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The First

SPE Norway Magazine

To gather members
To share knowledge

SPE Awards Gala and BBQ Dinner

The subsea gate box

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Accurate ECD prediction for improved digital models

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SECTION NEWS

Picture by Tapio Oskari Järvinen (Palfiner Marine Norway)

Articles from the Industry

EDITORIAL CONTENT

INSIDE THE ISSUE

Dear SPE Norway members,

First of all, we would like to thank for all contributions from the sections and the industry we have received for the second issue of 2018! Your editorial contributions are what makes this magazine great, helps us to promote knowledge sharing across the sections and across the companies.

We would like to encourage you to be even more active this year and submit your articles to The First Magazine. Our readership is expanding and online publication helps with a rapid growth of readers. This publication is a brilliant opportunity for you to promote your research and technological advancements.

On behalf of the editorial team,
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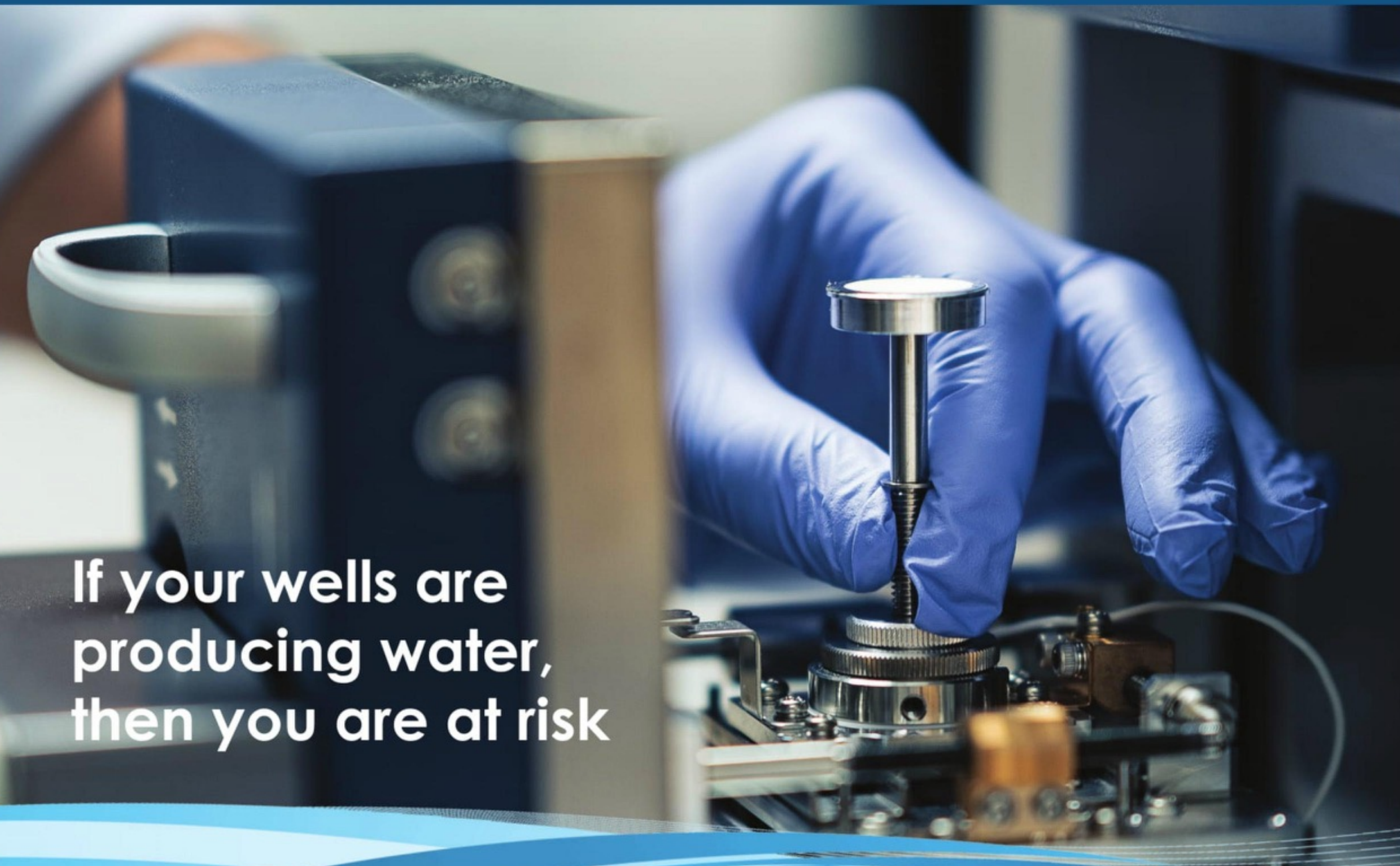
Scale deposition is one of the oil industry's major challenges



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SPE Awards Gala and BBQ Dinner

SPE Stavanger section hosted the annual barbecue for the 40th time on the 1st of June this year.
The venue for the evening was the Stavanger Konserthus, and we could hardly find any better location to mark the celebration. The Stavanger board had changed the name for the event slightly this year, calling it **Awards Gala and BBQ Dinner**, wanting to put more focus on the recognition being done as part of the event.
Around 200 privileged guests had chosen to attend this traditional event in a marvelous summer weather. Despite the fire department putting a ban on all barbecuing anywhere outdoor, the chef and his team did a fantastic job making the food taste extraordinary and 'grilly'.

The opening speech was held by the SPE section Chair, Vidar Strand, where he pointed out the importance of the work SPE as an organization of voluntaries is doing in terms of educating and driving networking for our members and through same adding values to our sponsors. Further he pointed to the new growth starting to be seen in the industry and the fact that the oil and gas industry have many technical challenges still to solve leaving an interesting work place for existing and new engineers for years to come.

Another name change done was the name of the most honorable award, the one previously known as the **Oilman of the year**.

Picture from SPE Gala and BBQ Dinner 2018

This year's Oil Professional of the year - Professor Bernt Inge Aadnøy (University of Stavanger)

This award has been renamed to the Oil Professional of the year to be in line with a more modern business environment. This year's award was handed out to Professor Bernt Inge Aadnøy at the University of Stavanger for his 40 years of commitment to both petroleum education, technology development, and his strong contribution to Norway's international reputation in the oil and gas industry. In addition, the following awards were handed out by SPE Stavanger:
Bachelor of Science - Kenneth Løland
Master of science - Diego Felipe Acevedo Parra SPE Young Engineer of the year - Vijay Kumar Keerthivasan.
On behalf of the SPE Stavanger and SPE Norway Council, a sponsorship of NOK 30.000,- was handed out to the Petrobowl team from the University of Stavanger for their representation in the finals at ATCE in Dallas, September 2018, after qualifying among the universities in Europe earlier this year.

The evening was packed with entertainment by the singing diva Karin Hodne, The Barbella Fellas Barbershop Quartet, Door Prices and live music by Stavanger Storband to live up the dance floor.

A great thanks to the events team, Jeremy Mazzilli and Frode Indreeide at the SPE Stavanger Board. The event was well received and we are already looking forward for next year's event – see you there!

Author:

Vidar Strand
SPE Section Chair
Stavanger

Pictures: Andrea Rocha

Photo Diary

Moments from SPE Awards Gala & BBQ Dinner

The Event has become a yearly tradition bringing SPE Stavanger community together. Here are a few snapshots, enjoy!

Oslo Student Chapter

Since the last issue, the Oslo Student Chapter has hosted three main events and is pleased with another successful semester. We had the pleasure of hosting Faroe Petroleum and the Norwegian Petroleum Directorate for a company presentation. It was the first time Faroe Petroleum visited our department and their recent success and role on the NCS sparked an interest in the audience. NPD returned for a company presentation after their first visit two years ago. We really appreciate the NPD taking their role seriously, sharing insights and opportunities to the next generation.

The Semester Quiz in May was a huge success with a big turn-up. A big thank you to quizmaster Jens Fredrik Kolnes. It was nice to see a jump in memberships before the event. I recommend all chapters and sections to take a look at the **membershipbuilder.spe.org** to keep track of memberships and utilize all the available information there.

Picture: The winning team of the Semester Quiz

Author:
Ole Kristian Bergsland Hansen
Oslo Student Chapter

News from SPE Bergen Section

SPE Bergen Section has concluded the season with yet another yearly sailing with Norway's most beautiful ship - Sstatsraad Lehmkuhl!

The event was once again fully booked, gathering professionals from Norway and abroad, including many students. If you missed the event, we hope you take a second to view our picture diary in the next page.

We are kicking of next season with many great events, including TechNights, Digitalization event and, of course, a yearly Lutefisk dinner. Follow us on Facebook and visit our website to keep updated!

Event calender for Autumn 2018:

17th September:
TechNight - SPE Distinguished Lecturer Program with Holger Thern

25th October:
TechNight - SPE Distinguished Lecturer Program with L.W. Ledgerwood III

22nd November:
Annual Lutefisk Dinner

22nd November - save the date!

We would like to invite everyone to what has become a yearly tradition - Lutefisk Christmas dinner! The event is normally sold out within a short time, so don't hesitate to reserve your place!

Photo Diary

A few moments from sailing with SPE Bergen

Yearly sailing event gathered a full ship of students and Oil&Gas professionals from Norway and abroad.

