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Improvements in Slide Quality and Execution Speed Through Automation

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Abstract

Slide drilling with a steerable motor bottomhole (BHA) assembly has historically been a manual and skill-dependent process. In the legacy steering process, a directional driller (DD) is responsible for computing the required slide length and steering direction, then executing the slide, and managing drilling parameters to optimize drilling performance. The quality of the slide (defined by the percentage of time the toolface is oriented in the required direction) and the drilling performance achieved during the slide is significantly dependent on the DD's skill and experience in the field. This paper describes an alternate steering methodology in which slide steering control and drilling parameters are automated via the rig's control system, with slide oversight from the rig driller to ensure directional performance.

With this workflow, the steering instructions (course length and toolface instruction) are communicated to the rig programmable logic controller (PLC), and a sequence of automated instructions are executed to align the toolface, place the bit on bottom, execute the slide, and resume rotary drilling at the conclusion of the slide.

Field testing of this steering automation has demonstrated directional control that meets or exceeds the slide quality achieved by DDs, is repeatable and consistent, and is not dependent upon experienced supervision to achieve high-performance results. Furthermore, this steering approach is an important component within an overall automated drilling workflow, in which all components of the directional drilling process (generation of directional instructions, execution of slide and rotary drilling, and management of rig activities) are fully automated.

Introduction

The automation of directional drilling is a priority for operators because of the potential reward: improved steering consistency, reduced drilling flat time, reduced crew or de-manned, remote operations, all of which ultimately lower well construction costs. Directional drilling automation has particular value in high-volume markets like US onshore, in which operators drill a large number of nearly identical wells to develop their acreage – a "factory drilling" or "well manufacturing" approach. Within this model, incremental improvements to drilling practices and execution performance throughout a full drilling program can significantly improve the economics of a project. A recent study (Rexilius 2015) found that a project NPV more than doubled when data gathered and analyzed throughout early project execution phases was used to optimize drilling and completion plans in subsequent wells without interrupting the "drilling factory".

Directional automation may seem more attainable with rotary steerable systems (RSS), whose steering behavior can be directed from surface through automated flow rate-related downlinks or other mechanisms (an approach conducive to process automation), than with steerable motor BHAs, which rely on manual control of autodriller and top drive parameters by a skilled directional driller to execute slide drilling. A cost and performance distinction between these technologies should be made – RSS BHAs are typically marketed as delivering better downhole performance (steering, tortuosity, elimination of slower slide drilling) at a higher cost, while steerable motor BHAs, which may exceed RSS in rotary ROP but lag in slide ROP, are the lower-priced option. Steerable motor BHAs are much more commonly used both in the US onshore and international markets due to cost-sensitivities in high-volume markets. In 2012, RSS accounted for approximately $3.5 billion (23%) of the estimated global $15 billion directional drilling market (Malcore 2012).

Because an automated solution is more economically compatible with a high-volume downhole motor BHA approach, and because automation can potentially overcome one of the key downsides to the use of motors (slow slide drilling), the potential prize for successful automation is much higher for both operator and service provider when implemented with steerable motor BHAs.

Technology Introduction

Over the past eighteen months, a method of automated slide steering control has been developed and implemented on multiple rigs in several major US onshore basins. This methodology, which is delivered as an integrated part of the rig's control system, is capable of automating the core off-bottom (slide preparation) and on-bottom (slide execution) activities that together comprise slide drilling.

Off Bottom

Off-bottom automation focuses on all activities that occur after the bit is picked up off bottom prior to the slide. For example, one of the core off-bottom activities is placing the bit on bottom to slide. The core activity of placing the bit on bottom has multiple subtasks – for example, inputting reactive torque prior to tagging bottom and detecting on-bottom status based on differential pressure – that must also managed by the control system. The automation of off-bottom activities has significant potential in the overall optimization of the slide drilling process. Analysis of manual slides conducted prior to and during the deployment of this automation technology showed that there was significant variability in off-bottom time between wells, sections, and directional drillers. An analysis of over 750 manual slides conducted in lateral sections revealed that while off-bottom tasks (pre-slide time) averaged 13.0 minutes, they ranged from as low as 7.7 minutes to as high as 23.5 minutes (see **Fig. 1**). This enormous discrepancy can be effectively addressed through slide automation and result in substantial cost savings to the operator.

