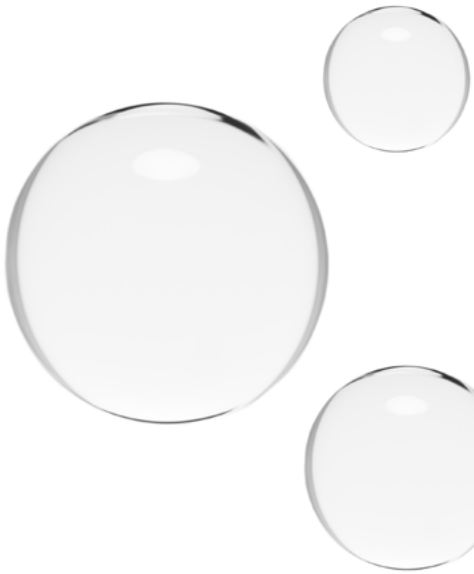
Save Weeks Drilling and Completing

Benchmarking study explains and quantifies exceptional time savings from cesium formate fluids



Sinomine Specialty Fluids

About the study

This publication extracts key findings and conclusions from an extensive investigation by Ridge AS into how well construction fluids and techniques affect North Sea well construction times. The study encompasses:

1) Benchmarking of 89 well constructions, including 56 high-pressure, high-temperature (HPHT) 8.5" reservoir sections.

2) A comparison of well construction times for low-solids formate drilling and overbalanced completion fluids versus oil-based muds (OBMs) drilling and over/underbalanced completion fluids.

Ridge used its experience to select wells based on data comparability within the group. Each data point was thoroughly quality controlled before entering the database.

About Ridge AS

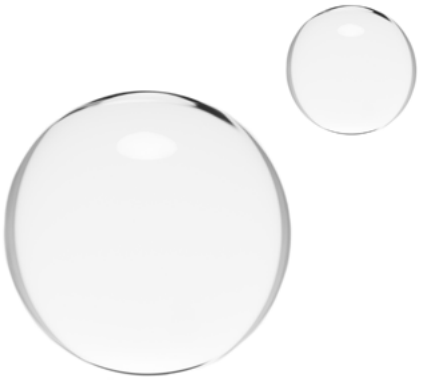
Ridge AS is an independent consulting company headquartered in Norway with one of the largest HPHT well-engineering teams in the country. Ridge provides well and completion support for many ongoing field developments in the North Sea and is Achilles JQS registered.

Key highlights

Formate fluids outperform OBMs to deliver significant rig-time savings.

- **Drilling:** Formate fluids deliver significant increases in rate of penetration (ROP):
  - **74%** higher for HPHT platform wells
  - **38%** higher for HPHT subsea wells
  - **68%** higher for non-HPHT subsea wells
- **Completion:** Formate fluids enable the safest and fastest completion designs, both for openhole (OH) and cased and perforated (C&P) completions
- **Cleanup:** Formate fluids can eliminate the need for expensive and time-consuming well cleanup to rig
- **Seamless operations:** Formate fluids provide seamless transitions between drilling, completion and production phases

In today's challenging oil and gas market, the need to optimise operational efficiency is more important than ever. Reduction of costly rig time, combined with additional early production revenues, can significantly impact the economics of field development projects.



