NSTF Wells Task Force

Right Scoping Group

Good Practice Guide to Drilling Long Horizontal Wells

September 2022

OEUK

1. Introduction

The Wells Taskforce, under the North Sea Transition Forum, was established to implement the OGA (now NSTA) Wells Strategy. The Right Scoping Work Group is one of five work groups created by the Wells Taskforce. Its objective is to identify, communicate, and promote good practice in well delivery across the UK industry.

The Oil & Gas UK (now Offshore Energies UK) Right Scoping Guidelines were produced by the Work Group in 2018. Since then, Well Operators have collaborated in many workshops to review each other's well design challenges and to select the optimal design for those wells. In 2021 the Work Group identified a requirement to focus on some key themes that would be of benefit to the wider industry. The challenge of drilling long horizontal wells was selected as one of those themes.

A cross-industry workshop was held on 23rd June 2022 with representatives from Well Operators, Regulators, industry groups and the service sector. The topic was split into three themes for discussion by separate groups. The themes were: Narrow margin drilling with & without MPD; Wellbore Stability; and Losses Mitigation Techniques. This aim of this brief document is to record the good practices identified by the discussion groups. Many of these themes apply to all wells, but are considered particularly important for the delivery of horizontal wells.

2. Organisation and Culture

The characteristics of an organisation which can best manage the risks and opportunities of drilling long horizontal wells are likely to be as follows.

- Has a culture where challenge can be given and taken in a respectful way, without fear of retribution.
- Exhibits collaborative behaviours: jointly owns, tests, and understands the data and assumptions being used to base the well design on.
- Takes decisions based on thorough analysis with input from all sides. If one strong personality predominates then poor decisions for the well are likely to also predominate
- Is able to clearly articulate the risks, benefits and costs of various choices and the reasons for the chosen selection.

3. Well Planning

Subject	Considerations

Subsurface assumptions & models	Understand, and test the credibility of, the assumptions in the subsurface models, to ensure a range of plausible scenarios are developed. Consider:
	• Pore Pressure / Fracture Gradient (PPFG) models and the potential range in outcomes.
	  ▪ Plot minimum, most likely, and maximum pore pressures and fracture gradients.
	  ▪ Verify that the range is justified based on offset wells and the anticipated formations.
	  ▪ Initially, use the worst case (narrowest drilling window) to

	establish if the well is drillable.
	
	• Validation of PPFG and WBS models
	  ▪ Offset well pressure data – questions to ask.
	    ▪ Has the pressure data been reviewed, and quality checked, by both Wells and Subsurface personnel?
	    ▪ Has the source of the data been verified?
	    ▪ With fracture pressure data is it clear whether the data is from a Leak Off Test (LOT) or a Formation Integrity Test (FIT)?
	    ▪ Has the LOT/FIT data been, or need to be, reviewed by a specialist? Identifying the appropriate limit can sometimes be difficult, and may have a big impact on the available drilling window.
	  ▪ Interpretation of offset well calliper data - recognise and understand the difference between washout and formation breakout.
	  ▪ Core tests for rock strength etc. Is there evidence of any weakness in the rock which may fail at higher inclinations, such as laminations, bedding planes etc.? These may affect the minimum required mud weight for stability.
	• Presence of faults and fault sealing expectation.
	• Proximity to, and interaction with, other wells in the field e.g. via high permeability zones, faults or fractures.
	• Minimum horizontal stress (σ_{Hmin}) vs. fracture breakdown pressure. Review the rock type and properties, instability and failure mechanisms, likely tolerance to range in pressures and how the rock is expected to behave. Is the minimum fracture gradient based on fractured rock (which has already lost tensile strength and may re-open at fracture opening pressure) or unfractured rock? Offset data using the former may be too low if faults and fractures are not expected.

Well design configuration and contingencies	• Use right-scoping processes to agree the minimum acceptable reservoir hole size - balancing data acquisition, completion, productivity, drill ability and risk aspects. • Design from the bottom-up to include any required contingency casing strings. • Contingency strings and expandable liners. These may increase ECD deeper in the well and require careful consideration of the balance between hole stability, fracture gradient and ECD. Expandable liners are not recommended in unstable formations due to the greater risk of the expansion going wrong and compromising the well. • Have a clear decision tree for implementation of contingencies. • Calibrate drilling and completion torque, drag and hydraulics models with offset wells.
Wellbore stability, mud and mud weight selection	• Consider allowable wellbore breakout damage angle vs. hole inclination. Test varying levels of damage angle e.g. 0°, 60°, and 90°. Is the justification for the chosen allowable damage angle robust? ▪ Swab-down-to and surge-up-to margins should be accounted for

