Technical Benchmarking Report

Effect of formate fluids on rig time in North Sea HPHT and non-HPHT wells

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for Cabot Specialty Fluids

Date	**19/02/2016**
Author	**André Larsen, Ridge AS**
Author	**Jan Tore Hatland, Ridge AS**
Contributor	**Jone Sømme, Ridge AS**
Reviewed	**Lasse Hermansson, Ridge AS**
Accepted	**Christian Busengdal, Cabot Specialty Fluids Ltd.**

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Executive summary

Rig-time analysis is important in establishing the optimum well construction strategy. Cabot Specialty Fluids engaged Ridge AS to perform a high-level realistic rig-time analysis for use of cesium formate as drilling and completion fluid compared to traditional oil-based mud (OBM) and underbalanced or solids-laden completion fluids. The study mainly focuses on HPHT wells.

Realistic rig times for North Sea wells have been collected from several sources, sorted, structured and presented. Eighty-nine wells were included in the study, including 56 HPHT wells. Each data point was thoroughly quality controlled before it was added to the database.

The rig-time study concludes that significant potential value can be gained from drilling and completing HPHT and non-HPHT reservoir sections in formate brines compared to other fluid options. For example, when a 500-metre long 8.5" reservoir section is completed openhole with a standalone sand screen, drilling and completing in cesium/potassium formate fluids rather than drilling and running screens in OBM and installing the upper completion in underbalanced fluid saves around 13 days of rig time.

For cased and perforated wells, about 17 days can be saved by drilling with formate fluid and perforating on drill pipe in overbalanced formate fluid compared to drilling with OBM and perforating underbalanced on wireline. Significantly larger time savings – about 26 days as a best-case example – can be gained by changing from a cased and perforated completion design, drilled with OBM, and with underbalanced perforating and upper completion installation, to an openhole standalone sand screen completion design, drilled and completed entirely with overbalanced formate fluid.

These significant time savings reduce costly rig days and facilitate early production with the revenues that come with it.

It is recommended that cesium/potassium formate fluids should be seriously considered for well construction and field development projects in a proper time-cost-risk analysis that incorporates their positive effects on HSE, risk, early production and completion design.

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1 Introduction

When Benjamin Franklin coined the phrase "time is money" in *Advice to a Young Tradesman* he could very well have been talking about the oil and gas industry. With all-inclusive rig rates up to USD 1 million per day and the low oil price, it is easy to understand how reductions in rig time positively impact the economics of field development projects.

Reducing expensive rig time is a goal for all operators. Drilling and completion strategy, including fluid selection, determines how long a rig is on site. Consequently, Cabot Specialty Fluids asked Ridge AS to analyse the effects of drilling and completion type and fluid use on rig time. Focus is on formate-based drilling and completion fluids in comparison to traditional oil-based muds (OBMs) and underbalanced or solids-laden completion fluids.

Formate brines have been used extensively for a range of well construction applications since the early 1990's. Cabot [1] divides applications for formate brines into four categories:

1. **Enhanced reservoir fluids**
   With solids content below 10% vol and full compatibility with reservoir fluids, cesium formate drilling and completion fluids provide optimum productivity through the entire density range up to 2.3 g/cm^3. The low solids content also allows for excellent screen compatibility in sandface completions.
2. **Performance drilling fluids**
   Low water activity and low solids content provide exceptionally good borehole stability, low equivalent circulating densities (ECDs) and increased ROP (rate of penetration) when drilling through shale. The low ECDs make it suitable for extreme narrow window, extended reach and horizontal drilling.
3. **Clear brine fluids**
   A safe and trouble-free barrier for upper completion installations, suspensions, workovers and interventions.
4. **Special applications**
   A variety of unique properties make formate brines suitable as hydrate dissolution pills, kill pills, stuck pipe release pills and debris-barrier pills.

Cabot considers an understanding of how formate fluids impact the entire well construction operation, including rig time, cost and risk in comparison to conventional fluids, essential for establishing formate fluids' value proposition.

1.1 Rig-time savings from drilling with formate fluids

Based on the many drilling applications with low-solids cesium and potassium formate drill-in fluids since the late 1990s, users of formate fluids have documented significant rig-time savings compared to OBMs [2-10]. One study by Cambridge Energy Research Associates (CERA) [11] quantifies drilling time savings and suggests reductions of six to eight days for an ordinary HPHT well and 21 to 23 days for an extended-reach HPHT well.

Significant rig-time savings have also been quantified and reported when drilling shale sections with formate fluids [7][8][9][12], although time savings included in this study are limited to those from reservoir sections.

Studies [2-9] document that drilling fluids formulated using solids-free formate brines save drilling time through:

- Higher penetration rates
- Longer bit runs
- Faster tripping due to 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 open-hole times and wellbore strengthening from osmotic effects
- 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 lead to improved hole cleaning in horizontal wells
- Quicker pump ramp-up due to fragile gels in formate fluids
- Reduced tool failures as formate fluids provide improved cooling

1.2 Rig-time savings from completing with formate fluids

Rig-time savings from completion applications are more difficult to quantify than those from drilling. This is because one is not always comparing similar operations. Time savings are less related to the actual fluid used than they are to the way certain fluids enable more time-efficient completion solutions and processes.

Statoil has demonstrated in Huldra and Kvitebjørn that low-solids formate screen running fluid is an enabler for openhole 300-µm SAS (standalone sand screen) completions [3][5]. 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 [3].

Attempts to install screens in OBM in the Huldra near-HPHT field resulted in a serious kick [5] and in the Kristin HPHT field it resulted in poor production with the production index (PI) ten times lower than expected [13]. Also the Marnock field had poor production from SAS completions installed in OBM [14]. Both the Kristin and Marnock field development teams believed that the poor results were due to mud blocking of screens. Although screens have later been installed successfully in OBM [15], they have very large openings of 610 µm compared to 300-µm openings used in the Huldra and Kvitebjørn wells, which makes comparison difficult.

2 Methodology

Rig times have been collected from various reliable sources [16][17] and collated. As some wells have been both drilled and completed with cesium/potassium formate and other wells have only been completed with cesium/potassium formate, drilling and completion phases have been analysed separately. However, additional time savings from drilling and completing with the same fluid type are also recognised.

The wells drilled and/or completed with formate fluids included in this study are referred to as 'formate wells' and the fluids as 'formate'. These fluids are all based on blends of cesium and potassium formate brines.

During data selection, the following 'rules' were applied for selecting data points:

- Best knowledge was used to select the data sources
- To use the data for realistic benchmarking (comparing apples with apples) several special, older or extreme cases were disregarded
- Only North Sea data were gathered, with special focus on HPHT fields
- Wells with two reservoir sections (slim liner) in the dataset have been analysed as one section (slim section data removed)
- For non-HPHT wells, reliable and comparable data for OBM have been retrieved from wells that are similar to wells where formate fluids have been used

Although NPT is included in some result tables, it has not been analysed. Consequently, its fluid dependency is unknown. WOW (waiting on weather) has not been included as it is assumed to be fluid independent.

It is assumed that data sources are correct. Detailed risk analysis, time analysis (including NPT) and accompanying estimates using, for example, Monte Carlo simulations, probabilistic models and uncertainty analysis were not performed.

2.1 Drilling data

The OBM reference mud selected for comparison with cesium/potassium formate drilling fluid is the flat rheology drilling fluid system [18][19][20], which is one of the OBM types most commonly used for drilling with narrow window.

For HPHT wells, reliable and comparable drilling data could be retrieved from the Statoil wells. Other wells in the North Sea were also analysed, but are excluded in this report. By focusing only on Statoil wells, comparison is easier as data and execution procedure are similar from well to well and field to field. Exploration wells and wells drilled with MPD technology were rejected. Underreaming, logging and coring times were excluded from the study as these are fluid independent.

Net ROP has been used as the performance indicator for drilling. The net ROP corresponds to the industry's perception of the 'old' hole-making process, including tripping, circulating, flow checks and conditioning, but excluding time spent on underreaming, coring, logging, WOW and NPT (if not specified).

