CHAPTER 2

Reserves, Peak Oil and Medieval Maps

Are we running out of oil? Before we can answer that question, we need to understand what oil and gas reserves are and how they are measured.

Reserves are very significant numbers. They form the base of a slew of Key Performance Indicators (KPI) for all types of oil companies. Yet, the lack of a globally accepted standard makes the measurement and auditing of reserves a thorny issue*. An integrated understanding of worldwide reserves is also lacking. In this chapter, we consider reserves measurement systems, global reserves and 'peak oil'. One key question interests us: are we navigating through global reserves using a 'medieval' and outdated map? If so, is peak oil a physical or psychological shortage?

Invariably, reserves* grab headlines due to their financial significance, measurement methods or the geo-political dimension. On the one hand, the sustainability of oil companies depends on reserves and, on the other, oil company profits depend primarily on production**. By breaking down reserves and production data, analysts can derive KPIs such as net worth, reserves to production ratio, reserves replacement and production quotas and positive cash-flow. Consequently, reserves and production are inextricably linked to financial performance.

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*Reserves estimation is a sensitive area and the definition of related terms attracts considerable debate from both inside and outside the industry. For our purposes, we use the term reserves to mean proved reserves. Reserves classifications are dealt with shortly.

** Other factors include oil price, industry costs, inflation and efficiencies of scale.

Major, National and Private

Existing irrespective of oil company size or shareholding, the link between reserves and financial performance is a fundamental one. Majors, public or 'floated' companies, will be judged by analysts on their short-term earnings and long-term prospects. Private companies will be judged by shareholders on Return on Investment (ROI). National or state companies are subject to analysis too which we will consider shortly. The stock prices of oil companies are heavily influenced by their stock-in-trade—oil. The oil company itself will use KPIs such as production rates and reserves replacement to make financial valuations and earnings projections. Financial analysts ultimately look to these figures and make 'buy, sell or hold' recommendations.

Reserves, therefore are a major influence on the stock price of major International Oil Companies (IOCs). Of course, IOC stock prices will be affected by quarterly profits and shareholder dividends. The oil price and other contextual factors that affect the attractiveness of the industry as a whole for investment—geopolitics, speculation and 'futures' trading—will also affect stock ratings. Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased. Usually this happens in one of three ways: first, through the 'drip-feed' of incremental recovery using mature field improved technology; second, by boosting reserves through the bit which means that successful wildcat strikes open new frontiers; and finally,, by the acquisition of another oil company through its stock[1].

National Oil Companies

There is a common yet incorrect perception that National Oil Companies (NOC) are somewhat immune from scrutiny of financial indicators; however, there are at least two scenarios where NOCs will be judged by analysts. This primarily occurs when financial experts assess financial risk and assign credit ratings to NOCs and their countries of origin. In major oil exporters, i.e. exporting more than 2 million barrels of oil per day (MMbbl/d), the NOC is often the largest business in the country*. Country risk can therefore be considered a function of the NOC's performance. This has a direct bearing on the credit rating of countries. A secondary situation occurs when analysts assess the attractiveness of financial instruments or debt (bonds), issued by the oil company or government, based on ROI and risk.

Certain NOCs, such as those within the Organisation of Petroleum Exporting Countries (OPEC), also depend on reserves in another way. OPEC production

* By most measures i.e. contribution as % GDP, gross revenue, contribution to state revenues or as an employer or by the contracting of services and the indirect creation of infrastructure

quotas are allocated as a proportion of total proved reserves. Consequently, countries with high reserves volumes are given higher thresholds of production[2,3].

Uncertainty

Measuring reserves is difficult and involves a basic uncertainty because reserves lie hidden away in deep subterranean reservoirs. It would be physically impossible to accurately measure oil and gas in place; therefore, the industry relies on extrapolated measurements as accurate measurements can only occur upon production. Consequently, measuring, corroborating and auditing the measurement of reserves is an inexact science.

To make matters more complex, there is no single standard or methodology that is universally accepted by the industry or by the financial community, i.e. regulators/analysts. Substantive variations exist between institutions and nations. Exemplifying this are differences between the SPE (Society of Petroleum Engineers) and SEC (Securities Exchange Commission) criteria for reserves classification, and international variations between the Russian and Norwegian systems[4,5].

