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A Survey of Drilling Cost and Complexity Estimation Models

Mark J. Kaiser

Center for Energy Studies Louisiana State University
Energy Coast & Environment Building Nicholson Extension Drive
Baton Rouge, LA 70803, U.S.A
E-mail: mkaiser@lsu.edu

Abstract

Over the past several decades, various methods have been proposed to evaluate drilling cost and complexity, but because of the large number of factors and events that impact drilling performance, predictive models are difficult to construct. Quantifying well costs and complexity is challenging, due either to restrictions on data collection and availability, constraints associated with modeling, or combinations of these factors. Drill rates are often constrained by factors that the driller does not control and in ways that cannot be documented. The Joint Association Survey and Mechanical Risk Index the most popular methods used to evaluate drilling cost and complexity in the Gulf of Mexico, and specialized indices have been introduced to characterize are the complexity of drilling directional and extended reach wells. Recently, the concept of Mechanical Specific Energy has been used to obtain a more objective assessment of drilling efficiency. The purpose of this paper is to review the primary methods used to assess drilling cost and complexity. The foundational basis of each approach will be described and a critical assessment of model assumptions provided.

Keywords: Drilling performance, cost and complexity models, technical limit.

Introduction

Drilling a hole in the ground in the search for or production of oil and gas is a complex and multifaceted activity that is subject to significant sources of variability. Although the physics of drilling is the same everywhere throughout the world, geologic conditions, contractor experience, equipment availability, well specification, and numerous other factors can lead to a wide range in drilling performance. Cost estimation is difficult and benchmarking efforts are often unreliable. Performance comparisons are mostly done on a well-by-well, actual-versus-plan basis, or seek to correlate costs to performance indicators, metrics, or drilling parameters. To evaluate the differences that exist in drilling wells and to compare costs, it is necessary to establish statistically reliable relationships between performance metrics and the factors that impact drilling.

The formation geology at the site and the location of the target reservoir is a primary factor that influences drilling cost. Geologic formations vary across the world, and indeed, within the same producing basin. Hard, abrasive, and heterogeneous formations typically have low penetration rates, frequent drill string failures, and significant deviation from the planned trajectory. Deep reservoirs are usually characterized by low permeability, high temperature and pressure, complex fracture growth and stress regimes, and contaminants such as CO_2 and H_2S which increase the complexity of the well and require operators to deal with a number of issues concerning safety and operational performance. The drilling methods used to make hole depend upon the geologic formation and the technology applied, the amount of information known about the formation, the experience and preferences of the operator, available equipment, and the drilling contractor's experience and execution.

The characteristics of the well are specified by the drilling plan, the location of the target reservoir, and the conditions encountered during drilling. Bit hydraulics has a major influence on drilling efficiency, and its role is complex since it is closely tied to other drilling variables, such as lithology, bit type, downhole conditions, mechanical drilling parameters, circulation system and drilling mud. Site characteristics such as the water depth, operators experience in the region, and expected environmental conditions influence the operator's decision regarding the selection of the contract and rig type, which in turn influence drilling performance metrics. Exogenous events such as stuck pipe, adverse weather, and mechanical failure cannot be predicted and can have a significant impact on the time and cost to drill a well.

Two methods are commonly used to benchmark drilling performance. The first method is based on experimental design and controlled field studies. Typically, one or more parameters of the drilling process are varied and the impact of the variable(s) on output measures such as the rate of penetration (ROP) or cost per foot examined [1]. The most common is the "drill rate" test, in which the driller experiments with various weight on bit (WOB) and rotations per minute (RPM) settings, and then selects the parameters that result in the highest ROP. Controlled field studies are often the best way to understand the relationships between drilling factors under a set of conditions that are tightly controlled. The analytic results that are derived under field studies are often based on engineering and scientific principles specific to the wellbore conditions, experimental design, equipment, and contractor, and thus, the ability to generalize the results to other wells and locations may be limited. All optimization schemes use a similar comparative process, to identify the parameters that yield the best results relative to other settings.

The second method to study factor effects is based on an aggregate assessment of well data collected from a variety of drilling contractors, locations, and wellbores. In this method, data that characterizes a set of wells are collected, and relationships are established between the variables based on empirical modeling techniques; e.g., [2].The aggregate approach to analysis uses a set of drilling data and seeks to discover relationships between various factors of drilling and the cost and complexity of the wellbore. It is common to try to capture the best practices by comparison to an ideal well or offsets. In the technical limit approach, for instance, the technical limit describes a level of performance defined as the ‘best possible” for a given set of design parameters [3]. This allows engineers to compare and contrast a variety of factors that impact drilling and to develop models that describe the behavior of the performance metrics.

The evaluation of drilling performance commands a high degree of visibility within management circles, and over the years, a wide variety of cost and complexity models have been developed within engineering and service companies across a wide variety of firms, but these techniques are usually company specific and confidential, without a public record to assess, and thus, not available for analysis. In the Gulf of Mexico, the Joint Association Survey (JAS) and the Mechanical Risk Index (MRI) are popular methods used to evaluate drilling cost and complexity. The JAS estimates drilling cost using survey data and quadratic regression models constructed from four descriptor variables. The MRI employs primary variables and qualitative indicators to measure drilling risk and complexity. A Directional Difficulty Index (DDI) and Difficulty Index (DI) has also been introduced to characterize the complexity of drilling directional and extended reach wells. Recently, the use of Mechanical Specific Energy (MSE) surveillance in drilling workflows has been used to improve bit efficiency and performance by identifying specific limiters and re-engineering, rather than seeking a better performing system from empirical experience.

The purpose of this paper is to describe the development of cost and complexity metrics associated with drilling, to examine the computational basis of each method, and to critically examine the underlying assumptions of each model. We begin with a quick review of the well construction process and engineering cost estimation. The Joint Association Survey cost estimation methodology is then presented, followed by an Energy Information Administration (EIA) procedure. The MRI, DDI, and DI are described. A review of the use of MSE surveillance in drilling workflows concludes the paper.

