Drilling, a high precision technology – current challenges and possible ways forward

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1 Why do we need directional drilling?

Previously in the history of oil exploration it was assumed that all wells drilled would be vertical. However, it was realized that this assumption did not hold true when a number of wells drilled close to each other in the same field penetrated the producing zones at different measured depths and, more importantly, some of the wells encountered pre-existing wells while drilling. Understanding of this fact was then used to deliberately deviate wells in order to drill around obstacles, e.g. a fish left in the hole, which eventually evolved to controlled directional drilling and to reporting the length of the wellbore as measured depth (MD), true vertical depth (TVD), the hole inclination angle (deviation from vertical), and the hole azimuth (deviation from North).

Some of the uses of directional drilling today include: sidetrack drilling from a pilot hole; reaching hydrocarbon reservoirs under inaccessible surface locations; penetrating reservoirs in challenging structures such as in the vicinity of salt domes and faults, etc. (Fig. 1).

Yet another application of directional

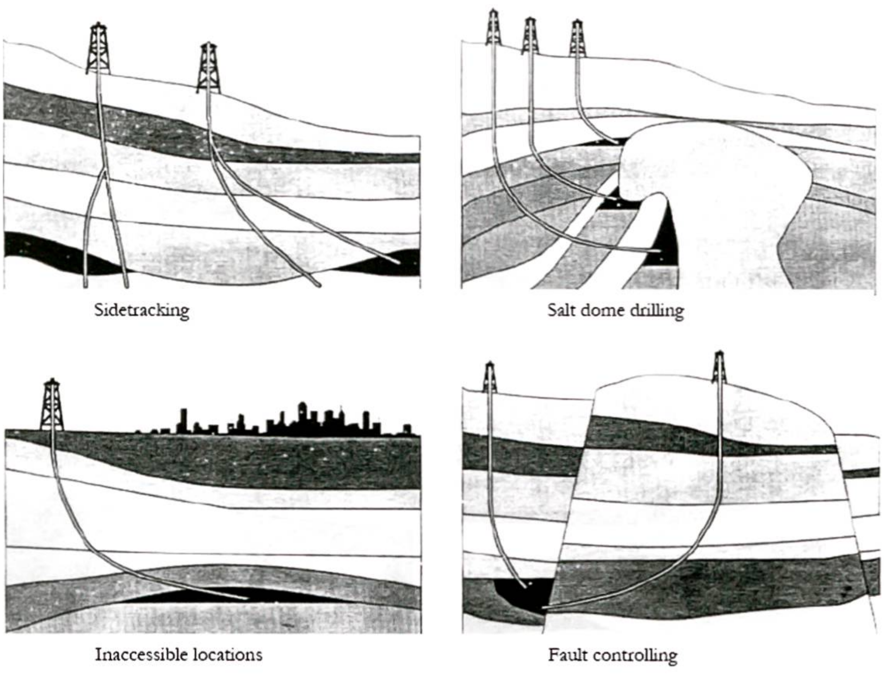

Fig. 1: Applications of directional drilling (Source: Weatherford).

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drilling is extended reach drilling (ERD) where the ratio of the horizontal displacement to true vertical depth is at least 2. Driven by tough offshore economics and weather conditions, as well as by the goal to reduce the environmental footprint of drilling by using existing infrastructure ERD envelope was stretched in Sakhalin, Russia where an ERD well with a measured depth (MD) of over 12,000 m and a true vertical depth (TVD) of approximately 1,800 m was drilled. Not only do the advances in directional technology allow drilling wells with complex trajectories and long stepouts, but also precisely hitting relatively small targets. A relief well drilled in 2010 intercepted a $9^5/_8$" (244 mm) casing at planned MD of almost 5,500 m. Another good example of breaking the drilling limits is Wytch Farm Field, Offshore UK, where multiple wells, some of them reaching approximately 11,000 m MD, were drilled from onshore which dramatically reduced the reservoir development costs.

2 Methods of well deviation and directional control

In the past, wells were traditionally kicked off from a whipstock, a wedge-shaped steel casting with a tapered concave groove down one side to guide the bit. For proper orientation of the whipstock a unit recording inclination and direction at a survey station on a photographic film, called a single shot instrument, was used. These operations required a significant amount of time to achieve a fixed and typically abrupt kick off angle and direction.