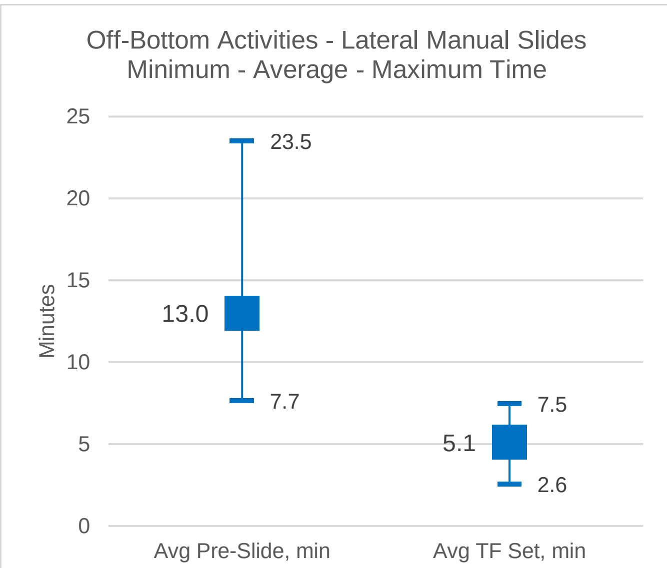

Figure 1. Off-Bottom Time Analysis, Lateral Interval

On Bottom

On-bottom automation focuses on precise slide execution, as measured by the MWD toolface measurement. The core on-bottom activity that must be automated is the use of toolface position and other surface measurements to make proactive and reactive steering corrections when required. The magnitude and frequency of the corrections must match the amount of toolface movement, which is in turn influenced by drilling parameters, the formation type, the penetration rate, and other operational factors.

The objective of this automated slide methodology is to deliver a 'precise' slide – the toolface consistently aligned in the desired direction – not to automate control of the autodriller. Presently, control of autodriller drilling parameters (weight on bit, differential pressure, ROP setpoints) is maintained with the rig driller, while the slide control automation responds to parameter changes generated through autodriller setpoint changes. For example, an increase in weight on bit produces more differential pressure, which requires additional reactive torque to maintain the toolface measurement. This division of responsibilities (setpoint control with a human driller or DD, toolface control with an automated system) permits the human to focus on drilling performance and is an enabler for a de-manned operation.

Data & Control Relationships

To function effectively, an automated slide system must have functional links (input and output of data and commands) to multiple rig systems and data sources: the rig top drive, the rig hoisting system, surface drilling parameter measurements, and MWD toolface measurements.

- Rig Top Drive – the automation system must control the rig top drive quill position in order to align and maintain the toolface in the desired position.
- Rig Hoisting System – the automation system must control the hoisting system (i.e. draw-works) in order to slack off the drill string to tag bottom and pick up after completion of a slide.
- Surface Drilling Parameter Measurements – the automation system must receive surface differential pressure, WOB, torque, and ROP measurements to make top drive quill position adjustments and maintain the TF in the desired direction.
- MWD Toolface Measurements – the automation system must receive MWD TF measurements (gravity and magnetic) to make top drive quill position adjustments and maintain the TF in the desired direction.

Because this automated slide system is implemented within the rig control system of a single-OEM rig (i.e. the rig control system and EDR are already integrated), the aggregation of required data and transmission of commands to rig systems is easily accomplished.

Steering Approach

Steering automation methodology aims to replicate the steering behavior of an experienced directional driller with both reactive and proactive steering algorithms. Reactive steering logic is based on incoming MWD toolface measurements, while proactive steering logic is based on observed drilling parameters.

Within each of these steering algorithms are numerous parameters that govern the behavior of the system. These control parameters must be dynamically adjusted by the system to ensure that the steering algorithm produces accurate and applicable instructions. For example, when an increase in differential pressure is observed, the system must input a quill position adjustment that corresponds to the quantity of reactive torque to maintain the toolface in the desired direction. The magnitude of quill position adjustments versus delta differential pressure will vary based on the drill string size, differential pressure, and other drilling parameters, and must be defined to produce an accurate steering response. Further, the system must account for complexities that would conditionally alter the steering response: for example, if the reactive torque from an increase in differential pressure would move the toolface in the desired direction no action should be taken. These adjustments must be made on a continuous, real-time basis to steer effectively. Finally, the system must operate within existing safety interlocks that maintain safe operations.

The selection of the steering algorithm to use (reactive, proactive, or both), and the parameters that determine the algorithm behavior vary significantly depending on the hole section (vertical, curve, lateral) and the drilling depth within the hole section. To facilitate flexible operations, these parameters are aggregated into initialization files referred to as "steering recipes". As each well is drilled, different steering recipes are automatically loaded (typically triggered by the start of a section or by depth) to maintain optimized steering behavior.

Standardizing Best Practices

Directional drilling best practices vary widely between basins and directional drillers. One of the key value drivers for this automated system is the opportunity to define and consistently implement best practices across wells and rigs. Typically, an exploratory / evaluation phase is defined as part of the implementation plan:

- If the technology has previously been implemented in a basin or area, identify all previously-captured best practices.
- Assess slide drilling best practices from a top-performing rig in the basin or area.
- Codify these best practices into updated steering recipes for each drilling interval.
- Deploy the technology with SME supervision.
- Assess the performance of the technology using key performance indicators.
- Iteratively improve the steering recipe until the technology meets performance expectations.