Before we go into detail, it is fair to note that the lack of a single international or institutionally recognised set of standards makes reserves measurement somewhat dependent on the system chosen[6].

Missing Barrels

With many oil companies based in the US or floated on US stock markets, the oil industry has been lobbying US regulators to overhaul the system by which the industry's reserves are measured[7].

The SEC classifies reserves using conservative and narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. This is a problem because not only does the industry have a track record of technology development, but technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond Earnings Before Income Tax Depreciation and Amortisation (EBITDA). Peak oil theorists also tend to minimise the value of E & P technology. We will examine the value of technology in detail shortly in the 'medieval map'.

The SEC measurement leads to a substantive variation with internal industry measures such as the SPE which places more emphasis on technology 'unlocking' reserves to make them more recoverable. The variation often results in discrepancies that amount to billions of barrels of oil across the industry[8].

Industry analysts have lobbied the SEC to change its reserves accounting so that the benefits of E & P technology can be better applied. Essentially,, this covers a raft of technologies such as seismic, geosteering and horizontal drilling which enable higher recovery rates through pinpointing reserves and well placement[9]. At issue is the realistic valuation of energy companies themselves, as well as how we calculate replaced or future reserves. While analysts look to earnings as a short-term performance measure, the more long-term measure looks to reserves to production ratios as the basic indicator of the oil company's future wealth.

What's On the Books?

Due to the way financial and technological factors impact on reserves measurement, it is worth reviewing the types of reserves classifications that ultimately lead to KPI and valuation.

Getting a Slice of the Pie

It is worth distinguishing between the oil and gas resource and reserves. The 'global resource' is the 'size of the pie' or the entirety of the earth's oil and gas. The slice of this pie that is recoverable using today's technology at today's cost—price structure is known as 'global proved reserves'. According to BP's Statistical Review 2008, worldwide proved reserves of oil are 1.238 trillion barrels (see Figure 1 opposite) and those of gas are 6.263 trillion cubic feet (see Figure 2). The US Geological Survey, however, places the global resource of oil initially in place at 3 trillion barrels. We will come back to the size of the pie in the context of peak oil; however, for now it is worth noting that reserves are ranked based on their ultimate probability of production. That is to say one day in the future they will be brought to surface and sold*.

Once the resource is discovered, reserves need to be booked. This process involves mapping out and visualising one or more underground structures (leads or prospects) that may extend over 200 square miles. Reserves must then be classified and assigned values according to the probability of their production. Finally, the value

* Despite operations being integrated, it is the E & P department of a Major or NOC that operates the reserves classifications and not refining and marketing which are in fact separate business lines.

Figure 1 - The Total Size of the Oil Resource is 3.012 Trillion Barrels (EPRasheed)

Figure 2 - The Total Size of the Gas Resource is 15.401 Trillion Cubic Feet (EPRasheed)

of reserves are discounted to today's worth. For financial and asset planning purposes, the key determinants are the likely size of discovered reserves and their ease of recovery[10].

The most common classifications are the generic three 'Ps' and the more specific 'P factor'.

The Three 'Ps'

Defined according to a sliding scale of the 'probability' or percentage chance of production, the three 'Ps'—Proved, Probable and Possible—are illustrated by the figure below. They indicate the relative ease or difficulty with which the reserves in question can be produced. It is standard practice for a numerical 'P factor' to be assigned to represent the specific probability of the reserves being produced. Typically, 'P' values for ultimate recovery range from P90 for a very high probability, P50 for medium probability and P10 for a very low probability. A series of questions related to location, accessibility and technology need to be answered before 'P' values can be ascertained. Are the reserves located in easily accessible areas or shallow depths? Are there wells, platforms or pipelines in place? Does the technology exist to reach the reserves today? If the answer is 'yes' to these questions, the probability of production is clearly high so these are proved reserves. Where the answer is 'no' and nothing is in place other than outline plans, such reserves are low probability. Most reserves will fall between these two extremes in that they have varying degrees of infrastructure in place.

Corresponding to a value, i.e. P 90, P 50 or P 10, the 'P factor' simply represents the percentage chance of reserves being produced. Proved is 90%, Probable is 50% and Possible is 10%[11].

