Let us speak deep offshore

Up until the mid-80s, offshore developments were limited to oil or gas fields that lay under no more than 400m of water. As was the case for conventional offshore at the end of the 60s, the emergence of deep offshore was justified by the progressive decrease in the potential of conventional offshore and by the increasing demand from emerging countries. The high price of the barrel at the beginning of the 90s, in particular after the Gulf War, forced operators to develop what appeared to be a new "black gold mine".

The potential of the deep offshore had been identified several decades previously, but the self-sufficiency of onshore production up until the first oil crisis, and then of traditional offshore production until the beginning of the 90s, meant that the deep offshore was an issue of purely scientific interest. Proof of this fact was that before 1983, only a few deep offshore wells existed and no major discoveries had been made.

In a particularly fertile economic setting (the barrel price peaking in 1982) and in the wake of the considerable progress made in seismic imaging techniques, the second part of the 1980s saw the situation gradually turn around, a change characterized by the limitation of the number of wells drilled and by a few significant discoveries in the Campos basin (offshore Brazil) and in the Gulf of Mexico.

It was only towards the end of the twentieth century that deep offshore exploration really began to bear fruit, in particular after the discovery of the "legendary" field of Girassol[1] which for the first time, demonstrated that deep offshore reservoirs are very different from those produced using traditional offshore techniques.

Deep offshore turbidite reservoirs

Contrary to popular belief, the great rivers of the world do not stop at the sea. Far, far away from their embouchure, they carry along dozens of millions of tons of sediments right up to the edge of the continental slope (**Figure 1**).

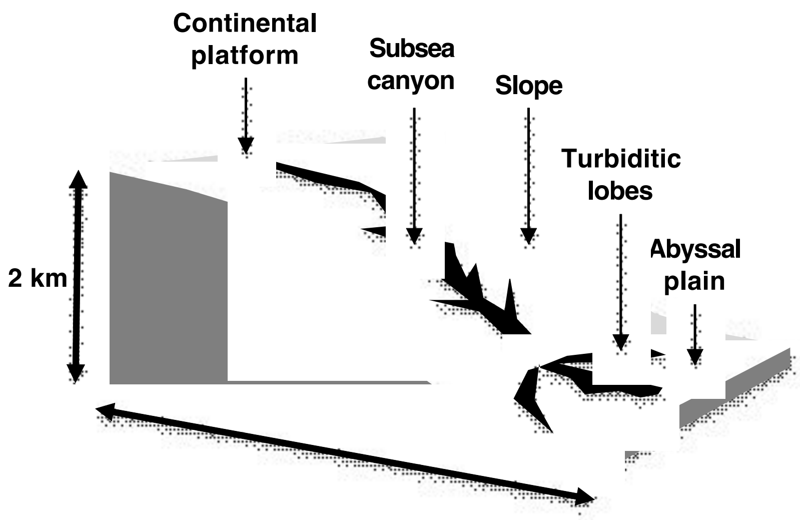

Figure 1 – Formation of subsea canyons and turbidite lobes

In a situation of gravitational instability, the alluvial deposits slide periodically, as subsea avalanches (called turbidity currents) that plough into the seabed, sculpting meanders and channels up to the foot of the continental margin (abyssal plane) where they

[1] Located off-shore Angola and operated by Total Girassol is recognized as the first large size deep water oil development

accumulate in the form of deltaic-type structures and are finally deposited as continuous spreads, called turbidite lobes.

Over 90% of deep offshore reservoirs identified to date are located in the so-called passive margins in direct continuity with the great oceanic rivers of four basins (the river Congo, the Niger in West Africa, the Mississippi in the Gulf of Mexico and the Campos basin offshore Brazil) and all contain turbidite sands that present excellent petrophysical qualities (in particular, very high permeabilities) which have given rise to very high production levels and the discovery of abundant reserves per wells.

It was essentially thanks to the progress of seismic technology that turbidite reservoirs lying at shallow depths below the seabed, where the imaging is generally of very good quality, were rapidly identified. The wells were implanted in highly favorable conditions, which meant that discoveries were made one after the other. In 1999 alone, the volume of oil discovered in the deep offshore exceeded…..9 billion barrels!

