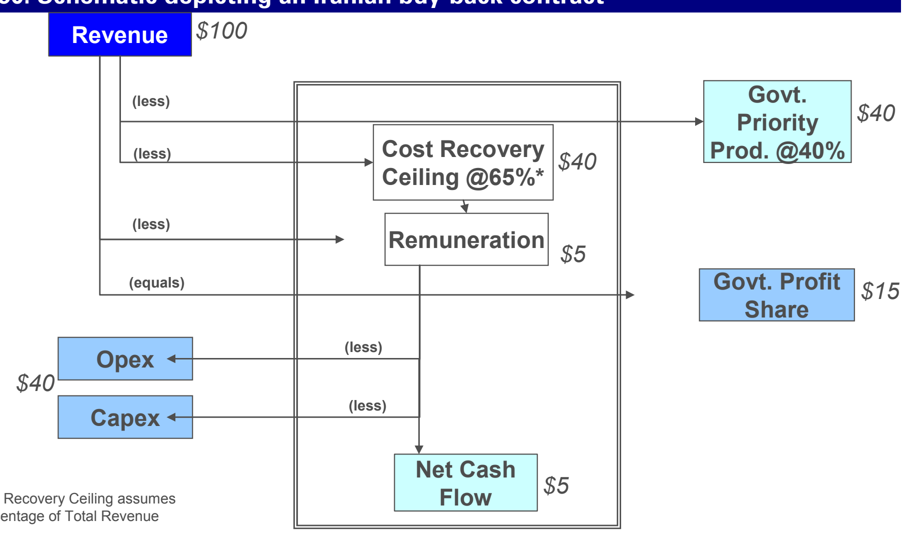
In almost every major oil producing territory, hydrocarbon taxation takes the form of either a concession or production sharing contract. There is, however, one major exception; Iran.

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

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.

The commercial rewards in buy back contracts have changed gradually since the first contract was signed with TOTAL in 1995. The level of return afforded to contractors has reduced from an average of 21% to around 15%. Such tightening of returns to the foreign parties reflect the level of competition for quality assets in the sector and the level of return which participants have been prepared to accept in the contracts signed to date.

Figure 160: 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.

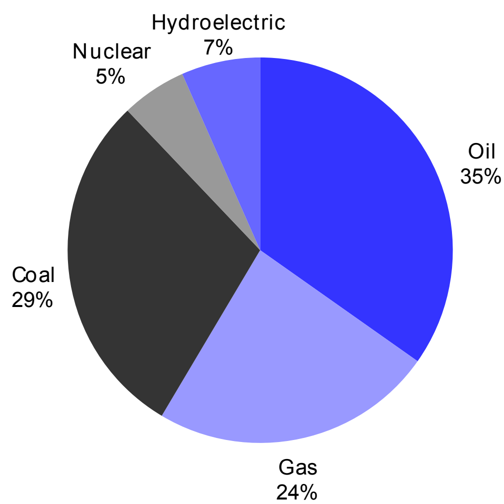
World Oil Markets

Fundamentals, physical and financial

Oil continues to be the world's most important source of energy

For many years, oil has been the world's most important source of energy, meeting almost 35% of global energy needs in 2009 (natural gas 24% and coal 29% are its nearest rivals). This has resulted in the oil becoming the world' largest traded commodity, whether measured by value or volume. Indeed, we estimate the physical crude oil market alone to be worth some USD2.2 trillion per year based on a 5 year WTI average historical price of USD71.5/bbl and 2009 global demand of c.85mb/d. In recent years however, oil markets have often become increasingly complex which in recent times has resulted in the oil price on the screen becoming disjointed from the underlying fundamentals. We examine the various different components of oil markets and how they ultimately impact the oil price.

Figure 161: World Energy Consumption by fuel in 2009 (ex. alternatives)



Source: BP Statistical review 2010

Key exchanges and benchmarks

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.

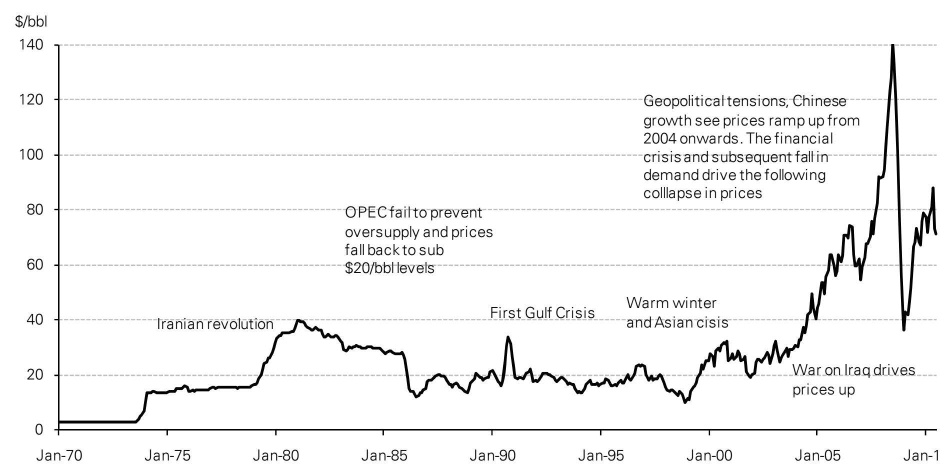
Nymex WTI: WTI is the largest exchange-traded commodity, with traded volumes often being four times that of Brent. WTI is by and large only consumed by refineries in US mid-continent, thus very little of the world's physical volumes are actually priced against it. It remains, however, a key benchmark given it is one of the most liquid crude contracts globally. 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. There are many factors which affect the oil price; the most important being supply and demand fundamentals but also the strength of the US dollar given that all oil is traded in US dollars and of course geopolitics also play a hugely important role, in particular any action taken by OPEC. In recent years, however, oil prices are ever more affected by the fact that commodities are increasingly viewed as a financial asset class by investors which has led to increasing levels of involvement by financial market participants and, consequently, to a more volatile oil price.

Figure 162: Brent oil price (nominal) 1970 - 2010



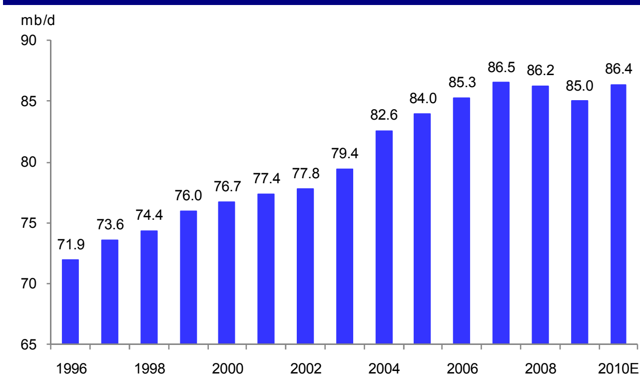
Source: DataStream, Deutsche Bank

Other factors that impact the oil price include inventories, oil product markets and OPEC spare capacity. 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 price of crude. OPEC spare capacity, being the volume by which OPEC nations can theoretically increase production if required, has increasingly impacted oil prices as the world has become more reliant on OPEC oil. If OPEC capacity decreases this will invariably put pressure on supply (or fuel fears that supply will tighten) and hence the oil price will increase (see section on OPEC).

Oil Demand

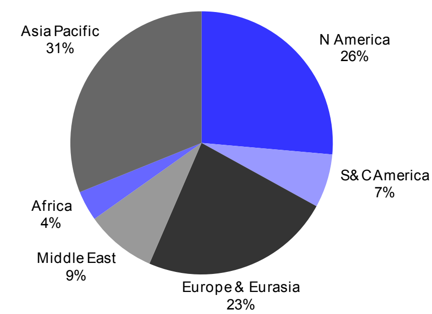
From the early days of boom and bust, demand for oil has experienced sustained growth worldwide over the past 15 years, with 2008/9 being the exception to the rule. In 2009, the level of world demand is estimated to have stood near 85mb/d, down from a peak of 86.5mb/d in 2007, reflecting the impact of the severe financial crisis. Looking forward, global oil demand is forecast to expand by an average c.1.5% p.a. between 2009 and 2015 assuming annual global GDP growth of c.4%, with the majority of growth forecast to come from non-OECD countries. Despite this, the US does remain the world's largest consumer of oil, accounting for some 22% of total world demand in 2009 with its consumption of 18.7mb/d far outstripping the 8.5mb/d consumed by China.

Figure 163: World oil demand, 1996-2010e (mb/d)



Source: DB estimates

Figure 164: Regional breakdown of world oil demand 2009 (%)

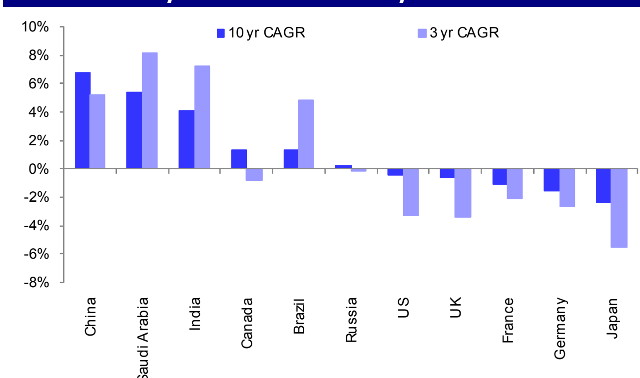


Source: BP Statistical Review

World demand is likely to be driven by non-OECD countries, particularly China.

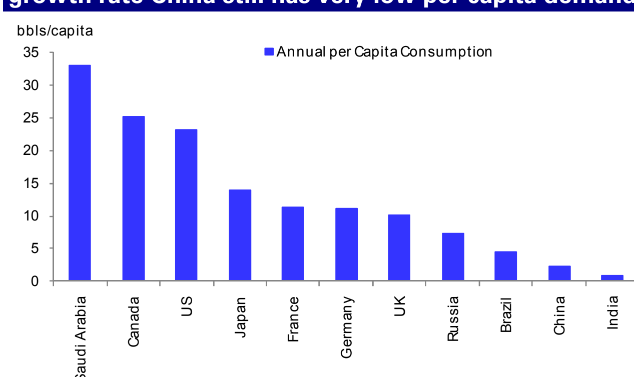
Continued growth in world crude demand is likely to be driven by non-OECD countries, in particular China and the Middle East. Demand in non-OECD countries is projected to expand at over three times the rate of that of OECD nations (3% relative to 0%). However, in spite of these comparative growth rates, non-OECD countries will still represent only 46% of global oil demand in 2015, rising to 49% by 2030 according to data from the EIA. China will continue to represent the greatest source of growth with demand expected to grow by an average 4.5% across the same period.

Figure 165: Avg. growth rate of oil demand – non-OCED has been a key driver over last 10 years



Source: BP Statistical Review of World Energy, June 2010

Figure 166: Oil consumption/capita (2009) – despite its growth rate China still has very low per capita demand



Source: BP Statistical Review of World Energy, June 2010, World Bank Development Indicators 2009

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

If it sustains its high levels of GDP growth, China's oil consumption per capita will likely converge over time towards the level of countries such as the US or Japan. Moreover, with Chinese oil demand forecast to grow at 4.5% p.a. from 2009 to 2015, China is likely to consolidate its position as the world's second largest consumer of oil, consuming an estimated 11mb/d by 2015 according to EIA estimates.

While absolute demand is increasing, it should be noted that energy intensity is in fact decreasing as OECD economies continue to focus on the services sector. The IEA estimates that energy intensity has declined by an average 2% p.a. since 1996 and will continue to decline by a similar level out to at least 2014. While much of non-OECD economic growth is energy intensive industry, the new facilities and cities being built for example in China are highly energy efficient, thereby reducing future energy intensity.

Demand by sector

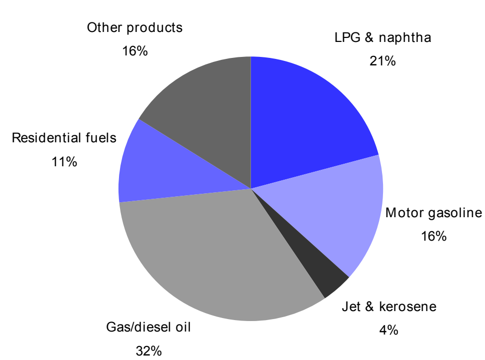
The three principal energy-generating uses for oil include transportation, power generation and heating. However, oil is also used for alternative non-energy, or process functions e.g. as a raw material in the petrochemicals industry. All non-transportation uses are commonly referred to as "stationary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

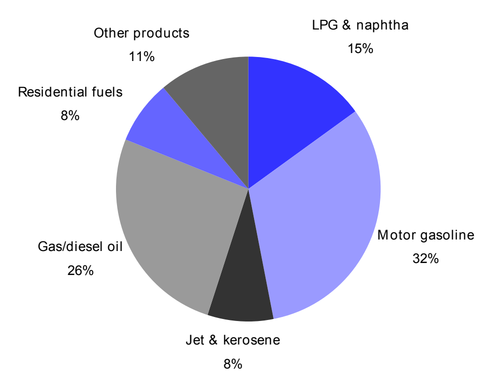
The composition of oil demand by sector is by no means uniform across all countries. Mature economies are characterised by well-developed distribution infrastructures, service-based industries and high levels of private vehicle use. Consequently, gasoline and distillate form the bulk of end-product demand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

Figure 167: Chinese end-product demand breakdown



Source: International Energy Agency

Figure 168: Total OECD end-product demand breakdown



Source: International Energy Agency

Climate influences oil demand, particularly in the northern hemisphere.

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.

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

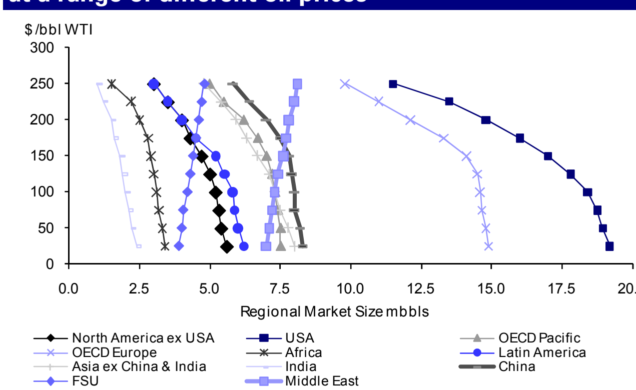
In theory, oil demand and price have an inverse relationship.

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.

…whilst transport fuels are relatively price inelastic.

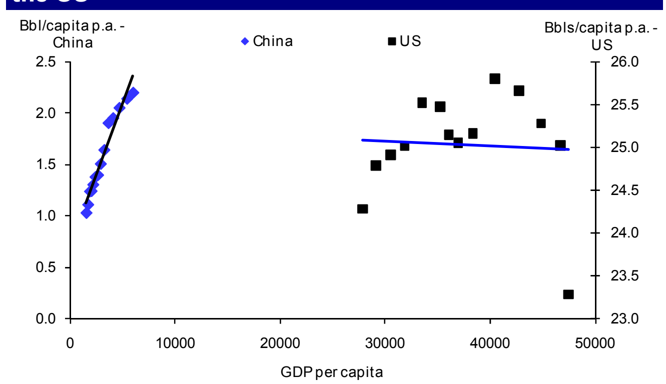
Transportation fuel, by contrast, is relatively price inelastic as no readily available substitute exists as yet i.e. it is a captive market. However, changes in spot crude prices do not tend to pass through immediately to retail prices as a result of government policy. Firstly, a large tax component 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.

Figure 169: Price elasticity - Regional estimated demand at a range of different oil prices



Source: Deutsche Bank estimates

Figure 170: Income elasticity of oil demand in China vs. the US



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

Income

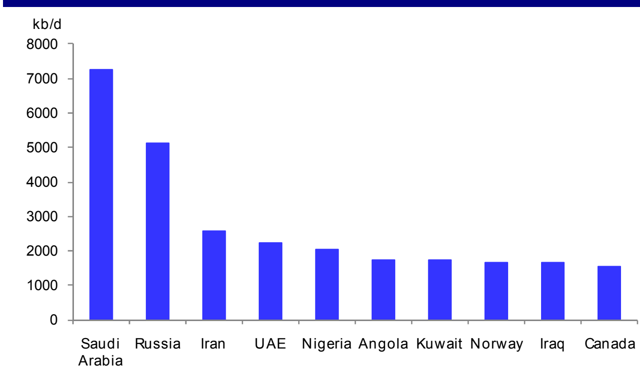
Historically, the main driver of demand growth has been income (or GDP). Strong economic growth, as measured by rising GDP per capita, boosts levels of oil demand, as industry is developed and people start to consume more energy-intensive products such as motor vehicles and domestic appliances. This 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

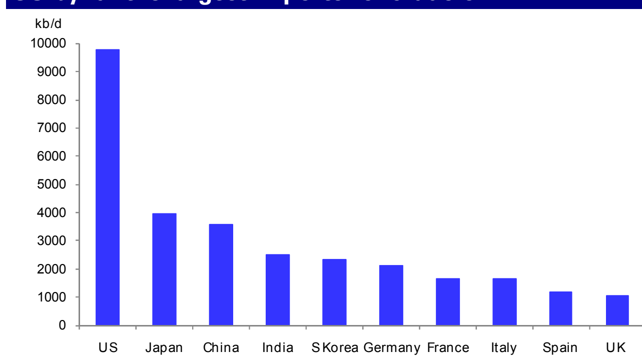
With OPEC controlling 77% of total global oil reserves, it goes without saying that a significant portion (41% in 2009 – and this following a 14% production quota cut) of the world's oil supply is derived from its member countries. The graph below shows the world's largest exporters of oil in 2008 and clearly indicates how dependent the world is on Middle Eastern and OPEC crude oil.

Figure 171: World's largest net exporters in 2009- Saudi Arabia dominates



Source: EIA

Figure 172: World's largest net importers in 2009 – the US by far the largest importer of crude oil

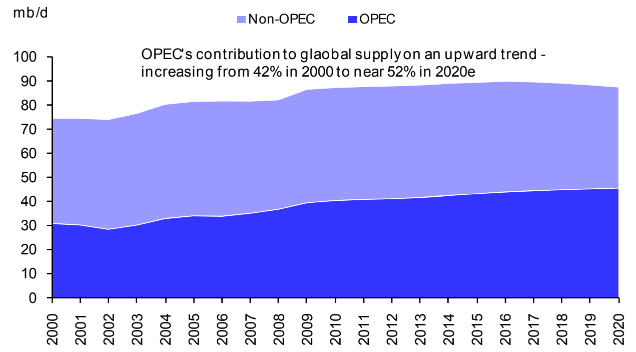


Source: EIA

In its reference scenario (published in the 2009 World Energy Outlook), the IEA forecasts that despite an increased focus on sourcing energy elsewhere, total non-OPEC supply will only grow at an average 0.4% between 2008 and 2030. This growth will initially be driven by biofuels and OPEC NGLs, with substantial increases in crude supplies from the GoM, Canada's oil sands, the FSU, Brazil and Africa. Over the same period OPEC crude production is forecast to increase by almost 1%, contributing c.61% to global crude supply by 2030 according to estimates by Wood Mackenzie. Of note, a big chunk of this growth is expected to come from NGLs, with the IEA estimating that NGLs should represent c.55% of total liquids production growth in OPEC between 2008 and 2014. Splitting the data another way shows (unsurprisingly) that Non-OECD countries constitute the bulk of global supply (79% in 2009), and will also see an upward increasing trend across the same period, with Wood Mackenzie estimating that some 85% of crude oil production will be sourced from non-OECD countries by 2030.

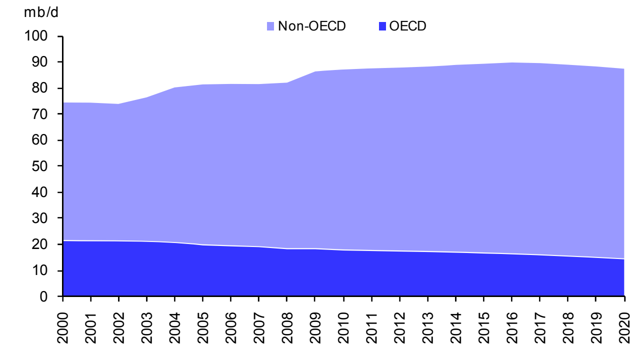
As illustrated in the chart above, the US is the world's single largest importer with net imports of crude and products increasing every year. However, given both Canada and Mexico are two of the US' largest suppliers, it is not North America but Asia Pacific that is the largest regional importer. On the export side, Saudi Arabia and the Middle East are the largest net exporting country and region respectively, an accolade both have held for many years and are likely to continue to hold in the future, particularly as Iraqi production ramps up.

Figure 173: OPEC oil production set to increase to over 52% by 2020 and 61% by 2030



Source: Wood Mackenzie GOST

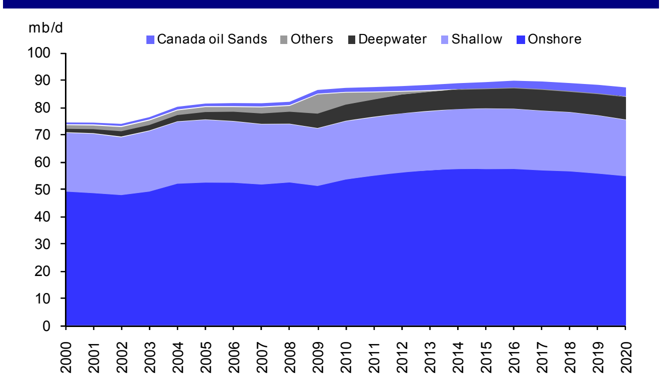
Figure 174: Unsurprisingly Non-OECD contribution to global oil production will also increase



Source: Wood Mackenzie GOST

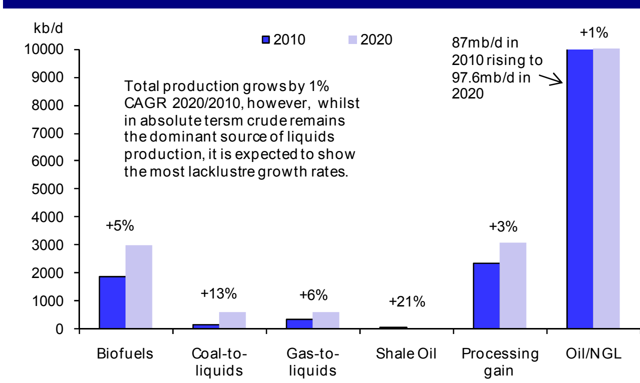
Access to resource has become increasingly challenging for integrated oil companies over recent years as the expertise and indeed financial clout of national oil companies has grown. As such we have seen an increasing trend toward more unconventional oil production such as deepwater and oil sands at the oil majors a trend which looks set to continue as projects come on-stream in Brazil, the US GoM, Western Africa to name a few. 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%). Looking at the bigger picture in the right hand figure below, we consider growth in oil supply vs. growth in other liquid fuels across the same period. What is clear is that while crude remains the main source of liquid energy in absolute terms, at 1% CAGR between 2020 and 2010, its growth is somewhat lacklustre when compared to that of bio-fuels (+5%) or gas to liquids (+6%); albeit both are growing from a very small base.

Figure 175: Unconventional oil production looks set to grow in importance



Source: Wood Mackenzie GOST

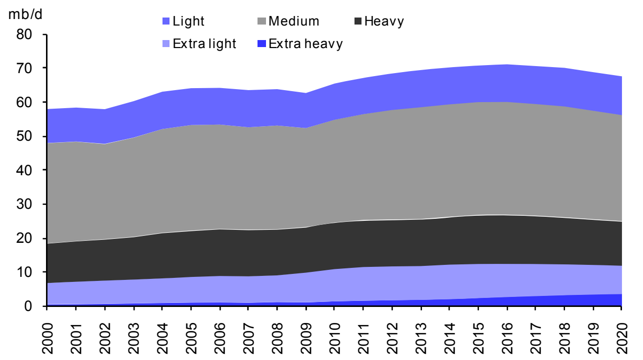
Figure 176: Growth in other non-crude sources of energy far superior to that of oil supply between 2010-2020



Source: Wood Mackenzie GOST, Deutsche Bank estimates

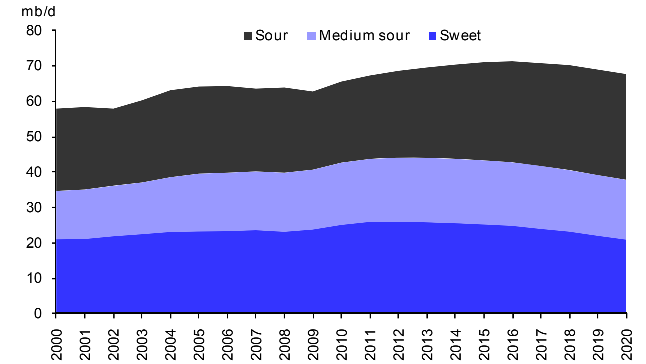
Moreover, as the figure below shows, future oil production is expected to be increasingly heavy and sour. Heavy and extra heavy crudes currently represent some 23% of global crude production but this is expected to increase to nearer 27% according to Wood Mackenzie estimates as production at the Canada oil sands and Venezuela's Orinoco belt ramp up. Similarly, production of sour crude is also set to increase largely as a result of increased production in the heavy crude regions mentioned above, but also Iraq and Saudi Arabia are set to see substantial increases in production of sour crude.

Figure 177: Crude oil production is becoming increasingly heavy....



Source: Wood Mackenzie GOST, Deutsche Bank

Figure 178: ....and increasingly sour...over 50% of crude produced in 2030 will be sour



Source: Wood Mackenzie GOST, Deutsche Bank

Inventories

The other key fundamental element that impacts oil prices is the level of crude and product inventories, as these go some way to smooth any fluctuations in supply and demand. As such any movements in inventories can also impact the market and the price of oil. The world's largest storage capacity is unsurprisingly in the US, which first started storing oil in 1975 when oil supplies were cut off during the 1973-4 oil embargo in an attempt to mitigate future oil disruptions. This prompted the creation of the Strategic Petroleum Reserve (SPR), an emergency petroleum store which is maintained by the US Department of Energy (DOE). It is the largest emergency supply in the world with current capacity to hold 727mbbls of crude oil (theoretically 37 days of supply at current consumption levels). Elsewhere, Japan also has significant inventory capacity (583mbbls), while China has begun to expand its SPR targeting capacity of some 685mbbls by 2020. In Europe, governments require that oil companies are required to keep a specified minimum level of crude and oil products (typically 90 days consumption) in inventory as opposed to having a separate, stand alone SPR.

The Energy Information Administration (EIA, part of the DOE) publishes weekly inventory data for crude, crude products and refinery utilisation in the US which the market eagerly awaits, as it is largest petroleum inventory in the world and is thus used as an indicator to estimate current capacity/tightness in the market. Another widely watched report is the IEA's monthly Oil Market Report 'OMR' that reports crude and product inventory levels in OECD countries.

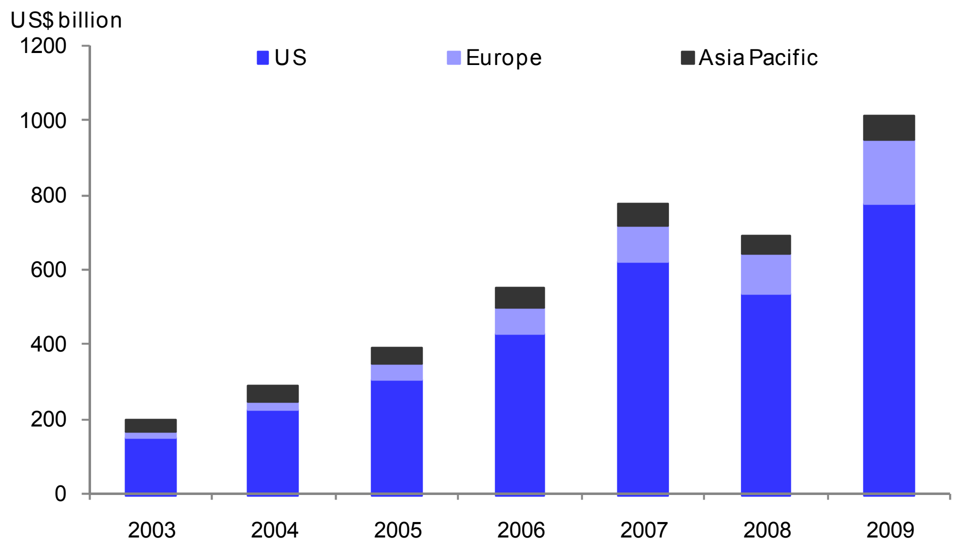
Physical vs. Financial

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 under management in exchange traded products has exploded since 2003, growing by an average 30% pa. Moreover the volumes of exchange traded products (ETPs) has also exploded with almost 2400 ETP currently in circulation from a paltry 260 in 2003. This highlights the ever increasing importance of the financial market in impacting on the oil price.

Figure 179: Exchange Traded Products Assets Under Management have grown significantly since 2003



Source: Deutsche Bank

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. For example, when Brent was trading at a premium to WTI over a sustained period of time in 2009 (typically it's vice versa given US the world's largest consumer and importer of crude) this indicated that 1) the US was oversupplied 2) Europe, due to a number of issues including disruptions in Nigeria and an outage on the North Sea, appeared at risk of entering a tight market. This type of trade also impacts on the heavy-light spread (i.e. the difference between for example heavy Russian Urals and light Brent) between crudes of varying API quality.

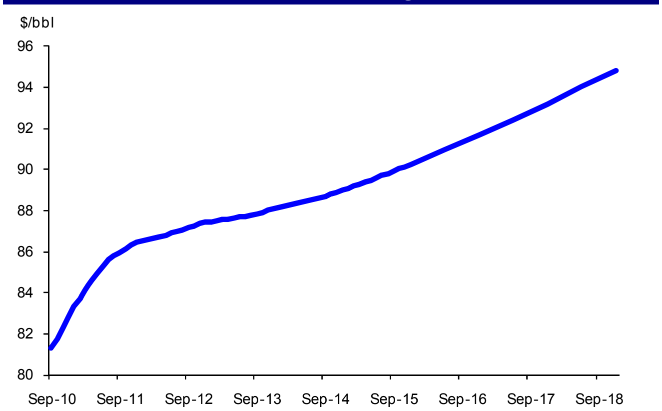
Inter-commodity: Crude is not traded in isolation and is in fact of limited use without being turned into oil products. Thus the relationship between crude and oil products is crucial in energy markets. For example, from a commercial point of view, if diesel is trading at a strong premium to gasoline, 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

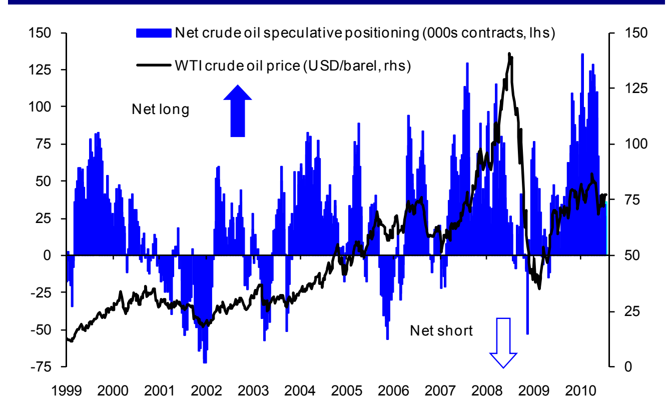
The forward curve: As levels of financial involvement in oil trading have increased, the importance of the futures curve has increased as an indicator of market sentiment (albeit it has not always necessarily proved itself to be a good predictor of the actual forward price). The shape of this curve reflects 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 more often than not in backwardation as short-term supply constraints continue to support prices.

Figure 180: The forward curve – upward sloping thus the oil market is currently in contago



Source: Bloomberg Finance LP, data as of 30th July 2010

Figure 181: 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

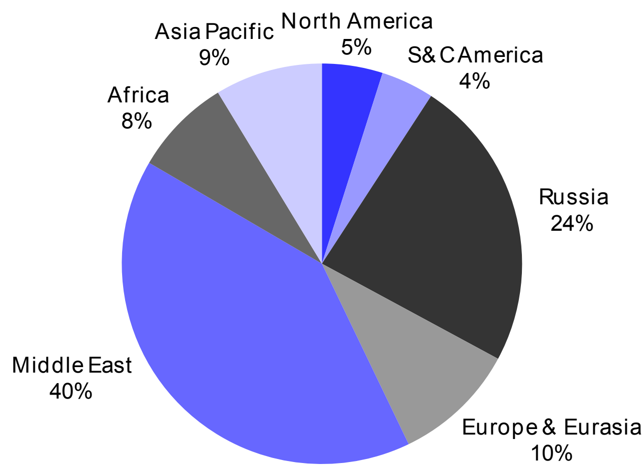
The clean fuel of choice

Natural gas is the world's third largest source of primary energy

Natural gas is the world's third largest source of primary energy, accounting for 24% of total energy use in 2009. Gas markets are generally regional owing to the limitations of infrastructure, transportation and currency pricing. We expect this to gradually evolve as technologies such as LNG, together with increasing environmental pressures and favourable pricing provide strong incentives to both private industry and governments to opt for gas over coal or oil as the source for energy generation. The natural gas market, whilst still 'young' compared to the oil market is nevertheless worth an estimated $850bn per year based on 2009 demand of 291bcf/d and a 5-year average Henry Hub price of $7.70/mmbtu.

Proven global natural gas reserves stand at 1.1tln/boe according to the 2010 BP Statistical Review, some 10% below those of oil (20% inclusive of the oil sands). This near parity between oil and gas reserves is a relatively new occurrence. Commercial gas reserves have risen by almost 30% over the last decade, in part because oil companies have begun to search for gas in its own right, but also because gas which historically would have been flared is now being re-injected for later recovery. Despite the increased focus on gas reserves, natural gas demand has not kept pace with discoveries in recent years. Consequently the reserves/production ratio for natural gas is over 60 years, compared with 43 years (inc. Canadian oil sands and based on 2009 production levels) for oil.

Figure 182: Regional disposition of natural gas proved reserves 2009



Source: BP Statistical Review 2010, Deutsche Bank

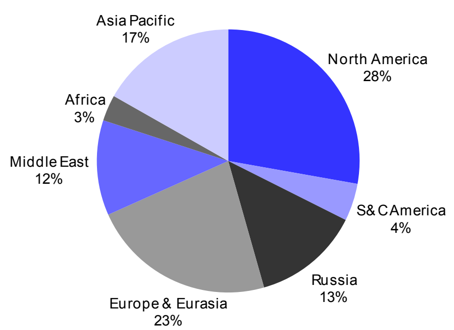
Gas demand

Demand for natural gas achieved important levels in recent years as gas has increasingly grown to be viewed as a viable source of energy due to improvements in technology, increasing instability in oil rich nations and the fact that gas is less environmentally damaging than oil. Despite a sharp 2% fall in consumption in 2009 as global economic recession impacted demand from industry, average compound growth in demand for gas over the past decade of 2.4% compares with compound oil growth demand of 1.0% over the same period. As economies recover gas demand is expected by the EIA continue growing by at least this level through to 2013.

Demand by region

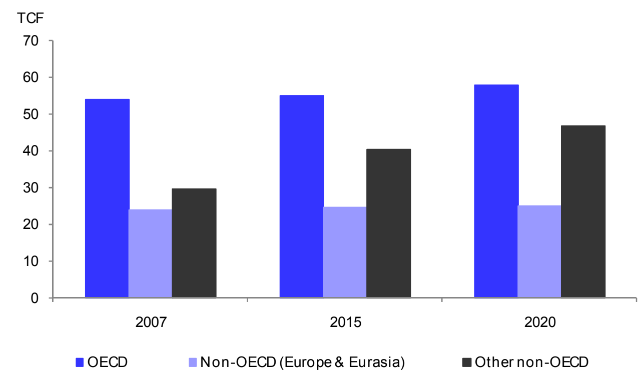
The largest consumers of gas in the world are the US and Russia, the main difference being that Russia is self-sufficient in gas while the US has shown a supply deficit since 1970. US domestic gas supply as a proportion of consumption troughed in 2005 at 82%, albeit it has subsequently increased hitting 91% in 2009 as production of shale gas has increased. Europe, with its historic focus on oil projects, imported c.13.6TCFbcm of gas in 2008 (20% of which was LNG) and accounted for 55% of total global gas trade movements. However, going forward, growth in gas demand is expected to come primarily from Asia, notably China and India where demand is expected to grow by more than 5% across p.a. out to 2030. Overall, the IEA forecasts demand growth of some 4% p.a. in non-OECD Asia between 2007 and 2030, effectively more than doubling current demand in this region from 11.3TCF in 2007 to 26.4TCF in 2030. Demand in OECD countries, which currently account for c.50% of gas consumption, is expected by the IEA to decline to 41% as a proportion of total global demand over the same period. Overall the IEA expects global gas demand to grow by an average 2.5% p.a. between 2010 and 2015 (or 1.5% between 2007 and 2030).

Figure 183: Gas Demand by region in 2009



Source: BP Statistical review 2010

Figure 184: Forecast Gas Consumption by region

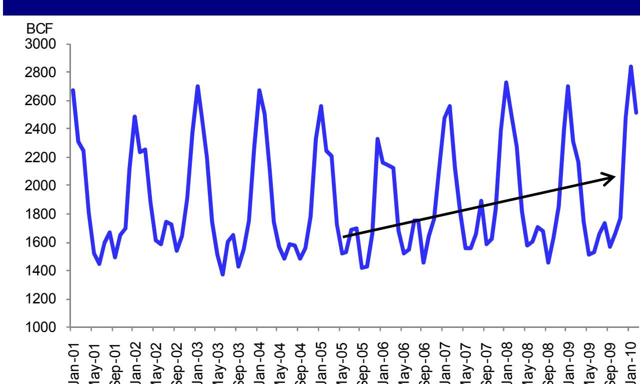


Source: IEA World Energy Outlook 2009

To a greater extent than oil, gas is affected by the weather, fuel competition and storage

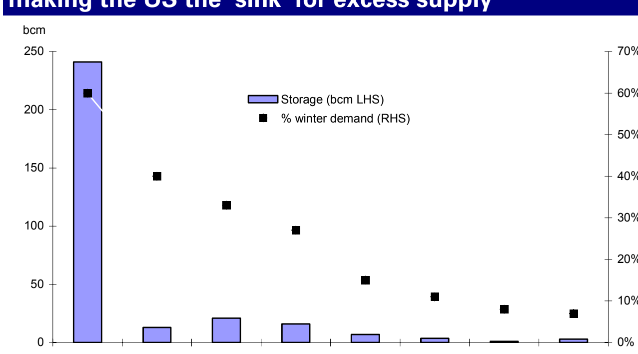
To a greater extent than oil, gas demand is affected by the weather, inter-fuel competition and storage. As clearly illustrated in the chart below, demand for gas usually peaks during the colder winter months due to increased residential demand for heating. One noticeable trend however to emerge in recent years is a mini-peak in gas demand in the summer months due to increased electricity generation demand in summer as a result of the increasing popularity of air conditioning. Unlike the majority of crude uses, natural gas can be replaced with either fuel oil or coal by energy generators depending upon which is most economical at any given time. As such, when gas prices become too high, many power generators can switch to a cheaper substitute where possible thereby depressing demand for gas, which in theory eventually reduces the gas price.

Figure 185: Seasonality of US gas demand



Source: EIA Natural Gas Monthly data

Figure 186: US storage facilities dwarf those of Europe making the US the 'sink' for excess supply



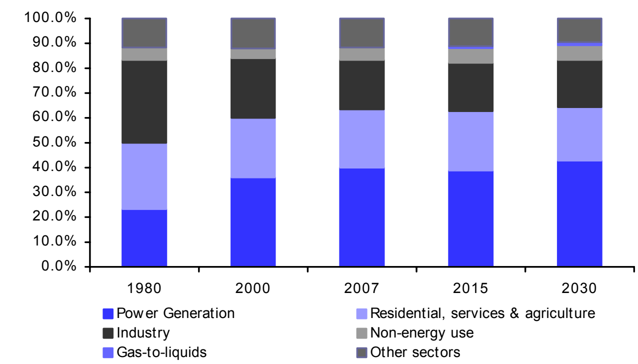
Source: IEA World Energy Outlook 2009

Additionally, natural gas storage levels will have a significant impact on the commodity's price; when storage levels are too low, the market interprets it as there being a smaller supply cushion hence prices will generally rise. 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. See below for further detail on gas storage.

Demand by Sector:

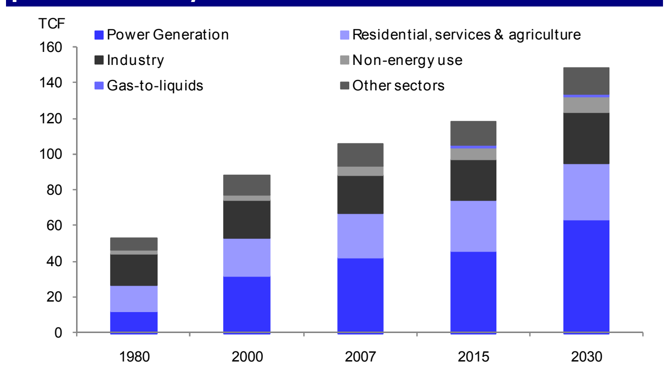
The principal uses of gas are for electric power generation, industrial sector processes (such as refrigeration, process heating/cooling) and other (primarily heating, air-conditioning and ventilation for both residential and commercial purposes). Power generation accounts for the bulk of consumption (c.39% by 2015) and the IEA anticipates that the sector will remain the leading driver of gas demand in most regions, accounting for some 45% of the increase in world demand out to 2030 i.e. gas demand in the power sector will grow by a CAGR of c1.7% between 2007 and 2030 and will represent c.41% of total gas demand in 2030.

Figure 187: Natural gas demand by sector – power and residential dominate



Source: Deutsche Bank

Figure 188: Natural gas demand growth by sector – power is the key driver



Source: Deutsche Bank

Gas Supply

Since 1996 gas production has grown at a compound rate of 3%

In 2009 global gas production fell by just over 2% to reach 105TCF (49.8mboe/d), marking a break with a long term trend of steady upward growth that had seen production more than triple since 1970. This reflected the sharp downturn in industrial activity associated with the economic crisis which led to sharp declines in demand for power, not least in the mature economies of the OECD. With demand slipping by some 2% this has seen global gas markets move to a state of potential oversupply, encouraging producers to restrict production. Absent a much stronger than anticipated recovery in global economic growth, gas markets look set to remain in a position of potential excess supply 2012/13 at the earliest.

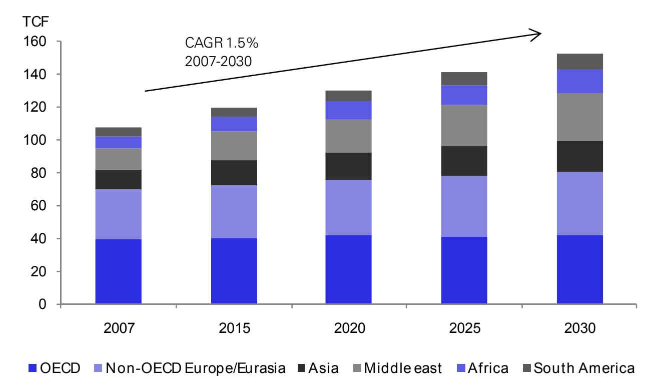
OECD production faltering – for now

At present approximately 37% of gas production is derived from OECD countries, a statistic which looks set to change over the longer term as production ramps up in Russia and LNG projects around the world are implemented. Indeed, the EIA estimates that by 2030 only 27% of gas production will be derived from the OECD, with the majority of new production coming from Russia. The biggest increase however is likely to be seen in the Middle East (CAGR of 3.6% across the period of 2007-2030), primarily due to LNG projects in Qatar and increased production in Iran.

Although as with the US unconventional sources could afford long term relief

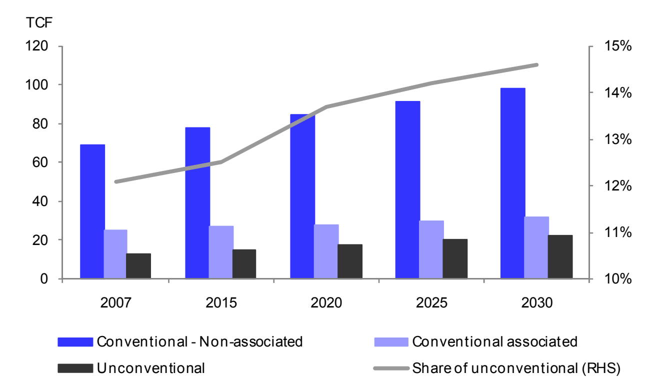
The other notable trend is the expectation that unconventional gas will grow in significance out to 2030. The IEA estimates that unconventional production will grow at a CAGR of 2.5% out to 2030 (vs. overall global growth of 1.5%) taking its contribution to gas supply from the current 12% to near 15% by 2030. Most of this growth will come from various tight gas/shale gas/CBM projects in the US, although unconventional gas production is also forecast to grow in Australia, China, India and Europe (albeit the share of unconventional gas to total gas production in these regions is expected to remain small).

Figure 189: Forecast gas production by region



Source: IEA World Energy Outlook 2009

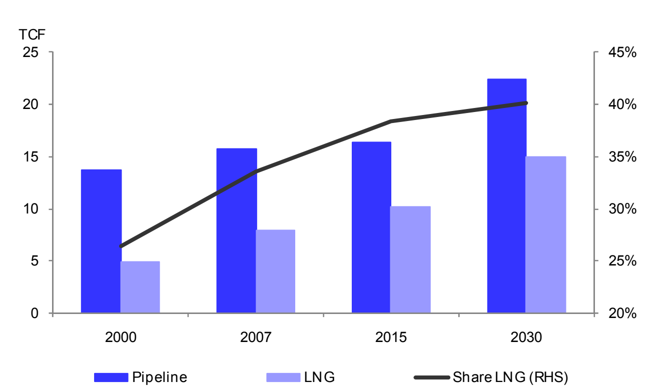
Figure 190: Gas production by type



Source: IEA World Energy Outlook 2009

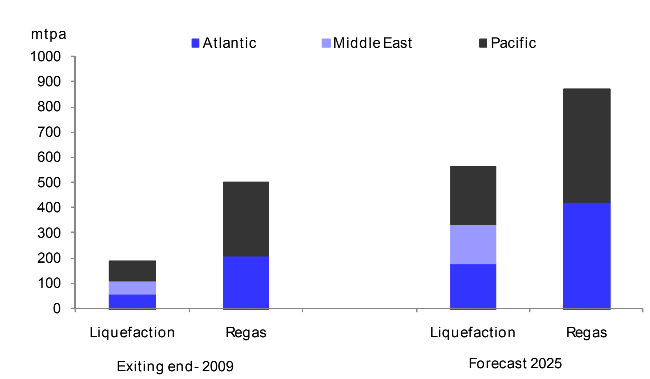
Historically, because of the challenges associated with transporting gas over large distances and limitations on storage the major centres of production have tended to be within piping distance of the major demand centres. However, as indigenous production not least in Europe starts to decline so the delivery of gas in liquid form as LNG from often stranded or displaced sources is likely to become more prevalent. LNG as a proportion of supply has been increasing over the last number of years, a trend the IEA expects will continue through to 2030. A glance at its forecasts for world inter-regional natural gas trade indicate that the contribution of LNG to international gas trade is expected to increase from the current 34% to nearer 40% by 2030. Beyond the decline in indigenous supply sources, this is as a result of both new LNG capacity coming on-stream, but also as a result of efforts from countries to diversify sources of supply, particularly in Europe where most importing countries are dependent on Russia as a key source of supply. The figure overleaf shows the number of planned re-gas facilities in Europe – which if all were to materialise would result in a 150% increase in regas capacity by 2025 from 2009 levels of 106mtpa.

Figure 191: LNG's % of global trade set to reach 40%



Source: IEA World Energy Outlook 2009

Figure 192: Re-gas capacity set to increase by c.75%



Source: Wood Mackenzie LNG tool

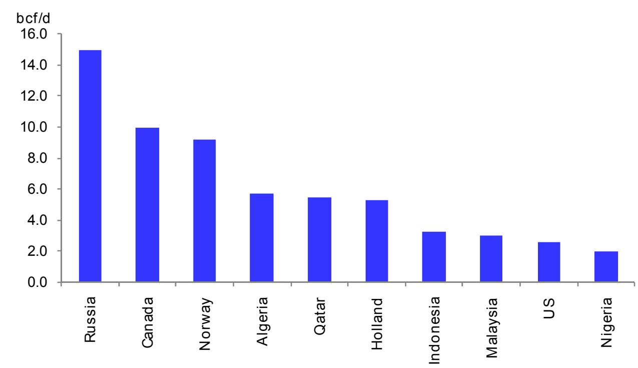
Figure 193: Existing and planned LNG regasifcation terminals in Europe

Source: Deutsche Bank, Wood Mackenzie

Gas reserves – more dispersed than oil

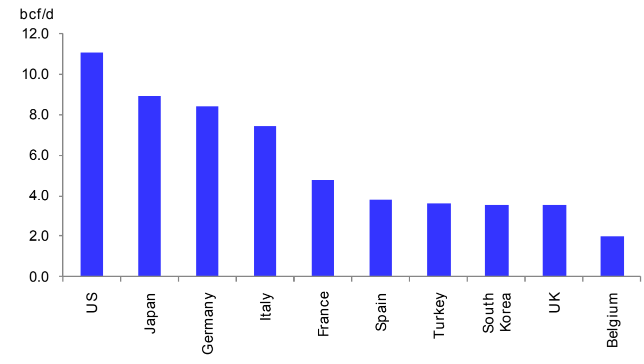
Gas reserves are for the main part more geographically dispersed than oil, with many of the world's top consumers holding significant domestic reserves. Russia has the world' largest gas reserves (23% of total), and since 2002 is also the world's largest producer (58.2bcf/d in 2006) and largest exporter of gas. The fact that c63% of gas reserves are found in regions other than the Middle East increases the appeal of gas to governments wishing to reduce their energy dependence on this region.

Figure 194: World's largest net gas exporters 2008



Source: BP Statistical Review 2009

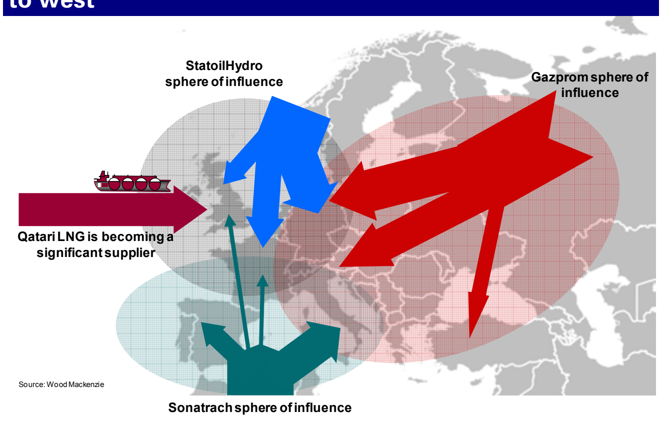
Figure 195: World's largest net gas importers 2008



Source: BP Statistical Review 2009

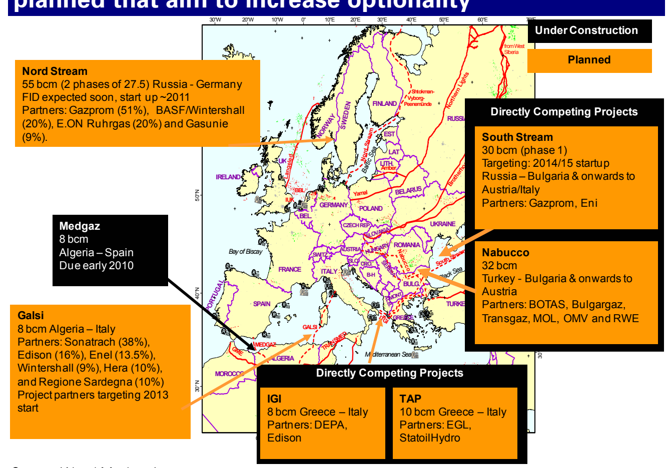
Factors impacting gas supply include pipeline capacity, storage and increasingly whether there are sufficient regasification facilities available to handle LNG supplies (refer to the section on LNG for further detail on regasification). Prior to the LNG era, pipelines were the only way to transport gas from the wellhead to the market, a fact which to some extent stunted the growth of gas as a reliable source of energy on the basis that gas located in remote locations was effectively stranded if transporting it via pipeline was not economic (distance/technical reasons). While the US has an extensive, interconnected pipeline system (a fact which has contributed to it becoming the largest gas market in the world that is often referred to as the "sink" for gas that cannot be sold elsewhere), Europe's pipeline infrastructure by and large can only flow gas east to west, which effectively impedes free movement of gas around Europe.

Figure 196: Majority of gas piped into Europe flows east to west



Source: Wood Mackenzie

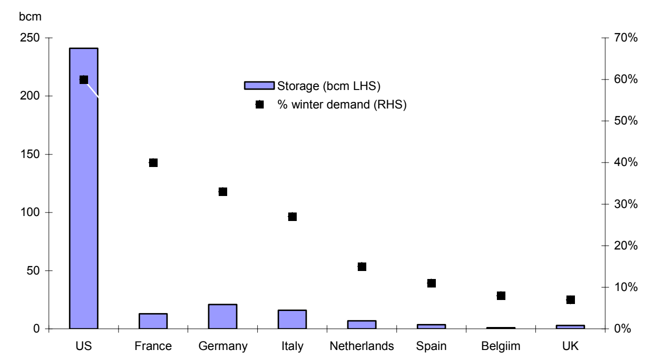
Figure 197: There are a number of new pipelines planned that aim to increase optionality



Source: Wood Mackenzie

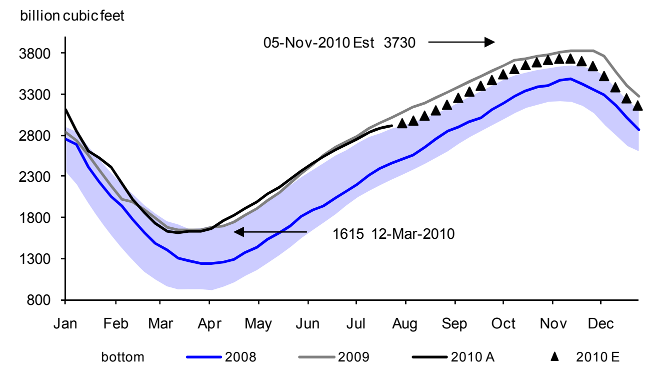
Finally given the seasonality of natural gas demand, storage facilities are used to meet peak demand in winter (the winter heating season) and in summer (gas used for electricity generation to power increased air conditioning demands). Storage facilities tend to be depleted salt caverns (or other aquifers) 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 as illustrated in the figure below. However, with countries putting increased focus on ensuring the necessary infrastructure to support a liquid spot market is put in place, there are plans to increase the levels of storage capacity, particularly in Europe.

Figure 198: Gas storage in existence



Source: Wood Mackenzie

Figure 199: US weekly gas storage data



Source: Deutsche Bank

Gas Pricing

Unlike oil markets, gas markets are regional and for the main part, not liberalised

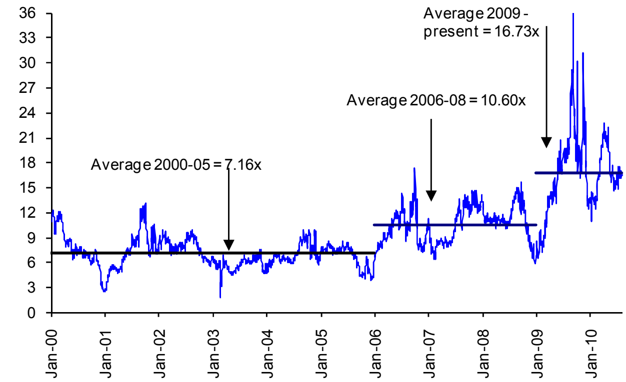
Unlike oil markets, gas markets are regional and for the main part, not liberalised. In fact, until 2000, natural gas prices were linked to oil prices limiting competitive pricing and free market mechanisms. Even today despite some 'deregulation', markets in Europe remain opaque and only the US and the UK are transparent and for the main part, liberalised. On the most basic level, natural gas is priced based on energy content and proximity to consuming markets, however, pricing mechanisms vary considerably across the world. We discuss the key pricing regimes (US, Europe and Asia) below.

US – Henry Hub gas pricing

All gas sold in the US whether piped gas or LNG is traded on both the spot and futures market much in 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.

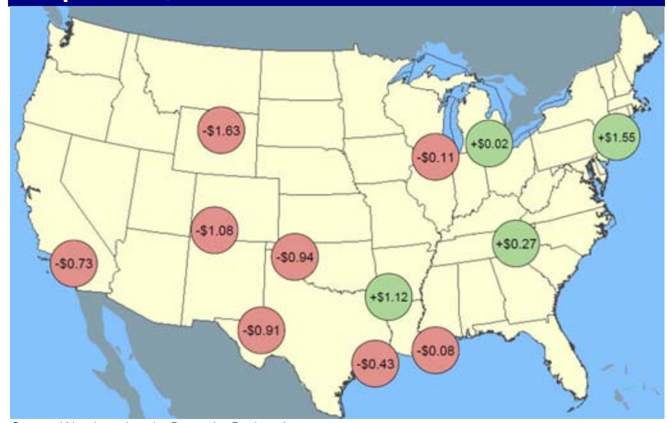
While supply interruptions have caused spikes in pricing, the longer term price tends to reflect limitations in resources and their rates of development, albeit the price of interchangeable, competing fuels (namely coal and fuel oil) will also impact. In the long term, the drive by the US to reduce its dependency on foreign sources of energy could impact longer term gas prices as gas derived energy production is ramped up thus increasing the US appetite for both domestic natural gas and LNG. However, nearer term the outlook is somewhat different. Historically, HH traded at an average 7:1 ratio to the price of crude oil, but recent years have seen this relationship break down with the ratio rocketing as high as 20:1 at times. Since the renaissance of US domestic gas production levels, the US gas market is more than well supplied even before LNG volumes (currently 2% of total consumption) are taken into consideration. Thus as long as this situation persists, the pricing relationship between crude and natural gas in the US is unlikely to return to historic norms.

Figure 200: US Henry Hub gas price vs. the oil price equivalent – ratio has disappeared of late



Source: Bloomberg Finance LP, EIA, Deutsche Bank estimates

Figure 201: Gas price differentials within the US – East at a premium, west at a discount



Source: Wood mackenzie, Deutsche Bank estimates

Europe – a mixed bag with many moving parts

The majority of gas sold in Europe is sold under long term oil indexed contracts. This is as a result of the fact that historically in order for producers to be able to sanction the development of a gas project, volumes needed to be sold forward under some agreed pricing mechanism in order to guarantee a market for gas. Furthermore, most gas consumed in Europe is pipeline gas coming mainly from Norway, Russia or Algeria. However, with LNG an increasingly viable option, more and more European countries are investing in regasification facilities in order to diversify sources of gas.

Spot pricing in Europe: is nascent. However, a number of disputes between Russia and the Ukraine which reduced gas supply to Europe for periods in 05/06, 07/08 and most recently in Jan 2009, coupled with the current oversupplied gas market have seen several countries establish or grow their gas trading platforms in order to 1) reduce dependence on Russian gas and 2) benefit from cheaper spot gas prices. At present the UK is the only European country with an 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. While a number of gas trading hubs have established themselves in continental Europe in recent years, a full move to spot pricing in Europe is not realistic in the near term for a number of reasons. Aside from the size, liquidity and transparency of gas markets in Europe, infrastructural limitations will impede a move away from LT contracts. 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, while access to other sources of gas via LNG remains limited at present given lack of regasification facilities in Europe. Finally, Europe is short gas storage facilities thus sufficient volumes of gas cannot be easily stored. However, as regasification capacity in Europe grows and as demand for gas increases, it is expected that trade on both spot and forward markets in Europe will also increase. The expectation that spot pricing in Europe will become more relevant in future years is starting to be recognised by key producers with both Statoil and Gazprom recently introducing spot gas prices as part of the basket of products against which gas is priced under long term gas contracts (to the extent that the contract in question also has access to a spot market). Indeed, we note that all gas sold in the UK, even volumes sold under a long term contract, is priced against NBP.

Long term contracts: 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 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 general key terms of long term contracts of Europe's second largest gas supplier (Statoil).

Figure 202: 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: Statoil average is that consumers must take a minimum of 80% of contracted volumes in any one gas year. Daily: Daily average volumes can fluctuate between 60% to 110% of the delivery obligation
Nomination	Long term contract customers can nominate volumes to be delivered 24 hours in advance of delivery. For Statoil c.85% of its long term contracts can nominate 24 hours ahead of delivery. The remaining contracts are newer and tend to have less flexibility.
Take-or-pay	If consumers take less than the 80% minimum in a gas year, they must pay for the difference between the volumes taken and minimum volumes permissible under the contract
Make-up volumes	Where a customer has paid for volumes but not taken them they are entitled to take between 50-80% of these 'pre-paid' volumes over the next 5 gas years (Note this is 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.

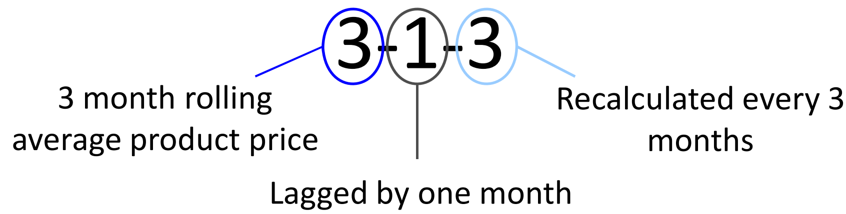
  All the different elements vary dramatically from contract to contract and indeed within a single contract but we try to illustrate above how indexation works in a European gas contracts.

- **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.

The above comments can be summarized pictorially as shown overleaf:

Figure 203: 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 estimates

Asia – oil parity and S-curves

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

- **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.

Each of these is depicted further in the later discussion of LNG markets and pricing.

Figure 204: Oil & Gas reserves, production and consumption by country

	Oil					Gas				
Countries	**Reserves**	**Production**	**CAGR**	**Consumption**	**CAGR**	**Reserves**	**Production**	**CAGR**	**Consumption**	**CAGR**
	Bn Bbls	**kb/d**	**99-09**	**kb/d**	**99-09**	**Tcf**	**Bcf/d**	**99-09**	**Bcf/d**	**99-09**
Algeria	12.2	1810.9	1.8%	331.1	5.9%	159.1	7.9	-0.5%	2.6	2.3%
Angola	13.5	1784.0	9.1%							
Argentina	2.5	676.3	-2.2%	473.1	0.6%	13.2	4.0	1.8%	4.2	2.9%
Australia	4.2	558.7	-1.1%	941.3	1.1%	108.7	4.1	3.2%	2.5	2.4%
Austria				270.4	0.8%				0.9	0.9%
Azerbaijan	7.0	1033.0	14.0%	59.7	-6.0%	46.3	1.4	10.5%	0.7	3.5%
Bahrain						3.0	1.2	3.9%		
Bangladesh				92.8	3.2%	12.5	1.9	9.1%	1.9	9.1%
Belarus				191.7	2.2%				1.6	0.8%
Belgium & Luxembourg				781.2	1.5%				1.7	1.6%
Bolivia						25.1	1.2	18.4%		
Brazil	12.9	2029.0	6.0%	2404.9	1.3%	12.7	1.2	4.8%	2.0	10.4%
Brunei	1.1	167.9	-0.8%			12.4	1.1	0.2%		
Bulgaria				97.6	0.5%				0.2	-1.8%
Cameroon		73.1	-2.6%							
Canada	33.2	3212.5	2.1%	2195.5	1.3%	62.0	15.6	-0.9%	9.2	0.8%
Chad	0.9	117.8								
Chile				332.9	2.9%				0.3	-4.0%
China	14.8	3790.4	1.7%	8625.2	6.8%	86.7	8.2	13.0%	8.6	15.2%
China Hong Kong				285.6	3.9%				0.2	-2.7%
Colombia	1.4	685.4	-2.0%	193.9	-2.0%	4.4	1.0	7.3%	0.8	5.3%
Czech Republic				205.4	1.7%				0.8	-0.5%
Denmark	0.9	264.5	-1.2%	174.1	-2.4%	2.3	0.8	0.8%	0.4	-1.2%
Ecuador	6.5	495.1	2.6%	216.5	5.1%				^	
Egypt	4.4	741.9	-1.1%	720.5	2.3%	77.3	6.1	14.1%	4.1	10.0%
Eq. Guinea	1.7	307.0	11.9%							
Finland				211.7	-0.6%				0.3	-0.3%
France				1833.4	-1.1%				4.1	1.2%
Gabon	3.7	229.0	-3.9%							
Germany				2421.6	-1.5%	2.7	1.2	-3.7%	7.5	-0.3%
Greece				417.1	0.8%				0.3	8.4%
Hungary				161.4	0.7%				1.0	-0.9%
Iceland				20.4	1.0%				-	
India	5.8	754.4	0.2%	3182.8	4.1%	39.4	3.8	4.6%	5.0	7.5%
Indonesia	4.4	1021.4	-3.2%	1344.3	2.8%	112.5	7.0	0.3%	3.5	1.4%
Iran	137.6	4216.0	1.6%	1740.7	3.6%	1045.7	12.7	8.8%	12.7	8.5%
Iraq	115.0	2482.0	-0.5%			111.9				
Italy	0.9	95.0	-0.9%	1579.5	-2.2%	2.3	0.7	-7.4%	6.9	1.4%
Japan				4396.1	-2.4%				8.5	2.3%
Kazakhstan	39.8	1681.6	10.3%	259.6	5.9%	64.4	3.1	13.6%	1.9	9.8%
Kuwait	101.5	2481.1	1.8%	418.5	5.6%	63.0	1.2	3.8%	1.3	4.5%
Libya	44.3	1652.0	1.5%			54.4	1.5	11.8%		
Lithuania				60.7	-0.3%				0.3	1.3%
Malaysia	5.5	739.8	0.0%	468.1	0.7%	84.1	6.1	4.4%	3.0	6.9%

Source: BP Statistical Review 2010

Figure 205: Oil & Gas reserves, production and consumption by country - continued…

	Oil					Gas				
Countries	**Reserves**	**Prod'n**	**CAGR**	**Consump'n**	**CAGR**	**Reserves**	**Prod'n**	**CAGR**	**Consump'n**	**CAGR**
	Bn Bbls	**kb/d**	**99-09**	**kb/d**	**99-09**	**Tcf**	**Bcf/d**	**99-09**	**Bcf/d**	**99-09**
Mexico	11.7	2979.5	-1.1%	1944.5	0.5%	16.8	5.6	4.6%	6.7	6.4%
Myanmar						20.1	1.1	21.0%		
Netherlands				1053.9	1.8%	38.3	6.1	0.4%	3.8	0.1%
New Zealand				148.1	1.3%		0.4	-2.9%	0.4	-2.9%
Nigeria	37.2	2060.8	0.0%			185.4	2.4	15.2%		
Norway	7.1	2342.1	-2.9%	210.6	-0.2%	72.3	10.0	7.9%	0.4	1.3%
Oman	5.6	809.6	-1.2%			34.6	2.4	16.3%		
Pakistan				413.6	1.3%	32.0	3.7	6.4%	3.7	6.4%
Papua New Guinea						15.6				
Peru	1.1	145.3	3.1%	188.1	1.7%	11.2			0.3	
Philippines				265.1	-3.4%				0.3	
Poland				553.2	2.5%	3.8	0.4	1.8%	1.3	2.9%
Portugal				269.3	-2.0%				0.4	6.7%
Qatar	26.8	1344.9	6.4%	209.4	15.1%	895.8	8.6	15.0%	2.0	4.2%
Rep. of Congo	1.9	274.3	0.3%							
Republic of Ireland				169.3	-0.1%				0.5	3.7%
Romania	0.5	92.6	-3.6%	211.3	0.8%	22.2	1.1	-2.5%	1.3	-2.3%
Russia	74.2	10032.1	5.0%	2695.1	0.3%	1567.1	51.0	-0.2%	37.7	1.0%
Saudi Arabia	264.6	9713.1	0.9%	2614.2	5.4%	279.7	7.5	5.3%	7.5	5.3%
Singapore				1001.9	4.9%				0.9	20.5%
Slovakia				82.6	1.2%				0.5	-1.4%
South Africa				517.9	1.3%				-	
South Korea				2327.0	0.7%				3.3	7.2%
Spain				1492.2	0.5%				3.3	8.7%
Sudan	6.7	489.8	22.8%							
Sweden				286.8	-1.6%				0.1	3.2%
Switzerland				262.1	-0.3%				0.3	1.1%
Syria	2.5	376.1	-4.2%			10.0	0.6	0.7%		
Taiwan				1014.2	0.5%				1.1	6.1%
Thailand	0.5	329.9	8.9%	975.4	2.2%	12.7	3.0	4.9%	3.8	7.4%
Trinidad & Tobago	0.8	150.7	0.7%			15.4	3.9	13.2%		
Tunisia	0.6	85.7	0.2%							
Turkey				620.9	-0.3%				3.1	10.0%
Turkmenistan	0.6	205.9	3.7%	119.5	4.1%	286.2	3.5	5.8%	1.9	6.1%
Ukraine				307.0	1.2%	34.7	1.9	1.6%	4.5	-4.0%
UAE	97.8	2599.0	0.3%	455.4	5.3%	227.1	4.7	2.4%	5.7	6.5%
UK	3.1	1448.0	-6.7%	1611.4	-0.7%	10.3	5.8	-4.9%	8.4	-0.8%
USA	28.4	7196.0	-0.7%	18686.2	-0.4%	244.7	57.4	1.1%	62.6	0.2%
Uzbekistan	0.6	107.1	-5.6%	100.6	-3.1%	59.4	6.2	2.5%	4.7	0.2%
Venezuela	172.3	2436.7	-2.5%	608.8	2.5%	200.1	2.7	0.2%	2.9	0.8%
Vietnam	4.5	345.3	1.6%			24.1	0.8	19.9%		
Yemen	2.7	298.0	-3.0%			17.3				
Other	5.6	985.5	0.7%	5551.8	2.1%	78.3	5.2	7.1%	11.6	8.7%
Total	**1333.1**	**79947.9**		**84076.9**		**6621.2**	**289.0**		**284.4**	

Source: BP Statistical Review 2010

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 206: 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.

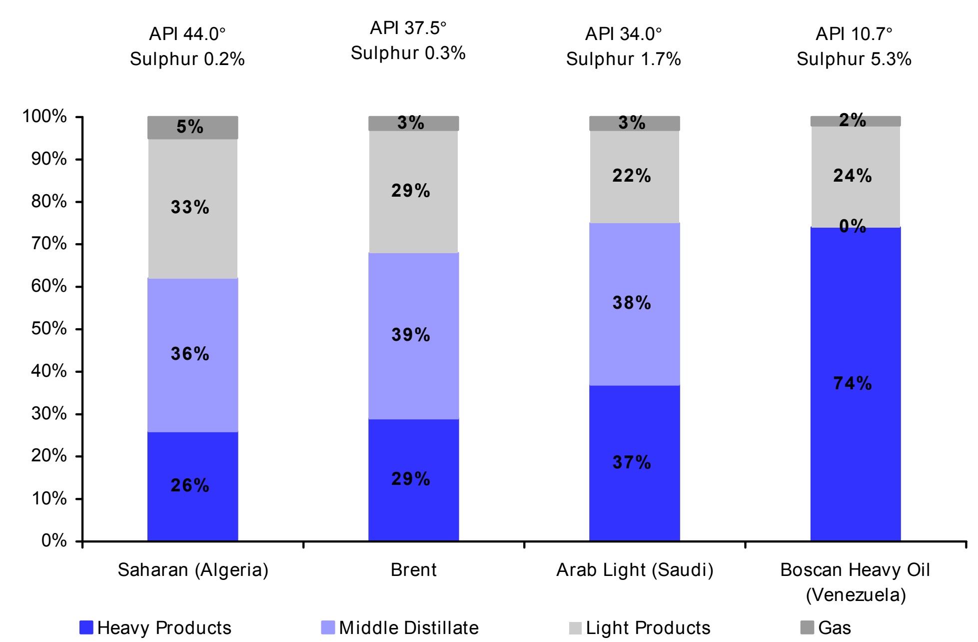
API Gravity = 141.5/SG at 60°F – 131.5

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.

Figure 207: Typical refining output of crude oil for selected blends



Source: Wood Mackenzie

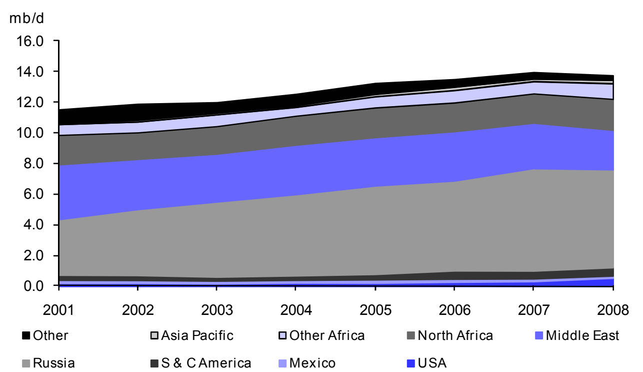
Both heavy and sour crude trades at a discount

In general both heavy and sour crudes trade at a discount due to higher processing costs and the fact that historically the majority of refineries were built to process light, sweet crude. The above diagram shows the typical refining slate of a number of different crude oils.

Trends in crude oil

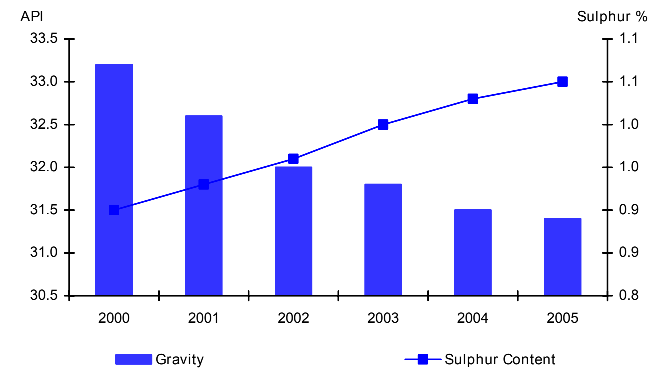
In Europe, the slate of crude available has changed in recent years as oil production in the North Sea has begun to decline. Supply is being replaced to some extent by the Russian Urals blend, which is both heavier and sourer. This is illustrated in figure below which indicates that imports from Russia have increased by 75% (from 3.7mb/d in 2001 to 6.4mb/d in 2008) over the last seven years. Globally, since 2000 the same trends have also been in evidence with production of heavier oils having increased by a total of 18% not least as heavier Middle Eastern oils produced by OPEC members have gained market share. Unsurprisingly, with OPEC forecast to steadily increase its share of global production this trend is expected to continue.

Figure 208: European crude imports (mb/d)



Source: Deutsche Bank, BP Statistical report

Figure 209: Trends in non-OPEC crude production



Source: Wood Mackenzie

In general, the early refineries were constructed to process light sweet crude (i.e. non-complex refineries) hence this has driven demand for light sweet crudes. However, in light of a trend to reduced production of light-sweet crude and with higher oil prices rendering the exploitation of heavy crude more economically attractive, there is growing interest in developing heavy crude resources. To this end the oil industry has been developing new, cost-effective methods for extracting heavy crude, upgrading it either in situ or at the wellhead, transporting the heavy crude or synthetic crude (syncrudes) to the refinery, and refining it to obtain high yields of valuable light and middle distillate fuels. Heavy investment has also been made by refineries (refer to section on refineries) in order to process and desulphurise heavy and/or sour oil. This trend will continue as oil regulations get tighter. 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 210: Gasoline and Diesel Maximum sulphur level

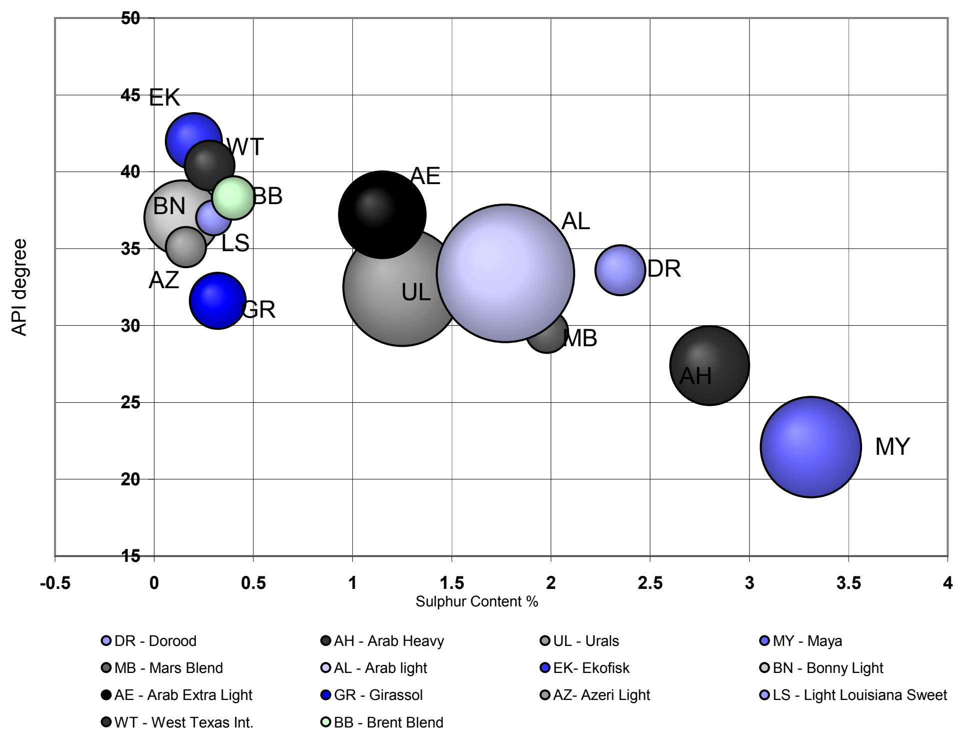
	Gasoline (ppm sulphur)				Diesel oil (ppm sulphur)			
Country	**2000**	**2005**	**Current**	**Started from**	**2000**	**2005**	**Current**	**Started from**
EU	150	50	10	2009	350	50	10	2009
USA	300	90	30	2006	500	500	15	2006
Canada	320	30	-	-	500	500	15	2006
Australia	800	150	50	2008	1500	500	10	2009
Japan	100	50	10	2007	800	50	10	2007
China	800	500	150	2010	2000	500	350	2012

Source: Deutsche Bank

Key Global Blends

The figure below shows the different characteristics of some familiar crude blends and highlights higher volumes of production in light but sour blends indicating that the need for refineries to de-sulphurise crude will increase in coming years. 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 two former blends were once produced in such high volumes that they became the key pricing benchmarks for crude oil.

Figure 211: Quality and Production volumes of crude oil 2006



Source: Deutsche Bank estimates, and ENI World Oil and Gas Review

Refining Overview

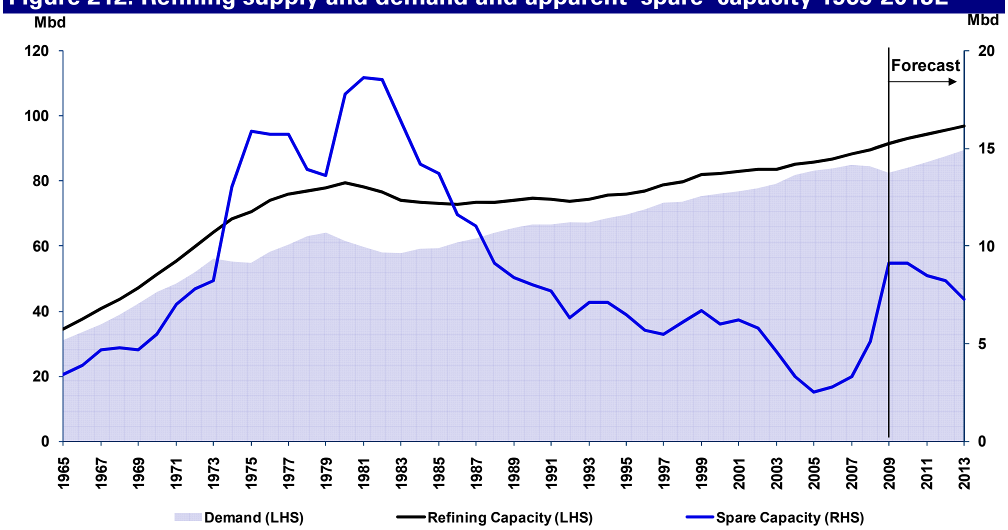
The Black Sheep of the family

Refining has long been the least favoured child of the integrated oil company's portfolio.

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.

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 212: Refining supply and demand and apparent 'spare' capacity 1965-2013E



Source: BP Statistical Review; DB estimates

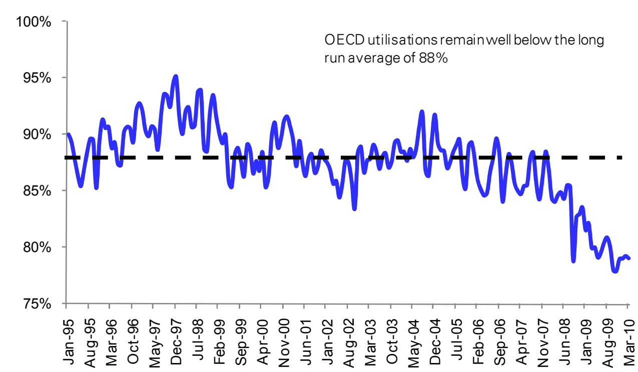
The 'Golden Age of Refining' more of a Golden Moment?

Recently refining profitability has, however, seen something of a renaissance

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.

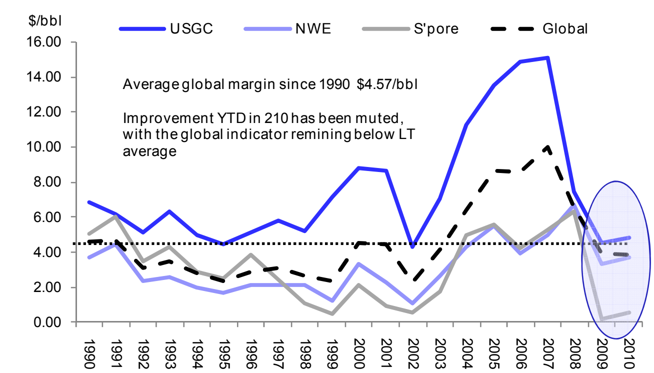
However, the financial crisis of 2008/09 sent the golden era to an early grave, with refining margins in 2009 dropping sharply to pre-2004 levels. Weak demand, a sharp increase in existing spare capacity (with the risk that new capacity additions currently under construction will further exacerbate the situation) and increased supply of both bio-fuels for blending and NGL production all put downward pressure on margins, with most majors now commenting that perhaps the Golden Era of refining was more of a "Golden moment". Whilst refining margins have recovered somewhat since the end of 2009, this is largely due to low utilisation rates with many refiners shutting-in units or reducing throughput to support margins. More telling perhaps is that a number of IOCs, particularly in Europe where margins remain significantly below long-run averages, are actively seeking to reduce their refinery exposure, with a sale of assets being the preferred route. However, finding a buyer has proved to be difficult, highlighting perhaps the extent to which industry believes the refining market is oversupplied.

Figure 213: OECD refinery utilization rates 1995-2010



Source: IEA

Figure 214: 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:

Refining at its simplest is about the separation of the different components of the crude oil barrel.

The impact of rising crude oil prices on conversion margins

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 below table which depicts the benefits to Total from a conversion plant inaugurated in 2006 for production of diesel from heavy fuel oil.

Figure 215: 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

However, this is not always the case as was demonstrated in 2009, when one of the key challenges for complex refiners was the sharp decline in the fuel oil-middle distillate crack spread. The majority of refinery shut-ins that occurred in 2009 were simple refiners with a product slate more biased toward fuel oil that is often sold to complex refiners for further processing. The closure of simple refiners meant less volumes of fuel oil were available on the market thereby supporting fuel-oil prices, the result being that the fuel oil-middle distillate crack spread fell dramatically.

The light-heavy spread

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

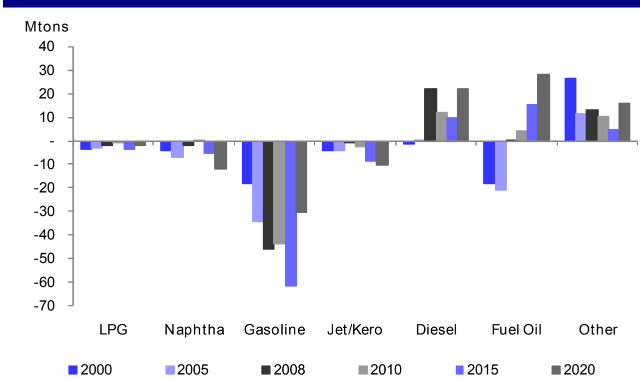
Theoretically, the prices of different crude oils should reflect variances in their composition and the different value of the product slate that emerges from their distillation. However, because not all refineries can process heavier, sour blends, at times of tightness in crude oil markets or if the 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. The result is that the differential between the heavy and light crude oils will increase beyond its theoretical value. In the past, this has meant that those refiners that had invested in the equipment necessary to process such blends have been able to capture this incremental value.

However, this phenomenon reversed somewhat in 2009 as OPEC production cuts reduced the availability of heavy crudes to the market. While there has subsequently been an improvement in the heavy-light spread as OPEC production has come back on-stream, with the majority of investment (both on-going and proposed) in refineries aiming to increase the ability of the refinery to process heavy crudes, there is a risk that going forward demand for heavy oil could exceed that for light oil, with prices eventually reflecting that.

Product imbalances

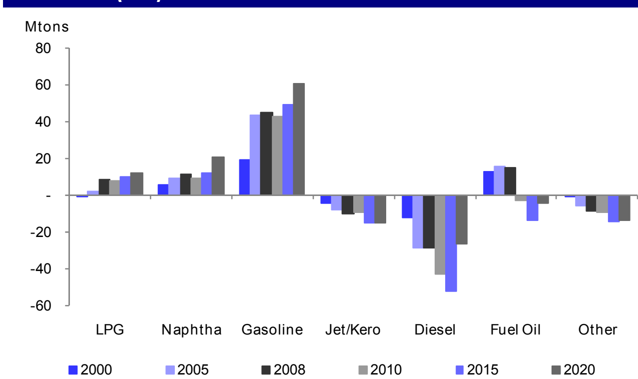
Although refining capacity globally may be in surplus, there are clear regional differences in capacity utilization. Moreover, whilst it is possible through investment to alter the products emerging from the refining process, ultimately the product slate cannot be tailored to exactly meet the needs of 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 216: US – Future product balances (Mt)



Source: Wood Mackenzie Balancing the World

Figure 217: 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.

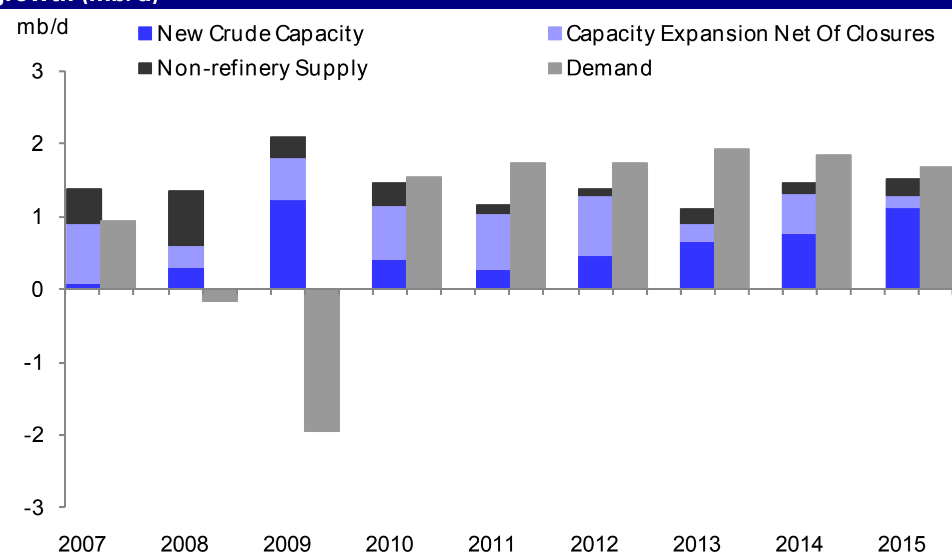
Conclusion: refining profitability the sum of many parts

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.

Figure 218: Planned global refining capacity additions and annual expected demand growth (mb/d)



Source: Wood Mackenzie; Deutsche Bank

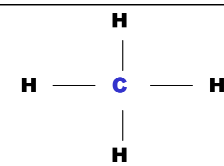
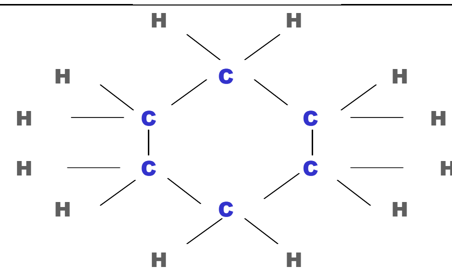
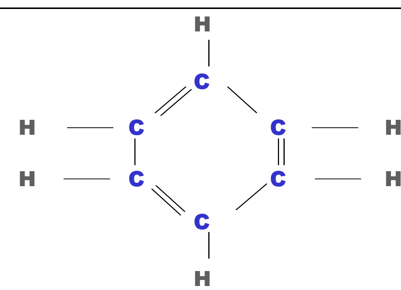
Simplistically, if the above scenario was to manifest itself, we would expect this to continue to place significant downwards pressure on margins. Distillation margins certainly look likely to remain under pressure and, with capacity building, the scope for gross refining margins to spike at times of temporary tightness as has been the case over the past two to three years looks likely to diminish. Assuming oil prices remain relatively high conversion margins should in theory continue to prove attractive most significantly for those who are able to benefit from a return to a more normal heavy-light spread.

What is Refining?

Refining is a process of converting crude oil into usable products.

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.

Figure 219: 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.

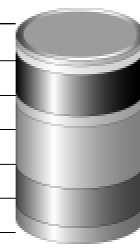
A typical product yield or a refinery's **product slate** (the proportion of refined products obtained by refining one barrel of crude) obtained from a complex refinery in Western Europe is shown in the figure below. This yield reflects both the refineries configuration but, because all crude oils differ 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 220: Typical Western Europe Product Yield

Product	Western Europe (%)
Petroleum Gas	3
Naphtha	6
Gasoline	22
Kerosene	6
Gasoil/ Diesel (aka middle distillates)	34
Fuel Oil	20
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. Taken together with a heavy fuel oil's low hydrogen to carbon ratio, this makes it the most potentially 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?

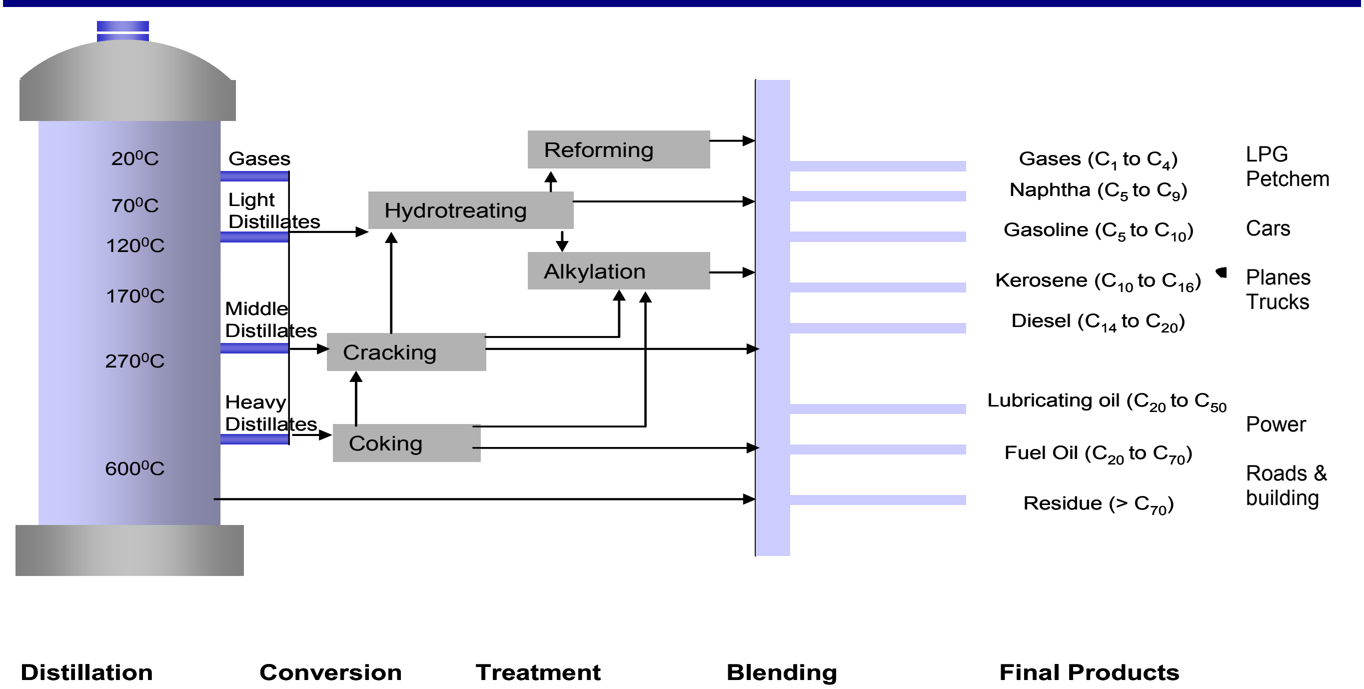
The function of a refiner is to convert crude oil into finished products required by the market in the most efficient, and therefore profitable, manner

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.

Overall, however, there are four major refining steps taken to separate crude oil into useful substances:

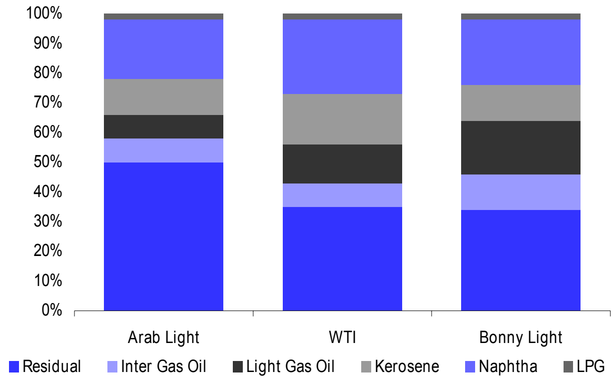
- Physical separation through crude distillation
- Conversion or upgrading of the basic distillation streams
- Product treatment to purify and remove contaminants and pollutants
- Product blending to create products that comply with market specifications

Figure 221: The oil refinery crude distillation process – fractionation through blending



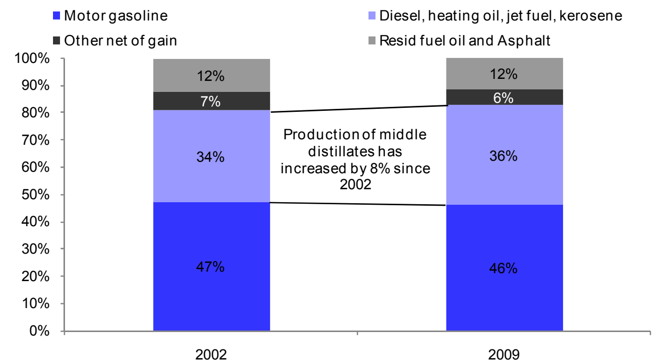
Source: Deutsche Bank

Figure 222: Product yields from simple distillation of different crude stream



Source: Deutsche Bank, EIA

Figure 223: Average US refinery yield – complexity improves the product slate



Source: Deutsche Bank, EIA

Distillation or fractionation is a process by which crude oil is separated

Crude Distillation (also known as 'Topping' or 'Skimming')

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^{0}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 (such as 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.

Unlike distillation, which maintains the chemical structure of the hydrocarbons, conversion alters their size and/or structure

Conversion (or upgrading)

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 maintainedhav 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.

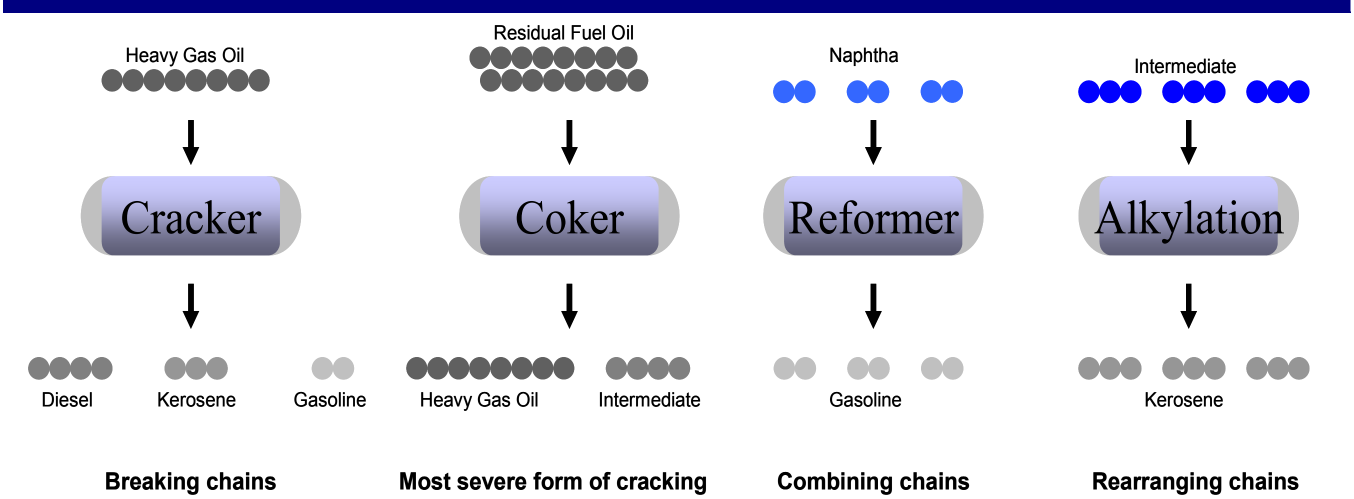
Figure 224: Catalytic cracking – FCC is used to produce gasoline whilst hydro-cracking is used to increase distillate yields

	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 225: Pictorial representation of major refining processes



Source: Deutsche Bank, http://science.howstuffworks.com/oil-refining5.htm

Treatment includes processes such as dissolution, absorption, or precipitation to remove/separate these undesirable substances

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 about 90% of contaminants such as nitrogen, sulphur, oxygen, and metals from liquid petroleum fractions.