Well Construction Process

The well construction process typically consists of four stages: design, planning, execution, and analysis. The design and planning phases represent the first stage of well construction, and is usually initiated through the preparation of a drilling proposal by geologists and reservoir engineers. The proposal provides the information upon which the well will be designed and the drilling program prepared. Project team selection; well design; health, safety, and environmental quality; tendering contracting procurement; finance and administration; operations planning; and logistics are the main elements included in the proposal.

The drilling engineer prepares the drilling prognosis, and all the information that is required to safely and efficiently drill the well, including the well location and water depth, the vertical depth and total measured depth, the depth of the expected reservoir sands, downhole reservoir pressures, expected hydrocarbons, the presence of H_2S or CO_2, evaluation requirements (mud logs, electric logs, drillstem tests, etc.), special drilling problems such as loop currents, shallow hazards, or shallow water flows, final disposition of the well, and future sidetracking.

The well is drilled according to the drilling plan, usually under a dayrate contract, although turnkey contracts – where the drilling contractor assumes most of the risk of the operation – can also be employed. The sequence of operations are well established. Since the drilling budget can represent a significant part of the captal expenditures for a field, drilling operations are carefully planned and closely watched, and operators maintain meticulous and detailed records of each well drilled, which are normally available in a drilling database (e.g., [4]). In order to better understand the drilling operations – what worked and what didn't, and why – a post-mortem analysis of the well or a collection of wells may be performed.

Engineering Cost Estimation

Cost estimation is performed specific to the drilling prognosis. The usual procedure is to decompose costs into general categories of (1) site preparation, (2) mobilization and rigging up, (3) drilling, (4) tripping operations, (5) formation evaluation and surveys, (6) casing placement, (7) well completion, and (8) drilling problems. Spreadsheet models are employed under various levels of detail. Typically, several categories are specified, with the drilling engineer itemizing the expected time and cost per category [5-7].

Each cost component is identified and subdivided into minor cost elements, and the percentage contribution of the total cost for each major category is computed to help identify the key cost drivers. To improve the range of the estimate, the uncertainty of the cost drivers are frequently quantified [8, 9]. A contingency is added to accommodate some of the uncertainty of costs before the final Authorization for Expenditure (AFE) is determined. The well budget is then sent to management for approval.

Well construction costs are categorized according to variable and fixed cost expenses, and the relative proportion of each will vary from well to well. Variable cost are decomposed into time-dependent cost, such as the drilling rig day rate, tool charges, rentals, fuel, power and time-independent cost elements, such as cement, drill bits, and other consumables.

Fixed costs are decomposed into well-dependent and well-independent cost. Well-dependent fixed costs include items such as the cost of casing, wellheads, and mobilization/demobilization. Well-independent fixed costs include, but are not limited to, administration, office services, insurance, legal support, interest charges on the money tied up in the equipment, expenses associated with maintaining and storing the equipment, etc.

Joint Association Survey

History

The JAS on drilling costs has been performed in the United States since 1954 in cooperation with the American Petroleum Institute, Independent Petroleum Association of America, and Mid-Continent Oil and Gas Association. The first cost surveys were performed in 1944, but 1954 is generally recognized as the official start of the JAS. Since 1959, JAS data has been collected and published on an annual basis.

The purpose of the JAS is to provide information pertaining to drilling cost and the expenditures for finding, developing, and producing oil and gas in the United States. The JAS is the only publication in the U.S. that contains annual state-by-state and offshore drilling cost data, and is considered a primary source of information by industry, academia, and government.

Questionnaires are mailed to operators to verify information on well completions performed during the year and to provide cost data for each well drilled. Re-entered wells, workovers, stratigraphic tests, core testing, and service wells are excluded from consideration, and wells started in the survey year but not completed are not reported. The response rate of the survey varies, but typically, between 40-50% of operators respond to the request for information, representing anywhere between 40-60% of the total number of wells and footage drilled during the year. Since not all operators respond to the survey, it is necessary to estimate drilling cost for unreported wells. The JAS accomplishes this task by constructing models to infer the expected cost of drilling for unreported wells. The model estimated costs are added to the reported costs to obtain the total estimated expenditures for the year.

Primary Variables

The geographic location of each well is specified as either offshore or onshore and the well type (exploratory, development) and well class (oil, gas, dry) is declared. An offshore well is defined as a well which is bottomed at, or produces from, a point which lies seaward of the coastline; offshore wells are further classified according to state or federal jurisdiction. The distinction between exploratory and development well is defined according to convention: wells that are drilled in an unproved area to add reserves are defined as exploratory wells, while wells drilled to produce known reserves are development wells. Well delineation is somewhat ambiguous, since most wells usually produce a combination of oil and gas. In the JAS survey, an “oil” well is a well completed for the production of crude oil from at least one oil zone or reservoir, while a “gas” well is one which can produce hydrocarbons existing initially in gaseous phase. Gas-condensate wells are reported as gas wells. A dry hole is defined as a well incapable of producing either oil or gas in sufficient quantities to justify completion.

The total depth of the well is the total feet of penetration drilled down the wellbore, including water depth and all plugged back footage, but excluding by-passed footage from sidetrack drilling.

Well direction is classified as vertical or horizontal. Most offshore exploration wells are drilled vertically, while typically only the first development well is "vertical" – subsequent wells are drilled vertical to a certain depth and then kicked off to target. Directional and horizontal drilling is carried out at an angle, or horizontally, to increase the surface area of the intersection between the well and the formation target layer. The majority of onshore footage is vertical, while total offshore footage is primarily directional.

