Module # 1 – Component # 9

How to Analyse an Oil Mining Company

1. Introduction

This module is part of a series on the analysis of resource companies and we recommend that it be read in conjunction with the umbrella module, '*How to analyse a resource company*.'

This particular module focuses on crude oil and the companies that produce and refine this commodity. The oil market is the most important and probably the most complex commodity market. It should be analysed within the context of the global energy market as a whole.

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Abbreviations & Terms

	Abbreviation
first nine months of the year	9M, 9M11, 9M12
barrel of oil	bl
barrel per day	bd
barrels of oil	bls
barrels of oil equivalent	boe
basis points	bpts
billion cubic feet	bcf
billion cubic metres	bcm
billion tonnes	bnt
billion tonnes per year	bnt pa
capital expenditure	capex
carbon dioxide	CO_2
circa (around, approximately)	c.
kilogram	kg
kilometre	km
kilowatt	kW
million barrels of oil per day	Mb/d
million British thermal units	MBtu
million cubic metres	mcm
million tonnes	mnt
million tonnes per year	mnt pa
month-on-month	MoM
not applicable	n/a
ounce	oz
quarter-on-quarter	QoQ
Run-of-mine	RoM
secondary public offering	SPO
thousand barrels of oil per day	kb/d
thousand ounces	k oz
thousand tonnes	kt
thousand tonnes per year	kt pa
thousands	k
tonne	t
tonne per annum	t/a
versus	vs
year-on-year	YoY
year-to-date	YTD

2. Crude Oil

Crude oil is a complex mixture of various compounds known as hydrocarbons as well as other minor elements. The commodity, like coal, is not homogenous and occurs in over 130 different product grades around the world. Production is usually measured in million barrels per day (Mb/d). Oil is priced in $/bbl (US dollar per blue barrel [which equates to about 159 litres]).

The oil market is the most important commodity market globally and is extremely large. Annual crude sales amount to almost 4% of global GDP and have a mass of roughly 4bnt.

The most important characteristics of the different types of crude are sulphur content and American Petroleum Institute (API) gravity which determines the grade or quality of the crude. The API gravity is an inverted scale for denoting the 'lightness' or 'heaviness' of crude oils and other liquid hydrocarbons. Calibrated in API degrees (or degrees API), it is used universally to express crude's relative density in an inverse measure i.e. the lighter the crude, the higher the API gravity, and vice versa because the lighter the crude the higher its market value. Oil with API greater than 30º is termed light; between 22º and 30º, medium; below 22º, heavy; and below 10º, extra-heavy. Brent crude, on average, has an API of 35.5°. A high sulphur content crude (>1.5%) is referred to as being sour whereas a low sulphur (<0.5%) content is referred to as being sweet. The middle band is intermediate and may be judged to be intermediate sweet or intermediate sour.

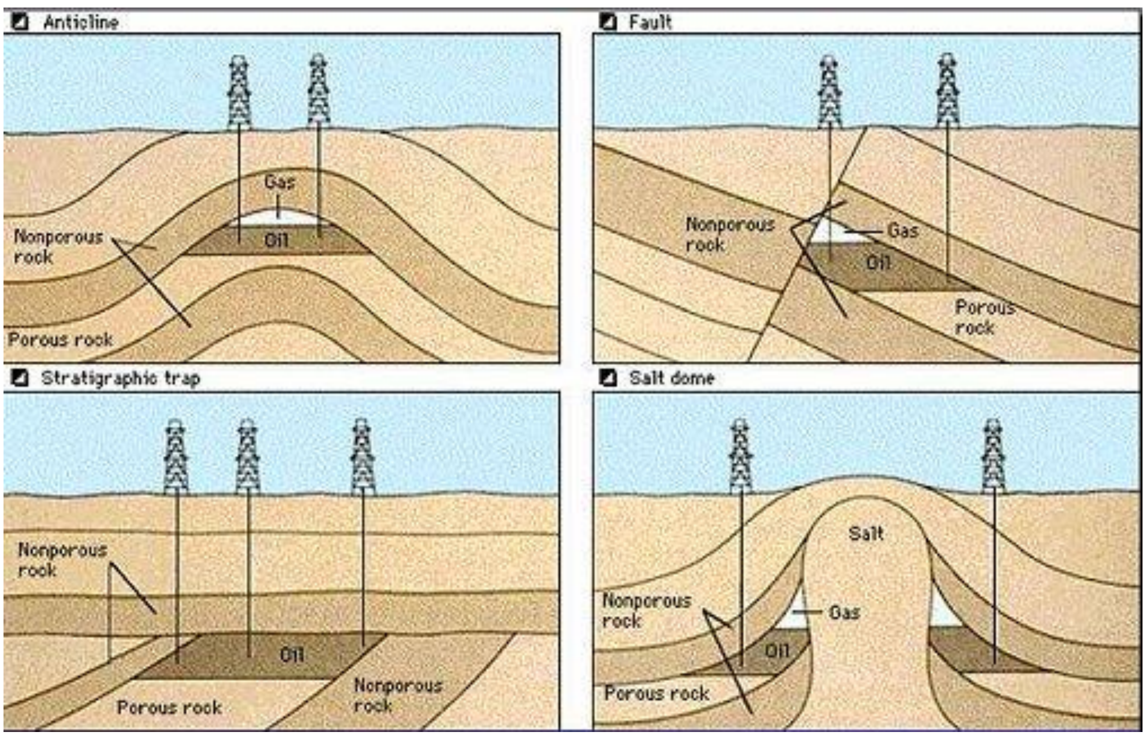
The best quality crudes are light and sweet whereas the lower quality crudes are heavy and sour. On these metrics the **Malaysian Tapis** and the US **West Texas Intermediate** (WTI) are the best quality crudes. Poorer quality crudes will trade at a discount to these benchmarks. **Brent crude** is generally accepted as the world benchmark for crude oil.

2.1. Geology and recovery

Oil is a fossil fuel that originates from the accumulation, burial and transformation of ancient dead biomass. The commercial viability of oil deposits depends on the existence of 1) a rich source rock; 2) a permeable and porous reservoir rock, and 3) a suitable trap to hold the liquid in place (*Smil 2008: 68*).

The source rock is the location where dead biomass was originally accumulated and transformed into oil. The oil then usually goes through some process of migration, as a result of relative densities or seepage and ideally it gets trapped in a reservoir rock. The fact that it gets trapped in such a reservoir is the result of some non-permeable non-porous rock acting as a trap and holding the liquid in place. The following illustration shows four possible oil traps which would be suited to commercial exploitation:

Figure 1: Four possible oil traps suited to commercial exploitation



Source: geomore.com

Drilling in the oil industry is extremely expensive and for this reason exploration usually begins with extensive 3D seismic surveys. These surveys are followed by drilling which remains a costly and risky exercise. The drilling results are then evaluated to determine whether the borehole will be converted into a well or will simply be plugged and abandoned.

Once an oil well is in place the oil needs to be lifted to the surface. Often the existing underground pressure is sufficient for this to happen automatically. However, with time the underground pressure tends to decline and artificial pressure or pumping is required to bring the oil to the surface. Artificial pressure is exerted by injecting water, steam or gas into the reservoir, which displaces crude oil to the surface (*Wikipedia1*). These processes result in the recovery of up to 60% of the original oil, compared with only 20-40% without these processes (*ibid*). The well is often plugged and abandoned beyond this stage as further extraction becomes uneconomical.

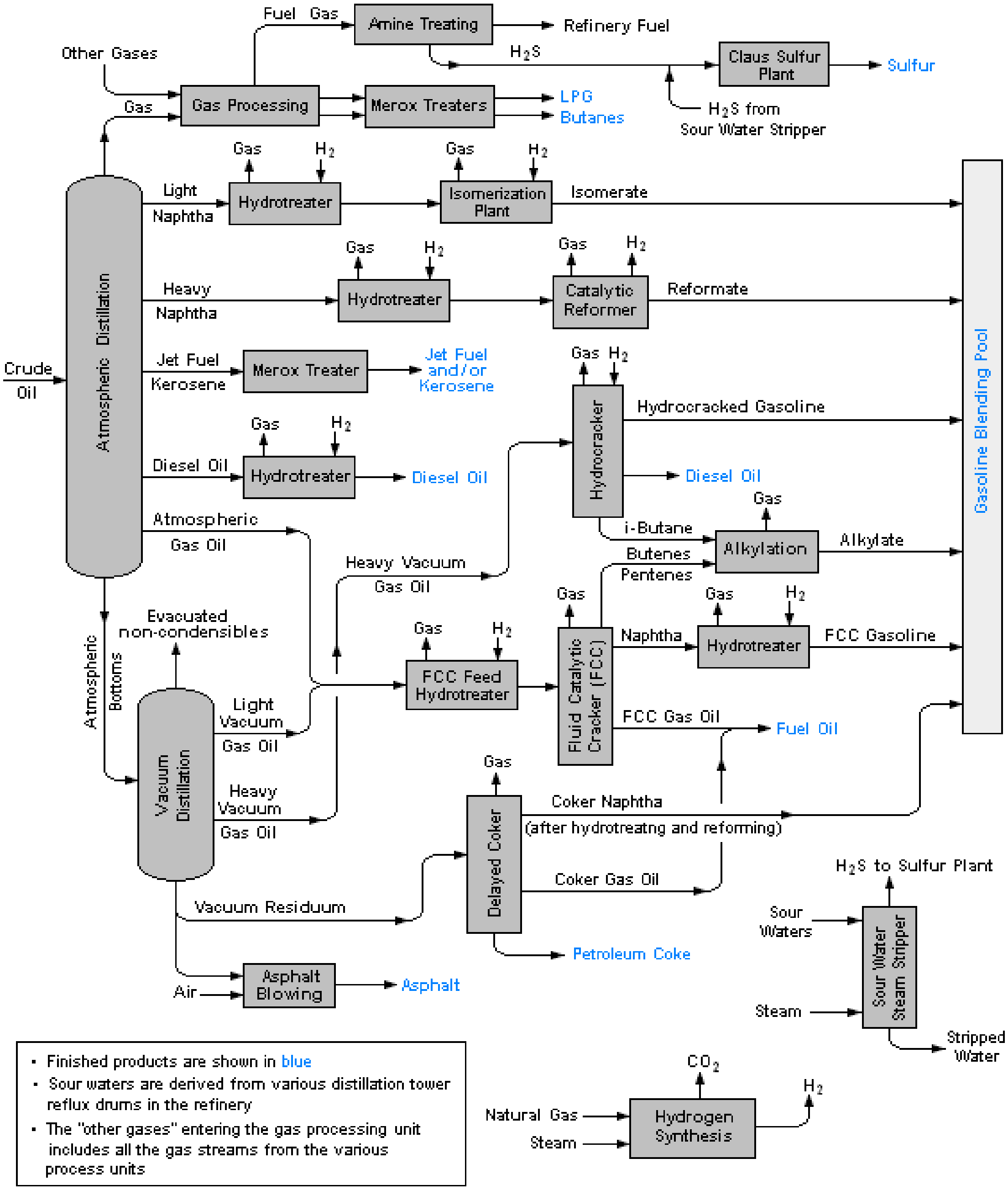
2.2. Transport and storage

Crude oil is transported and stored by an enormous global infrastructure of tankers, pipelines and storage facilities. Consider some examples: According to the *CIA World Factbook* the US has approximately 244,620 km of petroleum-product pipelines; while at the time of the fall of the USSR, that country had approximately 94,000 km of pipelines. To contextualise these numbers, the circumference of the earth is 40,075 km. If one considers the enormous global investment in oil wells, transport and storage infrastructure, petrol, diesel and gas stations and internal combustion engine vehicles, it is apparent that any transition away from oil is likely to be a very gradual process spanning many decades. The cost, and likely dislocations, associated with replacing this enormous capital stock is very significant and could only be digested by the global economy over an extended period. We make this point to counterbalance the view of a rapid substitution away from oil – yes such a substitution is happening, but there is also a considerable force of inertia which will likely keep oil in a significant and important position in global energy supply for many decades to come.

2.3. Refining process

The process of refining crude oil is essential to produce a wide variety of liquid fuels and other products such as chemical feedstocks and waxes that are derived from crude oil. The refining process is also extremely complex and involves many sub-processes such as distillation (heating the oil and separating it into the various cuts), cracking (breaking certain chemical bonds to produce lighter compounds) and isomerisation (the process by which one molecule is changed into another but has exactly the same atoms), amongst others. The following graph provides a relatively simplified diagram of the process:

Figure 2: The refining process



Source: Wikipedia

The various processes involved in the refining and conversion of crude oil allow the refineries some flexibility to adjust the mix of final products to suit the demand of the market. Gasoline is the most important refined product followed by diesel fuel. Kerosene, used mostly to power jet engines, is another important oil-based fuel.