2.2 Completion data

Completion time analyses are more complex as there are several sub-operations included in the data. Four main categories have been derived for HPHT wells and four for non-HPHT wells. The categories are defined according to operator (Statoil or other (UK)), lower completion type, fluid type in lower completion, fluid type in upper completion and well type (subsea or platform).

Completion data were split into the following operational phases:

1. Lower completion – time used for lower completion operations
   a. Open hole (OH)
      i. Standalone screens (SAS).
      ii. Slotted liner (S).
   b. Cased & perforated (C&P)
      i. Wireline (WL) and coil tubing (CT). These are performed in hydrostatic underbalance after the well is completed.
      ii. Drill pipe (DP) conveyed perforation. These are performed in hydrostatic overbalance after cementing of liner and casing clean-out.
2. Upper completion – time used for upper completion operations.
3. Perforation (only valid for C&P wells) – time used for perforation operations. These have been analysed separately as they are well specific.
4. Christmas tree (XT) installation – time used for XT/horizontal XT/vertical XT installation. These have not been analysed as they are well specific and fluid independent.
5. Clean-up – time used for well clean-up to rig. These have been analysed separately as operations are well and reservoir specific.
6. Other – time used for other operations such as cased-hole logging, tie-back installation, BOP modifications, well flowing, additional sampling, etc. These have not been analysed as they are well specific and fluid independent.
7. There are also suspension and subsea movement (drift-off) operations included in the well database. These are excluded from the study as they are independent of the fluid system.

3 Results of drilling data analyses for HPHT and non-HPHT wells

For the drilling part of this study, scope of work was divided into two categories:

1. Rig-time savings from HPHT reservoir drilling.
2. Rig-time savings from non-HPHT reservoir drilling.

The authors of this report have quantified rig-time savings for each of these groups of wells. As mentioned previously, the drilling analyses reported here are limited to Statoil wells.

Results of the data analyses are summarised in **Table 1** below. The table shows average net ROP, associated NPT and number of platform and subsea wells drilled with OBM and cesium/potassium formate.

Table 1 Summary table – 8½" HPHT reservoir section.

Case	Fluid system	Number of wells	Average NPT (days)[1)]	Average net ROP (m/day)
HPHT, platform	OBM	8	3	27
HPHT, platform	Formate	10	2	47
HPHT, subsea	OBM	10	8	34
HPHT, subsea	Formate	2	12	47
Non-HPHT, subsea	OBM	18	7	66
Non-HPHT, subsea	Formate	5	4	111

1) NPT has not been analysed, so it is unknown to what extent it is fluid dependent.

The main uncertainties in the drilling analyses are:

- Lack of offset data for subsea wells drilled with formate could possibly give an incorrect image of expected times for this well category
- Average net ROP values (directly derived from the benchmarking data) have been used for comparing performance. Detailed statistical analysis has not been performed to identify the uncertainty range of these numbers. As operators have different time-estimation policies, their expected performance may differ from the average number used in these analyses
- Due to limited datasets for some categories and associated range variations, the uncertainty range is not uniform throughout the datasets. Uncertainty ranges should therefore be analysed using the operator's policy

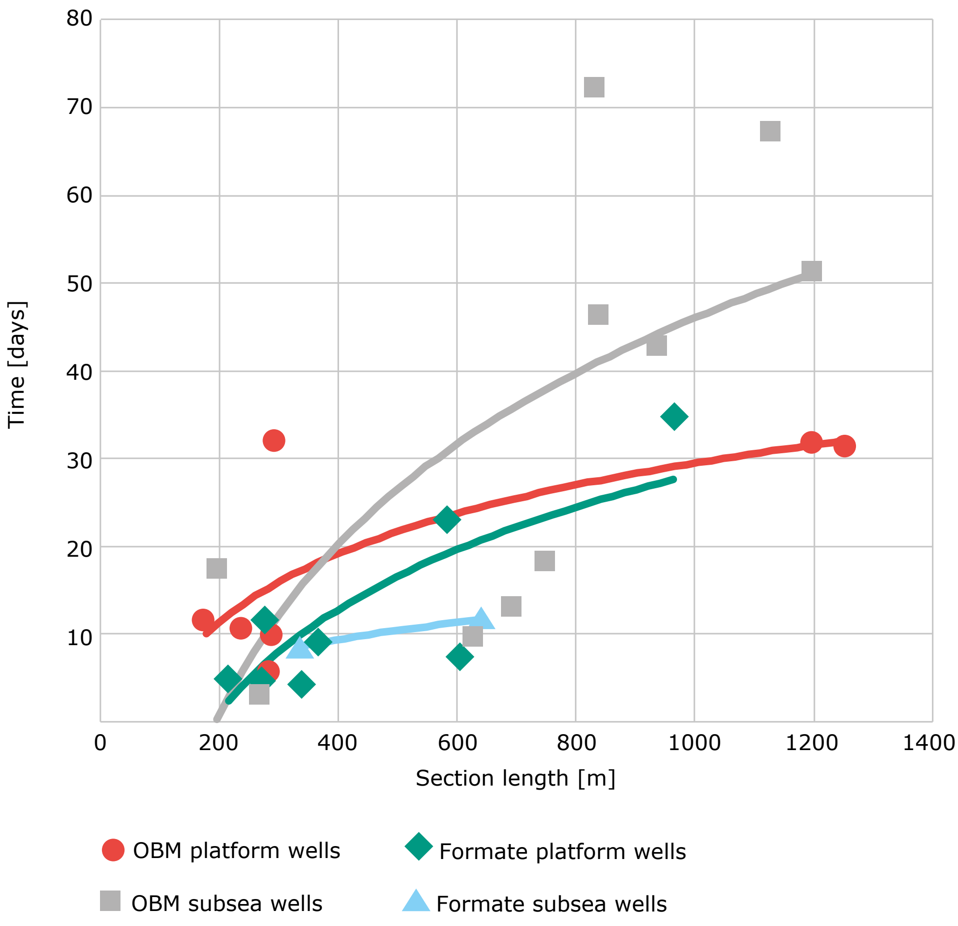
Mud weight has not been considered in the benchmarking study. However, when analysing the non-HPHT category the authors noticed that wells with lowest mud weight were generally those with highest net ROP, which mainly applies to OBM wells. This means that non-HPHT wells are less suitable for benchmarking than HPHT wells.

3.1 Reservoir drilling data analyses for HPHT wells

Figure 1 displays drilling times versus section length for the 8½" reservoir sections in the four well categories defined in Table 1.