Wells are evaluated after the drillbit reaches the target depth. A drill stem test may be used to evaluate the flow rates of hydrocarbons, and integrating this data with logs and other tests, leads to the completion decision. The total cost of a dry well includes the cost to set concrete plugs and to remove casing, as required by local/state/federal regulations. The total cost of a producing well includes the cost through completion and installation of the Christmas tree. Completion costs will typically include the cost of casing and production tubing, perforation, packers, safety devices, kits at the reservoir sands (e.g., gravel pack, frac pack, wire-packed screens), and a tree at the top of the well.

The cost of lease equipment and artificial lift, and the cost for flow lines, separators, tank batteries, etc. that are required to equip wells for production, are not included in the JAS cost data. For offshore wells, the costs on fixed platforms are included, and where facilities serve more than one well, costs are allocated to each well. Depreciation and amortization for company-owned mobile platforms, barges, and tenders are also included as cost elements.

Development

The JAS cost estimation procedure has evolved in five phases: I. 1954-1965, II. 1966-1977, III. 1978-1992, IV. 1993-1994, and V. 1995-present.

I. 1954-1965. From 1954-1965, wells were classified according to geological structure, drilling conditions, and economic expectations. Well cost per foot drilled by depth range was regressed against the average depth per well in each class interval for each region and well class for both tangible and intangible costs [10].

II. 1966-1977. From 1966-1977, the average cost per foot drilled was computed for wells classified according to well type, location, and depth [11]. The tangible and intangible cost categories were aggregated, and regression lines were computed to describe the functional relationship between cost per foot and depth for each area under consideration:

$$Z = \alpha_0 + \alpha_1 TD\,, \tag{1}$$

where Z represents the cost per foot and TD the total depth of the well.

III. 1978-1992. From 1978-1992, a stepwise linear regression on the cost per foot for each sample area and well type was employed [12]. Three depth variables were applied – inverted depth, depth, and depth squared – as well as a set of dummy classification variables for well type (oil, gas, dry), well class (exploratory, development), and completion type (single, multiple).

The functional form,

$$\log Z = \alpha_0 + \frac{\alpha_1}{TD} + \alpha_2 TD + \alpha_3 TD^2 + \beta_1 I_1 + \cdots + \beta_9 I_9 \tag{2}$$

was specified, and the coefficients α_i (i = 0,…, 3) and β_i (i = 1,…, 9), estimated through least-squares regression. The value Z represents the cost per foot and the indicator variables I_i, i = 1,…, 9 are defined as $I_1 = \{1$, oil, exploratory, single completion well; 0, otherwise}, I_2 = {1, oil, development, single completion wells; 0, otherwise}, etc. for each of the nine classification categories:{(oil, exploratory, single), (oil, development, single), (oil, exploratory, multiple), (oil, development, multiple), (gas, exploratory, single), …, (dry)}.

IV. 1993-1994. From 1993-1994, regression models were developed for well type and geographic area using the functional relations,

$$Y^{\alpha} = \beta_0 + \beta_1 TD + \beta_2 TD^2, \tag{3}$$

where Y denotes the total well cost and α, β_0, β_1, and β_2 are determined by regression [13]. A "stabilizing" transformation was performed by adjusting α to convert the dependent variable to a form that was linearly correlated with the independent variables. Three transformations were found to be statistically significant – the natural log, α = 4, and α = 0.5. The estimates were then adjusted with a correction factor to eliminate the bias introduced by the transformation.

V. 1995-present. Wellbore data is currently aggregated into 16 geographic regions following the Gas Research Institute's Hydrocarbon Supply Model [14, 15]. A non-linear two-factor regression model is constructed for each region based upon the following model specification:

$$\ln Y = \alpha_0 + \sum_{i=1}^{5} \alpha_i X_i + \sum_{i<j} \alpha_{ij} X_i X_j \tag{4}$$

where $Y = Y(\Omega)$ = total well cost in region Ω, $X_1 = TD$ = total depth (ft), $X_2 = TD^2$ = total depth squared (ft^2), $X_3 = WT$ = well type, $X_4 = WC$ = well class, and $X_5 = DIR$ = well direction. The X_1 and X_2 variables are numeric, while the X_3, X_4 and X_5 variables are categorical, defined in terms of indicator variables; e.g., $X_4 = WC = \{0$, exploratory well; 1, development well}. The coefficients α_i (i = 0,1,…,5) and α_{ij} (i, j =1,…,5, $i < j$) are evaluated for each geographic region and only statistically significant variables are maintained in the final model. Statistical tests are employed to accept/reject outlier data, and a correction factor is employed to account for bias introduced through the nonlinear transformation.

Discussion

In the JAS drilling cost model, four variables – total depth, well type, well class, and well direction – are applied in a two-factor non-linear regression model. Two-factor interaction terms were incorporated in the model to "build up" the number of available terms and improve the statistical fit of the regression. The limitations of the procedure are obvious from the model construction, since four variables cannot possibly describe the complexity and operational aspects involved in drilling a well. A quadratic expression is appropriate for the requirements of the survey, but it is clear that the JAS methodology cannot provide a reliable cost predictor on an individual well basis. For the purpose of estimating (unreported) cost data and developing aggregate expenditure patterns, the JAS procedure works well, but to predict individual well cost the level of categorization is too broadly defined to be useful except "on average." A well is characterized by a large number of descriptor variables which are not captured in the survey response, and thus, not adequately represented in the output model. A more robust model would incorporate additional descriptor variables of the wellbore and drilling process and relax the quadratic specification.