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 226: Summary of main downstream processes

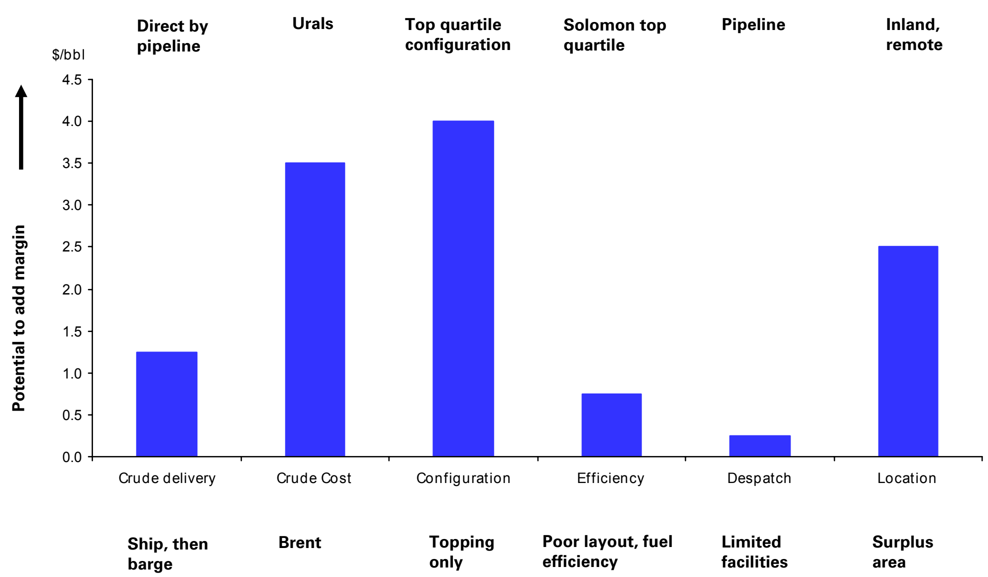
Process Name	Action	Method	Purpose	Feedstock (s)	Product (s)
Distillation					
Atmospheric distillation	Separation	Thermal	Separate fractions	Desalted crude oil	Gas, gasoil, distillate, residual
Vacuum distillation	Separation	Thermal	Separate fractions	Atmospheric tower residual	Gasoil, lube stock, residual
Conversion – cracking					
Catalytic cracking	Decompose	Catalytic	Upgrade gasoline	Gasoil, coke distillate	Gasoline, petrochemical 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 227: 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 costs associated with the investment mean that it need not necessarily achieve a similar improvement in return on capital. For example, BP has amongst the most complex refineries in North America. Its return on capital in recent years has, however, been woeful even allowing for production outages at major refineries.

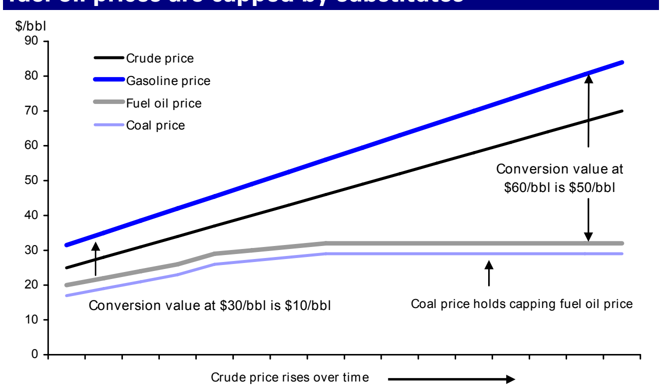
Equally, it is possible for refineries to be highly complex yet for that complexity to be directed towards making products which are now in surplus and therefore poorly rewarded. This is particularly true in Europe where a number of refineries invested in earlier years in upgrading equipment (predominantly fluid catalytic crackers) 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. Again, this is in part the story behind BP's decision to sell its UK Coryton refinery, it's third most 'complex' refining asset, for a seemingly modest $8100/bpd of capacity.

High oil prices are good for complex refiners.

The economics of conversion are dramatically improved at high oil prices,

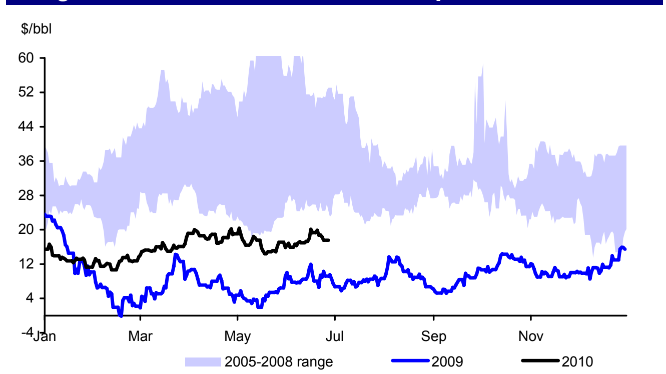
The importance of complexity should not, however, be underestimated particularly at high oil prices. This is because the economics of conversion are dramatically improved at high oil prices, a feature which reflects the widening price differential between transport fuels and heavy fuel oil at high oil 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 228: Conversion margins expand as lower value fuel oil prices are capped by substitutes



Source: Deutsche Bank estimates

Figure 229: The result is a significant rise in conversion margins (diesel/fuel oil here) for complex refiners

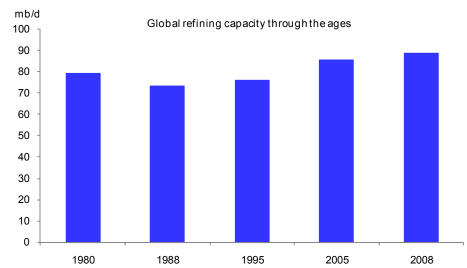


Source: Bloomberg Finance LP, Deutsche Bank estimates

Refining is getting more complex

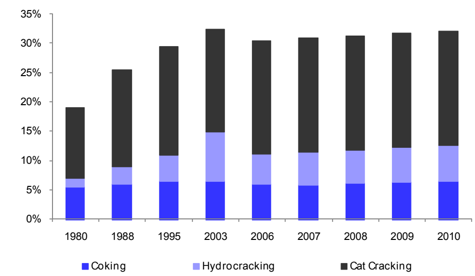
Not surprisingly, with limited underlying growth in product demand the bias of investment in the US and Northern Europe in recent years has been towards increasing the complexity of refineries rather than expanding capacity. In the US, for example, no new refineries have been built since 1980 although improvements in process design and the removal of bottlenecks has seen capacity creep of around 1% per annum. Complexity has, however, increased significantly. The European trend is depicted below. Note also how investment in gasoline-geared FCC's has given way to investment in diesel biased hydro-crackers.

Figure 230: Refining capacity on the increase since the 1990's



Source: BP statistical review; Deutsche Bank

Figure 231: 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 the 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 primary distillation unit (atmospheric distillation unit). The complexity of an individual refinery is calculated by summing the following equation for all the major refinery processes: (Complexity Factor x Unit Capacity)/Crude Distillation capacity). In the below example it tabulates as 3537/817=4.3

Figure 232: 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 233: 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.

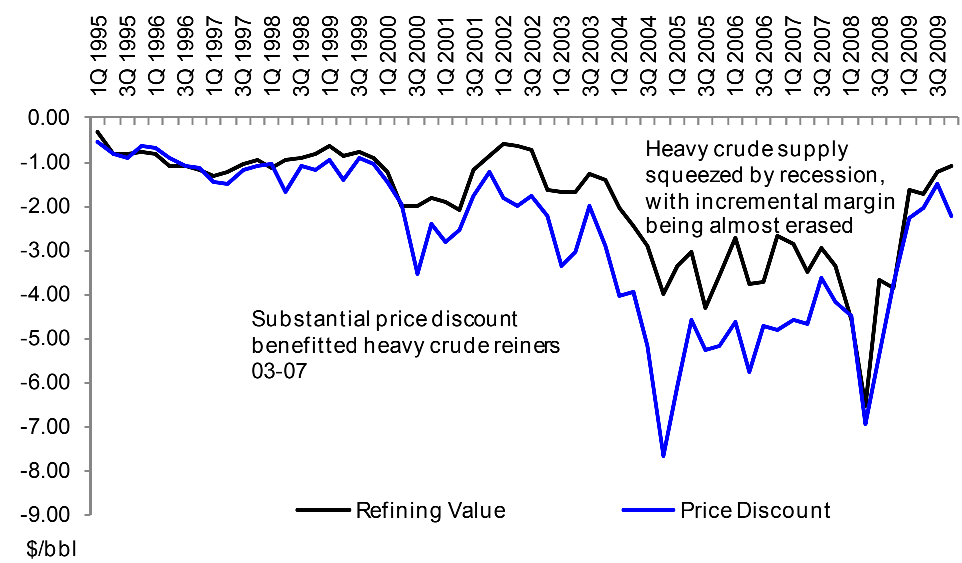
Crude oil prices reflect the different refining value of the distillate slate
Crude oil pricing reflects these differences with light sweet crudes such as Brent or WTI trading at a significant price premium to heavy, sour blends such as Russian Urals or Mexican Maya. Theoretically the difference in price 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 have gone into oversupply this position has subsequently reversed.

Figure 234: 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

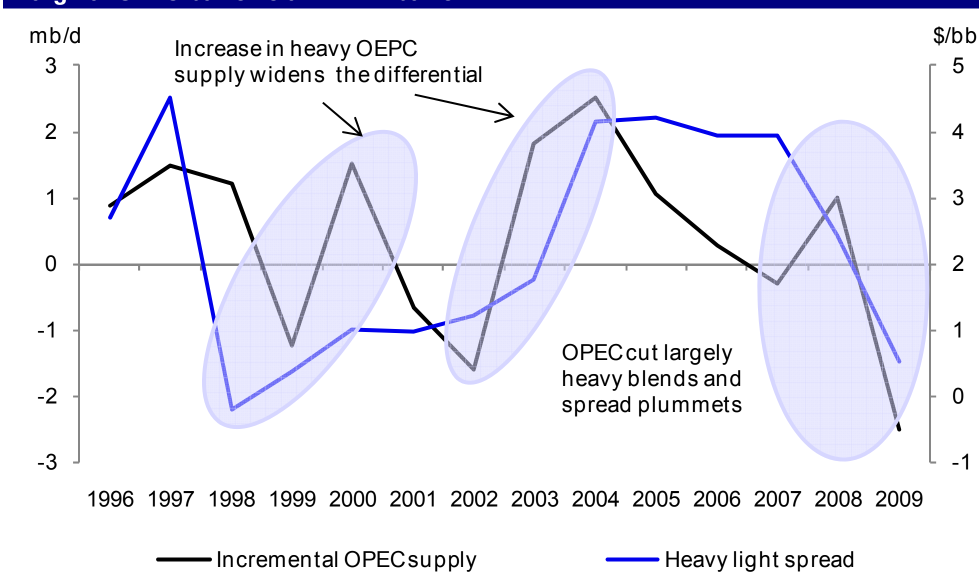


Source: Wood Mackenzie

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.

Figure 235: OPEC production has had a clear influence on the heavy light spread – the marginal OPEC barrel is a HEAVY barrel



Source: Wood Mackenzie

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.

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.

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.

In general, refineries use some 5-7% of their feedstock as fuel to run the refinery.

- **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 5-7% 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 but a few years ago.

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

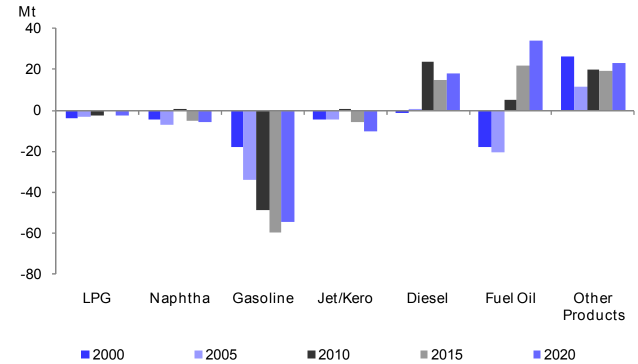
The charts overleaf depict Wood Mackenzie's estimates of current product balances across four major regional markets and how they are expected to move over the course of the next decade. The charts serve to emphasise that, where the US market is now short across almost every major product group, significant 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.) depending essentially on companies' ability to de-bottleneck plant (so called capacity creep). As such, in the absence of a major deterioration in demand US refining 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

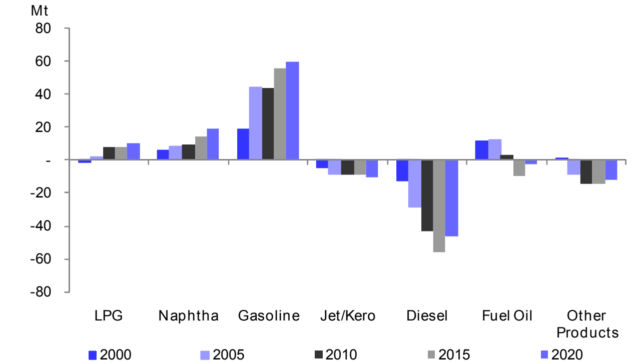
This difference in product balances is also well reflected by refinery utilization rates across the different regional centres. Again, these emphasise that rates have been more robust in the US. Utilisation fell dramatically across all regions in 2009 due to the financial crisis which precipitated a decline in demand across all regions. Despite some improvement in demand (and a corresponding uplift in refining margins) utilisation rates remain low at present given the underlying fundamentals (market well supplied at existing levels of demand) and the fact that there exists an over-supply in global refining capacity.

Figure 236: US – Future product balances (Mt)



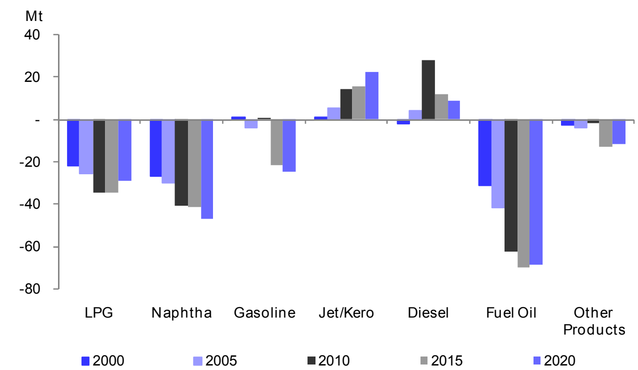
Source: Wood Mackenzie

Figure 237: North West Europe – Future product balances (Mt)



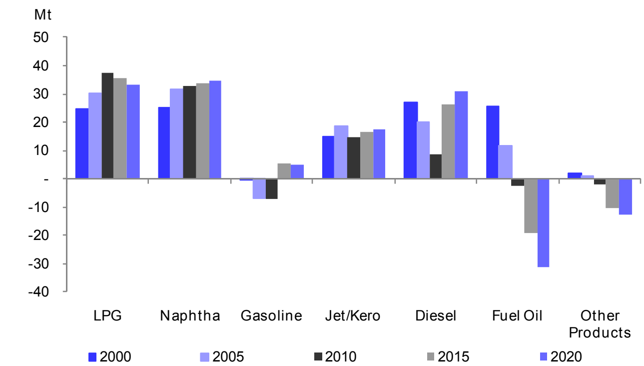
Source: Wood Mackenzie

Figure 238: Total Asia – Future product balances (Mt)



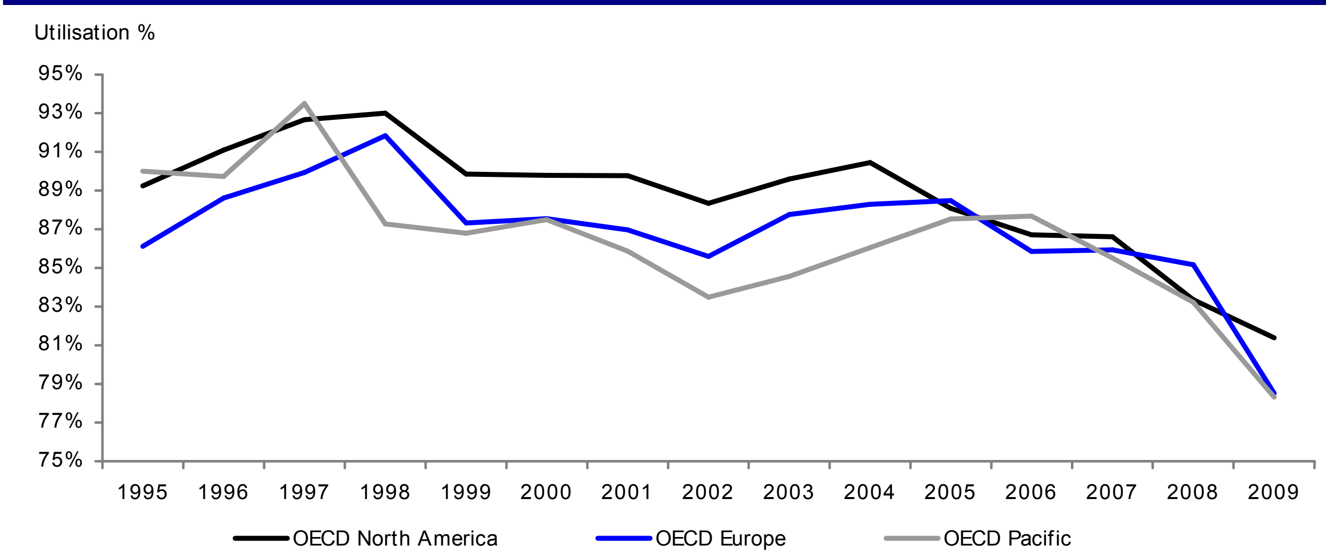
Source: Wood Mackenzie

Figure 239: Middle East – Future product balances (Mt)



Source: Wood Mackenzie

Figure 240: Regional capacity utilization rates 1995-2009 (%)



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 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 $71 whilst the price of gasoline is $1.95/gallon and that of heating oil $1.65/gallon. Given that there are 42 gallons in a barrel the crack spread calculates at $6.74/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*1.95*42) + (0.33*1.65*42)] - $71.00 = ($54.87 + $22.87) - $71.00 = $6.74

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).

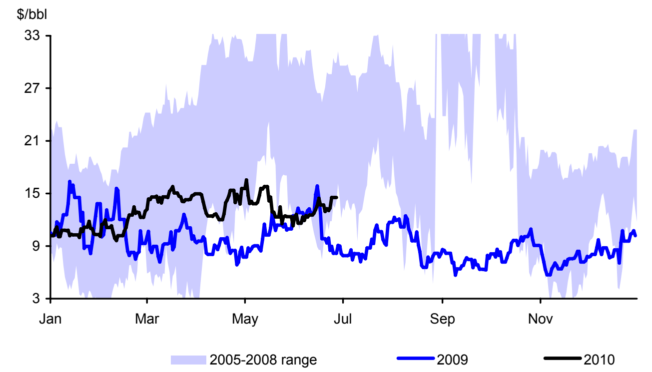
Product cracks

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.

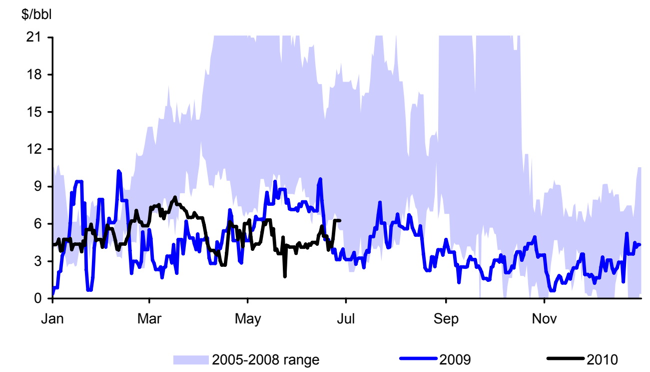
US margins ($/bbl)

Figure 241: US Gulf Complex



Source: Deutsche Bank estimates, Bloomberg Finance LP

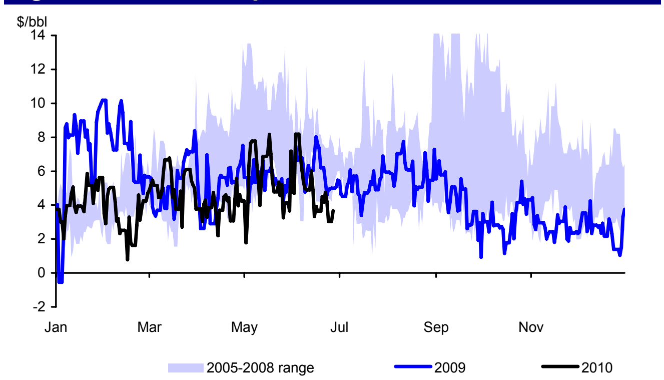
Figure 242: US Gulf Simple (3-2-1)



Source: Deutsche Bank estimates, Bloomberg Finance LP

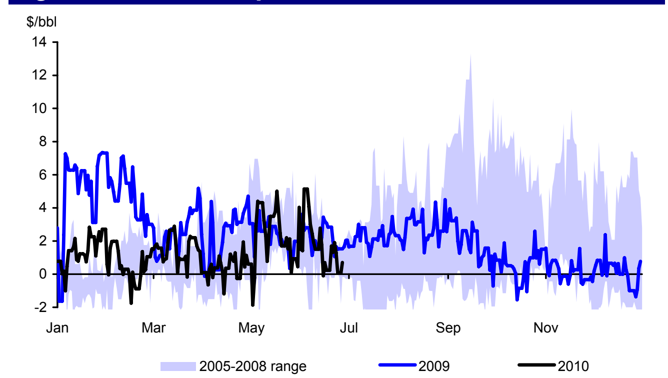
NWE margins ($/bbl)

Figure 243:NWE Complex



Source: Deutsche Bank estimates, Bloomberg Finance LP

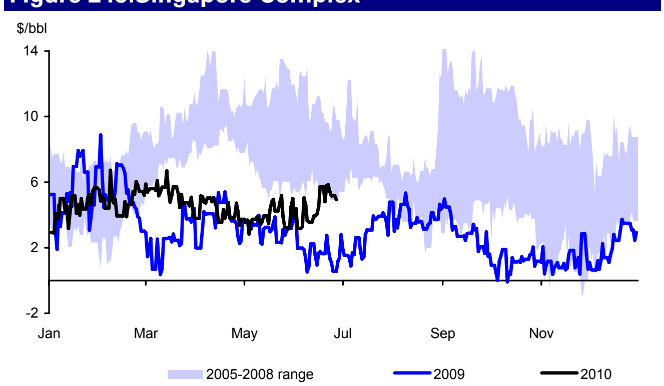
Figure 244: NWE Simple



Source: Deutsche Bank estimates, Bloomberg Finance LP

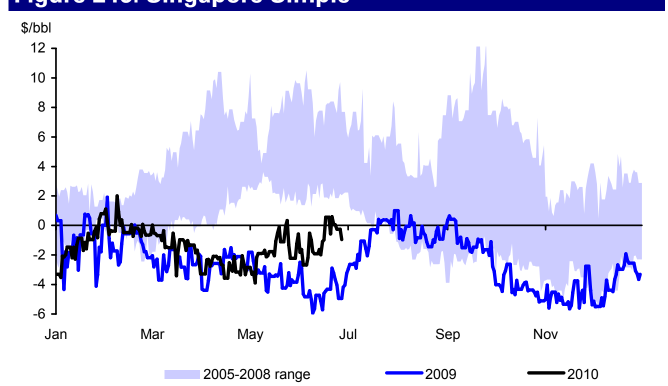
Asian margins ($/bbl)

Figure 245:Singapore Complex



Source: Deutsche Bank estimates, Bloomberg Finance LP

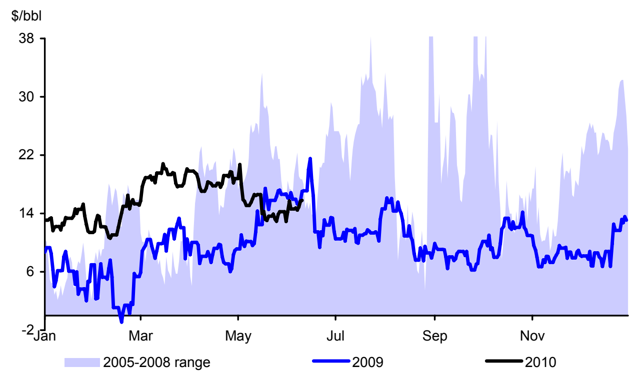
Figure 246: Singapore Simple



Source: Deutsche Bank estimates, Bloomberg Finance LP

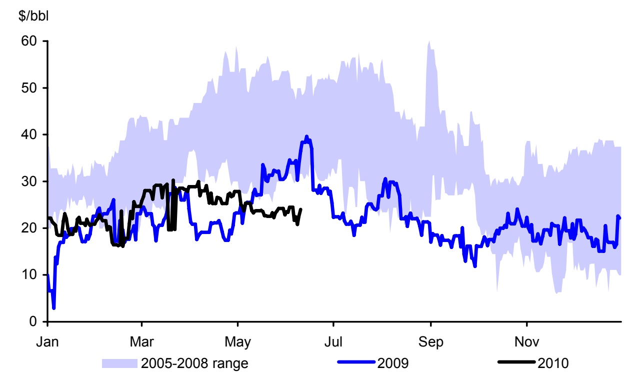
Gasoline/fuel oil crack spreads US/Europe

Figure 247: US Gasoline/Fuel Oil



Source: Deutsche Bank estimates, Bloomberg Finance LP

Figure 248: 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

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:

- **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 concerns around supply 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.

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, ConocoPhillips, Shell, BP 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, we would expect the western integrated majors to continue to downsize their refining portfolios through the sale of non-strategic assets on a piecemeal basis. This is likely to prove especially true within 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 has seen each of the major Europeans (BP, Shell, Total) divest individual refineries in the past (and indeed they continue to seek buyers for further divestments), in part as they look to upgrade the assets within their portfolios but do so without investing significant excess capital in refining in aggregate.

Asia and the Middle East will gain share

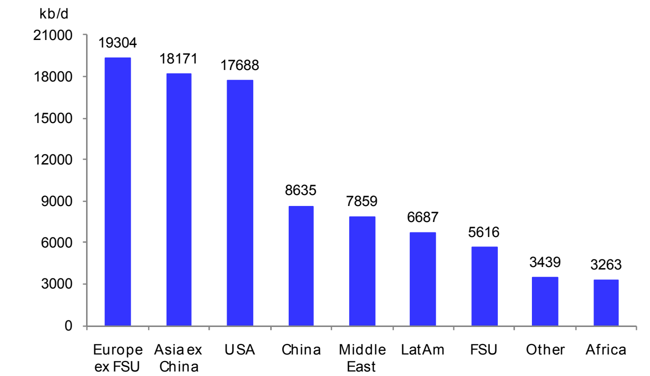
Longer run, with oil demand in much of the OECD essentially static, greenfield investment in new capacity is likely to centre on those markets which offer volume growth (essentially Asia) or which are advantaged by virtue of access to raw materials (essentially the Middle East). Little surprise then 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.

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:

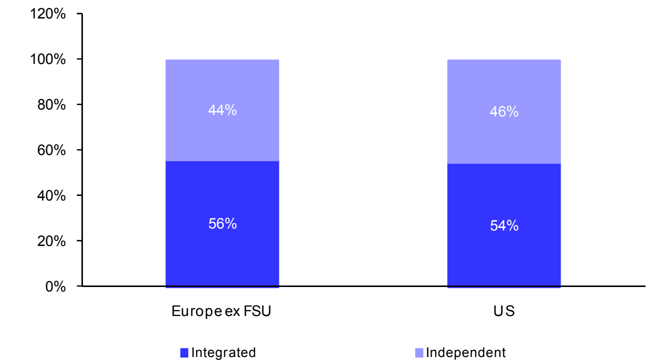
- PADD I (East Coast) is composed of the following three sub-districts A (New England); B (Central Atlantic); and C (Lower Atlantic).
- PADD II (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee, and Wisconsin.
- 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

Figure 249: Global refining capacity by region 2009 (kb/d



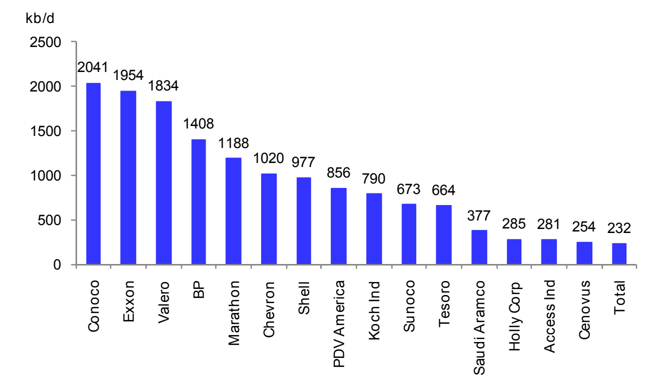
Source: BP Statistical Review; Deutsche Bank

Figure 250: Share of refining capacity in mature markets integrated and independent (%)



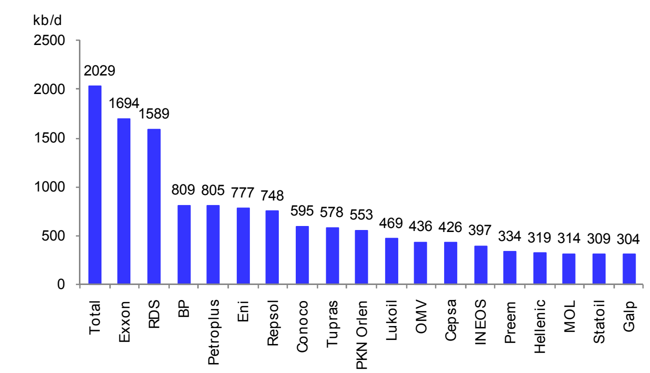
Source: EIA, Wood Mackenzie, Deutsche Bank

Figure 251: Major US refiners – CDU capacity (bpd)



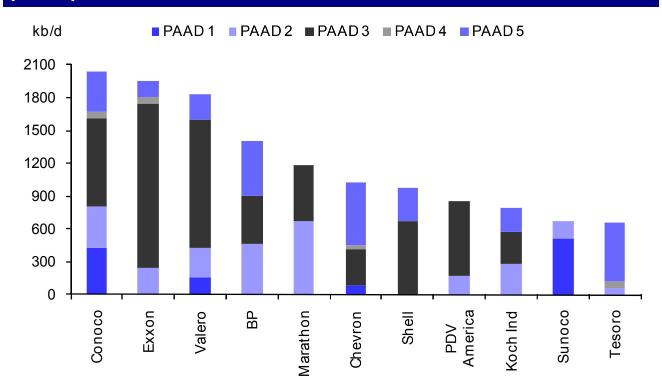
Source: EIA, Deutsche Bank

Figure 252: Major European refiners – CDU capacity (bpd)



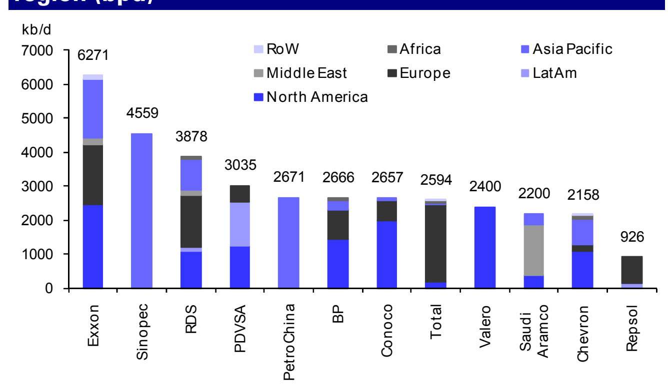
Source: Wood Mackenzie, Deutsche Bank

Figure 253: Major US refiners – CDU capacity by PADD (kb/d)



Source: EIA, Deutsche Bank

Figure 254: Major refiners – CDU capacity globally by region (bpd)



Source: Company data, Deutsche Bank estimates

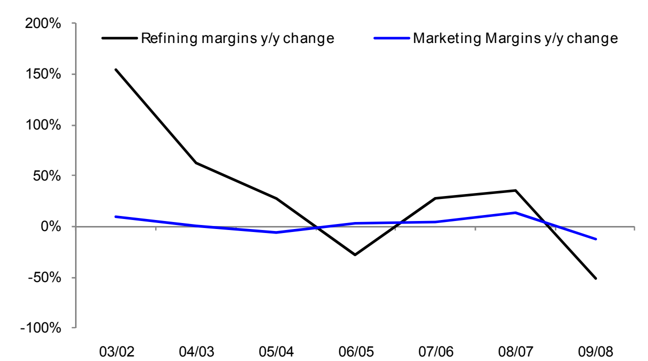
Marketing

Stability in a cyclical world

Marketing, or the wholesale and retail sale of fuel products, is the final step in the integration chain

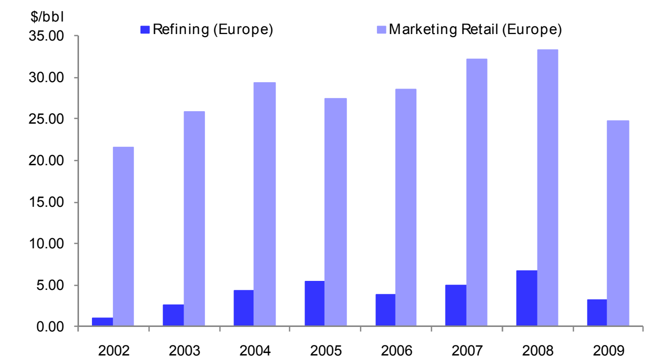
Marketing, or the wholesale and retail sale of fuel products, is the final step in the integration chain and the oil industry's main point of contact with the end-market consumers of its products and, consequently, its public face. Profits tend to be much less volatile than those of its refining activities 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.

Figure 255: Change in European marketing (retail) margins and refining margins y-o-y % (2002-2009)



Source: Wood Mackenzie, BP

Figure 256: Absolute gross retail margins are higher and less volatile than those achieved in refining

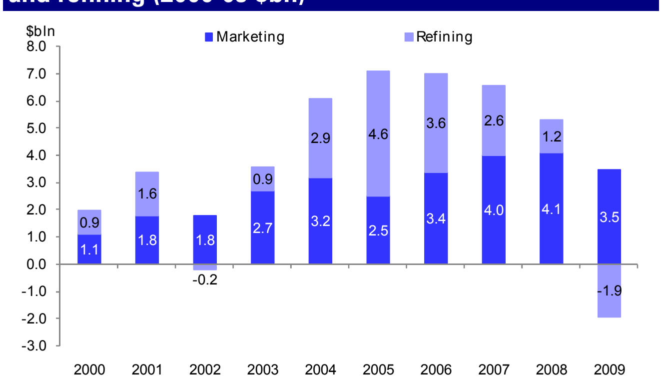


Source: BP Statistical Review; Deutsche Bank

Profits are sizeable

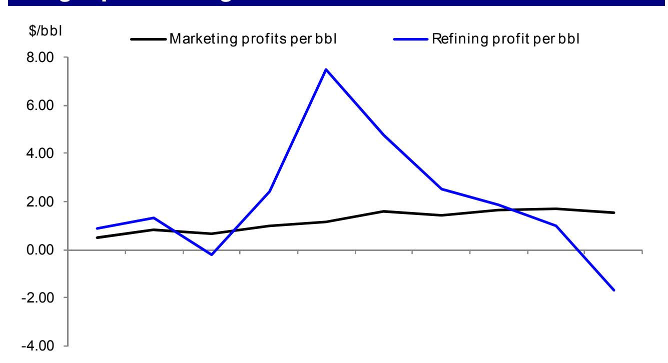
Perhaps it is because of this stability that the absolute scale of the marketing profits achieved by the majors is easily overlooked. Despite the fact that net margin tends to be very thin as a percentage of revenues (at somewhere between 1-2% of sales), given the huge volumes of product moving through an integrated oil company's marketing network, the absolute level of profit is substantial. This is well illustrated by reviewing Royal Dutch Shell's downstream performance in recent years, the marketing profits of which have fairly consistently stood at in excess of $2.5bn 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 257: RDS; Oil products net profit split - marketing and refining (2000-09 $bn)



Source: RDS; Deutsche Bank estimates

Figure 258: RDS Net margin per marketing barrel vs. net margin per refining barrel ($/bbl)



Source: RDS; Deutsche Bank estimates

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

Securing end markets

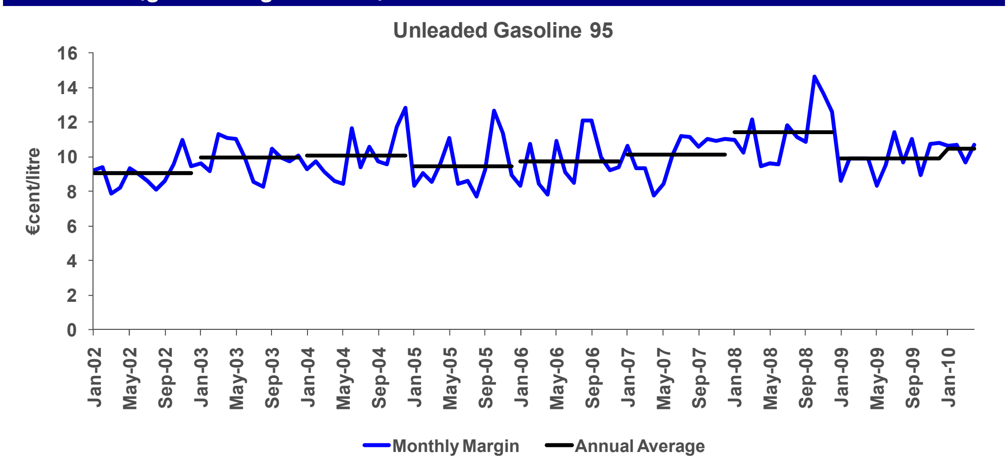
Profit aside, the key role of marketing is to secure end markets for an integrated oil company's refined products and so act as the engine of refining output growth. Moreover, through providing a route to market and customer access, marketing helps to ensure that at times of faltering demand an integrated 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.

Equally, marketing typically represents the first step of downstream entry into a new market. Again, once a market presence is established and sufficient base demand 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. More likely, this obfuscation reflects a sensible desire to shield the absolute level of profit achieved 'at the pump' from the prying eye's 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 259: European marketing margins (retail) – overall steady but not without short term noise (gross margin €cents)



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. 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 feature 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.

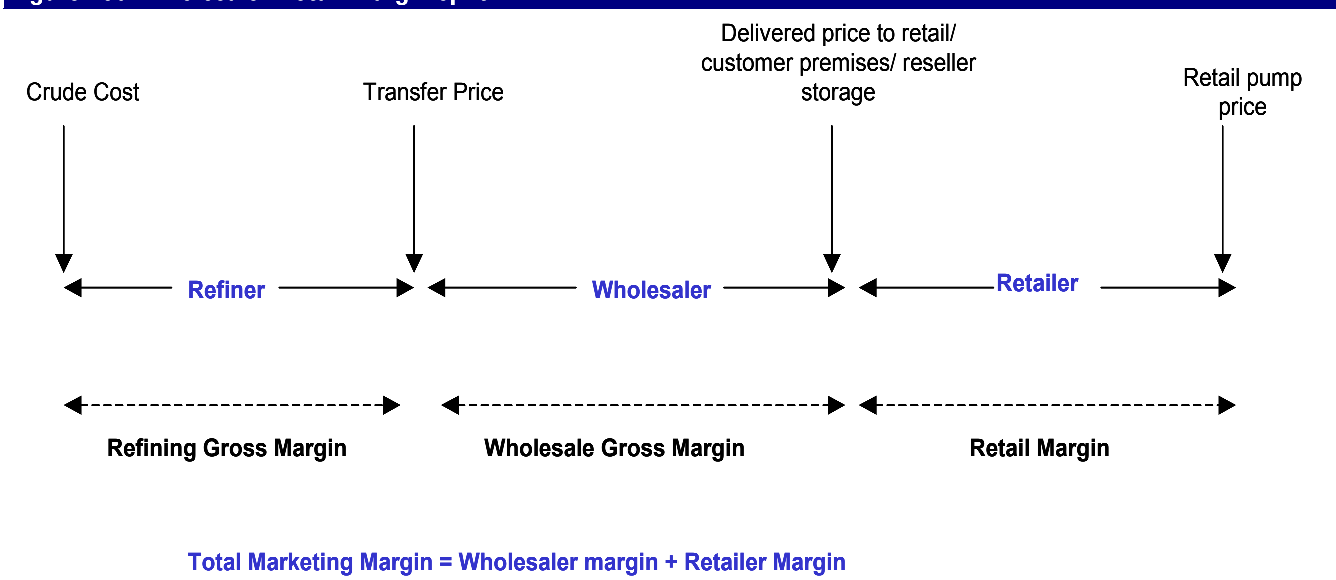
The wholesale/retail chain

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 20% of the value of the sale excluding government excise duty. As such, marketing operations are highly operationally geared with control of costs absolutely key to profitability. Given the need for volumes and throughput, well located retail outlets are key as is the product offering.

Figure 260: 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 until recently 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).

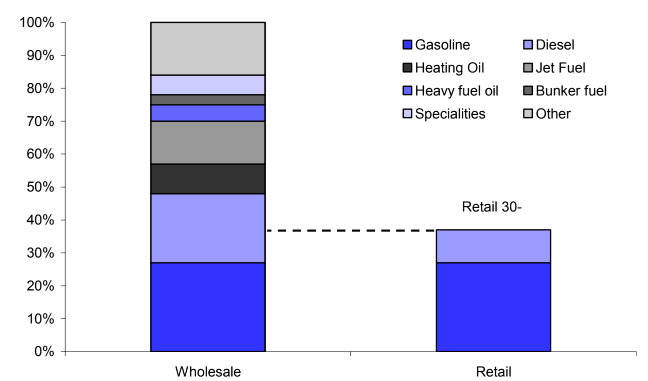
Retail; the smaller volume but higher value component

Overall, around 30-40% of marketing volumes tend to arise through service stations in retail end markets

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.

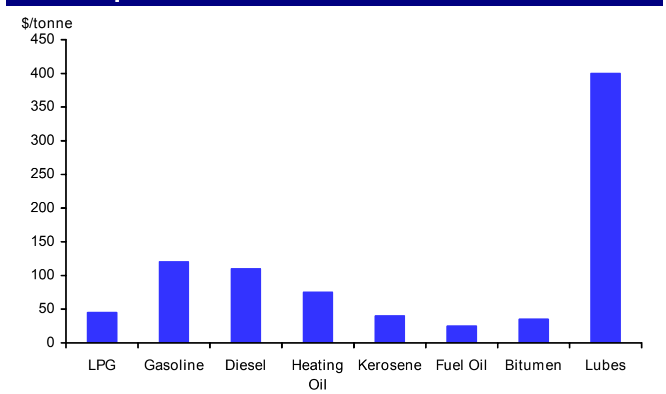
As companies have striven to improve returns so they have sought to increase the retail offering of their service stations, driving incremental revenues and gross margin from their non-fuel activities. Perhaps ironically, these activities have achieved faster growth than almost any of the companies' other activities although contribution in general remains very modest.

Figure 261: Illustrative split of marketed products by volume (%) and those through the retail chain



Source: Wood Mackenzie; Deutsche Bank

Figure 262: Illustrative split of net contribution per tonne of product sold



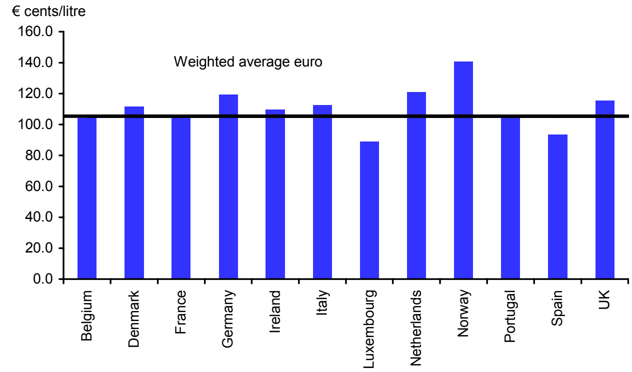
Source: Wood Mackenzie; Deutsche Bank

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 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.

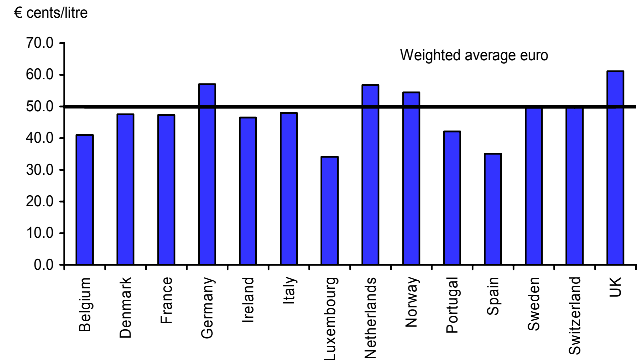
What's in a litre of fuel? European Retail Data

Figure 263: Retail prices by Country (2009)



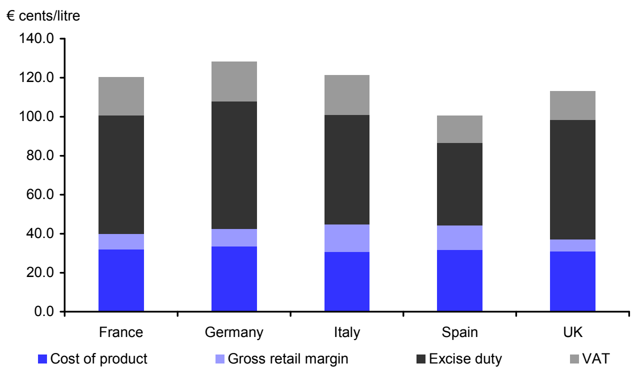
Source: OPAL, Deutsche Bank

Figure 264: Excise duty by country (2009)



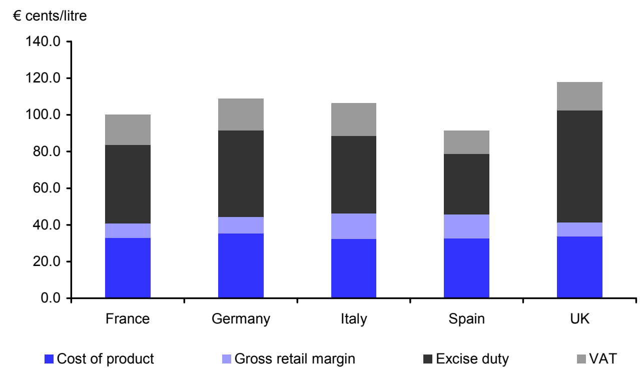
Source: OPAL, Deutsche Bank

Figure 265: What's the cost? Gasoline (2009 averages)



Source: OPAL, Deutsche Bank % Is proportion represented by taxation

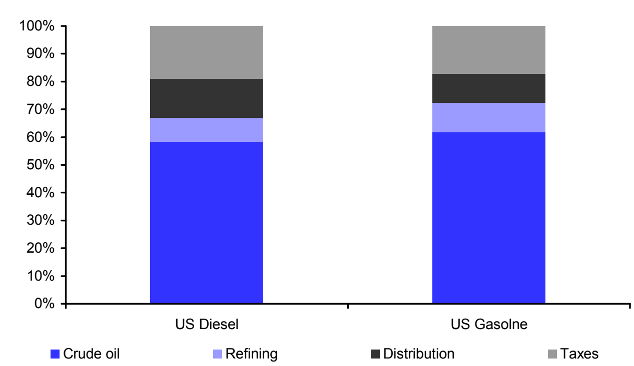
Figure 266: What's the cost? Diesel (2009 averages)



Source: OPAL, Deutsche Bank % Is proportion represented by taxation

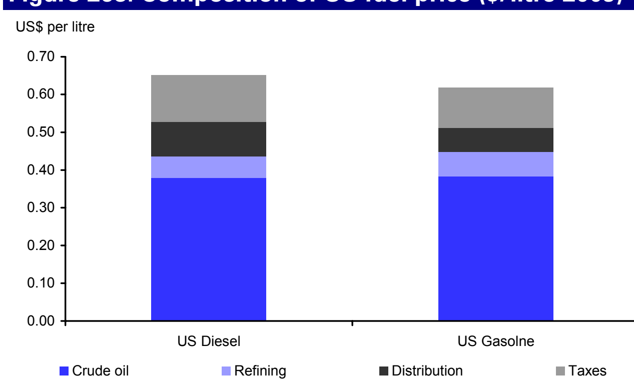
What's in a litre of fuel? US Retail Data

Figure 267: Composition of US fuel price (% 2009)



Source: EIA, Deutsche Bank

Figure 268: Composition of US fuel price ($/litre 2009)



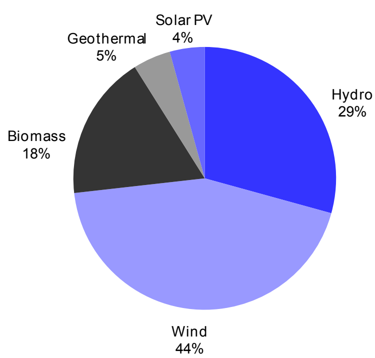
Source: EIA, Deutsche Bank

Biofuels

What are biofuels?

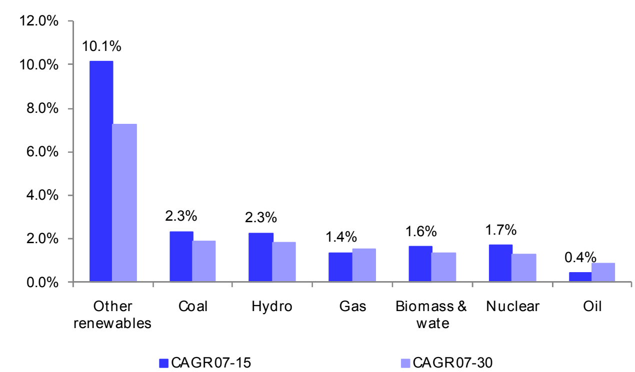
Biofuels are fuels made or processed from vegetation from which energy can be extracted (known as biomass and can be such things as corn, wood, sugar cane). Biofuels currently comprise only a small part of today's global energy supply, accounting for a modest 1.5% of total road-transport fuel usage, however, growth rates for biofuel supply are expected to continue to outpace those of more conventional sources of energy with the IEA suggesting a growth rate of 1.7% out to 2015 vs. oil at 0.4%. Renewable energy overall (bio-energy, hydro, solar etc) represented 12.6% of total energy demand in 2007 according to the IEA's world energy outlook in 2009.

Figure 269: Breakdown of renewable energy, 2008



Source: Renewables 2009 Global Status Report

Figure 270: Annual growth rates, 2007-2015 & 2030



Source: IEA World Energy Outlook 2009 Reference Scenario

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 nascent, there are already 2 recognised generations of technology, with fuel from algae considered by many to be the third generation.

Biofuels are distinguished as either first or second generation biofuels.

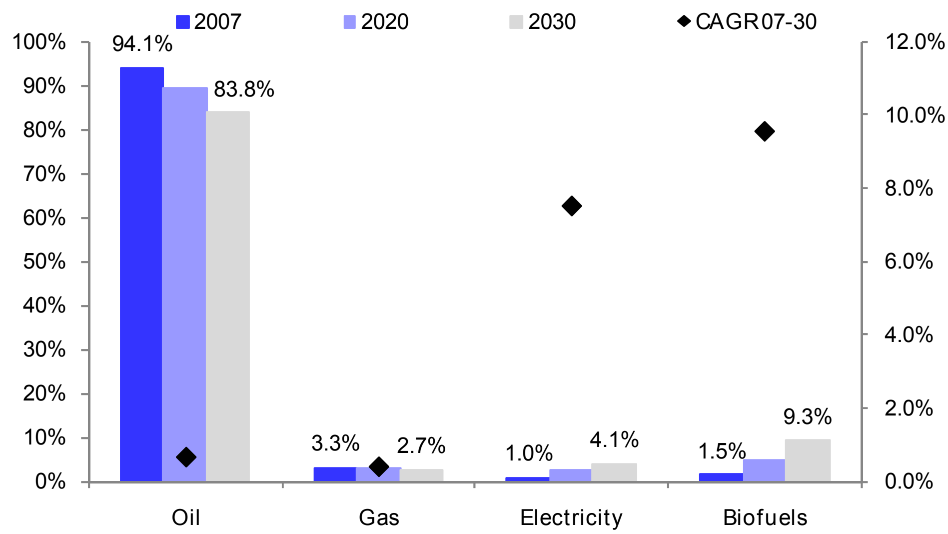
- **First generation biofuels.** These are biofuels produced using conventional technology and by and large use food crops (such as sugar, corn) as the source of biomass. The two most notable first generation biofuels are bioethanol and biodiesel. Other first generation biofuels include butanol, alcohol 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 an environmentally friendly substitute for fossil fuels and this is naturally where their strengths lie. Moreover increasing difficulties in accessing resource mean that alternative energy sources are increasingly attractive to governments seeking to reduce their reliance on imported crude. Advantages include:

- **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).

Figure 271: Bio-fuels as a proportion of transport fuel, 2007-2030



Source: IEA World Energy Outlook 2009. 450 Scenario Based on global average GDP growth of 4.5% p.a. 2008-2012.

- **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 regulatory framework

Regulation continues to play an important role in the advancement of biofuel use. Strong 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.

United Kingdom

The key directive currently in place in the UK is the Renewable Transport Fuel Obligation, which mandates that 5% of all transport fuel must be from a renewable source by 2010. This will primarily achieved by blending with fossil fuels given all existing vehicles are already capable of running on a 5% blend.

European Union

At present, the Biofuels Directive (May 2003) is the principal regulatory measure for biofuels in the EU. This establishes a non-binding target to replace at least 5.75% of all transportation fuels with biofuels by 2010, rising to 10% by 2020. In 2008, the EU announced that it is rethinking its biofuel targets due to environmental and social concerns given the impact 1st generation biofuel production has had on food prices over recent years. There are also concerns over rainforest destruction and concerns that poorer, smaller farmers could be driven off their land (particularly in African countries) leading to increased poverty and starvation levels.

The Biofuels directive is complemented by the EU Directive of Taxation on Energy which grants biofuels special exemption from fuel taxation in member states.

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 and there are plans to eventually increase this to 85%.

Key legislative measures

Policy has switched from tax subsidies to blending requirements.

Legislation is integral to the effective regulation of the biofuels industry. The industry has witnessed a gradual switch from fiscal-based programs 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 additional burden of providing subsidies on tax revenues. More importantly, it eliminates the distortionary impact created by undue reliance on subsidies.

United Kingdom

A tax rebate of £0.20 per litre on both bio-ethanol and biodiesel is currently in place. This is to encourage suppliers to ensure that 5% of their sales of transport fuel is made up of biofuels by 2020.

European Union

Germany has been a leader in supportive legislation for biofuels. The key piece of legislation is the Biokraftstoffquotengesetz which outlines mandatory blending requirements. Present requirements are 6.25% biofuels in fossil fuels from 2010 and should remain at that level until

2014. Germany has been the most compliant of all EU members in reaching biofuel targets, surpassing the 5% 2010 target in 2006.

In France there are favourable tax measures such as a partial tax exemption from the internal consumption tax for all biofuels that have received a licence (a licence is required to sell biofuels in France). More generally, to be eligible for reduced taxes, the ethanol must be produced within France.

United States

In the US, biofuels receive a simple tax rebate of $0.51 per gallon for bioethanol and $1.00 per gallon for biodiesel.

Figure 272: Regulatory and legislative measures

Region	Target	Tax rebate		Blending requirements	
		Bioethanol	Biodiesel	Bioethanol	Biodiesel
United Kingdom	5% by 2010	£0.20 per litre		2.50% in 2008/2009	
				3.75% in 2009/2010	
				5.00% in 2010/2011	
European Union	5.75% by 2010				
	10% by 2020				
United States	4.7 billion gallons in 2007				
	15.2 billion gallons by 2012	$0.51 per gallon	$1.00 per gallon		

Source: Deutsche Bank

Bioethanol

Overview

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

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

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 considered to cause cancer. Two key issues surround the blending of ETBE:

- **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 probability that knocking will occur.
- **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 world's primary producer of bioethanol.

The US is the leading bioethanol market worldwide, accounting for c.55% of world production in 2009. Bioethanol currently represents c.4% of all vehicle fuel consumed in the US. The US is currently a net importer of ethanol (largely from Brazil which represents c42% of total US ethanol imports) a situation which is likely to remain given high annual demand growth rates (demand has grown by c.30% pa since 2002) and tax incentives to promote the construction of more stations capable of supplying bioethanol (cost of construction of c.$200k is in line with normal filling station construction cost).

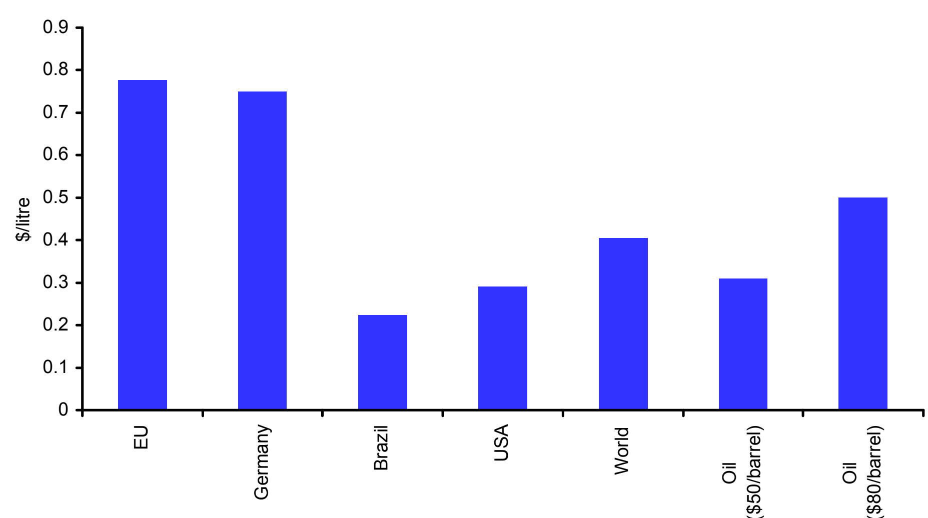
By contrast, the EU produced only 5% of the world's supply of bioethanol in 2009. Demand is currently in excess of supply and presently, this situation is being met by imports. The demand dynamics for bioethanol will be determined by the level of blending ratio requirements. Forecasts indicate that excess demand will persist after the introduction of these requirements even under conservative demand estimates.

Pricing

Bioethanol is more expensive to produce than conventional gasoline.

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.

Figure 273: Production cost of bioethanol vs. oil



Source: Deutsche Bank

Biodiesel

Overview

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.

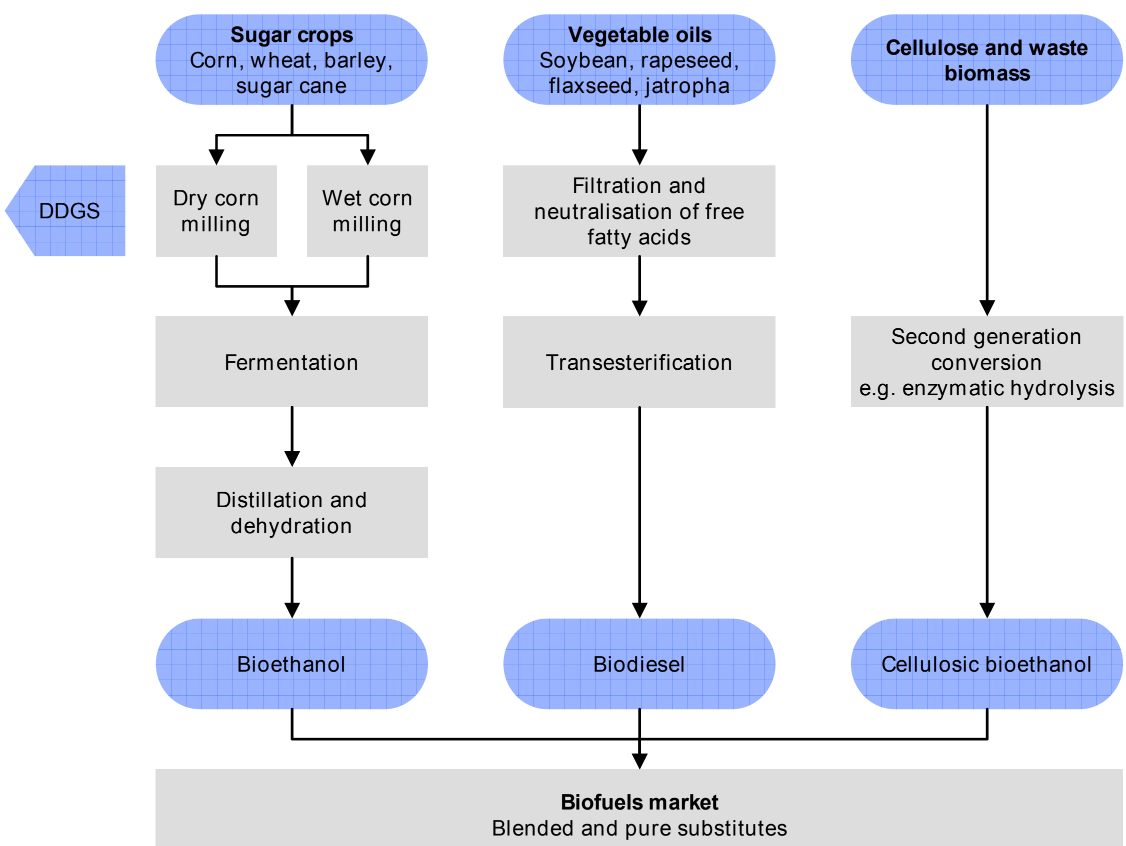
In the US, the industry is at a relatively early stage of development, producing 700 million gallons of biodiesel in 2008 (up from 2 million gallons in 2000). The preferred source of biodiesel in the US is soybean oil since and constitutes c.90% of US vegetable oil production. It is possible to use low 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).

Production

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 274: 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 often directed towards the use of biofuels, some justifiably 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 will 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.
- **Toxic emissions.** A widely cited benefit of biofuels is carbon neutrality. However, agricultural techniques used in the production of biofuels require use of fossil fuels, reducing the net benefit of biofuel use. The production process also results in local air pollution, or smog, caused by nitrous oxides. This contributes to global warming and further offsets the benefit of carbon neutrality.
- **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. However, with the US targeting 35 billion gallons of ethanol production by 2017 of which only 15 billion are likely to come from corn, the implication is that cellulosic ethanol will need to contribute c.20 billion gallons p.a. by 2017.

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.

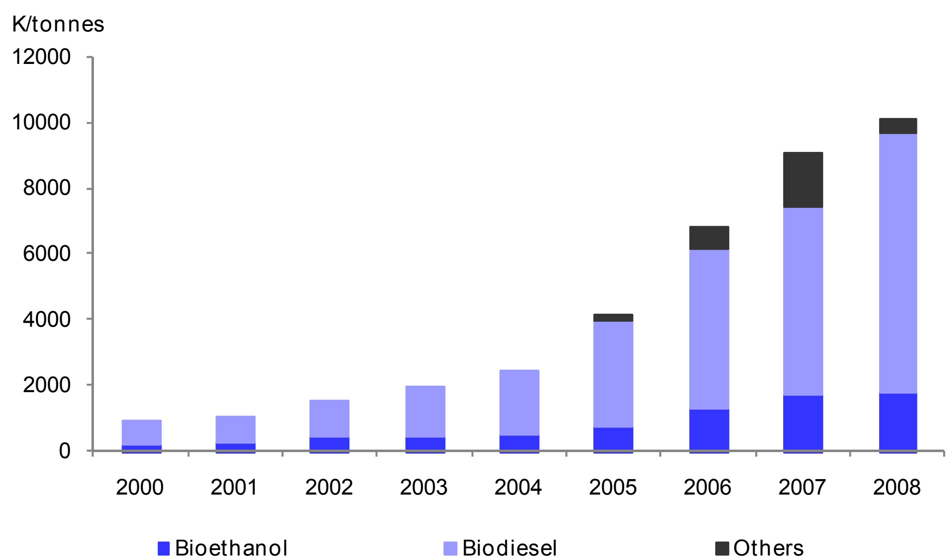
Figure 275: Comparison of yields for typical oil crops

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 276: 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, Shell and Total 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).

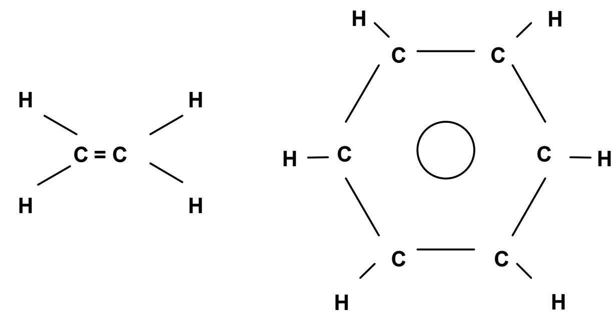
Olefins and aromatics.
Base chemicals can be broadly classified into two groups: olefins and aromatics. Olefins have chains of carbon atoms as their 'backbone' whereas aromatics contain a ring of carbon atoms at the core of the molecule.

Figure 277: 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 278: The molecular structure of ethylene and benzene



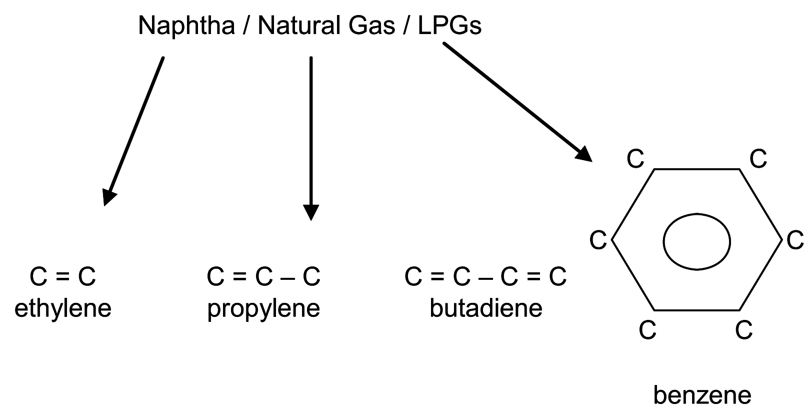
carbon atoms are denoted by C, hydrogen atoms by H

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 279: End products of the cracking process



C denotes a carbon atom: C-C represents a carbon single bond: C=C represents a carbon double bond

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 280: 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 consequence 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.

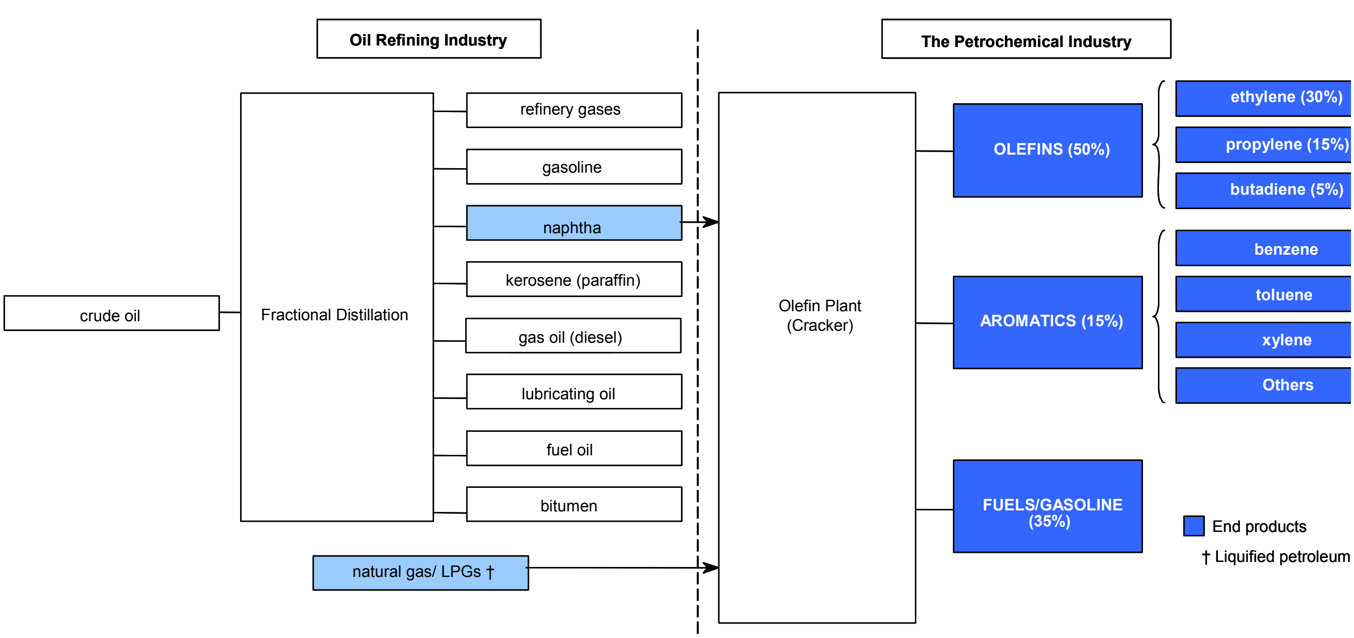
Figure 281: Percentage of base chemicals produced by feedstock

	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 282: Simple flow chart depicting refinery input to an olefins plant



Source: Deutsche Bank

Petrochemical Industry profitability

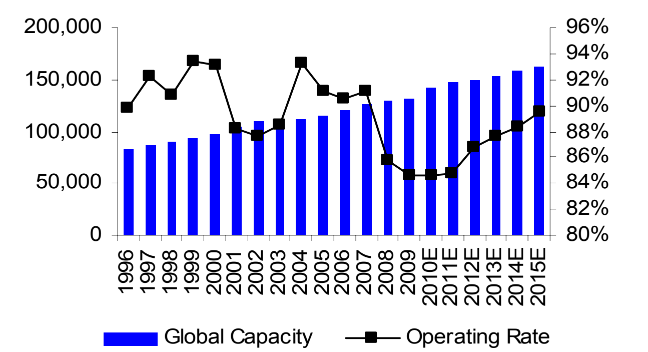
The petrochemical industry exhibits significant cyclicality.

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. As such, the industry fluctuates between periods of supply tightness and slack, with product prices and margins varying accordingly.

Feedstock costs are key

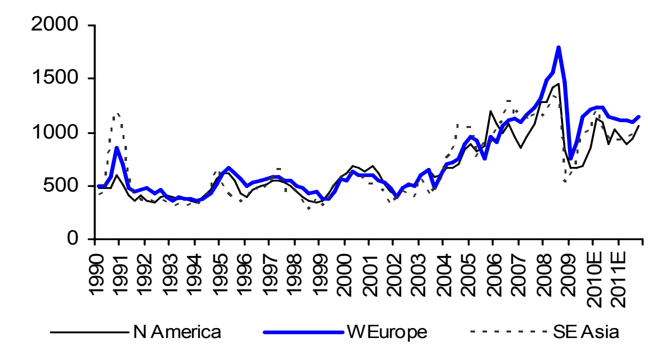
Central to profitability across the cycle are therefore the different cost structures of the players involved, together with their proximity to consumer end markets. Plant scale, integration and cost efficiency all have a key role in determining relative profitability. However, the sheer weight of feedstock 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 283: Global ethylene operating rates



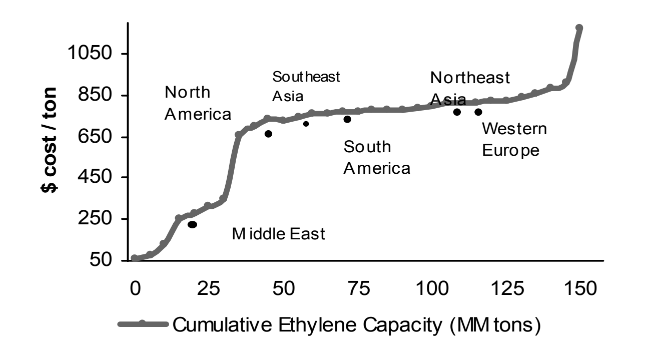
Source: Deutsche Bank, CMAI

Figure 284: Ethylene margin ($/tonne) 1990 – 2012E



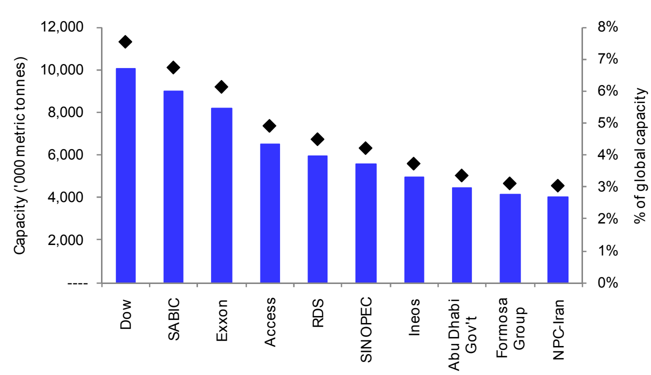
Source: Deutsche Bank, CMAI

Figure 285: Global chemicals cost curve (ethylene)



Source: Deutsche Bank, CMAI

Figure 286: Top ethylene producers 2009



Source: Deutsche Bank, CMAI

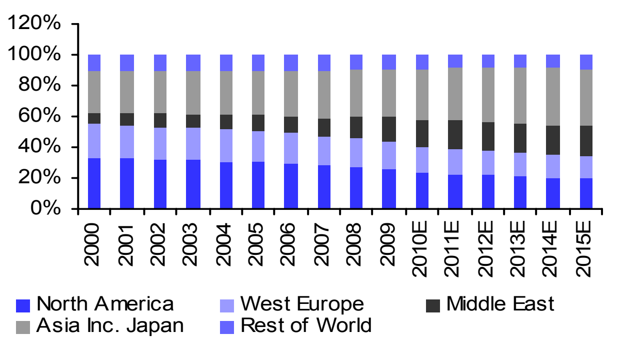
The emergence of the Middle East – altering strategies

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.

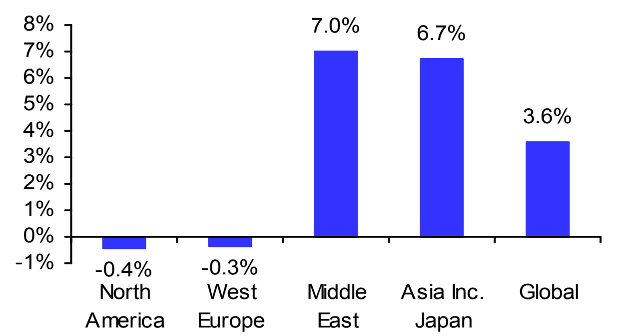
Consequently, to the extent that the oil industry continues to invest in petrochemical capacity its focus has been to build facilities that are close to the major demand centres (e.g. Shell in Nanhai, China and Total in Daesan, Korea) or in those Middle Eastern countries with an advantaged supply of 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).

Figure 287: Regional share of global ethylene capacity



Source: Deutsche Bank, CMAI

Figure 288: CAGR in ethylene capacity by region (2009 – 15E)



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

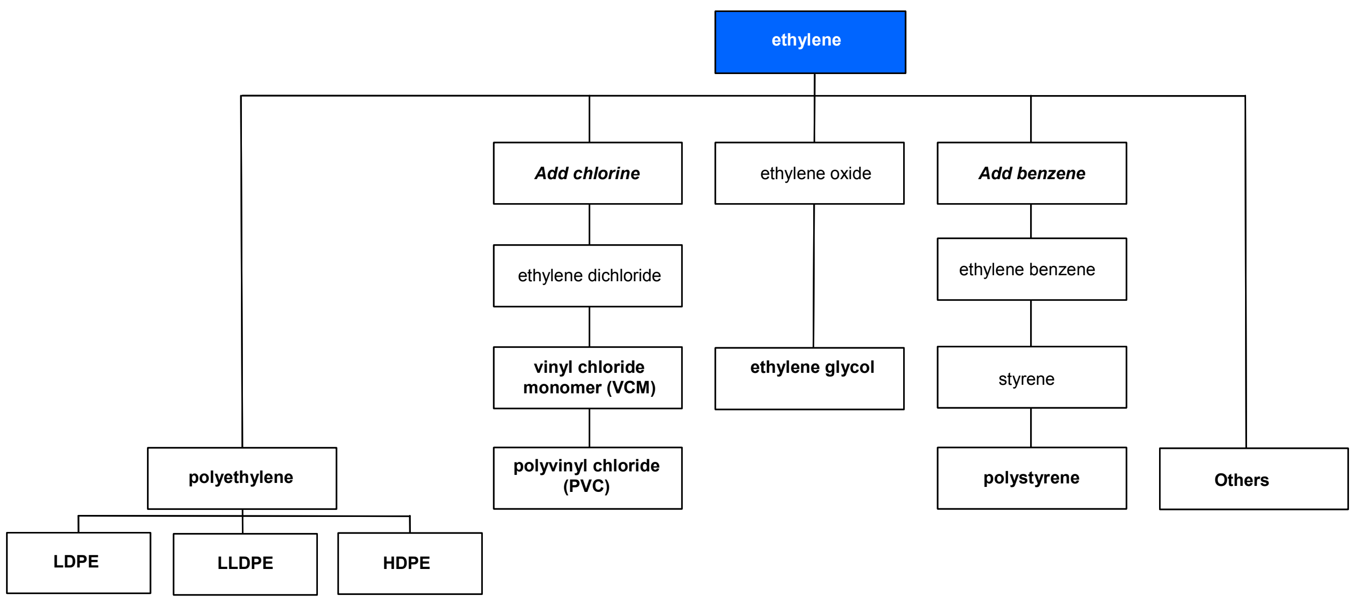
Over the following pages we summarily discuss the major petrochemical building blocks. It is these often highly reactive first derivatives produced in the upstream petrochemical cracker that form the basis of today's plastics industry and the starting point for almost all organic chemistry.

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 289: A simple flow chart of ethylene and its derivatives



Source: Deutsche Bank

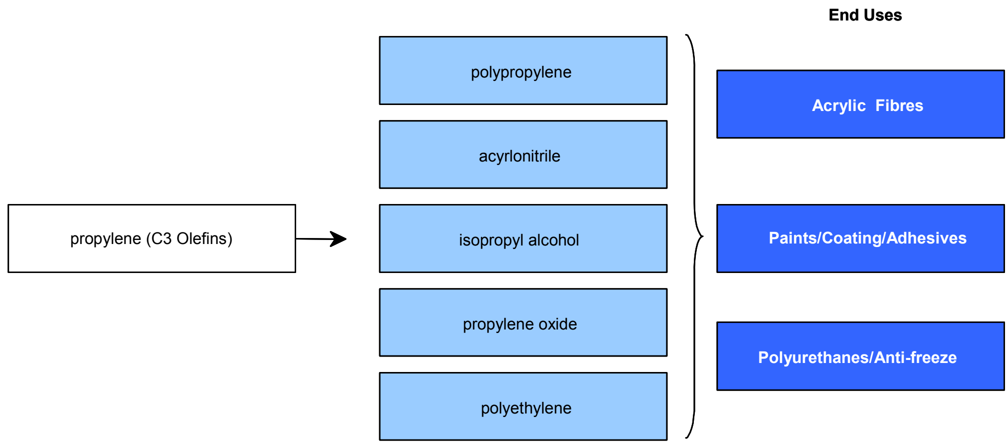
Propylene – C_3 Olefin

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 290: The polypropylene chain

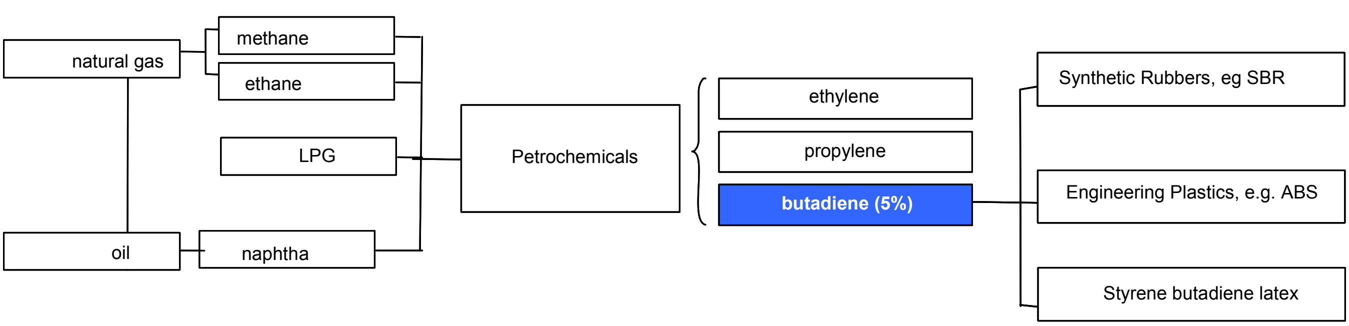


Source: Deutsche Bank

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 291: Production process of butadiene



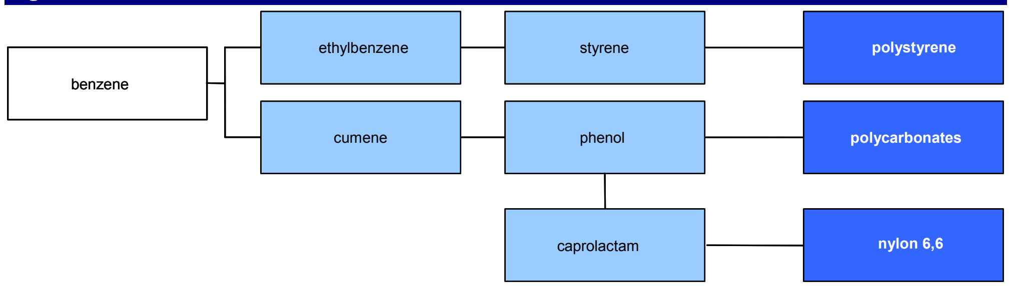
Source: Deutsche Bank

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 292: The benzene chain



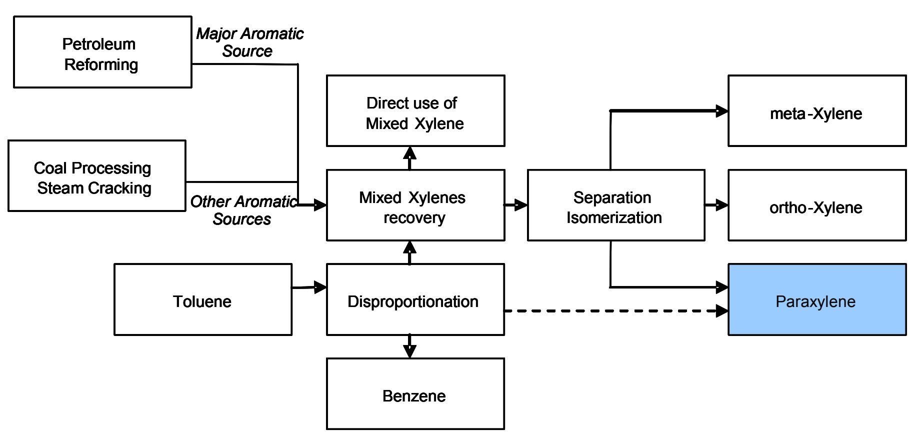
Source: Deutsche Bank

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 293: 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.

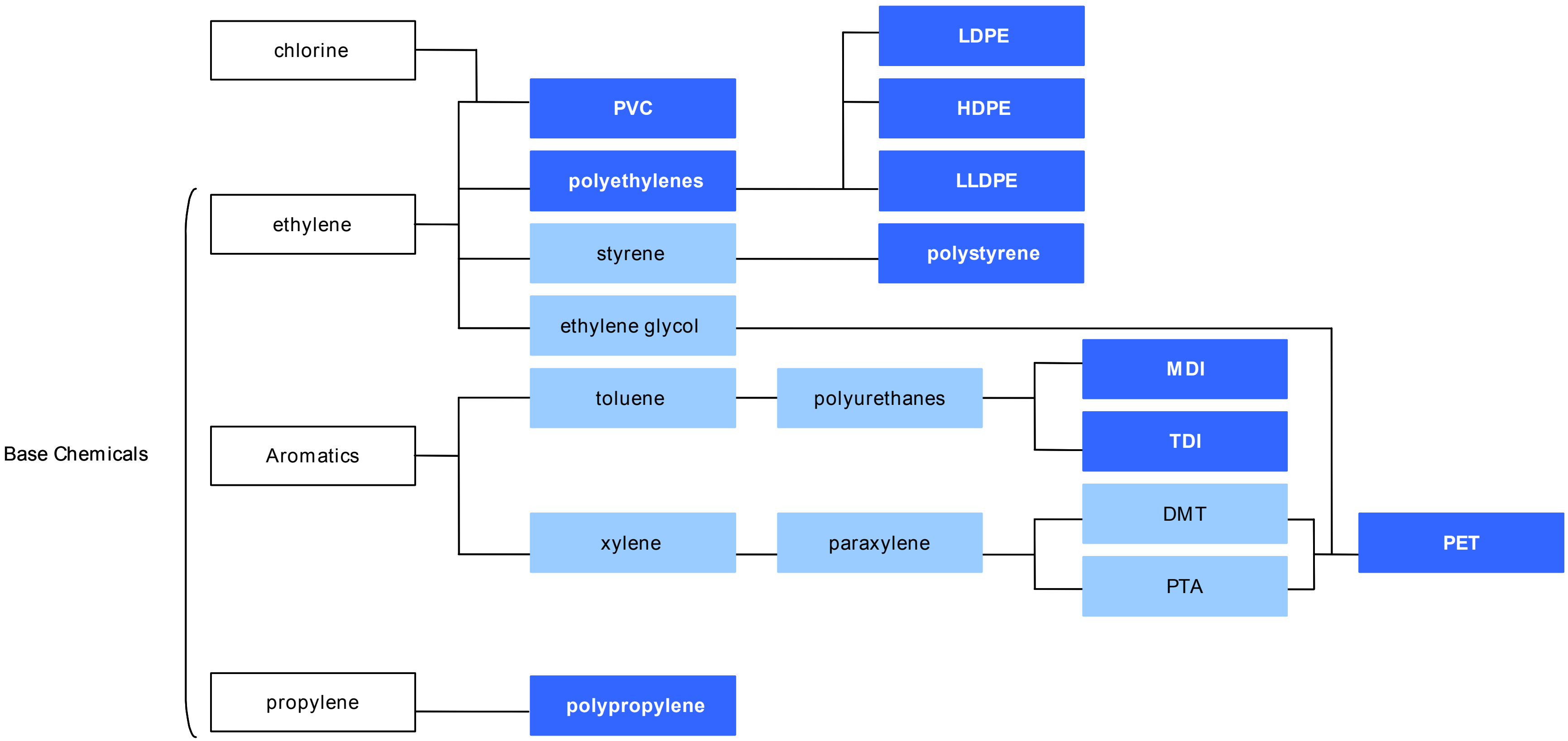
Although common usage tends to apply the generic term 'plastics' to everything, there are in fact numerous types of plastics with a variety of characteristics suitable for a wide range of applications. Plastics can be divided into two main categories - thermoplastics and thermosets. Thermoplastics soften 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 294: Common types of plastic

Thermoplastics	Thermosets
HDPE	MDI
LDPE	TDI
LLDPE	Epoxy
PET resins	Phenolic resins
polypropylene	
polystyrene	
polyvinyl chloride (PVC)	

Source: Deutsche Bank

Figure 295: Polymers: simplified flow diagram of the product pathways Involved in their production



Source: Deutsche Bank, industry sources

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

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.

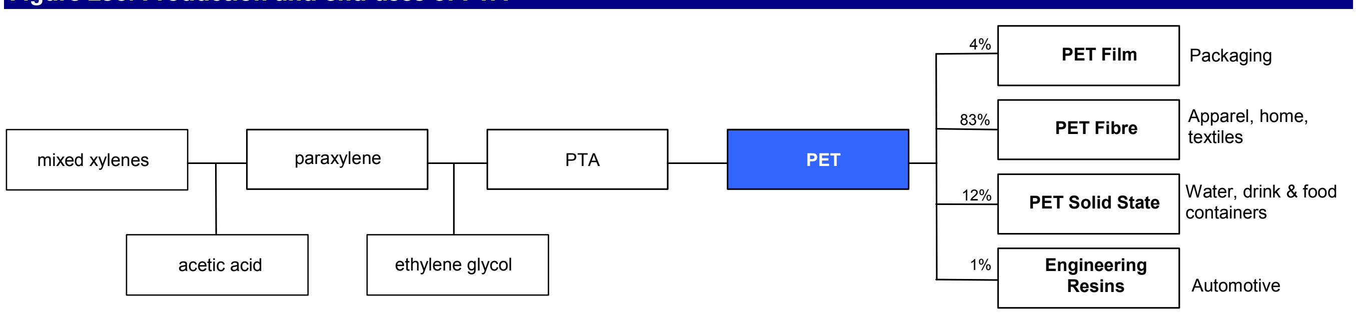
Polypropylene

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)

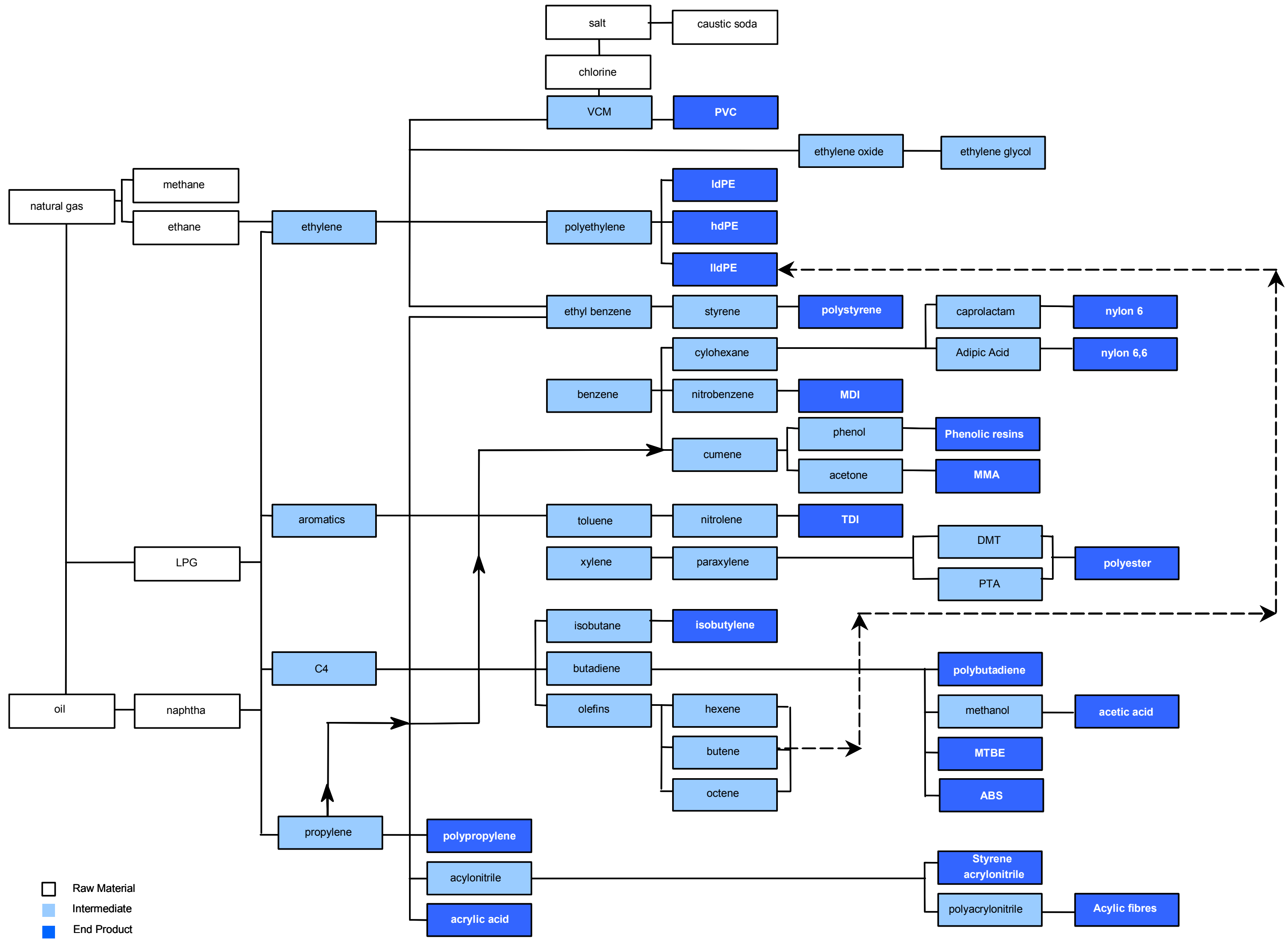
Purified terephthalic acid is a white, water-insoluble powder obtained from the oxidation of paraxylene with the solvent acetic acid. It is used primarily in the manufacture of polyester (either resin called PET or fibre). PTA is also known at TPA (terephthalic acid). Demand growth in PTA is expected 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 296: Production and end uses of PTA



Source: SRI

Figure 297: 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

Tight Gas

Liquefied Natural Gas (LNG)

Overview

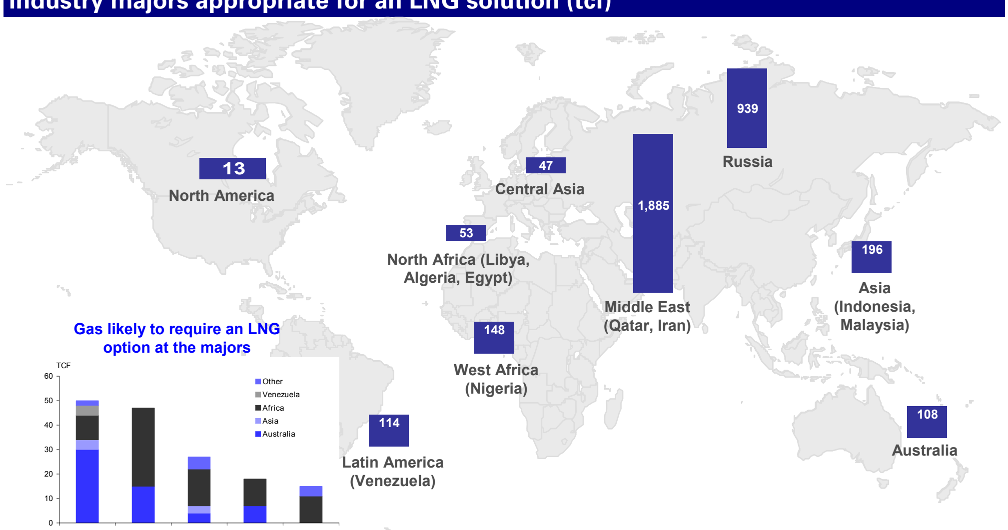
Liquefied natural gas (LNG) is produced when natural gas (predominantly methane) is cooled to a temperature of -162°c at atmospheric pressure

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 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 west (USA, UK, etc) move from a position of self sufficiency in natural gas supply to one of deficit, demand for LNG is growing at an estimated 5-10% per annum. In 2009 LNG capacity at the world's 24 LNG facilities stood at an estimated 189 million tonnes per annum and represented around 7% of global gas consumption. By 2020, production is expected to stand at around 460mtpa from 51 facilities, a 10 year CAGR of 8%. Major producing countries include Qatar, Nigeria, Indonesia and Australia whilst the major IOCs involved in the production and marketing of LNG include Shell, Exxon and Total.

A brief history

Relative to both oil and piped gas, the LNG industry is still very much 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 298: Global un-contracted gas reserves and the technical reserves of the industry majors appropriate for an LNG solution (tcf)



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.

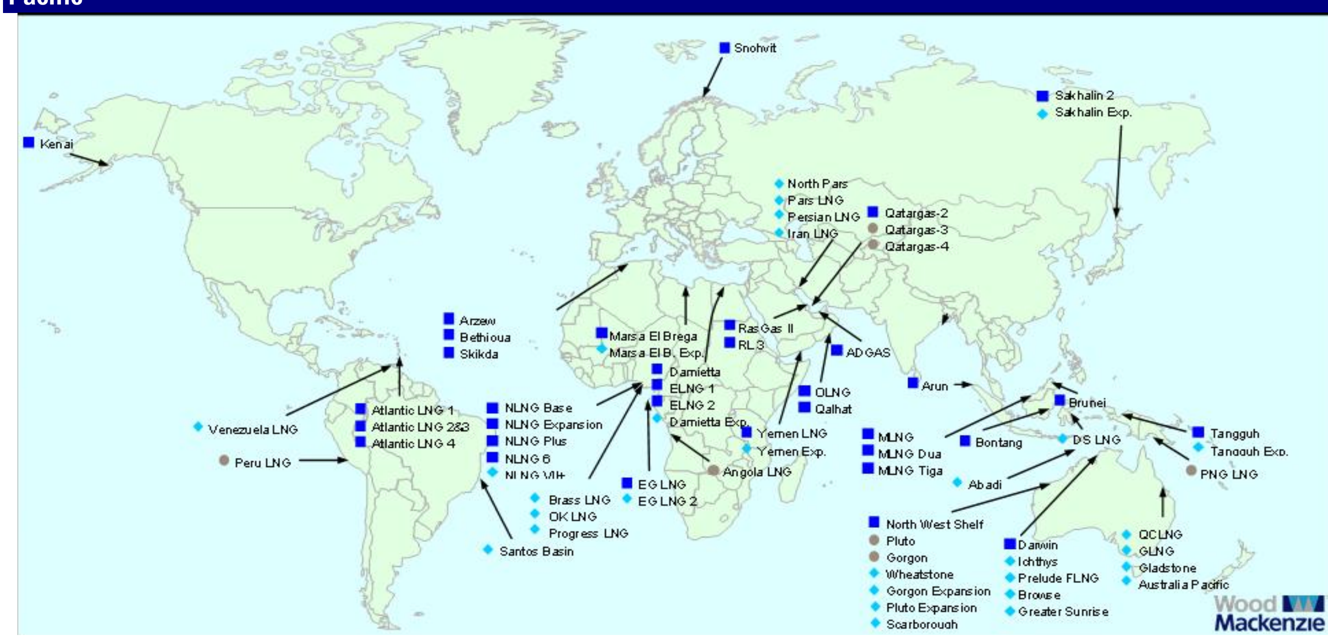
The LNG market today

Today, international trade in LNG centres on two geographic regions.