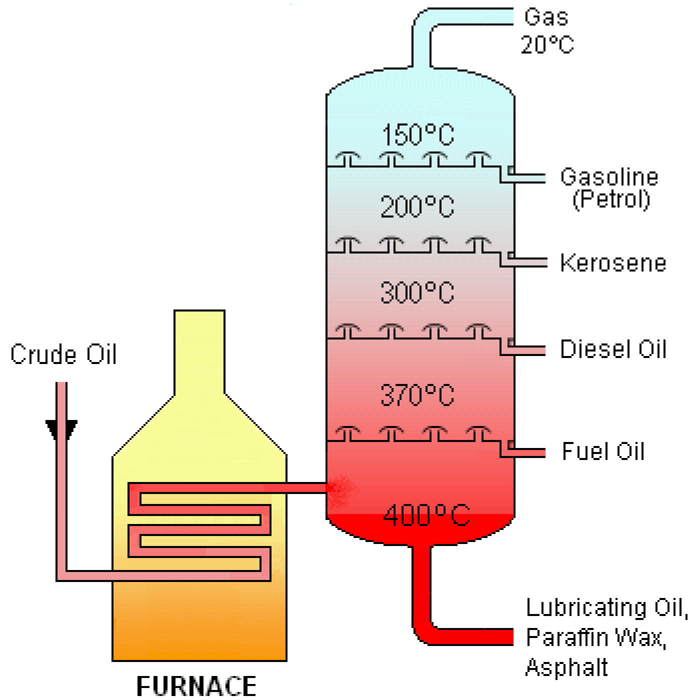
The various products derived from crude oil are often referred to according to their weight and position in the typical barrel of oil. A standard barrel contains 42 US gallons (equivalent to 158.98 litres) of crude oil. The 42 gallons (158.98 litres) will result in more than 44 gallons (166.56 litres) of petroleum products. This effectively means that during the refinement process, there is actually an increase in the volume of product realised through this process as a result of a reduction in the density of some of the original crude oil as different petroleum products are created during the refinement process.

In effect the refining process involves a distillation of crude oil into its constituent elements, conversion occurs after distillation, which is the process of cracking molecules to allow for a further refinement of elements that form crude oil in the first instance. Finally, enhancement occurs, as the name indicates this is a process by which the quality of the final product is enhanced in various ways. For example, sulfur might be removed in order to increase the quality of a product refined from crude oil. The biggest share of the 158.98 litres of crude oil ends up as petrol, petrol accounts for c. 74.38 litres of the finished product while distillate fuel oil is next at 37.97 litres. Jet fuel is third in the refinement process at 15.41 litres while residual fuel oil accounts for 6.51 litres of the overall refined product.

During the refining process the following important crude-based products are also created from a barrel of oil: liquefied petroleum gas (LPG), gasoline, kerosene, naphtha, diesel, fuel oils, lubricating oils, paraffin wax, asphalt, petroleum coke and feedstock for plastics and petrochemicals, amongst others. These different end-products differ in their percentages depending on what part of the globe the crude oil originated from initially.

The lightest products, like fuel gases and LPGs are said to come from the **top of the barrel**. Heavier compounds, such as lubricants, greases and waxes are from the **bottom of the barrel**, while heavier liquids, such as diesel, are from the **middle of the barrel**. Figure 3 illustrates the distillation of crude oil into its light, middle and heavy fractions:

Figure 3: Distillation of crude oil into light, middle and heavy fractions



Source: Wikipedia2

Depending on the nature of final demand, different refineries prefer varying types of crude. Some crudes are more suited to produce the desired mix of end-products with less catalytic cracking than other crudes, hence it costs less to produce the same end-product. Therefore, for example, a market that is dominated by gasoline and kerosene would prefer a lighter oil as the refining process can produce these fuels at a lower cost than if heavier crudes were used.

2.4. The oil market

This section will consider the structure of the oil market as well as the fundamentals of oil demand, supply and inventories. Although these factors are the most important drivers of the oil price in the medium-to long-term, the price in the short term is also influenced by commodity speculation (the world's main petroleum exchanges are New York Mercantile Exchange [NYME], London's International Petroleum Exchange [IPE] and Singapore's International Monetary Exchange [SIMEX]), geopolitical security risks (there is quite significant concern internationally about the political stability of the majority of Organisation of the Petroleum Exporting Countries [OPEC] countries) and catastrophic events (such as hurricanes which can result in production cuts).

2.4.1. Market structure

The global crude oil market is very large and like most commodity markets, its fortunes rise and fall with the global business cycle (i.e. it is a cyclical commodity). What makes the market unusual is the fact that it is dominated by state-owned oil companies and OPEC, a large and influential cartel. Thus it can be seen that the market is certainly not perfectly competitive. OPEC has its own oil price reference in the form of the OPEC basket, which is the average of 11 different crudes. The 11 crude oils included in this basket are Saharan Blend (Algeria), Minas (Indonesia), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and BCF 17 (Venezuela).

OPEC has a powerful influence on the global oil market and is able to artificially support prices above a level that would probably be maintained in a more competitive market. In a relatively weak price environment, OPEC will often issue production quotas to its members in order to support a softening price. That said, the cartel is well aware of the risk of an oil price spike resulting in significant and aggressive substitution away from oil towards other energy sources. A price spike would most likely also trigger significant investment in oil exploration and field development outside of OPEC, thus reducing the cartel's influence on the market. Therefore it can be said that OPEC also has an incentive to keep oil prices down and reasonably priced.

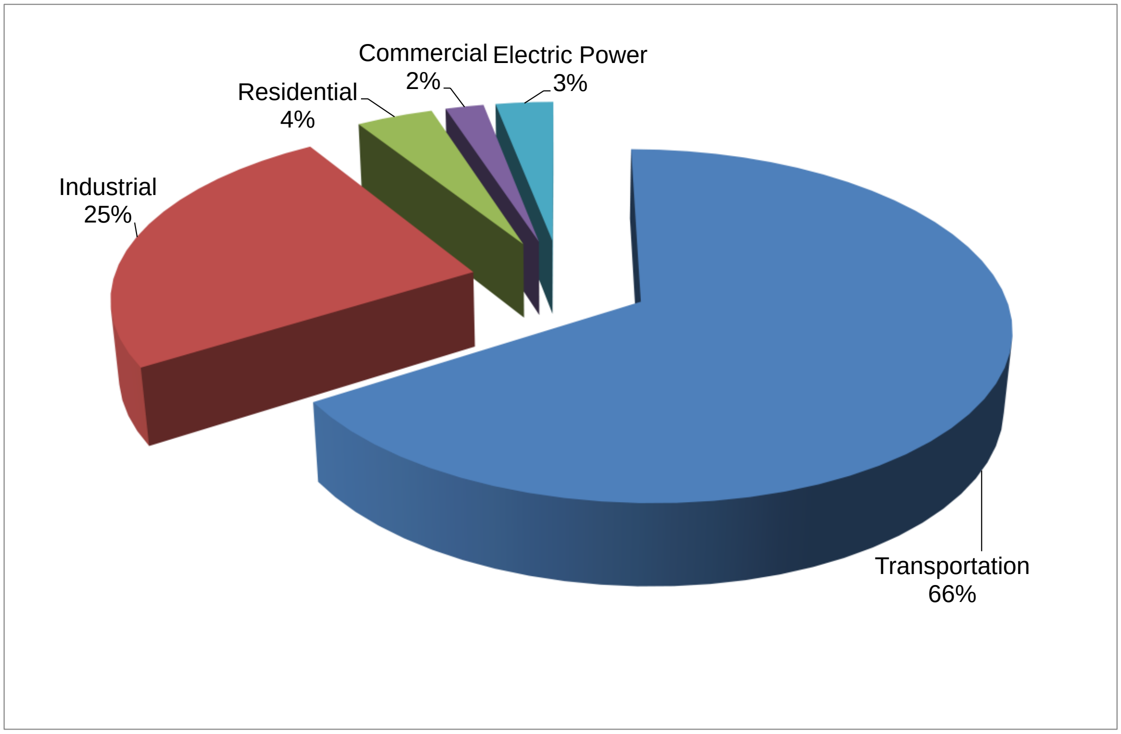
2.5.2. Demand

The largest consumer of oil is the US followed by China and Japan. US consumption of crude is more than double that of China (the next highest user), with the country importing just below half of its oil and producing the rest within its own borders. The top-10 countries consuming oil account for 58% of world demand which is still dominated by Organisation for Economic Co-operation and Development (OECD)[1] countries. Emerging markets (EM) have been increasing, and are expected to continue to increase, their share of world oil consumption.

The vast majority of petroleum demand originates from fuel products – about 65% of world refined petroleum production is used in transport (*Smil 2008*). Almost 10% of petroleum liquids are used as chemical feedstock's (*ibid*). It is also used in the production of solvents, waxes, lubricants, fertilisers, rubber and plastics.

[1] The OECD countries are Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, UK and US.

Figure 4: US oil consumption by sector



Source: lowimpactliving.com

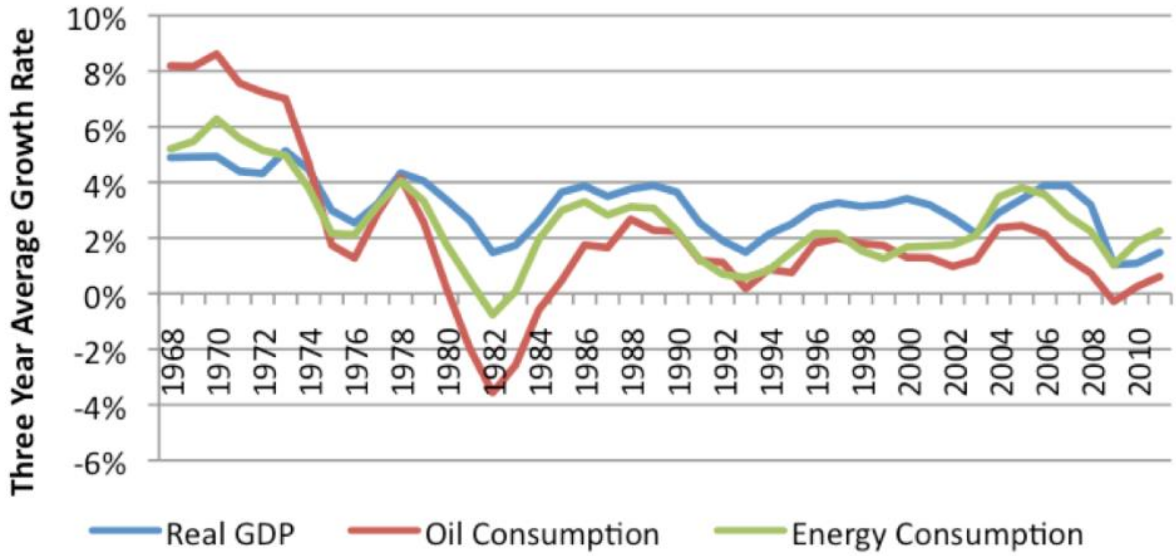
Figure 5: Global crude demand by country:

Consumer	k bpd	% of global
US	18 835	21.4
China	9 758	11.1
Japan	4 418	5.0
India	3 473	3.9
Russian Federation	2 961	3.4
Saudi Arabia	2 856	3.2
Brazil	2 653	3.0
South Korea	2 397	2.7
Germany	2 362	2.7
Canada	2 293	2.6
Total Top-10	**52 006**	59.1
Total global	**88 034**	100
OECD	**45 924**	52.2

Source: BP Statistical Review 2012

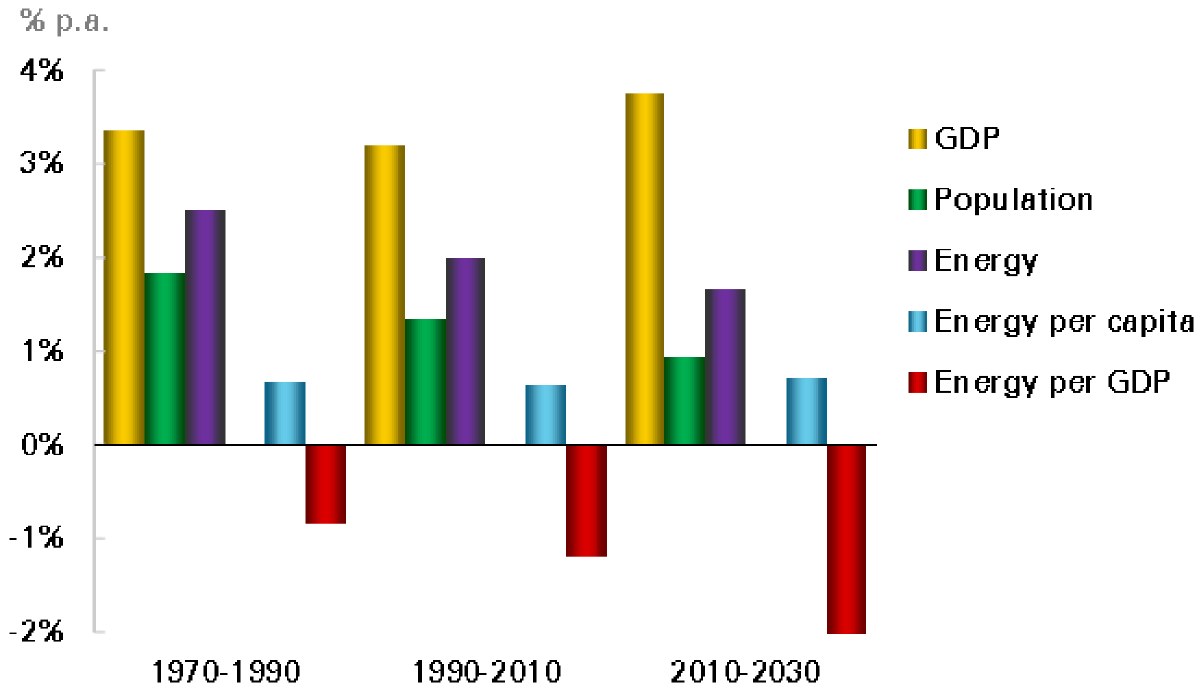
Given that petroleum products are used so ubiquitously in the global economy one would expect a high degree of correlation between global GDP and petroleum demand. This expectation certainly appears justified when considering the relationship between these two variables, as illustrated in the following graph:

