Dissertation

"Digital Modeling of the Drilling Process and Automated Operations Recognition as Basis for Optimizing Drilling Economics"

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I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

CONTENT

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1 Scope

This work presents the development of a description of the processes via discrete tasks and activities comprising the drilling phase of a well and uses this approach to define its impact on the overall economic efficiency of drilling operations. It is not a representation of a generic well construction process (including the planning, approval and subsequent closeout phases) but the detailed breakdown of all operational processes/tasks from spud until TD of a well. It intentionally is not a description of the physical "drilling process" how rock is being crushed by the cutting elements of a drill bit but rather the systematic description of how a well is being drilled.

Located under the overarching main process, multiple sub-processes, tasks and activities "dock" on the critical path at certain times. They all are characterized by their own preparation and closeout activities (typically off critical path), start and stop points along the process.

Each sub-process, task and activity is characterized by its individual sequential time steps, QA/QC measures for each process/task step and KPIs to measure process/task performance. Wherever possible, automated measurements to detect process/task start/end are identified or suggested.

This process description forms the basis for monitoring, evaluating and ultimately enhancing performance of the drilling unit by providing

- Key Performance Indicators
- Automatic recognition of drilling unit operations without human bias
- Historic/statistical performance benchmarks

While there exists a widespread belief that work flows throughout the drilling process are well defined in the drilling industry, once attention is shifted to the details it becomes apparent that most of the tasks are based on implicit rather than explicit knowledge, in other words staff "knows how to do things" with little to no controlled/documented work flows.

Because of the demographics of the drilling community, there has already been (and will continue to be for the foreseeable future) a shift from long-term experienced key staff to young and/or cross-trained individuals. While the long-term experienced staff provided the implicit knowledge how to execute planned operations without a need for detailed written instructions, the "great crew change" that has commenced over the last decade creates new requirements for clearly defining workflows as a basis for educating new staff upon their entry to the industry. The recent massive increase in the rotary rig count – predominantly due to the shale gas development boom in North America – has put an additional strain on the industry to staff these rigs and to properly induct the new personnel.

It is stipulated that by proper definition of the individual tasks/activities, their start/end points along the process, means of automatically tracking these start/end points (and thus duration of these tasks/activities) together with adequate QA/QC measures (i.e. key performance indicators – KPIs) it is possible to enhance drilling project performance and at the same time increase operational (i.e. process) safety. This can be achieved by

- Better standardizing the way individual tasks are performed by providing individuals with a clear structure of the workflow to follow and ensuring that all required process/task/activity steps are in fact being executed as planned, i.e. implementing an enhanced man-machine-interface (MMI)
- Reducing the spread in the duration of certain tasks/work steps by making the activity more consistent
- Reducing/eliminating non-productive-time (NPT) by better planning/scheduling events and resource requirements through enhanced process transparency

Ultimately this work shall form the basis for better utilization of assets (both human and material) and reduction of total well cost by optimizing drilling unit operating performance. While on the individual rig-level this may enable drilling of an additional well per year simply by reducing/eliminating lost time from normal operations, impact on a worldwide scale ranges in the multi-billion USD level. Current worldwide rotary rig count runs in the 3000-3500 unit range (both on- and offshore), and assuming an average daily operating cost per drilling unit of only 100.000 USD (small land rigs operate at ~20.000 USD/d while floating offshore units routinely reach 1,000.000 USD/d operating spread rate), even a one percent performance improvement equivalents 1 billion USD total worldwide operating cost reduction per year.

2 Introduction

2.1 From “Makin’ hole” to Well Planning

From its beginnings 150 years ago, the drilling industry has for more than a century been characterized by a “cowboy” or “wildcatting” approach. Media have always been supporting this image of adventurers working in a highly dangerous and frontier environment. Interestingly, other industries (most notably the car manufacturing industry with Henry Ford’s move from craft to mass production along assembly lines and the subsequent development of the Japanese car manufacturing industry half a century later) have always been far advanced over the drilling industry, in spite of the substantial financial expenditures typically associated with drilling wells. The fact that almost each well – due to the inhomogeneity of the subsurface – is different from others, thus precluding a high level of standardization, has kept the drilling industry “locked” in craft production paradigms for decades. It might also be the lingering “adventure spirit” from the early wildcatting days that has kept the drilling industry from adopting advances in standardizing well designs and work processes.

There exists a fundamental difference between the engineering part of planning a well (i.e. designing well paths, casing programs and wellhead configurations and selecting the necessary tools and drilling fluids etc.) and the economic/scheduling exercise. While personal experience has only limited influence on engineering solutions, estimations of how long it will take to perform certain tasks and thus predicting total well duration and cost are heavily dependent on the knowledge of the planning individual and his/her previous exposure to operations.

Only the requirement to enhance time and cost planning procedures, moving away from ”analogous” offset well performance and personal experience as basis for cost/schedule predictions, caused the introduction of process management tools to the drilling industry by the late 1980ies and early 1990ies. Oil price slumps to below 10 USD/bbl by January 1999 further increased interest in optimization of well delivery performance, based on a clearly perceived need to deliver consistent, top-performing well execution in exploration and development phases. A study conducted in 1999 by ARCO British Limited[1] indicated that approximately 70% of the deficiencies in their then existing business process stemmed from lack of project definition and planning rather than poor execution. As with many other organizations, the implementation of a new well design and construction process was dependent upon the need to understand the existing company business processes and to enable the wider organization to acknowledge where the problems lay.

While high-cost offshore operations have earlier on sparked a more detailed interest in monitoring/controlling the efficiency of drilling operations, this for quite a long time remained targeted at individual wells rather than field- or even global-sized systems. Only the massive increases in the number of wells drilled in the continental US throughout the last decade associated with the search for and especially the development of shale gas and more recently shale oil have sparked what is commonly referred to as “factory drilling”, with rigorous standardization in the way these wells are planned and drilled.

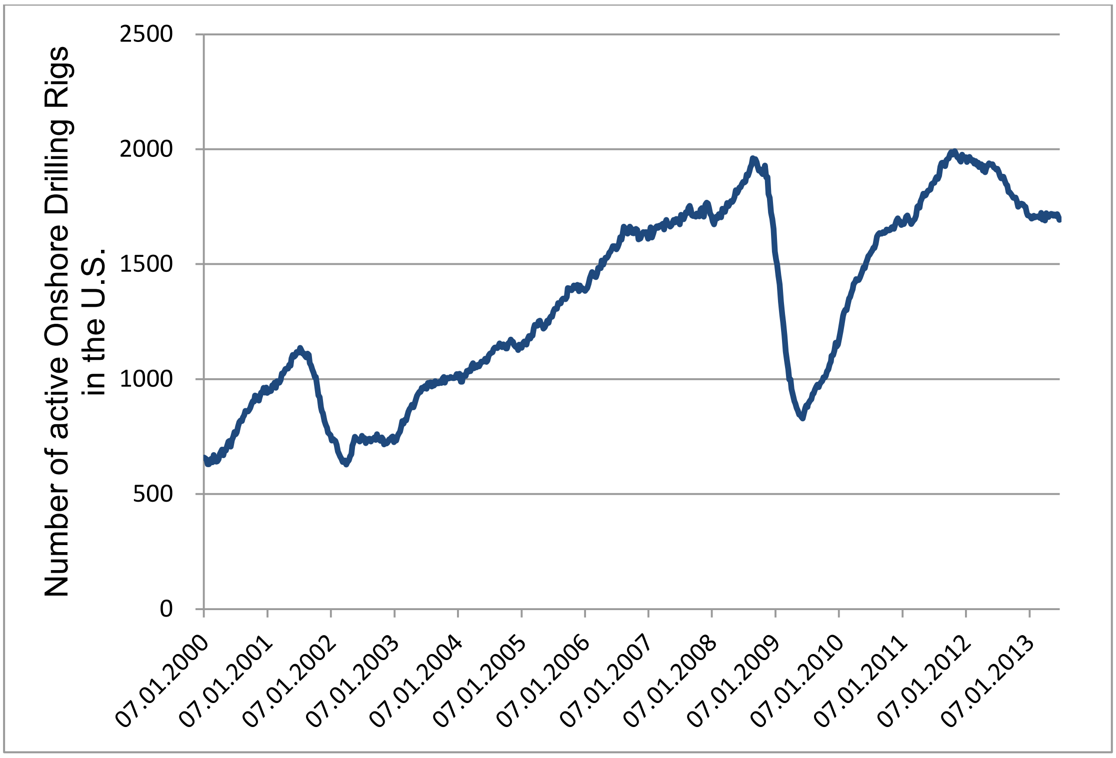


Figure 1: U.S. Rotary Land Rig Count 2000-2013[2]

Note the massive and continuous increase in the number of US operating land drilling units from around 700 to almost 2000 in the period between 2002 and 2009. While some of this increase has undoubtedly been caused by the consistent increase in oil prices during the same period, the development of the “unconventional” shale gas plays accounts for most of this increase. The sharp drop in 2009 was a result of the global economic crisis beginning in fall of 2008, with intermediate oil price drops down into the 40 US$/bbl region, however the drilling industry quickly recovered in 2010/2011. Recent drops in rig counts have been caused by the drop in domestic US gas prices (a result of the oversupply due to more and more shale gas plays coming on stream) and a move of some of those rigs into the shale oil plays, predominantly in the Bakken shale in North Dakota.

There exists a fundamental difference between “factory floor” environments and drilling wells in the way that boundaries can be defined very precisely and processes controlled tightly in factory environments, while drilling of wells – especially when done with multiple different rigs – introduces a wide array of rig- and subsurface-specific factors. This work will address these open boundaries in more detail in Chapter 7.

While drillers for generations felt that “making hole” was a value in itself, getting wells from the surface to their reservoir target today is more and more seen as a simple means of getting from here to there. A hole in the ground today has zero value in itself. It either produced information/data or it provides a conduit to bring oil/gas production to surface. The transformation from the traditional values to this current understanding of "well objectives" marks the first step in defining a "well construction process", similarly to a manufacturing approach. The activities along a factory assembly line have zero value in themselves; it is the finished product that counts. Spending resources (time, money, raw materials etc.) in keeping the assembly line running without meeting the requirements for the end product (in the case of drilling a well without gaining the desired information or achieving the targeted production) erodes company value. The oil and gas industry has typically been referring to the success rates commonly seen on exploration wildcats in justifying the relatively large number of wells not meeting their expectations. When developing resources that require a huge number of wells, the individual well cost (and obviously the overall percentage of wells achieving their objectives) becomes the crucial driver in making projects economically viable.

2.2 Optimizing drilling performance – the way to "Technical Limit" planning

DeWardt in a 1994 publication[3] proposed the concept of Lean Production as a possible solution to the dilemma of single-well planning and construction procedures, combining the advantages of craft production with mass production while avoiding the high cost of the former and the strict rigidity of the later by utilizing teams of multi-skilled workers and highly flexible, increasingly automated machines. In a more recent work[4], he references 50% time reduction while at the same time improving quality by 25% as achievable in other industries when moving to "manufacturing" processes.

Concentrating on the total time spent by a rig on a particular drilling project (i.e. well) led to a systematic description of the well construction process as basis for detailed execution time estimation. This thesis will not go into detail on the various time and cost estimation methodologies developed for drilling projects, suffice it to say that the concept of a "technical limit" – where it is assumed that each individual sub-task of the well construction process would go perfectly on every operation making up the well time – has been introduced by Bond, et al, as far back as 1998[5]: *"Technical limit was a term used to describe a level of performance defined as the best possible for a given set of design parameters. Such performance can be approached but requires a perfect set of conditions, tools and people. A close analogy of the technical limit is a world record in athletics."* In contrast to this approach, Kadaster in a previous work[6] had introduced the concept of total quality management to the well construction process. Bearing in mind the oil price scenarios at the time of this publication (1992), it is understandable that he wrote *"The industry can no longer afford the prolonged cycle periods in recognizing and solving inefficiencies and problems and the associated costs in the current or future financial climate. The cost of learning to live with a problem may be just as unaffordable".*

For the first time, the overall activity of constructing a well was broken down into well sections and sub-activities (such as drilling the open hole section, running and cementing the casing, installing wellhead and blowout preventer stack etc.), going to sufficient detail to allow accurate time estimations for each activity step while avoiding excessive detailing of the process which would have introduced new – artificial and cumbersome – inaccuracies.

It should be noted that the technical limit approach carries the inherent risk of de-motivating rig crews and project teams as these technical limits are by definition almost always unachievable. It is a tough challenge to – after agreeing on what would be technically feasible – set the objective for the whole team how much above the technical limit they want to set their project target (by definition “planning for suboptimal performance”). However, given a motivated team and strong leadership, the joint development of a planned well duration under this method (i.e. a well duration based on trouble-free and optimum performance for each process step) can bring about a paradigm shift about what is in fact possible. Bond, et al, also for the first time introduced the concept of “invisible lost time”, i.e. time taken to perform those activities included in a normal well but excluded in the theoretical well and represented by the difference between technical limit time and “normal” industry times (i.e. well durations where conventional lost time or downtime had already been eliminated).

While this concept can yield substantial reductions in actual well duration, it heavily depends on the knowledge and operations experience of the team members involved in the exercise as they are called upon to individually estimate and agree the minimum time necessary to be spent on a particular task under perfect conditions. Alternatively, generating “aggregate” well durations from the best individual offset well sections will provide an indication of what has been achieved in the past but still falls somewhat short of the true “technical limit”.

Simplistic approaches at defining such technical limits start with personal experience of past performance or theoretical simulations of “best performance”. Only the application of statistical methods, based on vast amounts of historic data provides a robust means of defining “best performance”. The approach varies from that of the “technical limit” methodology in that it does not attempt to define a theoretical optimum case but tries to achieve repeatable and consistent good performance. Instrumentation and data acquisition technology already some time has reached the necessary level to measure individual performance, utilizing these data sets to investigate statistical distributions and subsequently identify targeted performance levels has the advantage that rig crews are not challenged to achieve an artificially developed “performance factor” but simply to repeat what they have already achieved in the past – consistently. As mentioned previously, the technical limit approach does recognize that expecting an Olympic record performance all the time is unrealistic, thus the target performance for a crew will be set at “x plus” (a certain percentage below the maximum possible performance). This approach clearly has the flaw that the definition of the “plus” is again subjective and debatable. Utilizing past performance as the basis for what should be achieved in the future is a lot better received and accepted by crews than such artificial target levels.

Spoerker, et al, in a 2011 publication[7] presented a methodology for identifying (and subsequently reducing/eliminating) invisible lost time as a basis for performance enhancement. They defined invisible lost time as a somewhat "fuzzy" category generally hidden in the planned operations time (as compared to clearly defined and visible non-productive time):

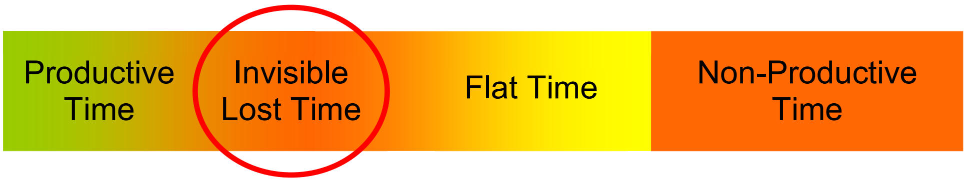


Figure 2: Invisible or Hidden Lost Time

In this context, "productive time" is defined as that part of the operation during which hole is made; other elements of the planned operations cycle are called "flat time" (e.g. logging, running casing, cementing etc.). The term "non-productive time" represents time spent on activities resulting from problems occurring (e.g. equipment failures or hole problems) and is generally estimated as providing 10-25% or savings potential. Interestingly, this value has remained almost constant over the last twenty years, indicating a certain complacency that "things invariable do go wrong from time to time". While this may be acceptable for geology-related uncertainties and resulting downhole problems, it definitely does not apply for the surface operation of the drilling machinery.

Invisible (or "hidden") lost time can be defined as the savings potential resulting from the cumulative sum of all differences between actual and best practice duration of operations. Extending this concept a little further into the area of "productive time" leads to further savings potential (if for example penetration rates do not reach those expected under optimal conditions).

As an example, if one wanted to plot the rig performance in making drill pipe connections ("weight-to-weight connection time"), plotting several hundreds or thousands of connections in a histogram typically provides the following result:

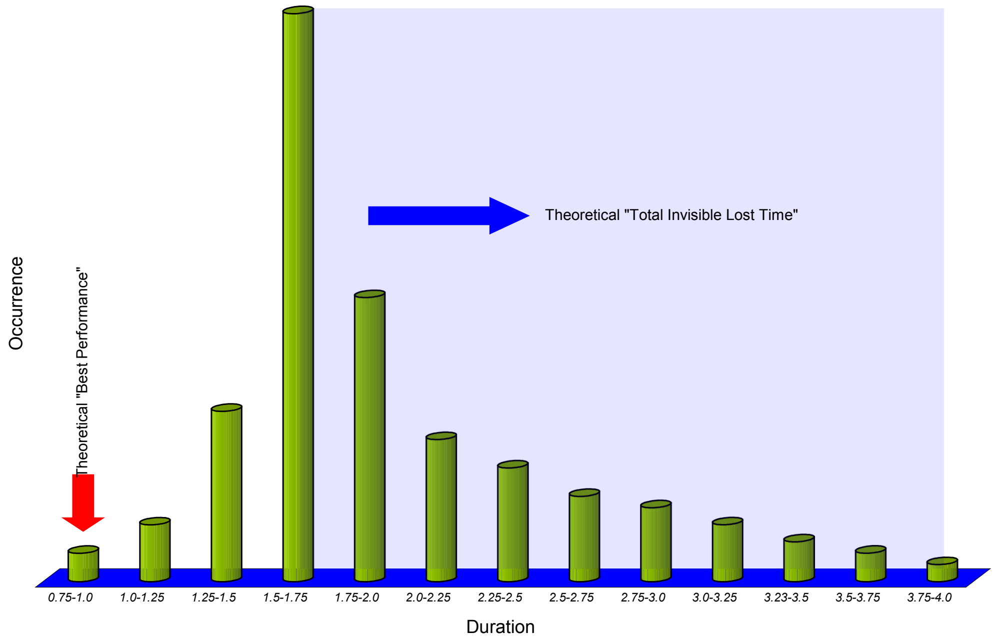


Figure 3: Histogram as used to define Invisible Lost Time

Assuming the P_{50} or P_{Mean} value of this distribution as a possible consistent and repeatable performance, the portion above this value can be taken as invisible (and thus potentially removable) lost time.

It should be stressed that this approach by no means challenges rig crews to work faster (thereby potentially sacrificing safety to achieve higher performance) but in a more consistent manner. A "theoretical best performance" value could be used for defining a "technical limit" while defining a P_{50} value as the objective for operational performance simply requires the crew to work as they normally are – without any undue delays or slowdowns.

2.3 Key Performance Indicators (KPIs)

The advent of quality control concepts also in the drilling industry forced this sector into describing its activities in a standardized manner, developing key performance indicators (KPIs) and implementing common benchmarking procedures. The most widely accepted and high-level benchmarking database for drilling performance are the Rushmore Reviews, originally started by a group of operating companies in 1988 and outsourced into an independent benchmarking joint venture in 1993. It has to be noted however, that also this benchmarking approach – while collecting a plethora of well data – does not address the procedural planning/execution of a well but rather depicts well construction performance via the same KPIs already in use for decades (rates of penetration, time/depth/cost curves etc.). It might be characteristic for the oil and gas industry (and especially for its sub-sector, the drilling community) to be somewhat resistant to innovation in the way it is conducting its business. While the industry is quick in developing and applying new technologies, adopting management theories or manufacturing principles that have been common to other industries for decades is in many cases seen as not feasible. It may be characterized by the notion “we are drillers, we know what we are doing, and you don’t”.

The availability of robust and clearly defined KPIs is a necessary requirement for defining the “baseline” against which operational performance is evaluated when identifying invisible lost time. Especially when comparing penetration rates or rig/equipment performance, these values cannot be universally defined as they are heavily dependent on subsurface factors (in the case of penetration rates) and surface machinery setup/capabilities (in the case of equipment performance. Therefore, the intelligent definition of best applicable KPIs and the subsequent evaluation of their optimum (or “technical limit”) become crucial in enhancing performance.

KPIs can generally be categorized by a business (“commercial”) relation or a technical relation. Business KPIs are typically related to scheduling and cost, while technical KPIs become a lot more detailed and can be broken down to individual tool/job performance.

Examples of business KPIs commonly used on the well-level are:

- **Footage cost** (total dry-hole or completed well cost divided by total drilled well length)
- **Footage drilled** (total drilled well length divided by total number of days spent on the well, either dry-hole or completed case)
- **Budget compliance** (total dry-hole or completed well cost divided by planned well cost)
- **Schedule compliance** (total dry-hole or completed well duration divided by planned well duration)
- **Time spent drilling with bit-on-bottom** (actual “drilling time” making hole relative to total well duration)
- Planned and unplanned **Non-productive time** (percentage of total well duration spent on planned and/or unplanned non-productive time)[1]
- …

Technical KPI’s can be extremely diverse, some examples for commonly used technical KPIs are:

- **Average** and **Instantaneous Rate-of-Penetration** (additional hole length drilled over a given period such an a reporting day and “drilling speed” of the bit at any given moment, typically given as m/hr or ft/hr)
- **Tripping Speed** (length of pipe pulled from the well or run into the well per time interval, typically indicated as m/hr or ft/hr)

[1] Note the difference between “planned non-productive time” (any activity planned on the well that does not directly result in hole being drilled, i.e. logging, casing/cementing, wellhead/BOP work etc.) and “unplanned non-productive time” (unplanned activities, generally resulting from downhole or surface equipment problems; sometimes also referred to as “trouble time”)

- **Slip-to-Slip** or **Weight-to-Weight Connection Time** (time elapsed between setting the string into the slips before breaking a connection until putting it out of the slips again after making up the next single/stand, typically given as seconds)
- **…**

Examples for more sophisticated KPIs related to technical as well as commercial factors are:

- **Wellbore Compliance** (actual well trajectory within predefined tolerance of planned well trajectory)
- **Wellbore Tortuosity** (minute deviation of the well path around the planned well path, generally due to oscillations of the bottom-hole assembly or frequent small-scale course corrections during drilling; optimum would be a smooth well path with no tortuosity; due to the rotating cutting action of bit and bottom hole assembly this ideal can never be achieved)
- **Waste Management Performance** (total amount of solid/liquid waste discharged from the well location per m³ of hole volume drilled)
- **…**

An extremely challenging area is the definition of health and safety related KPIs, as some critics voice concerns that using low incident frequencies (e.g. Lost-Time-Incident-Rate, LTIR) as a KPI will drive the organization into a "hiding" mode rather than promote active incident and near-miss reporting. This concern highlights the requirement for a robust organizational culture, with leadership "walking the talk" rather than concentrating on monitoring KPIs only.