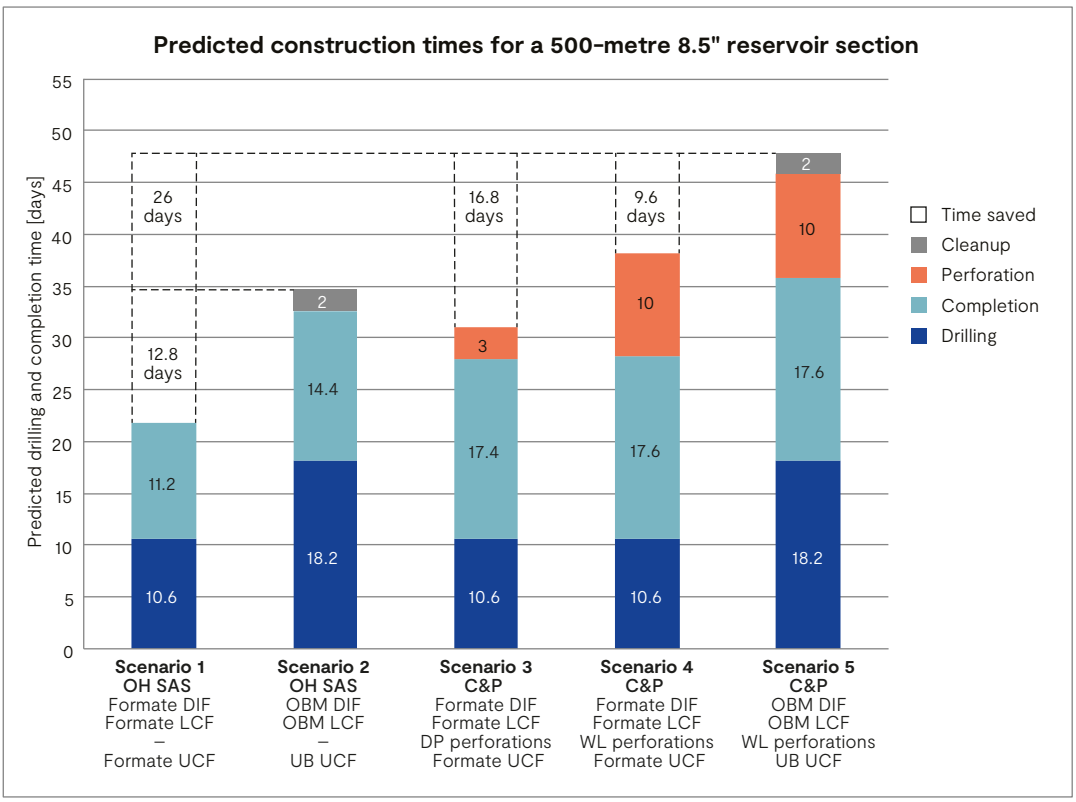
Time use for drilling and completion

The study has delivered an extensive database for predicting well construction times for different completion concepts and fluid choices. Base-case time estimates for five commonly used scenarios have been calculated based on benchmarking performance data.
These are:
Scenario 1: Openhole standalone sand-screen (OH SAS) completion: Formate drill-in fluid with overbalanced (OB) upper completion (UC) in formate brine.
Scenario 2: OH SAS completion: OBM drill-in and lower completion (LC) fluid and underbalanced (UB) upper completion.
Scenario 3: C&P completion: Formate drill-in fluid, perforation on drill pipe (DP), overbalanced upper completion in formate brine.
Scenario 4: C&P completion: Formate drill-in fluid, overbalanced upper completion in formate brine, wireline perforation.
Scenario 5: C&P completion: OBM drill-in fluid, underbalanced upper completion, wireline perforation.

All five scenarios are based on an HPHT platform 8½" 500-metre reservoir section. The perforation times have been set to three days for drill pipe perforation and ten days for WL/CT (wireline/coiled tubing) perforation respectively (study average). Figure 1 depicts time used for the five drilling and completion strategies. The graphic shows that cesium formate fluids in overbalanced operations should deliver the following rig-time savings when compared with OBM drill-in fluid used in conjunction with underbalanced upper completion operations:

- **13 days of rig-time savings** in wells completed in simple OH SAS – see scenario 1 compared to 2
- **17 days of rig-time savings** in cased and perforated (C&P) wells – see scenario 3 compared to 5
- **26 days of rig-time savings** on changing from OBM and C&P completion (underbalanced perforating on WL) to cesium formate drilling and completion fluids in OH SAS – see scenario 1 compared to 5

In the future, findings from this study will be included in a complete time/cost/risk-benefit analysis, which will predict how fluid choice and completion strategy influence total well construction economics.



DIF = Drill-in fluid, LCF = Lower completion fluid, UCF = Upper completion fluid, UB = Under-balanced

Figure 1 Predicted time to drill and complete an 8.5" HPHT reservoir section with five different configurations/fluids. Times are taken from the benchmarking study results as follows:
a) drilled from platform,
b) section length (500 m),
c) average net ROP (47 m/day for formate fluids and 27 m/day for OBM),
d) average completion time (depending on completion type),
e) average drill pipe perforation time (three days),
f) average WL perforation time (ten days),
g) cleanup to rig for OBM (two days).

Where formate fluid is used for drilling-in, lower completions and upper completions, it acts as the primary barrier through all operations.