Main challenges of a cold and, dark world

The technical challenges raised by the production of deep offshore hydrocarbons are above all related to surface conditions, a cold, dark world subject to high pressures. In the oceans, temperature drops rapidly with depth until it stabilizes at about 4°C as from 600m. Conversely, the pressure increases by 1 bar every 10 meters and therefore reaches 150 bar at a depth of 1,500m. In such conditions, fluid flow and the accessibility of subsea infrastructures are the most critical challenges, all the more so that the deep offshore is inaccessible to man and only remote-controlled robots capable of withstanding the pressure can intervene if required. Subjected to the cold, the high pressures and the currents, installations must be able to operate safely, autonomously and remotely while assuring optimal reliability and availability for several decades.

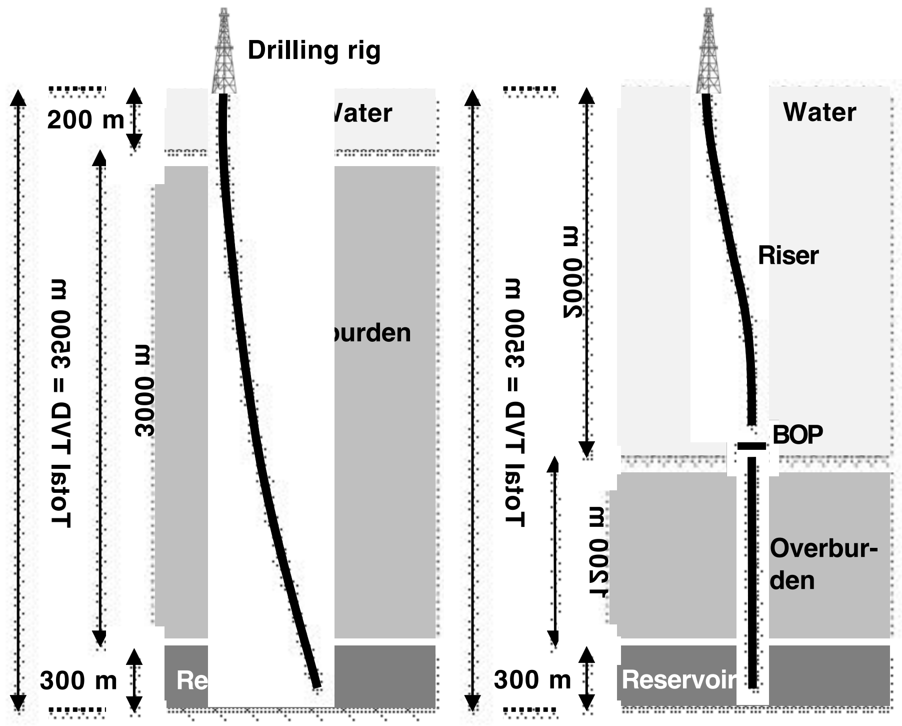

Figure 2 – Notional comparison of a conventional offshore well and a deep offshore well

Challenge number 1: cost-effective drilling

The essential difference between a conventional offshore well and a deep offshore well is shown in **Figure 2.** In both cases, the 'target' is located at 3,500m below sea level but, in the case of deep offshore wells, 1,800 meters of overburden are replaced by 1,800m of water.

To satisfy these specific conditions, many of the installations previously located on the surface are moved to the seabed : wellheads and BOP – Blow Out Preventers- that secure the well in the event of an eruption and which must be controlled remotely with all the required reliability. Moreover, as the deep offshore is inaccessible to man, operations are performed with the help of remote controlled robots (the well-known ROV –Remote Operated Vehicle) that install equipment or intervene in the event of a malfunction if necessary.

To get through the thick layer of water, a very long riser needs to be used containing very large quantities of drilling mud, the weight of which can cause severe flexion forces on the wellhead. The stability of the overall structure is all the more critical given that its foundations (in this case, the seabed) are poorly consolidated and mechanically unstable as they are made of highly-unstable geological structures (mud volcanoes or bothersome pockmarks) that must be avoided at all costs (**Figure 3**). The geotechnical reconnaissance of the deep offshore is therefore a prerequisite for the location of drilling campaigns and the implantation of production facilities.