3 Project Management and its Application on Drilling Wells

Thorogood[8] in 2004 reported the repeatable best performance on different wells and with different rigs due to the implementation of – what BP Amoco then called – the "World Class Drilling Process". He concludes that *"[…] problems always occur where plans have not been properly detailed both for the expected and unexpected events."*

He goes on defining the "ten key principles to every project":

- Project manager's commitment and management support
- Highly competent team members
- Clear, delivery-focused accountabilities
- Early and effective planning
- In-depth risk assessment and management
- Efficient project processes (schedule, cost, logistics, documents)
- Alignment throughout the team to a world class goal
- All involved are able to speak and listen openly and give feedback
- Performance assessed continuously against stretch targets
- Being absolutely serious about ALL these principles – not "playing at them"

While this thesis will not attempt to address issues like crew competence and management commitment, the requirement for efficient processes and the necessity for early and effective planning underline the importance of a standardized description of the way the project is to be executed – a Well Construction Process. The next step in enhancing project (i.e. well construction) performance is to not only standardize the way how these projects are being executed but also standardizing their design (drilling multiple wells of the same design with the same consumables and services), thus more closely matching a "factory-style" drilling activity.

3.1 The Well Construction Process

An introduction to the overall business process of planning, drilling and completing a well will facilitate the understanding of many concepts subsequently discussed later. An overall Well Construction Process consists of the planning phase as well as the execution (or implementation) phase of a drilling project. Like most processes oriented toward manufacturing/ construction of an end product, the planning and implementation of a drilling project (a "well") is structured along the "plan – do – check – act" loop, in other words from each well to the next a systematic learning/optimization approach is crucial.

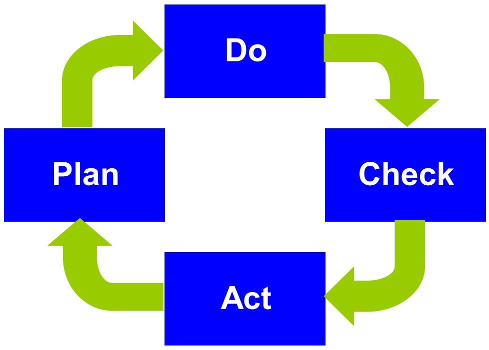


Figure 4: Plan-Do-Check-Act Loop

Traditional “wildcat drilling” throughout most of the 20th century has been characterized by bringing in a rig and making a hole into the ground, planning/optimizing as one went along. Only the ever deeper target depths of wells and the move offshore triggered higher and higher levels of front-end-loading, either because of logistical restrictions when operating farther offshore or due to longer delivery times for special tools and consumables when drilling deeper/hotter/higher pressure wells. Nevertheless, these approaches in most cases remained reserved for high-cost/high-profile wells, with the average “run-of-the-mill” shallow/on-shore project still pretty much drilled “on-the-fly”.

Looking at a generic well construction process, it is generally structured along a three-sectioned approach:

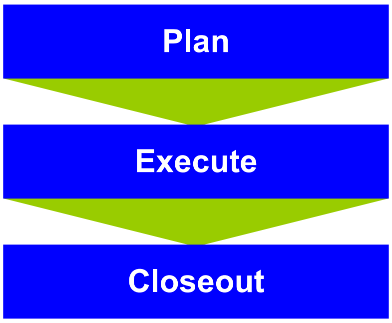


Figure 5: Typical Well Construction Process

It is perfectly acceptable (and even intended) that the “Plan” sub-process consists of several iterative revisions, constantly challenging and optimizing planned well designs and operational solutions from the initial concept until the final – and frozen – detailed work program. Such constant changes however would be a sign of operational weakness would they occur regularly during the “Execute” sub-process. A well-structured and robust organization is typically characterized by strong and rigorous adherence to a Management-of-Change culture, that – while allowing necessary adaptations to initial work programs – ensures that such change is being done in a structured way, complying with the same QA/QC, review and approval procedures that were applicable during the planning stage (between project concept and detailed work program).

Similarly, the closeout phase of each well should include the capturing of critical lessons learnt and the dissemination of these lessons both laterally across the organization (i.e. to other operating entities involved in planning and executing drilling projects) and inside the current operating unit to ensure such lessons are rapidly included in subsequent planning activities.

Application of learning-curve theory to drilling operations has first been done by Brett and Millheim in 1986[9]. Based on a typical planning-implementation-evaluation approach ("plan-do-check-act"), they concluded that *"[…] The application of learn curve theory to drilling is a quantification of what has been known qualitatively – that is, that the first well drilled in an area is expensive and the last well is cheap."*

A typical learning curve conforms to the relationship

$$t = C_1 * e^{(1-n) * C2} + C_3$$

with

- C_1 being a constant reflecting how much longer the 1^{st} well will take than the idealized n^{th} well
- C_2 being a constant reflecting the speed with which the organization reaches the minimum drilling time for a given area, and
- C_3 being a constant that reflects the ideal minimum drilling time for an area

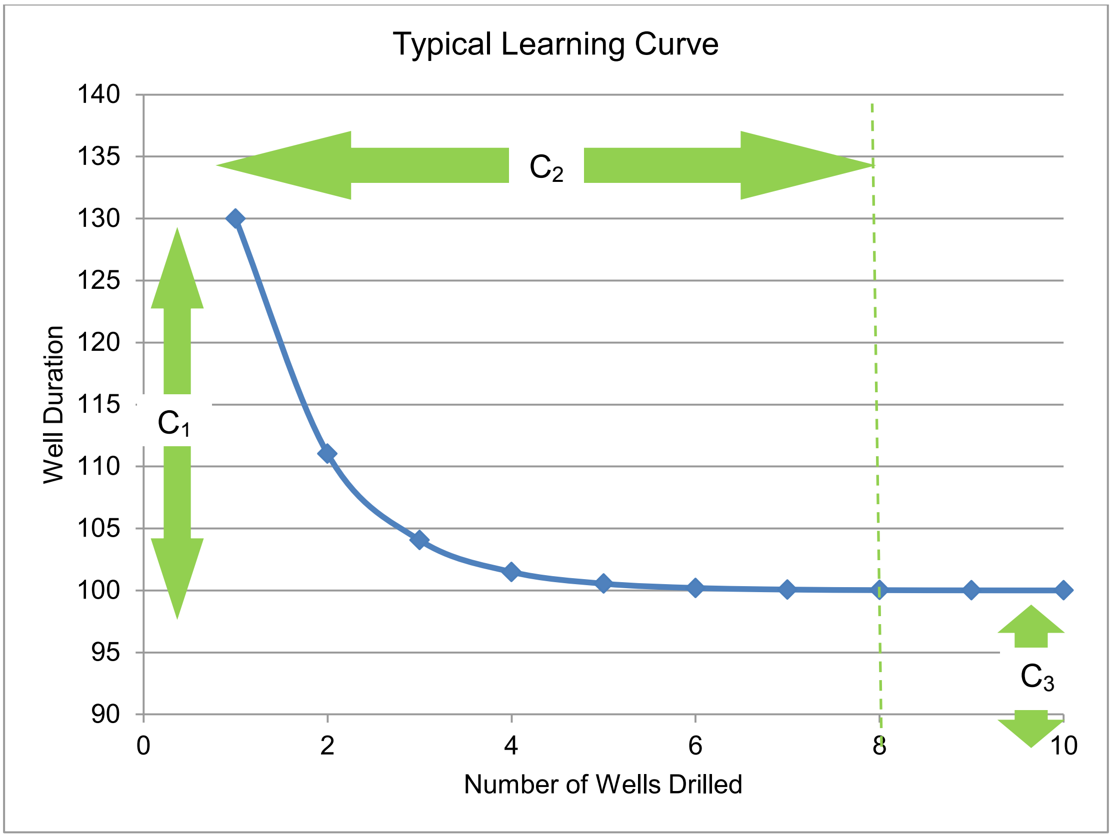


Figure 6: Typical Learning Curve

C_1 is predominantly dictated by the overall difficulty of drilling wells in a certain area and the existing (or lacking) previous experience within the drilling team of operations in similar settings. If the drilling team has experience with drilling wells in similar geological settings, it is possible that C_1 gets very close to one.

Obviously the absolute value for C_3 is heavily dependent on the engineering and design paradigms applied to certain drilling environments. Any changes to these paradigms (e.g. introduction of new technologies, changes in overall well designs such as eliminating well sections etc.) will trigger the start of a new learning curve, with the C_3 of the previous curve now representing the starting point of the next (if it has been achieved already):

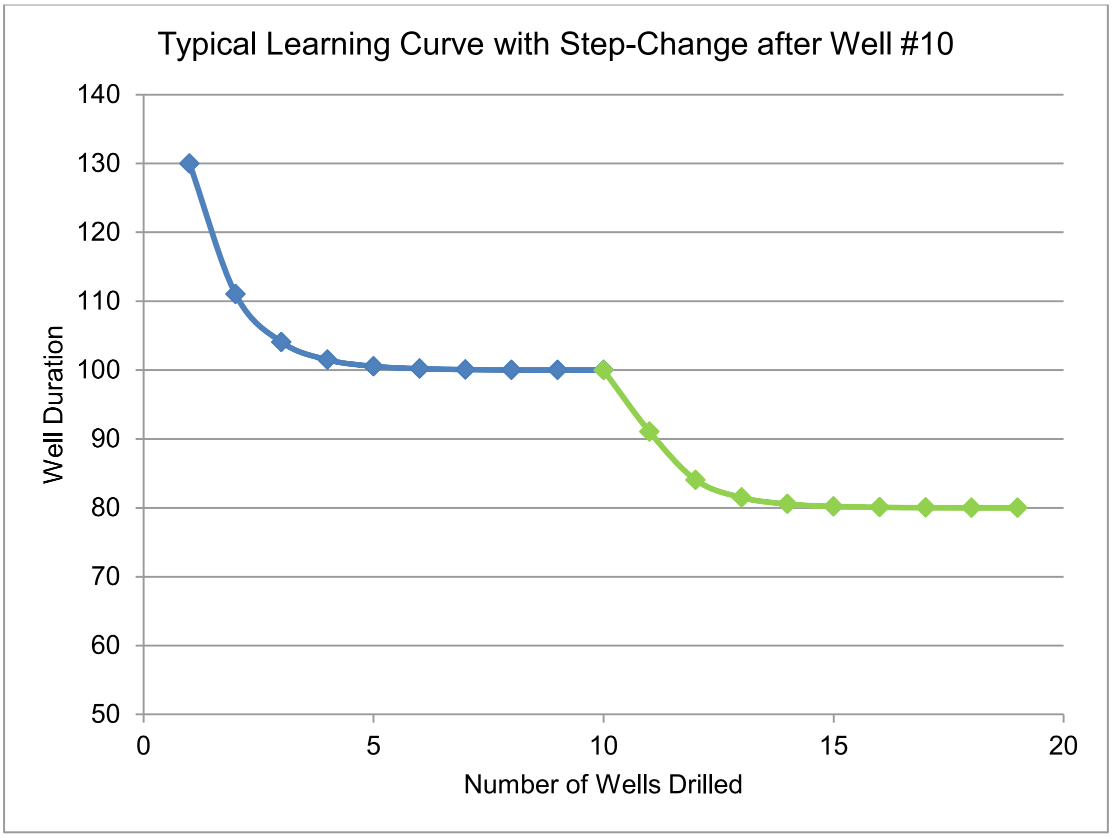


Figure 7: Typical Learning Curve with Step-Change

Brett and Millheim in their paper conclude that *"[…] High values of C_2* [… i.e. a fast learning performance …] *are produced by personnel and organizations when the following occur: an organizational structure has good communication between well planners and the field, there is good documentation and analysis of drilling problems, there is competent implementation of drilling plans and there is a high level of preparedness. As such, the C_2 value is one collective measure of the overall effectiveness of a drilling organization."*

Moving down into more detail, the actual ("physical") construction of a well happens in the "Execute" part of the Well Construction Process – the Drilling Process.

3.2 The Drilling Process

As previously mentioned, this thesis only addresses the actual well operations (or "Execution") part of an overall well construction process, typically starting with spud of the well (i.e. the first time a drill bit passes through the rotary table to drill formation) and ending with the release of the rig (either after running and cementing the final casing string or after completing the well including all production tubing and Xmas tree installations).

From a helicopter perspective, five core sub-processes (or "jobs") can be identified that typically account for all planned operations during well construction and that repeat themselves constantly (section-by-section) in the construction of a wellbore:

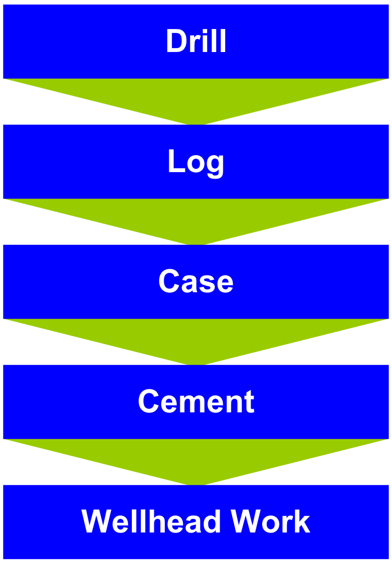


Figure 8: Core Processes in Well Construction

This sequence is repeated for each well section (typically characterized by the respective open hole or casing diameter. Deviations from this sequence generally denote some kind of trouble (optimistically also called “optimization potential”, i.e. activities that could be omitted as they were not in the originally planned operational sequence).

Obviously, introduction of new or different technologies can impact this “classic” job sequence. Best example is the introduction of “casing drilling”, or “drilling with casing” or “casing while drilling”, all names denoting the same concept that instead of using drill pipe to drive the bit, drilling new hole and then subsequently running a casing string into it, the casing itself is used to drill the hole and cemented in place once the intended shoe depth has been reached.

Each of these five core sub-processes can now be underpinned with tasks, generally organized around the “run” concept, i.e. every time a tool is run into the hole to perform a dedicated task. Deviations from the “run” concept occur when activities are performed on surface that do not include actual running of tools into the wellbore – this will later be addressed in more detail.

Examples for such tasks are:

Figure 9: Typical Tasks in Well Construction

Each task can subsequently be broken down into activity steps, which ultimately results in the basis for any “drill well on paper” (DWOP) exercise. Such exercises are commonly done during the planning stage of a well to (a) ensure that no required activities have been overlooked and that (b) planned well duration reflects the amalgamated opinion of all parties involved in the execution of a work program.

As a typical example, the activity list for the task “bit run” looks as follows:

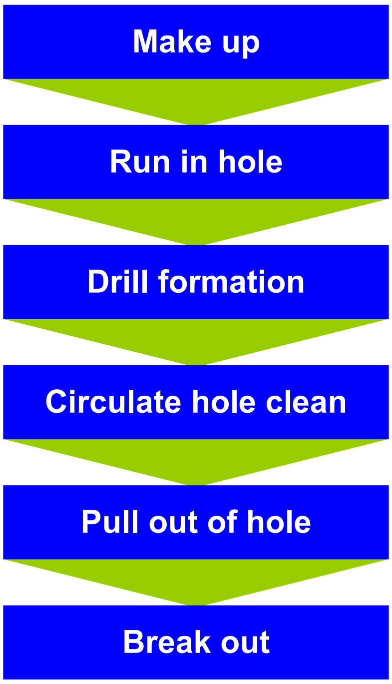


Figure 10: Example Activity List for “Bit Run” Task

When plotting spatial position of the tool (i.e. depth that the tool is at) over elapsed time, a typical “run signature” can be generated:

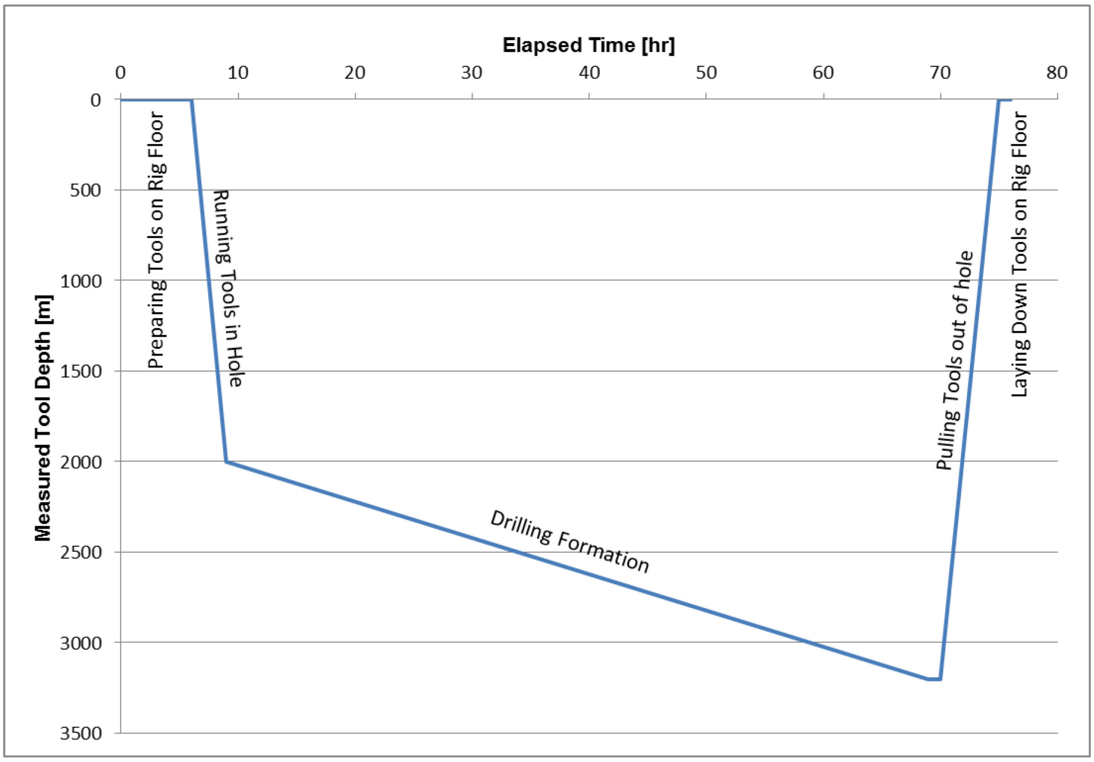


Figure 11: “Tool Run” Signature

Obviously these activities only reflect the portion of the bit run that contributes to the critical path activities in drilling the well. “Critical path” shall be defined in this work as any task for which a delay causes the delay of all other (subsequent) tasks until the end of the well (or every activity that blocks the rig from doing other activities, in other words whenever the rig floor and the crew are occupied carrying out a specific activity then this activity is considered to be “on the critical path”).

Including the preparatory and closeout activities of the bit run, it can be expanded into:

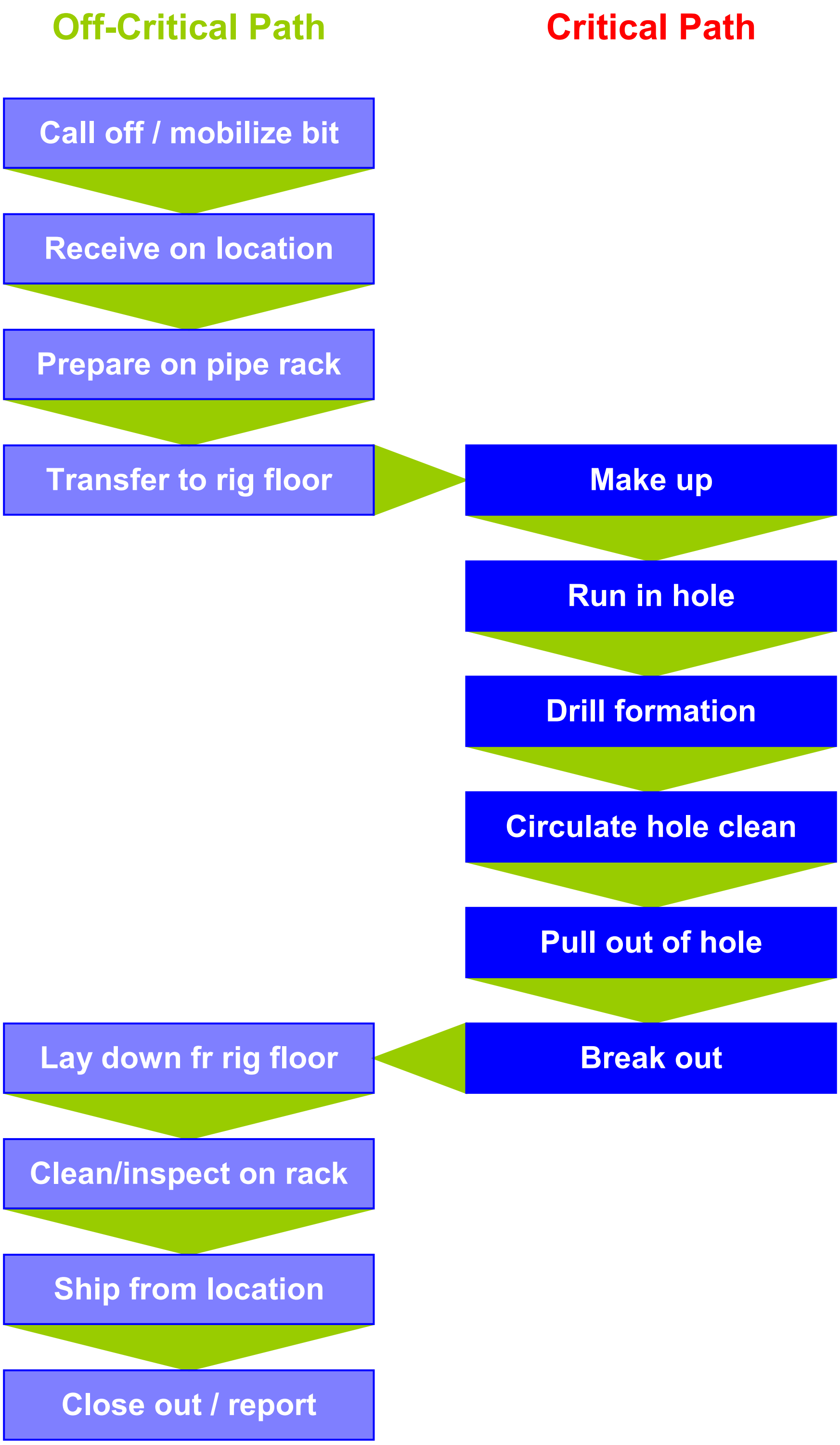


Figure 12: Critical-Path and Off-Critical-Path Activities (1)

It can easily be seen that while the critical path is made up of the sequenced tasks in the core sub-processes, the preparatory and closeout activities of these tasks are running in parallel to the critical path and can be visualized as follows:

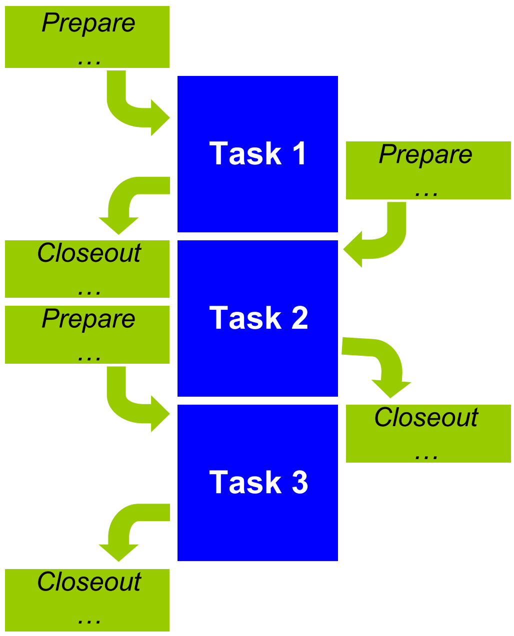


Figure 13: Critical-Path and Off-Critical-Path Activities (2)

The challenge to the organization lies in the correct sequencing and timing of when to initiate the preparation activities so that the tools/equipment/services are ready at the required "docking point" into the critical path. It is by no means uncommon even on high-cost drilling operations to have "waiting on equipment", "waiting on services" or "waiting in orders" periods on the actual operations time log (if they are reported) when the interface between preparatory and critical-path activities is not managed well.

