Abstract

A case history from Offshore Israel is presented that describes the successful delivery of five (5) ultra-high rate gas wells (+250 MMscf/D) completed in a significant (10 TCF) gas field with 7 in. production tubing and an Open-Hole Gravel Pack (OHGP). Maximizing gas off-take rates from a gas reservoir with high flow capacity (kh) requires large internal diameter (ID) tubing coupled with efficient sand face completions. When sand control is required, the OHGP offers the most efficient as well as the most reliable, long-term track record of performance. A global study of ultra-high rate gas wells was made to select and finalize the design concept after which the commensurate engineering rigor was applied. This paper will highlight the design, qualification, Quality Assurance / Quality Control (QA/QC) and operational performance of the completion fluids inclusive of the Reservoir Drill-in Fluid (RDIF) and the breaker. Completion fluids are critical to the success and production efficiency of an OHGP. The completions were installed with minimal operational issues (Average NPT ≈4%). Production commenced on March 31, 2013. All wells have performed to expectations with maximum well rates up 340 MMscf/D.

Introduction

Operated by Noble Energy, the Tamar field was discovered at the Tamar-1 wildcat, by the Tamar co-venture group (Noble Energy Mediterranean Ltd., Isramco, Delek Drilling LP, Avner Oil Exploration LP, and Dor Gas Explorations LP) in 2009 in 5505 feet (1678 meters) of water at a total depth of 14,967 feet (4,562 meters). Tamar is one of several recent gas discoveries made in the northern offshore deep waters of Israel in the Levant Basin (Figure 1).

Geologic Overview

Structure

The Tamar field consists of three (3) gas bearing sandstone layers separated by two (2) shaley units. The trap for the reservoir is a large four-way anticline, cross-cut by northwest bearing faults. There is a ~1500 m thick evaporate sequence in the shallow overburden above the field consisting of mostly halite, with interbedded anhydrite and clastics. Figure 2 shows a structure map of the top of the reservoir.
Reservoir
The Tamar reservoir section is an Oligocene-Miocene sequence of deepwater turbidite sandstones interbedded with minor siltstone and shales. Clean end-member sands are greater than 95% quartz arenite with minor amounts of feldspar and other minerals. Clean sands have porosities greater than 20% and permeabilities greater than 1000 mD. Sands are slightly to fairly consolidated with no significant change in reservoir quality across the gas water contact.

Stratigraphy from Logs and Cores
Conventional cores were taken in the Tamar 2, Tamar 3, and Tamar 5 wells for a total of 143 meters of core. Routine and special core analysis was performed to understand and characterize the reservoir properties. Figure 3 illustrates the reservoir facies and the productive interval.
Project Statement of Requirements

Background
After discovery in 2009, the Tamar project was put on a fast track for development to deliver first gas in time to replace the declining gas production from the Mari-B field. Tamar was designed as a subsea development with five (5) initial wells tied back 150 km to a new shallow water processing platform located near the existing Mari-B platform. As the world’s longest subsea tie-back, the Tamar field came online in March 2013 at gas rates in the 600-950 MMscf/D range (depending on daily gas demand) from a production platform designed for 1,200 MMscf/D.

Key Project Deliverables
Drill and complete five (5) wells each capable of safely and reliably producing gas at rates of up to +250 MMscf/D for 25 years.

Completion Guiding Principles & Delivery Process
The key performance indicators (KPIs) and guiding principles that were developed to guide the decision making process for the completion design are discussed in detail in previous papers by the Authors. These completion KPIs and guiding principles were coupled to a completion delivery process (for “critical” wells) which was originally published by the Authors in 2012. The process is comprised of four (4) sequential phases. Each phase identifies key tactics considered imperative to the successful delivery and flawless execution of the completion.

Right Design
Feasibility Study
A study was undertaken to support and underpin the selection of the right design for the upper completion and lower completion (sandface). The primary scope of the study was to review existing developments to understand field proven designs. The study focused on a global review of ultra-high rate gas wells which included nine (9) areas and over 130 wells. This study, combined with the experiential knowledge of the team, resulted in a design that integrated the field proven lower
completion (sandface) design of the OHGP as demonstrated in Trinidad (Amherstia, Mahogany, Kapok, and Cannonball) and Ormen Lange\textsuperscript{18} with a simplified deepwater upper completion design.

Completion Statement of Requirements

Based on the front-end engineering studies, several operational completion statement of requirements (SOR) were also specified. They included the following:

- The $\frac{95}{8}$ in. casing to be set $\pm$ 5 meters inside the reservoir section.
- The reservoir interval must be under-reamed to 12\% in.
- The reservoir interval must be vertical to low angle ($\leq 20\degree$).
- Only $\pm$40 meters (131 ft) of reservoir interval will be drilled / completed.

Completion Fluid Design & Qualification

A “stage gate” process was introduced for the design and qualification of the completion fluids as illustrated below (Figure 4).

The Tamar field consists of three gas bearing sandstone layers, designated A, B and C, separated by two shaley units. Geological analysis was undertaken with data relevant to the selection of an appropriate completion fluid outlined in the following paragraphs.

Mineral content studies, by XRD, SEM and thin-section, outlined that reservoir quality in all three sands ranges from Fair to Good, with portions of the A & B sands being Very Good, and much of the C sand having Very Good reservoir quality. Additionally it was noted that expandable clays are present throughout all three intervals as a mixed-layer illite/smectite (MLIS) composed of 45-55\% expandable smectite layers. The MLIS clay abundances are generally low (0-3\%), but some of the more clay-rich samples analyzed by XRD techniques contained MLIS weight percentages up to 9\%. Therefore, clay expansion/dispersion and damage was anticipated to result if low-salinity brines were selected.