Figure 6: Global GDP, oil consumption and energy consumption growth rates:



Source: USDA, BP 2012 Statistical Review of World Energy data

Figure 7: Global growth rates:



Source: BP Energy Outlook 2030

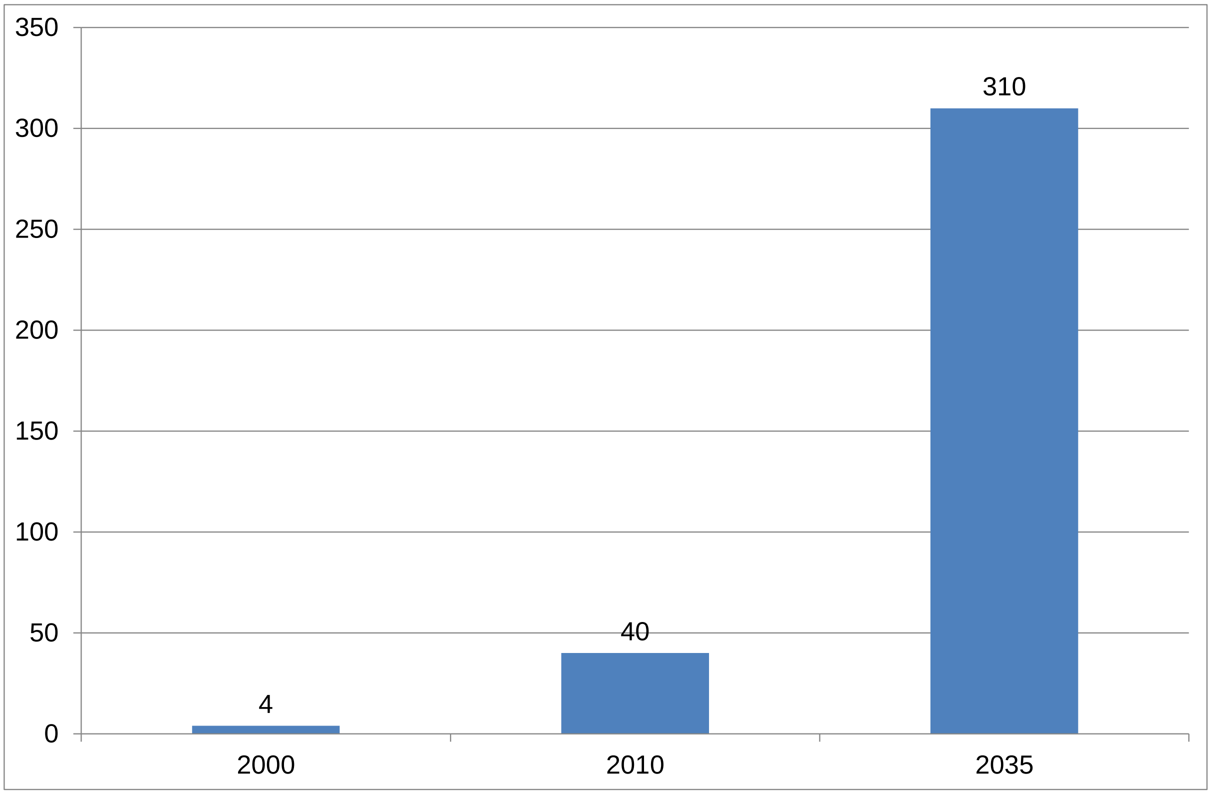
Thus, when forecasting oil demand, one can begin with a base year and increase or decrease this demand level by a factor of GDP growth. For example, assume your GDP growth forecast is 3% p.a. each year for the next four years. Assume further that you have calculated oil demand growth to be, on average, 65% of GDP growth. This would give a very rough oil demand growth forecast of 1.95% p.a. for the next three years. You could then refine this forecast by taking into account the long-term trend of reducing oil intensity of GDP (refer 2.6 below) and thus you may expect oil demand growth to be lower than your original estimate. Alternatively, you may consider the rapid increase in vehicle ownership in China and India (which, let's assume, you have estimated to be 3x the rate of GDP growth in these countries) to be so high that it will actually result in oil demand growth being higher than global GDP growth. These hypothetical examples are an attempt to show how one can begin with quite a basic forecast and refine it for known trends. Forecasting oil demand and supply is no mean feat and can become extremely complex. Consider the complexity of the *International Energy Agency's (IEA)* supply model, for example, the structure of which is illustrated in Appendix 1.

The nature and size of the world's **vehicle[2] stock** is an important driver of global oil demand. According to forecasts from the *IEA* by 2035 the number of vehicles on the road worldwide will double to 1.7bn.

[2] Motor vehicles include cars, buses and freight vehicles not two-wheelers.

The developed markets are highly saturated, with the US for example at around 800 vehicles per 1,000 people but the far more populous EMs still have very low vehicle penetration rates. High-growth EMs such as India and China (their populations are 1bn and 1.3bn people, respectively, compared with only around 300mn in the US) especially, have an extremely low vehicle saturation level at below 10 cars per 1,000 people for India and c. 50 cars per 1,000 for China. Most of the IEA's forecast growth comes from China. The chart below shows the current growth and the IEA's forecast of vehicle growth per 1,000 in China. According to the *IEA,* India will also see explosive growth over the next 23 years, going from 14mn cars currently to an estimated 160mn by 2035.

Figure 8: China – growth in vehicles per 1,000:



Source: IEA, Investor Campus

The situation described above means that there is enormous scope for growth in the global vehicle stock and hence scope for growth in liquid fuels.

Such an enormous increase in the global vehicle stock does not simply translate into an equally large increase in demand for liquid fuel. There are other important trends in the market such as increased fuel efficiency (often enforced by government legislation) and the development and substitution of hybrid and battery cars. That said, the expected growth in global vehicle stock does provide a tailwind to oil demand and cannot be ignored.

2.4.3. Supply

Global annual oil production is about 84mn bbl per day. The world's largest producer of oil remains Saudi Arabia, followed by Russia and the US. The top-10 producers of oil account for over 60% of global oil production. The value of oil traded each year is very large, and *BP's World Energy Outlook to 2030* shows the world cost of oil is only slightly above 4% of global GDP. OPEC controls about 45% of world oil production.

The table below shows the composition, by country, of global oil production:

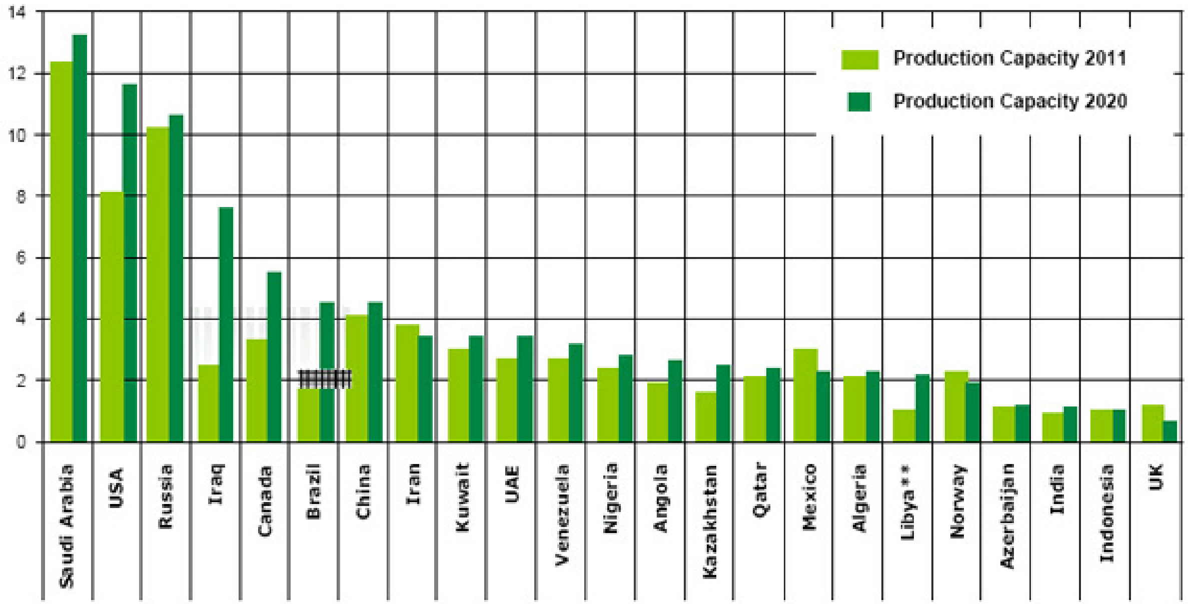
Figure 9: Global crude production by country:

Consumer	k bpd	% of global
Saudi Arabia	11 161	12.7
Russian Federation	10 280	11.7
US	7 841	8.9
Iran	4 321	4.9
China	4 090	4.6
Canada	3 522	4.0
United Arab Emirates	3 322	3.8
Mexico	2 938	3.3
Kuwait	2 865	3.3
Iraq	2 798	3.2
Total Top-10	**53 138**	60.4
Total global	**83 576**	100
OECD	**18 543**	21.1

Source: BP Statistical review 2009

Figure 10 shows select countries' long-term trends in global oil production, highlighting country-by-country projected increases of (gross) oil production capacity to 2020 (vs. 2011). It must be noted that long-term oil production has been persistently increasing despite the ever-present peak oil theories, which have spooked many investors for decades. The *Harvard University* study from where this graph was taken also concludes that oil supply capacity is growing worldwide at such an unprecedented rate that it might outpace consumption which could potentially result in a glut of overproduction and a steep dip in oil prices.

Figure 10: Long-term trends in global oil production



Source: [Harvard University's Belfer Centre for Science and International Affairs]

2.4.4. Inventory

Long-term inventory is the crude oil resource which has been identified but which remains underground (refer section 2.5). This section focuses on short-term inventories, which are oil inventories that have been extracted and are being stored in ships or other storage facilities. The price:inventory relationship for oil is quite typical of that observed for many commodities – high inventory levels tend to exert downward pressure on the oil price and *vice versa*. Thus, one will often see headlines reading something like "Oil rallies on drop in US inventories".

At any one time there is 7–8bn bbl, or three months' consumption, in industry and government stocks (*US EIA*) available. The US is the only country to publish weekly oil inventory data and these tend to exert an important influence on short-term oil prices.

2.4.5. Key price levels

The most important price levels for oil are the *marginal cost of production*, the *incentive price to expand production,* the point of *demand destruction and* the point at which *Saudi government budgets balance* (note that in this context the word 'point' refers to an ideal and practically we settle for the 'region' instead). These prices are discussed in further detail below.

The marginal cost of production: This would be the cash cost per barrel associated with the highest cost decile of the crude oil cost-curve. This will most likely always be the higher cost wells of privately owned non-OPEC companies. A famous oil economist, Morris Adelman, has estimated the average cost/bbl of Saudi oil to be in the region of $2.90/bbl (*Smil 2008: 133*). Note however that these are cash operating costs and not the 'all in' cost which would include exploration, capital and other sunk costs.

The incentive price to expand production: This is the price that would incentivise an expansion of oil production, in other words the price that would attract capital into the industry and into the development of as-yet undeveloped oil resources. Given that the oil industry is very capital intensive there will probably always be a very large discrepancy between the marginal cost of existing production (which only takes account of the cash cost of production) and the incentive price to expand production (which has to cover capital production costs and the required return on capital). Note also that the presence of a large and dominant cartel and the significant state influence in the industry means that decisions are not made on the basis of economics alone – the rent-seeking behaviour of the cartel as well as the political motives of governments are just as influential as the dictates of economics.

The point of demand destruction: This is the point at which there is a significant decrease in the quantity of oil demanded. It is the region where consumers become more sensitive to the oil price and adjust their behaviour accordingly. It could be expressed in absolute terms (e.g. above $100/bbl there is a significant curtailment in vehicle use and hence fuel consumption) or relative terms (e.g. when the oil/natural gas ratio is above a certain level there is a significant substitution away from oil).

The price of oil at which the Saudi government's budget balances. The Saudi government has an incentive to maintain oil prices at a level which is at least high enough to balance their budgets. As the largest OPEC producer they have the ability and the incentive to exert upward pressure on the oil price when it is low enough to push their budget into a deficit.