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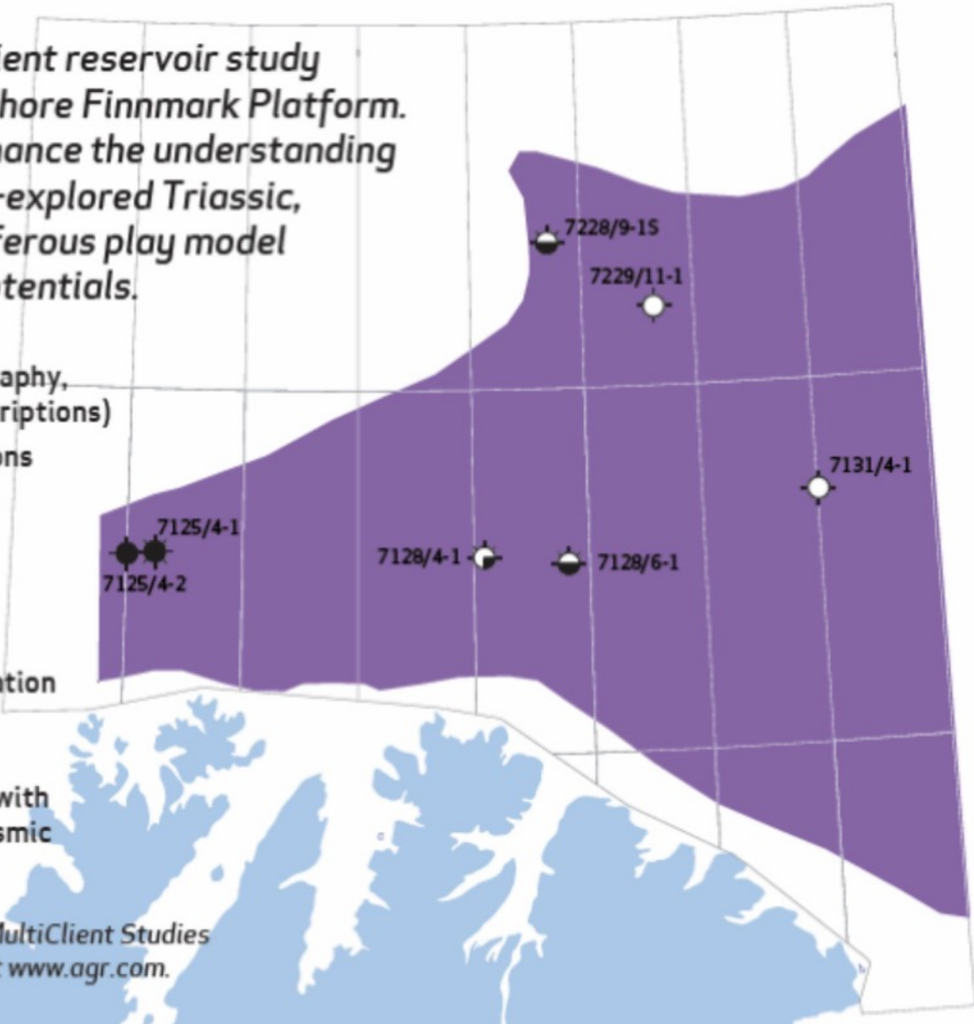

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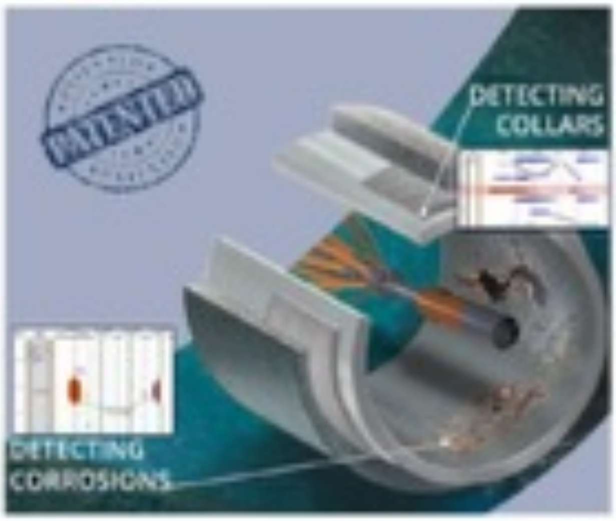

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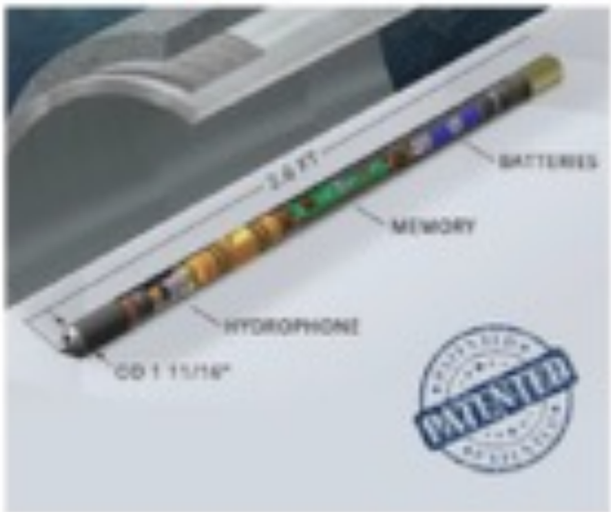

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New technology can change deep well economics

Offshore deep drilling has marginal economics. One reason for this is the slow rate of penetration (ROP) that follows the need for heavy mud weights. To explain the significance of the problem, the same rock will drill at 1/10 of the speed when the mud weight is brought up by a couple of points.

With a big semisubmersible rig or ship, the slow speed becomes a big cost element. Many medium and more smaller fields are abandoned for this reason. In deep offshore regions like Brazil, even fields with larger reserves are put on the backburner for the same reason.

The heavy overbalance effect on ROP is well known to drillers and is also thoroughly debated and discussed in academia. New computer tools have recently given further details and insight to the cause of the problem. SPE paper 105885-PA from May 2009 gives a description of the problem and potential solutions by group of authors from both Schlumberger and Baker Hughes covering fluid, drilling and bit technologies. Leroy Ledgerwood III, Baker Hughes and Stefan Mizka, University of Tulsa has quantified the same effects in single cutter tests. The results were presented in paper SPE-119302-PA, March, 2010. Legerwood have later summarized the research in the 2018 SPE Distinguished Lecturer program.

THE AFTERBURNER PROJECT

In 2012 Tomax started a project to reduce the hydraulic jetting forces and reducing the impact pressure on the bottom. A reliable solution was found by applying the suction principle from a sewage pump for bottom hole cleaning. The pump would by design eliminate the flow pressing cuttings down to the bottom to be re-ground. It would also remove the risk from reactive pressures charging natural fractures. This meant more stable near bore rock. The solution was realized for drilling by five ejector pumps, also known as jet pumps, arranged to replace the waterways in a stabilizer located close to the bit. The system was set up for standard pump rates from surface. In addition to keeping the bottom clean, the jet pumps also produced a significant extra thrust or tractor force. This gave the project its name. Figure 2 shows a sketch of one of the five Afterburner ejector pumps.

Figure 1. The Afterburner project has demonstrated how a fluid-driven jet ejector can clean the well by suction and stop the bottom-hole balling at deep depths.

PREDICTABLE PERFORMANCE

In its first well, the Afterburner was used to drill hard rock at 1,094m MD (3,200 feet). The photo in Figure 1 is from this test. Before tripping in to the hole, the ability to clean the bottom by suction was verified. The verification also included a check of the pressure intrusions in to an artificial fracture 6 feet deep. The pressure at the end of the fracture was measured to peak 34 bar with a conventional bit while the reading was 0.5 bar with the Afterburner. This was quantitative evidence of the Afterburner advantage in unstable layers.

As drilling commenced in the test well, the reactive torque and the return of cuttings over the shakers confirmed the bottom was kept clean.

The hole cleaning capacity was stress-tested by using fresh water to lift the heavy cuttings from basement rock. The circulation rate was 1,800 liters per minute, or 480 GPM in imperial units. Key performance data was obtained from a downhole quartz gauge with readings taken at the face of the bit.

CFD ANALYSIS

An advanced, Computational Fluid Dynamics (CFD) analysis was needed for a detailed characterization of the Afterburner. The specialist engineers at Flow Design Bureau AS and EnginSoft took on the task. Their more advanced EngineSoft™ computer tools proved to be very useful for predicting and optimizing the solution for a wider variety of applications. The first analysis was run on the same drilling test that had already been completed. The CFD results came within decimals of both the previous MATLAB results and the pressure gauge recordings.

DEEP OFFSHORE TESTING

With the updated CFD models that also included predictions for sand erosion, operator VNG Norge AS sent an Afterburner unit to a deep offshore well. VNG had seen the rates of penetration (ROP) drop with increasing mud weight on this location and wanted to check out if the Afterburner could indeed help reducing the problem. Measuring the thrust force was a secondary objective but would serve to confirm if the suction effect was enough to evacuate the cuttings rather have them ball-up on bottom. Downhole data was obtained from a dedicated MWD drilling dynamics sub (Co-Pilot). The Afterburner, RSS and PDC bit were