Preliminary screening of completion fluid for use on the Tamar project was based on the initial consideration of brine density, crystallization temperatures (TCT and PCT) and brine type. Three candidate brines met the basic requirement for these three properties,

- calcium bromide (CaBr2)
- sodium bromide (NaBr)
- sodium bromide/sodium chloride (NaBr/NaCl)
Salt blends for three primary densities were required for the Tamar completions, specifically, 10.2 ppg, 10.6 ppg and 10.8 ppg blends. These fluids will be required for the Reservoir Drill-In Fluid (RDIF), the completion fluid / packer fluid, and the GP carrier fluid, respectively. CaBr₂, NaBr and NaBr/NaCl systems for these required densities can all be formulated to meet the TCT and PCT requirement for this application given the mud line temperature of 57°F. Achieving the required density, while maintaining the TCT and PCT requirements for this application did not differentiate the selected brines types, so evaluation of brine options under scrutiny with regard to the well and operating parameters was required to narrow the completion fluid type.

Bottom hole temperature, mud line temperature and bottom hole pressure affect the actual surface density needed for the selected brine. The effect of pressure and temperature on brine is well known but, for this application, these effects do not differentiate the brines to allow for completion fluid selection.

Retained gas permeability flow data indicated that neither NaBr nor CaBr has an advantage over the other. Effective permeability to gas at irreducible water saturation (KgSwi) regained to the original value or better. Additionally, it appears that the samples tested recovered rather well (time wise) under the same or similar pressure as the original KgSwi. Large improvements in permeability may be due to fines movement clearing pore throats and/or lower terminal water saturation.

Fluid sensitivity data was obtained by means of Capillary Suction Time (CST) and Roller Oven (RO) Formation Stability testing. The data indicates that, overall, the sands favor NaBr over CaBr and the addition of 3% KCl to a NaBr brine improves the response slightly. However, it should be noted that both these tests use disaggregated/homogenized material which exposes all clays or other reactive minerals with the testing solution(s), and thus tend to overestimate the sensitivity of formations to treatment fluids.

A significant potential for damage to the near wellbore region is precipitate formation due to incompatibility of the completion brine with formation water. This can be a distinguishing parameter when selecting completion brine, with monovalent brine generally having less potential for damage compared to di-valent brine. To this effect, water from the Tamar-2 well was analyzed and the concentration of selected ions and pH data are presented in Table 1 for three water samples.

<table>
<thead>
<tr>
<th>Table 1—Tamar 2 Water Chemistry</th>
</tr>
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<td>Water Analysis for Tamar-2</td>
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<td>Sample #</td>
</tr>
<tr>
<td>-------</td>
</tr>
<tr>
<td>1.09</td>
</tr>
<tr>
<td>1.1</td>
</tr>
<tr>
<td>1.11</td>
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Scaling tendencies for barium sulfate, calcium sulfate and calcium carbonate were determined using commercial scaling software, which outputs a Saturation Index, SI, for selected salts with relatively low solubility. The Saturation Index of a solution with respect to mineral scale is defined as the logarithm of the ion activity product divided by the thermodynamic solubility constant of the mineral. For example, the Saturation Index of a solution with respect to calcium carbonate scale is defined:

\[ SI = \log \left( \frac{(Ca^{2+})(CO_3^{2-})}{K_{sp}} \right). \]

For the Tamar-2 water, barium sulfate and calcium sulfate were found to have SI values less than 1.00, and therefore would not be expected to precipitate at either 77°F or 172°F. However, SI values for calcium carbonate, presented in Table 2, were found to be greater than 1.00, and therefore would be expected to precipitate from solution at both 77°F and 172°F.
These results indicate the potential to precipitate calcium carbonate, which would be magnified if calcium-based completion brine were mixed with the formation water downhole, potentially resulting in in-situ precipitation and formation damage. To avoid such potential, sodium bromide or sodium bromide/sodium chloride brine is indicated.

To obtain the performance level required for this application, the preferred type of base brine for the RDIF and also the breaker/gravel pack carrier fluid is sodium-based. This preferred base-brine reinforces the use of sodium-based completion brine to complement the sodium-based RDIF and sodium based-breaker fluid.

To determine the compositional requirements of the recommended sodium based brine formulations, the primary considerations were:

1. Minimization of corrosion risks
2. Provision of gas hydrate protection.

The general brine related corrosion risks on the Tamar completions result from the exposure of completion metallurgy to the various brine fluids during the well completions and critically, during the production phase. The salt composition of the brine affects the severity of the risk and this can often be mitigated by manipulation of brine blends within the confines of operational requirements.

The presence of the chloride ion (Cl⁻) in brine solutions has been documented and is generally accepted as a significant factor in the corrosion of downhole equipment and, in particular, in relation to stress corrosion cracking (SCC). High alloy steels have been shown to be particularly susceptible to Cl⁻ ion induced SCC and given the proposed use of such steels in the Tamar completion equipment and production tubing, it was desirable to formulate brines that minimized the concentration of the Cl⁻ ion.

The total elimination of the Cl⁻ ion from the recommended NaBr/NaCl brine by the use of pure NaBr was not possible if the required gas hydrate protection was to be provided. The hydrate protection capability of the brine is related to the concentration of ions in solution and the use of pure NaBr brine reduces the salt concentration below the level necessary to provide gas hydrate protection in the proposed brines.

The preferred formulation should therefore provide the optimum balance between sodium chloride and sodium bromide concentration which would provide the required operational density and gas hydrate protection while minimizing the Cl⁻ ion concentration.

The requirement of the completion fluid to mitigate against the potential for hydrate formation was an operational parameter that was investigated with regard to the brine types that met the initial fluid parameters. Mud line temperature, applied pressure and bottom hole pressure influence the formation of hydrates. The relevant parameters for the Tamar project were specified as:

- Minimum mud line temperature of 57° F
- Anticipated maximum pressure of 8,500 psi at the minimum temperature
- Tamar reservoir gas composition
Hydrate calculations were determined using commercial hydrate software (PVTsim, 2010). The relative salt component concentrations were adjusted to gain a 5°F safety factor under the given operating conditions, i.e. the hydrate calculations targeted 8,500 psi at 52°F such that the brines would prevent the formation of gas hydrates with Tamar gas at the specified 8,500 psi pressure and 57°F. In addition, the formulations were manipulated until the required hydrate protection was achieved with the lowest possible Cl⁻ ion concentration.

