Horizontal Openhole Completion Techniques Revitalize Fields on the Texas Gulf Coast

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Abstract

Production from old fields is being resurrected in new horizontal wells along the Texas coast through the use of openhole completion technology. This use of technology presents a significant contrast to traditional high profile wells utilizing engineered reservoir drill-in fluids and openhole sand control. The economics of these wells requires a careful balance of risk tolerance while maintaining critical best practices to minimize formation damage and ensure well productivity.

Completion operations on land require a clear understanding of operational requirements, which must be communicated to rig personnel who might be completely unfamiliar with openhole completions as practiced offshore. The planning phase subsequently requires education to enable more informed decisions on key steps.

For example, the reservoir drill-in fluid might be limited in design parameters due to the lack of information available at the design stage. Several steps can be taken to manage this high level of uncertainty while assuring better outcomes. Operational planning demands creative management of the rigs with limited capabilities to adapt to the demands of openhole sand control installations. Basic functions such as fluid movements might be partially hindered by the lack of pits and surface volume for well displacements.

A case study is reviewed to compare common best practices developed offshore with economically realistic measures in land operations to minimize well risk under a highly restricted cost environment. Even under these constraints, technologies typically found in more expensive drilling programs are converging to deliver low-cost, high-volume wells that meet or exceed anticipated production targets.

Introduction

The abundance of hydrocarbon fields along the southern Gulf Coast of the United States have been a major source of production since the late 1920s (Martyn 1930). From the major oil companies to the smaller independents, these fields demonstrate how the development and advancement of oilfield technology can resurrect production targets beyond what was historically understood. Many of these fields were developed long before the advent of horizontal drilling paired with openhole completion technology and customized reservoir drill-in fluids (RDFs). Since these technologies emerged in the early to mid-1990s (Ali et al. 2006), it has become possible to economically recover significant amounts of the previously deemed "residual" hydrocarbon reserves from these once-prolific fields with new methods (Hulsey 2016, Harrington 2017).

The Portilla, Magnet Withers, West Ranch, and McFaddin are just a few fields that represent this trend – old fields seeing a revival by using new technologies. More than 500 million barrels of oil (and counting) has been produced in the region. For example, the West Ranch field featured multiple discoveries in the 1930's, producing more than 400 million barrels of oil to date (Harrington 2017). A recent pilot EOR project, funded in part by the federal government, includes utilizing carbon capture from a coal plant as the injection fluid (Harrington 2017). These and other technologies are changing the economics of revitalizing older wells.

Since the heyday of production in these fields, dozens of operators from small independents to major conglomerates have been granted drilling permits to further develop these fields utilizing new technologies, including horizontal openhole drilling and completions. These horizontal wells capture hydrocarbon layers that were not drained by the previous vertical well production.

Typical monthly production values on the fields referenced in this paper range from 2,800 to 20,200 barrels of oil per month (Texas Railroad Commission 2020, Figure 1), with opportunities for additional production (Billingsley 2010) increases from similar reservoirs.
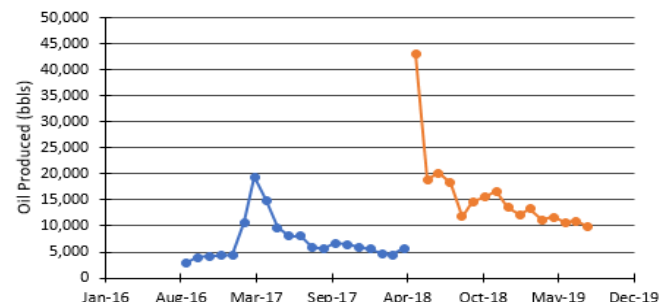

Figure 1: Recent production from Portilla Wells, including those using openhole completion techniques (Texas Railroad Commission 2020).

Historical Review of Openhole Completions

Openhole completion technologies continue to evolve based upon fundamental concepts of formation damage control and sand control. These foundational concepts, regardless of the cost environment, remain essential to delivering an economic well and ensuring optimal return on investment.

As well technology evolved, historically prolific fields on land declined, reducing the need for techniques to complete high-rate production jobs on land. At the same time, prolific offshore wells demanded reliable completion techniques to support the resources to develop them. This dichotomy set the stage for today's diversity in economics and technology fundamentals between land and offshore drilling.

Openhole Sand Control

In unconsolidated sandstone reservoirs, loose formation materials are transported by produced fluid into the wellbore, blocking the production pathways. In addition, if sand reaches production equipment, it has the potential to erode and destroy the equipment, leading to costly downtime. Thus, controlling the sand intrusions became an economic necessity.

