Extreme E&P

Tough-to-Produce Reserves

Worldwide, the exploration objective is clear: locate new frontiers and reserves. Every new frontier, however, brings new problems that are not always easy to predict. In this chapter, we look at the development of oil and gas reserves that are tough-to-produce due to their location in extreme environments*.

It is fashionable these days to use different labels to distinguish particular types of drilling: Arctic, deepwater, and High Pressure High Temperature (HPHT) practices. The common denominator of all drilling activities is the management of people, technology and processes. Customs, environmental, and legal issues also exist as does the detail of prospect selection. That's fine.

This logistical labyrinth is essentially the same whether you're sitting in a company man's office in offshore Angola or onshore Azerbaijan. Technology applications aren't necessarily exclusive to deepwater either. Smart completions using fibre optics and satellite communications are enabling the production of multiple zones

* The definition of tough to produce encompasses tough-to-reach or tough-to-access locations such as the Arctic, deepwater or hard to reach marginal reservoirs and hard to produce viscous oils. Within this definition, we are concerned with conventional oil and gas (above 13° API)[1]. We stop short of considering oil shales and gas hydrates as tough-to-produce.

to be commingled and controlled. Acidisation through water injection lines permits live well intervention without skidding land rigs. New gravel packing and filtering techniques can be used to control sand production in shelf fields. In fact, it seems an equally compelling case can be made for technology to be used in onshore or shelf locations to improve marginal economics as can be made for deepwater operations.[2].

So what are the differences behind the drilling labels? Let's look at them.

Location

'Location, location, location'. The mantra of property gurus could equally be applied to oil and gas reserves. After all, location determines the ease or difficulty with which reserves can be accessed and this in turn is a major determinant of finding and lifting costs.

Clearly, access to oil and gas reservoirs is restricted in extreme environments. In Arctic areas, it is restricted due to severe seasonal weather conditions. Alaskan Arctic exploration, which mostly involves onshore projects, is restricted by the access to the tundra and the conditions that enable ice roads to be constructed over the permafrost or across the shallow coastal waters to get to the exploration sites. In deepwater, restrictions are created by increased water depth. HPHT Temperature conditions restrict access in other locations. Perhaps, the most difficult combination for oil and gas E&P, is the well-from-hell—a combination of an Arctic, deepwater and HPHT well.

In this way, a sliding scale of costs exists—from the deepwater Arctic wildcat (with HPHT contingency) to deepwater to the Arctic to deep shelf HPHT or deep onshore. Adding to the location issue are government regulations restricting vast areas of land onshore or offshore from drilling activity on environmental or public opinion grounds. The State of Oklahoma used to be proud of the fact that it had a pumping oil well on the property also occupied by the State Capitol building. Such a thing would be unthinkable today. Fortunately, extended reach drilling technology has alleviated many of these types of problems. The famous THUMS manmade islands offshore from long beach, California were constructed by a consortium of oil companies: Texaco, Humble (now Exxon), Union, Mobil and Signal. From the beach they looked like beautiful semi-tropical islands housing luxury condominiums. In fact, the 'condos' concealed drilling rigs and the outbuildings concealed production facilities. Similar 'Hollywood' tactics were employed in downtown Los Angeles, where drilling rigs in soundproofed building shells were sited along famous Sunset Boulevard, unseen and unknown by the general population. Wells from these sites were directionally-drilled outward for thousands of feet to tap prolific oil reservoirs under the city.

E&P Finding and Lifting Costs

The finding and lifting costs table shows how E&P tough-to-produce environments cost more. Technically challenging environments create a series of engineering, technical and financial needs that do not exist with easier-to-access counterparts. These needs range from higher-rated equipment, such as upgraded or specialised rigs, as well as dedicated field development techniques. Wildcats or poorly characterised conditions create contingency scenarios. In these cases, a single well plan will have several casing and completion contingencies which must all be budgeted[3]. Contingencies can include HPHT conditions or tight Pore-Pressure/Fracture Gradient (PPFG) windows creating the need for revised casing depths and increased casing strings[4].

Seasonal challenges such as those associated with offshore Arctic conditions will also create technical and financial challenges due to a narrow window for operations before they are interrupted by ice formations[5].

Keeping Costs Down

Undoubtedly, deeper water environments add greater cost and complexity to operations; however, these expenses can be cut in three ways.

Firstly, you could simplify the well design. Well trajectories should not only be compared in terms of how effectively targets are reached, but also on their overall cost effectiveness. Secondly, you could reduce the number of casing strings. Casing can be set deeper, based on real-time pore pressure and fracture gradient detection. Accurate prediction will reduce contingency casing. Offset data can help to refine pore pressure models and enhanced pore pressure detection will make the best of the casing program while drilling. Modeling steady and dynamic state fluid behavior will reduce surprises. Last but not least, costs can be cut by contracting 'fit-for-purpose' technology, especially on rigs. (See Chapter 7 Pregnant Ladies Cost Reduction Case Study)

Simplified well design may be possible based on setting casing deeper. Real-time pore pressure and fracture gradient detection and prediction reduces the number of contingency strings. Eliminating casing strings by taking calculated risks during well construction can reduce mechanical risks and lower costs. Where offset data exists, more accurate pore pressure models can be constructed. Enhanced pore pressure detection will optimise the casing programme during drilling and will reduce costs. Logistics and importation issues should be fully understood as this can reduce the need for pre-deployment of contingency equipment. All of these opportunities, combined with adequate planning processes, time and resources will cut costs[6].

Arctic Seismic

Acquiring and interpreting geophysical data helps reduce some of the risk associated with exploration. In Arctic environments, logistical and technical challenges accompany seismic. Shooting seismic data can only be conducted within a seasonal window of good weather (usually three to six months). Interpreting seismic data is also challenging as seismic must penetrate thick sheets of permafrost (in rare cases up to 1000 m) which creates noise and weathering problems and ultimately interferes with attribute analysis and structural imaging[7].

Deepwater Seismic

Geotechnical and oceanographic data supplies exploratory deepwater asset teams with seabed and water column information which is necessary for well construction and production activities[8]. Getting deepwater seismic is, however, very difficult. In the case of deepwater frontier drilling—wildcats—oil companies must also perform what are at times unprecedented seismic programs. This has led oil companies to initiate various projects to refine oceanographic data from deepwater basins. Comprising geo-hazard assessment, geo-technical characterisation and slope stability, these projects help identify and characterise potential geo-hazards. The aim of the geo-technical characterisation and slope stability analysis is to investigate seabed sedimentary properties and to model slope stability through surveys and integrated geological data. Reservoir and production engineers use data such as seabed and water column to optimise production[9].

Other projects include exploratory seismic 3D, high resolution sonar and bathymetry. Exploratory 3D seismic is used for rendering seafloor and underlying structures while the seafloor texture is mapped by sonar. Cores are used to 'ground-truth' geophysical interpretation and date geological events[10].

In certain deepwater basins, studies concentrate on mapping salt structures and seeing what lies beneath them. Active salt tectonics play an important role in shaping the seafloor and salt-induced topography and fluid seepage are investigated. Continental slopes may be the focus of geo-hazard assessment, while oceanic current-induced seabed erosion may also be studied[11].