Small adjustments can also be made as the well is drilled to optimize steering behavior. All recipe changes are logged and can be exported for analysis or future use. Field experience to-date indicates that optimized steering recipes may vary substantially between major basins due to differences in common wellbore geometry, drill string equipment, and drilling parameters, while recipes within a basin are generally consistent and require only small adjustments to accommodate operator-specific best practices.

Key Performance Indicators

The granular assessment of slide drilling performance must be measured with specific key performance indicators that accurately measure the factors that are impacted or influenced by slide automation. Macro drilling key performance indicators (KPIs) – e.g. total well cycle time, well average rotating and sliding penetration rates, rig activity percentages – are useful metrics when making broad comparisons between rigs and wells. However, these macro KPIs frequently do not contain the necessary resolution to measure the performance impact that automated directional drilling can deliver. For example, comparing the average penetration rate between a manual and automated slide will likely not describe the full performance difference between these slides, as there are other factors – principally, slide precision and slide preparation time – that are equally a part of the overall "slide performance". Conversely, a comparison of the time required to (1) come off bottom from rotary drilling, (2) execute pre slide activities, and (3) go back to bottom to slide drill – all activities that may be automated – will clearly demonstrate whether automated slide activity is faster or slower than a human executing the same activity.

An assessment of the success of implementation of an automated sliding system should consider both slide precision and slide speed. Whether or not one performance area is more important that the other is specific to the operation.

Slide Precision

The precision of a slide may be generally understood as a measurement of how consistently throughout the slide the steerable motor was held in the desired toolface orientation. A slide that is consistently held in the desired direction will result in a higher motor yield (MY) and higher dogleg severity (DLS), while slides without consistent toolface control will produce reduced, high-variability motor yields and dogleg severity. From a directional control perspective, it is desirable for the motor's yield to be both close to the planned (expected) motor yield, and also consistent between slides, so that the course length and toolface orientation of subsequent slides may be correctly determined. A consistent motor yield is an enabler for reduced wellbore tortuosity and better directional decisions.

For this application, slide precision is measured with three metrics: Slide Score, Delta Toolface Distribution, and Burn Footage. Slide Score is a measurement computed throughout the slide that cumulatively indicates how close the actual toolface control was to the desired toolface measurement. Slide scores range from -100 to 100, with -100 a slide that was drilled in the exact opposite from the intended direction (e.g. slide at a GTF of 90 instead of 270); and 100 a slide that was drilled perfectly in the intended direction. This measurement is typically used to compare the precision performance of individual slides, although it may be averaged for an interval (e.g. average slide score in curve) for well-to-well comparisons.

Delta Toolface Distribution is a graphic indicator that displays the toolface control precision throughout a drilling interval. Toolface control is considered either "Good" (within 20 degrees of target), "Acceptable" (within 45 degrees of target), or "Poor" (more than 45 degrees from the target). The percentage of slide drilling spent within each control range is plotted to enable quick precision comparisons between wells and drilling intervals. This indicator is illustrated below in **Fig 2**:

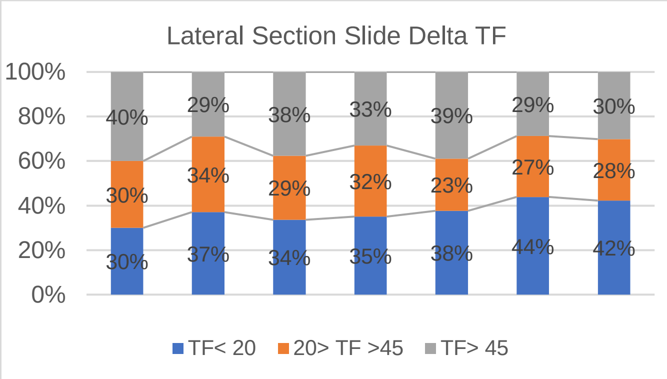

Figure 2. Example of Delta Toolface Distribution.

In this graphic, each bar represents the TF distribution within the lateral interval of a different well. A possible conclusion from this data may be that more recent wells on the right of the graph have increased the percentage of slide drilling with "good" toolface control and reduced the percentage of drilling with slide drilling with "poor" toolface control.