The primary method to control sand utilizes a retention media to retain the mobilized material near the wellbore wall, minimizing movement. The retention media ranges from slotted liners to screens with mesh sleeves or wrapped wires.

In the 1930s, gravel packing was regularly used for sand control in California (Coberly and Wagner 1938). Gravel packing involves pumping sized natural or synthetic sand material in between the wellbore and the sand retention media, holding the formation in place with highly permeable material. This completion technique quickly demonstrated superior production relative to previous conventional methods, increasing its adoption in applicable wells (Clark 1939).

Openhole sand control technology continued to evolve, with greater attention placed upon carrier fluid chemistry and pump rates in gravel packs (Gajdosik and Willingham 1976). By the early 1980s, these techniques were reaching 1000 feet in reservoir length with deviated (non-vertical, non-horizontal) trajectories (Gottschling and Legan 1981). By the late 1990s, the application technology of horizontal openhole gravel packs matured to being a requirement for major projects worldwide.

Sand control screens, both for gravel packing and for standalone applications, continue to evolve from imprecise slotted liners. Today, filter media options are available across a wide range of sizes, materials, and retention methods to meet numerous well challenges.

Reservoir Drill-In Fluids

Formation damage from drilling fluids began to receive attention at a very early stage in openhole sand control design. Filtercake quality and the distinctions between oil-based and water-based drilling fluids were under discussion as early as 1946 (Kersten). By 1947, Radford reported on the investigation of formation damage from filtrate and solids.

Originally, many procedures utilized a strategy of drilling with conventional drilling fluid, displacing to a solids-free fluid, and reaming the reservoir with the solids-free fluid

(Gottschling and Legan 1981). Research and development, along with field observations, revealed the damage potential of solids-free fluids (Wilton et al. 1993). Relative permeability testing using a variety of techniques revealed the numerous formation damage mechanisms, particularly those from drilling fluids, requiring special consideration (Krueger 1986).

RDF design continued to advance along with sand control techniques, separating general drilling fluid systems from these fluids designed specifically to mitigate formation damage. Sophisticated testing methods, including today's return permeability tests, have become standard practice to ensure RDF compatibility with the reservoir (Marshall et al. 1999).

In concert with advancing sand control and RDF technology, filtercake removal options also continued to grow. Cleanup through flowback is now complemented with acid treatments to remove some damage, although acid introduces its own set of damage risks.

By the mid-1990's, enzyme treatments designed to degrade polysaccharides were introduced (Moore et al 1996). Other filtercake breaker options introduced include chelants, esters, oxidizers.

Drilling Environments

The rapid growth in openhole sand control and drill-in fluid technology that started in the 1990's continues to advance. The economic drivers for these technologies are centered around high-rate wells in unconsolidated reservoirs. Many of these applications were in ever-deepening water depths and remote operations.

The cost of failure and intervention in high-cost environments demanded reliability, justifying premium costs for completion equipment and fluids. Meanwhile, the depleted fields of the Gulf Coast continued to produce at low volumes via low-cost cased and perforated completions.

Leveraging the Reservoir Drill-In Fluid Composition

Technologies and design methods employed in today's market focus on minimizing filtrate invasion while reducing flow initiation pressures.

A low flow initiation pressure is essential for effective filtercake cleanup, particularly in horizontal wells. This is the differential pressure required to begin the flow of production fluid. A high flow initiation pressure increases the risk of uneven production, sometimes called hotspots, where unusually high, localized flow rates erode sand control equipment. Uneven drawdown pressure also increases the risks of coning, or excess gas or water production, and lower oil production volume (Figure 2).