With ever more complex well trajectories, thinner and tighter reservoirs and multiple wells drilled from a single location and often from a single parent wellbore, it is critical to accurately control the well position while drilling to hit the planned targets of a well. Advancements in directional drilling technology allow us to drill wells with inclinations over 90° and intentionally turn horizontal wells 180° in azimuth. Therefore, today, Positive Displacement Motors (PDM) and Rotary Steerable Systems (RSS) along with downhole sensors measuring the inclination and azimuth are commonly used to guide a well along the planned trajectory. These instruments enable steering a borehole in a desired direction while they are still downhole. Real-time communication between the surface, RSS and downhole sensors are typically provided by Measurement While Drilling (MWD) systems.

Elements essential for understanding the operation of PDMs include (Fig. 2): a steel rotor and an elastomer stator; and an adjustable bent housing above the bit providing a preset misalignment of a bit face

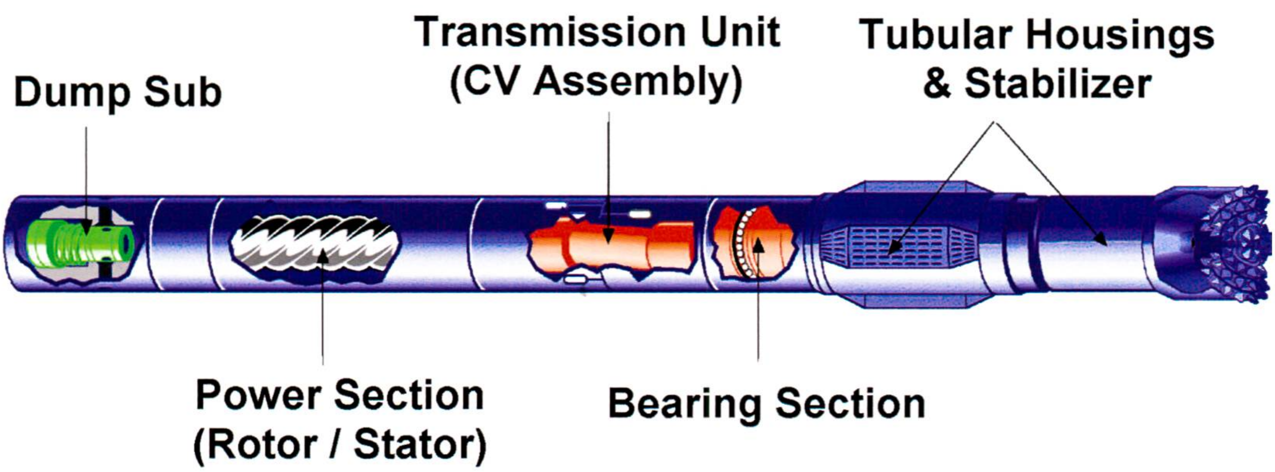

Fig. 2: A general downhole motor configuration (Source: HALLIBURTON).

from the drill string axis and, when stationary, causing the bit to drill in the direction of the bend. Drilling fluid flowing through the motor forces the rotor to rotate the motor driveshaft and in turn, the bit. To follow the wellpath, the drill string rotation is stopped and the bend in the motor is oriented in the desired direction. This is referred to as sliding mode, and typically results in high frictional drag and tortuous well profile. To drill a straight hole section the drill string is rotated from surface, which is referred to as rotary mode.

Another more advantageous and typically more expensive tool used for directional drilling is the Rotary Steerable System (RSS). There are two rotary steerable systems available – point the bit and push the bit which allow the rotary drilling to continue while desired changes in wellpath are made. In the former, the bent housing is located inside a collar, essentially a tilted shaft connected with a bit, where hydraulic pistons deflect the shaft forcing the bit in the opposite direction. And in the latter, trajectory change is achieved by applying side force, using non-rotating pads, against the borehole wall to push the bit in the desired direction.