Burn footage is a measurement of the distance at the start of a slide with poor toolface control (more than 45 degrees from the target). It may be assessed on a per-slide basis or averaged over an interval to compare performance between wells. Poor toolface control at the start of a slide is wasted effort – it is slide drilling that does not contribute to the desired directional change. A significant quantity of burn footage at the start of a slide requires the directional driller to extend the slide to meet their directional objective, which results in more slide time. When coupled with various slide speed metrics, burn footage is useful in assessing the "go to bottom" logic within the automated slide system.

The combination of Slide Score, Delta Toolface Distribution, and Burn Footage enables a quick and meaningful assessment of slide performance on a per-slide, per-interval, or per-well basis.

Slide Speed

The speed with which a slide is executed is as critical to the success of the slide as the toolface control precision. As discussed previously, ROP is insufficient as a performance KPI when evaluating automated slides as the system is responsible for more than just the on bottom performance. A significant amount of savings has been observed in the pre-slide time metrics when compared against manual slides.

Note that there may exist circumstances in which it is informative to compare the slide ROP of a slide executed by a directional driller versus a rig driller to assess the success of a reduced crew operation (i.e. ensuring that the shift to a reduced crew operation does not impact on-bottom drilling performance).

Three performance metrics are used to assess the speed of automated slides: cumulative Rotate to Rotate (or Slip to Rotate) time (RtR, StR); RtR or StR time per slide; and Slide Rate.

RtR and StR are measurements of the total time required to execute a slide. RtR is used when a slide takes place between two rotary periods on the same stand. It begins when the bit comes off bottom from first rotary period and ends the moment the bit is back on bottom for the second rotary period. StR is a similar measurement but accounts for slides that occur at the top of the stand without any prior rotation on the stand. StR starts the moment the driller exits slips and ends after the moment the bit is back on bottom after the slide. These time measurements encompass all of the off-bottom activities that are impacted by slide automation or by a directional driller.

Total RtR and StR time is averaged over the number of slides executed to obtain the RtR / StR per slide metric, which is useful to track slide efficience between wells and to identify improvement opportunities within the control logic.

Finally, dividing the total slide distance for the interval by the cumulative RtR / StR time yields the Slide Rate metric, a velocity metric (i.e. feet per hour) that incorporates the off-bottom time prior to and after the slide. Slide Cost is significantly more useful as a metric than ROP when assessing the performance of manual or automated slides as it considers all of the activities associated with slide drilling.

It may be circumstantially useful to examine the duration of specific tasks within the slide process – for example, average pre-slide time or average toolface setting time. While these times are accounted for in the RtR or StR time metric, examining them specifically can lead to improvements in the slide recipe.

All KPIs are summarized in **Table 1** below:

Table 1. Slide Performance KPI Summary

KPI	Measures
Slide Score (-100 to 100)	Toolface control precision of individual slides.
Delta Toolface Distribution (graphic)	Toolface control precision for an interval or well.
Burn Footage (ft)	Quantity of footage at the start of a slide with poor toolface control (> 45° from target toolface).
RtR (StR) Time (hr)	Cumulative time, inclusive of off-bottom time, spent slide drilling within an interval or well.
RtR (StR) per Slide (hr)	Average RtR or StR per slide for an interval or well.
Slide Rate (ft/hr)	Slide speed, inclusive of off-bottom time, for an interval or well.
Pre-Slide Time (hr)	The interval of time after coming off bottom prior to a slide and before tagging bottom for the slide.
Toolface Setting Time (hr)	The time within Pre-Slide Time spent aligning the toolface.

Other Considerations

When conducting well-to-well comparisons using these sliding KPIs, it is important to be aware of operational characteristics that may color the data. For example, tangents are commonly drilled in vertical intervals to accommodate pad drilling. Because a well drilled with a higher-inclination tangent requires more sliding, KPIs will likely be impacted, and analysis of the data must consider this to make an accurate comparison between wells. Similarly, the depth within the interval where sliding was conducted can dramatically change KPIs – for example, all slide speed metrics will be much faster when most of the sliding in the lateral interval is conducted at a shallow depth versus close to TD.

Measurements Drive Development

The benefits of computing and tracking KPIs with granular detail extend beyond field performance optimization to product development decision-making. Because resource limitations often force the prioritization of new feature development, it is valuable to have a dataset that permits quantification of the impact of the new features. For example, these KPIs could be used to make a development decision between new logic that reduces burn footage versus new logic that speeds the toolface lineup sequence. A reduction in burn footage would produce more precise slides, while an improved lineup sequence could speed operations. By computing and tracking these KPIs on a systematic basis, the development team can choose to prioritize the issue that has more significance to field performance.

An ongoing area of development lies in the use of granular slide drilling KPIs to automate control of drilling parameters setpoints – WOB, dP, and ROP. As previously discussed, the current methodology maintains ownership of autodriller parameters with the rig driller or directional driller, with the automated slide system responding to parameter changes that are manually initiated. Analysis of slide drilling KPIs is critical to the development of a system that automates setpoint control to improve both slide speed and precision.