Elevated flow initiation pressures also increase the risk of excess production at the heel, where drawdown pressures are higher and little or no production at the toe. This can result in coning, where overproduction draws gas or water into the wellbore along with the desired oil. Filtercake confinement, such as through gravel packing, further elevates flow initiation pressures (Figure 3).
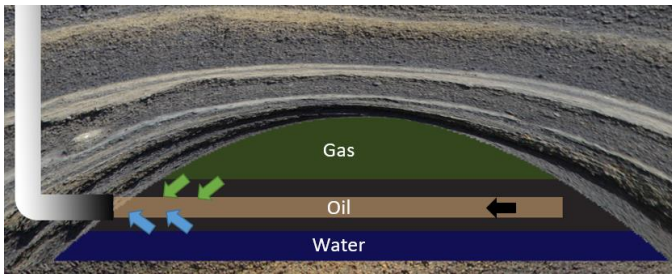
Figure 2: Oil reservoirs typically contain a layer of gas on top of the oil layer on top of a water layer. Substantial drawdown at the heel may result in coning of water and/or gas (green and blue arrows) instead of producing oil from the toe of the reservoir (black arrow)
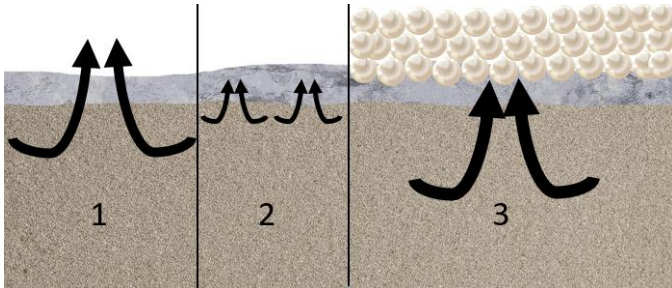

Figure 3: Flow initiation pressure from the permeable formation must pass through the filtercake. In Scenario 1, the cake has elevated yield stress, requiring high pressure for it to lift and/or tear to allow passage of fluid through the cake. In Scenario 2, much less pressure is required because the yield stress is lower. In Scenario 3, the filtercake is confined by gravel and substantially higher pressure is required to break the yield stress as little filtercake material can separate from the formation.

Minimizing flow initiation pressure is inherent to reservoir drill-in fluid design objectives. To further reduce flow initiation pressures, partial or complete removal treatments utilize acid, filtercake breakers, or washes (Bailey et al. 1998).

Invert emulsion systems have inherently low fluid loss and flow initiation pressures relative to water-based drilling fluids. However, due to cost concerns, water-based drilling fluids were the choice of the operator in the case history noted in this paper, so the discussion will focus solely on water-based reservoir drill-in fluid system options.

Component Selection
Component selection of a RDF requires careful consideration of many factors, including economics, environmental regulations, reservoir characteristics, planned wellbore structures, and programmed completion design.

A water-based RDF usually consists of four components:
- Base brine
- Fluid-loss additive
- Viscosifier
- Bridging/weighting component

Acid-soluble components are preferred, whenever practical, to preserve the option for treatment to remove the filtercake after drilling.

Base brine selection depends upon density requirements, available salt solutions, and cost. Use of excess solids in the RDF increases the risk of producing a thicker filtercake that in turn requires a higher flow initiation pressure. Brine provides solids-free density, with the solids content designed specifically for bridging. Brine solutions also provide various levels of shale inhibition.

The RDF should minimize fluid loss to the formation, but a minimal amount of the base brine will interact with the native reservoir fluid as filtrate. It is imperative the base brine be compatible with the formation fluid to prevent precipitation of undesired solids, which can lead to formation damage and blocking of pore spaces during production.

Other considerations include additive-brine compatibility. For example, xanthan gum does not readily disperse or hydrate in saturated or near-saturated divalent brines.

Excess filtrate invasion increases the risk of formation damage. Elevated fluid loss is linked to thicker filtercake and thus, higher flow initiation pressures. Filtrate invasion also increases the potential for greater interaction with the formation, mobilizing fines, swelling clays, and blocking production flow.

To minimize fluid loss, an RDF utilizes a fluid-loss reducer and a blend of sized solids to enhance sealing. A common fluid loss reducer is starch; however, starch selection requires careful consideration as it impacts flow initiation pressure. For example, polyanionic cellulose (PAC) lowers fluid loss but increases flow initiation pressure (Healy et al. 2012). Starches also provide some of the necessary viscosity to control fluid loss and support the bridging solids.

Because water-based fluid-loss reducers can create "sticky" filtercakes that typically require a higher lift-off pressure versus oil-based RDFs (Browne and Smith 1994), consideration must be given to selecting the proper type and concentration – especially in cases where the well is to be flowed back without the use of a filtercake breaker.

A viscosifier aids hole cleaning and suspension of bridging materials. The preferred option is xanthan gum, a widely available, shear-thinning, biopolymer. Without the aid of a filtration-control additive and bridging package, xanthan gum can be highly damaging. As part of a RDF system, using the minimal concentration of xanthan limits the risk of formation damage.

Linear polymers, such as hydroxyethyl cellulose (HEC), are considered less damaging, but they fail to provide the same level of suspension. Diutan and scleroglucan are occasionally used, but compatibility and cost limit widespread adoption of either.