For the 10.6 ppg completion/packer fluid, pure NaBr is not sufficient to control the specified conditions, as shown in Figure 5. The addition of ethylene glycol (MEG) to NaBr provides a formulation that is acceptable for hydrate control. In addition, two NaBr/NaCl brines were formulated to be hydrate inhibitive and are also presented in Figure 5. Please note that the NaBr/NaCl #2 formulation and the NaBr/MEG formulation fall on top of each other and are the center two lines.

In some formulations MEG is needed to control hydrate formation, but MEG is also used in the glycolation process to help disperse and identify clay minerals. This interaction of MEG with clays might also occur with clay/shale segments found in sections of the target formation. Therefore, the use of MEG within a completion brine or RDIF base fluid is not recommended due to the increased risk of fluid induced formation damage.

With all the relevant testing data discussed above taken into consideration, a 10.6 ppg NaCl/NaBr completion/packer fluid was recommended.

By applying the same logic and design criteria formulations for the 10.2 ppg and 10.8 ppg brine required as the base fluid in the RDIF and breaker/gravel pack carrier fluid design respectively, were optimized.

**RDIF Design & Qualification**

A laboratory project was initiated to formulate and test a drill-in fluid that will minimize any fluid induced damage while drilling on the Tamar project. Secondly, an enzyme remediation package was optimized.
that would completely disrupt and mainly remove the components of the drill-in fluid; the treatment was to be incorporated in the gravel pack carrier fluid to achieve the most efficient contact with the filter cake to ensure its removal from the wellbore and completion. The well fluid formulations were engineered and tested to provide the lowest possible effect on formation and completion permeability. This was verified on core in a dynamic permeameter, using synthetic core to create the best representation possible of the reservoir under laboratory condition. The following parameters were considered when designing and testing the reservoir drill-in fluid and remediation solution:

- Geotechnical Analysis
- Pore Throat profile and Bridging
- Breaker Optimization
- Retained Permeability
- Formation Fluid Compatibility

**Geological Analysis**

Small pieces of actual reservoir core underwent XRD and SEM analysis to allow for an accurate description of the mineralogy and give some indication how it could affect the fluid’s composition. Shale samples can be tested against WBM for their hydration capacity, which in conjunction with CEC and XRD data will enable us to verify the applicability of WBM for any project. The shales that are present in the reservoir were also tested for compatibility with the completion brines. These brines should be selected to allow low deformation of clays in the wellbore so as not to change the physical conditions in pore spaces. The clays in these wells must be stabilized to allow for successful running of screens and gravel packs.

**Reservoir Drill-in Fluid (RDIF) Formulation Components**

Selection of an appropriate drill-in fluid and clean-up procedure is critical in ensuring the productivity of open-hole wells, particularly gravel packs which are problematic if remediation treatments are required. Drill-in fluids are typically formulated to deposit a high quality, relatively impermeable filter cake, which seals the wellbore and minimizes fluid leak-off to the formation. In theory, such cakes may be removed by produced fluids and from sufficient drawdown in the production direction. In practice, clean-up may be uneven due to, for example, heterogeneous reservoir characteristics across the open-hole section. This can result in variable draw down and/or variation in the extent of initial damage across the production interval. Typically, the part of the wellbore that has been exposed to the drill-in fluid for the longest period has the potential to incur the most damage. Drill-in fluids are relatively clean compared to conventional mud systems and are designed to minimize the effects of drilling fluid damage when drilling through the pay zone or pay interval. As well as minimal effect on productivity the fluid was to have “green”
chemicals (best environmental status), and have a high hydrate inhibition. Other requirements for the RDIF were to provide good hole cleaning, borehole stability and efficient filtration control to lower risk of differential sticking and loss of mud column while drilling. Efficient filtration control would avoid deep invasion of fluid and solids into the formation and avoid excessive filter cake build up as a gravel pack completion was planned. The fluid was also required to have a low lift-off pressure which would allow a quick and efficient cleanup when the wells were turned on to production. If a post treatment was required, all the components of the fluid would have to be readily dissolved and broken down by a breaker system. After a series of tests the following formulation was found to give the required parameters to drill the open-hole section under downhole conditions.

<table>
<thead>
<tr>
<th>Table 3—Reservoir Drill-In Fluid (RDIF) Generic Formulation</th>
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</thead>
<tbody>
<tr>
<td>Constituent</td>
</tr>
<tr>
<td>10.2 ppg Brine</td>
</tr>
<tr>
<td>Water</td>
</tr>
<tr>
<td>Viscosifier</td>
</tr>
<tr>
<td>Fluid Loss Polymer</td>
</tr>
<tr>
<td>Clay Stabilizer</td>
</tr>
<tr>
<td>Surfactant</td>
</tr>
<tr>
<td>pH Buffer</td>
</tr>
<tr>
<td>Carbonate A</td>
</tr>
</tbody>
</table>

**Pore Throat profile**

Core samples were selected that represented the areas of interest in the reservoir. The permeability and the dimensions of the pore spaces were measured. The pore throat dimensions are required to accurately predict the sizes of the bridging materials that can be used in a drill-in fluid to ensure that any solids invasion is kept to a minimum. By accurately measuring the pore throats a full understanding is achieved of the size distribution and this information can be inputted into software that will predict the most efficient bridging size distribution.

![Figure 7—In House Mercury Porosimeter](image)

**Bridging**

Software has been developed by Baker Hughes to help minimize any potential fluid loss and the resultant formation damage by maximizing the bridging efficiency. The software utilizes the pore throat data gathered from the mercury porosimeter, or uses supplied permeability and porosity to approximate the
expected range of pore throat diameters. The Vickers Method (AADE-O6-DF-HO-I6) is used to select the appropriate blend of CaCO₃ bridging additives. The Vickers Method states the following criteria of the Particle Size Distribution (PSD) of the bridging particles to obtain optimum bridging:

- D₉₀ = largest pore throat
- D₇₅ < 2/3 of largest pore throat
- D₅₀ = 1/3 of the mean pore throat
- D₂₅ = 1/7 of the mean pore throat
- D₁₀ = smallest pore throat

The calculated blend is taken forward to be refined by further tests in the laboratory. The figure below shows an example output from the software.