This classification uses a scale based on the development status, the infrastructure in place and the ease of recovery of oil and gas. Reserves that score lower on development status and infrastructure are harder to develop so their percentage chance of recovery falls; therefore, they are assigned a lower 'P' class with a lower 'P' value.

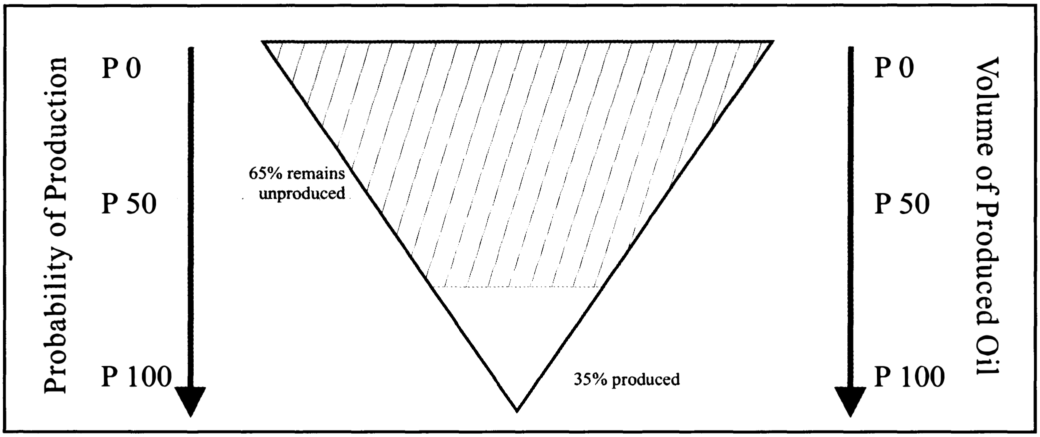

Figure 3 - The Relationship Between Probability and Volume of Oil Production (EPRasheed)

'Proved reserves' refer to the estimated quantities of crude oil, natural gas and Natural Gas Liquids (NGLs) which can be recovered with demonstrable certainty using geological and engineering data. This applies, for example, to future production from known reservoirs under existing economic and operating conditions, i.e., oil prices and lifting costs as of the date the estimate is made.

Reservoirs are considered 'proved' if economic production is supported by actual production or conclusive formation tests showing an increase in production. The area of a reservoir considered proved includes: the portion identified by drilling and defined by gas-oil and/or oil-water contacts and the immediately adjacent areas not yet drilled, but which can be reasonably expected as economically productive based on the available geological and engineering data[12].

Reserves which can be produced economically through improved recovery techniques (such as water injection to maintain reservoir pressure) are included in the 'proved' classification when an increase in production is seen. Estimates of proved reserves do not include the following: oil that may be produced from known reservoirs but is classified separately as 'indicated additional reserves'; crude oil, natural gas, and NGLs, the recovery of which is subject to uncertainty as to geological, reservoir characteristics, or economic factors; crude oil, natural gas, and NGLs that may occur in undrilled prospects; and, crude oil, natural gas, and NGLs that may be recovered from unconventional sources such as oil shales.

Further distinctions blur the boundaries between classes; for example, 'proved developed reserves' refers to reserves that can be recovered from existing wells using existing technology. Additional oil and gas production obtained through the application of improved recovery techniques can be included as 'proved developed reserves' only after successful testing. Tests can either be pilot projects or improved applications that show an actual increase in production.

'Proved undeveloped reserves' are reserves that are recoverable from new wells on undrilled acreage, or from existing wells where further major expenditure is required. Reserves on undrilled acreage are usually limited to those areas where there is reasonable certainty of production when drilled. Proved reserves for other undrilled units can only be claimed where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

Russian and Norwegian Reserves Classification

Russian and Western methods of estimation and classification of reserves are somewhat different. The Russian officials have divided oil and gas reserves into six classes: A, B, C_1, C_2, D_1 and D_2. Class A represents proven reserves and B provable reserves. Class C_1 represents reserves estimated by means of drilling and individual tests, and C_2 reserves are based on seismic exploration. Classes D_1 and D_2 represent hypothetical and speculative reserves[13].

Norway uses its own definitions of reserves, which run from Category 0 – 9[14].

