Lessons learned on sand control failure, workover at Magnolia deepwater development

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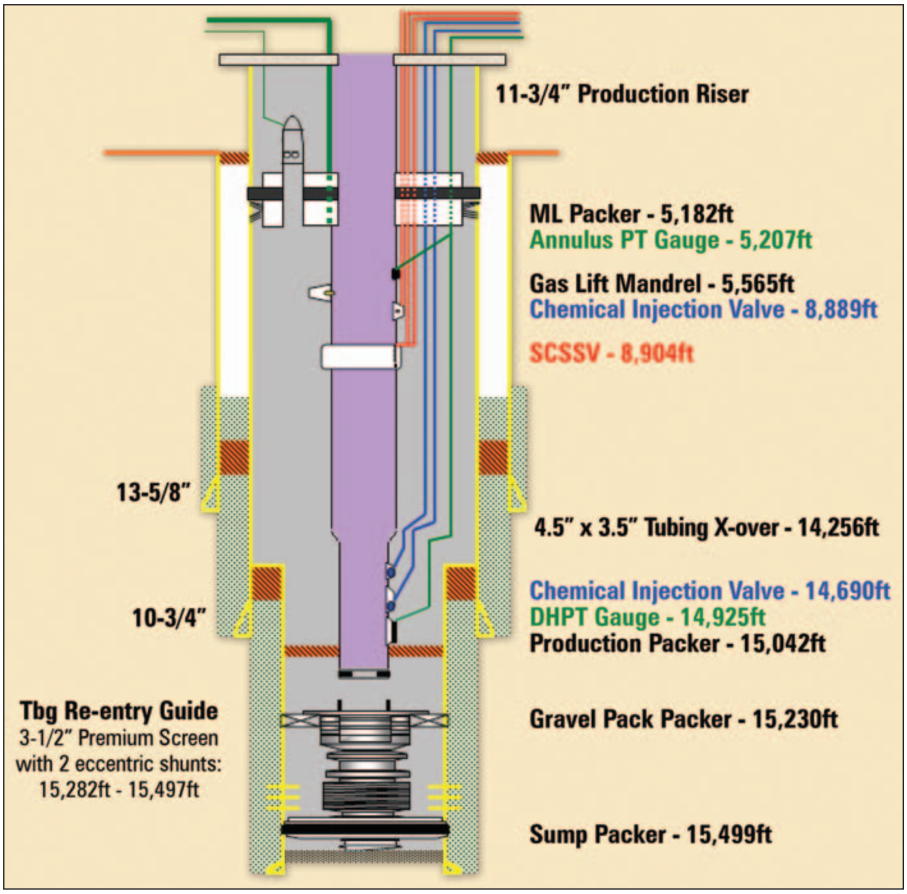
CONOCOPHILLIPS IS developing the Magnolia field with a tension leg platform (TLP) in 4,674 ft of water at Garden Banks block 783 in the Gulf of Mexico. The wells produce primarily from thick, fine-grained, Pleistocene-age reservoirs. Due to the long lengths of the producing reservoirs and large variations in sand grain sizes/permeabilities, premium screens with shunt tubes in conjunction with cased hole frac packs have been used to complete the wells.

The 3rd well, A1ST1BP1, was completed using the same techniques as were successfully used on the first 2 wells. The A1ST1BP1 completion failed during initial unloading, allowing unacceptable rates of sand production. The well was worked over, and the tubing with 8 control lines and premium sand control screen with shunt tubes were retrieved/fished from the well with minimal problems. The retrieved screens had collapsed around the perforated base pipe. The well was re-perforated, new screens were run, and a second frac-pack was pumped. When laying down the washpipe after the 2nd frac-pack, erosion marks indicated an apparent second screen failure.

A detailed examination of both A1ST1BP1 frac-pack jobs was conducted in conjunction with laboratory collapse and erosion testing of the premium screens. Collapse testing revealed the screen lost sand control at less than 1,000 psi. The collapse rating stated by the manufacturer was greater than 7,000 psi. The erosion tests demonstrated that inflow from supercharged reservoirs into the wellbore could erode hole(s) in the premium screen. Revised operational procedures were used in 6 subsequent frac-packs without any additional failures and 0 to negative completion skins.

This article will discuss the failure modes of the 2 frac-pack/premium screen sand failures, workover planning and execution to remove tubing with multiple control lines and fish screens with shunt tubes from close tolerance casing, as well as procedural revisions developed to successfully frac-pack the subsequent Magnolia reservoirs.