MWD tools are used as a part of the bottom hole assembly (BHA) located above the bit and incorporate downhole sensors, directional and typically gamma ray and resistivity, as well as telemetry systems, which allow transmission of data recorded downhole to surface. Most commonly used telemetry systems are: mud pulse and electromagnetic telemetry. In a former system, the data is converted into binary code, which is transmitted to surface at a rate of about 20 bits/sec (depending on the system and downhole conditions) as pressure waves generated by downhole pulser, i.e. a downhole actuator briefly restricts the flow of drilling fluid down the drillstring and creates a positive pressure pulse. In a latter one, the encoded data is sent to surface as a modulated current by a downhole emitting antenna that injects an electric current into the formation around the borehole. Electromagnetic waves created are picked up at surface by means of an antenna arrays. This technology provides data transmission rates of up to 100 bits/sec, but suffers from hole depth and formation related electric impedance limitations.

3 Geosteering

Continuous effort to reduce costs and limitations of wireline logging lead to the development of Logging While Drilling (LWD). Unlike MWD, LWD incorporate more sophisticated downhole sensors for detailed formation evaluation such as spectral gamma ray, neutron-density, resistivity, sonic, etc. Combination of the above mentioned technologies enabled development of reservoirs that would have otherwise been deemed uneconomical, e. g. thin pay zones, low permeability formations, mature areas, multiple small targets, etc. Using the data from sophisticated downhole sensors allows controlling the wellbore trajectory based on real-time measurements of formation properties rather than following a planned wellpath, this method is referred to as geosteering. It allows staying in the payzone providing increased contact area, which in turn results in higher production rates at equivalent downhole conditions.

4 Importance of horizontal drilling

Horizontal drilling is one of the crucial technologies that made unconventional resources economically and or technically feasible in the US. Improvements in technology, significant reduction of surface footprint (so called pad drilling), and economic benefits from larger contact area with hydrocarbon bearing formation as well as from reduced number of wells required for developing a field drove the operators to prefer horizontal wells over vertical ones. As a result the number of horizontal wells has risen drastically over the first decade of 2000s.

5 Directional drilling challenges

Planning and drilling directional wells can often be very challenging, and even more so when those are horizontal or ERD wells. Effectively drilling these types of wells calls for real-time monitoring of, and improvements in, the drilling fluid and drilling practices to ensure proper hole cleaning and wellbore stability. Despite the availability of advanced fit-for-purpose equipment and tools the critical success factor for highly-deviated complex-trajectory wells is rigorous engineering and planning. Most critical issues that have to be addressed can be summarized in the following three groups: torque and drag; casing design and running casing; and drilling hydraulics and hole cleaning. However, inadequate hole cleaning can exacerbate most of the above mentioned drilling problems, e. g. stuck pipe; excessive overpull while tripping the drillstring; high torque; hole pack-off; slow drilling rate; difficulties while running casing and logging tools; etc. Effective removal of cuttings from the wellbore can be a difficult exercise, as it is dependent on a number of variables that might be controllable only to a certain degree. Insufficient flow rate or inadequate drilling fluid rheology can result in solids settling through the fluid creating cuttings beds. Furthermore those may be worsened by enlarged hole or reground cuttings respectively. Cuttings that settle on a low side of the borehole tend to avalanche or stay at the bottom, as can be seen in Fig. 3. Those cutting beds need to be mechanically stirred to be moved to the flow stream by rotation of the pipe, in addition to that a given rotational speed is necessary to keep the cuttings in the flow, which may be limited due to downhole conditions and/or equipment limitations.

Numerous drilling optimization methods have been and being developed in an effort to overcome localized drilling challenges, to improve safety and to make the drilling prospects economically and technically viable. Some of those techniques will be discussed below.

