

Wellbore Integrity, Sand Management, and Frac Pack



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Technology development in our industry continues to boost efficiency and profitability in existing fields, while enabling exploration and development in more-remote and -hostile geological environments around the world. Wellbore integrity, sand management, and frac-pack-completion technologies each can have a tremendous effect on oil-/gas-asset performance. When each technical theme is linked to provide a comprehensive model, risk and uncertainty of asset design and operation can be diminished greatly.

As an example of linking formation integrity to sand management, one of the papers highlighted this month describes how sand-control campaigns can morph, or change, over time as field performance is monitored, areas of improvement are identified, and solutions are implemented by use of new completion technologies. This sand-control-philosophy change stems from an understanding of the reservoir-failure mechanism, a thorough knowledge of sand-exclusion-device options, and careful consideration of completion-fluid-sensitivity performance.

Furthermore, recent implementation of a new sand-control technology for extensive, stacked reservoir intervals provided an option that can significantly reduce rig time associated with the completion. A highlighted paper discusses this completion technique, describing execution for conventional gravel-pack and frac-pack sand-control completions.

With regard to borehole-fluid exposure to the formation over time, another highlighted paper introduces a shale-core stability-test procedure that enables field-applicable comparisons of whole water-based muds. The differences in shale-stability preservation are striking. The results are presented in a fashion that blends good science and careful laboratory procedures with practical linkages to the field.

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Wellbore Integrity, Sand Management, and Frac Pack additional reading available at OnePetro: www.onepetro.org

SPE 114273 • "Casing Ultradeep, Ultralong Salt Sections in Deep Water: A Case Study for Failure Diagnosis and Risk Mitigation in Record-Depth Well" by Jincal Zhang, SPE, Shell, et al. (See JPT, May 2009, Page 78.)

SPE 120219 • "Prediction of Wellbore Stability Using 3D Finite-Element Model in a Shallow Unconsolidated Heavy-Oil Sand in a Kuwait Field" by K. Ahmed, SPE, Kuwait Oil Company, et al.

Temana Field: A Shift in Sand-Control Philosophy

The Temana field consists of unconsolidated reservoirs that require active sand control. The conventional internal-gravel-packed (IGP) technique has been used widely because it has provided a reliable means of abating sand production. These completions, however, have skin factors greater than 15, which increases with time as a result of fines migration into the packed area. In many cases, flow efficiencies were reduced by 70%, which affected well performance severely.

Introduction

The Temana field was discovered in 1962 and brought on production in 1979. The field is approximately 19 miles west of Bintulu in a water depth of approximately 96 ft. It consists of three hydrocarbon accumulations, Temana west, Temana central, and Temana east. The field has undergone a complex tectonic history and is highly faulted and compartmentalized.

The latest development is from the existing Platform A, which penetrates the Temana saddle, in the southeastern part of Temana central. The main reservoir target is the I-65 sand. The

sand has a fining-upward log signature with a sharp base at the bottom of the sand. The sand contains light oil of approximately 41.1°API with reservoir pressure of 1,553 psi, average porosity of 26% (oil), and effective permeability of more than 1 darcy. The main drive mechanism of this reservoir is depletion drive, with weak-to-moderate aquifer support.

There are seven existing platforms and two additional production-processing-facilities platforms. Approximately 44 out of 74 of the existing oil-producer wells were completed cased hole IGP, and only two wells had premium screens installed in horizontal open holes. On the basis of well-test data for these wells for a similar type of reservoir, the average skin is 10 to 15 and increases to 20 to 30 after several years of production. The average productivity indices (PIs) of these wells ranged between 1 to 20 bbl/(psi-D). Investigation shows that the increasing skin and deterioration in production are a result of fines movements into the gravel-packed sand, and this was aggravated when water broke through.

Well-Design Considerations

The best standalone screen (SAS) available in the market should be selected for the new Temana wells, considering economics and well deliverability. The well-design team developed a workable solution to be used to minimize various risks. The SAS proposed is the direct wire-wrapped screen (WWS), which is a surface-filtered screen, where plugging tendency is minimized.

