

Performance analysis of “Petroleum Well”

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Abstract— Oil exploration is a capital intensive activity. Uncertain outcome, high stakes and volatile crude oil price makes it a high risk business. In such circumstances, companies relying on two key factors: operational efficiency and cost optimization. Moreover, problem of disproportionate attribution of input cost to the revenues often exists. For these issues, understanding the oil well-costs is very important. This paper describes various phases of oil well drilling activity and cost associated with it. Drilling time is very vital due to limited availability and high rental cost. The study draws the conceptual background for the oil well performance analysis. The various factors influencing cost of petroleum well like time dependent and time-independent cost, well planning cycle, and authorities for expenditure are studied in this paper. The study focuses on complexity involved in cost estimation of oil well drilling operation.

Keywords—Oil Exploration, Oil well, Technical Limit, Authority for Expenditure, Pre-Spud

I. INTRODUCTION

Drilling activity constitutes major portion of cost for oil exploration companies. The detail analysis and knowledge of drilling cost (well cost) are prime factors to know economic viability of exploration projects and licence. Drilling cost is one of the criteria for the selection of exploration area. Each drilled well is unique in nature. So, forecasting of drilling cost remains an imprecise process despite of an important component of exploration cost.

Significant variation of Lithology (physical characteristics of rocks) over short distances leads to variation in drilling cost and efforts. Equipments and personnel working on exploration activity vary from rig to rig. Uncertain weather, difficult geology, and equipment failure leads to substantial ‘Non-Productive Time’ in drilling operation results in cost escalation. Market rates for equipment and services are very dynamic. Experiential knowledge can help to improve the performance in subsequent operations. For Indian operators, this kind of information is either lacking or not properly documented. This leads to high degree of variances in drill cost estimation.

II. SCOPE AND OBJECTIVES OF THE STUDY

Drilling cost of oil well is a function of time (drilling time), cost (\$/day), variable costs (\$) and fixed costs (\$). Numerous factors can affect these costs. For example, Management, markets, environment, geology and technology are. These influences may lead to innumerable combinations and can cause variable outcomes. Based on scope, we have identified following objectives:

- To study techno-commercial aspects of Well Performance (Time and Cost).

III. PAGE STYLE CONCEPTUAL FRAMEWORK OF OIL WELL DRILLING

Oil wells are classified as exploration well, appraisal well, and development wells. The classification is merely based on distance from previous drilled well. Distance from previous well is comparatively more in case of Exploration wells than appraisal wells or development wells. Moreover, uncertainty and complexity involved in drilling phase are more compared to other types of well. Sometimes, well operations are concluded because of no indication of hydrocarbons, then the exploration well is plugged and abandoned (P&A). It is referred as “Dry Hole Cost” by drilling ‘Authority for Expenditure’ (AFE).

To evaluate petroleum-bearing reservoir, wells drilled nearby previous well is known as appraisal wells or development wells. It has low uncertainty compared to exploration well. Moreover, full-hole coring, extensive logging, production testing and other operations may be done on appraisal well. Development well is to be drilled, If testing indicates commercial viability of discovery. Large scale offshore development wells may includes horizontal drilling from a central drilling platform. Higher complex nature of development well increases the risk for the exploration companies. However, knowledge gained from previous drilling operation helps to mitigate increase risk.

There are three main phases of well drilling operation: Pre-spud phase; Drilling phase; and the Completion phase (Figure – 1).

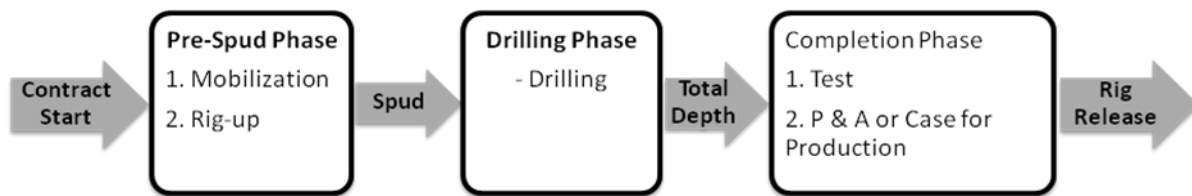


Figure 1 Phases of Oil Well Drilling Operation

1. Pre-spud Phase: period from start of contract to spud.
2. Drilling Phase: time period from start of well spud to reach Total Depth (TD).
3. Completion Phase: time period from Total Depth to release of drilling rig.