Category 0 is defined as 'Petroleum resources in deposits that have been produced and have passed the reserves reference point. It includes quantities from fields in production as well as from fields that have been permanently closed down'.

Category 9 includes resources in leads and unmapped resources and covers undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated[15].

Geologic Assessment Procedures

Oil companies often use models to assess geologic structures or oil and gas plays. A common model defines a play as 'a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration patterns, timing, trapping mechanisms, and hydrocarbon types'.

Oil companies use this approach to process exploration knowledge such as seismic or aerial surveys or wildcats generated by the exploration teams. A fundamental part of this process is the attributing of probabilities for each petroleum play. Geologists will also assign subjective probability distributions to characterise attributes of undiscovered conventional oil and gas accumulations[16].

The geologic risk structure is modelled by assigning a probability to each play. This probability is based on at least one accumulation meeting the minimum size requirements (50 MMBO in place or 250 BCF gas recoverable). In particular, the oil company will assign probability distributions for reservoir attributes such as net reservoir thickness, area of closure, porosity and trap fill.

Net pay estimates are derived from the data and include the extent and distribution of the reservoir. These estimates are essentially refined and related to P values, i.e. P90, and are verified to see whether they are consistent with existing knowledge. Other factors to be considered will be hydrocarbon recovery factor, porosity and permeability forecasts and initial production[17].

Peak Oil and Medieval Maps

Since the publication of Hubbert's Peak in 1956, the theory of 'peak-oil' has gained in importance with a growing chorus of support from within the industry and wider society. Yet is peak oil really a physical decline in production levels or is it a philosophical debate mired in the minutiae of reserves and production systems?

To answer these questions, we need to adopt a global E & P perspective that integrates prospective E & P areas with technology applications. Equally we need to recognise the limits of conventional wisdom. Are we navigating with a 'medieval map' of worldwide hydrocarbon reserves—one that does not adequately reflect the total resource?[18].

Figure 4 - The Americas Do Not Exist According to Medieval Maps

Optimist or Pessimist?

Two schools of thought exist. Optimists state there is an abundance of oil and gas and that there is enough for everyone, while pessimists state there is a deficit and we are doomed. These two positions, and the consequent debate, have generated much emotion, not to mention a multi-million dollar niche industry. What appears to be important here is that no-one disagrees that a peak or decline will occur, that is the natural state of systems. Yet, no-one can agree on when or even why this event will occur. It is worth considering this debate as it can help us understand the 'psychological' supply shortfall of prospects. This has a knock-on psychological effect on supply which is compounded by a herd mentality within the oil and gas markets (see *Chapter 12: Paper Barrels* for detail).

The pessimists reason as follows:

1. Rare conditions allow petroleum reserves to be produced.

2. Once production peaks, reserves decline rapidly in output.

3. Most global petroleum reserves have peaked. Further large finds are unlikely.

4. Global production is therefore declining[19].

The optimists argue:

1. Rare conditions allow petroleum reserves to be produced.

2. Production can be made to plateau, not peak, through technology.

3. Technology finds more reserves, makes smaller reserves more accessible and sustains overall production on a global scale.

4. Global production is therefore sustainable[20].

There is also a third, or alternative view, to consider:

1. Rare conditions allow petroleum reserves to be produced.

2. Today's theories regarding petroleum reserves and recoverability are incomplete.

3. Knowledge increases over time.

4. Many prospective petroleum plays are unexplored.

5. All known sources of petroleum systems have therefore not yet been quantified; hence, the use of the 'medieval map' analogy[21].

In this alternate scenario, no one can state categorically that peak oil has, or has not occurred because our current knowledge is incomplete. Just as when we look at medieval maps and note the Americas are missing, so future generations will look at today's map of worldwide reserves as incomplete. Just as when previously wise petroleum engineers looked at deepwater reserves and shook their heads deeming them unrecoverable, we see the limits of their wisdom.

Deepwater production has been made routine, almost mundane through 'game-changing' and cost-effective technology. This ranges from pre-drill packages that incorporate sub-salt imaging to seabed to surface risers to directional drilling techniques that can enable multiple reservoir completions.