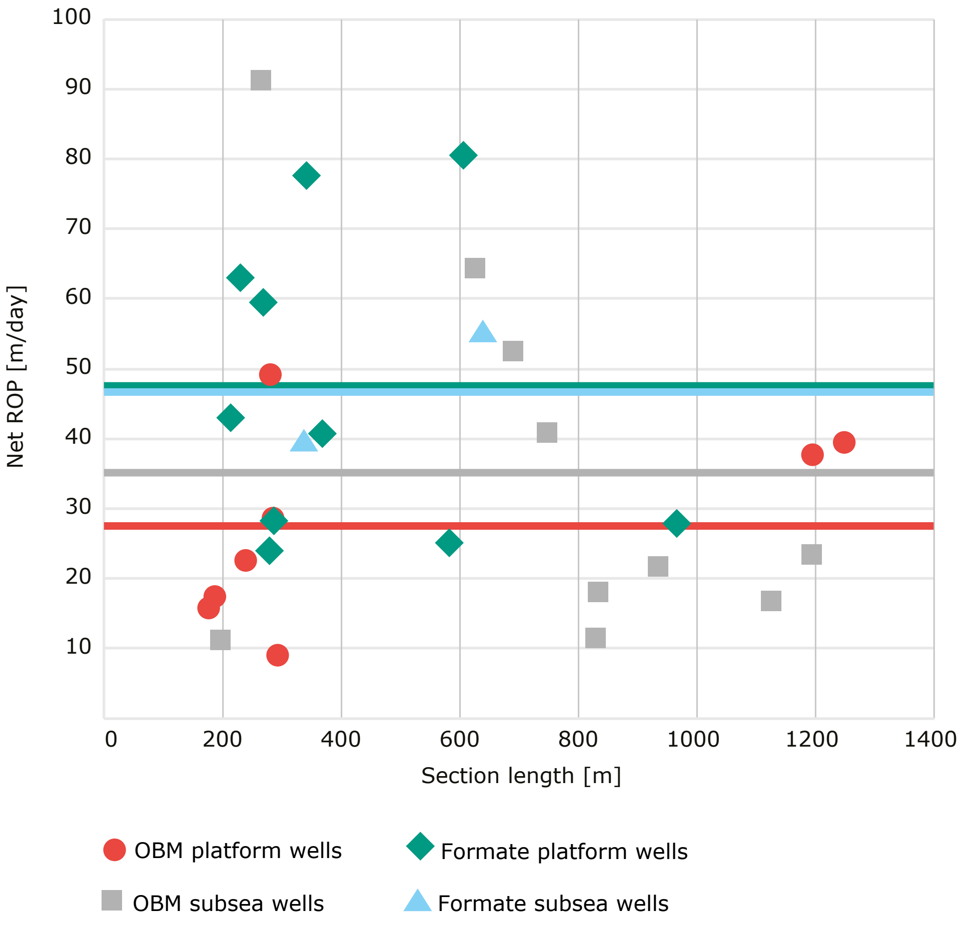
Very few data points exist for the category of subsea wells drilled with formate (see blue markers and trend lines) in the available benchmarking dataset. This can give an inaccurate prediction of performance.

Figure 1 Drilling time versus section length without NPT and WOW for Statoil HPHT wells (8½" section).



Average reservoir section length varies from 414 metres to 745 metres depending on well category. As can be seen from Figure 1, section length also varies significantly within each category. Therefore, as an alternative to the drilling time versus section length plot, **Figure 2** shows drilling times through a more generic display by converting them to net ROP, which is a commonly used drilling performance indicator. This gives a distinct indication of fluid system performance as results are independent of section length.

Figure 2 Net ROP (m/day) versus section length without NPT and WOW for Statoil HPHT wells (8½" section).



The calculated net ROP values are listed in **Table 2**. By using these values or the complete dataset, each operator can use their own policy to calculate time and cost estimates.

From the net ROP values shown in Figure 2, it is evident that wells drilled with formate are drilled significantly faster than wells drilled with conventional oil-based fluid systems. Based on net ROP benchmarking data, it can be observed that wells drilled with formate are drilled approximately 74 and 38 percent faster than wells drilled with OBM for platform and subsea wells respectively.

Table 2 Summary table showing net ROP for HPHT wells, excluding time used for logging, coring and WOW (8½" section).

Average net ROP							
Cesium/potassium formate [m/day]		OBM [m/day]		Increase in net ROP with cesium/ potassium formate [m/day]		Increase in net ROP with cesium/ potassium formate [%]	
Platform	Subsea	Platform	Subsea	Platform	Subsea	Platform	Subsea
47	47	27	34	20	13	74	38

The following is observed from these graphs:

- HPHT platform wells: Cesium/potassium formate drilled with 74% higher average net ROP than OBM
- HPHT subsea wells: Cesium/potassium formate drilled with 38% higher average net ROP than OBM
- Based on these data analyses, it seems reasonable to conclude that drilling 8½" HPHT reservoir sections with low-solids cesium and potassium formate fluids gives time and potential cost benefits.

3.2 Reservoir drilling data analyses for non-HPHT wells

Even if wells or reservoirs are not categorised as HPHT, the character of the reservoir can still make them suited for cesium/potassium formate applications. Many of the non-HPHT reservoirs are localised moderately close to the HPHT reservoirs included in this study and therefore have similar characteristics. Consequently, these have been included in the study.

Figures 3 and 4 display drilling performance for the two categories of non-HPHT wells defined in Table 1. Figure 3 illustrates time spent on drilling the reservoir section, while Figure 4 illustrates net ROP. Both are shown as a function of section length.

By comparing Figures 3 and 4 with Figures 1 and 2, it seems reasonable to conclude that non-HPHT wells can be drilled faster than HPHT wells. The average net ROP for the two well categories are summarised in **Table 3**.

Table 3 **Summary table showing net ROP for non-HPHT subsea wells, excluding time used for logging, coring and WOW (8½" section).**

Average net ROP			
Cesium/potassium formate [m/day]	OBM [m/day]	Increase in net ROP with cesium/ potassium formate [m/day]	Increase in net ROP with cesium/ potassium formate [%]
111	66	45	68

Figure 3 **Drilling time versus section length without NPT and WOW for all non-HPHT subsea wells (8½" section).**

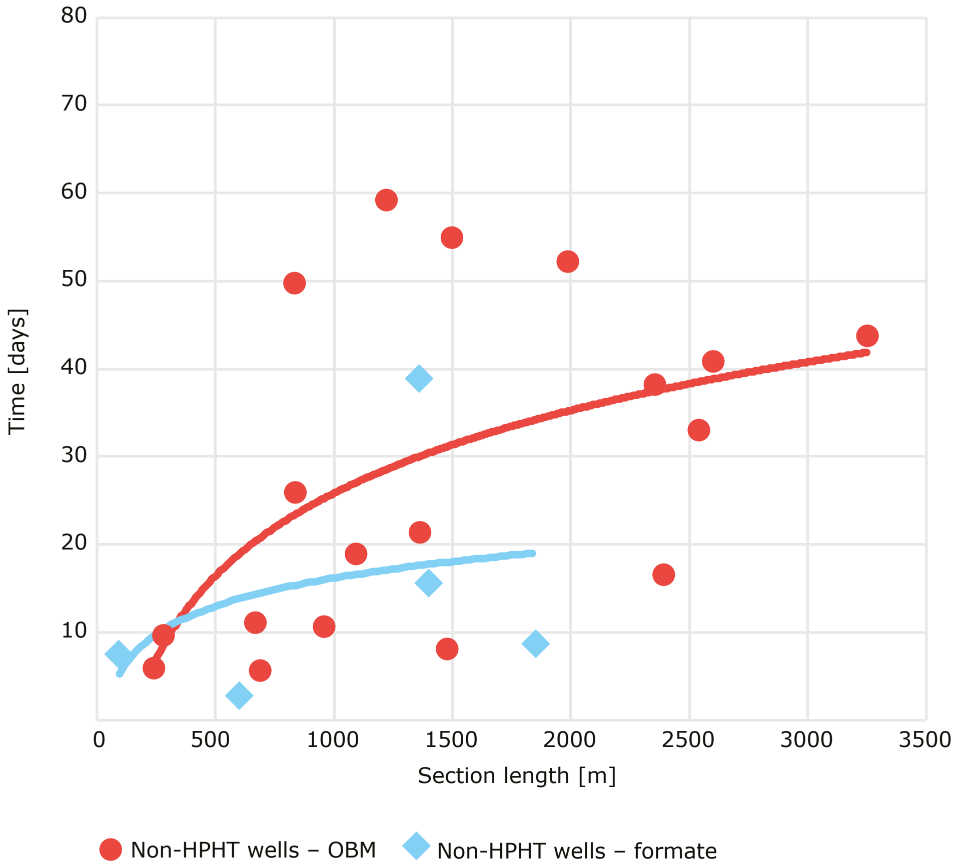
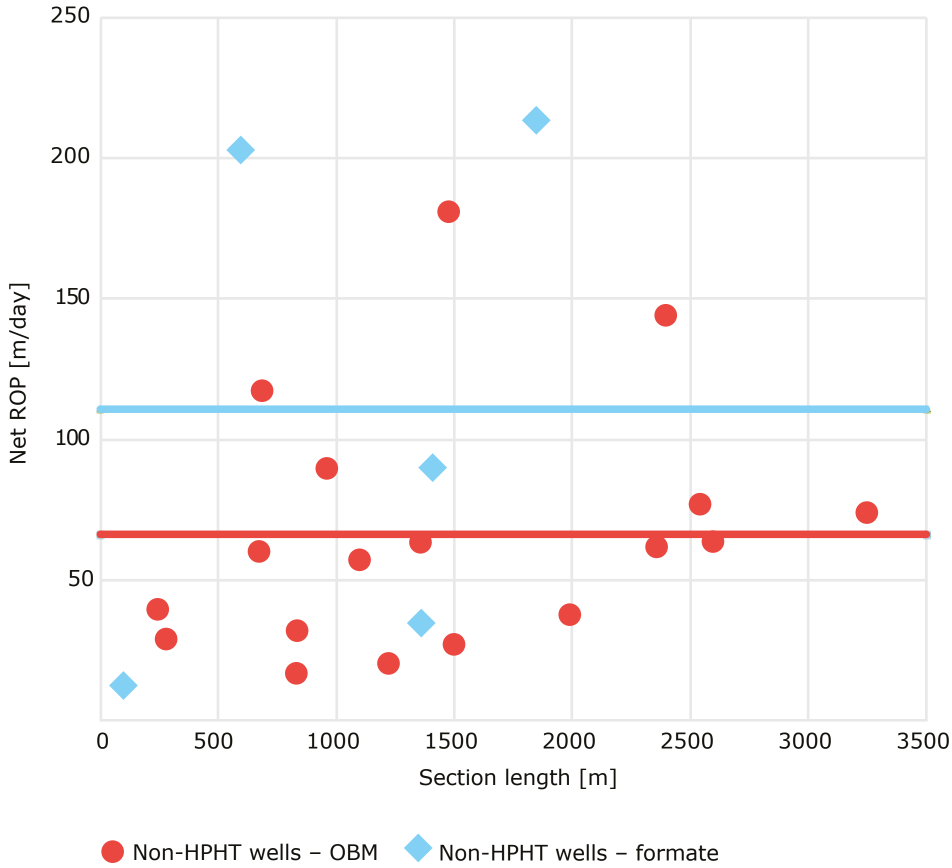