Perfect time duration for each phase is difficult to estimate due to overlap of phases. Time and date for different phases cannot be determined in case of onshore well because of improper or no documentation.

Each phase of drilling activity can be divided into sub-phases comprises of many operations (ten to thousand operation per sub-phase). From the past experience or experts opinion, time and cost estimation of individual operation are laid down in advance. However, definitions and codes for detailed operations vary across different operator.

The details of the wells to be analysed are as follows:

A. Pre-spud phase

Usually, it takes some time to start a contract after contract award. Time duration from contract start time to well spud time is known as pre-spud phase. This phase further divided in to two phases: 1) Mobilization - from contract start to arrival of drilling rig at location; 2) Rig-up – from completion of mobilization to start of drilling.

B. Mobilisation

Mobilisation cost includes transportation charges to mobilize the rig to well location. Transportation charges may be lump sum or on daily rate or combination thereof. Cost of technical overheads for operator, site surveying and site preparation are also included in pre-spud cost. The accounting policy decides the allocation of other costs (i.e. non-rig, pre-well charges etc.) to the Total Well Cost. Finally it is reported in a “Well Completion Report” (WCR).

C. Contract start

The mobilization cost from previous well is usually charged to receiving well both for onshore and offshore operations. This practice may differ from location to location. For example, in Australian basins, moving drilling rig one kilometre from drilled well indicates starting of new contract and ending of previous one. In United States, long term contracts are very common, the movement of drilling rig one kilometre from or off the well site decides contract start and end time. In case of offshore well, the first anchor dropped is recorded as arrival time of the rig (for jack-up rig, pinning of leg to the sea floor).

D. Drilling phase

The time duration from start of drilling to the time when it reaches to Total Depth (TD) of drilling is referred as drilling phase and further drilling stops. A conductor hole is drilled first and then main drilling starts by primary drilling rig.

E. Rate of Penetration (ROP)

Depth travelled per unit time by drill bit is known as Rate of Penetration (ROP). ROP depends on rock density which is function of mineralogy and depth of burial. Also, at a particular depth, variation of rock density depends on rock types. Increase in depth increases overall rock density because of high temperature and pressure on sediments. This process of diagenesis changes the physical and chemical structure within the rock. Moreover, increase in drill depth reduces the ROP (time required for drilling increase as depth of drilling increases). So, there exists more than one rate for drilling (i.e. slow, medium, and fast).

F. PDC drill bits

Traditionally, roller cone drill bits were used for hard and difficult rock formation. Technical innovation in Polycrystalline Diamond Compact (PDC) bit allows drilling in harder formations (Hartley, 2004). PDC bits can drill faster and have high ROP compared to traditional drill bits.

G. Mud drilling

Mud is a drilling fluid used in drilling operation to maintain high pressure in the bore hole, which in turn prevents invasion of reservoir fluids. New innovative and environment friendly drilling fluids may be required in certain environmentally sensitive area. High cost of unconventional drilling fluids substantially increases the drilling cost.

H. Casing

Casing is required to maintain and balance pressure of drilling fluid as the bore-hole deepens. Casing process (running and cementation of casing) substantially increase the drilling time rig cost. Casing is a significant part of Total Well Costs. Therefore, primary engineering and economic analysis need to be done for the selection of casing operation parameter like size, grade, connectors, and setting depth etc. (Economides et al., 1998).

I. Flat time

The time period during which no actual drilling occurs is known as 'Flat Time'. Following are reasons for flat time in drilling operation:

1. Tripping: To change worn out drill bit, the drill string need to bring to the surface and again run to the bottom of the hole. This time is known as tripping time. Depth of drilled well, crew efficiency and rig capacity affect the trip time.
2. Setting casing: it is the time required for process of casing (running, cementation and setting of surface casing) in the borehole.
3. Testing: To evaluate formation before reaching Total Depth (TD), testing is done.
4. Non-productive time: Sometimes drilling stops due to uncertain events like disturbance in weather. This downtime in drilling operation is referred as Non-productive time.