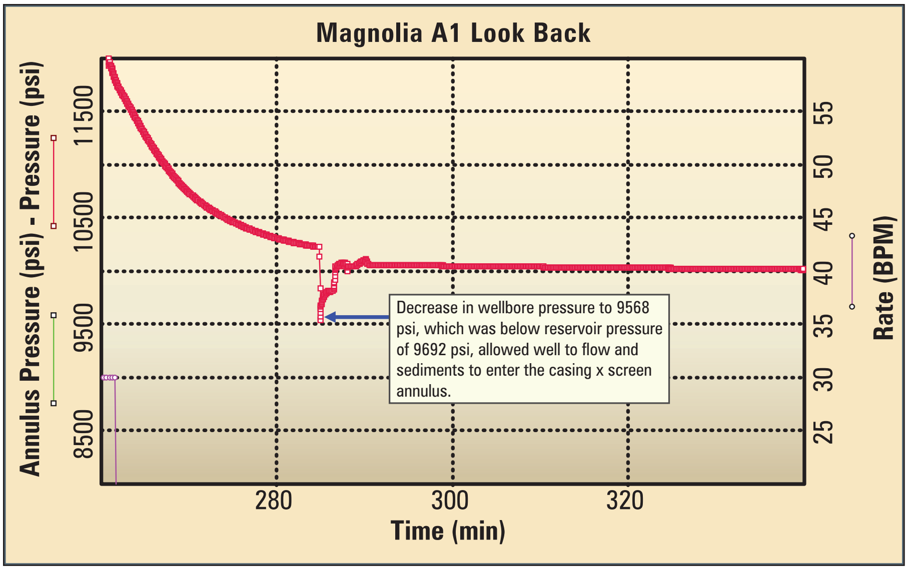
The 3rd well in the development of the Magnolia field in the Gulf of Mexico was completed using the same techniques as successfully used on the 1st 2 wells — yet failed. In a 2nd attempt, there was another apparent failure. Above is a simplified well sketch of the 3rd well, A1ST1BP1.

INTRODUCTION

The Magnolia field consists of a series of highly faulted, compartmentalized, geopressured, unconsolidated silt/very fine sand Pleistocene-age reservoirs. Due to the high degree of compartmentalization, a majority of the reservoirs produce under depletion and compaction drive with minimal water influx. Reservoir pressures have declined during production from initial pressures in the 11,000 psi range to expected abandonment pressures as low as in the 1,500 psi range. These large reservoir pressure declines, on the order of 9,000 to 10,000 psi, are expected to generate large geotechnical loads on the wells. As a result, thick-walled production casing was installed to curtail compaction-related failure.

The B25 Sand is the largest producing interval in the Magnolia field and has been a target for most of the field's frac-pack completions, including the A1ST1BP1 well. The reservoir properties of the B25 Sand are also similar to other pay intervals in the Magnolia field. The vertical height of the B25 ranges from 104 ft to 365 ft (127 ft to 595 ft MD) throughout the Magnolia field, with a high net-to-gross ratio of around 0.9. The sand is unconsolidated and consists of laminated, fine-grained silt/sand with median -grain diameters ranging from a few micrometers (μm) up to 80 μm. To maximize well productivity with minimum solids production, all wells in the field have been completed with cased-hole, frac-packs.

Given these challenging parameters, several steps have been taken to reduce the potential for completion failure and sand production. Premium, metal-mesh, laminate screens were run, with a nominal



During completion operations, it was observed that while preparing to reverse out after the mini-frac, a valve behind the choke was inadvertently opened, allowing flow from the formation to the well for a short period of time.

opening size of 75 micrometers to allow effective retention of formation grains in case of voids in the gravel pack. US 30/60 mesh ceramic proppant was selected for the B25 frac-packs based on laboratory testing, which showed it to provide the best balance of sand bridging, retained permeability and low plugging characteristics. To help ensure proppant placement in the casing/screen annulus over the entire reservoir interval, shunt tubes were installed with the screens. A viscoelastic surfactant (VES) frac-pack fluid was chosen because testing showed it to be more compatible with the completion brine and less apt to cause screen plugging.

The general Magnolia frac-pack completion procedure is summarized below:

1. Re-enter the pre-drilled well and displace casing to brine.

2. Perforate underbalanced with 5-in. OD, 21 shot per foot (SPF), 0.66-in. diameter big-hole charge pipe-conveyed guns and flow back 20 bbls to clean up the perforations.

3. Kill well with a fluid loss control pill and retrieve the perforating guns.

4. Run the screens and gravel pack equipment.

5. Place HCl / Acetic acid mixture across the perforated interval to remove the fluid loss control pill.

6. Pump a mini-frac; analyze and confirm/redesign main frac-pack treatment.

7. Pump the main frac-pack.

8. Pull out of the hole with washpipe, closing the mechanical isolation valve. Retrieve gravel pack tools and washpipe.

9. Run tubing and sub-assemblies.

The first Magnolia frac-pack was performed on well A2ST3BP1 17 months prior to start of TLP completions, to test completion performance and measure reservoir flow properties. The A2ST3BP1 frac-pack successfully packed 342 ft true vertical thickness (TVT) / 378 ft MD of the B25 interval. The subsequent 5,000 barrel completion flow test verified that the completion techniques would deliver low-skin, high-flow capacity wells. After installing the Magnolia TLP, the 249 ft TVT / 418 ft MD B25 interval in the A4BP1 well was successfully frac-packed and produced, reconfirming the procedures and the resulting low-skin, high-flow capacity results.

INITIAL RESULTS

As the 3rd Magnolia completion, A1ST1BP1 was frac-packed and completed in the same manner as the 1st 2 successful completions. Premium 75 μm laminated screen on 3.5-in. OD, 9.2 lbm/ft base pipe with 2 shunt tubes was placed across the perforated interval. Because of the relatively short (104 ft TVT, 127 ft MD) interval, low inclination (36°), and success of the first 2 completions, radioactive (RA) tracer and annulus pack density logs were not run as a cost-saving measure.

Relevant observations during completion operations include:

• Underbalanced perforating bottomhole pressure (BHP) gauge data indicated a low-skin, high-productivity interval.

• Two hydroxyethylcellulose (HEC) polymer-based viscosified pills were spotted after perforating to control fluid loss.