Figure 4 **Net ROP (m/day) versus section length without NPT and WOW for non-HPHT subsea wells (8½" section).**



The following is observed from these graphs:

- Non-HPHT wells: Cesium/potassium formate drilled with 68% higher average net ROP than OBM
- Drilling non-HPHT wells with cesium/potassium formate seems to improve time and potential cost benefits

3.3 Drilling time savings – discussion

A range of different reasons for drilling time savings are noted in the literature (see list in section 1.1). These time savings have mainly been the result of lower ECDs, higher ROP, lack of solid weighting material, and low solubility and diffusivity of gas in formate fluids. Drilling the reservoir section with OBM is more likely far more time consuming than drilling with formate fluid due to well control factors, such as high gas diffusion rates in OBM and the need for circulating and checking gas content in mud more often while drilling and POOH (short trips). Gas fingerprinting is also a challenge with OBM.

Due to improved well control, lower stuck-pipe risk and elimination of sag-induced kicks, formate drilling fluids are also expected to cause less NPT. In this study, no attempt was made to analyse NPT values and extract the portion that is fluid related, as the dataset is too limited.

HPHT wells are drilled in accordance with operators' HPHT procedures (HPHT mode), which ensure increased levels of well control incident prevention and preparedness. In order to guarantee that the same company-specific HPHT procedures apply to all wells, it was decided to only include Statoil HPHT wells in the drilling dataset. It should be noted, however, that Statoil stated that its HPHT procedures were made more efficient in the last couple of years, something that favours some OBM drilling times included in this study (Gudrun and Valemon wells).

All Statoil HPHT wells drilled with cesium/potassium formate drilling fluid in the North Sea have been drilled in accordance with old HPHT procedures. 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.**

4 Results of completion data analyses for HPHT and non-HPHT wells

To extract the key differentiating factors, each well was sorted into one of four main categories for HPHT or one of four main categories for non-HPHT as listed in Tables 4 and 5 below. The tables show the number of wells in each category, completion style and fluid type. The study includes three additional categories for subsea and other (non-Statoil) wells. These categories are not included in the results as datasets are too limited to draw any conclusions.

Results from the well clean-up analyses show an average clean-up time of two days for OBM. Formate fluids' dataset includes no clean-up to rig.

The perforation time analyses give the following results:

- HPHT DP perforation time is generally lower for platform wells than for subsea wells
- Time spent on WL/CT perforation is generally much higher than time spent on DP perforation. This is typically due to long rig-up times and perforation gun length restrictions
- HPHT wells take longer to perforate than non-HPHT wells

Table 4 HPHT platform wells completion categories.

<table>
<tr><th>No.</th><th>Category</th><th>Sub-category</th><th>LC style</th><th>LC fluid</th><th>Perf. fluid</th><th>UC fluid</th><th>No. of wells</th></tr>
<tr><td>1</td><td>Statoil wells with formate in LC and UC</td><td>N/A</td><td>OH SAS</td><td>Formate</td><td>N/A</td><td>Formate</td><td>11</td></tr>
<tr><td>2</td><td>Statoil wells with OBM in LC and UB fluid in UC</td><td>N/A</td><td>OH SAS</td><td>OBM</td><td>N/A</td><td>UB fluid</td><td>3</td></tr>
<tr><td rowspan="3">3</td><td rowspan="3">Wells with formate/ OBM in LC and various fluids [1] in WL/CT perforation and UC</td><td>a) Statoil wells with formate WL perforation and formate in UC</td><td>C&P WL</td><td>Formate</td><td>Formate</td><td>Formate</td><td>2</td></tr>
<tr><td>b) Statoil wells with UB fluid in WL perforation and UC</td><td>C&P WL</td><td rowspan="2">OBM</td><td>UB fluid</td><td>UB fluid</td><td>2</td></tr>
<tr><td>c) Other wells with UB fluid in CT/WL perforation and UC</td><td>C&P CT/WL</td><td>UB fluid</td><td>UB fluid</td><td>7</td></tr>
<tr><td>4</td><td>Statoil wells with formate/OBM in LC and formate in DP perforation and UC</td><td>N/A</td><td>C&P DP</td><td>OBM/ formate</td><td>Formate</td><td>Formate</td><td>3</td></tr>
</table>

1) Various fluids include OBM/seawater/formate, i.e. both in overbalanced and underbalanced fluids.

Table 5 Main non-HPHT subsea wells completion categories.

No.	Category	Lower completion style	LC fluid	Perf. fluid	UC fluid	No. of wells
1	Wells with formate in LC and UC	OH SAS	Formate	N/A	Formate	3
2	Wells with OBM in LC and any OB brine[1)] in UC	OH SAS	OBM	N/A	OB brine	7
3	Wells with formate in LC and formate in DP perforation and UC	C&P DP	Formate	Formate	Formate	3
4	Wells with OBM in LC and formate/OBM in DP perforation and any OB brine [1)] in UC	C&P DP	OBM	Formate/ OBM	OB brine	6

1) 'Any OB brine' includes formate and other overbalanced brines.

The main uncertainties in the completion analyses are:

- Average completion time values (directly derived from the benchmarking data) have been used for comparing performance. Detailed statistical analysis has not been performed to identify the uncertainty range of these numbers. As operators have different time-estimation policies from one another, expected performance may differ from the average number used in these analyses
- The uncertainty range is not the same for all datasets, as range and number of wells differ. The uncertainty range should be analysed using operator's policy

4.1 Completion data analyses for HPHT wells

The HPHT completion data analysis for upper and lower completions is summarised in **Figures 5 to 7** and **Table 6** for the categories listed in **Table 4**. Note that XT installation and other operations are not included in these numbers.

Table 6 HPHT platform wells – time summary for upper and lower completions. Categories 1 to 4 are defined in Table 4.