6 Coiled tubing drilling

Coiled tubing drilling (CTD) evolved from application of standard coiled tubing (CT) technology in workover and completion industry. Coiled tubing is a continuous length of pipe that is stored on a reel and straightened before running it into the borehole. Coiled tubing unit consists of a surface set of equipment required to carry out continuous length tubing operations. It includes the following main elements (Fig. 4): power pack, for required power generation; tubing reel, for CT storage; tubing injector; for

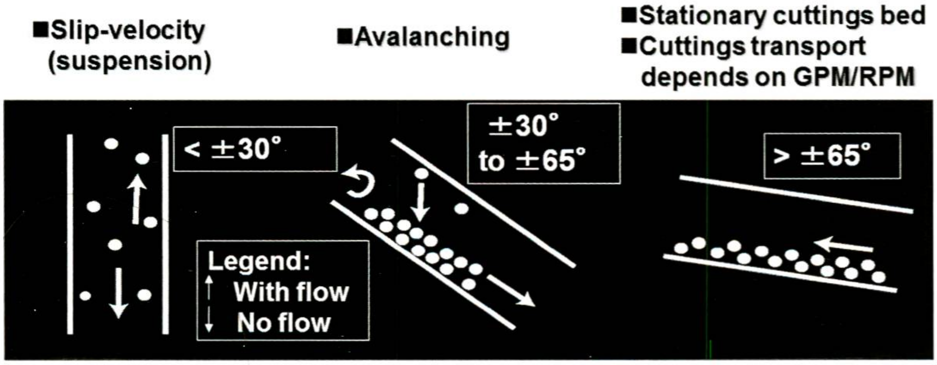

Fig. 3: Cuttings behavior as a result of borehole inclination.

injecting and retrieving CT into/out of the hole; and well control equipment, for sealing around CT during tripping and when there is no movement.

In comparison to conventional rotary drilling, where jointed drill pipes are used (resulting in lengthy tripping operations), CTD provides a multitude of advantages for specific projects, including: improved safety due to reduced personnel as well as reduced pipe and tool handling requirements; reduced environmental impact due to smaller footprint and smaller diameter wells (slimhole technology); operational benefits due to reduced trip times (very few connection to make up), short mobilization and rig-up times, and high speed data transmission rates («wired CT telemetry»); and resulting economic benefits.

CTD can be used to drill non-directional and directional wells. In a former case, a conventional drilling assembly with no instruments for directional control is used below the CT. Whereas in a latter one a bottom hole assembly with an orientation device is required to control the well trajectory. Furthermore, other downhole sensors may be run as part of the BHA, e. g. formation evaluation, pressure, vibration and weight on bit sensors. Applications of this type of CTD systems might include new wells; re-entry wells: conventional (sidetracking, horizontal drilling), thru-tubing (deepening wells); rig-less platforms, etc.

Along with all the potential benefits of CTD there are quite a few limitations. For example, even though hole sizes up to $13^{3}/_{4}$" have been drilled with CT, the majority of the applications are up to $8^{1}/_{2}$"; high cost of downhole instruments and of CT string. CT string has significantly lower lifecycle than conventional jointed drill pipe at equivalent downhole conditions, as CT is plastically deformed in normal use which will eventually lead to fatigue failure and the entire CT string getting scrapped. In addition, there are mechanical and hydraulic limitations resulting in reduced torque and weight on bit; as well as challenging hole cleaning, since CT string cannot be rotated (which mechanically stirs cuttings to keep them in the flow) and flow rate is limited due to higher frictional pressure losses (fluid has to travel the entire length of coiled tubing independent of current depth). Close consideration to the abovementioned points has to be given when assessing the feasibility of the technology.