• Good results were obtained from the pre-frac-pack acid stimulation, with injectivity of 15 bbl/day/psi.

• While preparing to reverse out after the mini-frac, a valve behind the choke was inadvertently opened, allowing flow from the formation to the well for a short period of time. Formation sand and gas were observed at bottoms up, indicating that some amount of formation sand had been deposited in the screen x casing annulus.

• Comparison of casing/screen annular circulating pressures before and after the in-flow showed pressures to have risen approximately 400 psi at 2 bbl/min, indicating partial filling of the casing/screen annulus. In addition, injectivity decreased from 10 bbl/day/psi before the in-flow to 4.1 bbl/day/psi after the in-flow.

• The frac-pack was pumped as planned at 35 bbl/min, placing 79,000 lbs of US 30/60 Mesh ceramic proppant. A net pressure of approximately 110 psi was built before quickly falling, indicating that the fracture probably broke out of zone.

• The pump rate was reduced at the end of the frac-pack to 2 bbl/min to induce a screen-out at 8,076 psi treating pressure.

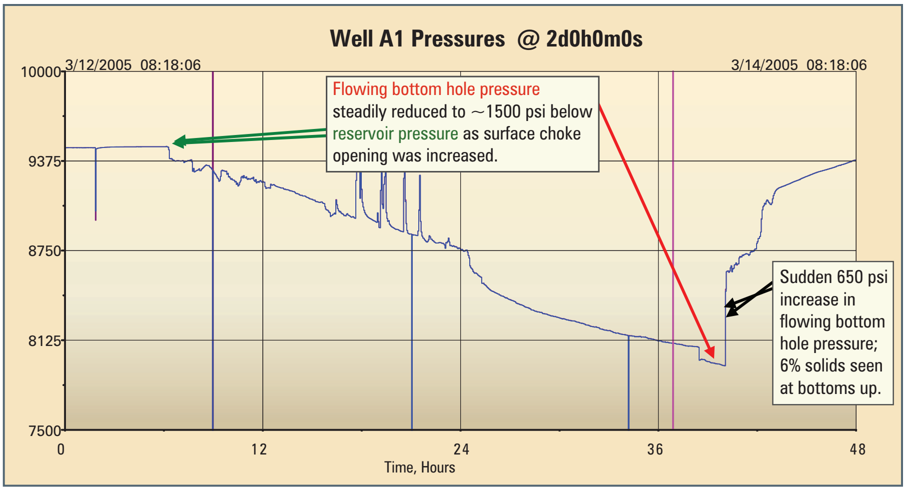
• The wash pipe was slowly pulled until the single shifting tool attempted to close the mechanical isolation valve. The isolation valve did not fully close, as it did not hold a pressure test and fluid loss continued at 3 bbl/hr.

• A 14 bbl xanthan-based proprietary pill was spotted to further reduce fluid loss before pulling out of the hole and running tubing. Pre-testing of a calcium carbonate ($CaCO_3$) solids-laden version of this pill had indicated acceptable return-perm through the frac-pack. However, due to concerns over the solids settling out on top of the partially closed isolation valve, the $CaCO_3$ was omitted from the pill.

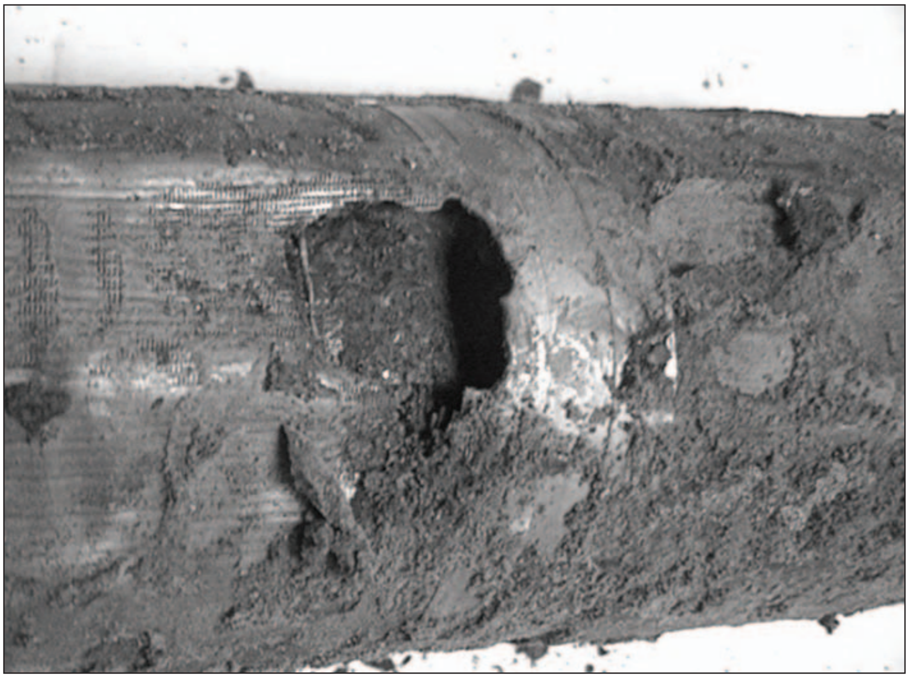
• After running tubing, an attempt was made to hydraulically open the mechanical isolation valve. However, sufficient hydraulic pressure could not be established to cycle the valve open. Pump pressure (1,589 psi at 3 bbl/min) indicated a restriction, thought to be filter cake from the fluid loss pill on the inner diameter (ID) of the screens. Previous testing established that it should flow off once the well was put on production, or if not, could be removed with acid treatment if the high skin remained after the well cleaned up.