EIA Estimation/Forecast Model

In the mid-1980's, the EIA released a report on drilling cost to supplement the JAS and to provide a more frequent and timely indicator of drilling activity in the U.S. Drilling cost from the annual JAS reports were correlated to 11 variables using a "mathematical procedure" that was not identified [16]. The drilling depths and costs were normalized for nine depth categories, for each area and type of well, to create the data set. Eleven variables, which included a rig-use factor, wildcat ratio, fuel index, tubular index, labor index, mud index, prime-rate index, hydrocarbon-value factor, inventory-adjustment factor, and a hole production factor, was employed. The manner in which the data was analyzed, relying on the JAS summary statistics as opposed to survey data, and the methodological basis of the procedure, relying upon various gross measures, was not carefully executed. Little useful information actually resulted from the work, and the project was mothballed soon after it was completed.

Mechanical Risk Index

History

The MRI was developed in the late 1980's when Conoco engineers were tasked to compare offset drilling data for a collection of offshore wells in the Gulf of Mexico [17]. Engineers developed a "mechanical risk index" to compare operations and derived an algorithm based on empirical analysis of well data taking into consideration factors such as the water depth, measured depth, and kick off point for sidetracts. In the mid-1990's, Dodson modified the MRI through the use of key drilling factors, copyrighted the formula, and incorporated the measure as part of a commercial well database (http://www.infogulf.com). Reference to the MRI is found in various trade publications (e.g., [18]), but little systematic analysis of the metric has been performed.

The MRI is defined in terms of four "component factors" and a weighted composite "key drilling factor." The component factors are described in terms of six primary variables, and the key drilling factor represents the composite impact of 14 qualitative indicators. The MRI is computed as an additive function of the component factors weighted by the composite key drilling term.

Primary Variables

The six primary variables of the MRI include the total measured depth (*TD*), vertical depth (*VD*), horizontal displacement (*HD*), water depth (*WD*), number of casing strings (*NS*), and mud weight at total depth (*MW*). All distances are measured in feet (ft) and mud weight is reported in pounds per gallon (ppg).

The depth of a well measured from the rotary table along the length of the wellbore is called the total depth (or total measured depth), while the (true) vertical depth is the distance from the rotary table measured in a vertical plane to *TD*. The horizontal displacement is the distance measured in plan view from the rotary table to *TD*. The water depth is the distance from the waterline to mudline.

The problems, costs, and hazards of drilling are a function of variables that are observable, such as water depth and drilled interval, as well as may variables that are unobservable. The deeper the hole, the more time is lost in round trips to replace worn bits and to run casing, tests, logs, etc., and as the depth of the well increases, the number of formations encountered will typically increase along with the number of casing strings required to maintain well control. As the number of casings increase, the trip time, installation, and cementing time will increase, all negatively impacting drilling time and cost. Beyond a certain depth, technical complications and the opportunity for problems increase significantly.

Casing serves several important functions in drilling and completion and is one of the most expensive parts of a drilling program, ranging anywhere from 10-20% of the average cost of a completed well [6]. A well that does not encounter abnormal formation pore pressure gradients, lost circulation zones, or salt sections usually require only conductor and surface casing to drill to the target. Deeper wells that penetrate abnormally pressured formations, lost circulation zones, unstable shale sections, or salt sections generally will require one or more strings of intermediate casing to protect formations and to prevent well problems.

A well is usually spudded with a 36", 30", or 26" casing, depending on the subsurface structural features and pressures which are expected to be encountered. As the hole deepens, the casing becomes progressively narrower, typically finishing with $7\frac{3}{8}$" or $9\frac{5}{8}$" diameter at target. The number of casing strings of a well provides an indirect measure of well complexity, since complex wells are frequently associated with multiple strings, and narrow margins between formation pore pressure and fracture pressure gradients often result in the requirement of a greater number of casing strings [19]. If hole sections can be drilled without setting intermediate strings or liners, then drilling can usually proceed quicker. Troublesome formations such as high pressure zones, sloughing shale, and shallow water flows require more intermediate casing.

Drilling fluids are used to control the pressures that exist in the wellbore at different depths, to carry the cuttings out of the hole, to lubricate the drill string, and stabilize the wellbore.

Wells may be drilled with water or oil-based muds through the entire wellbore, or one mud may be displaced for another over a selected interval. The mud weight at total depth serves as a proxy for the wellbore formation pressure. Heavy mud is typically used to create an overbalance to prevent fluids from entering the well. For all other factors equal, the greater the hole pressure the heavier the mud, and the slower the drilling. In under-balanced drilling, the fluid pressure inside the annulus of the well is maintained below the formation pressure. Underbalanced drilling requires the use of special equipment to handle formation fluids entering the well and its primary use has been where casing is set and cemented on top of a subnormal or pressure-depleted formation [20, 21].

Component Factors

The primary variables of the MRI are combined into four normalized component factors:

$$\varphi_1 = \left(\frac{TD+WD}{1000}\right)^2,$$

$$\varphi_2 = \left(\frac{VD}{1000}\right)^2 \cdot \left(\frac{TD+HD}{VD}\right),$$

$$\varphi_3 = (MW)^2 \cdot \left(\frac{WD+VD}{VD}\right),$$

$$\varphi_4 = \varphi_1 \sqrt{NS + \frac{MW}{(NS)^2}}.$$

The units of φ_1 and φ_2 are [ft^2]; the unit of φ_3 is [ppg^2]; the unit of φ_4 is [ft^2 $\sqrt{1+\text{ppg}}$]. Each component factor is nonlinear in the primary variables.

Key Drilling Factors

Key drilling factors are defined to capture drilling characteristics that are encountered, or are expected to be encountered, but not described by the component factors. Dodson introduced drilling factors to generalize the MRI to a larger class of wells.