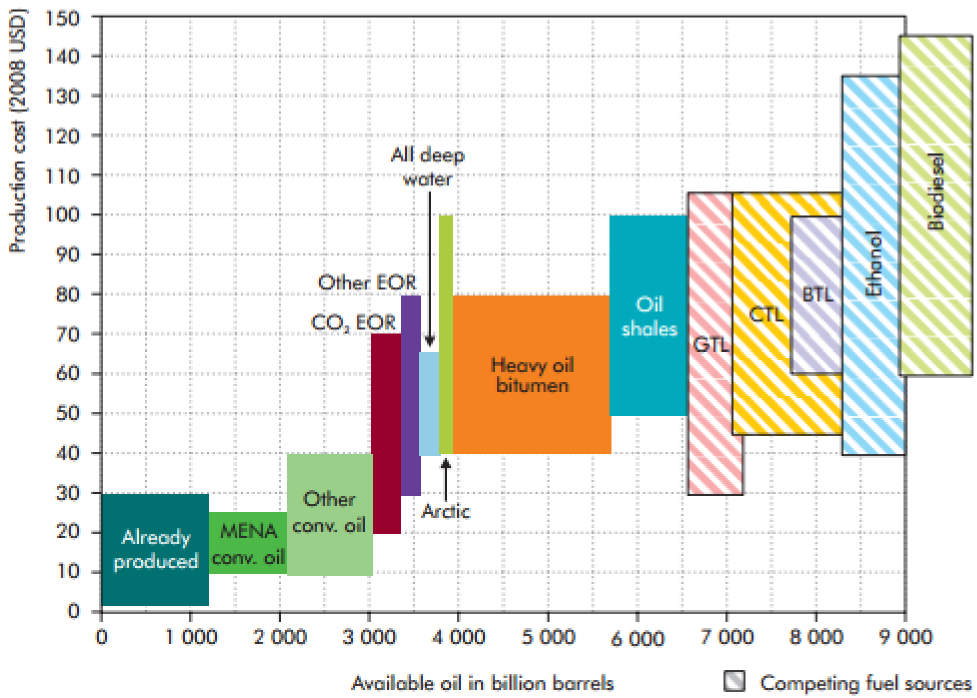
2.4.6. The oil supply curve

There are many different ways to construct a supply curve and each method tends to shed some light on a different aspect of the market under consideration. The following supply curve, taken from the *IEA's* world energy outlook 2008, is particularly interesting.

First, note that the x-axis measures the total estimated resource potential of each oil category (as opposed to the more conventional annual production volume). The y-axis measure the range of costs associated with producing each category (so, for example, the extraction of the total gas to liquids resource is estimated to cost between $40/bbl and $115/bbl, at 2008 costs).

The curve also combines historical information (i.e. the cost and volume data relating to oil already produced) and forward-looking estimates (e.g. coal to liquid resource and production costs).

Figure 11: Production cost curve (not including carbon pricing)



Source: IEA

This graph is quite rich in information and many useful conclusions can be drawn from it. For example, one could note that the MENA and 'Other conventional oil' resources are recovered at a very low cost and, based purely on economic concerns, should be extracted before the more expensive gas-to-liquids (GTL) and coal-to-liquids (CTL) resources.

Another observation is that the vast majority of oil resources, both conventional and non-conventional, are economically recoverable at or below \$100/bbl. This could be useful to bear in mind when speculation and geopolitical worries have driven the oil price well above \$100/bbl and this high price is being discounted in listed oil companies' share prices.

2.4.6. Oil alternatives

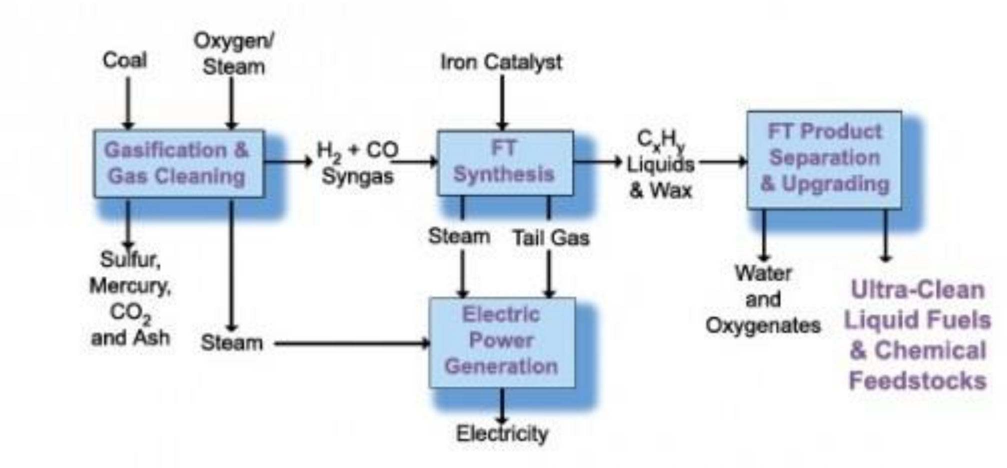
The world's energy supply hasn't always been dominated by oil. Before the nineteenth century, **wood** was the most important global source of energy. In the nineteenth century **coal** became the most important source of energy. The early twentieth century saw the rise of **oil**'s importance in the global economy. Although coal and oil remain the dominant sources of energy supply the world is gradually moving towards less polluting energy sources such as **natural gas** and even **greener alternatives** including wind, solar and nuclear power. These large-scale energy transitions are nothing new and they certainly needn't be catastrophic (some prominent, and arguably a little eccentric, peak oil theorists view the potential decline of oil as synonymous with the end of civilisation).

There are many types of energy alternatives to oil ranging from non-conventional oil to wind and solar power. Some of these alternatives are explored briefly below.

Natural gas is the least polluting fossil fuel and has been taking market share from oil for many decades. This process is expected to continue into the future. Some of the largest oil and gas companies expect their profits from natural gas to exceed those from oil in the near future. Natural gas reserves are also very large – almost as large as conventional oil reserves. **GTL**, is the process whereby natural gas is converted to liquid fuel.

The South African company, Sasol, uses the Fischer-Tropsch process to convert syngas, a mixture of hydrogen and carbon monoxide, to synthetic liquid fuels. Syngas is produced from coal, natural gas or biomass either through incomplete burning of the fuel or by way of a gasification process whereby the starting fuel is heated in the presence of a controlled amount of oxygen and steam to give the best syngas mixture. The syngas is then passed at high temperature and pressure over a catalyst which in turn speeds up the reaction of the gases together to form larger products. Often the catalyst used is iron but substances such as cobalt and nickel can also be used. In the reaction chamber several products are then formed of which the most important are alkanes (chains of carbon atoms with hydrogen attached - the longer the chain the heavier the fuel). The lightest product is methane, longer chains give liquid fuels such as gasoline and kerosene, and the longest chains give paraffin and wax. Products are then separated, cleaned and can be processed further in order to increase yields of desirable products and are then ready to use. This process is commonly referred to as **CTL.** The main problem with this process is that it emits an extremely high amount of greenhouse gas.

Figure 12: The Fischer-Tropsch process



Source: Clean Coal Technology

Some of the trendier green fuels are **bio-diesel, ethanol, wind, hydro** and **solar power**. Certain market commentators have pointed out that these fuel sources are too expensive when compared with fossil fuels. One relevant argument against this observation is that when the externalities associated with burning fossil fuels are incorporated into their price (this is partly achieved by internalising the cost of pollution by means of carbon taxes, for example), the cost differential is significantly diminished. Furthermore, as time progresses it is expected that technological innovation will reduce the cost of these fuel sources, making them much more competitive.

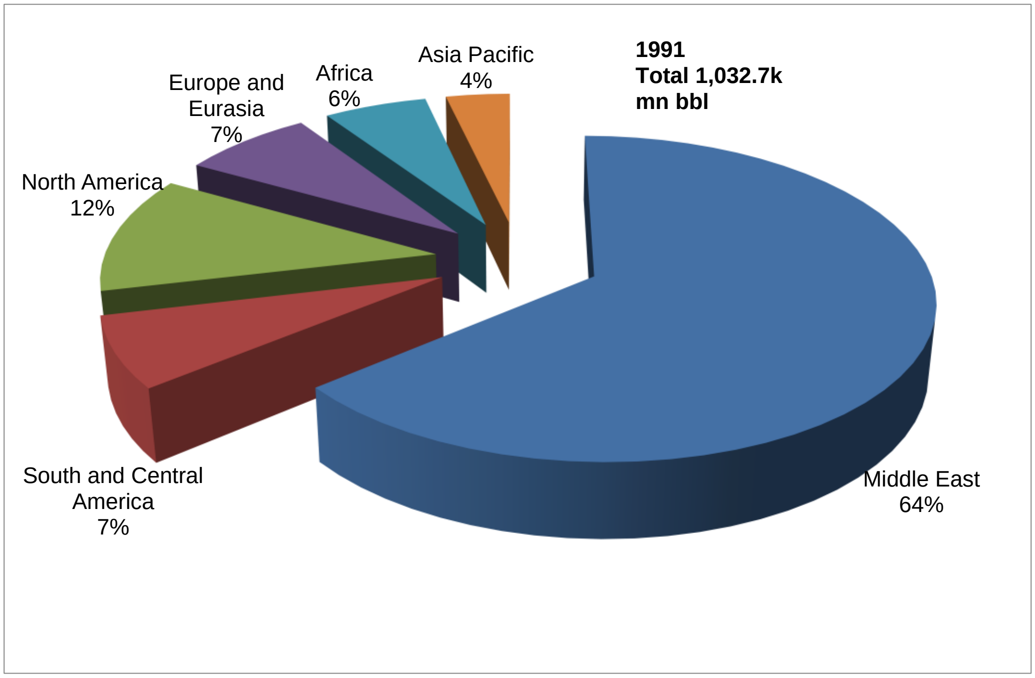
2.5. Reserves

World oil reserves are concentrated in two senses. First these reserves are concentrated in the hands of OPEC, who control about 75% of proved global oil reserves. Second they are concentrated in the really large oil fields, often referred to as the supergiants. In 2005, the largest 120 oilfields in production (out of a total of over 4,000 oilfields and over 800,000 oil wells) accounted for nearly 50% of all global oil extraction (*Smil 2008: 81; 133*)

The world's largest oil field is the Al-Ghawar oilfield in Saudi Arabia. The next largest are Kuwait's al-Burqan, Mexico's Cantarell, Venezuela's Bolivar and Saudi Arabia's Safaniya-Khafji. (Smil 2008: 80)

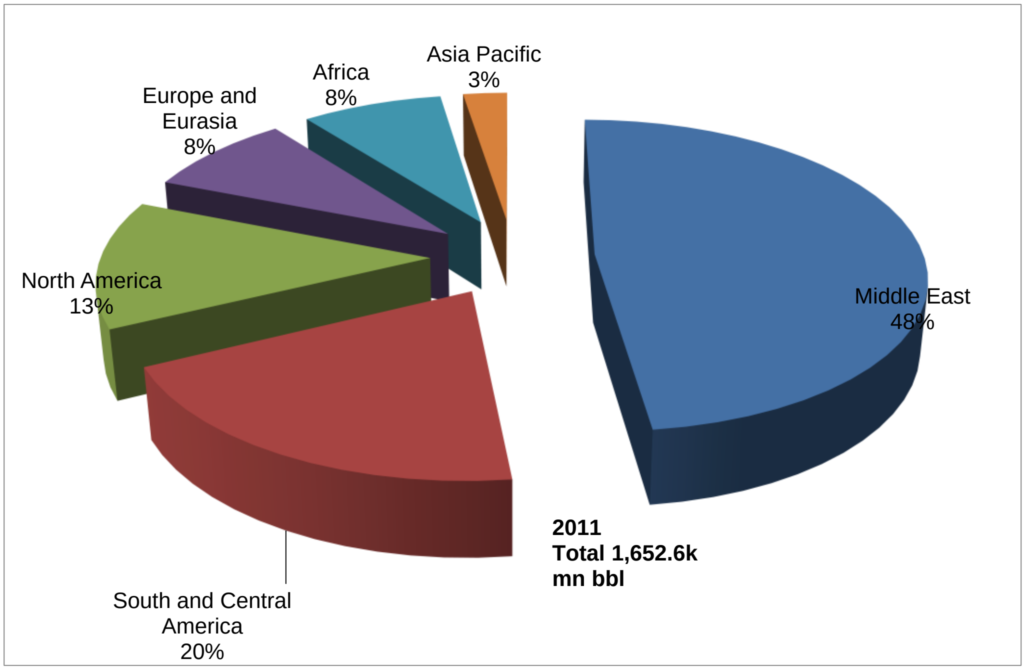
The following pie charts show the composition of proved global oil reserves in 1991 and 20 years later in 2011:

Figure 13: Distribution of proven oil reserves 1991



Source: BP Statistical Review 2012

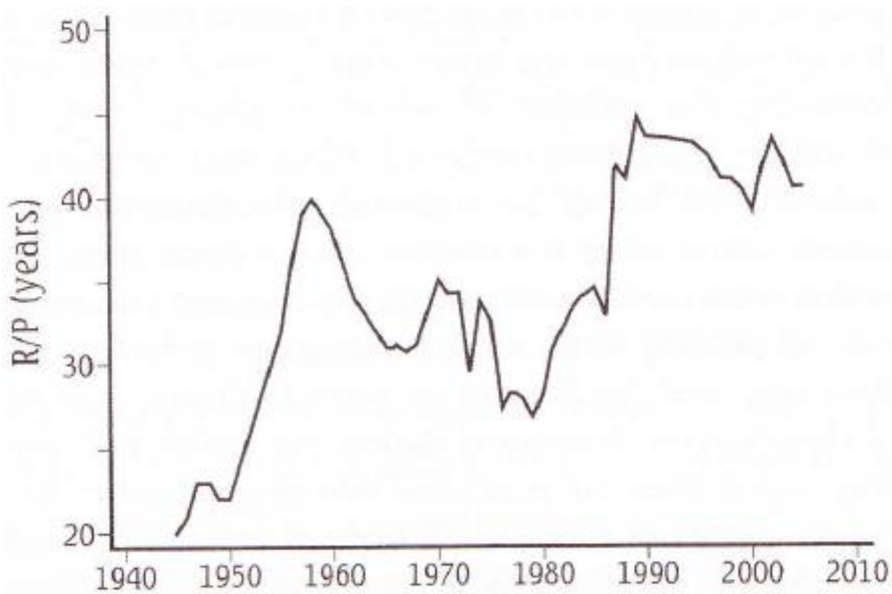
Figure 14: Distribution of proven oil reserves 2011