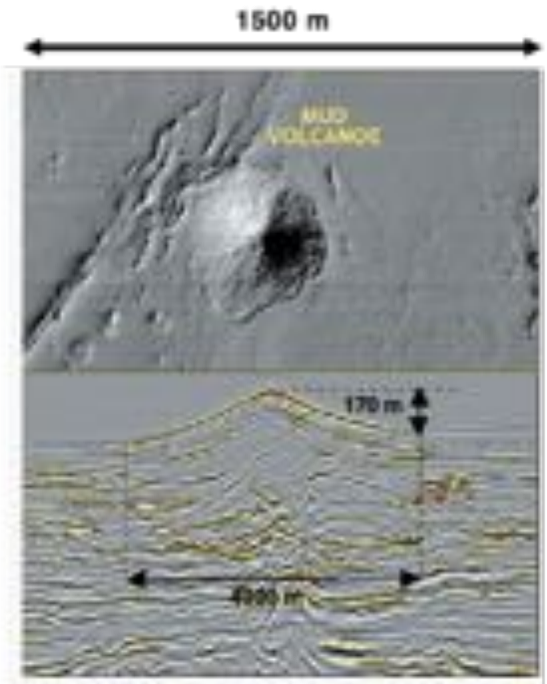

Figure 3 – Example of submarine structure : mud volcano

The great water depths no longer allow drilling rigs to rest on the seabed as they do in conventional onshore drilling. Since the end of the nineties, dynamic positioning rigs have taken preference over anchored systems as they enable the vessel to maintain its position around a fixed point without being anchored, using its own propulsion means via highly-accurate positioning sensors (**Figure 4**). They must have in particular, considerable lifting capacities that enable them to handle the drilling risers. The most recent dynamic positioning rigs can drill wells under water depths greater than 3,000m and often have two derricks, which helps reduce the operating time required by 10-20%. Finally, the deep offshore turbidite reservoirs are poorly consolidated geological formations that, when subjected to high production levels, move sands that mix with the hydrocarbons. The sand represents a potential threat to the integrity of equipment (erosion of certain items of equipment and the blockage of others). Completions have to include filters that block the migration of the sand to the surface.

Figure 4 – Dynamic positioning drilling rig
(Total library)

Guaranteeing the fluidity of different effluents
Fluid circulation is one of the most critical deep offshore issues. Without any precautions and while drilling through the thick layer of cold water, the different fluids (production and drilling fluids) tend to increase in viscosity to the point at which they set and block any fluid flow whatsoever. The pressure and temperature conditions that are usually encountered in the deep offshore are also conducive to the formation of methane hydrates, crystalline structures that look like ice and proliferate around gas molecules. Methane hydrates can form either during drilling when gas vents out, or during production. Likely to block pipelines irreversible, they are a major risk. To drill and produce in the deep offshore, it is therefore crucial to prevent the fluid from cooling down to guarantee its fluidity and to prevent the formation of methane hydrates. The need for prevention is compounded by the near-impossible access to subsea pipelines.