Field Results

Automated sliding technology was deployed on multiple rigs in several US onshore unconventional basins over the past 12 months. The technology was continuously developed over this period of time to improve the consistency and reliability of slide steering control.

Results Summary

The slide drilling performance of 44 wells in a US onshore basin were evaluated for slide precision and slide speed, according to the previously-discussed KPIs. These wells were drilled by four rigs in close geographic proximity over a period of several months in 2018. 23 wells utilized in at least one drilling interval the automated slide methodology described in this paper, and 21 were conventionally drilled. The dataset includes over 21,000 feet of automated slide drilling throughout vertical, curve, and lateral intervals (**Fig. 3**).

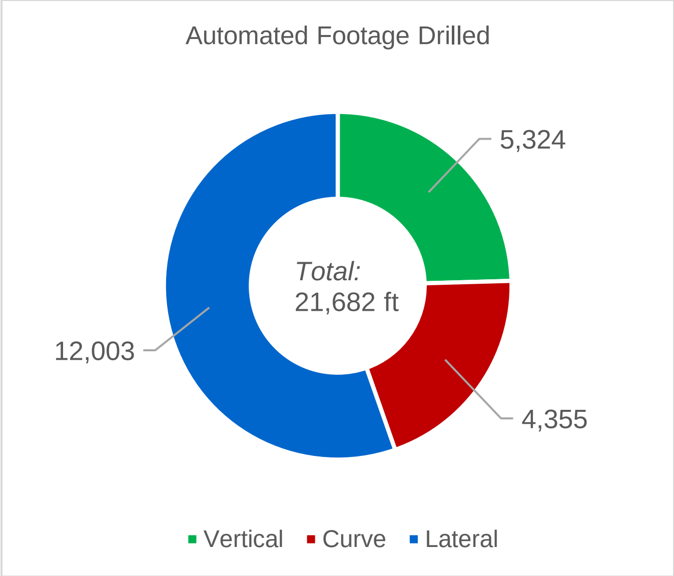

Figure 3. Automated Footage Breakdown

Slide drilling in the vertical and lateral sections of the 23 automated wells was locally supervised and executed by the rig driller, with remote directional driller oversight of slide instructions and execution. Curves were drilled using the automated system with local supervision from a directional driller in the event that manual intervention was required. Performance is assessed by section (vertical, curve, and lateral).

Slide Performance in Vertical

Slide control automation resulted in slide speed and precision results in the vertical hole section that are generally consistent with performance from manual offset wells according to the previously-discussed KPIs. Data from 44 vertical intervals was assessed: 23 automated verticals and 21 manual verticals. Automated vertical intervals were executed with no directional driller on location. Key findings are as follows:

- Automated wells averaged a Slide Rate of 34.2 ft/hr versus 29.8ft/hr for manual wells, 15% higher (**Fig. 4**).
- The average on-bottom sliding ROP in automated wells was 58.4 ft/hr versus 52.2 ft/hr for manual wells, 12% higher (**Fig. 4**).
- Automated wells averaged 4.9 minutes pre-slide time and 1.7 minutes TF setting time versus 5.0 minutes and 2.4 minutes for manual wells, indicating a modest reduction in off-bottom times (**Fig. 4**).
- When measured by slide score and delta toolface distribution, slide precision was functionally identical between the automated and manual wells (**Fig. 5**).

On-bottom ROP and Slide Rate KPIs were higher in the automated wells; the off-bottom KPIs (pre-slide time) were consistent between automated and manual wells, indicating that the faster automated Slide Rate was attributable primarily to faster on-bottom drilling. As previously outlined, the automation methodology outlined in this paper maintains control of on-bottom drilling performance with the rig driller.

The RtR / StR per slide metric can be used to compute the difference in average slide drilling time between automated and manual wells. Multiplying RtR / StR per slide by the average number of slides executed in the vertical interval provides the average total slide time. Automated slides were executed marginally faster than manual slides, resulting in a time savings of approximately 1.3 hours (**Table 2**).

Table 2. RtR Per Slide and Total Slide Time

	Automated	**Manual**
RtR / StR per slide (hrs)	0.32	0.37
Avg Number of Slides	26	
Total Slide Time (hrs)	8.3	9.6

These results show clearly that it is possible to deploy an automated sliding system that meets or exceeds the speed and precision performance of an experienced directional driller. The improvement in on-bottom ROP demonstrates that slide drilling speed can be managed by the rig driller without the presence of a directional driller on location.

Furthermore, the granular KPI computation and tracking that accompanies the introduction of the automated sliding system provides the operator and service provider with data that can be used to define specific actions in subsequent wells to increase the speed and consistency of the drilling operation.