• Coiled tubing was used to mechanically open the isolation valve. A 2.26-in. outer diameter (OD) bull nose wash string was then run to the sump packer, encountering no restrictions. No acid was pumped.

The well was handed over to the production group, and well-unloading operations commenced. Although the unloading procedure addressed both rate and drawdown, actual operations focused mainly on rate with less attention placed on drawdown. The flowline choke opening was gradually increased to attain the scheduled rate, ultimately allowing a drawdown of about 1,500 psi at 2,000 bbl/day flow rate. At this point, a significant increase in flowing BHP was observed. At bottoms up from when the increased BHP was observed, shake-out tests indicated 6% solids (mixture of sand and proppant). Gravel pack screen failure was apparent, and the well was shut in.



After the flowline choke opening was gradually increased to attain the scheduled rate, ultimately allowing a drawdown of about 1,500 psi at 2,000 bbl/day flow rate, a significant increase in flowing BHP was observed.



A short period of lost circulation was experienced while washing over the screens near the suspected screen failure depth. After washing over the screens down to the sump packer, the screens and shunt tubes were retrieved fully intact. One shunt tube was packed with formation sand. The outer layer of screen was packed with filter cake. The premium screen laminate had unexpectedly collapsed around the drainage layer underneath. A hole, with a diameter of about 2 in., was observed in the premium screen adjacent to an end ring.

WELL CLEAN-OUT

A slickline run was made to determine the amount of debris and stopped at 12,090 ft MD, roughly 3,250 ft above the top of the screen. Coiled tubing was rigged up with the objectives of 1) washing sand and proppant to below the sump packer; 2) running diagnostic logs to determine the location of the pack failure; and 3) repairing the screen if practical. Sand and proppant were successfully washed to below the sump packer. However, a coiled tubing bottom-hole assembly (BHA) was left in the well below the production packer. Coiled tubing operations were ended, and planning for the workover began.

The objectives of the first phase of the workover, i.e. well clean-out, were the following: 1) retrieve tubing, mudline packer, sub-assemblies and control lines through the production packer; 2) locate the coiled tubing fish and retrieve it if in the way; 3) wash over and retrieve the gravel pack packer and screen assemblies down to the sump packer; and 4) clean out the wellbore and test the sump packer. A pre-requisite to minimize well control issues was to have mechanical isolation from the open perforations, in addition to kill-weight fluid, while pulling the tubing, due to the potentially long exposure time of pulling tubing with control lines across the blowout preventers (BOPs).

The above objectives were achieved in 39 days, of which 6 days were for storm evacuations. Activities went generally as planned, with 15% (5 days) non-productive time mostly associated with retrieving the coiled tubing fish. Key learnings and success factors are:

• "Retrievability" of all sand face components and completion tubulars was considered early-on during well completion design. A preferred fishing tool company was consulted to help ensure that everything run in Magnolia wells had a reasonable probability of retrieval without getting into extended milling operations.

• At the suggestion of one of the field-based company men, a "what-if" flowchart was prepared early in the planning stage. This flowchart helped to put operational details in the most effective sequence, illustrating how problems in one step could affect subsequent steps. It also helped prioritize areas requiring contingency planning in case activities didn't go per the primary plan.

• Other operators were contacted who shared their workover experiences and best practices.

• Several fishing tool companies were consulted to learn from their experiences. A single fishing company was chosen after this process to do the detailed planning.

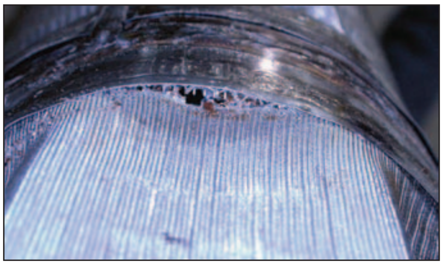
• A Pull Well On Paper (PWOP) session was held with the primary service companies. This session validated the sequence of activities, ensured the service companies understood the scope of work and how their particular service fit into the overall plan, established that appropriate contingencies were considered, and provided a basis for the service companies to finalize procedural and equipment details.

• To meet the mechanical isolation prerequisite, a plug was set in the tubing below the production packer. The tubing was then cut above the production packer and retrieved. The production packer was retrieved on a separate trip. Even though this required an extra trip, it was controllable and eliminated the risk of complications from the coiled tubing fish. It also provided an additional well-control advantage by eliminating the chance of swabbing from the close tolerances on the production packer while pulling tubing.

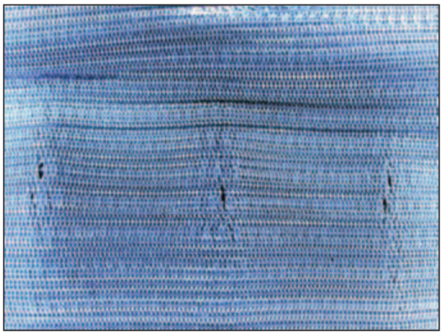
• Testing was done with a radial cutting torch to confirm that tubing could be cut and control lines severed (or at least crippled) without damaging the casing, to control the breaking point of the control lines in the event that tubing had to be fished up the hole (e.g., above the mudline packer if its primary and secondary release methods failed).