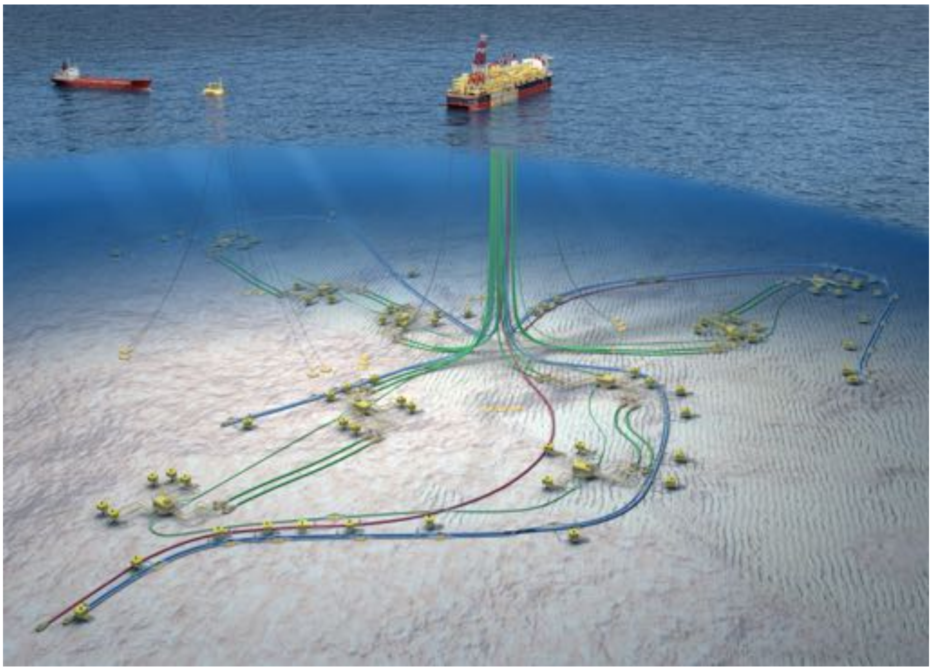

Figure 5 – Deep offshore development scheme
(Dalia field – Angola – Total library)

Any deep offshore development involves a large number of subsea pipelines being laid on the seabed. They collect the effluents from wellheads and transport them to vertical riser towers which on the one hand, carry hydrocarbons to the surface and on the other, inject water and gas as artificial lift methods to support production (**Figure 5**).

Stabilized by a thick central steel tube, such towers comprise several production lines within an insulating sheath that maintains the temperature high enough to prevent the liquid solidifying.

On the Girassol field (Block 17 Angola) developed at the end of the 90s, the eight production risers which were the most spectacular elements of the transportation system, were a world first in the sector. These "monsters" 1,650m long and weighing in at nearly 800 tons, had an external diameter of 60cm. Each tower housed four production columns, delivering an effluent at 40°C to the surface. In the event of a multi-hour production shutdown, they helped maintain the temperature of the effluent above 25°C.

It was on the Dalia field, developed five years later that all the risers were grouped together in three "*towers*", 1,250m high, for a diameter of 1.5m and maintained by a buoy 40m high. An epoxy resin foam assured both the thermal insulation and the buoyancy, which considerably reduced the load borne by the production support.

Housing the essence of technical innovations (metallurgy, materials, fabrication and installation), the risers were a decisive factor in meeting the challenge to produce deep offshore reservoirs, in particular when it came to viscous, barely mobile oils.

1. Gigantic production supports

Beyond 400m[2], it becomes impossible to use standard production platforms that rest on the seabed. It is for this reason that the **FPSO** (**F**loating **P**roduction **S**torage and **O**ffloading) concept was designed. These floating supports are anchored and, on board, concentrate all activities concerning the steering of operations such as the treatment of effluents (oil/water/gas separation) and the storage and export of production. The tankers are filled directly from the loading buoys where the FPSO offloads crude oil via dedicated pipelines. FPSOs are able to process production volumes of up to 250 kbop. Their deck supports topsides weighing hundreds of tons and comprising operating facilities and living quarters. The hull, measuring more than 300m long and 60m wide, houses in particular, vast storage tanks, the capacity of which can reach two million barrels.

[2] The platform of the Bullwinkel field installed by Shell in the Gulf of Mexico in 1991 is the deepest to date to rest on the seabed.

Figure 6 – The FPSO Girassol
(Total library)

Although many companies contribute to the construction of the equipment that makes up the topsides and which will be positioned on the hull after complex lifting operations (a single module can effectively weigh more than 3,000 tons), only a handful of naval worksites are able to assemble FPSO. The world leaders are essentially South Korean. In any deep offshore development, the construction of the FPSO is by far the most important phase, mobilizing over 3,000 people when activity peaks. The whole operation lasts for two to three years and represents about 10 million man hours.