Today, international trade in LNG centres on two geographic regions. These remain discrete although they are increasingly becoming linked by Middle Eastern supply.

- The Atlantic Basin involving trade in Europe, northern and western Africa and the US eastern sea board.
- The Asia Pacific Basin involving trade in South Asia, India, Russia and Alaska.

Figure 299: LNG operates within two distinct basins with the Middle East positioned to supply both Atlantic and Pacific



Source: Wood Mackenzie Dark Blue = existing; brown = under construction; light blue = proposed)

Asia's dependence historically 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 this 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 as a significant buyer of LNG under long term contracts, with that market alone now expected to account for around 10% of world demand by 2020.

North American unconventional gas alters the Atlantic Basin outlook

The loss of North America as a major LNG growth opportunity over the medium term at least does, however, hold significant implications for global LNG markets long term. As illustrated below, where in May 2007 North American LNG demand by 2020 had been expected to reach over 100mtpa the successful development of unconventional gas in that region suggests that in reality LNG imports by the end of this decade will quite likely be little changed from current levels of around 20mtpa. As a consequence, much of the LNG that was being developed to supply the North American market, not least from Qatar, has had to seek an alternative home. Short term this has clearly added to the over-supply already evident as industrial demand collapsed following the 2008 global economic downturn.

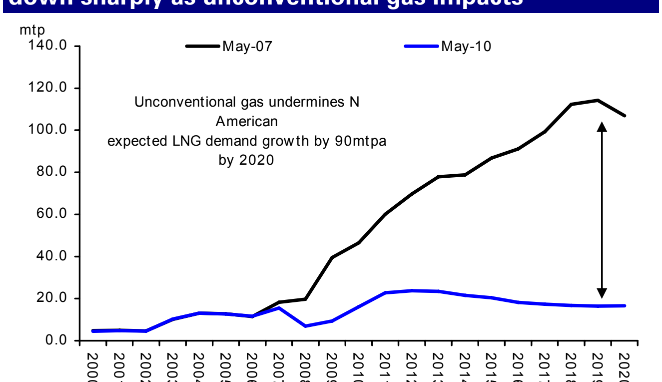
Longer term, however, not only has the development of unconventional sources reduced the outlook for growth in LNG from double digit rates to a more likely 6-8%. It has also raised questions on the economic viability of future expansions in the Atlantic Basin. Of importance here is that, with the US natural gas price now anticipated by many to trade in a $5-7/mmbtu band, current break-even costs for a green-field LNG scheme ($7-8/mmbtu) are such that delivery into the US at anticipated Henry Hub prices is unlikely to be economically viable. As such, future Atlantic Basin LNG plants look unlikely unless built as expansions of existing facilities or where the sponsor has committed a significant proportion of the output to a pre-defined utility buyer under a contract with supportive pricing terms. In short, the Asian point-to-point model using an oil-linked formula looks likely to once again become increasingly prevalent in the Atlantic Basin with the US no longer proving an economic backstop.

Growth should remain robust but contract and spot pricing will vary with the cycle.

Having said this with demand from Asia (and notably China) expected to continue to grow and a multitude of new demand opportunities emerging, not least in the Middle East and Latin America, global demand for LNG is expected to continue to expand at healthy mid-single digit rates. This is illustrated in Figure 303 which shows Wood Mackenzie's expectations for global LNG demand and supply growth out through 2020.

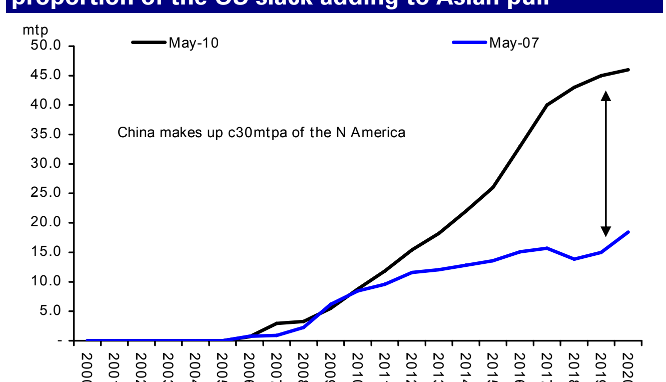
The industry is, however, almost certain to remain prone to its own very notable supply/demand cycles. Given that the latest downturn in LNG markets has marked a confluence of negative demand factors coinciding with the 2008-11 start-up of some 80mtpa of new supply (40% of existing capacity) these are unlikely to be as extreme as has been the case over the 2008-11 period. However, as with many other capital intensive industries which have a four-five year construction cycle the addition of new supply will invariably be lumpy something which has been only too evident in the LNG industry in recent years.

Figure 300: US LNG demand growth has been revised down sharply as unconventional gas impacts



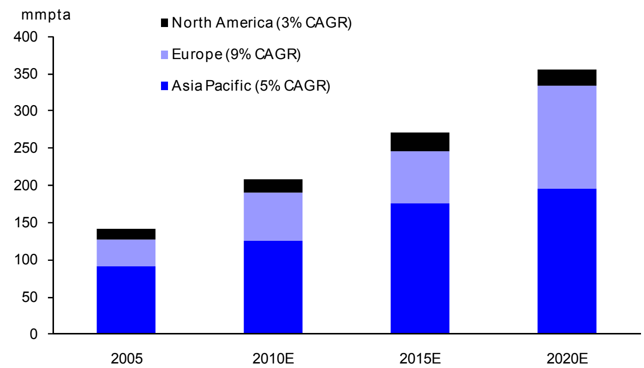
Source: Deutsche Bank

Figure 301: China is forecast to offset a significant proportion of the US slack adding to Asian pull



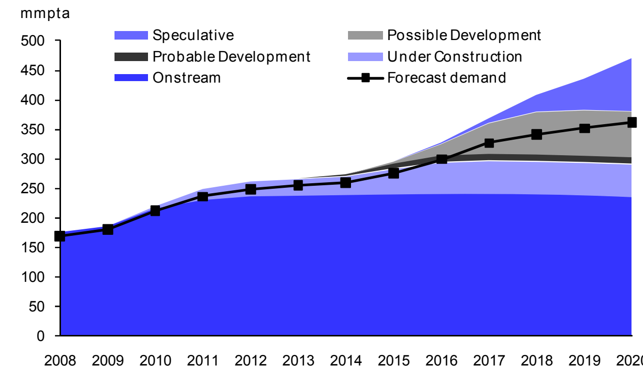
Source: Deutsche Bank

Figure 302: Asia continues to dominate LNG markets but the strongest growth is in Europe



Source: Wood Mackenzie

Figure 303: Based on probable developments the LNG market remains oversupplied thru 2015

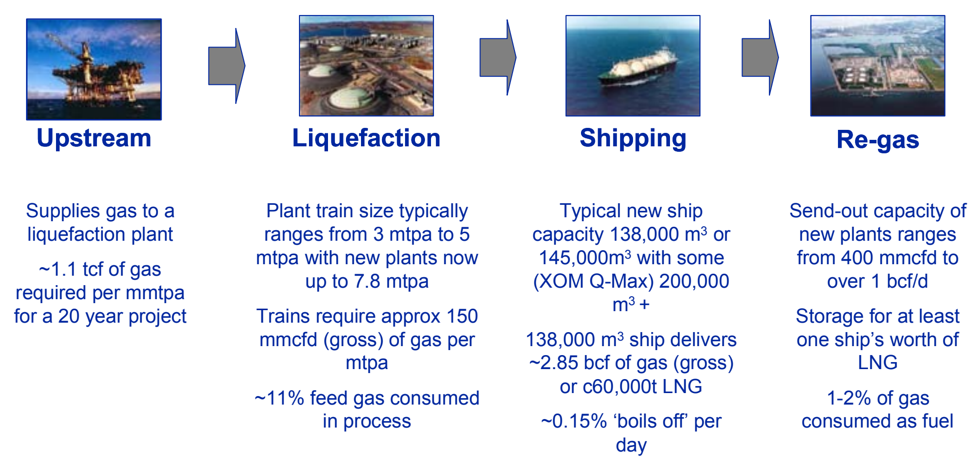


Source: Wood Mackenzie

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 304: The LNG Chain – for every 1mtpa of LNG supplied under a 20 year contract 1.1TCF of gas is required



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 a gas hungry national gas market (e.g. US market).

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

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.

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 305: Indicative returns and investment proportions and returns across the LNG chain assuming a 5mtpa offshore fully integrated scheme

Source: Wood Mackenzie

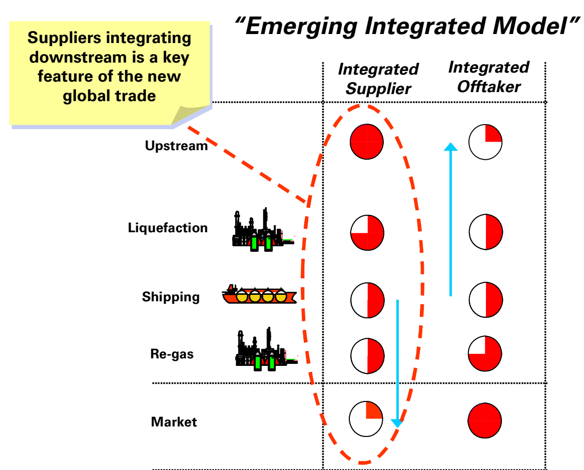
North America – driving integration across the chain

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 a position in the Atlantic Basin. 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 a sizeable 'merchant' portfolio committing to buy LNG under contract and then placing it with dedicated end users either through back-to-back contracts or selling it directly into a traded gas market (i.e. UK/US) using re-gas facilities which they have access to under long-term capacity commitments, or have constructed for their own use. As a consequence, we estimate that around 10-15% of LNG deliveries globally are now effectively made on a 'spot' basis, the LNG buyer (or merchanter) effectively re-marketing LNG bought into their own portfolio.

Figure 306: Up or down, it's all about integration

- **Integration being driven more out of necessity than desire**
  - **Particularly in the Atlantic Basin**
  - **But integration does help control project delivery**
- **An increasing proportion of trade is taking place within integrated portfolios**
  - **~1/3 of total volumes by 2010**
- **As a result, some of the largest suppliers (including NOCs) are becoming the largest buyers of LNG**
  - **Qatar Petroleum largest supplier of gas for LNG and purchaser of LNG by 2010**

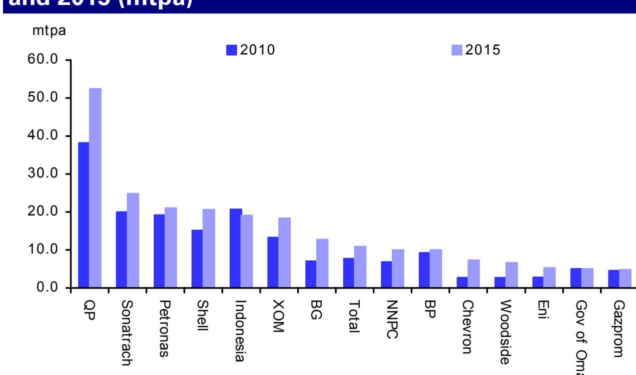


Source: Wood Mackenzie

NOC resource holders push down the chain

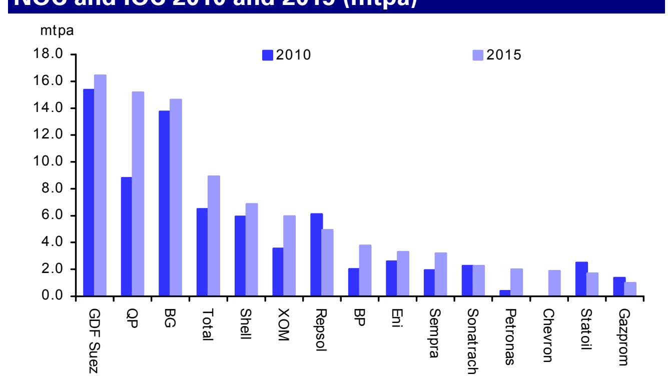
Similarly, several of the major NOCs have also shown their desire to push into downstream markets as they seek to capture the full value of their upstream resource. This has proven especially true of the Qatari's, whose involvement in downstream markets suggests that, from a standing start, they are now the world's largest producer of LNG, a position that only looks likely to grow further as more plants come on-stream over the next twelve months. Importantly, of Qatar's 77mtpa in excess of 25mtpa remains available for diversion to different geographic markets depending largely upon price.

Figure 307: Liquefaction capacity by NOC and IOC 2010 and 2015 (mtpa)



Source: Wood Mackenzie

Figure 308: LNG contracted for potential remarketing by NOC and IOC 2010 and 2015 (mtpa)



Source: Wood Mackenzie

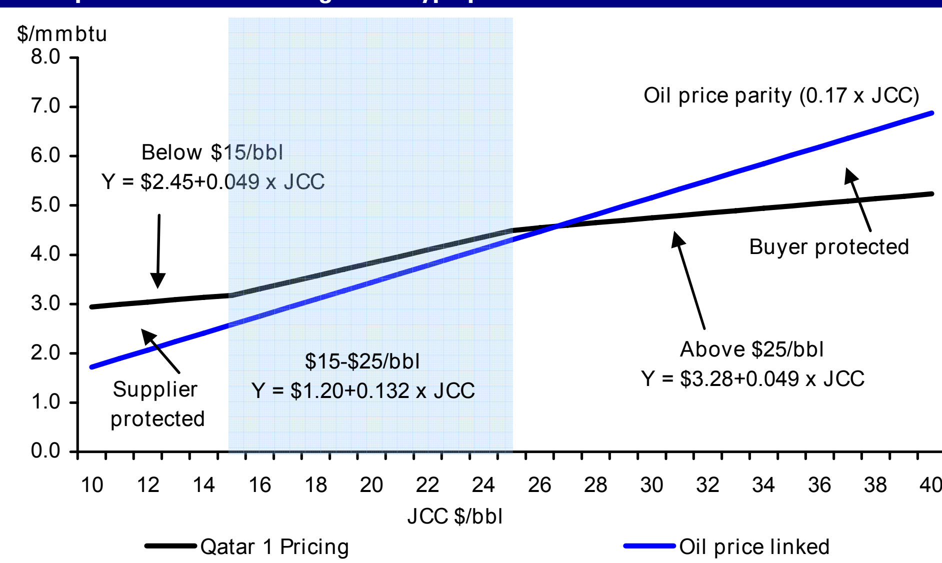
Pricing of LNG

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 contract prices for supply of gas from Qatar Gas 1 to certain Japanese customers.

Figure 309: Historically, Japan and European LNG supply contracts have been priced with caps and collars creating an 'S' type price curve



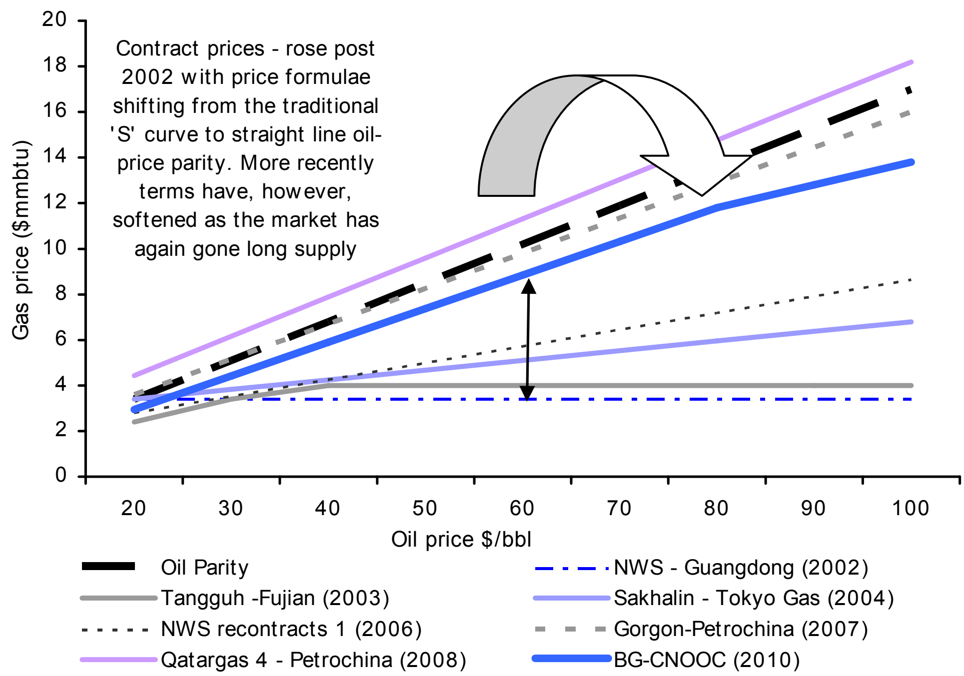
Source: Deutsche Bank

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 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 below figure. 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.

Figure 310: Contract price terms fluctuate along with the cycle



Source: Deutsche Bank

Separately, 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 adjustment typically reflecting the realities of the then prevalent market.

North America – changing the basis of price

Where pricing under Asian and European contracts continues to retain an oil-linkage clause the growth of the US as a market for LNG has seen the emergence of contracts which use the market derived, quoted Henry Hub gas price as the basis for contract pricing, buyers paying a fixed percentage of the prevailing Henry Hub price for delivered gas. Not only has 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 has also set something of a floor for price negotiations in the rest of the world.

Whether the use of a Henry Hub derived price formula as the basis for long term pricing of LNG remains is, we would suggest, now open to debate. For as indicated earlier if the emergence of shale gas as a material source of North American supply means that North American gas prices are likely to remain below those required for the economic build of a new LNG plant it is hard to see suppliers agreeing to its use in the contract price formula.

Cargo flexibility – FOB and DES (or CIF)

Indexation aside, 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 - shipping will be organized by the buyer

- **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.

DES cargoes are generally written with a specific destination in mind

- **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.

Breaking down value across the chain

the As an illustration of the allocation of absolute value across the LNG chain the following schematic provides an indication of how value might be accorded on a US Henry Hub indexed contract at a prevailing gas price of $3.50/mmbtu. Clearly this depicts an upstream project in which the liquefaction plant operates as a tolling facility receiving a fixed fee per unit of gas processed.

What it emphasizes however, is that the netback to the resource holder under a US indexed contract represents the local market price less a fixed cost for shipping and a % of the value of Hub for re-gas and marketing. This differs from the traditional Asian contract both in the calculation of the end market price (formula derived versus traded market derived) but also the re-gas and trading costs (a % of Hub in the US and thus variable depending on end-market price but likely fixed in Asia at, say, $0.40/mmbtu).

Figure 311: Breaking down the chain – illustrative long haul supply (Nigeria to Lake Charles) at a $4.50/mmbtu HHub gas price

Source: Courtesy of BG Group

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. We estimate that liquefaction capacity alone has broadly trebled in cost over the past five or so years from c$300m/mtpa to c$1bn/mtpa today.

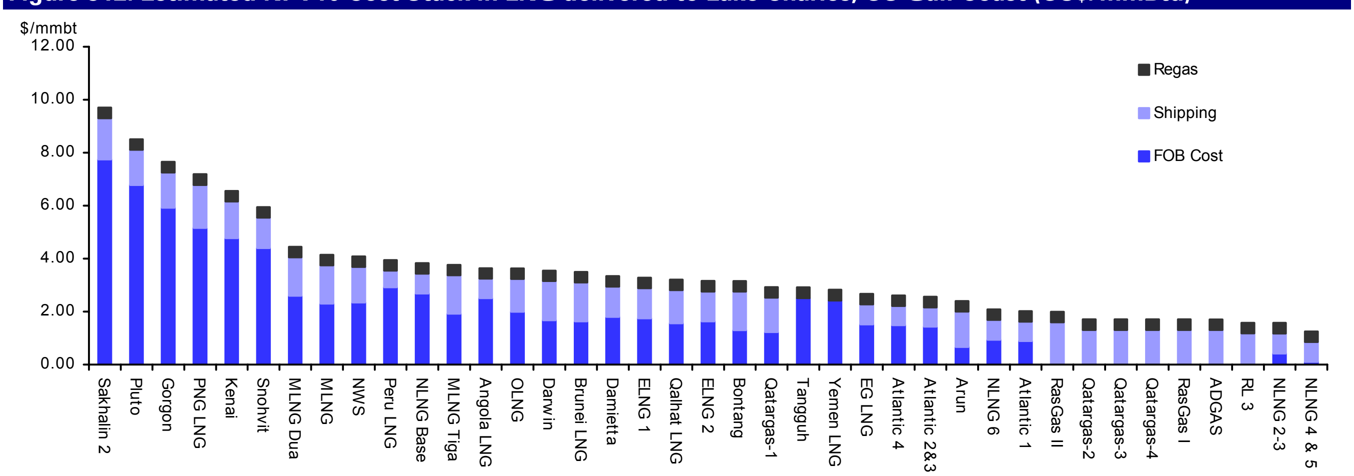
Depreciation per unit of production is the key cost

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 $2/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 $0.25/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 the US market through a re-gas facility (Lake Charles on the Gulf Coast 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).

Figure 312: Estimated NPV10 Cost Stack in LNG delivered to Lake Charles, US Gulf Coast (US$/mmBtu)



Source: Deutsche Bank estimates, Wood Mackenzie

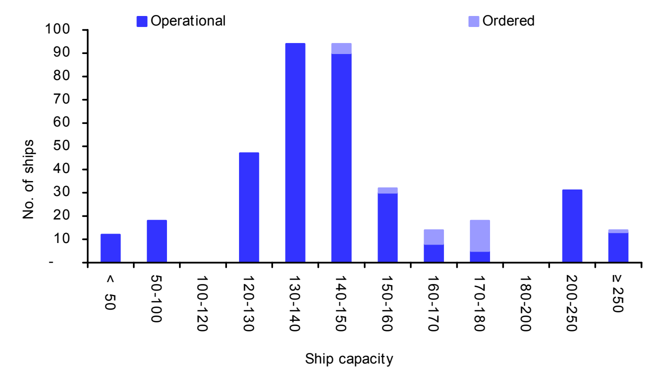
Shipping of LNG

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.138,000m³ (c55kt LNG) today to nearer 170,000m³ (c.70kt LNG) and beyond (the latest orders for the Qatari projects involve ships called the Q-Max with a capacity of some 260,000m³ 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 313: LNG shipping capacity 1965 to 2010E ('000m³)

Source: Deutsche Bank

Figure 314: Capacity distribution of existing and future LNG shipping fleet



Source: Deutsche Bank

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). Indicative rates for delivery into the US 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 315: Freight rates ($/ mmbtu) in Q3 '10 for 145,000m3 charter ship at $40k/day

Exporter/Destination	Trinidad	Nigeria	Algeria	Norway	Qatar	Australia	Malaysia	Russia
US Gulf	0.37	0.89	0.73	0.75	1.59	1.77	1.94	2.25
US East Coast	0.32	0.76	0.58	0.62	1.43	1.69	1.89	2.21
UK	0.56	0.61	0.26	0.28	1.10	1.52	1.54	1.85
Spain	0.60	0.57	0.14	0.47	0.91	1.33	1.34	1.65
India	1.42	1.00	0.92	1.30	0.25	0.56	0.55	0.86
China	1.77	1.36	1.43	1.83	0.79	0.46	0.35	0.32
Japan	1.92	1.50	1.58	1.98	0.93	0.55	0.40	0.20
Argentina	0.66	0.68	0.84	1.09	1.22	1.26	1.30	1.47
Chile	0.99	1.00	1.16	1.42	1.50	1.20	1.27	1.27

Source: Deutsche Bank

Re-gasification of LNG – facilitating access

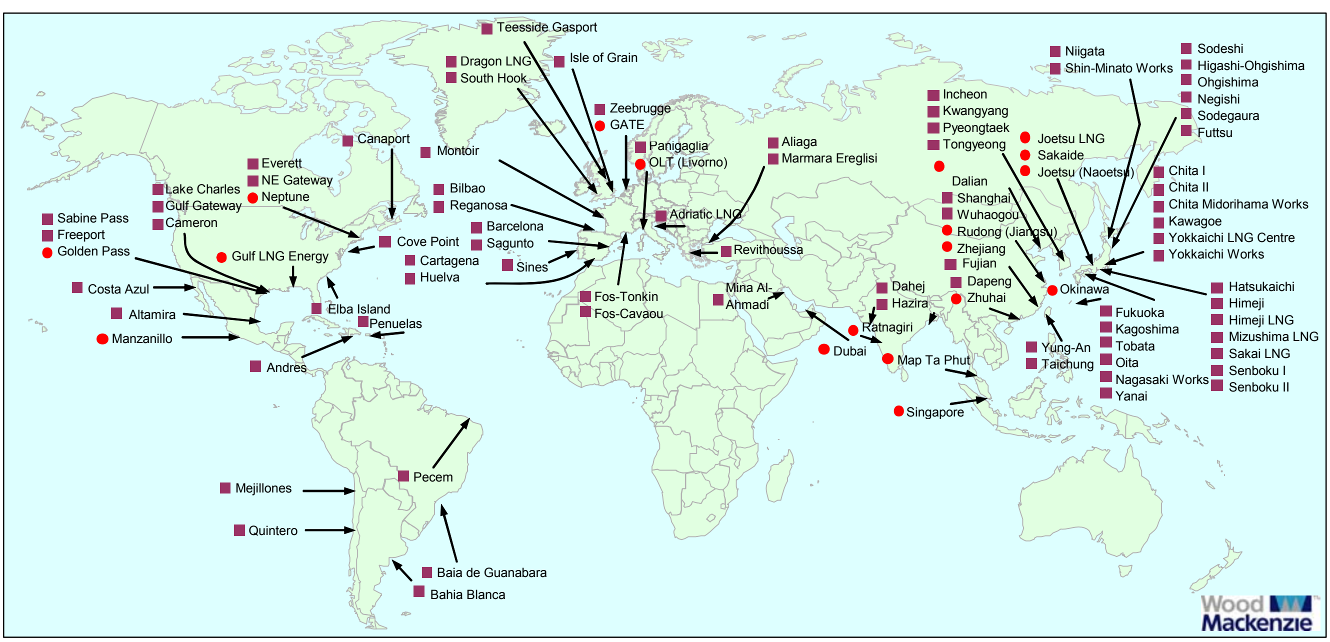
Re-gas capacity rights afford access to new markets

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 there 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 their dependence on any single market for the sale of their contracted gas;
- Argue for higher prices from end-customers given their range of end-market options;
- Negotiate more favourable terms of supply from upstream producers through arguing that they will be able to maximize 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 316: Re-gas facilities both in existence and under construction globally



Source: Wood Mackenzie

Existing LNG facilities and facilities planned 2010-15

Figure 317: Existing LNG Facilities, capacities and major upstream and mid-stream participants

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
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
Curtis Queensland	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	1	3.6	Integrated	Santos (60%) Petronas (40%)	
Gorgon LNG	Australia	2015	3	15.0	Integrated	Chevron (50%), Exxon (25%), Shell (25%)	
Ichthys	Australia	2016	2	8.5	Integrated	Inpex (74%); Total (24%)	
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%
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: Deutsche Bank

Figure 318 (cont): 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%	
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)
Yemen LNG	Yemen	2009	2	6.6	Liquefaction	Total 50.6%, Hunt Oil 22%; SK 12.2%; Kogas 7.7%, Hyundai 7.5%	

Source: Deutsche Bank

Main LNG facilities planned 2016 and beyond

Figure 319: LNG – Main proposed projects 2016 plus

Project	Country	Start-up	Scale mtpa	Gas in mscf	Main plant IOC's	Main Upstream IOC's	Project cost – LNG plant	FOB B/E (US$/mmbtu)	Buyers
2012 plus									
NLNG 7	Nigeria	2016	8.4	1300	NNPC 49%, RDS 25.6%, Total 15.0%	Shell 17.5%; Total 13%; ENI 8%	US$7.7bn	US$2.16	BG, ENI, Shell, Oxy, Total
OK LNG**	Nigeria	2016+	22.0a	3300	CVX 20%, RDS 15%, TOT 5%, ENI 3%	CVX 18.5%%, RDS 18.5%, BG 13.5%	US$11bn	US$2.19	Equity lifted
Brass LNG**	Nigeria	2016+	10.0	1466	TOT/COP/ENI 17% each	TOT 20%, ENI 10%, COP 10%	US$10bn	US$1.14	BG, BP, Suez, ENI, TOT
Asia Pacific LNG	Australia	2016+	7.0	1100	Origin 50%, Conoco 50%		US$7bn	US$7.02	TBD
Wheatstone LNG	Australia	2016+	8.6	1350	Chevron 75%, Apache 16.25%, KUFPEC 8.75%		$10.4bn	US$6.79	Tepco
Prelude FLNG	Australia	2016+	3.6	700	Shell 100%		$5.0bn	US$6.53	n.a.
PARS LNG	Iran	2016+	10.0	1600	Total 30%; Petronas 30%	NIOC	n.a.	n.a.	Petronas; Total; other
Shtokman LNG	Russia	2016+	7.8	1200	Gazprom 75%; Total 25%	Gazprom 75%; Total 25%	US$8bn	n.a.	n.a.

*Source: Deutsche Bank ** Likelihood of delays of at least 1-2 years*

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 both their position across all aspects of the LNG chain in 2010 as well as the anticipated position by 2016. 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.

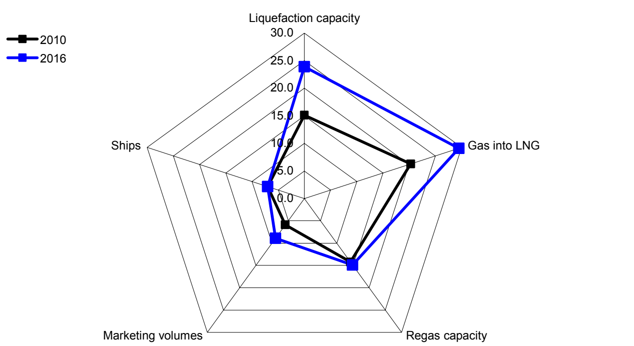
Shell the clear leader – but watch Total

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, however, 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 NOCs will be an increasing force

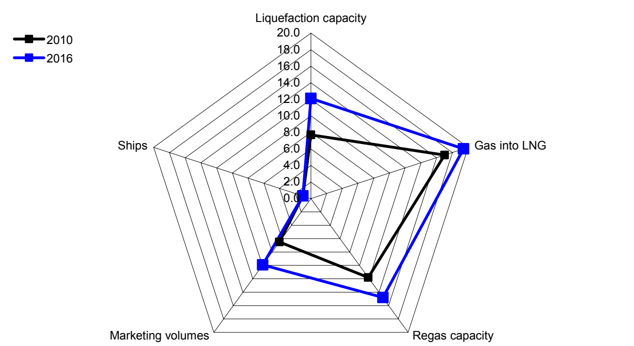
The IOCs aside, as the LNG market expands it is also clear that the role played by the NOCs with their often substantial resource base is likely to increase significantly. This is already evident in Qatar, QPC playing an increasing role in all aspects of the chain. We would expect the same of Russia's Gazprom and, given time, potentially the Iranians.

Figure 320: RDS - Spread of LNG assets 2010 through 2016E



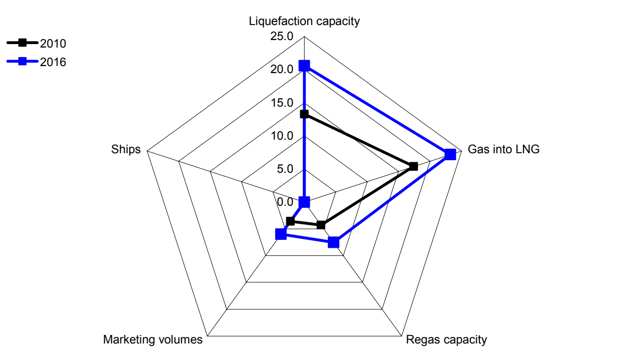
Source: Wood Mackenzie; Deutsche Bank

Figure 321: Total - Spread of LNG assets 2010 through 2016E



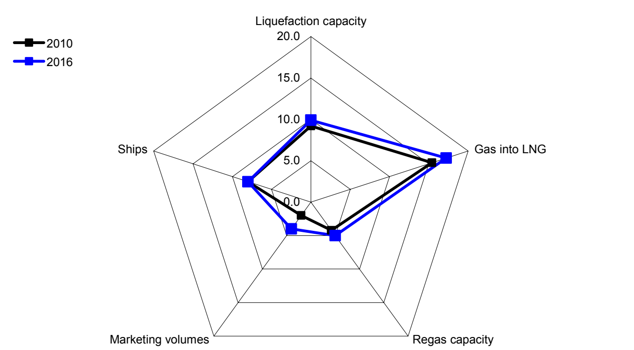
Source: Wood Mackenzie; Deutsche Bank

Figure 322: Exxon - Spread of LNG assets 2010 through 2016E



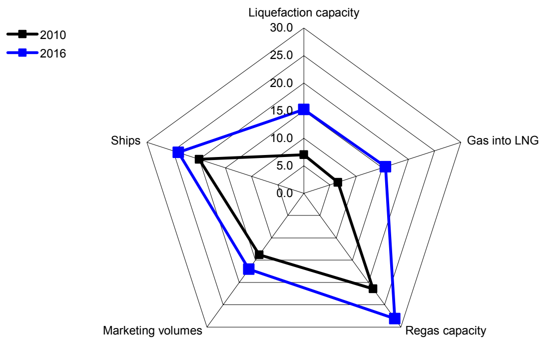
Source: Wood Mackenzie; Deutsche Bank

Figure 323: BP - Spread of LNG assets 2010 through 2016E



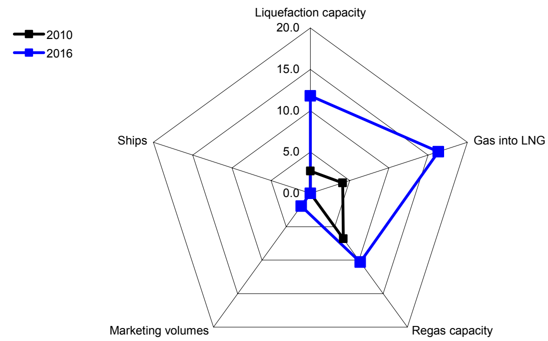
Source: Wood Mackenzie; Deutsche Bank

Figure 324: BG - Spread of LNG assets 2010 through 2016E



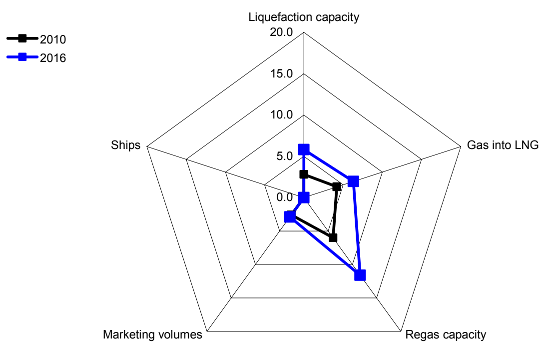
Source: Wood Mackenzie; Deutsche Bank

Figure 325: Chevron - Spread of LNG assets 2010 through 2016E



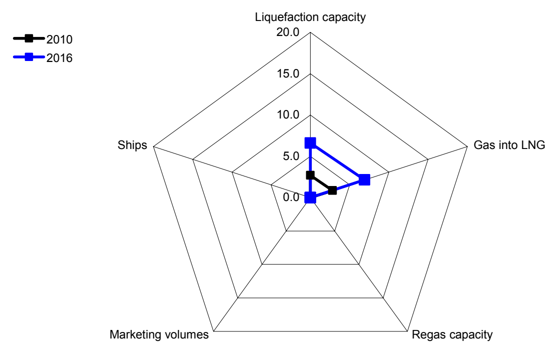
Source: Wood Mackenzie; Deutsche Bank

Figure 326: ENI - Spread of LNG assets 2010 through 2016E (ex share of Union Fenosa & GALP)



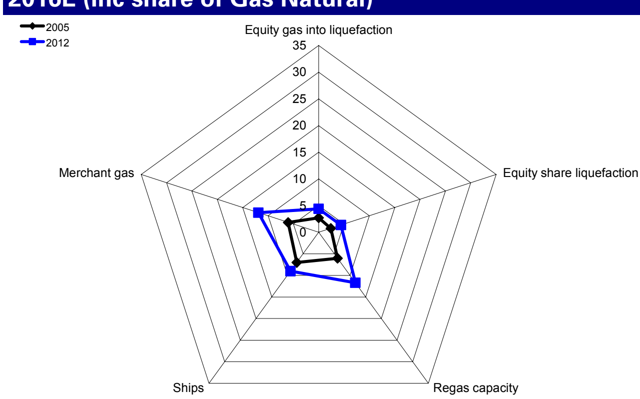
Source: Wood Mackenzie; Deutsche Bank

Figure 327: Woodside - Spread of LNG assets 2010 through 2016E



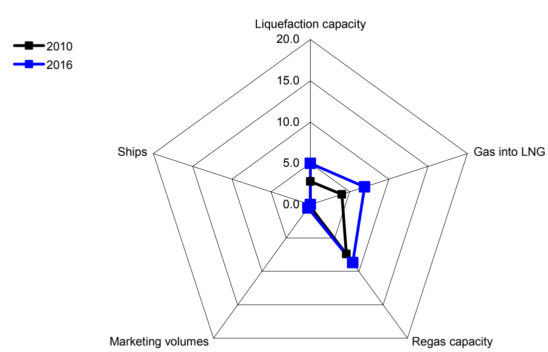
Source: Wood Mackenzie; Deutsche Bank

Figure 328: Repsol - Spread of LNG assets 2010 through 2016E (inc share of Gas Natural)



Source: Wood Mackenzie; Deutsche Bank

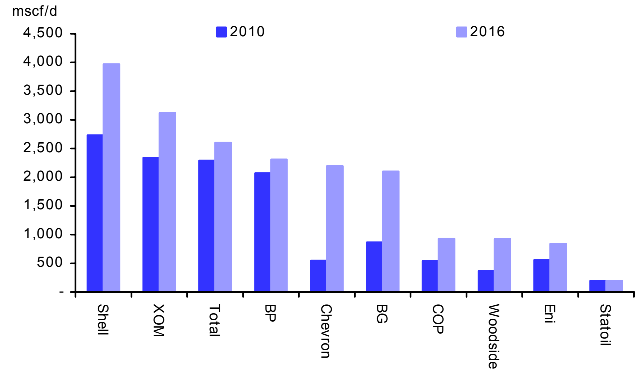
Figure 329: ConocoPhillips - Spread of LNG assets 2010 through 2016E



Source: Wood Mackenzie; Deutsche Bank

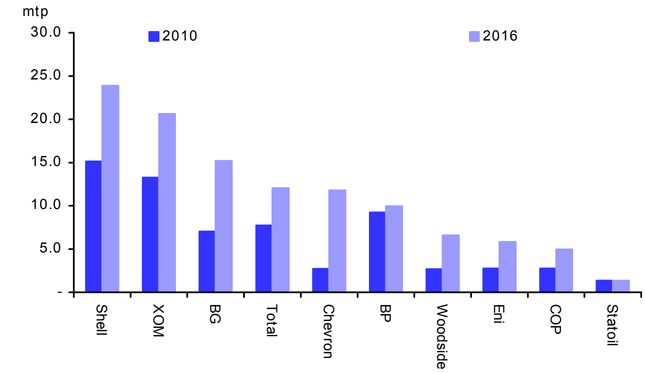
The IOC majors compared

Figure 330: Equity gas into LNG 2010 and 2016E (mscf/d)



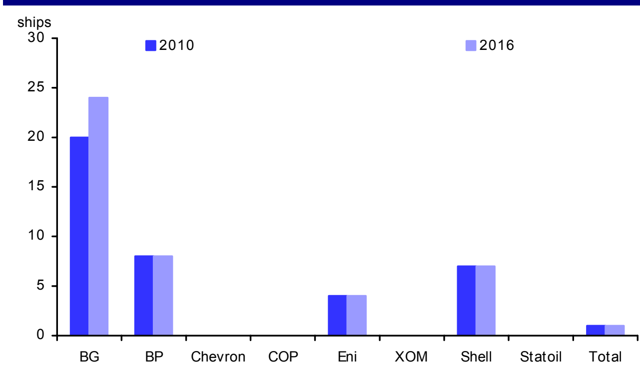
Source: Deutsche Bank

Figure 331: Share of liquefaction capacity 2010-16E (mtpa)



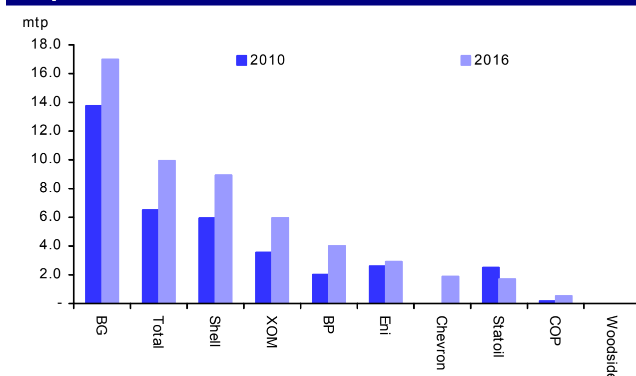
Source: Deutsche Bank

Figure 332: Shipping capacity 2010 and 2016E (mtpa)



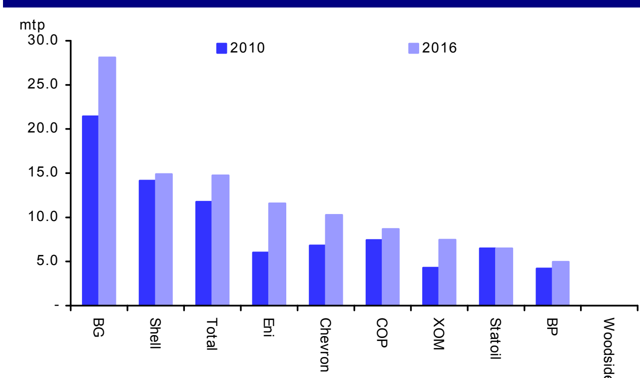
Source: Deutsche Bank

Figure 333: Merchant volumes into portfolio 2006-12E (mtpa)



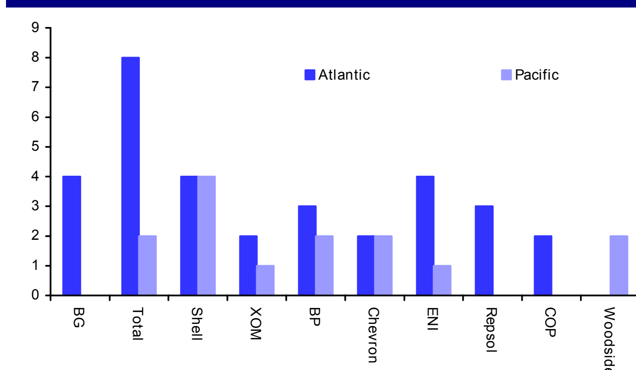
Source: Deutsche Bank

Figure 334: Re-gas capacity 2012 and 2016E (mtpa)



Source: Deutsche Bank

Figure 335: Supply positions Atlantic and Pacific Basin 2010



Source: Deutsche Bank

Deepwater

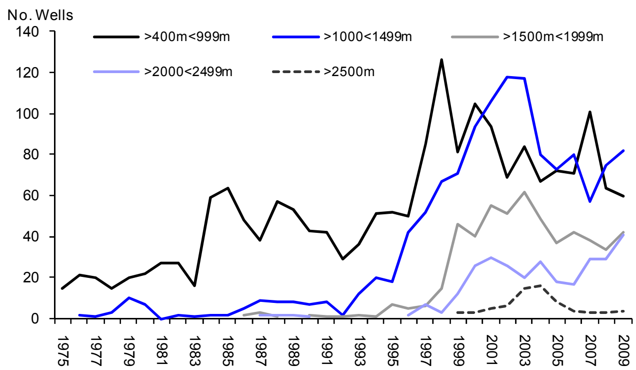
Peering into deepwater

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 classically 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.

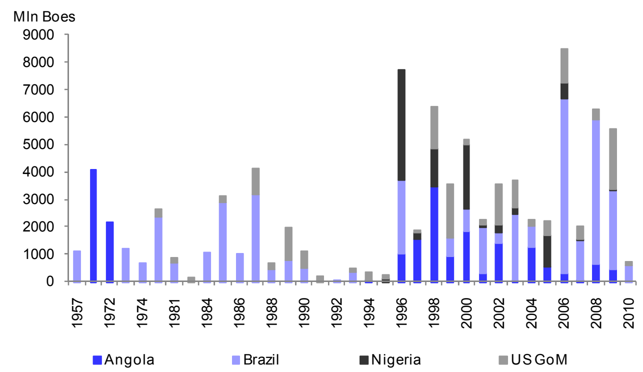
Developing these fields has been crucial to the world's oil supply, has provided diversification away from OPEC, given the IOCs a major new play to focus on and has driven step changes in oil service company capabilities. Three areas currently dominate the world's deepwater oil fields; the US GoM, Brazil and West Africa (Angola and Nigeria).

Figure 336: Global deepwater production 2000-2015E



Source: Wood Mackenzie data; Deutsche Bank

Figure 337: Deepwater discoveries, US GoM, Brazil, Angola and Nigeria, 1957-2010

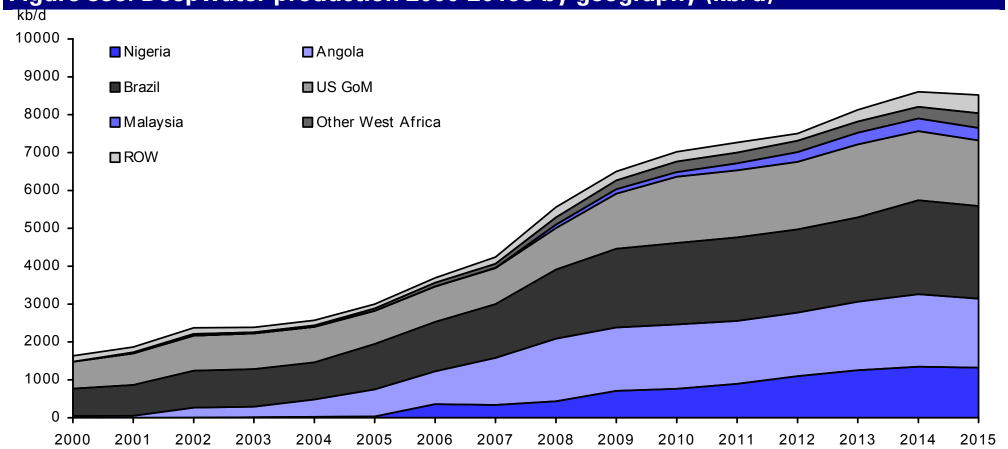


Source: Wood Mackenzie; Deutsche Bank *includes all discoveries in depths of water over 1000 metres where recoverable oil resource is greater than 50mbbls

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 7mb/d in 2010, 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).
- 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 338: 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 339: The deepwater is the fastest growing source of forecast oil production

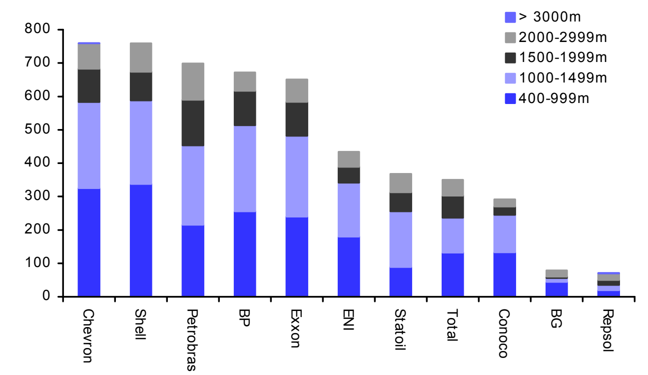
	2000	2007	2008	2009	2010	2011	2012	2013	2014	2015	8 year	15 year
Onshore	49735	52883	54871	57047	58556	58934	59561	59547	59145	59114	1.4%	1.2%
Shallow	21233	22789	23456	23315	23419	23308	23286	22812	22282	21502	-0.7%	0.1%
Deep	1637	4241	5560	6506	7021	7267	7598	8128	8604	8519	9.1%	11.6%
Other/YTF	1792	1610	2929	1935	1426	2442	3150	4216	5940	7676	21.6%	10.2%
Total	**74397**	**81523**	**86816**	**88802**	**90423**	**91951**	**93594**	**94702**	**95970**	**96811**	**2.2%**	**1.8%**
% total	*2.2%*	*5.2%*	*6.4%*	*7.3%*	*7.8%*	*7.9%*	*8.1%*	*8.6%*	*9.0%*	*8.8%*		

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.

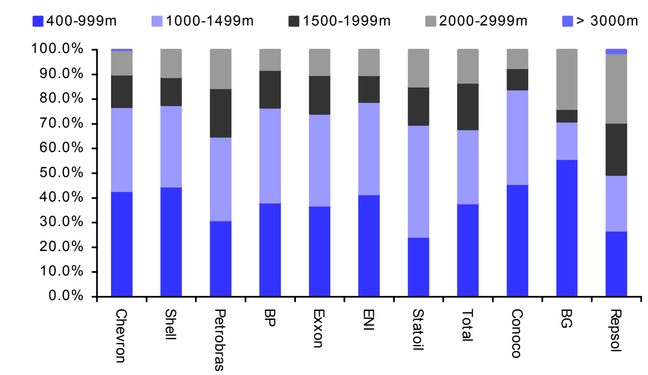
Clearly the deepwater has been an important source of reserves growth and oil production for the major territories involved. Equally apparent is that it has very much been the major oils that have been responsible for much, if not all, of the exploration activity undertaken.

Figure 340: Number of IOC operated wells at depths of >400m 1975 - 2010



Source: Wood Mackenzie; Deutsche Bank

Figure 341: 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 by depth. Evident from this is that despite the often very different portfolios of the different companies, their deepwater experience relative to absolute scale is very 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 c10% 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 and illustrated below we estimate that the deepwater now accounts for around 10% of the major European and US companies' 2P reserves. Evident is that in absolute terms BP accounts for more deepwater barrels than any of its 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, however, only modestly above the average although if its TNK-BP associate is excluded BP's % exposure moves to a much more significant 18%. By contrast BG's success in Brazil has resulted in a very significant increase in its exposure with an estimated 32% of its 2P reserves base located in the deepwater, something which has similarly increased the deepwater exposure of Repsol YPF relative to its peers. Interesting also is the relative under-representation of both Shell and Exxon, the deepwater accounting for a relatively modest 7% of each company's 2P reserves base not least given the typically greater breadth of these companies' upstream portfolios.

Figure 342: Reserves (WoodMac 2P entitlement) by Deepwater province

	US GoM	Brazil	Angola	Nigeria	Malaysia	Deepwater	Total portfolio	% deepwater
BP	2,370	-	1310	-	0	3,680	30515	12%
Shell	852	352	-	576	367	2,146	29545	7%
Exxon	277	-	1191	636	-	2,104	29348	7%
Chevron	1,069	447	751	576	-	2,843	25586	11%
Total	116	-	1510	1018	-	2,644	16269	16%
BG	-	2468	-	-	-	2,468	7683	32%
ENI	183	-	542	165	-	890	10781	8%
Statoil	377	-	686	81	-	1,594	12243	9%
Repsol YPF	99	424	-	-	-	523	3802	14%
Petrobras	291	12232	3	245	-	12761	20335	63%
COP	70	-	-	0	243	313	19234	2%
Total ex PB	**5,703**	**3690**	**5,993**	**3,297**	**610**	**18441**	**205,341**	**10%**

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 10% 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 $76/bbl we estimate that on average the deepwater accounts for 17% of the companies' upstream portfolio value with the average barrel worth an estimated $12/bbl against a portfolio average of nearer $7/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 c.50% above the average, reflecting the company's strategy of concentrating on dominating major production basins and its deepwater expertise. Repsol and BG's recent success in Brazilian deepwaters also means that almost a quarter of each of these companies reserves can now be seen to be in the deepwater, a number that is only likely to rise as additional Brazilian barrels are proved up. 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 343: Value ($m) by deepwater province*

Company	US GoM	Brazil	Angola	Nigeria	Malaysia	Total DW value	Upstream Value	DW as % Total
BP	36,941	-	15,074			52,015	189103	28%
Shell	16,666	3,384		11,879	771	32,700	237121	14%
Exxon	5,624	-	14,255	11,956		31,835	222416	14%
Chevron	12,968	3,414	3,728	15,640		35,750	207139	17%
Total	1,817	-	13,427	9,673		24,917	129028	19%
BG	-	10,705	-	-		10,705	48022	22%
ENI	2,940	-	5,598	3,602		12,140	95919	13%
Statoil	4,502	-	9,097	3,481		17,080	94408	18%
Repsol	2,200	3,151	-	-		5,351	23400	23%
COP	1,317	-	-	568	115	2,000	100734	2%
Total	**84,975**	**17,503**	**64,330**	**56,799**	**886**	**224,493**	**1,347,290**	**17%**
Average barrel value ex PB	***15.70***	***4.74***	***10.74***	***18.61***	***1.45***	***12.17***	***7.28***	

*Source: Wood Mackenzie; Deutsche Bank *Assumes an oil price of $76/bbl escalating at 2% from 2014.*

Deepwater production should grow by c.5% out to 2015

We illustrate below our estimates in aggregate for oil & gas production at the integrated oil companies. Taken in aggregate, our estimates suggest that for the majors as a whole, production from the deepwater currently accounts for around 2.2mb/d or c.10% of total reported production. This is expected to rise to around 13% by 2015 with production from the deepwater set to grow at a compound rate of near 5% against closer to 2% for group volumes overall. In effect, the deepwater is thus expected to account for c30% of the growth in reported production over the 2009-2015E period.

Over this timeframe we also expect some notable change in mix, not least as recent discoveries in Brazil come on-stream whilst production in the US GoM undergoes some modest decline (most notably at Shell). We should state however that these estimates are before any changes or delays that may arise in the deepwater markets globally as a consequence of BP's travails in the US GoM.

Figure 344: The deepwater as a % of sector production

Kboe/d by region	2009	2010	2011	2012	2013	2014	2015	CAGR
US GoM	1011	997	1034	1010	985	983	1027	0.3%
Angola	739	680	675	787	869	927	968	4.6%
Nigeria	436	460	416	466	553	545	555	4.1%
Brazil	26	70	122	162	223	322	390	57.0%
Other	13	35	40	65	80	75	66	31.1%
DW Total	**2225**	**2242**	**2287**	**2490**	**2710**	**2852**	**3006**	**5.1%**
Group Total	**21184**	**21562**	**22065**	**22729**	**23096**	**23319**	**23837**	**2.0%**
% Source								
US GoM	*4.8%*	*4.6%*	*4.7%*	*4.4%*	*4.3%*	*4.2%*	*4.3%*	
Angola	*3.5%*	*3.2%*	*3.1%*	*3.5%*	*3.8%*	*4.0%*	*4.1%*	
Nigeria	*2.1%*	*2.1%*	*1.9%*	*2.1%*	*2.4%*	*2.3%*	*2.3%*	
Brazil	*0.1%*	*0.3%*	*0.6%*	*0.7%*	*1.0%*	*1.4%*	*1.6%*	
Other	*0.1%*	*0.2%*	*0.2%*	*0.3%*	*0.3%*	*0.3%*	*0.3%*	
% DW	***10.5%***	***10.4%***	***10.4%***	***11.0%***	***11.7%***	***12.2%***	***12.6%***	

Source: Deutsche Bank

As to the profiles for the companies themselves, we would make the following observations:

- At 15% of group production, BP has the most significant exposure to the deepwater not least as a consequence of some 10% of its production arising in the US GoM. Based on current estimates this exposure is also expected to increase not least as the US GoM grows in significance. Indeed, it is of note that the US GoM is expected to account for just over 20% of BP's expected barrel growth over the period to 2015 albeit that, with overall GoM growth estimated at around 60kb/d against c260kboe/d for the group, the relatively high percentage is more a reflection of the very modest barrel growth anticipated overall rather than an outlook of prolific growth in the US GoM itself.
- Chevron has by far the most future exposure among the US majors and likewise looks to see the highest growth rates from the DW, with a 17.8% CAGR in deepwater production for the 2009-2015 period.
- Exposure to Brazil means that BG and Repsol are expected to see the most rapid increase in their deepwater exposure over the forecast period with deepwater barrels expected to rise from 0% to 14% of production at BG and from 6% to 12% of production at Repsol.
- Of the super-majors, Total is expected to see the strongest growth in the deepwater with production expected to increase at a CAGR of 8% as new production in Angola and Nigeria comes onstream. Overall, 43% of growth arises from the DW.

- ENI and Shell are the only two companies expected to see a decline in the proportion of production arising from the deepwater. For both, this decline arises largely as a consequence of our expectation that US GoM production is set to fall sharply over the forecast period although at Shell it also reflects a faster rate of underlying growth in the portfolio as a whole (not least as Qatar comes onstream from 2011). Indeed, it is of note that at c9% p.a. it is ENI that is expected to see the sharpest compound annual decline in deepwater production over the period to 2015.
- Both Total and BG Group have minimal if any exposure to the US GoM. Total is, however, the most exposed to developments in Angola with its DW activities in Nigeria also expected to contribute increasingly as AKPO ramps up and Usan comes onstream.

Figure 345: Summary of DW as % of integrated companies production, reserves, value and growth

Company	Production		Reserves		Value		Deepwater Prod'n Growth			Group Prod'n
	2010 (kboe)	% DW	Total	% DW	Upstream	% DW	2009	2015	CAGR	CAGR
ExxonMobil	3985	9.70%	29348	7.20%	222416	14.30%	405	576	6.10%	2.60%
BP	3972	14.20%	30515	12.10%	189103	27.50%	624	696	1.80%	1.00%
Shell	3144	10.50%	29545	7.30%	237121	13.80%	343	250	-5.10%	1.70%
Chevron	2736	9.60%	25586	11.10%	207139	17.30%	192	513	17.80%	1.90%
Total	2383	7.50%	16269	16.20%	129028	19.30%	183	285	7.70%	1.70%
ENI	1832	13.80%	10781	8.30%	95919	12.70%	255	150	-8.50%	1.20%
Statoil	1811	9.10%	12243	9.30%	94408	18.10%	168	251	6.90%	2.20%
Repsol	896	6.00%	3802	13.80%	23400	22.90%	52	117	14.50%	-0.40%
BG	668	0.40%	7683	32.00%	48022	22.00%	2	169	109.48%	10.60%
Total	**21562**	**10.25%**	**165772**	**11.13%**	**1246556**	**17.85%**	**2224**	**3007**	**5.16%**	**2.14%**

Source: Wood Mackenzie, Deutsche Bank estimates

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 WTI 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.

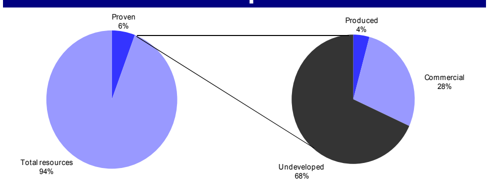
Canada's Oil Sands

A huge unconventional resource

An estimated 143bn barrels of recoverable oil lie in the sand, water and clay of Northern Alberta.

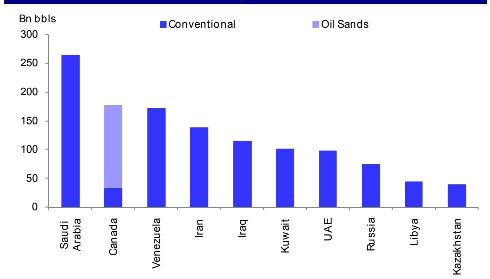
Canada's oil sands represent the largest single undeveloped, discovered, oil resource globally. All told, an estimated 143bn barrels of recoverable oil lie in the sand, water and clay of Northern Alberta. These reserves are second in size only to Saudi Arabia and 50% greater than those of Iraq. Moreover, 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 346: Of 2.5trillion bbls, 143bn are recoverable and 6bn produced to date



Source: BP Statistical Review, Wood Mackenzie

Figure 347: 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 75 metres 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. However, of the reserves attributed to current projects around two-thirds will be exploited by mining.

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. The resulting synthetic crude oil or syncrude as it is commonly termed, sells at a similar price to WTI.

Given all of this it is perhaps surprising that the oil sands should be the subject of such a wave of investment. However, high oil prices aside, in an era of 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, together with the outlook for production is discussed further in the Countries section.

Figure 348: 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.3,400km², 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 some further treatment to remove any remaining water and fine solids, the bitumen is then 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 have associated upgraders although several un-integrated projects are in planning or underway.

Figure 349: Canada Oil sands Mining projects – existing and planned

Project	Status	Start-up	Reserves (mbbls)	Peak (kb/d)	Capex (US$m)	Main Participants	Method
Suncor Mine	Onstream	1967	3,182	287	36,351	Suncor Energy* (100%)	Mining with Upgrader
Syncrude	Onstream	1978	6,507	600	67,304	Syncrude JV (See note below)	Mining with Upgrader
Foster Creek	Onstream	2001	1,788	210	8,566	Cenovus Energy* (50%), COP (50%)	SAGD no upgrader
Christina Lake	Onstream	2002	1,534	218	8,184	Cenovus Energy* (50%), COP(50%)	SAGD no upgrader
AOSP	Onstream	2003	3,671	370	50,486	Shell* (60%), Chevron (20%), Marathon (20%)	Mining with Upgrader
Suncor SAGD	Onstream	2004	2,431	229	21,479	Suncor Energy* (100%)	SAGD with upgrader
Long Lake	Onstream	2008	1,693	144	24,764	Nexen* (65%), OPTI (35%)	SAGD with upgrader
Horizon Project	Onstream	2008	2,294	162	21,027	Canadian Natural Resources* (100%)	Mining with Upgrader
Planned							
Kai Kos Dehseh	Development	2010	900	80	4,500	Statoil* (100%)	SAGD no upgrader
Kearl	Development	2013	3,541	220	19,221	Imperial Oil* (71%), ExxonMobil (29%)	Mining no upgrader
Sunrise	Development	2014	3,000	200	11,316	Husky Energy* (50%), BP (50%)	SAGD with upgrader
Fort Hills	Probable	2019	1,940	160	12,007	Suncor Energy* (60%)	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.

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

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.

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

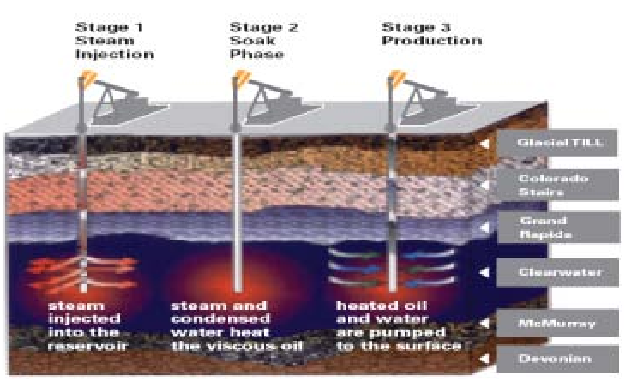
CSS is a common enhanced oil recovery technique, accidentally discovered by Shell while it was doing a steam flood in Venezuela and one of its steam injectors blew out and ended up producing oil at much higher rates than a conventional production well in a similar environment.

CSS consists of three stages: injection, soaking and production.

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.

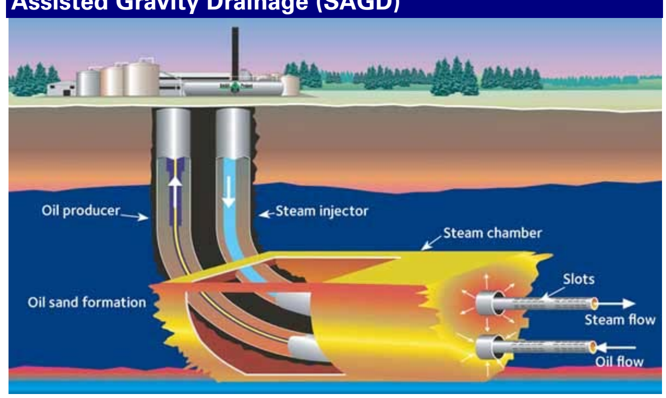
The process can be quite effective, especially in the first few cycles. However, it is typically only able to retrieve approximately 20% of the OOIP. As a result, it has given way to the use of SAGD as a preferred method of extraction with only three founding projects now using CSS as their primary means of extraction Cold Lake, Peace River and Primrose/Wolf Lake.

Figure 350: Diagrammatic representation of Cyclic Steam Simulation (CSS)



Source: Courtesy of Shell

Figure 351: Diagrammatic representation of Steam Assisted Gravity Drainage (SAGD)



Source: Courtesy of Shell

Figure 352: Canada Oil sands Projects and start up dates (all Athabasca except those shaded)

Project	Status	Start-Up	Reserves (mmbbls)	Peak (kb/d)	Capex ^(US$m)	Partners	Method
Primrose/Wolf Lake	Onstream	1983	951	120	4303	CNR* (100%)	CSS/SAGD no upgrader
Cold Lake	Onstream	1986	900	165	5203	Imperial Oil* (100%)	CSS no upgrader
Peace River	Onstream	1986	109	13	897	Shell* (100%)	CSS no upgrader
Hangingstone	Onstream	1999	380	35	2255	Japan COS 75%; Nexen 25%	SAGD no upgrader
Foster Creek *	Onstream	2001	1788	210	8566	Cenovus Energy* (50%), COP (50%)	SAGD no upgrader
Christina Lake *	Onstream	2002	1534	218	8184	Cenovus Energy* (50%), COP (50%)	SAGD no upgrader
MacKay River	Onstream	2002	563	68	4179	Suncor Energy* (100%)	SAGD no upgrader
Suncor SAGD	Onstream	2004	2431	229	21479	Suncor Energy* (100%)	SAGD with upgrader
Joslyn	Onstream	2006	889	100	11986	Total* (75%), Oxy(15%), INPEX (10%)	SAGD/Mine with upgrader
Tucker	Onstream	2006	347	30	1875	Husky Energy* (100%)	SAGD with upgrader
Surmont	Onstream	2007	890	111	4354	ConocoPhillips* (50%), Total (50%)	SAGD no upgrader
Long Lake	Onstream	2008	1693	144	24764	Nexen* (65%), OPTI (35%)	SAGD with upgrader
Horizon Project	Onstream	2008	2294	162	21027	Canadian Natural Resources* (100%)	Mining with Upgrader
Kai Kos Dehseh	Development	2010	900	80	4500	Statoil* (100%)	SAGD no upgrader
Kearl	Development	2013	3541	220	19221	Imperial Oil* (71%), ExxonMobil (29%)	Mining no upgrader
Sunrise	Development	2014	3000	200	11316	Husky Energy* (50%), BP (50%)	SAGD with upgrader
Fort Hills Mine	Probable	2019	1940	160	12007	Suncor Energy* (60%)	Mining with Upgrader

*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.

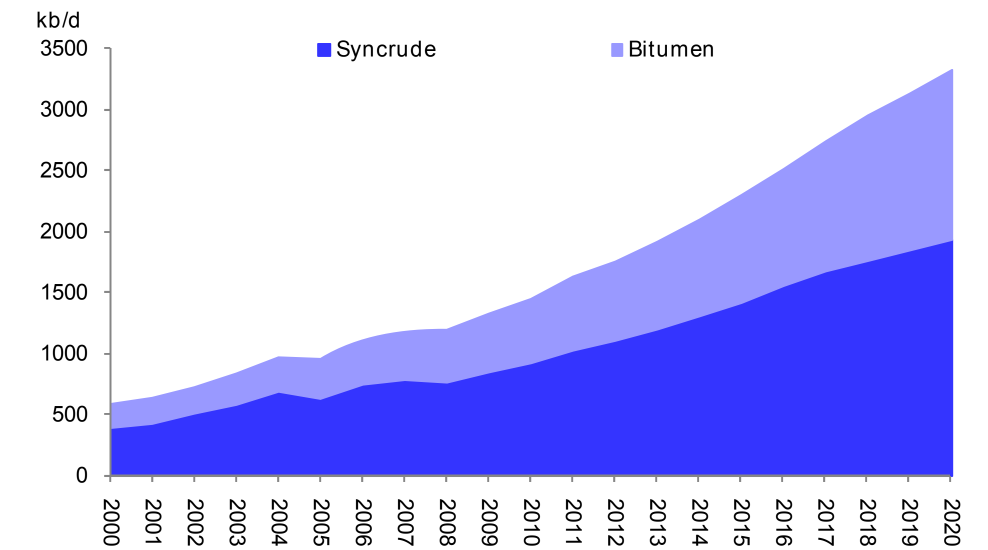
Because of limited demand for bitumen itself in North America, the bitumen output from the oil sands needs to be upgraded if it is to find a market. Consequently, many of those involved in the production of the tar sands have invested in complex upgrading refineries designed to break down the long chain 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 $15,000/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. Similarly, both the upgrader and the upstream development of Total's Northern Lights project were postponed due to the overheated cost environment in Canada's oil sands industry.

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 353: 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/bbl (discounted at 15%).

The very heavy, upfront capital costs associated with doing business in the oil sands are thus a high 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 $20 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.

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

In the table below we have used Wood Mackenzie estimates of full cycle project costs to estimate the fixed and variable costs per barrel of production over a range of different projects. The analysis emphasizes that on average, the full cash costs for a mined, upgraded barrel runs at around $30/bbl with the more recent projects looking at something nearer $40/bbl. Of this the variable component stands at $25/bbl. Remove the upgrader and the full costs per barrel fall by almost half to $20/bbl. However, this reduction in cost is achieved for a c$25/bbl reduction in end market price.

For SAGD projects the upfront capital costs are cheaper with DD&A running at a modest $5-8.50/bbl against nearer $11/bbl for those from a mined barrel with upgrader. At an average $18/bbl the variable costs of production are, however, even higher than those of a non-upgraded mine a feature which in large part reflects the even greater energy-requirements of the SAGD process (namely the gas required to produce steam).

Figure 354: Fixed, variable and full cost estimates for a range of oil sand facilities

Project	Reserves (mmbbl)	Capex (US$m)	Opex (US$m)	DDA ($/bbl)	OPEX ($/bbl)	Full cost ($/bbl)
Jackfish	588	2949	10372	5.02	17.64	22.65
Kearl	3541	19221	42625	5.43	12.04	17.47
Average Mine no Upgrader				**5.37**	**12.84**	**18.21**
AOSP	3671	50486	126035	13.75	34.33	48.08
Fort Hills Mine	1940	12007	25991	6.19	13.40	19.59
Horizon Project	2294	21027	57176	9.17	24.93	34.10
Suncor Mine Project	3182	36351	101887	11.43	32.02	43.45
Syncrude Project	6507	67304	210641	10.34	32.37	42.71
Average Mine with Upgrader				**10.64**	**29.65**	**40.29**
Christina Lake	1534	8184	22767	5.34	14.84	20.18
Foster Creek	1788	8566	30848	4.79	17.25	22.05
Hangingstone	380	2255	6761	5.93	17.77	23.70
Kai Kos Dehseh	900	4500	14893	5.00	16.55	21.55
Orion	185	1020	2682	5.50	14.48	19.98
Surmont	890	4354	15348	4.89	17.24	22.13
Average SAGD no Upgrader				**5.09**	**16.43**	**21.52**
Long Lake	1693	24764	29676	14.63	17.53	32.16
Suncor SAGD Project	2431	21479	60191	8.83	24.76	33.59
Sunrise	3000	11316	48865	3.77	16.29	20.06
Tucker	347	1875	5585	5.41	16.11	21.52
Joslyn	889	11986	18472	13.48	20.78	34.26
Average SAGD with Upgrader				**8.54**	**19.47**	**28.02**

Source: Wood Mackenzie Pathfinder, Deutsche Bank estimates

Gas to Liquids (GTL)

An expensive alternative to LNG

Gas-to-liquids technology represents a means of converting natural gas into liquids

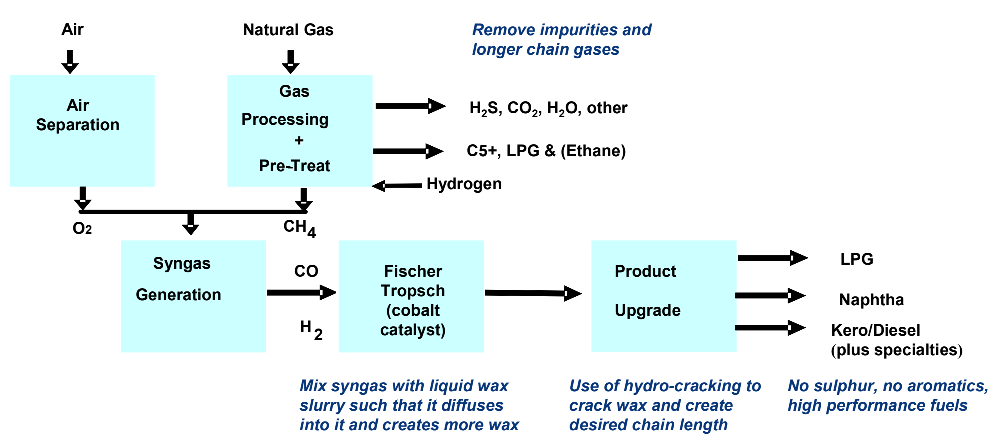
Gas-to-liquids technology represents a means of converting natural gas into liquids. Energy and capital intensive, the process offers the potential to convert large reserves of stranded gas to higher value, high purity, synthetic liquids namely diesel, naphtha and lubricant base oils which can be transported 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 in 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.

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 base chemicals such as methanol.

Figure 355: The GTL process –straightforward addition chemistry removes the need for a refinery. But very commercially and technologically challenging



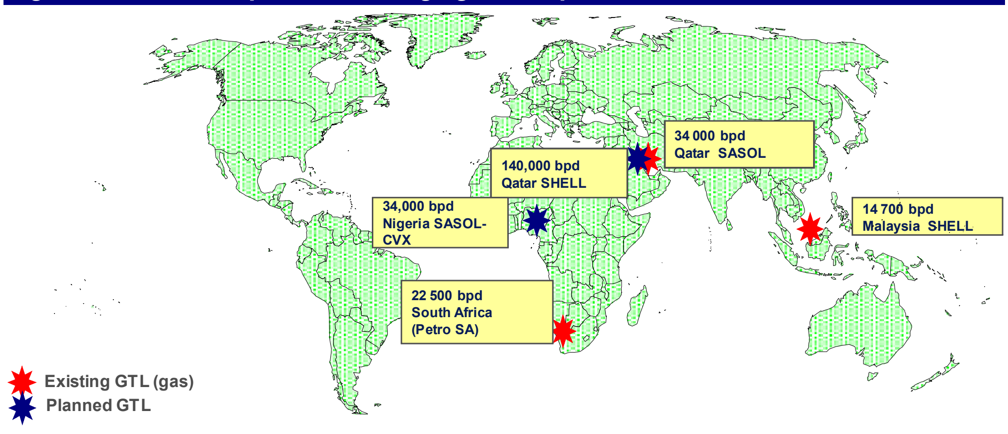
Source: Deutsche Bank

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 three plants are operating commercially, Petro SA's 22.5kb/d in South Africa, Shell's 14.7kb/d Bintulu plant in Malaysia and SASOL's 34kb/d Oryx facility in Qatar (where teething problems deferred full output to mid-08). Shell's giant Pearl GTL facility is due to commission at the end of 2010 and is expected to ramp up slowly over a 12-18 month period.

Figure 356: GTL today: Still an emerging industry

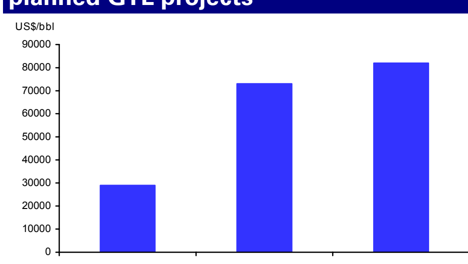


Source: Deutsche Bank

The low number of GTL plants reflects several factors:

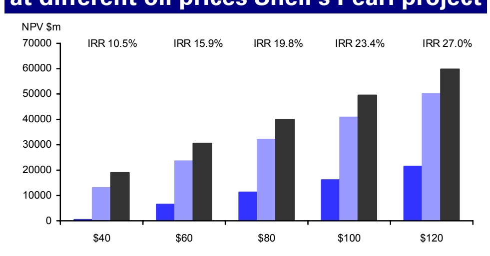
- **Capital costs:** The capital costs associated with constructing GTL facilities remain substantial. In part this reflects the inability of companies to find benefit from improved reactor economics. Given the extremely explosive and challenging conditions under which these operate, increasing reactor 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 expected to cost around $80k per barrel of capacity.

Figure 357: Costs per b/d of the three planned GTL projects



Source: Deutsche Bank

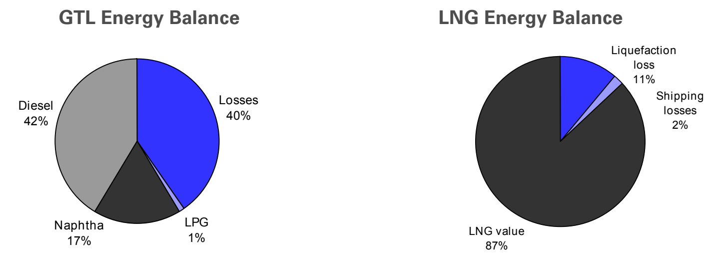
Figure 358: Estimated IRR (%) and NPV at different oil prices Shell's Pearl project



Source: Deutsche Bank

- **Energy intensity:** GTL is a very energy intensive process. Overall, around 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 refineries consumption of around 7% of its crude oil feedstock.

Figure 359: 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 360: 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	Teething issues
Planned					
Pearl GTL	Shell	Qatar	2012	140,000	Huge cost
Escravos	SASOL-Chevron	Nigeria	2012+	34,000	Delayed
On hold/cancelled					
Tinrhert GTL	Under bid	Algeria	n.a.	36,000	Postponed (cost)
Palm	Exxon	Qatar	2012+	154,000	Cancelled (costs)
n.a.	Conoco Phillips	Qatar	2010	80,000	Cancelled
n.a.	Marathon	Qatar	2010	120,000	Cancelled

Source: Deutsche Bank

- **Oil price:** Because of the substantial capital costs of the process and its poor energy efficiency, the GTL process is rarely economic unless the price of crude oil is high. As illustrated by the previous figures, based on our estimates a new full cycle GTL plant being considered today would require an oil price near $40/bbl just to break even and an oil price nearer $55/bbl to achieve a return nearer typical industry standards. Historically, the expectation that oil prices were likely to trade at around a $20/bbl band has meant that the economics around GTL made little commercial sense.

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.

For example, we estimate that where Shell's Pearl project would create little more than $0.5bn of NPV at $25/bbl oil on an $18.5bn investment, at current oil prices nearer $75/bbl the project would create value of almost US$29bn over its full life-cycle.

For the resource holder GTL also offers the potential to reduce its dependence upon international gas prices and gain greater exposure to the higher value oil products, not least diesel and lubricants, so diversifying its 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 361: 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 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 both SASOL and Shell's development projects. If technologies are proven here and costs contained at budgeted levels, considerable enthusiasm could follow. In its absence, however, GTL is likely to play only a niche role in energy markets for some time to come.

Coal Bed Methane

Exactly what it says on the label

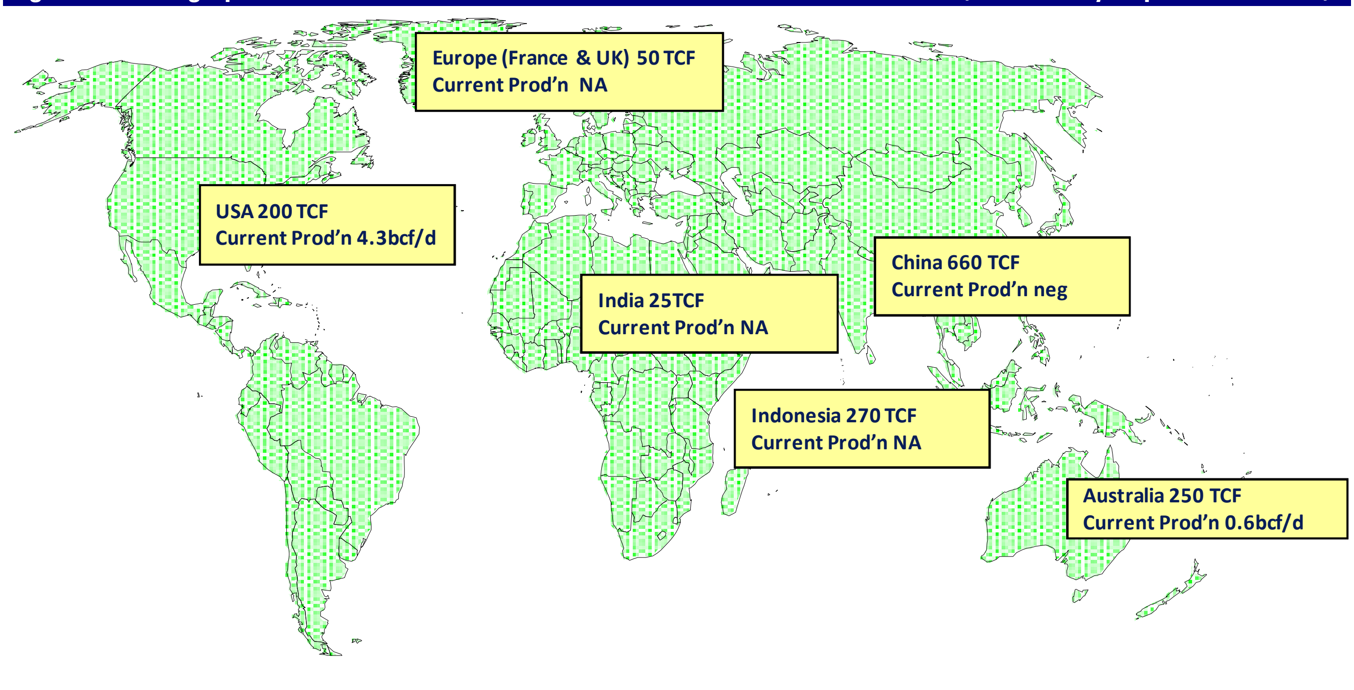
Coal bed methane (CBM) is simply methane found in coal seams

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 escape from the coal.

A substantial resource

During coalification large quantities of methane rich gas are generated and stored within the coal on 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. In addition, 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 362: Geographical location of coal bed methane resources around the world (Gas-initially-in-place estimates)



Source: Wood Mackenzie Unconventional Gas Tool, Deutsche Bank estimates

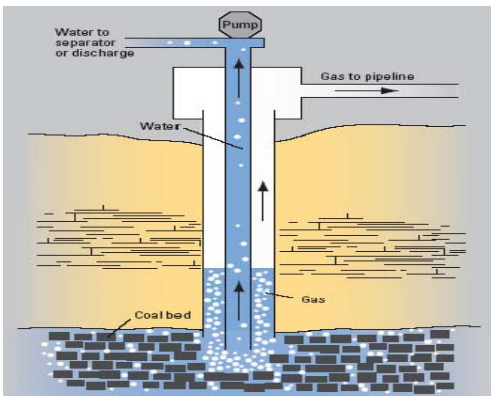
Although scientific understanding of, and production experience with, coal bed methane is in the early stages, it is believed to represent a very substantial resource of natural gas. In the US alone, US Geological Society estimates suggest that as much as 700TCF of CBM resources are in place, of which 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 the most interesting region, however, is China where Wood Mackenzie estimates there are some 660TCF of commercial CBM gas reserves, yet the industry is in its infancy with only the Qinshui region producing any CBM gas (and at less than 20mscf/d this is negligible). 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

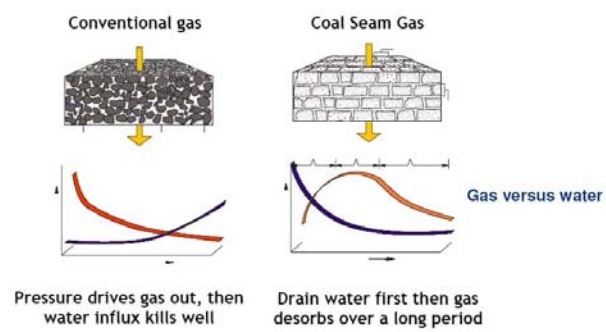
Several methods exist for extracting CBM. The focus of most extraction techniques is, however, to reduce the pressure of the coal stream and the water within it, predominantly by releasing a large volume of water and fracturing the coal seam. Since CBM travels with ground water in coal seams, extraction 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.

Figure 363: Extracting Coal Bed Methane/CSG



Source: Wood Mackenzie

Figure 364: Conventional gas production profile vs. CSG



Source: Wood Mackenzie

As illustrated above, 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 CSM 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.

Tight & Shale Gas

Huge potential resource

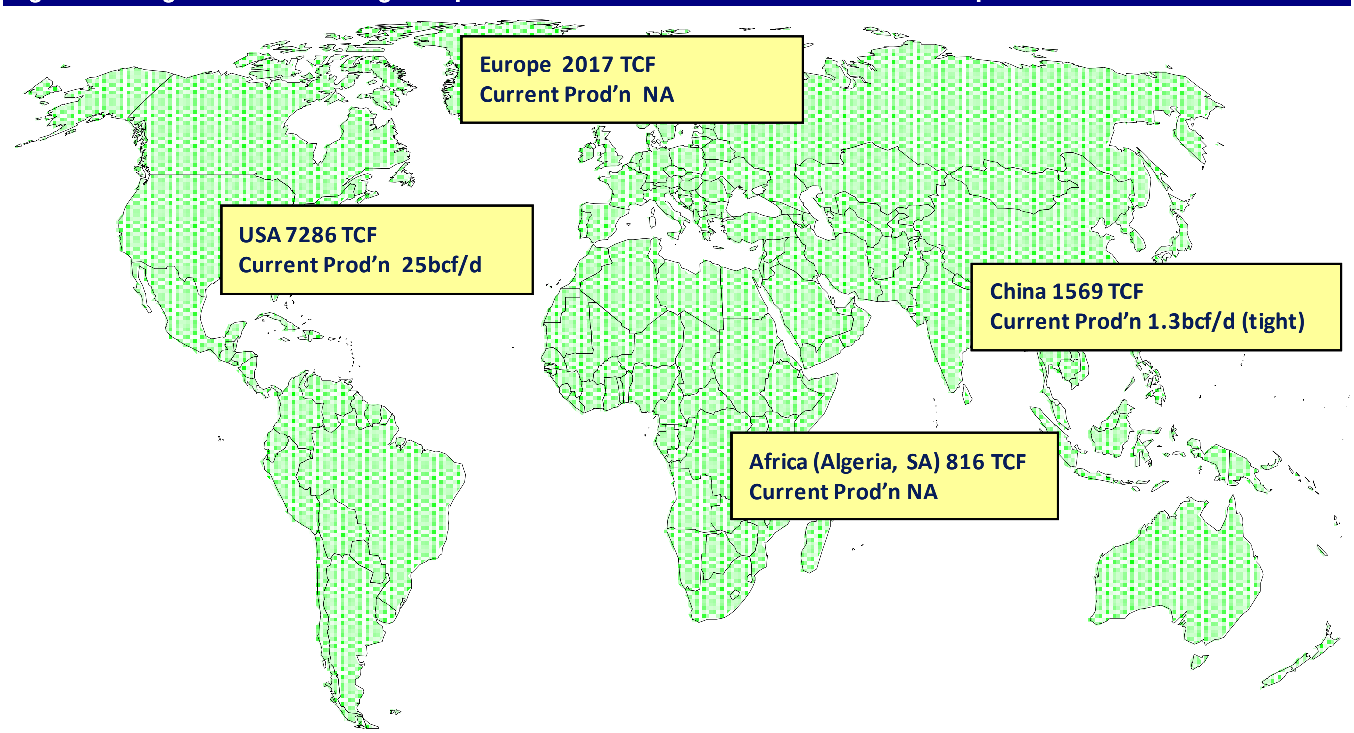
Recent years have seen a huge surge in interest in developing tight and shale gas reserves, particularly in the US. Not only are these resources by and large based in energy hungry OECD countries (i.e. access to both resource and end-market), improvements in technology that have improved productivity 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 that have low porosity and permeability

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 365: Tight and Shale Gas gas-in-place reserves – at an estimated 11688 TCF represents a vast resource

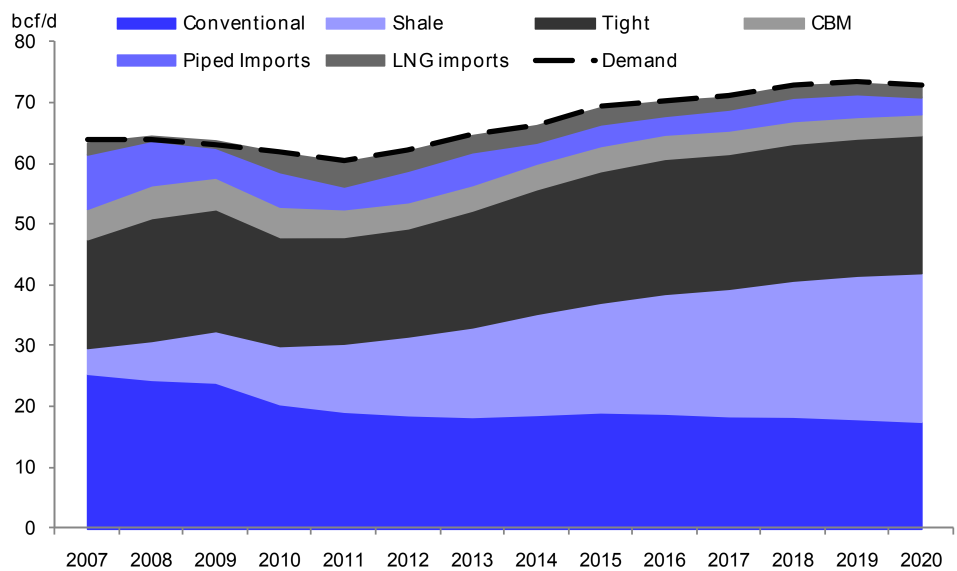


Source: Wood Mackenzie Unconventional Gas Tool, Deutsche Bank estimates

Global resources of tight and shale gas are vast with Wood Mackenzie estimating almost 12000TCF of initial gas to be in place. However, despite these vast reserves of tight/shale gas around the world, its development has only come to the forefront in recent years as a commercially viable and reliable source of gas. Steadily increasing US gas prices since the turn of the century made previously uneconomic tight gas reservoirs more financially appealing. Moreover, operational improvements that lowered well costs and improved productivity have also played a big part; techniques such as horizontal drilling, multi-lateral well completions, fracturing and acidising all increase well productivity dramatically. A key advance was 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.

Nonetheless, the US remains the only region to have significant production levels (25bcf/d or 4.3mb/d – 43% of total US gas production). With recoverable tight gas reserves in the US estimated to be at least 200-500TCF (33-38bn boe) compared to oil reserves of 28bn bbls, it is clear that if gas prices remain above $3/mmbtu there remains the potential for strong tight/shale gas production. Indeed Wood Mackenzie estimates that production of tight and shale gas in the US will almost double between 2009 and 2020, with the majority of growth coming in shale gas production.

Figure 366: North America gas supply/demand



Source: Wood Mackenzie

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 15mscf/d in the Haynesville with EURs of up to 6.5BCF.

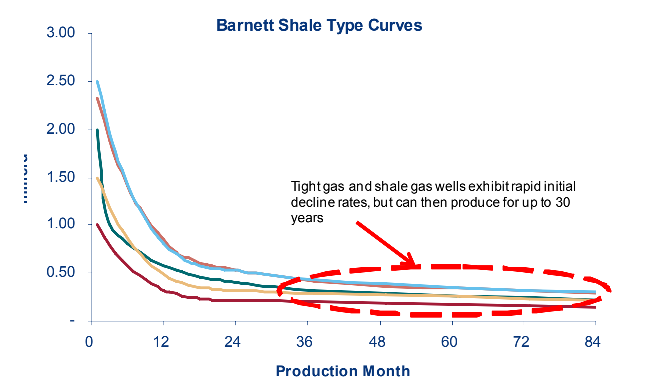
Vertical drilling is typically used in the initial or pilot-testing phases of an emerging shale/tight play given the lower cost of coring and drilling vertically. However, once the play is deemed to be commercially viable based on early testing, almost without exception wide-scale development is undertaken using horizontal drilling (explained below). 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. In 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, we most commonly hear about lateral lengths of 3000 to 6000 feet with fracs performed every 500-700 feet.

Some technical lingo

Horizontal drilling: in a horizontal well, a vertical well is deviated to drill laterally so as to expose the wellbore the 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.

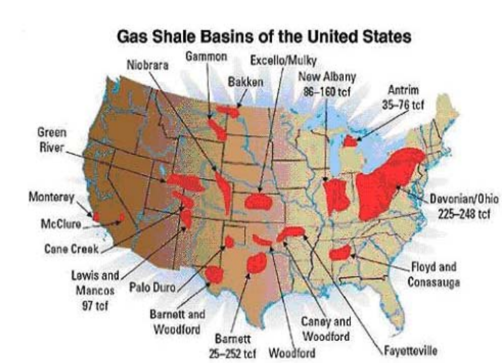
Fraccing: a procedure used to improve reservoir effective permeability. Fluid (such as water or acid) and propellant (such as sand) are pumped at high pressure into the reservoir. The result being that the reservoir rock fractures with the propellant effectively wedged inside the fractures thus keeping them open and allowing the gas to flow (also known as fracturing).

Figure 367: Typical Flow rates of a tight/shale gas play



Source: Wood Mackenzie

Figure 368: Shale Gas in the US by play



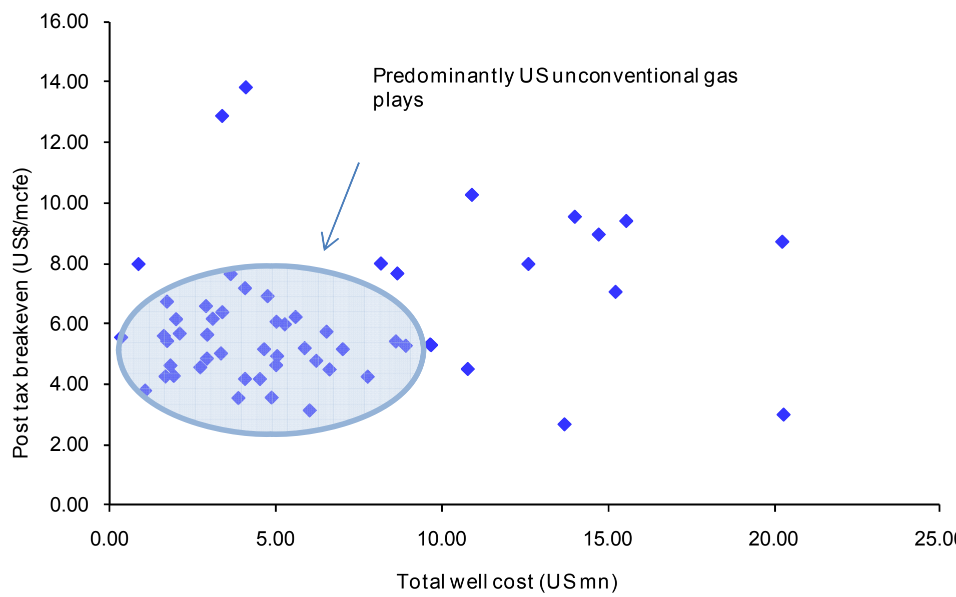
Source: American Association of Petroleum Geologists (AAPG)

Economic at current gas prices?

With rig rates dramatically reduced due to the fall in drilling activity during the financial crisis and given improvements in drilling efficiency and completion techniques, US tight and shale gas reserves can now break even at gas prices as low as $3/mmbtu (from between $4.50-8/mmbtu but 3 years ago). This means that many projects are competitive with both conventional piped gas and with LNG imports. Moreover, given the ready supply of gas and the strong likelihood that production volumes are set to significantly increase in the future, it is likely that unconventional gas will set the marginal price of gas in the US for the foreseeable future.

The same cannot be said however for the rest of the world where exorbitant drilling costs require a gas price nearer $7-10/mmbtu. 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 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). Below we present Wood Mackenzie's most recent assessment of well costs and break even gas prices around the world. This highlights the challenging economics of developing unconventional gas plays outside the US in most other regions.

Figure 369: 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. Recent licensing rounds in Romania and Poland saw a significant up-tick in the level of companies tendering for acreage, with the focus being on those areas which are believed to contain significant gas reserves. We expect increased investment in the evaluation of these resources over the coming years.

Environmental pros and cons

Finally, 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. 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. The US Energy Policy Act of 2005 exempted hydraulic fracturing from regulation under the Safe Drinking Water Act. However, the FRAC Act 2009 (not yet legislation) makes calls for the practice to be regulated and for energy companies to disclose what chemicals they are using in the fraccing process.