4 Drilling

As part of its background study, Ridge conducted secondary research into earlier publications on formate fluids and OBMs. It noted that time savings are documented in many reports and technical papers based on the numerous reservoir sections drilled with low-solids cesium and potassium formate brines since the late 1990s. These time savings, although mostly unquantified, relate mainly to lower equivalent circulating densities (ECDs), higher rates of penetration (ROPs), lack of solid-weighting material and low solubility and diffusivity of gas in formate fluids[1), 2), 3), 4), 5), 6), 7), 8)].

Timesaving benefits from drilling with formate fluids

- Higher penetration rates
- Longer bit runs
- Faster tripping through lower ECDs and reduced swab/surge pressures
- Less mud conditioning – up to two bottom-up circulations are required to condition an OBM after a round-trip in an HPHT well
- Fewer wiper trips due to stable mud properties and elimination of sag
- Faster and fewer flow checks
- Better borehole stability through shorter openhole times and wellbore strengthening from osmotic effects
- Less non-productive time (NPT) – better well control, lower stuck-pipe risk, no barite sag or sag-induced kicks
- Instant detection of gas influx cuts circulating time in formate fluids
- Improved hole cleaning. Lower ECDs allow higher pump rates and more turbulent flow, which leads to improved hole cleaning in horizontal wells
- Quicker pump ramp-up due to fragile gels in formate fluids
- Reduced tool failures through better cooling in formate fluids

In one report, based on a study completed by Cambridge Energy Research Associates for Sinomine Specialty Fluids in 2002[9)], drilling time reductions of six to eight days for a normal-length HPHT well and 21 to 23 days for an extended-reach HPHT well were established. Three other studies have quantified significant time savings from formate fluids compared to alternative fluids when drilling shale sections[6), 7), 8), 10)].

Drilling results

High-performance OBM drilling fluid systems, commonly used for narrow-window drilling, were selected as the comparison to low-solids formate drilling fluids. Exploration wells and wells drilled with MPD technology were rejected. Net ROP, defined as drilling progress per day including tripping, circulating, flow checks and conditioning, but excluding time spent on underreaming, coring, logging, waiting on weather (WOW) and NPT, has been calculated and used as the performance indicator.

The Ridge study concludes the following based on results shown in the graphs opposite:

- **74% higher average net ROP with formate fluids** compared to OBM for HPHT platform wells
- **38% higher average net ROP with formate fluids** compared to OBM for HPHT subsea wells
- **68% higher average net ROP with formate fluids** compared to OBM for non-HPHT subsea wells
- HPHT wells drilled with formate drilling fluid in the North Sea have been drilled in accordance with standard HPHT procedures to ensure increased levels of well control incident prevention and preparedness (HPHT mode). The HPHT procedures are typically designed for OBM to mitigate high ECDs, barite sag risk, high gas diffusion and solubility, and high compressibility. Consequently, further time savings can be achieved if HPHT procedures are specifically designed for operations using formate fluids

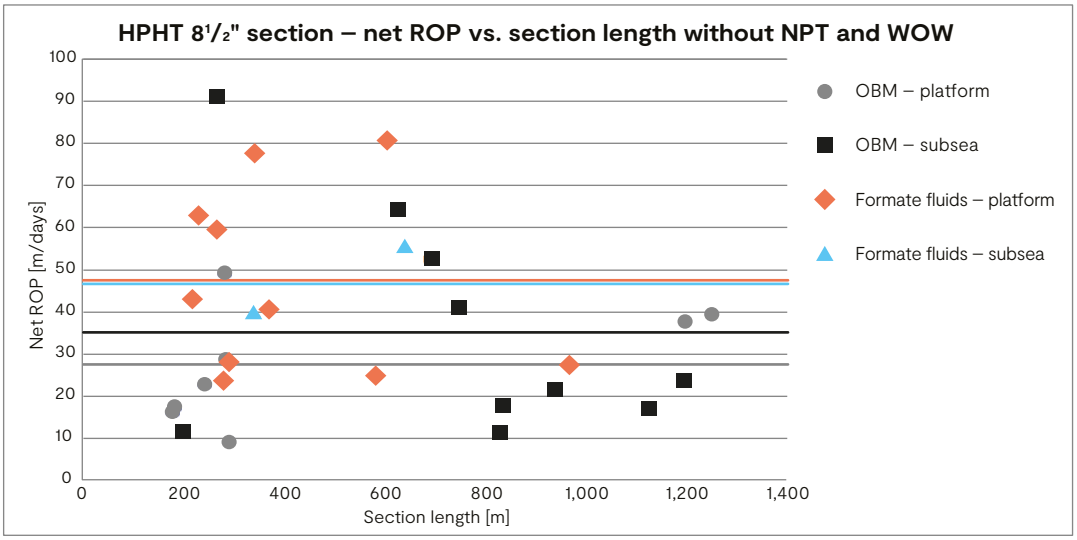


Figure 2 Net ROP versus section length for 8.5" HPHT reservoir sections. NPT and WOW are not taken into account. Horizontal lines represent average net ROP.