This direct WWS has higher mechanical strength compared to the WWS used in gravel-packing operations. It is robust and can be rotated downhole, especially during running

in tight holes or collapsed boreholes. One of the special features of the screen is the shrink-fit wrap-on-pipe screen construction that allows all forces to be transferred to the base pipe. As such, the screen and base pipe behave as a unit whereby both end connections and screen jacket will still be intact in tension and compression conditions.

Four other criteria that also were considered were well productivity, slot sizing, critical-drawdown pressure (CDP), and packing mechanism.

Well Productivity. To maximize the productivity of the wells in the main reservoir target (I-65 sand), the wells were drilled highly deviated using drill-in fluid along the I-65 sand. This will ensure that there will be maximum exposure and minimum formation damage to the wellbore. The cased IGP option was replaced with properly designed SAS in openhole completions to avoid recurrence of plugging and impairment as seen in the previous IGP installations in Temana. Because no gravel-pack solids and damaging fluids were introduced, the SAS option should provide maximum productivity. Well cleaning, mud conditioning before running the screen assembly, and use of an enzyme breaker to dissolve mudcakes become critical.

As long as the CDP is not exceeded, there will not be any physical movement of sand particles into the screen and the well PIs should remain high. However, movement of the sand is expected at a later stage as the reservoir pressure depletes, and the SAS should provide an active control, retaining the coarse sand for natural packing. The high PIs are expected to be reduced at this stage, and therefore the objective is to delay this situation as long as possible. These changes in the comple-

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IPTC 12390, "Temana Field Pilot Implementation: A Shift in Sand Control Philosophy To Improve Well Performance," by Wan Amni Bt Wan Mohamad, SPE, Maharon Jadid, SPE, and Mahmoud A. Wahba, SPE, Petronas Carigali Sdn. Bhd., originally prepared for the 2008 International Petroleum Technology Conference, Kuala Lumpur, 3-5 December. The paper has not been peer reviewed.

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tion philosophy resulted in total cost savings of USD 1.4 million/well (estimated), which includes the rig spread cost and well-completion cost.

Slot Sizing. On the basis of dry-sieve analysis and laser particle-size-distribution (PSD) analysis, the sand is categorized from moderately to very poorly sorted, where the uniformity coefficient ranged from 15 to 18 and the fines percentage is approximately 35%.

To achieve natural packing of sand particles on the screen surface, a certain quantity of large particles in the completed sand is required. All sidewall core samples analyzed contain in excess of 30% particles larger than 80 μm . Experimental work has shown that for single WWSs with long slots and retention medium that is not square mesh, a given slot opening would retain particles with diameters of approximately $1/2$ of the slot opening. From the PSD for the I-65 sand, the suitable range for the screen slot size is between 160 and 200 μm .

It was found that the optimum screen sizing is 175 μm , where any fines or sand particles below this size will be produced initially through the screen and particles larger than that will be retained before stable bridge formation and will provide natural packing.

CDP. CDP for sand production is a function of reservoir-pressure depletion and other factors such as initial rock stresses, stress changes, rock strength, well inclination, and perforation orientation. Accordingly, to avoid sand production, the largest effective tangential stress should be smaller than the effective strength of the formation. By using in-house software, the CDP was derived on the basis on the bulk density, porosity, reservoir thickness, compression and shear values, fractional shear volume, reservoir pressure, and core-strength data. The calculated CDP of the I-65 sand is approximately 250 psi at initial reservoir conditions, which is equivalent to

flowing bottomhole pressure (FBHP) of 1,300 psi, while the failure reservoir pressure is approximately 1,350 psi.

Packing Mechanism. A common design criterion, as per hydraulic propped-fracturing guide, is that particles $1/6$ of the pore-throat opening will bridge the pore throat and provide a diverter effect. The same criterion used for passing particles for the sharper slots would indicate that a particle approximately $1/5$ (i.e., less than 30 to 35 μm) of the slot opening (175 μm) will be produced initially through the screen.