Further oceanographic data will also be acquired using satellite images, Sea Surface Temperature (SST), Sea Surface Height (SSH) and radar data. This information, along with pre-existing data, will validate oceanic circulation numerical models. As a result, extreme currents will be analysed to identify instabilities. In this way, a picture of the deepwater operation is built-up and incorporated into an in-house database that can be queried.

Oceanographers know that the sea can be a complex environment with temperature inversions and subsea loop currents at different levels and in different directions. Deepwater offshore structures, for example, are the victims of Vortex-Induced Vibration (VIV) caused by sea currents interacting with tubular riser pipes. Unchecked, this VIV can totally destroy a production riser in a matter of a few days or hours. Oceanic currents affect the velocity of seismic waves, and if unaccounted for, can produce erroneous results when the seismic section is interpreted[12].

Deepwater Wildcats

Deepwater portfolios are important for the long-term renewal reserves especially for International Oil Companies. Basins in offshore areas such as West Africa, the Caspian Sea, Gulf of Mexico (GOM) and Eastern Brazil are very highly sought after production opportunities for this reason.

Irrespective of resources or experience, however, picking and drilling deepwater prospects is tough. Imagine having to pick and drill two wells from within an unexplored area of 9000 sq mi (25000 sq km—equivalent to 1000 GOM blocks)[13].

With the potential *dryhole* risk in mind, IOCs will seek to reduce risk by entering into agreements with other oil companies before exploring. Many of these partners will be companies that have similar concessions and can bring technical know-how to the deal.

Organisational Challenge

In order to deliver wildcat wells in frontier regions, oil companies need to manage different working cultures, languages and physical locations. They will have to work through many issues with local government, customs, environmental, and legislative bodies. They will also have to agree on prospect selection with their oil and gas partners.

Enrolling and focusing the drilling team is often achieved through 'Training to Reduce Unscheduled Events' and 'Drill the Well On Paper' exercises. Major changes, however, can take place during operations; for example, prospects and contractors can be changed. Problems with equipment or facilities can also cause major delays. With a high-end rig on rental, these costs can quickly eat through the largest of budgets. Success in dealing with these late changes depends mostly on the support that the oil companies receive from sister deepwater teams[14].

Planning Exploration

With frontier locations, it is often the case that little or no infrastructure is in place. This means that many challenges associated with the frontiers' remoteness must be assessed and overcome. This can include setting up onshore supply bases, access routes and overcoming the logistical issues associated with the equipment and services required for E&P.

Poor transport links means that look-ahead logistics and transport options will be critical to success. Potential importation delays can also be problematic, but with good planning they can be avoided.

Rig selection will be influenced by the strength of offshore currents, environmental requirements and other challenges such as Arctic conditions. In order to ensure rigs will be capable of meeting operating conditions, potential high current studies or the impact of floating ice are carried out. Research will show whether the rig will be capable of maintaining station and whether or not VIV suppression is a requirement. In all parts of the world, environmental considerations are important, and if not properly addressed, delays in obtaining a drilling permit can result.

Health, Safety and Environment (HSE) and Drilling Performance

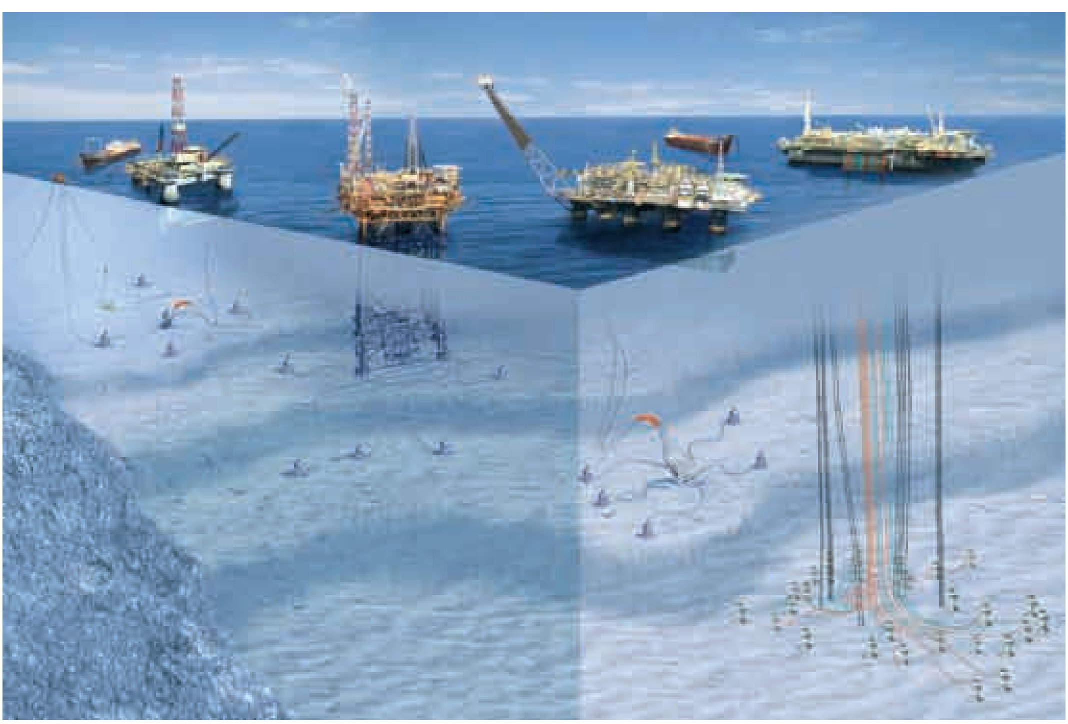
From a safety and environmental standpoint, drilling will be completed without significant environmental damage, while a measurement of a safety 'Day Away From Work Case' (DAFWC) will be recorded and will highlight the importance of conducting proper risk assessments. Performance will be measured and key criteria assessed such as days per ten thousand feet and Non-Productive time (NPT).

Deepwater Development

Poised to produce hydrocarbons in waters reaching 10,000-ft (3049 m), the industry is certainly not standing still regarding deepwater. The future is clear. Many billions of barrels of oil and gas reserves lie in deep, 3280 ft to 8200-ft (1000 to 2500 m), and ultra-deepwaters (8200 ft+ or 2500m +). As the industry looks to production in 10,000-ft (3000 +m) water depth, we consider two key questions: what are the unique considerations for deepwater developments and what special technologies are required for production[15]?

Water Depth[16]

What really differentiates and impacts deepwater activities are the challenges associated with incredible sea depths. Of course, block size in deepwater frontier areas such as Brazil can reach huge proportions; for example, 25,000 sq km (that's 1000 GOM blocks). This makes picking and drilling prospects tough, irrespective of operator resources or experience; however, it is greater water depth that leads to higher pressures and overburden and that's where the problems arise. The drilling engineer has to consider and overcome bottomhole pressures that can exceed 22,000 pounds per square inch (psi) and drilling fluid line temperatures that can fall below zero degrees Celsius.



So where is the deepwater line drawn? According to Petrobras, waters between 3280 ft to 6560 ft (1000 m to 2000 m) depth are classified as 'deep'. Beyond this are the ultra deepwaters which are about 11,480 ft (3500 m) for the present. Definitions aside, deeper seas mean deeper pockets[17].