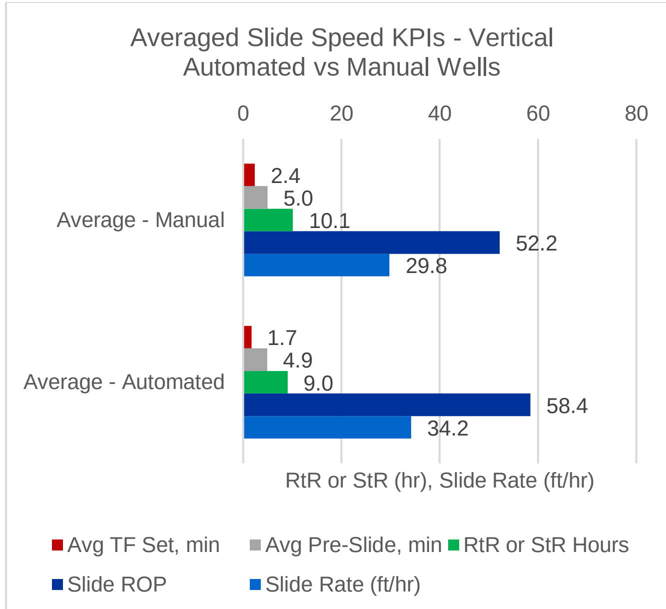

Figure 4. Slide Speed KPIs - Vertical

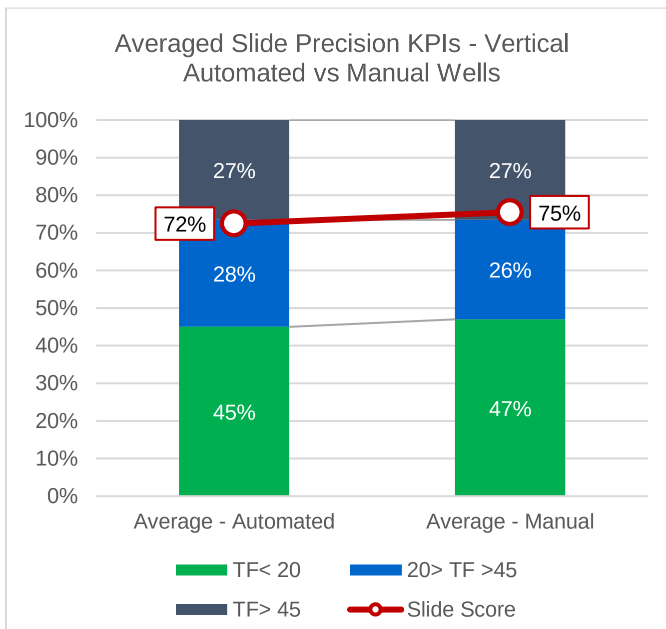

Figure 5. Slide Precision KPIs – Vertical

Slide Performance in Curve

As in the vertical section, automated slide speed and precision in the curve section was generally consistent with offset manual wells. Data from 43 curves was assessed: 12 automated curves and 31 manual curves. Unlike the vertical and lateral intervals, automated curves were drilled with a directional driller on location due to the critical nature of the operation. Fewer automated curves were drilled due to BHA and other operational considerations, resulting in a smaller dataset.

Note that RtR / StR time and Slide Rates are not useful to compute in the curve interval due to drilling circumstances, such as frequent surveys, that interrupt operations and create difficulties in accurately computing performance metrics. Additionally, because the curve interval is shorter and more focused on slide quality to achieve desired build rates, analysis of curve interval data focuses on slide precision KPIs and does not include RtR / StR KPIs.

Key findings are as follows:

- The average on-bottom sliding ROP in automated wells was 90.1 ft/hr versus 103.6 ft/hr for manual wells, 13% lower (**Fig. 6**).
- Automated wells averaged 9.8 minutes pre-slide time and 2.2 minutes TF setting time versus 12.7 minutes and 4.3 minutes for manual wells, indicating that the automated system was able to effectively reduce off-bottom time through process optimization (**Fig. 6**).
- When measured by slide score and delta toolface distribution, slide precision was functionally identical between the automated and manual wells (**Fig. 7**).

Reductions in off-bottom pre-slide time – a 23% reduction in off-bottom pre-slide time (12.7 minutes to 9.8 minutes) was observed in the curve dataset – are typically accomplished by optimizing off-bottom activities. For example, there are sub-functions within the lineup toolface sequence that can be streamlined or eliminated if the function is determined to be unnecessary.