No.	Category	Completion style	Perforation time excluded			Perforation time included		
			Total time without NPT [days]	NPT [days] [1)]	Total time with NPT [days]	Total time without NPT [days]	NPT [days] [1)]	Total time with NPT [days]
1	Statoil wells with formate in LC and UC	OH SAS	**11.2**	2.8	14.0	**N/A**	N/A	N/A
2	Statoil wells with OBM in LC and UB fluid in UC	OH SAS	**14.4**	1.6	16.0	**N/A**	N/A	N/A
3	Wells with formate/ OBM in LC and various fluids [2)] in WL/CT perforation and UC	C&P CT/WL	**17.6**	2.3	19.9	**25.5**	3.4	28.8
4	Statoil wells with formate/OBM in LC and formate in DP perforation and UC	C&P DP	**17.4**	13.4	30.8	**20.5**	13.4	33.9

1) NPT has not been analysed, so it is unknown to what extent it is fluid dependent.
2) Various fluids include OBM/seawater/formate, i.e. both overbalanced and underbalanced fluids.

Figure 5 Total time used for lower and upper completion of HPHT platform wells as a function of well length. NPT, WOW and perforation times are excluded. The categories 1 to 4 are taken from Table 4.

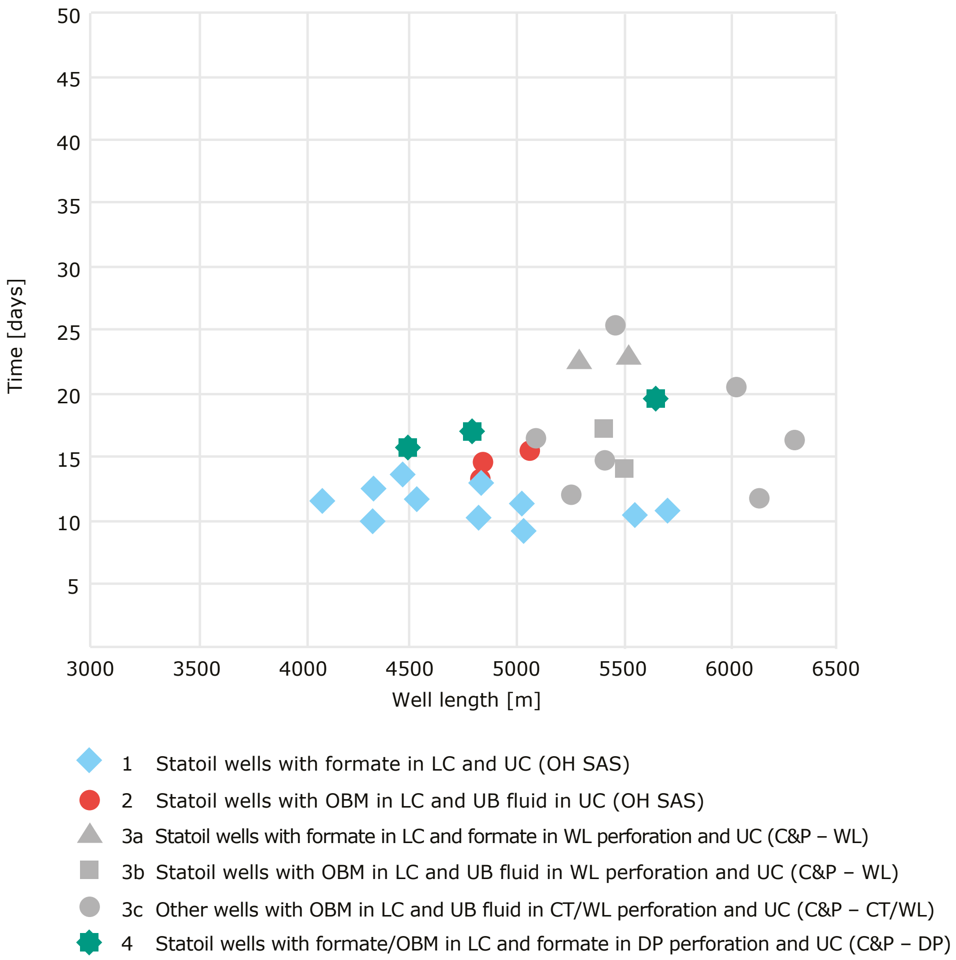


Figure 6 Total time used for lower and upper completion of HPHT platform wells as a function of well length. NPT and WOW are excluded. Perforation times are included. The categories 1 to 4 are taken from Table 4.

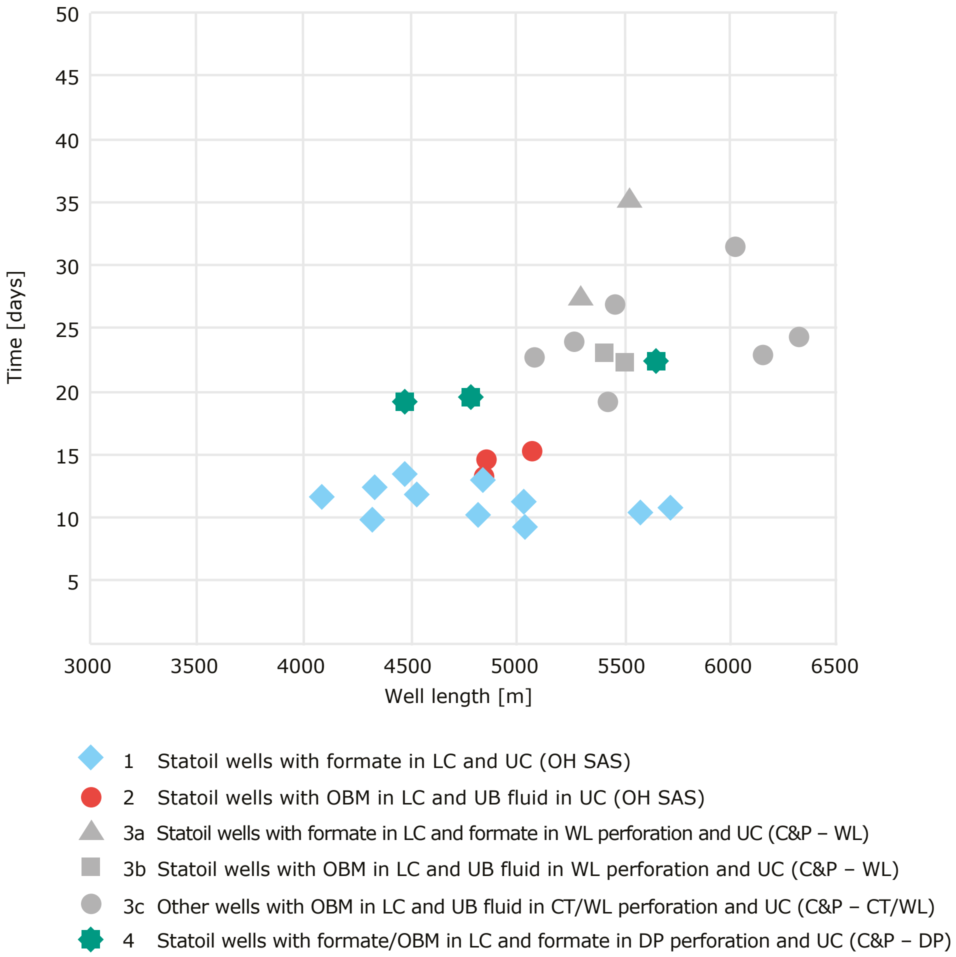
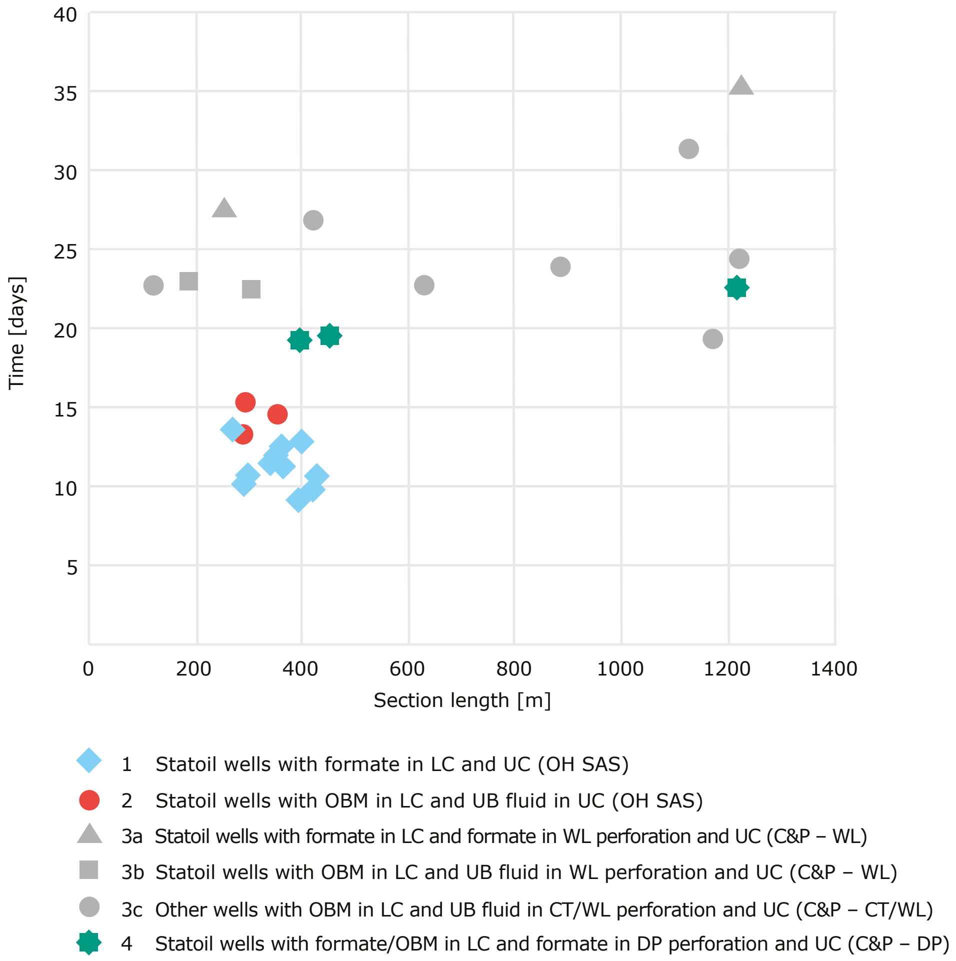