Bridging solids usually consist of sized calcium carbonate or salt particles. Solids concentration can be increased for more density; however, this can result in elevated flow initiation pressures.

Bridging Solids and Particle Size Distribution
Historically, the principle guideline for designing a proper particle-size distribution in order to minimize the depth of invasion of a filtercake was derived from Abrams' rule (Abrams 1977). This rule states "the median particle size of the bridging material should be equal to or slightly greater than ⅓ the median pore size of the formation". The rule also suggests the

concentration of the bridging particles must be 5% by volume or greater to form a proper bridge and stop the fluid invasion. Using this theory alone, a fluid should be designed with a wide range of particles in order to cover a supposedly wide bridging spectrum.

New theories, built upon Abrams' rule, claim superior packing efficiency. The Ideal Packing Theory (IPT) considers the total particle range required to seal all pore spaces, including the spaces created by bridging particles (Dick et al. 2000). The Ideal Packing Theory states that optimum or "ideal" packing occurs when the percent of cumulative volume vs. the $D^{1/2}$ forms a straight-line relationship (Figure 4). The IPT also suggests that the minimum volume of bridging particles needed to effectively seal is 2 to 3% by volume.
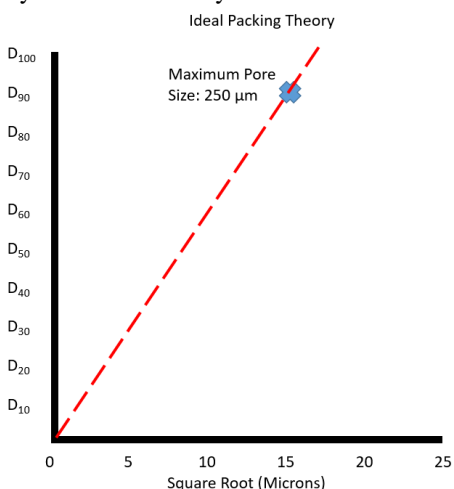

Figure 4: Example target line (red) for particle distribution. For a maximum pore size of 250 μm, the target line is set by drawing a line from the origin through the point at the D_{90} and the square root of the maximum pore size.

Another method, proposed by Vickers et al. (2008), attempted to "fill-in" the gap left by the Abrams rule by taking a closer look at reservoir flow characteristics and looking beyond the median pore size. This method factors the predominant portion of production that will flow through the largest pore throats and that many pore throats could be much smaller than the median pore size. In essence, the distribution of pore throat sizes found in any given rock tend to vary widely and require more than one measurement. Vickers' criteria matches the particle size distribution with multiple target pore throat sizes to address this gap: D_{90}, D_{75}, D_{50}, D_{25}, and the D_{10} (Figure 5).

Best Practices versus Practical Implementation

There are distinct differences in best vs practical when it comes to designing, planning, and executing a RDF job given the well site location and economic profile. While the ultimate goal is to minimize formation damage and maximize production, there are distinct differences in the approach depending on the cost environment.

The most significant difference between a high-cost environment, typically a deepwater application, and a basic

land operation, is risk mitigation. Delays or failure in remote or extreme environments, such as deepwater, cost the operator
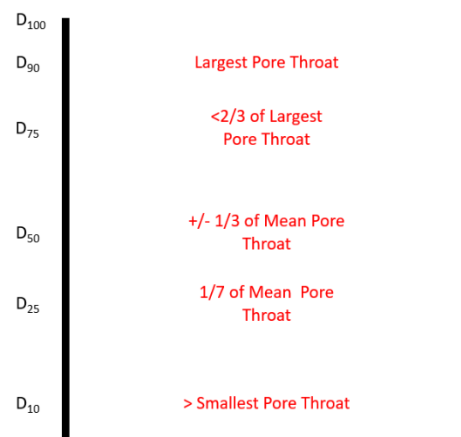

Figure 5: Example target percentages (red) for particle distribution. Note that the resulting PSD line is no longer linear.

millions of dollars in lost time and remediation. On land, these costs can be orders of magnitude less, limiting the justification for added costs and extra steps (Table 1).

Table 1: Typical Costs of Remediation for Deepwater & Remote Area vs Land		
Factor	**Deepwater & Remote Environment**	**Land**
Theoretical Day Rate	$500,000	$25,000
Theoretical Well Production (bbl/day)	5,000 - 25,000	100 - 500
7-Day Sidetrack Cost	$3,500,000	$175,000
Lost Production (daily at $50/bbl)	$250,000 - $1,250,000	$500 - $15,000
Extra Trip (2 Days)	$1,000,000	$50,000

Across the following sections, the authors compare the design, planning, and execution steps of typical high-profile, high-cost wells versus the practical reality of applying these concepts to a low-cost land operation.