The key drilling factors are user-defined qualitative variables ψ_i that are assigned an integer-valued weight $\psi_i(w)$ according to the occurrence of the condition and its degree of complexity. Let ψ_i denote the *i*th drilling factor of well *w* and $\psi_i(w)$ the corresponding numerical weight:

$$\psi_i : w \rightarrow \psi_i(w). \tag{5}$$

The composite key drilling factor is determined by the sum of the drilling factor weights:

$$\psi = \sum_{i=1}^{14} \psi_i(w), \tag{6}$$

where the variables and corresponding weights are as follows: ψ_1= horizontal section ($\psi_1(w)$ = 3), ψ_2= J-curve directional ($\psi_2(w)$ = 3), ψ_3= S-curve directional ($\psi_3(w)$ = 2), ψ_4= subsea well installed ($\psi_4(w)$ = 2), ψ_5= H_2S/CO_2 environment ($\psi_5(w)$ = 1), ψ_6= hydrate environment ($\psi_6(w)$ = 1), ψ_7= depleted sand section ($\psi_7(w)$ = 1), ψ_8= salt section ($\psi_8(w)$ = 1), ψ_9= slimhole ($\psi_9(w)$ = 1), ψ_{10}= mudline suspension system installed ($\psi_{10}(w)$ = 1), ψ_{11}= coring ($\psi_{11}(w)$ = 1), ψ_{12}= shallow water flow potential ($\psi_{12}(w) = 1$), ψ_{13}= riserless mud to drill shallow water flows ($\psi_{13}(w) = 1$), and ψ_{14}= loop current ($\psi_{14}(w) = 1$).

Most exploratory wells are drilled as straight as possible, while usually only the first development well is vertical. Horizontal drilling is less stable than drilling vertically, and also more difficult to log and complete [22]. If a horizontal section of a well is drilled, then a weight of “3” is assigned to the key drilling factor, while if a J-shaped or S-shaped trajectory was employed, an additional weight of “3” or “2” is included in the metric.

A subsea well is a well in which the wellhead, Christmas tree, and production-control equipment is located on the seabed. Subsea well drilling tends to be more complicated and costly than a normal tree installation, and a weight of “2” is assigned to subsea completions.

Hydrogen sulfide (H_2S) and CO_2 environments require special consideration when drilling since the corrosive gases weaken the steel casing and drill string and require special operating procedures. Hydrogen sulfide is a poisonous and corrosive gas, and when in contact with steel casing and drill pipe, causes embrittlement and weakening. Wells with high CO_2 concentrations also lead to corrosion-related problems.

One of the technical problems in deepwater drilling is the possible formation of hydrates in the blow out preventer (BOP) or choke and kill lines. Hydrates may plug the BOP stack and well circulation path, and are difficult and time consuming to remove.

Drilling problems associated with depleted reservoirs are intrinsic to many mature fields. The water-wet sands that typify depleted zones propagate seepage losses and differential sticking. Drilling fluid losses are frequently unavoidable in large fractures, and pressured shales are often interbedded with depleted sands, requiring stabilization of multiple pressure sequences with a single drilling fluid [23].

Salt is an effective agent in nature for trapping oil and gas, since as a ductile material, it can move and deform surrounding sediments and create traps. Drilling salt is risky, however, since the salt is weak and undergoes continuous deformation like a fluid [24]. Below intruded salt, sediment layers are often disrupted and overpressured, and special considerations, from selecting drilling fluids to implementing casing programs and cementing procedures, are required to produce long-lasting wells in salt domes. Extreme mud costs have occurred in the GOM where massive lost circulation may be tolerated in sub-salt wells.

A slimhole well describes a borehole significantly smaller than a standard approach, commonly less than 6" or 6½" in diameter. Mudhole suspension systems and coring also add to the time and complexity of drilling.

Unusual geologic and environmental events, such as loop currents, eddies, and shallow water hazards, create special problems during drilling. Loop currents and eddies subject facilities to stress and vibration, and drilling risers that are in place may bend or bow from the current to such an extent that the vessel has to change position to stay connected. In some cases, the drill pipe may rub against the drilling riser forcing immediate shutdown. Shallow water flow occurs when drilling into over-pressured sand zones [25]. Installation of additional casing is usually required to maintain wellbore integrity in shallow flow.

Definition

The MRI is defined through the component factors, weighted by a normalized composite key drilling factor, as follows:

$$MRI = \left(1+\frac{\psi}{10}\right)\sum_{i=1}^{4}\varphi_i \tag{7}$$

The MRI is frequently used to compare the drilling performance of two or more wells, and as a predictive tool for wells in the design stage. MRI is also correlated to drilling cost. For a well that has previously been drilled, the input data and MRI can be calculated precisely. If a well is part of a planned drilling program, then estimates for the variables {*TD*, *WD*, *VD*, *HD*, *MW*, *NS*} and key drilling factors $\{\psi_1,\cdots,\psi_{14}\}$ are required to estimate the anticipated drilling risk.

Example

1. (a) Specify well characteristics encountered/expected; e.g.,{*TD*=15,000 ft, *WD* = 150 ft, *VD*=13,800 ft, *HD*=2500 ft, *MW*=16 ppg, *NS*= 6}
   (b) Specify risk factors encountered/expected; e.g., {ψ_1= horizontal section, ψ_3= S-curve directional, ψ_7= depleted sand section, ψ_9= slimhole, ψ_{12}= shallow water flow potential}
2. Compute component factors and key drilling factors:{ $\varphi_1 =$ 229.5, $\varphi_2 = 241.5$, $\varphi_3 =$ 258.5, $\varphi_4 = 582.6$, $\psi = 8$}.
3. Compute MRI:

$$MRI = \left(1+\frac{\psi}{10}\right)\sum_{i=1}^{4}\varphi_i = 2{,}362$$

■

Discussion

The MRI was originally developed to compare the drilling performance of a small number of offset wells drilled in the late 1980’s, and as such, the formulation of the metric is closely tied to the characteristics of a particular well set drilled during a specific period. The MRI was later modified to incorporate additional drilling factors not covered in the original formulation.

The MRI currently serves as the de facto industry standard in the Gulf of Mexico. The MRI has a long history, is easy to comprehend and serves a useful role in aggregate comparisons, and is defined by simple, spreadsheet-programmable relationships. The parameters of the MRI are based on a minimal set of high-quality drilling data which is readily acquired.