In this way, the ultimate recoverability of reserves is tempered by the cost of technology. If E & P technology can be made available at cost-effective prices, reserves can be developed. This is because finding and lifting costs ultimately determine development. If the costs of development outweigh the price of oil, there simply is not enough profit to develop them.

As noted earlier, the SEC classifies reserves according to very narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. Peak oil theorists tend to use such classifications too.

Peak oil theorists tend to overlook the industry's track record of technology development. Technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond earnings.

This does not imply that petroleum is infinite. It means that even though petroleum is a finite and scarce resource, technology can increase production and ultimate recovery.

Aside from the technology factor, there is the question of the medieval map of reserves. As our globe-trotting exercise will show shortly, there are still several petroleum provinces waiting to be mapped out.

Given that demand for oil and gas will rise in the long-term, and considering the track record of the E & P industry to date, further advances in E & P technology will permit almost all petroleum reserves, irrespective of location, to be developed before new energy sources and exits from the Hydrocarbon Highway are created. Consequently, the limiting factor for reserves will be the cost of development rather than their shortage.

Worldwide Reserves

Referred to as 'the low hanging fruit' that is effortlessly picked, onshore basins are generally easy-to-access with low finding and lifting costs. Consequently, these reserves have been both extensively characterised and produced; however, several tough-to-reach onshore basins remain unexplored. Exemplifying this is the Amazon Complex (Brazil, Colombia, Peru and Bolivia), the Arctic Circle (the Alaska National Wildlife Reserve being part of this territory) and Antarctica*[22].

No one has any real knowledge on the potential size of these onshore reserves. The historic finding and lifting costs in similar areas such as Sakhalin or Alaska , however, range on average from US $12 to US $18. With production, total costs rise further due to a lack of infrastructure in remote areas (see *Chapter 8: Extreme E & P* for detail[23]).

Middle East

More prospective areas exist in unexplored basins within the Middle East such as the Empty Quarter (Rub Al Khali) in Saudi Arabia, the Bushehr province in Southern Iran and North and South Iraq. Typically, these countries are blessed with prolific source rock, high permeability and trapping systems found at very shallow depths starting at approximately 700 m (2,100 ft) and ranging to 2,000 m (6,000 ft). New ** finds* continue to maintain the Middle East as a dominant long-term reserve base, with common recognition that Saudi Arabia and Iran respectively are the world's largest and second largest holders of light oil reserves. Further, finding, lifting and production costs are the lowest worldwide, averaging between US $1 to US $3 a barrel[24].

Lifting costs can vary, however, by way of comparison. In other relatively low-cost areas like Malaysia and Oman, lifting costs can range from US $3 to US $12 a barrel to produce. Production costs in Mexico and Russia might potentially be as low as US $6 to US $12 per barrel (higher under current production arrangements by local companies)[25].

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* Antarctica is the third-smallest continent after Europe and Australia; 98% of it is covered in ice and will not be developed until 2048. The call for an environmental protocol to the Antarctic Treaty came after scientists discovered large deposits of natural resources such as coal, natural gas and offshore oil reserves in the early 1980s.

By reviewing the world's prospective shallow coastal waters, deltas and oceans, it becomes clear that our map of global resources is incomplete. In the offshore realm, there are many unexplored basins with finding, lifting and production costs varying from US $18 to US $25 per barrel for certain deeper waters. Large tracts off the coast of West and North Africa are undeveloped. The West African margin has been extended from the high-profile plays in the shallow waters of the Niger Delta, Nigeria and the Congo Basin, Angola to deeper waters and to highly prospective sub-salt plays. Mauritania and Tanzania are other examples where new discoveries have been made[26].

South of Australia in Tasmania, oil companies have been studying gas plays since 2000 which had previously been neglected due to the search for oil. This has led to indications of oil being found in Africa near Madagascar, which has been identified as a potential new petroleum province[27]. Mauritania and Tanzania are other examples where new African discoveries have been made. Another area is offshore Morocco, where the deposition of an ancient river system was found over salt. A mobile substrate, either salt or shale, is a key element all along the West African margin because it provides geological factors necessary for oil and gas[28].