Figure 7 **Total time used for lower and upper completion of HPHT platform wells as a function of section length. NPT and WOW are excluded. Perforation times are included. The categories 1 to 4 are taken from Table 4.**



From the completion time analysis for HPHT platform wells the following conclusions are suggested:

- OH completion concepts are delivered significantly faster than C&P completion concepts
- Wells completed in OH SAS are delivered fastest with cesium/potassium formate fluids. Reasons could be:
  - Less circulating for gas and conditioning purposes
  - Less circulating for well clean-out as wells were drilled with formate drill-in fluid
  - Faster screen-running speeds
  - No inflow testing required in formate wells due to hydrostatic overbalance

- C&P completion concepts with drill pipe perforation are delivered significantly faster than C&P completion concepts with WL/CT post-completion perforation
- The data do not reveal any significant difference in delivery times between C&P wells (DP/WL/CT) with OBM and formate fluids (based on limited dataset)

4.2 Completion data analyses for non-HPHT wells

The non-HPHT completion data analysis for upper and lower completions is summarised in **Table 7, Figure 8** and **Figure 9** for the categories listed in Table 5. Note that WOW, XT installation and other operations are not included in these numbers.

Table 7 Non-HPHT subsea wells – completion time summary (average times). Categories 1 to 4 are defined in Table 5.

No.	Category	Completion style	Perforation time excluded			Perforation time included		
			Total time without NPT [days]	NPT [days]	Total time with NPT [days]	Total time without NPT [days]	NPT [days]	Total time with NPT [days]
1	Wells with formate in LC and UC	OH SAS	**9.6**	4.3	14.0	**N/A**	N/A	N/A
2	Wells with OBM in LC and any OB brine[1)] in UC	OH SAS	**9.2**	4.6	13.8	**N/A**	N/A	N/A
3	Wells with formate in LC and formate in DP perforation and UC	C&P – DP	**14.2**	9.6	23.8	**24.9**	7.6	32.4
4	Wells with OBM in LC and formate/OBM in DP perforation and any OB brine [1)] in UC	C&P – DP	**33.2**	7.5	40.6	**51.2**	22.1	73.4

1) 'Any OB brine' includes formate and other overbalanced brines.

Figure 8 **Total lower and upper completion times for non-HPHT subsea wells as a function of well length. NPT and WOW are excluded. Perforation times are included. The categories 1 to 4 are defined in Table 5.**

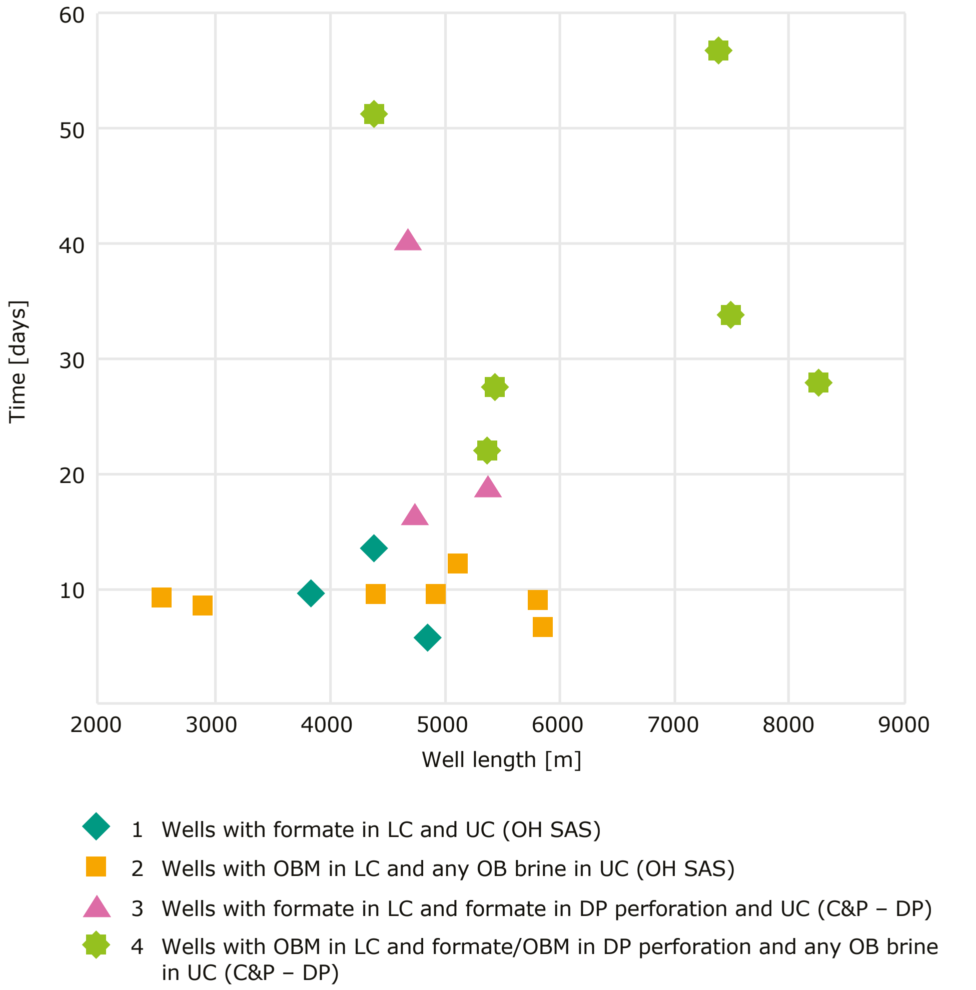
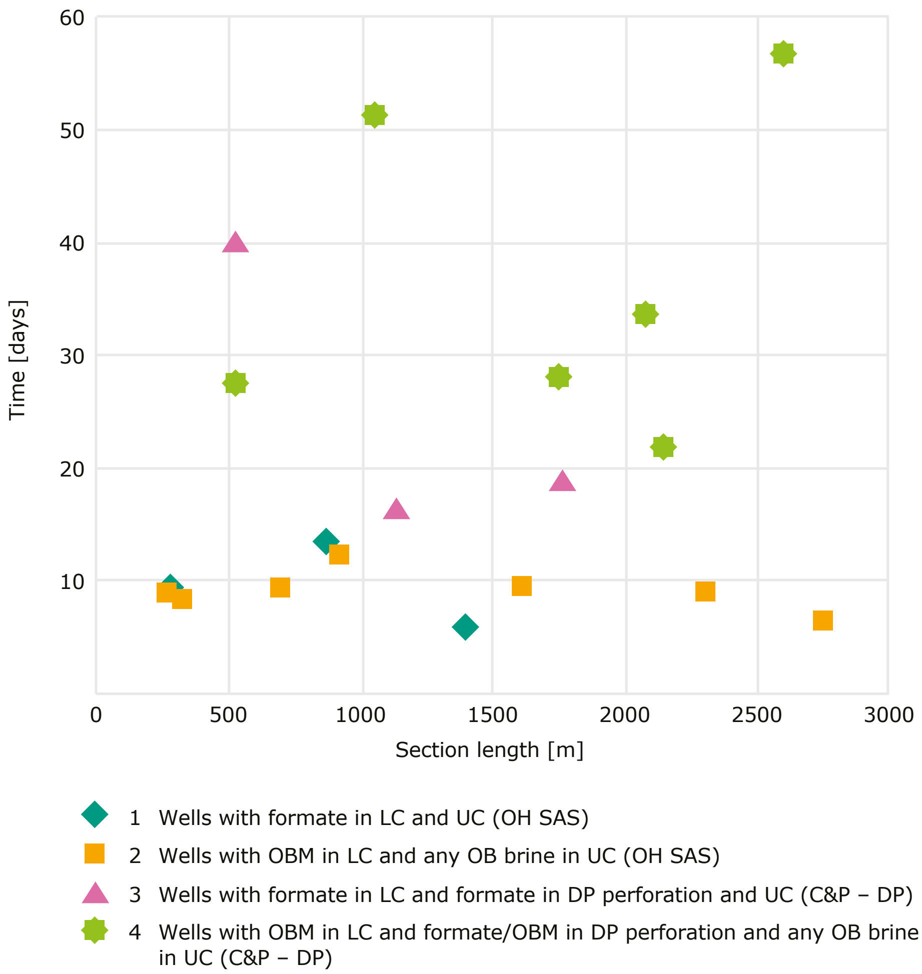