Deepwaters are characterised by strong currents, which create a need for high specification rigs that are capable of maintaining station and in some instances of suppressing VIV. Such rigs are expensive. Contracting one in the GOM can cost a cool US $500,000 per day or more.

Under Pressure

Deepwaters are also characterised by young depositional formations that differ from shelf and onshore scenarios. Exemplifying this is the typically narrow window between Pore Pressures and Fracture Gradient (PPFG). Low fracture gradients can necessitate lighter drilling fluids and lighter cement slurry, while rising pore pressures can often upset the delicate fracture gradient destabilising the well-bore and jeopardising the section, if not the entire well.

A consequence of a narrow PPFG window is the need for close tolerance and contingency casing schemes to isolate formations. In short, deepwater operators must have an excellent knowledge of well bore stability to avoid a formation influx (kick) or a fracture of the casing shoe, which would result in losses. New well construction methods are being developed for just such an eventuality. These include the 'dual gradient system'. Oil companies are presently sponsoring a Joint Industry Project (JIP) that develops a subsea pump to control the pressure at the wellhead and study gas injection systems. For this technology to work, risers must be resistant to collapse forces as soon as gas is injected into their bases[18].

Temperature Gradients

Further engineering challenges are added by temperature gradients. A negative gradient runs from surface to seafloor, but this turns positive below the mud line. Equations become more complicated as cooler surface mud alters the temperature profile as it is pumped downhole, while gas hydrate formation is a common problem that is difficult to resolve. Hydrates trap natural gas inside water molecules and bond with metal. This can result in tubing blockages which affect the valve and Blowout Preventer (BOP) operation. Unfortunately, deepwater environments present the ideal combination of low temperatures, high seabed pressures, gas and water that cause hydrate formation. Extensive modeling is required to minimise hydrate formation. Low temperatures alter the properties of cement which mean new designs of cement slurry composition are required. Existing American Petroleum Institute (API) norms do not cover low deepwater temperatures and stringent test procedures are now determining the properties of cement slurries in deepwater operating conditions[19].

Riser Manipulation

Riser manipulation is another challenge found in ultra deepwaters and beyond. Research is being carried out on innovative lightweight risers. By reducing the weight of the risers and their joints, it should be possible to use lower cost fit-for-purpose rigs in ultra deepwater. A parallel technology that has been developed is the 'Slender Well' concept to permit the use of smaller diameter well bores and lighter risers. .

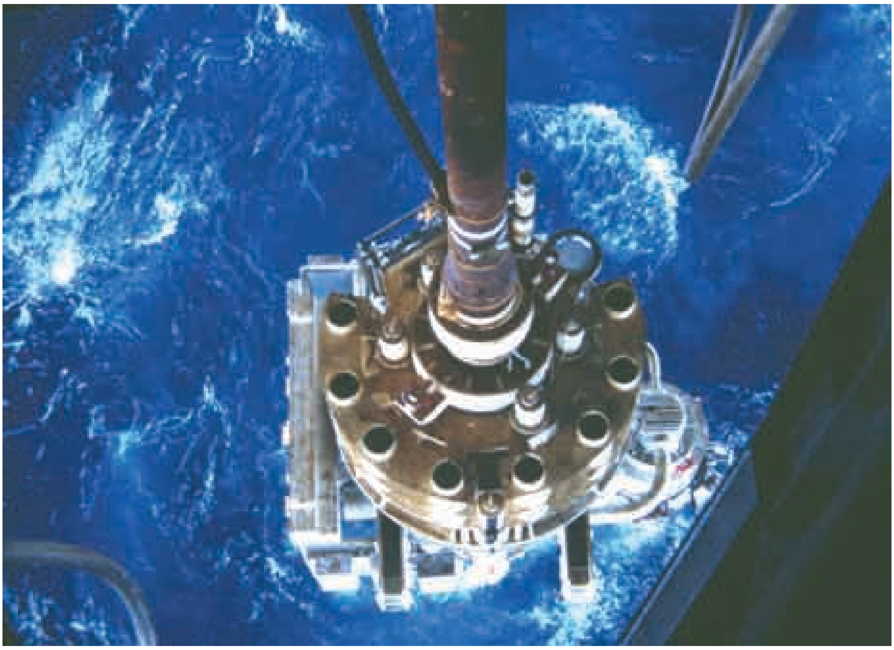
The constant development of new subsea equipment is a must in order to meet new water depth challenges while keeping costs low.

Major limitations associated with ultra deepwater developments which are associated with very expensive day rates include high installation loads of subsea equipment and high flow rate subsea wells. 'Drill-Pipe-Risers' have been used to perform completions and workovers at water depths reaching 6,860-ft (2,000 m) and although they are far more efficient than conventional risers, control umbilicals and hang-off equipment presented problems in 10,000 ft (3,000 m) water depths.

Control umbilicals require careful handling, particularly during the tubing hanger mode when the hanger has to be deployed inside the marine riser.

Mooring mechanisms that will function in greater water depths are also a challenge. Design software must be able to check a specific mooring system's calculations and determine the validity of truncated scale tests as well as modelling mooring systems.

Extended Reach Development (ERD) wells are being successfully drilled in deeper waters. ERD wells offer the ability to reach complex targets and present good thermal flow pipeline properties which are important in deepwater scenarios due to negative temperature gradients. Widely spaced reservoir targets can be tapped using a single well bore, thereby reducing environmental impact and well construction



costs. Because less heat is lost through the pipeline, average flow temperatures are kept higher which reduces hydrate and wax formation and ultimately maintain production rates. Alternatively, costly heated subsea pipelines are required.

Intelligent completions are improving hydrocarbon production from both ERD and multilateral wells. With the emphasis on reservoir management to optimise performance and maximise recovery, the likelihood for costly well intervention is reduced. Coupled with this is the deepwater gas lift optimisation project, which addresses the software, equipment and automated processes required for gas lift design.

Deepwater subsea completions often present major problems, especially with the completion riser. As a result, a lightweight composite drilling riser joint is being used with conventional risers up to 2300 ft (700 m) water depth. More research is necessary, but results have been promising. Production risers, subsea wellhead sand other production equipment designed specifically for deeper water depths and differing rig types are just some of the technologies being developed[20].

Deepwater Flow Assurance

Companies are developing inter-related technologies capable of predicting and preventing sub-sea flow lines and pipelines from getting blocked. The technologies here

range from low-density foam cleaners to mechanical pigs to tractors for wax or hydrate plug removal.

Arctic E&P

Arctic E&P is a term that is generally applied to fields that are located within the Polar or Arctic Circle which extends from Russia, Finland, Sweden, Denmark, Norway, Canada and Alaska (US). This territory also covers offshore areas such as the Sea of Okhotsk, Sakhalin Island, the Beaufort Sea and the Barents Sea.

Antarctica is the third-smallest continent after Europe and Australia; 98% of it is covered in ice and is bound not to be developed until 2048 and therefore is not considered. 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.