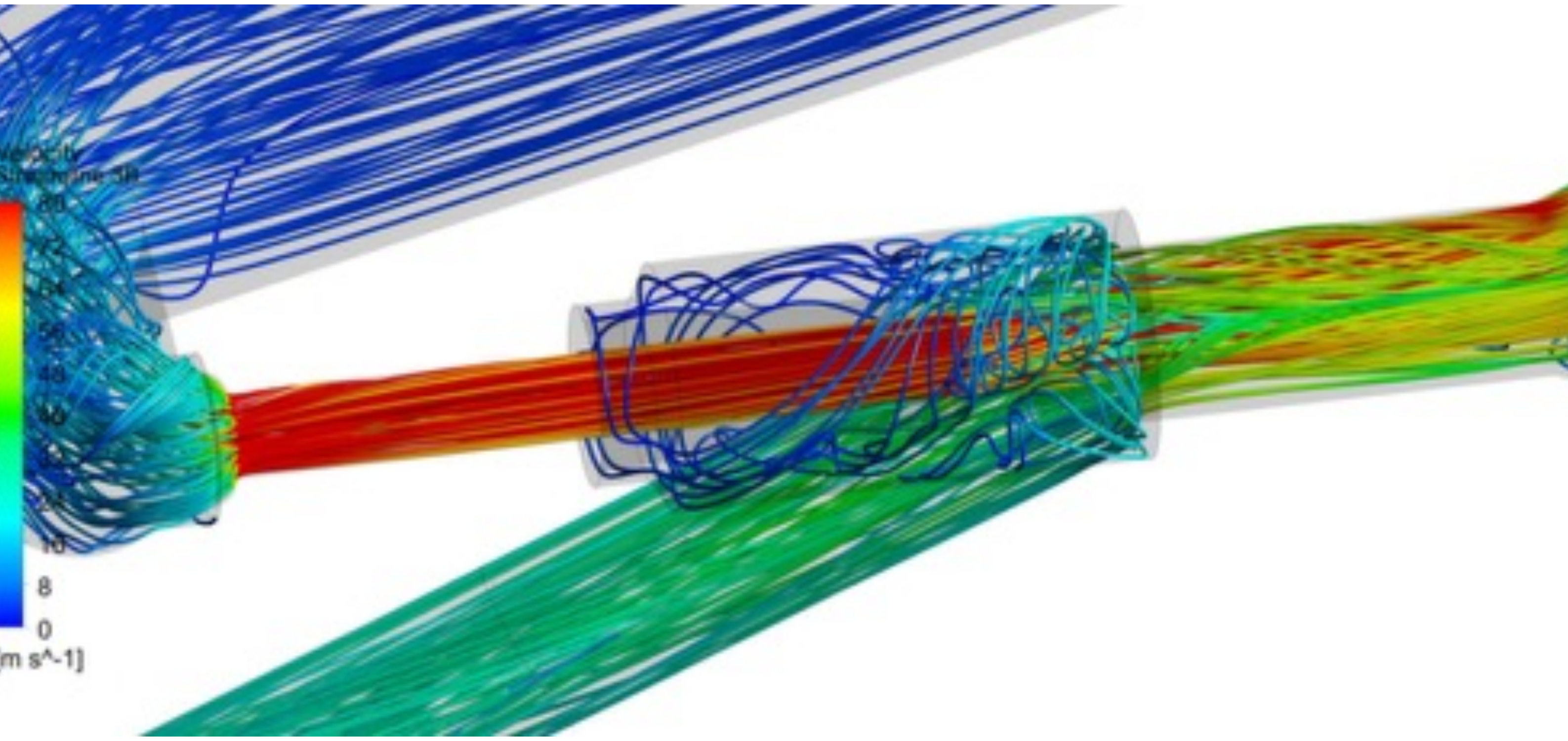

Figure 2. The Afterburner ejector pump principle: The flow from surface makes a fast (red) jet of fluid with low pressure in its core. The low pressure draws in mud and cuttings from the suction channel that keeps the bit on bottom clean.

tripped in to 4,100m MD (13,400 feet). When drilling commenced, double ROP at less than half the WOB from the previous run confirmed clearly no re-grinding was taking place. The Co-Pilot data showed the WOB contribution from gravity was between 2 and 3 kdaN. The driller simultaneously reported WOB readings between 7 and 9 kdaN from the hook. The bit size was 8½" and the mud was 1.55 SG. The flow was 1,630 lpm (430 GPM).

CLEAN CUT

The bottom hole cleaning by the Afterburner is done by suction. An important aspect in preventing re-grinding and bottom-hole balling is the fact that suction simply works better than jetting: This can be appreciated by observing how the household vacuum cleaner works best in tight corners. The CFD modeling of the Afterburner dynamics showed the same. A 3D velocity plot from the CFD model is presented in Figure 3. The plot shows how the sweep is at its best in the corners of the cylinder. This was what triggered VNG Norge AS to try out this principle for eliminating the infamous chip hold-down phenomena.

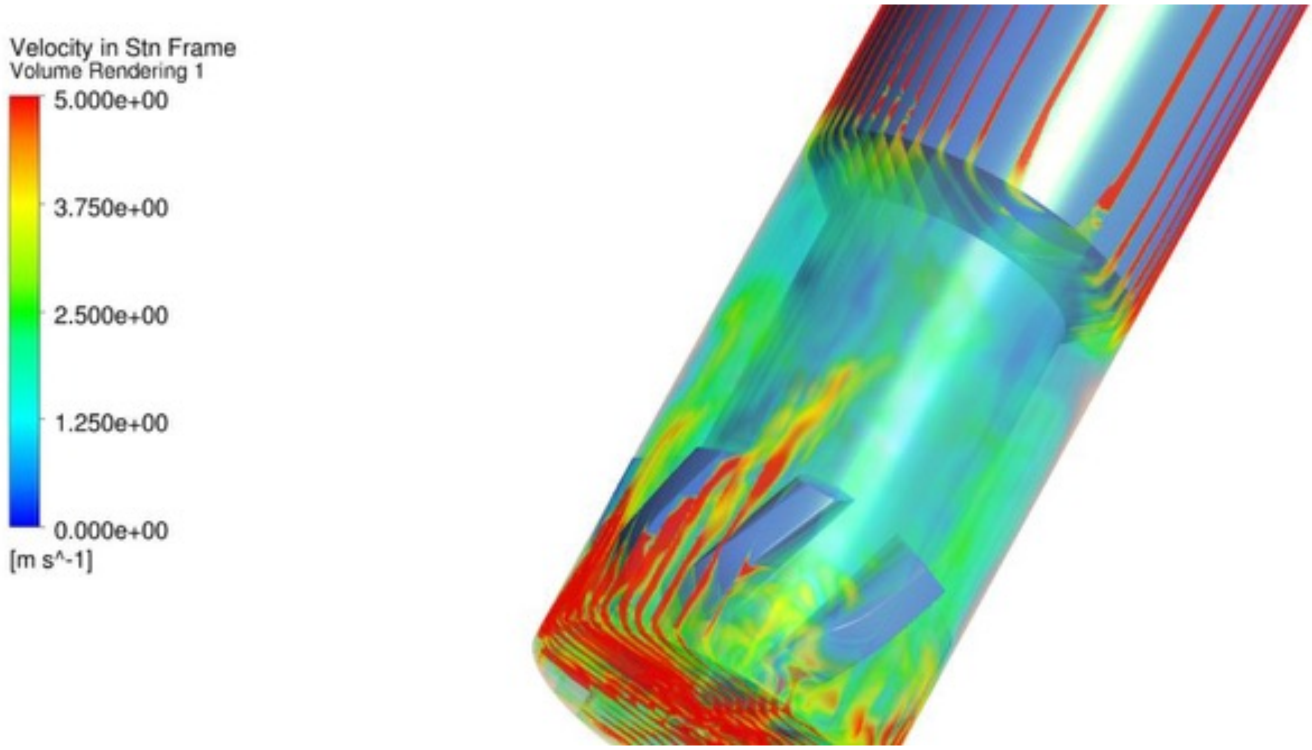

Figure 3. Computerized Flow Dynamics (CFD) model showing the bit.

SPECIAL CONSIDERATIONS

The Afterburner tested was based on a 40cm (1.2') long, spiral blade stabilizer. Instead of waterways, the 8 3/8" OD stabilizer had five ejector pumps. The unit is also characterized by five fluid channels leading from above the stabilizer and down to the bit nozzles. A sharp PDC cutter that is making hole needs practically no more cooling than the heat sink provided by the bit matrix and the rock. Hence the circulation of fluid sufficient for lifting out the cuttings is also sufficient for cooling. The drawdown pressure will by design level out below 100 psi. The cross-section of the Afterburner body with its large pumps and its borehole clearance makes the surge and swab pressures peak at about 20 psi. This is when tripping at 30 seconds/stand. The figures have been verified by both quartz gauges and comparison of drag readings in deep offshore testing.

SELF CLEANING

The risk of blocking one or more of the ejector pumps was considered a risk factor in the design phase. The ejector pumps are therefore opened up to let through 14mm (11/16") ball shapes or marbles. This is far beyond any conceivable size and shape of cuttings from a PDC bit. Larger cuttings than 13mm can't enter the pumps anyway and will be trapped on the outside to be ground to pieces before entering. Continuous successes in cleaning up

“An advantage from the compact design is easy integration with existing technology.”

fill from the bottom of the hole in testing have indicated that the internals of the five pumps are self-cleaning. The mechanism behind this is believed to be the intensity of the vibrations created when rotating the bit and the BHA. The continuous impacts to the Afterburner body make it virtually impossible for cuttings of measurable mass to settle or bridge. With the cutters engaged in drilling, these vibrations will intensify further. The result is a very low risk of blockage.

BHA INTEGRATION

The Afterburner consists of a stabilizer converted into a jet pump.

An advantage from the compact design is easy integration with existing technology. In the latest field run, the unit was added to a 3-point push-the-bit RSS system. That made it a stiff, 4-point system that was acceptable for drilling straight ahead. Unfortunately, plans changed and called for maximum turn. This was not doable with such a stiff system in a deep well and the bit parted. The lesson learned was to either run the Afterburner in a plain rotary BHA or to fully integrate it as a stabilizer in a 3-point geometry. Figure 4 shows such an integrated Afterburner having the Tungsten Carbide pump installed.

Figure 4. 2018 version Afterburner with wire-feed for integration in commercial RSS system.

Figure 5. The Afterburner aims to replace cuttings cleaning by jet impact. This picture shows the jet impact from a rate of 1600 lpm.

THE DRILLER'S PERSPECTIVE

One success criterion in the introduction of new technology is the driller's interface. The Afterburner makes no changes to the driller's practices. The WOB is read and understood as always and the brake is operated accordingly. There are no changes to barriers and well control procedures. A piece of good news for both the driller and the drilling engineers is the removal of the problematic blind zone in front of the bit: The blind spot is gone because the highest pressure in the system now moves up into the annulus where the MWD's pressure sensors are located. This mean ECD readings are accurate and less error margins are needed.

CONCLUSION

The Afterburner development has demonstrated how a fluid-driven jet pump can clean the bit, remove the crushed rock detritus by suction and thus eliminate the regrinding of cuttings that slows down the drilling, causes over-heat and limited bit life. The ability to speed up drilling in deep wells can bring back the potential and value of many offshore prospects.

ACKNOWLEDGEMENT
The authors like to thank VNG Norge AS for their contribution to this article.

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Morten Kjeldsen from Flow Design Bureau AS. He has a PhD in mechanical engineering from the Norwegian University of Science and Technology (NTNU).

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Accurate ECD prediction for improved digital models

The current practice, independent on type of industry, is to create digitalized models for all industrial processes. Hence, different processes may be controlled by simple applications on computers and in many cases also on mobile phones. To be applicable, these models must be reasonably accurate. Current practice within

"as will be shown in the following sections, an improved model accuracy will be obtained if the least square fit is conducted only for the shear rates relevant for the flow situation"

drilling rely on standards like API RP13 (American Petroleum Institute, 2014). These standards base their viscosity models on measurements with VG viscometers. Earlier, all models were based on viscosity measurements at the very high shear rates of 511 and 1022 1/s to create their viscosity data. These shear rates are far too large to represent practical drilling operations. It is recommended in the current standards to use a least square fit of all shear rate measurements to increase the accuracy of the viscosity models. However, with the exception of the flow around the Bottom Hole Assembly (BHA), shear rates in excess of 200 1/s are seldom experienced in the field. Therefore, as will be shown in the following sections, an improved model accuracy will be obtained if the least square fit is conducted only for the shear rates relevant for the flow situation. These viscosity data are then used to calculate the annular frictional pressure losses in a well model experimental equipment.