Figure 9 **Total lower and upper completion times for non-HPHT subsea wells versus section length. NPT and WOW are excluded. Perforation times are included. The categories 1 to 4 are taken from Table 5.**



From completion time analysis for non-HPHT subsea wells, the following observations are made:

- OH completion concepts are delivered significantly faster than C&P completion concepts
- C&P concepts are completed faster when the liner is installed in formate rather than OBM
- Lack of offset subsea wells with lower completion using formate could possibly give an incorrect image of expected completion times for this well category

4.3 Completion time savings – discussion

From the results presented in Sections 4.1 and 4.2 it becomes clear that the time it takes to complete a well is more dependent on the completion type than on the actual fluid system. The study shows that low-solids formate fluids are enablers for the fastest types of completions. By investigating the impact fluid selection has on the three main groups of completions used in the North Sea (OH lower completion, overbalanced perforation and underbalanced perforation) time savings become more obvious. Studying how fluid choice affects the following completion steps is the easiest way of investigating fluid impact:

1. Lower completion

Open-hole (OH) lower completions. This completion concept is common in the Norwegian North Sea. The data proves that OH completions are significantly faster than C&P completions. Low-solids formate screen-running fluid is an enabler for this type of completion and is compatible with clear-brine formate UC fluid.

Cased and perforated (C&P) lower completions. This completion concept is the base case in the UK North Sea. In most fields, sand control has not been a focus and perforating has been performed on coil tubing (CT) or wireline (WL) in underbalance after the well was completed. This is significantly more time consuming than perforating in overbalance on drill pipe before installing the upper completion and XT. This is due to the long rig-up time for CT/WL operations combined with the limit of perforation guns per run. Typically, this results in between five and ten runs for a 100-metre pay section. Overbalanced perforation on pipe in OBM has been performed successfully on Kristin and some other fields, and in cesium/potassium formate perforation pills on Kvitebjørn and Gudrun.

2. Reservoir isolation and casing clean-out

Installation of the middle completion, casing clean-out and displacement to completion brine in a well with formate fluids combined with overbalanced formate brine in the upper completion is intuitively less complex than using OBM and underbalanced fluid in the upper completion for the same operation. The following advantages have been identified from using formate fluids:

- Faster casing clean-out due to larger swab/surge margins and less mud conditioning
- Reduced risk of middle completion installation issues as fluid has minimum debris. For example, there were several problems on Morvin with stuck running tools and packers not sealing
- Reduced risk of debris on top of the pre-installed barrier. This is a major industry problem
- Less cost and time to displace to completion brine as the well is already filled with formate fluids
- Significant time savings as no inflow test for the middle completion is required when the completion string is run in overbalance. Inflow testing HPHT wells is complex and time consuming

- Lower risk of premature packer setting and leakages of packer elements due to cleaner well conditions

3. Upper completion

It is not possible to say that running the completion in overbalanced fluid is faster than running it in underbalanced fluid without including the operations required to make the well ready for the upper completion. These operations are typically casing clean-out, inflow testing, running the middle completion or plugs and displacing the well to completion fluid. These operations are dependent on the barrier philosophies selected for the project, which also provide the key case for fluid selection. The two barrier philosophies are:

Hydrostatic overbalance. This method uses formate fluid as the primary barrier and the 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. This was the standard solution on Kvitebjørn and Huldra and, as mentioned above, requires no inflow test.

Hydrostatic underbalance. This method uses the casing/liner (or middle completion) and the BOP as primary and secondary barriers respectively. The well is cleaned-out and displaced to underbalanced packer fluid prior to running the upper completion. This is the standard UK solution and requires an extensive inflow test.

Underbalanced completions seem to be accepted in several North Sea HPHT operations to save cost, but the well control risk involved must be fully understood. It is fair to say, based on the authors' knowledge, that the level of well control preparedness required to handle a deep-barrier leak during an underbalanced completion lays far beyond normal competency levels that rig crews are certified for by the International Well Control Forum (IWCF). Any subsequent off-bottom kill operation is also 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.

4. Well clean-up and production

A well completed in formate fluids does not typically require clean-up to rig and is flowed directly to the process facility. This was achieved routinely on Kvitebjørn, both for C&P and OH completions. 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. In addition, there are HSE issues with flaring and leakage in temporary flow lines.

5 Overall time-savings example

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 drilling and completion scenarios (see **Table 8**) have been calculated based on the benchmarking performance data.

Table 8 Base-case time estimates for five commonly used drilling and completion scenarios.