• The probability of successfully jarring the screens out with the gravel pack packer was considered very low and not worth the downside risk. Especially with shunts, the jarring action would likely damage screen components and significantly decrease the chance of being able to wash over the screen assemblies. Downhole and surface vibrator tools were considered but were not used due to their low success rate on similar well configurations.

• Both brine-based drill-in fluids and completion brine plus gel sweeps were considered for use during the workover. The fluid properties while washing over the gravel pack equipment were considered critical to effectively carry the sand/proppant to surface and prevent settling or bridging off. The brine-based drill-in fluid was more expensive but would minimize fluid loss and maximize hole cleaning. The solids-free completion brine would result in higher fluid losses and require pumping gel sweeps on a routine basis to ensure hole cleaning.



The first collapse test showed that the laminate layer began to collapse to the screen basepipe at a differential pressure of approximately 500 psi. Total failure occurred at a differential pressure of 950 psi. Upon removal of the shroud, the failure point was quickly identified (above). The failure point near the end ring was similar in appearance to the failure point identified on the screens that were fished out of the well.



In the 2nd collapse test, total failure again occurred at around 950 psi, although the failure location was not as visually apparent. Rather than a large tear at the end ring, there were many small tears from the laminate layer stretching as it collapsed onto the drainage layer.

The economic consideration is the net cost (after buy-back) of the more expensive drill-in fluid versus the costs associated with using a typical completion brine (cost of lost fluid, sweeps, rig time, etc). A brine-based drill-in fluid was used on A1ST1BP1, and the 225 ft of blank and screen were washed over in 13 hrs (2 trips) with minimal fluid loss and no sweeps required.

• Other washing best practices offered were:

1. Utilize high-torque washpipe for wash-over operations.

2. Rotate at 40-50 rpm the entire time washing, not just when burning a centralizer, especially on higher-angle wells.

3. Set a modest torque limit well below the torque rating of the washpipe. Resist the temptation to bump the torque limit up as progress slows. Added torque probably won't help and increases the risk of damaging the screens or leaving washpipe in the hole.

4. Limit set-down weight while washing. The A1ST1BP1 well was washed at 2-4 kips down.

A short period of lost circulation (35 bbl to regain full circulation) was experienced while washing over the screens near the suspected screen failure depth. After washing over the screens down to the sump packer, the screens and shunt tubes were retrieved fully intact. One shunt tube was packed with formation sand, supporting the suspicion of formation inflow during frac-pack operations. The outer layer of screen was packed with filter cake. The premium screen laminate had unexpectedly collapsed around the drainage layer underneath. A large (~2-in. diameter) hole was observed in the premium screen adjacent to an end ring.

LABORATORY TESTING

A laboratory testing program was initiated following the first completion failure on the A1ST1BP1 frac-pack. The tests focused on determining the cause of the high skin values observed during initial production of the A1ST1BP1 frac pack. The test set-up placed screen, proppant and formation sand in a single test cell. The VES frac-pack fluid was pumped through the simulated completion, and the system permeability obtained. The solids-free LCM was then pumped through the simulated completion and allowed to set at temperature. Following injection of all fluids, the return permeability of the completion (screen + proppant) and formation sand in the opposite flow direction was measured.

Four separate flow tests were conducted to evaluate the formation/completion damage potential of different combinations of formation sand, proppant, VES frac fluid and the xanthan LCM. The first test simulated the permeability reduction with formation sand and proppant in the screen x casing annulus if only VES frac fluid had been pumped. The second test simulated formation sand in the screen x casing annulus while pumping the VES frac fluid followed by the xanthan solids-free LCM. The third test simulated mixing of formation sand and proppant in the screen x casing annulus while pumping the VES frac fluid followed by the xanthan solids-free LCM. The fourth test simulated pumping through layers of formation sand, proppant, and a 50/50 mixture of proppant and formation sand with the VES frac fluid followed by the xanthan solids-free LCM.

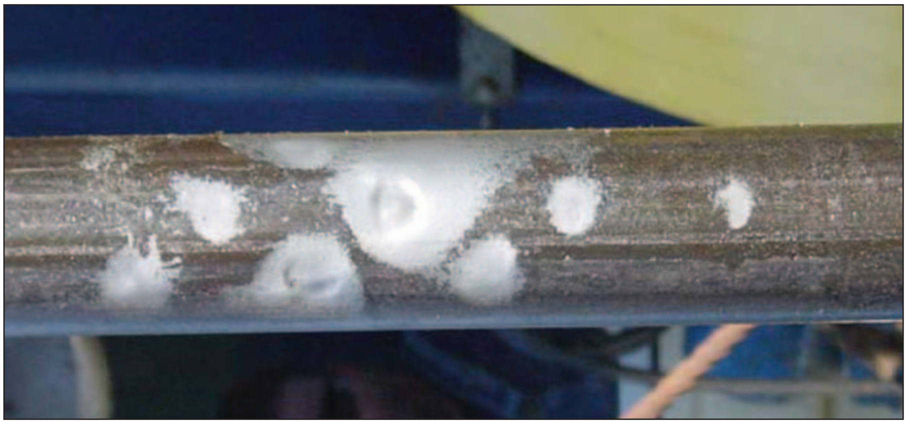
The results of this series of tests showed that neither formation sand nor the xanthan solids-free LCM by itself caused catastrophic reduction in permeability. Retained permeability of the 2 above cases was 76% and 25%, respectively. However, combining both formation sand and proppant with the xanthan solids-free LCM resulted in less than 1% of original retained permeability. These results indicated that severe plugging of the completion would occur from pumping the xanthan solids-free LCM into a mixture of proppant and formation sand in the annulus.