Continental Plate Reconstruction

A clear example of continental plate reconstruction and conjugate oil and gas of plays is offshore West Africa and offshore Brazil. By using reconstructions, it can be seen that the Rio Muni Basin was the 'mirror' basin to the Sergipe-Alagoas Basin in Brazil, and the Congo Basin to the Campos Basin. By repeating this process along the coast of West Africa and Brazil, several emerging oil and gas plays can be drawn up. These include the sub-salt frontiers of offshore Brazil including Tupi. Although production is not likely to make a major impact on world oil exports over the next decade, the point is that new frontiers have been discovered[29].

In Central America, the offshore area between Venezuela and Trinidad, the Gulf of Paria, is largely unexplored as are the waters off Colombia and Peru[30].

The Gulf of Mexico (GOM) has unexplored waters that stretch from the shallow waters off Florida, US and move into the territorial GOM waters of Cuba, vast areas of deep waters in the Mexican GOM and the deeper waters of the US GOM. Within the US GOM, the sub-salt play has been instrumental in new finds.

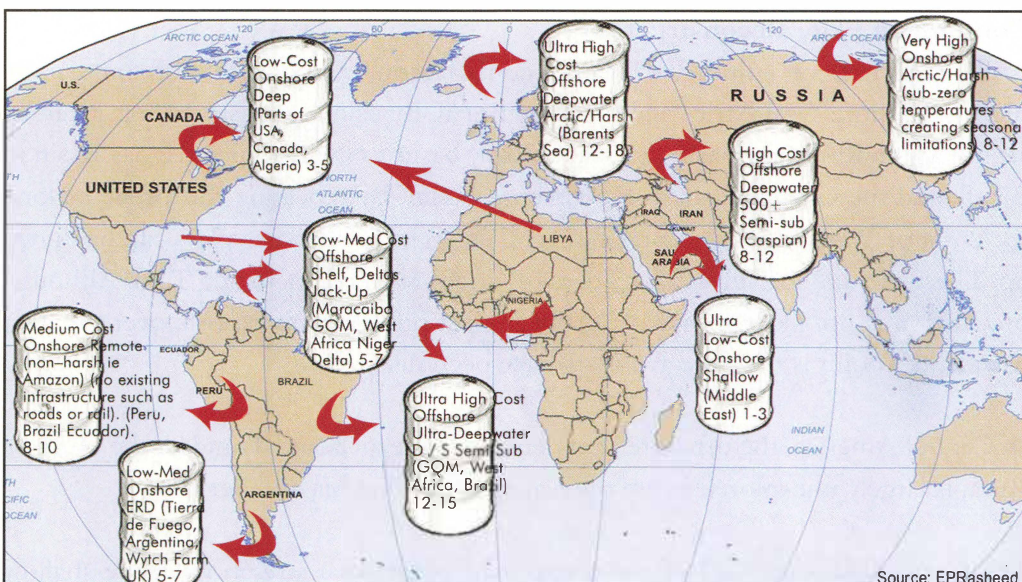
Offshore production in areas like the North Sea with offshore platforms, can run to US $12 to US $18 a barrel. As reservoirs become smaller, those costs tend to rise. In Texas and other US and Canadian fields, where deep wells and small reservoirs make production especially expensive, costs can run above US $20 a barrel.

Further East, we note that certain areas of the Northern North Sea and the Barents Sea are still to be explored. While in Russia, Sakhalin Island, the Central Asian Republics, the Red Sea, the Persian Gulf, the Indian Ocean, Offshore Australia and New Zealand, several offshore basins represent prospective yet unexplored areas[31].

What is the total resource base? The US Geological Survey puts this at 3 trillion barrels of oil. Again, it's hard to say because we are still waiting to finalise the map.

Sweating

The Finding and Development in Figure 5 clearly shows that, when crude oil prices fall below US $20 a barrel, many areas become unprofitable and production is reduced if not halted altogether. Only certain lower cost areas can remain profitable and hence maintain production during a 'good sweating' period[32].



Note: Not included are development, lifting costs or production taxes/sharing agreement quotas. Based on several wells incl. 3D and sidetracks. Total depths vary. Deepwater includes adverse drilling challenges such as salt, tight ppfg, close tolerance casing and EPS early production system. Figures will vary depending on reservoir size. Does not include processing costs for heavy oil below 18 degree API which are by order of magnitude higher.