![Figure 8—Example Output from Bridging Software](image)

**Breaker Optimization**

Enzyme breaker technology was selected to be used as the method of choice for remediation after drilling the reservoir. The breakers are used to remove the filtercake deposited during the drilling operation before it is put on production. After effective clean-up, production is maximized - removal of the filter cake allows an increase in production compared to when the filter cake is present. Enzymes are also included in the breaker to break down the polymers and starches used in drilling fluids to provide an effective means of removing the whole filter cake. In addition to the enzyme a weak organic acid was used in the breaker to dissolve the calcium carbonate to ensure the most efficient disruption and removal of the filter cake components.

**Retained Permeability**

In the Aberdeen facility there are a number of permeameter types, the most advanced of which can test a fluids’ formation damage behavior when stressed up to the actual bottom hole temperature in combination with the hydrostatic overbalance pressure. This permeameter (Chandler 9000) also has the ability to simulate completions under downhole conditions without having to dismantle the core holder during the test. This prevents the filter cake from “relaxing” and affecting the final result and is regarded as the most accurate way of testing a fluids performance under simulated downhole conditions. Different screen completions, and gravel packs can all be simulated in the permeameter and mesh coupons were obtained of the same type and size that was planned for the Tamar completion. As the actual completion
components were used in the permeameter test we could measure the effect of the mud and its components on the permeability of the meshes when the screens and gravel in place as well as its potential changes in the pressure created when gas is flowed through reservoir core. The permeameter measures permeability using humidified gas (nitrogen) thus very accurately replicating actual well conditions. The equipment is also able to measure the changes in permeability along the length of the core, thus we can accurately predict the depth of any damage if the bridging is incorrect and take remedial action as the design stage.

![Figure 9—Chandler 9000 Advanced Dynamic Permeameter (Aberdeen)](image)

**Formation Damage Testing**

Initially, a retained permeability test was performed on simulated core alone to verify that the PERF-FLOW CM was fit for purpose and did not induce permanent damage to the core. The next step was to test the designed fluid to evaluate the effect of the selected screen completion. This test indicated that there is minimal fluid-induced formation damage with a retained permeability of 81%.

Two subsequent tests were performed using a full sequence to simulate the proposed drilling conditions and full completion, including gravel pack placement, with and without breaker system. The baseline full sequence formation damage test (without breaker system) showed a retained permeability of 74%, indicating that the fluid-induced formation damage is within the design limits. There are minimal observed detrimental effects to the permeability while passing the filter cake through the gravel pack and screen completion.

The final full sequence test shows a retained permeability of 91%, indicating a statistically significant improvement to retained permeability when applying the MUDZYME Breaker system. The enzyme breaker performed extremely well to efficiently clean up the filter cake, allowing for an improvement of 17% compared with the test without enzyme breaker.
A detailed engineering study was undertaken for the mixing of completion fluids (brine and RDIF). This study resulted in the decision to build a fit-for-purpose completion fluid plant and lab in-country (see pictures on following pages). Key factors beyond fluid quality which influenced the decision included:

- 9 different fluids
- 9 different displacements (in a 12 day period)
- Significant volumes (> 20,000 bbls per well)
- Expensive fluid = $300 / bbl

The construction, hook-up and commissioning of the fluid plant (tank farm + blending / mixing plant) took approximately 12 months. A “Commissioning Document” was developed by the Construction Team that ensured that key technical, functional and HSE elements were in place prior to “handing-off” the plant to Operations. The final layout drawing of the fluid plant is shown in Figure 14.

Table 4—Formation Damage Test Results

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<tr>
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<td>668.88 (+74.12%)</td>
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</table>

**Fluid Plant**

**Design & Construction**

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Figure 10—Aerial View of Proposed Fluid Plant Location

Figure 11—Completion Fluid Plant - Before (Construction of Bulkhead Area)
Figure 12—Completion Fluid Plant - After

Figure 13—Onshore (Haifa) Fluid Lab
The driving philosophy of the fluid QA/QC strategy was “to ensure what was designed and qualified in the lab was delivered at the sandface” (see Figure 15). While in principle this philosophy is uncontested; in practice, however, it is very difficult to execute and we have generally found this process to be lacking in terms of rigor (as measured in the extreme). The remainder of this section highlights several of the principles and key tactics (process, procedures, etc.) that were developed and implemented for this project.
As previously discussed, significant engineering effort is expended on the design of the various fluid systems. It must be remembered, that fluid systems are qualified at lab scale using very small volumes. This qualified system must then be mixed in quantities that (in the case of Tamar) approached 30,000 bbls per well. For the campaign, over 200,000 bbls were mixed. Realizing that the fluid system was the key determinant in the success of the OHGP, the Tamar team designed the Fluid QA/QC with the following key principles:

1. Ensure bulk raw materials - “the ingredients” - procured thru the Global Supply Chain conform to the materials used in the lab testing.
2. Ensure the compositions (constituents and proportions) mixed at “field scale” conform to the compositions used in the lab testing (“lab scale”).
3. Verify that the fluid properties and parameters at “field scale” match (within the acceptance / rejection criteria) the reported lab results.
5. Develop and apply ‘Best Practices” for fluid QAQC for the supply boats.
6. Develop and apply ‘Best Practices” for fluid QAQC at the rig.
7. Develop and apply ‘Best Practices” for fluid QAQC within the well (e.g., Wellbore Clean-out, WBCO).