Therefore, to generate the greatest productivity impairment, the annulus must contain a mixture of formation sand and proppant that has been exposed to solids-free LCM.

COLLAPSE TESTING

Since the 1,500-psi drawdown took place early in the well's unloading process, it was surmised that the majority of the pressure drop was occurring across the screens themselves and not as much through the perf tunnels and proppant pack. Prior testing done by the screen manufacturer had shown that the screen laminate material should have withstood the differential pressures that were applied, as the well was unloaded without losing sand control. The collapse rating of the manufactured screen joint was stated by the manufacturer to be 7,000 psi. Prior collapse testing had been carried out with only 4-ft sections of the laminate material. It was decided that a full-scale test would be the best way to duplicate downhole conditions.

To conduct the full-scale collapse tests, a test apparatus was built using a joint of 7 5/8-in. Magnolia casing that would hold a 13-ft section of premium screen.



While circulating in packer fluid prior to pulling out of the hole after frac-pack operations, a slug of sand was observed at the shale shakers. When the service tool and washpipe were pulled out of the well, the washpipe was full of sand and proppant. In addition, scale on the outside of the lower 4 stands of the workstring appeared to be blasted off. The recovered washpipe showed severe erosion damage over roughly 180º of the circumference for a length of approximately 1 ft, suggesting high velocity flow of solids through the screen. The marks on the washpipe matched the pattern of holes on the screen's perforated basepipe.

The screen x casing annulus was filled with completion brine plus "sized" $CaCO_3$ that would plug the 75 μm openings in the premium screen. The interior of the screen joint was vented to the atmosphere for monitoring purposes to help determine when a hole in the screen developed. The testing involved pumping in the pill, pressuring up on the exterior of the screen and holding the pressure for 10 minutes. The screen was then extracted and inspected for deformation to the laminate and any failure points. The test was repeated at increasing pressures until total failure was observed.

The first test showed that the laminate layer began to collapse to the screen basepipe at a differential pressure of approximately 500 psi. Total failure occurred at a differential pressure of 950 psi. Upon removal of the shroud, the failure point was quickly identified. The failure point near the end ring was similar in appearance to the failure point identified on the screens that were fished out of the well. The test was repeated, and total failure again occurred at around 950 psi, although the failure location was not as visually apparent. Rather than a large tear at the end ring, there were many small tears from the laminate layer stretching as it collapsed onto the drainage layer.

From this testing, the probable downhole mode of failure of the premium screens was determined. The 1,500-psi differential pressure across the laminate layer during production caused the laminate to collapse on the basepipe. Deformation of the laminate layer was limited to the annular space between the basepipe and the outer protective shroud. The deformation continued until reaching the end rings, which are much stiffer than the laminate layer. At that point, the laminate tore away from the end ring.

Based on these test results indicating much lower collapse resistance, modeling of the pressure drop from the formation through the perforations across the annulus pack and through the screen was done to determine if it was acceptable to continue using these screens for the remainder of the Magnolia project. The modeling showed that unless there was severe near-wellbore damage, as illustrated in the lab testing with the solids-free LCM, the differential pressure across the screen laminate would be much lower than 500 psi. The screens were therefore determined to be acceptable for continued use at Magnolia.

RE-COMPLETION, FRAC-PACK

After fishing the failed screens out and cleaning the hole, it was decided to re-complete the interval. In designing the re-completion, several new factors had to be weighed in order to get the best result. Probable modes of failure were known from the first failure, but confirmation was desired.

It was decided to re-perforate due to concern over plugged perf tunnels from washover/fishing fluids. The perforating

Test #	Flow Cell Layers (from Screen)	Fluids Injected	Initial System Permeability (mD)	Final System Permeability (mD)	% Retained Permeability
1	Screen Formation Sand Formation Sand Mixed w/ Proppant	Viscoelastic Surfactant	32	24	76
2	Screen Formation Sand	Viscoelastic Surfactant, Solids-Free LCM	44	11	25
3	Screen Formation Sand Formation Sand Mixed w/ Proppant	Viscoelastic Surfactant, Solids-Free LCM	36	0.13	0.4
4	Screen Formation Sand Formation Sand Mixed w/ Proppant Proppant Formation Sand	Viscoelastic Surfactant, Solids-Free LCM	63	0.44	0.7

Lab testing showed that neither formation sand nor the xanthan solids-free LCM by itself caused catastrophic reduction in permeability.

data would also give an indication as to whether the formation outside casing had a high skin similar to the initial completion. Post-perforating gauge analysis confirmed that the majority of the damage was confined to the screens and gravel pack, which were removed from the well.

Prior to running new screens in the well, a vacuum tool and watermelon mill were run to remove any debris and any burrs on the casing caused by fishing operations and re-perforating. The new screen assembly was run in the hole and set in place without incident.