As one would expect, offshore Arctic E&P is heavily constrained by harsh weather conditions. The offshore Arctic is characterised by the ice period during which time no operations can take place. In Alaska, where the exploration is predominantly on land, getting access to the tundra locations is actually dependent on ice and snow cover so as to avoid damage to the permafrost. Exemplifying this is the Sea of

Okhotsk which is routinely subjected to dangerous storm winds, severe waves, floating ice, icing of vessels, intense snowfalls and poor visibility. The average annual extreme low ranges between -32°C and -35°C. Ice sheets up to 5 ft (1.5 m) thick move at speeds of one to two knots. Operations in the Barents Sea need to contend with drifting sea ice, icebergs and long transportation distances[21].

Offshore structures can be exposed to icing from October through to December and the ice period extends for six months. It is only during the following six months, or the ice-free period, that operations can take place. Even so, wave heights range between three ft and 10 ft (1 m and 3 m) and strong winds can cause even higher waves during the ice free period.

To combat such extreme conditions, operators must use beefed-up rigs and facilities. In the case of the Sakhalin development, engineers reconditioned the Molikpaq, an Arctic offshore drilling unit originally designed for use in the Beaufort Sea in North America, where ice conditions are more severe than offshore Sakhalin Island. The Piltun Astokhskoye field is developed by the Vityaz Production Complex. This consists of the newly refitted Molikpaq, a Single Anchor Leg Mooring (SALM) 1.25 mi (2 km) away and a Floating Storage and Offloading Cessel (FSO)[22].

Technical and environmental experts reconditioned the Molikpaq so that it could handle pack ice, the temperatures, and the strong waves in the Sea of Okhotsk. The Molikpaq required substantial modification to convert it from a drilling platform to a drilling and processing platform and it was towed 3600 nautical miles from the Beaufort Sea to the Okpo yard in South Korea. The redesign included major rig modifications including raising the height of the drilling unit by 16.4 ft (5 m) to create space for the wellheads and increasing the eight conductor slots to thirty-two. Cumulatively over seven work seasons since the first oil in 1999, the Molikpaq has produced over 70 million barrels of oil.

HTHP

HTHP wells are generally considered to be those which encounter bottomhole temperatures in excess of 300°F (150°C) and pressures which require a mud weight of 16.0 ppg (1.92 SG) or more to maintain well control. Another way to consider pressure is to note that standard downhole tools and equipment are rated at 20,000 psi (1,361 bar).

Many offshore regulatory authorities require some sort of emergency plan be in place prior to issuing the drilling permit. In addition to the company's standard emergency plan, many operators have a Blowout Contingency Plan (BCP) that specifically covers well control events such as:

- Immediate response activities
- Emergency organisation
- Well capping and killing procedures
- Specialised well control equipment
- Hazardous fluids such as H2S and CO2
- Logistics, and
- Relief wells

Pre-planning for HTHP wells can greatly benefit the operator in terms of drilling performance, but also in conventional as well as non-conventional well control operations. The pre-planning should include detailed well design engineering and HTHP awareness training.

Connections that lose their integrity impact numerous HPHT development and production operations worldwide and are responsible for huge costs as they can lead to stuck-fish, lost-in-hole and even sidetracks[23].

Salt Challenge

Prevalent worldwide, massive salt sections add to well construction challenges.

Several deepwater blocks in the GOM, West Africa (Congo Basin) and Eastern Brazil (Santos Basin) are characterised by salt provinces; for example, sub-salt wells have been drilled with total depths exceeding 30,000 ft (9146 m) and salt sections exceeding 8000 ft (2,439 m) in thickness.

Production companies who hold sub-salt acreage face a combination of imaging and deepwater drilling problems. Other operators in deepwater areas, such as West Africa and Brazil which have had relatively limited salt challenges to date, also need sub-salt strategies as exploration reaches salt provinces. In some cases, spanning over half a well-bore's true vertical depth, salt can present sizeable difficulties.

Where salt is just 'salt' things are relatively simple; but where salt sections are heterogenous containing halite, anhydrite, sedimentary channels, flows or rubble zones, things become complex. This makes the mapping and imaging of salt a difficult process with subsurface phenomena often going unseen. Seismic data cannot always represent salt flows or channels with many anomalies only truly characterised through drilling.

Anomalies, represented or not, create drilling problems that range from loss scenarios with pore pressure regressions below salt, loss of directional control, stuck-pipe due to salt closure and destructive vibration induced by alternating salt/sediment bedding[24].

Hole stability can be affected by active salt tectonics. Intermediate sections can be subjected to geo-hazards such as faulting and fluid seepage. Salt closure increases the loads on the casing and its cement as both must be able to withstand the forces applied by the salt as it expands radially and pinches the well. Simultaneously drilling and casing the well may be a good way of overcoming this. Maintaining directional control in salt is not straightforward as there is a tendency for well-bore deviation.

Certain salts require higher weight-on-bit to drill compared with sediments.

Consequently, the higher weight-on-bit, the greater the tendency for the bottomhole BHA to build inclination.

Costly deep-water rig rates mean that operators are right to require high performance levels. Consequently, more rigorous Quality Assurance/Quality Control (QA/QC) standards are demanded of downhole tools to permit sections to be drilled in single runs at high penetration rates. Salt sections have higher fracture gradients (when compared with sediments located at the same depth) enabling longer sections and reduced well-control problems associated with permeable formations. predicting pore pressure and fracture gradient in sediments below the salt, however, is tricky. Pressure regressions below the salt often dictate casing depth.

It is known that Synthetic Oil-Based Mud (SOBM) can be the most effective salt drilling fluids as they avoid borehole enlargement and well-bore instability.

Although many risks associated with salt can be reduced through pre-drill seismic, look-a head tools and real-time pore pressure profiling, there are still plenty of 'un-knowns' to keep everyone excited.

Heavy Oil

Although large volumes of heavy and high viscosity oil have been discovered world-wide, both onshore and offshore, economic production is a challenge for the oil industry. Increased oil viscosity means increased E&P costs as well as higher refin-ing costs. The definition and categorisation of heavy oils and natural bitumens are generally based on physical or chemical attributes or on methods of extraction. Ultimately, the hydrocarbon's chemical composition will govern both its physical state and the extraction technique applicable. (See Chapter 3 What's in a Barrel?)

These oils and bitumens closely resemble the residue from crude distillation to about 1,000 degree/F. If the residue constitutes at least 15% of the crude, it is considered to be heavy. This material is usually found to contain most of the trace elements such as sulfur, oxygen, nitrogen and metals such as nickel and vanadium.

A viscosity-based definition separates heavy oil from natural bitumen. Heavy oil has a rating of 10,000 cp or less and bitumen is more viscous than 10,000 cp. Heavy crude falls in the 10°- 20 ° API range inclusive and extra-heavy oil less than 10° API.

Most natural bitumen is natural asphalt (tar sands or oil sands) and has been defined as rock containing highly viscous hydrocarbons (more than 10,000 cp) or else hydrocarbons that may be extracted from mined or quarried rock.

Other natural bitumens are solids, such as gilsonite. The upper limit for heavy oil may also be set at 18°API, the approximate limit for recovery by waterflood.

The industry reference for offshore heavy oil production is the Captain Field which is operated by ChevronTexaco and located in shallow waters in the North Sea.