There are a number of issue associated with the metric, however, that are deserve closer attention. Dodson introduced drilling factors to generalize the MRI to a larger class of wells, but the selection of the factors and their weight assignment appear arbitrary. The use of the drilling factors serve to create a cost-estimation tool, but the manner in which the parameters enter the model as a binary indicator with weighting factors may lead to ambiguity.

The application of user-defined weights is always problematic. If weights are not inferred through an empirical assessment of well data, the assignment can be considered arbitrary and may possibly be ambiguous; e.g., if a horizontal section of a well is drilled, a weight of "3" is assigned to the key drilling factor. On a cost per foot basis, however, horizontal wells are not necessarily more expensive than vertical holes [15]. Key drilling factors are assigned weights according to the "complexity" of the characteristic/condition that is encountered (or expected to occur) without differentiating between the magnitude of the condition; e.g., if a horizontal section of a well is drilled, then regardless of its length, it is assumed to be three times more complex/difficult than if a salt section is drilled or if a loop current is encountered. A loop current that leads to a 5-hour delay is treated identical to a 5-day delay.

Primary and key drilling factors represent the drilling process in a manner superior to the JAS variable selection, but the manner in which the MRI factors are combined and the weight selection can be improved. The composite drilling factor weight is ad hoc, and it would be better to normalize the component factors prior to summation. Although the MRI incorporates more drilling parameters than the JAS approach, the JAS methodology is more structured, and it is clear that the manner in which factors are incorporated in the MRI limits generalization. The MRI is defined by an additive functional and a fixed weight selection. Generally speaking, metrics defined through a formula assignment are usually not optimally specified.

Directional Difficulty Index

A directional difficulty index (DDI) was proposed by Schlumberger engineers to evaluate the difficulty in drilling a directional well [26]. Key performance measures were identified through a questionnaire and quantified using three drilling factors derived from four primary variables:

$$DDI = \log\left[TD\left(\frac{AHD}{VD}\right)TORT\right], \tag{11}$$

where *TD* is the total measured depth, *AHD* is along hole displacement, *VD* is total vertical depth, and *TORT* is the tortuosity. *AHD* is computed from an elliptical integral, and *TORT* describes the total curvature of the wellbore. The primary parameters related to trajectory curvature are bending angle (dogleg angle) and borehole curvature. Extensive turning of a well trajectory may twist a downhole pipe string, greatly increasing the forces applied, causing deformation. The multiplicative functional ensures that each drilling factor is given equal weight in the index, but the DDI does not consider the difficulty of drilling the formations penetrated by the trajectory.

Example

1. Specify well characteristics encountered/expected; e.g., {*TD* = 21,000 ft, *AHD* = 11,000 ft, *VD* = 17,500 ft, *TORT* = 70°}.
2. Compute DDI:

$$DDI = \log\left[TD\left(\frac{AHD}{VD}\right)TORT\right] = 6. \qquad \blacksquare$$

Difficulty Index

History

The difficulty index (DI) was introduced by K&M Technology Group (http://www.kmtechnology.com) to characterize the expected difficulty in drilling an extended reach well. In an extended reach well, high angles are built before drilling onward to a distant target [27]. The DI has similarities to the MRI specification, but the weights employed are frequently specified in terms of a one- or two-dimensional functional, as follows:

$$\begin{aligned} &\delta: \ f_i \rightarrow \delta(f_i), \\ &\hat{\delta}: \ f_i, f_j \rightarrow \delta(f_i, f_j), \end{aligned} \tag{12}$$

where δ denotes a one-dimensional functional, $\hat{\delta}$ denotes a two-dimensional functional, and f_i the *i*th factor of the drilling process, well bore, or other descriptor.

Factor Description

Well Path

A vertical depth factor $\delta(VD)$ employs a stepwise increasing linear function from 8,000 ft to 22,000 ft as shown in Table 1. The weight factor is zero for $VD < 8{,}000$ ft and saturates when $VD \geq 22{,}000$ ft.

Table 1: Vertical Depth Weight Function.

$\delta(VD)$	VD (ft)
0	$VD < 8{,}000$
1	$8{,}000 \leq VD < 10{,}000$
2	$10{,}000 \leq VD < 12{,}000$
3	$12{,}000 \leq VD < 14{,}000$
4	$14{,}000 \leq VD < 16{,}000$
5	$16{,}000 \leq VD < 17{,}000$
6	$17{,}000 \leq VD < 19{,}000$
7	$19{,}000 \leq VD < 20{,}000$
8	$20{,}000 \leq VD < 22{,}000$
9	$VD \geq 22{,}000$

A two-dimensional weight function is defined in terms of the total vertical depth below mudline, *VD-WD*, and horizontal reach, *HD*:

$$\hat{\delta}: VD\text{-}WD, HD \rightarrow \hat{\delta}(VD\text{-}WD, HD). \tag{13}$$

The smallest target width at *TD* perpendicular to the well azimuth, *STW* (ft), determines the weight factor (Table 2). Inclination is usually easier to control than azimuth in a deep well, and so the target width perpendicular to the well trajectory is applied. Shallow and very deep wells usually cannot achieve the reach of aggressive moderate wells due to frictional forces and mechanical load limits.

The horizontal reach at *TD* is computed as the "unwrapped" total length projected more onto the horizontal plane. The weight associated with the cumulative planned dogleg at *TD*, *DOG* (°), attempts to account for directional changes beyond a simple build and hold plan (Table 3). The ideal well survey directional plan dogleg is used according to well type: for two-dimensional wells the inclination changes are added from spud to *TD*; for S-Turn wells, the cumulative build is added sans section doglegs; for three-dimensional wells, the survey calculation program is used to calculate cumulative dogleg from spud to *TD*.