3.3 Process and Workflow Description

When describing workflows, four main layers of process/workflow description granularity can be distinguished:

- **Strategic**
- **Tactical**
- **Detailed**
- **Machine**

Using this military analogy, it can be envisioned like strategic planning of operations on a large geographic scale and lasting over weeks and months. These strategic objectives then have to be translated into smaller, short-term unit objectives and plans by the field commanders. Once it reaches the level of the individual soldier, he vary rarely receives instructions on how to carry or shoot his rifle – he is expected to have acquired this skill before and to execute his orders based on his “implicit” knowledge. Finally, when reaching the fourth tier (machine), instructions on how to operate and maintain a single truck or tank are again very explicit and detailed; however they are typically repetitive and not specific to a certain operation.

As an example for this four-tiered approach, a typical drilling day can be used:

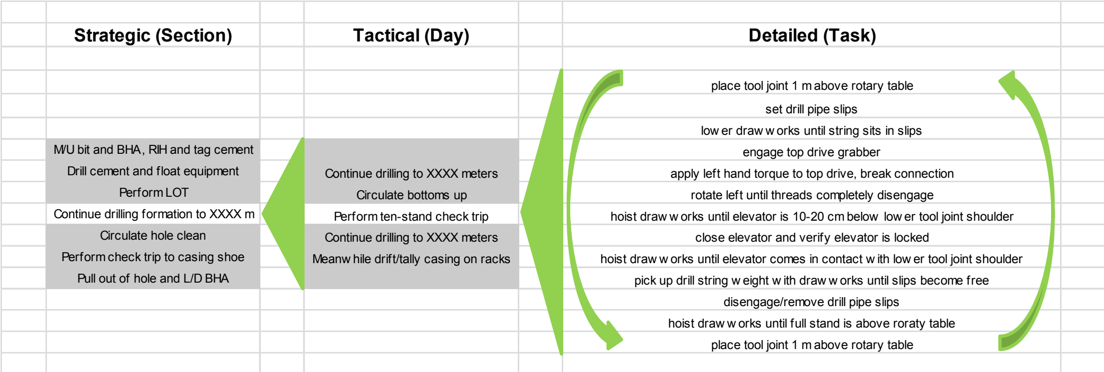


Figure 14: Strategic/Tactical/Detailed activity planning

3.3.1. The First Tier – Strategic Planning

“Strategic” in the sense that these activities typically start weeks/months (in case of sophisticated HP/HT, deep water or remote wells sometimes years) before the actually foreseen spud date, they include all steps from conceptual to detailed well planning, i.e. the transition from an “idea” which subsurface targets to reach with a new well through optimization and third-party (e.g. peer) reviews to a final and frozen detailed work program. Such programs are generally structured around the well construction work flow, i.e. well bore sequence by wellbore sequence, with all necessary design calculations and a foreseen timeline from spud to rig release. They can be relatively well structured, as all wells are constructed in the same sequence, and – aside from floater (i.e. offshore) operations are generally not too rig-dependent.

3.3.2. The Second Tier – Tactical Planning

This type of operations sequencing is generally used on the well site to issue instructions from the operator representative (“well site supervisor”) to the drilling contractor team and mostly depends on the organizational skills and leadership style of the operator representative. Such 24-hour “standing instructions to driller” could include items like “drill to XXXX meters, circulate the well clean, do a ten-stand check trip, run back to bottom and continue drilling”. Note that in a typical drilling environment forward plans are rarely based on expected times but rather on well depths or certain operational milestones being reached, another example of the open system boundaries as compared to tightly controlled shop-floor environments.

3.3.3. The Third Tier – Detailed Workflow Planning

It is here that the transition from explicit to implicit knowledge occurs, mostly because most rig crews operate on the assumption that “they know how to do a certain task, they don't have to write it down". This is a similar environment to our day-to-day life where we may prepare a shopping list before going to the supermarket but we never write down the step-by-step procedure how we grab a bottle of mineral water from the counter and place it into our shopping cart – we implicitly know how to do that. Still we sometimes drop the bottle because it may be wet (environment), we may accidentally grab it in the wrong place (operator error) or the carrying basket that holds the bottles might break just as we pick it up (equipment failure). The same applies to translating the "tactical" instruction "drill to XXXX meters" into the next lower level of detail. Once a stand is drilled down and the next stand or drill pipe needs to be added, this doesn't even need an instruction from the driller, everybody on the rig floor "knows" that now it is time to add another stand – they have done this a thousand times before. Still, for this example, this third level of detail shall subsequently be investigated as it provides the biggest opportunity for standardization and repeatable performance. Thorogood and Chrichton[10] in 2013 identified five typical problems arising from this bias:

- Team members with dissimilar backgrounds assume others do things the same way, so there is conflict until the differences are resolved […]
- Selection, training and competence assessment of a new drilling supervisory staff or inducting new members into a team becomes difficult in the absence of a framework to explain "how things are being performed"
- Developing the capability of teams to operate competently and demonstrating their readiness to control an operation cannot be structured effectively, nor is there an objective basis for competency assessment
- Absence of clarity around processes and ways of doing things leads to improvisation and organizational drift when guidance is not available
- Diversity within a large organization results in inefficiencies, additional learning and a potential for misunderstandings when members are deployed from one operation to another

As mentioned before, the transition from Tier 1 via Tier 2 to Tier 3 progressively migrates from predominantly explicit knowledge in the initial planning stage to predominantly implicit knowledge in the detailed execution stage. The instructions move from "what to do" to "how to do it". Nevertheless it is at this stage that least planning and documentation occurs; there is a common belief that "everybody knows how it's done"[11]. Safety-critical systems or high-reliability-organizations put strong emphasis on documenting (i.e. standardizing) workflows, not so much to increase performance but to control risk. At the same time, Thorogood advocates to *„avoid over-prescription and acknowledge and manage the improvisation gap between procedures and the workface but codifying or clarifying practice in areas where improvisation is frequently required"*.

It should be noted that the majority of major accidents in drilling do not result from planning mistakes (i.e. absence or failure of explicit knowledge) but in the execution of planned tasks at the rig level (i.e. inadequate implicit knowledge of how to execute tasks that were included in the plan).

3.3.4. The Fourth Tier – Machine Controls

This fourth (and lowest) level of workflow description is better developed than the third since drilling rig manufacturers have for some time been faced with the challenge to electronically control and partially automate their products. It contains the actual step-by-step machine control definition to perform a certain activity. Automation usually starts at the lowest tier since it involves least influence from human operators (the tasks are highly repetitive, and due to their short and well defined duration these tasks can be well described). Also, very few of these tasks are triggered automatically, they rather represent pre-defined activities that are started manually by the operator and then run their course until they return control back to him. They generally do not require any additional tools or equipment to be provided by human interference. As an example of this fourth level, the task "break connection" shall be dissected further:

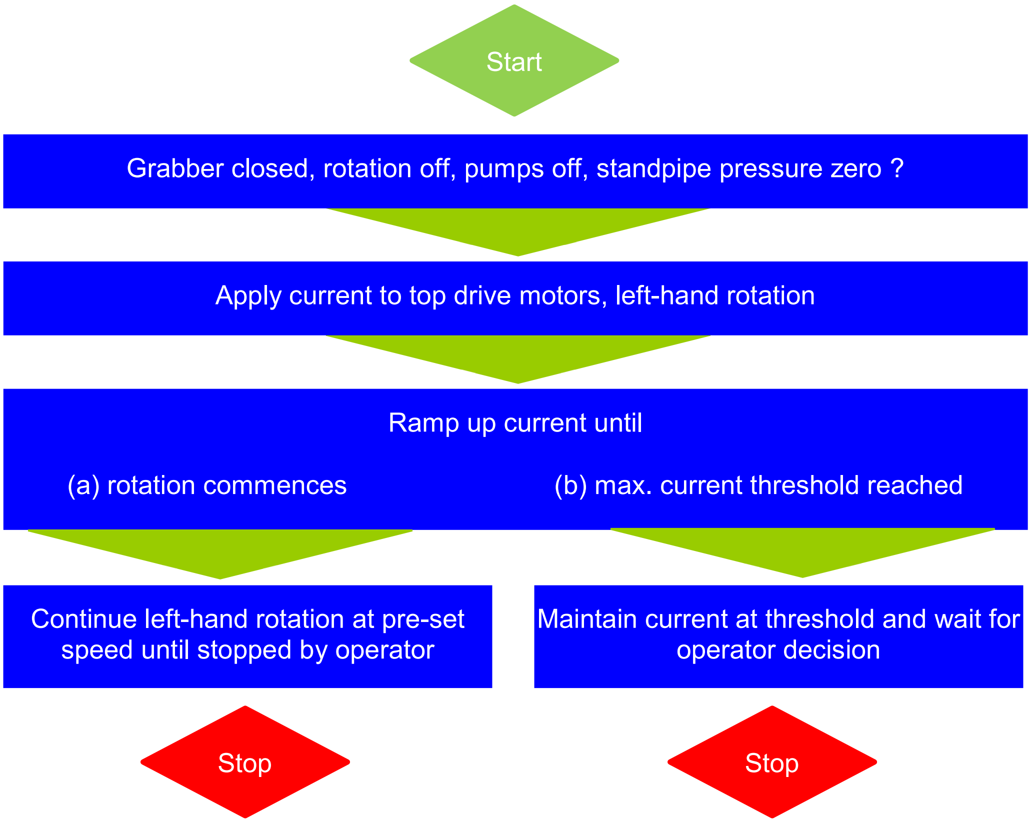


Figure 15: Machine control sequence "Break Connection"

Let us now investigate a typical rig operation that mostly is among the first activities to be addressed when talking about "automation" – tripping (drill)pipe out of the hole. It would seem that this activity is ideally suited to be automated:

- it is highly repetitive (pulling one double or triple stand after the other through the rotary table, grab it, break the connection and rack it back into the mast)

- in its routine execution it can be performed entirely without human intervention (draw works, slips, tongs, pipe handlers have been developed and automated decades ago)
- the machine environment of the rig necessary to perform these activities can be tightly controlled (small area around rig floor and mast without necessary interfaces to other rig components)

To better understand the increasing level of complexity as we progress from strategic via tactical to detailed and machine planning the following section "dissects" such a tripping operation.

3.3.5. Example Activity – Tripping Drill Pipe

Strategic	Tactical	Detailed	Machine (assuming AC rig)
• “Drill from XXXX to YYYY meters”	• “Today we will need to pull out of hole to change the bit and run back in”	• Pull with draw works and move string upwards until tool joint is ~1m above rig floor • Set string into drill pipe slips • Break connection • Pick up with draw works another meter • Grab stand with pipe handler • Disconnect top drive (open elevator) • Move stand to rack-back area with pipe handler • Lower draw works until top drive (elevator) is in position to grab tool-joint stick-up at rig floor • Close elevator	• Apply current to draw works motors in “forward” and slowly pick up blocks/top drive until string weight is transferred from slips to hook • Open drill pipe slips • Ramp up motor frequency until draw works reaches pre-set hoisting speed • Monitor hook load to stay below pre-set maximum overpull (maintain control over remaining drill string weight in hole); if pre-set overpull is reached, stop draw works motors, apply draw works brakes and alert driller • Monitor block/hook position in mast; start decreasing draw works hoisting speed as blocks near upper target position; at upper target stop motors • Lower drill pipe slips into bushing on rig floor, apply low-frequency current to draw works motors in “reverse” to lower string until hook load reading reaches empty-block (or top drive) weight • Move pipe handler from park position in side of derrick to well center; grab stand, close grabber and confirm grip • Move iron roughneck from park position to well center • Close back-up tongs of iron roughneck on gripping area of tool joint box, confirm full closing pressure • Close break-out tongs of iron roughneck on gripping area of tool joint pin, confirm full closing pressure • Apply left-hand torque (hydraulic pressure) on iron roughneck and monitor for rotational movement of between box and pin; if no movement up to pre-set maximum break-out torque bleed off pressure(s), stop activity and alert driller • Bleed off pressure from break-out tong; open tong; close pipe spinner and apply hydraulic pressure for left-hand rotation; rotate pre-set amount of turns (i.e. number of engaged threads); open pipe spinner; bleed off pressure from backup tong; open tong; retract iron roughneck from well center and move to park position • Pick up stand out of box with pipe handler; retract pipe handler with stand from well center; move stand to position (X/Y) in racking board fingers; close retaining pin in finger; lower stand with pipe handler until full stand weight sits on setback-board; open pipe handler grabber(s); retract pipe handler and return it to park position • In the meantime as soon as pipe handler has left well center with broken stand apply current to draw works motors in “reverse” and lower blocks/top drive until elevators are at pre-set target position above rig floor; stop draw works motors • Close hydraulic elevators, confirm closure • REPEAT CYCLE

Already this example of a relatively well-defined and limited activity shows two open boundaries where the system has to stop and rely on human decisions on how to proceed:

- Overpull when picking up the string (typically due to restrictions in open hole such as key seats etc.)
- Excessive break-out torque (typically due to downhole make-up or inadequate greasing of the connection)

In both cases the system cannot automatically apply a remedy and has to default to alerting the (hopefully present) driller to manually select a way forward. This becomes even more pronounced when the tubular types in the string frequently change (e.g. when pulling the bottom hole assembly). Already during drill pipe tripping operations, typical automation relies on all drill pipe singles being more or less of the same length. Detection of tool joint position above the rotary table can be done visually (via cameras and picture recognition), however no such systems have reached marketability yet. As soon as complex configurations like bottom hole assemblies need to be made up/broken, automatic detection of tool/tubular dimensions has to be coupled with full database availability of connection types, thread lengths and make up/break out torques. Again the “implicit” knowledge of the roughneck on the rig floor comes into play – he doesn’t have to measure the length of the tool, he sees when the bottom of the tool passes through the rig floor.

For these reasons, even such repetitive tasks as drill pipe tripping in most cases are still controlled by two individuals, one operating or “supervising” the draw works, the other operating iron roughneck and pipe handler. As long as everything runs according to plan (i.e. the rig “flies on autopilot”), their job is to simply supervise and control; however as soon as the system encounters an unexpected event (or leaves its standard operating envelope), human intervention is necessary. Instead of fully automating, the system is again based on “automation” of repetitive low-level tasks, triggered by an individual and returning machine control back to this individual as soon as the task-sequence has run its course.

3.4 Off-Critical Path Activities

While on the strategic level, off-critical path tasks and activities are mostly ignored, even the tactical (day-to-day) level has a tendency to relegate these activities to an “obviously required” role, thus not requiring specific instructions to be executed. This may in many cases be justified, however as soon as a certain piece of equipment or a certain consumable for the drilling process is not available at the specific time it is required, a low-priority off-critical-path activity suddenly impacts the critical path causing delays and shut-downs.

A trivial example of such preparations is the availability of hand tools at the time they will be required on the rig floor. A simple wrench to tighten the bolts on a safety clamp during tripping of drill collars has the potential to shut down the whole tripping operation if it can’t be found at the time when it is needed. Still, almost never will a “tactical” instruction from the operator representative to the tool pusher include a statement of “verify that wrench is available before starting tripping operations” – it is assumed to be implicitly known to the crew that they will need this tool sometime during the next several hours and will make sure it’s handy on the rig floor.

A more sophisticated example is the mud mixing process, a routine off-line rig activity to prepare new drilling fluid in the mud tanks to either compensate for amounts lost, to account for the additional hole volume created by the drill bit or to swap the existing fluid in the well bore for a different system. This task might encompass a multi-hour exercise, building tens or even hundreds of cubic meters of fluid, mixing tons of different chemicals and additives and conditioning this “new” fluid until it finally has reached the correct parameters to be pumped into the hole. None of these preparatory, mixing and conditioning activities impact the critical path, however if at the required time this fluid volume is not ready to be fed to the pumps, the critical path will be interrupted and rig activity will be stopped. Therefore verifying that the mud mixing operation progresses along its own planned schedule is a vital means to ensure that it will be finished at the required time, allowing the rig management staff to intervene in time if delays become apparent.

As this example task is precisely at the “detailed” level (the rig crew has been told at the beginning of their shift to build a certain volume of drilling fluid with certain parameters), the actual procedure of how to execute this task is left to the implicit knowledge of the persons assigned this responsibility, and in most cases there is no progress reporting throughout the activity and only a verbal “we are ready” feedback to the tool pusher when the task is finally finished.

Let us look at the actual procedure involved in mixing new drilling fluid volumes and identify options for better standardizing (and subsequently monitoring/controlling) its execution:

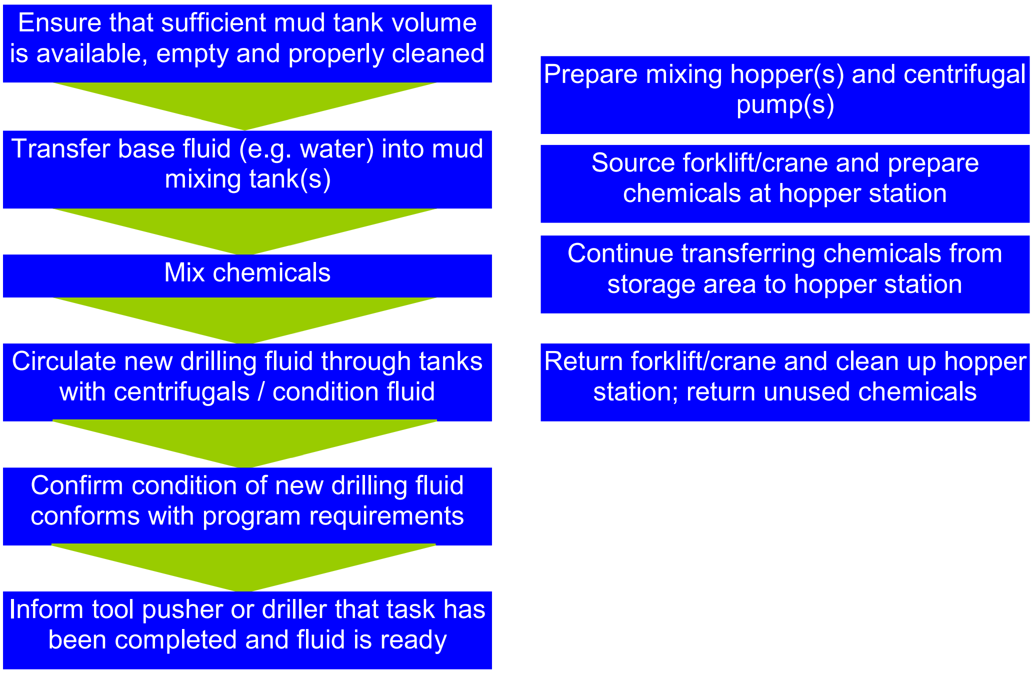


Figure 16: Detailed task sequence “Mixing New Mud”

Very few of these process steps can be automatically recognized via machine monitoring, however if the procedure itself could be provided digitally to the personnel tasked with executing this operation, and if this personnel had a simple and reliable option to simply report finalization of each planned step in the task, then a monitoring system could provide continuous update and forward estimates whether the task will be completed at the required time.

The challenge to provide a rugged but reliable man-machine-interface integrating drilling rig staff into an information exchange and process monitoring network is similar to the requirements seen in logistic services. Mail delivery staff is connected via hand-held computers to central servers, reporting delivery of each package in real time, packaging staff enters inventory control data into hand-helds in real time as the individual product is taken from the shelf and placed into a specified shipping container, etc.

Extending this concept to a drilling rig environment, “connecting” rig staff via hand-held computers (or in this particular case smart clothing to facilitate operations) would enable them to receive the “packing list” (i.e. the detailed planned job sequence for the mud mixing task including all consumable types and volumes) and subsequently simply confirm finalization of each sub-step in the activity (e.g. “25 m³ of water transferred to tank A, started adding chemical 1”).

Not only would such a system allow continuous tracking of well site operations, enabling timely intervention in case off-critical-path tasks indicate a potential delay in their docking point to the critical path, it would also substantially enhance standardization and quality control of processes/tasks/activities by providing detailed work instructions together with immediate feedback of whether/how these instructions are carried out in real time.

Again it has to be pointed out that such systems shall never be intended as additional control or supervision of staff but as a support to personnel. Any indication of “big brother syndrome” penetrating an organization has to be rigorously and plausibly eliminated.

3.5 Project Progress Reporting

Traditionally, drilling operations have always been compiling “daily reports”. Before the availability of data transmission technology, these reports were in many cases transmitted verbally by radio or telephone, restricting their content to a few key parameters and a short description of “what happened”. They were to a large degree driven by what regular information the licensing authorities required rather than what the organization needed to monitor performance. For several decades, the industry standard daily drilling report was based on the form developed and marketed by the International Association of Drilling Contractors (IADC) since it was predominantly the drilling contractor who needed a basis for invoicing the client for rig services. It was more a sort of “daily rig job ticket”, concentrating on listing the number of chargeable operating hours and a general overview of rig operations during this period.