Section II: The Countries

Major non-OPEC producers

Norway

UK

USA – Alaska

USA – Gulf of Mexico

Canada – Oil Sands

Azerbaijan

Kazakhstan

Russia

Argentina

Brazil

Australia

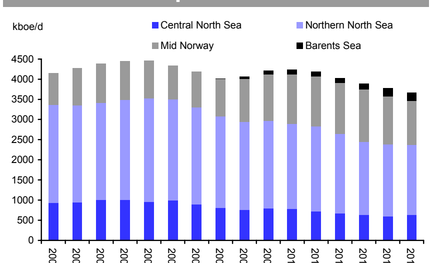
Norway

Key facts

Oil production 2009E	**2.4mb/d**
Gas production 2009E	**1.8mboe/d**
Oil reserves 2009E	7.9bn bbls
Gas reserve 2009E	80.7TCF
Reserve life (oil)	9.3 years
Reserve life (gas)	19.2 years
GDP 2008E ($bn)	$382bn
GDP Growth 2008E (%)	-1.1%
Population (m)	4.7m
Oil consumption (mb/d)	220kb/d
Oil exports (mb/d)	2.3mb/d
Fiscal regime	Tax & royalty
Marginal tax rate	78%
Top 3 Oil fields (2009E)	
Troll	672kboe/d
Asgard	343kboe/d
Ormen Lange	328kboe/d
Top 3 Producers (2009E)	
Statoil	1,457kboe/d
Exxon	1,163kboe/d
Total	393kboe/d

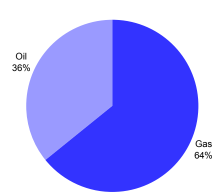
Source: Wood Mackenzie; EIA

Oil Production profile kb/d



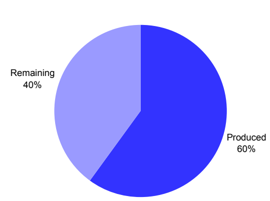
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

Norway is a relatively mature hydrocarbon province having commenced oil production in the early 1970s. Nevertheless, helped by the Norwegian State's generally conservative approach to the development of the country's natural resource base, it retains substantial hydrocarbon reserves estimated by Wood Mackenzie at end 2009 to stand at 7.9bn bbls of oil (2P) and 87TCF of gas (2P). Production is entirely offshore and, in 2009, production of oil ran at around 2.4mb/d of which circa 2.2mb/d was exported, making Norway the world's sixth largest net oil exporter, while gas production ran at 1.8mboe/d. Importantly, the Norwegian state holds a significant interest in the nation's oil production both directly through the State Direct Financial Interest (SDFI) and but also indirectly through its 67% interest in Statoil. Major 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.

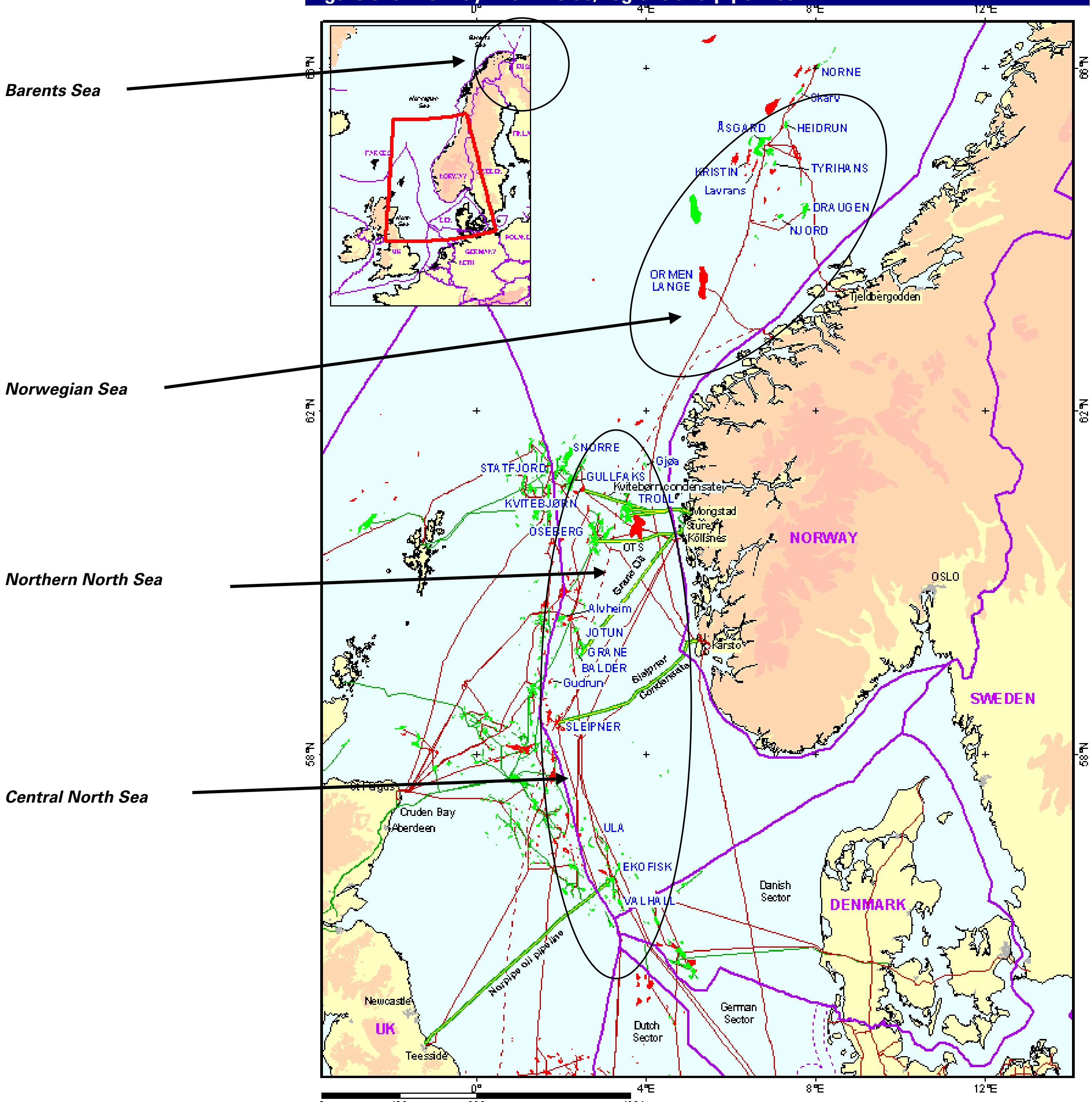
Moving further north, the mid Norwegian Shelf has traditionally been perceived as a gas prone province. To date most of the exploration has concentrated on the Haltenbanken area and, with the geological knowledge of the Shelf still limited, expectations around exploration remain relatively high. Similarly, the Barents Sea which contains the most northerly acreage in the Norwegian sector remains highly prospective although enthusiasm has waned in recent years following disappointing results from early exploration. Having said this, significant finds have been made around the Hammerfest Basin not least Statoil's Snohvit and Eni's Goliat.

Regulation and history

The rights to Norway's natural resources are administered by the Norwegian Petroleum Directorate or NPD. 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.

Figure 370: Norway: Main fields, regions and pipelines



Source: Wood Mackenzie

Licensing

First licensing in the Norwegian sector took place in 1965 and the licensing of **frontier** acreage continues today on a biannual basis with the '19th Round' concluded in April 2006. 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 only for up to 30 years.

More recently, 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.

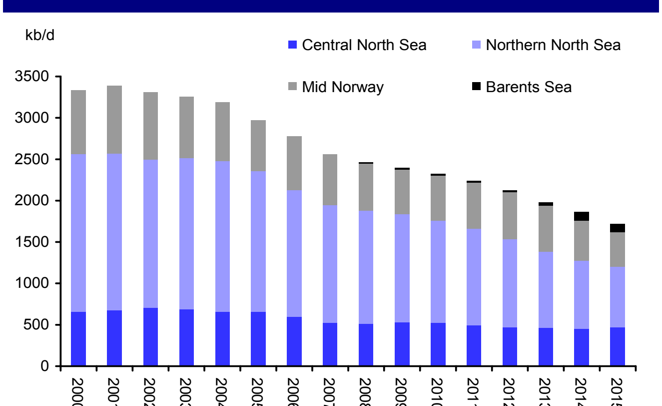
Production of Oil & Gas

Norwegian oil production rose strongly through the 1980s and into the 1990s, peaking at around 3.3mb/d in 2001 and thereafter steadily declining to the current 2.4mb/d. Production remains concentrated in the North Sea which accounts for c.1.8mb/d of volume. As these fields continue to mature it is likely that output will now gradually decline, Wood Mackenzie data suggesting that by 2015 liquids production will be running at 1.7mb/d. There is, however, some hope that success in the Barents Sea will go some way to offset the pace of decline. In 2009 the largest producing fields in Norway were Ekofisk (210kb/d), Oseberg (168kb/d), Grane (165kb/d), Asgard (164kb/d), Gullfaks (158kb/d) and Troll (152kb/d).

In contrast to liquids, gas production has shown significant growth in recent years and Norway is the world's third largest gas exporter. This trend is expected to continue into the next decade note least following the start up in 2007 of the 14TCF Ormen Lange with c.2bcf/d of production. Overall, gas production in 2009 was c.3.9TCF. Troll was the single largest gas production field with 3.1Bcf/d and other major gas fields were Ormen Lange (1.8bcf/d), Sleipner (1.1bcf/d) and Aasgard (1.1bcf/d). The major importers in 2009 were Germany (932bcf), UK (893bcf) and France (562bcf)

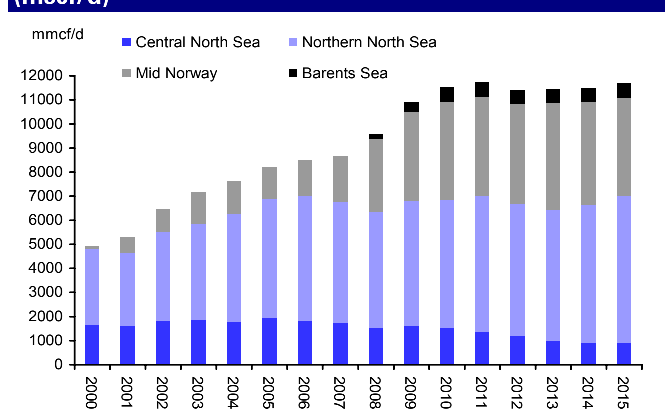
From a company perspective it comes as little surprise that in 2009 Statoil was the country's main producer. Exxon and Total represent the international players with the greatest absolute exposure to Norway's upstream.

Figure 371: Norwegian Oil production 2000-15E (kb/d)



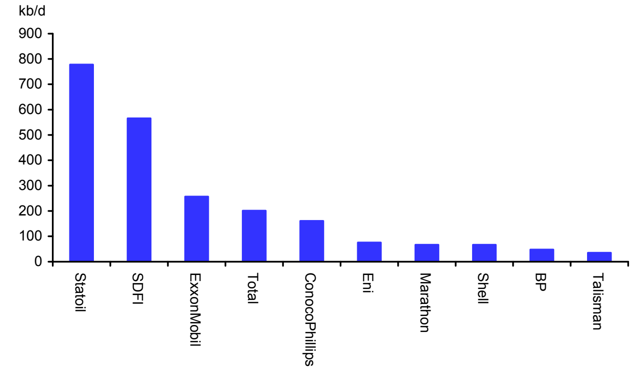
Source: Wood Mackenzie

Figure 372: Norwegian gas production 2000-15E (mscf/d)



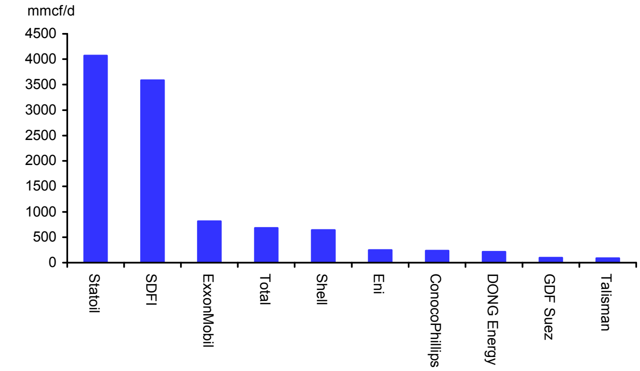
Source: Wood Mackenzie

Figure 373: Liquids production 2009 by company (kb/d)



Source: Wood Mackenzie

Figure 374: Gas production 2009 by company (kboe/d)



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data, 2P reserves in Norway at the end of 2009 include some 7.9bn bbls of oil and 80.7TCF of gas. Of these an estimated 53% 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 20bn boe largely in the relatively unexplored Norwegian (8bn boe) and Barents (6bn boe) Seas. The Barents in particular has been a source of significant excitement although to date results have, by and large, been relatively disappointing. Nevertheless, with oil discovered on several different horizons within the Triassic in addition to those of Goliat and Snohvit in the Jurassic, the Barents remains a much discussed frontier province. 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. Several of the major gas pipelines are indicated in the table below.

Figure 375: 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). In addition, as an incentive to encourage greater exploration activity, exploration costs are allowable as an offset against tax in the year in which they are incurred whether a company has income or not. This effectively reduces the cost of exploration to 22 cents in the US$.

Refining and downstream markets

Norway had some 310kb/d of refining capacity in 2009 through two major refining facilities; the Exxon owned and operated 110kb/d Slagen plant and the Statoil operated 200kb/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 4.7mtpa 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. At over $13bn (in 2009 real terms) this is almost triple that anticipated when the initial FID was taken. Dependent upon the discovery of additional gas reserves it is hoped that additional train(s) may be added at some future point. Following extensive maintenance work in which the plant was shut-in for three months in 2009 during which the cooling system was replaced it is hoped that the Snoehvit facility will run at full capacity without further glitches.

Norway - Notes

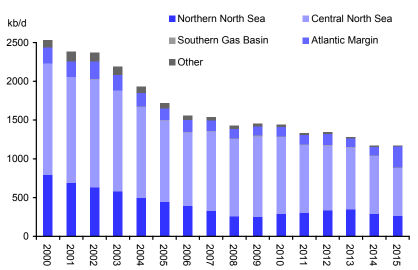
United Kingdom

Key facts

Oil production 2009E	**1.5 mb/d**
Gas production 2009E	**1.2 mboe/d**
Oil reserves 2009E	5.2bn bbls
Gas reserve 2009E	18.9TCF
Reserve life (oil)	9.8 years
Reserve life (gas)	7.9 years
GDP 2009E ($bn)	$2.2trillion
GDP Growth 2009E (%)	-2.9%
Population (m)	61.5m
Oil consumption (mb/d)	1.7m/d
Oil exports (mb/d)	NIL
Fiscal regime	Tax (CT & SCT)
Marginal tax rate	50%
Top 3 fields (2009E)	
Buzzard	190kboe/d
Elgin Franklin	167kboe/d
Alwyn Area	85kboe/d
Top 3 Producers (2009E)	
BP	313kboe/d
Shell	243kboe/d
Total	221kboe/d

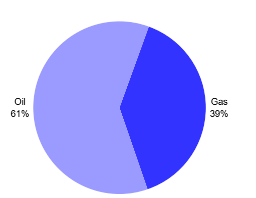
Source: Wood Mackenzie; EIA

Oil Production profile kb/d



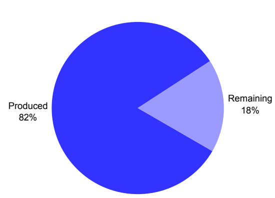
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

The UK 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 production is expected to continue to decline steadily over the coming years with the UK now a net importer of both oil and gas. Nevertheless, the country remains the largest hydrocarbon producer in the EU and retains reserves estimated by Wood Mackenzie at end 2009 of 5.2bn bbls of oil (2P) and 18.9TCF of gas (2P). Today's production arises from a huge number of often modest fields, is largely offshore and, in 2009, ran at around 1.5mb/d of oil and 1.2 mboe/d of gas. Major IOCs with a strong presence in the UK include BP, Shell, Total and Exxon.

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 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.

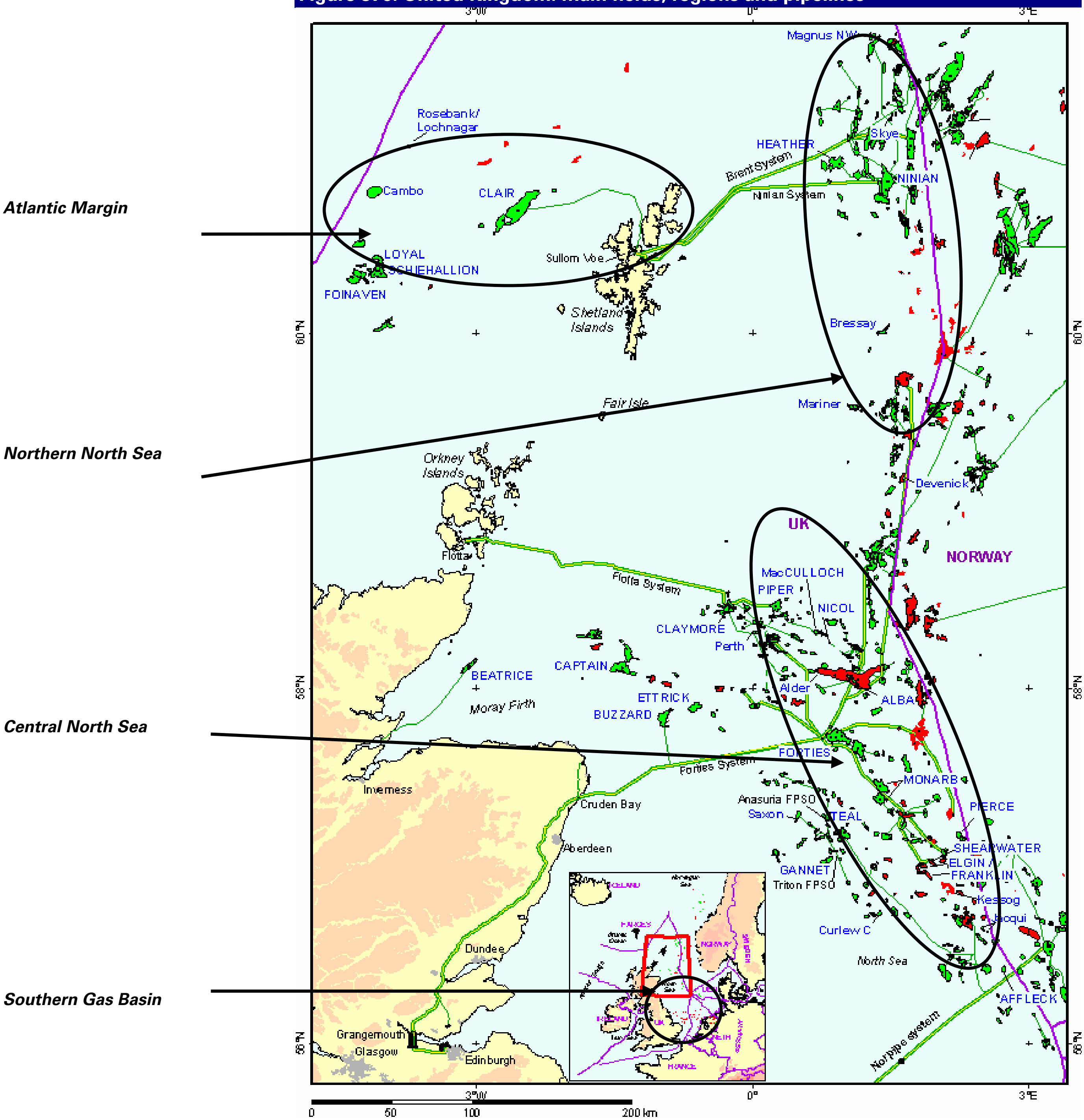
Regulation and history

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 bringing on stream technical discoveries, not least some significant heavy oil deposits (Bressay, Mariner, etc) which at the present time remain uncommercial.

Given an outlook of 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. This clearly 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 Trade and Industry, has in recent years thus focused on ways of increasing activity and reducing 'fallow' acreage.

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). However, tax income from UK oil and gas at over £10bn p.a. continues to represent around 7% of annual UK tax revenues.

Figure 376: 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.

Five 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'.

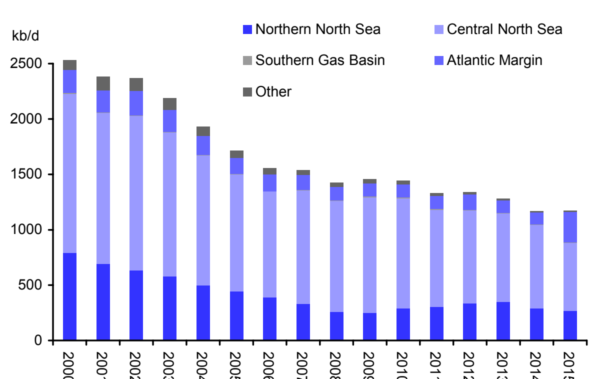
- **Seaward Production Licence (Traditional).** This enables the holder to explore and exploit the reserves in the area awarded in the form of an Offshore Licensing Round. The license runs for an initial 4 years at which point half the acreage must be relinquished with the option to extend on the balance 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).** Introduced in the 22nd round in 2004, companies were able to apply for Frontier Licenses in the West of Shetland sector. These have an initial term of just two years with rental set at 10% of the Traditional License rental. At the end of this period 75% of the acreage must be relinquished. The Licensees then have a further four years in which to complete a work programme.

Production of Oil & Gas

Despite a temporary renaissance in oil production associated with the start up of the Buzzard field in 2007, hydrocarbon production in the UK is now expected to show a steady and permanent decline. Most fields today are relatively small, with only two fields, Buzzard and Elgin-Franklin, expected to produce over 100kboe/d in 2009 and only seven over 50kboe/d. Indeed, with almost 40% of industry infrastructure at risk of decommissioning by 2020 unless significant investment is made, time is becoming an increasingly important factor in the UK's ability to maximise recovery from currently stranded reserves. To the extent that the majors are divesting tail assets and attracting smaller players to the region with different economic hurdles, the pace of decline may ease. Activity remains, however, very oil price dependent.

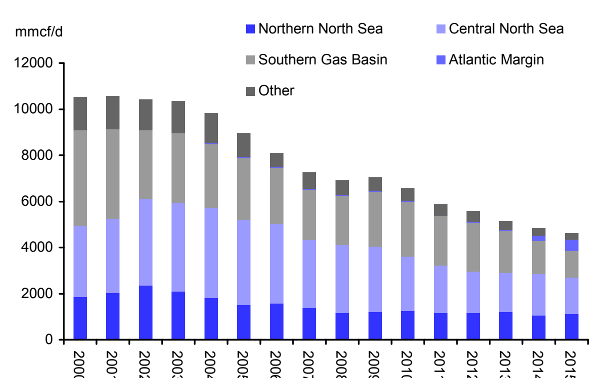
The pace of decline is also reflected in the production profiles of the major players – BP, Exxon, Shell, Total and Conoco, each of whom is expected to witness a c5-25% reduction in their annual rate of UK production over the next four or so years.

Figure 377: UK: Liquids production 2000-15E (kb/d)



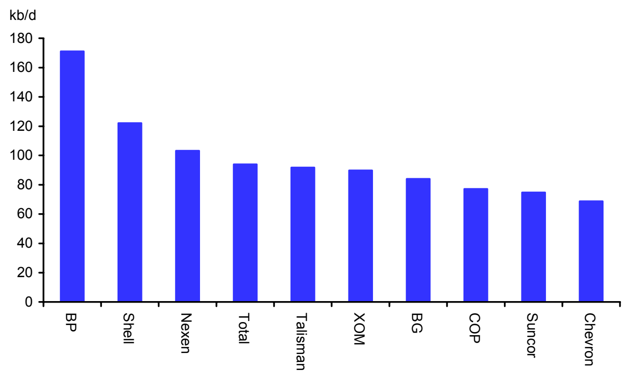
Source: Wood Mackenzie

Figure 378: UK: Gas production 2000-15E (kboe/d)



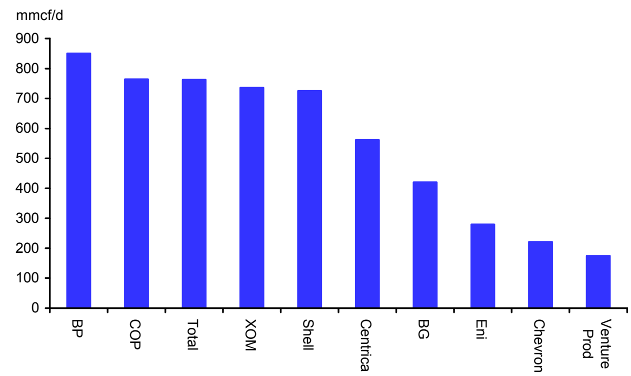
Source: Wood Mackenzie

Figure 379: UK: Major producers of liquids 2009E



Source: Wood Mackenzie

Figure 380: UK: Major producers of gas 2009E



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data, estimated 2P reserves in the UK at the end of 2009 included some 5.17bn bbls of oil and 18.9TCF of gas. Of these the vast majority reside in the North Sea. Wood Mackenzie further estimates that stranded technical reserves of circa 2.5bn bbls and 9.9TCF of gas have been discovered but as yet have no development plan. Separately, the UK's DECC has suggested yet-to-find reserves of up to a further 11.7bn of oil and 36.8TCF of gas may exist in UK waters 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 381: 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 UK corporation tax (CT), which despite being reduced for industry in general in the 2007 UK Budget was held at 30% for the oil & gas industry, and a special additional 'supplementary corporation tax' or SCT. The latter was introduced in the 2002 Budget at a 10% rate and, despite significant protests from the industry, further increased to 20% in 2006 although at the same time the Government did increase the writing down allowance (WDA) on eligible capex to 100% from 25% previously. As such, today's effective UK tax rate runs at 50%. 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 75% 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 2009 the UK had eleven refineries with an aggregate 1.9mb/d of refining capacity. At 326kb/d ExxonMobil operates the single largest refinery at Fawley in southern England although Total (218kb/d), Shell (302kb/d), Petroplus (277kb/d), Chevron (209kb/d) and Conoco (210kb/d) all have significant positions. Significantly, and despite its leading retail position, BP has in recent years exited UK refining through divesting its interests at Grangemouth to Ineos and Coryton to Petroplus. 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, BP leads the products market with a 17% market share followed by Exxon (14%), Shell (13%), Total (11%) and Chevron (11%).

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.24MTPA, with a number of expansions and new facilities expected to increase total capacity by c.10% p.a. out to 2015. Indeed, at an aggregate 1.2TCF p.a. in 2009 or c.40% of current UK gas demand, significant capacity is likely to remain idle till the early years of the next decade.

Figure 382: LNG re-gas facilities

Name	Location	Capacity	Holders	Onstream
Isle of Grain	Isle of Grain	9.7mtpa/1,243mmcf/d	BP/Sonatrach/Centrica/GDF Suez	Yes
South Hook	Milford Haven	7.7mtpa/990mmcf/d	QP/XOM	Yes
Teeside Gasport	Teesport	3.1mtpa/400mscf/d	Excelerate Energy	Yes
Dragon LNG	Milford Haven	4.8mtpa/614mmcf/d/d	BG/Petronas	Yes
South Hook Phase II	Milford Haven	7.7mtpa/990mmcf/d	QP/XOM/Total	Yes
Isle of Grain Phase III	Isle of Grain	4.9mtpa/633mmcf/d	Iberdrola/Centrica/ E.ONh	Q1 11

Source: Wood Mackenzie, Deutsche Bank

United Kingdom - Notes

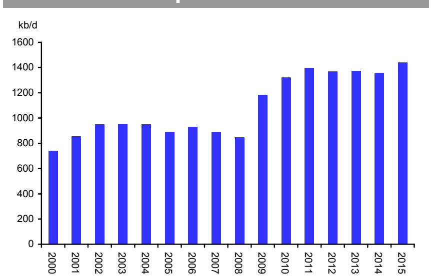
US Deepwater Gulf of Mexico

Key facts

Oil production 2009E	**1.2 mb/d**
Gas production 2009E	**0.5 mboe/d**
Oil reserves 2009E	8bn bbls
Gas reserve 2009E	9.7TCF
Reserve life (oil)	16.6 years
Reserve life (gas)	8 years
GDP 2009E ($bn)	$14.3 trillion
GDP Growth 2009E (%)	-1.2%
Population (m)	307m
Oil consumption (mb/d)	19.5m/d
Oil exports (mb/d)	n.a.
Fiscal regime	Tax & royalty
Marginal tax rate	35% - 47%
Top 3 GoM fields (2009E)	
Thunder Horse	235kboe/d
Mars	127kboe/d
Atlantis	125kboe/d
Top 3 Producers (2009E)	
BP	418kboe/d
Shell	267kboe/d
Anadarko	168kboe/d

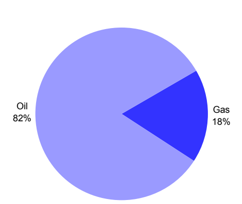
Source: Wood Mackenzie data

Oil Production profile kb/d



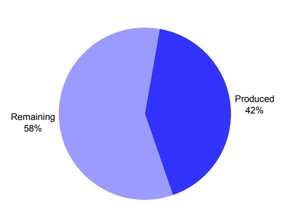
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

The US Deepwater Gulf Of Mexico is the largest single oil and gas producing region in the US accounting for around 20% of US liquids and gas production in 2009. As a relatively immature province its significance also looks set to increase markedly over the coming years with production expected to rise to around 1.4mb/d of oil and 3.2TCF of gas by 2011. Significant infrastructure exists tying together a very broad number of fields at water depths that are frequently in excess of 1500 metres and transporting the produced hydrocarbons back to shore. At end 2009 2P oil reserves were estimated by Wood Mackenzie to stand at 8bn bbls of oil and 9.7TCF of gas. BP's recent giant oil discoveries in Tiber and Kasikida showcase, however, the enormous potential of the region. Recent events in the shape of the Deepwater Horizon incident could however impact negatively on the outlook for production in the region and on barrel value if taxes are increased and/or costs increase due to higher HSE standards.

Basic Geology and topology

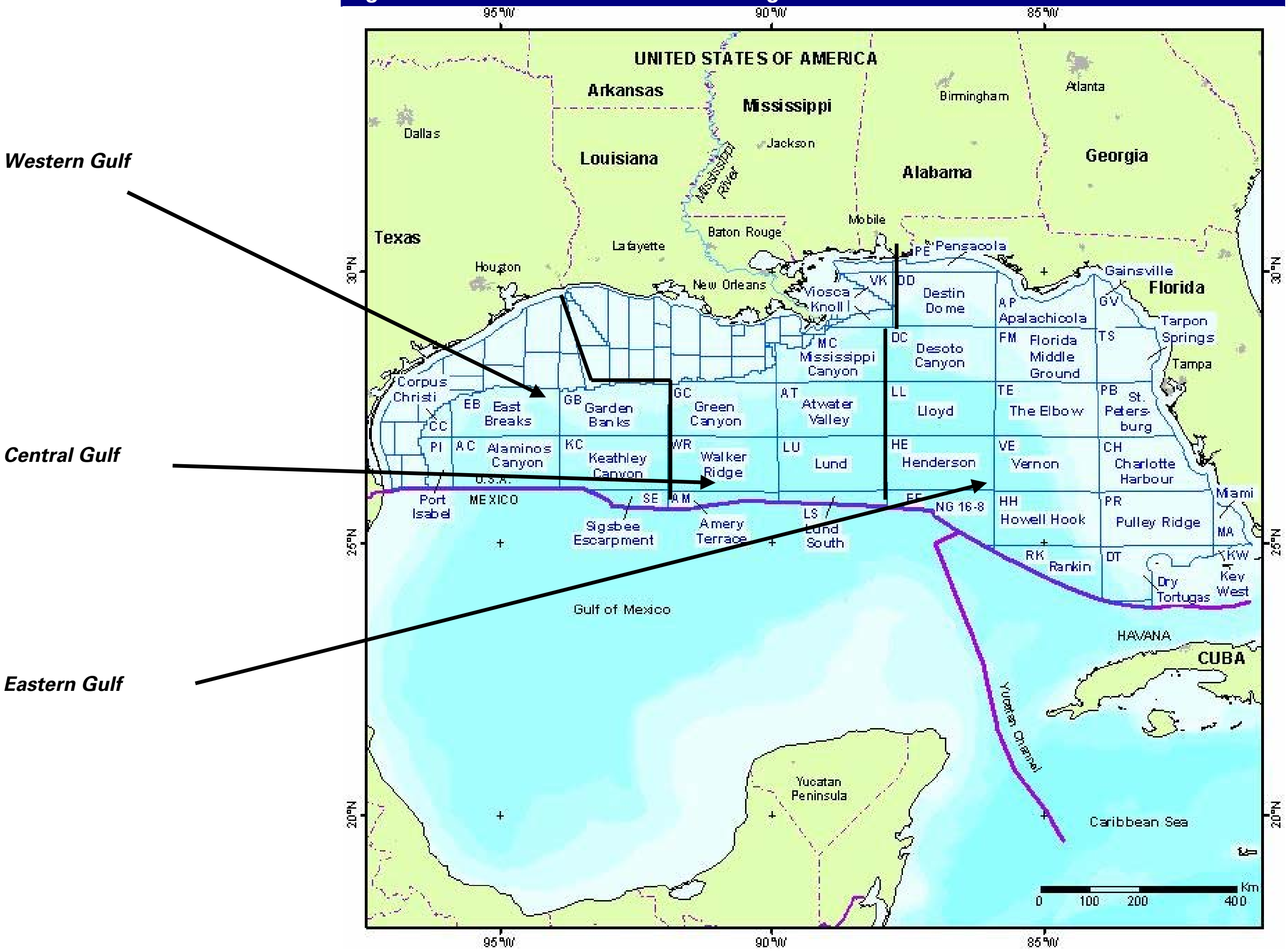
The GoM Basin originated in the Late Triassic during a major rifting episode which continued into the Middle Jurassic at which time the westerly advance of the sea resulted in the formation of extensive salt deposits. These impermeable salt deposits played a critical role in the migration and entrapment 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. 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 the Tertiary) suggests that the US Deepwater GoM is likely to retain its prospectivity for many years to come with the US MMS (see below) estimating that the region has some 86bn boe of yet-to-find resources. The pace and extent of future exploration will, however, depend very much on the outcome of any change in legislation and/or taxes in the region following the 2010 Macondo incident which resulted in the largest oil spill in US history.

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. Although today several agencies have some form of jurisdiction over hydrocarbon exploration and production (not least the Environmental Protection Agency (EPA) and US Coast Guard), it is the MMS that essentially oversees the development of the US Outer Continental Shelf (OCS). The bureau has two primary functions namely managing the Government's program for mineral resources on the OCS and collecting and distributing bonuses, rents and royalties from the producing and leasing companies. Following the Deepwater Horizon disaster it is intended to split the MMS into three separate entities.

Figure 383: US DW GoM Blocks and Regions



Source: Wood Mackenzie

Licensing

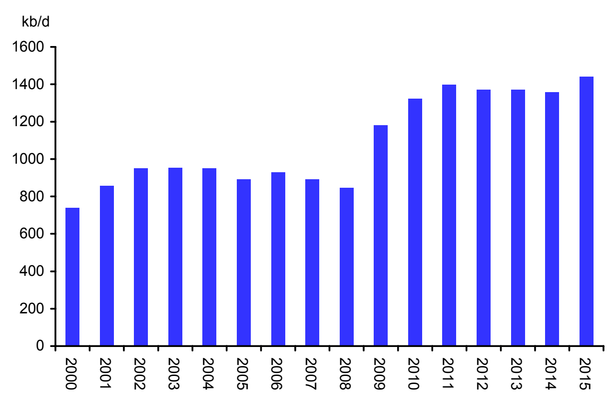
The MMS administers the allocation of leases on the US deepwater GoM with leases issued by public sales on a closed cash bid basis to an approved bidder who offers the highest gross bonus. Since inauguration in 1982 lease sales have generally been undertaken twice a year with sales in the OCS Central 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 MMS, 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

Temporarily disrupted by the negative impact of hurricanes in 2004 (Ivan), 2005 (Rita and Katrina) and 2008 (Ike and Gustav), oil production on the US GoM deepwater has since shown steady improvement following the start up of a number of major new projects, not least BP's Thunderhorse (c.250kboe/d start up late '08), Atlantis (160k, start-up late '07) and Chevron's Tahiti (110kboe/d, start-up '09). Prior to the Macondo incident, production was expected to remain stable until 2015 when a spate of new projects such as Chevron's Big Foot (c50kb/d from 2014), Shell's Friesian (c50kb/d from 2015), Hess's Pony (c45kb/d from 2015) and Knotty Head (c45kb/d from 2015) were expected to further boost production. However, with a 6-month drilling moratorium in place, there is a strong likelihood that efforts to maintain production may be negatively impacted while start-up of future projects may be pushed out to later years. Remaining production in the region is quite fragmented with over 100 fields contributing to the regions overall profile. Similarly, the production of gas is also very fragmented with ten fields producing more than 100mscf/d. Under current plans gas production is expected to peak in 2010 before declining sharply over subsequent years.

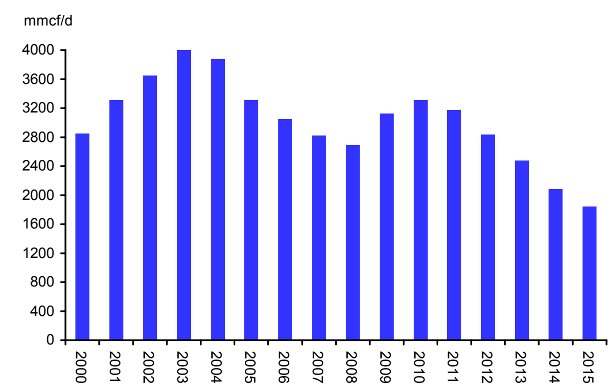
With so many small fields it is perhaps surprising that GoM production should be concentrated in the hands of a relatively small number of producers, BP, Shell, Anadarko and BHP Billiton dominating in 2009. Further out, BP's substantial exploration success from acreage that was acquired through the mid 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 384: DW GoM: Liquids production 2000-15E (kb/d)



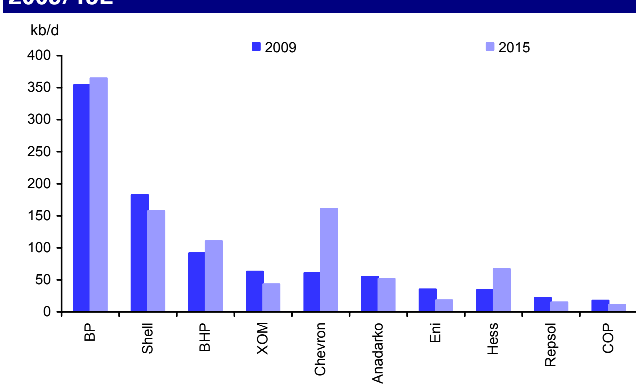
Source: Wood Mackenzie

Figure 385: DW GoM: Gas production 2000-15E (mscf/d)



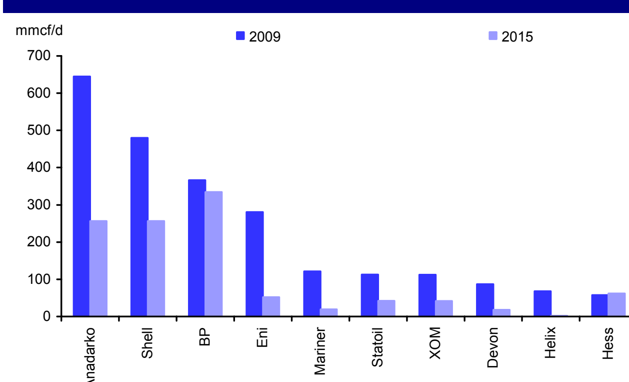
Source: Wood Mackenzie

Figure 386: DW GoM: Major producers of liquid 2009/15E



Source: Wood Mackenzie

Figure 387: DW GoM: Major producers of gas 2009/15E



Source: Wood Mackenzie

Reserves and Resources

Based on Wood Mackenzie data, estimated 2P reserves in the US DW GoM at the end of 2009 stood at some 8bn bbls of oil and 9.7TCF of gas of which the majority lie in the central Gulf. The substantial prospectivity of the region is, however, reflected by MMS data which suggests undiscovered resources stood at around 45 billion bbls of oil and 233 TCF of gas i.e. twice the level of reserves that have been produced to date. Amongst the companies BP clearly dominates, its equity interest in existing and future developments accounting for almost 28% of the 2P reserves estimate, more than twice those of the next nearest player, Chevron with c1170m bbls.

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 FPSO is currently under construction by Keppel and is expected to be deployed early 2010.

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 Medium 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 388: 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. The region has thus proven 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. At present, six re-gasification plants with aggregate annual capacity of c.62mtpa are operational. A further two plants are expected to be operational by 2012 adding some 25mtpa capacity. In addition, at the time of writing plans for a further 12 re-gas terminals are proposed with a total projected capacity of over 150mtpa. Past experience suggests, however, that many of these will ultimately not proceed.

Figure 389: Gulf Coast re-gas facilities – on-stream and under construction

Name	Status	Capacity mscf/d	Capacity mtpa	Holders (capacity %)
Lake Charles	On-stream	2100	14.2	BG (100%)
Gulf Gateway	On-stream	500	3.9	Excellerate Energy (100%)
Freeport	On-stream	1550	12.1	COP(58%),Dow(32%), Mitsubishi(10%)
Sabine Pass	On-stream	2600	20.3	Cheniere(76%),Total(12%), Chevron(12%)
Cameron LNG	On-stream	1500	11.7	ENI (40%)
Under construction				
Golden Pass	Q3 10	2000	15.6	QP (70%), XOM (17%), COP (12%)
Gulf LNG Energy	Q2 12	1300	10.1	El Paso(50%), Crest(30%), Sonagas(20%)

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 41% or 7.5mb/d of current US refining capacity (18.2mb/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. This concentration of capacity has left the refining market in the US increasingly 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 390: Major US Gulf Coast Refining Assets

	US rank (size)	Company	State	Location	Barrels per day
1	1	Exxon	Texas	Baytown	562,500
2	2	Exxon	Louisiana	Baton Rouge	501,000
3	3	BP	Texas	Texas City	437,000
4	4	CITGO	Louisiana	Lake Charles	429,500
5	6	Exxon	Texas	Beaumont	348,500
6	8	Shell/Aramco	Texas	Deer Park	333,700
7	11	Flint Hills Resources LP	Texas	Corpus Christi	288,126
8	12	Shell/Aramco	Texas	Port Arthur	285,000
9	14	Citgo	Texas	Houston	270,200
10	17	Premcor	Texas	Port Arthur	260,000

Source: EIA; Deutsche Bank

US Deepwater GoM - Notes

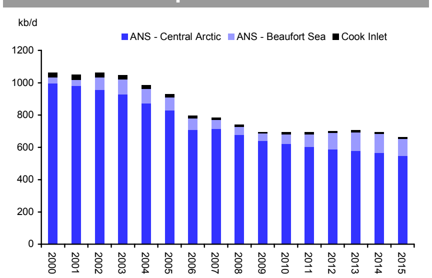
US Alaska

Key facts

Oil production 2009E	**0.7 mb/d**
Gas production 2009 E	**0.1mboe/d**
Oil reserves 2009E	4.2bn bbls
Gas reserve 2009E	32TCF
Reserve life (oil)	16.6 years
Reserve life (gas)	236 years
US GDP 2009E ($bn)	$14.3 trillion
US GDP Growth 2009E (%)	-1.2%
US Population (m)	307m
US Oil consumption (mb/d)	19.5m/d
US Oil exports (mb/d)	n.a.
Fiscal regime	Tax & royalty
Marginal tax rate	c.64%
Top 3 oil fields (2009E)	
Prudhoe Bay	381kboe/d
Kuparuk	144kboe/d
Colville	109kboe/d
Top 3 oil producers (2009E)	
Conoco	282kboe/d
BP	190kboe/d
Exxon	128kboe/d

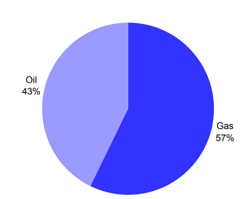
Source: Wood Mackenzie data; EIA

Oil Production profile kb/d



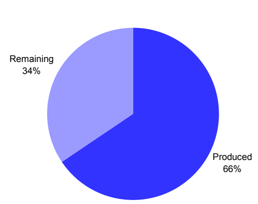
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

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 billion bbls of yet-to-find oil suggested to exist both onshore and offshore by the USGS and MMS. At this time both oil and gas production are, however, in decline although with c700kb/d of oil produced in the state in 2009 it continues to account for comfortably over 10% of total US liquids production. At the end of 2009 Wood Mackenzie estimates that 2P oil reserves stood at 4.2bn barrels and those for gas at 32TCF, although of the gas reserves almost 95% are associated with Arctic located fields that, as yet, have no route to market.

Basic geology and topology

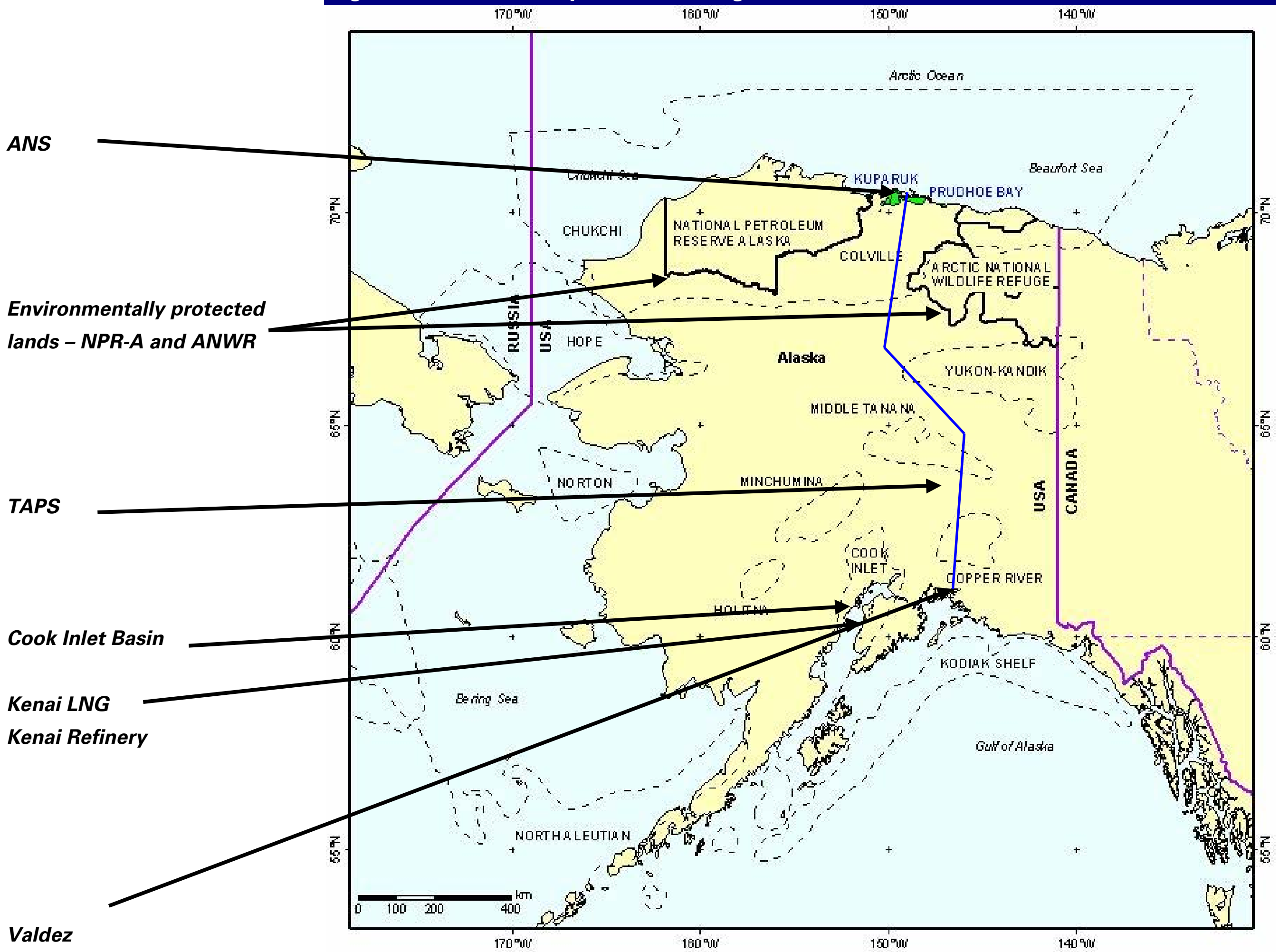
To date hydrocarbon exploration and production has focused on two main areas, the predominantly gaseous Cook Inlet and the Alaskan North Slope (ANS), which borders the Artic Ocean and accounts for near all of the state's oil production. Formed during the Triassic and Jurassic, the ANS lies within the Artic-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.

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 artic 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 no more than 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 Alaskan National Wildlife Refuge (ANWR). Discussed later, these two 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 391: 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.

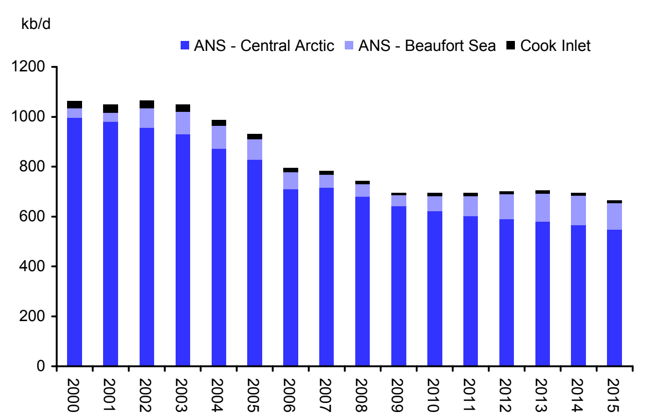
Where the leasing program typically focuses on mature areas, Alaska's exploration licensing is designed to encourage exploration in frontier areas. As such, portions of the ANS and Cook Inlet which are covered by the lease program are off limits to the exploration license program. Licensing begins in 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

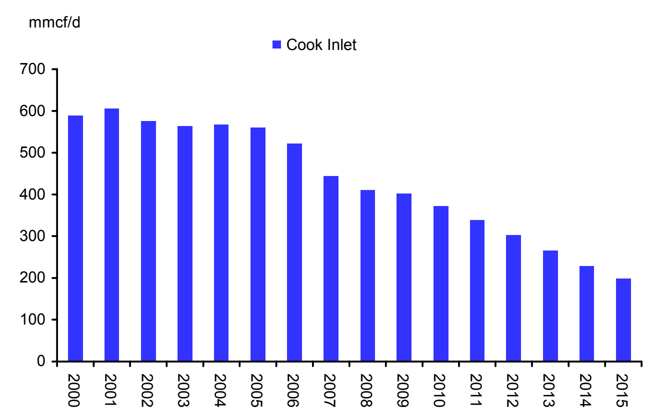
After peaking at over 2mb/d in 1988, oil production in Alaska has been on a declining trend for much of the past decade with oil production from the Cook Inlet in particular now in its twilight years (production peaked at 230kb/d in 1970). Alaskan oil production is concentrated on the ANS and this is likely to remain the main source of oil for many years to come. Key ANS fields are Prudhoe Bay (c381kboe/d), Kuparuk (c144kboe/d) and Colville (c109kboe/d), the former has 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) 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, with around half the gas produced used as feedstock to the 1.4mtpa Kenai LNG plant, the contracts for which extend until 2011.

Figure 392: Alaska: Liquids production 2000-15E (kb/d)



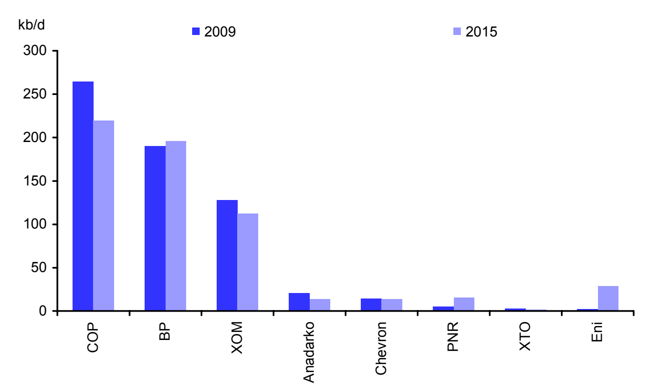
Source: Wood Mackenzie

Figure 393: Alaska: Gas production 2000-15E (mscf/d)



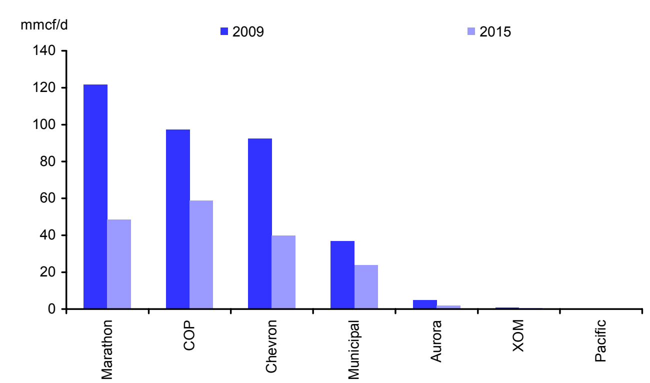
Source: Wood Mackenzie

Figure 394: Alaska: Major producers of liquids 2009/15E



Source: Wood Mackenzie

Figure 395: Alaska: Major producers of gas 2009/15E



Source: Wood Mackenzie

Reserves and resources

At the end of 2009 Wood Mackenzie estimates that oil reserves on a 2P basis stood at just over 4bn barrels with around 65% of these associated with Prudhoe Bay and Kuparuk. Compared with initial recoverable reserves of 21bn barrels this clearly illustrates the maturity of existing production. Similarly, the Cook Inlet estimated remaining reserves of c220mboe compared with an initial recoverable reserve of over 10x that figure. In this respect Alaska thus looks a spent force in the world of hydrocarbon production.

However, with some 32TCF of proven ANS gas reserves as yet untapped, gas production at least remains a relatively substantial near term opportunity for the players involved with many commentators assuming that the issues surrounding development (a stable and attractive fiscal environment) will allow for the required infrastructure investment. First delivery is anticipated through the second half of the next decade. The US DoE also estimates that heavy oil reserves of some 36bn barrels of viscous heavy oil overlie the main producing zones at Prudhoe Bay and Kuparuk although this is as yet uneconomic to produce.

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.

- **ANWR**. Lying on the shores of the Arctic Ocean to the east of Prudhoe Bay, the Alaskan 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.

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 development of a pipeline, 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 (26.5TCF) it is the clear desire of the producers involved (BP, COP, Exxon) to lay down infrastructure. However, with the state wishing to ensure that it captures its share of the value of the resource base and the producers reluctant to invest the $25billion plus that a pipeline would likely cost unless they are certain of the fiscal backcloth, progress has been limited.

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 and trades at around a $5/bbl discount.

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 396: Alaska Refineries

Company	Location	Capacity (bpd)
Flint Hills Resources Alaska Llc	North Pole	210,000
Tesoro Alaska Petroleum Co	Kenai	72,000
Petro Star Inc	Valdez	48,000
Petro Star Inc	North Pole	19,700
ConocoPhillips Alaska Inc	Prudhoe Bay	15,000
BP Exploration Alaska Inc	Prudhoe Bay	12,780

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. LNG produced is sold under two long term contracts expiring in 2011 with Japanese utility contracts. Absent the discovery of significant new supplies of gas the plant is unlikely to remain in production post this time.

US Alaska - Notes

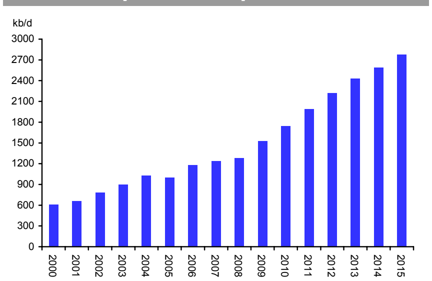
Canada – Oil Sands

Key facts

Oil sands production 2009E	**1.5mb/d**
Oil production 2009E ex sands	1.6mb/d
Oil sands reserves 2009E	37bn bbls
Oil & gas reserves 2009E (ex-oilsands)	23bn boe
Reserve life (oil sands)	66 years
Reserve life (gas)	15 years
GDP 2009E ($bn)	$1,288bn
GDP growth 2009E (%)	-1%
Population (m)	33.6m
Oil consumption (mb/d)	2.3mb/d
Oil exports (mb/d)	1.1mb/d
Fiscal regime (concession)	Tax & royalty
Marginal tax rate (concession)	48%
Top 3 producing licenses (2009E)	
Syncrude	341kboe/d
Suncor	265kboe/d
AOSP	155kboe/d
Top Producer (2009E)	
Suncor	363kb/d
CNR	181kb/d
XOM	139kb/d

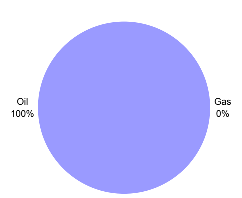
Source: Wood Mackenzie, EIA, IMF

Oil sands production profile kb/d



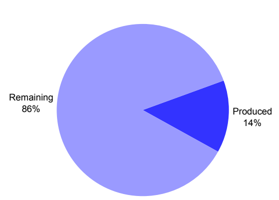
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

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 37 billion barrels are deemed recoverable at this time. Production in 2009 is estimated at 1.5mb/d or roughly half of Canada's total oil production. On the back of planned investment of $90bn over the next eight or so years this is, however, expected to rise to over 2.8mb/d by 2015 leaving Canada as the world's 6th largest oil producer with the sands representing over two-quarters of the country's oil production. Key producers in 2009 included Suncor (363kb/d), Canadian Natural Resources (181kb/d) and Exxon Mobil (139kb/d).

Broad geology and topology

Covering the north eastern part of the Western Canadian Sedimentary Basin the oil sands of Alberta are believed to have been 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 became concentrated as bitumen creating an oil sand composed of 70% sandstone and clay, 10% water and 20% bitumen.

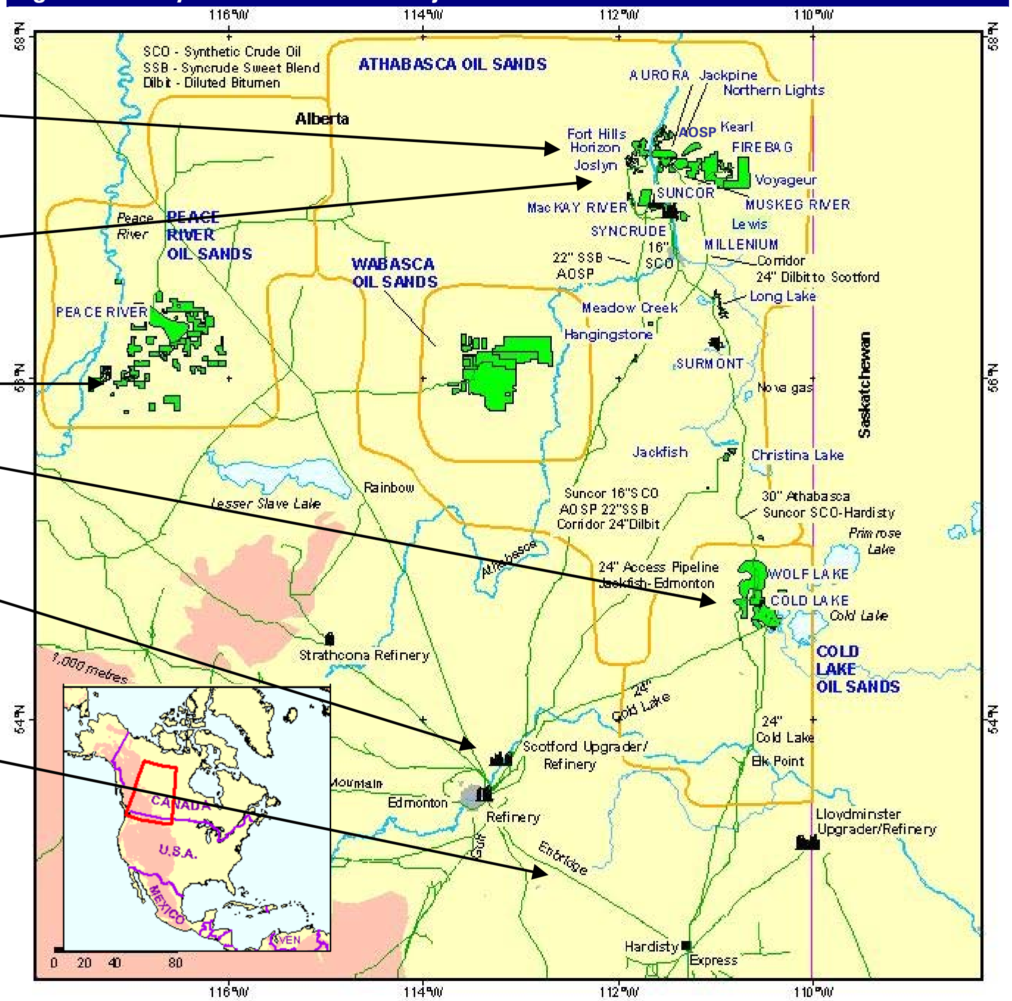
History and regulation

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 seventeen projects are producing with a further five 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.

Figure 397: 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.

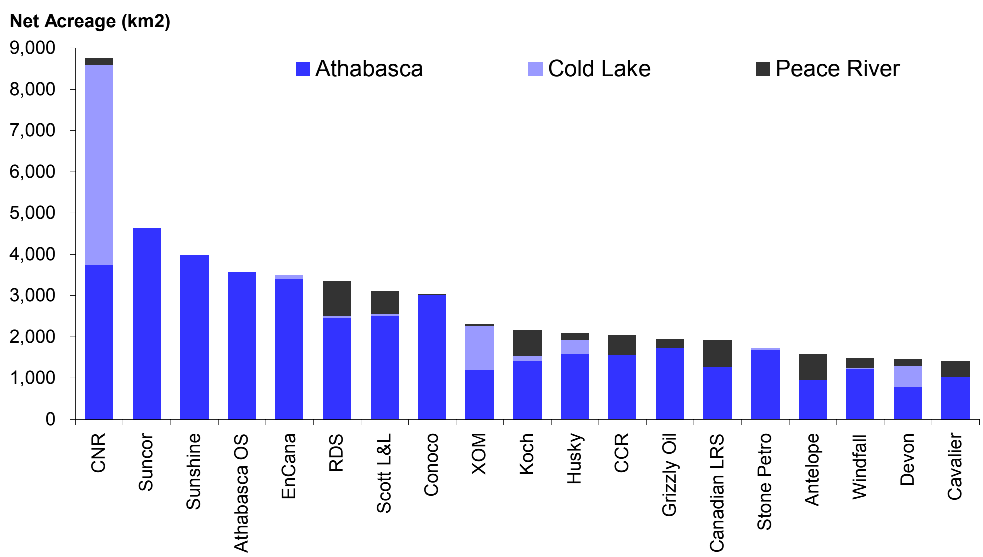
The body responsible for awarding Oil Sands Leases (OSLs) is the Alberta Energy and Utilities Board (AEUB). The Board must grant approval before any oil sands operation can commence. Leases have been awarded across all potential regions since operations began in the 1960s. At present, active licences 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 8,000km² 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 398: Land under license in Athabasca, Cold Lake and Peace River



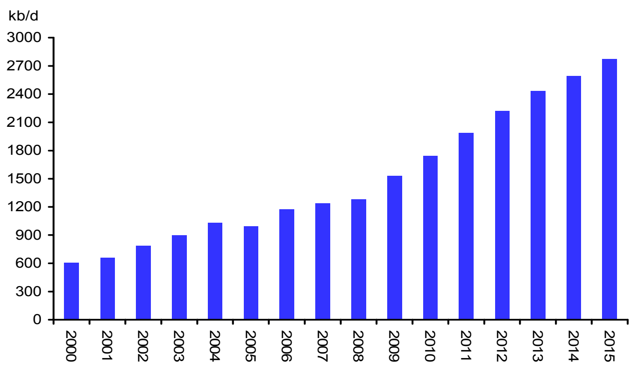
Source: Wood Mackenzie; Deutsche Bank

Production of oil & gas

As the oil price has climbed and access to resource particularly in fiscally stable regions of the world decreased so interest in the development of Canada's oil sands has surged. After several decades of fairly static levels of production, a steady flow of new project developments looks set to see a surge in Canadian production. Based on Wood Mackenzie estimates, from 2009 production of around 1.5mb/d is expected to rise at a 10% CAGR to around 2.8mb/d by 2015, although with labour and supply markets very tight it would seem reasonable to expect some slippage in this estimate. Of this, around 2.5mb/d is expected to arise from bitumen sourced from mining projects with the balance predominantly extracted by the less capital intensive, steam assisted gravity drainage (SAGD) process. *For a description of the different production techniques (mining, SAGD and Cyclic Steam) please see the Industry section on non-conventional oils.*

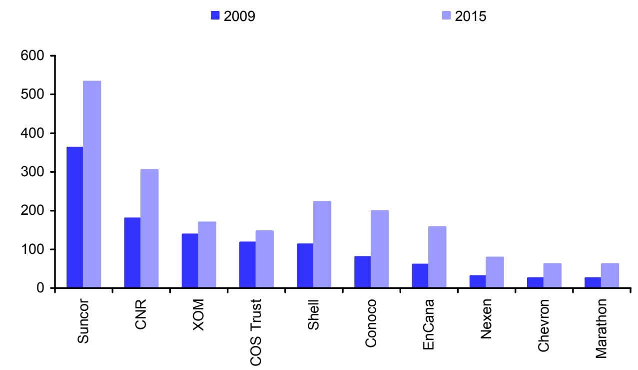
By company, at the present time Suncor (363kb/d), Canadian Natural Resources (181kb/d), Exxon (139kb/d), Canadian Oil Sands Trust (118kb/d) and Shell (113kb/d) are the leading producers, these five names accounting for almost 70% of anticipated output in 2009. However, as new entrants develop facilities production is expected to become far less concentrated. By 2020 under current plans around ten companies are expected to be producing over 100kb/d with the share of production controlled by the current big five falling to nearer 50%.

Figure 399: Canada – Oil sands output to 2015E (kb/d)



Source: Wood Mackenzie

Figure 400: Canada – Oil sands main producers 2009/15E



Source: Wood Mackenzie

Figure 401: Canada Oil sands Projects and start up dates (all Athabasca except those shaded)

Projects	Status	Start-up	Reserves (mmbbls)	Peak (kb/d)	Capex ($m)	Main Participants	Method
Suncor Mine Project	Onstream	Oct-67	3,183	287	23,388	Suncor (100%)	Mining with upgrader
Syncrude Project	Onstream	Nov-78	5,132	577	60,931	COS Trust (37%), Imperial (25%), Suncor (12%)	Mining with upgrader
Primrose/Wolf Lake	Onstream	Jan-83	956	120	4,124	CNR (100%)	CSS & SAGD with upgrader
Cold Lake	Onstream	Nov-86	900	165	4,390	Imperial (100%)	CSS, LASER
Peace River	Onstream	Nov-86	105	12	754	Shell (100%)	CSS
Pelican Lake (CNRL)	Onstream	Jan-96	211	46	2,796	CNR (100%	Primary Projects
Hangingstone	Onstream	Jan-99	377	35	2,463	Japan COS (75%), Nexen (25%)	SAGD
Seal (Shell)	Onstream	Jan-01	56	18	529	Shell (100%	CSS & SAGD
Foster Creek	Onstream	Nov-01	1,787	210	8,210	EnCana (50%), Conoco (50%)	SAGD, VAPEX,SAP
Pelican Lake (EnCana)	Onstream	Jul-02	146	28	1,752	EnCana (100%))	Primary Projects
Christina Lake	Onstream	Oct-02	1,535	218	8,201	EnCana (50%), Conoco (50%))	SAGD, VAPEX,SAP
MacKay River	Onstream	Nov-02	563	70	3,796	Suncor (100%)	SAGD
AOSP	Onstream	Apr-03	3,655	370	30,884	Shell (60%), Chevron (20%), MRO (20%)	Mining with upgrader
Seal (Penn West)	Onstream	Jan-04	59	17	492	Penn West Energy Trust (100%)	Primary Projects
Suncor SAGD Project	Onstream	Mar-04	1,678	161	17,040	Suncor (100%)	SAGD with upgrader
Joslyn	Onstream	Nov-06	993	111	14,269	Total (74%), Occidental (15%), INPEX (10%)	SAGD
Tucker	Onstream	Nov-06	346	30	1,836	Husky (100%)	SAGD
Orion	Onstream	Sep-07	180	20	1,038	Shell (100%)	SAGD
Great Divide Project	Onstream	Oct-07	74	10	602	Connacher Oil & Gas (100%)	SAGD
Surmont	Onstream	Oct-07	886	111	4,486	Conoco (50%), Total (50%)	SAGD
Jackfish	Onstream	Nov-07	584	70	3,056	Devon (100%)	SAGD
Long Lake	Onstream	Mar-08	1,492	144	19,160	Nexen (65%), OPTI (35%)	SAGD with upgrader
MEG Christina Lake	Onstream	May-08	249	25	1,458	MEG (83%), CNOOC (17%)	SAGD
Horizon Project	Onstream	Sep-08	2,222	162	21,663	CNR (100%)	Mining with upgrader
Kai Kos Dehseh	Probable	Oct-11	900	80	4,771	Statoil (100%)	SAGD
Sunrise	Development	Jan-14	3,000	200	13,942	Husky (50%), BP (50%)	SAGD
Fort Hills Mine	Probable	Nov-14	1,940	160	12,472	Suncor (60%), Teck (20%), Total (20%)	Mining with upgrader
Kearl	Development	Jun-15	2,712	220	16,844	Imperial (71%), Exxon (29%)	Mining

Source: Wood Mackenzie

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 43 billion barrels of which 37 billion barrels have yet to be produced. However, as recovery rates improve and, more significantly, further developments are established over time 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 operating in Alberta. These are associated with the major producers, with Suncor and Syncrude operating the two main facilities which have a total current upgrading capacity of 700kb/d in the Athabasca area. Shell's 155kb/d Scotford upgrader (which it intends expanding to some 700kb/d) is located some 450km to the south near Edmonton. Husky's 82kb/d facility lies some 150km to the East of Scotford on the Alberta Saskatchewan border (see area map). CNRL's 135kb/d Horizon upgrader is located 70km north of Fort McMurray, while Nexen's Long Lake upgrader (72kb/d) which began operation in Jan 2009 is located 45km south of Fort McMurray. These facilities aside, a number of other projects are either under development or have been proposed to increase Alberta's upgrading capacity.

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 2.2mb/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 172kb/d of Canadian crude to Montana, Wyoming and Utah whilst the Platte runs 1490km carrying crude to Colorado, Kansas and Illinois.

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 250kb/d although with several new projects coming on stream volumes are likely to increase substantially. 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

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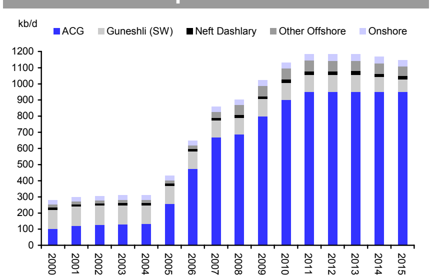
Azerbaijan

Key facts

Oil production 2009E	**1 mb/d**
Gas production 2009E	**0.3mboe/d**
Oil reserves 2009E	7.6bn bbls
Gas reserve 2009E	20.8 TCF
Reserve life (oil)	18.5 years
Reserve life (gas)	25.8 years
GDP 2009E ($bn)	$81.7.billion
GDP Growth 2009E (%)	9.2%
Population (m)	8.7m
Oil consumption (mb/d)	0.12m/d
Oil exports (mb/d)	0.75mb/d
Fiscal regime	IRR-based PSC
Marginal (corporate) tax rate	25%
Top 3 fields (2009E)	
ACG	870kboe/d
SW Guneshli	223kboe/d
Shah Deniz	171kboe/d
Top 3 Producers (2009E)	
Socar	426kboe/d
BP	167kboe/d
Statoil	70kboe/d

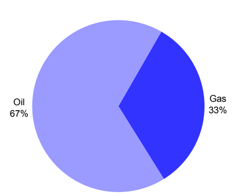
Source: Wood Mackenzie data; EIA

Oil Production profile kb/d



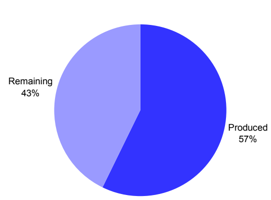
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

Azerbaijan is one of the oldest oil producing regions in the world. In the onshore, production peaked in the early 1940s at just under 500kb/d and following decades of exploration and production the region is now largely spent. Onshore reserves of oil & gas at the end of 2009 are estimated by Wood Mackenzie at less than 600 mboe. However, in the offshore significant prospectivity and reserves remain, much of which is associated with a single PSC; BP's Azeri Chirag Guneshli (ACG) contract, production from which is expected to peak towards the end of the current decade. With this five field combination project ramping up over the next few years, production in the country is expected to more than double reaching c.1.1mb/d by 2010. Similarly, giant 27TCF Shah Deniz gas field producing currently c.121 kboe/d is expected to see gas production broadly triple towards the end of next decade reaching c400kboe/d. Overall, at the end of 2009 Azeri 2P reserves are estimated to total some 7.6 billion barrels of oil and 20.8 TCF (3.7bn boe) of gas excluding some 2.4bn boe of gas at Shah Deniz for which there are, as yet, no clear plans for commercial development.

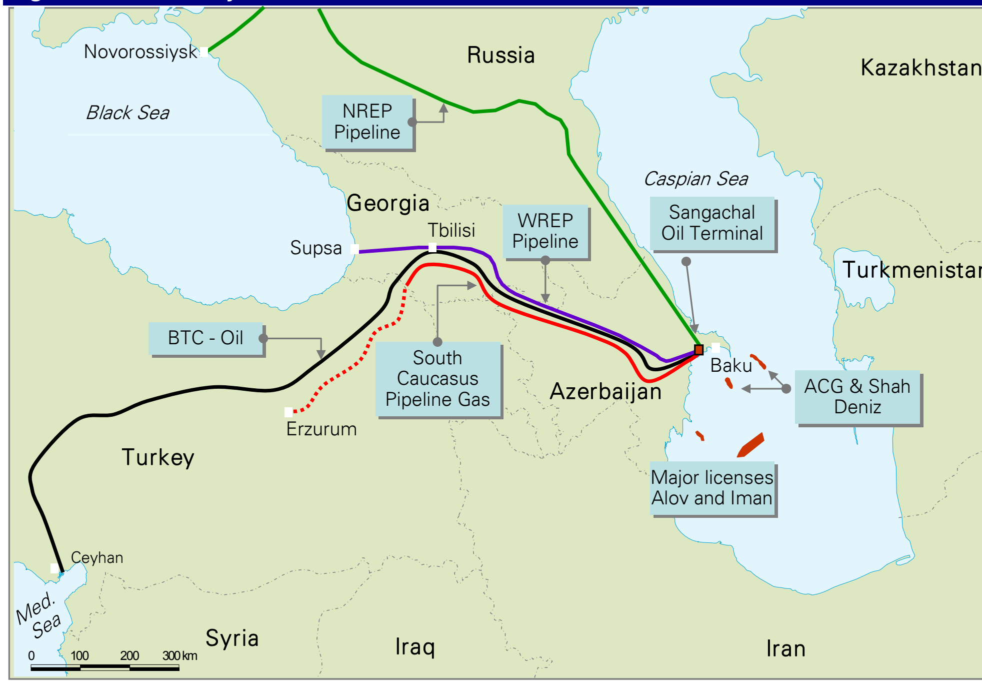
Basic geology and topology

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. Offshore Azerbaijan is however a difficult reservoir system not least given the 6,000 metres 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.

Figure 402: 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 recent years licenses have been relinquished more frequently than awarded. As a consequence in the offshore and excluding the two producing fields (ACG and Shah Deniz), only four exploration licenses remain intact today. Moreover, of these one looks set to be relinquished after disappointing exploration results (Lukoil's Yalama) whilst a further two (BP's Alov and Exxon's Lekira) are in Caspian waters which at present are subject to an ownership dispute with Iran (it is of note that in past years Iran has sent out gunboats to prevent drilling). As such, only BP's Iman license can fairly be described as currently active.

Production of Oil & Gas

With the ACG field now moving towards peak production, the oil industry in Azerbaijan is witnessing something of a renaissance. Indeed, through much of the current decade oil production is expected to run at some 1.1mb/d, the overwhelming majority of which will arise from the key ACG PSC. Besides this major producing asset there are, however, few other development plans of note. With little happening on exploration 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. Key here, however, is the scale of the technical reserve base which, at around 27TCF, suggests significant long term opportunity for growth as, and when, commercial contracts can be signed and routes to market developed.

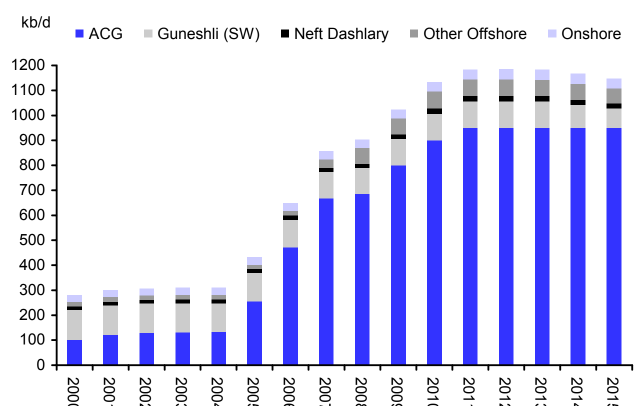
Figure 403: Azerbaijan International Operating Company members (BP operator)

Name	Stake	Narrative
BP	39.7%*	Operator. Gained status 6/99 post merger with founder member Amoco
Chevron	10.3%	Acquired through Unocal
Inpex	10.0%	Acquired from Lukoil for $1.35bn in '02 after others declined pre-emption rights
SOCAR	10.0%	State oil company
Statoil	8.6%	Entered as part of the BP/Statoil JV
Exxon	8.0%	
TPAO	6.8%	
Itochu	3.9%	
Hess	2.7%	

*Source: Wood Mackenzie, BP, Deutsche Bank *Operator*

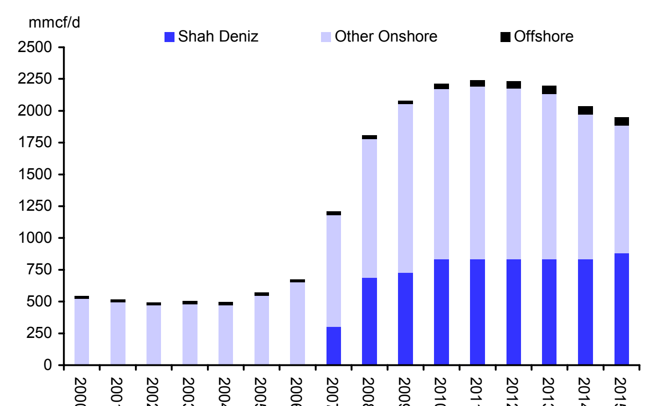
Initially, the ACG development was to be managed by a joint operating company comprising those companies that had signed up for the 1994 PSC, the Azerbaijan International Operating Company or AIOC. However, following its acquisition of Amoco in 1998, BP sought and was granted the role of operator. With a 39% 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 (Statoil also holds a 25.5% interest in Shah Deniz and has responsibility for marketing the gas). Other companies with a significant interest in ACG include Chevron (10.3%), Statoil (8.6%) and Exxon (8.0%) whilst of the IOC's Total and Lukoil each hold a 10% interest in Shah Deniz.

Figure 404: Azerbaijan – Oil production to 2015E (kb/d)



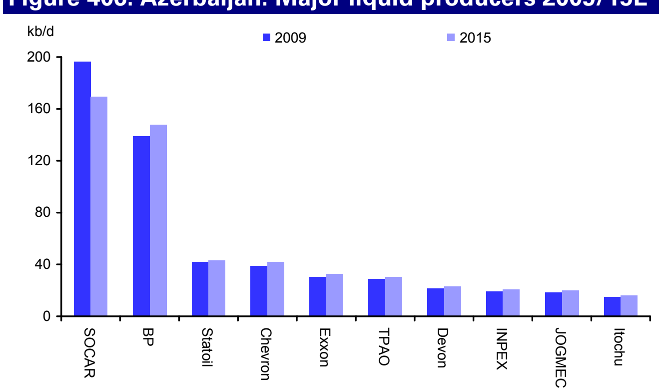
Source: Wood Mackenzie

Figure 405: Azerbaijan –Gas production to 2015E (mscf/d)



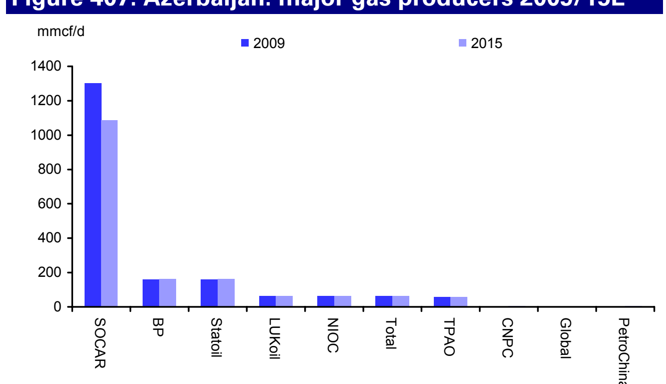
Source: Wood Mackenzie

Figure 406: Azerbaijan: Major liquid producers 2009/15E



Source: Wood Mackenzie

Figure 407: Azerbaijan: major gas producers 2009/15E



Source: Wood Mackenzie

Reserves and resources

At the end of 2009 Wood Mackenzie estimates that total 2P reserves of liquids stood at 7.6bn barrels of which 6bn were associated with the ACG fields. Similarly, 2P Gas reserves are estimated at 3.7bn boe, 2.5bn boe of which are associated with Shah Deniz. It is, however, of note that a further 13.7TCF of gas are estimated to be associated with Shah Deniz although with no commercial contracts in place for their sale at this time these are regarded as a technical resource. These reserves aside, SOCAR estimates that there could be 1.5bn boe associated with BP's Inam offshore prospect.

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. The pipeline exported some 653mb/d in 2008 and it is also used to export Kazakhstan's oil from giant Kashagan field.

- 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 65% utilisation 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 100kb/d. In 2008, it transported only 29kb/d well below its capacity due to disagreement with SOCAR on transit terms, albeit flow rates have since increased with the BTC achieving close to capacity utilization. In future, there is a possibility of using the pipeline to transport Kazakh and Turkmen oil.

- 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, 780mmcfd, 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 4%). 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. The share of profits aside, profits achieved under the ACG PSC are liable to corporation tax at a rate of 25%, slightly higher than the standard CT rate of 22%.

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, with an estimated utilization rate in 2008 of 35-40%, running substantially below capacity. SOCAR is currently investing significantly to improve output although it is doubtful that they will ever achieve nameplate capacity.

Figure 408: Azerbaijan major refineries

Name	Location	Nominal Capacity	Focus
Azerneftyag	Baku	239kb/d	Fuel and lubes
Heidar Aliyev	Baku	160kb/d	Fuel and coke

Source: O&G Journal; Deutsche Bank

Azerbaijan Notes

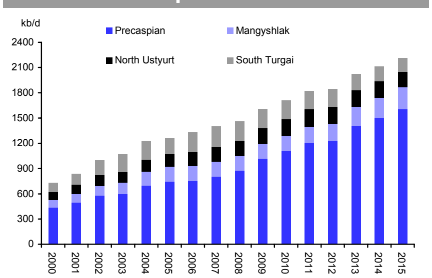
Kazakhstan

Key facts

Oil production 2009E	**1.6mb/d**
Gas production 2009E	**0.4mboe/d**
Oil reserves 2009E	26.7bn bbls
Gas reserve 2009E	47TCF
Reserve life (oil)	44 years
Reserve life (gas)	59 years
GDP 2009E ($bn)	$177 billion
GDP Growth 2009E (%)	-0.5%
Population (m)	15.6m
Oil consumption (mb/d)	0.23m/d
Oil exports (mb/d)	1.3mb/d
Fiscal regime	T&R and PSC
Marginal (corporate) tax rate	46% & 75%
Top 3 fields (2009E)	
Tengizchevroil	608kboe/d
Karachaganak	404kboe/d
CNPC AktobeMunaiGas	181kboe/d
Top 3 Oil Producers (2009E)	
KazMunaiGas	432kboe/d
Chevron	376kboe/d
Exxon	154kboe/d

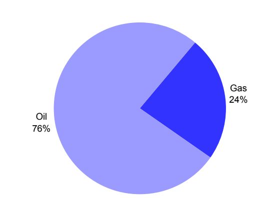
Source: Wood Mackenzie; EIA data

Oil Production profile kb/d



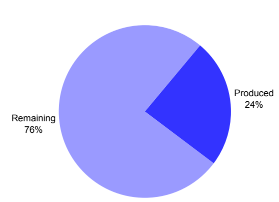
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

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 1.6mb/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. This production performance is expected to centre on the output from three giant fields, Kashagan, Tengiz and Karachaganak. At almost 50TCF the country also has substantial reserves of natural gas, most all of which is associated with its liquids output, and for which 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 Chevron, Eni and Exxon.

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. 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 KazMunaiGaz (KMG). Through its subsidiaries KMG not only holds material stakes in a number of key fields (Kashagan, Tengiz, Uzen) but, through KazMunaiGaz E&P, also acts as the operator for a multitude of others. Moreover, through KazTransOil (KTO) and KazTransGaz (KTG) the 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, KMG's key functions include its participation in the strategic planning and development of the country's 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 KazMunaiGaz 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 aggressive in its dealings with western companies, not least through its negotiation of a greater equity interest for KMG in Kashagan and, potentially, Karachaganak.

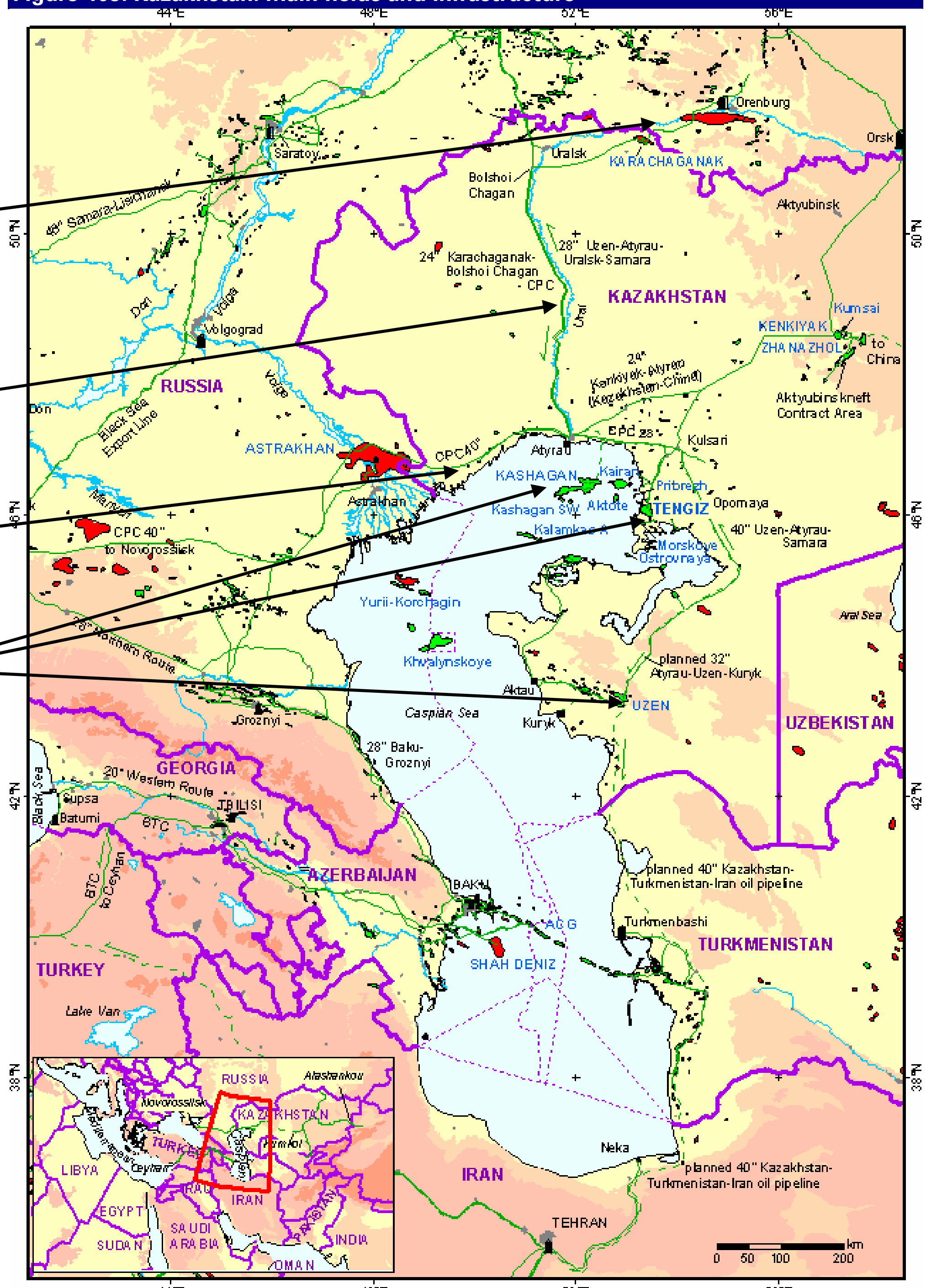
Figure 409: Kazakhstan: Main fields and infrastructure

Karachaganak with Orenberg processing plant across the Russian border

Atyrau-Samara pipeline to Russia

CPC's 650kb/d of capacity transport oil from Tengiz and Karachaganak to the Black Sea

Main Caspian fields Kashagan, Tengiz and Uven



Source: Wood Mackenzie

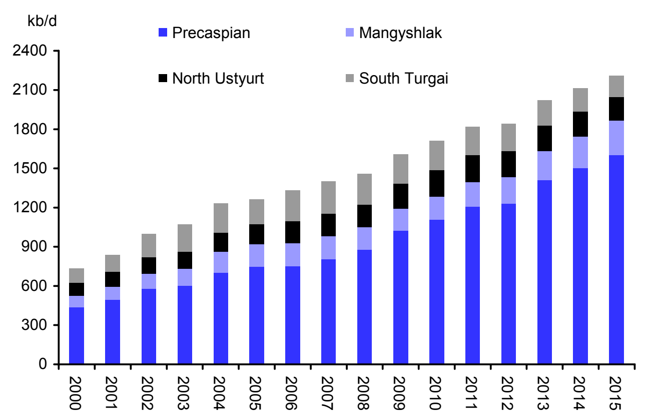
Licensing

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.

Production of Oil & Gas

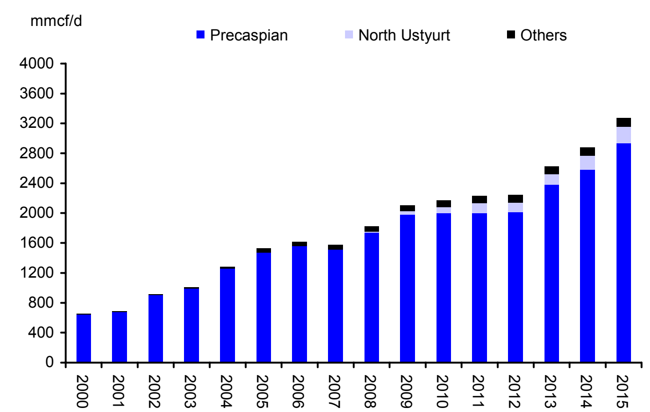
With additional phases of production scheduled at both Karachaganak and Tengiz and the planned start up of the giant Kashagan development, oil and gas production in Kazakhstan is expected to increase substantially over the coming years. Assuming that work proceeds in line with current expectations, oil 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 410: Kazakhstan – Oil production to 2015E (kb/d)



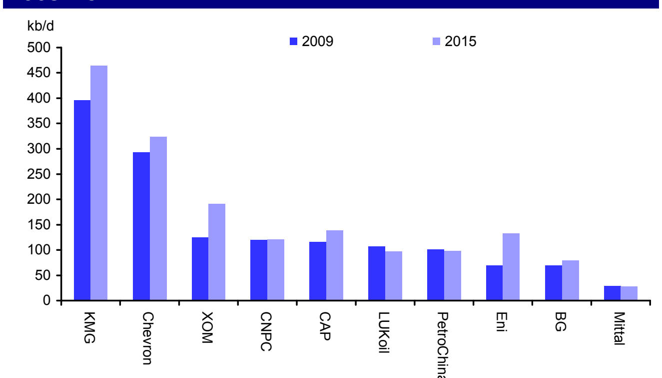
Source: Wood Mackenzie

Figure 411: Kazakhstan: Gas production to '15E (mscf/d)



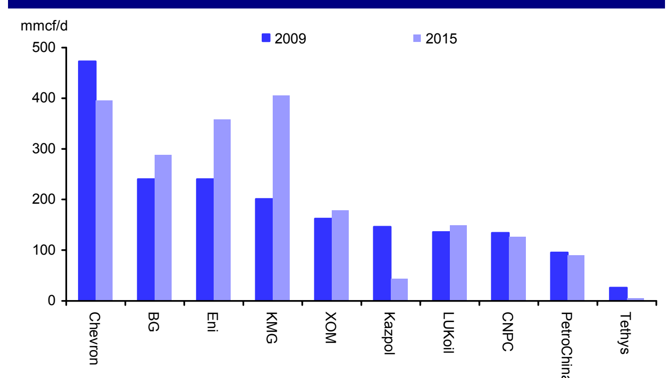
Source: Wood Mackenzie

Figure 412: Kazakhstan: Major liquid producers 2009/15E



Source: Wood Mackenzie

Figure 413: Kazakhstan: Major gas producers 2009/15E



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data 2P reserves in Kazakhstan at the end of 2009 included 26.7bn barrels of oil and liquids and some 47TCF (8.3bn boe) of natural gas. Of these over three quarters (25.5 bn boe) were associated with Kashagan (13bn boe), Tengiz (7.2bn) and Karachaganak (5.4bn). Given existing production this suggests a 2P reserve life of over 44 years. Moreover, these reserve estimates are almost certain to understate actual reserves given the scale of the technical resource known to exist at Tengiz, not least some 44TCF of solution gas.

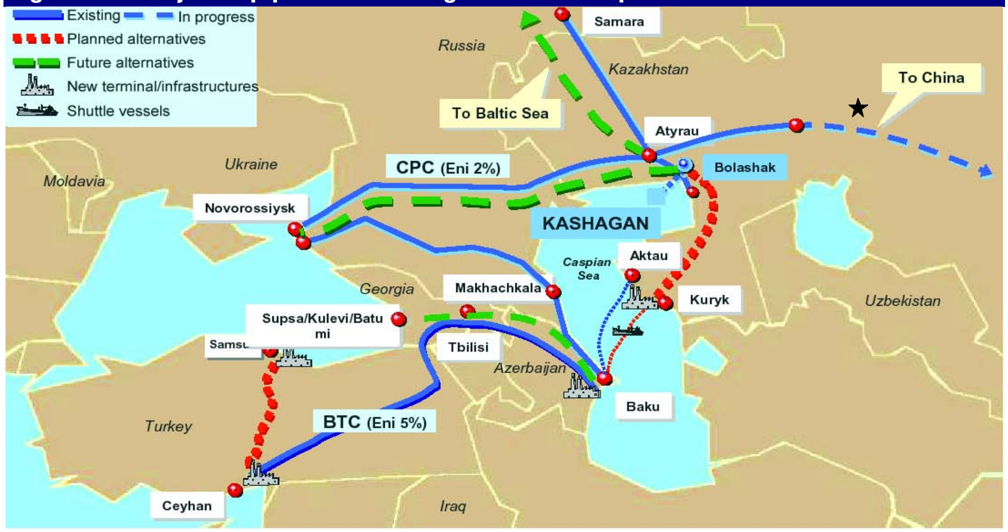
Pipelines and infrastructure

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 at 700kb/d well above its nominal capacity of 560kb/d due to the use of drag reducing agents. The capacity is expected to expand to 1.4mb/d by 2014. 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, Karachaganak and, in future years Kashagan.
- **K-C:** 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 200kb/d with plans to increase to 400kb/d. The capacity of the first phase section Kiyak-Atyrau is 120kb/d and there are plans to expand this to 240kb/d in two stages.
- **KCTS**: Beyond CPC and K-C, the development of the Kazahstan Caspian Transport System will establish pipeline transport for oil from Kashagan, and other connected fields, to the Caspian port of Kuryk. From here oil can be transported by ship to Baku before being transported through the BTC to southern Turkey. Scheduled to be completed in line with the start up of Kashagan, initial capacity is planned at 300kb/d rising to a potential 1mb/d.

Figure 414: Major oil pipelines: existing and in development



*Source: Courtesy of ENI, * K-C pipeline was completed late in 2009.*

These two major export routes aside, the key export line is the **Atyrau-Samara** pipeline which connects the Kazakh and Russian systems. This currently has a capacity of 350kb/d but an increase to 500kb/d is under consideration.

Other routes to export markets

Pipelines aside, Kazakhstan has the potential to export up to 340kb/d of oil by rail and 200kb/d by ship from the port of Aktau. Shipping facilities are, however, expected to be significantly increased with capacity at Aktau moving to 400kb/d by 2010 with similar capacity also laid down at the new port of Kuryk.

Figure 415: Export routes for Kazakhstan's main producing fields

Field	Export routes
Tengiz	CPC to Novorossiysk - 650kb/d
	Atyrau-Samara to Russia (and on through Transneft) – Limited export at present
	To BTC via future Kazakh Caspian Transport System (KCTS)
	Rail potential for 120kb/d
Karachaganak	To CPC through the Bolshoi Chagan-Atyrau pipeline – 150kb/d
	Atyrau-Samara to Russia (and on through Transneft) - 66kb/d by 2012
	Rail - 100kb/d by 2012
	Orenburg processing plant - 80kb/d condensate processing
	Orenburg processing plant - 8bcm rising to 16 bcm in 2012. Sold to KRG.
Kashagan	Likely to be a mix of CPC, BTC, Atyrau-Samara and Kazakh-China

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. After some considerable state investment in recent years refining performance has improved significantly with utilization rates rising to over 50% of nameplate capacity. Despite the poor performance of the country's three refineries, production is sufficient to meet the country's demand requirements which in 2009 stood at around 230kb/d.