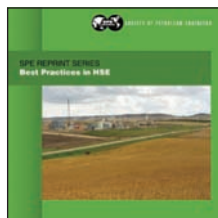
For the I-65 sand, it was found that all the sand samples show less than 25% particles smaller than 35 μm . Accordingly, the particle sizes greater than 30 to 35 μm will be expected to be retained behind the screen before stable bridge formation and to form a sort of natural packing and provide a sort of sand filter on the screen surface. This can be achieved by slow bean up while cleaning the well/production.

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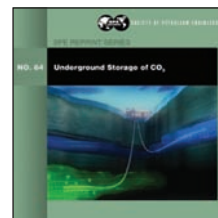
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Well Completion

The two new wells, TE-1A and TE-1B, are highly deviated because Platform A is approximately 1¹/₄ miles from the Temana saddle area and the depth of the I-65 sand is very shallow, approximately 3,600 ft true vertical depth (TVD). The angles are 76 and 86°, respectively, for the twin wells. With these high angles and long-reach condition, measured depths of the wells are quite deep compared to their TVDs. TE-1B well was equipped with a permanent down-hole gauge.

The TE-1A well was completed as 6-in. open hole with 4¹/₂-in. SAS 175- μ m mesh size across the I-65 sand (126-ft completed interval). To isolate the shale sections at the top and bottom of the sand, two 4¹/₂-in. constrictors (swellable elastomers) were used.

The I-65 sand in TE-1B well was completed as 4³/₄-in. open hole with 3¹/₂-in. SASs (134-ft completed interval) with 175- μ m mesh size.

Production Performance

As of July 2008, the total average net oil production for the two new wells stands at 7,000 to 8,000 BOPD. No sand production has been observed at the surface. This is to be expected because the producing drawdown was kept at a low level. The downhole gauge installed in Well TE-1B provides a good indicator for controlling well operations.

Well TE-1A was opened for clean-up, with gas lift for initial kick-off. The initial choke size was 1⁴/₁₂₈ in., producing 100% brine. The well cleanup achieved 100% crude and natural flow in less than 24 hours, and this is regarded as fast considering that almost all previous IGP completions required approximately 1 week to achieve total cleanup. This is the first indication that the well has a good productivity.

Well tests were conducted several times during 2007. The results showed that the average flowing wellhead pressure recorded was 510 to 520 psig

at a steady gas/oil ratio (GOR) of 420 scf/bbl, with average production of 3,300 BOPD. This production at the relatively small choke is far better than those achieved by previous IGP wells in Temana even during the initial production years. Furthermore, this rate was higher than the forecasted rate of 2,000 BOPD.

On the basis of the initial nodal-analysis simulation, the well PI was estimated at 120 bbl/(psi-D). This was validated against the actual well-test data and interpreted pressure-buildup survey. As of July 2008, the well production averages 3,000 to 3,300 BOPD.

Similar to Well TE-1A, the Well TE-1B was cleaned up within 24 hours; 100% crude was produced by natural flow. The initial choke setting was 8⁸/₆₄ in. and was gradually beaned up to 1²/₆₄ in. and it was recommended that this choke size be maintained. Average initial oil production was 2,900 BOPD with flowing wellhead pressure of 510 psig and GOR of 410 scf/bbl. **JPT**



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Wellbore-Stability Performance of Water-Based-Mud Additives

A critical property for many water-based muds (WBM) is the ability to prevent a near-wellbore pore-pressure increase in shales. By slowing or preventing this pressure increase, an overbalance pressure is maintained that promotes wellbore stability. Using a device that simulates downhole rock stress and overbalance fluid-pressure conditions and preserved shale samples, four different muds containing different additives were tested. Direct measurements of shale pore pressure vs. time were obtained, representing the pore pressure inside the near-wellbore region.