With the advent of first the telefax and shortly thereafter digital linkups, daily drilling reports evolved into multi-page descriptions of the activities during the reporting interval – typically a 24-hour period. While this provided continuous updates to the operations offices on what the rig had been doing the last 24 hours, these reports only in very rare cases actually reflected project (i.e. well) progress against plan. A good example of this shortfall is the – typically – reported actual cumulative well cost versus the total AFE planned well cost. It can easily be seen that a comparison of these two values is completely meaningless without a clear picture of where the project stands relative to the planned project progress. Only a continuous comparison between actual cumulative well cost and **planned well cost at the specific stage of the current operation** will provide a meaningful measure of project performance. Since the major tracking mechanism of constructing a well is the current depth reached by the drill bit (plus the associated activities at pre-defined intervals such as logging, running and cementing casing etc.), it has for a long time been common to plot planned depth vs. actual depth as one means of keeping control over project progress:

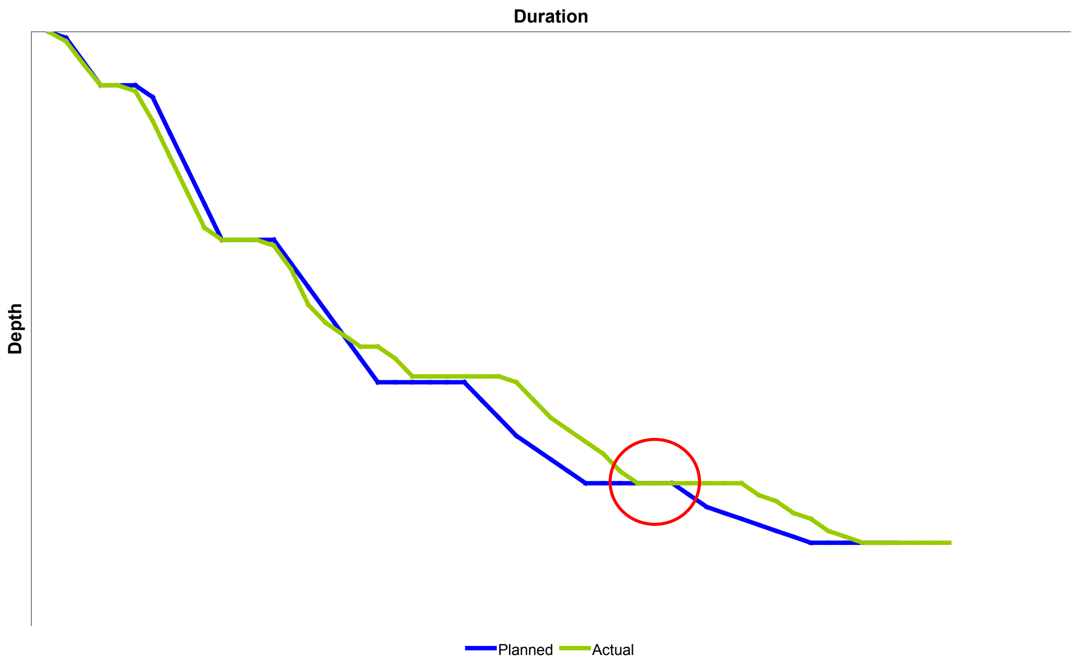


Figure 17: Generic Time/Depth Diagram

Looking at the red circle it can easily be seen that while a simple “planned vs. actual” time/depth comparison would show no deviation from planned performance (well is at the depth planned for this particular time spot), the project is in fact already delayed.

Only a more detailed project progress description will enable proper tracking. The need to standardize how rig activity gets planned and subsequently reported caused the introduction of activity coding systems.

3.6 Activity Coding

Projects can only be tracked properly, and performance can only be benchmarked across larger organizations (i.e. multi-rig environments) if the description of rig activities is standardized. This not only applies to using the same phraseology but strictly enforcing the same definitions of tasks and activities throughout the rig fleet. An old adage says “only what gets measured gets done”; the ability to measure activities, their duration (by identifying start/end points) and their results is the necessary foundation for any performance monitoring and/or enhancement program.

Activity coding is typically based on a multi-tier concept, mostly using the top (highest-level) tier to distinguish between planned (or “productive”) and un-planned (or “non-productive”) activities. While it can be argued that any activity that does not immediately result in more hole being drilled should be referred to as “non-productive” (e.g. taking logs, running and cementing casing or support tasks such as slipping/cutting drilling line, pressure testing of equipment etc.), it is generally accepted that all activities associated with planned operations should be coded as “productive” and only those activities that deviate from the detailed work program should then be classified as “non-productive”. A possible exception from this rule is time spent waiting on weather, as this is generally not included in the work program at specific time intervals but rather reflected as an overall well duration contingency percentage, however should be split out of the general “non-productive” time chunk as it is mostly out of control of the operations team.

Using the activity coding as implemented across OMV’s worldwide drilling operations as an example, there are four tiers describing rig activities:

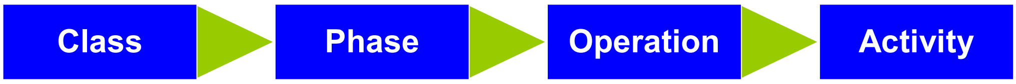


Figure 18: Typical Four-Tier Activity Coding System

With **Class** distinguishing between PLANNED, UNPLANNED and WAITING-ON-WEATHER conditions, the next tier reflects the **Phase** of the well – characterized by the open hole wellbore diameter – starting with the mobilization/rig-up prior to spudding the well and typically ending with the testing, completion/abandon and rig-down-demobilization phases.

The **Operation** tier reflects the run-based definition concept, and each Operation is composed of one or more **Activities**. These Operations and Activities are based on the following standardized classification:

Code	Description	Possible Activities[2]
BOP	BOP/WH/HP system	
		CRA, E/C, F/T, HPS, N/D, N/U, P/J, P/T, WB, WHW
CAS	Casing Run	
		C/H, C/M, C/P, C/T, CCA, CIR, E/C, F/C, L/D, P/H, P/J, P/U, R/B, R/D, R/U RUN, S/I, S/O, W/E, W/P, WAS
CEM	Cementing Run	
		CEC, CEM, CEM, F/C, HPS, P/J, P/T, P/U, R/U, R/D, TRI, W/E
CNR	Conditioning Run	
		BHA, C/H, C/M, C/P, CIR, F/C, FIT, L/D, P/H, P/J, P/U, R/B, REA, TRI, W/E, W/P
COR	Coring Run	
		BHA, C/H, C/M, C/P, CIR, D/F, F/C, FIT, L/D, P/H, P/J, P/U, R/B, REA, TRI, W/E, W/P
DRL	Drilling Run	
		BHA, C/H, C/M, C/P, C/S, CIR, D/C, D/F, D/S, F/C, F/T, FIT, L/D, LOT, OPH, P/H, P/J, P/U, R/B, REA, TRI, W/P, W/T, WAS
EQU	Equipment Run	
		BHA, C/H, C/M, C/P, C/T, CCA, CIR, E/C, F/T, L/D, P/H, P/J, P/T, P/U, R/B,

2 *See Appendix A for a description of the various activity abbreviations*

		R/U, R/D, TRI, W/E, W/P, WAS
EVR	Evaluation/Logging Run	
		BHA, C/T, CCA, CIR, E/C, F/C, L/D, N/U, N/D, P/H, P/J, P/T; P/U, R/D, R/U; R/B, REA, TCL, TRI, W/E, W/P, WAS, WLR
FIS	Fishing / Milling Run	
		BHA, C/H,; C/M, C/P, C/T, CIR, CCA, E/C, F/C, L/D, M/C, M/O, P/H, P/J, P/U, R/B, TRI, W/E, W/P, WAS
FTR	Formation Treatment Run	
		BHA, CIR, C/P, C/T, CIR, F/C, F/T, L/D, P/H, P/J, P/U, P/T, R/B, R/U, R/D, TRI, W/E, W/P, WAS
HSE	Health safety Environment	
		DRI, INV, S/M, TRA
MIL	Milling Run (if planned)	
		BHA, C/H, C/P, CIR, F/C, L/D, M/C, M/O, P/H, P/J, P/U, R/B, REA, TRI, W/E, W/P, WAS
OTH	Other (whatever is not covered elsewhere)	
PER	Perforation Run	
		BHA, E/C, L/D, P/J, P/U, R/U, R/D, TRI, W/E
RRE	Rig Repair	
		DRW, HPS, PMP, POS, POW, SCE, SKD, TDS
RSE	Rig Service	
		DRW, HPS, PMP, POS, POW, SCE, SKD, TDS, S/C (for RSE)
SUV	Survey	
		E/C, F/T, L/D, R/U, R/D, T/S, WLR, W/E
WCO	Well Control	
		C/M, C/P, CIR, E/C, F/C, P/H, P/J, P/T, S/I
WOC	Wait on Cement	
		BHA, CIR, L/D, P/H, P/J, P/U, R/B, TRI
WOE	Wait on Equipment	All activities carried out during the relevant waiting period
WOO	Wait on Order	
WOW	Wait on Weather	
WSF	Work Surface	
		DRW, E/C, F/T, L/D, P/J, P/U, R/U, R/D, SCE, TDS

In its most simple implementation, time break-downs and the associated allocation of the discrete time intervals to the respective activities and operations is done by wellsite staff as part of the daily reporting procedure. Inherent risks of this approach are

- Inaccuracies in the allocation of start/end times – reports typically limit their granularity to 15-minute (in some cases even 30-minute) intervals
- Differences in the personal interpretation of operations and activities; a classic example of this risk is "Circulate to Condition Hole" while doing other tasks on the rig. If the reason for spending this time is in fact hole conditioning, then the classification would be correct, however rigs routinely circulate while preparing/repairing equipment/services or simply waiting for materials or decisions; the inherent interest of a rig crew not to show downtime (repairing, waiting etc.) but instead log it as wellbore conditioning is understandable but destroys much of the value in time split investigation and rig operation optimization.
- Agglomeration of activities – sometimes rig crews tend to "lump together" several activities into one overall statement; this is especially the case where activities sometimes overlap.

It should also be pointed out that when running plan-vs.-actual comparisons on rig activities, there has to be a consistent understanding of each operation and activity description between the planning team and the execution (or wellsite) team.

3.7 Automatic Operation Recognition

The ever increasing availability of sensor data over the last decade has caused increased interest in the possibility of automatically identifying the rig's operating conditions and using this information as a basis for automatic time coding.

Initial attempts to integrate rig sensor telemetry into automated decision support systems coincide with the advent of personal computer technology. Mainframe environments as introduced already in the 1950 did not lend themselves for applications on drilling locations, and drilling data telemetry had not been developed to a sufficiently powerful level. The advent of the first smaller-sized computer systems in the early 1980ies triggered interest into the development of "expert systems" to support the rig crews in optimizing the drilling operations. Corti, et al[12], in 1992 described the development of a Real Time Expert System, used to determine operating state, perform time analysis, data validation and trend evaluation using raw sensor data. Based on UNIX workstation technology, their system operated on a 1 Hz sampling frequency on the data acquisition channels, at that time deemed to be adequate for monitoring most (if not all) rig site phenomena. The frontier aspect of attempting the definition of rig activity conditions from real-time sensor data is best reflected by the authors' conclusion that the "*… decision of putting strong (and costly) efforts into a Real Time Expert System implementation was a pondered gamble on a leading edge technology; present results mark it as a winning gamble …*".

Already three years before, the Information Transfer Committee (a subcommittee of the IADC's Rig Instrumentation and Management Committee) developed its Wellsite Information Transfer Specification (WITS) for Digital Rig-Site Data[13]. This specification was based on a 5-layered structure:

- **Level 1 – Predefined Records**; based on Schlumberger's Log Information Standard (LIS) format and compatible with the API Digital Log Interchange Standard (DLIS), this layer includes logical groups of parameters called "records" (e.g. depth-based drilling parameters, tripping information, cementing data etc.)
- **Level 2 – Modified Records**; for flexibility, this layer adds the option to add up to five additional parameters per record
- **Level 3 – WITS-Compliant (Customized) LIS**
- **Level 4 – LIS 1979**
- **Level 5 – LIS 1984**

As this standard in the meantime has been superseded by subsequent developments, this work will not go into further detail on it.

Spoerker and Kroell in 1997[14] stated that "*mud logging services on location cannot produce information, but they can visualize information otherwise lost or undetected among the vast amount of fuzzy indicators*" and concluded that while wellsite instrumentation systems were quickly adopted by rig crews with little previous exposure to computer applications, management would be "*challenged to make it clear that such installations support the crew, allow evaluation of operational efficiency, but that their primary goal was not to continuously look over the tool pusher's shoulder*". They also concluded that "*it should be the aim of any modern rig site information acquisition system to provide access to as many third parties as possible, allowing them to feed their data into the database as well as access the stored information and use it as basis for their services*", something which ten years later became pretty much standard with the advent of web-based services.

By the turn of the century, the WITS standard was adapted to the new environment of web-based applications and the dramatic increase in connectivity and data exchange between various service providers. This WITSML initiative was started in 2000 to *"provide an improved oil-industry standard to enable service companies at the well site to seamlessly exchange data with the software system in the oil company's office, regardless of its origin, during wellbore construction, planning and execution phases."*[15]

Automatic operations recognition from real-time sensor data which by the late 1990ies was seen as something "on the horizon", restricted by the limited availability of high-frequency data and the still very much restricted network and data transmission capabilities, by the early 2000s became more and more common.

Freithofnig et al[16] in 2003 report on the utilization of real-time rig sensor data as a basis for reducing/optimizing wellbore conditioning activities (e.g. re-reaming drilled stands before making a connection). They based their findings on the need to reduce and condense the amount of data nowadays recorded on drilling rigs as rig crews cannot anymore be expected to retain a full overview of all data channels continuously being monitored and immediately detect anomalies or deviations from "normal" trends. Similarly, because of the relatively short duration of the individual reaming activities they were generally not reported and simply lumped into the "drilling" activity (or – in case of more detailed time breakdowns – mostly fell into the "connection time" category), which makes this one of the classic examples of "hidden non-productive time".

Thonhauser and Mathis in 2006[17] presented a novel project management approach utilizing automated operations reporting based on rig sensor data. Again basing their approach on the Plan – Do – Check – Act loop, they concentrated on the monitoring aspect during the execution part of the well construction process. Instead of relying on daily reports generated by the rig crews, they suggested to automate the identification of rig activities based on data received from rig and/or mud logger telemetry. This enabled different "views" of the same project:

- Operations receives information on detailed process parameters
- Engineering can monitor essential design variables for future wells
- Management obtains cost information
- …

Their approach developed a "Drilling Process" description not in the planning phase (as a "Drill–Well–On–Paper" exercise) but rather from acquired sensor data over time as well construction went along. They also advocated to progress from a conventional well "planning" stage to the definition of an "expectation", providing targeted information to all organizational levels. It is a transition from defining "what" should be done throughout the construction of a well to "how" these individual tasks should be performed.

When monitoring job execution as basis for reporting project progress, the utilization of sensor data instead of human reporting activities enables a progression from subjective observations to objective measurements. The focus of the human contribution to the reporting process should be to describe the differences between expected (planned) behavior and actual performance. Quality control of the collected and reported data should be to a large degree automated, human contribution should predominantly provide value-adding feedback. A typical example of how rig activity is represented by sensor telemetry data looks as follows:

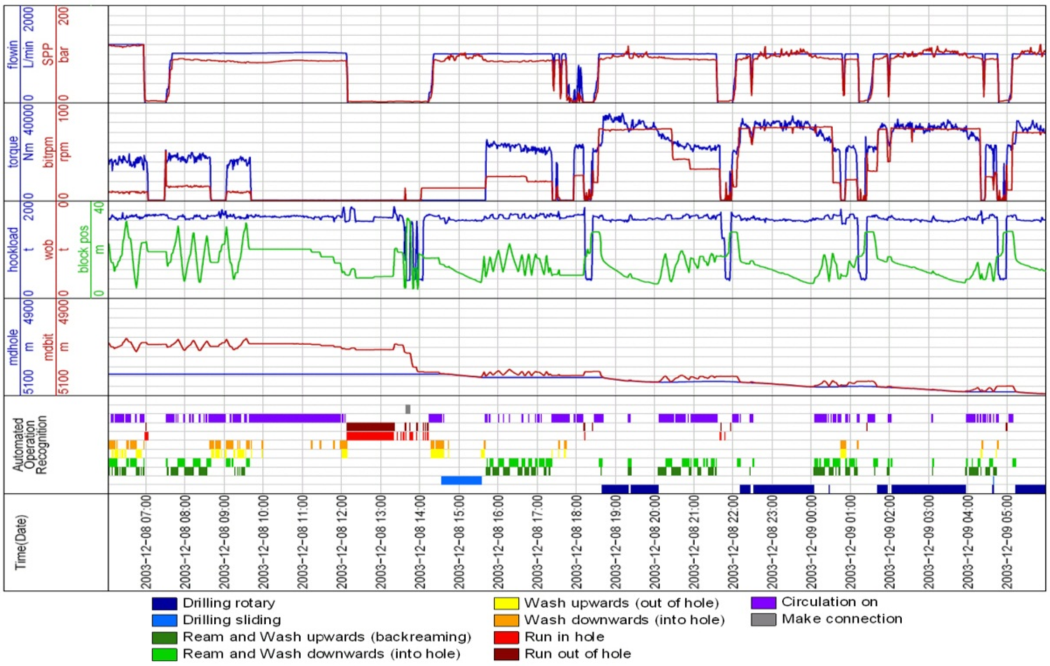


Figure 19: 24-hour rig telemetry time record

Automatically identifying the individual rig operating modes over a given 24-hour period, the authors presented a graphical representation as follows:

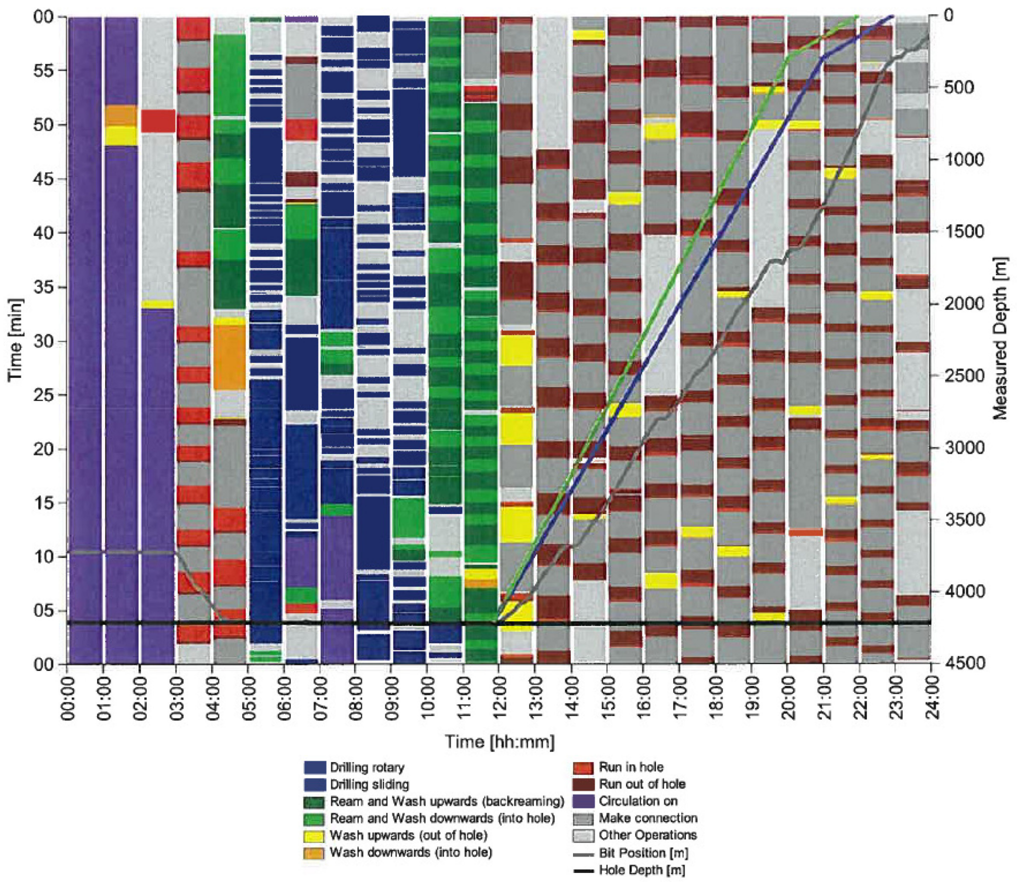


Figure 20: 24-hour operations record sample

This data was processed by an automatic operations recognition algorithm; each column represents one hour of chronological data from bottom to top (left axis with scale in minutes). The black and grey lines represent hole MD and bit MD over time.

The authors concluded that *“using measurements as the basis to generate drilling operations reports lead to a standardized and objective description of the drilling process”*.

4 Practical Applications

Enhancing operational performance based on modeling of the drilling process and subsequent detailed monitoring of process parameters as described at the end of the previous chapter has been applied within OMV E&P GmbH over a multi-year period (2006-2009) and has been investigated in detail for a three-rig drilling campaign in the Northeastern part of Austria in 2008. The rigs were diverse,

- KCADEUTAG T52 being a conventional, rather old (originally built in 1981) 450-ton heavy DC rig drilling deep directional gas wells (15000-20000ft),
- KCADEUTAG T208 being a highly modern (2004) 350-mt AC-rig drilling directional multi-target oil and gas wells,
- KCADEUTAG T65 being an ageing and not optimized 140-mt rambler rig drilling shallow (max. 8000ft) oil and gas development wells.

All three rigs were operated by the same drilling contractor, thus the same crew training and rig operating procedures applied. All three rigs were running under supervision by OMV staff, drilling programs were developed by the same engineering group for all three drilling units. Since all three rigs were operating within the same geographical area, external factors influencing rig performance could be kept to a minimum. The results of this project have been published by Spoerker, et al, in 2011[18] and will be referenced throughout the remainder of this chapter.

To enable meaningful automated recognition of drilling unit operating conditions, a sampling frequency of 1 Hertz has been identified as the most suitable resolution. While today's monitoring systems sample sensor readings at much higher frequencies for on-site visualization, transmission and especially storage of such high-frequency data puts an unnecessary strain on bandwidths and data bases without adding additional value. For example, hook loads due to the large mass involved simply because of the inertia in the system will not exhibit fluctuations in the >1Hz spectrum (if we ignore vibration characteristics monitoring which is used for a completely different purpose than to identify drilling unit operating condition). The same is true for mud pump pressures where – aside from high-frequency monitoring in machine preventive maintenance applications – no fluctuations >1Hz are of interest to identify the operating status of the drilling unit.

For all rigs monitored, the following sensor readings have been acquired with a 1-Hz frequency:

Measured bit depth
Measured hole depth
True vertical hole depth
Block Position
Average Rate of Penetration
Average hook load
Maximum hook load
Average weight on bit
Maximum weight on bit
Average torque
Maximum torque
Average top drive RPM
Average mud pump pressure
Average choke pressure
Speed mud pump 1
Speed mud pump 2
Speed mud pump 3
Active tank volume
Total tank volume
Average flow out
Average flow in
Average mud density out
Average mud density in
Average mud temperature out
Average mud density in
Total mud pump strokes
Mud flow out (pedal)
Average gas in mud
Methane in mud
Ethane in mud
Propane in mud
Ibutane in mud
Nbutane in mud
Ipentane in mud
Npentane in mud

Figure 21: Data channels monitored (fields marked in yellow were actually utilized for automatic operations recognition algorithms)

It can easily be demonstrated that during any 24-hour operating day, the raw volume of sensor data acquired and transmitted to the central data base runs in the millions of data points (35 channels x 86400 seconds per day x 5 bytes[3] equivalents 15 MB of raw data per operating day for each rig). For automated operations recognition, only 8 out of the 35 monitored channels were required.