Design Phase

The data collected and case history referenced in this paper span multiple operators. In each case discussed herein, the operator had limited experience with reservoir drill-in fluids and openhole completions.

Engineering Personnel

Deepwater operations utilize one or more drilling engineers and a separate completion engineering team. Collaboration requires understanding drilling requirements, formation damage mitigation, and openhole sand control across all of the parties and operation phases with overlapping responsibilities. Well planning requires months of planning, design review, and approvals. Extensive test programs occasionally include multiple parties and outside consultants.

When drilling onshore, typically a single drilling engineer

has oversight of one or more rigs and all associated activity. Well plans can overlap drilling operations, limiting time to review steps between wells. For the case history discussed in this paper, test programs were limited to recommendations by the service provider.

Background Data

Planning for formation damage mitigation requires samples and information for laboratory testing and product selection. Typical data points required are summarized in Table 2.

It is not uncommon for deepwater field development to include dedicated coring sections and downhole fluid sampling as part of the exploration phase. Analysis and samples are available for testing, although the quantity and quality varies.

In an onshore field, this type of data and customization process is unavailable. Coring and other information-bearing analysis is too expensive to collect. Primarily the process relies upon basic information to design the sand control and estimate production. For well-known fields, supplemental information may be available in the public domain.

Table 2: Comparison of Resources Available for Laboratory Testing		
Data Set	Deepwater/ Remote Environment	Land
Crude Oil	Available	Available
Formation Water (ionic composition)	Available	Available
Thin Section Studies	Available	Seldom to never available – typically rely upon permeability testing or sand PSD for bridging
Reservoir Material (Core)	Available – or a full petrophysical report is available	Seldom to never available
Shale Material (Core)	Occasionally Available	Seldom to never available
Funds for Return Permeability Tests	Available	Seldom to never available

Laboratory Design

For the case history, limited information and samples resulted in a narrow testing scope. Per customer request, the planned system was a ~9.0 lb_m/gal polymer-carbonate system with calcium chloride base brine. In some cases, calcium can add risk of precipitation, but in this case the calcium was viewed as an shale inhibitor option.

Calcium chloride was used successfully in previous wells in the area, indicating little or no risk of incompatibility with the formation water. Without formation water samples or ion analysis to synthesize formation water, no testing was performed.

Crude oil was available, but given the low density of the brine and historical success of its use, this testing was also not performed.

The drilling fluid components utilized proven materials, including starch and xanthan gum. The calcium carbonate bridging material required appropriate sizing for the formation. Selecting the bridging material depends upon pore sizing, available using several different methods. Each method has drawbacks in reliability as some involve interpretations of data and others involve direct readings.

The only information available was the maximum permeability in each case. For modeling purposes, the square root of the maximum permeability was calculated to estimate the median pore size (D_{50}). This target was used to determine the appropriate blend using the IPT method.

The model was adjusted slightly to reflect the experience of the authors. Specifically, in high overbalance environments larger and coarser materials are required to maintain a low flow initiation pressure as materials compact (Bailey et al. 1998). The heavily depleted reservoir sands in the target area implied significant overbalance even at low mud weights.

Fluid-loss testing was performed on ceramic disk media using a range of sizes to account for the uncertainty of exact pore size distributions. The spurt loss results were elevated, requiring the addition of a small amount of fine calcium carbonate. Follow-up testing demonstrated acceptable fluid loss.

At this stage in the design process, standard procedure calls for a flowback test to evaluate the critical flow initiation pressure on a small-scale flow assembly. In most cases, this test apparatus is a pressurized canister attached to an HPHT cell. Fluid is pumped at pressure through a disc and the rate is measured as a time per unit volume. This test is repeated after applying a filtercake and comparing the results. In this case, the equipment was unavailable. Given the limited options to alter the fluid formulation and insufficient time to run the test, this evaluation was not performed. The proven formulation built confidence for success, but in different circumstances with testing available and no proven successful wells, this would be an important test to run.

Frequently the flowback test is also used to compare filtercake breaker performance, which was also not planned for these wells, with a post-acid treatment considered a contingency only. Acid solubility was verified for the RDF components in case acid was necessary.