Introduction

One of the main shale-instability mechanisms that occurs with water-based drilling fluids is the wellbore pressure penetrating into the shale pore space. This increases the near-wellbore pore pressure and reduces the overbalance. This reduction of overbalance, which acts like a support pressure for the hole, can result in shale failure and wellbore instability. This pressure penetration cannot be prevented with standard filtration additives because shale pores are extremely small, approximately 0.01 μm , and shale permeability is extremely low, typically approximately 0.01 microdarcy or less.

Experimental

Each sample was cut from preserved downhole shale core and had never been contacted by water or brine. By

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 116139, "Wellbore Stability Performance of Water Base Mud Additives," by R.T. Ewy, SPE, and E.K. Morton, SPE, Chevron Energy Technology Company, originally prepared for the 2008 SPE Annual Technical Conference and Exhibition, Denver, 21–24 September. The paper has not been peer reviewed.

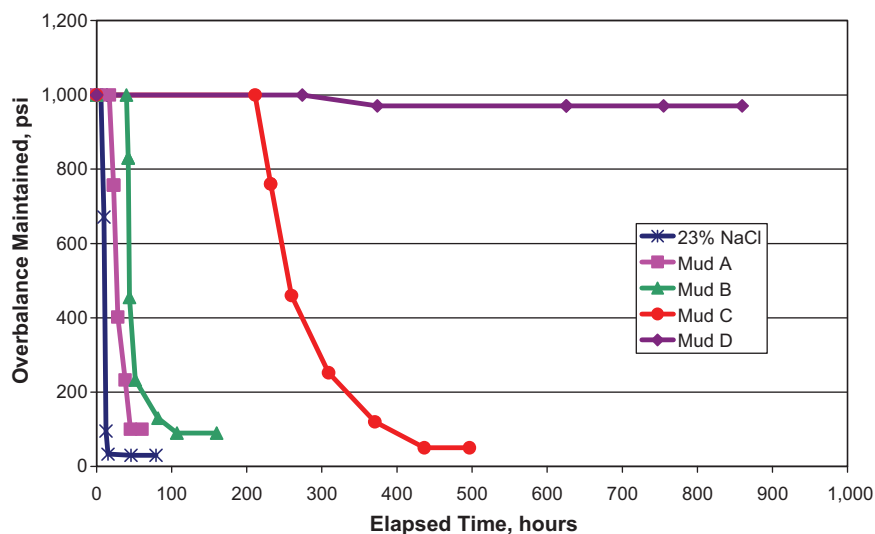


Fig. 1—Loss of overbalance with time because of pressure penetration into shale.

avoiding “premature” contact with aqueous fluids, a meaningful swelling response on the shale as caused by the drilling fluid can be measured.

Each mud test was performed on a new, preserved shale sample. The shale used for this study contains approximately 70% clay, approximately one-third to one-half of which is kaolinite, with the remainder being mostly mixed-layer illite/smectite. All samples were equilibrated to 96% activity in a vacuum desiccator before testing. This downhole shale core was cut with an oil-based mud and was kept fully preserved. The samples were cut and end-ground using decane, and they were not contacted by any aqueous fluid.

Fig. 1 in the full-length paper illustrates the inner part of the shale/fluid-interaction test apparatus. The samples were right-circular cylinders with a 0.75-in. diameter and 0.5-in. length. The sample was surrounded by an impermeable jacket, which also extends to the top and bottom end caps. This allows a confining pressure to be applied to the

sample using hydraulic oil (the entire illustrated section in Fig. 1 sits inside a pressure vessel). The confining pressure represents the in-situ stress acting on the shale near the wellbore.

The top end cap has channels, and a flow-distribution insert, that allow the test fluid to be flowed under pressure past the top surface of the shale sample. The difference between the fluid pressure and the initial sample pore pressure (usually set to zero) is the initial overbalance pressure.

The bottom end cap has a channel leading to a valve and a pressurized accumulator. It also contains a miniature pressure transducer. The small channel between the sample and the valve is filled with a fluid that transmits pressure but does not interact chemically with the shale. The arrangement is such that, when the valve is closed, the transducer measures the pore pressure at the bottom of the shale sample. This represents the pore pressure in the near-wellbore region. By opening the valve, a constant pressure differential can be set up across

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the sample to cause flow of the test fluid into the sample, just as would occur next to a wellbore because of the overbalance.