During the total monitored period (2006-2009), the three monitored rigs drilled a total of 54 wells with depths ranging from 500 to as much as 6000 meters. These wells can typically be represented by their time-vs.-depth (TxD) curves, showing the development of the well over a time axis:

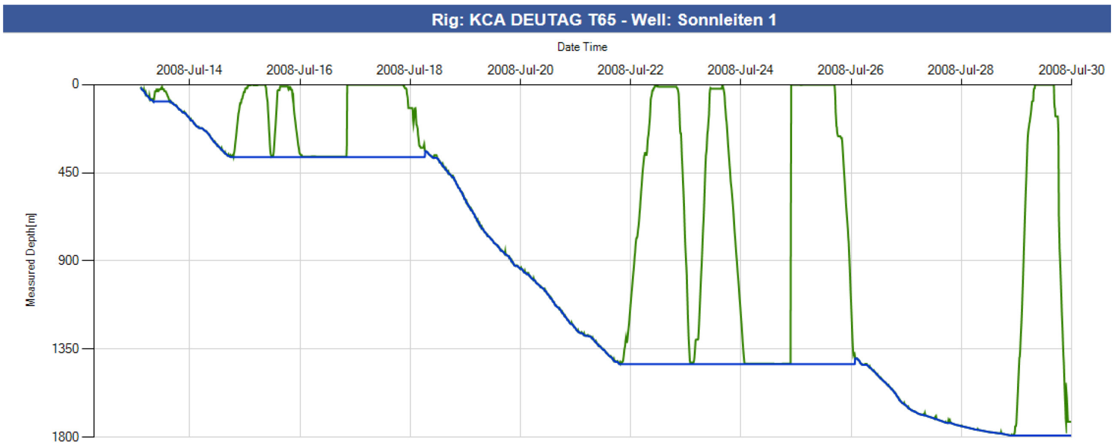


Figure 22: TxD curve for shallow well Sonnleiten 1, drilled with Rig T65 to a total depth of 1793 meters

[3] Assuming already optimized data compression

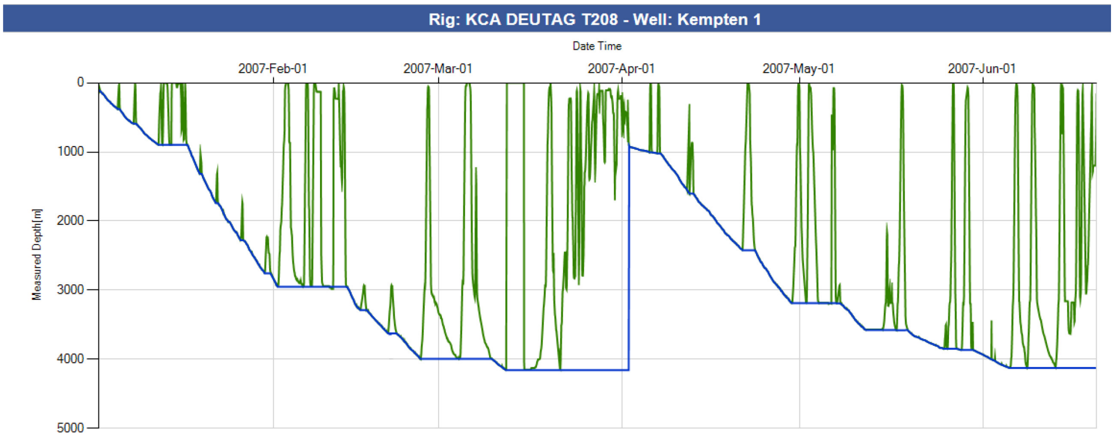


Figure 23: TxD curve for medium-depth well Kempten 1/1a (including a geological sidetrack), drilled with Rig T208 to a total depth of 4146/4130 meters

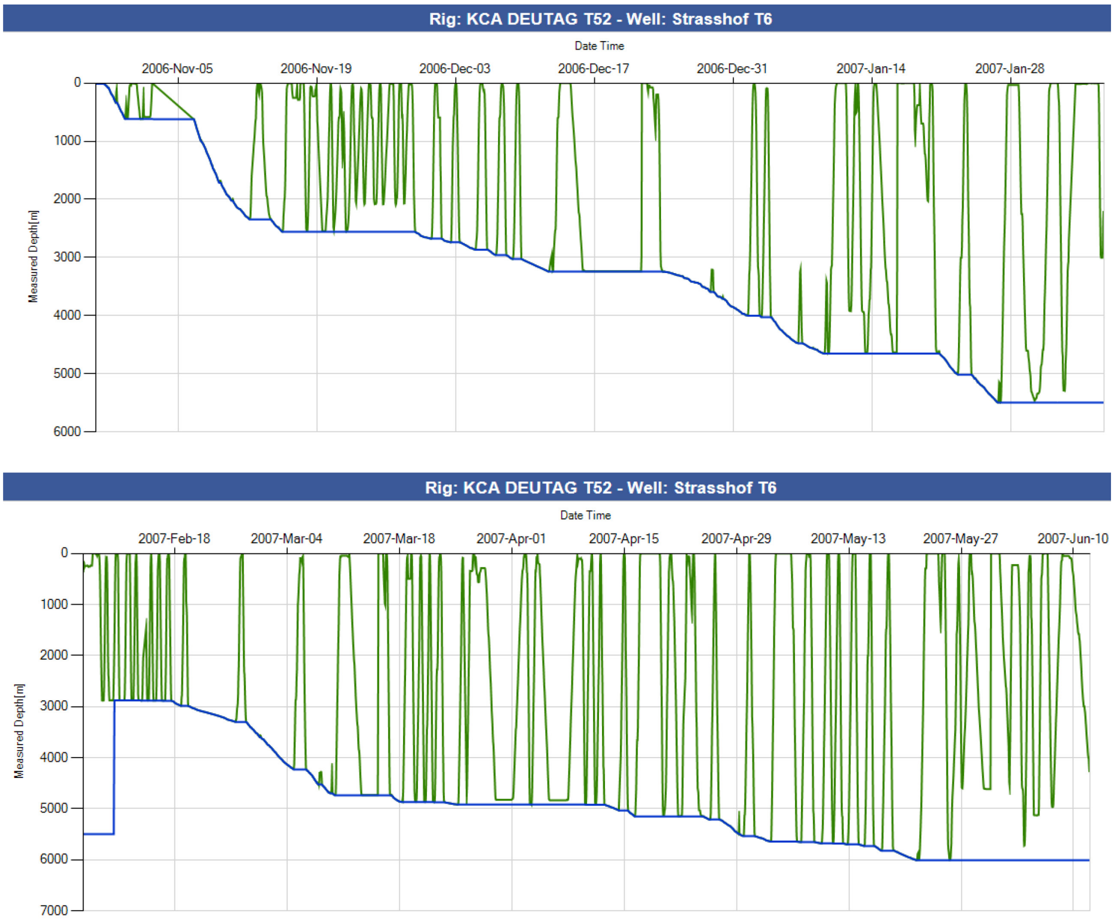


Figure 24: TxD curve for well Strasshof T6/T6a (including a geological sidetrack), drilled with Rig T52 to a total depth of 5501/6013 meters

If we consider “making hole” (i.e. the time that is spent by the rig with the drill bit on the bottom of the hole) as the coarsest definition of “productive time” during the process of constructing a new wellbore, historically the industry has always experienced approximately 1/3 of the total well time being spent in this condition, the remainder being required for tripping, logging, casing, cementing, etc. (subsequently referred to as “flat time”, “non-productive time” and “invisible lost time”).

Taking the previously selected three reference wells, a typical time-pie-chart representation provides the following distributions:

Color	Operation	[hh:mm]	[%]
	Drilling rotating	111:51	26.27
	Drilling sliding	10:56	2.57
	Ream upwards (backreaming)	08:42	2.04
	Ream downwards (into hole)	09:25	2.21
	Wash upwards (out of hole)	07:35	1.78
	Wash downwards (into hole)	04:02	0.95
	Run in hole	07:19	1.72
	Pull out of hole	05:15	1.23
	Circulate hole	27:12	6.39
	Make connection	56:28	13.26
	Other operation	177:02	41.58
	Sum	**425:46**	**100.00%**

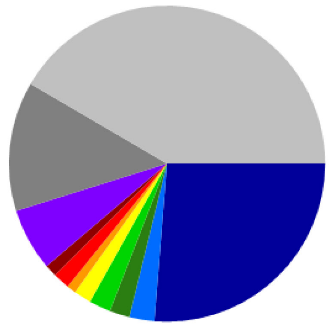


Figure 25: Time distribution for well Sonnleiten 1

Color	Operation	[hh:mm]	[%]
	Drilling rotating	1157:49	28.60
	Drilling sliding	259:17	6.41
	Ream upwards (backreaming)	223:30	5.52
	Ream downwards (into hole)	372:14	9.20
	Wash upwards (out of hole)	60:09	1.49
	Wash downwards (into hole)	64:17	1.59
	Run in hole	75:09	1.86
	Pull out of hole	77:19	1.91
	Circulate hole	461:52	11.41
	Make connection	441:33	10.91
	Other operation	854:48	21.12
	Sum	**4047:56**	**100.00%**

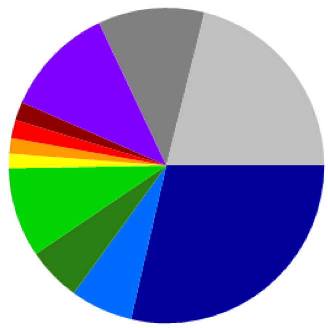
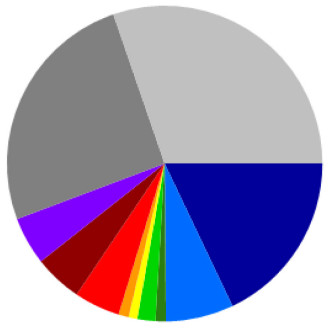


Figure 26: Time distribution for well Kempten 1/1a

Color	Operation	[hh:mm]	[%]
	Drilling rotating	539:31	17.92
	Drilling sliding	209:32	6.96
	Ream upwards (backreaming)	31:50	1.06
	Ream downwards (into hole)	55:53	1.86
	Wash upwards (out of hole)	26:51	0.89
	Wash downwards (into hole)	31:28	1.05
	Run in hole	141:30	4.70
	Pull out of hole	148:38	4.94
	Circulate hole	148:11	4.92
	Make connection	765:48	25.44
	Other operation	911:34	30.28
	Sum	**3010:46**	**100.00%**



Color	Operation	[hh:mm]	[%]
	Drilling rotating	512:03	20.96
	Drilling sliding	147:58	6.06
	Ream upwards (backreaming)	59:13	2.42
	Ream downwards (into hole)	67:10	2.75
	Wash upwards (out of hole)	33:35	1.37
	Wash downwards (into hole)	42:31	1.74
	Run in hole	86:18	3.53
	Pull out of hole	123:26	5.05
	Circulate hole	121:59	4.99
	Make connection	399:38	16.35
	Other operation	849:41	34.77
	Sum	**2443:32**	**100.00%**

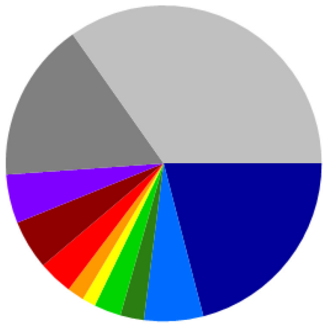


Figure 27: Time distributions for well Strasshof T6 (top) / T6a (bottom)

These three wells provide several interesting anomalies in the time distribution. One would normally expect a trend of time spent on bottom ("drilling") getting less and less as total well depth gets deeper, easily explainable as the rig needs to spend more time tripping, changing bits and bottom hole assemblies and running/cementing more casing strings to get to TD. In reality, while the deepest well (StrT6/6a) at ~26% does indeed show the smallest "drilling" share in its time split, the medium-depth well (Kempten 1/1a) achieved a remarkable 35% share and the small rig sits somewhere in between at 28.9%.

There is a similar inconsistency in the time spent making connections (i.e. breaking or making up drill pipe connections during tripping in/out of the hole). Again, the deeper the well the more connections will have to be made/broken and the more roundtrips will be expected. While StrT6/6a shows an expected larger percentage of time spent making connections (20.9%) and the shallow Sonnleiten well sits at 13.3%, again the Kempten 1/1a well at 10.9% is even lower than the shallow well.

Subsequently we will concentrate on a one-year period out of the full three-year monitoring project time. During this year, 16249 hours of rig time were analyzed, and the average time spent on bottom (actually creating new well bore, characterized as "Drilling rotating" and "Drilling sliding") was found to be less than 20% (3127 hours). Utilizing an un-biased monitoring system (not based on time coding done by the rig crews but totally relying on rig and mud logging telemetry and automatically identifying rig operating conditions) provided an objective basis for assessing operational performance.

Based on the description of the drilling process as described in Chapter 3.3 and on the procedures of automatically recognizing operating conditions of the drilling “machinery” as described in Chapter 3.7 of this work, invisible lost time (ILT) could be identified across all wells drilled under this project. ILT in this context has been defined as the difference between a pre-defined KPI target and the actual KPI performance shown by a crew, rig or entire fleet of rigs. It is thus not a “standard” or “fixed” parameter but rather the result of an assessment what “target” performance should be. This assessment obviously is dependent on the philosophy adopted by the operator. Selecting “best historic performance” or even “best industry performance” is the most demanding target parameter definition, carrying the highest risk of continuously failing to meet target values, resulting in crew dissatisfaction and little buy-in. The most impact on enhancing overall system (i.e. crew) performance resulted from selecting not even the best but the mean average performance attained historically by a certain rig or crew, then concentrating on making field performance more consistent around this average (in other words, eliminating outlying data-points that caused excessive time delays). While this applies to all rig operations, in the following we will concentrate more on the concept or reducing/eliminating invisible lost time (ILT).

The measurement of ILT starts by analyzing each individual KPI that can be produced by a particular rig or crew (drilling crew, casing crew, etc.) or by a machine automated operation or a combination of both. The time period is typically selected to allow for different rigs to perform the same operation many times under similar conditions, therefore an example of a time interval could be the duration to complete (drilling and flat times) a particular well section (i.e. hole size), or the time complete a particular tubular run and so forth.

Once this data is gathered, individual histograms are prepared for each rig for each routine operation. For the purpose of this thesis we will select the time spent to make or break a connection, i.e. the time spent between setting the string into the slips until it is picked out of the slips again when adding or removing a stand of drill pipe. This sequence shall subsequently be referred to as “slip-to-slip” connection time.

A typical histogram of such a slip-to-slip time distribution for one rig in the fleet looks as follows:

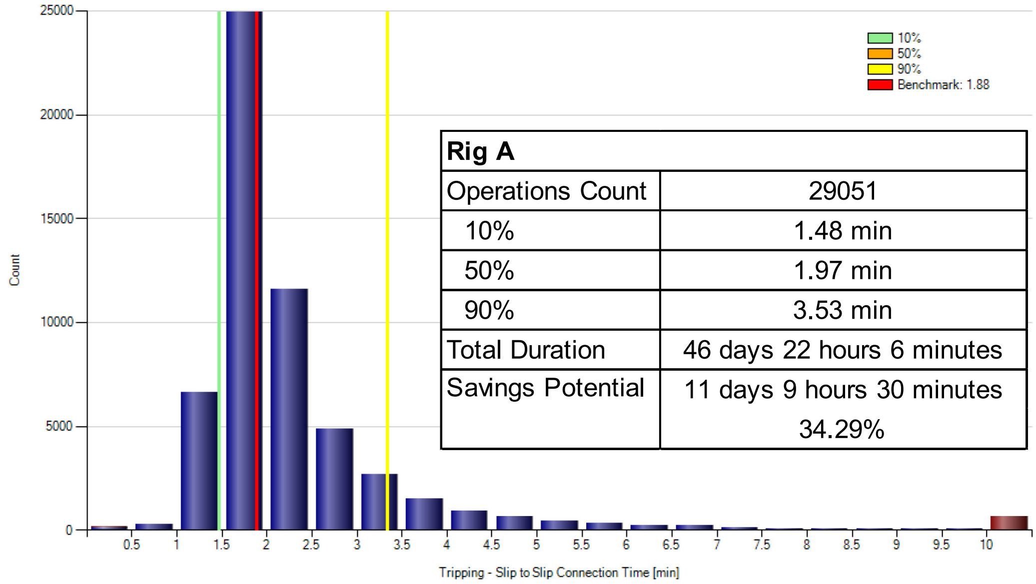


Figure 28: Slip-to-slip time histogram example Rig A

For this rig, during the whole observed period of about one year, more than 46 days were spent making connections, with the duration of such slip-to-slip operations ranging from 1.48 minutes (P_{10}) to 3.53 minutes (P_{90}) when we truncate the extremes. While a "technical limit" approach would now pick something around the P_{10} performance as target-KPI, it has already previously been mentioned that such extreme objectives carry the substantial threat of crew demotivation, comparable to a Fomula-One race driver being told "now that you've won your first Grand Prix, we expect you to win every future one". To avoid such a paradigm, the target-KPI is set at the P_{50} performance value (1.97 minutes), in other words the crews are being challenged to simply produce average performance – but predictably and consistently. In this case if this rig could consistently deliver slip-to-slip operations closely around their historic P_{50} performance of 1.97 minutes, throughout the one monitored operating year a total time savings of 34.3% (11 days and 9 hours) could have been achieved.[4]

Statistics reflect the "consistency" of such an operation by the standard deviation, i.e. how much the individual values "concentrate" around a median value. For the three rigs monitored in this project, standard deviations for slip-to-slip connection times varied between 1.07 (rather consistent) to 1.35 (more "flattened out" histogram, less consistency in operational performance). Generally, low standard deviations (i.e. high consistency in operational performance) could be correlated with higher safety performance.

[4] The invisible lost time in this case is defined as the cumulative time to the right of the target value; therefore the selection of the target basically determines the amount of invisible lost time that is detected.

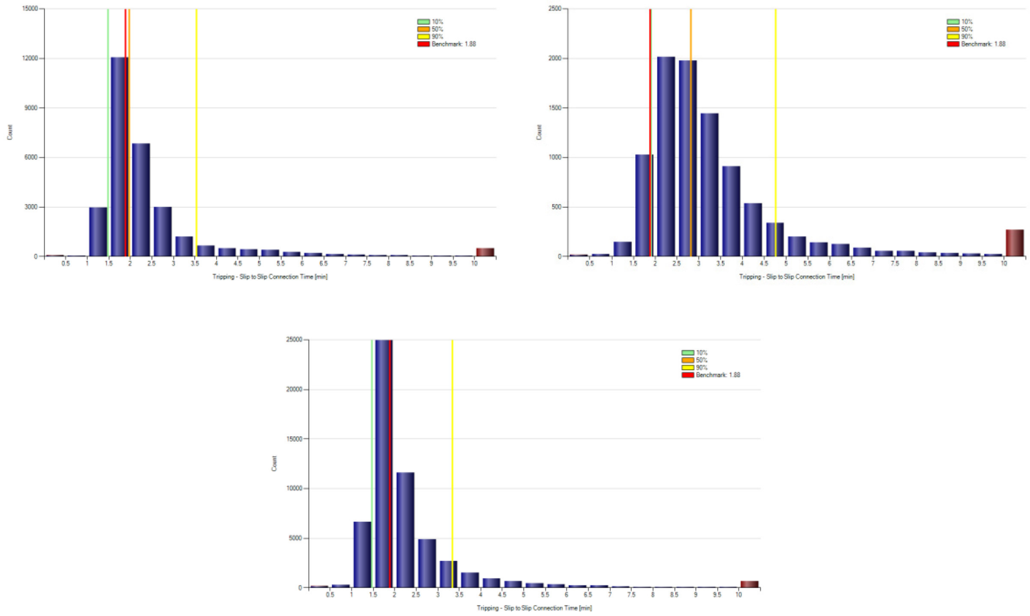


Figure 29: Standard deviation on slip-to-slip time histograms for three monitored rigs

It can easily be seen that Rig B has a larger standard deviation (i.e. a larger spread) around the mean, in other words this rig delivers slip-to-slip connections at a less consistent performance than the other two rigs.

Since this slip-to-slip connection time is a rather short and well controlled operation, let's extend the monitoring scope a little. Instead of simply investigating how long the crew leaves the string sitting in the slips until the next connection has been made, let's look at how long it takes between picking the bit off bottom (i.e. interrupting the physical "drilling activity" of crushing rock and creating new hole) until it is back down on bottom and resumes the rock crushing action. We now refer to this time as "weight-to-weight" connection time as it is characterized by the elimination of weight-on-bit at the beginning and the return of weight-on-bit at the end of this operation:

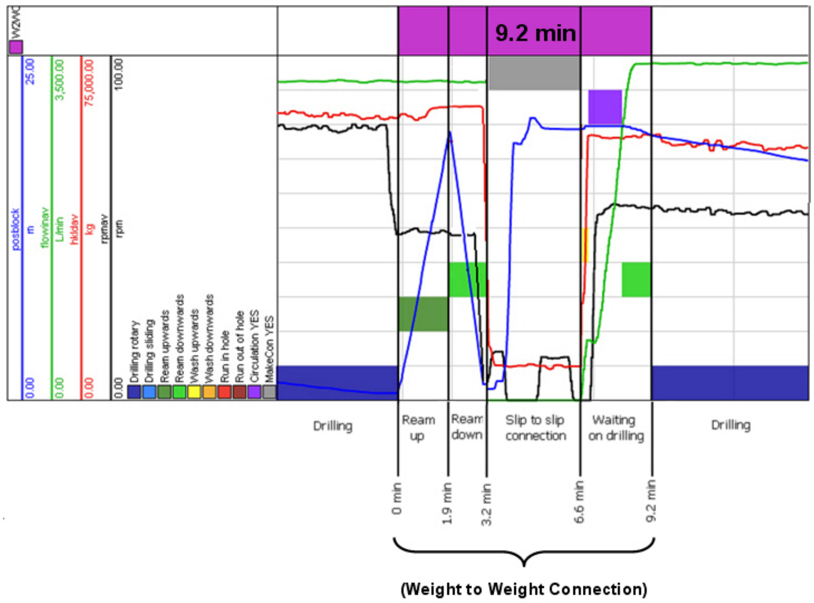


Figure 30: Definition of weight-to-weight and slip-to-slip times based on automatic operations recognition from rig sensor data

Taking the same rig as for the previous slip-to-slip example, the weight-to-weight histogram now looks as follows:

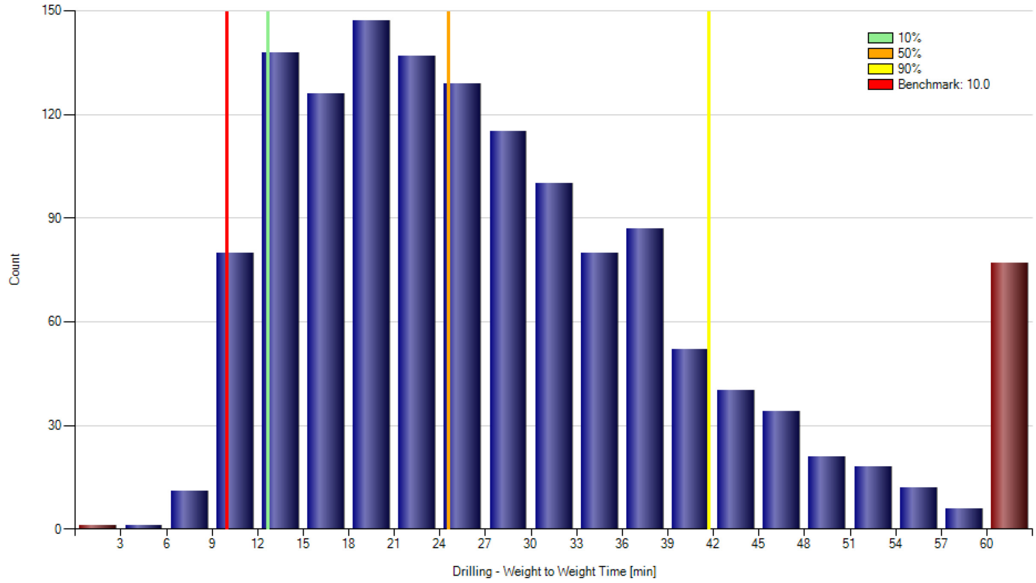


Figure 31: Weight-to-weight time histogram example Rig A

Since this time slice now includes variables such as how much time the crew spends on wellbore treatment between picking-up off-bottom (i.e. interrupting the "drilling" activity) and actually stopping pumps and top drive and setting the string into the slips in preparation for breaking the connection) or staged re-starting of mud pumps after picking the string out of the slips in preparation of running back to bottom, obviously there is a lot more room for variation in the individual time records.