Source: BP Statistical Review 2012

The **reserve/production ratio** (R/P ratio) indicates the number of year's production at current production rates that can be met from existing reserves. Even if no further discoveries are made there are currently sufficient oil reserves to meet about 54.2 years of production at the current production rate. This does not take into account other resource estimates which do not yet qualify for recognition as reserves. The following graph illustrates the global trend in the R/P ratio for crude oil, it is significant that this ratio has actually increased over the past 60 years:

Figure 15: The global R/P ratio trend for crude oil



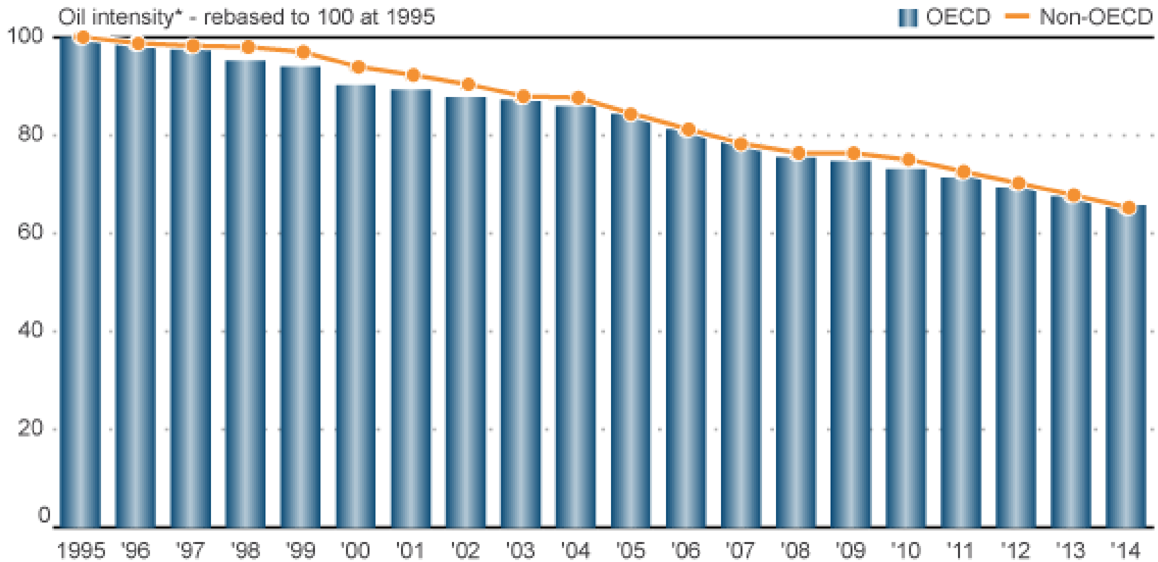
Source: Smil

2.6. Important long-term trends

There are many important long-term trends affecting the oil industry. In this section we briefly consider the decreasing oil intensity of GDP and the shift away from fossil fuels. Another important trend is that of increasing vehicle ownership which should result in increased demand for oil-based fuels (refer section 2.4.2). Finally, for historical perspective, the long-term real and nominal oil price is considered.

The **decreasing oil intensity of GDP** has been a historic fact for some decades and is expected to continue for many decades to come. In 2005 the US economy was only half as oil-intensive as it was in 1973, in other words it used only half the volume of oil in 2005, per unit of GDP, as it did in 1973 (Smil, 2008: 176). The *IEA* agency forecast a significant decrease in the oil intensity of GDP in the future, as shown by the following graph:

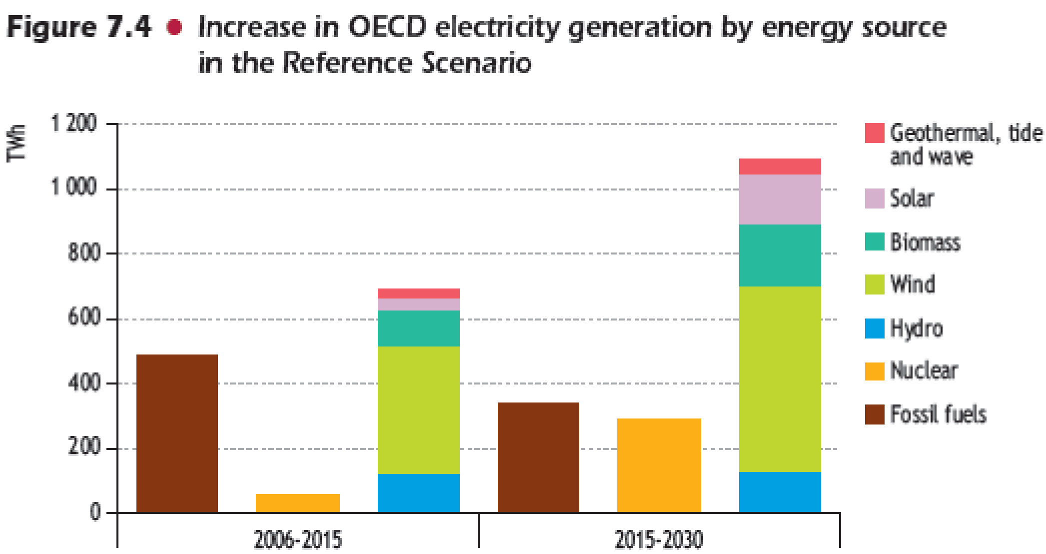
Figure 16: OECD and non-OECD oil-intensity (rebased to 100 in 1995)



Source: Reuters

With rising concerns about global warming and the depletion of fossil fuels, there is a **shift away from fossil fuels** toward cleaner and more sustainable energy sources. This trend is expected to continue for many decades to come. One illustration of this shift is the IEA's forecast of electricity generation, by source, illustrated in the graph below (note the decrease in fossil fuels and the increase in solar, wind, hydro and nuclear-based sources):

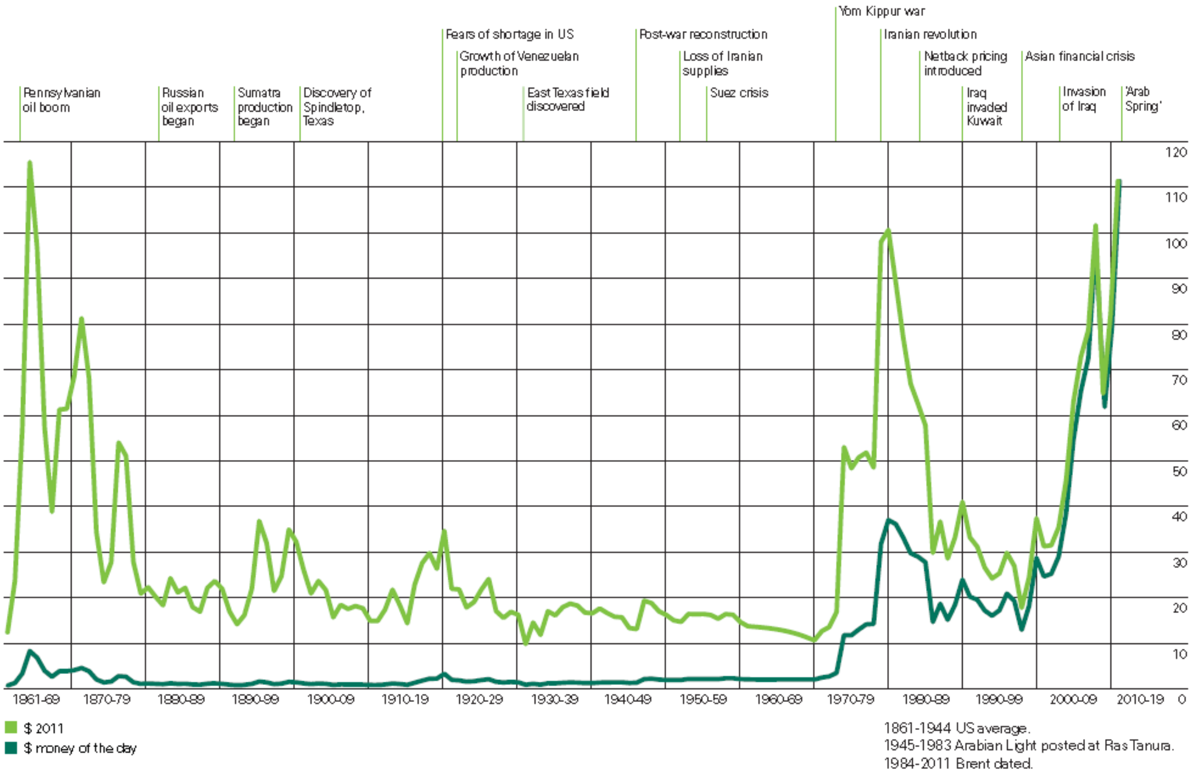
Figure 17: OECD and non-OECD oil-intensity (rebased to 100 in 1995)



Source: IEA

The following graph shows the long-term real and nominal oil price (Note that the real price of oil has never sustained a price above $80/bbl for any extended period of time):

Figure 18: Long-term real and nominal oil price (1861-2011), $/bbl



Source: BP Statistical review 2012

2.7. The major oil companies

The world's largest state-owned oil companies are:

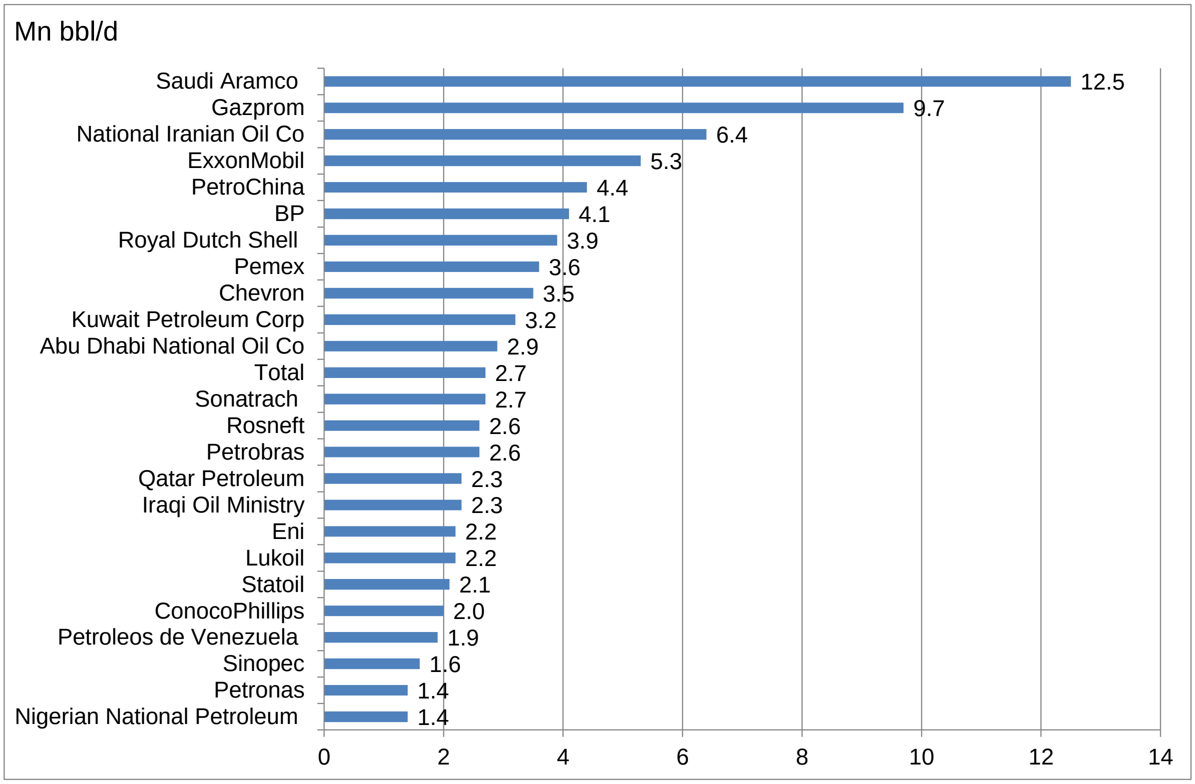
- ☑ Saudi Aramco - by far the biggest energy company in the world, generating more than $1bn a day in revenue;
- ☑ Russia's Gazprom, with profits of more than $40bn p.a., is the world's largest producer of natural gas. The company is controlled by the Kremlin and the company effectively has a monopoly on gas deliveries to much of Europe.
- ☑ China National Petroleum Corporation (CNPC) is a Chinese state-owned oil and gas corporation and the largest integrated energy company in China,
- ☑ Iran's National Iranian Oil Company (NIOC); and
- ☑ Venezuela's Petroleos de Venezuela S.A (PDVSA) is the state-owned natural gas company that has dominated the oil industry in the country since its founding in 1976. It is also the world's fifth-largest oil exporter.

The largest privately owned oil companies are:

- ☑ Royal Dutch Shell,
- ☑ ExxonMobil,
- ☑ BP,
- ☑ Chevron; and
- ☑ Total.