The sample was instrumented to measure strains in all directions. In addition, the top and bottom end caps contain acoustic crystals so that *P*- and *S*-wave velocities can be measured during the test. The stages of the test for this shale are as follows.

1. Apply confining pressure of 2,500 psi, with no fluid contact to shale. This brings the shale back to a simulated in-situ condition and ensures that it is fully saturated (with only its native pore fluid).

2. Apply fluid to top of shale at 1,000 psi (simulating 1,000-psi overbalance). Start slow flow of fluid across top of shale.

3. Open valve below sample to allow steady-state flow of fluid into the shale. Flow approximately 0.1 to 0.3 cm³ into the shale. This simulates mud penetration into the near-wellbore region, and also allows a permeability measurement.

4. Close the valve to allow pore-pressure buildup at the bottom of the shale sample. This measures the time-dependent change in true overbalance and the osmotic pressure. Also, record sample swelling by use of the strain devices.

5. Drop fluid pressure to zero, and then reduce confining pressure to 500 psi. Measure additional swelling.

6. Reduce confining pressure to 100 psi, and measure additional swelling.

Note that Step 4 has a constant fluid pressure on top of the sample and a no-flow boundary at the bottom of the sample. With no chemical forces present, the pore pressure at the bottom of the sample would become equal to the applied fluid pressure at the top of the sample. As long as the sample has some nonzero permeability, the pressure will move through the sample and build up at the bottom. Once the pressure at the bottom of the sample reaches equilibrium, any difference between that pressure and the applied fluid pressure is a direct measure of osmotic pressure.

Muds

Four different high-performance WBMs, each from a different provider, were tested. Formulations of the four muds are listed in Tables 1 through 4 in the full-length paper. The muds were unweighted, and they were tested at room temperature. Each of the mud providers stated that the shale-stabilizing performance of

the mud did not require elevated temperature and did not require the addition of drill solids or weighting material.

Each mud sample was mixed by the source company. In addition to the four muds, a base-case run was performed using 23.2-wt% sodium chloride (NaCl) brine.

Results

Pressure Results. The pressure results are compiled in **Fig. 1**. With the NaCl brine, the pore pressure rose to 970 psi, nearly equal to the applied 1,000 psi, after 15 hours. The actual overbalance at that time was therefore only 30 psi, with this 30 psi being a reflection of weak osmotic forces, or a low membrane efficiency of only 1%. This is the typical result found when testing shales of this porosity range with clear brines. The overbalance plotted in **Fig. 1** is computed as the applied fluid pressure minus the pressure at the bottom of the sample, after the valve has been closed. This represents the “true” overbalance that would act to stabilize the wellbore.

Mud A and Mud B performed slightly better than the base-case brine. The onset of pressure increase (overbalance loss) was slightly delayed, but once it started, it progressed rapidly. However, both of these muds gave some improvement to the membrane efficiency, resulting in approximately 100-psi true overbalance. This converts to a membrane efficiency of approximately 4%.

Mud C performed quite well, delaying the onset of pore-pressure increase by more than 200 hours and significantly slowing the loss of true overbalance. After 300 hours, an overbalance of approximately 250 psi was still present. The overbalance eventually dropped to approximately 50 psi (membrane efficiency of approximately 2%), but only after 430 hours. The earlier high overbalance pressures might be a result of temporary increases in membrane efficiency, along with permeability reduction.

By far the most effective fluid was Mud D. Only a 30-psi increase in pore pressure occurred, meaning that nearly the full 1,000-psi overbalance was maintained. This small amount of pore-pressure increase did not occur until after 400 hours, and the test was run for a total of 860 hours with no further reduction in overbalance. This high overbalance pressure, if entirely a result of osmotic forces, converts to a membrane efficiency of 45%.