Brazil, Canada, China and Venezuela are just some of the countries that hold significant heavy oil volumes within the 13°API to 17oAPI range. Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

New production technologies are required for the economic development of offshore heavy oil reservoirs. Long horizontal or multilateral wells, using high power pumps such as Electrical Submersible Pumps (ESPs), hydraulic pumps or submarine multiphase pumps, could partially compensate for a decrease in productivity caused by the high oil viscosity.

Additionally, flow assurance could be improved with insulated or heated flow-lines, or alternatively, with the use of water as a continuous phase system. Heavy oil processing in a Floating Production Unit is not straightforward and new separation technologies, as well as the feasibility of the heavy oil transportation with emulsified water, needs to be investigated. The existence of light oil reserves in neighbouring reservoirs, even in small volumes, will play an important role this determination.

Reservoir Technologies for Offshore Heavy Oils

Heavy oils are difficult to produce.

From a reservoir standpoint, increased viscosities impair the flow of oil while in an offshore environment traditional enhanced recovery methods are often limited.

Most of the heavy oil reservoirs offshore Brazil, for example, are found in non-consolidated deepwater reservoirs. Potentially heavy oil cold production, caused by natural depletion or water-flooding, seems to be a practical option.

It is known however, that the displacement of oil by water is much less efficient than by using 'regular' viscosity oil. Petrobras' research on reservoir technologies for heavy oil production concentrates on the following topics:

• Flow through porous media, which can be used to improve methods for understanding the relative permeability of water and heavy oil in non-consolidated, heavy oil bearing formations

• Modelling of oil varietals in offshore heavy oil reservoirs

• Optimised heavy oil field development

• Modelling to minimise remedial workovers, and

• Fundamental reservoir simulation studies in order to optimise the design of offshore production systems for heavy oils.

Flow Assurance for Heavy Oil
In terms of physical properties, heavy oil differs considerably from lighter crudes, generating a need for new production techniques. Higher viscosities, gravity and pour point combine to make fluid flow through pipelines more difficult than for lighter oils. Higher viscosity also means higher pressure drops and the need for more powerful pumps and pipelines with higher pressure ratings. Increased oil gravity also increases the pressure gradient in upwardly flowing pipelines such as the wellbore and riser.

These issues become more important in deepwater fields as low pour points can create flow assurance concerns in the case of 'cold start-up' of pipelines or wells.

Core annular flow is being developed to flow through pipes. The idea is to use water to reduce pressure drops. Water is added in an annular flow pattern so that oil is kept at the centre of the pipeline while the water maintains contact with pipe walls. As pressure drops due to friction are proportional to fluid viscosity, the only phase that is sheared at the wall is water; therefore, the obtained pressure drop is almost the same as if only water flow was involved. This reduction in pressure drop for heavy oil can reach a magnitude of a thousand. This technology has been used already for onshore oil export pipelines* and is now under development by Petrobras to be used in offshore production systems including well bores, pipelines and risers in the presence of gas.

* Core annular flow was successfully applied by Petrobras in the onshore field of Fazenda Alegre enabling viscous oil to flow across a 300 m production pipeline[25].

Emulsion behaviour is an equally important issue for heavy oil production. Emulsion is a fine dispersion of two liquid phases and is generated when the fluids mixed together shear.

There are also other techniques that can be used to reduce fluid viscosity and pressure drops; for example, heavier crudes can be diluted with lighter ones. Another example is the generation of an inverse emulsion (oil in water) using chemicals.

Flow assurance is another concern for heavy oil production. Wax deposition and crystallisation may occur and create pour-point problems to an already viscous fluid. Also, hydrates can form in heavy oil systems creating an even more viscous slurry (shown in Figure 9) which may clog pipelines.

The existence and characterisation of tarmac beds, sometimes present at the bottom of the heavy oil zone close to the oil water contact, is extremely important. Limited connectivity of the bottom aquifer with the oil zone would avoid rapid increases in water coning. This would make for more efficient water injection and could radically change the development scheme.

Many issues still merit research and oil companies are pursuing both laboratory and field based technology[26].

We have outlined the Extreme E&P challenges that the industry faces in adding new reserves. The next Chapter, Mature Fields, looks at making the most of existing assets.

Mature Fields

Inevitably, all producing fields reach maturity one day so the importance of mature field technology is set to grow as greater numbers of assets enter maturity. Pumps, polymers and permanent seismic are just a few of the technologies used to enhance and improve production in mature assets. This chapter provides an overview of Enhanced Oil Recovery (EOR) or Improved Oil Recovery (IOR) as well as several practical field applications.

Mature fields are challenging as they exhibit a decline in hydrocarbon rates, increased water production as well as the responsibility of decommissioning platforms, wellheads or pipelines[1].

For our purposes, a field is defined as mature once its natural reservoir drive mechanisms—gas-drive, water-drive or gravity drainage—are incapable of sustaining production. Consequently, hydrocarbons must be artificially swept from the reservoir and be able to travel through production tubing, the wellbore and to surface installations[2].

Reservoir Drive

Reservoir pressure curves correlate directly with reservoir production rate curves. As long as reservoir pressure is greater than bottom hole pressure, the differential pressure will result in production. Pressure differentials can be created by reducing bottomhole pressure or by increasing reservoir pressure, either of which will increase hydrocarbon production[3].

Following the development of low-hanging fruit, most mature assets have traditionally been distributed onshore; however, the trend now shows extensive numbers of shelf and deepwater assets entering maturity. Already, several notable offshore fields are classified as mature assets; for example, Brent and Troll in the North Sea, and Marlim in offshore Brazil.

Pump Up Production

Primary or artificial lift methods to increase production include the nodding donkey or rod pump, Electrical Submersible Pump (ESP) or a gas-lift system. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically around 10% for oil reservoirs and 15% for gas reservoirs[4].

Secondary production of hydrocarbons is achieved when a fluid such as water or gas is injected into the reservoir through injection wells. Injectors are carefully drilled into formations so that fluid communication or flow pathways can be made to production wells. The purpose of secondary recovery is to increase reservoir pressure and to displace hydrocarbons toward the production wellbore[5]. As a consequence of prudent reservoir management, wells may be converted from producers to injectors or new injector wells may be drilled. The trick is to consider the entire field as a 'production unit' and manage all wells with the objective of increasing overall production. This can be a very complex and contentious issue when several landowners are involved. Imagine an oil company telling a farmer that the prolific oil well on his property that is returning him a handsome revenue in royalties is about to be converted into a water injection well.

Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. The mechanics of gas and water injection are complex and include consideration given to directional injectors and multi-phase flow. A pressure maintenance program can begin during the primary recovery stage, but it is still considered a form of enhanced recovery. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and the production is no longer economical. For some fields this could be 50%, while for others it could be as high 80%. In Oman, wells are currently producing economic volumes of oil with over 90% water cut. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15% to 40% of the original oil in place[6].

Tertiary or EOR not only restores formation pressure, but also seeks to improve reservoir flow characteristics. With greater numbers of mature assets, oil companies target mature onshore and offshore oil fields worldwide in order to extract maximum value from sunk costs. Tertiary oil recovery applications are internationally recognised and this area of production engineering covers most categories of crude oil with American Petroleum Institute (API) grades varying from 13° to 41°. The industry adopted a broad ranging methodology, which enabled pilot testing to commercial/field applications using steam injection, Carbon Dioxide (CO2) injection and polymer flood. EOR methods range from chemical flooding (alkaline or micellar-polymer based), biological flooding (microbial or bacterial based), miscible displacement (CO2 injection or hydrocarbon injection), and thermal recovery (steam flood or in-situ combustion)[7].