	in the mud weight selection, to reflect the impact of moving drill pipe on wellbore stability. ▪ Consider how the rock is expected to behave and the resulting risks. ▪ Some degree of breakout and cavings may be acceptable. However, this should be calibrated against successful offset wells and should not be ignored. Sustained levels of cavings that persist and do not clean up are usually indicative of continuing rock failure downhole. ▪ Consider whether the rig equipment or the BHA impose any pumping and rotating constraints which may limit the ability to clean the hole. ▪ Consider the sandface completion type e.g. running sand screens and open hole packers will likely have a lower tolerance for breakout. • In selecting the mud weight for optimum stability the preference should be to maintain hole stability and accept some mud losses (as opposed to the other way around) because instability is harder to manage and recover from than treating losses. • Generally, higher mud weight is the solution to wellbore stability issues. However, if the rock contains micro-fractures, then higher mud weight may force mud into the fractures and exacerbate the situation. Specialist ERD consultancy companies may need to be consulted to carry out detailed modelling. • Oil-based mud (OBM) is preferred for long horizontal wells across the industry, usually resulting in a lower required mud weight. • Using OBM, the time-dependent instability of formations is normally much reduced, if the rock does not have a weak-plane failure type.
ECD management and reduction	• Well design choices ▪ Consider a liner and tieback casing vs. long casing string. ▪ Under-ream to increase the hole size. ▪ Increase ID of casing e.g. thinner wall and higher grade, or 10 ¾” vs. 9 5/8” casing. ▪ Consider drillpipe size, balancing ECD, flow rate and hole cleaning requirements. Reducing the drillpipe size will reduce ECD but will increase pump pressures and the required flow rate to clean the hole. ▪ In deepwater, consider controlled mud level techniques with riderless mud recovery systems. • Drilling techniques ▪ If available, use Managed Pressure Drilling equipment to allow reduced static mud weight and ECD. ▪ Maximise the flow by area of drilling assemblies. • Mud ▪ Higher oil content in OBM may reduce ECD. ▪ Marginal changes in mud properties can make the difference in getting to TD without losses. ▪ Validate hydraulics and swab/surge modelling with reference to offset wells.

	▪ In low mud weight scenarios, using hollow glass spheres can reduce the mud weight and ECD even lower. ▪ Micronized barite. Experience suggests that using micronized barite can reduce ECD but potentially at the cost of poorer hole cleaning. The low friction coating reduces the low-end rheology and allows cuttings to fall out of suspension more easily. It is therefore not proposed as an ECD reduction measure. • Cement ▪ Consider light weight cement and/or two-stage cementing. ▪ Avoid cementing in conjunction with external packers, which can increase ECD. ▪ Select casing and liner hangers that have the largest possible hanger flow-by area. If possible, consider wellhead bypass loops to remove restrictions at the casing hanger. ▪ Validate cementing ECD modelling with reference to offset wells.
Lost circulation management	• With the fluids and cement service providers develop a comprehensive loss management plan, from seepage to total losses, for the specific formations anticipated. • If there are partners in the well then collaborate with them to access their knowledge, identify alternatives, and increase the robustness of the LCM strategy. • Conventional LCM and wellbore strengthening materials: consider core analysis, material sizing, compatibility with sand face completion, impact on productivity, and liner hanger flow-by area. • Do not be constrained by the service provider's range of products. • Defluidising pills in fractured reservoirs have been very effective. • Consider deployment methods, especially for cement products. Placement through a stinger is simpler and less prone to failure. However, if placement through the BHA is likely then consider what can and can't be pumped through it, minimise the BHA components, maximise bit nozzle size, and include multi-opening circulating subs in the string. • Consider onshore pre-mixing of high concentration LCM pills to avoid mixing risks offshore, such as clumping. • Adding fibres to cement slurries has been effective in reducing losses during cementing. • Consider drilling with liner or using Floating Mud Cap techniques to get through zones that suffer from catastrophic losses. Drilling blind for a short distance with a liner across a loss zone is relatively straightforward.