Swelling Results. Strain measurements were collected during the tests, and shale swelling was computed for various test stages. The swelling magnitudes are not a result of only chemical effects. The swelling upon fluid exposure includes mechanical (elastic) swelling caused by any increase in sample pore pressure. Similarly, swelling at confining pressures of 500 psi and 100 psi (even though with zero fluid pressure) includes the elastic effect of reducing the confining pressure from 2,500 psi. Nevertheless, the results allow comparison of the different fluids, and they also can be used to estimate swelling next to the wellbore that results from pore-pressure increase plus loss of confinement. The shale next to a wellbore has very low confining stress in the radial direction, because the rock has been removed and the wellbore fluid is (usually) slowly increasing the near-wellbore pore pressure.

The initial swelling, as a result of fluid exposure, is low for all the samples. This is consistent with earlier findings that the presence of a confining stress will greatly limit chemically induced shale swelling. However, it is noted that all muds except Mud B resulted in even less swelling than the base-case NaCl brine.

Upon reducing the confining pressure to 500 psi near the end of the test, all the muds resulted in somewhat less swelling compared to the base-case NaCl brine. At 100-psi confining pressure, swelling magnitudes are significantly greater than at 500-psi confining pressure, even though the confining pressure has been reduced only by 400 psi. In most cases, much of this additional swelling is driven by chemical swelling forces that play a greater role when confinement is very low (the fluid is still in contact with the shale at this stage of the test). However, it is noticed that the swelling is significantly different for the different muds. Mud A and Mud B result in swelling slightly less than that of the base-case NaCl brine. Mud C resulted in even less swelling, and Mud D resulted in the least swelling of all the muds tested.

Swelling is important for two reasons. First, it could give rise to near-wellbore swelling stresses. Second, it may be related to shale weakening, or loss of compressive strength. This is another potential wellbore-instability mechanism when using WBMs, which exacerbates the effects of any near-wellbore pore-pressure increase. **JPT**

Single-Trip Multizone Gravel Packing

Stacked gravel packs involve limited technical risk, but require considerable rig time when completing deep multizone, sand-control wells. Four field developments are challenging the conventional approach to completing long sand-control zones by using newer technologies. Nineteen wells have been completed with single-trip multizone (STMZ) technology comprising 77 frac packs/gravel packs.

Introduction

For many years, simple stacked gravel packs have been used in Indonesia as the primary cased-hole sand-control method. This kind of completion involves limited technical risk, but requires considerable rig time and cost when completing multizone wells with sand-control completions. Because of escalating prices, operators completing wells with multizone gravel packs are striving to cost-effectively produce as many unconsolidated reservoirs within a single wellbore as possible.

The development of the Handil, Bekapai, Sisi, and Nubi fields illustrates the challenge of maximizing the recoverable reserves from such wells while mini-

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IPTC 12388, "Single Trip Multi-Zone Gravel Packing—Case Study at Handil, Bekapai and Sisi-Nubi Fields," by Mark Banman, Total E&P Indonesia; Mohammad Sofyan, SPE, Total; Siswara Suryadana, SPE, Total E&P Indonesia; and Eric Delattre, Halliburton, originally prepared for the 2008 International Petroleum Technology Conference, Kuala Lumpur, 3–5 December. The paper has not been peer reviewed.

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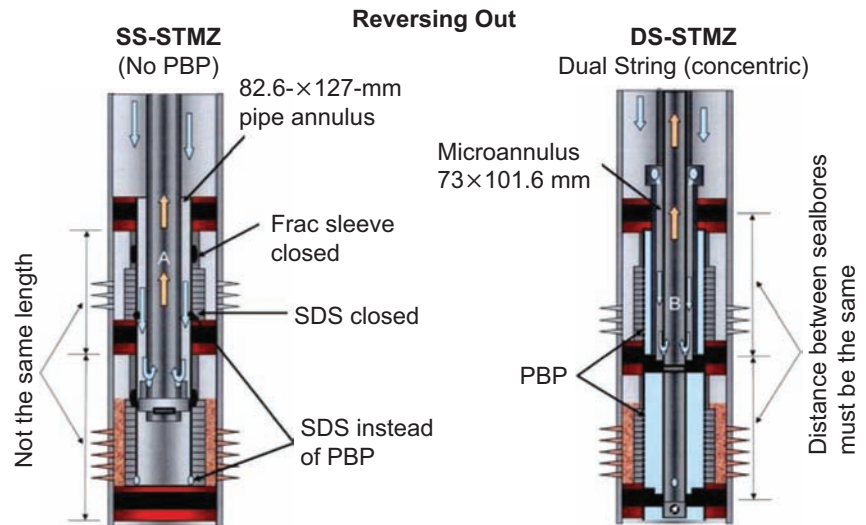