Sometimes these methods are accompanied by additional stimulation services, such as hydraulic fracturing, or by drilling sidetrack lateral wells from the main wellbore to access stranded oil.

A thorough characterisation of reservoir heterogeneity and the nature of reservoir fluids are required for a mature field production strategy and only after extensive analysis of the application can a particular method be chosen. The application process can be spilt into three basic stages: modelling future behaviour, field data analysis and corrective correlation of the model[8].

Typically, data maybe collected from permanent seismic (time-lapse or 4D) or downhole equipment that monitors production. The objective is to draw up a reservoir management strategy that will address:

- The effect of recovery methods on reservoir fluids
- Migration and production of oil and gas
- Communication with adjacent reservoirs
- Sealing faults
- Fracturing

- Induced pathways due to modified permeability
- Scale formation
- Hydrogen Sulphide (H2S) mitigation, and
- Water disposal

Analysis will include:

- Reservoir temperature
- Pressure
- Depth
- Net pay
- Permeability and porosity
- Residual oil and water saturations, and
- Fluid properties such as oil, API gravity and viscosity[9,10]

Seismic
A major goal for oil companies is to improve recovery factor for mature fields. A key method is to use imaging as a way of identifying stranded hydrocarbons and improving the efficiency of water injection. This helps mitigate the problems associated with water production, such as souring and scaling, and thus decreases the lifting costs of old fields. By using 4D seismic, and examining the differences between subsequently acquired seismic images, production geophysicists can: map reservoir drainage patterns; identify flow barriers such as faults or unconformities that are below the resolution of direct seismic imaging; and plan the location of future injector wells.

Mature Field Applications

Water Injection
Water management is a major challenge associated with mature fields. Besides handling increasing volumes of water at surface, the challenge is to increase recovery by improving the sweep or production of hydrocarbons through water injection. This requires the correct evaluation of reservoir drainage patterns. . In order to meet water management and environmental needs, oil companies are shifting from water injection to water re-injection. To ensure smooth transition from lab technology to

field application, oil companies run pilot programs; for example, a pilot water re-injection program would handle say 5% of actual water volumes produced from the reservoir and re-inject this to maintain reservoir pressures. Water injection is easily applicable offshore where the entire ocean is available, but recently land operators have had problems finding water to inject. Farmers object to the use of aquifers for obvious reasons.

Accordingly, operators have figured ways to re-inject unwanted water produced in conjunction with the oil. This recycling solves two problems at once: it is an elegant way to dispose of the unwanted saline water that is not suitable for irrigation or drinking, and it augments oil production. Now, even offshore operators are recycling produced water because it is unlawful to dump it into the sea because of its high saline content and because it contains traces of residual oil.

To get an idea of the volumes manipulated, Petrobras handles an average water injection volume of two million barrels of oil per day (MMbbl/d) half of which come from produced water. This accounts for approximately 1.87 million barrels (MMbbl/d) of oil which is an average water cut of 50%. Petrobras plans to construct a system for 'raw' water injection which would be placed over the seabed and used to capture and filter water prior to injection. It has a good application on mature fields or fields whose small platforms are often space-limited[11].

H_2S in Mature Fields

The term 'souring' describes various sour gas and H_2S management strategies. The Health, Safety and Environmental (HSE) implications of water injection are well understood as injection has been ongoing in certain areas since 1978. In Brazil's Offshore Campos Basin in the Marlim field, water injection begun in 1994 and a H_2S breakthrough occurred in 2003. Injecting nitrate to mitigate the problem and to simulate the reservoir behaviour of H_2S generation processes helps to define, for the fields under development, which strategy to adopt. This approach is dependent on the forecast of how much H_2S is involved and when it is being produced[12].

If only trace H2S volumes are expected, there is no need to act; if there are medium levels, metallurgical improvements may be selected. In addition, sulphate removal for scaling treatment may help to mitigate some of the souring problems. If levels are high, nitrates must be injected. Field pilots usually test the effectiveness of nitrate injection by having one pilot re-inject reservoir water and another pilot inject seawater. It should be noted that both would be using nitrate. These technologies are developed in conjunction with service and research companies, which are performing lab tests to help determine the simulation parameters of H2S generation in the reservoir[13].

Salt and Scale

Offshore operations also create salt and scale problems. This can occur anywhere between surface and sub-surface equipment.

Remote operations have been used successfully to perform interventions such as well cleaning and squeezing of scale inhibitors into the formation. Satellite wells using subsea Christmas trees are employed in all Brazilian deepwater fields and remote handling avoids incurring high rig costs for intervention. The problems of corrosion and its effects on subsea installations need to be carefully considered[14].

Steam Onshore Fields

Onshore fields have seen good results from EOR using cyclic or continuous steam injection, as is demonstrated by the production of a total of 20,000 bbl/d . Applications in the Fazenda Alegre, Espirito Santo basin, have seen production rates improve in horizontal wells due to the introduction of thermal recovery methods. Several research projects are testing theories and feasibility of in-situ combustion. Petrobras is also considering variations of in-situ combustion and steam injection. The old vertical injector–vertical producer scheme - is being substituted by innovative geometries; for example, a vertical well to inject and a horizontal well to produce. Another alternative is to associate steam with solvents. This technology was recently applied in a field in the Espírito Santo basin to mobilise oil which had not responded to steam injection alone.

Steam Assisted Gravity Drainage (SAGD) is an enhanced oil recovery technology for producing heavy oil. It involves the parallel drilling of a pair of horizontal wells spaced apart a few metres. Pressurised steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out.

In all thermal recovery processes, the cost of steam generation and the availability of water will play a major part in determining whether the cost of oil production is commercially viable.

Microbial Applications

Another EOR front uses microbial applications based on water and bacterial interaction to increase production. The water and bacteria are pumped down and this is followed by nutrients. The bacteria develop a biomass that clogs the porous medium and subsequently increases the viscosity of water and diverts flow along new pathways to increase production. The bacteria, native to the oilfield, are injected along with nutrients. Biopolymers, generated by the metabolic process of the bacteria, clog the water pathways of higher permeabilities. Continuously injected water displaces the remaining oil from the lowest permeability zones. This process has been tested by Petrobras' Carmópolis field in the Sergipe Basin[15]. Alternatively, microbes are used to 'eat' clay particles that clog pore throats, thus improving permeability. A limitation to the use of microbes is their relative temperature limit. Ongoing research seeks to breed colonies of microbes that are more temperature resistant.

Bacteria Injection Facilities in the Carmópolis Field, Sergipe Basin.

Modifying Relative Permeability

A neat application is the use of chemicals to control water. Water shut-off control in more than 200 wells has been achieved with the injection of a patented polymer called Selepol, which is a relative permeability modifier. Several formulations were attempted with the more recent based on tiny pieces of hydrophilic gel[16].