Measurements and modelling

Annular pressure loss experiments have been performed in a realistic size flow loop setup with a free whirling drill string inside a cased hole (pipe in pipe). Annular flow conditions in the tests are relevant for drilling in holes from 8,5" and up to 17,5". Experiments in a similar setup representing annular flow in open hole sections are described in Werner et al. 2018. The presented data here are all from tests in a horizontal annulus (90 degrees inclined wellbore). The applied fluid is a field applied low viscosity oil based drilling fluid with density 1430 kg/m3 made with micronized barite. It is primarily used for ERD, narrow margin (low ECD) and HPHT wells.

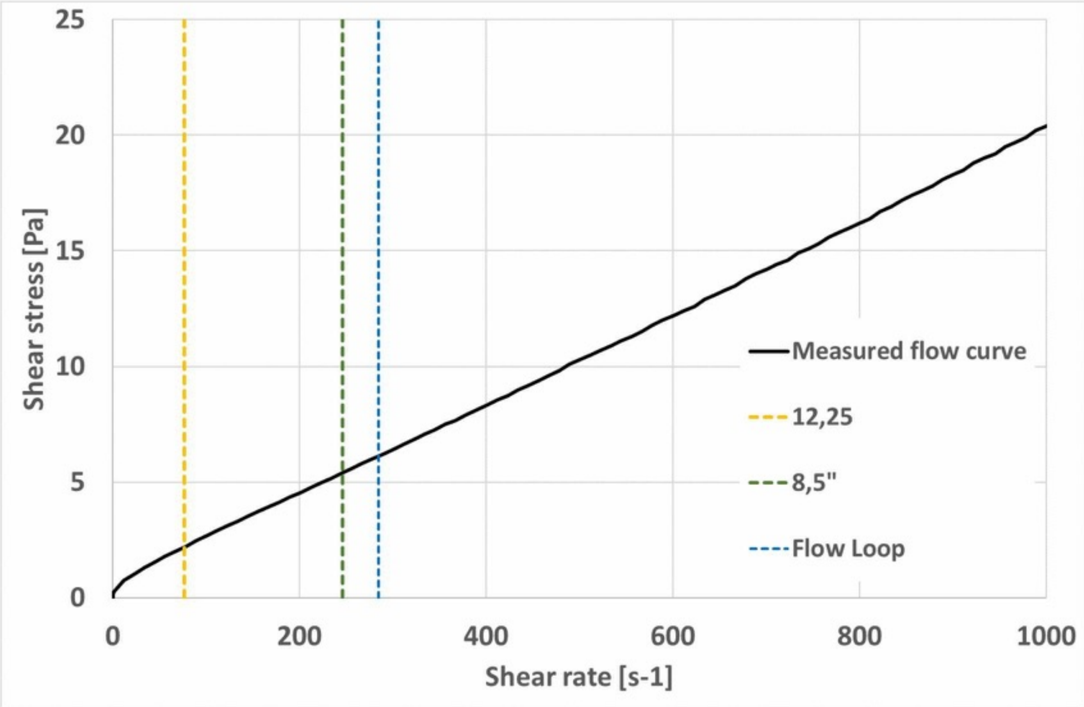

Figure 1. Flow curve is plotted for measurements according to API standards. Normal maximum shear rates for operations and flow loop are included.

References of use have been found for various North Sea fields and offshore Newfoundland, but it is applied in drilling operations all over the world. More details on the test setup and fluid details can be found consulting Ytrehus et al. (2018).

The flow curve of the oil-based drilling fluid is presented in traditional form in Figure 1. In the figure the maximum shear rates for annular flow in relevant deviated wellbore sizes are also included. These shear stresses are derived from pump capacity limits in operations. Similar maximum shear rate for the experimental setup is also included. An observation in this case is that only the lower area shear rates are relevant when considering the hydraulics and cuttings transport in the wellbore annulus. A Herschel-Bulkley viscosity model is known to present steady state drilling fluid viscosity with reasonable accuracy. The model shows the shear stress as the sum of the yield stress and the shear rate in the power of n multiplied by the constant K in the equation below:

$$\tau=\tau_y + K\gamma^n$$

Figure 2 is included, considering only the relevant shear rate range. The two Herschel-Bulkley curves are included as well: One fit by considering the whole shear rate range recommended by API and one fit by considering only

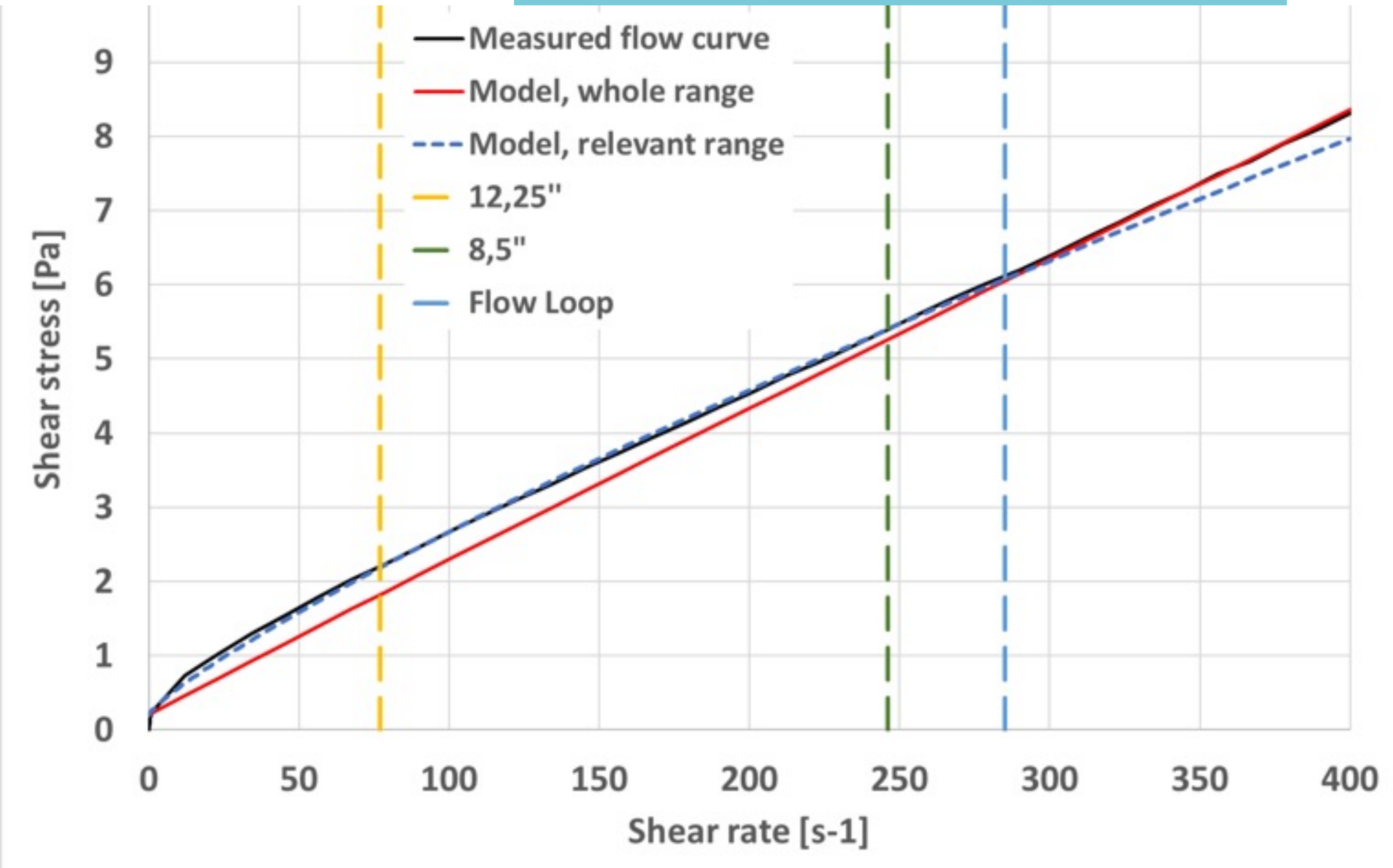

Figure 2. Measured flow curve is plotted for the relevant shear range. Herschel-Bulkley models are applied for the fluid. One is based on measurements in the relevant shear range (0-300) and one considers the entire shear rate zone up to 1022 1/s as recommended in API standards.

	τ_y [Pa]	K [Pa*s^n]	n [-]
Match A	0.2	0.0229	0.9806
Match B	0.2	0.0548	0.8269

Table 1. Herschel-Bulkley parameters for the two applied models are presented here.

the relevant shear rate range for the actual flow conditions. As seen in the figure the model considering the relevant range (Match B) has a significantly better fit in the lower shear region. Above this region the traditional fit (Match A) is significantly better. The Herschel-Bulkley parameter values of the two models are show in Table 1.