Fig. 1—SS-STMZ and DS-STMZ comparison: SDS=sliding-door sleeve.

mizing the incremental cost of completing additional zones. These four fields are part of the giant Mahakham delta complex on the east side of Borneo Island (East Kalimantan, Indonesia). Two of these fields, Handil and Bekapai, are redevelopment projects, while Sisi and Nubi fields are new developments. All the fields are in relatively shallow waters.

In each of the fields, production comes from two major sand/shale sequences. There is a series of deeper gas sands that produce without sand control and a series of shallower, oil/gas-bearing sands that require sand control for efficient production. The shallow hydrocarbon reserves are distributed over a large vertical interval. This leads to wells with long multizone gravel-pack completions.

Conventional gravel-pack techniques for multiple zones consist of a series of individual gravel packs, each one placed on top of the one below ("stack pack"). This generally uses at least two service-string trips per zone, one for perforating and the other for gravel packing. Use of a packer plug to isolate lower zones when

perforating adds one additional trip per zone. A typical well in the Mahakham delta has five zones and would need 14 service-string trips and consume 20 to 30 rig days to install the stack pack together with the upper completion depending on the depth, perforating time, and use of packer plugs. This represents a significant capital cost.

Handil Field. Handil was discovered in 1974 and is in the modern Mahakham delta. At the time of development, certain shallow reservoirs were bypassed intentionally in favor of deeper horizons. The new development wells at Handil target previously bypassed shallow oil- and gas-reservoir sands and do not penetrate the deeper zones, which were developed many years ago. The gross sand-control interval at Handil ranges from 300 to 700 m long, with the gravel-pack packer typically set at a depth of 1000 m true measured depth (TMD). There is no production liner because there is no need to accommodate production from below the gravel-pack intervals. Handil wells are completed

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with dual-string STMZ (DS-STMZ) completions using an 88.9-mm inner production string isolating the gravel-packed zones. The sand-control completions are configured either as a single multiple-gravel-pack completion inside 244.5-mm casing or as two multiple-gravel-pack completions, one on top of the other inside 244.5-mm casing.

Bekapai Field. Bekapai also was discovered in the 1970s and is a complicated offshore oil field where the operator is targeting the shallow sands starting at a depth of 1800 m TMD. This field has a complex gas cap on top of a largely depleted oil reservoir. This project initially targets bypassed oil with gas-cap production as a secondary objective. Because the gas cap and upper oil zones are prone to sand production, both selective isolation and sand control are required. Bekapai is using DS-STMZ technology combined with a liner to accommodate initial production from deeper oil zones. As much as possible, production from the gas cap will be deferred until the bypassed oil has been recovered. Bekapai also has one "pilot" well using the single-string STMZ (SS-STMZ) technology.

Sisi and Nubi Fields. Sisi and Nubi are neighboring gas/condensate fields 25 km east of the modern Mahakham delta (offshore and down structure). Consequently, the loosely consolidated gas sands start at a depth of 1800 m subsea and occur as deep as 2500 m subsea. Additionally, a series of consolidated gas sands reach a depth of 3800 m subsea. Typically, the gravel-pack packer is set at approximately 3000 m TMD, depending on the lateral displacement of the reservoir target. The gross interval requiring sand control is more than 500 m long and can be as long as 1000 m. Most wells will have five sand-control zones distributed throughout this interval. Many wells also will include a liner that is used to produce from the consolidated gas sands. These wells are intended to produce simultaneously from both the shallow and the deeper reservoir sands. Sisi and Nubi are in the early stages of development. To date, four SS-STMZ sand-control wells have been completed. More than 22 additional SS-STMZ wells are pending drilling and completion.