The above QA/QC elements were implemented via a Fluids Quality Control Plan (QCP) see Figure 16. The architecture of the Fluids QCP was based on the framework of typical (oilfield) manufacturing QCPs. Within the QCP, a key document - the Mixing Instruction Sheet (Figure 17) - was developed to ensure fluids were mixed properly and tested to ensure conformance to acceptance criteria.
# Fluids Quality Control Plan

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<th>Activity No.</th>
<th>Phase</th>
<th>Activity Description</th>
<th>Activity Site</th>
<th>Responsible Party</th>
<th>Reference Document / Procedure</th>
<th>Acceptance Criteria</th>
<th>Verifying Document</th>
<th>Databook</th>
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<td>Baker</td>
<td>BH Qualification Reports #7, 8, 10, 13 &amp; 15</td>
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</tr>
<tr>
<td>90</td>
<td>Fluid Preparation</td>
<td>Inspection of Offshore Fluid Mixing Plant tanks</td>
<td>Haifa</td>
<td>BH Plant Manager</td>
<td>Completion Fluids Tank Inspection Form 07 07 07</td>
<td>Visual Inspection: “clean &amp; dry”</td>
<td>Signed Inspection Form 07 07 07</td>
<td>Yes</td>
<td>W</td>
<td>W</td>
<td>R</td>
</tr>
<tr>
<td>100</td>
<td>Fluid Preparation</td>
<td>Mix 10 ppg NaCl</td>
<td>Haifa</td>
<td>Fluid Plant Manager</td>
<td>ISL-BHDF 09.09.30</td>
<td>Density = 10.0 ppg (±0.1) Clarity &lt; 20 NTUs</td>
<td>ISL-BHDF 09.09.30</td>
<td>Yes</td>
<td>W</td>
<td>W</td>
<td>W</td>
</tr>
<tr>
<td>110</td>
<td>Fluid Preparation</td>
<td>Mix 12.5 ppg NaBr</td>
<td>Haifa</td>
<td>Fluid Plant Manager</td>
<td>ISL-BHDF 09.09.31</td>
<td>Density = 12.5 ppg (±0.1) Clarity &lt; 20 NTUs pH = 7 units (±1)</td>
<td>ISL-BHDF 09.09.31</td>
<td>Yes</td>
<td>W</td>
<td>W</td>
<td>M</td>
</tr>
<tr>
<td>120</td>
<td>Fluid Preparation</td>
<td>Mix 11.1 ppg RDIF</td>
<td>Haifa</td>
<td>Fluid Plant Manager</td>
<td>ISL-BHDF 09.09.28</td>
<td>Density = 11.1 ppg (±0.1) Plastic viscosity &lt; 28 cp Yield Point &gt; 16 lb/1000°F 10 sec gel &lt; 10 lb/1000°F 10 min gel &lt; 15 lb/1000°F API Fluid Loss &lt; 8 ml API Cake Thickness &lt; 3/32” pH = 8.5 units (±1)</td>
<td>ISL-BHDF 09.09.28</td>
<td>Yes</td>
<td>W</td>
<td>W</td>
<td>R</td>
</tr>
<tr>
<td>130</td>
<td>Fluid Preparation</td>
<td>Mix Solids-Free RDIF (SF-RDIF)</td>
<td>Haifa</td>
<td>Fluid Plant Manager</td>
<td>ISL-BHDF 09.09.05</td>
<td>Density = 11.1 ppg (±0.1) Plastic viscosity &lt; 18 cp Yield Point &gt; 10 lb/1000°F 10 sec gel &lt; 8 lb/1000°F 10 min gel &lt; 10 lb/1000°F API Fluid Loss &lt; 10 ml pH = 8.5 units (±1) MUST PASS SCREEN PLUGGING TEST</td>
<td>ISL-BHDF 09.09.05</td>
<td>Yes</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>140</td>
<td>Fluid Preparation</td>
<td>Mix 11.1 ppg Completion Fluid</td>
<td>Haifa</td>
<td>Fluid Plant Manager</td>
<td>ISL-BHDF 07.07.24</td>
<td>Density = 11.1 ppg (±0.1) Clarity &lt; 20 NTUs pH = 7 units (±1)</td>
<td>ISL-BHDF 07.07.24</td>
<td>Yes</td>
<td>W</td>
<td>W</td>
<td>R</td>
</tr>
<tr>
<td>160</td>
<td>Preparation @ Rig Site</td>
<td>Review of Pit Management Plan</td>
<td>Rig</td>
<td>Lead DF Engineer</td>
<td>Pit Management Plan</td>
<td>Signature on Pit Management Plan</td>
<td>Signed Copy of Pit Management Plan</td>
<td>Yes</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>270</td>
<td>Displacement: WBCD Run #3</td>
<td>Spot Solids-Free RDIF (SF-RDIF)</td>
<td>Rig</td>
<td>Lead DF Engineer</td>
<td>NEI Completion Procedure: BH Fluid Program</td>
<td>Density = 11.1 ppg (±0.1) Plastic viscosity &lt; 18 cp Yield Point &gt; 10 lb/1000°F 10 sec gel &lt; 8 lb/1000°F 10 min gel &lt; 10 lb/1000°F API Fluid Loss &lt; 10 ml pH = 8.5 units (±1) MUST PASS SCREEN PLUGGING TEST</td>
<td>Photograph of WBCD tools Description of debris &amp; observations Weight measure (lbs) of debris</td>
<td>Yes</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
</tbody>
</table>

**Inspection Codes (see QS-1)**

*H* Hold

Noble Energy or designated TPI shall be notified (by e-mail) a minimum of 12 hours prior to reaching the activity unless otherwise agreed by the Noble Energy. Do not proceed past the activity without the TPI’s presence.

The TPI will sign/stamp documentation when an activity has been observed by the TPI.
Mix Instructions:
1. Prior to mix, re-verify QA/QC on 10 ppg NaCl and 12.5 ppg NaBr.
2. Ensure mix tank is clean and dry.
3. Mix the base brine as per Table 1 and record actual.
4. Circulate the base brine to achieve the target density.
5. Take sample.
6. Perform QA/QC and record results in Table 2.