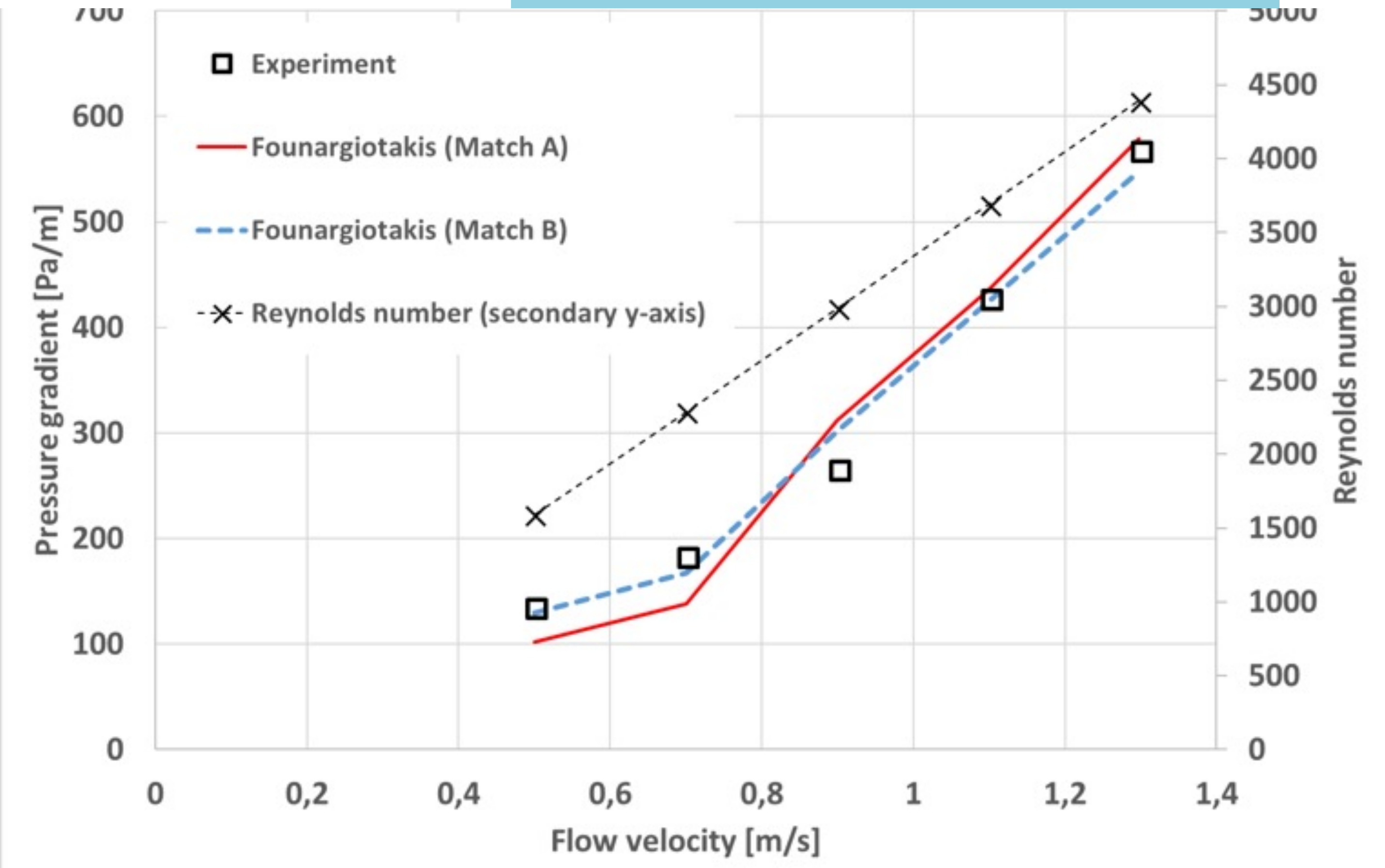

Figure 3. Pressure gradient is plotted for the experimental data and for modelling with fluid parameters based on the curve matches A and B. The corresponding Reynolds numbers are also included.

Experimental results from annular pressure drop tests are presented in Figure 3. The pressure gradient is calculated using a model described by Founargiotakis et al. 2008 for the two fluid parameter sets. The results show that the match between model and experiments is significantly better if fluid model based on relevant range is used. Some deviation is found at Reynolds number 3000. This can be expected as this highly likely is in the transitional flow regime where laminar flow models no longer applies, and turbulent behavior is not yet applicable. The pressure drop model based on viscosity match using API recommendation underpredicts the actual dynamic pressure drop (ECD) in the laminar regime. This is in line with the observations in Figure 2 where match A shows a lower viscosity than the measurement values in the relevant shear rate region.

Conclusions

The set of experiments has shown that it is important that relevant shear rate measurements are used in detail to develop the Herschel-Bulkley model for drilling fluid viscosity. Optimal digital applications require relevant input values to provide acceptable accuracy.

In order to fulfill the industry's vision to digitalize operations for automatization and remote controlling it is necessary to investigate and select input data properly. This also includes understanding the consequences from parametric studies in controlled environments as a supplement to field data.

“In order to fulfill the industry's vision to digitalize operations for automatization and remote controlling it is necessary to investigate and select input data properly”

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HeaveLock™ - an autonomous downhole tool for automated drilling

The last step on the path towards full drilling automation are tools that act autonomously, without the need of the driller to interfere (Thorogood et al., 2010). Such tools rely on their sensory data and make decisions using advanced control algorithms, keeping control variables in check and correcting any unwanted events before they have a chance to occur. HeaveLock™ is one such tool, currently being developed by a small start-up company in Trondheim with roots at NTNU with support from Equinor, Innovation Norway and the Research Council of Norway. HeaveLock™ addresses the important issue of avoiding downhole pressure oscillations due to surge & swab effects, caused by vertical movement of floating drilling rigs due to swell. Solving this problem is an important step towards accelerated introduction of Managed Pressure Drilling (MPD) techniques on floating rigs and drill ships in harsh weather environments. MPD has large potential when it comes to significantly improving IOR on mature fields, since it enables drilling of previously "un-drillable" wells with narrow pressure windows.

MPD is a drilling technique that allows improved control of downhole pressure compared to conventional drilling. MPD has been offered by all major drilling service companies for almost 20 years and has gained wide use in such applications as onshore drilling and drilling from fixed offshore installations in shallow water. MPD has also been introduced in offshore drilling from floaters, but mainly in regions with relatively mild weather and limited swell such as South China Sea and Brazil.

Utvinningsutvalget suggested in 2011 that utilization of MPD on floaters is one of the twelve measures to reduce costs and improve oil & gas recovery on the NCS. According to the Norwegian Petroleum Directorate, MPD is an important technology to achieve a boost in IOR and its utilization on the NCS was considered a priority (NPD, 2009). Rystad Energy report from 2012 estimated potential pre-tax value from utilizing MPD from floaters on six chosen NCS case fields to be more than 11 billion NOK between 2013 and 2030 (Rystad, 2012). Associated gross value (including costs collected as revenues by service companies) would then be almost 35 billion NOK. This value was claimed to originate from cost reductions (20%) and increased revenues (80%). The main assumption in the report was that MPD would be available on floaters from the start of 2013 and more than 1000 wells were pointed out as potential candidates, see Figure 1.

“North Sea would see the most rough seas, but HeaveLock™ would really apply anywhere MPD is used on a floater. GOM might see more benign seas than the North Sea but heave is still going to be an issue on floaters”
Subject Matter Expert, major oil company

Projection in the report was that 45% of the production on NCS would be within the potential scope of MPD from floaters by 2020. In an earlier study made by the Society of Petroleum Engineers (SPE) and published in the Journal of Petroleum Technology (JPT), more than 600 SPE members predicted that the share of offshore wells to utilize MPD would be around 40% in 2015 (Jacobs & Donnelly, 2011).

Higher utilization of MPD on NCS floaters has four main advantages:

1. Accelerated production and boost in IOR
Drilling in depleted mature reservoirs with tight pressure margins

►Predicted value from accelerated production and drilling the un-drillable wells on 6 NCS fields 2013-2030 was over 13 billion NOK (Rystad, 2012).

2. Ability to drill previously un-drillable exploration wells
Deepwater exploration

►Mandarin East HPHT well (BG) was only possible to drill due to utilization of MPD. MPD-related savings offset the costs of MPD by 185% (Syltøy et al., 2008).

3. Reduced costs due to less Non-Productive Time during drilling, related to pressure control

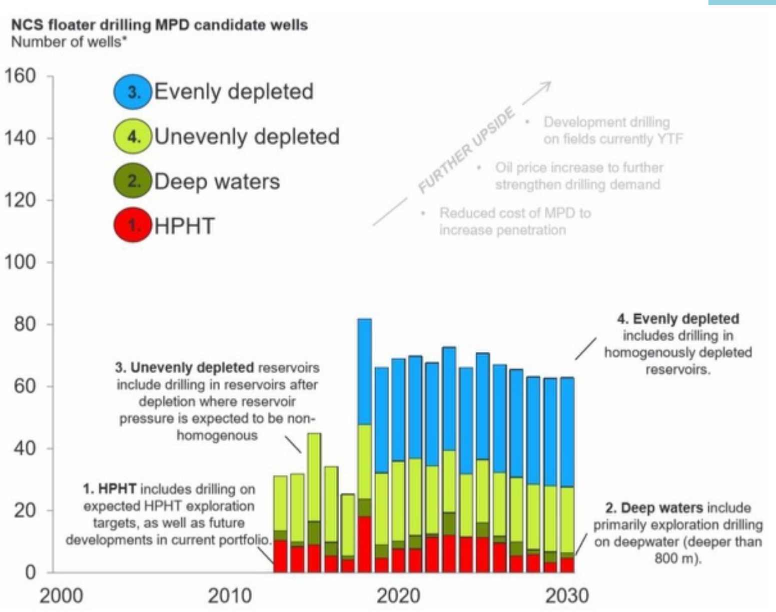


Figure 1 Over 1000 wells, mainly on mature fields, were considered as candidates for MPD from floaters (Rystad, 2012).

25% of drilling-phase NPT on NCS floaters is likely addressable with MPD technology

►4-7% of the total drilling NPT is addressable by MPD, corresponding to savings of 3-5 mNOK per month for one drilling rig (assumed day rate 2.4 mNOK). Overall projected value for 6 NCS field cases 2013-2030 was >3 billion NOK (Rystad, 2012).

4. Safer operations

►Utilization of MPD provides superior well control and early detection of kicks.

meters, the drill string is fastened to the drill floor to perform an extension with another pipe stand. During such extensions, the drill string cannot be heave-compensated, and it thus starts to move up and down in the well like a piston, creating downhole pressure oscillations. Much of the point with MPD is to keep the downhole pressure steady and within a tight window, defined by reservoir characteristics. Understandingly, large downhole pressure oscillations due to swell cannot be tolerated. These oscillations are referred to as "surge and swab effects", see Figure 2. Surge (pressure increase) can damage a well, fracking it and reducing its future productivity.