Discussion

To minimize completion costs, STMZ techniques must successfully reduce

the number of trips required to install gravel packs in the well. Additionally, the systems must accommodate adequate isolation for gravel placement and subsequent reservoir management without prohibitive risk or cost.

Five-zone stack-pack programs require as many as 14 trips with the service string. Each additional zone adds three extra trips to the program. The five-zone STMZ gravel-pack program requires as few as three trips with the service string. Adding or deleting a zone does not affect the number of service-string trips required. In the case of a five-zone completion, use of STMZ technology has the potential to save 5 to 10 rig days/well or 11 service-string round trips. The five-zone STMZ program consists of the following steps.

1. Set the sump packer on electric line.
2. Run tubing-conveyed perforating for all five zones, and pull out of hole.
3. Run scrapper and mill to deburr the perforations, and check the sump packer and pull out of hole.
4. Run screens and service tools, and selectively gravel pack/frac pack all five zones and pull out of hole.

DS-STMZ Systems. The majority of industry experience with STMZ operations is with DS-STMZ completion systems. More than 90% of the DS-STMZ completions performed to date have been in China. The main feature of the DS-STMZ system is use of conventional screen with perforated base pipe (PBP) together with a concentrically arranged "false annulus." Screens for use inside 244.5-mm casing mainly use 139.7-mm PBP. Inside the screen, two concentric washpipes are arranged to allow circulation in isolation from the other gravel-pack zones. This is referred to as a dual-string (concentric washpipe) configuration, or alternatively as a microannulus. Typically, 73-mm tubing is placed inside 101.6-mm tubing with service tools, providing the crossover ports and isolation, hanging out the bottom of the microannulus on 73-mm tubing. This entire assembly then is run inside the gravel-pack packer and screens.

As shown in **Fig. 1**, reverse circulation can be accomplished by circulating down the 244.5-mm casing annulus into the 73×101.6-mm microannulus, with returns to surface coming up inside

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Society of Petroleum Engineers

eMentoring— Become a Mentor

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the 73-mm tubing. Only two zones are shown in Fig. 1, with the microannulus spanning the entire upper zone. The gravel-packing crossover tool is positioned at the bottom of the microannulus with an isolation tool below the bottom perforation. For five gravel-pack zones, the microannulus would span all four upper gravel-pack zones. The service-tool assembly spans only the treated zone. In the case of DS-STMZ technology, each set of screens and blanks must be arranged carefully so that the service tool can seal off each treating interval in turn. The longest zone determines the minimum length of the washpipe. The key constraint is that because the service-tool assembly has a fixed length, all the treating zones must be approximately the same length. The DS-STMZ technology provides a cost-effective solution for mature fields, such as Handil. It is a proven technology with a substantial performance history and provides reliable single-trip applications in the correct well application.

Results

The ultimate goal of the completions has been to maximize economic return of the development projects. Managing risks and advancing rapidly through the learning process have been key objectives in terms of reducing the effect of unexpected development issues.

Over 14 wells with 60 gravel packs, the average completion time has been 11.3 rig days/well for the DS-STMZ process. This includes the associated upper completions and all nonproductive time (NPT). To date, there has not been a serious malfunction or failure. The DS-STMZ projects are now progressing along a stable portion of the learning curve.

Over five wells with 18 frac packs/gravel packs, the SS-STMZ completions have taken an average of 22.2 rig days/well, inclusive of all NPT and the installation of the upper completion. There have been problems resulting in significant NPT on the SS-STMZ wells. However, all the wells are fully capable of both production and future interventions as per the intended scope of work. The SS-STMZ project is still in the midst of making significant improvements.

Including the time and cost related to NPT issues, both STMZ technologies have compared favorably to the expectations of the operator for stack-pack technology.

JPT

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- Productivity enhancement
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