The most significant outstanding challenge faced by automation in the curve section is maximizing on-bottom ROP while maintaining precise toolface control. The observed lower ROP is likely attributable to the directional driller constraining parameters to ensure that the desired slide quality is achieved. Because the RtR / StR metric is not available here, it is not possible to determine whether the improvement in off-bottom time had an impact on Slide Rate.

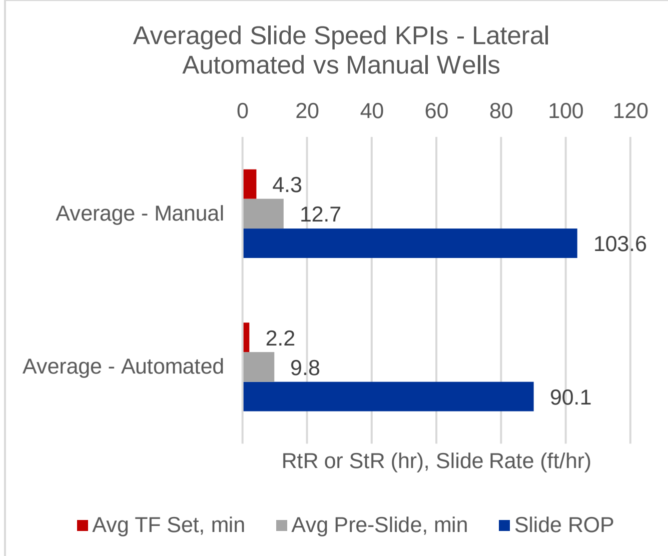

Figure 6. Slide Speed KPIs – Curve

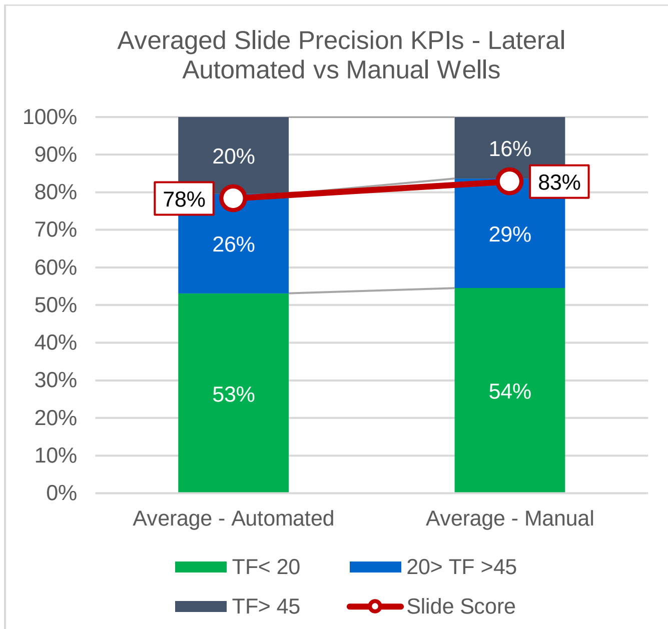

Figure 7. Slide Precision KPIs – Curve

Slide Performance in Lateral

Analysis of the lateral sections demonstrate clearly how the automation of slide control can improve the effective sliding ROP through optimization of off-bottom activities. Data from 43 vertical intervals was assessed: 23 automated and 20 manual laterals. Automated lateral intervals were executed with no directional driller on location. Key findings are as follows:

- Off-bottom pre-slide activities were significantly faster in the automated wells: 2.3 minutes average toolface setting time and 10.5 minutes average pre-slide time in automated wells versus 5.1 minutes and 13.0 minutes in manual wells (**Fig. 8**). This can be attributed to adjustments made to the slide recipe that optimize off-bottom activities and eliminate unnecessary steps.
- While the on-bottom ROP was higher among manual wells, faster pre-slide activities in the automated wells resulted in a higher Slide Rate: 29.9 ft/hr automated versus 27.3 ft/hr manual (**Fig. 8**). This clearly indicates that a reduction in time required for off-bottom activities can have a significant positive impact on the overall operation.
- Slide precision was marginally better among the analyzed wells as measured by Slide Score and Delta Toolface Distribution (**Fig. 9**). While the discrepancy between automated and manual wells was largest in the lateral intervals, these automated precision metrics are sufficient to achieve directional objectives.

Results from the lateral section capture clearly how off-bottom pre-slide activities can have a higher impact on slide execution speed than the on-bottom drilling performance. Despite a 15% reduction in on-bottom ROP, automated slides were completed with a lower "cost" (higher slide rate) than manual slides because of the reduction in pre-slide time. An assessment of RtR / StR hours per slide and the total slide time quantifies this benefit: sliding in automated wells was executed on average approximately four hours faster than in manual wells.