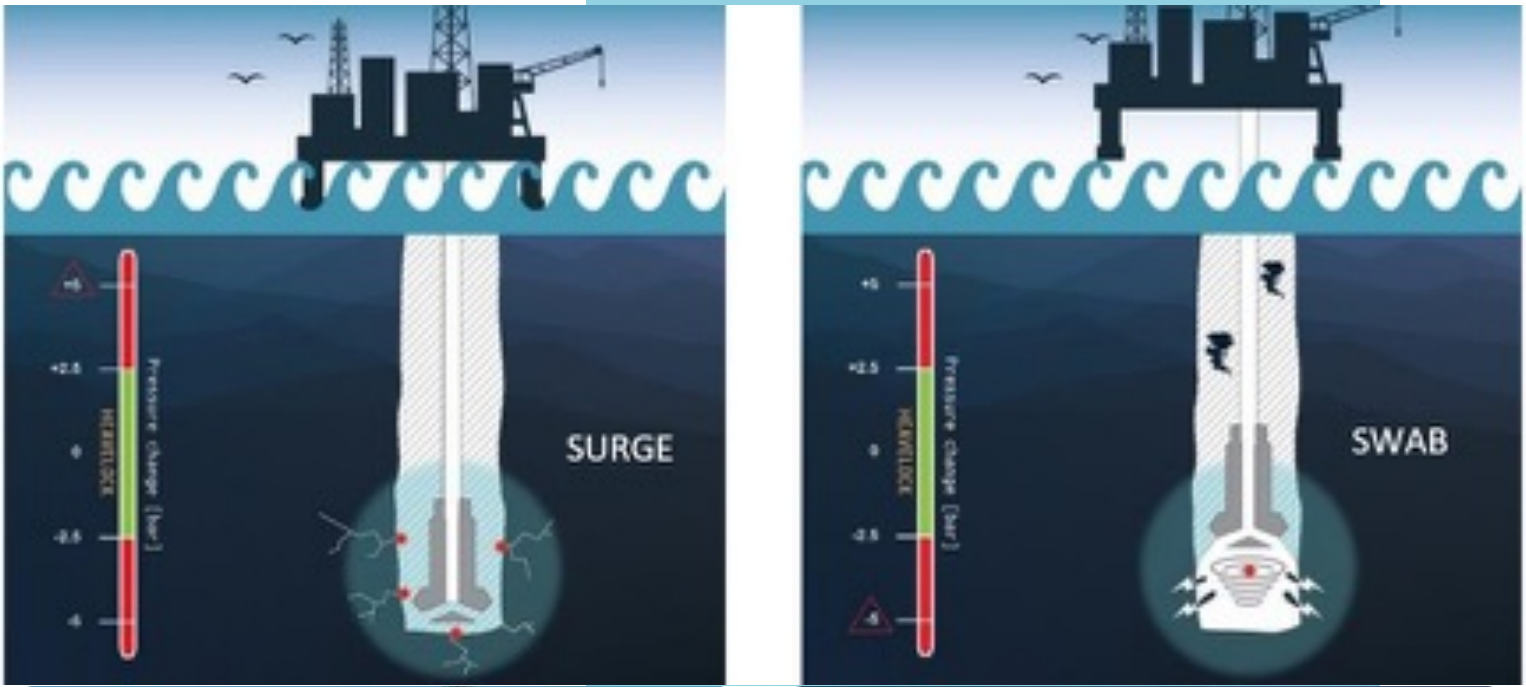
"You would need HeaveLock™ everywhere" Subject Matter Expert, another major oil company

Despite the significant upside and the positive forecasts, very few MPD wells on NCS have been drilled from floaters per today. A version of MPD called Controlled Mud Level (CML) has been utilized by Equinor on the Troll field and by Lundin on the Alta/Gotha field, although not more than 20 wells in total have been drilled utilizing CML (Rystad forecasted 180 wells between 2013 and 2018). There are many factors contributing to this fact. The oil price crisis of 2014-2017 certainly did not help. But there is also a technology gap; efficiency of MPD from floaters is seriously hampered by swell.

Vertical movement of floating drilling rigs and ships due to swell is called "rig heave". Rig heave is normally compensated by control of the draw works during drilling, but every 30

Swab (pressure decrease) can cause hydrocarbons to enter the well bore during drilling, a potentially dangerous well control situation called "kick". This problem has been identified as one of the main factors preventing widespread utilization of MPD when drilling from floating rigs and ships. During an Equinor-hosted workshop in May 2018, devoted to MPD from floaters, a panel of industry experts from service and operator companies agreed that issues related to surge and swab during connections are the one of the main technical reasons MPD has not seen wide implementation on floaters in harsh weather environments.

Several methods of dealing with surge and swab effects have been proposed earlier.



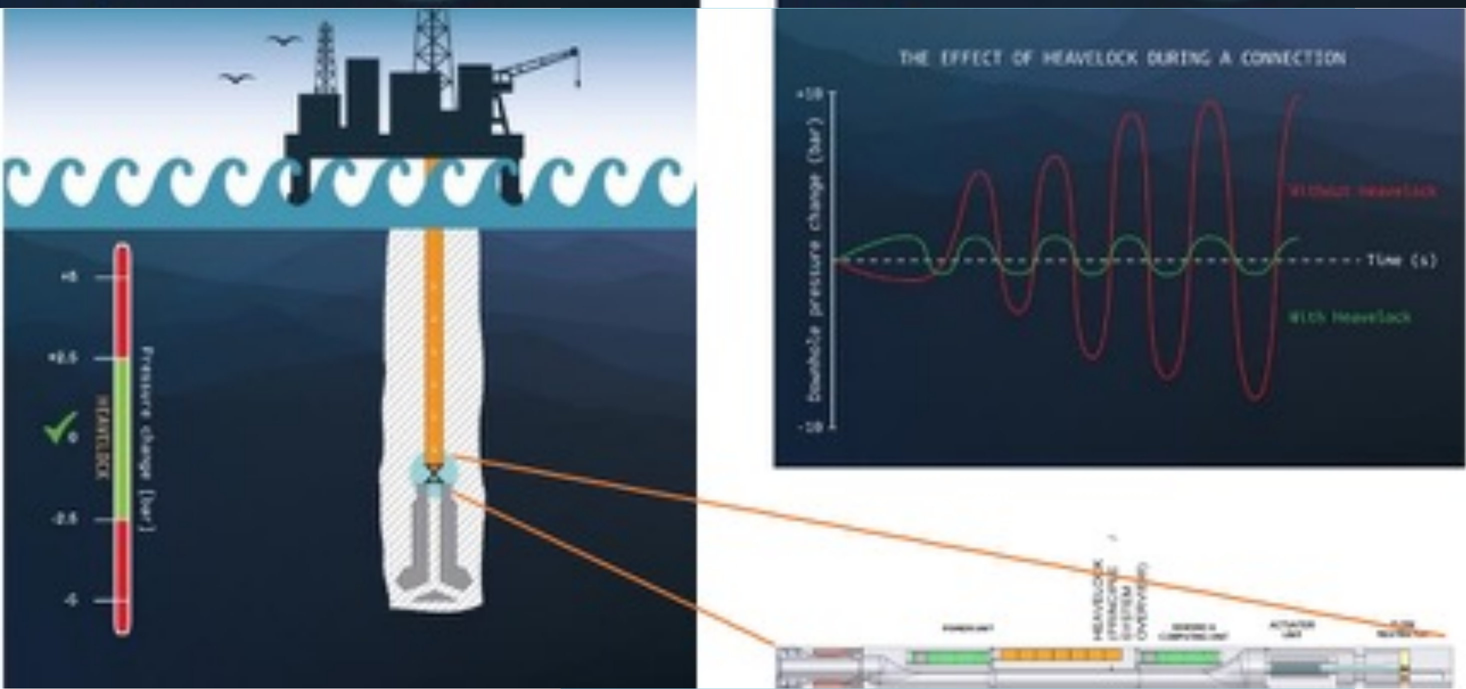


Figure 2 (top) Surge and swab phenomena cause downhole pressure oscillations that can damage a well or lead to a kick.

Figure 3 (bottom) HeaveLock™ downhole choke is able to stabilize the pressure under the drill bit during surge and swab through precise control of the mud flow.

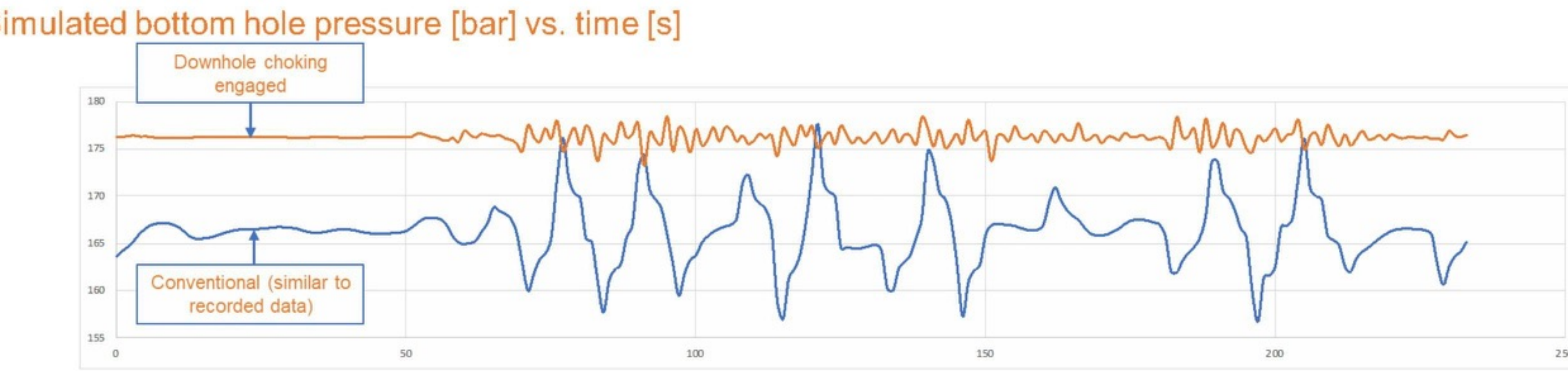


Figure 4 Simulated North Sea well - downhole pressure oscillations with (orange graph) and without (blue graph) HeaveLock™ engaged. Significant wave height is only 2 meters in this example.

Attenuation of downhole pressure oscillations using the topside choke has been proposed as a way of dealing with the heave-related issues (Pavlov et al., 2010). This idea has been investigated extensively with the conclusion that such a solution is theoretically possible (Landet et al., 2012, Albert et al. 2015, Mahdianfar et al. 2016). However, simulations of a realistic drilling operation reveal severe shortcomings of this approach, mainly linked to the combination of time delays being in the same order as wave periods, complicated multiphase flow in the annulus and highly stochastic character of ocean waves (Strecker et al., 2017; Strecker and Aamo, 2018). Other approaches have mainly been centered around compensation of the motion of the drill string during connections, rather than compensation of the downhole pressure. Drill string motion compensation is an approach associated with high mechanical complexity and high costs.