A pre-frac matrix acid treatment was pumped that was designed to remove damage caused by the clean-out and washover operations. While pumping the frac-pack job, operational problems on the frac-boat caused the first attempt to be terminated. About 40,000 lbm of intermediate strength ceramic proppant were reversed out through the choke. Since proppant had not yet reached the crossover tool, it was determined that the treatment could be redone. The job was pumped as designed, and at the end of the job, the choke was opened to take returns and induce an annular screen-out. While pumping at 2 bbl/min, a spike of at least 9+ bbl/min was seen in the return flowmeter. The actual flow rate was not determined since the flow meter could measure up to only 9 bbl/min. Screen-out was induced, and the well was shut in. Later inspection of the choke showed it to have been washed out, which allowed the higher rates from the well. The choke damage probably occurred when 40,000 lbm of proppant from the first frac attempt was reversed out.

While circulating in packer fluid prior to pulling out of the hole after frac-pack operations, a slug of sand was observed at the shale shakers. When the service tool and washpipe were pulled out of the well, the washpipe was full of sand and proppant. In addition, scale on the outside of the lower 4 stands of the workstring appeared to be blasted off. The recovered washpipe showed severe erosion damage over roughly 180º of the circumference for a length of approximately 1 ft, suggesting high velocity flow of solids through the screen. The marks on the washpipe matched the pattern of holes on the screen's perforated basepipe. A similar pattern on the washpipe has been seen on another erosion-induced screen failure. The radioactive tracer time data also indicated that tracer may have passed by the sensor prior to the tool at the base of the washpipe being pulled up through the gravel pack. The data indicated a definite screen failure during the job. The well was temporarily abandoned prior to running production tubing, and the rig proceeded to the next well.

EROSION TESTING

Review of data from the downhole pressure/temperature gauges run in the washpipe showed several areas of concern:

• Three apparent low-velocity in-flow events prior to pumping the frac-pack: 1) When preparing to reverse out after the mini-frac; 2) After completing the post-mini-frac reverse-out; and 3) After reversing out the first frac-pack attempt.

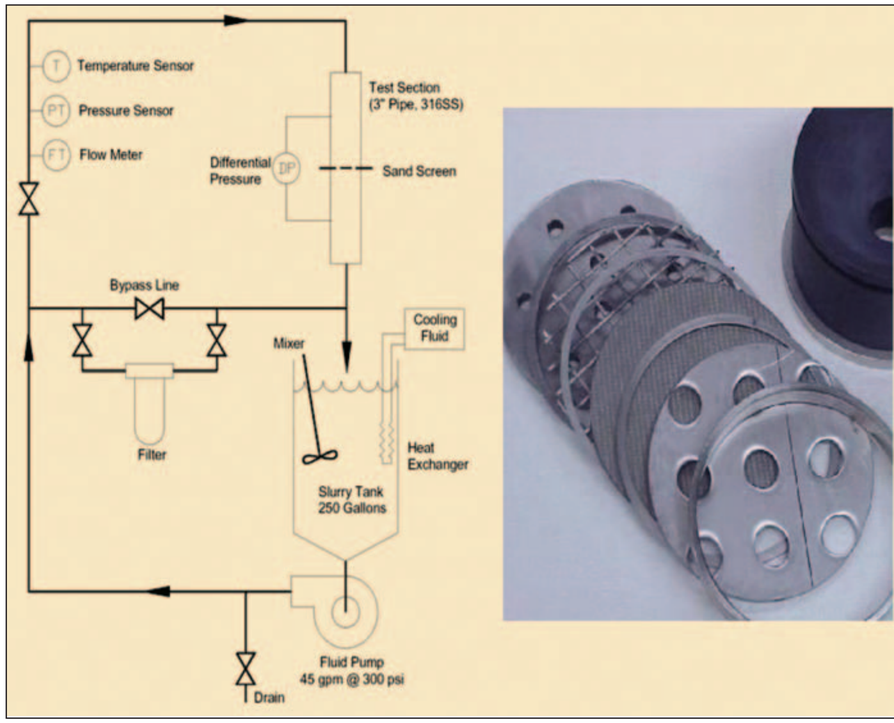
• Apparent high-velocity in-flow event upon opening the cut-out back-side choke to induce a screen-out. The well flowed at 9+ bbl/min for about 30 seconds, followed by some lower rate for another minute while the annulus continued to pressure up.

Prior to the A1ST1BP1 failure, it was believed that gravel-pack voids would be filled by produced solids long before significant erosional damage to the screen could occur. This view was based on a number of studies showing that direct impingement erosion of premium sand screens caused limited short-term damage.In addition, the very-small opening size, 75 μm, for the Magnolia screens was thought to prevent large-scale production of formation solids through the screen, thereby preventing more rapid flow-through erosion damage.

To determine the magnitude of flow required to cut out the screen, a series of erosion tests were conducted at a third-party test facility. Slurries with increasing particle concentrations were flowed at screen erosion targets to determine weight loss and time to failure. Both impingement erosion and flow-through erosion testing was performed. The slurries used a blend of 220/280/360 mesh grit having a D10 value of 112 μm and a D50 value of 41 μm to simulate Magnolia formation solids. The direct impingement erosion testing showed that the screen plugged off before any significant erosion occurred. This result implied that direct impingement erosion was not the likely cause of the A1ST1BP1 2nd frac job screen failure. Alternatively, results of flow-through erosion testing showed severe erosion damage could occur if small particles flowed at high velocity through the screen. For this series of tests, 360 Mesh grit having a maximum particle size of roughly 40 microns was used to simulate formation fines flowing through the screen. Results of these tests are summarized in the figure on Page 125.