Scenario	Comp. type	Drill-in fluid	Lower completion fluid	Perforation fluid	Perforation type	Upper completion fluid
1	OH SAS	Formate	Formate	–	–	Formate
2	OH SAS	OBM	OBM	–	–	UB brine
3	C&P	Formate	Formate	Formate	Drill pipe	Formate
4	C&P	Formate	Formate	Formate	Wireline	Formate
5	C&P	OBM	OBM	UB brine	Wireline	UB brine

The following assumptions have been made for all scenarios:

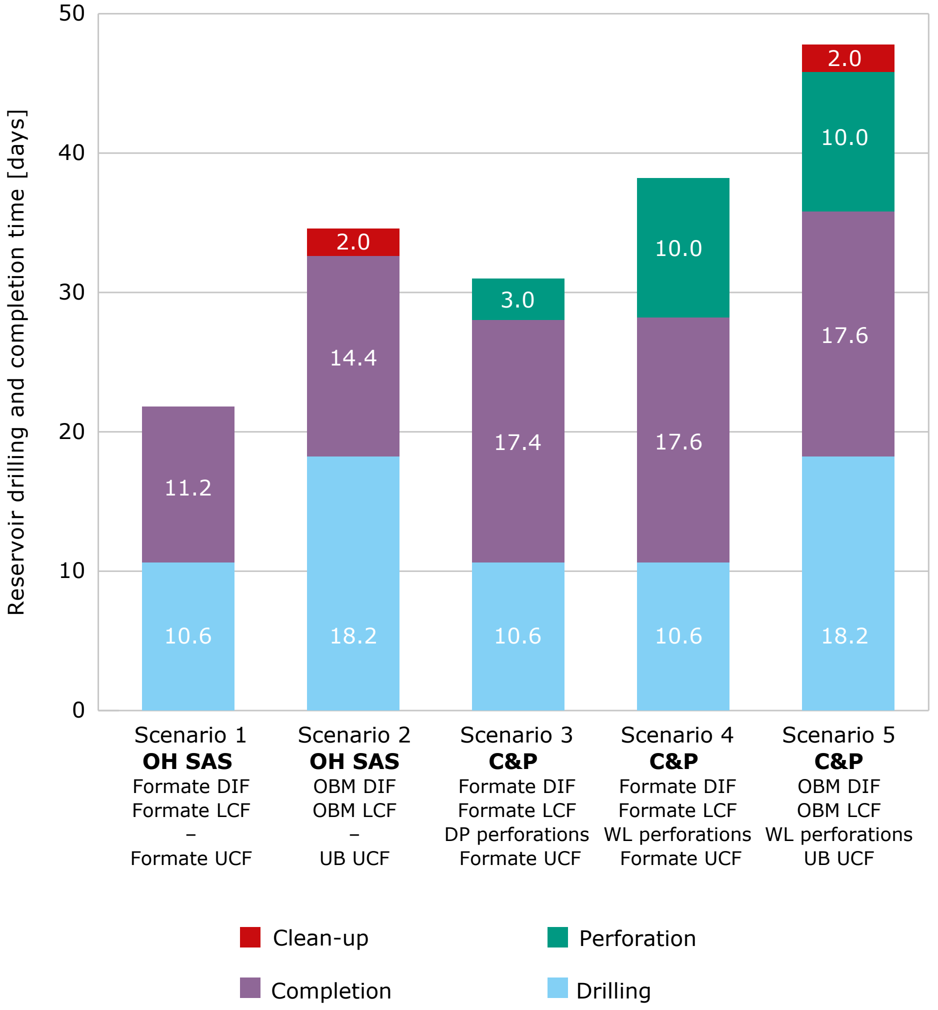
- HPHT platform and standard HPHT well design
- 500-metre reservoir section
- Drilling time is estimated from average net ROP data used in this study
- Completion time is estimated from average completion data used in this study
- Time for perforating on drill pipe is three days, which is study-data average
- Time for perforating on WL/CT is ten days, which is study-data average
- Clean-up to rig with OBM is two days, which is study-data average
- No clean-up to rig after drilling with formate fluids

Figure 10 displays time used for the five drilling and completion scenarios. The graphic shows that cesium formate fluids in overbalanced operations should deliver the following time savings:

- 13 days of rig-time savings in wells completed in simple open-hole standalone sand screen (OH SAS) – see scenario 1 compared with 2
- 17 days of rig-time savings in cased and perforated (C&P) wells – see scenario 3 compared with 5
- 26 days of rig-time savings by 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 with 5

Results from this exercise show how the completion design should be carefully selected as it can significantly affect final cost and net present value (NPV). Different operators are using more advanced time and cost analyses such as Monte Carlo, uncertainty analysis, etc.

Figure 10 Platform HPHT reservoir drilling and completion time estimate – example well case for 500-metre long 8½" reservoir section.



6 Conclusions and recommendations

An extensive investigation into how well construction fluids and techniques affect North Sea well construction times shows significant potential value in implementing cesium/potassium formate fluids for drilling and completion of both HPHT and non-HPHT wells. The major value is in their potential to enhance the probability of successfully delivering these challenging wells in much shorter time and with lower risk.

From the drilling time analyses of HPHT and non-HPHT wells, the following observations were made for drilling efficiency:

- HPHT platform wells: Formate fluids drilled with 74% higher average net ROP than OBMs
- HPHT subsea wells: Formate fluids drilled with 38% higher average net ROP than OBMs
- Non-HPHT subsea wells: Formate fluids drilled with 68% higher average net ROP than OBMs

Key time savings are believed to be in two areas. Firstly, time spent on circulating and checking gas content during drilling and POOH is greatly reduced due to lower gas solubility and gas diffusion rates in formate brines and, secondly, less fluid conditioning is needed due to the sag-free and stable nature of formate drilling fluids.

From the completion time analyses of HPHT platform wells and non-HPHT subsea wells it is clear that the time it takes to complete a well is more dependent on completion type than on the fluid system. The study shows that low-solids formate fluids are enablers for the fastest type of completions:

- For both categories, OH SAS completion concepts are delivered significantly faster than C&P completion concepts
- For HPHT platform wells, those completed in OH SAS with cesium/potassium formate are fastest. This could be due to:
  - Less circulating for gas and conditioning
  - Less circulating for well clean-out as wells were drilled with formate drill-in fluid
  - Faster screen-running speeds
  - No inflow testing required in formate wells due to hydrostatic overbalance
- C&P completion concepts with drill-pipe perforation are delivered significantly faster than C&P completion concepts with WL/CT post-completion perforation

Formate fluids appear to provide highest savings when used for both drilling and completion as they provide seamless transition between drilling, completion and production phases.

Wells completed in formate fluids do not typically require clean-up to rig and are flowed directly to the process facilities. Due to solids that cannot be handled in the production process, wells completed in OBMs usually require two days to clean up.

The study delivers an extensive database for predicting well construction times for different completion concepts and fluid choices. Base-case time estimates for five commonly used scenarios are calculated based on benchmarking performance data. Results for an 8½”, 500-metre HPHT reservoir section drilled from platform show that cesium formate fluids in overbalanced operations typically deliver the following time savings:

- 13 days of rig-time savings in wells completed in simple open-hole standalone sand screen (OH SAS)
- 17 days of rig-time savings in cased and perforated (C&P) wells
- 26 days of rig-time savings by changing from OBM and C&P completion (underbalanced perforating on WL) to cesium formate drilling and completion fluids in OH

The above observations are derived from carefully selected and quality controlled datasets, although in some categories these are limited. This means that uncertainty ranges vary between well categories analysed.

HPHT wells drilled with cesium/potassium 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. It is recommended that HPHT procedures are specifically designed for operations using formate fluids to give further time savings.

Results from this study show that cesium/potassium formate fluids should be considered for well construction and field development projects in a proper time-cost-risk-benefit analysis, including their effect on improving HSE, lowering risk, aiding early production and optimising completion design.

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8 Glossary

BOP	Blowout preventer
C&P	Cased and perforated
CT	Coil(ed) tubing
DIF	Drill-in fluid
DP	Drill pipe
ECD	Equivalent circulating density
HPHT	High pressure high temperature
LC	Lower completion
LCF	Lower-completion fluid
NPT	Non-productive time
NPV	Net present value
OB	Overbalanced
OBM	Oil-based mud(s)
OH	Open hole
PI	Production index
POOH	Pull out of hole
ROP	Rate of penetration
SAS	Standalone sand screen
UB	Underbalanced
UC	Upper completion
UCF	Upper-completion fluid
WL	Wireline
WOW	Wait(ing) on weather
XT	Christmas tree

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