Evaluation of formation (coring, logging or drill stem testing) is done intermittently during drilling operation which in turn slowdown the drilling process. Rock segments are continuously captured and brought to the surface in coring process. So, ROP is slower in coring process compared to normal drilling. Logging is done using 'logging while drilling' (LWD) tools to evaluate geological formation. LWD reduces testing and intermediate logging time. Drill stem tests (DSTs) are done prior to completion for measuring hydrocarbon flow rates. Intermediate DSTs increases daily well cost.

J. Total Depth

The maximum depth that can be reached in drilling operation is referred as 'Total depth' (TD). Sometimes, for testing or coring purpose, a side-tracked hole is drilled. The signal of "Drilling Ahead End" is an indication of Total Depth (TD) and well 'bottom up' operation start. Well bottom up operation cleans all drilling fluid and cuttings in the well. Setting a production casing defines the transition from drilling to completion phase (Noerager, White, Floetra, & Dawson, 1987). Exclusion or inclusion of operations in drilling phase or completion phase depends on company policy. For example, CSIRO Petroleum excludes all operations performed after reaching well TD from the drilling phase (Kravis, Irrgang, Scott, & Lollback, 2004).

K. Completion phase

Time duration from reaching Total Depth (TD) to rig release is known as completion phase. Final logging is performed after reaching TD in spite of use of 'Logging While Drilling (LWD) or Measurement While Drilling (MWD) tools. Additional tests for side-wall coring, velocity surveys etc. may also carried out. In case of abandoned well, to protect reservoir leakage and contamination, cement plugs are set in the well bore. Plugged & Abandoned (P&A) is a common indicator for completion phase for exploration well independent of hydrocarbon indication. In case of dry hole, removing of casing may also part of completion phase.

Demobilisation starts by transporting drilling rig to another location within the basin. In case of semisubmersibles, demobilization starts from raising the anchors transporting the rig one kilometre from the current location and handed over to other client or moved to nearest port. The cost of mobilization or demobilization again depends on types of contracts.

IV. TECHNICAL LIMIT CONCEPT

Historical data provides base for 'Technical Limit' (TL) time. It requires valid offset data to carry out detailed time analysis. Best performance (time, cost and quality) of each drilling operation defines 'Technical Limit' time for oil well drilling activity considering current technology, methods and flawless operation. For future planning, TL will be set as per the most efficient operation from previous experience. So, it is a dynamic standard time for an operation. TL time analysis helps to identify area of improvements and act as benchmarks for well performance.

The figure 2 depicts pictorial view of different time slots. Removable time shows the opportunity for improvements. It is the deviation of actual well time from theoretical well time. Removable time comprises of conventional lost time, down time (NPT – 'Non-Productive Time'), and 'Invisible Lost Time' (ILT). The invisible Lost Time represents accepted deviation from plan time due to some unexpected (wasteful) events. ILT presents due to lack of optimization in resource usage, procedures or unavailability of efficient equipments and resources. For example, time lost due to lower rate of penetration than expected (ROP - when the bit is actively making hole) would be classified as ILT. Invisible Lost Time provides possible area of improvement in future drilling operations.