Kazakhstan – Notes

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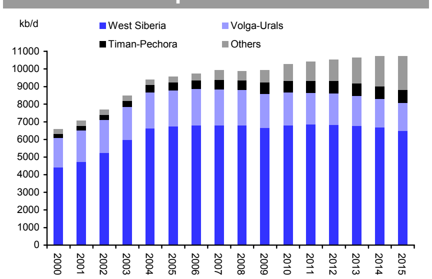
Russia

Key facts

Oil production 2009E	**9.9mb/d**
Gas production 2009E	**8.9mboe/d**
Oil reserves 2009E	96.7bn bbls
Gas reserve 2009E	861.1tcf
Reserve life (oil)	26.9 years
Reserve life (gas)	41.8 years
GDP 2009E ($bn)	$2.13trillion
GDP Growth 2009E (%)	-6.1%
Population (m)	141.0m
Oil consumption (mb/d)	2.9m/d
Oil exports (mb/d)	6.9mb/d
Fiscal regime	T&R and PSC
Marginal (corporate) tax rate	73.4%&86.05%
Top 3 fields (2009E)	
Yamburgskoye	1,468kb/d
Zapolyarnoye	1,391kb/d
Urengoiskoye	1,262kb/d
Top 3 Producers (2009E)	
Gazprom	8,451kb/d
Rosneft	2,369kb/d
Lukoil	2,084kb/d

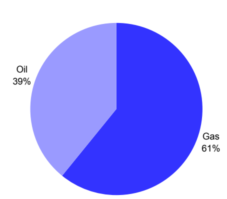
Source: Wood Mackenzie; EIA data

Oil Production profile kb/d



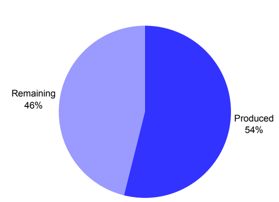
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

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 2009 stood at 96.7 billion barrels of oil and 861TCF of natural gas. Production is concentrated in four main regions and, at c.9.9mb/d and 64bcf/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 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 second largest oil company. With the exception of BP, which in 2003 established a material position through the acquisition of a 50% interest in TNK, foreign participation in Russia is limited.

Broad geology and topology

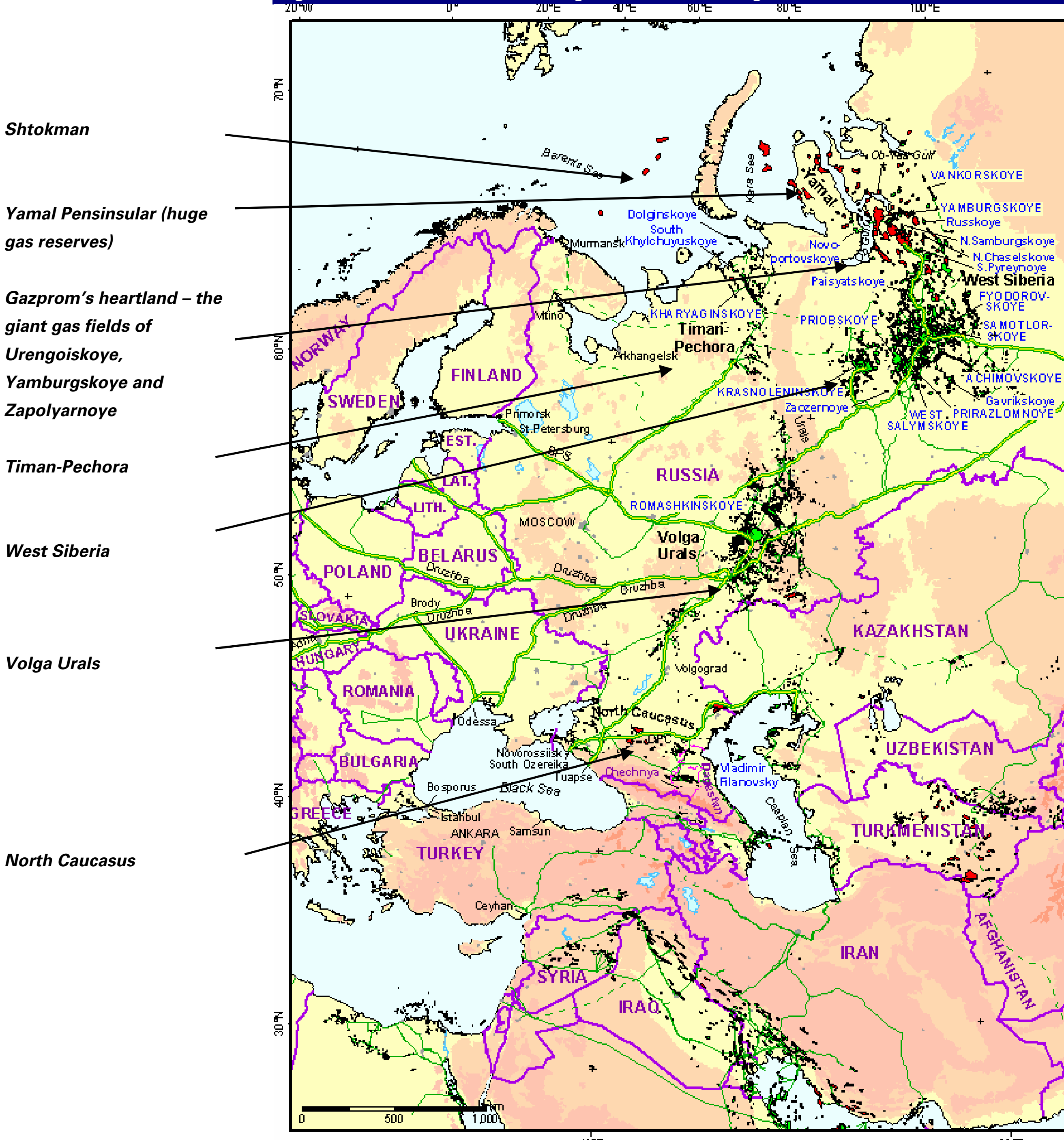
Russia's oil and gas provinces are formed around two ancient and stable tectonic plates or 'cratons', the East European craton to the west of the Ural Mountains and the East Siberian craton to the east. Fourteen oil and gas provinces are defined, each of which is synonymous with Russia's major geological 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 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 Artic 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 recovered from its lows of 1999 and Russia's economy has stabilized, so an increase in drilling activity together with the introduction of foreign recovery techniques have helped drive a dramatic upturn in production.

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 416: 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 then 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. Thus the dilution of Shell's interest in the Sakhalin II PSA, the 'negotiated' purchase of BP's interest in the giant Kovytka field not to mention the recent corporate governance issues at TNK which led to the resignation of the BP elected CEO. This has raised the stakes for foreign investment and made very clear that foreign involvement over and above that which exists today is only likely to arise on terms set by the state, with the international investor very clearly in a minority position.

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.

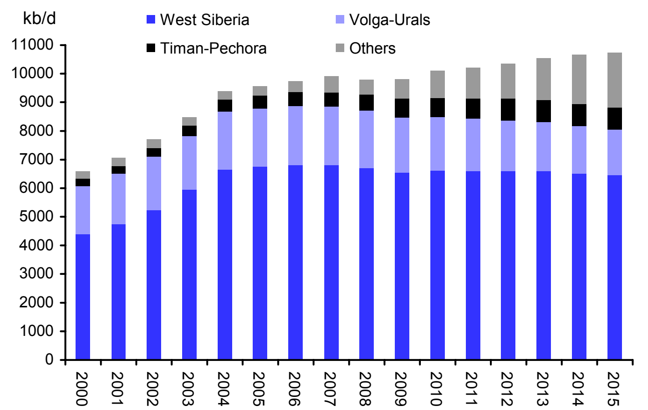
Production of oil & gas

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 10.7mb/d by 2015 and gas to roughly 69bcf/d by 2015. 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 (666kb/d), Samatlor (555kb/d) and Noyabrskneftegaz (335kb/d). Russia's oil production is dominated by the national majors Rosneft, Lukoil and Surgut and the BP joint venture, TNK-BP. With the state playing an increasing role in overseeing resource allocation Rosneft has emerged as the leading oil producer in recent years.

Similar to oil, gas production is expected to grow at a compound 1-2% for the foreseeable future rising to an estimated 69bcf/d by 2015. However, gas production is far more concentrated with the three largest fields (Yamburg, Zapolyary and Urengoy) accounting for over 41% of current production. With production from the last two of these now in decline, sustaining growth into the medium term is almost certain to require increased levels of investment and the development of giant fields which lie in very hostile environments, namely Bovanenkovskoye on the Yamal Peninsular and Shtokman in the Artic waters of the Barents Sea.

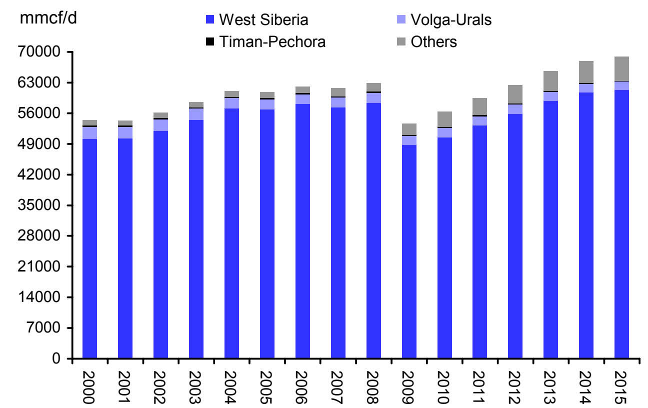
Gas production is dominated by state controlled Gazprom, which by law has the right to any gas fields deemed of strategic importance (provided no development licence has been granted), a monopoly over gas exports and domestic supply. Gazprom also retains a monopoly over Russia's gas transport network 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 417: Russia – Oil production to 2015E (kb/d)



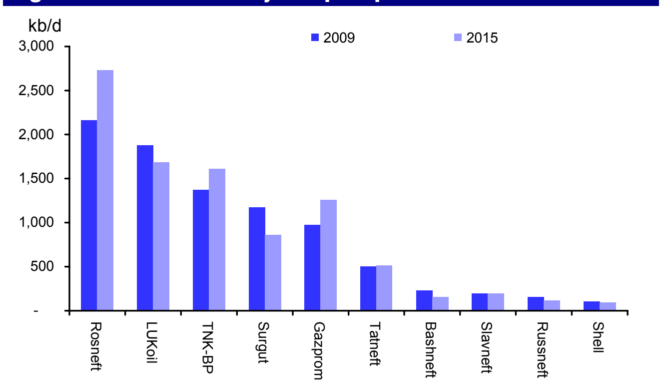
Source: Wood Mackenzie

Figure 418: Russia: Gas production to '15E (mscf/d)



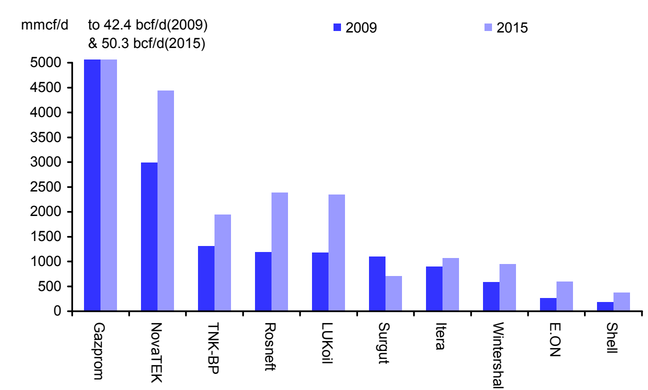
Source: Wood Mackenzie

Figure 419: Russia: Major liquid producers 2009/15E



Source: Wood Mackenzie

Figure 420: Russia: Major gas producers 2009/15E



Source: Wood Mackenzie

Reserves and resources

Based on Wood Mackenzie data Russia held estimated 2P reserves of oil at the end of 2009 of 96.7bn bbls. The country has the world's 8th largest bank of oil reserves and, at 861tcf (c. 148bn 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.

Figure 421: Major oil and gas fields and remaining reserves (1/1/10)

OIL				GAS			
Name	**Region**	**Reserves (mbbls)**	**Status**	**Name**	**Region**	**Reserves (TCF)**	**Status**
Priobskoye	West Siberia	9,674	Producing	Bovanenkovskoye	West Siberia	104	Planning
Samotlorskoye	West Siberia	4,279	Producing	Yamburgskoye	West Siberia	94	Producing
Romashkinskoye	Volga-Urals	3,879	Producing	Zapolyarnoye	West Siberia	81	Producing
Tatneft Other Fields	Volga-Urals	3,173	Producing	Shtokmanovskoye	Barents	61	Planning
Fyodorovskoye	West Siberia	3,108	Producing	Urengoiskoye	West Siberia	54	Producing
Vankorskoye	East Siberia	3,072	Producing	Kovyktinskoye	East Siberia	49	Producing
Samaraneftegaz	Volga-Urals	1,929	Producing	Kharasaveiskoye	West Siberia	34	Planning
Sakhalin-1 Area	Far East	1,556	Producing	South Russkoye	West Siberia	25	Producing

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 urgent 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 1.45mb/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. At the present time, infrastructure across the east of Russia is limited. However, in 2006 Transneft commenced construction of Stage 1 of the **East Siberia to Pacific Ocean Pipeline (or ESPO).** This is intended to connect West and East Siberian fields to China and Pacific markets, although quite where the pipeline will ultimately extend to is likely to depend heavily on world politics. The 600kb/d first stage from Tayshet to Skovorodino is expected to be completed in 2010, from where oil will then be transported by rail to a port terminal that is currently being constructed on the Pacific Coast at Kozimino (near Vladivostok). The second stage connecting Skovorodino to Kozimino with a separate spur running down to Daquing in China is expected to be completed by 2014.

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 **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 4.5bcf/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. The **Shtokman** project envisages the construction of a c1.3bcf/d pipeline linking this huge field in the Barents Sea with markets in Germany and beyond.

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), given the Russian government believes PSCs are inappropriate for use in Russia any 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 typically runs at around 16.5% of the well head price. On gas MET is set at a fixed RR147/mcm (c$6/mcm) and on condensate at 17.5% of the well-head price. Note that certain development regions such as the Arctic and East Siberia are entitled to certain exemptions from MET provided reserves depletion is under 5%.
- 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 65% at an average price above $25/bbl. The duty payable is calculated on the average official Mediterranean and Rotterdam price over the previous month and is recalculated every two weeks.
- 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 73%, 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

According to the EIA, Russia has some 41 refineries with a total distillation capacity of 5,490kb/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. Separately, Gazprom has also announced its intention to establish a second LNG facility, of 7.5mtpa capacity, near Murmansk with feed gas coming from the Shtokman field in the Barents Sea. Plans have also been mooted to establish a facility on the Arctic Coast around the Yamal Peninsular (Baltic LNG) although as yet no firm plans have been laid.

Russia - Notes

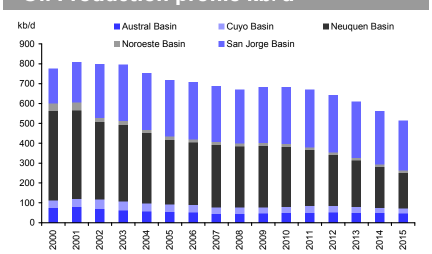
Argentina

Key facts

Oil production 2009E	**683kb/d**
Gas production 2009E	**703kboe/d**
Oil reserves 2009E	2.9bn bbls
Gas reserve 2009E	18.6TCF
Reserve life (oil)	11.8 years
Reserve life (gas)	11.9 years
GDP 2009E ($bn)	$567billion
GDP Growth 2009E (%)	-1%
Population (m)	40.1m
Oil consumption (mb/d)	594kb/d
Oil exports (mb/d)	198kb/d
Fiscal regime	T&R
Marginal (domestic) tax rate	44%
Top 3 fields (2009E)	
Loma la Lata	152kboe/d
Cerro Dragon	137kboe/d
Aguada Pichana	83kboe/d
Top 3 Producers (2009E)	
Repsol YPF	450kboe/d
BP (PAN)	137kboe/d
Bridas (PAN)	91kboe/d

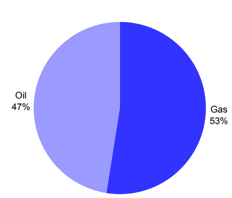
Source: Wood Mackenzie data

Oil Production profile kb/d



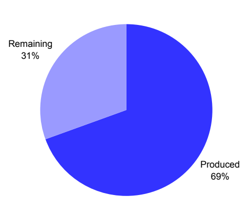
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

Although not a major oil producer, Argentina remains an important source of oil and gas production for several of the international majors. A mature hydrocarbon province, in 2009 the country produced some 683kb/d of oil and 4.2bcf/d (703kboe/d) of natural gas from reserves which, at the end of 2009 were estimated by Wood Mackenzie to stand at some 2.9bn barrels of oil and 18.6TCF of gas. Sadly the economic crisis of 2002 and subsequent government price controls have served to undermine investment in the industry, not least the development of the country's significant natural gas reserves. The leading producer in Argentina is Repsol-YPF, followed by BP (through its 60% interest in Pan American Energy) and Total.

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.

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 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 effectively 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) progress to date has been slow in the extreme. Moreover, as demand from the economy for lowly priced gas has increased, domestic gas production has struggled to make progress and Argentina has moved from a position of gas self sufficiency to one bordering on import dependence. Export contracts with Chile have been curtailed and contracts for the supply of gas from Bolivia extended. To encourage investment, the Argentine government introduced the "Gas plus" programme in 2009 which allows higher gas prices (c.$4/mmbtu vs the existing average of $1.5 to $2/mmbtu) for gas sales from new discoveries, unconventional sources or incremental production from existing areas.

Figure 422: The location of Argentina's major fields and oil infrastructure

Source: Wood Mackenzie; Deutsche Bank

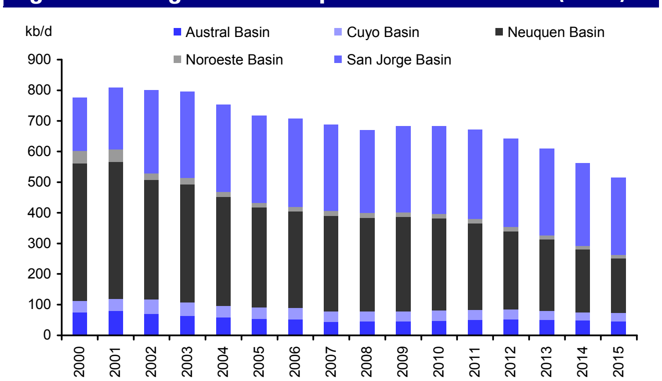
Licensing

At present the upstream sector in Argentina is regulated at the federal level by the State Secretariat for Energy. A new Hydrocarbon Law which will almost certainly give the provincial authorities greater powers is, however, under development. This follows initiatives undertaken since the late 1990s by the provinces (not least Neuquen) to gain increased autonomy over the licensing process, the result of which has essentially been the near complete cessation of license awards.

Production of Oil and Gas

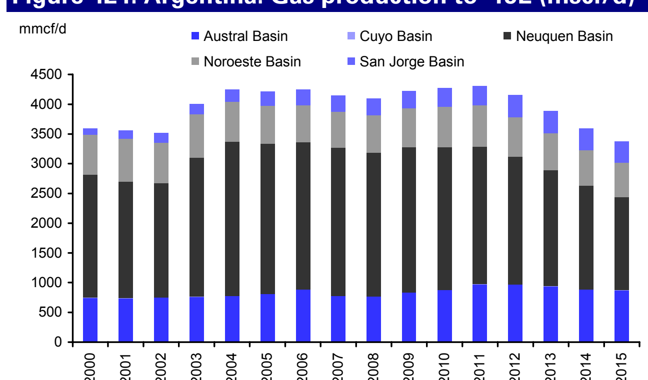
Argentina's oil fields are, by and large, very mature. This coupled with reduced investment following the economic crisis in 2002 has meant that oil production, which in 2009 stood at 683kb/d, has been declining in recent years, a trend which is expected to continue. Similar to the previously aforementioned 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. Development activity has picked up following the 2004 increase in the regulated gas prices payable by industrial customers. Nonetheless, unless the economics around gas pricing improve further investment is likely to mean that gas production will decline post 2011. This is despite the existence of both significant 2P and technical reserves. Given internal demand for gas is strong (in large part as a consequence of the low end market price) and that the country has moved from being a gas exporter to an importer with premium prices for gas being paid to Bolivia, the pressure to increase domestic prices and with them incentivise production 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 Repsol-YPF whose largest producing asset, Loma La Lata accounts for 16% of the country's gas production. BP's position in large part reflects its status as operator (through Pan American Energy) of the country's key oil producing asset, the 100kb/d Cerro Dragon field in the San Jorge Basin.

Figure 423: Argentina – Oil production to 2015E (kb/d)



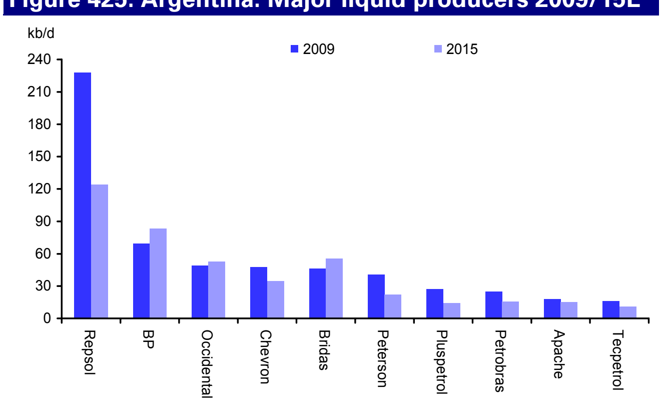
Source: Wood Mackenzie

Figure 424: Argentina: Gas production to '15E (mscf/d)



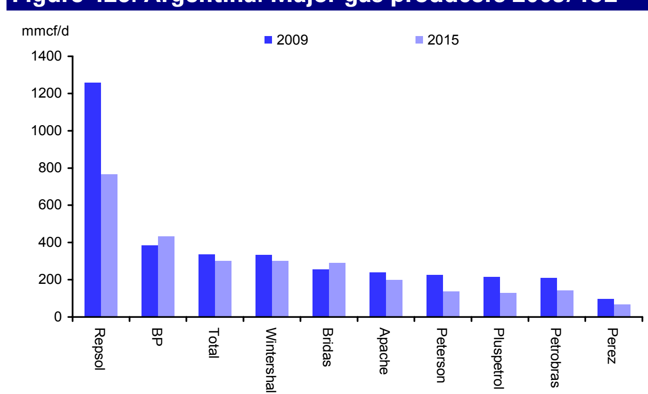
Source: Wood Mackenzie

Figure 425: Argentina: Major liquid producers 2009/15E



Source: Wood Mackenzie * through Pan American Energy

Figure 426: Argentina: Major gas producers 2009/15E



Source: Wood Mackenzie

Reserves and resources

At the end of 2009 Wood Mackenzie estimates suggest that Argentina had 2P oil reserves of 2.9bn bbls and gas reserves of 18.6TCF. 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 and the modest scale of discoveries in recent years, the country's oil reserves are not expected to grow in the onshore at least. There may, however, be some greater prospectivity in the offshore.

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 Repsol. 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 Repsol-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. As such, their ability to transport gas has, of late, been significantly curtailed. We detail below some of the more significant international pipelines.

Figure 427: Selected international 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 ten operating refineries have 640kb/d of refining capacity compared with a demand for product from the domestic market of some 594kb/d of crude oil. Utilization is consequently relatively low at around 75-80% with the simplicity of the industry's configuration limiting its ability to export product. Most of the capacity is located near Buenos Aires. Repsol-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. Shell (Dock Sud 110kb/d) and Exxon (Campana 85kb/d) also operate refineries which again are located near Buenos Aires.

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 throughout 2009 although at the time of writing the price of fuel at the pump in Argentina remains some 30-40% below comparable prices in neighbouring countries such as Chile and Brazil.

LNG

The state owned company, ENARSA, constructed a Regasification facility at Bahia Blanca GasPort located 600km southwest of Buenos Aires following the energy crisis in the winter of 2007 where gas shortages let to blackouts. The 3.1mtpa facility was fast-tracked and came on stream in June 2008 to help meet the country's increasing import requirement. At present, there are no plans to export gas via LNG.

Argentina - Notes

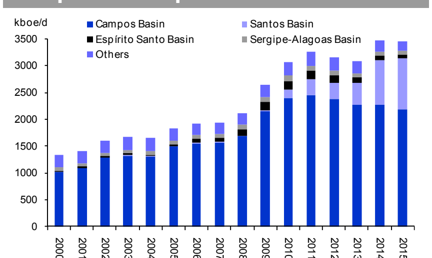
Brazil

Key facts

Oil production 2009E	1.9mb/d
Gas production 2009E	0.2mboe/d
Oil reserves (2P) 2010E	19.7bn bbls
Gas reserves (2P) 2010E	19.1TCF
Reserve life (oil)	23 years
Reserve life (gas)	28 years
GDP 2009E ($bn)	$2000bn
GDP growth 2008E (%)	0.9%
Population 2009E	192m
Oil consumption 2008E (b/d)	2.5mb/d
Oil exports 2008E (mb/d)	na
Fiscal regime	Royalty & IT
Marginal tax rate (concession)	40-65%
Top 3 Oil fields (2009E)	
Roncador	408kb/d
Marlim	382kb/d
Marlim Sul	283kb/d
Top Producer (2009E)	
Petrobras	2.5mboe/d
Shell	34kboe/d

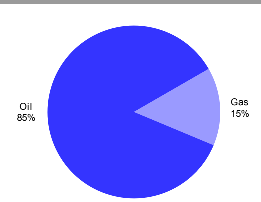
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



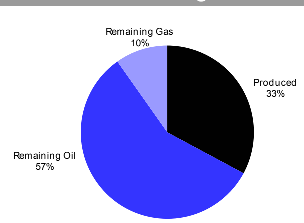
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Success in the deepwater off its Atlantic coastline, not least the prolific Campos and Santos basins, has seen Brazil's emergence as a significant oil producer in recent years. At an estimated 1.9mb/d in 2009 crude oil production is expected to continue to rise strongly with Wood Mackenzie estimating production at some 3.3mb/d by the end of this decade, so altering the country's status as an oil consumer to an oil exporter. Current reserves are estimated at 19.7bn barrels of oil and 19TCF of gas although this too is expected to improve markedly following recent exploration success, not least the discovery of 5-8bn boe Tupi in 2006. Accounting for over 95% of output, production is dominated by the 56% Government controlled oil company, Petrobras, although with the country having opened up to external investment in the late 1990s the coming years are expected to see the emergence of several IOCs, not least Shell and Chevron, as material producers. However, recent exploration success and the subsequent decision of the Government to retain certain of the more attractive prospects initially on offer in the 2007 9th licensing round, have raised questions on IOC access to Brazil's more prospective opportunities in the coming years.

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.

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 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 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.

Unsurprisingly, given its acreage position Petrobras remains the dominant production company in Brazil and in 2009 accounted for around 95% of oil production, the vast majority of refining capacity and the control of pipeline infrastructure, amongst others. Following a public offering on the NYSE, the Brazilian State reduced its interest in the business, with its stake standing at just under 56% in mid-2010. This could increase following the approval of the capitalisation bill in June 2010 depending on how many minorities take up their interests.

Urucu area in the Solimoes Basin produces 15% of Brazil's gas

Key Campos, Santos and Espirito Santo Basins

Major refineries including Brazil's largest Paulinia or REPLAN (300kb/d)

Pipelines feed in from Bolivia to Sao Paolo (BBPL) and from Argentina to Uruguaiana (TGM)

Figure 428: The location of Brazil's major basins and refining infrastructure

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 rather muted with only onshore blocks on offer while the government seeks to approve a new PSC regime for future deepwater, subsalt licenses. 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 recently approved capitalisation bill paves the way for the establishment of a new entity, PetroSal, which will be in charge of administering the new PSC regime and any contacts awarded therein.

Production of Oil and Gas

Brazil's c1.9mb/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 over 85% of output. More recently, offshore discoveries in the Espirito Santo (e.g. Golfinho) and Santos Basins (e.g. Tupi) suggest, however, that these basins will grow in significance over the coming years. Overall, oil production in Brazil has seen strong growth in recent years as the major Campos Basin discoveries of Marlim and Roncador have been brought on stream. This growth is expected to continue through the next decade as production at these key fields is ramped up and more recent discoveries in the Espirto Santo and Santos Basin developed. Indeed, with new and sizable opportunities in the pre-salt of the Santos Basin emerging, growth is, if anything, likely to prove more robust than Wood Mackenzie estimates suggest (WM forecast 10 year CAGR of 2.5%).

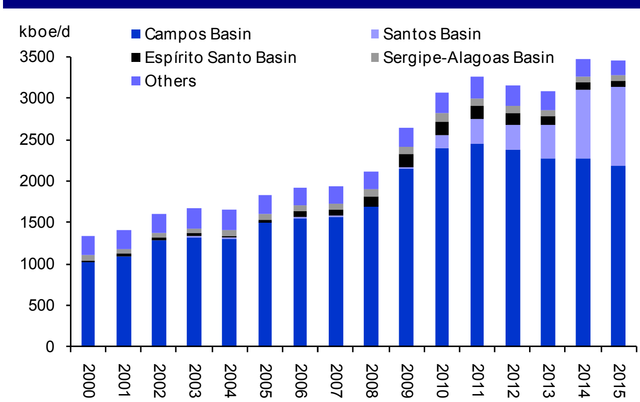
Figure 429: Brazil's major producing assets

Field	Operator	Basin	Start up	Reserves mboes	2010E kb/d	2015E kb/d	Gravity
Marlim Leste	Petrobras*	Campos	1987	637	253	115	19°API
Marlim	Petrobras*	Campos	1991	1218	392	205	21°API
Marlim Sul	Petrobras*	Campos	2001	1726	295	283	17-27°API
Roncador	Petrobras*	Campos	1999	2266	388	440	19-31°API
Barracuda	Petrobras*	Campos	2004	480	160	88	25°API
Albacora (Leste)	Petrobras*	Campos	1987	500	135	78	28°API
Tupi	Petrobras	Santos	2010	5-8000	15	467	28-30°API

*Source: Wood Mackenzie; Deutsche Bank * All 100% operated and owned*

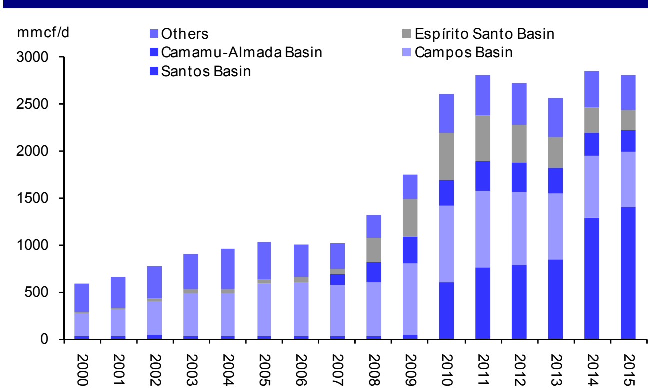
In general, production of gas has been from oil-associated fields, with only two non-associated onshore gas fields developed. Despite the country's growing demands for gas, poor infrastructure has, however, meant that around half of the gas produced is either flared or re-injected. Overall, gas production is less concentrated than that of oil with significant volumes coming from the Espirito Santo, Campos and Camamu-Almada basins. The Santos basin in particular is expected to see the development of >1bcf/d of output over the course of the next few years as two significant fields (BS-500 Pole and Mexilhao) come on-stream.

Figure 430: Brazil oil production 2000-15E (kb/d)



Source: Wood Mackenzie

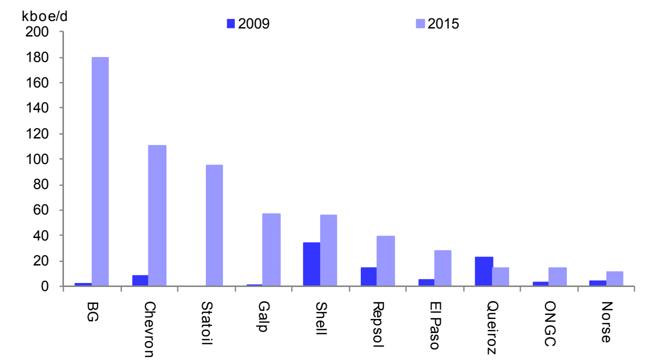
Figure 431: Brazil gas production 2000-15E (mscf/d)



Source: Wood Mackenzie

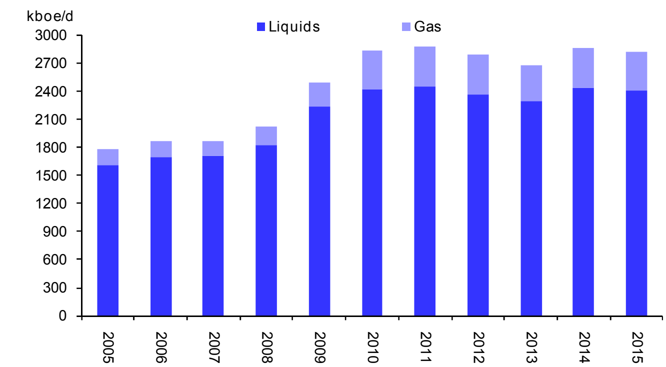
As mentioned, production of oil and gas is dominated by the state oil company, Petrobras which accounts for comfortably over 90% of both oil and gas volumes. Although Petrobras' dominance is unlikely to change, the start up of several additional fields in the Campos, not least Shell's BS-4 RDS' and Chevron's Papa-Terra plus the start-up of the giant Tupi field at the end of 2010 (BG Group and Galp), will see the Brazilian offshore become a more important part of the IOC major's portfolios.

Figure 432: Brazil: Major hydrocarbon producers 2009/15E excluding Petrobras



Source: Wood Mackenzie,

Figure 433: Petrobras: Hydrocarbon production in Brazil 2009-15E



Source: Wood Mackenzie

Reserves and Resources

At the end of 2009 Wood Mackenzie estimates suggest that Brazil had 2P reserves of 19.7bn barrels and 19TCF 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. 49% of commercial oil reserves are based in the Campos basin, with a further 47% located in the Santos basin. Gas reserves are somewhat less concentrated but again the Campos (14%) and Santos (61%) dominate. With exploration efforts continuing on the Santos basin we would expect reserves growth to continue over the coming years. The Tupi pilot project (due to start-up late 2010) will be very telling in terms of the operational challenges, costs and timelines it will take to commercialise these vast reserves.

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 two oil pipelines carrying oil to shore are in place although capacity is relatively limited. Otherwise, pipeline systems do connect the remote onshore basins with the major centres of demand (production is, however, modest). Similarly, gas infrastructure is under developed, covering mainly the urban centres of Rio and Sao Paolo. Recent years have, however, seen investment in 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. There are also plans to investigate the viability of FLNG as a means of commercialising gas reserves in the deepwater Santos basin as opposed to constructing pipeline.

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. 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 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).

Finally, it's worthwhile noting the Brazilian government are in the process of drafting and approving a new PSC fiscal regime for all future contracts awarded.

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, with Repsol the only international major with any kind of material presence. In recent years, Petrobras announced ambitious plans to expand the country's refining capacity and several projects are already underway (or in planning) that will add c.1.2mb/d of new capacity. Of the existing 13 refineries, over 60% is associated with the county's five largest facilities not least the 365kb/d Paulina facility located near Sao Paolo.

Figure 434: 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. Initial reports suggest a design capacity of 2.7mtpa. A Final Investment Decision is not expected until the FEED study is completed along with an analysis of other commercialisation routes. We do not expect a FID until 2012 at the earliest.

Brazil – Notes

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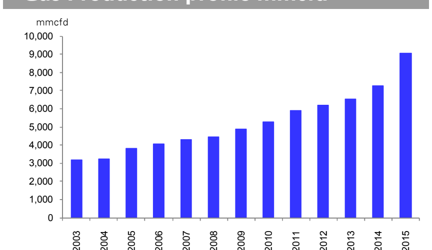
Australia

Key facts

Liquids production 2009E	0.559mb/d
Gas production 2009E	0.77mboe/d
Oil reserves 2009E	4.2bn bbls
Gas reserve 2009E	108.7TCF
Reserve life (oil)	14.2 years
Reserve life (gas)	69.1 years
GDP 2009E ($bn)	799
GDP Growth 2009E (%)	2.3%
Population (m)	22
Oil consumption (mb/d)	0.219
Fiscal regime	Tax & Royalty
Top Gas Projects (2009E)	
North West Shelf Venture	2,722mmcf/d
Bass Strait	465mmcf/d
Cooper Basin	395mmcf/d
Top 3 Gas Producers (2009E)	
BHP	702mmcf/d
Woodside	592mmcf/d
Santos	517mmc/d

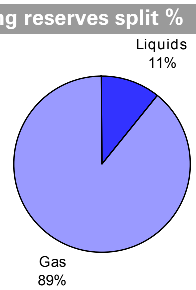
Source: Wood Mackenzie; IMF; BP statistical Review 2010

Gas Production profile mmcfd



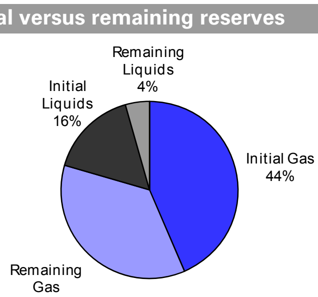
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Predominantly a gas province, Australia's gas reserves are estimated to have stood at 109TCF at the end of 2009, the second highest in Asia Pacific after Indonesia and thirteenth 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 some 559kb/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 c.64% 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. The country commenced oil production in the early 1960's following the discovery of significant liquids in the Gippsland Basin. In 1969 the gas market took off with gas produced at ExxonMobil's Bass Strait in the southeast being sold to nearby Victoria. However, production gradually moved northwest with the discovery of the Cooper basin fields and the commissioning of the Moomba-Adelaide pipeline. Gas production was further boosted with the discovery of Dongara (Perth Basin) followed by the large offshore North Rankin Field (Carnarvon Basin) in 1984.

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.

Darwin LNG in the Bonaparte basin

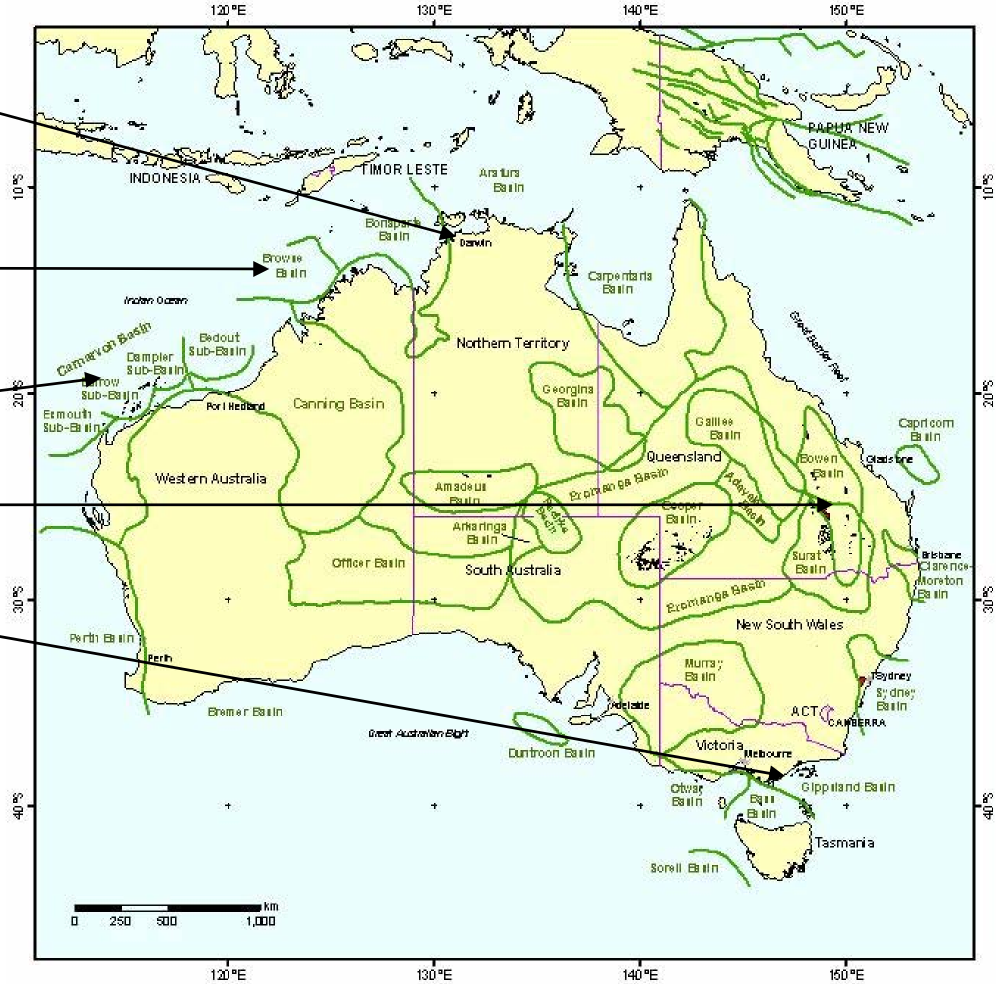
The Browse Basin: source of many large planned conventional LNG projects

The North West Shelf gas project in the Carnarvon basin

Key CSG regions: the Bowen and Surat basins

The Bass Strait in the Gippsland Basin

Figure 435: 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, however, this requirement was 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.

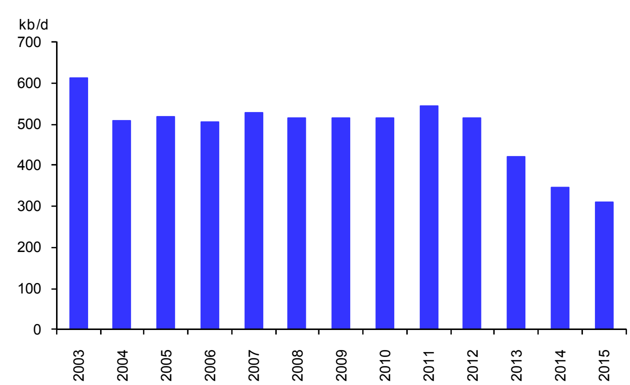
Onshore licensing, which comes under State jurisdiction, is administered by the relevant State Authority thus licensing legislation can vary considerably. Although some States conduct formal annual licensing rounds, in general exploration blocks can be applied for at any time. The table below illustrates 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 the time of writing, LNG production is concentrated on just two main gas projects producing around 20mtpa, namely Darwin LNG (Conoco, ENI) and, more significantly the five train 16mtpa North West Shelf Venture, (NWSV) which accounts for 54% of Australia's current gas production and is run by a consortium of six companies (Woodside, Shell, BP, Chevron, Japan Australia LNG and BHP Billiton). However, the next five or so years are expected to see the development of a further 40mtpa of LNG capacity as a number of intended LNG projects reach completion. As a consequence gas production is set to rise sharply with Wood Mackenzie estimating gas production growth of c.11%pa out to 2015. 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. ExxonMobil is the third largest producer with Chevron, BP and Shell other key IOC's operating in the region.

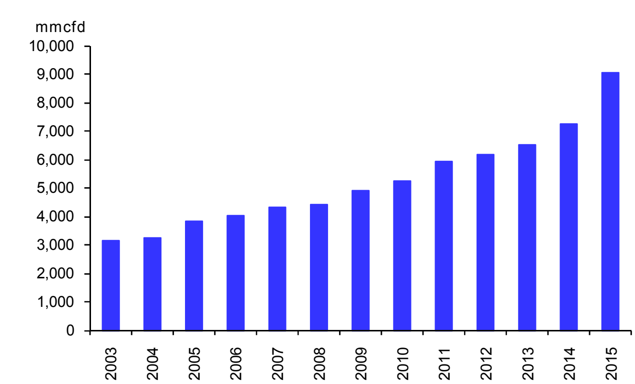
Conversely, oil production remains in decline, a trend that is not expected to reverse in the near term. The Bass Strait whose production has halved over the past decade still represents a significant 19% of oil production. Similarly, liquids production on the North West Shelf is thought to have peaked in 2009. Looking forward Australia's liquids production is likely to increasingly arise from the output of condensates associated with its large gas fields.

Figure 436: Liquids production 2003-15E (kb/d)



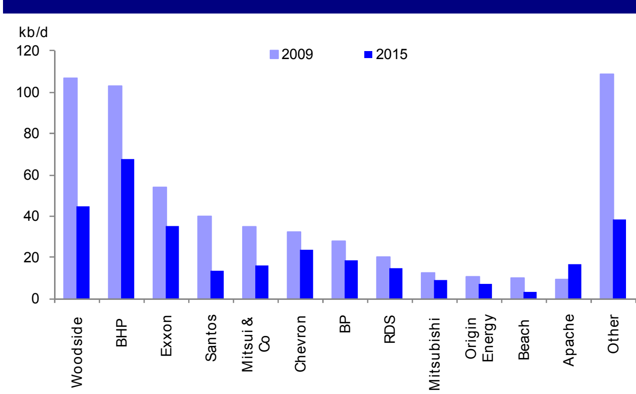
Source: Wood Mackenzie

Figure 437: Gas production 2003-15E (mmcfd)



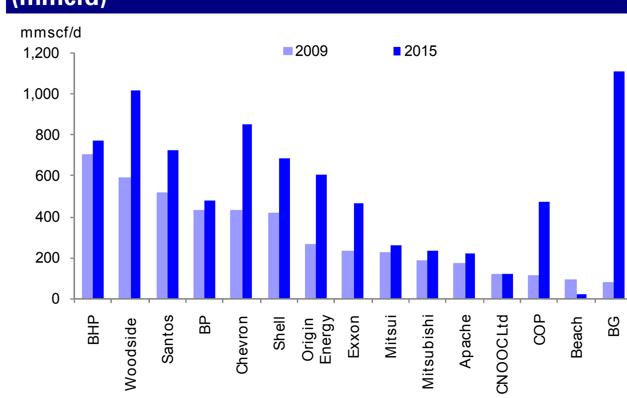
Source: Wood Mackenzie

Figure 438: 2009/15 Liquids prod'n by company (kb/d)



Source: Wood Mackenzie

Figure 439: 2009/15 Gas production by company (mmcfd)



Source: Wood Mackenzie

Reserves and resources

Australia's total remaining gas reserves are estimated at approximately 4.2 billion barrels of liquids and 109 TCF 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 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 some 17% of the total gas reserves. Given the youth of Australia's oil and gas industry and the fact that is remains relatively under-explored, exploration efforts could yield further reserve increases in the future.

Pipelines and infrastructure

Given the sheer scale of Australia's land mass and the distance between the main sources of production and delivery, Australia has extensive infrastructure. Over 11,000km of pipeline have a combined capacity of 2930mmcfd, the more important of which are tabulated below:

Figure 440: Australia's key gas pipelines

Pipeline	Operator	From	To	Length (km)	Diameter (inches)	Capacity (mmcfd)
Moomba to Adelaide	Epic Energy	Moomba Gas Plant (Cooper Basin)	Adelaide	781	22	398
Moomba to Sydney	Australian Pipeline Trust	Moomba Gas Plant	Wilton	1375	34	550
DBP – Dampier to Bunbury (Perth)	Babcock & Brown Infrastructure	Withnell Bay (NWS)	Bunbury	1547	26	672
SEA Gas Pipeline	SEA Gas	Iona (Queensland)	Adelaide	690	18	323

Source: Wood Mackenzie, Deutsche Bank estimates

Crude oil blends and quality

Given the fact that Australia's oil production has peaked and its importance lies in its vast gas reserves, it is a net importer of oil. 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. With the main exception of the CSG to LNG projects fields that are located onshore or fall within state boundaries are by contrast subject to royalty together with corporation tax. 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.

Refining

Australia has seven major refineries with a total crude oil capacity of 696kbbl/d, with feedstock mainly coming from oil produced in the Bass Strait. As liquids production continues to decline, these refineries look set to become increasingly dependent upon imported crude. With Australia's demand for crude oil and products estimated at 940kb/d the country remains dependent upon the import of products in order to meet its demand requirements.

Figure 441: Australian Refineries

Name	Location	Owners	CDU capacity (kb/d)
Altona	Melbourne, Victoria	ExxonMobil	78
Bulwer Island, Brisbane	Brisbane, Queensland	BP	97
Clyde	New South Wales	Shell	82
Geelong	Geelong, Victoria	Shell	122
Kurnell (Caltex)	Sydey, NSW	CVX (50%), Other (50%)	127
Kwinana	Kwinana, Perth	BP	130
Lytton	Brisbane, Queensland	CVX (50%), Other (50%)	103

Source: Wood Mackenzie

LNG

Currently the world's fifth largest LNG exporter, Australian LNG exports have risen by almost 50% over the last decade. The two 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 aiming to take FID as early as end 2010 and targeting first production as early as 2014. We outline below the key existing, under construction and planned LNG projects below.

Figure 442: 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	18.3	515	16.3	1989	Woodside*, BHP, BP, Chevron, MIMI, Shell (all 16.7%)
	Darwin LNG	Bonaparte	3.0	214	3.6	2006	COP* (57%), Santos (11.4%), INPEX (11.3%), Eni (11%).
Under Construction	Pluto	Carnarvon	4.8	55	4.8	2011	Woodside* (90%), Kansai (5%) and Tokyo Gas (5%)
	Gorgon	Carnarvon	43.4	276	15	2014	Chevron* (50%), ExxonMobil (25%), Shell (25%)
Planned Offshore (conventional)	Ichthys	Browse Basin	12.2	527	8.4	2016	INPEX* (76%), Total (24%)
	Wheatstone	Carnarvon	10.6	154	8.6	2016	Chevron* (75%), Apache (16.25%), KUFPEC (8.75%)
	Browse	Browse	13.3	350	12.0	2018+	Woodside (50%)*, BHP (8.3%), Shell (8.3%), BP (16.7%), Chevron (16.7%)
	Greater Sunrise	Bonaparte	5.8	295	4.8	2018+	Woodside (33%)*, Shell (27%), COP (20%), Osaka (10%)
Planned Onshore (CBM)	Curtis	Surat	11.0	-	8.5	2014	BG (95%)*, CNOOC, Tokyo Gas
	Gladstone	Surat	1.4	-	1.5	2014	Liquefied Natural Gas Limited (60%)*, Golar LNG (40%)
	GLNG	Bowen/Surat	5.1	-	3.6	2014	Santos (60%)*, Petronas (40%)
	Australia Pacific	Bowen/Surat	3.8	-	7	2016+	COP(50%)*, Origin Energy (50%)
Planned Offshore FLNG	Prelude	Browse basin	3.3	150	3.6	2017	Shell (100%)*

Source: Wood Mackenzie

Australia - notes

Major OPEC Producers

Angola

Iran

Iraq

Kuwait

Libya

Nigeria

Saudi Arabia

UAE

Venezuela

Qatar

Major OPEC - Notes

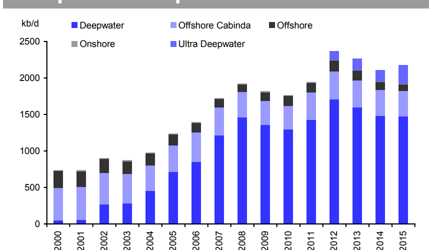
Angola

Key facts

Oil production 2009E	1.8 mb/d
Gas production 2009E	NIL
Oil reserves 2009E	12bn bbls
Gas reserves 2009E	8TCF
Reserve life (oil)	18.7years
Reserve life (gas)	n.a.
GDP 2009E ($bn)	$107bn
GDP growth 2009E (%)	1.8%
Population 2009E	17.3m
Oil consumption 2008E (b/d)	67kb/d
Oil exports 2008E (mb/d)	1,948kb/d
Fiscal regime	Offshore-PSC, Onshore-T&R
Marginal tax rate (concession)	72.5%
Top 3 Oil fields (2009E)	
Kizomba A	200kb/d
Dalia_Camelia	192kb/d
Kizomba B	184kb/d
Top Producers (2009E)	
Sonangol	197kb/d
BP	183kb/d
ExxonMobil	148kb/d

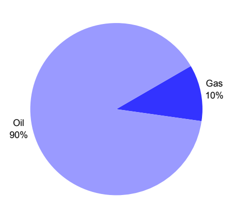
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



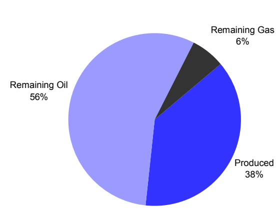
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Although Angola's admission to OPEC membership in 2007 with a 1.9mb/d production quota has raised some uncertainties over the future pace of its development as a major oil producer, the successful discovery in the deepwater of over 12 billion barrels suggests an outlook of continued strong production growth over the medium term. Complemented by ongoing production of around 350kb/d from the Chevron-operated shallow waters of the Cabinda enclave to the north of the country, developments in a host of deepwater blocks not least by Exxon in Block 15, Total in Block 17 and BP in Block's 18 and ultra-deep 31 offer the potential for some 1.6mb/d of crude oil production by 2012. This will be complimented by the planned 2012 start up of the country's first LNG facility, to be operated by Chevron with nameplate capacity of some 5.2mtpa. Key producers include Exxon, Total, BP and Chevron together with the 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, namely the Congo, the Kwanza and the, yet to be explored, Namibe. Key to current production is the Congo Basin which contains the entire Cabinda enclave as well as deepwater blocks 14-18 which lie in water depths of 1200-1500m. To date, discoveries and production from the largely onshore Kwanza Basin have been relatively modest.

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 of recoverable reserves, not least those in Exxon-operated Block 15 (3bn barrels) and Total-operated Block 17 (c4bn 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 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 2.4mb/d by 2012.

Figure 443: The location of Angola's major basins and refining infrastructure

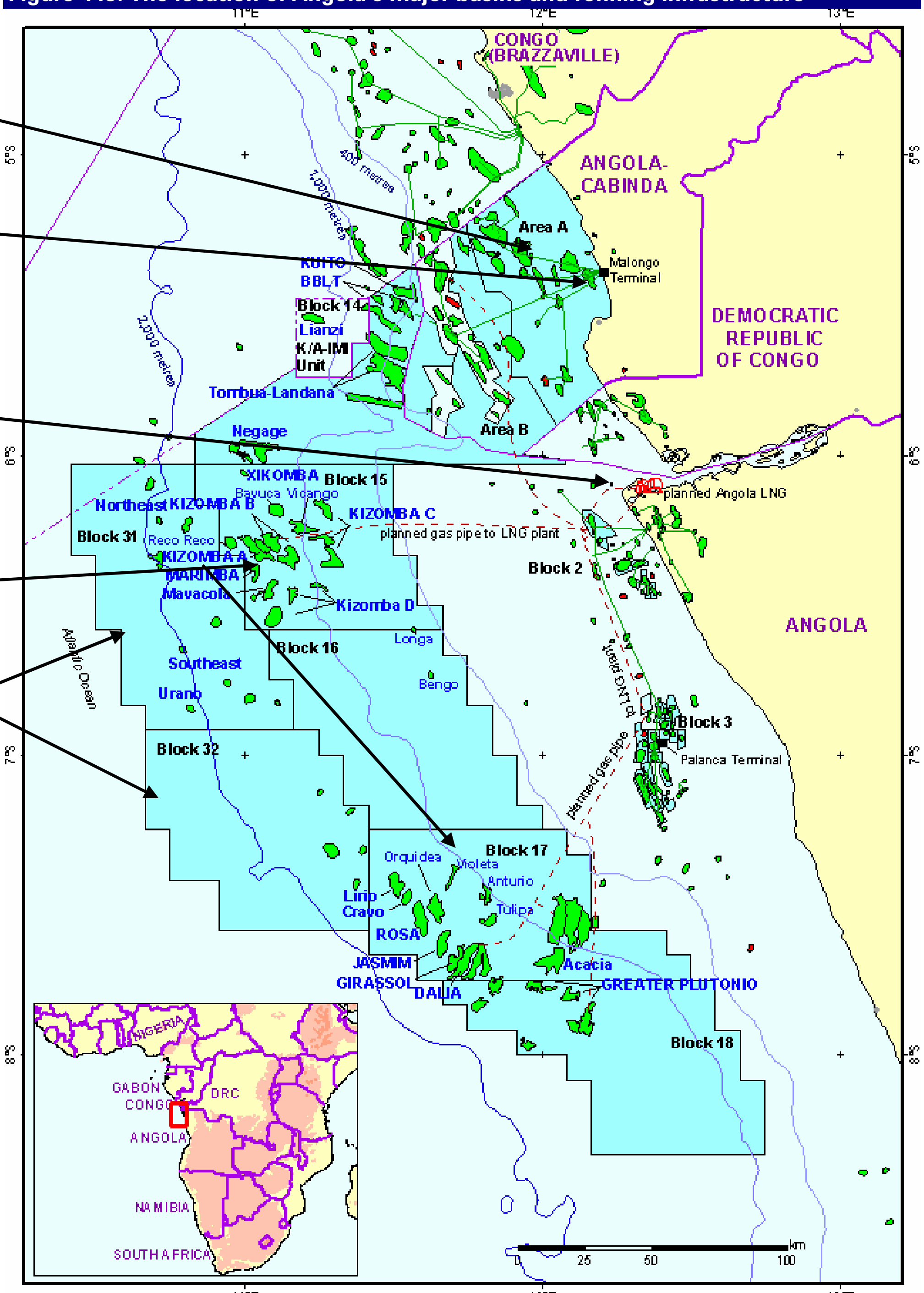
Key shallow water Cabinda A&B concession areas (Chevron operated)

Malongo terminal and shipping point for Cabinda production

Planned 5.2mtpa LNG facility at Soyo

Key deepwater blocks 15 (Exxon) & 17 (Total)

Ultra-deepwater Blocks 31 (BP) and 32 (Total)



Source: Wood Mackenzie; Deutsche Bank

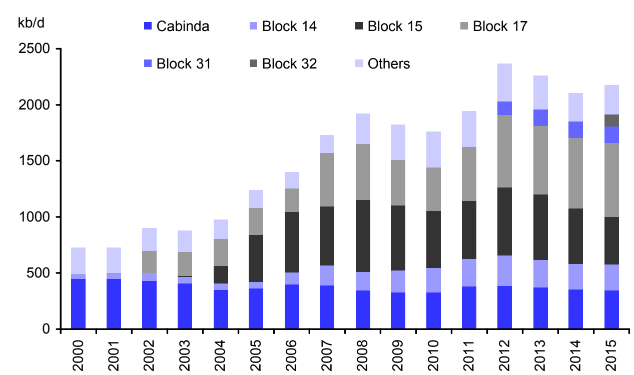
Licensing

The principle 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 thru 30, again of around 4,000 km² 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. Through various licensing rounds, the latest of which took place in 2006 when several relinquished territories in the shallow and deepwater were re-licensed, Sonangol has set in place a series of production sharing contracts for the exploration and production of oil. License awards depend upon the signature bonus offered, with Sonangol often taking an equity interest in the awarded Block. This interest will typically be carried through the exploration phase.

Production of Oil and Gas

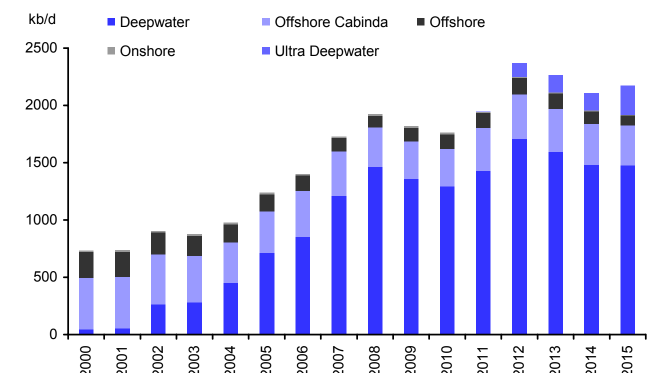
In 2009 oil production in Angola was estimated at 1.8mb/d. This has the potential to expand aggressively with current plans for developments suggesting a production peak by 2012 of some 2.4mb/d, subject to OPEC quota restrictions. Following OPEC quota cut in 2009, Angola's production quota in 2010 is indicated at c.1.5mb/d (from official quota of 1.9mb/d) with the country's official ability to drive growth therefore dependent upon the extent to which its quota sees expansion (assuming of course, Angola's intent to comply). Evidenced below, the key producing Blocks are Exxon operated Block 15, the production from which is expected to peak at 601kb/d in 2012 and Total's Block 17 (the so-called 'Golden Block') with peak production of 657kb/d in 2015. First production from BP's ultra-deepwater Block 31 is anticipated in 2012 with that from Total's Block 32 following in 2015.

Figure 444: Angolan oil production 2000-15E by Block (kb/d)



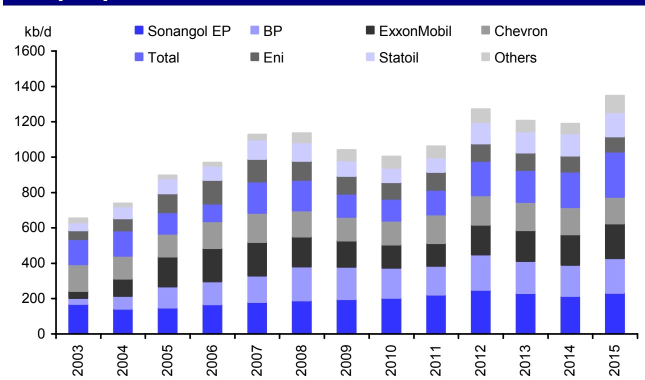
Source: Wood Mackenzie

Figure 445: Angolan oil production 2000-15E by location (kb/d)



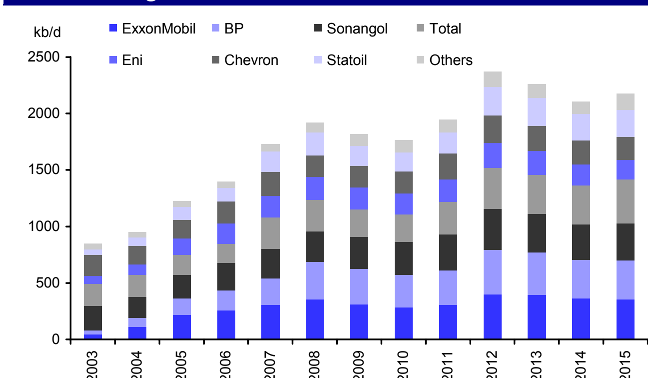
Source: Wood Mackenzie

Figure 446: Angolan oil production 2003-15E by company on an entitlement basis (kb/d)



Source: Wood Mackenzie

Figure 447: Angolan oil production 2003-15E 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. Although 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 by 2012. 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 2012 planned 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 2009 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. Although no sales gas is produced, Angola has estimated proven and probable reserves of high quality gas in its offshore licenses of around 8TCF, most of which is re-injected to aid oil recovery. 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. Sonangol intends, however, to develop a pipeline network such that gas can in future be supplied to the planned 5mtpa Angolan LNG facility (see later). Initially this will see the development of a pipeline in the shallow water Cabinda area near the proposed Soyo LNG site.

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 (or 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 $25.55/bbl in 2010). For the purposes of TTP an investment allowance or uplift equating to 50% of capital spend is also allowable.

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 4 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 (as illustrated below) with capital uplift reduced and the trigger points for a change in the share of profit oil based on lower project IRRs.

Figure 448: Change in Angolan Deepwater terms upon re-licensing

License	Block 15 initial	Block 15/06 re-license	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

Refining and Downstream markets

Angola presently has one refinery based in Luanda with a capacity of c63kb/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 (expected to cost c$3.75bn) the construction of a new 200kb/d refinery at Lobito in Southern Angola. The refinery which was expected to come on stream in 2012 was put on hold following the break-down of talks between Sinopec and Sonangol.

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 by early 2012. 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%). Despite much discussion and several years of planning, FID was only taken in December 2007 with the delay owing, in part, to the significant anticipated costs of both construction and laying down the necessary infrastructure to gather gas from the producing fields in Cabinda and Blocks 14, 15, 17 and 18 and transport it to shore. Note that the LNG produced is expected to be delivered to the Pasaguola re-gas terminal in Mississippi where it will be purchased as natural gas for marketing in the US by the respective partner's US gas marketing operations. Given that the project requires a gas price estimated at nearer $7/mmbtu to achieve an economic return we expect alternative end markets to be sought.

Angola - Notes

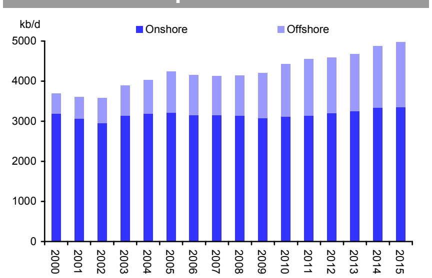
Iran

Key facts

Oil production 2009E	4.2mb/d
Gas production 2009E	2.5mb/d
Oil reserves 2009E	136 bn bbls
Gas reserve 2009E	948TCF
Reserve life (oil)	88 years
Reserve life (gas)	172 years
GDP 2009E ($bn)	830 bn
GDP Growth 2009E (%)	3.1%
Population (m)	74.1m
Oil consumption (mb/d)	1.74 mb/d
Oil exports (mb/d)	2.4 mb/d
Fiscal regime	Buybacks
Marginal tax rate	n/a
Top 3 fields (2009E)	
South Pars	1,512kboe/d
Ahwaz	877kboe/d
Parsian Gas	568kboe/d
Top 3 Producers (2009E)	
NIOC	5,319kboe/d
Petro Pars	88kboe/d
Eni	17kboe/d

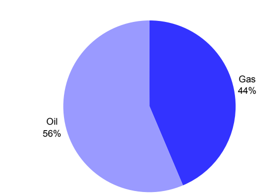
Source: Wood Mackenzie, EIA, IMF

Oil Production profile kb/d



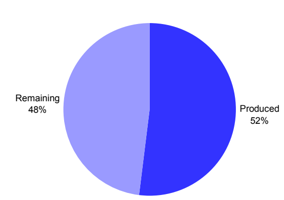
Source: Wood Mackenzie data

Remaining reserves split %



Source: Wood Mackenzie data

Initial versus remaining reserves



Source: Wood Mackenzie data

With 2009 crude production of around 4.2mb/d Iran is the fourth largest producing nation in the world, behind Saudi Arabia, Russia and the US, and the second largest within OPEC. Its potential production is higher; proven oil reserves of 136 billion bbls (c.10% of the world total) imply a reserves life of over 88 years and ordinarily would indicate an opportunity for production growth. Unfortunately such growth requires massive investment and the participation of the IOCs, and this is not currently occurring in sufficient scale. The reasons include 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, international concerns over Iran's nuclear ambitions and the general inefficiencies associated with a massive state controlled oil company. With these issues unlikely to change in the short term, Iran's production target of 5 million b/d by 2015 looks optimistic, especially since underlying decline rates at the core producing fields are thought to be at least 7% p.a. Main IOCs with exposure to Iran include Eni, and Statoil.

Basic geology and topology

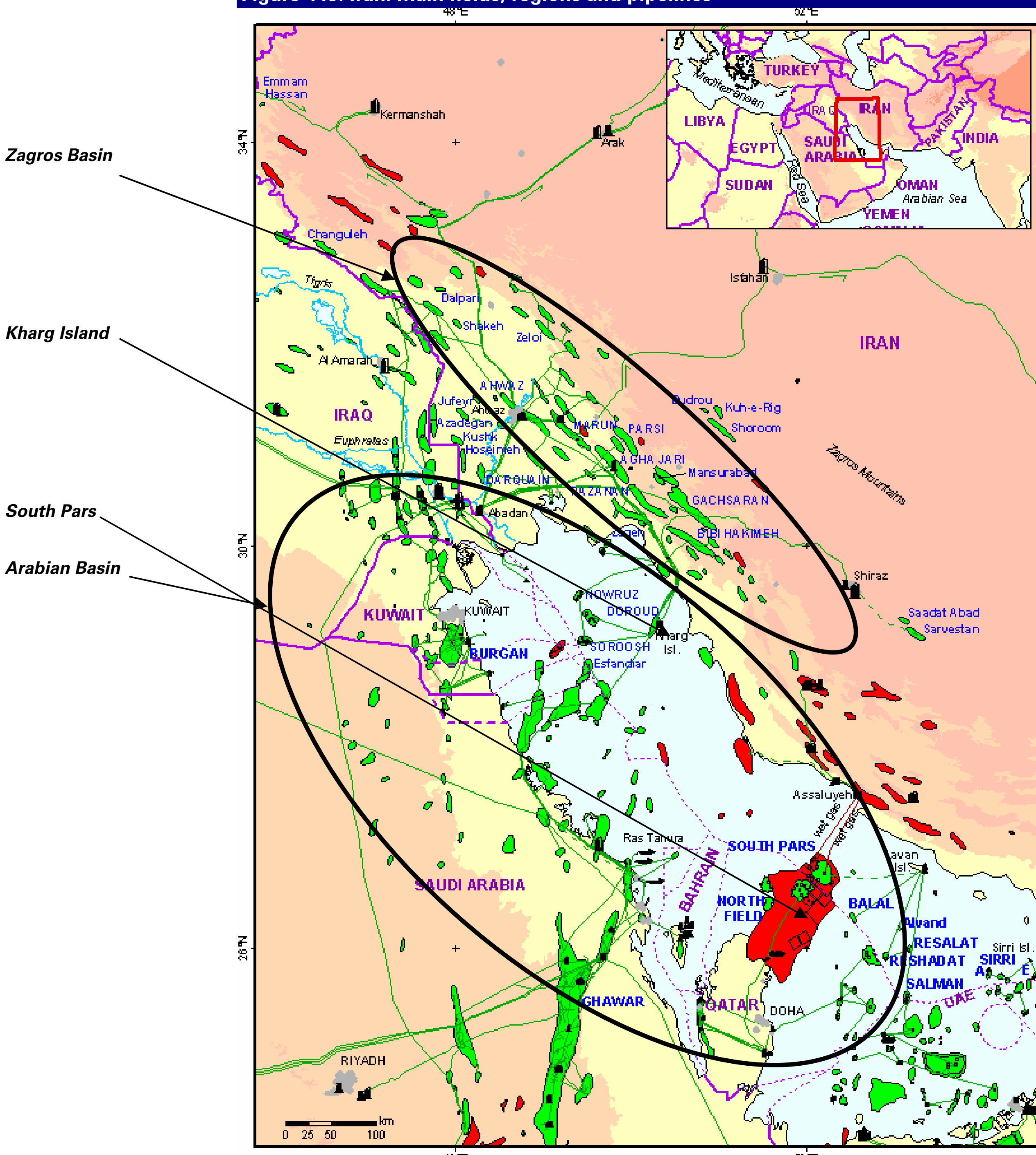
Two areas dominate Iran's hydrocarbon production; the Arabian and Zagros basins. Both basins contain a high proportion of giant and super giant oil and gas fields, and numerous smaller reservoirs and prospective structures. The Arabian basin extends roughly South West from Iran's Gulf Coast and goes 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 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 up 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 the 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. The US Iran-Libya Sanctions Act (ILSA) prevents US companies from investing in Iran and this act was rolled over in 2006 to extend until 2011 (although now renamed the Iran Sanctions Act).

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.

Figure 449: 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.3.8mb/d in 2009, however the giant South Pars gas field provides NGLs to the extent of another c.0.4mb/d, taking total liquids production to c.4.2mb/d. The largest oil producer is the giant onshore Ahwaz field (c.854kb/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, currently 150kb/d), South Pars 2&3 (Total, currently 112kb/d), South Pars 4&5 (Eni, currently 112kb/d), Darquain (Eni, currently 110kb/d), and Doroud (Eni, Total, currently 150kb/d) amongst others. Without buyback contracts with IOCs Iran would have likely at best posted flat production from the late 1990s onwards, and the fact that additional such contracts are not being signed in the current environment leaves the future production profile at 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 US sanctions further hamper IOC involvenment.

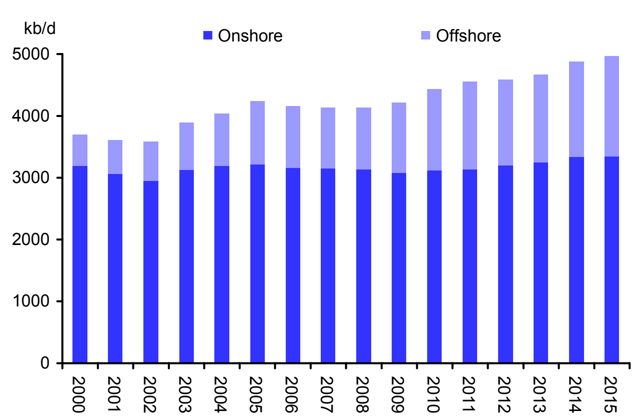
Figure 450: Key Fields in Production

Fields	Remaining Reserves (mmbbl)*	Production 2009 kb/d	Production 2015 kb/d
South Pars**	6,394	389	809
Ahwaz***	5,546	855	760
Gachsaran	4,148	470	500
Marun Fields	2,693	512	368
Karanj-Parsi	2,217	310	320
IOOC Fields	1,913	374	321

*Source: Wood Mackenzie. * As at 1.1.2010; Proven plus Probable; total liquid. **South Pars includes fields 1-18*** Ahwaz and Ahwaz Area fields*

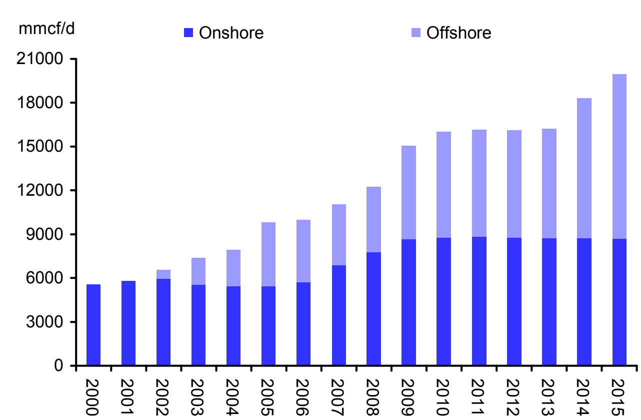
In Wood Mackenzie's scenario (which we regard as a best possible outcome) Iran's overall liquids production is forecast to increase steadily out to 2015 (at c.2.8% p.a.). Most of the net growth in liquids production is the result of the planned increase in condensate production from the South Pars field. Conventional oil production is forecast to increase slowly, at best.

Figure 451: Iran liquids production, 2000-2015E (kb/d)



Source: Wood Mackenzie ; Deutsche Bank

Figure 452: Iran gas production, 2000-2015E (mmcf/d)



Source: Wood Mackenzie; Deutsche Bank

Gas production has historically been associated with onshore oil fields; however non-associated gas fields have been developed from 1983 onwards. The significant increase in gas production that has occurred from 2002 onwards is mainly due to the various South Pars phases coming on-stream – some of this production is used for re-injection into ageing onshore oilfields.

IOCs have made significant investments in Iran over the last ten years, but a combination of high oil prices and the buyback contract model means that the current IOC exposure by production is insignificant; in 2009 Eni was estimated to be the highest, receiving 16.9kboe/d via buyback contracts, followed by Statoil with 10.7kboe/d and then Shell with 5.3kboe/d.

Reserves and Resources

Iran's stated proven oil reserves are at 136 bn bbls. The offshore Arabian basin and the onshore Zagros basin contain over 90% of these 2P reserve estimates, with some small prospectivity thought to also exist in the largely unexplored South Caspian Sea.

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 Azadegan, Kushk, Housseineh and Anaran. 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 of perhaps a similar scale. 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

Iran has the second largest gas reserves in the world after Russia. With the massive South Pars field's 870TCF (150bn boe) of 2P reserves largely untapped as yet, Iran has a gas reserves life of over 170 years. As with oil, there is plenty of scope, from a resource perspective, to increase production.

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 pipelines 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. NIOC has stated that it expects as much as 1.6m b/d of Caspian crude to 'cross' its territory by 2010.

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 2.0bcf/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 construction of IGAT-5 and IGAT-6 were completed and 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.

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 453: 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 has to seek final approval from the Ministry for Oil. Foreign companies can only invest 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. The problem today is that with a current environment of industry-wide cost escalation, committing to a certain capex level with no hope of a decent return in the face of any cost overrun is not a risk most IOCs are willing to take. There is 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 1.65mb/d split among nine refineries. Although it plans to add seven more refineries, only two have progressed beyond the initial stage. 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 optimistic at present.

Figure 454: Main refineries in Iran

Operator	Refinery	Capacity (Kb/d)
National Iranian Oil Company	Abadan Refinery	360
National Iranian Oil Company	Arak Refinery	150
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	240

Source: Wood Mackenzie

A surprising statistic is that as much as 40% of the country's total gasoline consumption is met by imports. The planned refinery capacity expansion is 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 of merely 42cents/gallon. In order 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 same period), the government introduced gasoline rationing in 2007. Although, this saw fuel demand fall by 16% within a year, demand is now back to pre-rationing levels following the government's decision to allow consumers to buy at unsubsidised prices (i.e. market price).

LNG

The huge South Pars gas field is an obvious candidate for Iran to enter the world as a major supplier of LNG, however to date progress has been far less than has been seen in Qatar, which shares South Pars (known by Qatar as the North Field). Four projects are currently on the drawing board:

- Pars LNG – a 10mmtpa liquefaction plant using gas from South Pars phase 11 (Total, Petronas and NIGEC).
- NIOC LNG – another 10.5mmtpa plant to use phase 12 gas (NIOC, OMV).
- Persian LNG – a 16mmtpa plant to use gas from phases 13 and 14 (NIOC).
- In 2006 an MOU was signed between CNOOC and NIOC to develop a 20mmtpa facility.

Quite aside from US 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. If bids are submitted, they are thus far higher than NIOC can understand.

Pars LNG is thought to be the most advanced of the projects, but FID has not been taken and the project status is still highly uncertain.

Various MOUs have been signed by Iran to supply LNG, including to Sinopec, India (2009), PTT (Thailand, 2011) and Petrochina. None however looks likely to be fulfilled at this time.

Iran - Notes

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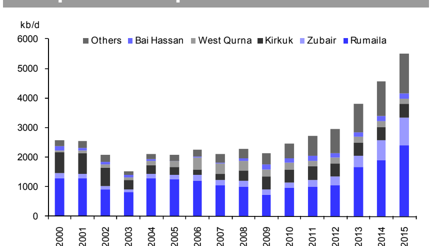
Iraq

Key facts

Oil production 2009E	**2.5mb/d**
Gas production 2009E	0.1mm**boe/d**
Oil reserves	115bn bbls
Gas reserves	112TCF
Reserve life (oil)	126 years
Reserve life (gas)	365 years
GDP 2009E ($bn)	$112bn
GDP growth 2009E (%)	6%
Population (m)	31.2m
Oil consumption 2008E (b/d)	616b/d
Oil exports 2008E (mb/d)	1.8mb/d
Fiscal regime	Concession and PSC
Marginal tax rate (concession)	35%
Top 3 Oil fields (2009)	
North & South Rumaila	1010kb/d
Kirkuk	390kb/d
West Qurna	260kb/d
Top Producer (2009E)	
INOC	2.1mb/d

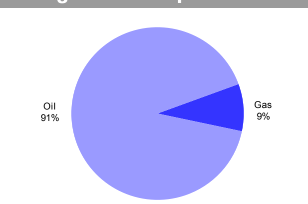
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



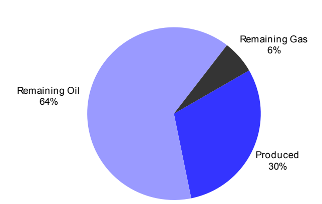
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Iraq contains the world's fifth largest proven petroleum reserves. However, only a fraction of its known fields are in development given continued internal political problems and external regional conflicts which have constrained its production capacity over the past 30 odd years. According to the BP Statistical Review of World Energy, total estimated oil reserves are around 115 billion barrels. However, 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 (2.5mb/d) is mostly derived from Iraq's three main oil fields and all production and refineries are owned and operated by the State owned Iraq National Oil Company (INOC). Western participation in production is currently marginal although following the 2009 licensing rounds this is set to change, albeit participation will be limited to service contracts only.

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

Despite several years having passed since the start of the 2003 Iraqi war, the regulatory structure of the Iraqi oil sector post-Saddam is still evolving. Legislation governing the country's future hydrocarbon industry has been subject to detailed on-going 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 in February 2007, however, a breakdown in relations between the KRG (Kurdistan Regional Government) and the Oil Ministry has prevented any meaningful progress. Different views are held by each of the main political parties on the most contentious elements of the proposed legislation, particularly those concerning the equitable distribution of revenue, the role to be played by the Iraq National Oil Company (INOC) and the IOCs, Kurdish sovereignty and who will have the authority to negotiate and sign contracts for future developments (federal or regional government). It was hoped that the law will be resubmitted to parliament following the 2010 national elections, however, with the country yet to agree on a government post the March elections this time line looks like it could be pushed further out.

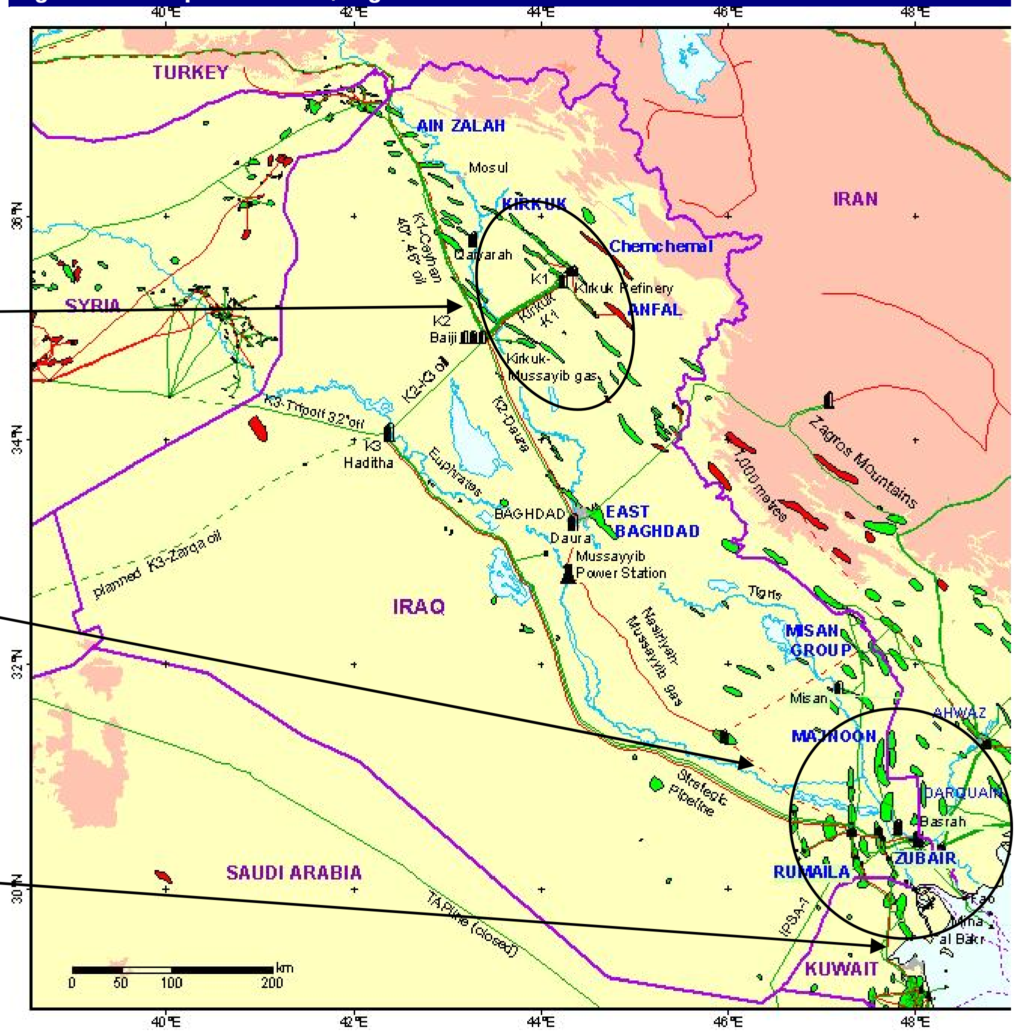
Historically, Iraq's oil industry has been plagued by political instability, manifested primarily in wars. Subsequent to Iraq's invasion of Kuwait in 1990, the UN comprehensively embargoed Iraq of all trade save that approved by the UN for humanitarian goods, leading to the 'Oil-for-Food' programme in 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 Iraqi war in 2003, but have since been lifted. It goes without saying that any regulation and future production will inevitably depend on the resolution of Iraq's internal security situation. While violence has fallen sharply since 2007, attacks do continue. This, couple with the political unrest means it is likely that the political future of Iraq will remain turbulent for some time to come.

Figure 455: Iraq: Main fields, regions and basins

Kirkuk and the Kirkuk-Ceyhan pipeline (the Northern Export Route) which has been subject to continued sabotage since '03

Main oil producing region - The Rumaila oil fields

Southern export route, via Mini Al Bakr, Basrah and Khor Al Amaya ports



Source: Wood Mackenzie

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 has been 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 contracts awarded on further fields including Zubair, West Qurna, Majnoon and Halfaya to name a few.

Elsewhere, in the self governed northern Kurdistan region, a number (c.32 PSCs) of exploration licenses have been awarded since 2004. However, questions remain over the legitimacy of these agreements (having not been approved at the federal level) and there are fears they may have to be re-approved by the Federal Authority once the Federal Oil and Gas Law is enacted before they will be considered legal.

Contract award process under the proposed new law

Under the Federal Oil and Gas Law proposed in 2007, the Ministry of Oil, the INOC and the Regional Authorities were nominated as Designated Authorities (DA) and hold the right to award contracts. An institutional process was been designed to satisfy the conflicting views of the Kurdistan region and the central government with respect to the former's degree of autonomy in the award of petroleum development contracts, however, progress on this front has been limited. Once a contract has been granted, the DA must submit it to the Federal Oil and Gas Council (FOGC) within 30 days. The FOGC will approve the contract or refer it to the PIA, if it is considered to be inconsistent with FOGC guidelines.

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. Production reached its highest level in years in 2009 when it averaged 2.3-2.4mb/d throughout the year.

Figure 456: Iraq's key fields and production

	Initial Reserves (mb)	Remaining Reserves (mb)	Start-up	Production 2005 (kb/d)	Production 2010 (kb/d)	Production 2015 (kb/d)
Rumaila	30900	16848	1954	1267	1086	1984
Kirkuk	25278	6653	1934	242	403	460
West Qurna	14633	13644	1998	200	244	1500

Source: Wood Mackenzie

Historically, approximately two thirds of total production arose in the southern fields. At present, c.70% of Iraqi oil production comes from just three fields; Rumaila, Kirkuk and West Qurna. The Rumaila fields have been producing at near 1mb/d well below pre-war levels of nearer 1.3mb/d. However, daily production at Kirkuk of around 390kb/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 12mb/d by 2020, however, lack of infrastructure, an insufficient services industry and potential difficulties accessing funds could see some slippage to this target. Indeed we note Wood Mackenzie is only forecasting near 10mb/d for the same period.

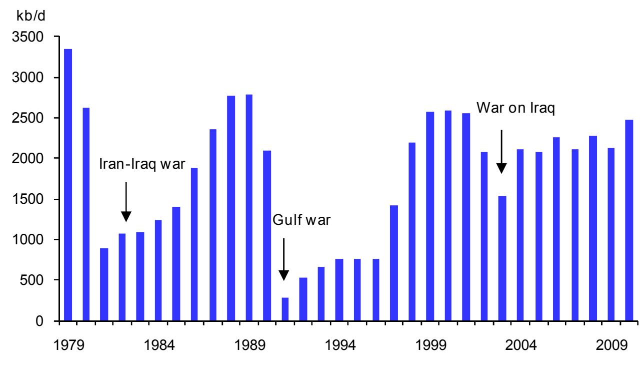
Figure 457: Contracts awarded in 2009 licensing round

Project	Comm'l Reserves	Current output	Plateau Production	Remun'n Fee	Sig Bonus	Main 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

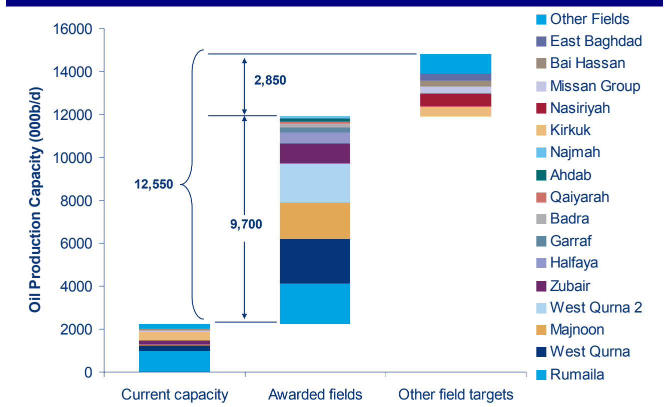
The majority of Iraq's gas production is associated gas, thus its profile has tended to follow that of oil production. Production currently stands near 800mscf/d but the government aims to increase this to more than 6000mscf/d with about 50% of this intended for export. It is hoped that Iraq will become a major supplier of gas for the Nabucco pipeline – a 3300km pipeline intended to pipe gas from the Middle East and Caspian to Austria for delivery to the rest of Western Europe. However, as in the past development of the Iraqi gas industry will be dependent on progress made in the oil sector. 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 458: Iraqi oil production over the last 30 years (kb/d)



Source: Wood Mackenzie; Deutsche Bank

Figure 459: Prospective Iraqi production as capacity starts to increase

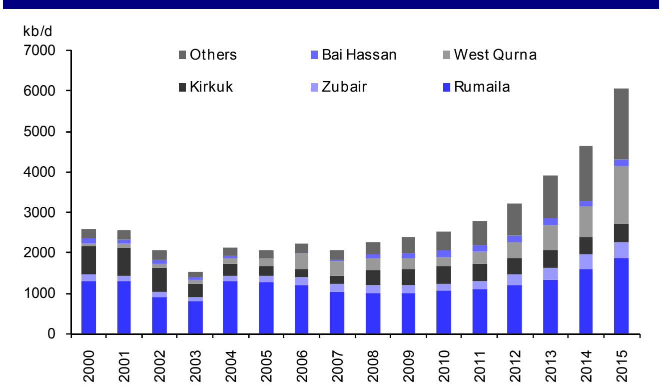


Source: Wood Mackenzie; Deutsche Bank

Finally, 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.

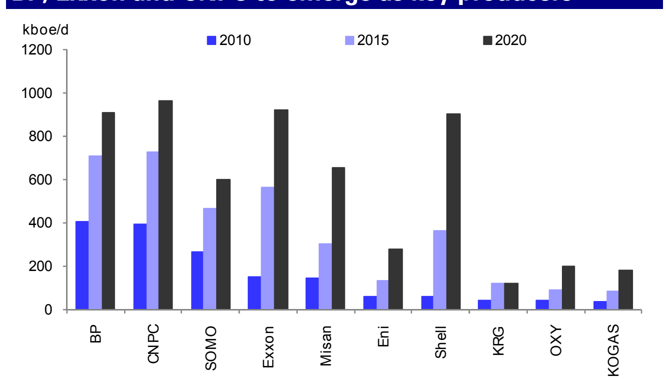
From a company perspective, all of Iraq's current production is controlled by the Ministry of Oil via its two operating units the North (NOC) and the South (SOC) Oil Companies. As detailed above, a number of service contracts were awarded to various western companies in 2009 including BP, RDS, Eni, Statoil and Exxon. Wood Mackenzie production forecasts suggest that by 2015 CNPC, BP and Exxon will be the top three foreign producers in the country.

Figure 460: Iraqi oil production 2000-15E(kb/d)



Source: Wood Mackenzie, Deutsche Bank

Figure 461: Working Interest Production by company – BP, Exxon and CNPC to emerge as key producers



Source: Wood Mackenzie, Deutsche Bank

Reserves and Resources

In global terms, with reserves standing at 115bn bbls of oil and 112TCF 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, due to reasons described above, large volumes of oil remain undeveloped and Iraq has the lowest reserves to production ratio of the major oil-producing countries (126 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.2.2mb/d to oil production by 2020. Longer term developments include Nasiriyah (100kboe/d) and Bai Hassan (180kboe/d) albeit these are relatively small in the context of the giant fields awarded in 2009.

Figure 462: Potential new fields in Iraq

	Recoverable Reserves (mb)	Remaining Reserves (mb)*	Start-up	Current Production (kb/d)
Majnoon	6349	6280	2002	42
Halfaya	2409	2405	2010	10
Gharraf	1126	1126	2012	0
Nasiriyah	971	964	2009	9
Bai Hassan	3489	2498	1960	155

*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 112TCF of 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 to the extent that operational capacity today is much lower than what it was 30 years ago. 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 463: Iraq's main pipelines

Pipeline	Operator	From	To	Length	Diameter	Capacity
				(km)	(inches)	(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 9.4mb/d although actual usage is no-where 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 by 4.5mb/d. This is expected to come on-stream by 2013 at the earliest.

Gas infrastructure within Iraq is limited, a factor which 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. While no new gas infrastructure projects have yet been announced, if the country is to meet its production targets and also participate in the Nabucco gas project it is likely that significant investment will be made in gas infrastructure in forthcoming years.

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 only exported 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 464: 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 service contracts which were awarded in the 2009 licensing round. Key feature 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 between $1.15/bbl to $2/bbl (albeit this will be adjusted according to the 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 table below. 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 465: 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 in order 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 677kb/d although effective capacity is nearer 550kb/d. The main refineries include Daura (110kb/d), Baiji (310kb/d) and Basrah (150kb/d). A new 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. In order to achieve this, Iraq is inviting IOCs to build a total of four new refineries with total capacity of 750kb/d. The total cost is estimated at some $25bln thus in order to incentivise companies Iraq is offering a 5% rebate on world crude prices (vs. the typical 1% rebate offered by other Gulf states). With the planned refineries already at the design phase, the Iraqi government is hoping for FIDs by the end of 2010.

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. It is believed to have completed this exercise in 2006, but no further details have been released.

Iraq - Notes

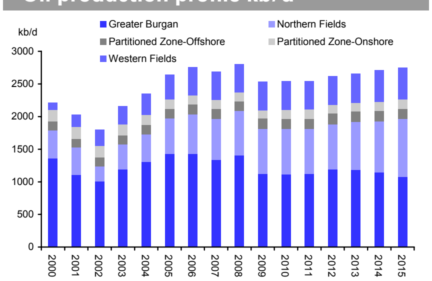
Kuwait

Key facts

Oil production 2009E	2.5mb/d
Gas production 2009E	0.2mboe/d
Oil reserves 2009E	115bn bbls
Gas reserves 2009E	63 TCF
Reserve life (oil)	110 years
Reserve life (gas)	143 years
GDP 2009E ($bn)	$137.5bn
GDP growth 2009E (%)	0%
Population 2009 (m)	3.5m
Oil consumption 2008E (b/d)	351kb/d
Oil exports 2008E (mb/d)	2.4mb/d
Fiscal regime	OSA, Royalty, IT
Marginal tax rate	55%
Top 3 Oil fields (2009E)	
Greater Burgan	1,124kb/d
Raudhatain	398kb/d
Sabriya	250kb/d
Top Producer (2009E)	
KOC	2.7mb/d

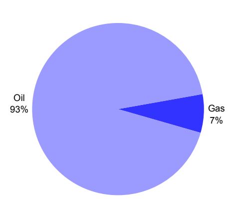
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



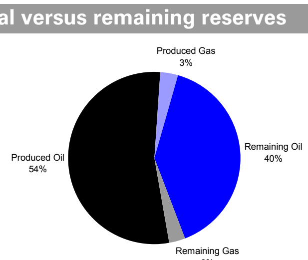
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

Kuwait is one of the richest nations in the world on a per capita basis, due primarily to its significant accumulated oil wealth. With official reserves of 115bn 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 2.5mb/d. However, the government plans to spend an estimated $27.6 billion through 2020 to increase sustainable production capacity to 4mb/d 2020. To this end, Kuwait is considering inviting the IOCs to return to the country in order to help meet its hydrocarbon targets via the somewhat controversial 'Project Kuwait'.