Table 2: Smallest Target Width Weight Function

$\delta(STW)$	STW (ft)
0	$STW > 300$
1	$250 < STW \leq 300$
2	$200 < STW \leq 250$
3	$150 < STW \leq 200$
5	$100 < STW \leq 150$
6	$50 < STW \leq 100$
7	$STW \leq 50$

Table 3: Cumulative Planned Dogleg Weight Function

$\delta(DOG)$	DOG (°)
0	$DOG < 40$
1	$40 \leq DOG < 60$
2	$60 \leq DOG < 80$
3	$80 \leq DOG < 100$
4	$100 \leq DOG < 120$
5	$120 \leq DOG < 140$
6	$140 \leq DOG < 160$
7	$160 \leq DOG < 180$
8	$180 \leq DOG < 200$
9	$200 \leq DOG < 220$
10	$DOG \geq 220$

Mud/Temperature/Pressure

The maximum mud weight *MXMW* (ppg) and oil-based mud weight *MXMW/O* (ppg) factor applies a stepwise increasing scale to mimic the operational complexity associated with high mud weight systems (Tables 4, 5). δ(*MXMW/O*) characterizes the complexity, risk, and cost due to lost returns and the propagation of existing/induced fractures in abnormal pressure wells [28]. If a well is drilled in an underbalanced mode, a weight factor $\delta(U) = 11$ is assigned.

Table 4: Maximum Mud Weight Function

$\delta(MXMW)$	$MXMW$ (ppg)
0	$MXMW < 12$
1	$12 \le MXMW < 13$
2	$13 \le MXMW < 14$
3	$14 \le MXMW < 15$
4	$15 \le MXMW < 16$
6	$16 \le MXMW < 17$
8	$17 \le MXMW < 18$
10	$MXMW \ge 18$

Table 5: Maximum Oil-Based Mud Weight Weight Function

$\delta(MXMW/O)$	$MXMW/O$ (ppg)
0	$MXMW/O < 14$
4	$14 \le MXMW/O < 15$
5	$15 \le MXMW/O < 16$
6	$16 \le MXMW/O < 17$
7	$MXMW/O \ge 17$

The bottom hole static temperature $T(TD)$ (°F) weight factor employs a stepwise increasing linear function to account for the additional complexity of managing mud systems and personnel safety (Table 6).

Table 6: Bottom Hole Static Temperature Weight Function

$\delta(T)$	T (°F)
0	$T < 250$
1	$250 \le T < 300$
2	$300 \le T < 325$
3	$325 \le T < 350$
4	$350 \le T < 375$
5	$T \ge 375$

Pore pressure and fracture gradients in the subsurface are uncertain in most drilling operations [29]. The fracture gradient factor FG (ppg) and the equivalent circulating density (ECD) string factor NS/ECD assigns a weight depending on the string count and fracture gradient interval as follows:

$$
\begin{aligned}
&\delta(NS/ECD) = NS/ECD && 0 < FG < 1.0 \\
&\delta(NS/ECD) = 2\cdot\ NS/ECD && 1.0 \le FG \le 1.5 \\
&\delta(NS/ECD) = 4\cdot\ NS/ECD && 1.5 \le FG \le 2.0
\end{aligned}
\tag{14}
$$

Fracture gradients in hole sizes less than 8 ½" are challenging to drill and can have high *ECD*'s due to pipe rotation, cutting pickup when circulation is initiated, and pressure surges due to pipe movement [30]. In larger hole sizes, *ECD*'s are lower and usually not an issue [31].

Casing/Re-Drill

The number of casing strings/liners below the drive casing is denoted *NS* and the corresponding weight function is shown in Table 7. For each liner tied back or string requiring rollers, simple flotation, and/or inverted string weights, one point is added to the difficulty index, while two points are added for high angle wells for each casing string/liner requiring the use of differential techniques and/or rotation to slide into the hole. Additional weights are assigned as follows. Wells that require a cased-hole whipstock kickoff or a cement plug kickoff are assigned a weight of two points. Drill pipe whipstock slot recovery wells are assigned a weight of five points. Fishing operations that require casing string sections to be cut and pulled, milled, or pilot milled are assigned a weight of two points.

Table 7: Number of Strings Weight Function

$\delta(NS)$	NS
0	1
1	2
2	3
4	4
6	5
9	≥ 6

Well Type and Learning Curve

Exploration wells usually have a higher degree of risk/complexity than a typical development well, and learning economies in development drilling often reduce the difficulty of drilling a series of wells. Well type and learning is characterized by assigning the following point scheme: "6" (rank wildcat), "5" (near field wildcat), "4" (first well in a development program, or no drilling within the past two years), "2" (second well in development program, or no drilling for at least one year), and "1" (third well in development program, or no drilling for the past six months).

Equipment Capacity

The drilling system used and the available rig can have an impact on drilling success with complex systems requiring additional planning and well time. A jackup or platform with a surface wellhead is assigned the weight "1", tension leg platforms and spar systems with surface *BOP*'s and subsea hangers the weight "3", and floaters with subsea *BOP*'s/wellhead the weight "5".

A number of operational constraints may also arise. "Big" rigs usually place no constraints on well design or operation, but "new" or "stacked" rigs may encounter extra mechanical problems. If the rig and crew have not previously worked for the operators drilling group additional accommodation time may be required. Weight factors are assigned as follows: "0" (extra capacity rig), "3" (rig at capacity), "6" (undersized rig); "4" (new rig or stacked within 90 days); "4" (time between rig activation date and spud date less than 30 days), "2" (31-60 days), "1" (61-90 days); "2" (rig and crew have not worked for the operator within the last two years).