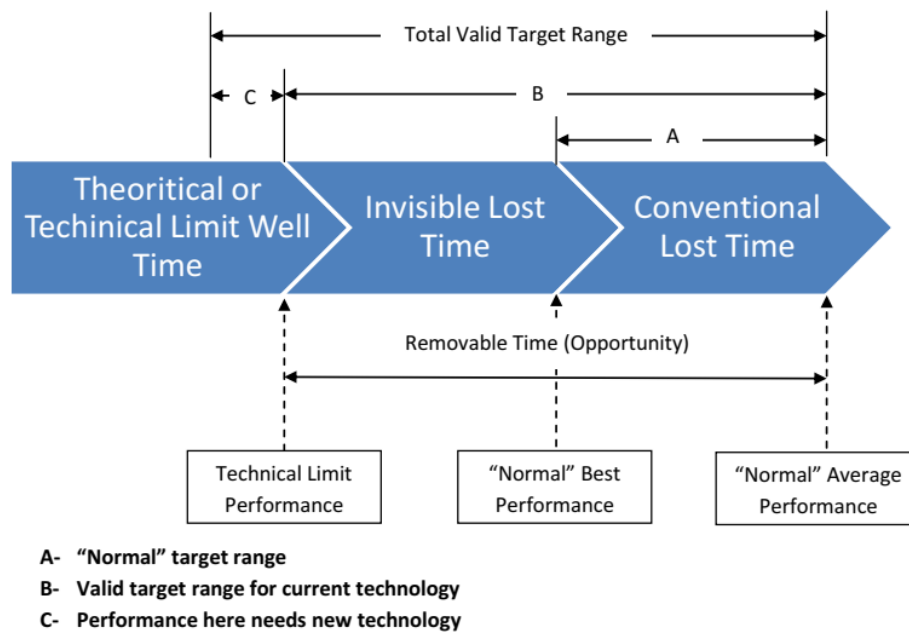


Figure 2 Technical Limit Time

V. TIME INDEPENDENT COSTS

There are three components of well construction cost: 1) Variable cost (time dependent); 2) Variable cost (Time Independent) and 3) Fixed Cost. Time independent variable cost represents cost of materials used in well construction activity i.e. cement, drill bits and other consumables. Time independent costs make substantial proportion of well costs (Marshall, 2001). Technical limit analysis will not be able to reduce these costs. The relative percentage of cost elements with reference to total well cost vary from well to well (Marshall 2001). However, drilling cost (rig day rate) remains largest component normal well cost. Generally, 30% to 60% of well construction costs are not time dependent cost. Cost for casing generally represents a fixed cost and procurement is done in advance. So, it is a tangible capital cost.

VI. WELL PLANNING AND AFES (AUTHORITY FOR EXPENDITURE)

A. Well planning

Well planning refers to processing and analysis of data collected from previous drilling operation performed in proposed drilling areas. Knowledge acquired about problems encountered in previous drill operation helps in accurate well planning. Technical Limit analysis of historical data and learning from past experience helps in drill well planning to outperform the competitors. For example, Anadarko's well analysis process uses best composite time and cost, learning curve analysis and quantification, detailed cross correlative plot/analysis of drilling problems, interdisciplinary collaboration, and feedback of learning and solutions to problems (Iyoho et al, 2005).

B. The AFE process

The estimation of cost and requests for fund for well planning is to be done in the form of Authority for Expenditure (AFE). Well Cost Report gives estimation of cumulative incurred cost up to reporting day. It is referred as accrued costs rather than a cash flow. The AFE process results in to total well cost. However, importance has not been given to document AFE (Pieters, 1994).

Conventionally, historical performance remains the base for time estimation of drilling activities and total well cost. The result was a deterministic estimate of well time and cost (i.e. an estimate built up from single values and itself expressed as a single value). To account for uncertain events, contingency factor will be added to deterministic well cost (Kadaster et al, 1992).

C. Objectives of an AFE

AFE may differ from company to company due to accounting policy. Moreover, accounting of costs like planning, country head office costs etc. in AEF. Rig mobilization cost for the first well in a particular basin area remains an issue. The primary objectives of AFE are cost control and play an important role for well delivery. For example, drilling performance is being evaluated using AFE deviation analysis (Peterson et al, 1993). The AFE deviation analysis indicates a moderate performance if it shows balanced upside or downside from mean time or cost for a well. It is a conventional philosophy that budget should be approved such that there is no shortage or surplus of funds to drill a well (Peterson et al, 1993). Today, companies treat AFE as a 'delivery promise' and must be stick to it in any circumstances. Most of the time this threshold is exceeded due to exclusion of sunk cost follows from the principle of 'ignoring sunk costs'.

D. What does an AFE represent?

The setting of AFE is based on median, mean or on percentile of costs. In median case, AFE is set at P50 (50/50 or median) of estimated time (Bond et al. 1996). P50 indicates 50% probability of deviation from estimated AFE estimate. Allowance of 10% is added to have P70 outcome when AFE set to the mean cost. P70 means that the well cost will be less than AFE in 70% cases and 30% cases have higher well cost than the AFE and required additional funds. To select setting of AFE, different scenarios need to be generated based on percentile setting of AFE and initial funds. The choice of AFE percentile depends on financial control and operational autonomy. Lower percentile for AFE indicates close financial control and higher indicates autonomy of operation. For remote exploration well, higher percentile of AFE is desirable. The deviation of final well cost from AFE can be due to various causes like change of scope of work or evaluation programme etc.