Table 3. RtR Per Slide and Total Slide Time

	Automated	Manual
RtR / StR per slide (hrs)	0.58	0.68
Avg Number of Slides	39	
Total Slide Time (hrs)	22.6	26.5

As in the curve interval, the most significant remaining challenge for the automated slide system is to pursue on-bottom ROP while maintaining toolface control of sufficient accuracy.

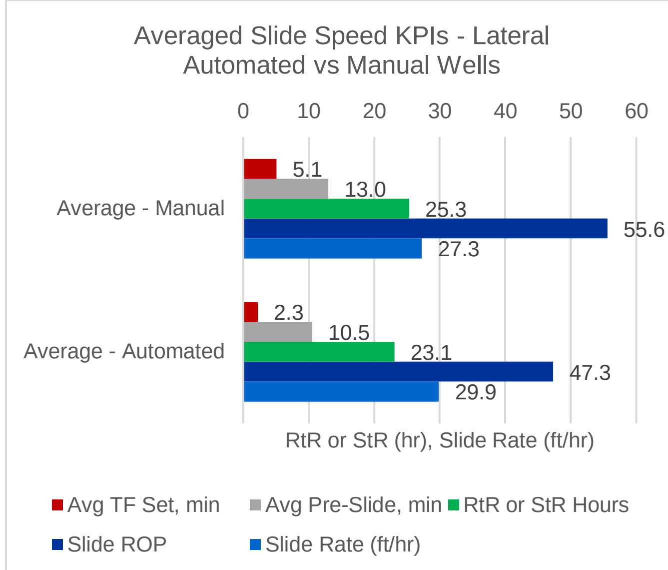

Figure 8. Slide Speed KPIs – Lateral

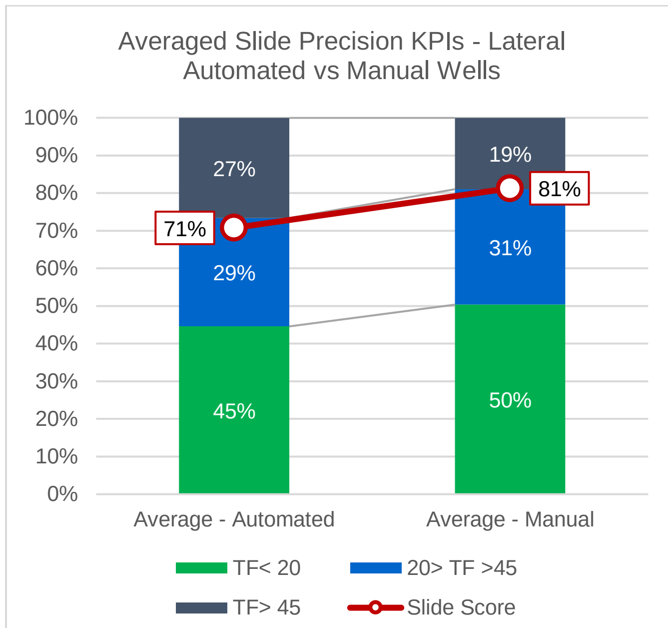

Figure 9. Slide Precision KPIs – Lateral

Conclusions

This paper describes an automated slide drilling methodology that is currently being deployed in multiple US onshore basins. Key conclusions are as follows:

1. An automated slide system is a technology critical to the execution of remote, reduced-crew, and de-manned directional drilling operations without sacrificing performance.
2. Slide Speed KPIs: RtR / StR per slide and Slide Rate KPIs provide a more comprehensive way of evaluating the true “cost” of a slide when compared with on-bottom ROP. These metrics measure those activities that are more directly impacted by automation, and can be used to evaluate both automated and manual slides.
3. Slide Precision KPIs: Slide Score, Delta Toolface Distribution, and Burn Footage describe how effectively a slide is executed in the desired toolface direction. These metrics can be used to drive the configuration and operation of the system in the field, as well as the development of new features.
4. Results from a comparison of 23 automated wells and 21 manual wells demonstrate that the automated system is capable of executing slides with KPIs largely in-line with manual sliding.
5. Slide Speed: the automated system delivers a higher Slide Rate in both the vertical and lateral section. Slide Rate is not computed in the curve, but the on-bottom ROP lagged in the automated versus manual wells.
6. Slide Precision: the automated slide system is capable of producing slides with comparable toolface control in the vertical and curve sections of the well and lags slightly behind manual slides in the lateral.

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Nomenclature

BHA = Bottomhole assembly
DD = Directional Driller
DLS = Dogleg Severity
dP = Differential Pressure
MY = Motor Yield
PLC = Programmable Logic Controller
ROP = Rate of Penetration (ft/hr)
RSS = Rotary Steerable System
RtR = Rotate to Rotate (time)
StR = Slips to Rotate (time)
TD = Total Depth
WOB = Weight on Bit

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