The graph shows respective **net ROP increases of 74% and 38%** for platform and subsea wells drilled with formate fluids.

Average net ROP							
Formate fluids [m/day]		OBM [m/day]		Increase in net ROP with formate fluids [m/day]		Increase in net ROP with formate fluids [%]	
◆ Platform	▲ Subsea	● Platform	■ Subsea	Platform	Subsea	Platform	Subsea
47	47	27	34	20	13	74	38

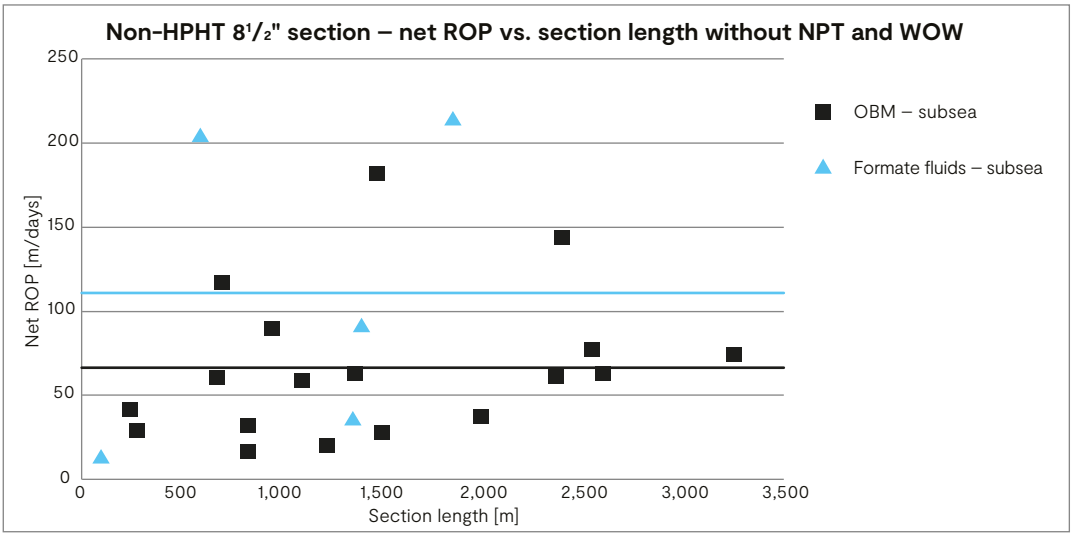


Figure 3 Net ROP versus section length for 8.5" non-HPHT reservoir sections for subsea wells. NPT and WOW are not taken into account. Horizontal lines represent average net ROP.

The graph shows a **net ROP increase of 68%** for non-HPHT wells drilled with formate fluids.

Average net ROP			
▲ Formate fluids [m/day]	■ OBM [m/day]	Increase in net ROP with formate fluids [m/day]	Increase in net ROP with formate fluids [%]
111	66	45	68

Completions

For completion operations, time savings are generally related to how fluids enable more time-efficient completion solutions and processes rather than direct time savings from the fluids.

Enables openhole standalone sand-screen completions

The report states that cesium/potassium formate brines have a long and successful track record for enabling openhole standalone sand-screen (OH SAS) completions in the North Sea. For example, in Statoil's Kvitebjørn and Huldra wells low-solids formate screen-running fluids have successfully facilitated OH SAS completions with highly productive wells as the result[1), 4)]. Kvitebjørn well A-6 was completed in a record time of 12.7 days with an operation factor of 98.1%. This was the fastest HPHT well completion ever performed in the North Sea[1)]. Attempts to install screens using OBM in the Huldra near-HPHT field resulted in a serious kick[4)] and in the Kristin HPHT field it resulted in poor production with the production index ten times lower than expected[11)]. In addition, the Marnock field[12)] saw poor production results from SAS completions installed in OBM. Both the Kristin and Marnock field development teams believe that the poor results were due to mud blocking screens. Although screens have later been installed successfully in OBM[13)], they have very large openings of 610 µm compared to standard 300 µm openings used in the Huldra and Kvitebjørn wells, which makes comparison difficult.