Basic geology and topology

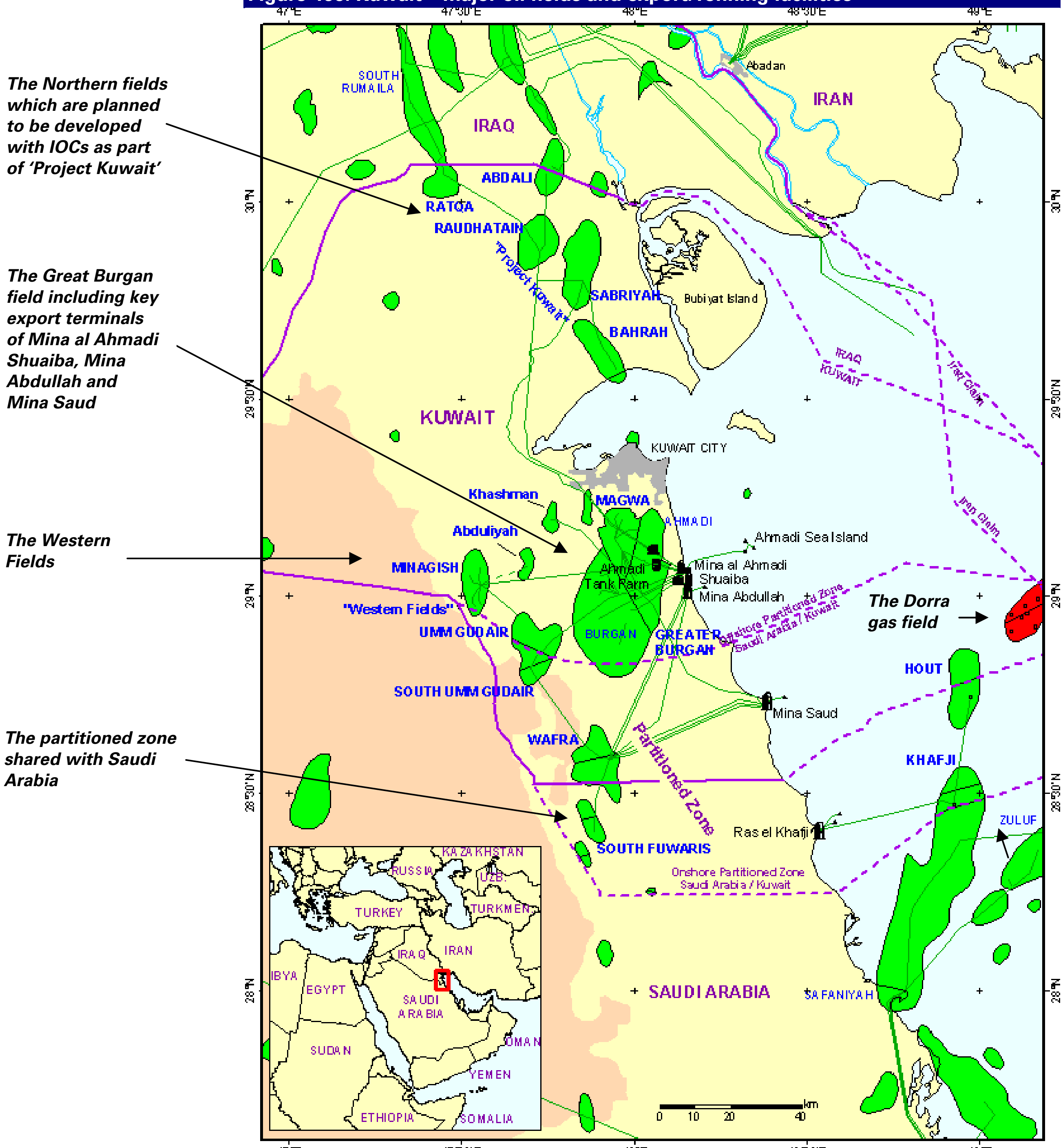
Kuwait lies in the prolific Arabian basin which contains some of the world's largest and richest oil and gas accumulations. Predominantly an oil province, the principal reservoirs in Kuwait comprise Cretaceous carbonates and sandstones, although oil has more recently been produced from Jurassic formations. 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. To date Kuwait has only awarded licences under concession terms in the neutral zone to Japanese-owned Arabian Oil Company (AOC) in the offshore and to Aminoil in the 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 which governs the industry, in addition to being the chairman of KPC and sitting on the board of SPC. The proposed re-entry of foreign companies is a very contentious point in the country and the parliament has been determined in its opposition to the proposal. The government is, however, determined to invite the IOCs to participate in developing the country's resources in order to secure continued military support from those western countries involved. The presence of the IOCs would also help to maintain the production capacity and optimise the production lives of Kuwait's major oil fields.

Figure 466: Kuwait – major oil fields and export/refining facilities



Source: Wood Mackenzie; Deutsche Bank

Licensing

The ban on awarding foreign companies upstream licences may be lifted, should Project Kuwait proceed through Parliament. Project Kuwait, to be developed over 25 years, plans 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 allows 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 are 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.). Reportedly, KPC would prefer to have three groups working under three separate OSAs: one for Raudhatain and Sabriya (the largest OSA); one for Ratqa and Abdali; and one for Minagish and Umm Gudair fields (in the west)

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 in order 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. Kuwait's current quota is 2.2mb/d. However, growth in global demand coupled with supply constraints in other countries have meant that Kuwait has produced above its official level for the last few years. Oil production in 2008 was 2.7mb/d 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 467: Key commercial fields

Field	Recoverable Reserves (mbbl)	Remaining Reserves (mbbl)	Start-Up year	Production 2009 (kb/d)	Production 2012 (kb/d)	Production 2015 kb/d
Greater Burgan	47,861	16,305	1946	1,124	1,189	1,079
Raudhatain	8,242	4,701	1960	398	401	468
Sabriya	5,871	4,173	1961	250	252	320
Minagish	2,936	1,844	1961	215	215	215
Umm Gudair	2,704	1,691	1964	178	178	178
Walfra (PNZ)*	1,748	906	1954	105	117	135
Khafji (PNZ)	2,864	761	1961	135	137	137

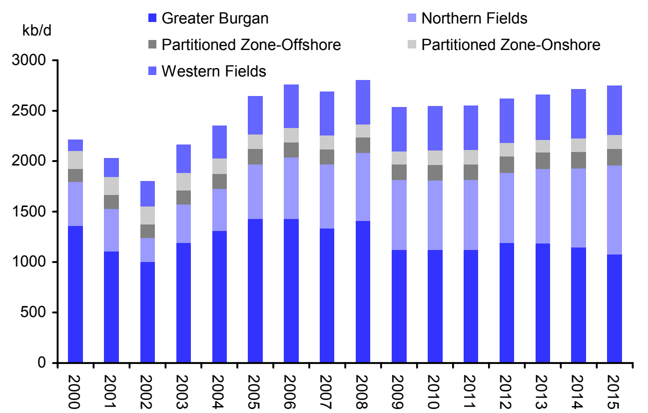
*Source: Wood Mackenzie * PNZ is the Partitioned Neutral Zone*

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 principals 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 in order 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 a total production capacity of 4.0 million b/d by 2020 and develop a 15% spare capacity above expected demand;

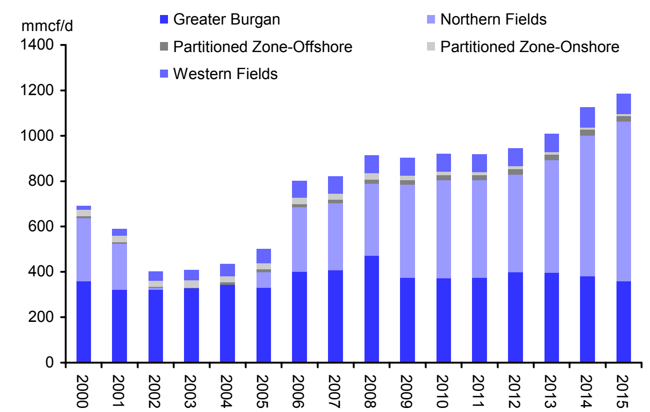
- Replace production and add 8 billion barrels of incremental reserves by utilisation of modern technology to enhance oil recovery;
- Develop the expertise within KOC to deal with the more sophisticated reservoir management challenges expected in the future.

Figure 468: Kuwait oil production 2000-15E (kb/d)



Source: Wood Mackenzie

Figure 469: Kuwait gas production 2000-15E (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 on-stream in 2008 with 50mmcf/d and is expected to reach its capacity of 175mmcf/d with a slow ramp up in production through 2010. Phases 2 and 3 (500mmcf/d each) are expected to come on-stream by 2011 and 2015 respectively.

Reserves and Resources

Kuwait ranks amongst the world's top five countries in terms of its oil reserves. Total estimated oil reserves in 2009 were 115bn/bbls according to EIA. Kuwait has several super-giant fields including Greater Burgan (16.3bnbbls), Raudhatain (4.7bnbbls), Sabriya (4.2bnbbls) and Minagish (1.8bnbbls) 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 64% 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 110 years to a mere 50 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 sixty years, field maturity is becoming an issue. One aspect of Project Kuwait is thus 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 which are 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

Figure 470: 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

With this in mind, Kuwait Oil Company (KOC) awarded contracts to Petrofac and SK Engineering to upgrade almost 80% of its oil production facilities in the South East to be able to handle sour crude.

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 471: 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 aging Shuaiba refinery will be decommissioned on completion of the project bringing total refining capacity in Kuwait to 1.2mb/d. In 2006 KNPC received 9 bids for the project, yet with all bids indicating costs almost double those budgeted ($6.3bn), the project was re-tendered in 2008. However, this also met issues related to the selection process, thus deferring completion to 2012 a date which seems likely to see further push back.

LNG

Following the announcement in 2006 of its interest in importing LNG from Qatar, Kuwait initiated discussions with IOCs (Shell and BG) for LNG imports as well as developing its own gas resources. Construction of an LNG import terminal commenced in 2008 with the installation of a regasification vessel at Mina al Ahmadi with a capacity of 600mmcf/d. KPC subsequently entered an agreement with Shell for the supply of 1.5mmtpa of LNG starting from 2010.

Kuwait - Notes

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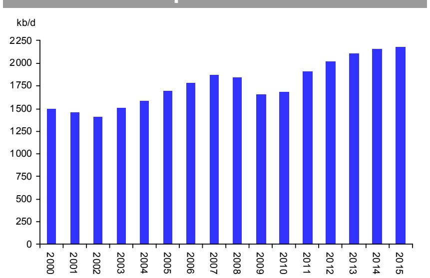
Libya

Key facts

Oil production 2009	1.7mb/d
Gas production 2009	0.3mboe/d
Oil reserves 2009E	43.7bn bbls
Gas reserve 2009E	54.4TCF
Reserve life (oil)	72 years
Reserve life (gas)	62 years
GDP 2009E ($bn)	$91bn
GDP Growth 2009E (%)	3.3%
Population (m)	6.3m
Oil consumption (mb/d)	278kb/d
Oil exports (mb/d)	1.6mb/d
Fiscal regime	PSC/concession
Marginal tax rate	92.4%
Top 3 fields (2009E)	
Agoco	328kboe/d
Waha	310kboe/d
EPSA Area D fields	280kboe/d
Top 3 Producers (2009E) – Entitlement	
NOC	1,156kboe/d
Eni	145kboe/d
Wintershall	48kboe/d

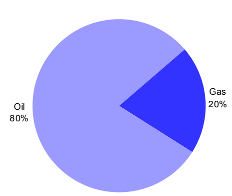
Source: Wood Mackenzie, EIA, IMF

Oil Production profile kb/d



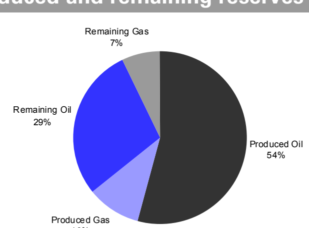
Source: Wood Mackenzie data

Remaining reserves split oil & gas %



Source: Wood Mackenzie data

Produced and remaining reserves



Source: Wood Mackenzie data

Following years of UN and US sanctions, Libya is finally back on the road to an oil industry recovery. The sanctions, imposed by the international community following accusations of involvement in international terrorism, caused significant delays in field developments and EOR projects (leading to decline rates of up to 7% in many of Libya's fields) and deterred foreign capital investment. Having publicly apologized in 2004, Libya is gradually being welcomed back into the international community. With some 44 billion barrels of proven oil reserves (the largest in Africa) the country now aims to increase oil production to around 2.2mb/d by 2015, a level last seen in the early 1970s, by attracting foreign investment. Many IOCs have already stepped up their exploration efforts. Key IOCs operating in Libya include Eni, ConocoPhillips, Total and Repsol YPF.

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 90% of total production. However, while each basin is believed to contain significant reserves, all are under-explored relative to Sirte, particularly the Kufra basin due to its remoteness from infrastructure and consumer 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

For most of its history, Libya has been subject to varying degrees of foreign control. However since it re-gained its independence from Italy in 1951, the country has been governed by Colonel Qadhafi and his 'green book', which combines socialist and Islamist theories and rejects parliamentary democracy and political parties. In theory, the General People's Congress (GPC) was established by Qadhafi to serve as an intermediary between the populace and the leadership of the country. However in reality Qadhafi exercises 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 2004 has, however, seen Libya forgiven and with sanctions now lifted, the US companies have returned and recovered their former assets.

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 40% 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 and no changes have been made since. How long this will last remains to be seen but the impact to date has been minimal given NOC was already heavily involved in the regulation of the industry and that the chairman of NOC is the former Prime Minister.

The offshore Pelagian Shelf

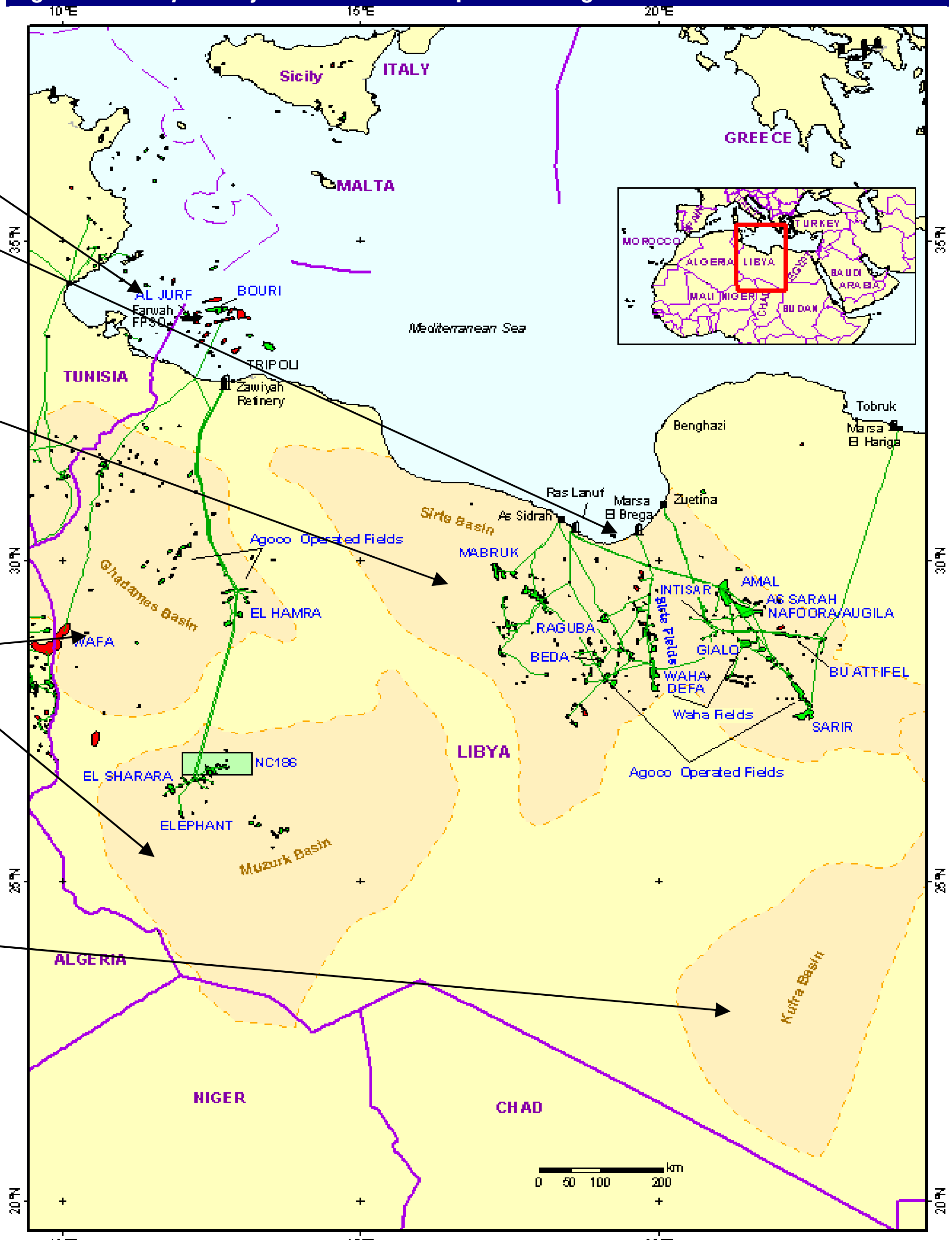
LNG facility

The Sirte basin which accounts for the majority of the country's output. The basin is serviced by miles of pipelines and the Ras Lanuf and Marsa El Brega refineries

The Ghadames and Muzurk basins. Production is transported to the Zawiyah refinery via the El Sharara pipeline (360kb/s)

The remote Kufra basin which is under-explored and developed relative to the other fields

Figure 472: 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 under a concession (tax and royalty) regime and subsequently as Exploration and Production Sharing Agreements (EPSAs). Under the concession regime, NOC was guaranteed a majority stake-holding and the participants had to commence exploration operations within 8 months of the award of the concession. Licences are no longer awarded under the concessions regime and Libya has gradually been converting concessions to the terms of EPSA either as they expire or via negotiation. EPSAs have terms lasting between 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 (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, again with a focus on gas 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. 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.

Production of Oil and Gas

Libya, a member of OPEC since 1962, is one of the largest oil producers in Africa. Oil production in 2009 totalled an estimated 1.7mb/d and is dominated by the Sirte basin (65% in 2009) which has been producing since 1961. However, production in the Sirte basin has been declining in recent years due to sanctions. These prevented Libya from importing much needed EOR equipment and perhaps more importantly, removed most foreign investment in the development of the fields. Indeed, a mixture of sanctions and poor management mean that production today is well below its 1970 peak of 3.3mb/d. While production is now dominated by NOC, on an entitlement basis Eni (63kb/d), Repsol YPF (27kb/d), Total (32kb/d), Occidental (12kb/d) and by virtue of a 16.33% interest each in the Waha Oil company, ConocoPhillips (41kb/d) and Marathon (41kb/d) have a notable presence in the country.

Figure 473: Key commercial oil fields

Field	Recoverable Reserves (mbbl)	Remaining Reserves (mbbl)	Start-up	Production 2009 (kb/d)	Production 2012 (kb/d)	Production 2015 kb/d
Agoco	9,555	3,877	1963	328	281	280
Sirte	4,762	1,112	1961	83	78	98
Waha	10,720	2,572	1962	288	394	458
Intisar	2,579	333	1968	37	57	72
Elephant	700	498	2004	120	135	98
NC186	731	587	2003	108	158	135
EPSA Area D	942	775	2004	94	100	104
EPSA Area B	2,261	423	1972	84	87	92
Nafoora-Augila	2,155	769	1966	36	73	150
EPSA East	1,733	599	1966	26	55	80
El Sharara	1,646	857	1996	169	191	167

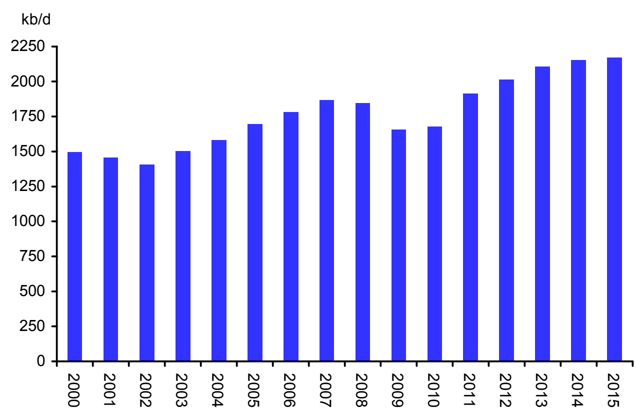
Source: Wood Mackenzie

Libya intends to raise production to 2.3mb/d by 2013 (a 25% cut from earlier targets), using enhanced oil recovery techniques, upgrading and expanding the country's infrastructure and by increasing exploration in basins other than Sirte. Given there are as yet no firm development plans in place for many fields and that much depends on NOC's ability to finance its share of the development costs, this target looks unlikely to be achieved before 2015. Furthermore, Libya is currently producing at its OPEC production quota, hence it is likely that Libya's production plans will be somewhat restricted, unless it is successful in obtaining an increase in quota (assuming of course it adheres to its quota).

Gas production has grown substantially over the last few years with Libya producing some 1.6bcf/d (or 0.26kboe/d) in 2009. Expansion of natural gas production remains a high priority for the country as Libya aims to use natural gas instead of oil for domestic power generation. Additionally the country wants to increase gas exports, particularly to Europe, via the

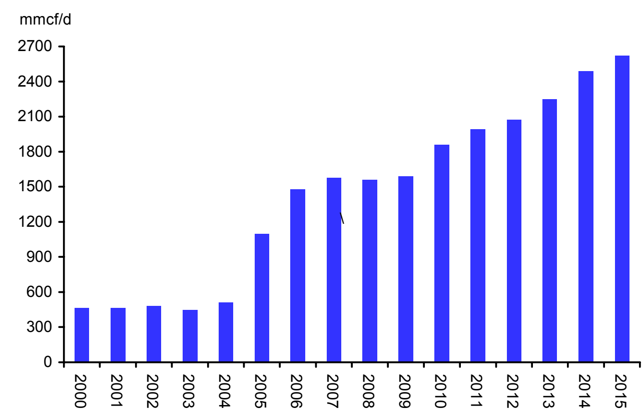
Western Libyan Gas Project (WLGP) a 50/50 joint venture between Eni and NOC. This project incorporates the Greenstream underwater natural gas pipeline which carries c.0.8bcf/d gas to Italy for export to mainland Europe. The planned Libya-Tunisia gas pipeline that aims to deliver c.200mmcf/d of Libyan gas to Tunisia originally envisaged a 2006 start-up. However, it is still at the initial stages given uncertainty over commercial demand for the pipeline.

Figure 474: Libya - Oil production 2000-15E (kb/d)



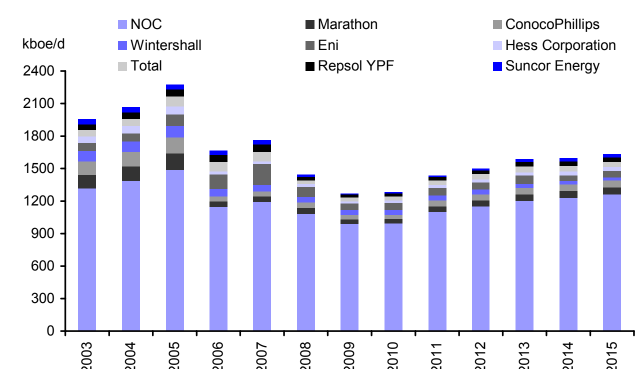
Source: Wood Mackenzie

Figure 475: Libya - Gas production 2000-15E (mmcf/d)



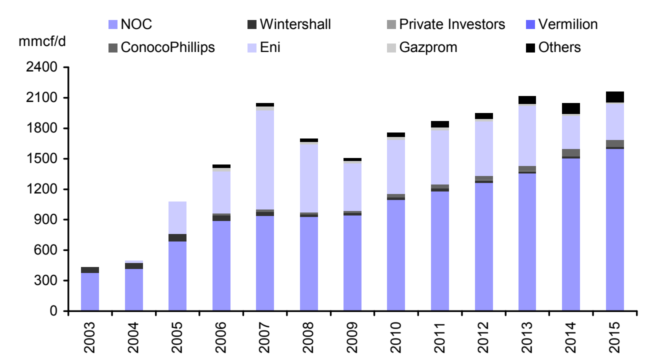
Source: Wood Mackenzie

Figure 476: Libya –Oil production by company 2003-15E



Source: Wood Mackenzie

Figure 477: Libya –Gas production by company 2003-15E



Source: Wood Mackenzie

Reserves and Resources

With estimated oil reserves of c.43.7billion barrels Libya holds the largest proven oil reserves in Africa. More than 85% 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. Its re-opening has subsequently led to a flurry of interest from the international oil community and could see significant future upward revisions to the reserves base. As to gas, an estimated 54.4TCF of reserves make Libya the fourth largest holder of gas in Africa. On-going exploration could see this figure increase (Libya estimates this could reach 70-100TCF with further exploration), particularly given the government's plans to increase both domestic gas usage and gas exports.

Pipelines and Infrastructure

Libya has a well established pipeline transportation system which connects oil fields in the Sirte basin to export terminals on its Mediterranean coastline. There are also pipelines linking the giant Sarir oil field to the Marsa El Hariga terminal and further pipelines linking the Murzak and Ghadames basins to the Zawiyah terminal 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 so called Green Stream 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). Additional export gas pipelines are planned to Tunisia (as described above), and Libya is also in on-going discussions with Egypt regarding the construction of a gas pipeline between Libya and Egypt.

Figure 478: 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 479: 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. Since 2007, however, the government has been re-negotiating concession contracts to bring them in line with EPSA IV contract terms.

- **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 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. In 2007 and 2008, whilst renewing existing concession contracts, NOC secured bonuses up to USD1bn as part of extension agreements (Note: signature bonuses are not recoverable costs).

All concession contracts and indeed older EPSA contracts are being renegotiated with the various IOCs. As such, over time all licenses look likely to migrate to the terms of EPSA IV although the impact will vary from company to company depending, amongst others, on timing and license extensions. For example, in 2007 Occidental renewed a soon to expire licence on terms which, whilst less favourable included a 30 year licence extension. In 2008, Eni finalised six contracts under EPSA IV terms that were originally signed in 2007, extending mining rights out to 2042.

Refining and Downstream markets

Libya has five domestic refineries with a total capacity of around 380kb/d. The plants are well utilised and, with an output of c360kb/d produce thrice the level of product that is required by the domestic market leaving scope for exports. The main refineries are:

Figure 480: Libya Refining capacity

Operator	Refinery	CDU Capacity
NOC	Ras Lanuf	220kb/d
NOC	Az Zawiyah	120kb/d
NOC	Tobruk	20kb/d

Source: Wood Mackenzie

Under the US sanctions, Libya was unable to import refinery equipment. It now intends a comprehensive upgrade to the entire refining system, with the particular aim of increasing output of gasoline and other light products. The proposed upgrades should enable Libya to meet the stricter European environmental standards in place for oil products whilst also ensuring the infrastructure is in place to cope with a targeted increase in production. 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 have seen production substantially reduced. Today the plant produces little more than 0.7mtpa. 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. The plant will be redeveloped in three phases. Phase 1 is focussed on maintaining the current level of output at 0.7mtpa, Phase 2 aims to achieve the nameplate capacity of 3.2mtpa dependent on the success of finding sufficient gas and Phase 3 (which is highly uncertain) will add an LNG plant at the port of Ras Lanuf. Separately, in 2007 as part of its contract renegotiations Eni was awarded a licence to construct a new 4mtpa plant at Mellitah, again dependent on ENI's ability to find sufficient reserves of natural gas.

Libya - Notes

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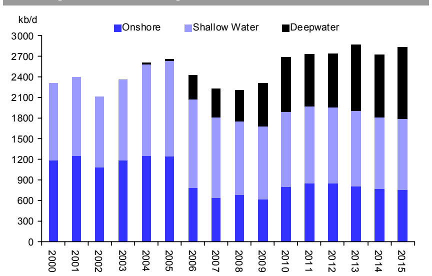
Nigeria

Key facts

Oil production 2009E	2.3mb/d
Gas production 2009E	0.6mboe/d
Oil reserves 2009E	37.2bn bbls
Gas reserves 2009E	184TCF
Reserve life (oil)	36.9years
Reserve life (gas)	85.5years
GDP 2009 ($bn)	$334bn
GDP growth 2009 (%)	4.5%
Population 2009 (m)	152m
Oil consumption 2008E (b/d)	286kb/d
Oil exports 2008E (mb/d)	1.9mb/d
Fiscal regime	PSC, JV Concession
Marginal tax rate	66%-85%
Top 3 Oil fields (2009E)	
Shell/NNPC JV	620kb/d
ExxonMobil/NNPC JV	368kb/d
Agip/NNPC JV	341kb/d
Top Producers (2009E)	
NNPC	1,015kb/d
Exxon	313kb/d
Shell	288kb/d

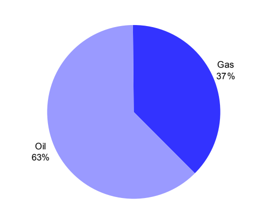
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



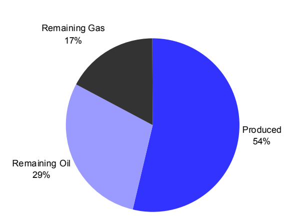
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

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 wealth, with oil accounting for 85% of government revenues. However, with an estimated $400bn of government income squandered or stolen since independence from Britain in 1960, per capita income fell from $1,000 to $390 by 2002. Little surprise the populace should voice its dissatisfaction especially in key oil producing regions. Yet with total reserves of 36 billion barrels and the potential to significantly increase production capacity from current levels of 2.3mb/d, Nigeria has the potential to become one of the world's most powerful oil exporting nations. 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 77% of Nigeria's remaining commercial reserves are located either on-shore or in the shelf areas of the Niger Delta, while the remaining reserves are in the off-shore 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

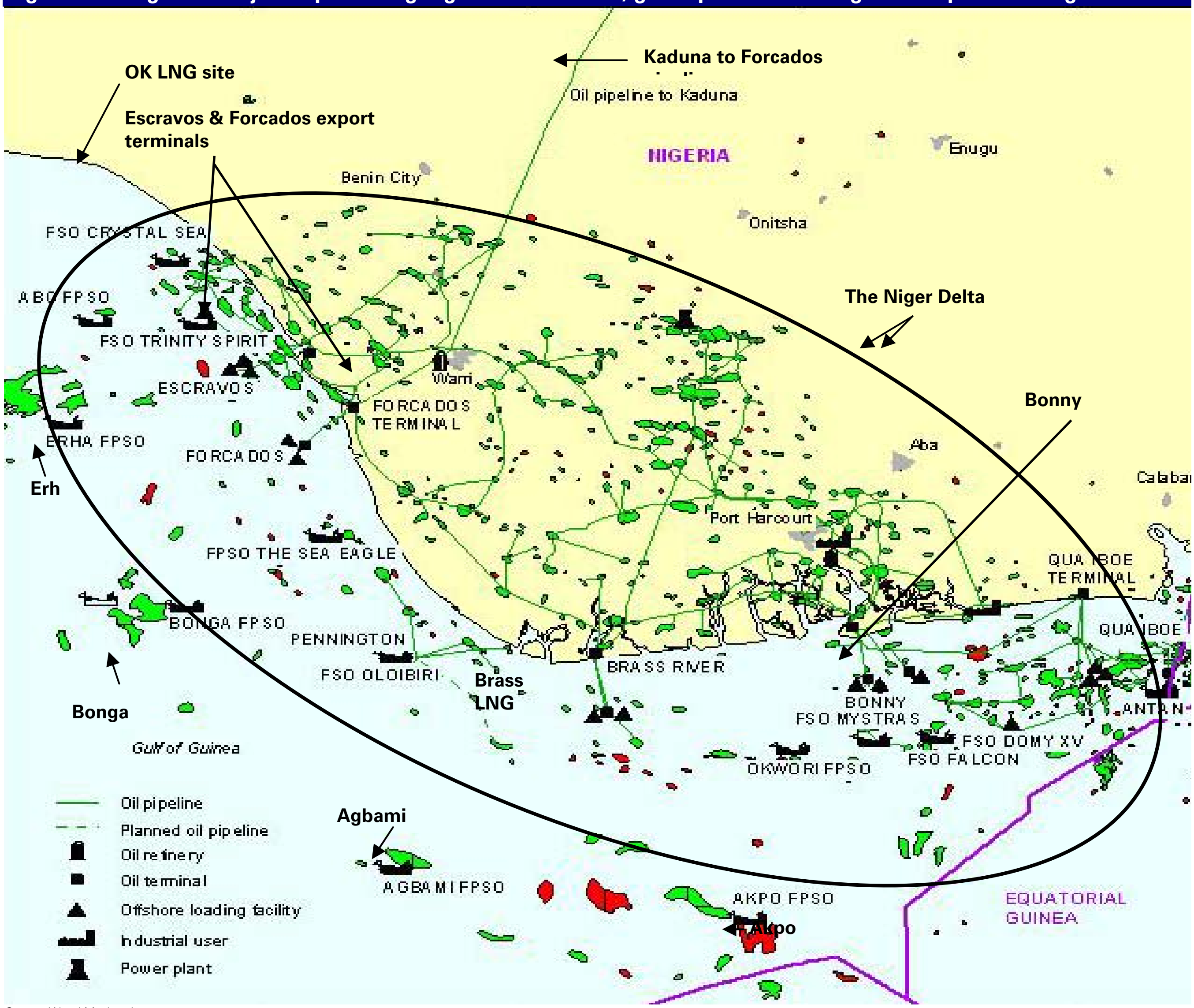
Similar to most of its OPEC compatriots, Nigeria's oil industry was nationalised in the 1970's, a move which was cemented with the creation of the Nigerian National Petroleum Corporation (NNPC). However, in contrast to other OPEC nations, Nigeria remained open to foreign investment, and today the majority (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 150m) 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). Since November 2009, a fragile ceasefire has been in place on government promises that local companies will have greater control over natural resources. However, we expect this ceasefire will end if progress is too slow

These tensions have meant that regulation of Nigeria's hydrocarbon industry has been erratic and weak, with NNPC considered for decades a source of corruption. Decision making has been slow and, despite the scale of its production, the funding of NNPC's investments a constant problem. In response to these issues, in July 2008, Nigeria drafted the "Petroleum

Industry Bill (PIB)"which has since undergone several changes. If PIB is eventually ratified, it will have a significant impact on Nigeria's oil and gas sector. Broad objectives include a reformation of both the oil and gas sector and regulatory bodies, conversion of NNPC into an autonomous government owned entity, incorporation of the main JVs into limited liability companies in order to resolve funding problems and finally consolidation of tax laws and oil and gas legislation. The proposed bill intends to create four main regulatory bodies as (1) 'National Petroleum Directorate' which will take over the responsibilities of Ministry of Petroleum, (2) 'Nigerian Petroleum Inspectorate' taking over the responsibilities of Department of Petroleum Resources (3) National Petroleum Assets Management Agency and (4) Petroleum Products Regulatory Authority.

Figure 481: Nigeria – major oil producing regions of the Delta, gas exploration acreage and export/refining facilities



Source: Wood Mackenzie

Licensing

Licenses are awarded via formal licensing rounds that are held on an adhoc basis. Recent licensing rounds have been dominated by small, inexperienced players, many of whom do not have the means to pay the required cash bonus. 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 3 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. This contains 23 blocks and could potentially hold up to 14 billion barrels of oil reserves. To date licences for the blocks are awarded under PSC terms.

Production of Oil and Gas

Oil production in 2009 was estimated at 2.3mb/d and gas production at 3.8bcf/d. with hydrocarbons accounting for 95% of the country's export revenues and 85% of total 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 Bonga, and has continued with the development of Erha and Agbami.

Figure 482: Major onshore/shallow water oil producing fields

Asset	Recoverable Reserves	Remaining Reserves	Start-up Year	Production 2009	Production 2012	Production 2015
	(mbbl)	(mbbl)		(kb/d)	(kb/d)	(kb/d)
Shell JV	17,882	5,018	1958	335	602	615
ExxonMobil/NNPC JV	6,659	1,810	1970	437	411	353
Chevron/NNPC JV	6,541	1,767	1964	224	335	312
Agip/NNPC JV	2,940	677	1970	164	137	106
Total/NNPC JV	2,438	1,025	1966	101	114	194

Source: Wood Mackenzie; Deutsche Bank

The figure above shows the most important onshore/shallow water developments. Overall, these accounted for 1.3mb/d of Nigeria's production in 2009 split 0.4mb/d onshore and 0.9mb/d shallow water. However, these projects have been the target of much sabotage with up to 10% of total lost to bunkering (i.e. theft) which is then sold on the black market. Through much of 2009, some one-third of capacity was shut-in due to militants attacks.

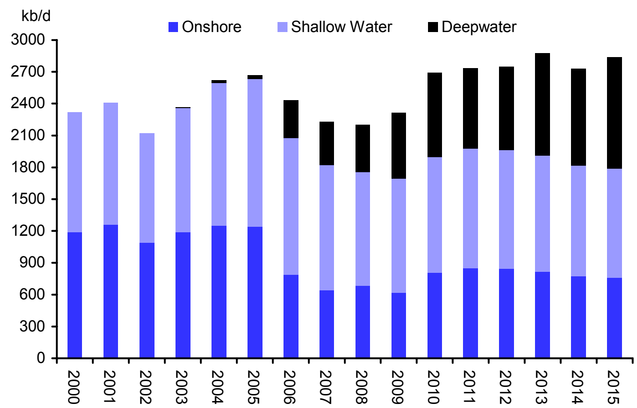
Figure 483: Major offshore oil producing fields

Asset	Recoverable Reserves	Remaining Reserves	Start-up Year	Production 2009	Production 2012	Production 2015
	(mbbl)	**(mbbl)**		**(kb/d)**	**(kb/d)**	**(kb/d)**
Bonga	1,350	1,069	2005	180	130	227
Akpo and Egina	1,240	1,218	2009	60	175	176
Erha and Bosi	1,160	905	2006	181	143	226
Agbami-Ekoli	900	820	2008	170	250	182
Usan and Ukot	610	610	2012	n/a	35	180

Source: Wood Mackenzie; Deutsche Bank

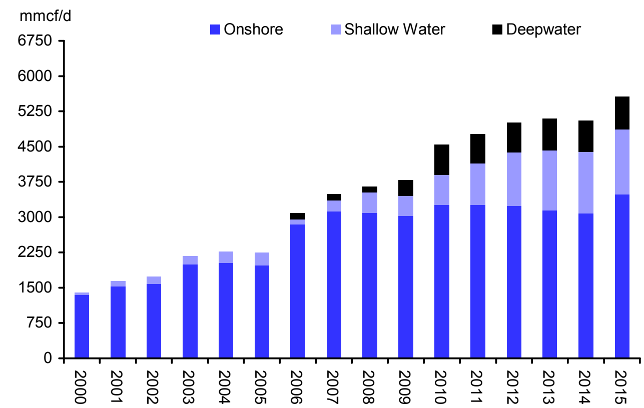
Looking to the medium term, we believe much of Nigeria's future growth is likely to occur in the deepwater. Based on Wood Mackenzie estimates, from 2009 total onshore production of 2.3mboe/d is expected to increase at a CAGR of 2.3% to c.2.6mboe/d by 2015 while deepwater production will increase by CAGR of 10% to 1.2mboe/d in the same period.

Figure 484: Nigeria oil production 2000-15E (kb/d)



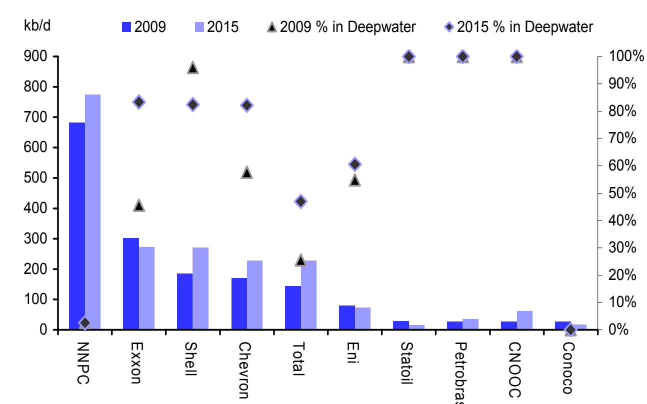
Source: Wood Mackenzie; Deutsche Bank

Figure 485: Nigeria gas production 2000-15E (mmcf/d)



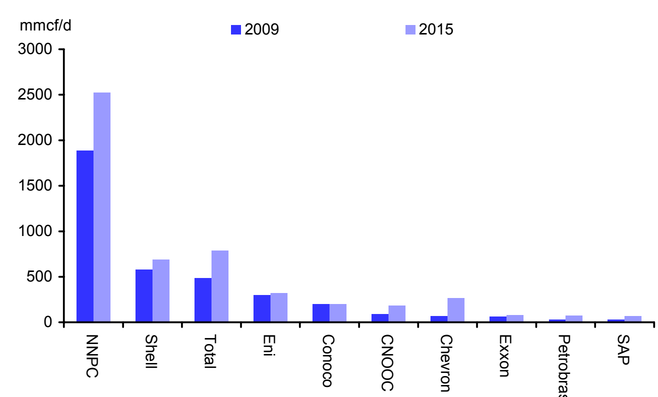
Source: Wood Mackenzie; Deutsche Bank

Figure 486: Nigeria: Major oil producers 2009/15E



Source: Wood Mackenzie; Deutsche Bank

Figure 487: Nigeria: Major gas producers 2009/15E



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, 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 on-shore 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.

Reserves and Resources

With total estimated oil reserves just over 37 billion barrels, Nigeria has one of the largest resource bases in Africa. The government had planned to increase proven oil reserves to 40 billion barrels by 2010, however, onshore reserve additions have been modest given the underlying tensions in the country given that NNPC is already struggling to meet its financial commitments. Further development of reserves will require significant investment due to higher budgets for ongoing oil and infrastructure developments, gas project investment, exploration and cost inflation. This funding is not fully met by the government hence there is a real risk that unless NNPC's funding is increased, future oil capacity from the JV areas may be jeopardised. In order 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 184TCF, which makes Nigeria the seventh 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 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 is 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 also 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 number of years, whether by protests or 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 200mmcf/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 table below. 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 488: 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. More recently there have, however, 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 489: 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.

Refining and Downstream markets

Put simply, Nigeria's downstream market is in disarray. Although its four refineries have a 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 490: Nigeria: Refining capacity vs. throughput (2008)

Operator	Refinery	CDU Capacity	Utilization (2008)
Port Harcourt Refining Company	Port Harcourt I	60	17.8%
Port Harcourt Refining Company	Port Harcourt II	150	17.8%
Warri Refining & Petrochem Co	Warri	125	38.5%
Kaduna Refining & Petrochem Co	Kaduna	110	19.6%
Total CDU		**445**	

Source: Wood Mackenzie, NNPC

Efforts are being made to reinstate refinery activity such as privatisation of the refineries and terminating price subsidies, a move which is widely opposed.

LNG

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 under $1/mmbtu hence the value is consequently in the liquefaction plant. Capacity utilisation over the past two years has however been poor given the issues on the Delta, not least the sabotage of pipelines and consequently a lack of gas. The 2010 start up of Shell's Gbaran Ubie development with its 1bccf/d of production is, however, expected to underpin gas to the plant and hence its better utilisation.

Given tax incentives, a huge reserve base and its favourable location for European and US markets, it is little surprise that significant plans for future LNG capacity should be in place. Following the late 2007/early 2008 start up of a sixth train, capacity at Bonny LNG rose to 22mtpa, with a possible seventh train with capacity of c.8mtpa anticipated for start up by 2015 at the earliest. Gas is primarily sourced from dedicated non-associated gas fields although it is anticipated that within a few years almost half of the feedstock will consist of associated gas thereby reducing flaring.

Bonny LNG aside plans have also been established for two further large facilities; a four train, 22mtpa facility towards the north of the country called OK LNG and a two train, 10mtpa plant called Brass River further south. Progress on these 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, the FIDs on each are still pending.

Figure 491: 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)	2015+	7	8	NNPC (49%), Shell (25.6%), Total (15%) ENI (10.4%)
OKLNG	2015+	1-4	22	NNPC (49.5%), Shell (18.5%), Chevron (18.5%), BG (13.5%)
Brass LNG	2015+	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 with production capacity of 33kb/d. Start-up has been pushed to 2012 from the earlier target of 2010.

Nigeria - Notes

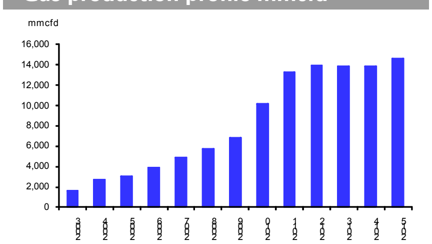
Qatar

Key facts

Oil production 2009E	1.345mb/d
Gas production 2009E	1.63mboe/d
Oil reserves 2009E	26.8bn bbls
Oil & gas reserves 2009E	895.8TCF
Reserve life (oil)	55 years
Reserve life (gas)	260 years
GDP 2009E ($bn)	106.87
GDP growth 2009E (%)	13.2%
Population (m)	1.2m
Oil consumption (mb/d)	0.209
Oil exports (mb/d)	1.15
Fiscal regime	PSC, tax and royalty
Top 3 Oil fields (2009E)	
Al Shaheen	330kb/d
Dukhan	321kb/d
Dolphin Upstream	89kb/d
Top Oil Producers (2009E)	
Qatar Petroleum	581kb/d
Maersk Oil & Gas	180kb/d
ExxonMobil	79kb/d

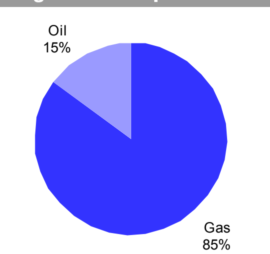
Source: Wood Mackenzie, EIA, IMF

Gas production profile mmcfd



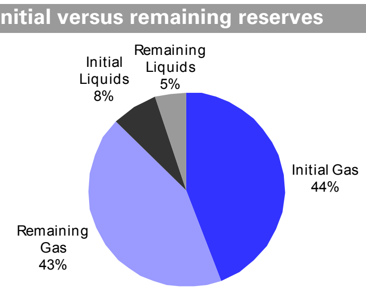
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie, BP Statistical Review 2010

From its roots as a British protectorate known mainly for pearling, Qatar is today a global leader in gas markets. With some 15% 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. Even with the current moratorium on further development of the giant North Field (the world's largest non-associated gas field), existing and planned projects should see gas production grow by approximately 14% pa to 2015. Oil production of 0.8mb/d continues to contribute significantly to GDP but has limited potential for growth. Rather this will come from an expansion in condensate production associated with the development of Qatar's gas resources. Qatar's natural gas production stood at c.9mscf/d in 2009 while liquids production was near 1.3mb/d (of which 0.5 mb/d is represented by condensates). 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 sixteen 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. Production didn't commence however until 1949 steadily increasing thereafter. 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 on-stream 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 somewhat of a renaissance in 1994 as IOCs and QP applied EOR techniques to improve production. This saw production improve by 5% pa, however OPEC production quotas and a lack of exploration success means that production beyond 2012 looks to set into decline. This will be offset to some extent by an increase in NGL and condensate production as further LNG trains come on-stream in 2010/11. However, with a moratorium on any future gas projects on the North Field until a reservoir study is completed, even NGLs and condensates will cease to provide respite from the natural underlying decline in oil production.

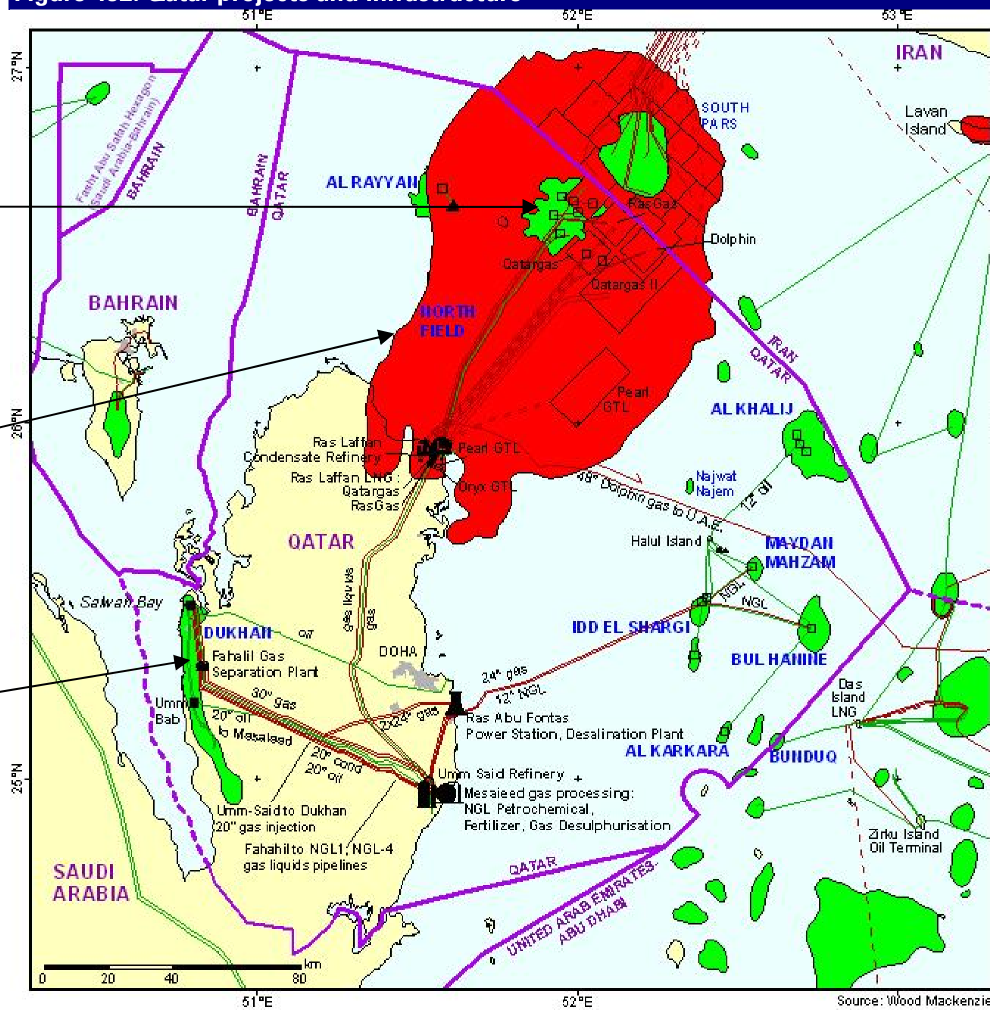
Qatar is unusual in that it has no dedicated petroleum law. Instead all exploration and production activities are regulated by the terms of Production Sharing Contracts (PSCs). These in turn are negotiated, awarded and administered by QP, which is also the designated authority to oversee all production and exploration operations on behalf of the government. Recent years have seen a number of licenses awarded for relatively unexplored 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.

Figure 492: Qatar projects and infrastructure

Al-Shaheen oil field – this will be the main source of future oil production growth

The giant North Field – with 900TCF of gas reserves it is the world's largest unassociated gas field.

Dukhan – one of Qatar's most important oil fields



Source: Wood Mackenzie

Licensing

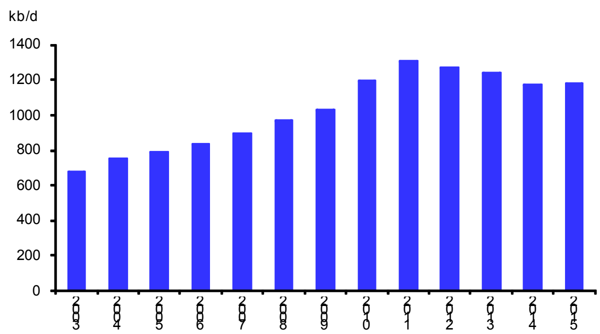
Qatar Petroleum directs and administers the allocation of licenses in Qatar. Unlicensed blocks are available for international oil company participation via direct negotiation with QP. Of the sixteen established exploration blocks, nine are currently unlicensed and QP typically offers a selection of these blocks to IOCs in an annual bid round or on an adhoc basis. The bidding criteria includes a work programme (seismic and three wells) and a signature bonus (generally around $2 million). In terms of gas, between 1991 and 2009, a total of eleven development blocks were awarded. Seven of these are for the production and export of LNG (Qatargas and RasGas), one is for a large scale GTL project (Pearl) and three are assigned to meet domestic demand.

Production of oil & gas

Bolstered by rising production of natural gas, the Qatari economy boasted GDP growth of over 13% in 2009 compared to global GDP growth of an estimated -1%. This highlights the increasing importance of gas in Qatar's balance of trade. In 2009 the country produced approximately 3.5TCF of gas, almost a six-fold increase in production levels since 1995. Moreover given the multitude of new gas projects set to come on-stream in the coming few years such as Pearl GTL and further trains at Qatargas LNG, production is expected to continue to rise steadily until at least 2013. Thereafter, Wood Mackenzie estimates gas production will remain essentially flat however we note the moratorium is scheduled to be reviewed around that time. This could see further developments sanctioned thus providing upside to existing production forecasts. The key players in gas production in Qatar are ExxonMobil, Occidental and Total (together represent 33% of production), with RDS set to join their ranks by 2013 following the start-up of Pearl GTL and Qatar 4 LNG.

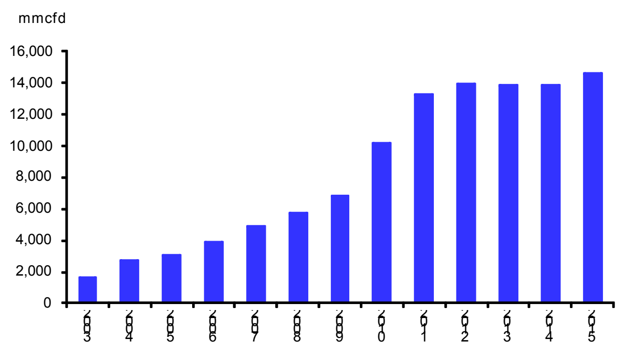
In terms of oil, Qatar was targeting production of 1mb/d by 2010. This milestone is yet to be achieved and with current production averaging nearer 830kb/d is unlikely to be met in the near-term particularly given OPEC output restrictions. As with gas, ExxonMobil, Occidental and Total are key IOC players while Maersk Oil & Gas also has significant production.

Figure 493: Liquids production to 2003- 2015E (kb/d)



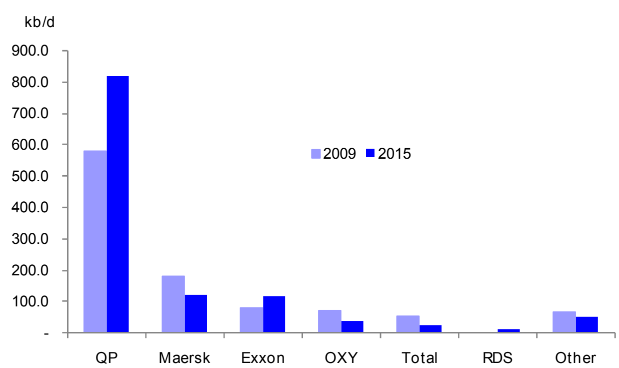
Source: Wood Mackenzie

Figure 494: Gas production to 2003- 2015E (mmcfd)



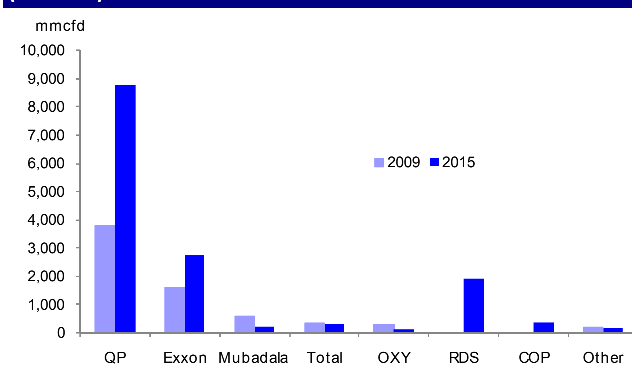
Source: Wood Mackenzie

Figure 495: 2009/15 Liquids production by company (kb/d)



Source: Wood Mackenzie

Figure 496: 2009/15 Gas production by company (mmcfd)



Source: Wood Mackenzie

Pipeline 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 oil consuming only 15% of the 1.3mb/d of oil 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 around $2 million.
- Cost Recovery: the contractor can recover costs from a negotiated percentage of production ranging between 20-65%. The only exception to this 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 497: 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%) however 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 498: 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 eleven 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 on-stream 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 499: Qatar: Key gas projects: on-stream and planned

Project	IOC*	BCF Gas Reserves	Mb Liquid reserves	Capacity (mtpa)	Start up
Qatargas	XOM 10%, TOT 10%	9257	193	9.7	1996
Qatargas 2	XOM 24%, TOT 8%	22064	804	15.6	2009
Qatargas 3	COP 30%	11368	398	7.8	2010
Qatargas 4	RDS 30%	11151	390	7.8	2011
Rasgas	XOM 25%	7676	307	6.6	1999
Rasgas II	XOM 30%	19362	678	14.1	2004
Rasgas 3	XOM 30%	21963	769	15.8	2009
Pearl GTL	RDS 100%	15,000	521	12.5**	2011

*Source: 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. This project has suffered a number of technical difficulties and to date has not yet achieved full design capacity. Pearl GTL, operated by Shell and due on-stream in 2011, promises to be the largest plant of its kind in the world. It aims to monetise some 15TCF of gas and condensates from the North Field over the next 25 years. Upon completion, Pearl's production 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

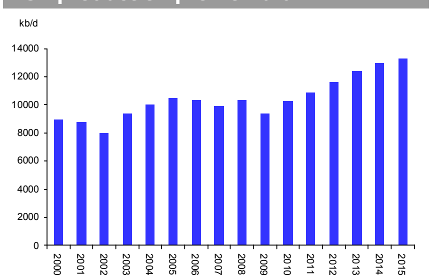
Saudi Arabia

Key facts

Liquids production 2009E	**9.4 mb/d**
Gas production 2009E	**1.0mboe/d**
Oil reserves 2009E	264bn bbls
Gas reserves 2009E	258TCF
Reserve life (oil)	77years
Reserve life (gas)	114years
GDP 2009E ($bn)	$597bn
GDP growth 2009E (%)	0.7%
Population 2009 (m)	25.5m
Oil consumption 2008 (mb/d)	2.4mb/d
Oil exports 2008 (mb/d)	8.4mb/d
Fiscal regime (concession)	Income tax & royalty
Marginal tax rate (concession)	80%
Top 3 fields (2009)	
Ghawar	5,168kboe/d
AFK Fields	673kboe/d
Safaniyah	606kboe/d
Top Producer (2009)	
Saudi Aramco	10,375kboe/d
Chevron	128kboe/d

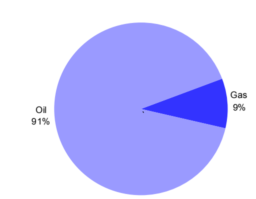
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



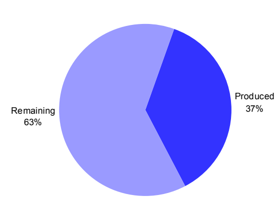
Source: Wood Mackenzie

Remaining reserves split %



Source: Wood Mackenzie

Initial versus remaining reserves



Source: Wood Mackenzie

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 in the beginning of 2009 stood at 264bn bbls and gas reserves at 258TCF. 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 to 9mb/d, fluctuating in response to global demand and OPEC production quotas. In 2009, crude oil output averaged 8.3mb/d (excluding NGLs, which accounted for 1.1mb/d) some way below estimated crude production capacity of 12.5mb/d due to quota cuts put in place in late 2008. Total gas production stood at 1mboe/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.

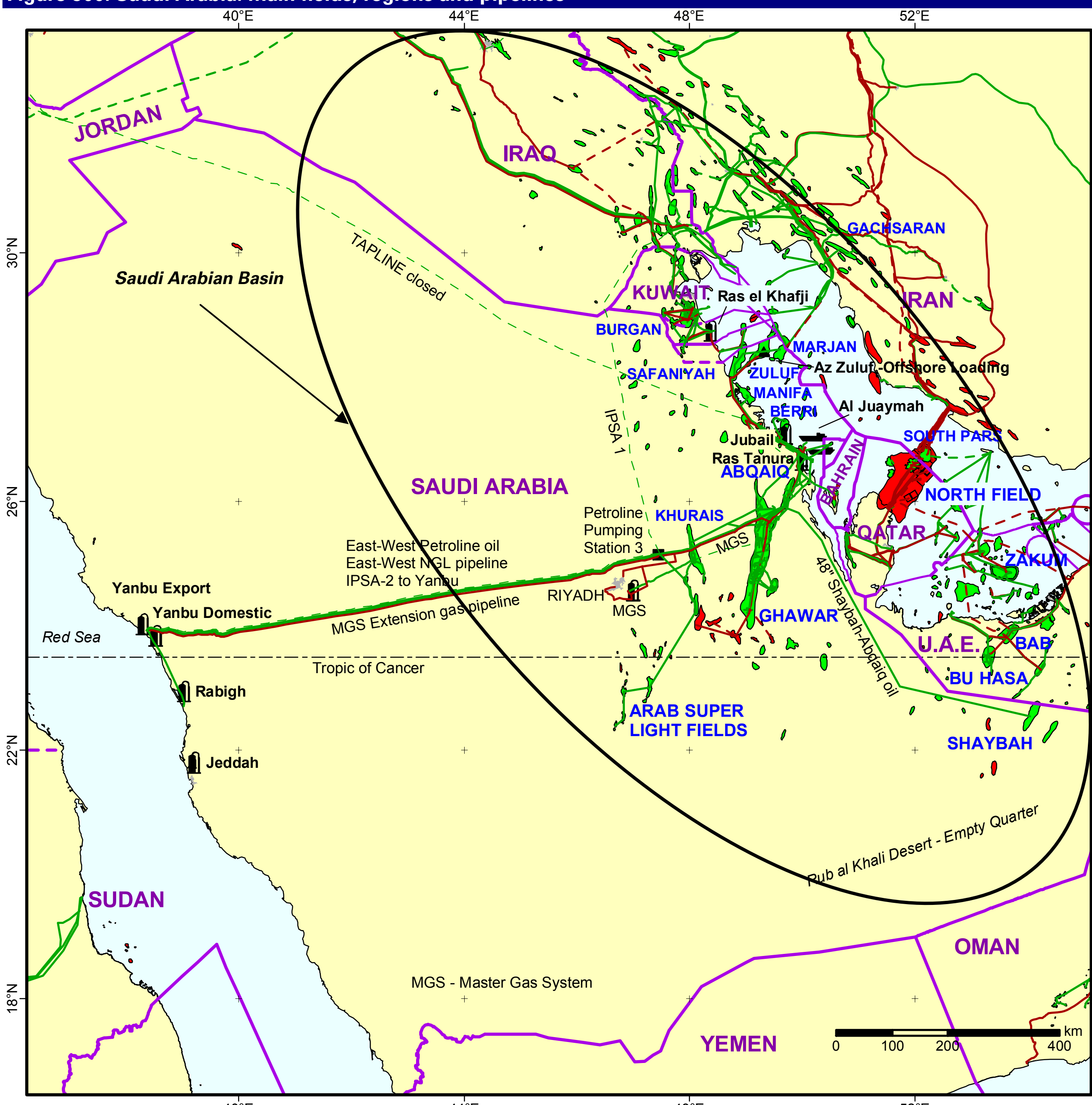
Regulation and history

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.

Figure 500: 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 km^2 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 out 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. 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 km^2. 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. Exploration results have however been disappointing with Total withdrawing from its partnership with Shell as a consequence.

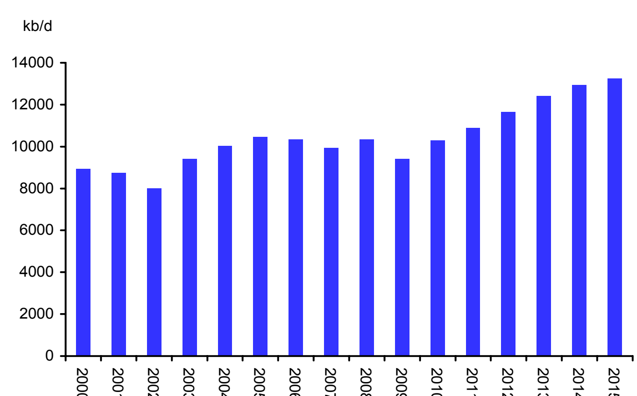
Production of Oil and Gas

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. As a result, production has never quite returned to its historical peak of 10 mb/d in 1980.

For much of the last decade, crude output has remained between 8 and 9 mb/d. However, the Iraq War and events in other OPEC nations allowed Saudi Arabia to expand its production levels. 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. Inclusive of NGLs, liquids production stood at 9.4mb/d in 2009. Production is heavily dominated by Ghawar, the largest oil field in the world. This single oil field accounted for 5.2mb/d of oil, over 50% of Saudi production and an estimated 6.5% of total world production.

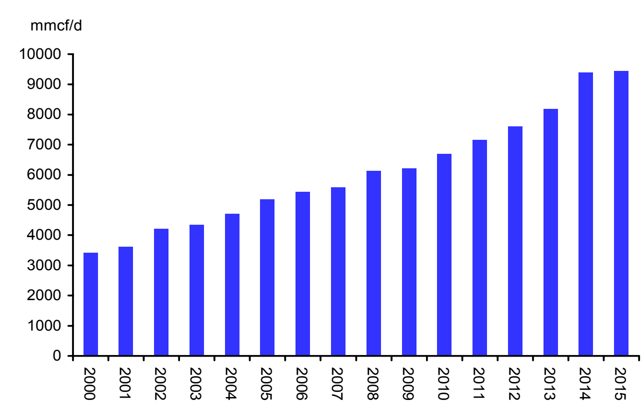
Gas production in Saudi Arabia also has considerable potential, however, only a small portion of this has been realised to date. In 2009, gas production stood at 6.2bcf/d but while significant additional potential exists, installation of the appropriate facilities is still required at most existing crude oil fields. Current production consists predominantly of associated gas and therefore remains heavily dependent on the global oil market. The government tried to address this issue by introducing the Natural Gas Initiative, however to date, it has not lived up to expectations. As such, Saudi Aramco increased its own gas exploration efforts which resulted in successful discoveries of non-associated gas at Arabiyah, Hasbah, Karan, most of which were put on fast tract development to meet growing domestic gas demand.

Figure 501: Saudi Arabia liquids production, 2000-2015



Source: Wood Mackenzie

Figure 502: Saudi Arabia gas production, 2000-2015



Source: Wood Mackenzie

Capacity expansion plans

Crude production still remains significantly below full capacity of approximately 12.5 mb/d. Saudi Aramco continually revises its five-year operation plans in line with market conditions. With 3mb/d of spare capacity at the end of 2009 (well above the desired 2mb/d), many of the new developments (we estimate 3mb/d of capacity is under consideration) will depend upon market conditions in the future. Detailed below are the projects that form the basis of Saudi Aramco's development plan:

Figure 503: Selected planned upstream projects

Project	Product type	Year onstream	Est. gross addition (kb/d)
Manifa	Arab Heavy	2013	900
Zuluf	Arab Heavy	2016-2021	900
Safaniyah	Arab Heavy	2016-2021	700
Berri and Khurais	Arab Light	2016-2021	300
Shaybah (Expansion)	Arab Extra Light	2016-2021	250

Source: Wood Mackenzie, Deutsche Bank

The trend in recent years has been to produce light, premium grade crude. This is because it is able to command a relatively high price. However, this is unlikely to be sustainable in the longer term. Heavier and sourer grades will have to be added to supply and these are likely to form the basis of production plans beyond 2010. The most notable of these is Manifa, an offshore, heavy crude field, which is scheduled to be brought onstream in 2013.

Reserves and resources

Saudi Arabia has the largest remaining reserves of oil in the world; at 264 billion barrels this is twice the volume of the next largest conventional oil reserve base in the world. As of January 2009, it is thought that around 40% of initial commercial reserves have been produced and c.1.7% of remaining reserves is 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 58 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. Initial commercial reserves are estimated to be 154TCF (2009E, Wood Mackenzie), 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 118TCF. Further potential for discovery also still remains; Wood Mackenzie estimates that an additional 112TCF 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 a 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 a capacity of over 6 mb/d. Along with several other smaller terminals, these facilities have an 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. With gas discoveries at Arabiyah, Hasbah, Karan and Manifa, Saudi Aramco plans to expand gas processing capacity at Khursaniyah and to construct a new plant at Manifa as part of the development of the fields.

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 70% of crude output by volume. Unsurprisingly, the primary source of Arab Light is the Ghawar oil field. Projects to expand production will also add a further 1.7 mb/d to capacity of Arab Light by 2009.

Both Arab Extra Light and Arab Super Light represent a comparatively small proportion of overall output, with 2009 production levels of 1000 kb/d and 200 kb/d respectively. Yet although light, premium grade crude currently dominates production, Arab Heavy is likely to have a significant role in Saudi Aramco's production plans beyond 2010.

Figure 504: 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, however, they have vastly improved in line with the Natural Gas Initiative. Terms focus exclusively on gas and condensate since commercial discoveries classified as oil automatically revert to the ownership of Saudi Aramco. Saudi Arabia has a 30% equity stake in the area operated by Shell and a 20% equity stake in the remaining three areas operated by Lukoil, Sinopec and ENI/Repsoil. Royalty payments do not have to be paid on gas and NGL. However, condensate is subject to a royalty on gross revenues of 20%. Net income is 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%. Corporate income tax levied at a rate of 30% is allowed as credit against NGIT liabilities.

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. Note that the Khafji refinery processes oil from the offshore concession in the Partitioned Zone. The key refinery units are listed below:

Figure 505: 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

Future plans for refinery development are expected to include foreign participation. In 2006, ConocoPhillips signed a Memorandum of Understanding to build a proposed 400kb/d full-conversion refinery in Yanbu designed to process heavy crude. Following a sharp downturn in refining markets and a greater focus on capital efficiency Conoco announced that it was withdrawing from the project in 2010. Aramco has, however, progressed with the development awarding contracts in July 2010 for the delivery of the refinery at an estimated cost of around $10-12bn. Separately, Saudi Aramco established a joint venture with Total to build a refinery of similar capacity and complexity in Jubail start-up of which is envisaged in 2012/13 at an estimated cost of just under $10bn. It is intended that 30% of the project will ultimately be sold to the public via a stock market listing. Elsewhere, a 400kb/d capacity expansion project at Ras Tanura is on track and is expected to come on-stream in 2013. All of these projects, together with the Yanbu capacity expansion plan, should see an incremental 1.3mb/d added to existing capacity by 2015.

Saudi Arabia – notes

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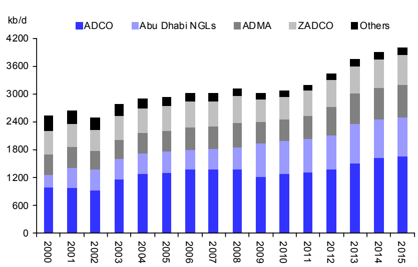
United Arab Emirates

Key facts

Oil production 2009E	3mb/d
Gas production 2009E	4bcf/d
Oil reserves 2009E	98bn bbls
Gas reserve 2009E	214TCF
Reserve life (oil)	89years
Reserve life (gas)	145years
GDP 2009E ($bn)	$188bn
GDP Growth 2009E (%)	1.4%
Population (m)	4.9m
Oil consumption (mb/d)	525kb/d
Oil exports (mb/d)	2.5mb/d
Fiscal regime	Tax & Royalty
Marginal tax rate	88%
Top 3 fields (2009E)	
ADCO Contract Area	1,676kboe/d
ADMA Contract Area	629kboe/d
Upper Zakum	450kboe/d
Top 3 Producers (2009E)	
ADNOC	2,633kboe/d
Exxon	243kboe/d
BP	198kboe/d

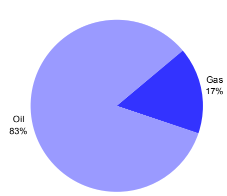
Source: Wood Mackenzie data; EIA; Deutsche Bank estimates

Oil Production profile kb/d



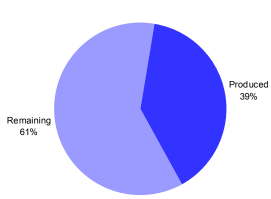
Source: Wood Mackenzie data

Remaining reserves split oil & gas %



Source: Wood Mackenzie data

Produced and remaining reserves



A confederation of seven Arab states, in 2009 the United Arab Emirates (UAE) is estimated to have produced some 3mb/d of crude oil and condensates from reserves which at the end of 2009 stood at 98bn barrels. Abu Dhabi, the largest Emirate, dominates the UAE's oil and gas industry accounting for all but 100kb/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 2.3mb/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 north-west 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 international oil companies 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 policy making 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 (principally BP).

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 the UAE's entry to OPEC in 1967, however 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 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 506: Ownership of Abu Dhabi's main oil producing companies

	ADNOC	BP	Total	Inpex	Shell	Exxon	Partex
ADMA	60.0%	14.7%	13.3%	12.0%	-	-	-
ADCO	60.0%	9.5%	9.5%	-	9.5%	9.5%	2.0%
ZADCO*	60.0%	-	-	12.0%	-	28.0%	-

*Source: Deutsche Bank *Shares shown are those for the main Upper Zakum field*

Figure 507: UAE: Main fields, regions, and pipelines

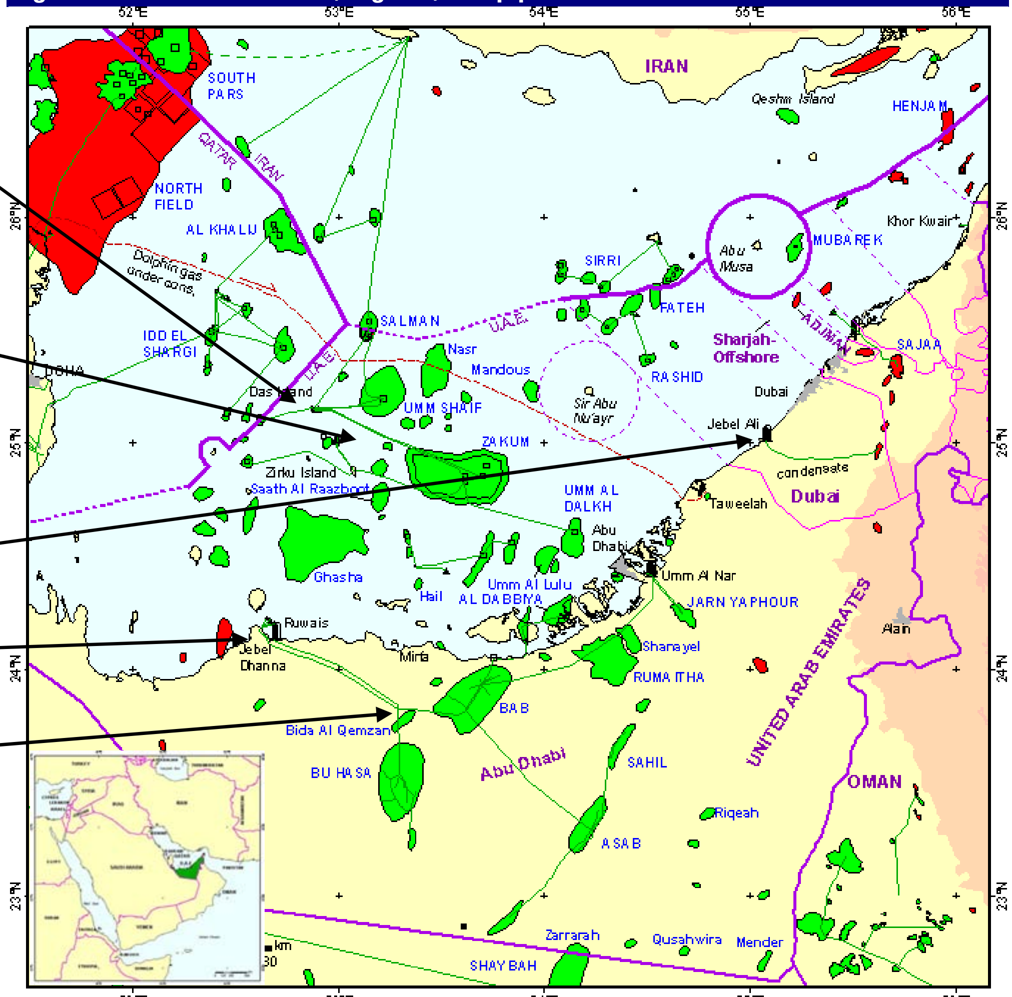
Das Island home of ADGAS LNG's 5.2mtpa facility

Major Zakum and Umm Shaif (ADMA/ZADCO) offshore fields

Main condensate processing facility

500kb/d Ruwais refinery

Key Bab, Bu Hasa and Asab fields onshore (ADCO)



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 near 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 on 2-04 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.

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 3mb/d in 2009 (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 508: Key fields in Abu Dhabi

Field Name	Emirates	Operator	Discovery	Current reserves (bn bbls)	2009E kb/d	2015E kb/d
Bu Hasa	Abu Dhabi	ADCO	1962	1,096	503	660
Upper Zakum	Abu Dhabi	ZADCO	1964	4,190	450	630
Bab	Abu Dhabi	ADCO	1954	589	293	370
Lower Zakum	Abu Dhabi	ADMA	1964	1,023	255	325
Asab	Abu Dhabi	ADCO	1965	445	215	265
Umm Shaif	Abu Dhabi	ADMA	1958	915	210	300

Source: Wood Mackenzie, Deutsche Bank

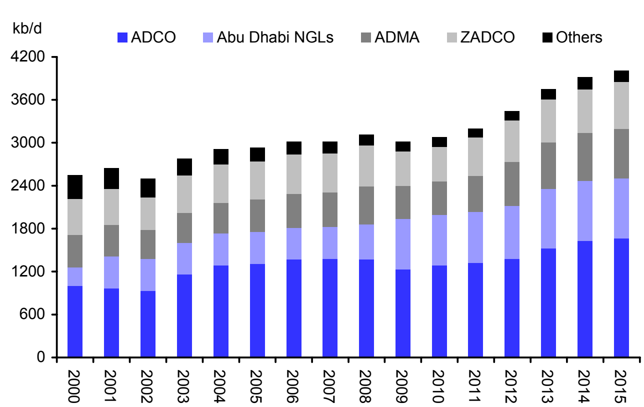
Abu Dhabi intends to increase production capacity from the current sustainable level of 2.8mb/d of liquids to 3.5mb/d by 2017 by upgrading and expanding the country's existing fields and infrastructure. Following some delays, this now looks achievable if the present capacity expansion programme is successfully implemented.

Figure 509: Capacity expansion programme by ADNOC

Fields	Type	Onstream	Capacity addition (kb/d)
Sahil-Asab-Shah (SAS)	Expansion	2013	60
Bab	II Phase	2015	100
Bu Hasa	Ramp up	n/a	130
Huwaila, Bida Al Qemzan and Qusahwira	Development	2013 - 2014*	120
Umm Shaif	Gas injection	2012	50
Lower Zakum	De-mothballing	Initial stage	100
Umm Al Lulu, Nasr and Saath Al Raazboot	Development	2011 - 2015*	265
Upper Zakum	Expansion	2015 - 2018	550
Umm Al Dalkh and Satah	Development	Initial stage	20

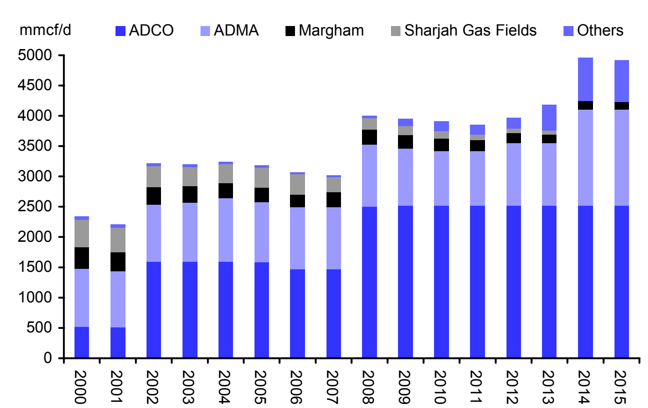
*Source: Wood Mackenzie, Deutsche Bank. *Full capacity is expected in 2018.*

Figure 510: UAE – Liquids Production 2000-15E (kb/d)



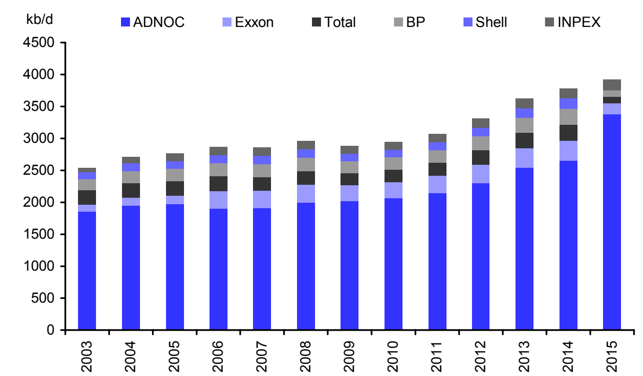
Source: Wood Mackenzie; Deutsche Bank

Figure 511: UAE – Gas production 2000-15E (mscf/d)



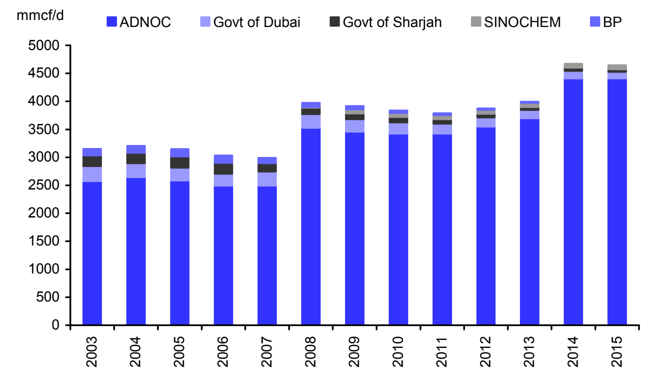
Source: Wood Mackenzie; Deutsche Bank

Figure 512: UAE – Main oil producers 2000-15E



Source: Wood Mackenzie; Deutsche Bank

Figure 513: UAE – Gas production 2000-15E (mscf/d)



Source: Wood Mackenzie; Deutsche Bank

In natural gas, strong domestic growth in demand has seen the UAE struggle to meet the requirements of its economy from its domestic production. Gas production in 2009 was around 4bcf/d, of which a quarter was exported as LNG, but is expected to grow to nearer 5bcf/d from 2015 as new sources are brought onstream, not least the huge Khuff reservoir in the Umm Shaif field. Despite this growth, the Emirates' emerging gas deficit has seen it source some 2bcf/d from neighbouring Qatar through the $3.5bn Dolphin project constructed by Total (24.5%) and Occidental (24.5%). Outside Abu Dhabi, around 500mscf of gas is produced in both Sharjah and Dubai although production from both is now in decline.

Reserves and Resources

At the end of 2008 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 214TCF 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 514: 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

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 off-settable 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 370kb/d is modest relative to oil production. Capacity is dominated by the 120kb/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 Sharjah (75kb/d at Hamriyah) and Fujairah (90kb/d). At the time of writing plans to build a further 500kb/d refinery in Fujairah are also being studied.

LNG

The UAE operates one LNG plant. Built in 1977 the ADGAS facility on Das Island offshore Abu Dhabi has a current capacity of 5.2mtpa, that capacity being reached post the start up of a 3mtpa second train in 1994. 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. Given the growth in domestic demand for gas further expansions of the ADGAS facility are not envisaged at this time despite the Emirates huge proven reserves of natural gas.

UAE – Notes

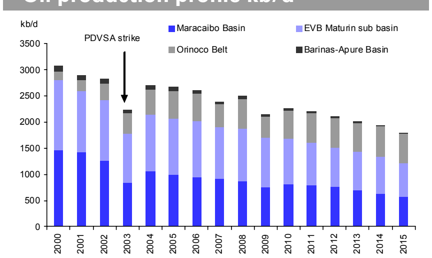
Venezuela

Key facts

Oil production 2009E	2.2 mb/d
Gas production 2009E	0.2mboe/d
Oil reserves 2009E	99bn bbls
Gas reserves 2009E	171TCF
Reserve life (oil)	120 years
Reserve life (gas)	387 years
GDP 2009E ($bn)	$357.5bn
GDP growth 2009E (%)	-0.5%
Population 2009E (m)	28.6m
Oil consumption 2008E (b/d)	0.75kb/d
Oil exports 2008E (mb/d)	1.89mb/d
Fiscal regime	Concession
Marginal tax rate (concession)	68%
Top 3 fields (2009E)	
Carito-Mulato	282kboe/d
El Furrial	203kboe/d
Maracaibo	187kboe/d
Top Producer (2009E)	
PdVSA	2,378kboe/d
Chevron	63kboe/d
Total	53kboe/d

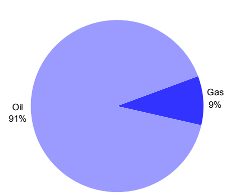
Source: Wood Mackenzie, EIA, IMF

Oil production profile kb/d



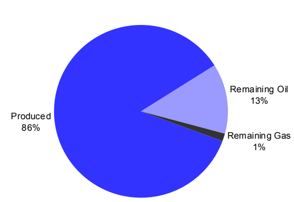
Source: Wood Mackenzie

Remaining commercial reserves split %



Source: Wood Mackenzie

Initial vs. remaining reserves (developed)



Source: Wood Mackenzie

One of the founding members of OPEC, Venezuela is currently estimated to produce around 2.7% of world crude oil supply. With 99bn barrels of oil reserves, Venezuela has the largest reserves of conventional oil in the Western hemisphere. This figure does not include substantial reserves of extra heavy oil and bitumen which could be as high as 270 billon barrels. Of the 2.2mb/d of oil produced, around 0.7mb/d is consumed domestically, with the balance exported, mostly to the US which receives c.1.2mb/d of Venezuelan crude and products (or c.9% 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 and BP.

Basic geology and topology

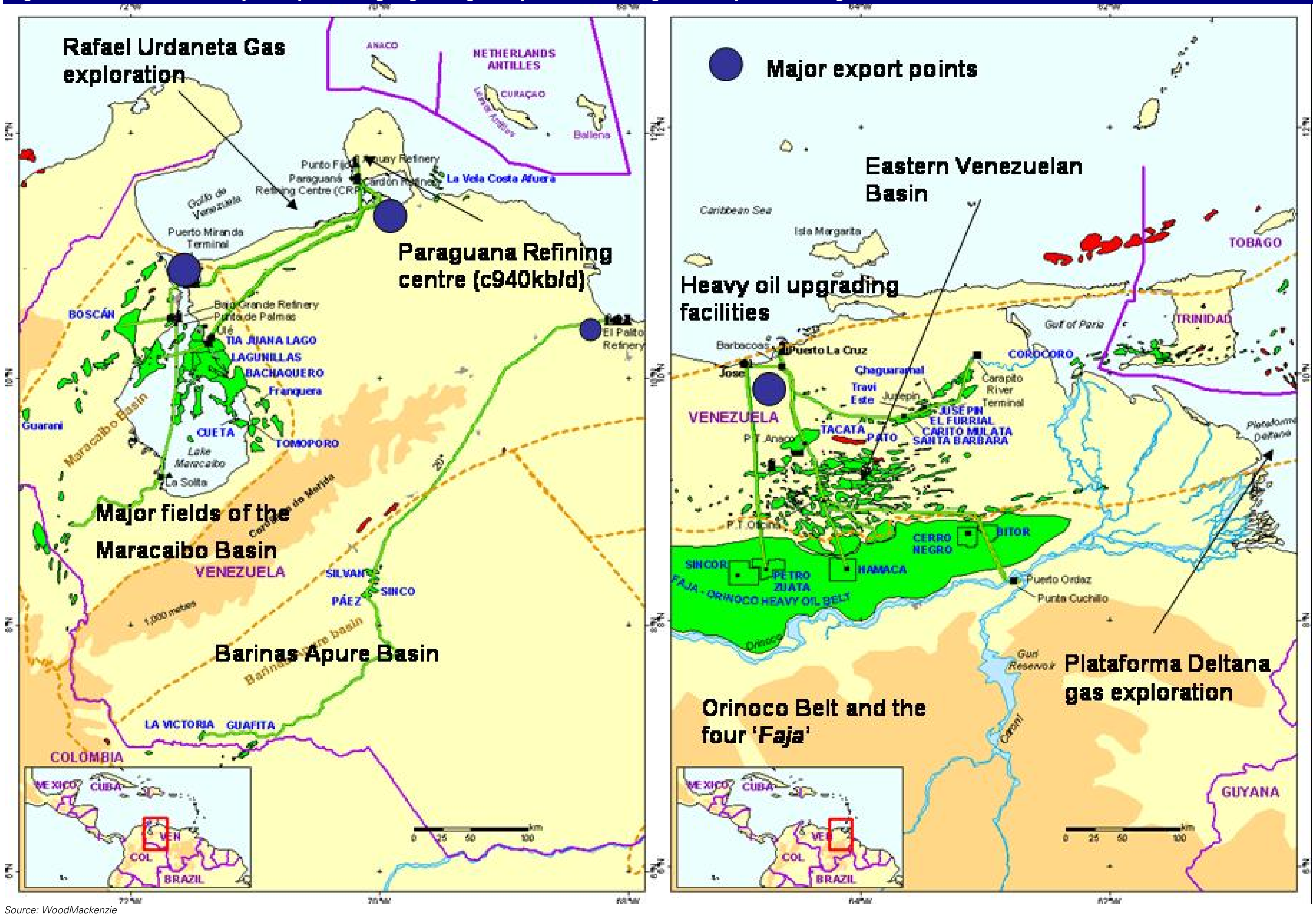
Venezuela occupies the northern coastal region of South America. Some 35% of the country is covered by sedimentary basins, all in northern Venezuela. There are five main sedimentary basins, all of which yield hydrocarbons. Two of these, the Maracaibo and Eastern Venezuela, are major oil and gas provinces, 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 existing heavy oil projects (Petromonagas, Petrocedeno, Petroanzoategui and Petropiar) contains vast reserves of extra heavy oil and dwarves all other fields found elsewhere in Venezuela.

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 thirty two Operating Service Agreements (OSAs) for the development of a series of so-called 'marginal fields' with twenty two 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 also embarked on 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, which 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 who failed to agree compensation effectively seeing their assets expropriated (notably ENI and Total). This trend towards nationalisation was repeated in 2007 when the authorities successfully pressured several IOCs to renegotiate the four Strategic Association.

Figure 515: Venezuela – major oil producing regions, gas exploration acreage and export/refining facilities



Source: WoodMackenzie

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, the only certainty regarding the granting of future oil licenses is that they must be signed in accordance with the 2001 Hydrocarbon Law. There has been no formal licensing round since 1996 with any future licensing likely to be undertaken on an ad-hoc basis. Former licensing rounds were characterised by the fact that winning bids were based on the cash bonus offered by each consortium and a number of blocks were reserved for consortia with a Venezuelan company as both operator and 30% stakeholder. Whether the same principals will be followed in any future rounds remain to be seen.

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). Any licenses awarded in these rounds were granted on the basis of a signature bonus.

Production of Oil and Gas

In 2008, Venezuela was the world's eighth largest oil producer and the largest net oil exporter in the western hemisphere. Current production is estimated by Wood Mackenzie at some 2.2mb/d of oil and 1.3bcf/d of gas, although PdVSA states production is nearer 3.11mb/d. 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.

The Maracaibo basin (c765kb/d) 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 Eastern Venezuelan basin (c936kb/d) especially when the Orinoco belt (407kb/d) is included. Key oil producing fields are detailed below:

Figure 516: Venezuela' s key oil producing fields

Field	Recoverable Reserves	Remaining Reserves	Start-up	Production 2009	Production 2015
	(mmbbl)	(mmbbl)		(kb/d)	(kb/d)
Carito-Mulata	2,283	669	1942	282	131
El Furrial	3,053	762	1986	203	141
PDVSA-Maracaibo	13,530	354	1920	186	66
Santa Barbara	1,352	437	1943	161	77
Petrocedeno (Sincor)*	1,935	1,491	2000	140	180
Ceuta-Tomoporo	1,945	761	1957	139	178
Petropiar (Hamaca)*	1,866	1,497	2001	135	171
Petroanzoategui (Petrozuata)*	1,279	883	1998	98	107

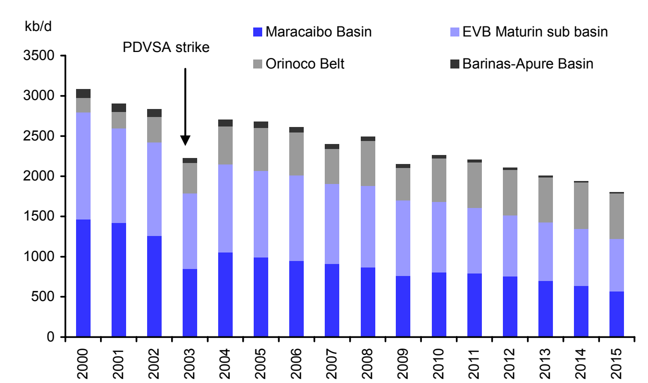
*Source: Wood Mackenzie, *Extra Heavy oil producing fields in the Orinoco Heavy Oil belt*

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 then 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 have 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.

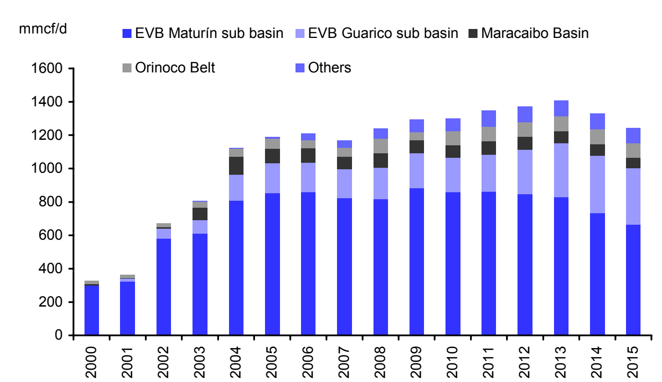
Gas production in Venezuela has always been tied to oil production, with the oil industry consuming up to 70% of output to enhance oil recovery. Total commercial gas production in 2009 was only 1.3bcf. However, PdVSA Gas has set a target of increasing domestic gas sales to 2.5bcf by 2012, a target it aims to achieve through expansion of the non-associated gas reserves base. Repsol-YPF is the largest private natural gas producer in Venezuela with total production of 198mmcf/d (largely Quirequire) in 2009, but other IOCs such as Total, Chevron, Statoil, BP and Eni also have a presence in the gas sector.

Figure 517: Venezuela oil production 2000-15E (kb/d)



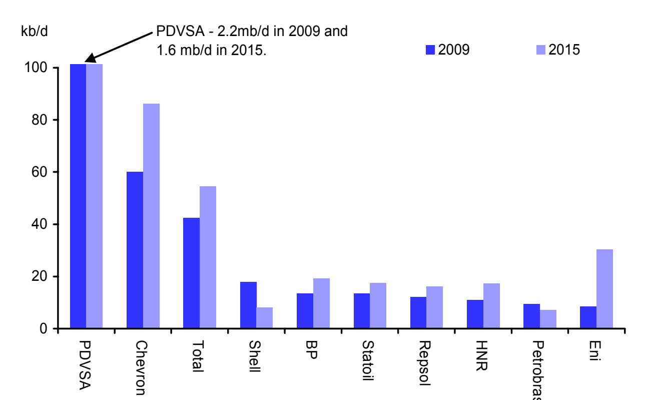
Source: Wood Mackenzie

Figure 518: Venezuela gas production 2000-15E (mmcf/d)



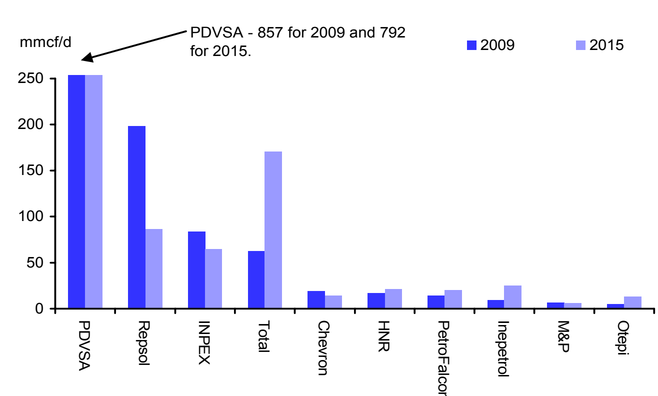
Source: Wood Mackenzie

Figure 519: Venezuela: Major Oil producers 2009/15E



Source: Deutsche Bank, ** exited country in 2007

Figure 520: Venezuela: Major Gas producers 2009/15E



Source: Deutsche Bank, ** exited country in 2007

Reserves and Resources

With total estimated remaining reserves of conventional oil at 99 billion barrels Venezuela has the largest proven reserves in the western hemisphere. Conventional oil reserves aside the country also has an additional 1.3 trillion barrels of extra heavy oil in place in the Orinoco belt of which 270 billion barrels are estimated to be recoverable.

PdVSA previously stated that it intends to invest some $26 billion in expanding reserves and production between 2006 and 2012 with the goal of increasing production to 5.8mb/d by 2012. However, the financial commitments of funding its share of investment under the Empresa Mixta, not to mention the financial demands placed on it by the government, have impeded PdVSA's ability to achieve its investment and as such its production targets. Currently the company spends more per annum on social programs than investments to maintain and expand oil production capacity. This drain on its finances, coupled with the diminishing presence of IOCs in the country has brought into question PdVSA's ability to meet the necessary investment required. Key fields for future development include Tomporo (100mbbl), Chaguaranal (350mbbls) and further development of the Orinoco Heavy Oil belt's 182bn bbls of reserves.

Oil aside, at 171tcf Venezuela has 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.

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 521: 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 2012, by which time Venezuela hope 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' 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.

Refining and Downstream markets

In 2009 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, which should add a further 650kb/d to domestic refining capacity. However, no progress has been made to date due to on-going 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 will 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.

Venezuela - Notes

Section III: the Companies

The European Majors

BP

RDS

Total

ENI

Repsol

Statoil

BG Group

OMV

Galp Energia

The US Majors

ExxonMobil

Chevron

ConocoPhillips

Europe United Kingdom
Oil & Gas Integrated Oils

8 September 2010

BP

Reuters: **BP.L** Bloomberg: **BP/ LN**

Visibility vs. Value

Despite the clear improvement in fundamentals associated with Tony Hayward's tenure as CEO, BP's prospects over the next 18-24 months look certain to be overshadowed by the GoM Macondo incident. Beyond adding uncertainty on the outlook for near term production growth and cash flow, reputational damage has the potential to be significant while litigation and BP's liability could take years to reach conclusion. Having said this, even allowing for considerable fines and litigation costs, the depth, quality and robustness of BP's asset base argues that the share price offers very significant potential upside over a 3-5 year view, with additional value set to be realized from a more aggressive approach to divestments.

Conventional E&P: Over the last decade, BP has built leading positions in some of the world's largest basins, not least the GoM, Angola and Caspian, and has found more oil and gas at a lower cost than any of its peers. These new growth centres now represent 50% of BP's upstream portfolio (from 30% in 1999), with mature regions such as the UK and Alaska having fallen to a modest 15%. Elsewhere, BP's unique and differentiated position in Russia via BP-TNK is fundamental to the company's overall performance (c.25% upstream volume), as well as being a key driver of organic reserves replacement.