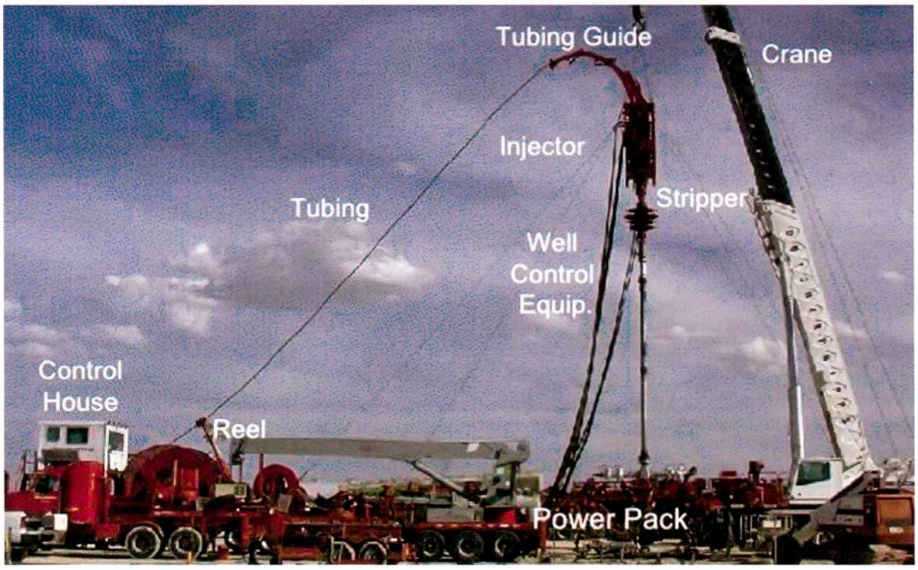

Fig. 4: Main components of CT unit (Source: HALLIBURTON).

7 Casing drilling

Casing drilling (CD) has been developed and successfully utilized to solve drilling challenges that typically cause substantial difficulties when drilled conventionally, such as: drilling through swelling/sloughing formations, depleted zones (lost circulation, stuck pipe), zones with wellbore stability problems, high non-productive time, etc. Unlike conventional drilling where the borehole is first drilled with a drill string and then casing is run for formation isolation, CD enables accomplishing those tasks simultaneously using «standard» casing string, potentially mitigating the drilling hazards, and reducing well time and costs.

There are a number of commercial systems available on the market for specific applications however, all of those can be subdivided into two groups, as can be seen in Fig. 5: non-retrievable and retrievable systems. The former system allows drilling to the required depth with a casing string and a bit, which can be drilled out after the casing has been set and cemented, however, this system provides no directional capability. The latter system enables drilling directional wells with retrievable bottom hole assemblies (BHA) and conventional bits. BHAs can be retrieved with coiled tubing, drill pipe, or wireline without the need to pull the casing string out of hole.

CD technology offers significant advantages, however, in order to determine its suitability for a specific project considerable engineering and risk assessment are essential. A number of challenges need to be solved and potential issues taken into account, e.g. additional time for rigging up and rigging down the equipment (i.e. making the rig fit-for-purpose); costs for additional personnel and expendable tools (non-retrievable bit); necessity to trip the entire casing string out of hole in case drilling from shoe-to-shoe is not possible (non-retrievable system) or in case casing getting stuck; equipment limitations such as torque limitations of special connections; etc.

8 Dual gradient / Managed pressure drilling

Offshore, typically in deep and ultradeep waters, much of the overburden is seawater, which is less dense than typical formation overburden, resulting in weak formation strength and thus narrow margins between pore pressure and formation pressure (also known as a narrow drilling window). Because of this, multiple casing strings might be required to allow drilling further

Fig. 5: Casing drilling systems (Source: Weatherford).

safely and efficiently. Driven by the fact that staying within this narrow window allows drilling to even deeper reservoirs; improved control of casing setting depth with fewer casing strings; as well as mitigating drilling hazards, including lost circulation, stuck pipe, wellbore instability, well control incidents, lead to the development of dual gradient drilling (DGD).

DGD is a variation of managed pressure drilling (MPD), where MPD is a drilling process aiming to control the bottomhole pressure from surface within a given range in order to stay in a typically narrow drilling window (in deepwater). Unlike conventional drilling, where a single fluid pressure gradient in the borehole is relative to the drilling vessel at surface, DGD employs two different fluids (one above the sea floor and one below) which results in lower pressure in the wellbore (Fig. 6). Most of the systems available on the market employ a complex combination of pumps and valves to isolate the borehole pressure gradient below the sea floor from the gradient above it.

The application of this technology requires significant engineering and planning efforts, and is quite cost intensive. Furthermore, additional surface space requirements for