Table 1 - Mix Verification for 4000 bbls

<table>
<thead>
<tr>
<th>Product Name</th>
<th>Mix Order</th>
<th>Mix Volume (bbls)</th>
<th>Tolerance</th>
<th>Actual (bbls)</th>
<th>Pass/Fail</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>1</td>
<td>xxx</td>
<td>+5 bbls per 1000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12.5 ppg NaBr</td>
<td>2</td>
<td>xxxxx</td>
<td>+5 bbls per 1000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10.0 ppg NaCl</td>
<td>3</td>
<td>xxxxx</td>
<td>+5 bbls per 1000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 2 - QA/QC Verification

<table>
<thead>
<tr>
<th>Sample Source</th>
<th>Record tank number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sample Point</td>
<td>Describe where sample is taken</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Acceptance Criteria</th>
<th>Result</th>
<th>Pass/Fail</th>
<th>Lab Procedures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, ppg</td>
<td>10.6 +/- 0.1</td>
<td></td>
<td></td>
<td>ISO/API 13503-3</td>
</tr>
<tr>
<td>Clarity, NTU</td>
<td>&lt; 20</td>
<td></td>
<td></td>
<td>ISO/API 13503-3</td>
</tr>
<tr>
<td>pH, (pH units)</td>
<td>7.0 +/- 1.0</td>
<td></td>
<td></td>
<td>ISO/API 13503-3</td>
</tr>
</tbody>
</table>

Witness

<table>
<thead>
<tr>
<th>Printed Name</th>
<th>Signature</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baker Fluids</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noble Energy</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
OHGP Design & Execution

A full review of the detailed engineering and operational (well site) analysis for the OHGPs is beyond the scope of this paper and will be the subject of a future paper. A few key points with regard to the design and execution are summarized below.

General

The design of the OHGP is multi-variant. In the case of the Tamar design, the Completion Engineers were strongly biased to rigorous simplification and standardization of the design. Some, but not all, of the key design constraints and criterion are enumerated below:

- **Low Angle**: 4 of 5 wells were completed at zero (0) degree inclination; low inclination reduced the pumping risk of premature screen out and bridging. The bias to water pack was fundamental driver to specifying low angle completion intervals.
- **Single Zone**: Only one sand was completed in each well, eliminating / minimizing any shale exposure.
- **Production Casing Point**: the production (9 5/8 in.) casing was set within (± 5 meters) the reservoir to eliminate any exposure to the over-lying, reactive shale.
- **Hole Size**: the open hole was drilled with an 8-½ in. bit and then underreamed to 12-¼ in.

Proppant & Screen Selection

A 20/40 proppant with 175-micron premium wire mesh screens were selected for all intervals (A, B, and C) in order to standardize the lower completion hardware. Core samples from full core were taken from each of the three completion intervals. Laser particle size analysis indicated that 84% of the samples suggested that a 10/20 proppant would provide adequate sand control, while 12% of the samples suggested a 20/40 proppant, 3% of the samples suggested a 40/60 proppant, and 1% suggested a 50/70 proppant. A third party lab conducted sand retention tests using the two most commonly recommended proppant and screen size combinations - 16/30 proppant with 15-gauge direct wrap screen and 20/40 proppant with 175-micron premium wire mesh screen. The lab produced artificial formation sand samples for conducting the tests to replicate as close as possible the actual formation sand taken from core samples. These artificial sand samples were mixed with fluid and pumped through a test cell which contained screen and proppant combinations. This testing validated the selection made (20/40 proppant and 175-micron premium wire mesh screen).

Shop QAQC & Yard Test

To ensure that the equipment selected would perform as expected (prior to shipping it to Israel), two (2) significant, atypical QA/QC efforts were undertaken. Firstly, a trial of the make-up of the sand screens was performed to ensure that the tubular running equipment would properly grip and make-up the connections (VAM TOP). This test was performed at a test facility (Aberdeen, Scotland, UK) of the tubular running company. This make-up test was to verify that the equipment was for fit-for purpose with proper dies and back-up / handling equipment. This also ensure the personnel were prepared for the job. The test was successfully completed and validated the make-up plan. This plan was implemented flawlessly at the well site; no equipment downtime was experienced due to the tubing make-up equipment. The pick-up and make-up plan for the rig was one of the keys to flawless execution. Secondly, prior to shipment to Israel, a “yard test” of gravel pack pumping equipment was performed. All of the gravel pack pumping equipment was new build (manufactured in USA) for this project. Due to the remote location of the Tamar field, it was deemed important to conduct a full rig-up and rigorous operational test of the pumping equipment. The entire rig-up was scaled to match the foot print planned for the rig (Transocean Sedco Express). The same rates were pumped and all pertinent variables were measured. It was all rigged-up once and pressure tested prior to each job. No significant pressure test failures occurred. The end result of these efforts was 0-hrs of downtime associated with the gravel pack pumping equipment.
Operations

As-Built Completion
The as-built completion schematic for Tamar #4 (Figure 20) is representative of Tamar #3, 4, 5 and 6.
Tamar #4ST01 AS-BUILT
July 5, 2012

Mean Sea Level (MSL)

10K 5x2 Horizontal Tree (Cameron)
Plugs: 5.75” ITC plug / 5.25” TH plug
TH Thread: 7” 29# VAM TOP
Tree Weight: 50T with TRT & BP
TH Penetraions: 7 hydraulic + 1 electrical
TH bore ID: 4.798”
TH SSR Plug installed & tested
ITC installed (w/ plug) & tested

RKB – MSL = 23.0-m (75.5’)
Water depth = 1,686.5-m (5533’)
RKB to Top of Tree = 1,702.0-m
RKB – ML = 1,709.5-m
Mud line temp = 57°F

8.8-ppg 40/60 MEG/DW
11.3-ppg WBM
TOC @ 2,073-m MD
5½” Baker CIM @ 2,416.6-m MD (1/2” CL)
5½” SLB TRC-II-10 SCSSV @ 2430.7-m
w/ 4,562” DB-HP Nipple
(¼” x ¼” CL)

11.4-ppg WBM
12.6-ppg Inhibited WBM
TOC @ 3,087-m MD
10.6-ppg NaCl/NaBr packer fluid