The final qualification in most testing programs includes a return permeability test. The test uses reservoir or analogous core to generate a filtercake on the core face. Permeability measurements are taken before and after fluid exposure to calculate loss of relative permeability. The equipment is complex and somewhat expensive.

Return permeability tests typically cost between $5,000 for a basic procedure and can exceed $10,000 for additional steps. In comprehensive testing programs, 5 to 6 successful tests are required to evaluate all of the fluids. In deepwater, this testing is considered mandatory. Onshore, this testing is out of the

question in almost every case due to cost.

Execution

Engineering design eliminates a number of uncertainties and problems, but many failures in completions result from mistakes made during execution. Lack of knowledge, poor equipment, incorrect maintenance, and mistakes in fluid movements and management are significant risk factors.

Rig Limitations

Deepwater operations feature thousands of barrels of extra fluid volume storage. In some cases, the rigs feature separate circulating systems to prevent contamination between systems. Limitations include available deck space and space for personnel. Lead times for materials can exceed 72 hours in remote locations.

Onshore, the limitations were not associated with space and logistics, but with circulating volumes and pit space. Fluid volumes are smaller, but there are few pits with reliable isolation for complex fluids movements, such as during a displacement.

RDF Preparation and Transport

In deepwater operations, most drill-in fluids are mixed onshore at dedicated mixing plants. It is easier to transport built fluids, particularly in the large volumes required. Onshore, it is possible to prepare the RDF at the rig; however, pit cleaning and other activities increase the risk of delays. The ~800 bbl necessary for a circulating system in this case history was mixed using a pristine mixing system and trucked to location.

The importance of insuring the RDF remains clean during transport to the rig is paramount. If the RDF is contaminated with any other fluids or drill solids, it can directly impact the reservoir causing formation damage and affecting future production. Workboat cleanliness and inspections prevent this risk from occurring.

Vacuum trucks, frequently used on land, transport a wide variety of liquids other than drilling fluid. It is not uncommon for residual wastewater to contain bacteria that can digest the starch component of the fluid. Steam cleaning is recommended, but inspection is difficult and some truck drivers can be unreliable.

Displacement to RDF

Care must be taken when displacing the a well to RDF. If displaced improperly, contamination from the water-based drilling fluid system, even the low-solids, non-dispersed system that was used to drill the intermediate interval, will cause damage to the wellbore and limit production of the well.

The well was displaced to water during the intermediate interval cement job. While offline, all surface lines were flushed and the mud pits dumped and cleaned thoroughly to prevent cross contamination before filling with RDF. Prior to drilling out, a high-viscosity spacer was pumped ahead of the RDF displacement to limit the interface between fluids. This performed as an excellent method to ensure overall cleanliness and minimize the risk of contamination in a constrained environment.

Dilution and Maintenance

In a deepwater well, the typical openhole volume is a small fraction of the overall circulating system volume. Drill solids, which increase the yield stress of the filtercake and increase flow initiation pressures, are a very small volume of the overall circulating system. Many targets from experts dictate maximum of 2% drill solids before dilution, although this is usually impractical for small rigs – including small jackups and platforms. In many cases, the limit is extended to 3% v/v for both logistic and fluid cost reasons.

The typical "dump and dilute" method often used in land operations is typically not necessary for offshore operations. For instance, given typical solids control efficiency and capabilities when running an RDF, the drilled solids in a 2000-ft x 6⅛-in. section remains low given the large casing/riser volumes. The land rigs for the case history discussed herein typically maintained <400-bbl circulating volume, with extra volume available from nearby fracturing fluid tank storage. Table 3 compares the potential for solids accumulation which is severely impacted by the difference in circulating volume.

Table 3: Comparison of Potential for Drill Solids Accumulation		
Volume	**Deepwater/ Remote Environment**	**Land**
Cuttings Drilled (bbl)	72.9	72.9
Circulating Volume (bbl)	6,000	800
% Volume Cuttings in Fluid (No Solids Control)	1.2%	11%
% Volume Cuttings in Fluid (60% Solids Control Efficiency)	0.5%	3.6%

Fluid property maintenance with an RDF is seldom complex. In most cases, fluid monitoring focuses on the accumulation of drill solids and maintaining low fluid loss. Most treatment involves additions of coarse calcium carbonate to replenish particles degraded by the drilling process, separated and removed by the shakers, or due to dilution.

Onsite testing for drill solid accumulation utilizes a gravimetric method to observe baseline acid solubility of a filtercake versus drill solid accumulation as drilling progresses.. Given the limitations of the rigsite in this case, samples were pulled during the first few wells for evaluation in the lab instead of testing in the field (Table 4). The measurements of solids accumulation were used to aid in a dilution schedule to limit onsite testing to spot checks.