Completion results

From its extensive study of North Sea wells, Ridge concludes the following:

- Formate fluids enable the safest and fastest OH completions for overbalanced upper completions and sand screens
- C&P completion concepts perforated on drill pipe are delivered significantly faster than wells perforated underbalanced on WL/CT, depending on number of WL/CT runs needed
- Cleanup to rig is typically not required when formate fluids are used for lower completions as opposed to an average of two days cleanup time with OBM completions
- Lower ECDs and swab/surge pressures with formate fluids enable faster running of liners and screens
- Instant detection of gas influx cuts circulating time in formate fluids
- Formate fluids enable use of safer and less time-consuming overbalanced completions

Why do formate fluids enable faster completions?

The study shows that low-solids formate fluids enable the fastest types of completions. By investigating the impact of fluid selection on the three completion types used in the North Sea (OH completions, overbalanced perforations and underbalanced perforations), comparative time savings are clear. The comparison is best achieved by studying fluid-choice impact on the following completion steps:

1. Lower completions

- **Openhole lower completions.** Data show that OH completions are significantly faster than C&P completions. Low-solids formate screen-running fluid enables this completion type and is compatible with upper completion clear brines and sand screens
- **Cased and perforated lower completions.** Perforations can be performed two ways:
  - On WL/CT in overbalanced or underbalanced fluid after installation of upper completion and Xmas tree. This is time consuming due to long rig-up time combined with limits of perforation guns per run (typically five to ten runs for a 100-metre pay zone)
  - On drill pipe (DP) in overbalanced fluid before installation of upper completion. This is significantly faster

2. Reservoir isolation and casing clean-out

Middle completion installation, casing clean-out and displacement to completion brine in a well with formate fluids and overbalanced formate brine in the upper completion is intuitively easier than using OBM and underbalanced fluid. Formate fluids provide:

- Quicker casing clean-out due to larger swab/surge margins and less mud conditioning
- Reduced risk of middle completion installation problems (running tool stuck, premature packer setting, packer not sealing, etc.) due to minimum solids
- Reduced risk of debris on top of the pre-installed barrier – a major industry problem
- Less time and cost to displace to completion brine as the well is already filled with formate fluids
- Significant time saving as complex and time-consuming inflow testing of lower primary barrier (liner, plugs) is not required when the completion string is run in overbalanced fluid

3. Upper completion

The selection of brine is largely dependent on the chosen barrier philosophy:

- **Hydrostatic overbalance** – run the upper completion in hydrostatic overbalance, typically with clear brine, such as formate, as the primary barrier and casing liner (or middle completion/barrier assembly) as the secondary barrier.

The well is displaced to underbalanced packer fluid after the tubing hanger seal assembly is set and tested. No inflow test is required

- **Hydrostatic underbalance** – clean out the well and displace to underbalanced packer fluid prior to running the upper completion. The casing/liner (or middle completion) and the blowout preventer (BOP) provide the primary and secondary barriers respectively. An extensive inflow test is required

4. Well cleanup

A well completed in formate fluids does not typically require cleanup to rig and can be flowed directly to the process facility. Wells completed with OBM will produce barite-weighting material, which cannot be handled by the production process system unless a costly system upgrade is in place. Cleanup to rig requires an expensive test package and causes HSE issues with flaring and leakage in temporary flow lines.

Underbalanced completions seem to be commonly accepted. Ridge quotes: *"The level of well control preparedness required to handle a deep barrier leak during an underbalanced completion lies far beyond the normal competency levels that rig crews are certified for by the International Well Control Forum (IWCF). Any subsequent off-bottom kill operation will also be extremely complex and risky. Snubbing or drilling of a relief well may ultimately be required. When it comes to time savings, the main timesaving element is the elimination of the inflow test and the reduced risk of debris on top of the reservoir barrier. Cesium/potassium formate completion fluids allow solids-free overbalanced operations and reduce risk in line with the ALARP (as low as reasonably practicable) principle".*