Definition

The difficulty index of well *w* is denoted $DI=DI(w)$ and defined as the summation of the one- and two-dimensional weight functionals, $\delta(f_i)$ and $\hat{\delta}(f_i, f_j)$,

$$DI = \sum_{i=1} \delta(f_i) + \sum_{i<j} \hat{\delta}(f_i, f_j), \tag{15}$$

Example

1. Specify well characteristics encountered or expected to be encountered; e.g., a rank wildcat is drilled with a surface BOP with subsea hangers and {VD = 12,000 ft, WD = 2,000 ft, HD = 4,500 ft, DOG = 65°, $MXMW$ = 15 ppg, $MXMW/O$ = 16 ppg, $T(TD)$ = 300°F, NS/ECD = 2, NS = 5}.
2. Compute weight factors: {$\delta_1(VD)$= 3, $\delta_2(VD\text{-}WD, HD)$= 1, $\delta_3(DOG)$= 5, $\delta_4(MXMW)$=4, $\delta_5(MXMW/O)$= 6, $\delta_6(T(TD))$ = 2, $\delta_7(NS/ECD)$ = 2, $\delta_8(NSD)$= 6, δ_9(rank wildcat)= 6, δ_{10}(surface BOP) = 3}.
3. Compute *DI:*

$$DI = \sum_{j=1} \delta_j(f) = 38.$$ ■

Discussion

The difficulty index is intended to gauge the difficulty of drilling an extended reach well, and as a gross measure, it may be useful to compare the various factors that impact drilling. Unfortunately, there is no foundational basis to the weight assessment beyond subjective reasoning. The weight functions vary with one or more factors and may be more robust than the drilling factors employed in the MRI, but the weights are not calibrated with drilling data. The DI weight functions are user-defined, similar to the DDI and MRI metrics, and this is a serious limitation since the weights are not supported by empirical analysis. It is possible in theory to discriminate between wells on the basis of the tactics employed in drilling, since some of these tactics may be observable, but frequently, most of the tactics are not reported or available for analysis.

Mechanical Specific Energy

History

The concept of Mechanical Specific Energy (MSE) was defined by Simon [32] and Teal [33] to quantify the relationship between the amount of energy required to destroy a given volume of rock. MSE has been used to evaluate the drilling efficiency of bits [34], post-well performance analysis [35], and most recently, as a real-time tool to maximize the rate of penetration and obtain a more objective assessment of drilling efficiency [36-39]. Drilling rates are often constrained by factors that the driller does not control and in ways that cannot be documented. Dupriest [38] classifies factors that determine ROP into two categories: (1) factors that create inefficiency (founder) and (2) factors that limit energy input. The three causes of founder are bit balling, bottom hole balling, and vibrations. Various factors may limit energy input, such as hole cleaning efficiency, hole integrity, mud motor differential pressure rating, logging rotational speed limits, etc.

Definition

The MSE is not a cost or complexity estimation model, per se, but an operational tool to optimize ROP and drill the technical limit. MSE is the calculated work that is being performed to destroy a given volume of rock. Teale derived the MSE equation

$$MSE = \frac{480 \cdot Tor \cdot RPM}{DIA^2 \cdot ROP} + \frac{4 \cdot WOB}{DIA^2 \pi} \tag{16}$$

where *Tor* is the torque and *DIA* is the diameter of the drillbit. Lab tests showed that MSE remained relatively constant, regardless of changes in ROP, WOB or RPM. When a bit is operating at its peak efficiency, the ratio of energy to rock volume will remain relatively constant. This relationship is used operationally to adjust drilling parameters, such as WOB or RPM, to avoid founder, and to manage the drilling process. The instantaneous penetration rate depends upon rock strength, borehole pressure, and formation fluid pressures. Typically, increasing borehole pressure will reduce penetration rate in an impermeable rock, while increasing the borehole and pore pressure differential will reduce penetration rate in a permeable rock. *ROP* (ft/hr) is related to the *MSE* (ksi), the bit diameter *DIA* (in), and the power input to drilling *W* (hp) by [36]:

$$ROP = \frac{2538 \cdot W}{MSE \cdot DIA^2} \tag{17}$$

The highest penetration rate that can be achieved under ideal drilling conditions is described by the technical limit penetration rate:

$$TLROP = \frac{2538 \cdot W}{TLSE \cdot DIA^2}.$$

Curry [36] correlated rotating days, normal, and total dry hole days per 1,000 m against *TLSE* for a small set of wells. The correlation for rotating days was very strong, but for the wider measures of drilling performance, many factors besides drillability affect performance.

Discussion

Operations personnel have tended to study the performance of successful wells to identify success factors, and in an attempt to duplicate the success, the tendency developed to use the bit, bottomhole assembly, and directional steering system in offset or similar wells [39]. ROP management as practiced by ExxonMobil focuses on the extension of limitations, rather than the identification of superior bit systems. ROP is advanced by identifying specific limiters and re-engineering, rather than seeking a better performing system from empirical experience.

The field process for using MSE allows drillers to adjust parameters and observe whether the MSE increases or declines. Parameters are maintained at the point in which MSE is at its minimum. After drilling is optimized, engineering redesign is often necessary to adjust nozzles and flow rates to achieve the highest hydraulic horse power per square inch. Dupriest describes the use of MSE surveillance to optimize the drilling process work flow, through the identification of the best operating parameters and by providing the quantitative data to costs justify design changes [37-39].

Conclusions

Many factors influence penetration rate, and as metrics become further removed from the technical aspects of drillability, additional factors influence the performance measures. Several methods exist to quantify drilling cost and complexity. The methods attempt to balance the variability involved in the operation with the uncertainty of selecting relevant factors in constructing a descriptive model. The primary models to estimate drilling cost and complexity was reviewed, including the structural basis of the models and their underlying assumptions. The JAS and MRI are commonly employed in the Gulf of Mexico, but little or no attention has been devoted to the structural basis of the procedures or reliability of the assessment. Recent advances in using the MSE to manage and quantify the drilling process was highlighted.

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