Table 4: Typical Properties for RDF Wells	
Property	Range
Mud Weight, lb_m/gal	8.8 – 10.1 (usually 9.4 – 9.6)
Yield Point, lb/100 ft^2	15 – 25
API Fluid Loss, mL/30 min	<6
pH	9.0 – 10.0
MBT, lb/bbl	<5
Low-Gravity Solids, %v/v	<3

In the multi-well campaigns from which this case history was selected, there was substantial pressure to reuse the RDF from well to well. This required careful tracking of the drilled solids accumulation along with a clear dilution schedule for introducing fresh drilling fluid at every new well. Properties, including particle size distribution, were monitored to ensure fluid quality. While this strategy is not preferred, it was considered the most practical approach to minimize risk at the lowest possible cost.

Displacement to Solids-Free Pill and Brine

In most cases, a wellbore cleanout run is performed prior to running screens. The wellbore cleanout assembly typically features a scraper, magnets, and brushes to scrape the casing, particularly the packer setting depth, and carry other debris to surface. In many applications the wellbore cleanout assembly is stiff in nature to simulate a drift run of the sand control screens. This aids to make sure they will reach target depth.

The consequences of proceeding forward without effectively cleaning the wellbore can include an inability to run screens to bottom, screen plugging, incomplete or poor gravel pack, screen erosion, and an inability to set the packer or to activate the fluid loss control valve. Despite these risks, the operator in each case determined a dedicated wellbore cleanout run was not necessary given the economic constraints.

In most cases, fluids utilized from one operation to the next are of the same phase (water-based) and moreover, utilize the same base salt (calcium chloride), steps were enacted to maximize cleanliness of the wellbore. The excess solids-free pill pumped above the open-hole and inside casing acted as a powerful sweep while swapping the casing over to clean brine.

The solids-free pill minimizes the chance for plugging production screens and acts as a fluid-loss control pill due to its viscous properties. The standard technique is to place the solids-free pill on the last trip before running screens and displacing the casing to brine. The lead end of the solids-free pill is spotted at least 200 feet above the packer setting depth to ensure it is displaced beyond the casing shoe.

A solids-free fluid must contain compatible components, ideally the same components found in the RDF. In order to effectively displace the RDF, the solids-free fluid should have a higher density, ideally an additional 0.2 lb/gal of density. Along with enhanced fluid loss capabilities, the viscosity of the solids-free fluid should also be higher than the RDF to further minimize interface during the openhole displacement. A common practice is to ensure the solids-free pill has elevated 6-rpm and 3-rpm readings compared to the RDF. A low-shear

yield point (LSYP) of 1.5 to 2 times that of the RDF is often used as a guideline.

An important test to confirm the solids-free fluid will not plug the production screens is the production screen test (PST). The test involves running a sufficient quantity of solids-free fluid through a small production screen coupon with minimal pressure. The apparatus appears like a tall API fluid loss cell, although it is typically run at 10 psi. The PST was not available, nor were the coupons for testing. The only option was to thoroughly blend the solids-free pill and use extreme caution. While the risk was a concern, there was no evidence of screen plugging from gauge analysis of gravel pack wells. This test is recommended whenever possible (Beldongar et al. 2017).

Screen Running

Screen running is another important step in achieving a successful completion. Sand control screens are run into the openhole with the solids-free fluid. The solids-free fluid will aid in "sliding" the screens to TD, particularly in deviated or horizontal wellbores.

Another source of screen plugging in deviated wells can be the scraping of the production screens against the formation or filtercake on the low side of the well, or due to wellbore instability. These solids, once embedded in the screen, block the flow path of produced hydrocarbons. Portions of the screen that have not been blocked will receive an disproportional amount of flow and will be subject to excessive pressures far beyond design parameters leading to collapse or hotspots (Hamid et al. 1997). These types of costly hardware failures can lead to lost production and potentially the need for well sidetracks to replace the sand screens.

No Breaker

A major completion challenge involved in sand control is the cost and risk of remedial treatments, especially in offshore deepwater environments. Although gravel packing provides a level of stability in the wellbore, the resulting gravel/screen media can trap the filtercake laid down by the RDF, as discussed previously. This can lead to higher drawdown requirements and/or low production rates. Options for filtercake cleanup can vary widely from no treatment to complex, expensive post spotting of breaker treatments.