5½” Baker CIM @ X461.3-m MD (3/8” CL)

5½” SLB DHPT GM @ X497.9-m MD (1/4” TEC)
9¾” Production Packer @ X531.8-m MD
4,500” SLB DB-6 Nipple @ X568.9-m MD

“A” Sand
Top = X612-m MD

“B” Sand
Top = X686-m MD

“C” Sand Completion Interval:
Top of Sand X735-m MD
Interval: X742.2 – X774.7-m MD (OAL = 32.5m)
Mid Interval: X757-m MD/TVD
Hole Angle @ Reservoir = vertical
BHP = 8254-psi
Pore Pressure = 10.33-ppg
BHT = 172°F

PIP TAG @ 4529.3
Cutting Zone (4.2 – 4.6-m below PIP tag)

9¾” x 6” GP Packer @ X604-m MD

9¾” 53.5# 13CRM-110 Vam Top @ X742-m MD

Under-reamed 12¼”

20/40 CarboLITE

6¼” Sand Screens (35-m)

12¾” TD @ X773.7-m MD
8¾” TD @ X774.7-m MD

Figure 20—Tamar 4 As-Built Completion Schematic
Operational Performance
The completions were installed exactly as designed with very minimal non-productive time (NPT). The total NPT for the 5 well campaign was 21 days (≈10%) which included a BOP stack pull (14 days) due to mechanical problems. Without the BOP stack pull, the total NPT was 5 days (≈4%). A summary time analysis is presented in Table 7. Completion NPT ranged from 1.6 to 0.6 days. Most significantly, there were zero (0) downhole mechanical failures through the entire completion campaign.

<table>
<thead>
<tr>
<th>Well</th>
<th>Total Actual (days)</th>
<th>Scope Change (days)</th>
<th>Normalized Time (1) (days)</th>
<th>NPT (days)</th>
<th>BOP NPT (days)</th>
<th>Completion NPT (2) (days)</th>
<th>Completion NPT (3) (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tamar #4</td>
<td>61.2</td>
<td>15.8</td>
<td>45.4</td>
<td>15.6</td>
<td>14.0</td>
<td>1.6</td>
<td>5.1</td>
</tr>
<tr>
<td>Tamar #3</td>
<td>34.8</td>
<td>3.6</td>
<td>31.2</td>
<td>2.2</td>
<td>1.5</td>
<td>0.7</td>
<td>2.4</td>
</tr>
<tr>
<td>Tamar #5</td>
<td>31.2</td>
<td>2.6</td>
<td>28.6</td>
<td>1.5</td>
<td>0.0</td>
<td>1.5</td>
<td>5.1</td>
</tr>
<tr>
<td>Tamar #6</td>
<td>28.3</td>
<td>2.4</td>
<td>25.9</td>
<td>0.6</td>
<td>0.0</td>
<td>0.6</td>
<td>2.3</td>
</tr>
<tr>
<td>Tamar #2</td>
<td>49.8</td>
<td>24.4</td>
<td>25.4</td>
<td>0.8</td>
<td>0.0</td>
<td>0.8</td>
<td>3.2</td>
</tr>
<tr>
<td>Total</td>
<td>205.3</td>
<td>49.1</td>
<td>156.2</td>
<td>20.7</td>
<td>15.5</td>
<td>5.2</td>
<td>3.7</td>
</tr>
</tbody>
</table>

Note 1 - Normalized Time = (Total Actual) - (Scope Change)
Note 2 - Completion NPT = (Total NPT) - (BOP NPT)
Note 3 - Completion NPT (%) = (Completion NPT) / (Normalized Time - BOP NPT)

Scope change is defined as any operation that was not planned for in the original AFE. The major scope changes were: 1) the requirement for BOP maintenance between the drilling and completion campaign, and 2) installation of the solid expandable tubular (SET) in Tamar #2. None of these operations were planned for in the original AFE; thus, are considered out of scope and consequently not included in the time comparisons.

The various completion operations were broken into phases. A comparative analysis of the 8 phases is presented in Figure 19. Fluids management is a significant portion of the overall completion construction process and is fundamental to 4 of the 8 phases. We estimate approximately 35% of the entire completion time is dedicated to fluids management. Based on the time required to perform these operations and the direct relationship of the fluid / reservoir interface to productivity, fluids are considered the most critical component of an OHGP completion.

Well Performance
All five (5) Tamar wells came online in 2013 and cleaned up with productivities as expected or better. After the Tamar jacket and platform were set and the subsea system was hooked up and commissioned, the field was ready to startup. The wells were brought online one at a time from the platform 150 km away and monitored closely. Because each well had previously flowed up to 120 MMscf/D to the rig, the production team was able to closely monitor the well performance and compare to the performance seen on the rig. When each well was ramped up past 120 MMscf/D, a conservative approach was taken to ensure the well performance was in line with Nodal analysis predictions. As the wells flowed at higher rates, the performance increased beyond what was seen on the rig flow backs as the sand face continued to cleanup with higher drawdown. The mechanical skin improved significantly from the lower rate of 120 MMscf/D to the higher rates. Because Productivity Index (PI) is affected by the non-Darcy skin (turbulent skin) the PI for the wells drops as the flow rate increases. Table 10 below shows the key well performance parameters as seen after field startup.
Production History / Performance
Initial start-up of Tamar commenced on March 31, 2013. The production history to date is presented in Figure 21. To date, well performance has met expectations with exceptional reliability (“Tamar continued to have exceptional uptime performance reporting less than 30 minutes of downtime in the quarter.”18) and production performance (skins values continue to show near zero based on pressure transient analysis).