The state-owned oil companies are massive in comparison with even the largest privately owned oil companies. The following graph, compares the production of the top-25 oil and gas companies in million barrels per day:

Figure 19: World 25 largest oil companies



Source: Fortune, Investor Campus

3. Ten Steps to Analysing an Oil Company

We recommend the following ten-step approach to analysing an oil company:

i. **Gather all relevant available information**. This includes annual reports, production reports, reserves and resources statements, technical reports on projects, company presentations, listing documents and the like.

ii. **Identify the company's major business units or segments.** Many oil companies are 'integrated' in that they recover crude oil and refine this crude into petroleum products. The oil recovery segment of the business would be the upstream operations and these have different profitability and value drivers to the downstream refining operations. Integrated oil companies often have significant gas reserves and production volumes as well and this should be understood and incorporated into your valuation. Also gain an understanding of the type of oil the company produces (is it sweet or sour? Light or heavy? What is a good comparative benchmark for pricing purposes?).

iii. **Understand the operational side of the business and its industries.** This includes understanding the oil recovery process involved and the nature of the company's wells (are they mostly on land or out at sea and what are the risks involved with each? Do they rely heavily on complex technology or do they have relatively simple extraction processes?). One should understand any relationships between the company and a state-owned oil company. The tax and regulatory environment is also important. Also understand the operational and risk aspects of oil transport and beneficiation.

    This step involves the **identification and assessment of the risks to which the company is exposed and how they are managed.** This risk assessment is a valid and important exercise in its own right, but it should also inform your estimate of the company's cost of capital.

iv. **Decide on the appropriate level of aggregation.** When analysing a smaller oil company, it may be appropriate to analyse each asset in detail. The larger oil companies have many different oil fields and usually have more than one business segment (e.g. oil recovery, oil beneficiation, natural gas and alternative energy all being likely business units within a large integrated oil and gas company). When analysing one of these larger companies it is often appropriate to consider each business segment but not to 'drill-down' further into assets within these segments.

v. **Identify any embedded options.** These could be anything from loss-making, breakeven or marginal assets to large undeveloped resources and potential brownfield expansions. Remember to take these into consideration when valuing the company. Even if the value of real options are not explicitly included in your valuation they may be the deciding factor between two otherwise very similar companies.

vi. **Analyse the financial statements and production reports.** This includes a comparison between the financial statements and the production report as well as an analysis of each statement. This step should provide insights into the company's historic performance, provide many of the inputs into the valuation models and highlight any problems the company might be facing.

vii. **Compare the assets or company with its industry.** The most important comparison here is the asset or division's cash production cost per barrel of oil or cubic foot of gas, with that of its industry (i.e. locate the asset, company or division on its industry cost curve).

viii. **Analyse the project portfolio and understand the medium and long-term volume growth outlook of the company.** Exploration and project development is particularly important in the oil industry as oil fields tend to have a declining production profile as the underground pressure in oil wells diminishes over time. This means that oil fields will exhibit a decline rate as they mature and this decline will need to be offset with new wells and new oilfields just to maintain production levels.

ix. **Meet with management.** This should involve a discussion of all your key valuation assumptions as well as your understanding of the business. For some suggested questions in a management meeting, see section 6.

x. **Value the company.** This could involve a number of different valuation approaches and these are discussed in more detail below.

4. Valuation Approaches

There are many different approaches to valuing an asset and we address the most important ones with respect to oil companies below. When deciding which approach (or combination of approaches) to follow one should first consider whether it **suits the asset** and second whether it **suits your specific purposes**.

In the sections which follow we consider the following valuation approaches: Discounted cash flow (DCF), earnings-based valuation, enterprise value to resource ratio (EV/Res), option pricing, price to book (P/B) and replacement cost.

4.1. DCF valuation

The DCF or NPV (net present value) valuation approach is the best approach to use when valuing a natural resource asset. When we use another approach it is only because the information is not available to construct a DCF or because we simply do not have the time to follow this more rigorous method. Where we have a high degree of confidence in our DCF assumptions the *valuation risk* associated with this method is lower than for other methods.

This method involves estimating the future cash flows attributable to an asset and discounting them at the asset's estimated cost of capital or weighted average cost of capital (WACC). The most important parameters for an **oilfield** DCF valuation are *volumes, commodity prices (oil and natural gas), unit cash costs, capex, expected life of the oil field and the cost of capital.* The most important valuation parameters for an **oil refinery** are the *refining capacity*, *utilisation rate* and the *refining spread* (these are explained further in the valuation example, refer to section 5).

In some cases market participants apply a price:DCF multiple to the DCF valuation to arrive at a fair value or a target price for the asset. For example, an asset may be valued using the DCF approach at $1bn. A price:DCF multiple of, for example, 1.2x is applied to this DCF to arrive at a fair value of $1.2bn.

The price:DCF multiple is regarded with some ambivalence by many investors. Is it theoretically correct or is it simply an attempt to justify irrational exuberance during a bull market? The answer is probably both.

Consider the following comments:

- If an analyst values ten stocks in a sector and finds that all of these stocks are trading at between 1.1x–1.4x his DCF estimate then he may simply be using too high a cost of capital, or commodity price assumptions that are too low, in his models. In this case the use of a price:DCF multiple may be appropriate.

- It may also be appropriate if the analyst is simply trying to identify the best value in the sector and not determine whether the sector itself offers value.

- Where analyst's DCF models only discount the next 25 or 35 years' earnings, or some other period less than perpetuity, the multiple serves to gross up the DCF value where the company is expected to continue in existence for a long, long time, effectively in perpetuity. As an example, if one discounts the first 30 years of an annuity this will arrive at about 75% (depending on what cost of capital assumption you use) of the value of a similar annuity in perpetuity. Thus an appropriate price:DCF multiple in this case would be about 1.33x (i.e. 75% x 1.33=100%).

- Finally, the price:DCF multiple often represents an attempt to capture the value of optionality in resource companies as the DCF approach does not capture this important component of value (Refer to section 4.4 below for further discussion on optionality).

Price:DCF multiples are however often used in bull markets when 'model tweaking' is no longer able to make DCF valuations keep pace with stocks that are hitting new highs every week. In this latter case the use of this multiple should be regarded with scepticism, indeed its popular use amongst analysts may even be regarded as a contra-indicator.

Here are some rules of thumb when constructing a DCF model:

- Decide whether to construct a **real DCF** or a **nominal DCF** and ensure you are being consistent with your inputs. For example, if your DCF model is in real terms then make sure the commodity price forecast, currency forecast and cost of capital are also in real terms. A common mistake is to use nominal exchange rates in a real DCF model which balloons the asset valuation estimate.

- **Assume management will make a reasonable decision regarding mine, or in this case oil well, closure**. If your model is forecasting a $10mn loss every year for 20 years, don't simply discount those cash flows and use that as your value. This often happens with a purely number-crunching approach to valuation. In reality management will probably shut the operation after one or two years if it is not on the road to recovery.

- ☑ If your model assumptions result in a wafer-thin profit margin and free cash flow margin then **a DCF may actually be an inappropriate approach** and you should consider an option-pricing model. In this situation a 1% change in the commodity price assumption often results in many hundreds of a percentage change in free cash flow and value. The asset, at least in theory, is behaving like an option and should be valued as such.

- ☑ **Apply a lot of thought to terminal value assumptions** (or long-term assumptions) as these are the most important drivers of your valuation. Are you discounting economic profits in perpetuity and is this reasonable given your industry analysis and the asset's position on the cost curve?

- ☑ **Don't construct DCF models with blinkers on**. Prepare the model and then compare your IRR and profit margins in the model to your knowledge of the industry and the asset's position in the industry (i.e. its position on the cost curve). Your model may estimate a high IRR but this may be reasonable in light of the competitive structure of the industry and the asset's position on the industry cost curve.

- ☑ **Make sure you use the correct discount rate**: when valuing an asset, discount asset cash flows at the WACC. When valuing equity, either discount equity cash flows at the cost of equity or subtract the value of debt from the value of assets determined above.

- ☑ **Keep the model as simple as possible**. There are usually only about five to ten key assumptions that drive the value of an asset. If the model tries to track too many minute details it can become a black box which obscures the important inputs.

4.2. Earnings-based valuations

Earnings-based valuations, where a P/E multiple is applied to earnings in order to estimate value, are generally not the best approach for natural resource companies. That said they are much simpler to understand and much less time consuming than DCF models and for this reason they certainly have a place in resource company analysis.

Earnings-based valuations work best for industrial companies where earnings volatility is much lower than in the resources sector. Generally a P/E multiple is used to value a listed share in which case a P/E multiple is applied to EPS. The earnings can relate to some historic period or a forecast period in the future.

In the resources sector we speak of **peak, trough** and **mid-cycle earnings** as well as **normalised earnings**. Peak earnings relate to a high commodity price environment, trough earnings to a low commodity price environment and mid-cycle earnings to a more normal commodity price environment (in the absence of 'normal' this just means the average of peaks and troughs). Normalised earnings are usually theoretical earnings at current production volumes but with commodity prices adjusted to an estimate of their long-term fair value. Normalised earnings can however take account of all sorts of other adjustments – for example, adjusting for an asset that is about to come into production; adjusting for an abnormal expense or abnormally large sales volume resulting from the sale of stockpiles.

There are risks associated with using any of these earnings as a basis for valuation. Because margins show such a high degree of variation over time and between companies it is very difficult to call anything a normal margin or normal profit level. It is thus very difficult to determine what P/E is appropriate at the peaks and troughs of the cycle. It is also extremely difficult to identify some stage as the peak and another as the trough: extreme trends can carry on for years and carry on much further than expected. Also, during a trough when margins are extremely thin, the appropriate P/E multiple can be well over 200x. At this stage a 1% change in revenue can cause many hundreds of a percentage change in earnings and thus the intelligibility of earnings-based valuations is seriously called into question. Thus, it is our opinion, that **natural resource valuations should not be based on peak or trough earnings**.

If one believes that commodities are at the mid-point in a cycle then it may be appropriate to apply a mid-cycle P/E (either for the company itself or from a relevant peer group) to current earnings. Of all the earnings-based valuations, **the normalised earnings approach is the most subjective but also the most useful**. It does require a more detailed understanding of the companies but often produces useful results. When estimating normalised earnings consider adjusting the following:

- ☑ Adjust commodity prices to your estimate of fair value.
- ☑ Adjust costs, especially where these are cyclical, to a more normal level. Mines and oil wells often have commodity inputs into their production processes and these prices also move in a boom-bust fashion (e.g. oil prices and tyres).
- ☑ Adjust volumes – where a new mine or well is at an advanced stage of development its imminent contribution to volumes should be taken into account; where a high price environment has resulted in management really sweating their assets then reported volumes may be higher than sustainable normalised volumes.

- ☑ Estimate the value of assets that are not yet generating earnings and remove these from the price of the company. For example: ABC Company has a market capitalisation of $250mn. It owns two operating oil wells and recently bought a high-quality undeveloped oil resource for $50mn. The two operating assets generated earnings of about $15mn in the previous financial year. Thus the entire company is trading on a trailing P/E multiple of 16.7x. This is expensive when compared with the peer group which trades at only 14x trailing earnings. However, when we adjust the price by removing the non-earning asset ($250mn less $50mn) we arrive at a trailing P/E of 13.3x. The company now appears cheaper than its peer group.

- ☑ Always separate out loss-making divisions and assets. If a P/E is applied to group earnings which include both profits and losses then you are effectively placing a negative value on the loss-making divisions. This is incorrect as in most cases they at least have some option value or are worth zero.

It is often said that one should **"buy resource shares on a high P/E and sell on a low P/E".** Although this statement seems counterintuitive it does have some merit. Effectively this statement is advising investors to buy commodity shares at the trough of the commodities cycle, when share prices are depressed and earnings are even more so. If this is how the statement is taken then it seems like good advice for such a cyclical industry. Of course this adage should not be followed blindly and there are certainly instances when resource shares should be sold when the P/E multiple is too demanding.

4.3. Resource-based valuations

This method of valuation is peculiar to the resources sector. It is a relative valuation method, like the P/E ratio, which applies a price per unit of resource to the total resource to arrive at a valuation. It is mostly used to value undeveloped resources or mineral assets. The most widely used ratio is EV/Res which stand for enterprise value per resource barrel of oil. Enterprise value is market capitalisation of equity plus market value of debt less cash. The resource to be taken into account is attributable barrels of oil (where the resource includes natural gas this should be converted to an oil equivalent to allow the addition of the resources). Resource-based valuations have a high degree of uncertainty as resource idiosyncrasies (e.g. oil type and quality, critical mass, accessibility etc.) are different in many ways that are not picked up in such a valuation.

4.4. Capturing optionality in resource valuations

In many respects resource companies can be seen as call options on the commodities they produce. First, the value of a resource producing company depends on the price of the commodity it produces. Second, resource companies often have undeveloped resources which will only be developed (akin to exercising an option) at or above a certain commodity price. Third, the value of a resource company changes by a multiple of the change in its commodity price, in other words its price exhibits the characteristic leverage associated with options.

When this optionality is not captured in valuation estimates these estimates often understate the true value of these assets. A resource company may have the potential to expand existing assets at the right commodity price or its main commodity may have a high degree of price volatility. It may also have large undeveloped resources, assets operating at break-even, very small profit margins or even assets that are loss making. All of these assets represent option value embedded within the company which, in most cases, is not adequately captured using a DCF valuation approach.

Probably the most theoretically correct approach to capturing the option value of these assets is to value them using either the **Black-Scholes** or **Binomial** models. In reality, incorporating the rather messy parameters of a mine or oilfield into these models, which are already complex, can prove quite a challenge. In the section which follows we explain the applicability of the Black-Scholes option-pricing model to the valuation of an undeveloped resource. We then explain a less theoretically elegant but more practical approach to capturing option value in resources, called the probability weighted average method. The purpose of this section is to draw the reader's attention to the importance of optionality in resource valuations and offer some practical solutions to at least begin incorporating this optionality into our valuations.