Downstream: Despite roughly 55% of its nominal 2.7mb/d of refining capacity being located in higher gross margin US markets, BP's downstream performance in recent years has been woeful. However, having now reinstated production at both Whiting and Texas City, utilisation and profitability should improve from here (coming as it does from a low base) and better reflect the business's underlying complexity and potential.

Other: BP has a leading presence in the growth petrochemical markets for polyester precursors (paraxylene and purified terephthalic acid or PTA). It is also active in alternate energy sources such as solar, wind, hydrogen and biofuels.

Valuation & Risk

Our Buy stance reflects our view that despite the very significant uncertainties associated with the Deepwater Horizon tragedy on the GoM, BP's valuation has now effectively written off the full value of its US portfolio. The risks associated with Macondo suggest to us that BP should trade at a 20% discount to our sector 2011 PE target which suggests a 520p PT. This is supported by its 510p NAV of non-US assets. The key downside risk to our stance is the risk of potential US litigation following the Deepwater Horizon tragedy in the GoM.

Forecasts and ratios

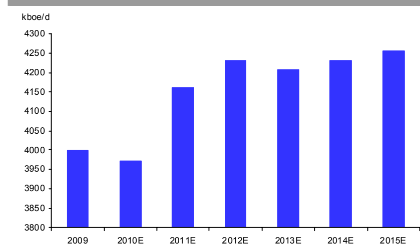
Year End Dec 31	2008A	2009A	**2010E**	2011E
DB EPS – ex Macondo (USD)	1.40	0.78	**1.04**	1.25
P/E (x)	7.1	10.4	**5.9**	4.9
Dividend Yield (%)	5.6	6.9	**2.2**	8.8

Source: Deutsche Bank estimates, company data

Buy

Price at 6 Sept 2010 (GBP)	**401.60**
Price Target (GBP)	**520.00**
52-week range (GBP)	**655.40 - 298.60**

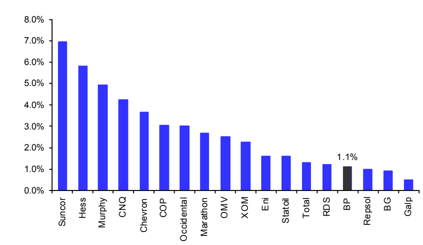
BP Production Profile 09-15E



Source: Deutsche Bank

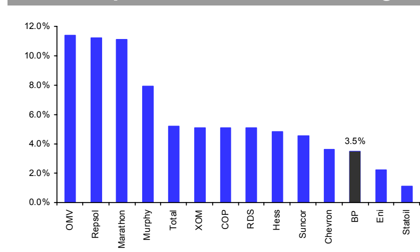
Upstream CAGR (2009 – 15E)	1.0%
Oil production (2009)	2,535kb/d
Gas production (2009)	1,463kboe/d
Oil Reserves (1P)	10.4bn/bbls
Gas Reserves (1P)	7.8bn/boe
Refining capacity	2,666kb/d
Marketing volumes	5,887kb/d
Wood Mackenzie 2P(E) Total reserves	30.3bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.25 %

Sensitivity to $1/bbl move in oil



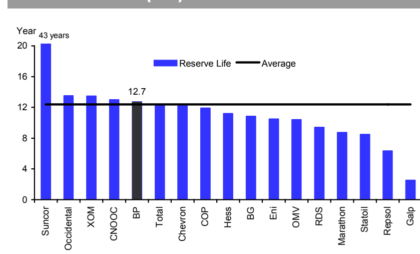
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 522: BP Net Asset Value by Asset

Upstream	Comments	Value ($ Million)	Value (GBP Million)	2 P Reserves	Value/2P Reserves	% of Total EV	GBP Value per Share
Algeria		2,731	1,773	806	3.4	0.9%	0.09
Angola	*OPEC inclusion could push out*	19,643	12,755	1846	10.6	6.5%	0.68
Argentina		3,735	2,425	1108	3.4	1.2%	0.13
Australia		9,662	6,274	614	15.7	3.2%	0.33
Azerbaijan	*Key asset - upside in Shah Deniz*	19,323	12,547	2133	9.1	6.4%	0.67
Bolivia		397	258	88	4.5	0.1%	0.01
Canada West sales value	*Sales value*	3,250	2,110	1853	1.8	1.1%	0.11
China		477	310	45	10.6	0.2%	0.02
Colombia sales value	*Sales value*	1,900	1,234	195	9.7	0.6%	0.07
Egypt		4,133	2,684	1484	2.8	1.4%	0.14
Indonesia		3,131	2,033	774	4.0	1.0%	0.11
Iraq		1,249	811	5317	0.2	0.4%	0.04
Norway		3,728	2,421	308	12.1	1.2%	0.13
Pakistan		683	444	67	10.1	0.2%	0.02
Qatar		9	6	0	19.5	0.0%	0.00
Russia	*All through TNK*	45,377	29,466	11317	4.0	15.1%	1.57
Trinidad		9,032	5,865	1620	5.6	3.0%	0.31
United Arab Emirates	*Big production barrels, little value*	2,290	1,487	587	3.9	0.8%	0.08
United Kingdom		16,116	10,465	1140	14.1	5.4%	0.56
United States Alaska	*Potential divestment*	14,610	9,487	2863	5.1	4.9%	0.51
United States Gulf Coast		2,474	1,607	292	8.5	0.8%	0.09
United States Gulf of Mex	*The BP heart*	44,219	28,714	2643	16.7	14.7%	1.53
US Conc MidContinent		6,804	4,418	1243	5.5	2.3%	0.24
US Permian sales value	*Sales value*	3,100	2,013	122	25.4	1.0%	0.11
US Conc Rocky Mountains		14,509	9,421	1880	7.7	4.8%	0.50
Venezuela		872	566	169	5.2	0.3%	0.03
Vietnam		972	631	100	9.7	0.3%	0.03
Sub-Total		**234,427**	**152,225**	**40,616**	**5.8**	**78.1%**	**8.11**
Refining							
Europe		7,152	4,644			2.4%	0.25
USA	*Understates value?*	18,032	11,709			6.0%	0.62
Rest Of World		1,590	1,033			0.5%	0.05
Sub-Total		**26,775**	**17,386**			**8.9%**	**0.93**
Marketing		15,200	9,870			5.1%	0.53
Refining & Marketing		**41,975**	**27,256**			**14.0%**	**1.45**
Chemicals		**9,000**	**5,844**			**3.0%**	**0.31**
Gas, Power & Renewables							
Liquefaction plants	*Liquefaction assets only*	2,769	1,798			0.9%	0.10
LNG contracts		2,515	1,633			0.8%	0.09
Renewables (BP estimate)		7,900	5,130			2.6%	0.27
Ships		1,750	1,136			0.6%	0.06
Sub-Total		14,934	9,698			5.0%	0.52
Total Enterprise Value		**300,336**	**195,024**			**100.0%**	**1038**
Adjusted end-2009 Net Debt		26,288	16,238			8.3%	86
Macondo liability	*As per BP provisions mid 2010*	21,850	14,188			7.3%	76
Net Asset Value		**252,198**	**164,597**			**84.4%**	**876**
Market Capitalisation		**117,568**	**76,343**				**407**
Premium to NAV		**-53%**	**-54%**				**-54%**

Source: Wood Mackenzie, Deutsche Bank

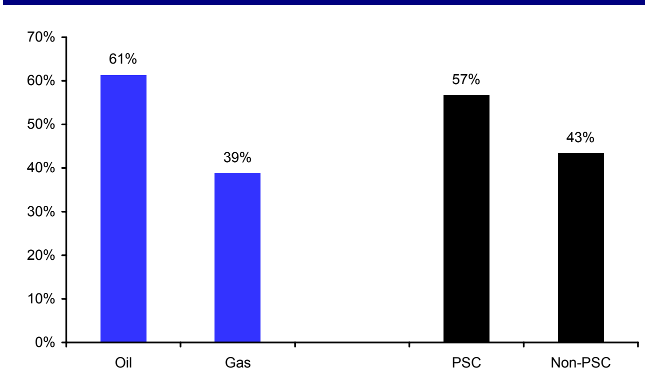
BP – Main projects 2009-15E

Figure 523: BP – Major Oil & Gas Projects by Year 2009-2015E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	BP %	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Berau PSC	Indonesia	2009	33	1,285	4	147	3,151	48%	Yes	19	59	72	72	72	72	70	1,605
Muturi PSC	Indonesia	2009	12	478	2	63	948	1%	Yes	0	1	1	1	1	1	1	9
Dorado (VK 915)	US	2009	30	6	15	3	488	75%		14	14	12	9	7	5	4	565
2010																	
Great White	US	2010	310	125	64	26	7,026	33%		0	8	18	21	23	25	26	1,943
2011e																	
Block 31 PSVM	Angola	2011	518	0	150	0	10,702	27%	Yes	0	0	1	32	40	40	40	1,494
Pazflor	Angola	2011	720	0	200	0	11,398	17%	Yes	0	0	4	31	33	33	33	1,452
Skarv Area	Norway	2011	172	254	85	88	6,207	24%		0	0	9	31	33	26	24	1,074
Liberty	US	2011	100	0	40	0	1,458	100%		0	0	11	22	34	40	32	1,156
Isabela (MC 562)	US	2011	28	12	16	7	487	67%		0	0	6	11	15	12	8	299
Santa Cruz (MC 519)	US	2011	28	12	16	7	487	47%		0	0	4	8	10	8	6	232
2012e																	
Angola LNG	Angola	2012		1,402	0	176	n.a	14%	Yes	0	0	0	10	21	24	24	n.a.
Kizomba Satellites (P1)	Angola	2012	253	0	100	0	3,519	27%	Yes	0	0	0	12	27	23	21	558
Devenick	UK	2012	12	60	7	35	679	96%		0	0	0	13	40	37	31	522
2014e																	
CLOV	Angola	2014	604	0	160	0	9,442	17%	Yes	0	0	0	0	0	13	27	527
Sunrise	Canada	2014	3,000	0	200	0	12,429	50%		0	0	0	0	0	3	13	762
Kessog	UK	2014	45	34	15	11	858	100%		0	0	0	0	0	23	26	792
2015e +																	
Block 18 West	Angola	2015	203	0	80	0	3,998	50%	Yes	0	0	0	0	0	0	24	403
Kizomba Satellites (P2)	Angola	2015	454	0	182	0	6,875	27%	Yes	0	0	0	0	0	0	3	767
Shah Deniz (P2)	Azerbaijan	2015	331	1,392	70	272	19,038	26%	Yes	0	0	0	0	0	0	2	706
North Alexandria Fields	Egypt	2015	50	950	10	158	6,630	60%	Yes	0	0	0	0	0	0	43	-170
Wiriagar PSC	Indonesia	2009	4	161	1	23	319	38%	Yes	0	0	0	0	0	0	5	110
Freedom (MC 948)	US	2015	206	44	67	14	4,786	46%		0	0	0	0	0	0	11	432
Kaskida (KC 292)	US	2015	350	31	65	6	7,962	70%		0	0	0	0	0	0	12	115
Tubular Bells (MC 725)	US	2015	108	17	33	5	3,153	50%		0	0	0	0	0	0	11	34
Total (kboe/d)										**32**	**82**	**137**	**262**	**335**	**362**	**473**	
of which : Oil										*12*	*19*	*51*	*155*	*202*	*223*	*290*	
: Gas										*21*	*63*	*86*	*106*	*134*	*140*	*183*	

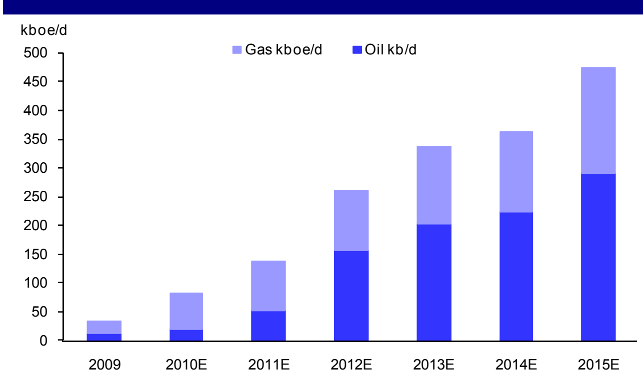
Source: Wood Mackenzie & Deutsche Bank estimates note – P1stands for phase 1 and P2 for phase 2

Figure 524: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



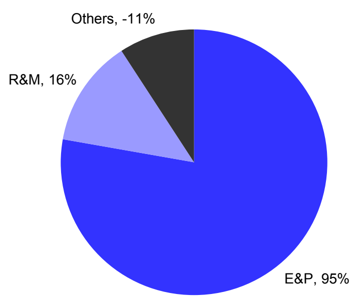
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 525: Growth profile 2009-15E by Oil & Gas



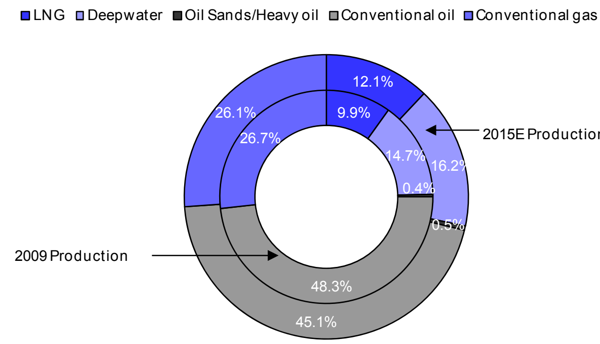
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 526: 2009 clean net income USD14,577m



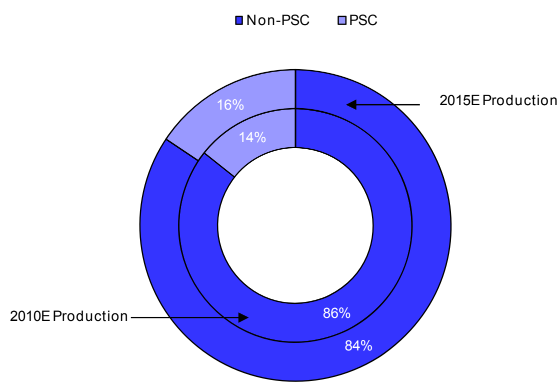
Source: Deutsche Bank

Figure 527: Trends in E&P Production



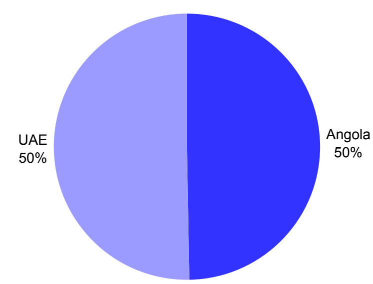
Source: Deutsche Bank

Figure 528: : PSC exposure 10E-15E – on the increase



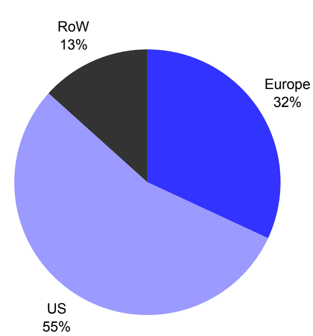
Source: Deutsche Bank

Figure 529: OPEC production 9% of total in 2010E



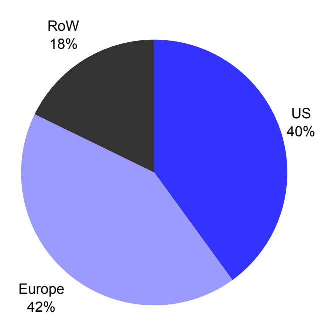
Source: Deutsche Bank

Figure 530: BP 2009 refining CDU 2,666kb/d



Source: Deutsche Bank

Figure 531: BP 2009 marketing by region



Source: Deutsche Bank

Europe Netherlands
Oil & Gas Integrated Oils

8 September 2010

Royal Dutch Shell plc

Reuters: **RDSa.L** Bloomberg: **RDSA LN**

Building a long lived base

Post 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. Our BUY stance reflects these positive attributes.

Upstream: Having committed to substantial exploration spend, Shell now boasts one of the few truly global exploration portfolios with plays in many of the world's largest basins such as the Gulf of Mexico, Nigeria, Brazil and Australia. Shell is the global IOC leader in LNG, 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 (CAGR to 2012 is 4%) and offers the potential for strong cash generation in addition to opportunities for further profitable growth.

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.

Other: Shell's Chemicals business encompasses the production and sale of bulk petrochemicals (olefins, aromatics etc), with a focus on integrating chemicals with refining at super-sites. Shell is also active in developing alternative energy sources and it is one of the world's leading distributors of bio-fuels.

Valuation & Risk

Given the relatively secure 6% yield we see limited absolute downside at Shell. Operational gearing, internal restructuring and the start-up of c.1mb/d of new production to 2012 also argue that upside potential is considerable. Taken together these points suggest Shell is deserved of a modest 5% premium to our 11.5x '10 EPS target sector multiple implying fair value at a $1.55/£ rate of 2100p. Downside risks to our positive stance include delays on key projects not least Pearl GTL and AOSP.

Forecasts and ratios

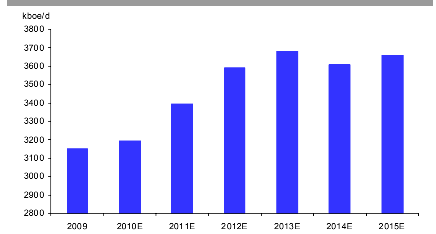
Year End Dec 31	2008A	2009A	**2010E**	2011E
DB EPS (USD)	4.60	1.89	**2.93**	3.96
P/E (x)	7.3	14.0	**9.4**	7.0
Dividend Yield (%)	4.7	6.4	**5.7**	6.0

Source: Deutsche Bank estimates, company data

Buy

Price at 6 Sept 2010 (GBP)	**1,780p**
Price Target (GBP)	**2,100p**
52-week range (GBP)	**1,957.50 - 1,418.00**

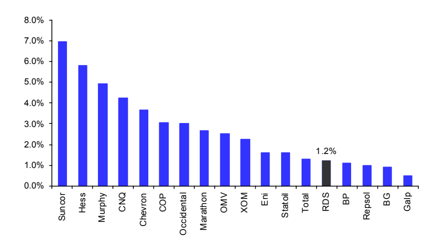
RDS Production Profile 2009-15E



Source: Deutsche Bank

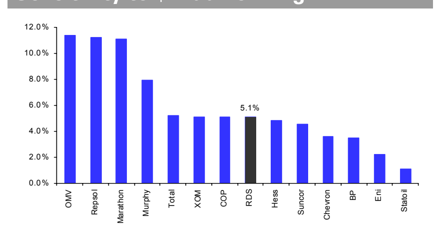
Upstream CAGR (2009-15E)	2.5%
Oil production (2009)	1,678kb/d
Gas production (2009)	1,474kboe/d
Oil Reserves (1P)	3.4bn/bbls
Gas Reserves (1P)	7.5bn/boe
Refining capacity	2,754kb/d
Marketing volumes	6,156kb/d
Wood Mackenzie 2P(E) Total reserves	29.6bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.19%

Sensitivity to $1bbl move in oil



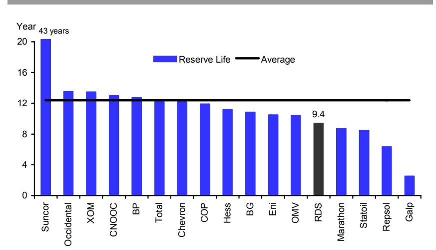
Source: Deutsche Bank

Sensitivity to $1/bbl refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 532: RDS Net Asset Value by asset

Upstream	Comments	Value ($ Million)	Value (GBP Million)	2 P Reserves	Value/2P Reserves	% of Total EV	Value per Share (p)
Algeria		16	11	17	1.0	0.0%	0.0
Argentina		444	286	80	5.5	0.1%	0.0
Australia	Key driver is LNG at NWS and Gorgon	28,578	18,437	3827	7.5	7.5%	3.0
Brazil		4,196	2,707	352	11.9	1.1%	0.4
Brunei		10,873	7,015	931	11.7	2.9%	1.1
Cameroon		389	251	36	10.7	0.1%	0.0
Canada	Muskeg and Jackpine only in the sands	29,084	18,764	3289	8.8	7.6%	3.1
China		464	299	129	3.6	0.1%	0.0
Denmark		7,144	4,609	445	16.1	1.9%	0.8
Egypt		931	600	196	4.8	0.2%	0.1
Gabon		1,745	1,126	94	18.6	0.5%	0.2
Germany		2,332	1,504	260	9.0	0.6%	0.2
Iraq		810	523	4649	0.2	0.2%	0.1
Ireland		1,306	843	67	19.4	0.3%	0.1
Italy		5,106	3,294	288	17.7	1.3%	0.5
Kazakhstan		13,414	8,654	1859	7.2	3.5%	1.4
Malaysia	Significant potential exploration upside	10,266	6,623	1813	5.7	2.7%	1.1
Netherlands Conc		25,393	16,382	1846	13.8	6.7%	2.7
New Zealand		1,508	973	148	10.2	0.4%	0.2
Nigeria	Huge value in NLNG	32,651	21,065	3897	8.4	8.6%	3.4
Norway		6,226	4,017	1014	6.1	1.6%	0.7
Oman		16,460	10,619	1367	12.0	4.3%	1.7
Pakistan		282	182	38	7.4	0.1%	0.0
Philippines		1,962	1,266	187	10.5	0.5%	0.2
Qatar	This number will grow sharply	36,566	23,591	3320	11.0	9.6%	3.9
Russia		8,430	5,439	1175	7.2	2.2%	0.9
Syria		1,000	645	116	8.6	0.3%	0.1
UAE Abu Dhabi OPCO		911	588	247	3.7	0.2%	0.1
United Kingdom		9,395	6,061	696	13.5	2.5%	1.0
United States Gulf Coast		2,682	1,731	544	4.9	0.7%	0.3
United States Gulf of Mex		17,901	11,549	937	19.1	4.7%	1.9
United States Rocky Mount		3,744	2,415	840	4.5	1.0%	0.4
Venezuela Concessions		331	214	36	9.3	0.1%	0.0
Sub-Total		**282,541**	**182,284**	**34740**	**8.13**	**74.3%**	**2,976.1**
Refining							
Europe		7,600	4,903			2.0%	80.1
Africa		331	214			0.1%	3.5
Middle East		848	547			0.2%	8.9
Asia Pacific (ex Showa)		4,000	2,581			1.1%	42.1
USA		9,924	6,403			2.6%	104.5
Other Western Hemisphere		1,392	898			0.4%	14.7
Marketing		32,934	21,248			8.7%	346.9
Sub-Total		**57,029**	**36,793**			**15.0%**	**600.7**
Power and Others							
Ships		2,685	1732			0.7%	28.3
LNG Contracts - Downstream share		6,929	4470			1.8%	73.0
Gas and Power	*Largely regas. LNG in upstream*	4,431	2859			1.2%	46.7
Sub-Total		**14,045**	**9,061**			**3.7%**	**147.9**
Chemicals		**11,932**	**7698**			**3.1%**	125.7
Equity Interests							
Woodside	34% interest	11493	7415			3.0%	121.1
Showa Shell	35% interest	2851	1840			0.7%	30.0
Comgas	18% interest	407	263			0.1%	4.3
		14752	**9518**			**3.9%**	**155.4**
Total Enterprise Value		**380,299**	**245,354**			100.0%	**4,006**
Adjusted end-2009 Net Debt		23,892	15,414			6.3%	251.7
Net Asset Value		**356,408**	**229,940**			**93.7%**	**3,754**
Market Capitalisation		**172,166**	**111,075**				**1,814**
Discount to NAV		**-52%**	**-52%**				**-52%**

Source: Wood Mackenzie, Deutsche Bank

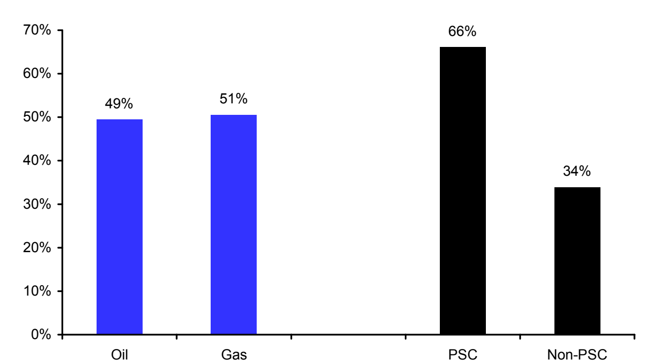
Royal Dutch Shell – Main projects 2009-15E

Figure 533: Royal Dutch Shell – Major Oil & Gas Projects by year 2009-2105E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	RDS %	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Sakhalin	Russia	2009	280	622	40	70	10425	27.5	Yes	61	101	110	110	110	110	110	5,308
Parque das(BC-10)	Brazil	2009	375	6	95	3	4,043	50%		11	48	43	36	31	45	48	2,208
Beryl	Malaysia	2009	12	160	3	26	n.a.	50%	Yes	6	8	11	11	12	14	14	n.a.
2010																	
AOSP Jackpine Mine	Canada	2010	1,000	0	100	0	7,464	60%		0	12	48	60	60	60	60	2,871
West Sitra Fields	Egypt	2010	0	25	0	7	18	75%	Yes	0	3	5	5	5	5	5	45
Gjøa	Norway	2010	138	203	55	62	4,987	12%		0	4	14	14	13	13	12	617
Great White	US (GoM)	2010	310	125	64	26	7,026	33%		0	8	18	21	23	25	26	1,943
2011																	
Pearl GTL	Qatar	2011	0	2,570	0	282	18,742	100%	Yes	0	0	70	211	282	282	282	21,997
Pluto	Australia	2011	12	231	3	37	15737	31%		0	0	0	37	37	37	37	3219
Qatargas 4	Qatar	2011	322	1,998	42	213	6,069	30%		0	0	49	75	77	77	76	5,636
Caesar/Tonga	US (GoM)	2011	221	29	47	6	3,505	22%		0	0	7	10	11	12	12	590
2012																	
Bonga North	Nigeria	2012	240	25	96	10	4,268	55%	Yes	0	0	0	6	58	55	48	n.a.
Corrib	Ireland	2010	0	150	0	56	2,937	45%		0	0	0	24	25	25	25	1,130
Bonga Northwest	Nigeria	2012	60	6	24	3	1,052	55%	Yes	0	0	0	4	15	14	12	n.a.
Haban (Gas)	Oman	2012	0	270	0	38	n.a.	34%		0	0	0	3	10	12	12	n.a.
2013																	
Kashagan	Kazakhstan	2013	10,383	657	1,475	120	141,901	17%	Yes	0	0	0	0	36	54	70	8,520
Kebabangan	Malaysia	2013	200	590	54	99	3,274	30%	Yes	0	0	0	0	10	16	17	112
SB J	Malaysia	2013	330	211	107	52	3,235	40%	Yes	0	0	0	0	21	36	43	1,385
2014																	
Tempa Rossa	Italy	2014	305	0	53	0	2,284	25%		0	0	0	0	0	12	13	571
Bosi	Nigeria	2014	500	0	135	0	n.a.	44%	Yes	0	0	0	0	0	18	59	n.a.
Friesian (GC 599)	US (GoM)	2014	207	35	51	8	648	50%		0	0	0	0	0	13	25	324
2015																	
Bonga SW	Nigeria	2015	400	51	112	15	n.a.	55%	Yes	0	0	0	0	0	0	35	n.a.
Total (kboe/d)										**87**	**187**	**390**	**580**	**785**	**879**	**987**	
of which : Oil										*12*	*68*	*120*	*147*	*253*	*336*	*437*	
: Gas										*5*	*119*	*270*	*433*	*532*	*543*	*547*	

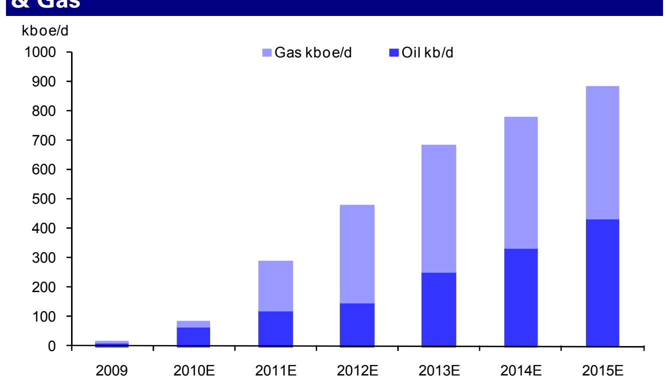
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 534: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



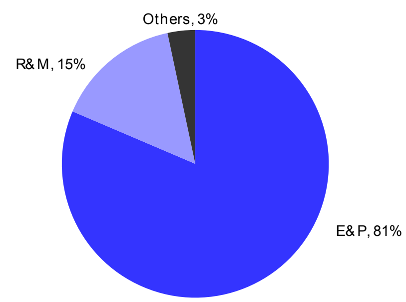
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 535: New project growth profile 2009-15E by Oil & Gas



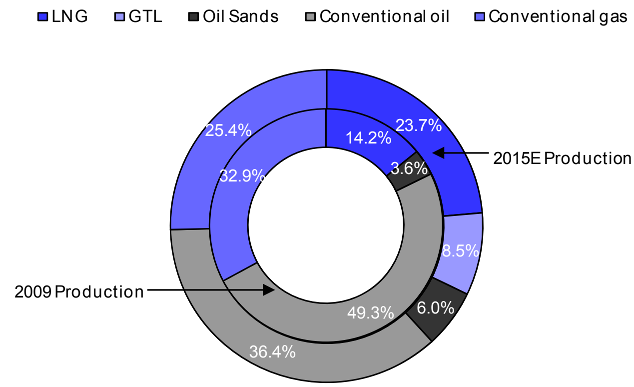
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 536: 2009 clean net income USD11,620m



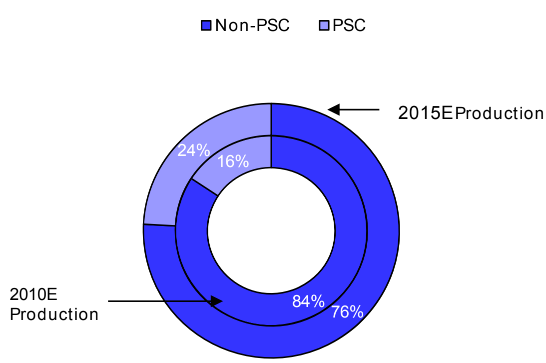
Source: Deutsche Bank

Figure 537: Trends in E&P Production



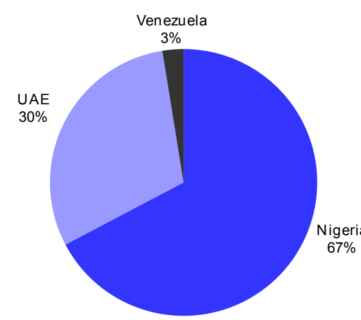
Source: Deutsche Bank

Figure 538: PSC exposure 10E-15E – on the increase



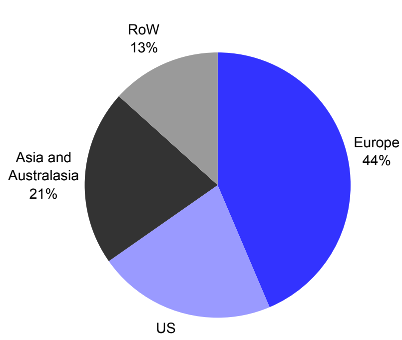
Source: Deutsche Bank

Figure 539: OPEC production 13% of total in 2010E



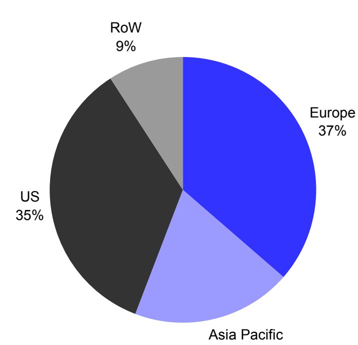
Source: Deutsche Bank

Figure 540: RDS 2009 refining CDU 3,639kb/d



Source: Deutsche Bank

Figure 541: RDS 2009 marketing by region



Source: Deutsche Bank

Europe France
Oil & Gas Integrated Oils

8 September 2010

Total SA

Reuters: **TOTF.PA** Bloomberg: **FP FP**

Visible Growth

Following its merger with Fina in 1999 and Elf in 2000, Total has done much to enhance its long term potential and maintain its record of above sector returns. Management is well respected with a strong reputation for project execution. Upstream, Total offers robust medium term volume growth (2%p.a. to 2013) from a suite of world class projects, has an established and strongly growing LNG business and growing exposure in non-conventional oil provinces, not least Canada. Total is Europe's leading refiner with distinct opportunities to upgrade the quality of its portfolio through modest capital investment. Our BUY stance reflects these positive attributes.

Upstream: Total's E&P portfolio is characterised by its geographical and functional diversity, with significant plays in both conventional and non-conventional oil and gas and a leading position in LNG. The company is a leading producer in West Africa and holds strong positions in the Middle East, but is notable for its limited position in the US market. Total's portfolio comprises a greater exposure to PSCs than most; it also derives a greater proportion of its oil production from OPEC countries. Successful exploration and resource capture in recent years has seen the establishment of a suite of future prospects with good visibility and the potential for sustainable upstream growth.

Downstream: With 2.3mb/d of European capacity including its 49% interest in the Spanish oil & gas company CEPSA, Total's 17% share of western European refining capacity makes it the market leader, a position it also holds in Africa. Growth is expected to be driven by ongoing investment in new refining capacity in Saudi Arabia (Jubail) with profitability also augmented by investment in conversion capacity across its portfolio. As in E&P the company is, however, notable by its limited US presence although it is amongst Europe's leading gasoline exporters.

Other: Total's chemical division encompasses bulk petrochemicals (e.g. olefins and aromatics) and leading positions in higher margin, added-value, adhesives and resins. Total also retains a $7bn non-core investment (6%) in Sanofi-Aventis.

Valuation & Risk

Balance sheet strength, a healthy list of potential projects and recent success in resource access all suggest to us that Total should trade in line with our sector target PE multiple of 11.5x 2010E EPS. This suggests to us a PT of EUR52/share in line with the EUR53/share suggested by our DCF models (assumes a 10% CoC, 0.9x Beta and a 1.5% long term growth rate). Downside risks to our positive Buy stance include project delays bit least at Usan and Pazflor.

Forecasts and ratios

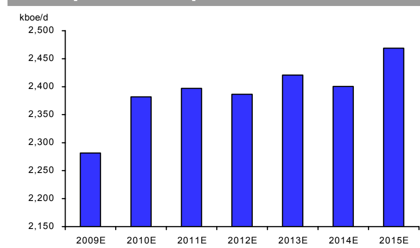
Year End Dec 31	2008A	2009A	**2010E**	2011E	2012E
DB EPS (EUR)	6.19	3.49	**4.57**	5.03	5.38
P/E (x)	7.7	11.4	**8.9**	7.9	7.2
Dividend Yield (%)	4.8	5.7	**5.8**	6.0	6.2

Source: Deutsche Bank estimates, company data

Buy

Price at 6 Sept 2010 (EUR)	**39.59**
Price Target (EUR)	**52.00**
52-week range (EUR)	**46.26 - 35.14**

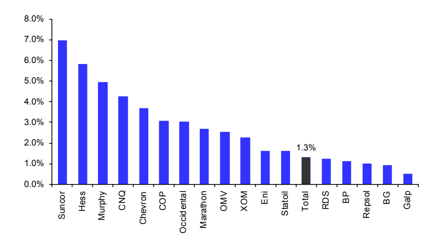
Total production profile 09-15E



Source: Deutsche Bank

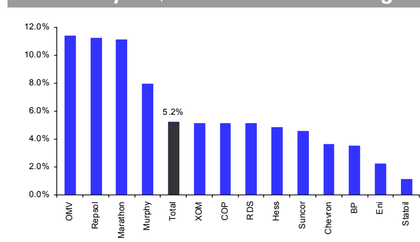
Upstream CAGR (2009-15E)	2.4%
Oil production (2009)	1,381kb/d
Gas production (2009)	900kboe/d
Oil Reserves (1P)	5.7bn/bbls
Gas Reserves (1P)	4.8bn/boe
Refining capacity	2,626kb/d
Marketing volumes	2,641kb/d
Wood Mackenzie 2P(E) Total reserves	16.3bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.49%

Sensitivity to $1/bbl move in oil



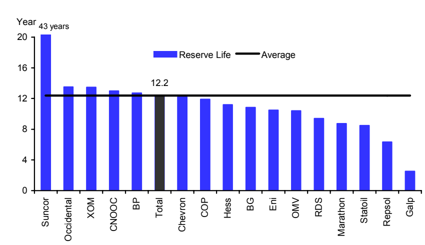
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl (long-run)

Figure 542: Total 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		1349	1062	321	4.2	0.6%	0.48
Angola		20515	16154	1945	10.5	9.5%	7.24
Argentina		2036	1603	386	5.3	0.9%	0.72
Australia		3834	3019	640	6.0	1.8%	1.35
Azerbaijan		2051	1615	293	7.0	0.9%	0.72
Bolivia		1167	919	256	4.6	0.5%	0.41
Brunei		393	310	55	7.2	0.2%	0.14
Cameroon		321	252	27	11.9	0.1%	0.11
Canada Oil Sands		2822	2222	1112	2.5	1.3%	1.00
Colombia		355	280	29	12.2	0.2%	0.13
Congo Braz		5798	4566	555	10.5	2.7%	2.05
France		294	232	37	7.9	0.1%	0.10
Gabon		1944	1530	215	9.0	0.9%	0.69
Indonesia		11141	8773	938	11.9	5.1%	3.93
Iran		176	138	191	0.9	0.1%	0.06
Iraq		64	50	493	0.1	0.0%	0.02
Italy		1822	1435	150	12.1	0.8%	0.64
Kazakhstan		12988	10227	1855	7.0	6.0%	4.58
Libya		3394	2673	113	30.0	1.6%	1.20
Myanmar		1894	1492	255	7.4	0.9%	0.67
Netherlands		1953	1538	113	17.3	0.9%	0.69
Nigeria		26625	20965	2812	9.5	12.3%	9.40
Norway		13628	10731	1763	7.7	6.3%	4.81
Oman		2477	1951	161	15.4	1.1%	0.87
Qatar		10006	7879	1879	5.3	4.6%	3.53
Russia		1561	1229	223	7.0	0.7%	0.55
Spain		2	2	0	9.7	0.0%	0.00
Syria		575	453	68	8.4	0.3%	0.20
Thailand		2043	1609	174	11.8	0.9%	0.72
Trinidad		147	116	58	2.5	0.1%	0.05
United Arab Emirates		2048	1613	571	3.6	0.9%	0.72
United Kingdom		9111	7174	798	11.4	4.2%	3.22
US Conc Gulf Coast		658	518	430	1.5	0.3%	0.23
United States Gulf of Mex		2353	1852	152	15.4	1.1%	0.83
Venezuela Concessions		4903	3861	605	8.1	2.3%	1.73
Yemen		6109	4811	955	6.4	2.8%	2.16
Sub-Total		**158561**	**124851**	**20626**	**7.7**	**73.1%**	**55.96**
Refining and Marketing							
Europe Refining ex CEPSA		14555	11461			6.7%	5.14
Europe Marketing ex CEPSA		10909	8590			5.0%	3.85
Africa Refining		270	213			0.1%	0.10
Africa Marketing		3647	2872			1.7%	1.29
Others Refining		1511	1190			0.7%	0.53
Others Marketing		1827	1439			0.8%	0.64
Sub-Total		**32719**	**25763**			**15.1%**	**11.55**
Chemicals		**7025**	**5532**			**3.2%**	**2.48**
Power & Others							
Power		215	169			0.1%	0.08
Re-gas value		3795	2988			1.8%	1.34
LNG contracts		5841	4600			2.7%	2.06
CEPSA	49% interest	2821	2221			1.3%	1.00
Sanofi Aventis	7% interest	5820	4583			2.7%	2.05
Sub-Total		**18492**	**14561**			**8.5%**	**6.53**
Total Enterprise Value		**216798**	**170707**			**100.0%**	**76.52**
Adjusted end-2009 Net Debt		17542	13440			7.9%	6.02
Net Asset Value		**199256**	**157267**			**92.1%**	**70.49**
Market Capitalisation		**109903**	**86538**				**38.79**
Premium to NAV		**-45%**	**-45%**				**-45%**

Source: Wood Mackenzie, Deutsche Bank

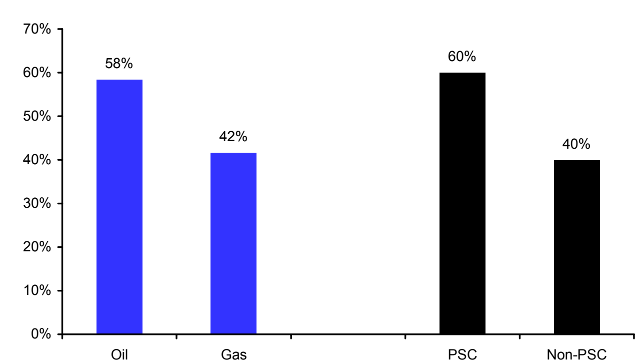
Total – Main projects 2009-15E

Figure 543: Total SA – Major Oil & Gas Projects by year 2009-2105E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	Total %	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Tombua	Angola	2009	184	0	58	0	2,844	20%	Yes	2	7	10	12	12	12	10	n.a.
OML 130 (PSA)	Nigeria	2009	620	260	144	48	8,586	48%	Yes	23	65	65	65	65	59	65	5,933
Tyrihans	Norway	2009	250	182	81	58	2,688	23%		4	13	15	20	25	28	28	1,092
Qatargas II	Qatar	2009	672	4,032	85	426	8,370	8%		14	34	43	42	42	42	42	3,465
Tahiti (GC 640)	US (GoM)	2009	410	40	101	10	6,575	17%		5	16	16	17	18	19	16	1,247
Yemen LNG	Yemen	2009	0	1,813	0	200	4,647	51%		7	65	97	101	101	101	101	5,328
2010																	
Itau	Bolivia	2010	16	158	3	31	387	75%	Yes	0	1	7	7	25	25	25	361
South Sulige	China	2010	0	415	0	51	1,264	49%	Yes	0	3	17	21	25	25	25	585
2011																	
Pazflor	Angola	2011	720	0	200	0	11,398	40%	Yes	0	0	10	74	80	80	80	3,483
2012																	
Angola LNG	Angola	2012	0	1,402	0	176	n.a	14%	Yes	0	0	0	10	21	24	24	n.a.
Moho	Congo	2012	100	0	30	0	660	54%	Yes	0	0	0	8	16	15	14	n.a.
Ima Gas (OML 112)	Nigeria	2012	16	278	4	62	893	40%		0	0	0	16	26	26	26	320
Bonga North	Nigeria	2012	240	25	96	10	4,268	13%	Yes	0	0	0	1	13	12	11	n.a.
Usan and Ukot	Nigeria	2012	610	0	180	0	10,088	20%	Yes	0	0	0	7	36	36	36	1,705
2013																	
Timimoun Fields	Algeria	2013	0	158	0	28	1,020	38%		0	0	0	0	4	11	11	99
Kashagan	Kaz'stan	2013	10,383	657	1,475	120	141,901	17%	Yes	0	0	0	0	36	54	70	8,520
2014																	
CLOV	Angola	2014	604	0	160	0	9,442	40%	Yes	0	0	0	0	0	32	64	1,264
Lianzi	Angola	2014	60	0	33	0	1,035	38%	Yes	0	0	0	0	0	4	13	158
Moho Nord	Congo	2014	250	0	70	0	2,606	54%	Yes	0	0	0	0	0	13	37	1,040
Tempa Rossa	Italy	2014	305	0	53	0	2,042	50%		0	0	0	0	0	24	27	1,142
Hild	Norway	2014	32	95	22	40	2,366	50%		0	0	0	0	0	5	31	97
Laggan & Tormore	UK	2014	18	192	8	67	2,911	50%		0	0	0	0	0	19	37	202
2015																	
Block 32 Southeast	Angola	2015	507	0	150	0	10,241	50%	Yes	0	0	0	0	0	0	32	1,255
Shah Deniz (P 2)	Azerbaijan	2015	331	1,392	70	272	19,038	50%	Yes	0	0	0	0	0	0	1	1,383
Total JV (OML 99)	Nigeria	2015	147	90	46	13	1,550	50%		0	0	0	0	0	0	5	140
Nkarika	Nigeria	2015	227	0	70	0	n.a	50%		0	0	0	0	0	0	14	n.a.
Total (kboe/d)										**54**	**204**	**281**	**402**	**545**	**665**	**845**	
of which : Oil										*31*	*83*	*100*	*185*	*270*	*351*	*493*	
: Gas										*23*	*120*	*181*	*217*	*275*	*314*	*352*	

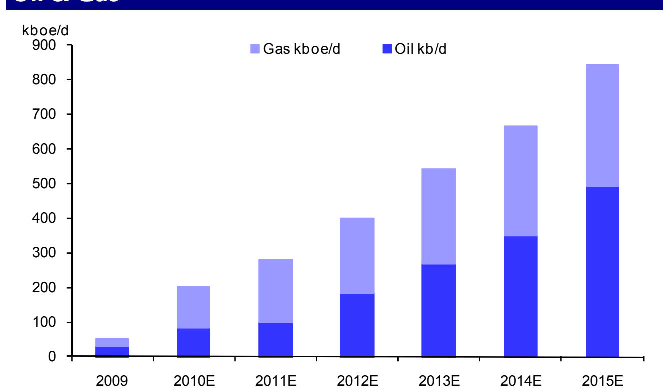
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 544: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



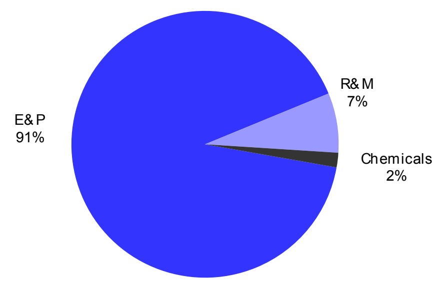
Source: Wood Mackenzie & Deutsche Bank estimate

Figure 545: New project growth profile 2009-2015E by Oil & Gas



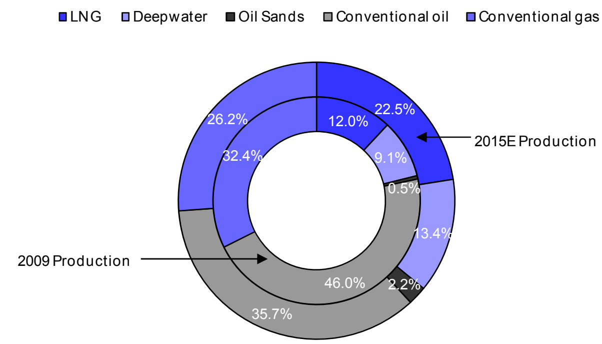
Source: Wood Mackenzie & Deutsche Bank estimate

Figure 546: 2009 clean net income EUR7,786m



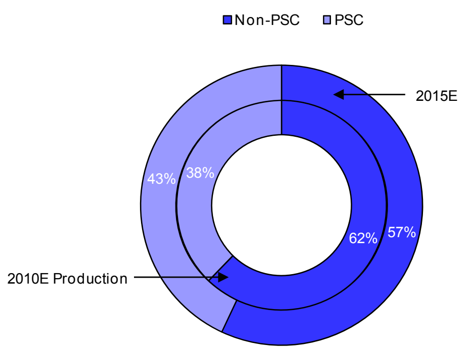
Source: Deutsche Bank

Figure 547: Trends in E&P Production



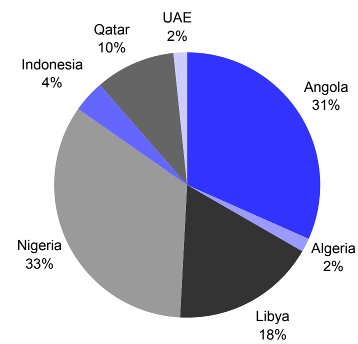
Source: Deutsche Bank

Figure 548: PSC exposure 10E-15E – on the increase



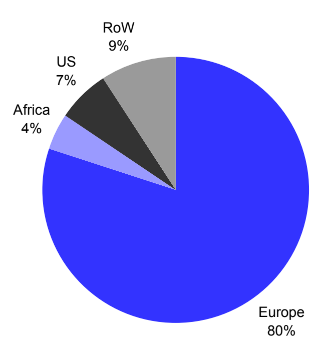
Source: Deutsche Bank

Figure 549: OPEC production 22% of total in 2010E



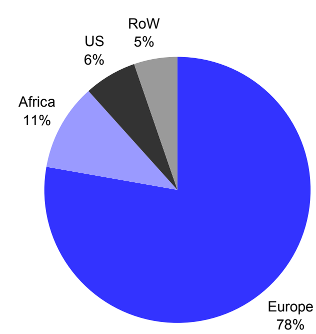
Source: Deutsche Bank

Figure 550: Total 2009 refining CDU 2,626kb/d



Source: Deutsche Bank

Figure 551: Total 2009 marketing by region



Source: Deutsche Bank

Europe Italy
Oil & Gas Integrated Oils

8 September 2010

ENI

Reuters: **ENI.MI** Bloomberg: **ENI IM**

Neither feast nor famine

While Eni remains committed to its strategy to 1) pursue production growth in low cost, giant projects 2) grow its G&P business to achieve 22% market share in Europe by 2013 3) continue to drive cost savings through the business; we have a cautious view on the near term outlook for the company. Earnings in the downstream are challenged while G&P will suffer increased competition in Italy. Further out we should see a return to production growth with the start up of Kashagan (2013). However, in the near term we maintain our Hold.

E&P: Eni has significant exposure to some of the fastest growing regions in the upstream sector (Caspian Sea, North & West Africa), which are set to contribute strongly to its production growth. A relatively high non-OECD exposure is mitigated by the company's long history of managing non-OECD risk, the wide breadth of its E&P portfolio and the 2007 US GoM acquisitions.

G&P: Eni's European Gas and Power segment covers all phases of the gas value chain and positions the company as the owner of the largest integrated gas business in Europe. However, c.87% of G&P gas sales volumes are bought under LT supply contracts from gas producers such as Gazprom and Sonatrach. This means that in the current oversupplied gas market ENI is exposed not only to weak demand from its own customers, but it also suffers from higher priced take-or-pay obligations under its supply contracts.

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, but has a higher average European complexity than any other major oil company.

Other: Eni has a small petrochemical division and it 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

We believe ENI should trade at 10x 2010e earnings, a c.15% discount to our sector target justified we believe by ENI's lack of near-term growth, its exposure to challenging gas and refining markets, its lack of balance sheet flexibility and given the relative lack of depth of its upstream portfolio vs. its super-major peers. Upside risks include higher than expected near term production and a favourable EU decision regarding Italian gas market competition. Downside risks include delays to project start-ups and poor news on key projects, not least Kashagan.

Forecasts and ratios

Year End Dec 31	2008A	2009A	**2010E**	2011E
DB EPS (EUR)	2.81	1.44	**1.74**	1.97
P/E (x)	7.6	11.5	**9.4**	8.3
Dividend Yield (%)	6.1	6.0	**6.1**	6.3

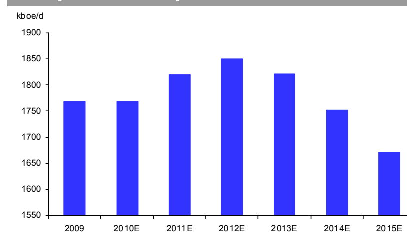
Source: Deutsche Bank estimates, company data

1

Hold

Price at 6 Sept 2010 (EUR)	**16.45**
Price Target (EUR)	**17.00**
52-week range (EUR)	**18.56 - 15.65**

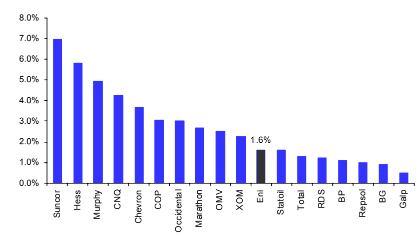
ENI production profile 09-15E



Source: Deutsche Bank

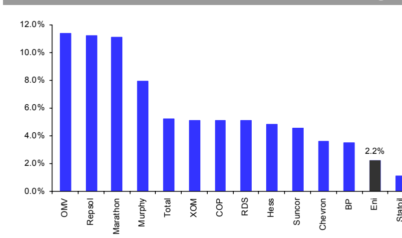
Upstream CAGR (2009-15E)	-0.9%
Oil production (2009)	1,007kb/d
Gas production (2009)	762kboe/d
Oil Reserves (1P)	10.4bn/bbls
Gas Reserves (1P)	7.8bn/boe
Refining capacity	711kb/d
Marketing volumes	915kb/d
Wood Mackenzie 2P(E) Total reserves	10.8bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.63%

Sensitivity to $1bbl move in oil



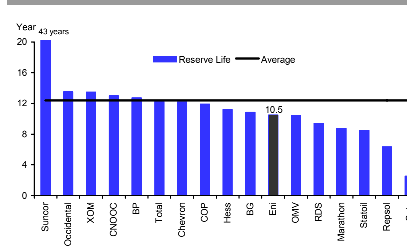
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 552: 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		6,676	5,215	773	8.6	4%	1.4
Angola	*Source of growth*	7,922	6,189	921	8.6	5%	1.7
Australia		780	609	131	6.0	0%	0.2
Azerbaijan	*BTC pipeline*	422	330	0	0.0	0%	0.1
China		322	251	15	21.0	0%	0.1
Congo	*Burren Energy acquisition*	6,290	4,914	576	10.9	4%	1.4
Ecuador		518	404	44	11.8	0%	0.1
Egypt	*Mainly gas*	6,734	5,261	1,634	4.1	4%	1.5
India		150	117	15	9.8	0%	0.0
Indonesia		1,956	1,528	215	9.1	1%	0.4
Iran	*Buy back contracts, little value*	674	527	2,869	0.2	0%	0.1
Iraq		370	289	1,321	0.3	0%	0.1
Italy	*OECD Italy dominates…*	13,897	10,857	978	14.2	9%	3.0
Kazakhstan	*…followed by non-OECD Kaskhstan*	19,584	15,300	3,177	6.2	12%	4.2
Libya		8,043	6,284	1,177	6.8	5%	1.7
Nigeria		6,348	4,959	1,490	4.3	4%	1.4
Norway		5,247	4,099	693	7.6	3%	1.1
Pakistan		1,112	869	175	6.4	1%	0.2
Russia	*EniNeftgaz*	2,322	1,814	550	4.2	1%	0.5
Timor Leste Australia JPD		739	578	99	7.4	0%	0.2
Trinidad		342	267	48	7.1	0%	0.1
Tunisia		576	450	43			
Turkmenistan		1,238	967	115	10.8	1%	0.3
United Kingdom		4,499	3,515	396	11.4	3%	1.0
US Alaska		1,688	1,319	230	7.3	1%	0.4
US GoM Deep	*Dominion acquisition*	2,886	2,255	166	17.4	2%	0.6
US Conc Gulf Coast		307	240	55	5.6	0%	0.1
Venezuela		905	707	104	8.7	1%	0.2
Sub-Total		**102,547**	**80,115**	**18,011**	**5.7**	**63%**	**22.1**
LNG							
LNG Contracts		922	720			1%	0.2
Australia Conc LNG	*Bayu Undan*	182	142			0%	0.0
Angola Conc LNG	*Damietta 1*	972	759			1%	0.2
Egypt Conc LNG	*via Union Fenosa Gas JV*	606	473			0%	0.1
Nigeria Conc LNG	*Trains 1-6*	6,660	5,203			4%	1.4
Oman Conc LNG		439	343			0%	0.1
Sub-Total		**9,781**	**7,642**			**6%**	**2.1**
Total Upstream		**112,328**	**87,757**			**69%**	**24.2**
Refining		6,407	5,006			4%	1.4
Marketing		4,296	3,356			3%	0.9
Gas Marketing & Distribution		28,497	22,264			18%	6.1
Power		2,699	2,109			2%	0.6
Chemicals		832	650			1%	0.2
Saipem		6,797	5,310			4%	1.5
Total Enterprise Value		**161,857**	**126,451**				**34.9**
Adjusted end-2009 Net Debt	*Excludes SRG and Saipem debt totalling €12.9bn*	13,014	10,167				2.8
Net Asset Value		**148,843**	**116,284**				**32.1**
Market Capitalisation		**76,288**	**59,600**				**16.5**
Discount to NAV		**-49%**	**-49%**				**-49%**

Source: Wood Mackenzie, Deutsche Bank

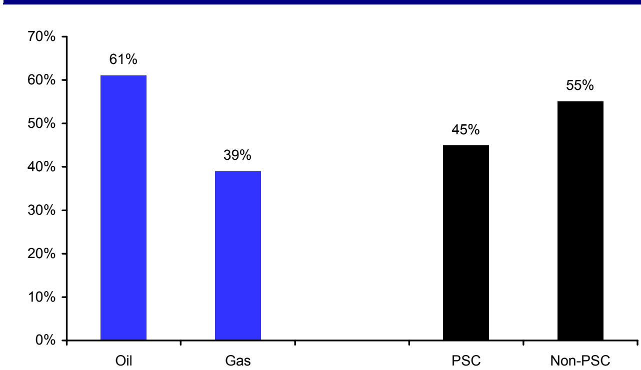
Eni – Main projects 2009-15E

Figure 553: Eni - Major Oil & Gas Projects by year 2009-2015E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	Eni %	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Tombua	Angola	2009	184	0	58	0	2,844	20%	Yes	2	7	10	12	12	12	10	0
Blacktip	Australia	2009	4	121	1	17	828	100		3	11	11	12	12	12	12	528
Awa Paloukou	Congo	2009	44	0	10	0	409	90%	Yes	4	9	8	8	7	7	6	759
North Bardawil	Egypt	2009	0	50	0	18	282	60%	Yes	7	11	11	11	9	8	6	127
Thekah Fields	Egypt	2009	0	39	0	12	188	50%	Yes	6	6	6	6	6	5	4	81
Oyo	Nigeria	2009	80	0	30	0	1,118	40%	Yes	4	12	12	11	9	8	7	762
Tyrihans	Norway	2009	250	182	81	58	2,688	6%		1	3	4	5	7	7	7	294
Longhorn	US (GoM)	2009	3	26	3	22	490	75%		8	18	13	9	6	4	2	340
Thunder Hawk (MC 734)	US (GoM)	2009	47	8	30	5	522	25%		4	9	8	7	4	2	1	257
2010																	
Seth	Egypt	2010	4	45	2	21	143	50%	Yes	0	3	9	12	10	8	6	0
Morvin	Norway	2010	54	20	31	12	1,495	30%		0	2	13	11	8	6	5	382
Nikaitchuq	US	2010	130	0	26	0	1,479	100		0	1	7	19	22	25	26	489
2011																	
Block 405b Fields	Algeria	2011	283	309	40	53	2,718	75%		0	0	33	40	60	70	70	1,224
Miglianico	Italy	2011	29	4	8	1	284	100		0	0	3	9	9	8	7	312
NC118-A	Libya	2011	25	0	10	0	143	50%	Yes	0	0	4	5	5	4	3	472
Kitan Area	Timor	2011	45	0	25	0	679	40%	Yes	0	0	4	10	9	9	7	124
2012																	
El Merk	Algeria	2012	444	0	126	0	3,707	12%	Yes	0	0	0	12	15	15	14	482
Angola LNG Gas Supply	Angola	2012	0	1,402	0	176	0	14%	Yes	0	0	0	10	21	24	24	0
Kizomba Satellites	Angola	2012	253	0	100	0	3,519	20%	Yes	0	0	0	9	20	17	16	418
Cassiopea Area	Italy	2012	0	101	0	51	984	60%		0	0	0	14	31	30	25	489
Bonga North	Nigeria	2012	240	25	96	10	4,268	13%	Yes	0	0	0	1	13	12	11	0
2013																	
Kashagan	Kazakhstan	2013	10,383	657	1,475	120	141,901	17%	Yes	0	0	0	0	36	54	70	8,520
Goliat Area	Norway	2013	204	44	83	21	4,831	65%		0	0	0	0	10	54	48	375
Jasmine	UK	2013	65	101	36	49	1,336	33%		0	0	0	0	16	28	26	538
2014																	
NC41-A	Libya	2014	90	263	14	40	0	50%	Yes	0	0	0	0	0	7	13	0
Laggan & Tormore	UK	2014	18	192	8	67	2,911	20%		0	0	0	0	0	7	15	81
2015																	
Kizomba Satellites	Angola	2015	454	0	182	0	6,875	20%	Yes	0	0	0	0	0	0	2	575
Malange	Angola	2015	60	0	30	0	974	20%	Yes	0	0	0	0	0	0	4	75
Mariner	UK	2015	318	0	45	0	4,686	29%		0	0	0	0	0	0	4	102
Total (kboe/d)										**39**	**91**	**158**	**233**	**356**	**442**	**452**	
of which : Oil										*15*	*43*	*81*	*129*	*199*	*266*	*276*	
: Gas										*24*	*49*	*76*	*103*	*157*	*176*	*176*	

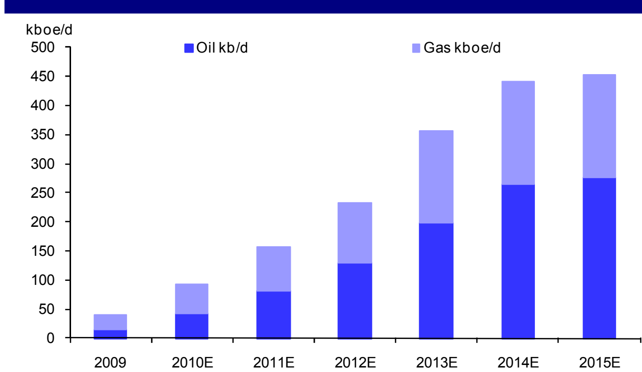
Source: Wood Mackenzie, Deutsche Bank estimates

Figure 554: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



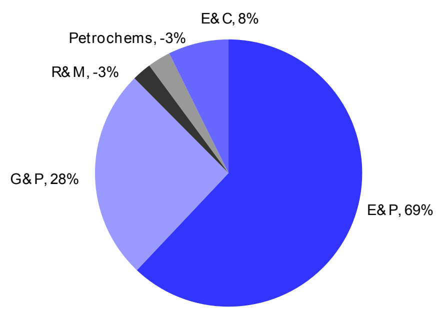
Source: Wood Mackenzie, Deutsche Bank estimates

Figure 555: Growth profile 2009-2015E by Oil & Gas



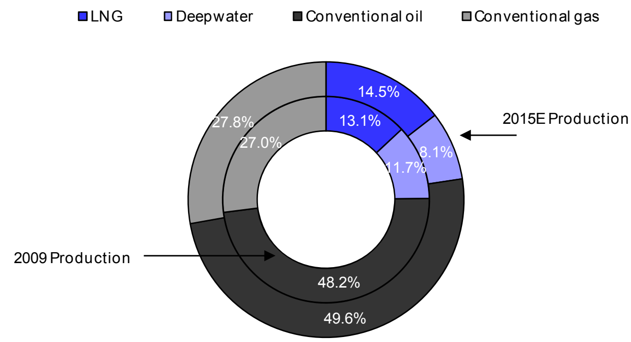
Source: Wood Mackenzie, Deutsche Bank estimates

Figure 556: 2009 clean net income EUR5,207m



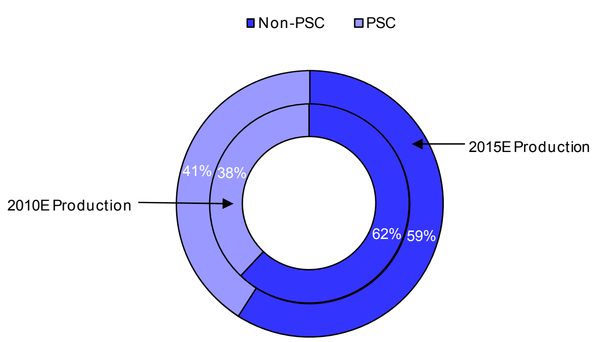
Source: Deutsche Bank

Figure 557: Trends in E&P Production



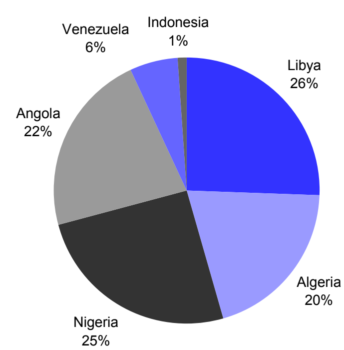
Source: Deutsche Bank

Figure 558: PSC exposure 10E-11E – on the increase



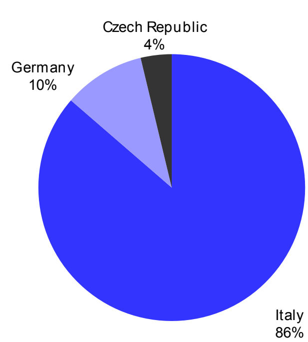
Source: Deutsche Bank

Figure 559: OPEC production 23% of total in 2010E



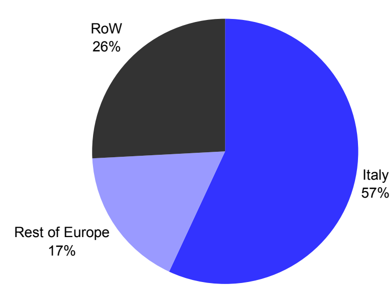
Source: Deutsche Bank

Figure 560: Eni 2009 refining CDU 711kb/d



Source: Deutsche Bank

Figure 561: Eni 2009 marketing by region



Source: Deutsche Bank

Europe Spain
Oil & Gas Integrated Oils

8 September 2010

Repsol

Reuters: **REP.MC** Bloomberg: **REP SM**

The explorer

With c.60% of reserves and production based in Argentina, the effects of Repsol's over exposure to this geopolitically volatile region with declining production have become all too clear over the few years. It may be a long road, but efforts to downsize exposure to that country and rebuild E&P in new territories have met with increasing success and, following a spate of highly positive exploration news flow, Repsol looks set to report a turnaround in production and cash-flow into the longer-term. BUY

E&P: Despite having one of the lowest reserves lives in the sector, recent exploration has seen Repsol make some of the largest discoveries in years with successes reported in Brazil, West Africa and Venezuela to name a few. As these discoveries are developed this should see a turnaround in both reserves bookings, production growth and will result in a more diversified upstream portfolio. By seeking to float part of its interests in Brazil Repsol is also working to ensure that this growth can be properly and sensibly financed with geographic risk contained. This latter point should be further assisted if the company can further reduce its YPF holding (from today's 85%) either through a float or private sale.

R&M: Repsol has significant refining capacity (1.2mb/d) in both Spain and Latin America from its interests in a number of refineries. In Europe, Repsol enjoys close proximity to the markets it supplies, thus benefiting from a location premium. Moreover, with a period of intense investment in upgrading two refineries in Spain nearing an end, this division should soon become a cash cow to fund upstream growth.

Other: Repsol has a presence in both the petrochemicals industry (where it is the market leader in Spain) and in gas and power. It owns 30% of Gas Natural (the Spanish gas utility) and has an LNG JV agreement with Gas Natural.

Valuation & Risks

If, as we believe, Repsol succeeds in de-risking and delivering its most significant projects we would expect to see a narrowing of the disconnect between our target price and the market valuation. We set our €21.5/sh target price based on four valuation inputs – NAV, DCF, EV/NCI and PE – with a deliberate bias toward longer-term metrics which seek to capture the skew to projects entering the development phase. See page 3 for further details on valuation and risk.

Forecasts and ratios

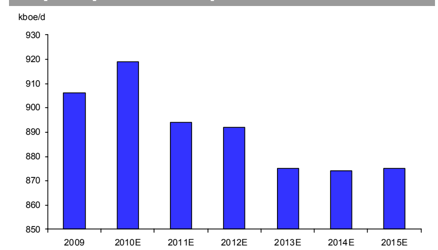
Year End Dec 31	2008A	2009A	**2010E**	2011E
DB EPS (EUR)	2.27	0.99	**1.56**	1.90
P/E (x)	9.3	16.2	**12.1**	9.9
Dividend Yield (%)	4.9	5.3	**5.0**	5.5

Source: Deutsche Bank estimates, company data

Buy

Price at 6 Sept 2010 (EUR)	**18.76**
Price Target (EUR)	**21.50**
52-week range (EUR)	**19.10 - 14.02**

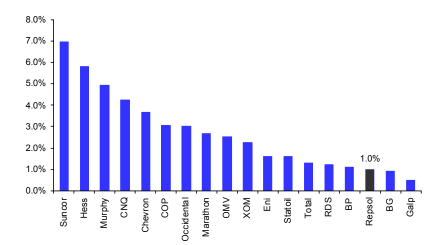
Repsol production profile 2009-15E



Source: Deutsche Bank

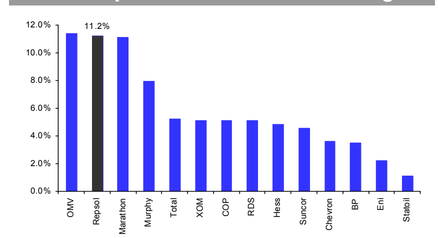
Upstream CAGR (2009-15E)	-0.6%
Oil production (2009)	438kb/d
Gas production (2009)	468kboe/d
Oil Reserves (1P)	0.9bn/bbls
Gas Reserves (1P)	1.3bn/boe
Refining capacity	1,233kb/d
Marketing volumes	1,071kb/d
Wood Mackenzie 2P(E) Total reserves	3.8bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.23%

Sensitivity to $1bbl move in oil



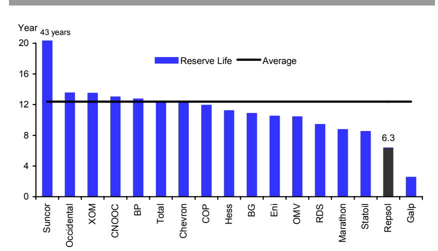
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 562: Repsol 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		520	426	209	2.5	1%	0.3
Bolivia		1905	1561	500	3.8	3%	1.3
Brazil	*Albacora*	590	483	60	9.8	1%	0.4
Brazil - Santos Development	*Guara, Carioca, Piracuca*	4411	3614	740	6.0	8%	3.0
Brazil Santos E&A	*Exploration*	750	615	300	2.5	1%	0.5
Colombia		191	156	10	19.7	0%	0.1
Ecuador		240	197	29	8.2	0%	0.2
Libya		2935	2405	83	35.4	5%	2.0
Peru		1727	1415	409	4.2	3%	1.2
Spain		130	107	8	15.9	0%	0.1
Trinidad		2793	2288	845	3.3	5%	1.9
US GoM		2375	1946	112	21.2	4%	1.6
Venezuela	*Excl Pearla/Carabobo*	876	718	190	4.6	2%	0.6
LNG (Liquefaction plant)							
Peru Concession LNG		1226	1004			2%	0.8
Trinidad Concession LNG		1084	888			2%	0.7
Total Gem Upsteam Value		**21752**	**17823**	**3496**	**6.2**	**38%**	**14.6**
Downstream							
Europe		10913	8943			19%	7.3
Other Latam		1061	869			2%	0.7
Total Downstream Value		**11974**	**9812**	**589**	**16.7**	**21%**	**8.0**
YPF							
YPF Equity Value		14745	12082			26%	9.9
Total YPF Value	*100% of YPF*	**14745**	**12082**			**26%**	**9.9**
Gas and Power							
Power		757	620			1%	0.5
LNG contracts	*Largely Peru & Atlantic*	1109	909			2%	0.7
Gas Natural	*30.01% interest*	4029	3302			7%	2.7
Total Gas & Power		**5895**	**4831**			**10%**	**4.0**
Logistics	*Stake in CLH now 10%*	354	290			1%	0.2
LPG		771	632			1%	0.5
Chemicals		1795	1471			3%	1.2
Total Other		**2920**	**2392**			**5%**	**2.0**
Total Enterprise Value		**57285**	**46940**				**38.4**
Adjusted end-2009 Net Debt	*Ex-Gas Natural/YPF*	9616	7879				6.5
Minority Interests	*YPF 15%*	2212	1812				1.5
Net Asset Value		**45458**	**37248**				**30.5**
Market Capitalisation		**28085**	**23013**				**18.9**
Premium to NAV		**-38%**	**-38%**				**-38%**

Source: Wood Mackenzie, Deutsche Bank

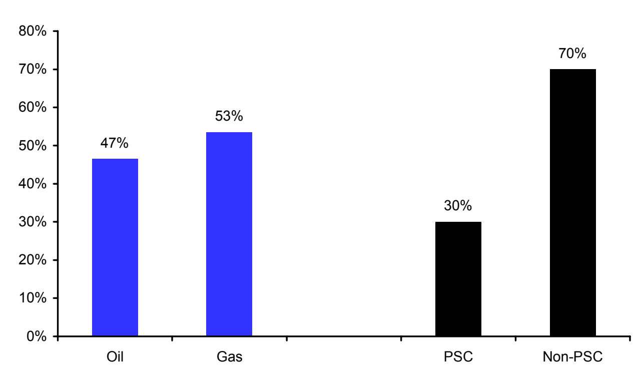
Repsol-YPF – Main projects 2009-15E

Figure 563: Repsol – Major Oil & Gas Projects by Year 2009-15E

Projects	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	REP %I	PSC	Production (kboe/d) - Working interest '09	'10	'11	'12	'13	'14	'15	NPV ($m)
2009																	
Shenzi (GC 654)	US GoM	2009	375	26	99	7	5,810	28%		0	30	28	28	28	25	21	2,204
2010																	
Pagoreni (Block 56)	Peru	2010	200	616	40	109	1,141	10%		0	8	14	15	15	15	15	353
2011																	
2012																	
Margarita	Bolivia	2012	133	482	20	70	1,259	38%	Yes	0	6	6	17	17	17	34	720
Lubina	Spain	2012	3	0	3	0	53	100%		0	0	0	2	3	2	1	73
Montanazo D5	Spain	2012	3	0	3	0	53	75%		0	0	0	1	2	1	1	48
NC200 fields	Libya	2012	74	0	21	0	280	21%	Yes	0	0	0	2	4	4	4	447
Kinteroni	Peru	2012	n.a.	n.a.	n.a.	n.a.	n.a.	54%		n.a.	n.a.	n.a.	n.a.	22	22	22	n.a.
2013																	
Guará	Brazil	2013	1,145	115	253	28	10,497	25%		0	0	2	2	27	30	31	1,900
Reggane North	Algeria	2013	0	273	0	62	2,713	34%	Yes	0	0	0	0	5	17	21	-61
2014																	
Block 39	Peru	2014	230	0	66	0	2,287	55%		0	0	0	0	0	6	11	455
Carabobo	Venezuela	2014	n.a.	n.a.	n.a.	n.a.	n.a.	11%		0	0	0	0	0	n.a.	n.a.	n.a.
Cardon IV	Venezuela	2014	n.a.	n.a.	n.a.	n.a.	n.a.	33%		0	0	0	0	0	n.a.	n.a.	n.a.
2015																	
Carioca	Brazil	2015	586	66	145	18	7,903	25%		0	0	0	0	0	0	0	n.a.
Piracuca	Brazil	2015	n.a.	n.a.	n.a.	n.a.	n.a.	37%		0	0	0	0	0	0	0	n.a.
Total (kboe/d)										**0**	**46**	**49**	**65**	**123**	**138**	**160**	
of which : Oil										*0*	*35*	*33*	*39*	*67*	*71*	*76*	
: Gas										*0*	*11*	*16*	*26*	*55*	*67*	*84*	

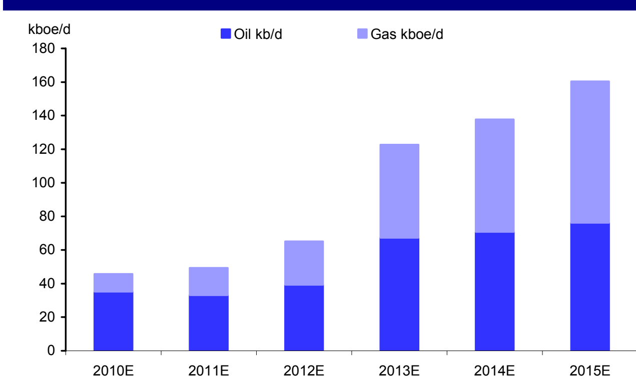
Source: Wood Mackenzie, Deutsche Bank estimates

Figure 564: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



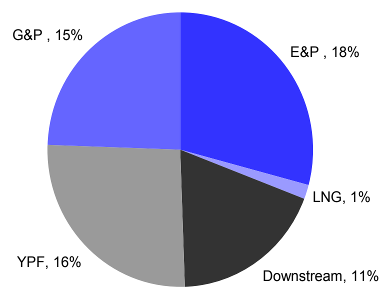
Source Wood Mackenzie & Deutsche Bank estimates

Figure 565: Growth profile 2010-15E by Oil & Gas



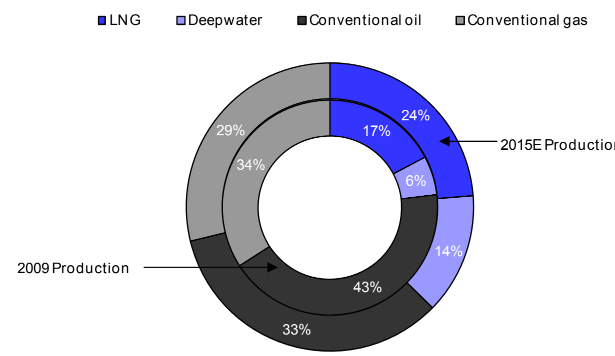
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 566: 2009 clean net income EUR1,209m



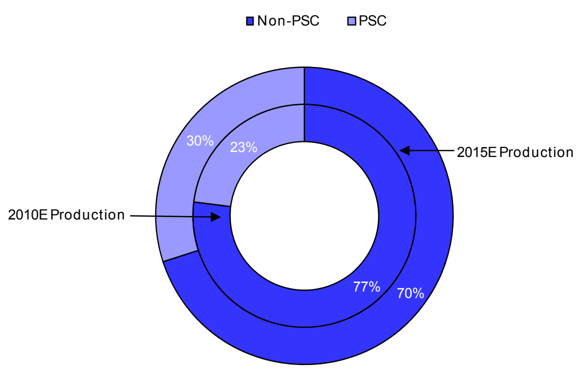
Source: Deutsche Bank

Figure 567: Trends in E&P Production



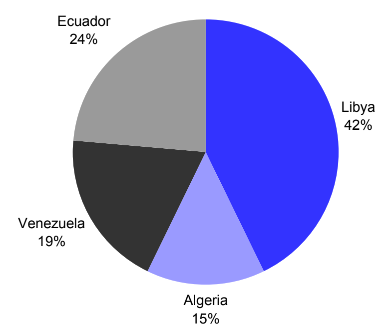
Source: Deutsche Bank

Figure 568: PSC exposure 10E-15E – on the increase



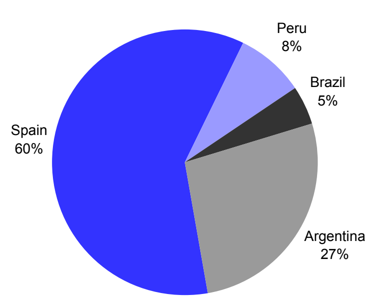
Source: Deutsche Bank

Figure 569: OPEC production 7% of total in 2010E



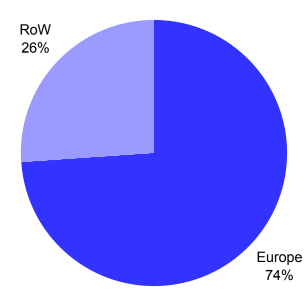
Source: Deutsche Bank

Figure 570: Repsol 2009 refining CDU 1,233kb/d



Source: Deutsche Bank

Figure 571: Repsol 2009 marketing by region



Source: Deutsche Bank

Europe Norway
Oil & Gas Exploration & Production

8 September 2010

Statoil

Reuters: **STL.OL** Bloomberg: **STL NO**

Expanding abroad

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 aging legacy North Sea assets, growing the international production base is key, as is seamless execution on its existing developments. High exposure to oversupplied European gas markets drives our Hold rating.

Upstream: Statoil's production is derived primarily from Norway (86% in 2009). However aging assets and declining production have spurred the company to seek opportunities further afield in the US GoM, Angola, Brazil, Nigeria and Canada's oil sands, amongst others. Of the European majors, Statoil is considered one of the most geared to the oil price for a number of reasons not least that 1) some 60% of production is oil 2) c.70% of its gas sales are indexed to the oil price and that 3) high rates of Norwegian tax make for strong operational leverage.

R&M: Statoil is a relatively small refiner but is a large European marketer of products. This should reduce further given the company is seeking to IPO its retail business by end 2010. The net result is that Statoil has relatively low R&M exposure versus the peers.

Natural Gas: Statoil markets not only its own gas production, but also the Norwegian government's share of gas production, thus making Statoil the second largest supplier of gas to Europe after Gazprom. Some 70% of its gas is sold under LT oil indexed gas contracts, with the balance sold at spot gas prices.

Valuation & Risk

Our NOK138 price target is based on a target 10.5x PE multiple of 2010 earnings, a 5% discount to out sector target of 11x, justified we believe by our concern for earnings in the current oversupplied European gas market and given our outlook for crude prices in 2010 ($73/bbl in 2010). Given Statoil's leverage to oil prices, the single greatest upside risk remains higher oil prices. Increased US or Asian gas demand, higher Euro spot gas prices and/or delays to LNG supply also provide potential upside.

Forecasts and ratios

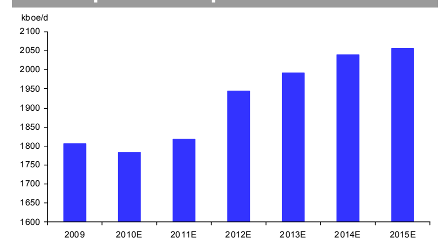
Year End Dec 31	2008A	2009A	2010E	2011E
DB EPS (NOK)	19.2	10.8	**12.88**	13.88
P/E (x)	8.0	12.0	**9.6**	8.9
Dividend Yield (%)	4.7	4.6	**4.2**	4.7

Source: Deutsche Bank estimates, company data

Hold

Price at 6 Sept 2010 (NOK)	**124.40**
Price Target (NOK)	**138.00**
52-week range (NOK)	**149.20 - 119.40**

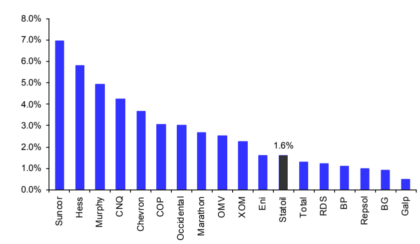
Statoil production profile 2009-15E



Source: Deutsche Bank

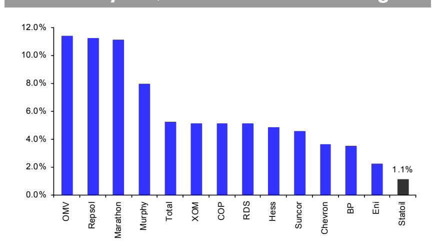
Upstream CAGR (2009-15E)	2.2%
Oil production (2009)	1,066kb/d
Gas production (2009)	740kboe/d
Oil Reserves (1P)	2,073bn/bbls
Gas Reserves (1P)	3,383bn/boe
Refining capacity	300kb/d
Marketing volumes	2.4mb/d
Wood Mackenzie 2P(E) Total reserves	12.2bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.21%

Sensitivity to $1bbl move in oil



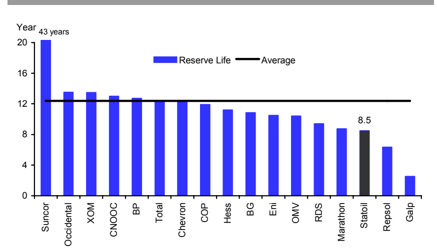
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 572: 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
Algeria		3093	18869	962	3.2	3%	5.9
Angola		11754	71697	1163	10.1	10%	22.5
Azerbaijan		8057	49149	1095	7.4	7%	15.4
Brazil Conc		6207	37866	446	13.9	5%	11.9
Canada		3718	22680	1029	3.6	3%	7.1
Iraq		123	748	1232	0.1	0%	0.2
Iran		180	1096	265	0.7	0%	0.3
Ireland		1075	6555	55	19.7	1%	2.1
Libya		580	3537	21	27.6	0%	1.1
Nigeria	*High value bbls*	3489	21283	155	22.6	3%	6.7
Norway		49530	302135	6860	7.2	42%	94.9
Russia		655	3994	66	9.9	1%	1.3
UK		3357	20478	488	6.9	3%	6.4
US GoM		6119	37323	465	13.2	5%	11.7
Venezuela		1525	9304	142	10.8	1%	2.9
Subtotal		**99461**	**606714**	**14444**	**6.9**	**85%**	**190.6**
LNG							
LNG Marketing - Contracts		93	567			0%	0.2
Norway Conc LNG		3939	24029	401		3%	7.5
Total Upstream Value		**103494**	**631311**	**14845**		**89%**	**198**
Refining and Marketing							
Refining		1460	8906			1%	2.8
Marketing		3042	18554			3%	5.8
Subtotal		**4502**	**27459**			**4%**	**8.6**
Natural Gas Marketing		**8574**	**52304**			7%	**16.4**
Total Enterprise Value		**116570**	**711074**				**223.4**
Adjusted end-2009 Net Debt	*includes pension liability*	15329	93509				29.4
Buyout of minorities		75	457				0.1
Net Asset Value		**101165**	**617108**				**193.8**
Market Capitalisation		**64245**	**391897**				**123.1**
Premium to NAV		**-36%**	**-36%**				**-36%**

Source: Wood Mackenzie, Deutsche Bank

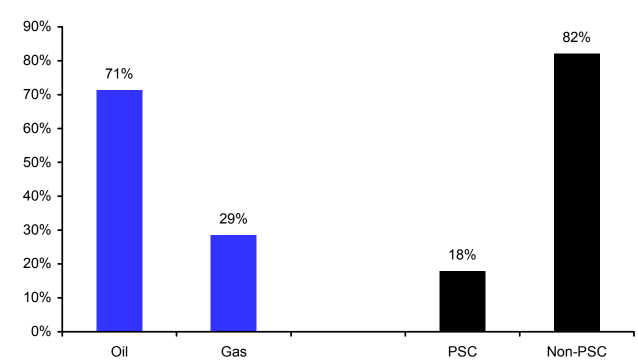
Statoil – Main projects 2009-15E

Figure 573: Statoil – Major Oil & Gas Projects by Year 2009-2015E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	STL %	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Block 4	Angola	2009	83	0	34	0	1,365	20%	Yes	4	6	5	7	7	5	4	237
Alve	Norway	2009	8	42	4	21	515	85%		19	21	21	16	13	9	6	454
Tyrihans	Norway	2009	250	182	81	58	2,688	59%		11	32	38	50	64	70	70	2,773
Tahiti (GC 640)	US (GoM)	2009	410	40	101	10	6,575	25%		7	24	24	25	27	28	23	1,834
2010																	
Gjøa	Norway	2010	138	203	55	62	4,987	20%		0	6	23	23	22	21	20	1,028
Morvin	Norway	2010	54	20	31	12	1,495	64%		0	5	28	23	18	13	10	816
Vega	Norway	2010	17	58	6	24	772	60%		0	7	18	16	14	12	11	481
2011																	
Block 31 PSVM	Angola	2011	518	0	150	0	10,702	13%	Yes	0	0	1	16	20	20	20	747
Pazflor	Angola	2011	720	0	200	0	11,398	23%	Yes	0	0	6	43	47	47	47	2,031
Peregrino	Brazil	2011	450	0	95	0	1,962	60%		0	0	56	58	58	58	58	4,053
Kai Kos Dehseh	Canada	2011	900	0	80	0	4,681	100%		0	0	5	10	25	48	56	1,231
Skarv Area	Norway	2011	172	254	85	88	6,207	36%		0	0	14	46	51	40	36	1,630
Caesar/Tonga	US (GoM)	2011	221	29	47	6	3,505	24%		0	0	7	11	11	12	12	619
2012																	
Kizomba Satellites(P1)	Angola	2012	253	0	100	0	3,519	13%	Yes	0	0	0	6	13	12	10	279
Grane Sør	Norway	2012	35	0	20	0	457	57%		0	0	0	11	9	7	6	110
2013																	
Gour Mahmoud	Algeria	2013	0	151	0	42	0	32%	Yes	0	0	0	0	8	13	13	0
Goliat Area	Norway	2013	204	44	83	21	4,831	35%		0	0	0	0	5	29	26	202
Gudrun & Sigrun	Norway	2013	99	90	68	41	3,400	47%		0	0	0	0	11	51	46	228
Maruk	Norway	2013	20	62	9	26	816	50%		0	0	0	0	13	18	17	132
Big Foot (WR 29)	US (GoM)	2013	163	14	57	5	2,921	28%		0	0	0	0	6	14	17	330
2014																	
CLOV	Angola	2014	604	0	160	0	9,442	23%	Yes	0	0	0	0	0	19	37	737
Corrib	Ireland	2010	0	150	0	56	2,937	37%		0	0	0	0	4	21	19	917
Astero	Norway	2014	30	10	17	6	689	45%		0	0	0	0	0	6	10	68
Hild	Norway	2014	32	95	22	40	2,366	21%			0	0	0	0	2	13	41
Peon	Norway	2014	0	131	0	56	1,581	72%		0	0	0	0	0	28	41	163
Knotty Head (GC 512)	US (GoM)	2014	230	20	68	6	5,922	25%		0	0	0	0	0	2	11	121
2015																	
Dagny	Norway	2015	103	97	48	62	2,100	50%		0	0	0	0	0	0	24	464
Bressay	UK	2015	288	0	43	0	4,819	82%		0	0	0	0	0	0	18	234
Rosebank	UK	2015	250	39	90	16	4,451	30%		0	0	0	0	0	0	24	816
Total (kboe/d)										**41**	**105**	**290**	**419**	**496**	**636**	**737**	
of which : Oil										*24*	*71*	*208*	*327*	*380*	*462*	*526*	
: Gas										*16*	*34*	*82*	*91*	*117*	*173*	*211*	

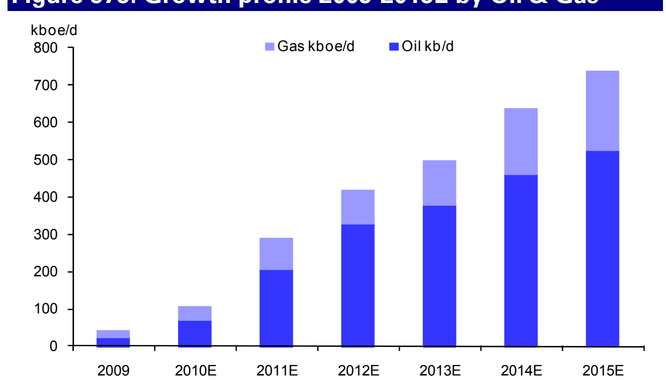
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 574: Project Mix – Oil/Gas, PSC/non-PSC % '15E



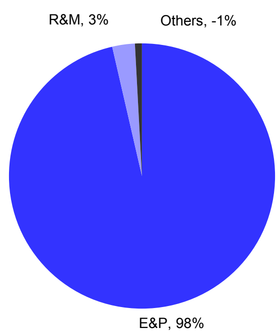
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 575: Growth profile 2009-2015E by Oil & Gas



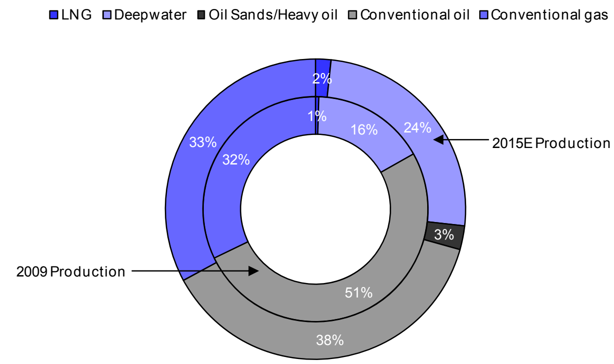
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 576: 2009 clean net income Nkr34,408m



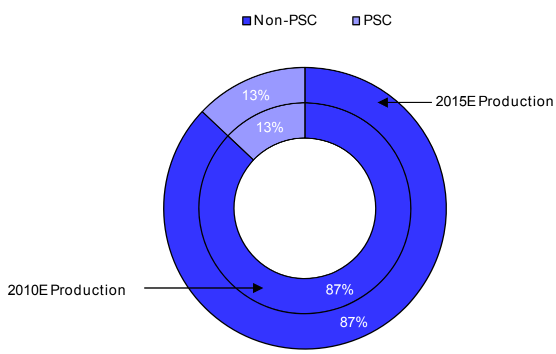
Source: Deutsche Bank

Figure 577: Trends in E&P Production



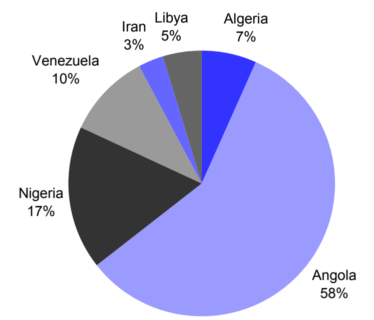
Source: Deutsche Bank

Figure 578: PSC exposure 10E-15E – staying flat



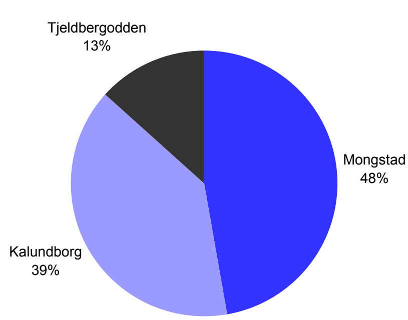
Source: Deutsche Bank

Figure 579: OPEC production 9% of total in 2010E



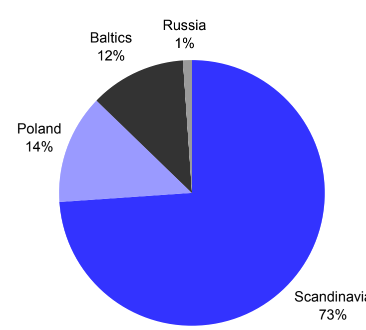
Source: Deutsche Bank

Figure 580: Statoil 2009 refining CDU 300kb/d



Source: Deutsche Bank

Figure 581: Statoil 2009 marketing by region



Source: Deutsche Bank

Europe United Kingdom
Oil & Gas Integrated Oils

8 September 2010

BG Group

Reuters: **BG.L** Bloomberg: **BG/ LN**

The growth opportunity

Although production growth through 2012 is expected to be sluggish major ongoing investment in Brazil, Australia and the US suggests that BG should be capable of delivering on management guidance of 6-8% p.a. upstream growth through 2020 as projects come onstream. In the interim, in an oversupplied gas market BG has shown itself once again to be a step ahead locking in a minimum of $1.8bn p.a. in LNG earnings between 2010-12. Our BUY stance reflects BG's strong growth potential, the excellence of its management and its unwavering delivery of value for shareholders.

E&P: BG's production is dominated by gas (73% of 2010 production) where the company has considerable technical and commercial expertise and a strong track record for execution. Focusing on high impact exploration, BG has successfully built a diverse portfolio of long lived assets which provide a solid base for production in the long term and have allowed it to reduce its former UK dependence. In terms of future growth, BG's legacy assets continue to offer real upside (Karachaganak, Bongkot, India) while, having re-loaded on exploration, BG's exposure to a number of opportunities (Brazil, Australia, US gas) has started to bear fruit, not least its 25% interest in 5-8bn bbl Brazilian Tupi.

LNG: BG has established a leading, independent marketing position in LNG through building a world-class portfolio which is distinguished by its level of integration and flexibility. This provides BG with a true competitive advantage and leaves it well placed to capture diverse opportunities even in today's oversupplied global LNG market. Furthermore, BG's ability to access demand and target the highest value end-markets enables the company to maximise profitability.

T&D and Power: T&D supplies gas to domestic markets through BG's transmission and distribution networks, most significantly in Brazil and India. BG also develops, owns and operates gas-fired power generations plants in a number of countries, a strategy which adds optionality to its core gas activities.

Valuation and risk

With so much of BG's value now dependent upon the future development of a substantially increased resource base valuing the shares on a near-term earnings basis is becoming increasingly inappropriate. As such our preferred method is to use our SoTP model. This suggests a target price of 1275p assuming some delays in development projects. Risks to our stance essentially concentrate around the timing and cost of delivery of BG's investment programme in Brazil and Australia.