Especially the decision how often (or whether at all) the just-drilled interval will be reamed/cleaned before adding a new stand is most often left to the driller on the rig floor. While highly experienced and educated/motivated drillers take into account factors like drilling speed (i.e. how heavily the annulus is loaded with cuttings), formation stability (hard vs. soft or poorly consolidated rock), over-pulls or hang-ups during picking-up and running back down to bottom, in many cases "rules of thumb" are followed to ream at least once or twice – even if there are absolutely no indications of hole problems. Block speed alone (the speed with which the string/bit is pulled out of the hole and run back down to bottom) can easily account for several minutes of wellbore treatment time for each connection.[5]

It can thus be easily understood that while slip-to-slip times varied in the 1-4 minutes range, weight-to-weight times range between 4 and 30 (and sometimes up to 60 minutes). Interestingly, minimum durations (5.75 – 5.37 – 6.03) and maximum durations (59.3 – 55.37 – 59.97) generally correlate

[5] See also the previously referenced paper by Freithofnig, et al

between all three rigs, however the standard deviation is quite diverse at 11.05 – 7.32 – 9.45, indicating that rig B at lowest mean and standard deviation delivers very consistent weight-to-weight performance while rigs A&C are rather inconsistent:

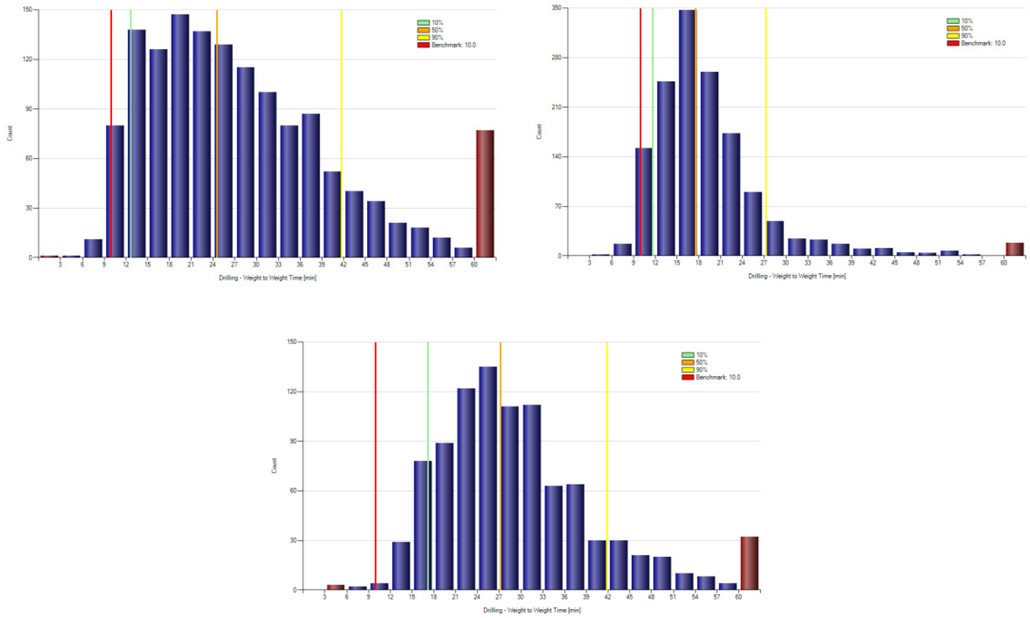


Figure 32: Standard deviation on weight-to-weight time histograms for three monitored rigs

Note that the rig that showed the largest standard deviation in slip-to-slip time records provides the best consistency (smallest standard deviation) in weight-to-weight performance. This seems to be a contradiction but can be explained by the different external influencing factors. Deeper wells generally result in higher standard deviations than shallow wells due to the greater changes in formation characteristics throughout the course of the well. A rig only drilling in shallow, soft, sand/clay Neogene environments will have a better chance of delivering consistent (i.e. low standard deviation) performance than one starting in these environments and subsequently penetrating deeper through more and more different formations and stress distributions. Geological factors only influence weight-to-weight times, since slip-to-slip times are predominantly controlled by machine and crew performance.

This dependency can be supported by plotting well TD vs. average Slip-to-Slip and Weight-to-Weight connections times:

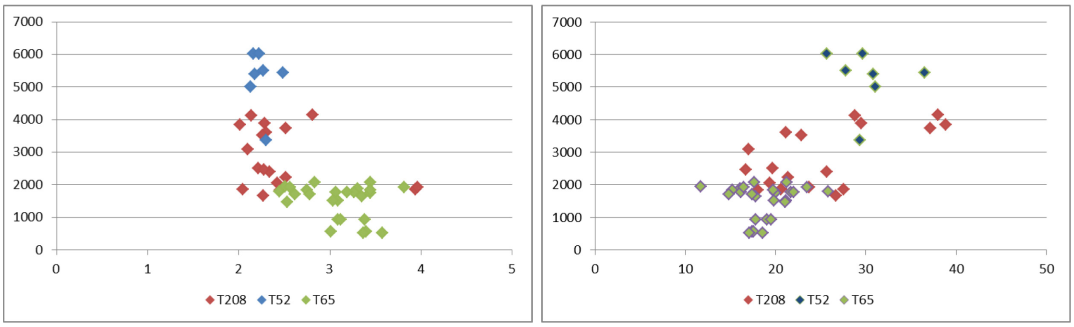


Figure 33: Well TD vs. average Slip-to-Slip (left) and Weight-to-Weight (right) connection times for all monitored wells

It can clearly be seen that while there does exist a dependency between well depth and Weight-to-Weight connection times, no such trend can be identified for Slip-to-Slip connection times that are not influenced by any subsurface factors.

This highlights the challenge to understand the input parameters in order to develop a meaningful result. The bigger the "averaging" (e.g. evaluating KPIs across several dozens or even hundreds of rigs in a fleet) the more basic influencing parameters will be "evened out". Looking at only three rigs drilling such diverse environments as soft Neogene sands to hard Triassic dolomites, horizontally layered young sediments and complex faulted and stressed lime stones etc. will by definition create more challenges in developing meaningful interpretations.

The comparison in the evaluation of slip-to-slip and weight-to-weight times illustrates that different objectives require different KPIs. While a slip-to-slip KPI is heavily concentrating on rig (i.e. machine) and crew performance (since there is very little to no influence from downhole parameters on how fast the crew will be able to make/break a drill pipe connection), weight-to-weight times more reflect overall organizational performance and driller experience/training. Using one to define a benchmark for the other will often result in confusion, demotivation and failure of the initiative.

This methodology can be extended to the whole well construction process, always basing the definition of target values on historically achieved performance and taking any human bias out of the assessment of field performance values. Continuous tracking of crew/rig/fleet/corporate performance trends and communicating these trends in an open and challenging way utilizes peer pressure and motivation to increase individual crew performance – nobody wants to be consistently shown in the lower quartile of a group of his/her peers. External definition of "performance enhancement measures" is replaced by challenging the crew to come up with options how to perform better. Drilling crews are mostly experienced individuals who have a pretty good understanding of how their job should be done. Accepting this competence, in fact utilizing it in a creative way to define ways and means to execute the job fast and safer will provide desired results and at the same time increase job satisfaction and crew morale.

The economic impact of such analysis and performance benchmarking in general can be derived from the average operating cost for the rigs investigated in this study. Daily operating cost ranges from 35.000 € to more than 100.000 € (including rig rental rates and all other services and consumables). Looking only at the Weight-to-Weight connection times, over the whole monitored period (1932 rig operating days throughout the years 2006-2009), the three rigs collectively spent approximately 270 days making connections. Applying the identified savings potential of 20-40% (depending on the rig) by making performance more consistent around the P_{50}, this translates into 54 to 108 rig-days potentially saved over a three-year period. Multiplying this factor with the average daily operating cost (65.000 €), simply achieving consistent connection-making performance on this OMV drilling project would have translated into an economic savings of 3.5-7 million €. All in all such time and cost performance enhancement would mean that the operator can drill five additional shallow or two medium-depth wells in the same duration and for the same budget (i.e. “for free”).

5 QA/QC measures in well construction

As already mentioned previously, this thesis will not address the pre-operations (planning) or post-operations (closeout) phases but concentrate on the actual field implementation of the well construction process. It is frequently stated that "only what gets measured gets done". Quality can be felt qualitatively (which things/tasks have been accomplished) or quantitatively (how these things/tasks have been done). While a qualitative assessment can be done relatively easily ("tick the box"), assessing the degree to which a certain task execution has achieved its desired optimum quality presents numerous challenges. Typically, qualitative assessments can be made during or immediately after the execution of certain task while quantitative assessments require subsequent measurements/interpretations etc.

5.1 Qualitative QA/QC

Examples for qualitative task QA/QC parameters are

- Task execution characteristics (workflow followed and completed as planned)
- Observations taken during task execution within the planned boundaries (e.g. "cement to surface" or "casing landed at section TD", "no mud losses during drilling of the section", "well path within planned tolerance" etc.)
- …

5.2 Quantitative QA/QC

As already implied by the designation, these assessments rely on measurable factors, for example

- Cement job quality (top of column, bond/zonal isolation etc.) from subsequent thermal or sonic logs
- Rate-of-penetration for a given bit run, total footage achieved with a bit run etc.
- Total task execution time (within planned time schedule or percentage ahead of time, "time saved")
- …

Experience has shown that wherever QA/QC factors can be measured automatically, not only do they become immune to human bias but their implementation is facilitated as their collection does not create additional workload for the staff involved. Whether appreciated or not, it is human tendency to "err on the side of caution" when reporting factors subsequently used for assessing performance. Taking this bias out of the process increases repeatability of results as well as comparability with other organizational units.

It has to be noted, however, that not all activities during the implementation of a detailed work program lend themselves to automatic measurements/ monitoring. Especially those steps that require action on the part of staff involved but do not include any equipment activity are difficult to monitor automatically. As an example, equipment call-off activities can be used. Unless they are generated via an established inventory/logistics control system (i.e. if they are done via telephone call or E-mail correspondence), tracking of such activities relies on the involved staff making the necessary entry in a process tracking register. The preparation of such a register (based on the process descriptions described in this thesis and a detailed DWOP exercise prior to spudding the well) will support wellsite staff in that they have a “storybook” of their planned activities already available which they can follow as they go along.

During preparation of this work, numerous discussions have shown that proper forward planning (typically done on the rig in the daily/weekly time span and in the office on the per-well time scale) has always been the trademark of good organizations and staff. However, one of the impacts of the “great crew change” in drilling office and field personnel over the last twenty years has resulted in ever more young and/or less experienced staff assigned to positions of more responsibility. What has been “standard” for wellsite staff a generation ago has become a sign of excellence today. This is not criticism but simply an observation of drilling industry staff developments.

During the remainder of this work, all process steps, runs, tasks and sub-tasks will always be assessed for their potential to be automatically monitored in a comprehensive QA/QC system.

6 Core Sub-Processes

Before we start with the detailed description of the various sub-processes, for the definition of necessary lead times and mobilization procedures of consumables and services we need to distinguish between operations in well-developed infrastructure environments (e.g. mature onshore regions) and remote operations (e.g. frontier onshore wildcatting or offshore floater operations). The following chapter will generally assume mature onshore operations. In case of frontier operations as mentioned before, the necessary additional lead-time in the off-critical-path activities will have to be included.

6.1 DRILL

6.1.1. Sub-Process Description

The core sub-process DRILL includes all tool runs intended to deepen the existing well section (i.e. all bit runs including sidetracking, wiper trips, wash/ream and wellbore conditioning runs). Ideally it covers all rig operations from initiating a wellbore section (i.e. running into the hole to drill out of the previous casing shoe) until laying down the drilling tools in preparation for either logging or casing the section. Obviously, planned operations as included into the detailed work program and discussed at the DWOP exercise rarely include wash/ream or wellbore conditioning activities except those immediately prior to running the next casing string. Also, the number of bit runs for a given wellbore section can differ greatly between shallow/soft-formation wells (where generally single bit runs are targeted from previous to subsequent casing shoe depth) and deep/hard-formation environments.

6.1.2. Preparatory (off-critical-path) Activities

Any tool run has to be preceded by providing all equipment/tools needed for this run. In the most simple case, only one downhole tool (e.g. a drill bit) has to be prepared, however this preparation can also include a plethora of other downhole tools to make up a more sophisticated BHA (e.g. jars, accelerators, shock tools, stabilizers, motors/MWDs, rotary steerable systems etc.). Therefore each tool run in this sub-process starts with the rig's call-off for all tools that will be required for the run. Again depending on the rig's location and the amount/type of tools, such mobilization **call-offs** can be required several days in advance. Note that procurement timing shall not be included in this activity as all equipment/tools required for a well should have been procured and pre-staged in the nearest logistics base sufficiently in advance of their mobilization to the well site. Following the timely call-off, tools and equipment **arrive at the well location** and can be tracked via a simple shipping manifest signed by the wellsite representative or via sophisticated inventory tracking systems. Shortly before their intended use in the well, all tools are **inspected and prepared on the pipe rack** for transfer to the rig floor. There is hardly any possibility for automatic tracking of these preparatory activities, unless there is a materials tracking system in place and monitoring can be tied directly into the materials tracking database. Otherwise, tracking of call-off, shipping and tool preparation has to rely on wellsite staff making the respective manual entries. QA/QC KPIs for these activities can include:

- Call-off made with sufficient lead time (i.e. no later than the minimum defined mobilization period before planned pickup of tools to run into the hole).
- Delivery of tools within the contractually agreed mobilization/shipping period and by transport compliant with contractual obligations and corporate standards.
- Delivery of all tools as ordered in the call-out document.
- Positive results of the pre-run inspection.

6.1.3. Execution (critical-path) Activities

Critical-path activities begin with the tools being picked up to the rig floor and being **made-up** prior to being run into the hole (since this activity precludes any other wellbore-related rig activity at the same time). The tools are then **run into the hole** to current TD and tool operations commence (e.g. drilling formation). At the end of the tool run (either reaching planned depth for the end of the run or reaching the end of the tools' service life), the wellbore is typically **circulated clean** (unless it is planned to "pump the string out of the hole", in other words maintain circulation while pulling out of hole, thus eliminating the need to circulate the annulus clean prior to tripping) and the tools are **pulled to surface**, where they are **broken out and laid down** from the rig floor to the pipe rack. This frees the rig floor for the next critical-path activity. As all of these activities involve the rig, automatic tracking/measurement offers a wide range of options:

- Time spent to pick up and make up tools on the rig floor (operations recognition from travelling block movement, hook load development and auxiliary rig floor equipment operations such as rig tongs, iron roughnecks etc.) vs. planned time.
- Tripping performance when running in the hole (overall average tripping speed in cased hole and open hole, weight-to-weight connection times).
- Possibility to run straight to TD (no fill in the hole, no need to wash/ream through tight spots etc.).
- Drilling performance (instantaneous and average ROP, possibility to run tools within planned operating envelopes, percentage of sliding/rotating intervals with conventional directional assemblies, dogleg severity and compliance of drilled well path with planned well path tolerances, torque/drag developments relative to planned/simulated torque/drag trends etc.).
- Wellbore treatment time at end of the tool run (circulation interval within planned time).
- Tripping performance when pulling out of hole (overall tripping speed in open hole and cased hole, weight-to-weight connection times, overpulls and requirements to back ream etc.).

- Time spent to break out and lay down tools on the rig floor (operations recognition from travelling block movement, hook load development and auxiliary rig floor equipment operations such as rig tongs, iron roughnecks etc.) vs. planned time.

6.1.4. Closeout (off-critical-path) Activities

As soon as all tools have left the rig floor (i.e. have been laid down on the pipe rack), the rig is available to continue with other critical-path tasks. The tools used in the previous run have to be **cleaned and inspected** and – if so planned – **demobilized from location**, either back to a logistics base or back to a service provider's inventory. As with the call-off/mobilization phase, this can either be monitored via entries into an inventory tracking system or by relying on wellsite staff making the respective entries manually. Finally, the operating parameters of the tool run have to be collected in a **report**. QA/QC KPIs for these off-critical-path activities can include:

- Assessment of tool condition after cleaning and inspection (abnormal wear/tear, premature failures etc.).
- Shipping of tools from location at the arranged time and by transport compliant with contractual obligations and corporate standards.
- Final report compiled and submitted to the company's document tracking system.

6.2 LOG

6.2.1. Sub-Process Description

The core sub-process LOG includes all tool runs intended to obtain measurements from the subsurface (i.e. all geophysical logs including assessment of wellbore conditions such cement bond or thermal logs, well path surveys such as gyro runs etc.). Note that a diligent detailed work program will define all necessary logging runs well in advance and not decide on these runs "on the fly" just after reaching section TD. There is always the option to cancel certain runs due to mud logging results, however each logging run should be justified in detail. If – after reaching section TD – the section is to be logged with LWD on drill pipe (or with drill pipe conveyed conventional logging tools), then this activity should be treated like a conventional tool run (see previous section).

6.2.2. Preparatory (off-critical-path) Activities

Wireline logging runs typically rely on tools and logging unit coming from a service provider, therefore the **call-off** from the rig will be directed to the service provider's supply base. Prior to the mobilization, the service provider will typically have received the detailed work program for the well (as developed in the DWOP exercise with his participation) to provide him with sufficient lead time to prepare equipment and staff in advance of the actual call-off. Depending on the rig's location and the amount/type of equipment, such mobilization call-offs can be required several days in advance. Following the timely call-off, tools and equipment **arrive at the well location** and can be tracked via a simple shipping manifest signed by the wellsite representative or via sophisticated inventory tracking systems. Shortly before their intended use in the well, all tools are **inspected and prepared on the pipe rack** for transfer to the rig floor. There is hardly any possibility for automatic tracking of these preparatory activities, unless there is a materials tracking system in place and monitoring can be tied directly into the materials tracking database. Otherwise, tracking of call-off, shipping and tool preparation has to rely on wellsite staff making the respective manual entries. QA/QC KPIs for these activities can include:

- Call-off made with sufficient lead time (i.e. no later than the minimum defined mobilization period before rig-up of logging unit to run tools into the hole).
- Arrival of logging unit within the contractually agreed mobilization period.
- Delivery of all tools as ordered in the call-out document.

6.2.3. Execution (critical-path) Activities

Critical-path activities begin with rigging up the logging unit and picking up logging tools to the rig floor for being **made-up** prior to being run into the hole. The tools are then **run into the hole** and logging operations commence. At the end of the last tool run the tools are **pulled to surface**, where they are **broken out and laid down** from the rig floor to the pipe rack. This frees the rig floor for the next critical-path activity. As all of these activities involve the rig, automatic tracking/measurement offers a wide range of options:

- Time spent to pick up and make up tools on the rig floor (operations recognition from travelling block movement, hook load development and auxiliary rig floor equipment operations such as rig tongs, iron roughnecks etc.) vs. planned time.
- Tripping performance when running in the hole (overall average tripping speed in cased hole and open hole, weight-to-weight connection times).
- Possibility to run straight to TD (no fill in the hole, no need to wash/ream through tight spots etc.).
- Drilling performance (instantaneous and average ROP, possibility to run tools within planned operating envelopes, percentage of sliding/rotating intervals with conventional directional assemblies, dogleg severity and compliance of drilled well path with planned well path tolerances, torque/drag developments relative to planned/simulated torque/drag trends etc.).
- Wellbore treatment time at end of the tool run (circulation interval within planned time).
- Tripping performance when pulling out of hole (overall tripping speed in open hole and cased hole, weight-to-weight connection times, overpull and requirements to back ream etc.).
- Time spent to break out and lay down tools on the rig floor (operations recognition from travelling block movement, hook load development and

auxiliary rig floor equipment operations such as rig tongs, iron roughnecks etc.) vs. planned time.

6.2.4. Closeout (off-critical-path) Activities

As soon as all tools have left the rig floor (i.e. have been laid down on the pipe rack), the rig is available to continue with other critical-path tasks. The tools used in the previous run have to be **cleaned and inspected** and – if so planned – **demobilized from location**, either back to a logistics base or back to a service provider's inventory. As with the call-off/mobilization phase, this can either be monitored via entries into an inventory tracking system or by relying on wellsite staff making the respective entries manually. Finally, the operating parameters of the tool run have to be collected in a **report**. QA/QC KPIs for these off-critical-path activities can include:

- Assessment of tool condition after cleaning and inspection (abnormal wear/tear, premature failures etc.)
- Shipping of tools from location at the arranged time and by transport compliant with contractual obligations and corporate standards.
- Final report compiled and submitted to the company's document tracking system.

6.3 CASE

6.3.1. Sub-Process Description

The core sub-process CASE includes all steps from call-off of tubulars to be run into the well until the departure of casing running equipment and services from the well location.

6.3.2. Preparatory (off-critical-path) Activities

While this process description intentionally does not include the planning, specification and procurement aspects of providing the necessary tubulars to the well construction effort, call-off of tubulars required to be run into the well can be several weeks in advance (in case of remote/offshore locations). Therefore the off-critical-path activities can start substantially before the actual job on site.

Prior to this call-off, the necessary procurement steps will have been taken, the tubulars manufactured, QA/QC procedures (manufacturer's as well as third-party) implemented and the materials delivered to staging areas (tool houses, pipe yard, logistics centers etc.).

The **call-off** from the rig will thus be directed to such a staging area or logistics center, and unless the rig's activities are fully integrated into a materials tracking system no automatic detection of the call-off will be possible. Instead, the operator's wellsite staff will have to make a respective entry in the project tracking system that such a call-off has been placed.

Following the call-off, tubulars **arrive at the well location** and can be tracked via the shipping manifest or inventory tracking systems. In preparation for running these tubulars into the well they are cleaned, visually inspected and tallied (the length of each joint of pipe is measured and recorded).