Table 10—Tamar Wells Key Performance Parameters - After Field Startup

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>T-2</th>
<th>T-3</th>
<th>T-4</th>
<th>T-5</th>
<th>T-6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max Stable Gas Rate</td>
<td>MMscf/D</td>
<td>265.0</td>
<td>262.2</td>
<td>263.3</td>
<td>271.3</td>
<td>263.5</td>
</tr>
<tr>
<td>Condensate Yield</td>
<td>BC/MMscf</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Condensed Water Rate</td>
<td>BW/MMscf</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>Flowing Wellhead Pressure</td>
<td>psig</td>
<td>6168</td>
<td>6371</td>
<td>6459</td>
<td>6349</td>
<td>6437</td>
</tr>
<tr>
<td>Flowing Down Hole Pressure</td>
<td>psia</td>
<td>7814</td>
<td>7924</td>
<td>7998</td>
<td>7936</td>
<td></td>
</tr>
<tr>
<td>Drawdown at Gauge</td>
<td>psi</td>
<td>340</td>
<td>238</td>
<td>179</td>
<td>212</td>
<td></td>
</tr>
<tr>
<td>Mechanical Skin</td>
<td>Unit less</td>
<td>+2</td>
<td>+0</td>
<td>+0</td>
<td>+0</td>
<td></td>
</tr>
<tr>
<td>Productivity Index at Gauge</td>
<td>MMscf/psi</td>
<td>0.78</td>
<td>1.1</td>
<td>1.47</td>
<td>1.28</td>
<td></td>
</tr>
</tbody>
</table>

***Note: T-6 down hole gauge not connected

Figure 21—Field Production Profile

Conclusions
Based on the work on this paper (and previous papers by the Authors) the following conclusions are made:

1. Technical rigor and due diligence in all phases of the completion delivery process is imperative to
successful execution, rate delivery and well reliability.

2. A “Stage Gate” approach to fluid design, engineering and qualification provided a deliberate and methodical approach to delivering fit-for-purpose fluid systems that are critical to a complex (OHGP) sandface installation.

3. The processes and rigor of a manufacturing quality control plan were adapted at the field level for mixing and blending of completion fluids to ensure absolute adherence to the qualified lab design.

4. A fit-for-purpose, large scale fluid plant (tank farm and blending / mixing plant) was successfully constructed and commissioned in approximately 12 months which supported 8 deepwater completions and ±30,000 bbls of fluid per well.

5. The sandface design concept (OGHP) and methodology (water pack + breaker entrained in the gravel pack carrier fluid) selected has proven extremely successful given the low skins.

Ultimately, five (5) ultra-high rate gas wells were successfully delivered as designed at Best-in-Class operational and productivity performance.

Acknowledgements
The authors wish to thank the Management of Noble Energy, and the Tamar co-venture group (Noble Energy Mediterranean Ltd., Isramco Negev 2 LP, Delek Drilling LP, Avner Oil Exploration LP, and Dor Gas Explorations LP) for their permission to publish this work. In addition the authors acknowledge the significant efforts and contributions of the Noble Energy Drilling & Completion team, Tamar project team, and Tamar Production Operations Team to install the wells, facilities, and subsea system to produce these world class completions. In addition, we thank the technical contributions of The University of Tulsa Erosion/Corrosion Research Center (Dr. Brenton McLaury), Dr. Chris Chow, Cedric Adams, Prospect Flow Solutions, Bill Roberts, and the following key suppliers: Expro, Baker Hughes, Cameron, Halliburton, Schlumberger and Weatherford.

Nomenclature

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFE</td>
<td>Authorization for Expenditure</td>
</tr>
<tr>
<td>BCF</td>
<td>Billion Cubic Feet</td>
</tr>
<tr>
<td>BOD</td>
<td>Basis of Design</td>
</tr>
<tr>
<td>BOP</td>
<td>Blow Out Preventer</td>
</tr>
<tr>
<td>bpTT</td>
<td>BP Trinidad and Tobago LLC</td>
</tr>
<tr>
<td>BPV</td>
<td>Back Pressure Valve</td>
</tr>
<tr>
<td>C&amp;P</td>
<td>Cased &amp; Perforated</td>
</tr>
<tr>
<td>CFD</td>
<td>Computation Fluid Dynamics</td>
</tr>
<tr>
<td>CGR</td>
<td>Condensate Gas Ratio</td>
</tr>
<tr>
<td>CHFP</td>
<td>Cased Hole Frac Pack</td>
</tr>
<tr>
<td>CVP</td>
<td>Captial Value Process</td>
</tr>
<tr>
<td>CWOP</td>
<td>Complete Well on Paper</td>
</tr>
<tr>
<td>DST</td>
<td>Drill Stem Test</td>
</tr>
<tr>
<td>FLCV</td>
<td>Fluid Loss Control Valve</td>
</tr>
<tr>
<td>GOM</td>
<td>Gulf of Mexico</td>
</tr>
<tr>
<td>HSE</td>
<td>Health Safety &amp; Environment</td>
</tr>
<tr>
<td>ID</td>
<td>Inner Diameter</td>
</tr>
<tr>
<td>LPSA</td>
<td>Laser Particle Size Analysis</td>
</tr>
<tr>
<td>mD</td>
<td>Milli-Darcies</td>
</tr>
<tr>
<td>MOC</td>
<td>Management of Change</td>
</tr>
<tr>
<td>mpy</td>
<td>mils (thousandths of an inch) per year penetration</td>
</tr>
</tbody>
</table>
NPT = Non Productive Time
OHGP = Open Hole Gravel Pack
PBR = Polished Bore Receptacle
PI = Productivity Index
POA = Plans of Action
POOH = Pull Out of Hole
ppge = pounds per gallon equivalent
QA/QC = Quality Assurance / Quality Control
QP = Quality Plan
RDIF = Reservoir Drill-in Fluid
SCSSV = Surface Controlled Subsurface Safety Valve
SET = Solid Expandable Tubular
SME = Subject Matter Expert
SOR = Statement of Requirement
SSTT = Sub Sea Test Tree
TCF = Trillion Cubic Feet
TD = Total Depth
TH = Tubing Head
WBCO = Well Bore Clean Out
WBM = Water Based Mud

* NODAL analysis is a mark of Schlumberger

CONVERSION FACTORS AND UNITS
1 mm/yr = 39.4 mpy

References