4.4.1. Applying Black-Scholes to an undeveloped resource

Under this approach we treat the undeveloped resource as the *underlying asset* and the capital cost to construct the mine, or establish the oilfield as an operating asset, as the *strike price*. The value of the underlying asset is a function of the commodity price, the cash operating cost excluding start-up capex (as we treat start-up capex as the strike price) and volumes. The valuation inputs into this model and their relation to a resource company are discussed in more detail below:

1. **Estimated value of available resource** – calculate a DCF of this resource which excludes start-up capex. This is the value of the underlying asset.

2. **Estimated cost of developing the resource** – this is the capital cost of building a mine, or developing the oilfield, and corresponds to the strike price.

3. **Time to expiration of the option** – this is the time the company has to develop the resource or face losing it. Many countries have this type of "use it or lose it" clause attached to natural resource rights.

4. **Variance in value of the underlying asset** – one approach is to use the variability in the price of the relevant commodity. Note however that the actual variance in the value of the resource is higher than the variance in its commodity price as a result of operating leverage (e.g. if an operation has a 20% margin and its commodity increases 10% in price its profit margins and hence value will increase 50%), thus a better approach is to estimate the variance in the value of the resource based on the appropriate commodity price variance.

5. **Cost of delay** – this is the operating margin foregone, in not developing the resource, as a percentage of the value of the resource. It corresponds to the dividend yield in share-option valuation.

6. The **risk free rate** should correspond to the time to expiration of the option.

We now have all the required parameters to value the resource asset as an option using the Black-Scholes model. This approach, although imperfect, makes some progress towards incorporating the resource optionality in our valuations.

4.4.2. Probability weighted average method

The probability weighted average method can be applied to any resource asset but works particularly well for marginal or loss-making assets and undeveloped resources which are not viable at spot prices but would be viable operations at higher commodity prices. Although these assets may contribute little or nothing towards cash flow at current commodity prices they often have significant option value. A simple way to capture this optionality in a valuation is to use the probability weighted average method. An example of this approach follows below (we use a gold mining company in this example, but the principle is easily transferable to oil, natural gas and indeed any other natural resource company).

Assume ABC Gold Company has a large undeveloped resource which at current and estimated long-term prices will not earn the company's cost of capital. When valued with a normal DCF method under our base-case scenario the asset has a DCF value of -$25mn and therefore a value of zero (as it will simply remain undeveloped given its negative DCF). This is depicted in the first line of the table below.

The other two scenarios are a bullish case with the gold price 40% higher and a bearish case with the gold price 40% lower. These two scenarios are also illustrated in the table below. We apply probabilities to these three scenarios to arrive at a weighted average asset value of $500mn.

Figure 20: Alternative scenarios

Scenario	Average gold price over life of mine ($/oz)	NPV	Therefore value of resource	Estimated probability	Weighted average valuation
Base case	1 000	(25)	-	50%	-
Bullish case	1 400	2 000	2 000	25%	500
Bearish case	600	(1 500)	-	25%	-
					500

The main challenge with this approach is to make accurate probability estimates. The example above is very simplistic. In reality the probability estimates would have to be based on more accurate and scientific statistical calculations.

We close this section with an extract from *Damodaran (2002: 23)* relating to the use of option-pricing models in resource company valuations: "When we use option-pricing models to value assets such as patents and undeveloped natural resource reserves, we are assuming that markets are sophisticated enough to recognise such options and incorporate them into the market price. If the markets do not do so, we assume that they will eventually; the payoff to using such models comes about when this correction occurs."

4.5. Replacement cost

It is sometimes useful to consider the replacement cost of an asset in relation to our valuation estimate. For example, we may have estimated the value of a mine or oil well at $650mn and estimate its replacement cost at $850mn. If this is the case we at least have some comfort that we are not being too optimistic in our assumptions.

In other situations, replacement cost may actually be the most appropriate valuation approach. Consider, for example, a mineral deposit on which expenditure has been incurred but no resource has yet been defined. A company wishing to sell such a deposit may begin price negotiations at the cumulative costs incurred on the deposit.

A note of caution on this method: make sure that you don't double-count cost escalations when doing this calculation. Some assets are already carried at their replacement cost, for example property, plant and equipment may be carried at its replacement cost in terms of IFRS. If one mechanically goes through this method – calculating the average age of the assets are restating them once again for that time period's cost escalations – it will result in a gross overstatement of the assets replacement cost.

4.6. Composite valuations

Some natural resource companies are large with many different types of assets in different sectors. It often happens that the most appropriate way to value such a company is a combination of the above approaches. For example, the profitable producing assets may be valued using the DCF approach, the exploration assets using the EV/Res approach and the loss-making producing assets using an option-pricing model.

In some cases, multiple valuation approaches will even apply to a single asset. For example a mine plan may exist for phase 1 of a large deposit, but phase 1 only covers 20% of this resource. In this case you should be able to get the information to construct a DCF for phase 1 but should apply an EV/Res valuation to the remainder of the resource if it is likely to become a mine in future.

When applying multiple valuation approaches you should also make sure not to double-count assets. This could happen, for example, if you applied a P/E multiple to company earnings and then applied an EV/Res multiple to its resources in the resources and reserves statement, and it was the assets in this statement that generated the earnings in the first place. So, make sure you don't double-count assets but also ensure that you value all the assets.

4.7. A note on forecasts and models

Company valuation almost always requires an element of forecasting and forecasts are almost always wrong. Therefore when trying to understand a sector or a company based on forecasts it's important to keep the models simple. Valuation models shouldn't have hundreds of inputs and sheets. There are usually only a couple of key inputs that drive valuation and these should be the focus of the model.

Decide what you will assess yourself and what you will leave in management's hands. For example, when analysing a top-quality international diversified miner, are you going to spend a lot of time trying to understand the geology of their projects or will you leave that to management, implicitly assuming that a company of that calibre will have more than enough skills to do this well.

As a rule of thumb: **the higher the estimation uncertainty the higher the margin of safety should be**. If all the estimates going into your DCF model are very approximate then the margin of safety should be very wide. If the estimates however come from audited financial statements and during a time of stable economics then the required margin of safety is much less.

4.8. Multiples estimation

An important part of any resource company valuation is the determination of an appropriate valuation multiple. Whether this multiple is a **P/E multiple, price:DCF multiple or EV/Res multiple** take the following factors into account:

- ☑ The multiple which the market has assigned to the relevant **peer group**.
- ☑ **General market factors** such as the risk free rate, equity risk premium and P/E/ price:DCF multiples on similar companies.
- ☑ **Company specific risks** associated with the location of assets, capital structure, debt burden and the nature of the company's assets.
- ☑ **Industry risks**: In the case of the oil industry, the risk that substitution away from fossil fuels is more rapid than anticipated is relatively important. This could be caused by many factors, for example the carbon emission legislation will be more aggressive than expected and trigger a more rapid substitution away from fossil fuels.
- ☑ **Adaptability**. Many large oil companies are being forced to develop oilfields in remote and difficult locations, such as ultra-deepwater oilfields. This is a result of the scarcity of accessible resources. These projects require technological sophistication and adaptability. The leading oil companies are also diversifying their businesses into natural gas and other energy alternatives. A company which is leading its peer group in this regard may well deserve some kind of premium rating; likewise a laggard may deserve a discount.
- ☑ **Quality of assets**: Higher-quality assets generally deserve a valuation premium.
- ☑ **Balance sheet strength**: A stronger balance sheet reduces liquidity and solvency risks, increases the likelihood of the company being a takeover target and allows the company to take advantage of growth opportunities when these present themselves. Such a company therefore justifies a premium over one with a weaker balance sheet.
- ☑ **Liquidity of shares**: Listed assets generally deserve a premium to unlisted assets. Highly liquid listed assets generally deserve a premium to less liquid listed assets.
- ☑ **Quality of management**: An excellent management team is more likely to extract value from assets and deliver their strategy and should be taken into account in rating multiples.

- ☑ **Cash conversion of earnings:** A company that converts a high proportion of its earnings into cash is preferable to one that struggles to convert its earnings to cash.

- ☑ **Leverage or optionality** embedded in the company: Take into account operating margins, debt levels, undeveloped resources and hedge-books. In principle, as a company becomes more marginal its value tends to decrease but the option component of its total value, as a percentage, tends to increase.

- ☑ Quality of the **project pipeline**: A deep inventory of projects which are of a high quality ensures that the company can continue to invest profitably and grow its earnings into the future.

- ☑ A high **growth** outlook is better than a weak growth outlook and should affect ratings.

- ☑ Where a company has a history of weak **cost control** there may be potential for cost cutting which would increase earnings.

- ☑ Where a company has an inefficient **corporate structure** there may be potential for a restructuring that would reduce costs.

- ☑ **Diversity of income streams** reduces the risks associated with relying on one commodity or one operation for all the company's income. This improves the quality of earnings.

- ☑ **Stability of income streams**: Less volatile income streams are more valuable than volatile income streams.

- ☑ **Life of assets**: Mines or oilfields that have an excellent reserve base have a longer expected life and therefore a higher value than operations that have largely depleted their reserves.

When **estimating a P/E multiple** it is sometimes helpful to use the mathematical formula which derives a P/E multiple assuming a constant growth rate in perpetuity and a given cost of equity:

$P/E = (1+g) / (k-g)$

Where:

P/E = price earnings multiple
g = perpetual growth rate in earnings
k = cost of equity

The following table illustrates the application of this formula in the derivation of P/E multiples (note that we have used a real perpetual growth rate and a real cost of equity capital in the calculation):

Figure 21:

PE Multiple		Real cost of equity 5%	6%	7%	8%	9%	10%
Real growth rate	0%	20	17	14	13	11	10
	1%	25	20	17	14	13	11
	2%	34	26	20	17	15	13
	3%	52	34	26	21	17	15
	4%	104	52	35	26	21	17

The block in the top right corner of the table represents what we consider to be a reasonable range of P/E multiples for the *normalised* earnings of resource companies.

Note that the P/E multiple is highly sensitive to the assumed perpetual growth rate. Also note that it is questionable whether a *perpetual* growth rate above 1% or 2%, or a perpetual growth rate at all, is really justifiable.

5. Valuation Example

The following example illustrates the application of the DCF valuation method to a large integrated oil company, Royal Danish Periwinkle. The company produced 435,000 bbl/day in 2007, accounting for about half a percent of global oil supply. The company also refines 100% of its own crude production but currently does not refine crude for any third parties. Their production has slipped quite markedly over the past three reporting periods going from 450,000 bbl/day in 2007 to 435,000 bbl/day in 2009. This is the result of field declines in its existing oil fields. The company is at the construction phase for a new oil field which they anticipate will be in production in 2010 and will reach full capacity in 2012.

They have guided the market to expect no production growth in 2010, production of about 450,000 bbl/day in 2011 and 455,000 bbl/day thereafter. They have other oil wells at the feasibility stage and some promising exploration prospects, at least some of which they expect to bring into production over the next few years. It is management's opinion that these new developments will at least offset the field declines from their existing wells (i.e. they expect to maintain production at 455,000 bbl/day from 2012 onward). Management has also given the market some guidance on their cash operating costs and capex profile over the next few years.

The following table shows the forecast income statement as well as the assumptions that went into this forecast:

Figure 22: Royal Danish Periwinkle forecast income statement example

1	**Royal Danish Periwinkle**								
2	**Real DCF valuation**								
3	**Financial Year to December**		**2007A**	**2008A**	**2009A**	**2010E**	**2011E**	**2012E**	**LT**
4	**Valuation Assumptions:**								
5	**Pricing**								
6	- Brent Crude	*$/bbl*	72.5	97.1	61.6	75	85	85	85
7	- Refining margin	*$/bbl*	8.00	6.00	5.00	5.00	4.50	4.20	4.20
8	- realised discount to Brent	*%*	4%	4%	4%	4%	4%	4%	4%
9	**Production volumes**								
10	- crude oil	*Kbbl/d*	450	440	435	435	450	455	455
11	**Refining volumes**								
12	- refining capacity	*Kbbl/d*	475	475	475	475	475	475	475
13	- capacity utilisation	*%*	95%	93%	92%	92%	95%	96%	96%
14	**Costs**								
15	- cash operating cost	*$/bbl*	20	21	22	23	23	24	25
16	- unit cost increase	*$*		5%	5%	3%	3%	3%	3%
17	**Forecast Cashflows:**								
18	Revenue	*$m*	12 738	15 940	10 176	12 226	14 142	14 249	14 249
19	- crude sales	*$m*	11 424	14 977	9 382	11 432	13 403	13 552	13 552
20	- refining margin earned	*$m*	1 314	964	794	794	739	698	698
21	Production costs	*$m*	3 285	3 373	3 501	3 606	3 842	4 002	4 122
22	Other operating costs	*$m*	329	315	332	330	330	330	330
23	Selling and admin expenses	*$m*	125	135	132	132	132	132	132
24	Capex	*$m*	5 000	4 500	4 500	4 500	500	500	3 640
25	Exploration costs	*$m*	550	800	525	611	707	712	712
26	Free cash flow before tax	*$m*	3 449	6 818	1 186	3 046	8 631	8 573	5 313
27	Tax	*$m*	1 069	2 113	368	944	2 675	2 658	1 647
28	Free cash flow after tax	*$m*	2 380	4 704	818	2 102	5 955	5 916	**3 666**
29									
30	Real cost of capital	*%*	*8%*						
31	PV of 2010 - 2012	*$m*	*11 748*						
32	PV of terminal value	*$m*	*36 379*						
33	**NPV**	***$m***	***48 126***						

Source: Investor Campus

Note the following:

- ☑ This particular DCF model is split into three periods: First the **historic reported period** encompassing the years 2007A, 2008A and 2009A which form the base for forecasting purposes. It is recommended that at least two years of history are considered and preferably five, if possible; second the **medium-term forecast period** which is 2010E–2012E. Finally the **long-term normalised year** (the column headed 'LT') which will be used to calculate the terminal value.