HeaveLock™ is a downhole choke valve, to be installed in the drill string as a part of the bottom hole assembly (Kvernland et al., 2018), see Figure 3. It senses movements of the drill string using an accelerometer and controls the flow of drill mud accordingly, thereby compensating for pressure variations under the drill bit. During swab, more mud is allowed to pass. During surge, the mud flow is restricted. Precise control of the mud

Figure 5 Pilot-scale HeaveLock™ prototype, ready to be tested at IRIS Ullrigg in Stavanger

flow keeps the downhole pressure steady. A Continuous Circulation System (CCS) is required to use HeaveLock™ and is available from several drilling equipment suppliers today.

The idea of downhole choking originates from NTNU and the company Heavelock AS was started in Trondheim in 2015. Using an in-house well simulator, it was shown that pressure oscillations could be reduced from ~20 barg down to less than 5 barg when HeaveLock™ was engaged, see Figure 4. A commonly utilized limit for downhole pressure oscillations in MPD is approximately +/- 2.5 barg. These numbers were later confirmed in laboratory scale experiments. First full scale prototype of the HeaveLock™ choke valve was tested in realistic flow and pressure conditions in mud loop of IRIS Ullrigg in Stavanger during the summer of 2018, see Figure 5".

Next phase in the HeaveLock™ development process is to design and construct a prototype for the first full-scale downhole test, which is planned to be carried out using an onshore test drill rig some time in 2020. Heavelock AS is pursuing partnerships with additional E&P companies as well as a drilling service company in order to succeed with the development. The ambitious goal of Heavelock AS is to contribute to higher utilization of automated and digitized drilling solutions and become an enabler for MPD operations from floating rigs and drillships, thus unlocking additional IOR potential on the Norwegian Continental Shelf and beyond.

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WELL CLEANED WELLS

FourPhase increases the efficiency of well clean-up interventions thereby reducing costs

During a well's lifespan, various issues may occur that will negatively affect operations and decrease production rates. A common problem is production sonstrained or halted due to sand.

SAND-LOGGED PROCEEDINGS

As 70% of all oil and gas fields worldwide produce sand, wellbores being blocked by sand plugs is a common issue. Sand plugs form due to insufficient energy for the transportation of sand up the well to the surface. The sand falls back into the well flow, where it accumulates in the wellbore and eventually brings production to a halt. In order to remove the sand plug, intervention operations are required. Consequently, sand clean-up is the most common coiled tubing (CT) operation.

EMPTY IT OUT

DualFlow – a solids removal system developed by FourPhase – greatly increases the efficiency of well clean-ups.

In any CT operation, DualFlow effectively removes solids from the flowback fluids. The DualFlow system allows for solids to be removed in any rig up without any manual handling, thereby having a positive effect on operational safety. With a separation efficiency of up to 99.8 %, DualFlow is the most effective tool for solids removal in sand clean-up interventionoperations. In addition to sand, DualFlow will effectively remove different types of solids, including fines, chalk, scale, proppants and cement.

SAVING SPACE

The DualFlow solids removal system has proved to be a safe and cost effective solution for flowback and coiled tubing well intervention operations. Considering its compact footprint of 2m x 2m and 3m heights and the possibility for installation on top of the choke, the DualFlow is made for a safe and easy installation.

To learn more about leading solids removal technology visit www.fourphase.com

FOUR PHASE

Pneumatic conveying of wet particles to illustrate offshore drill cutting handling

Disposal of drill cuttings, generated from the drilling operations in offshore rigs has always been a challenge. During the drilling operations the drill cuttings have to be transferred to storage locations on the rig and then must be transferred to the treatment facilities via transport vessels.

"The objective of the study was to investigate the impact of the presence of a drilling fluid towards the pneumatic conveying properties of a bulk solid"

Conveying of drill cuttings is a challenging task due to its sticky nature. Hence a new scientific study is required to optimize the offshore drill cutting handling process.

In a research project, the pneumatic characteristics of particles mixed with a drilling fluid was studied based on pilot scale experiments. The objective of the study was to investigate the impact of the presence of a drilling fluid towards the pneumatic conveying properties of a bulk solid, which can be utilized in offshore drill cutting handling.

Experiments

Pneumatic conveying and fluidization tests were conducted for sand samples with different size distributions (particles in the range of 100 µm upto 11 mm). The tests were conducted for both dry and wet (mixed with a drilling fluid) conditions. For this study a premix based on EDC 95/11 was considered. The experiments were conducted at the pilot scale pneumatic conveying rig at SINTEF Tel-Tek, Porsgrunn (Figure 1).

Results

The fluidization tests show that the minimum conveying velocity of a dry particle system is significantly increased when a small amount of drilling fluid (1.5% by weight) is introduced to the particle mixture. However, there was no significant deviation of the fluidization behaviour when the drilling fluid concentration was increased further from 1.5% up to 6.3%. (Figure 2)

Figure 1: Pilot scale pneumatic conveying rig

Horizontal pneumatic conveying pressure drop displayed a similar behaviour as the minimum fluidization velocity with the drilling fluid concentration. That is, the pressure drop corresponding to the sand-drilling fluid mixture at the concentration of 1.5% was significantly low compared to the pressure drop of the same dry sand mixture. It was also observed that the deviation of the minimum fluidization velocity of a wet sand mixture with respect to its dry condition and the deviation of the horizontal pneumatic conveying pressure drop of the same wet sand mixture with respect to its dry condition are closely correlated.

Conclusion

The reduction in the pneumatic conveying pressure drop and the increment of the fluidization velocity suggest that the presence of a drilling fluid in a particle mixture acts as a lubricating agent. As a thin layer of drilling fluid is formed on the surface of the particles, the air-particle, particle-particle and particle-wall frictions are reduced. The gradual increment of the drilling fluid concentration does not affect the change of either the minimum fluidization velocity or the pneumatic conveying pressure drop, until reaching a certain critical drilling fluid concentration (approximately 6-10% by weight).

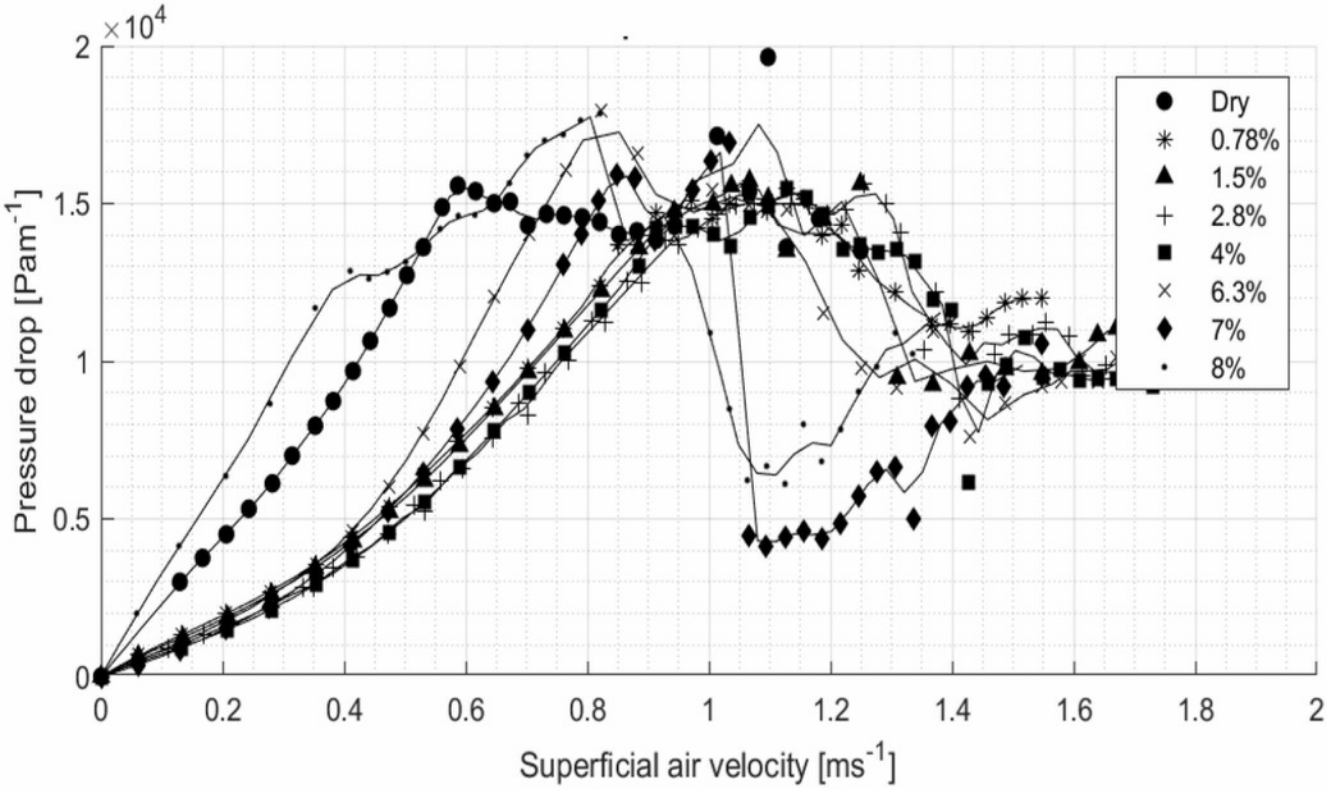

Figure 2 Deviation of fluidization curves with drilling fluid concentration

Practical applications

The study shows that an empirical model can be developed to predict the pressure drop in horizontal pneumatic conveying under dilute phase for dry particles. By incorporating the change of minimum fluidization velocity factor to the pneumatic conveying pressure drop model, the pressure drop of the particle -drilling fluid mixtures could be predicted approximately. Therefore, it can be concluded that by conducting pneumatic conveying tests for dry mixtures and fluidization tests for particle - drilling fluid mixtures, a model can be developed to predict the pneumatic conveying pressure drop of the particle - drilling fluid mixtures.

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The subsea gate box: an alternative subsea field architecture

The process of planning and developing an offshore hydrocarbon field is normally based on very limited information collected from exploratory wells and making proper assumptions on the reservoir characteristics. The uncertainties in the subsurface, in the development process and during the regular operations on the field production are an important challenge to overcome for the different disciplines involved. New constraints, changes in the operating conditions or new discoveries could lead to significant deviation from the initial forecast. Therefore, system flexibility is paramount not only for daily operations but also to enable adapting and upgrading the subsea facilities according to varying requirements and conditions of the field.