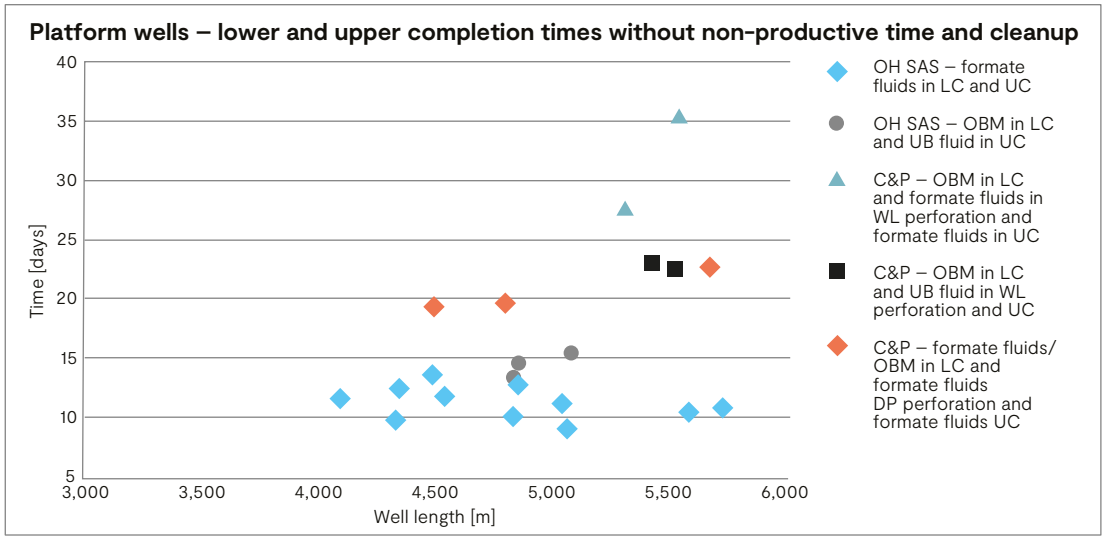


Figure 4 Installation times for lower and upper completions of platform wells as a function of **well length**. All data are taken from platform wells.

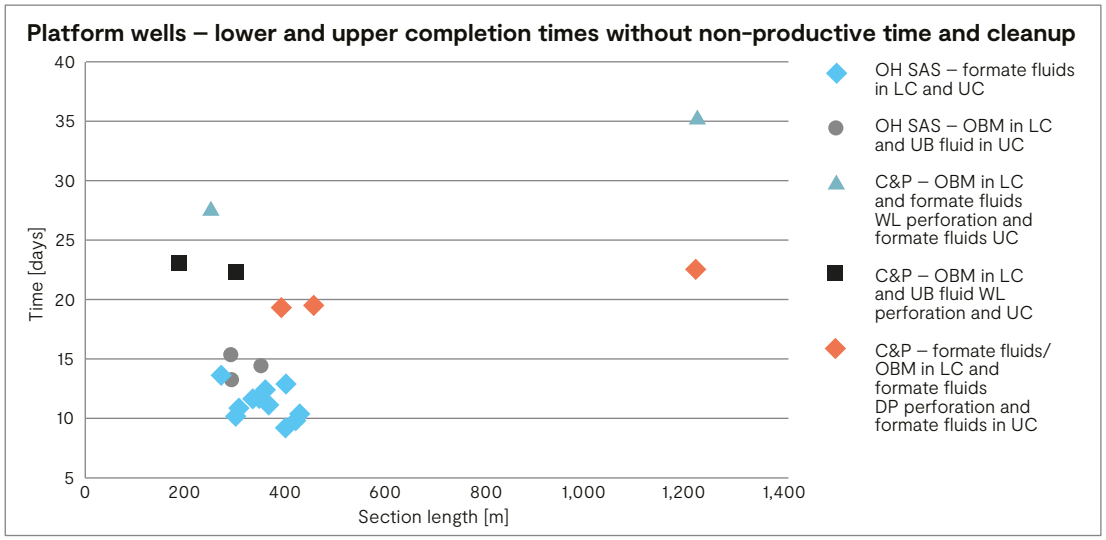


Figure 5 Installation times for lower and upper completions of platform wells as a function of **section length.** All data are taken from platform wells.

Drill and complete smarter

To find out how you can **save weeks** on your next well construction, deliver production revenues faster and work safer, please email **enquire@sinominecorp.com** or contact one of the offices listed below.

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