Figure 5 - Finding Costs for Oil Companies in US $

Two factors emerge from this globe-trotting exercise: first, there is a lack of characterisation in many highly prospective basins and gulfs; and second, there is high prospectivity, but it is tempered by technical limitations and increased costs.

None of these areas is mature; most are unexplored and some are even unlicensed. This is despite adjoining proven hydrocarbon producing basins or sharing geological characteristics such as source rock, trapping and faulting. It is fair to say that we have not yet characterised the world's oil and gas basins nor their accompanying reserves. Consequently, how can we even assume that global peak oil production has occurred? (Gas is another matter entirely as it can be man-made).

Conventional Wisdom and the Limits of Our Map

The limitations of our map of oil and gas reserves start to become clear when we consider past theories. In the 1990s, one widely held view stated that offshore oil and gas reserves would not be found at extreme conditions, i.e. depths exceeding a TVD of 20,000 ft (6,096 m). It was suggested that overburden pressures would either cause a loss of hydrocarbons due to migration to shallower traps or compaction[33]. Now that theory has changed because oil and gas trends have been located at far greater depths than prior knowledge would indicate. Think deep gas, US GOM.

In the 1980s, another example of a change in thinking occurred concerning the flow paths of fluvial deposition. Ancient river systems account for the sedimentation that leads to accumulations of oil and gas. In river deltas worldwide, as the shallow water plays were developed, exploration efforts evolved into the deepwater usually with only major international oil companies that could qualify for the blocks[34].

Smaller oil companies, therefore, were limited to exploring other geologic scenarios and plays. They recognised that over time the places where these river systems had been depositing sediment had changed, and the Independents' exploration discovered 'new' margins.

Another example of limited knowledge has been sub-salt basins. These have been discovered and are being explored in the GOM and worldwide. Sub-salt plays in West Africa, Brazil and GOM show deeper accumulations of oil and gas trends that had not been predicted or expected earlier.

Game-Changing Technology

Back in the late 1980s, it was thought that development of thin sands such as 'Norwegian Troll oil' would never be economically feasible, because the oil reserves were so thinly layered and the price of oil was US $10 per barrel. Game-changing technology such as 3D seismic improved the visualisation of reserves, while horizontal drilling and geosteering altered the definition of what was deemed uneconomic or unreachable at a given time. The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable. Service companies and operators develop technology in-house through joint industry projects and with best-in-class companies; for example, Shell and Petrobras respectively are involved in the monobore and the Procap 3000 initiatives—two examples of technology cascading downward. Underlying the monobore (a vision of drilling and casing a single-diameter well from top to bottom) is the creation of businesses to develop the downhole tools, tubes and markets for expandable tubulars. Procap 3000, a range of exploration and production technologies, is paving the way in ultra-deepwater development. Drilling contractors have introduced simultaneous drilling and completion of two wells by way of the dual-activity derrick system[35].

Technology

Scarcity of oil reserves and increasing reserve replacement costs are the twin factors that have accelerated the technological evolution of E & P and enabled extreme E & P (see *Chapter 8: Extreme E & P*). This evolution is most clearly visualised in the dramatic shift from onshore to offshore exploration. The incredible depth progression from land to shallow coastal waters to deep waters to the extremes of ultra-deepwater is shown in the graphic below[36].