Production management and optimization are crucial in subsea developments where each well, equipment and marine operation are considerably more expensive than for standard onshore fields. Therefore, field architecture concepts should allow a higher degree of flexibility in the well production and to increase production management capabilities.

On this line of thinking, the Subsea Gate Box Concept has been proposed as an alternative to integrate subsea processing on the field architecture, aimed to increase flexibility and efficiency. The concept is an ongoing study within SUBPRO research center, which is an SFI project founded by the Research Council of Norway, the Norwegian University of Science and Technology and different industrial partners from diverse sectors of the oil and gas industry. SUBPRO, “Subsea Production and Processing”, is mainly focused on five core areas of the subsea production system: separation concepts, flow characterization, system control, field architecture, and reliability and safety. SUBPRO primary objective is to provide the oil & gas industry with knowledge and technology innovation within subsea production and processing.

The Subsea Gate Box (SGB) is addressed to oil and gas fields with large heterogeneity among wells that might be due to different formations or reservoirs with very different properties and conditions. In standard field architectures, it is common to comingle the production of the different wells prior to pre-processing and transport. Such strategy might lead to a mismanagement of the naturally available energy and make it difficult to keep high efficiency of the process equipment. For instance, commingling wells with different reservoir pressures and productivities requires to choke-back the stronger wells to match the capacity of the low energy wells. In other words, the weaker wells are the ones dictating the wellhead pressure and, thus, the production. Moreover, the system might become constrained by wells with less favorable conditions (higher gas fraction, water cut, stream pressure, fluid composition, hydrate formation, waxes, etc.), or require very wide operational ranges for subsea processing units such as boosters and separators.

It is possible to design subsea processing units for wide operational conditions, but it requires large and more robust equipment, which might frequently work outside of their optimal operating envelope, thus wasting energy. Although the equipment footprint is not a constraint subsea, it is for the installation and maintenance of such units. Furthermore, deep-water applications require even more robustness to withstand high pressures, adding extra challenges from a manufacturing perspective. Therefore, modular and compact process units are gaining attention also for subsea developments.

Robustness is not only required from the hardware point of view but it also an important factor in the development of numerical models. In the current digitalization era, optimization of the production also relies on the capacity of the models to predict the different phenomena, from the reservoir dynamics and flow assurance issues within the network, to prognostics model for control and maintenance purpose. Hence, the gate box concept could potentially contribute to increase confidence in the process system performance and its management capability, enabling higher accuracy and applicability of numerical models on the prediction of a given process or equipment.

The subsea gate box has been defined as a multifunctional assembly that enables decoupling the well performance from the network by incorporating process modules to to prepare the wells stream to be introduced into the production system. The assembly would consist of retrievable modules for dedicated process trains, which could include separation, boosting, chemical injection, metering, among other auxiliary processes to improve the well performance. In principle, these individual trains only would contain primary stages of a given process. The ultimate objectives are to prepare the well stream for further processing and optimize the usage of both the reservoir energy and the external energy introduced to the fluid stream while avoiding reducing production.

“The Subsea Gate Box (SGB) is addressed to oil and gas fields with large heterogeneity among wells”

The SGB could be designed for different field architectures including satellite wells, clusters, and template configurations. Each module will give

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the opportunity to adapt the process train to the specific operating conditions of an individual well or group of wells over the lifetime of the field. In this way, the different using regular intervention vessels. As an example, a diagram of the SGB concept is shown in Figure 1. Assuming a given field development that includes different formations and reservoirs, all of which are developed on different project stages over the time. A well or a group of wells could present different performance and/or very different flow characteristics, from fluid composition to different water cut or gas fraction. A dedicated processing train could be designed to attend the different well fluids and operating conditions. Thus, a given train could contain units for separation or flow conditioning, liquid boosting and gas treatment, while another train could only contain some chemical treatment and leave some free slots for future modifications or upgrades. Furthermore, the trains could be interconnected among them to allow bypassing production from one train to another, as a means to increase redundancy or increase operational flexibility during maintenance procedures.

“ The subsea gate box concept opens the opportunity for increasing the flexibility in the production system ”

equipment could be designed for a more optimal operational range, potentially enabling higher process efficiency and smaller footprint per unit. The subsea gate box concept opens the opportunity for increasing the flexibility in the production system along the network and over the lifetime of the field. The assembly could easily allow for future modifications of the subsea system and redundancy for critical processes. The modules should be easily retrievable for replacement or upgrading of units

The main drawback of the concept lies on the increasing number of components and the increasing complexity of the system in terms of electrical and flow connections. Therefore, an important task on the concept evaluation would be to define the feasibility of the application of such assembly in terms of the cost-effective impact of the SGB and the reliability and availability of the major components. The analysis related to RAMS will be considered on a separate project within SUBPRO,

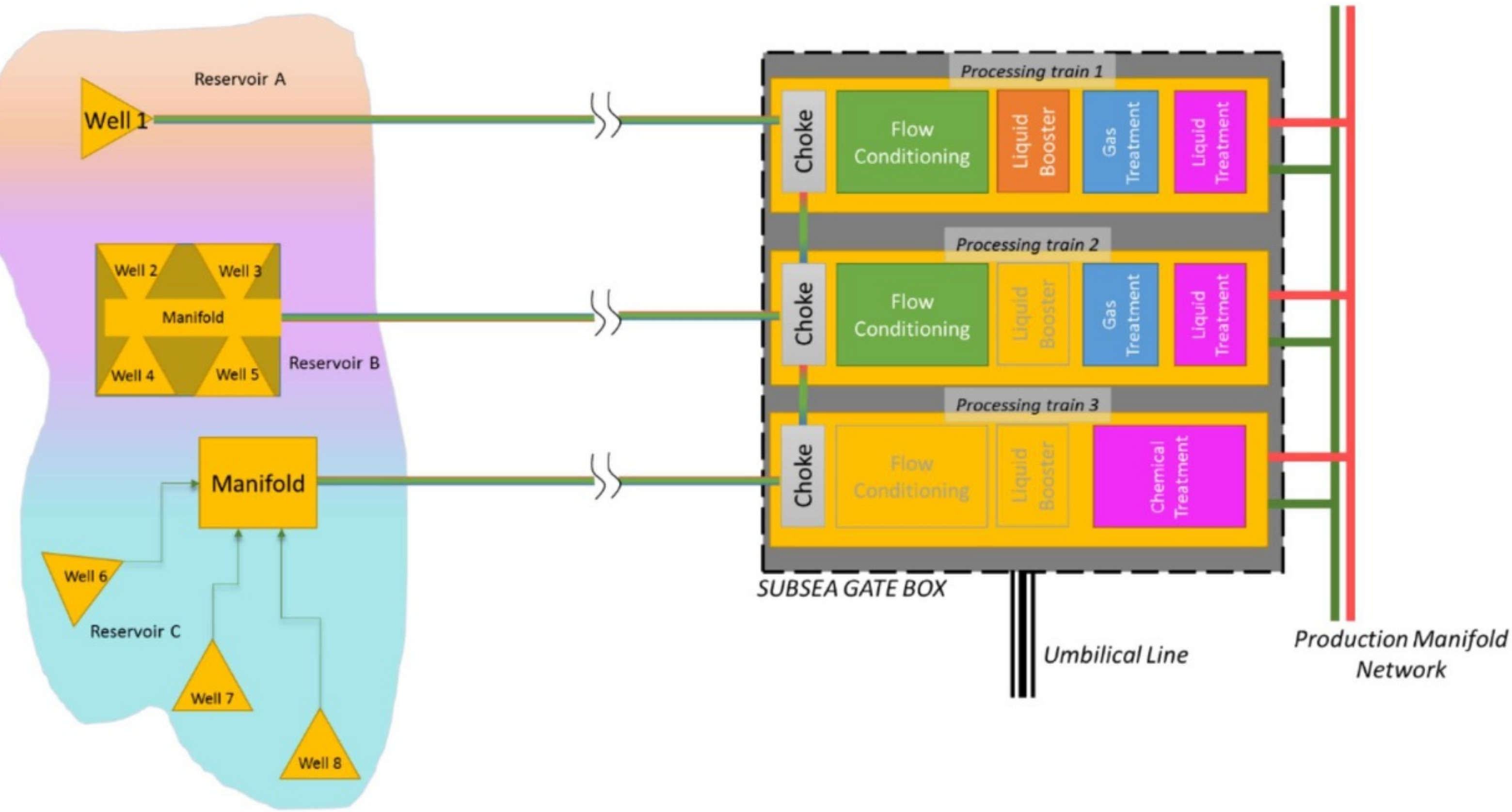

Figure 1 Subsea Gate Box Concept

where the Subsea Gate Box will be used as an example for including reliability analysis on the early design of subsea systems. The cost-effective evaluation, on the other hand, would be carried out in three stages. The first stage includes defining the niche of application for the concept and identifying the scenarios where the SGB would give the best benefit. The second stage is the identification of the technology available in the market or under development that could potentially be used within the SGB, mapping the current gaps in equipment and technology. The final stage is when the concept proposal, which includes looking at possible suitable configurations and arrangements

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that could be used in the SGB to provide easiness to connect and remove equipment and customizable units.

The objective was to evaluate the capability of the gate box concept by including liquid boosting within the modular assembly.

The simulations showed the possibility to increase production from a target well by 24% when applying the subsea gate box concept with respect to the production achieved by a central boosting configuration. Thus, the results have been encouraging for the subsea gate box concept and they have shown some potential for the application of such strategy.

Future work will focus on defining the main functional characteristics and requirements of the gate box, as well as performing a rough economic evaluation of such concept. Further analysis may consider the value of the flexibility against the complexity of the system.

"The simulations showed the possibility to increase production from a target well by 24% "

Furthermore, the concept proposal stage would explore the cost implications and benefits of the concept for subsea developments.

The first stage has been carried out based on a synthetic business case of a typical oil field development. The analysis has included numerical simulations using a commercial software for integrated modeling of a production system.

This aspect could represent one of the key element on the incorporation of such concept as a plausible alternative for a given subsea development.

Likewise, including optimization of the field architecture design and operational strategy might be important in order to ensure a fair comparison of the Subsea Gate Box concept respect the existing solutions.

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