4. Well Operations

Subject	Considerations
Operational controls	• Deteriorating hole conditions in horizontal wells can be much less forgiving than in vertical wells. It is important that trends are monitored closely and that changes are reacted to promptly. • Be clear in the programme what will trigger various contingencies. • Include clear decision trees where required e.g. LCM selection vs. loss rate. • Hold onshore and offshore pre-section meetings to review these. • Ensure everyone understands the key issues, their roles, what to look out for, and the action they need to take.
Subsurface Assumptions & Models	• Calibrate the PPFG model with Extended Leak Off Tests. • If using MPD carry out dynamic pore pressure test and dynamic formation integrity tests.
ECD management and reduction	• Include pressure while drilling subs in the BHA to validate the ECD modelling and use for ECD control. ▪ Stage circulation: consider breaking circulation in stages on trips to minimise pressure surges. • Marginal changes in mud properties can make the difference in getting to TD without losses. Pay close attention to optimising mud properties, especially plastic viscosity and low-end rheology. • Consider surge reduction tools e.g. self-filling casing, liner diverter subs, circulation subs etc.
Drilling and tripping practices	• RPM is the primary factor for hole cleaning in horizontal wells. • Clean the hole whilst drilling i.e. use sufficient RPM (>120) and GPM and adjust ROP to suit the hole cleaning ability. • Minimise, and ideally avoid, off-bottom remedial activity. • Connection procedures: agree and follow a standard procedure to prevent pack-offs occurring during connections, and to minimise pressure surges. Typically, this will consist of: 1. Break the mud gel first by establishing very slow rotation. 2. Start increasing the pumps slowly, ramping up over several minutes. 3. Increase rotation slowly being ready to back off rpm and pumps if signs of a packoff occur, particularly as rpm approaches the improved cuttings transport speeds of 80 and 120 rpm. 4. Don't rush. • Ensure shaker hands know what to look for and report in terms of reporting cuttings and cavings and trends at the shakers. • Be aware of the downside of pursuing hole cleaning if the wellbore is unstable and cavings are observed. ▪ In adverse hole conditions the shakers may never truly clean up. Doing more and more work to try and clean the hole can lead to a worsening spiral of increasing wellbore damage creating more material to clean.

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It's important for rig teams to understand the risks of trying to get a perfectly clean the hole when unstable formations are present. Understanding when the hole is clean enough to trip based on the shaker response, and drag, pressure and torque indications will require some trial and error.

Due to the elevated risk of wellbore damage, back-reaming should only be done in exceptional circumstances i.e. where the risks presented by not back-reaming are worse than from doing it. Primary hole cleaning is far preferable.

Ensure that the disadvantages of back-reaming compared to primary hole cleaning are understood by the wellsite team (cuttings beds, pack-offs, high vibration imparting high energy into the formation causing further instability etc.)
If back-reaming is unavoidable, then ensure that sufficient RPM and GPM are used to clean the hole.

Monitor hole cleaning trends.
Monitor torque and drag against the modelled trends and validate the model.
Have a chart of modelled trends vs. various friction factors with the Driller in the doghouse.
Record results using a consistent method at each connection.
If using OBM and capturing cuttings, monitor the volume of cuttings returning vs. expected.
React to any divergence from the trends, and to any observation of cavings at the shakers.
Low levels of sustained cavings may not present an issue while drilling but, if not responded to, can allow significant deterioration in hole condition which subsequently causes issues while tripping. This often leads to further degradation in conditions in the attempt to clean the hole with off bottom activity.

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<tr><td>Completion operations</td><td>

Hole conditioning

Check compatibility of LCM with sand face completion.
If required, condition the drilling fluid to remove Low Gravity Solids and LCM / wellbore strengthening material prior to completion operations.

Completion running

Consider the use of swivels when running completions for drag reduction purposes and account for the complication of non-rotatable equipment.
Monitor liner and screen drag against the modelled trends and validate the model.
React to any divergence from the trends.

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5. Additional Links to NSTA Wells Task Force & OEUK

NSTA NSTF Wells Task Force: https://www.nstauthority.co.uk/about-us/north-sea-transition-forum-task-forces/wells-task-force/

NSTA Wells Insights: https://www.nstauthority.co.uk/news-publications/publications/2021/wells-insight-report/

OEUK Guidelines for the Right-Scoping of Wells: https://oeuk.org.uk/product/https-oeuk-org-uk-wp-content-uploads-2022-09-guidelines-for-the-right-scoping-of-wells-pdf/

Thank you

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- NSTA – North Sea Transition Authority - Wells Task Force
- NZTC – Net Zero Technology Center
- OEUK – Offshore Energies UK
- PetroFrac
- Shell
- Three60 Energy
- TotalEnergies

For further information or to join the Wells Forum groups or NSTA Wells Task Force Sub-groups please contact Keith Wise kwise@oeuk.org.uk