Shortly before the actual casing running operation, the casing running service is called-off; depending on the remoteness of the rig this can be hours but also days in advance. Casing running services typically include the make-up tongs, QA/QC measurement tools and the personnel to operate this equipment. Casing accessories such as centralizers, float shoes and collars etc. are typically called off and shipped to the rig together with the tubulars themselves. Sometimes – especially when the accessories are being provided by the casing running service provide – they are delivered by the casing running crew upon their arrival at the rig site.

KPIs for all of these off-critical-path activities can include

- Call-off made with sufficient lead time (i.e. no later than the minimum defined mobilization period before running the tubulars into the hole).
- Absence of transport damage to tubulars (especially no "rejects" on the threaded connections).
- Availability of the right amount and types of casing accessories (centralizers, float equipment etc.) as ordered.
- Arrival of casing running service within the contractually agreed mobilization period.
- Casing running equipment in proper operating condition, casing running crew properly trained, competence management measures in place.

6.3.3. Execution (critical-path) Activities

Critical-path activities begin with rigging up the casing running equipment on the rig floor. In many cases, float equipment – float shoe and collar(s) – are already pre-made-up on the pipe rack to save rig time during picking them up top the rig floor and running them into the hole. Centralizers are mostly pre-installed, sometimes made up while running the tubulars. The complete string of pipe is made up and run into the hole, generally there are pre-defined circulation intervals at given depth intervals to perform intermediate wellbore and mud conditioning. Once the casing shoe has reached the planned depth (mostly close to the total depth of the hole being drilled so far – typically within 1-2 meters), casing running equipment and services are rigged down from the rig floor, and preparations for primary cementing operations commence.

At this time – depending on wellhead design and operating environment – the casing string can either be set into the slips (i.e. hung-off in the wellhead) or remain suspended below the travelling block until cementing operations have been completed. Setting the casing into the slips before cementing it in place typically occurs on offshore (subsea-wellhead) operations or when utilizing mandrel-type casing hangers on onshore wells. In the context of this work, the

KPIs for successfully setting the casing string into the wellhead will be listed at the end of the cementing section, but would apply to this section respectively.

The actual running of the tubulars can be tracked automatically, and KPIs can be defined for the performance of the job:

- Time spent to rig up casing running equipment on the rig floor (operations recognition from the end of pulling out of hole from the last BHA run until picking up the first casing joint, based on monitoring of travelling block movement, hook load development and auxiliary rig floor equipment operations such as rig tongs, iron roughnecks etc.) vs. planned time.
- Running performance of tubulars into the hole (overall average running speed in cased hole and open hole vs. planned running speeds); note that especially when running casing, block speeds while lowering the string are frequently limited to control surge pressures in the well.
- Possibility to run straight to TD (no fill in the hole, no need to wash/ream through tight spots etc.); execution of intermediate circulating intervals as per program (depth, duration, flow rates, stand pipe pressures, casing reciprocation/rotation characteristics, dynamic hook loads and torques etc.).
- When running premium connections (i.e. shouldered metal-to-metal seals), recording of make-up torque/turn trends for each connection provides an excellent QA/QC KPI that can be automatically monitored. On a higher level, the amount of casing joints that have to be laid down again due to impossible make-up (i.e. damaged threads) can be monitored on all casing running operations.
- Time spent to rig down casing running equipment and services from the rig floor (operations recognition from travelling block movement, hook load development and auxiliary rig floor equipment operations such as rig tongs, iron roughnecks etc.) vs. planned time; generally these activities overlap with the planned wellbore conditioning (i.e. circulation) period between lading casing at TD and starting cementing operations and therefore only constitute “lost time” if they take longer than the planned circulation period. This is a prime example where lost time rarely appears as such, since the rig crew typically circulates at least as long as it takes to rig down the casing running service and to rig up the cementing service.

6.3.4. Closeout (off-critical-path) Activities

As soon as all tools have left the rig floor (i.e. have been laid down on the pipe rack), the rig is available to continue with rigging-up cementing equipment. While cement mixing and pumping equipment can already be prepared and rigged up as an off-critical-path activity, picking up and making up the cementing head to the top of the casing string and connecting the high-pressure cementing lines to the cementing head is necessarily part of the critical path activities. The casing running equipment has to be **demobilized from location**, either to a logistics or back to a service provider’s base. As with the call-off/mobilization phase, this can either be monitored via entries into an inventory tracking system or by relying on wellsite staff making the respective entries manually. Finally, the parameters of the casing run have to be collected in a **report**. QA/QC KPIs for these off-critical-path activities can include:

- Time required to rig down casing running equipment from the rig floor to free it up for subsequent cementing operations (actual time spent compared to time planned for this rig-down)
- Shipping of tools from location at the arranged time and by transport compliant with contractual obligations and corporate standards.
- Final report compiled and submitted to the company's document tracking system.

6.4 CEMENT

6.4.1. Sub-Process Description

The core sub-process CEMENT includes all steps from call-off of the cementing service until the departure of all cementing equipment and services from the well location.

6.4.2. Preparatory (off-critical-path) Activities

Preparation of a cementing operation starts with updating cement slurry recipes based on actual wellbore conditions, running the necessary laboratory tests and subsequently calling off the required bulk cement and chemical additive quantities to the well location. Note that this is not part of the initial well planning exercise, as this prepares a generic cementing program which is subsequently updated with regards to both volumes (i.e. actual well depths and caliper logs) and recipes (taking into account actual recorded bottom hole temperatures and planned pump rates, job durations etc.).

The **call-off** for materials, equipment and service personnel from the rig will thus be directed to a staging area or logistics center, and unless the rig's activities are fully integrated into a materials tracking system no automatic detection of the call-off will be possible. Instead, the operator's wellsite staff will have to make a respective entry in the project tracking system that such a call-off has been placed.

Following the call-off, materials and equipment will **arrive at the well location** and can be tracked via the shipping manifest or inventory tracking systems. In preparation of the cement job, pumping/mixing equipment will be inspected and prepared. Cementing services typically include the high-pressure pumping and cement mixing equipment and the personnel to operate it.

Sound preparation of primary cementing operations should generally include a simulated job execution based on the actual field (i.e. downhole) conditions. This job simulation should be the basis against which job execution parameters should be monitored to detect deviations from predicted well behavior.

KPIs for all of these off-critical-path activities can include

- Timely and complete provision of the necessary input data for final cement recipe updating and slurry laboratory testing; execution of the required laboratory tests and provision of updated slurry recipes and test results to the operator's well engineering team; formal acceptance of the final and detailed cement recipe and pumping schedule by the operator.
- Availability of cement job simulation runs.
- Call-off for the cementing service made with sufficient lead time (i.e. no later than the minimum defined mobilization period before intended job startup).
- Availability of the right amount and types of cement and additives as ordered.
- Arrival of cementing service within the contractually agreed mobilization period.
- Cementing mixing/pumping equipment in proper operating condition, casing running crew properly trained, competence management measures in place.
- Where applicable, slurries pre-mixed and QA/QC'd by the time casing running service has been rigged down and cementing operations shall be started.

6.4.3. Execution (critical-path) Activities

Critical-path activities start with making up the cementing head/manifold to the top of the casing string and connecting the high-pressure cementing lines. The end of a cementing operation is reached either at the end of a pressure test done immediately after bumping the top plug (i.e. while the cement slurry is still liquid and thus any danger of cement sheath degradation due to expansion and contraction of the steel casing can be eliminated) or with laying down of the liner running tool. These time step definitions align with the concept that one job ends immediately before the rig can commence activities related to a subsequent task. The subsequent task to conventional (e.g. long-string) cementing is wellhead work, while the task subsequent to liner cementing operations should be negative (i.e. inflow) testing of the liner hanger area.

KPIs for the execution of primary cementing operations can be:

- Complete job pumped as planned (rates, volumes, densities and pressures as simulated prior to the actual job).
- Top plug bumped within +/- ½ shoe track volume of total planned displacement volume.[6]

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[6] *The term „shoe track volume" refers to the internal volume of the lower part of the casing/liner string between the landing plate for the cementing plugs and the casing/float shoe; displacement volume should not be exceeded by more than 50% of this shoe track volume to avoid over-displacement.*

- Absence of mud losses/gains throughout the job.
- Achieving forecasted final circulation pressure towards the end of the job (indicating proper cement displacement into the annulus).
- Possibility and execution of pipe movement (rotation/reciprocation) as planned.
- Top-of-cement in the annulus confirmed by subsequent logging (thermal or ultrasonic) at the planned depth.

6.4.4. Closeout (off-critical-path) Activities

Building on the notion that critical-path activities end as soon as the rig can commence execution of activities associated with the subsequent task, off-critical-path cementing activities include rigging down all cementing equipment (incl. high pressure lines to the rig floor), cleaning mud tanks eventually used for the preparation of cement slurry mixing water and preparation final job reports. While the execution of a cement bond log (or thermal top-of-cement log) can be seen as the final part of a cementing operation, the fact that it is separated from the critical-path operations by wellhead work makes it more suitable to general “logging” activity coding. QA/QC KPIs for the off-critical-path cementing activities can include:

- Time required to rigging down cementing equipment.
- Final report compiled and submitted to the company’s document tracking system.

6.5 WELLHEAD

6.5.1. Sub-Process Description

The core sub-process WELLHEAD includes all steps from mobilizing of a specialized wellhead service technician to (positive) finalization of pressure testing activities after installation/modification of wellhead equipment. Due to the predominant logical sequence between primary cementing (of casing strings) and the associated modification/installation of wellhead equipment, this task mostly starts right after the end of a cementing task.

6.5.2. Preparatory (off-critical-path) Activities

While this process description intentionally does not include the planning, specification and procurement aspects of providing the necessary wellhead equipment and accessories to the well construction effort, call-off of wellhead items required to be run into the well can be several weeks in advance (in case of remote/offshore locations). Therefore the off-critical-path activities can start substantially before the actual job on site.

Prior to this call-off, the necessary procurement steps will have been taken, the equipment manufactured, QA/QC procedures (manufacturer’s as well as third-party) implemented and the materials delivered to staging areas (tool houses, pipe yard, logistics centers etc.).

The **call-off** from the rig will thus be directed to such a staging area or logistics center, and unless the rig's activities are fully integrated into a materials tracking system no automatic detection of the call-off will be possible. Instead, the operator's wellsite staff will have to make a respective entry in the project tracking system that such a call-off has been placed.

Following the call-off, wellhead equipment **arrives at the well location** and can be tracked via the shipping manifest or inventory tracking systems. In preparation for installing these items on the well they are cleaned and visually inspected.

Shortly before the wellhead work, the wellhead service is called-off; depending on the remoteness of the rig this can be hours but also days in advance. Wellhead services typically do not include any larger tools but only the service technician to supervise correct installation and testing.

KPIs for all of these off-critical-path activities can include

- Call-off made with sufficient lead time (i.e. no later than the minimum defined mobilization period before installing the wellhead equipment).
- Absence of transport damage to equipment.
- Availability of all required accessories (seals, nuts and bolts, etc.).
- Arrival of wellhead service within the contractually agreed mobilization period.

6.5.3. Execution (critical-path) Activities

This description is based on the most extensive wellhead work, the installation of additional wellhead stages after running (cementing) casing strings into the well. Repair/modification activities to existing wellhead installations typically are not part of planned well operations and therefore will not be included here.

Critical-path activities begin at the end of the initial cement setting time (typically 6-8 hours after the finishing pumping operations). During this period the top of the casing string remains suspended below the hook/travelling block, thus the rig cannot undertake any further critical-path activities. Only when the cement has achieved sufficient strength to support the casing weight can wellhead work begin.

The time spent "waiting on cement (WOC)" is generally spent by loosening the bolts between the blowout preventer (BOP) stack and the top of the already installed part of the wellhead. Only when the top of the casing can be disconnected from the hook/travelling block will the BOP stack be lifted and the casing be cut just above the top of the previously installed wellhead section. This "rough cut" allows the remaining top part of the "landing joint" to be retrieved through the rotary table and be laid down together with the cementing head/manifold.[7]

Once the BOP stack has been moved out of the way, the "rough cut" on the casing stub sticking out of the previous wellhead section is dressed to specification ("fine cut") and the next wellhead section is moved in and placed on top of the previously installed wellhead. Bolts are tightened, and seals are energized to control evtl. annulus pressures. Once all of these installations have been completed and successfully pressure tested, the BOP stack is moved back into the substructure and installed on top of the new wellhead section. Again, the last connection needs to be pressure tested before critical-path wellhead work is finished.

QA/QC KPIs for this part of wellhead activities can include:

- Availability and ease of installation of all wellhead equipment and accessories.
- Positive result of pressure testing.
- Finalization of complete wellhead work within planned time.

6.5.4. Closeout (off-critical-path) Activities

As there are hardly any major tools associated with wellhead installation work, the only remaining issue after finalization of the critical-path activities is the preparation of the final wellhead installation service report and the release/demobilization of the wellhead service technician. The associated KPI is thus:

- Final report compiled and submitted to the company's document tracking system.

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[7] *Note that this procedure differs from that utilized with mandrel-type casing hangers; these systems consist of integral profiles machined into a sub made up between the top casing joint and the landing joint with running tool; casing is set into the wellhead before cementing, and the running tool is disconnected immediately after pumping operations are finished; running tool, landing joint and cementing head/manifold can be laid down immediately, and no cutting operations are required on the casing string; depending on the system design, BOPs still need to be lifted to install secondary seal assemblies and subsequent wellhead sections.*

7 Open System Boundaries – The Difference between Factory Floor and Oil Well Drilling

As already touched upon in the introductory chapter, oil well drilling is by definition different from tightly controlled manufacturing environments. Even with the advent of terms like “factory drilling” along the shale gas and oil development activities in the continental US, drilling still defies some of the core principles of mass production of identical products.

The major open boundaries impacting and drilling operation are

- The drilling rig
- The subsurface

7.1 The Drilling Rig

The drilling industry has come a long way towards standardization of its equipment, most of it driven by the concentration of equipment manufacturers. Even in the US as the birthplace of the large-scale drilling industry, until the early 1980ies multiple manufacturers offered their proprietary designs of drilling machinery. Mast designers/manufacturers included legendary names like Lee C. Moore, Pyramid or Ideco, the draw works market knew multiple large suppliers like National, Oilwell, Ideco and others. The first oil price collapse in the late 1980ies and the two subsequent low-price decades caused an unprecedented concentration in rig and equipment suppliers, with today’s market being dominated by National/Oilwell/Varco (NOV). However, steady oil price increases since the mid-2000s and massive price spikes since 2007/2008 have caused new entries to the market and another diversification. Thus, rather than “standardization” the industry underwent “concentration” to a few vendors and is now diversifying again.[8]

Generally, all drilling machinery has to provide four basic capabilities:

- Hoisting and lowering tubulars from/into the well
- Rotating tubular strings in the well
- Pumping (“circulating”) drilling fluid into the drill string and back from the well
- Storing, mixing and cleaning of drilling fluid

All other machinery installed on a drilling unit simply provides supporting functions to maintain these three capabilities.

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[8] Note that this overview is concentrating on medium and large-sized onshore drilling equipment; the light-weight drilling and workover market even during the downturn of the industry has seen multiple suppliers survive worldwide – thus making any standardization even less likely.

Consequently, any drilling rig consists of five major arrangements of machinery[9]:

- The hoisting system ("draw works"), either in the form of conventional drum/reel-type crane arrangements or telescopic mast designs based on hydraulic pistons or rack/pinion drives
- The rotary drive system, today commonly realized via a top drive (travelling up/down the mast suspended under the hoisting system and transferring the reactive torque into the mast structure) or on older/smaller units via rotary table mounted in the rig floor and driving the drill string via bushings and square/hexagonal drive pipes ("Kelly").
- The mud pumps, typically two or three positive-displacement, single-acting triplex units receiving fluid from the mud tanks and discharging it at pressures up to 500 bars (7500 psi) into the top of the (rotating) drill string.
- The mud tanks, providing various compartments for cleaning (i.e. removing drilled solids), mixing (i.e. building new) and storing drilling fluid.
- The power supply, typically sets of diesel-engine-driven AC generators providing electrical energy for the various drive motors and other power consumers on the rig.[10]

Monitoring of machine operating conditions has been developed primarily to optimize preventive maintenance and detect anomalies before they cause catastrophic machine failure and downtime.

Spoerker and Litzlbauer[19] in 2002 reported on the installation of triaxial accelerometers and vibration frequency measurements on triplex mud pumps enabling the early detection of pump wear (valves and liners), subsequently avoiding delays resulting from pump repairs on the critical path. The rapidly progressing integration of machine diagnostics via bus telemetry into data acquisition and machine/process networks enables continuous monitoring of machine conditions, timely wear/failure recognition and/or scheduling of repair/replacement/maintenance activities into time slots where the specific piece of machinery will not be required in a critical-path activity.

When talking about "standardization" it should be pointed out that "all rigs are basically alike" – just like all automobiles have an engine, a chassis and wheels. However nobody would consider the automobile world "standardized". There still exist a substantial number of older rig designs in the worldwide rig fleet, especially onshore where cost pressure is highest and drilling rigs reach service lives of up to forty years and more. We therefore still see DC-driven rigs (fully mechanically driven rigs have mostly been phased out by now) where modern designs almost exclusively rely on AC technology, in remote

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[9] *For the sake of simplicity, this work will concentrate on on-shore drilling equipment only, i.e. no marine machinery (e.g. propulsion, station-keeping, heave-compensation etc.) is included in the scope of this review.*

[10] *Only in rare cases are drilling units driven off a main (public) power grid, mainly because of the limited duration that drilling rigs operate on any one location (typically in the weeks to months range) making the installation of high-capacity power lines uneconomic.*

areas there are still rigs without top drives, while at the same time high-performance operations utilize recent new-builds, optimized for fast rig moves and making use of current automation trends.

Over the last decade, mining-type drilling rig designs have pushed their way into oil and gas applications. Due to the typically larger depths in hydrocarbon exploration compared to conventional mining type operations, rig technology has always been centered around relatively high structures (to allow tripping drill strings in doubles or triples, racking them back in the mast/derrick instead of laying the drill string down to the floor during every roundtrip). Mining-type rigs, due to their shallower drilling depths and less frequent round trips were historically developed around rack & pinion or hydraulic piston designs. Increasing the size and power of these "drilling machines" has resulted in such designs today being available up to hoisting capabilities of 400 metric tons, effectively allowing these rigs to drill and complete wells down to 5000 meters. The substantially lower tripping performance of these designs (max. 400 m/hr compared to 800 m/hr or more on "conventional" rig designs) has pushed the operators to a different optimization concept – reducing the amount of round trips by extending the durability of the bits and targeting "shoe-to-shoe" well operations, i.e. drilling from one casing shoe to the next with just one bit.

"Exotic" rig designs first made their entries with Ray Bromell's "Drilling Machine"[20] or Roy Cullen's "Retractor Rig"[21] in the 1960ies and 1970ies and were based on automating the pipe handling process or eliminating pipe handling completely by utilizing coiled (instead of jointed) tubing as drill pipe. The development of coiled tubing technology in the 1980ies triggered interest into utilizing "conventional" coiled tubing units as applied in well servicing for small-diameter or sidetrack drilling projects. Several attempts were made, one purpose-built coiled tubing drilling rig was even introduced to the market (by Baker Hughes in the late 1990ies[22]), however the necessity to at some point still run conventional jointed pipe (as casing or completion tubing) still required additional masts and hoisting systems, and the necessary mud systems and power packs rapidly made operating costs of these "coiled tubing drilling rigs" uncompetitive. They have since been phased out of the market.

7.2 The Subsurface

While any "manufacturing" environment is based on tightly controlled raw material supplies, drilling typically has to cope with sometimes very limited knowledge of subsurface parameters being encountered along the way. "Mother Nature" by definition is inhomogeneous, and most parameters affecting the drilling process are in one way or another related to the geological setting that the well encounters.

Examples for such external influences out of the planner's control is changes in casing setting depths because of formation tops encountered higher/lower, time spent conditioning the drilling fluid or the wellbore due to unexpected high or low formation pressures causing influxes or loss of circulation, different drillability (hardness, abrasiveness, plasticity etc.) of the encountered rock, etc.

Well planning always has to take into account such external influences, more and more they are reflected in probabilistic time/cost planning approaches where all input parameters are defined by probabilistic distributions, and the total well duration/budget is calculated by means of Monte Carlo simulations. Such probabilistic approaches result in distributions of expected well durations/budgets, typically defined by P_{10}, P_{mean} and P_{90} values. Large spreads between P_{10} and P_{90} indicate little previous knowledge of the expected geological setting or generally poor quality of the input data used to define the distribution functions of the input parameters for the Monte Carlo runs.

It has to be stated that the old adage of "garbage in – garbage out" equally applies to any probabilistic planning exercises. Frequently management erroneously believes that such forecasts have a high degree of accuracy when outputs are being presented down to several digits behind the comma. A well duration forecast of "1214.23 hours" with a P_{10} / P_{90} spread of 700 / 1600 hours simply is misleading. All recipients of such information need to have a clear understanding of the input data quality.

Even with plentiful and high-quality offset well information as a basis for defining all input distribution functions subsurface variations will still sometimes throw well plans off track.

8 Challenges in Automatic Recognition of Machine Operating Conditions

Certain operating conditions of the rig can be described by simply monitoring the condition of a certain piece of the machinery. As an example, "Drilling" will normally be associated with

- Mud pumps turning and positive pressure reading in the standpipe[11]
- Top drive applying rotation to the drill string and positive reading of reactive torque
- Draw works slowly reeling off line, thus lowering the travelling/block hook under which the drill string is suspended.

Nevertheless, already on this macro level limitations of automatic machine operation recognition become apparent. If one would use these three criteria to identify the condition "drilling", there are multiple potential operating conditions that also constitute "drilling" but where one or even more of these indicators will not be present. When using a downhole motor (i.e. a positive displacement hydraulic drive motor installed downhole immediately above the drill bit and driven via the circulating drilling fluid), there will be no surface rotation driven by the top drive or rotary table. Similarly, draw works rarely operate in "constant feed" mode, common operation still includes a lot of "feed-stop-feed" cycles. In this case simple operations recognition via draw works feed-off would constantly alternate between "drilling" and "circulating" (i.e. a stationary drill string not being lowered into the well, see also Section 11.4 of this thesis).

The increasing trend to automating drilling rig machinery has caused new interest into the start/stop procedures. As soon as some kind of "steady state" machine operation has been reached (for example mud pumps running at constant speed and pressure), even slight changes in this operating mode can be used to interpret changes in the environment (downhole) or the machine (wear). During the startup of the pump however (after any circulation shut down like when adding a new stand of drill pipe during drilling operations), the operating condition changes rapidly and – unless controlled automatically – also inconsistently from time to time. While one driller may engage the pump at idle speed, briefly check for a pressure response and then quickly bring it up to the desired operating speed and pressure, another driller may slowly ramp up pump speed in increments.