Drilling in carbonates or tight sands is another area of interest where stimulation technology plays a central role. There have been five fractures in a well drilled in the Enchova field, a shallow water, low permeability, light oil-bearing carbonate.

A new exploratory approach may bring into focus a new family of reservoirs of this kind, previously thought to be marginal in Brazil[17].

A novel gas management program was designed to characterise gas reservoirs, principally for the tight sandstone Mexilhao field in the Santos offshore basin. The development of a gas producing province at the Santos basin, south of Campos, is a major goal for Petrobras and the company is focusing on stimulating flow in low permeability porous media[18].

Figure The Main Brazilian Sedimentary Basins

This figure shows a map of Brazil's main sedimentary basins. Among the mature onshore areas, the best producers are the Ceará-Potiguar, Sergipe-Alagoas, Bahia, and Espírito Santo Basins, which have a total output of 220,000 bbl/d. About 90% of this production comes from mature fields[19].

Steam Injection

In the late '70s, following the discoveries of heavy oil reservoirs in the onshore part of the Sergipe-Alagoas and Ceará-Potiguar basins, cyclical steam injection was introduced into Brazil. These first successful projects were later expanded and commercialised[20].

Subsequently, continuous steam injection was applied to a total of 15 cyclical and continuous steam injection projects covering a broad range of oil viscosities. These range from 13° to 19° API in the Ceará-Potiguar basin to 16° to 22° API in the Sergipe-Alagoas basin and up to 18° to 35° API the Reconcavo basin where cyclical injection was used to produce oil with high paraffin content. Steam is responsible for virtually all tertiary recovery production, estimated to be presently 3% of Brazil's total oil production. In the Fazenda Alegre field, located in the onshore Espirito

Santo basin, extremely low API grade oil is being cold-produced using steam injection and horizontal wells completed with slotted liners and stem rod pumps[21].

In-Situ Combustion

Two in-situ combustion pilots were performed in the '80s in the Buracica and Carmópolis fields, and in the Recôncavo and Sergipe-Alagoas basins respectively. The best results were obtained in the Buracica pilot, which was characterised by a low temperature oxidation process; however, sand production and well surface facility corrosion were major operational problems. Additionally, oxygen breakthrough interrupted the project due to the risk of well explosion. The Carmópolis pilot showed poorer results, despite the fact that it generated the best combustion efficiency. Poor reservoir characterisation was the main reason for losing control of the combustion. Electrical heating was tried in two heavy oil reservoirs in the Potiguar basin as an alternative to steam injection. Results showed that the electrical heating process cannot replace steam, but can be useful in areas where steam is not applicable. Further electrical heating and water injection techniques have been applied in a pilot project conducted in the Canto do Amaro field[22].

Polymers

The first polymer injection project was implemented in 1969 in the Carmópolis field. After operating for some years, the project was interrupted but evaluations showed that an additional oil recovery of 5% could be credited to polymer injection. Besides the technical success of this project, the drop in the costs of polymers and the increasing ease with which polymer could be handled and prepared offered new opportunities to apply this technique. Currently, there are three polymer projects in course, one in the Carmópolis field and the other two being carried out in the Buracica field, Recôncavo basin and in the Canto do Amaro field in the Potiguar basin[23].

Water Management in the Petrobras Fields and Treatment of Subsea X-mas Tree Wells

Water Flooding

Flooding is the main recovery method used in Brazil in both onshore and offshore fields. Offshore operations in the Campos basin are responsible for a daily output of roughly 75% of the total country's output. The volumes of water injected exceed 800,000 bbl/d and the water production reaches values of over 350,000 bbl/d[24].

Due to the importance of water injection for the Petrobras fields, water management has become a major priority. Problems associated with water injection and production has been the focus of several important projects developed in the past few years.

It is worth emphasising that 'simple' problems in onshore fields, such as the stimulation of injector wells that have lost injectivity, become more complex offshore. Many wells located in deepwater areas are completed as satellites; therefore, workovers are extremely expensive due to the need for a floating rig. For such scenarios, remote operations are performed as a way of decreasing intervention costs.

A major factor in managing water is the rate of water injection that is required. The injection decline curve for injector wells must be precisely drawn in order to evaluate the economics of two options: to perform effective water treatment that requires fewer workovers or to inject lower quality 'water' that requires more frequent workovers.

Petrobras has been injecting seawater in offshore fields for twenty years. Water quality has been monitored using an index which covers parameters involved in water treatment such as injection and disposal volumes, corrosion risk, bacteria, solids

Figure Water Injection in the Campos Basin and oxygen content. Irrespective of the quality of the injection program, there is an ultimate loss of effectiveness over time. Some remote treatments using acid to remove damage in injection wells have been performed and have yielded very good results[25].

Remote Acidisation

This technique has been performed in the Marlim field which is a giant complex of oilfields located in water depths that vary from 600m to 1050m. It produces 600,000 bbl/d from high permeability turbidites. To maintain reservoir pressure, an equivalent amount of water is injected daily. Despite excellent reservoir properties, injector wells lose effectiveness after a few months of water injection. Conventional acid treatments cannot be performed due to high rig costs. The solution, therefore, is to pump acid from the production platform which is often several kilometres away from the subsea X-mas tree wells. Careful laboratory tests are needed before field operations can begin to ensure that the treatment does not damage subsea equipment such as injection lines, well heads and injection columns[26].

To date, only vertical or slant cased wells have been treated. The challenge is to perform remote pumping in horizontal wells completed with slotted liners.

An alternative that may help guarantee effective water injection is to inject low quality water at pressures high enough to keep fractures open. Safe water injection requires extensive modelling of reservoir sweeps, geometry and fracture propagation[27].

Flow Assurance

Flow can be interrupted or halted altogether due to inorganic scale formation caused by seawater and reservoir water mixing together; therefore, the prediction, prevention and corrective treatment of scale is fundamental to ensure the flow of oil. The Namorado field was the largest Brazilian offshore field in the '80s and suffered from scale formation. Interventions to squeeze scale inhibitors into the rock formation were performed and oil production was maintained without interruption.

As some deepwater fields contain horizontal, uncased satellite wells, scale treatments are more difficult to perform. Nevertheless, some excellent results were achieved in the Marlim field using a special chemical process developed by Petrobras. Oil production increased by more than 13,000 bbl/d after the treatment. Again, the challenge for the next few years is the application of these treatments in horizontal uncased wells[28]. Sea floor water separation and re-injection are techniques under development[29].

Polymers

The use of polymers to control water is another potential solution and Petrobras has performed more than 170 well treatments in onshore fields using 'Selepol', a patented process. The rate of success for such treatments is in excess of 65%. The process modifies the relative permeabilities of the oil-water-sandstone system, retaining water in the wellbore vicinity. Higher seawater salinities, higher temperatures, higher permeabilities and higher produced volumes, as compared to onshore conditions, are the main challenges to be overcome offshore[30].

Water Disposal

Once large amounts of produced water cannot be avoided, disposal becomes the priority. The focus is on treating water to remove oil (this can be difficult due to space restrictions on platforms) in an environmentally acceptable manner so that re-injection into the reservoir or disposal in non-productive formations can be achieved[31].