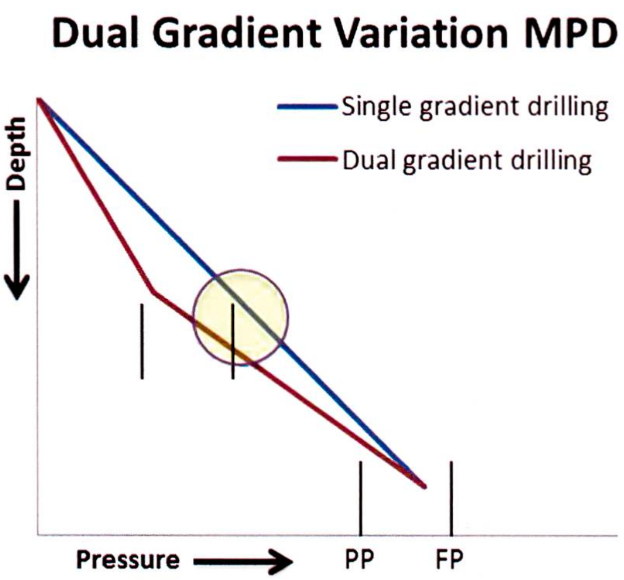

Fig. 5: Casing drilling systems (Source: Weatherford).

the equipment and increased potential well control risks have to be considered.

9 Well Costs

Well costs include a number of elements and might depend on a multitude of factors. The typical procedure is to break the well costs into general categories or main phases of a well, such as: wellsite preparation; rig move and rig up/down; formation evaluation and testing; casing and cementing; well completion; and drilling.

Wellsite preparation and rig mobilization costs are mainly a function of location terrain, its remoteness (e.g. how far the rig has to be moved; availability of developed market, roads, infrastructure, etc.) and the type of rig used. The costs associated with formation evaluation and testing depend on the complexity of logs required; downhole conditions; number of runs; means of getting the logging equipment to bottom; the number and type of production tests plus the rig time costs as the borehole and drilling fluid conditioning are typically required prior to running logging or testing equipment. The costs of casing and cementing operations are generally determined by number, length and type of casing strings; volume and type of cement and additives; as well as the rig time costs for rigging up/down the surface equipment and borehole and drilling fluid conditioning. Completion costs are essentially based on completion type, duration of the operations and workover rig rate. Drilling costs might depend on a variety of factors, including: location (offshore, onshore, country, etc.); well type (sour gas, high pressure high temperature, etc.); hole depth and geology; number of targets; well profile; subsurface problems; rig costs; knowledge of the area; etc.

Well costs in Europe might be spread over a wide range depending on the abovementioned factors. However, assuming a «normal» land development well in Europe (about 3,000 meters measured depth; 3 sections; simple build and hold well profile with inclination up to 30°) well costs in the range of a 4 to 8 million euros (depending on complexity of the project) can be estimated. Ways of keeping the well costs down might vary from company to company. However, in general those could be summarized as follows: an integrated approach to engineering and planning; utilization of well-maintained fit-for-purpose equipment; competent and experienced rig personnel.

10 Possible Ways Forward

Since more than a century rotary drilling has replaced cable tool drilling and has been widely used for oil and gas wells drilling. Up to now a multitude of drilling technologies have been researched, developed and implemented which aimed to improve safety, efficiency and reliability of drilling operations. Many of those technological advances required a considerable adjustment of the drilling process and represent a significant change in drilling technology. However, most of the technologies that have been commercialized to date are based on rotary drilling. Among other reasons, this probably has to do with a particular slow adoption of new technology in the oil industry in general, as well as with the fact, that the most basic requirement of drilling technology is to provide safe and economic access to the downhole targets. Various promising non-rotary drilling techniques are being investigated, such as laser and plasma drilling with potential benefits including improved rate of penetration, reduced downtime, forming a natural casing (due to formation melting), significantly reducing the rig site size, etc. Despite the significant advantages of those technologies, there are fundamental challenges that have to be solved, including substantial energy loss in transmitting power downhole (economic), as well as lack of established methods and practices of maintaining control of the well in the event of a kick (safety).

Among the most relevant emerging drilling technologies is drilling automation. This technology aims to bring together surface and downhole automation, where surface processes are controlled by mechanized equipment (e. g. pipe handling systems) and data from downhole and surface sensors is fed into control systems and predictive models to react in real time to changing drilling environment by adjusting the operational parameters.

Rig floor and other surface systems automation improve safety by removing people from potentially dangerous operations and increase efficiency by consistently and precisely performing repetitive tasks in any conditions those systems are designed for. In addition downhole automation will permit the performance of simultaneous complex calculations, predicting the drilling performance and decision making, to name a few potential advantages.