No machine operating mode recognition can provide the reason WHY certain activities are being performed. As an example, a drill string can be left stationary in the hole with the mud pumps running because the well is being "cleaned up" (i.e. the cuttings-laden drilling fluid is circulated out of the hole) or because there is a wellbore problem or because the crew is waiting on a decision how to proceed with drilling of the well. The machine signature is

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[11] *The fluid conduit leading up into the mast to the top of the rotating drill string*

always the same – the operating condition under the drilling process definition quite different. Especially when machines transition from “normal” operating mode into “trouble shooting” or “repair” mode, automatic recognition of which operation is currently being performed or interpretation why a certain machine activity happens becomes difficult to impossible. En example for such a rig operating condition is stuck pipe or fishing for parted drill string elements downhole.

From an automatic operations recognition standpoint, the task of the system becomes to identify such “unknown” operating conditions and flag those for designation by the operator representative during generation of the daily drilling report. A well-implemented automatic operations recognition system can dramatically relieve the operator representative from repetitive and/or dull tasks (such as writing down daily activity in 15- or 30-minute intervals), instead prompting him/her only to identify those time intervals where automatic algorithms fail.

A next higher level of automatic reporting quality starts where the daily operations plan is automatically generated from the pre-prepared Detailed Work Program, and as long as the planned procedure is being followed the report is compiled more or less automatically. Only where deviations from planned activities happen, human interference is prompted by the system, providing explanation/reasons for such deviations. This in many cases constitutes quite a substantial change to the reporting paradigm that supervisors are used to. The daily drilling report migrates from a description of “what” has been done throughout the previous 24 hour period to an explanation “why” certain activities were performed.

9 Conclusions

It has been demonstrated that the drilling process of physically constructing a well can be structured in a four-tier approach. Strategic, tactical, detailed and machine control tiers have their own distinctive requirements. Process execution knowledge shifts from explicit on the strategic and tactical to implicit on the detailed levels. The machine control tier today is still mostly centered on discrete, short and well defined operational sequences that are triggered by a human operator and in most cases run their course with very little decision making required. Upon successful completion of the sequence, control is returned to the operator.

Numerous publications exist on the challenges of strategic process planning. Almost all reputable companies involved in drilling for oil & gas have their own versions of “Well Construction Processes”, controlling how the design of wells is done and how these “Detailed Work Programs” are developed and provided to the field organizations. The translation of these strategic plans into tactical day-by-day instructions to the rig crew even today largely depends on the operating preferences and experience of the operator representatives at the well site and ranges from simple verbal orders to elaborate 24-hour written instructions.

Very little procedural control exists on the third tier – the translation of tactical day-to-day instructions into workflow-oriented procedures to be followed by the rig crew. Traditional beliefs still prevail that “everybody knows how to do this”. It is at this level that standardization and process control have the biggest potential for performance improvement, along the way also enhancing process safety.

Most safety-critical industries have documented their workflows in minute detail to allow proper induction and training of new staff before they get actual exposure to the task in the field. The massive influx of new (and generally un-trained) staff into rig crews due to the increase in the number of operating drilling rigs worldwide has caused a noticeably drop in the qualification of the average rig crew. Detailed definition/description of the Tier-3 processes not only helps in standardizing how these activities are performed on various rigs in the fleet but also in training new staff how they shall be performed properly.

There exists a joint interest with drilling rig manufacturers into defining detailed-tier procedures in minute detail to support rig automation. While the notion of a completely automated drilling machine autonomously constructing complete well bores without human intervention is seen by many as senseless to unachievable, advancing current automation levels through evolution rather than revolution will be unavoidable. Key drivers for this increase in machine automation will not so much be down-manning of drilling rigs but increases in operational performance (by making machine operations more consistent) and safety (by removing people from those areas of the rig where the highest injury potential exists and utilizing them for tasks better suited to humans such as controlling the machines and supervising processes).

Much work has been done addressing critical-path activities and optimizing their sequencing and execution. Today, it is mostly at the interfaces between individual tasks on the critical path that delays occur. Information of one task being completed is not immediately provided to the person deciding on starting the subsequent task, decisions are required from outside the drilling rig environment on how to progress, or other (off-critical-path) activities are not finished in time for their product to be available when required. Better defining, monitoring, controlling and integrating such off-critical-path activities will increase operational performance by reducing/eliminating delays to critical-path activities at the interface points.

Monitoring of many critical-path activities can be automated via operations recognition algorithms based on rig sensors and telemetry. It is mostly the off-critical-path activities (not directly reflected by machine activity) that present the biggest challenges from a monitoring and control standpoint. Transferring data acquisition and transmission solutions from other applications (e.g. the logistics industry) can enable full tracking of man-controlled processes, thus enabling better standardization, quality control and integration into critical-path activities. Challenging rig staff to regularly provide feedback on the progress of their current activity against overall project execution schedules enhances process control and can provide additional staff motivation by better demonstrating where their particular work activity contributes to the overall project progress.

Instrumentation is not anymore a restriction to monitoring and controlling drilling rig operations. A bigger challenge is the still largely varying rig configurations and layouts, reflecting a typical drilling rig service life of 30+ years. At the same time, adding more and more sensors and telemetry has the potential of creating such a vast flood of data that the average human supervisor cannot be expected to continuously monitor all of these signals and immediately react to safety-critical deviations from the norm. Monitoring and control systems today are tasked with filtering the sensor data and processing it in a way that it can be presented to a human supervisor in a meaningful and comprehensible way. Ensuring that such filtering never accidentally “deletes” a critical process signal remains one of the most difficult tasks in the development and implementation of such systems.

It has also been shown that better understanding (and subsequently better definition, planning and monitoring) of operational processes generally enhances operational performance. Elimination – or at least reduction – of “unplanned” events or operations results in better project economics at reduced operational risk. Higher consistency in how a crew/rig/fleet performs its operations can generally be correlated with better safety records.

Automated operations recognition provides a valuable means for objective measurements and tracking actual vs. planned performance. Key Performance Indicators can and should be used in setting performance targets for organizations and crews. Defining “SMART” (i.e. *Specific*, *Measurable*, *Achievable*, *Realistic* and *Timely*) targets supports an organization while setting unrealistic “technical limit” objectives carries the hazard of demotivating crews. Automated operations recognition algorithms coupled with real-time rig activity monitoring provides crews with constant and objective feedback on their performance. External “pressure”, “motivation” and “coaching” is thus replaced with internal “peer-pressure” and “group-motivation” to constantly enhance KPIs.

10 Appendix 1 – Activity Coding/Abbreviations

ANC	Anchor handling
BHA	BHA handling
BOT	Work boats (load/backload)
C/H	Circulate to clean hole
C/M	Circulate to condition mud
C/P	Circulate pill
C/S	Circulate for sample
C/T	Change tools
CCA	Cut Casing
CEC	Cement Casing
CEP	Cement Plug
CIR	Circulate
CRA	Change Rams
D/C	Drill Cement
D/F	Drill Formation
D/S	Drill and Slide
DIR	Directional Drilling
DRI	Drill (kick, H2S)
DRW	Drawworks
E/C	Equipment check
F/C	Flow check
F/T	Function test
F/W	Flow well
FIT	Formation Integrity Test
HPS	High pressure system
INT	Rig – Platform interface
INV	Investigation
JAC	Jacking operation
L/D	Lay down
LOD	Preload
LOT	Leak off test
LWD	Logging while drilling
M/C	Mill Casing
M/O	Mill Obstruction
N/D	Nipple down
N/U	Nipple up
OPH	Opening Hole
OTH	Other
P/H	Pipe handling
P/J	Prepare job
P/T	Pressure Test
P/U	Pick up
PIL	Pile Driving Stove Pipe
PMP	Mud pumps (e.g. for repair)
POS	Position Rig
POW	Power (rig electric power)
R/B	Rack back
R/D	Rig down
R/U	Rig up

REA	Ream
RUN	Run
S/C	Slip and cut
S/I	Shut in
S/M	Safety meeting
S/O	Space out
SCE	Solids control equipment
SKD	Rig skid cantilever
T/S	Take Survey
TCL	Tubing conveyed logging run
TDS	Top drive system (e.g. for repair)
TOW	Rig under tow
TRA	Training
TRI	Trip
TRT	Trouble time
TUG	Boat handling – hook up / release
W/E	Work Equipment
W/P	Work Pipe
W/T	Wiper Trip
WAS	Wash
WB	Wear Bushing
WHW	Well head work
WLR	Wireline / Slickline logging

11 Appendix 2 – Sensor Technology and Data Acquisition

Before continuing any further, an overview of the key parameters required to monitor a drilling rig's operational status, the sensors to obtain these measurements and the basics of data acquisition and storage shall be reviewed.

While a drilling rig may appear to be a highly complex piece of machinery, in fact only a relatively small number of machine parameters are required to define the operating condition of the unit.

11.1 Hook Load and Weight-on-Bit

Measuring the weight suspended below the travelling block and hook assembly is not specific to drilling applications, it is a common requirement for crane operations and has for a long time been based on measuring the tension in the dead line – calculating total hook load from the number of lines strung between crown block and travelling block. However it has to be noted that this approach neglects all friction effects in the crown and travelling block sheave assemblies as well as from travelling block movement. Luke and Juvkam-Wold in a 1993 paper[23] addressed the phenomenon that conventional dead-line weight indicators will read too low when the block is being raised and too high when it is being lowered – due to the friction in the various sheave bearings. While this is generally masked by the weight of the drill string suspended below the hook, moving empty blocks in the derrick clearly shows this behavior. The authors concluded that even when applying the corrective calculations derived hook load values could be up to 20% off, the prediction of hook loads from dead-line tension depends on travelling-block movement direction, and that hook and derrick load predictions are generally too low when coming out of the hole and too high when going back into the hole. Possible alternative and more accurate hook load measurement systems utilizing strain gauges or load cells either in the crown block of the derrick or directly in the top drive are still rare but have the advantage of also recording dynamic loads which are mostly dampened by the dead-line monitoring system.

Weight-on-Bit (i.e. the actual percentage of the total drill string weight that is not suspended from below the hook but resting on the bottom of the hole and thus acts as "cutting load" on the bit) is generally extrapolated from surface hook load measurements by "zeroing" the weight indicator when rotating with bit off bottom and displaying "Weight-on-Bit" (WOB) as the difference between off-bottom weight and current weight. It can easily be understood that this difference by no means reflects the true downhole weight that is resting on the bit but includes axial friction along the total length of the drill string in the hole (not even considering possible hanging-up of OD-changes in the BHA against the borehole wall). This difference between surface-indicated WOB and actual downhole WOB is especially apparent when drilling in sliding mode (i.e. with no drill string rotation and the bit driven by downhole motor) as in this condition the total friction along the drill string is governed not by dynamic but by substantially higher static friction factors. Especially in higher-deviated wells, surface-WOB cannot be used anymore to control downhole-WOB which is why directional drillers have long ago switched from WOB to standpipe pressure monitoring as a means of controlling bit weights (since the torque output of a downhole motor as constant speed is a linear function of the pressure drop across the motor, and reactive bit torque generally correlates with weight applied to the bit). MWD systems today provide the option to obtain downhole measurements of both WOB and bit torque, however without means of transmitting this information at high data rates to the surface (as recently made feasible with wired drill pipe technology), these measurements have only been available in recording mode for analysis after the bit had been pulled to surface.

11.2 Pipe Rotational Speed

Measuring the rotational speed of the drill string is one of the oldest measurements installed on drilling rigs. Historically this parameter was monitored via a dynamo driven off the rotary table on the rig floor, translating induced voltage of the dynamo to rotational speed of the Kelly and thus the drill string. The introduction of digital RPM encoders already decades ago substituted this technology with highly accurate and easily explosion-proofed solutions. However we still face the same dilemma as with the axial movement of the drill string – surface measurements do never fully correlate with downhole measurements. Accepting the long, thin drill string in the well bore as a mechanical spring, it does precisely that: cushion rapid and dampen high-frequency movements. With the advent of downhole measurement-while-drilling (MWD) systems, at least an option became available to monitor RPM downhole, right above the drill bit. Using the earth's magnetic and gravitational fields as reference, these systems measure downhole RPM and transmit these signals to surface. From such records it became obvious that even with constant surface rotational speeds, downhole bit RPM can in fact be highly erratic and – in case of resonance behavior – even reach reverse rotation conditions. Therefore RPM data should be taken with a grain of salt if only surface measurements are used. They provide a general trend of what the rig is doing but in many cases fall short of describing the actual movement of drill string and bit in the hole.

11.3 Drilling Torque

The measurement of the torque applied to the top of the drill string (either via a conventional rotary table and Kelly or via the top drive) mostly relies on monitoring the power supply to the respective drive motors. Only in the very early days of mechanically driven rigs and rotary tables, additional load cells had to be installed either against the rotary drive chain or in the rotary table support frame to measure the reactive torque transferred into the rig's substructure. With the introduction of electrically driven rotary tables (and subsequently top drives) in the 1970ies, measuring current drawn by the DC drive motors provided a simple and accurate means of monitoring torque. A slightly different problem originated from hydraulically driven top drives as torque monitoring on hydraulic motors has to be based on pressure measurements of the hydraulic oil flow to the motor. Unless pressure sensors were mounted directly at the motor (i.e. on the top drive in the derrick), pressures always included the frictional pressure drop through the hydraulic hoses – especially at higher rotational speeds (and thus higher hydraulic oil flow rates) these account for a substantial percentage of total system pressure drop and can only be approximated. Note that the same caveats apply for torque measurements as already previously mentioned for rotational speeds or axial loads – they can only be measured on surface, and "extrapolating" them to the bit relies on assumptions on the behavior of the drill string in between. Drilling torque consists of the initial torque generated by the drill bit cutting the formation, plus the friction forces along the total length of the drill string to surface. Especially in deviated wells, these friction forces generally account for most of the torque measured on surface.

The three afore mentioned parameters (hook load, rotational speed and torque) can be monitored with substantially higher accuracy when the respective sensors are installed into the top of the drill string right below the top drive since the dampening effects from the elastic drilling line and sheave systems (hook load) and the indirect measurement via the current consumption of drive motors (torque) is replaced by strain gauges located right in the drill string. Such instrumented subs have been developed over the last twenty years but have rarely been selected for actual field service unless in special cases when drill string vibration was the monitoring objective.

11.4 Block Position and Bit Penetration Rates

One of the most crucial – but also one of the most inaccurate – measurements to monitor progress of a well is the position of the travelling block in the derrick. It is at this point that the drilling rig is connected to the drill string and ultimately to the drill bit making hole. In a simplistic approach, as long as the drill string is attached to the travelling block (via the hook/swivel or top drive assembly), any movement of the travelling block will correspond to an identical movement of the drill string – at least its very top. This already indicates one of the biggest drawbacks even in today's monitoring systems. It is assumed that the drill string is non-elastic, i.e. the axial movement of the bit several kilometers down the hole is identical to the movement of the topmost drill pipe single right below the travelling block. Even in vertical wells this is inaccurate as any change in weight-on-bit (i.e. the amount of drill collar weight that is supported by the bit resting on the bottom of the hole instead of hanging suspended from the drill pipe above) instantly influences the axial tension along the whole drill string.[12] The phenomenon is well known to drillers that when "slacking off" drilling line from the draw works (thus lowering the travelling block), the top part of the drill string moves downward into the well, hook load decreases as more weight is being put onto the drill bit, however during these brief seconds of axial movement on the top the bit hardly drills any new formation. Its position along the axis of the well remains

[12] For thousand meters of 5" drill pipe, a decrease in axial tension by 10 tons causes a decrease in length by about ten centimeters.

stable while the travelling block is lowered. After applying a certain weight on the bit and locking the draw works brakes, the bit starts to “drill off”, i.e. with no axial movement of the top part of the drill string, the bit drills new formation, thus moving further down along the well axis and transferring back weight into tension force in the drill pipe. In an extreme sense, there would be no bit movement during movement of the travelling blocks and no travelling block movement during drilling off, i.e. axial movement of the bit. In reality, there is a constant interaction and overlap between block movement and bit making hole, however the assumption that the surface lowering of the travelling block represents the actual penetration rate of the drill bit is clearly inadequate.

Unfortunately, even the most sophisticated downhole monitoring systems until today cannot measure actual (“instantaneous”) penetration rates of the drill bit into the formation, simply because there is no possibility of a near-bit reference point against which to measure the spatial position change. Whenever records today reference instantaneous penetration rates, they simply provide a high-resolution/high-frequency track of travelling block movement.

It is theoretically conceivable to actually simulate the drill string in real time, calculating its stretch at any given second, thereby transferring block movement and hook load fluctuations into pipe stretch and bit weight records. In reality this approach will always be flawed because one of its main input parameters – the frictional force between the borehole walls and the moving drill pipe – will always be generally unknown and can only be estimated. This challenge is further complicated by the interaction of friction force and sidewall normal force which in itself depends on the axial tension of the pipe – precisely the parameter that should be modeled. Including other open interfaces like constantly changing lubricity of the drilling fluid (pressure, temperature, solids content) or different friction factors of different lithologies (sandstones, clays, lime stones etc.) makes this task formidable to impossible. This does not even include the interaction of torque fluctuations along the whole length of the several kilometer long drill string and their influence of wall contact forces and axial tension when the string “coils up”.

Another constraint in measuring the actual position of the travelling block in the derrick is the sensor system used. Since travelling blocks move freely up and down, suspended from the drilling line strung below the crown block, no direct-contact measurement (such as linear encoders along the path of the travelling block) are feasible.[13] Even with the advent of top drives that by definition require guide rails to transfer the reactive drilling torque into the rig’s substructure, only very few such encoding systems have been introduced. Rig instrumentation systems still rely on rotational encoders mounted on the main draw works drum shaft, mathematically compensating for the changing drum diameter due to drilling line spooling off and on. While these compensation

[13] Potential exceptions are rack/pinion rigs or hoisting systems based on hydraulic piston assemblies moving a yoke up and down guide rails

algorithms are generally quite accurate, the system still requires manual re-adjustments after regular line cutting operations (since the points where wraps "jump" onto a new layer change every time the anchor point of the drilling line on the draw works drum changes).

We will thus have to live with the inherent inaccuracy between travelling block movement and actual bit penetration rate. Nevertheless, for the purpose of monitoring drilling rig operating conditions, the achievable accuracy is sufficient.

Alternative methods of measuring the travelling block height in the derrick (primarily based on optical/laser distance measuring devices installed between crown and travelling block) have thus far not provided a feasible solution.

11.5 Drilling Mud Circulating Pressure

Pressure indicators are among those used on drilling rigs almost since the introduction of rotary drilling technology in 1900. Initially based on membrane transducers and analog gauge indicators, solid-state electronic strain-gauge sensors became available in the 1980ies and allowed a maintenance-free monitoring of stand pipe pressures. Their rugged design allowed utilization even with high-density (i.e. high solids-content), high-temperature mud systems in water-based and oil-based environments. They are accurate, reliable and have become state-of-the-art on today's drilling rigs.

11.6 Drilling Mud Circulating Flow Rates

While circulating pressures have always been easy to measure, monitoring actual flow rates has for more than a century been accomplished by either calculating flow rate from mechanical RPM measurement on the positive displacement mud pumps (assuming volumetric efficiency factors) or using crude mechanical devices like paddles or weirs in the return lines from the well bore to the mud tanks. Translating mud pump rotational speeds into fluid flow rates has always been an inaccurate approximation, since volumetric efficiencies not only depend on rotational speed itself (efficiency generally drops with increasing piston speeds) but is also massively influenced by restrictions in the suction lines (like from settling solids or inadequately sheared polymers plugging the suction screens) or degrading/turned-off charge pumps. It is not uncommon for stand pipe pressures to fluctuate with the pump rotational speed constant – not because of downhole changes but because of the previously listed surface influences.

Measuring the return flow from the well for the longest time relied on paddle-type meters and has mainly been used as a "trend" meter – sudden increases in flow indicated a downhole influx (or "kick"). Exact measurements of the return flow rate were hardly required. Starting with advent of magneto-inductive flowmeters (MID) in the 1970s, more accurate measurement of the "delta-flow" between flow in (i.e. pump rate) and flow out (i.e. return rate from the well) became possible. First investigations were done by Maus et al[24] in 1978 and Speers and Gehrig[25] in 1987, however applications of such flowmeters remained scarce and mostly done for R&D purposes. During the

1990s MIDs entered the drilling industry on a wider scale, initially driven by the emerging slim hole drilling projects requiring highly accurate kick control capabilities.[26,27] Without any moving parts and providing an unrestricted full bore to the mud flow, these sensors are ideally suited for drilling applications – as long as the circulating medium is electrically conductive. Once non-water-base-muds (NWBM) are used, the measurement principle of inducing a voltage into a conductive medium flowing through a magnetic field cannot be used anymore. Only in recent years, Coriolis mass flow meters have in rare cases been introduced to drilling rigs. Unfortunately their high cost and generally smaller dimensions make them difficult to install and maintain when monitoring large flow rates and varying solids contents.

Alternative solutions like ultrasonic Doppler flowmeters suffer from their low tolerance to changing solids contents in the fluid and have thus far failed to make an impact on drilling rig instrumentation packages.

11.7 Total Active Mud Volume

The previously listed parameters are generally sufficient in determining the operating condition of a rig from the machinery standpoint. Including a record of total active surface mud volume (or “mud in the tanks”) provides supporting information on why certain rig operating conditions came about (e.g. increases in tank volume preceding prolonged circulating periods indicating influxes and well control issues). Therefore this parameter is included in this overview.

Historically, only one tank chamber has been equipped with level-monitoring systems, generally based on a floater-type device, hardly ever connected to any recording system and providing the driller with an alarm when the fluid level in this tank chamber (typically the suction tank providing fluid to the mud pumps) increased or decreased by more than a predefined threshold. These systems were extended to “Pit Volume Totalizers” when multiple level measurement sensors were installed throughout most of the active tank chambers, providing the rig crew with a more or less accurate indication of changes in the total surface mud volume. These level sensors originally were based on pressure sensors measuring the pressure of air injected at a certain point in the tank bottom, thus translating the hydrostatic pressure of the fluid in the tank above the injection point to fluid level heights using known fluid density for conversion. It is obvious that these first attempts at level monitoring were by no means exact and heavily depended on human interference. Only the advent of ultrasonic distance (i.e. level) measuring devices provided the necessary step change to allow exact, continuous monitoring of fluid levels in multiple tank chambers. Still today, these measurements are challenged by wavy or foamy fluid surfaces. Alternative solutions based on radar distance measurements are available but are hardly utilized on drilling rigs.

11.8 Data Acquisition and Recording

This work shall not review data acquisition, A/D-conversion and storage technologies. The major challenge in utilizing sensor data as available today is the meaningful condensing of the vast amounts of recorded data to make it useful to the engineer instead of flooding and overloading him. Mathis and Thonhauser in 2007[28] described the workflow from initial sensor measurements to meaningful data sets as a basis for decision making. Modern rig instrumentation systems monitor several dozen channels at sampling rates of typically 1 Hz, resulting in raw data volumes of about 100000 data points per channel and day and easily a several million data points per rig and day. The industry has thus developed from a "data acquisition" service to a "rig monitoring" and ultimately towards an "operations monitoring" support. Detailed descriptions on data quality assurance, data processing and data visualization workflows are referred to the referenced paper.

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