Forecasts and ratios

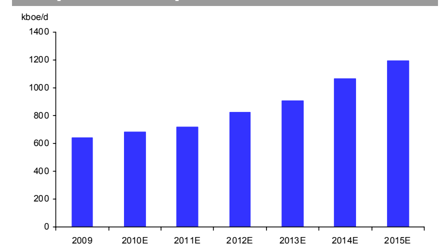
Year End Dec 31	2008A	2009A	**2010E**	2011E	2012E
DB EPS (GBP)	90.71	66.03	**73.89**	91.2	113.6
P/E (x)	12.0	16.0	**14.7**	11.8	9.6
Dividend Yield (%)	1.0	1.2	**1.2**	1.4	1.7

Source: Deutsche Bank estimates, company data

Buy

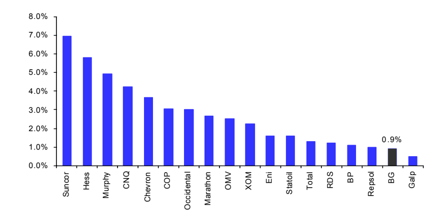
Price at 6 Sept 2010 (GBP)	**1,084.0**
Price Target (GBP)	**1,275.00**
52-week range (GBP)	**1,235.00 - 979.50**

BG production profile 09-15E



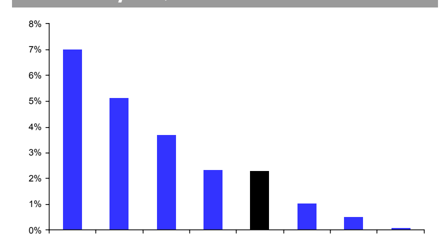
Upstream CAGR (2009-15E)	10.8%
Oil production (2009)	182kb/d
Gas production (2009)	462kboe/d
Oil Reserves (1P)	736mn/bbls
Gas Reserves (1P)	1,928bn/boe
Long lived assets % of Prod'n (2010E)	63%
LNG Contracted supply (2010E)	1,874mmscf/d
Wood Mackenzie 2P(E) Total reserves	7.7bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.53%

Sensitivity to $1bbl move in oil

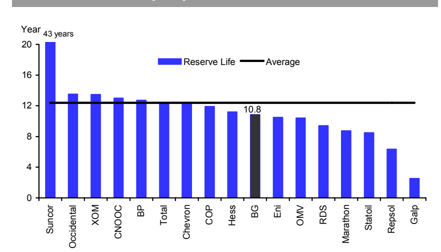


Source: Deutsche Bank

Sensitivity to $1/mmbtu move in H/Hub



Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 582: BG Net Asset Value by asset at $100/bbl long run oil

Upstream	Value $ Million	Value GBP Million	2 P Reserves	Value/2P Reserves	% of Total EV	Value per Share
Algeria	230	153	60	3.86	0.3%	0.05
Australia domestic	277	185	149	1.86	0.3%	0.05
Bolivia	1,343	895	288	4.66	1.5%	0.26
Brazil BMS 11 (Tupi/Iara)	18,921	12,614	2,439	7.76	21.4%	3.72
Brazil BMS-9 (Guara)	198	132	377	0.52	0.2%	0.04
Egypt	4,374	2,916	1,121	3.90	4.9%	0.86
India	1,270	847	133	9.58	1.4%	0.25
Kazakhstan	6,459	4,306	1,322	4.89	7.3%	1.27
Norway	488	326	67	7.25	0.6%	0.10
Thailand	1,362	908	116	11.76	1.5%	0.27
Trinidad	2,103	1,402	430	4.89	2.4%	0.41
Tunisia	2,965	1,976	184	16.08	3.3%	0.58
United Kingdom	7,260	4,840	414	17.55	8.2%	1.43
United States Gulf Coast	1,996	1,330	626	3.19	2.3%	0.39
Subtotal	**49,246**	**32,830**	**7,725**		**56%**	**9.69**
LNG Plant/midstream						
Egypt Concession LNG	923	616			1.0%	0.18
Trinidad Concession LNG	1,208	805			1.4%	0.24
Australia QGC	10,357	6,904	1,931	5.36	11.7%	2.04
Kazakhstan - CPC pipeline	136	91			0.2%	0.03
Total Upstream value	**61,870**	**41,246**	**9,655**		**70%**	**12.18**
LNG contracts (ex QGC)	**16,694**	**11,129**			**18.9%**	**3.29**
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
Quintero Bay	450	300			0.5%	0.09
Dragon, UK	1,320	880			1.5%	0.26
Subtotal	**1,770**	**1,180**			**2.0%**	**0.35**
LNG Ships						
Own fleet	4,250	2,833			4.8%	0.84
Subtotal	**4,250**	**2,833**			**4.8%**	**0.84**
Transmission & Distribution						
Comgas	1,560	1,040			1.8%	0.31
Gujarat Gas	489	326			0.6%	0.10
Mahanagar Gas	188	125			0.2%	0.04
Subtotal	**2,238**	**1,492**			**2.5%**	**0.44**
Power Plants						
BG Italia Power S.p.A.(SERENE)	240	160			0.3%	0.05
Genting Sanyen Power (Kuala Langat)	95	64			0.1%	0.02
First Gas Power (San Lorenzo)	120	80			0.1%	0.02
First Gas Power (Santa Rita)	240	160			0.3%	0.05
Premier Power (sale price)	150	100			0.2%	0.03
Seabank Power (sale price)	320	212			0.4%	0.06
Dighton/Lake Road/Masspower (sale price)	450	300			0.5%	0.09
Condamine	84	56			0.1%	0.02
Milford Energy Limited	14	10			0.0%	0.00
Subtotal	**1,714**	**1,141**			**1.9%**	**0.34**
Total Enterprise Value	**88,535**	**59,024**				**17.43**
Net Debt - end 2009	4,549	3,033				0.90
Net Asset Value	**83,986**	**55,991**				**16.53**
Market Capitalisation	**54,861**	**36,574**				**10.80**
Premium to NAV	**-35%**	**-35%**				**-35%**

Source: Wood Mackenzie, Deutsche Bank

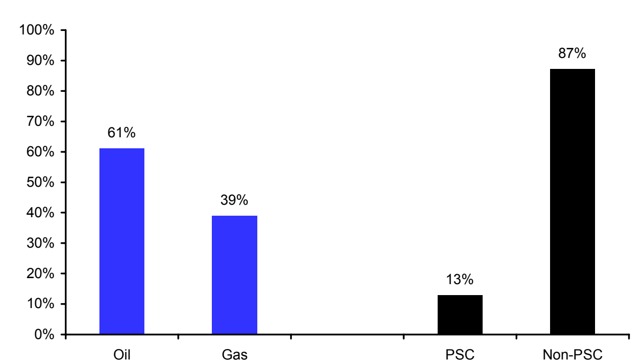
BG Group – Main projects 2009-15E

Figure 583: BG Group – Major Oil & Gas Projects by Year 2009-2015E

Projects	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	BG %	PSC	Production (kboe/d) - Working interest '09	'10	'11	'12	'13	'14	'15	NPV ($m)
2009																	
Hasdrubal	Tunisia	2009	35	43	16	15	1,231	50%		15	15	15	14	12	9	8	827
Palo Marcado	Bolivia	2009	1	9	0	4	0	100%	Yes	1	4	4	3	3	3	3	0
South Sequoia	Egypt	2009	0	88	0	18	319	80%	Yes	1	14	14	14	14	14	14	0
Ton Chan	Thailand	2009	7	9	3	3	0	22%		0	1	1	1	1	1	1	0
Ton Rang	Thailand	2009	2	9	1	3	0	22%		0	1	1	1	1	1	1	0
2010																	
Itau	Bolivia	2010	16	158	3	31	387	25%	Yes	0	0	2	2	8	8	8	120
North Sequoia	Egypt	2010	0	88	0	23	301	50%	Yes	0	4	11	11	11	11	11	0
South West Panna	India	2010	14	0	7	0	0	30%	Yes	0	1	2	2	1	1	1	0
Tupi	Brazil	2010	4,290	717	904	155	50,919	25%		2	4	30	31	39	85	116	4,488
2012																	
Pi	Norway	2012	5	10	6	10	306	60%		0	0	0	7	9	6	3	6
Ton Koon	Thailand	2012	2	31	1	9	0	22%		0	0	0	1	2	2	2	0
Ton Nok Yoong	Thailand	2012	2	66	1	19	0	22%		0	0	0	2	4	4	4	0
2013																	
Guará	Brazil	2013	1,145	115	253	28	10,497	30%		0	2	2	0	33	36	38	2,280
Jasmine	UK	2013	65	101	36	49	1,336	31%		0	0	0	0	15	26	24	5
Saurus	Egypt	2013	0	39	0	18	403	50%	Yes	0	0	0	0	5	8	9	0
Starfish	T & T	2013	1	70	0	28	278	50%	Yes	0	0	0	0	4	9	13	127
2014																	
Tupi North	Brazil	2014	2,530	425	525	91	27,626	25%		0	0	3	4	0	21	26	2,402
Queensland Curtis LNG	Australia	2014	0	1,764	0	202	14,650	100%		5	8	11	28	62	120	179	8,866
2015																	
Jacqui	UK	2015	5	5	3	5	164	31%		0	0	0	0	0	0	1	26
Total										**25**	**56**	**97**	**121**	**223**	**366**	**463**	
of which : Oil										*10*	*16*	*42*	*43*	*81*	*139*	*170*	
: Gas										*15*	*40*	*55*	*78*	*142*	*227*	*293*	

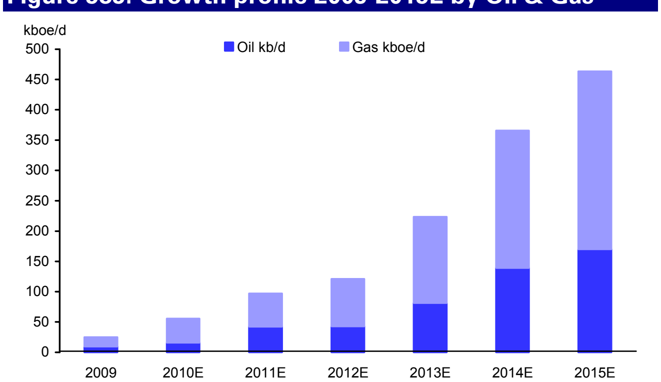
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 584: Project Mix – Oil/Gas, PSC/non-PSC % '15E



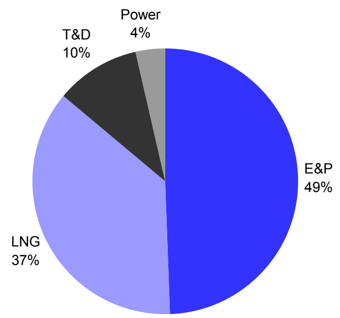
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 585: Growth profile 2009-2015E by Oil & Gas



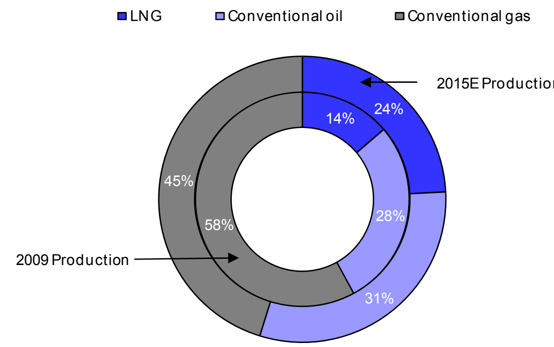
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 586: 2009 clean net income GBP2,264m



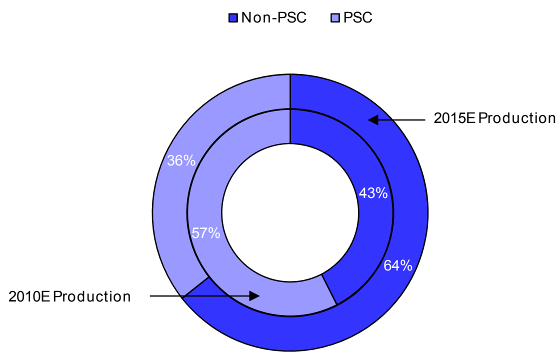
Source: Deutsche Bank

Figure 587: Trends in E&P Production



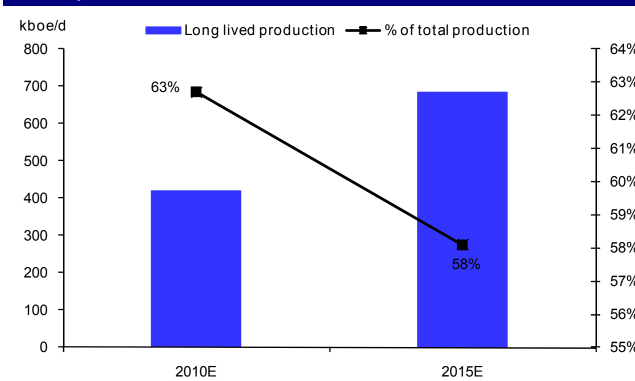
Source: Deutsche Bank

Figure 588: PSC exposure 10E-15E – in decline



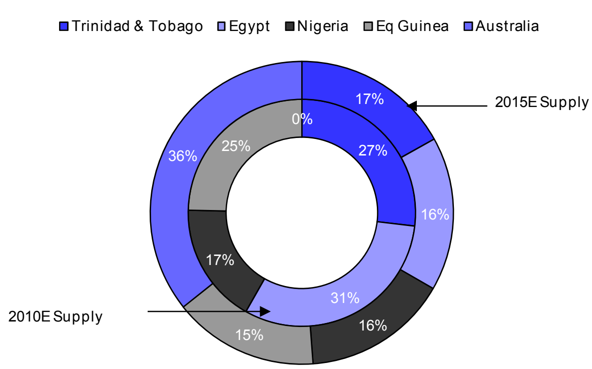
Source: Deutsche Bank

Figure 589: Long-lived assets (63% of total production in 2010E)



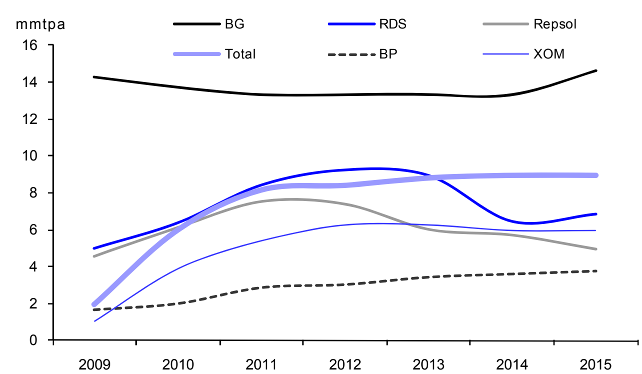
Source: Deutsche Bank estimates

Figure 590: LNG contract schedule 10E -15E



Source: Deutsche Bank

Figure 591: LNG contract volumes relative to peers



Source: Wood Mackenzie LNG tool, Deutsche Bank estimates

Europe Austria
Oil & Gas Integrated Oils

8 September 2010

OMV

Reuters: **OMVV.VI** Bloomberg: **OMV AV**

European Growth Belt

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 now firmly put the upstream as its primary point of focus for future investment. For investors seeking oil price exposure, OMV may be an attractive name. But given its lack of scale versus the peers, exposure to weak refining markets, exposure to Eastern European political risks, and a 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. Six years on and the impact of the acquisition is still evident with c.57% of production derived from Petrom (predominantly in Romania). OMV remains focused on six core regions (CEE, North Africa, NW Europe, ME, Australia/NZ and Caspian) albeit growth opportunities are somewhat limited. As such the focus is on enhanced oil recovery techniques, further integration with other business units and suitable M&A opportunities in its core regions. Given its low marginal tax rate, especially in Austria and Romania, OMV is the most geared company in the Western European integrated sector to oil prices.

R&M: With 530kb/d refining capacity and 20% retail market share in SEE/CEE, OMV is one of the lead players in the downstream in its core regions. Its crude slate is biased toward processing heavy crudes and producing middle distillates. Strategy is now focused on streamlining capacity and delivering cost savings.

Gas: While gas currently only accounts for c.10% of operational earnings, this is a key growth division for OMV. Not only is it developing a spot market in Austria to supports its trading activities, but it is also planning significant investment in the Nabucco pipeline and participating in the South Stream gas project while construction of a number of power plants is on-going in Romania and Turkey.

Valuation & Risk

We target OMV to trade at 7.5x PE multiple on 2010E EPS, a c.30% discount to our sector target of 11.5x justified by its high exposure to difficult refining markets, its narrow resource base and faltering production. Whilst the valuation is far from demanding, the outlook is one we expect to remain challenging with few clear near-term signs of improvement. Upside risk include a recovery in refining margins/oil price. Downside risks include weaker oil product demand, lower oil prices and drilling disappointment in the Erbil well in the Kurdistan region.

Forecasts and ratios

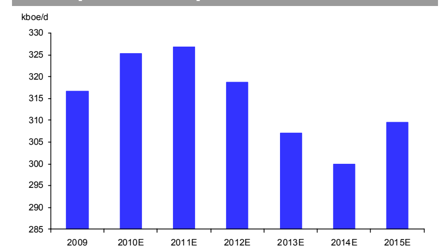
Year End Dec 31	2008A	2009A	**2010E**	2011E
DB EPS (EUR)	6.03	2.25	**3.85**	4.88
P/E (x)	6.7	11.5	**6.8**	5.4
Dividend Yield (%)	2.5	3.9	**3.8**	4.0

Source: Deutsche Bank estimates, company data

Hold

Price at 3 Sept 2010 (EUR)	**26.17**
Price Target (EUR)	**30.00**
52-week range (EUR)	**32.63 - 23.73**

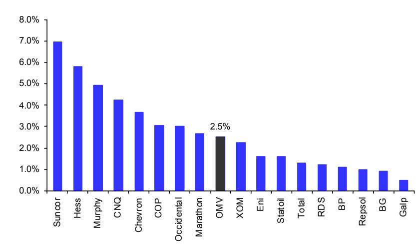
OMV production profile 2009-15E



Source: Deutsche Bank

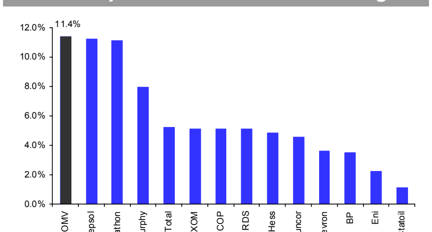
Upstream CAGR (2009-15E)	-0.4%
Oil production (2009)	173kb/d
Gas production (2009)	144kboe/d
Oil Reserves (1P)	700mn/bbls
Gas Reserves (1P)	489mn/boe
Refining capacity	518kb/d
Marketing volumes	350kb/d
Wood Mackenzie 2P(E) Total reserves	1,381/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.44%

Sensitivity to $1bbl move in oil



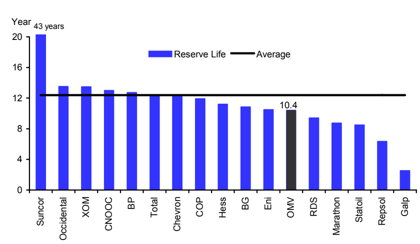
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 592: 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
Australia		-1	-1	1	-1.0	0.0%	0.00
Austria		3118	2424	208	15.0	11.8%	8.11
Libya PSC		2723	2117	97	28.2	10.3%	7.09
New Zealand		2402	1867	111	21.7	9.1%	6.25
Pakistan		386	300	66	5.8	1.5%	1.00
Tunisia		451	350	34	13.4	1.7%	1.17
UK		1297	1008	83	15.5	4.9%	3.37
Venezuela		8	6	1	9.3	0.0%	0.02
Yemen PSC		654	509	42	15.6	2.5%	1.70
Kazakhstan		411	320	25	16.4	1.6%	1.07
Romania		7045	5477	704	10.0	26.7%	18.33
Total Gem Upsteam Value		**18493**	**14378**	**1372**	**13.5**	**70.0%**	**48.13**
Refining and Marketing							
Europe Refining		2186	1700			8.3%	5.69
Europe Marketing		2026	1575			7.7%	5.27
Gas & Power		1572	1222			5.9%	4.09
Equity Interests							
Borealis	36%	1152	896			4.4%	3.00
Petrol Ofisi	42%	996	775			3.8%	2.59
Total Enterprise Value		26426	20546			100.0%	68.77
Adjusted end-2009 Net Debt		4111	3196			15.6%	10.70
Net Asset Value		**22315**	**17350**			**0.84**	**58.07**
Market Capitalisation		**10056**	**7818**				**26.17**
Premium to NAV		**-55%**	**-55%**				**-55%**

Source: Wood Mackenzie, Deutsche Bank

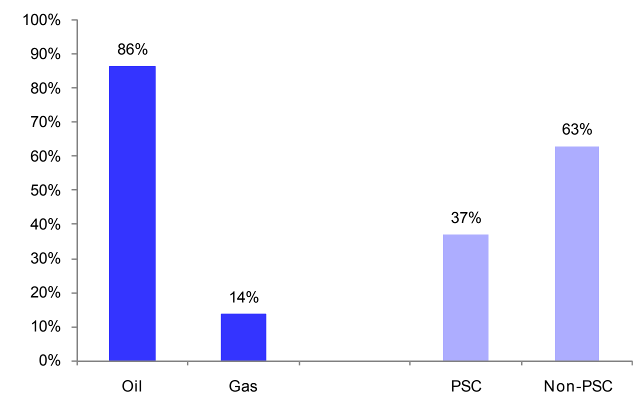
OMV – Main projects 2009-15E

Figure 593: OMV – Major Oil & Gas Projects by year 2009-15E

Projects	Country	Launch Year	Reserves Oil mmbl	Reserves Gas mboe	Peak Prodn Oil kb/d	Peak Prodn Gas kboe/d	Capex ($m)	OMV %	PSC	Production (kboe/d) - Working interest '09	'10	'11	'12	'13	'14	'15	NPV ($m)
2009																	
Komsomolskoye	Kazakhstan	2009	32	4	10	1	321	95%		2	4	6	6	6	5	5	499
Maari	New Zealand	2009	50	0	32	0	751	69%		18	22	16	12	9	6	5	648
Latif	Pakistan	2009	0	16	0	6	101	33%		1	1	2	2	2	2	1	33
Tajjal	Pakistan	2009	0	36	0	9	152	28%		1	1	2	2	2	2	2	49
2010																	
NC186-J	Libya	2010	50	0	19	0	108	12%	Yes	0	0	1	2	2	2	2	0
NC186-K	Libya	2010	16	0	6	0	47	12%	Yes	0	0	0	1	1	1	1	0
Bardolino	UK	2010	10	2	9	1	103	38%		0	4	3	2	1	1	0	123
2011																	
NC200 fields	Libya	2011	75	0	21	0	235	14%	Yes	0	0	1	1	2	3	3	323
Jenein Sud	Tunisia	2011	10	0	4	0	129	50%		0	0	1	1	2	2	2	46
2012																	
Habban S2 (Phase 2)	Yemen	2012	121	0	35	0	380	44%	Yes	0	0	0	6	12	13	11	605
2015																	
Rosebank	UK	2015	250	39	90	16	4,451	20%		0	0	0	0	0	0	16	544
Total										**22**	**33**	**32**	**35**	**39**	**37**	**48**	
of which : Oil										*20*	*29*	*26*	*30*	*34*	*32*	*42*	
: Gas										*2*	*4*	*6*	*5*	*5*	*5*	*6*	

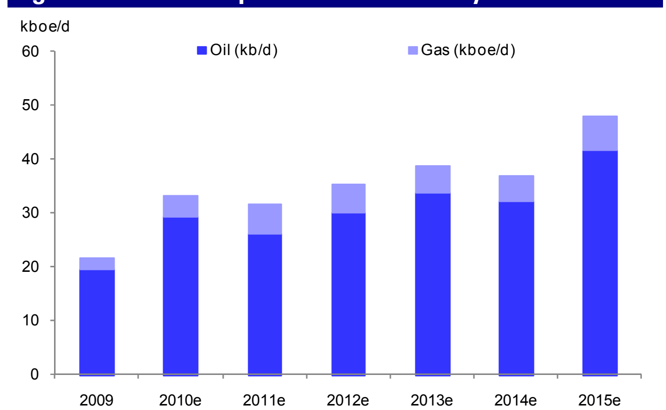
Source: Wood Mackenzie, Deutsche Bank

Figure 594: Project Mix – Oil/Gas, PSC/non-PSC % '15E



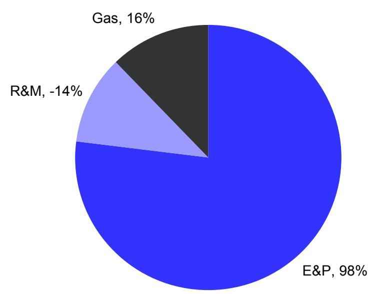
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 595: Growth profile 2009-2015E by Oil & Gas



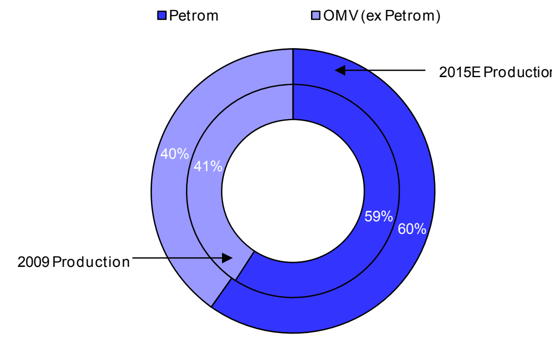
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 596: 2009 clean net income EUR637m



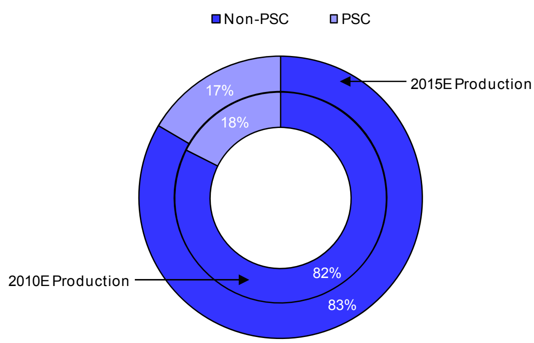
Source: Deutsche Bank

Figure 597: Trends in E&P Production



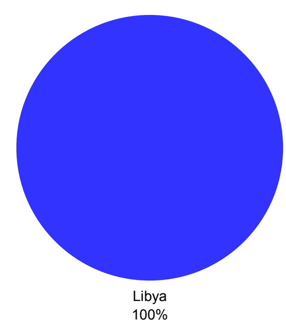
Source: Deutsche Bank

Figure 598: PSC exposure 10E-15E – diminishing



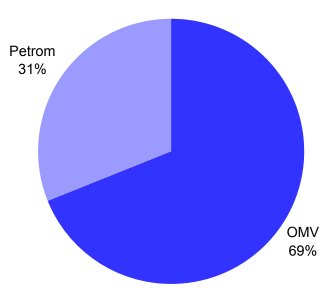
Source: Deutsche Bank

Figure 599: OPEC production 8% of total in 2010E



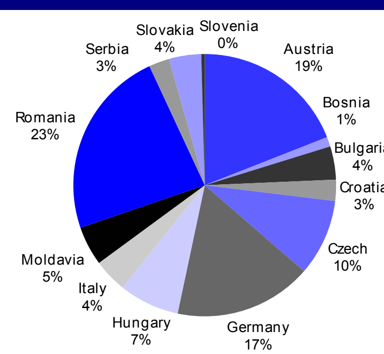
Source: Deutsche Bank

Figure 600: OMV 2009 refining CDU 518kb/d



Source: Deutsche Bank

Figure 601: OMV 2009 marketing by region



Source: Deutsche Bank

Europe Portugal
Oil & Gas Integrated Oils

8 September 2010

Galp Energia

Reuters: **GALP.LS** Bloomberg: **GALP PL**

Deep transformation underway

Galp Energia is a company undergoing a deep transformation. Since listing in 2006 exploration success and capex in its three key business units have changed its profile. We expect this transformation to continue not least as production at the giant 5-8bn boes Tupi field in Brazil starts up and its upgraded refineries come on-stream in 2011. However, given near term market uncertainties over the value/boe in Brazil and using our base case SoTP as a valuation basis, we recommend a Hold at present.

Upstream: Active expansion coupled with the success in the Brazilian off-shore segment is leading the company to a new phase. From a limited production profile (only Angola), the company has expanded its portfolio picking up exploration blocks in Mozambique, Uruguay, Equatorial Guinea, Venezuela, East Timor and Portugal with a special focus on Brazil, where its close relationship with Petrobras will likely drive a new E&P profile in the coming years. Indeed with Brazilian production coming on-stream and Angola ramping up, production is forecast to grow by a CAGR of 40% out to 2015 (vs. 1% across the sector).

Downstream: In 2007 Galp launched an ambitious investment plan for its two refineries with the aim of increasing complexity and thus production of middle distillates in order to benefit from the structural shortage of middle distillates on the Iberian Peninsula. The facilities should be operational by the second half of 2011 after which the downstream is expected to become a cash cow to fund developments in the upstream. Galp has also been active in recent years expanding its marketing presence into Spain, most recently via its acquisition of XOM and Agip's service stations.

Gas & Power: Galp is Portugal's largest supplier of gas, a key storage supplier and the largest marketer/distributor of gas. Moreover, with plans to increase power generation capacity and investments in wind power generation, earnings in this division look set to grow by a CAGR of 14% to 2015E.

Valuation & Risk

With so much of Galp's value dependent on project developments in Brazil and Angola and the start-up of its conversion projects in the downstream, valuing Galp's shares on near-term earnings strikes us as inappropriate. As such our preferred method is to use our SoTP model which suggests a price target of EUR12.75/share. Key upside risks to our Hold stance include a sustained economic recovery, high oil prices and further positive exploration news. Key downside risks include increasing interest rates (c.60% of LT debt is variable), a sustained downturn in the downstream and poor results in key exploration areas.

Forecasts and ratios

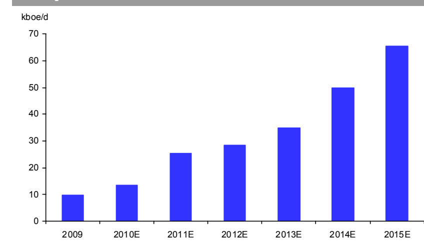
Year End Dec 31	2008A	2009A	**2010E**	2011E
DB EPS (EUR)	0.58	0.26	**0.48**	0.73
P/E (x)	22.7	39.6	**26.4**	17.3
Dividend Yield (%)	2.5	2.0	**1.6**	1.6

Source: Deutsche Bank estimates, company data

Hold

Price at 3 Sept 2010 (EUR)	**12.60**
Price Target (EUR)	**12.75**
52-week range (EUR)	**13.66 - 9.03**

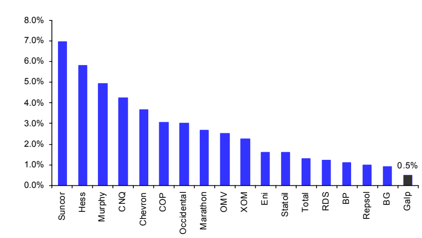
Galp Production Profile 2009-15E



Source: Deutsche Bank

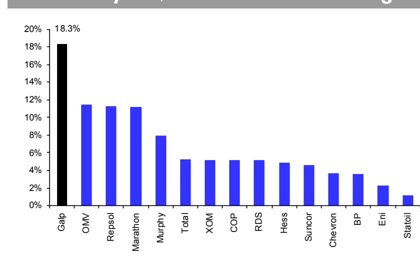
Upstream CAGR (2009-15E)	37.1%
Oil production (2009)	10kb/d
Gas production (2009)	Nil
Oil Reserves (1P)	24.5mn/bbls
Refining capacity	310kb/d
Marketing volumes	335kb/d
Wood Mackenzie 2P(E) Total reserves	922mn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.43%

Sensitivity to $1bbl move in oil



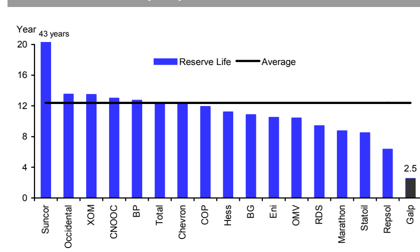
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 602: Galp 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
Angola		1694	1317	161	10.5	10.5%	1.59
Brazil	Tupi & Iara	6053	4706	975	6.2	37.6%	5.67
Brazil - Santos	Technical reserve @30% success	3195	2484	858	3.7	19.9%	3.00
Angola - blocks 14, 14K, 32 and 33	Technical reserve @30% success	488	380	62	7.9	3.0%	0.46
Total Upsteam Value		**11431**	**8887**	**2055**	**5.6**	**71.1%**	**10.72**
LNG Contracts		625	486			3.9%	0.59
Refining and Marketing							
Europe Refining		1645	1279			10.2%	1.54
Europe Marketing		1171	910			7.3%	1.10
Gas		1102	857			6.9%	1.03
Power		105	81			0.7%	0.10
Total Enterprise Value		16078	12500			100.0%	15.07
Adjusted end-2009 Net Debt		2479	1927			15.4%	2.32
Net Asset Value		**13599**	**10573**			**0.85**	**12.75**
Market Capitalisation		**13439**	**10449**				**12.60**
Premium to NAV		**-1%**	**-1%**				**-1%**

Source: Wood Mackenzie, Deutsche Bank

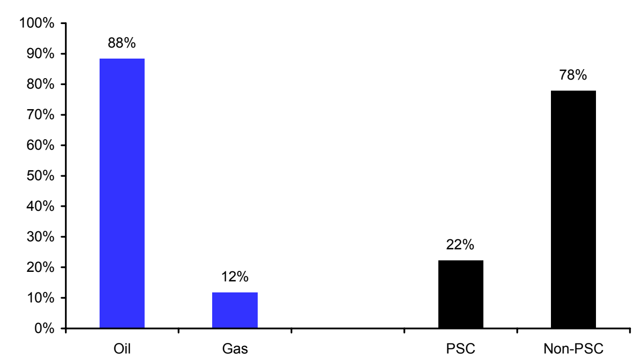
Galp – Main projects 2009-15E

Figure 603: Galp – Major Oil & Gas Projects by year 2009-2015E

Projects	Country	Launch Year	Reserves Oil mbbl	Reserves Gas mboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	Galp %	PSC	Production (kboe/d) - Working interest '09	'10	'11	'12	'13	'14	'15	NPV ($m)
2009																	
Landana	Angola	2009	133	0	42	0	2,114	9%	Yes	0	2	3	4	4	4	3	0
Tombua	Angola	2009	184	0	58	0	2,844	9%	Yes	1	3	5	5	5	5	4	0
2010																	
Tupi	Brazil	2010	4,290	717	904	155	50,919	10%		1	1	12	12	15	34	46	1,795
2012																	
Lianzi	Angola	2012	60	0	33	0	1,035	5%	Yes	0	0	0	0	0	0	1	19
2013																	
Iara	Brazil	2013	2,530	425	525	91	27,626	10%		0	0	1	2	0	8	10	961
2015																	
Block 32 Southeast	Angola	2015	507	0	150	0	10,241	5%	Yes	0	0	0	0	0	0	5	126
Malange	Angola	2015	60	0	30	0	974	9%	Yes	0	0	0	0	0	0	2	34
Total (kboe/d)										**2**	**6**	**22**	**23**	**24**	**52**	**73**	
of which : Oil										*2*	*6*	*20*	*21*	*22*	*45*	*64*	
: Gas										*0*	*0*	*2*	*2*	*2*	*6*	*9*	

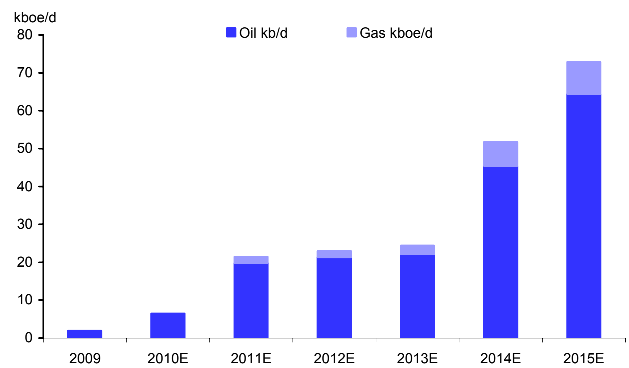
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 604: Project Mix – Oil/Gas, PSC/non-PSC % '15E



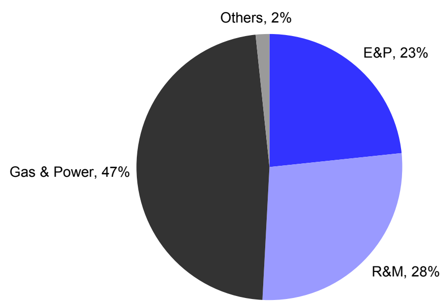
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 605: Growth profile 2009-2015E by Oil & Gas



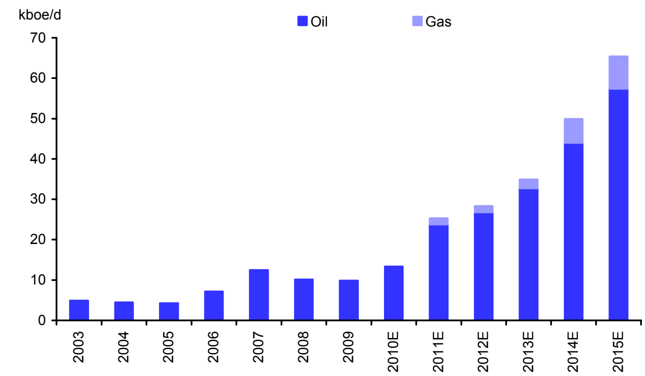
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 606: 2009 clean net income EUR214m



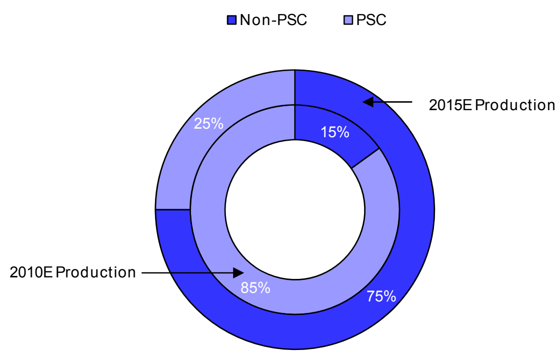
Source: Deutsche Bank

Figure 607: Trends in E&P Production – CAGR of 40% out to 2015



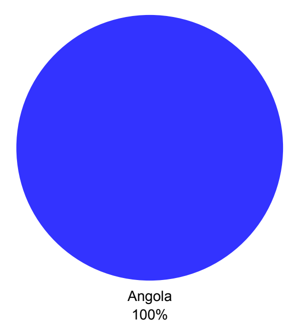
Source: Deutsche Bank

Figure 608: PSC exposure 10E-15E – diminishing as Brazil increases production



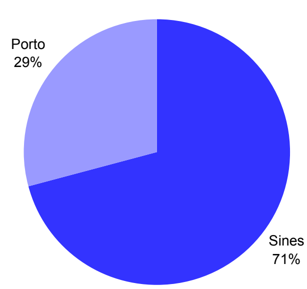
Source: Deutsche Bank

Figure 609: OPEC production 85% of total in 2010E



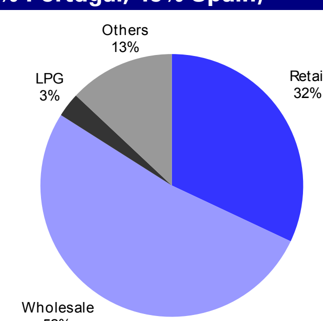
Source: Deutsche Bank

Figure 610: Galp 2009 refining CDU 310kb/d



Source: Deutsche Bank

Figure 611: Galp 2009 marketing by type – total of 11.1mton (55% Portugal, 45% Spain)



Source: Deutsche Bank

North America United States
Industrials Integrated Oil

8 September 2010

ExxonMobil

Reuters: **XOM.N** Bloomberg: **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 characterise 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. Given the quality of its assets in an uncertain economy, defensiveness in a falling oil price environment, we rate it BUY.

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 upstream ROACE of 23% in 2009 (from 54% in 2008), but short term performance should be pressured by the XTO deal in a weak US natgas market. 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 recent XTO acquisition. Under-appreciated strengths are Middle Eastern positioning (formerly Aramco partner, it dominates Qatar) and Russian understanding, with CEO Rex Tillerson having formerly headed Russian operations.

Downstream: ExxonMobil produces approximately 4.3mboe/d (2.4mb/d of oil), refines 5.4mb/d and sells 8.7mb/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.

Other: A sustained non-consensus push by ExxonMobil has been into chemicals, and it now stands alone as a truly integrated major oil. The company holds world-scale positions in both base and specialty petrochemicals, no other oil does.

Valuation & Risk

We set our PT for ExxonMobil at $70, in line with Net Asset Value estimate of $71, based on a bottom-up analysis of future cash flows and ROCE/WACC. Our PT implies $6.40 through-the-cycle EPS at $80/bbl x target P/E of 11x. Downside risks to our positive stance include rising taxes, shrinking access abroad, geopolitical instability, falling demand, management turnover and an expensive acquisition.

Forecasts and ratios

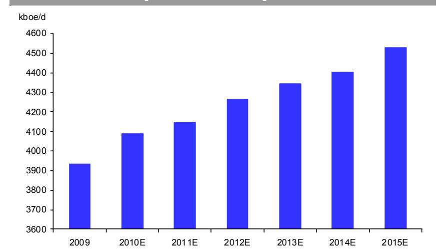
Year End Dec 31	2008A	**2009E**	2010E
EPS (USD)	8.47	**5.91**	6.34
P/E (x)	9.8	**10.4**	9.7
Dividend yield (%)	1.9	**2.8**	3.0

Source: Deutsche Bank estimates, company data

Buy

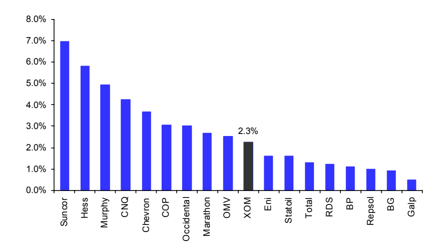
Price at 6 Sept 2010 (USD)	**61.06**
Price target	**70.00**
52-week range	**76.47 – 56.57**

ExxonMobil production profile 2009-15E



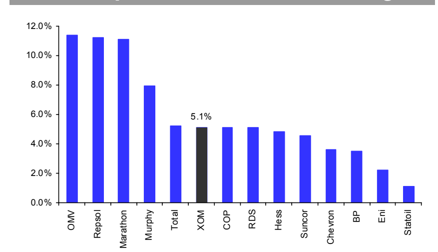
Upstream CAGR (2009-15E)	2.4%
Oil production (2009)	2,387kb/d
Gas production (2009)	1,546kboe/d
Oil Reserves (1P)	11.65bn/bbls
Gas Reserves (1P)	11.37bn/boe
Refining capacity	6,271kb/d
Marketing volumes	6,428kb/d
Wood Mackenzie 2P(E) Total reserves	29.3bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.74%

Sensitivity to $1bbl move in oil



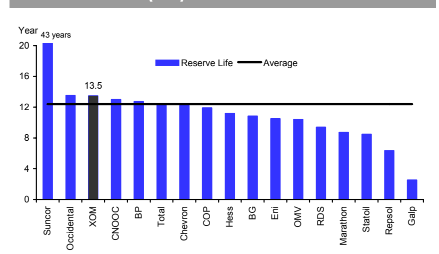
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 612: ExxonMobil Net Asset Value by Asset

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			1,361	1,432	1,350	1,421	1.0	0.4%	0.27
Angola PSC			12,593	20,988	1,200	2,000	10.5	3.5%	2.47
Argentina			298	338	65	74	4.6	0.1%	0.06
Australia			10,894	12,522	2,303	2,647	4.7	3.0%	2.13
Azerbaijan			2,594	3,283	257	325	10.1	0.7%	0.51
Cameroon			87	105	5	6	-	0.0%	0.02
Imperial Oil (Canada)	Includes gas, heavy oil, downstream		24,310	25,733	3,573	3,927	6.8	6.7%	4.76
Canada Mobil			6,560	7,372	523	588	12.5	1.8%	1.29
Canada Heavy Oil			146	159	885	962	0.2	0.0%	0.03
Western Canada			1,968	2,212	222	249	8.9	0.5%	0.39
Chad			1,338	1,760	141	185	9.5	0.4%	0.26
Equatorial Guinea			2,695	3,500	248	323	10.9	0.7%	0.53
Germany			4,825	5,134	501	533	9.6	1.3%	0.95
Indonesia			1,108	1,518	160	219	6.9	0.3%	0.22
Iraq			779	1,218	3,018	4,715	0.3	0.2%	0.15
Italy	BEB 50%		989	1,030	72	75	13.7	0.3%	0.19
Kazakhstan			20,315	38,330	1,848	3,487	11.0	5.6%	3.98
Malaysia			3,232	3,420	922	975	3.5	0.9%	0.63
Netherlands			27,250	28,386	1,859	1,937	14.7	7.5%	5.34
Nigeria	Includes infrastructure		10,805	21,611	1,012	2,024	10.7	3.0%	2.12
Norway	Includes infrastructure		9,323	11,370	846	1,032	11.0	2.6%	1.83
Papua New Guinea			5,803	7,165	512	632	11.3	1.6%	1.14
Qatar	Includes infrastructure		52,981	56,364	7,771	8,267	6.8	14.5%	10.38
Russia			6,401	7,806	464	566	13.8	1.8%	1.25
Thailand			166	201	14	17	12.0	0.0%	0.03
United Kingdom	Includes LNG plant, infrastructure		3,751	5,246	282	394	13.3	1.0%	0.73
United States DWGOM			7,265	10,379	492	703	14.8	2.0%	1.42
United States Alaska			7,150	8,938	1,110	1,388	6.4	2.0%	1.40
United States Rocky Mount			683	794	310	360	2.2	0.2%	0.13
United States MidContinent			1,281	1,490	175	204	7.3	0.4%	0.25
US Conc West Coast	Includes infrastructure		3,898	4,480	238	274	16.4	1.1%	0.76
United States Permian			2,217	2,578	217	252	10.2	0.6%	0.43
US Conc Permian			4,000	4,000	-	-		1.1%	0.78
Venezuela	No details on compensation yet		-	-	-	-		0.0%	0.00
XTO Energy			20,401	23,726	4,024	4,679	5.1	5.6%	4.00
Yemen			112	126	8	9	14.3	0.0%	0.02
Sub-Total			**259,580**	**324,711**	**36624**	**45446**	**7.1**	**71.2%**	**50.85**
Implied per barrel of booked reserves		23,023	$11.3 /bbl						
Implied PER on 2007-10E average earni		$24,825	10.5x	13.1x					
3P "Possible" Reserves			14,055					3.9%	2.75
Upstream Sub-Total			**273,635**					**75.1%**	**53.60**
Refining and Marketing									
Europe Refining			8,767					2.4%	1.72
Europe Marketing			4,836					1.3%	0.95
North America Refining			22,954					6.3%	4.50
North America Marketing	Excludes Imperial Oil		6,556					1.8%	1.28
Japan Refining			2,546					0.7%	0.50
Asia Refining			5,036					1.4%	0.99
Asia Marketing			2,088					0.6%	0.41
Latin America Refining			477					0.1%	0.09
Latin America Marketing			1,130					0.3%	0.22
Sub-Total			**54,389**					**14.9%**	**10.65**
Implied PER on 2007-10E average earni		$5,154	10.6x						
Gas, Power, Etc									
CAPCO	Majority stake in Hong Kong's		7,200					2.0%	1.41
Sub-Total	biggest generator		**7,200**					**2.0%**	**1.41**
Chemicals			**29,313**					**8.0%**	**5.74**
Implied PER on 2007-10E average earni		$3,525	8.3x						
Total Enterprise Value			**364,537**					**100.0%**	**71.40**
Adjusted 2Q10E Net Debt			5,163					1.4%	1.01
Net Asset Value			**359,374**					**98.6%**	**70.39**
Market Capitalisation			**291,357**						**57.07**
Premium to NAV			**-19%**						**-19%**

Source: Wood Mackenzie, Deutsche Bank

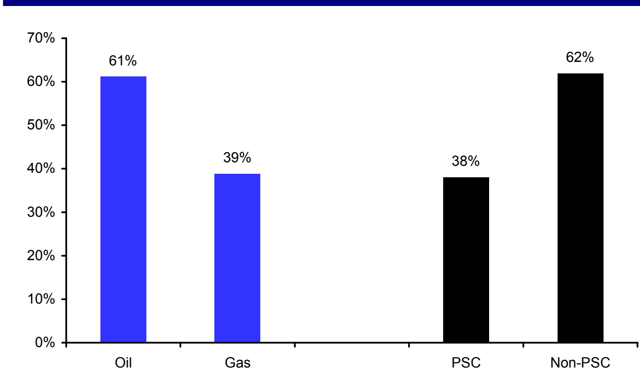
ExxonMobil – Main Projects 2009-2015E

Figure 613: ExxonMobil – Major Oil & Gas Projects by Year 2009-2015E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas Mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	XOM Share	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Tyrihans	Norway	2009	250	182	81	58	2,734	12%		2	6	8	10	13	14	14	554
Piceance Tight Gas Ph 1	US	2009	5	214	0	23	na	100%		14	23	23	23	23	23	23	na
Qatargas II Trains 4/5	Qatar	2009	672	4,032	150	405	8,264	24%		41	98	131	131	129	119	117	10,995
RasGas III Trains 6/7	Qatar	2009	683	4,156	150	405	9,658	30%		29	116	156	163	161	156	152	10,697
Al Khaleej Gas Phase 2	Qatar	2009	1,128	2,575	157	333	4,500	100%	Yes	36	174	282	287	287	285	284	6,081
2010																	
Odoptu (Sakhalin 1)	Russia	2010	139	557	77	24	na	30%	Yes	0	4	19	23	26	28	42	na
2011																	
Erha North Phase 2	Nigeria	2011	208	500	25	0	Na	49%	Yes	0	0	3	8	11	14	14	na
Pazflor	Angola	2011	720	0	200	0	11,398	20%	Yes	0	0	5	37	40	40	40	1,741
Upper Zakum Exp.	Abu	2011	4,962	0	250	0	na	28%		0	0	4	29	32	48	62	na
2012																	
Kizomba Satellites (P1)	Angola	2012	253	0	100	0	3,519	40%	Yes	0	0	0	24	40	35	31	836
Bonga North/NW	Nigeria	2012	240	25	96	10	4,268	20%	Yes	0	0	0	2	21	20	17	na
Usan	Nigeria	2012	610	0	180	0	9,951	30%	Yes	0	0	0	25	54	54	54	1,980
Turrum	Australia	2012	190	147	72	64	na	50%		0	0	0	9	12	12	20	na
Kearl Phase 1	Canada	2012	3,541	0	220	0	10,000	100%		0	0	0	15	50	55	65	825
2013																	
Kashagan Phase 1	Kazakhsta	2013	12,277	622	1,475	120	141,673	17%	Yes	0	0	0	0	36	54	70	8,520
Barzan	Qatar	2013	1,146	2,345	138	264	3,036	10%	Yes	0	0	0	0	13	40	40	162
Cold Lake Expansion	Canada	2013	900	0	30	0	na	100%		0	0	0	0	9	15	30	na
Block 31 PSVM	Angola	2013	518	0	150	0	10,702	25%	Yes	0	0	0	0	10	30	38	1,401
West Qurna-1 Exp.	Iraq	2013	7,565	3,182	1,300	0	23,432	60%		0	0	0	0	20	40	80	1,183
2014																	
CLOV	Angola	2014	604	0	160	0	9,442	20%	Yes	0	0	0	0	0	16	32	632
Greater Gorgon	Australia	2014	275	7,197	18	422	63,130	25%		0	0	0	0	0	14	61	3,843
Bosi	Nigeria	2014	500	0	135	0	7,217	56%	Yes	0	0	0	0	0	23	76	n.a
PNG LNG	PNG	2014	190	1,631	33	162	15,541	42%		0	0	0	0	0	44	75	5,079
2015																	
Block 32 Southeast	Angola	2015	507	0	150	0	10,241	15%	Yes	0	0	0	0	0	0	16	377
Kizomba Satellites (P2)	Angola	2015	454	0	182	0	6,875	40%	Yes	0	0	0	0	0	0	4	1,151
Tengiz Expansion	Kazakhsta	2015	4.986	619	100	0	Na	25%		0	0	0	0	0	0	33	na
Bonga Southwest	Nigeria	2015	400	51	112	15	6,912	20%	Yes	0	0	0	0	0	0	13	n.a
Dagny	Norway	2015	103	97	48	62	2,100	40%		0	0	0	0	0	0	19	371
Total (kboe/d)										**123**	**427**	**673**	**867**	**1,073**	**1,279**	**1,644**	
of which : Oil										*50*	*186*	*320*	*504*	*686*	*818*	*1,025*	
: Gas										*73*	*241*	*353*	*363*	*387*	*461*	*619*	

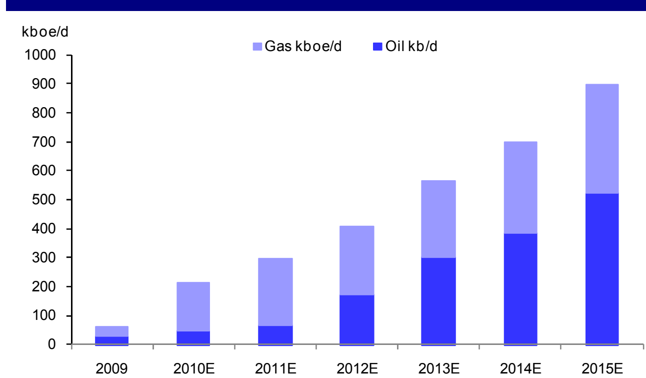
Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 614: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



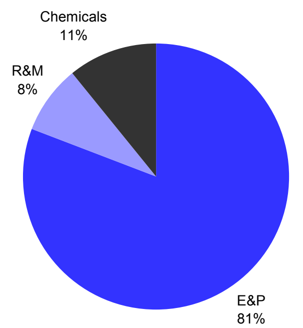
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 615: Growth profile 2009-15E by Oil & Gas



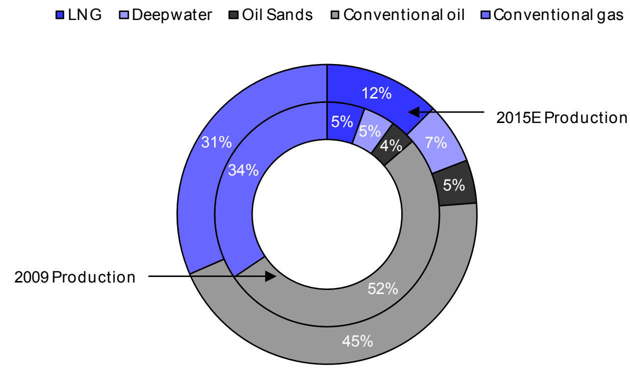
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 616: 2009 clean net income USD19,420m



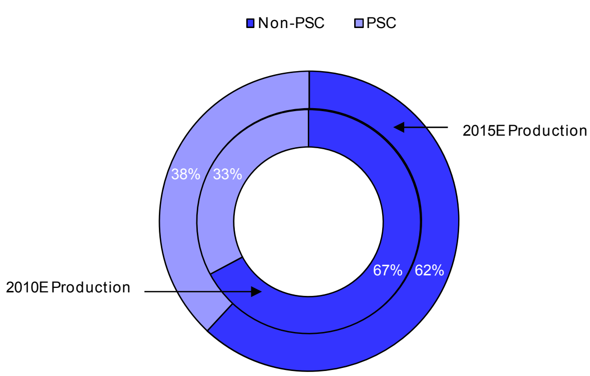
Source: Deutsche Bank

Figure 617: Trends in E&P Production



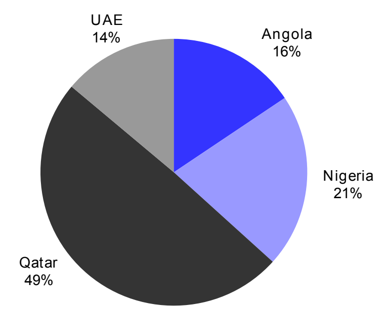
Source: Deutsche Bank

Figure 618: PSC exposure 10E-15E – on the increase



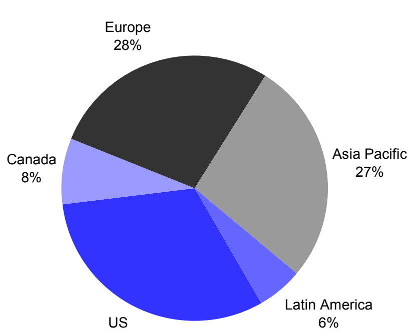
Source: Deutsche Bank

Figure 619: OPEC production 44% of total in 2010E



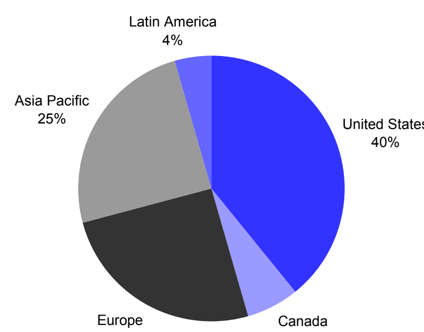
Source: Deutsche Bank

Figure 620: ExxonMobil 2009 refining CDU 6,271kb/d



Source: Deutsche Bank

Figure 621: ExxonMobil 2009 marketing by region



Source: Deutsche Bank

North America United States
Industrials Integrated Oil

8 September 2010

Chevron

Reuters: **CVX.N** Bloomberg: **CVX UN**

Resource rich

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. With its huge resource base, particularly in NW Australia gas, CVX has reported sector leading growth over the last 2 years however the medium term outlook for growth is now muted. With heavy exposure to the US GoM, CVX will continue to be negatively impacted by the changing post-Macondo spill environment. Hold.

Upstream: Chevron has differentiated itself in recent years by focusing aggressively on the deepwater, particularly in the US GoM, while its peers have been more focused on unconventional gas. That's not to say CVX is not in gas; the company holds massive gas resources in Australia, with both Gorgon and Wheatstone LNG projects forming a big chunk of the company's growth profile from 2014 onwards, while we expect the company's portfolio to move from 30% gas production to 37% over the next 7 years.

Downstream: Chevron is a Pacific refiner with a major Californian and Asian presence, a legacy of its deep history, namely Caltex, an outlet for Saudi oil. Including its share of affiliates, the company processes more than 2mb/d of crude and markets petroleum products worldwide (No.2 marketer in the US). Its downstream earnings have been characterised by low profitability of late with the company subsequently announcing a restructuring in the downstream that aims to dispose of a number of assets.

Other: Chemicals are a small and relatively weak part of the investment case. Through its JV CPChem Chevron produces olefins and aromatics. Chevron Oronite supplies 25% of the world's fuel and lubricant additives.

Valuation & Risk

We value Chevron based on the average of our NAV and P/E analyses. We estimate NAV at $104 based on a bottom-up analysis of future cash flows and ROCE/WACC, but apply a 15% discount to reflect the historical discount of the stock relative to NAV to get a $90 value. Our P/E methodology yields a valuation of $70, based on a target P/E of 9x (derived from ROCE/WACC) applied to a mid-cycle EPS estimate of $7.75. Averaging the two methods we arrive at our blended $80 PT. Upside risks include management's ability to turn its huge resource base into high value, producing mega-projects. Downside risks include challenges in Kazakhstan, West Africa, stranded gas in Asia, and deepwater Latin America causing over-spending and delays that could destroy shareholder value. A recent downside risk is in the political and operational fallout from the Deepwater Horizon oil spill disaster in the Gulf of Mexico

Forecasts and ratios

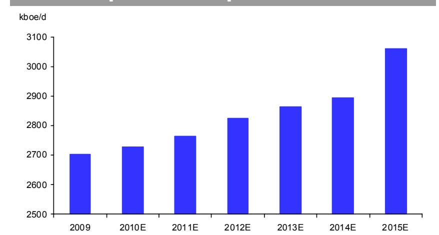
Year End Dec 31	2009A	**2010E**	2011E
EPS (USD)	4.81	**10.06**	10.59
P/E (x)	14.6	**7.8**	7.4
Dividend yield (%)	3.8	**3.6**	3.8

Source: Deutsche Bank estimates, company data

Hold

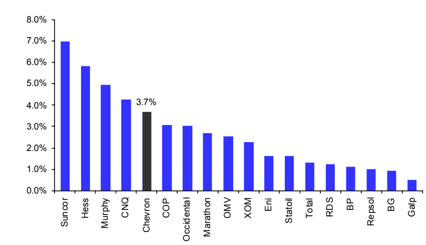
Price at 3 Sept 2010 (USD)	**77.45**
Price target	**80.00**
52-week range	**82.83 - 61.40**

Chevron production profile 2009-2015E



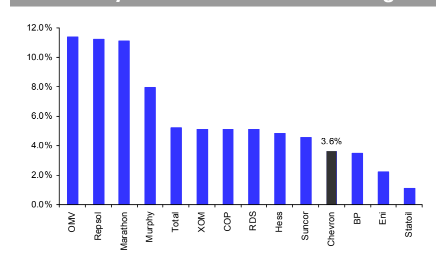
Upstream CAGR (2009-15E)	2.1%
Oil production (2009)	1,872kb/d
Gas production (2009)	832kboe/d
Oil Reserves (1P)	6.97bn/bbls
Gas Reserves (1P)	4.34bn/boe
Refining capacity	2,158kb/d
Marketing volumes	3,254kb/d
Wood Mackenzie 2P(E) Total reserves	25.6bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.1.23%

Sensitivity to $1bbl move in oil



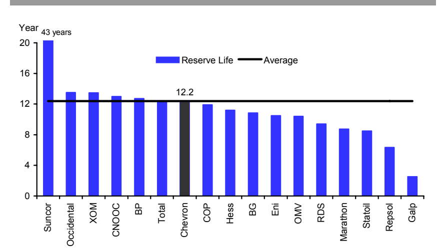
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 622: Chevron Net Asset Value by Asset

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		7,718	12,863	722	1,204	10.7	3.6%	3.9
Argentina		903	1,026	133	151	6.8	0.4%	0.5
Australia		23,358	26,849	5,112	5,876	4.6	11.0%	11.7
Azerbaijan		3,784	4,790	330	417	11.5	1.8%	1.9
Bangladesh		1,668	2,254	593	801	2.8	0.8%	0.8
Brazil		3,880	4,675	342	412	11.3	1.8%	1.9
Canada Newfoundland Labra		3,590	4,433	288	356	12.5	1.7%	1.8
Canada Oil Sands		5,651	6,687	620	734	9.1	2.7%	2.8
Chad		800	1,053	88	116	9.1	0.4%	0.4
China		1,293	1,437	64	71	20.3	0.6%	0.6
Colombia		463	532	54	62	8.6	0.2%	0.2
Congo Braz		1,861	2,416	190	247	9.8	0.9%	0.9
Denmark		2,426	2,527	139	145	17.4	1.1%	1.2
Indonesia		7,784	10,663	1,431	1,961	5.4	3.7%	3.9
Kazakhstan		25,520	48,152	2,161	4,077	11.8	12.0%	12.7
Myanmar		1,523	1,813	194	230	7.9	0.7%	0.8
Netherlands		299	311	21	22	14.1	0.1%	0.1
Nigeria		14,138	28,276	1,013	2,026	14.0	6.7%	7.1
Norway		104	127	7	9	14.5	0.0%	0.1
Philippines		1,842	2,070	167	187	11.1	0.9%	0.9
Saudi Arabia Partitioned		2,966	3,195	867	933	3.4	1.4%	1.5
Thailand		9,039	10,958	1,057	1,281	8.6	4.3%	4.5
Trinidad		1,009	1,062	251	264	4.0	0.5%	0.5
United Kingdom		5,241	7,330	318	445	16.5	2.5%	2.6
United States Alaska		811	1,014	267	333	3.0	0.4%	0.4
United States Gulf Coast		4,092	4,758	356	414	11.5	1.9%	2.0
United States DW Gulf of Mexico		12,158	17,369	833	1,190	14.6	5.7%	6.1
United States MidContinent		439	511	61	71	7.2	0.2%	0.2
United States Other Lower 48		21,476	24,686	1,473	1,693	14.6	10.1%	10.7
United States Permian		4,142	4,816	351	409	11.8	2.0%	2.1
United States Rocky Mount		1,662	1,933	219	254	7.6	0.8%	0.8
Venezuela Strategic Assoc		2,839	4,436	383	599	7.4	1.3%	1.4
Vietnam		369	450	253	308	1.5	0.2%	0.2
Sub-Total		**174,846**	**245,468**	**20,358**	**27,300**	**8.6**	**82.5%**	**87.2**
Implied per barrel of booked reserves	11,315	$15.5	$21.7 /bbl					
Implied PER on 2007-10E avg earnings $ M.	$15,885	11.0x	15.5x					
3P "Possible" Reserves		14,484					6.8%	7.2
Upstream Sub-Total		**189,330**					**89.3%**	**94.5**
Refining and Marketing								
Europe Refining		934					0.4%	0.47
Europe Marketing		2,295					1.1%	1.15
North America Refining		6,635					3.1%	3.31
North America Marketing		1,420					0.7%	0.71
Asia / Africa Refining		3,641					1.7%	1.82
Asia Pacific / Latin America Marketing		3,653					1.7%	1.82
Sub-Total		**18,578**					**8.8%**	**9.27**
Implied PER on 2007-10E avg earnings $ M.	$1,883	9.9x						
Gas, Power, Etc								
GS Caltex, Ships etc		2,000					0.9%	1.00
Sub-Total		**2,000**					**0.9%**	**1.00**
Chemicals		**2,026**					**1.0%**	**1.01**
Implied PER on 2007-10E avg earnings $ M.	$247	8.2x						
Total Enterprise Value		**211,935**					**100.0%**	**105.74**
Adjusted 1Q10E Net Debt		3,009					1.4%	1.50
Net Asset Value		**208,926**					**98.6%**	**104.24**
Market Capitalisation		**136,006**						**67.86**
Premium to NAV		**-35%**						**-35%**

Source: Company data, Wood Mackenzie, Deutsche Bank

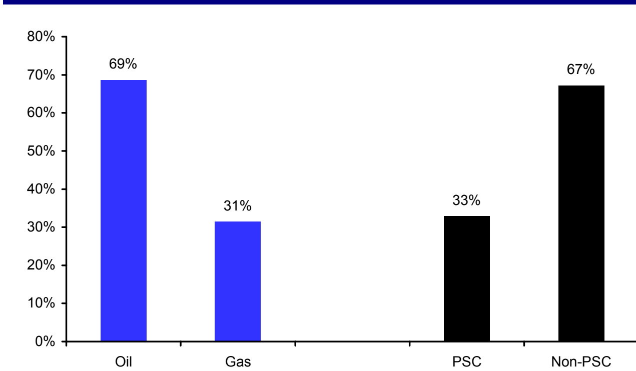
Chevron - Main Projects 2009-2015E

Figure 623: Chevron - Major Oil & Gas Projects by Year 2009-2015E

Project	Country	Launch Year	Reserves Oil Mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/d	Capex ($m)	CVX %	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
Tombua/Landana	Angola	2009	328	0	100	0	4,958	31%	Yes	4	20	27	28	27	26	25	2,065
Frade	Brazil	2009	240	8	85	5	2,638	52%		8	31	46	35	32	30	25	1,939
North Belut	Indonesia	2009	80	138	18	27	0	25%	Yes	4	9	10	10	9	10	10	na
Mafumeira Norte	Angola	2009	134	0	30	0	na	39%		8	19	23	32	36	33	29	na
Tahiti	US (GoM)	2009	410	40	125	10	6,575	58%		16	55	56	58	62	64	54	4,255
2010																	
Maromba	Brazil	2010	257	2	90	2	1,027	38%		0	4	4	0	0	19	27	595
AOSP Jackpine	Canada	2010	1,000	0	100	0	7,464	20%		0	4	16	20	20	20	20	957
Great White	US (GoM)	2010	310	125	64	26	7,026	33%		0	8	18	21	23	25	26	1,943
2011																	
Karachaganak Tr. 4	Kazakhstan	2011	1,775	2,263	60	27	na	20%		0	0	7	35	35	35	35	na
Chuandongbei	China	2011	0	884	0	101	na	49%	Yes	0	0	10	16	25	35	39	na
Agbami Phase 2	Nigeria	2011	546	0	100	0	na	32%		0	0	8	20	32	32	32	na
Tahiti Phase 2		2011	410	40	45	5	na	58%		0	0	12	20	29	28	25	na
Caesar/Tonga	US (GoM)	2011	221	29	47	6	3,505	20%		0	0	6	9	10	11	11	533
2012																	
Angola LNG	Angola	2012	0	1,402	0	176	na	36%	Yes	0	0	0	28	56	64	64	na
Sadewa	Indonesia	2012	8	18	6	11	408	93%	Yes	0	0	0	6	15	15	13	na
Sonam	Nigeria	2012	132	0	30	0	na	40%		0	0	0	8	12	12	11	na
Usan and Ukot	Nigeria	2012	610	0	180	0	10,088	30%	Yes	0	0	0	11	54	54	54	2,558
2013																	
Papa-Terra	Brazil	2013	470	7	160	4	5,329	38%		0	0	0	0	30	62	59	152
Starfish	T&T	2013	1	70	0	28	278	50%	Yes	0	0	0	0	4	9	13	127
Alder	UK	2013	13	22	11	16	391	70%		0	0	0	0	13	19	13	231
Big Foot	US (GoM)	2013	163	14	57	5	2,921	60%		0	0	0	0	14	31	37	721
2014																	
Lianzi	Angola	2014	60	0	33	0	1,035	30%	Yes	0	0	0	0	0	3	10	123
Greater Gorgon	Australia	2014	275	7,197	18	422	63,130	50%		0	0	0	0	0	28	122	7,686
Moho Nord	Congo	2014	250	0	70	0	2,606	32%	Yes	0	0	0	0	0	8	22	612
Jack/St. Malo	US (GoM)	2014	685	29	117	6	12,405	50%		0	0	0	0	0	2	14	2,164
Block 52/97	Vietnam	2014	7	374	1	45	2,295	43%	Yes	0	0	0	0	0	5	11	197
2015																	
Aparo	Nigeria	2015	70	8	20	2	1,181	100%	Yes	0	0	0	0	0	0	11	555
Nsiko and Aparo	Nigeria	2015	255	4	83	1	3,645	95%	Yes		0	0	0	0	0	19	1,090
Rosebank	UK	2015	250	39	90	16	4,451	40%		0	0	0	0	0	0	32	1,087
Total (kboe/d)										**41**	**163**	**267**	**385**	**562**	**724**	**916**	
of which : Oil										*37*	*148*	*224*	*276*	*393*	*488*	*570*	
: Gas										*4*	*15*	*43*	*109*	*169*	*236*	*346*	

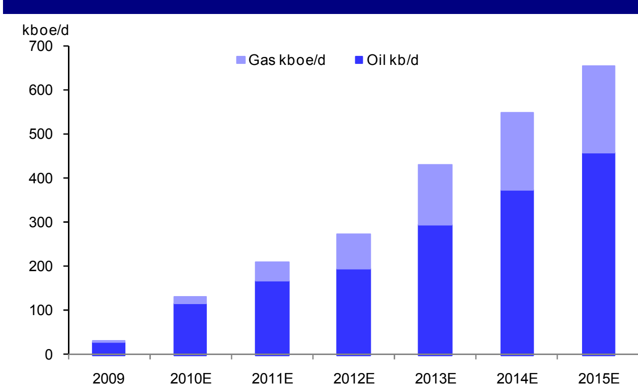
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 624: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



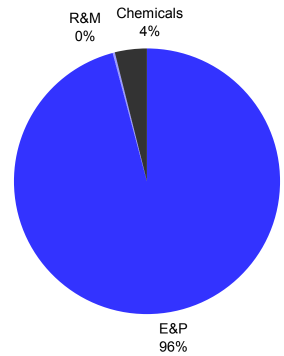
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 625: Growth profile 2009-15E by Oil & Gas



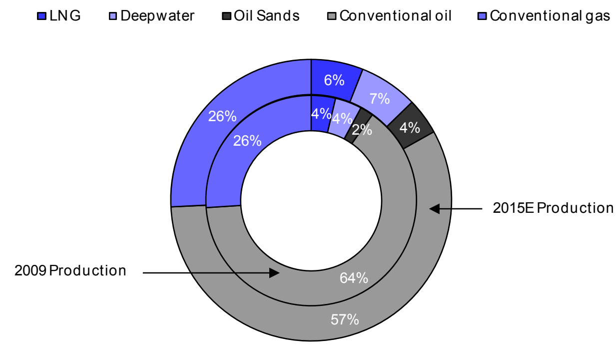
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 626: 2009 clean net income USD9,633m



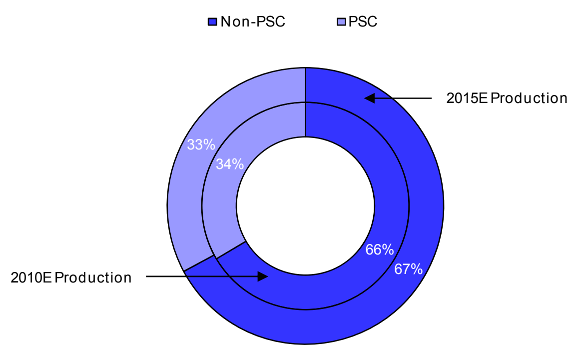
Source: Deutsche Bank

Figure 627: Trends in E&P Production



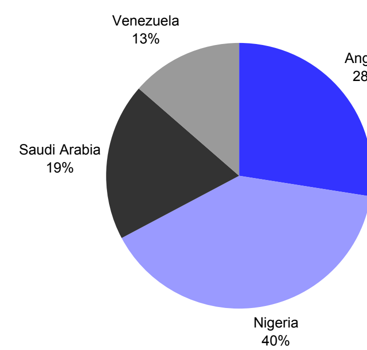
Source: Deutsche Bank

Figure 628: PSC exposure 10E-15E – on the increase



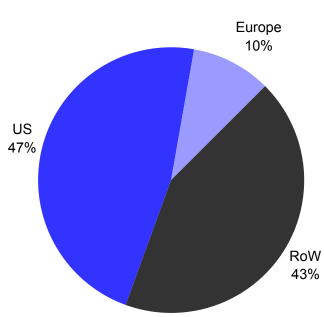
Source: Deutsche Bank

Figure 629: OPEC production 26% of total in 2010E



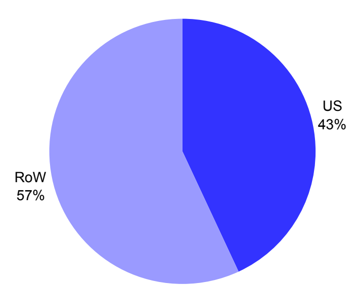
Source: Deutsche Bank

Figure 630: Chevron 2009 refining CDU 2,158kb/d



Source: Deutsche Bank

Figure 631: Chevron 2009 marketing by region



Source: Deutsche Bank

North America United States
Industrials Integrated Oil

8 September 2010

ConocoPhillips

Reuters: **COP.N** Bloomberg: **COP UN**

Trimming the fat

ConocoPhillips (COP) grew via acquisition into the third largest IOC in the US and the world's fifth largest holder of reserves, with a presence in more than 70 countries. Having grown reserves through M&A activity, however, it struggled to deliver volumes and returns and has recently embarked on a $15bln+ disposal-to-buyback programme. It also aims to convert some 10bln boes of resource into producing assets over the next 10 years while reducing the level of capital employed in the downstream. With management firmly committed to executing its new strategy, we rate it Buy.

Upstream: Despite COP's high levels of M&A activity (Burlington, Lukoil, Origin and a JV with Encana to name a few) the company has struggled to grow production with volumes down in both 2007 and 08 and only marginally improved in 2009. With many of these acquisitions completed at the peak of both commodity and asset prices, the company may now struggle to persuade investors it can achieve an acceptable return on investment. Key for COP now will be completing its asset disposal programme, reducing its level of gearing, ramping up share buyback and growing production organically over the coming years. In the interim, its legacy assets should be at least capable of sustaining production at current levels.

Downstream: COP is the second largest refiner in North America behind only Valero (COP is fourth largest in world) with total refining capacity of 2.7mb/d. It is relatively unsophisticated and short marketing, making it a highly levered play, with proportionately more US East Coast exposure than most.

Other: Through its 50% interest in Chevron Phillips Chemical Company, COP has its toe in the chemicals business, but this is not the investment case.

Valuation & Risk
Our NAV-implied target is $69 ($77 with 10% discount); our P/E methodology yields $64 (target P/E 9x, mid-cycle EPS estimate $7.10). The average results in our blended $66 PT. Risks include a disappointing execution of the restructuring plan, much weaker oil and gas prices, to which COP is highly exposed, and more so than rival super-major oils, and another unexpected acquisition that puts further pressure on equity holders, though this risk has been mitigated by the company's announced asset rationalization plan.

Forecasts and ratios

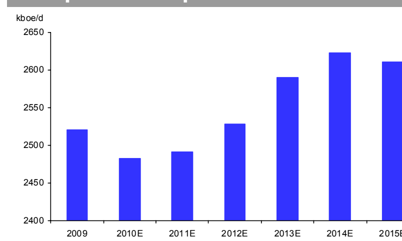
Year End Dec 31	2009A	**2010E**	2011E
EPS (USD)	3.65	**6.48**	8.50
P/E (x)	12.5	**8.5**	6.5
Dividend yield (%)	4.2	**3.8**	4.2

Source: Deutsche Bank estimates, company data

Buy

Price at 3 Sept 2010 (USD)	**55.05**
Price target	**66.00**
52-week range	**59.70 - 39.44**

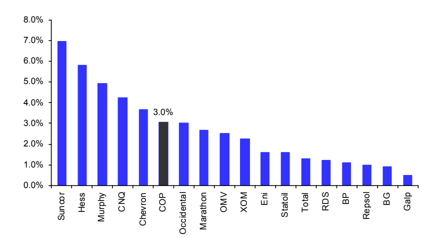
COP production profile 2009-15E



Source: Deutsche Bank

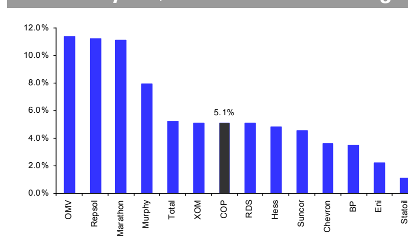
Upstream CAGR (2009-15E)	0.6%
Oil production (2009)	1,428kb/d
Gas production (2009)	1,093kboe/d
Oil Reserves (1P)	6.29bn/bbls
Gas Reserves (1P)	4.04bn/boe
Refining capacity	2,657kb/d
Marketing volumes	2,974kb/d
Wood Mackenzie 2P(E) Total reserves	16.6bn/boe
PSC sensitivity to $1/bbl move in oil (E)	c.0.34%

Sensitivity to $1bbl move in oil



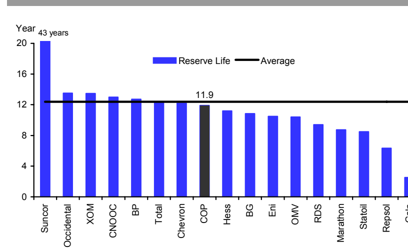
Source: Deutsche Bank

Sensitivity to $1/bbl move in refining



Source: Deutsche Bank

Reserve Life (1P)



Source: Deutsche Bank

Net Asset Value and Breakdown at $100/bbl long-run

Figure 632: ConocoPhillips Net Asset Value by asset

Upstream	Comment	Risked Value ($ Million)	Absolute Value ($ Million)	Risked 2P Reserves	Absolute 2P Reserves	Value/2P Reserves	% of Total EV	Value per Share
Australia		7,407	8,613	1,315	1,529	5.6	5.3%	4.93
Algeria		532	625	96	113	5.5	0.4%	0.35
Azerbaijan		175	222	na	na	na	0.1%	0.12
Canada Onshore		7,852	8,822	1,202	1,351	6.5	5.6%	5.22
Western Canada		6,592	7,406	2,010	2,258	3.3	4.7%	4.38
China		4,856	5,456	362	406	13.4	3.5%	3.23
Ecuador		22	31	3	5	6.5	0.0%	0.01
Indonesia		3,901	5,495	465	655	8.4	2.8%	2.59
Kazakhstan		3,415	6,443	490	924	7.0	2.4%	2.27
Libya		1,189	1,279	489	526	2.4	0.8%	0.79
Lukoil		8,636	20,233	4,121	4,965	2.1	6.1%	5.74
Malaysia		3,014	3,206	435	463	6.9	2.1%	2.00
Nigeria		1,669	3,338	386	771	4.3	1.2%	1.11
Norway		6,975	8,612	815	1,006	8.6	5.0%	4.64
Peru		462	633	57	78	8.1	0.3%	0.31
Qatar		8,212	8,736	656	698	12.5	5.8%	5.46
Russia		1,639	2,024	197	243	8.3	1.2%	1.09
United Kingdom		5,758	8,344	355	515	16.2	4.1%	3.83
United States Alaska		12,875	16,297	1,512	1,914	8.5	9.2%	8.56
United States DW Gulf of Mexico		905	1,331	50	73	18.2	0.6%	0.60
United States Rocky Mount		11,564	13,447	1,653	1,922	7.0	8.2%	7.69
United States Gulf Coast		2,712	3,154	562	653	4.8	1.9%	1.80
United States MidContinent		1,466	1,705	159	185	9.2	1.0%	0.98
United States Permian		2,544	2,958	197	229	12.9	1.8%	1.69
Venezuela (arbitration)		2,500	4,512					
Vietnam		1,022	1,246	61	74	16.9	0.7%	0.68
Sub-Total		**107,891**	**144,167**	**17,647**	**21,558**	**6.11**	**76.8%**	**71.76**
Implied per barrel of booked reserves	10,326	$10.4	$13.5					
Implied PER 2007-10E avg earnings $ M.	7,843	13.8x	17.8x					
3P "Possible" Reserves		9,861					7.0%	6.56
Upstream Sub-Total		**117,752**					**83.8%**	**78.32**
Refining and Marketing								
Europe Refining		2,748					2.0%	1.83
Europe Marketing		974					0.7%	0.65
US Refining		11,790					8.4%	7.84
US Marketing and logistics		3,238					2.3%	2.15
ROW Refining		303					0.2%	0.20
Sub-Total		**19,053**					**13.6%**	**12.67**
Implied PER 2007-10E avg earnings $ M.	2,136	8.9x						
Gas, Power, Etc								
DCP Midstream	50% owned	202					0.1%	0.13
Rockies Express Pipeline		585					0.4%	0.39
Other Midstream		1,100					0.8%	0.73
Sub-Total - 'other'		**1,887**					**1.3%**	**1.25**
Chemicals		**1,827**					**1.3%**	**1.21**
Implied PER 2007-10E avg earnings $ M.	228	8.0x						
Total Enterprise Value		**140,519**					**100.0%**	**93.46**
Adjusted 2Q10E Net Debt		23,353					16.6%	15.53
Net Asset Value		**117,166**					**83.4%**	**77.93**
Market Capitalisation		**73,975**						**49.20**
Premium to NAV		**-37%**						**-37%**
Implied PER 2007-10E avg earnings $ M.	11,338	10.3x						
Memo:								
Number of Shares in Issue	1,504							

Source: Wood Mackenzie, Deutsche Bank

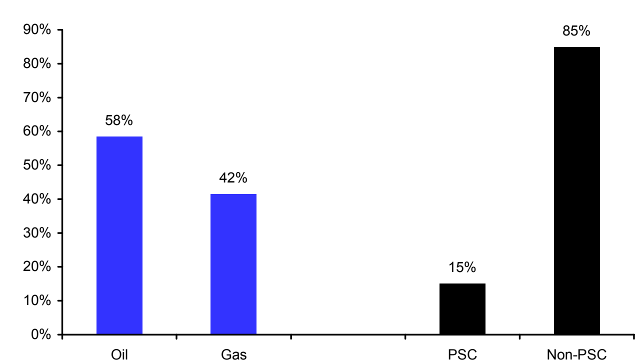
ConocoPhillips – Main Projects 2009-15E

Figure 633: ConocoPhillips - Major Oil & Gas Projects by year 2009-2015E

Project	Country	Launch Year	Reserves Oil mmbbl	Reserves Gas mmboe	Peak Prodn. Oil kb/d	Peak Prodn. Gas kboe/	Capex ($m)	COP Share	PSC	Production (kboe/d) - Working interest 2009	2010	2011	2012	2013	2014	2015	NPV ($m)
2009																	
North Belut	Indonesia	2009	80	138	18	27	0	40%	Yes	7	14	16	15	15	15	17	na
2010																	
Peng Lai 19-9	China	2010	20	0	9	0	0	49%	Yes	0	2	4	3	3	3	3	na
Peng Lai 25-6	China	2010	50	0	16	0	0	49%	Yes	0	4	8	7	6	6	5	na
Qatargas 3	Qatar	2010	333	2,055	42	213	4,700	30%		0	43	72	77	76	76	76	5,651
2011																	
Sambar	Indonesia	2011	0	16	0	5	0	54%	Yes	0	0	3	3	3	3	3	na
Christina Lake Ph C	Canada	2011	1,551	0	40	0	na	50%		0	0	5	15	20	20	20	na
2012							na										na
El Merk (405a)	Algeria	2012	51	0	15	0	212	65%	Yes	0	0	0	7	9	9	8	na
Eldfisk II		2012	655	129	50	1	na	35%		0	0	0	1	2	3	6	na
SB J - Gumusut	Malaysia	2013	330	211	107	52	3,235	40%	Yes	0	0	0	0	21	36	43	1,385
Bawal	Indonesia	2012	0	25	0	14	0	40%	Yes	0	0	0	1	3	6	5	na
2013																	
South Belut	Indonesia	2013	0	18	0	7	0	40%	Yes	0	0	0	0	1	1	2	na
Kashagan	Kazakhstan	2013	10,383	657	1,475	120	141,901	8%	Yes	0	0	0	0	18	27	35	4,260
NC98	Libya	2013	na	na	0	34	Na	16%		0	0	0	0	2	5	5	na
Christina Lake Ph D	Canada	2013	1,551	0	40	0	na	50%		0	0	0	0	5	15	20	na
Kebabangan Cluster	Malaysia	2013	200	590	54	99	3,274	30%	Yes	0	0	0	0	10	16	17	112
Alder	UK	2013	13	22	11	16	391	25%		0	0	0	0	5	7	5	82
Jasmine	UK	2013	65	101	36	49	1,336	37%		0	0	0	0	18	31	28	596
Crossans	UK	2013	0	9	0	4	93	100%		0	0	0	0	1	4	4	51
Surmont Phase 2	Canada	2013	889	0	110	0	na	50%		0	0	0	0	8	14	25	na
2014																	
Bungin	Indonesia	2014	0	42	0	12	520	45%	Yes	0	0	0	0	0	4	5	na
Block 39	Peru	2014	230	0	66	0	2,287	35%		0	0	0	0	0	4	7	290
Yareiyuskoye	Russia	2014	142	0	30	0	777	30%		0	0	0	0	0	3	5	80
SB G – Malikai	Malaysia	2014	150	0	53	0	1.040	35%	Yes	0	0	0	0	0	10	18	279
Darwen	UK	2014	0	14	0	7	131	100%		0	0	0	0	0	2	4	60
2015																	
Jacqui	UK	2015	5	5	3	5	164	55%		0	0	0	0	0	0	2	47
AP LNG	Australia	2015	0	1,905	0	96	15,008	50%		0	0	0	0	0	0	20	2,162
Foster Creek Ph 1F	UK	2015	1,788	0	30	0	na	50%		0	0	0	0	0	0	5	na
Christina Lake Ph E	UK	2015	1,551	0	40	0	na	50%		0	0	0	0	0	0	5	na
Total (kboe/d)										**7**	**63**	**108**	**129**	**226**	**320**	**398**	
of which : Oil										*3*	*17*	*33*	*49*	*110*	*169*	*220*	
: Gas										*4*	*46*	*75*	*80*	*116*	*151*	*178*	

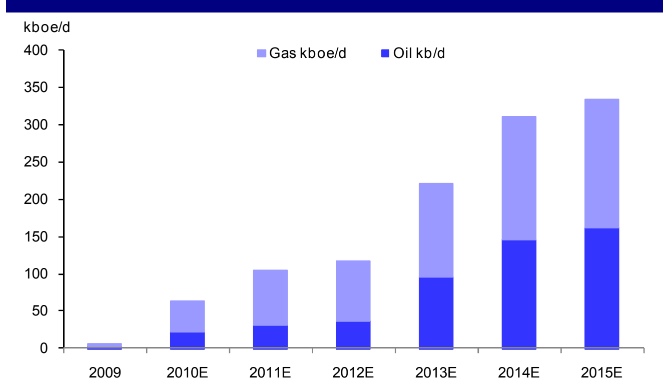
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 634: Project Mix – Oil/Gas, PSC/non-PSC % in '15E



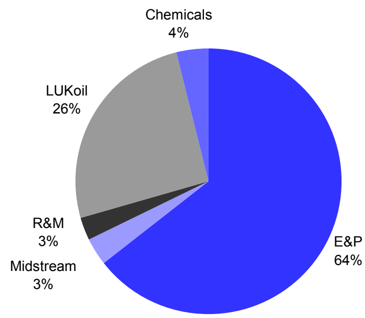
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 635: Growth profile 2009-15E by Oil & Gas



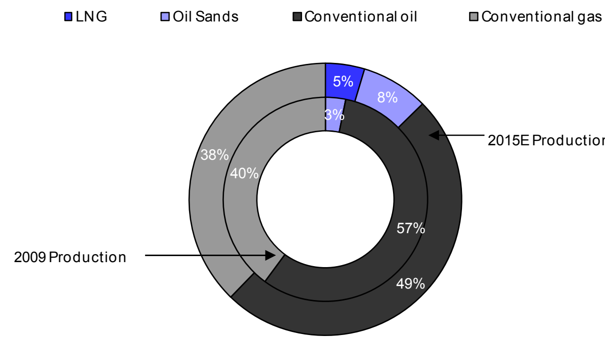
Source: Wood Mackenzie & Deutsche Bank estimates

Figure 636: 2009 clean net income USD5,475m



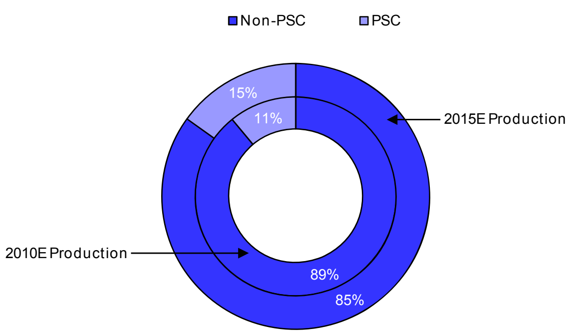
Source: Deutsche Bank

Figure 637: Trends in E&P Production



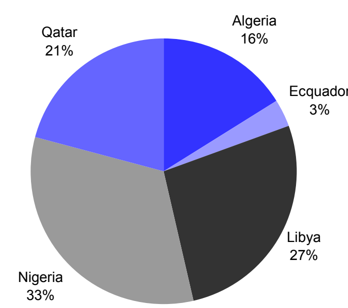
Source: Deutsche Bank

Figure 638: PSC exposure 10E-15E – on the increase



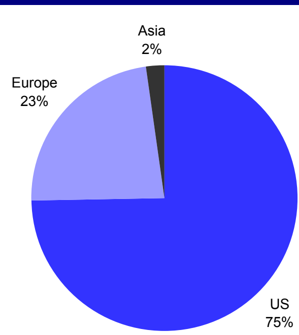
Source: Deutsche Bank

Figure 639: OPEC production 8% of total in 2010E



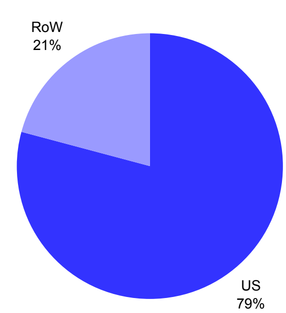
Source: Deutsche Bank

Figure 640: ConocoPhillips 2009 refining CDU 2,657kb/d



Source: Deutsche Bank

Figure 641: ConocoPhillips 2009 marketing by region



Source: Deutsche Bank

Glossary

Abandonment	to cease work on a well which 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 process 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 to 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 which 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 which is 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 which 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 contracts	only used in Iran and is 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 which 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 condition 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 remain stationary and also prevents any leakage
Cetane number	a measure of diesels 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 diesel.
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 which 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 in a wide range of processes to upgrade distillate
Condensate	hydrocarbons which are gaseous under reservoir condition but which 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 which are estimated to be potentially recoverable from known accumulation, but which are not yet commercially recoverable

Conversion process which alters the size and/or structure of hydrocarbons in other to further upgrade 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 with 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 break 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 suppliers 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. Is 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 which results in changes to the rocks 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

Donkey dick the rubber guide placed beneath wireline logging tools that help them get past well bore obstructions when being lowered to total depth

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 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'.
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 use to produce petrochemical products
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	these are 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 which are economically recoverable at a set oil price. In general companies only book reserves once a positive FID has been made.
Finding costs	the costs of exploration and appraisal programmes i.e. how much did its 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 which 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	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 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 on industry for heat or power generation
Gas injection	processing by which gas is re-injected into the reservoir either to conserve the gas for extraction at 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	
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 which is 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
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, so 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 plus triggering the ignition - the process of which produces an audible 'knocking' sound
Liquefaction plant	plant which process natural gas to remove any impurities such as water or carbon dioxide before cooling the gas via a series of compressors i.e. it is the equivalent of a large refrigerator. Also referred to as the LNG train
Liquefied Natural Gas (LNG)	naturally occurring gas which has been cooled to a temperature of -162˚C at atmospheric pressure in order to condense the gas into a liquid which 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 which is stored under pressures 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 wholesales 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 which 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 base chemicals and additives used to carry cuttings from the drill bit, lubricate the drill bit and to provide pressure that in theory prevents any oil or gas from blowing out
Mud logging	equipment which continuously analyses and records and 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 which gives a better pictures 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
Naphtha	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 countries respective OPEC quotas
Nipple up	the process of assembling and pressure testing the BOP
NYMEX	New York Mercantile exchange - along with ICE these are the two main exchanges where oil and gas and associated products are trade
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. Where gasoline has a low octane this 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 Earths 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 which is used to determine the price band that OPEC wishes to see the world oil markets
Open hole	drilled hole in which casing has not been set
Paraxylene (PX)	a colourless liquid which 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 either by wireline of 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 contains 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 circumstance combine 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. Application 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. The 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 rocks' bulk volumes accounts 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 projects 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 which is 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 of 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 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.
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 the 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 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 back 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 and is 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 which are 'leftover' 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. Its 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 which 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 only account for proved reserves. See Proved (1P) reserves.
Secondary Recovery	recovery of oil/gas from a reservoir by artificially enhancing the pressure within the reservoir by injecting water, gas or other substances into the reservoir
Sedimentary Rocks	the primary source of almost all oil and gas reserves. The are formed by the compaction of mineral grains which 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 and 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 which 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 which 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 sometime connected with salt domes.
Superposition	within a sequence of layers of sedimentary rock, the oldest layer is at the base and that 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	the 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	a plastic that melts to a liquid when heated and freezes to a brittle, very glassy state when cooled sufficiently i.e. they can be re-moulded, extruded or even recycled
Thermosets	polymer material that 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 which is positioned on top of the drill pipe and which 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 can not 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 levers 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 lead 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 which 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 which is 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 the lighter hydrocarbons to create heavier hydrocarbons of desired characteristics
Uniformitarianism	the principal developed by Charles Lyell which states 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 searching 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 reduced the thickness of residual oils
Water cut	the percentage of produced fluids that are 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 down (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, potential flow rates of the reservoir and its physical size
Wellhead	the part of an oil well which 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 or 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

Industry Investment thesis

Outlook

We expect 2010 to continue to prove challenging for the global oil and gas industry. Despite a recovering global economy excess supply across several markets suggests to us that pricing will offer only a limited tailwind for earnings relative to H2 2009 and that any improvement in earnings will again prove more dependent upon self-help. Whilst we expect crude oil prices to average c$71/bbl for the year, with significant excess capacity remaining in place and developments in Iraq threatening to undermine the consensus view of a long run supply crunch, we expect fiscal tightening (China and India already initiated), most significantly by the US Fed, towards the middle of the year and subsequent strength in the US$ to undermine prices. Elsewhere, the ongoing build in excess LNG capacity threatens to continue to undermine gas prices across each of the main regional markets. Similarly, refining markets look set to remain depressed as the start-up of new capacity across the globe further undermines the supply demand balance. Nevertheless, having said this we expect cash flow and operating income to benefit notably through the year as capex budgets start to benefit from price deflation and cost cutting feeds more meaningfully into results. Increased focus by the majors on driving cash flow whilst sustaining production will importantly in our opinion also see investor perception towards the sector improve not least as investors gain confidence in the outlook for sector dividends and dividend growth.

Valuation

We use a multitude of earnings and cash flow valuation techniques to value the oils. These include P/E relatives, cash return on capital analysis (CROCI) and discounted cash flow models amongst others. Given the sector's attractive current dividend yield of around 5-6% we see limited absolute downside with the potential for significant upside as investors gain confidence in dividend sustainability. Moreover, as a mid to late cycle industry we believe that the current 20% P/E discount at which the sector trades allows significant scope for contraction, our expectation being that as relative earnings momentum turns positive the sector will move towards the 5-10% discount more typical at this stage in its earnings cycle. This suggests to us that the sector should be trading at around 11.5x 2010 earnings compared with a broader Euro market average which at this time is around 12.5x. Similarly, on cash return (CROCI) metrics, our analysis suggests that, with the multiple placed on the sector's capital now trading at only just over 1x invested capital against its long-run average of 1.3x the shares offer significant absolute upside of some 15-20%. Indeed, we are struck by the fact that despite clear evidence that sector earnings bottomed through the second and third quarters of 2009 with sign of improvement in the last quarter of 2009, the sector's current valuation continues to assume that 2010 will prove a year in which the sector delivers limited, if any, economic profit.

Risks

As ever, forecasting for an operationally geared sector through a downturn in the cycle is fraught with difficulties - not least assessing the impact of rising costs on business profitability at a time of falling prices and volumes. This challenge aside, the key risk to our estimates remains the prospect for commodity prices and crude oil in particular. Our forecasts are consequently vulnerable to a significant move in the price of crude about our $71/bbl 2010 oil price estimate. Other risks include material changes to our expectations for volume output that could arise as a consequence of a worse-than-anticipated demand outlook. 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.

Figure 642: Deutsche Bank Global Oil & Gas Team

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Source: Deutsche Bank

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Appendix 1

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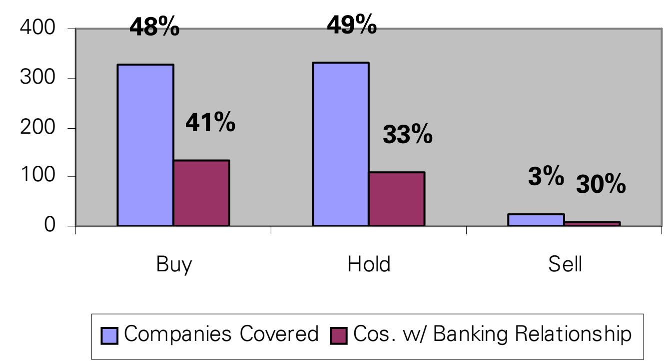

European Universe

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