- ☑ **Price** assumptions are shown in line 5–8. Although the company does not actually sell its crude to third parties, but refines 100% of the production themselves, they are of the opinion that their crude would sell at a 4% discount to Brent crude. We use this price in our valuation as it allows us to calculate revenue from crude sales (which in this case are all inter-company sales) and revenue from refining separately without having to calculate revenue derived from the vast array of crude-based products produced by their refinery.

- ☑ **The refining margin** (line 7) is the margin earned by the refinery on each barrel of crude refined. The refining margin is a function of global refining capacity. Higher crude prices simply flow through to the cost of the end-products. In this case we have forecast a declining refining margin which bottoms at $4.20/bbl in 2012. This forecast would be based on your analysis of available global refining capacity.

- ☑ **Production volumes** are shown in line 10 and are based on management guidance.

- ☑ **Refining volumes** are shown in line 11–13. The company has an installed refining capacity of 475,000 bbl/day, which is sufficient for its own needs, even after the development of the company's new oilfields.

- ☑ Unit **cash operating costs** are shown in line 14–16. Management guidance was for a 3% p.a. real increase in unit costs. This is lower than the actual cost increases observed in 2008A and 2009A. We can however accept management's guidance as reasonable because volumes actually decreased in 2008A and 2009A which, due to a high proportion of fixed costs in most resource companies' cost base, would result in higher unit cost increases.

- ☑ **Revenue** (line 18) comprises crude sales (inter-company) and the refining margin earned. Crude sales are calculated as follows: Brent price x realised price discount to Brent x daily production x 365 days. Refining margin earned is calculated as follows: Daily crude volumes x 365 days x refining margin.

- ☑ **Production costs** (line 21) relate only to crude production and not to refining (since we are accounting for refining on a net basis). This is acceptable here, in a cash flow valuation, but would not be acceptable for financial accounting purposes. Production costs are daily production volumes x 365 days x unit operating costs.

- ☑ **Other operating costs** (line 22) and **selling and admin expenses** (line 23) have been relatively stable over the past few years and are expected to remain stable, in real terms, in the future.

- ☑ **Capex** (line 24) is based on management guidance. Capex in 2010 is expected to be quite large as it is the final year of construction of the new oilfield. Capex in 2011 and 2012 is just maintenance capex. The capex estimate in the normalised year (LT) is our estimate of the long-term average annual capex and is roughly equal to depreciation. The logic here is that the LT year is being extrapolated in perpetuity and this will involve many investment and capex cycles. Thus, it is appropriate here to include the average of this cycle in a normalised year.

- ☑ **Exploration costs** (line 25): Management has guided the market to expect exploration expenditure in the region of 5% of revenue.

- ☑ **Tax** (line 27) has averaged about 31% of profit in the past. Our tax calculation here simply extrapolates this rate into the future. Note that a more detailed DCF valuation should incorporate a more sophisticated tax estimate and that it is unlikely that actual cash taxes will be 31% of free cash flow each year (although on average this assumption is reasonable).

- ☑ **The NPV** (line 33) is the sum of the present value of cash flows for the 2010E–2012E period plus the present value of the terminal value. The terminal value is the value of an annuity of the LT free cash flow after tax. In this case we have assumed zero long-term real growth. Hence the terminal value is $3,666/8% = 45,825. This needs to be discounted for another three years to bring it back to our valuation date (January 2010), so we have: $45,825/(1.08)^3$ = 36,379. Consequently this rather simple model gives a valuation estimate of $48bn for the operating assets of Royal Danish Periwinkle.

This model is very simplistic and there are many ways in which it could be improved and refined. Note however that a simple model isn't always bad and in many cases the 80:20-rule applies – you get an answer that is 80% correct with the first 20% of the effort. The next 80% of effort only serves to refine the answer.

Looking back on this first-pass valuation model we make the following suggestions:

- ☑ In reality, a large integrated oil company would most likely have **other major divisions** such as natural gas, liquefied natural gas, petrochemicals and energy alternatives. When these divisions are part of the business they would obviously need to be included in your analysis.

- ☑ Our operating cost analysis is very **simplistic**. A more accurate estimate would break down the unit costs into their fixed and variable components. One may also want to consider the cost base of existing oil fields separately from the cost base of new oilfields.

- ☑ Our cost inflation forecast was simply taken from management. It may be worthwhile to get a **deeper understanding of the nature and structure of the businesses costs** and make a more sophisticated cost inflation forecast. One potential pitfall of the approach adopted here is that it could be inherently illogical – for example, management's cost forecast may be based on their assumption that the global economy will boom over the next five years and push up operating costs significantly. Our forecast oil price is however quite tepid in contrast to management's optimism and hence we are penalising our company on the cost line (which inherently assumes a booming economy) as well as the revenue line (which inherently assumes a weaker economy). A deeper understanding of costs would avoid such pitfalls.

- ☑ Our valuation extrapolates cash flows in **perpetuity**. One would need to consider whether such an assumption is reasonable, especially in an industry that is in long-term, albeit very long-term, decline. For a large integrated oil company that has demonstrated an ability for technological innovation and ingenuity, extrapolating cash flows perpetually may be quite reasonable – one would expect such a company to adapt to a changing energy environment. Indeed, many large oil companies are doing exactly this with gas and alternatives becoming an increasingly significant component of their total business.

- ☑ Finally, note that a **forecast balance sheet and income statement** are not shown here but these are important elements of any company analysis. In the balance sheet forecast we would be particularly interested in the forecast debt ratio and balance sheet strength, in general. In the forecast income statement we would be particularly interested in profitability ratios, earnings per share and the resulting P/E ratio, especially in comparison with the company's peer group.

6. Key Questions to Ask Management

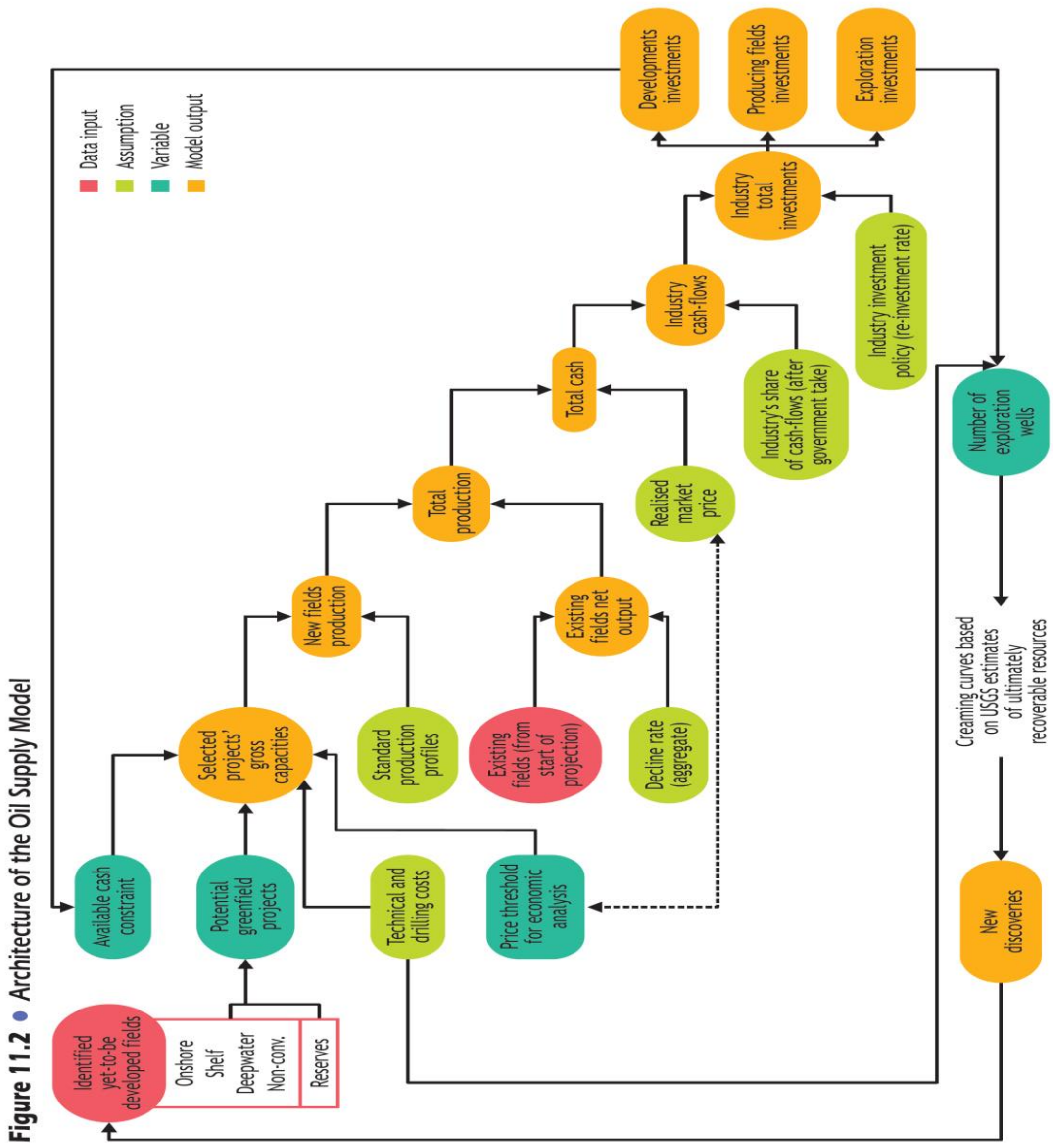
1. How would you describe your business?
2. What are the growth prospects of your company?
3. In what way is your company unique?
4. What is your vision for your company?
5. What is your current volume capacity and what will it be in three and five years' time?
6. What is your capex profile over the next five years and how is this split between maintenance and expansion capex?
7. What is your exploration strategy and budget?
8. What are you criteria for new investments?
9. What type of mines/oilfields do you aim to build and own?
10. Is the tax rate sustainable and why?
11. What is your targeted debt/equity ratio?
12. What do you consider to be your key risks?
13. What is your relationship like with the government – both in the fiscal and mining departments?
14. Do you have the necessary skills to maximise the potential of your assets?
15. What will your weighted average number of shares be in the current year and the year after that?
16. What is your policy regarding dividends and share buybacks?
17. What is the approximate level of maintenance capex vs depreciation?
18. If you don't build any new mines/develop any new oilfields, at what point will your volume profile peak and at what rate will it decline thereafter?
19. Please describe the growth/acquisition and international expansion strategies.
20. What do you look for in an acquisition?
21. How is IT changing the business and is the business investing sufficient capital in IT?
22. How would you characterise your relationship with local communities?
23. How would you describe your relationship with labour and labour unions?
24. What is labour's attitude towards mining companies in your main operational jurisdictions?
25. Do you meet South Africa's Black Economic Empowerment (BEE) policy and other indigenisation standards set by the government in your country/countries of operation and if not how will you do so?
26. Are there any environmental risks associated with your operations and how do you manage these?
27. In what way, if any, do your operations pollute or damage the environment and how do you manage this?
28. Do you have any large closure liabilities in the foreseeable future and what do you estimate these to be?
29. How do you manage commodity price risk?

30. How do you manage currency risk?
31. What is your succession plan for key roles in the business?
32. Are there any risks associated with the supply of water, electricity and other services provided by the state?
33. Are there any problems or challenges associated with access to your mining operations? Any other logistical difficulties?
34. Are your mining rights and other permits in good order?
35. Are there any seismic or abnormal safety risks associated with your operations?
36. What is your safety record and are you satisfied with it? If not how do you propose to improve it?

7. A Final Checklist

- ☑ Have you incorporated all the assets in your valuation?
- ☑ Have you double-counted any assets?
- ☑ Do you have the correct ownership percentage and minority stakes in the assets?
- ☑ Does the company have all the necessary permits to continue in operation?
- ☑ Have you considered political risk in your valuation?
- ☑ Would you back management to deliver on their vision/mission/strategy?
- ☑ Is your long-term commodity price forecast above the marginal cost of production and if so how would you justify this?
- ☑ Have you applied any Price:NPV multiples in your valuation and is this really appropriate?
- ☑ Have you considered a sensitivity analysis with lower and higher commodity prices than your base-case forecast?
- ☑ Have you taken account of any hedges or fixed-price contracts?
- ☑ Does the company have the balance sheet to fund the capex profile in your cash flow models?
- ☑ What could go wrong and create a real disaster for the company?
- ☑ If the company does not achieve its asset development targets will this lag create any major cash flow problems? (e.g. if they deliver a major project six months late will this result in a funding problem?)
- ☑ How does the company's liquidity and solvency position relate to the external environment? For example, do you have a highly cash generative business in a world that is starved for cash? Alternatively, do you have a highly leveraged company that is hungry for capital in a world where capital is very scarce?

8. Appendix A – IEA's oil supply model



Source: IEA

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