VII. PETROLEUM WELL COST MODELLING

The petroleum well cost modelling would require to identify the major factors affecting the well costs. Following data need to be collected related to well costs:

- Operating company's name
- Well name
- Location – onshore/offshore, basin, sub-basin and state
- Rig – name and type (land, jack up, semisubmersible, platform etc)
- Dates and times – start move, on location, spud time, total depth, and rig release
- Depths – total depth, rotary table elevation, water depth, ground elevation
- Well type – exploration, appraisal or development
- Well direction – vertical, directional or horizontal
- Well results – P&A, Oil, Gas, Oil & Gas, Gas P&A, suspended
- Previous well name and next well name
- Trouble time (or Non Productive Time) and waiting on weather (WOW) days
- Borehole diameter at TD and maximum depth of casing diameters

The data which can be recorded from the Well Completion Reports (WCR) can be:

- Costs – First daily cost, last daily cost, final cost, Rig Rate and AFE estimate
- Exchange rate - US\$/A\$ (from WCRs, company and USA Federal Reserve)
- Budgeted well days and 'Technical Limit' days

The information which would need to be derived from the above data would be:

- Drilled Interval
- Well phase times – Pre-spud, Drilling, Completion, spud to release, time off well, total contract time.
- Phase costs – Pre-Spud, Drilling & Completion
- Daily Cost – Average Daily Cost at well site, total cost/total time, budget cost
- Rig day rate as a percentage of Daily Cost
- Key Performance Indicators – metres per day & drill cost per metre

The figure 3 shows the Process flow and co-relation between gathered information.

VIII. TERMINOLOGIES

A. Drilled Interval

It is the total measured interval of rock drilled from ground level or sea floor to total depth. Drilled Interval excludes the water column and air above ground or sea. WCRs usually reference well depths to RT (Rotary Table or Kelly Bushing), so corrections need to be applied to reported depths to calculate the Drilled Interval. For wells that deviate from the vertical, Drilled Interval is not the true vertical depth. Some operators include water depth when calculating their key performance indicators (KPIs). KPIs that include the water column in their drilled depth will produce higher ROPs. This approach distorts comparisons of drilling performance between deep water and shallow water wells.

B. Daily Cost

Daily Cost = (Last Cost – First Cost) / (Last Cost Time – First Cost Time)

The average Daily Cost is used to estimate phase costs. Daily Cost is an average of all Daily Costs while the drilling rig is at the well site. The estimation of Daily Cost can be done from the daily operations logs. The first reported cumulative cost in the daily reports is subtracted from the last reported cumulative cost and divided by the time interval between the first and last costs. For wells reporting AFE costs but not daily costs, the average Daily Cost is achieved by subtracting the Pre-Spud Cost from the final cost and dividing by the time from spud to rig release. I

calculate only one Daily Cost while the rig is Onsite. Fixed costs during are averaged for all Onsite time. Thus Drilling Costs may be an overestimated while Completion Costs may be underestimated.