Trends in Reservoir Geophysics

The challenge for seismic contractors is to increase the quality and resolution of seismic data, not only in exploration, but also in mature applications. New acquisition and seismic processing parameters oriented to reservoir characterisation and monitoring are helping improve seismic quality and resolution. With this new data set, reservoir geophysicists can potentially better understand external reservoir geometry, the internal heterogeneity of turbidite reservoirs and monitor the fluid flows. Historically, reservoir geophysicists have been using the same sequential process normally used in exploration. Nowadays, oil companies are applying new techniques such as 4D seismic adapted to reservoir needs[32].

Mature Field Seismic

In the following applications, we look at the benefits of seismic in brown fields owned by BP, Petrobras and StatoilHydro. These oil companies have successfully used the latest 4D and time-lapse seismic to maximise the life of the reservoir, characterise stacked and thin-bed reservoirs as well as monitor water injection in deepwater reservoirs. This has helped these companies reach bypassed payzones, extend production and even change the definition of what was once considered economic.

Reservoir Studies of BP's Mature Fields in the Columbus Basin, Trinidad

4D seismic accompanies the lifecycle of an oil and gas asset and can provide valuable production monitoring information. This is because, as with all technology,

Figure Columbus Basin, Trinidad

seismic is subject to constant improvement. Seismic shot 20 or 10 years ago would have had limited 'vision' and likely only located 'shallow' reservoirs. Today, opportunities exist to find deeper reservoirs in mature fields, which were once characterised by 2D (early less sophisticated seismic). This can be seen in the new frontiers or deep gas plays, which are being explored in the Gulf of Mexico (GOM) and in the Columbus Basin[33].

This has tremendous value in shaping decisions as to the peaking of production rates and decline curves. Usually, a cost-benefit analysis is conducted which measures costs and attributes the value gained. This exercise can be difficult as the value gained may often be indirect. 4D seismic is used mainly to better manage reservoir production across the lifecycle of a field. Due to the increasing number of brown fields worldwide, 4D seismic applications have increased substantially; however, as seismic is a recent technology, there are relatively few processes available to evaluate it[34].

In 2004, BP in Trinidad and Tobago faced the challenge of valuing a number of seismic survey options over the Greater Cassia Complex in the Columbus basin, Trinidad. In Southern Greater Cassia, several tcf of gas reserves are located under shallow gas reservoirs, which often blur seismic visualisation. Development of these reserves is complicated by the presence of 27 stacked reservoirs with reserves trapped in over 100 separate segments[35].

BP had to identify and value the style of survey required to improve seismic visualisation over the southern half of the Complex, which was affected by shallow gas imaging Problems, and value the benefits that 4D seismic could offer for reservoir management and future well placement. This required consideration of expensive 4D OBC (Ocean Bottom Cable) seismic acquisition options. Additional benefits from 4D seismic for monitoring dynamic reservoir performance could be foreseen with a permanent installation. Here BP developed several research programs to ascertain which 4D acquisition option was the best solution. The integration of these results, along with other elements, helped support decisions for a seismic strategy for the 'Life of the Cassia Complex'[36].

Mature Field Seismic Application in Petrobras' Deepwater Campos Basin, Brazil

Petrobras acquired its first 4D seismic in the Marlim field in 1997. In 1999, Petrobras started several 3D, reservoir -oriented seismic acquisition programs covering former 3D surveys. These occurred in the South Marlim, Barracuda and Caratinga, Espadarte, Marimbá, and Pampo-Linguado fields in the Campos basin.

Common seismic processing techniques were used to map reservoir turbidite systems and to reduce appraisal and production risk. Visualisation techniques were applied in 3D views of exploration and development projects[37]. From its initial evaluation of the 4D interpretation, Petrobras was able to re-locate the trajectories of 11 development wells planned for the Marlim Complex. In addition, the company was able to identify the need for nine additional wells to improve reservoir drainage efficiency. The wells in Marlim average about US$81 million each. The cost of the 4D seismic acquisition and processing was slightly more than US$40 million. In short, the company realised a Return on Investment (ROI) of more than 40 times by saving $1.6 billion by not drilling wells in the wrong place. It remains to be seen how much additional revenue the company will gain from drilling its development wells in the right place.

Geosciences

Oil companies commonly apply dual geoscience programs of seismic for reservoir characterisation and also 3D geological modeling. Seismic for reservoir characterisation is a main issue. An acquisition project was started in 2005 with the objective of acquiring base 4D timelapse data of the whole Marlim Complex (Marlim, Marlim Sul and Marlim Leste fields). Petrobras has a '4D-room' where geologists and engineers

This figure shows the location and geological age of the Campos basin's 41 oilfields[38].

can visualise geological phenomena[39]. At the time, Marlim was the largest seismic acquisition ever acquired both in terms of area and the amount of data acquired. The data amounted to 157 terabytes and required the continuous application of 12,000 processing units (9000 which were located in Houston and 3,000 which were located in Gatwick, UK).

Regarding the specific challenges that reservoirs create, modelling reveals such things as key depositional features and reservoir geometry which can help explain the gross size, volumes and channels of the reservoir[40].

Mature Field Application of 3D Seismic and Multilaterals in Norway's Troll Field

The Troll field is located approximately 80 km off the west coast of Norway in shallow seawaters. Troll's reserves are mainly gas (at one time it was considered to be a gas play only), but it also contains sizeable oil reserves and has surpassed oil production of one billion barrels.

This oil, however, was distributed in hard-to-reach thin oil-bearing layers that were just four to 26 metres thick and spread out over an area of approximately 450 square km[41,42].

A combination of multi-laterals and state-of-the-art geosteering drilling technology was required to drain the thinly dispersed pockets of oil. This included the latest rotary steerable systems in conjunction with reservoir imaging tools, which allowed the oil company to place the well in the best parts of the reservoir. This, however, was only half the story as state-of-the-art completion and production technology was required due to challenges such as sand and water separation. Subsea sand and water separation systems had to be used to achieve maximum production.

In the late 1980s, it was the belief that the development of Troll oil would ‘never’ be economically feasible because its oil reserves were so thinly layered and the price of oil was US$10 per barrel; however, with the creative use of technology, Troll became one of the largest oil producing fields in the North Sea. The success of this drilling and production approach led to its application in even thinner oil layers measuring just seven to 14 metres thick[43].

Figure Troll

The Troll story is one of realising the potential of the field by: applying modern drilling technology; placing well trajectories within a very difficult and challenging reservoir; and keeping sand and water production to a minimum to achieve maximum production.

These case studies illustrate the immense financial and technical risks faced by the oil companies in reaching their prize, and show how challenges can be overcome to realise added profit and extended reservoir life.

We have seen how technology in Extreme E&P and mature field applications has extended Hubbert's peak into a plateau. Technology and knowledge is extending the frontiers by drilling deeper, drilling in deeper waters, drilling to tougher targets, and producing reservoirs once thought to be unproduceable.

One day of course, oil usage will decline. Yet, before that happens, the industry will continue to find, develop and produce oil more effectively. Why? The answer is simple - to provide an essential resource to mankind that will remain the preferred source of energy for the near future. To put it simply, despite oil price fluctuations, the demand for oil will continue to grow. The next chapter helps break down where all this demand comes from and the long list of products and processes that are dependent on oil.