2. Deep offshore perspectives

Fifteen years of intensive exploration contributed to the discovery and production of the most prolific basins, almost exclusively in turbidite reservoirs. In 2012, deep offshore reserves were thought to hold 7% of the world hydrocarbon resources (gas and oil), i.e. approximately 330 Bboe and represented over a quarter of the world resources remaining to be discovered. In less than ten years, deep offshore production increased five times, from 1Mb/d in 2000 to 5Mb/d in 2010. In 2010 it represented 7% of the total global production and about a quarter of offshore production. Between now and the 2020, their contribution should double, to reach 10Mboe/d i.e. 10% of world production. (**Figure 7**).

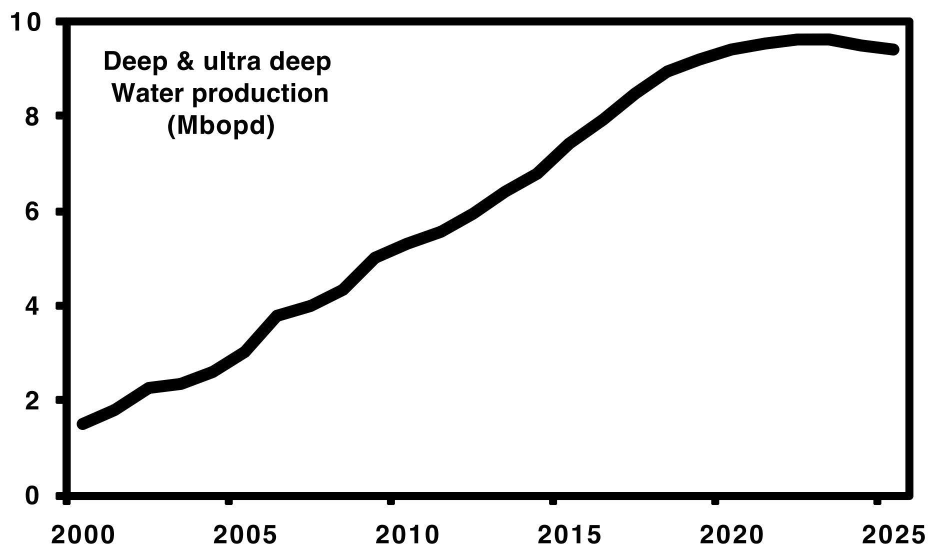

Figure 7 – Deep offshore production (Source IHS CERA)

In parallel to the large reservoirs, there are many little isolated structures, containing between 50 and 200 million barrels of reserves which cannot be developed cost-effectively in a 'stand-alone' configuration. When the distances between the satellites and the existing FPSO remain within acceptable limits, a number of small reservoirs can be connected up to it. If the distance exceeds thirty kilometers, current technology does not allow this kind of field to be produced cost-effectively.

Up to now, the deep offshore operations focused essentially on the development of oil fields, but for the next decade, the focus will shift to the production of gas fields. Often located hundreds of kilometers from the coast, the production of this type of gas reservoir will require major leaps forward in technology.

Among the major future projects is Ichthys, a giant gas (+condensates) field discovered in 2001, measuring 20 km by 40 km and currently in the development phase (**Erreur !**

Source du renvoi introuvable.). It lies about 230km off the west Australian coast under a water depth of approximately 250 to 275m. The gas reserves are estimated at somewhere between 15 and 20 TCF (between 2,5 and 3,5 Gboe) and the condensates at between 350 and 450 million barrels. When it levels out, gas production should plateau at 0.5TCF/year (230 kboepd) and condensate production at 85 kbopd.

Although strictly speaking, it is not a deep offshore reservoir, the distance from the coast makes it very complex to produce. Ichthys' subsea production system comprises about fifty wells divided up into about a dozen drilling clusters (**Erreur ! Source du renvoi introuvable.**). The effluents (gas + condensate + water) converge via subsea pipelines and risers to a giant submersible platform measuring 110m (Central Processing Facility - CPF) where the gas will be separated from the liquid (condensate + water). The liquid will then be sent to an FPSO anchored approximately 2 km away, whereas the gas will flow through a giant pipe measuring almost 900 km[3] in length, to the Darwin terminal comprising two LNG trains with a capacity of 8.4 million tons per year. Production is due to start on Ichthys at the end of 2016.

[3] Measuring nearly 900 km, the export pipeline will be the longest in the world