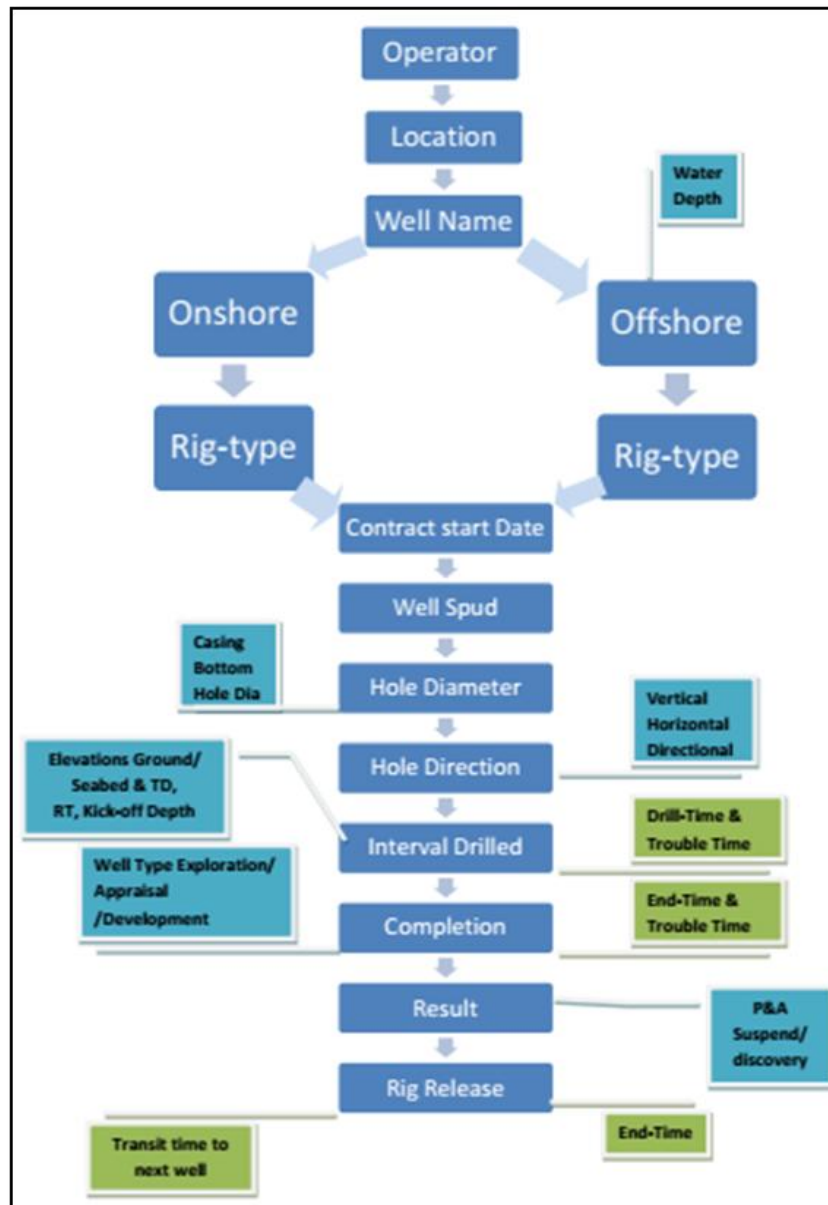


Figure 3Process flow and information gathering in oil well drilling

C. Total Well Cost

The Total Well Cost is the total ‘booked cost’ for the well. The booked cost may not be confirmed for some time after well operations are concluded. The last reported cost in the daily operations report is usually very close to the booked cost.

D. Pre-Spud Cost

Pre-Spud Cost = Last Cost – (Average Daily Cost x (Last Cost Time – Spud Time))

The Pre-Spud Cost includes all costs incurred up to well spud. It includes Onsite costs for rig- up and all off-site costs. Pre-spud Time is not required to calculate Pre- Spud Cost only the spud time, a last cost and last cost time.

E. Drilling Cost

Drilling Cost = Daily Cost x (TD Time – Spud Time)

Drilling Cost is the product of Daily Cost and Drilling Time. Drilling Cost can only be estimated if Daily Cost and TD time are known.

F. Completion Cost

Completion Cost = Daily Cost x (Rig Release Time – TD Time)

Completion Cost is the product of the Daily Cost and the Completion Time. Rig release typically occurs when the rig leaves the well site. Rarely does it include demobilisation.

IX. CONCLUSIONS

Well times have traditionally been used to measure technical performance. However, well cost is a better indicator of commercial performance. The final well cost is the result of a complex mix of interacting elements, including geological, environmental, technological, commercial, government and human. Well costs are influenced by many factors including the well plan, rig type, market rates, rig availability, rig demand, well location and drilling performance. The influence of each factor on well cost varies from well to well and location to location. Thus there are performance leaders and laggards. Performance leaders will drill similar wells at lower costs than performance laggards to achieve the same objective.

Major improvements in well performance can be attributed to better management, harnessing collective experience through better planning and problem solving. Team work, experience and contributions from everyone involved in the drilling of a well are important for continuous improvement.

In the future, drilling and service contractors will be exerting greater influence on the way wells are drilled, ensuring experience gained on one well becomes a learning point for a region as a whole.

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