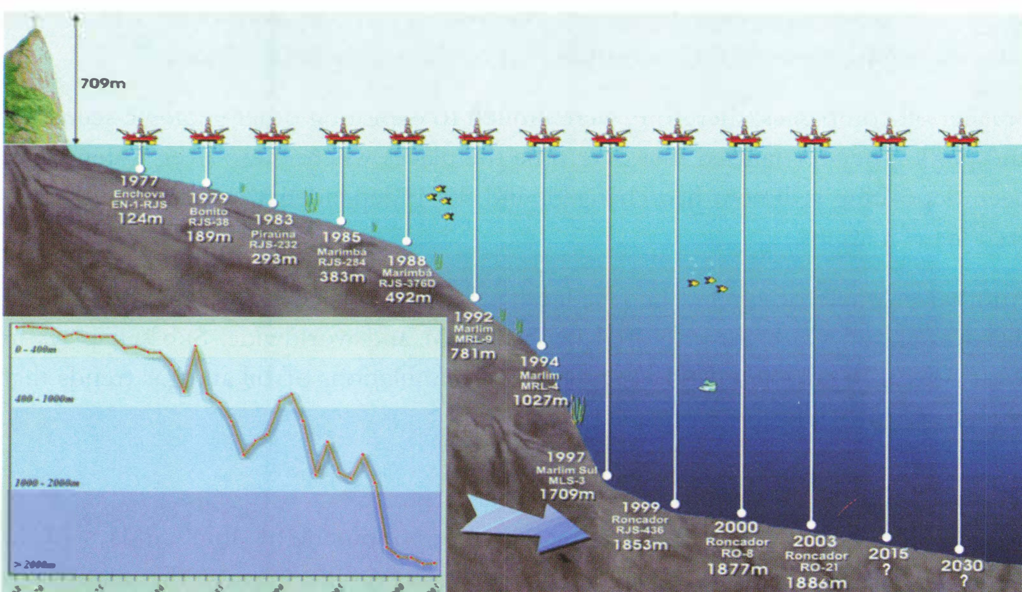


Figure 6 - The Incredible Depth Progression from Shelf to Deep Waters (Petrobras News Agency)

A few decades ago, it was not considered possible to produce in waters beyond 6,561 ft (2,000 m) depth, and accordingly, those reserves were listed as 'P 10s' with a very low possibility of production. Rigs and risers were just some of the incredible challenges. The industry has, however, progressively tapped deepwater accumulations. First, it targeted shallow onshore reserves as the less challenging 'low-hanging fruit'. As those resources became scarcer, E & P went deeper onshore and spread to shallow offshore waters. E & P operations in 8,200 ft (2,500 m) water depth are routine, and the challenge now is 9,842 ft (3,000 m) and deeper.

Records are continually set and broken not just in deeper water depths (3,000 m) but also in deep reservoirs below salt domes, tar zones and in the remote basins of the world and in new frontiers. This includes the latest subsea water separation systems and subsea sand separation to achieve maximum production. Remarkably, however, almost all of this enabling E & P technology is considered an outsourced commodity marketed by service and supply companies, which means the NOCs have no shortage of technology vendors. The buzzwords of 'ultra-deepwater, digital oilfield and barrel-chasing' may first be heard in oil company offices due to the engineering challenges and risks oil companies 'buy'. They resonate most loudly, however, throughout the service-side: in product development, in research facilities and on test rigs before technology is commercially run in field applications[37].

In addition to developing the technology to drill in deeper waters, the industry has developed the ability to drill extreme offsets from a single surface location. This has profound implications in reducing our environmental 'footprint' and providing economic access to thousands of 'satellite fields'. As of 2008, the world's record Extended Reach Drilling (ERD) well was drilled in the Persian Gulf from a jack-up drilling rig. The total measured depth of the well was 40,320 ft (12,293 m), and the well's bottom was offset 37,956 ft (11,572 m) from its surface location. In the UK, ERD techniques enabled BP to develop Wytch Farm, an entire oil field under an environmentally sensitive resort and vacation area on the south coast of England, with no visible footprint. Off Sakhalin Island in far east Siberia, Russian companies are exploiting oil reservoirs from land by drilling ERD wells out under sea ice that would ordinarily damage offshore facilities.

These feats were inconceivable to Hubbert when he developed his peak oil theory. Hubbert was correct to state that oil is a finite resource—and he can't be blamed for letting a medieval mentality affect his prediction of when we would run out. People today who are still letting medieval thinking guide them, however, should know better.

What emerges from the peak oil debate is that we are reading the directions to worldwide reserves from a 'medieval map'. Clearly, there are new frontiers and plays to be developed. Think Subsalt, Arctic and Deepwater E & P which is changing the definition of P 10's into P 90's. Coupling this with innovative thinking and cutting-edge technology makes for a convincing argument; peak oil as far as reserves are concerned, is a philosophical debate rooted in a psychological shortage not a physical one.

We are not in fact running out of oil. We have many areas yet to explore before we have to worry about oil and gas shortages. As we have been shown, there are plenty of barrels of oil remaining. The next logical question then would be 'What is in a barrel of oil?' Everyone always talks about barrels, but no really talks about their composition or how this affects recovery.