While there are several factors involved when determining a filtercake clean-up method for a given well, one significant consideration is the permeability of the target formation and resulting gravel sizing. Both laboratory testing and case studies indicate the necessity for chemical treatment of the filtercake in openhole gravel pack (OHGP) scenarios is justified in low permeability (100 to 250 mD) and intermediate permeability (500 to 800 mD) formations. A lower risk of filtercake entrapment and higher drawdown pressures exists in higher permeability formations which include larger sized gravel media, thus lowering the necessity for chemical treatment (Brady et al. 2000, Hodge et al. 2010).

Considering the permeability of the targeted formations were in the Darcy range and planned gravel size (30/50), breaker options were discussed. The operators indicated they

had been performing acid treatments with coiled tubing, but they had stopped and did not see any changes in well production.

No production logging tools (PLT) or tracer data is available to determine if production favors specific areas of the horizontal well. Nevertheless, positive feedback from production results indicates wells are meeting their targets for performance and economics.

Case Study – Openhole Gravel Pack Completion

While offline, the rig was cleaned and prepared for the RDF by cleaning all surface lines and mud pits. Prior to drilling out, a high-viscosity spacer was pumped ahead of the RDF to limit interface between the fluids. Shale shakers were dressed out with 80-mesh shaker screens in order to retain as much sized calcium carbonate as possible while removing drilled solids. Fluid properties were maintained throughout the drilling phase of the 6⅛-in. reservoir section by whole mud dilution. Table 5 shows the typical RDF properties while drilling this section.

Table 5: Comparison of RDF and Solids-Free Fluids		
Property	**RDF**	**Solids-Free Fluid**
600-rpm Reading	50	78
300-rpm Reading	35	52
200-rpm Reading	28	41
100-rpm Reading	21	30
6-rpm Reading	7	12
3-rpm Reading	5	10
10-Sec/10-Min Gel Strength (lb/100 ft^2)	6 /7	10 / 13
Plastic Viscosity (cP)	15	26
Yield Point (lb/100 ft^2)	20	26
p	9.2	9.0
API Fluid Loss, mL/30 min	3.2	-
Density, lb$_m$/gal	10.2	10.4

At interval total depth, a solids-free pill was built in the rig slugging pit and pumped into the open hole to over 200 feet inside the casing. The solids-free pill was blended on location using cut brine and a viscosifying polymer to slightly exceed the RDF rheology (Table 5). After spotting the solids-free pill, the drillstring was pulled into the shoe and the residual RDF/Solids-Free fluid was displaced to completion brine. Visual confirmation of the solids-free pill was observed at the shakers, confirming the correct spotting procedure. All RDF fluid was transferred from the pits to storage frac tanks for use on subsequent wells to drill reservoir sections.

After further cleaning prior to the commencement of completion operations, pits were filled with completion brine to be used for gravel packing operations. The 3½-in. production screens were made up and ran in hole, followed by 3½-in. blank pipe, 3⅜-in. wash pipe ran inside the screen assembly, and the gravel pack packer. Once screens were run to bottom, surface lines and manifolds were pressure tested and the solids-free pill was circulated out. After dropping the ball, packer elements were set by pressuring up and confirmed by over pulling the proper amount. The drill pipe was then pickled to remove any pipe dope and debris before initiating gravel pack.

Gravel packing was performed without issues – covering screens and blank pipe with excess sand being reversed out. Completion brine was filtered to specification (<30 NTUs) using diatomaceous earth filter presses.

Challenges throughout the operation included a low active pit volume of 350 barrels which included poor isolation valves that leaked between slug, pill, and active pits. Completion fluid volumes were limited by lack of pad space; the available storage being the frac tanks. The sand trap and settling pits were bypassed while gravel packing in order to eliminate dead volume.

Conclusions and Looking Forward

Maturing technologies have created an opportunity to increase production and capture overlooked hydrocarbon deposits from old fields using new methods including advanced completion techniques.

- Reduced horizontal openhole completion costs favor their utilization in low-cost operations
- The traditional utilization of openhole completion technologies requires a practical balance with the low-cost land environment.
- Lack of information limits many design options from being tested resulting in more design features based on best practices and knowledge of the area. The cost of mitigating techniques must be balanced with the risk of failure and the cost of remediation.
- Judicious use of best practices for cost reasons can effectively deliver desired production in certain cases.

As technology matures, it is possible that other technologies, such as inflow control devices and swell packers may complement standalone and openhole gravel pack installations in these depleted fields (Freyer and Huse 2002, Offenbacher et al. 2015).

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