Using the trend-line shown in that figure, a fluid with high-solids loading flowing at a velocity of 100 ft/sec to 200 ft/sec could cut through a screen in a few minutes. While high, these types of flow velocities are consistent with high rate flow (9+ bbl/min) through a small area of screen (less than 1 ft of eroded washpipe with all erosion on one side).

Finding a source for formation solids small enough to fit through the 75 μm screen without bridging is more problematic, but can be explained by noting the sand/shale interface opposite the screen failure. It is thought that the fine solids in the sand/shale interface could have produced solids small enough to flow through and cut out the screen before bridging.



To determine the magnitude of flow required to cut out the screen, a series of erosion tests were conducted at a third-party test facility. The figure above shows the erosion test set-up.

PROCEDURAL CHANGES

Prior procedures followed at Magnolia were normal Gulf of Mexico practice. The Magnolia wells, due to the low unconfined compressive strength (UCS), fine-grained nature of the sands, and wellbore deviation, had a high tendency to mobilize sand into the wellbore with tool movements and any time after pumping into the well when the sands would become charged. Several procedural changes were made in order to prevent reoccurrence of either failure mode.

Normal procedure after the matrix acid treatment and mini-frac was to shift the gravel pack service tool to the reverse position to reverse out the flush fluid. Since this is when the first influx occurred, it was desired to eliminate this step to eliminate the potential for flow from the formation to the well while shifting the tool. Supercharging of the reservoir to a pressure higher than exerted by the completion brine was seen on several wells after the mini-frac. Because a VES frac fluid was used, damage from injecting the additional amount of flush fluid would be very minimal. To minimize the amount of excess fluids injected, a portion of the flush of the mini-frac was designed to be the pad of the actual frac treatment. Since several jobs had been performed at Magnolia already, a good indication of the fluid leakoff and closure stress was known such that only a little tweaking of the frac job was needed. Laboratory tests also showed that the rheology of the VES frac fluid only minimally increased while sitting at the mudline temperature for a long period while analyzing the mini-frac, which did not affect the ability to pump the frac job.

To address the high return rate seen at the end of the job on the A1ST1BP1 re-completion, a 2nd 2-in. manual choke was added to the surface manifold that would be used solely for inducing a screen out at the end of the treatment.

The main 3-in. choke would still be used for holding backpressure while reversing out. The 2-in. manual choke would be set prior to each job to give a flowrate of 1 bbl/min with the expected annular pressure at the end of the job so that only the valve in front of the choke would have to be opened and the presetting would prevent any high initial rates due to opening too far.

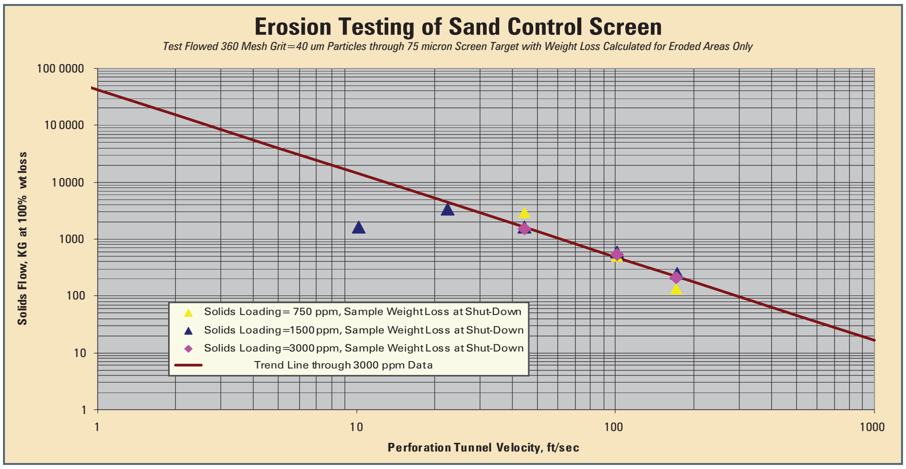
The lack of RA tracer and annulus pack density logs on the original A1ST1BP1 completion made it hard to evaluate the integrity of the annulus pack. It was decided that where possible, all future completions would include several pressure/temperature gauges at various depths, and RA tracer and annulus pack density logs would be run.

In addition, all equipment pulled from the well after the job would be inspected closely for proppant, sand and evidence of erosion. A more detailed well unloading/ramp-up procedure has been implemented, which closely monitors and sets controls on actual versus expected (i.e., low-skin) rate versus drawdown, as well as flux.

SUBSEQUENT RESULTS

Following the A1ST1BP1 workover and second screen failure, 5 zones in 4 wells have been frac-packed using the modified procedures. After obtaining circulating rates and verifying that injection can be established, the service tool flapper was sheared. Subsequent acid treatment, step rate test, mini-frac treatment and frac-pack were all pumped without moving the gravel pack service tool.

The same service provider has pumped the subsequent frac-packs. No failures have been observed to date, from either erosion marks on the washpipe or produced sand.



The direct impingement erosion testing showed that the screen plugged off before any significant erosion occurred. Results of flow-through erosion testing showed severe erosion damage could occur if small particles flowed at high velocity through the screen. Using the trend-line shown in the graph above, a fluid with high-solids loading flowing at a velocity of 100-200 ft/sec could cut through a screen in a few minutes.

Due to the thickness of the Magnolia zones, the amount of pad to be pumped was generally larger than the capacity of the work string. Thus the decision to displace the mini-frac with pad has not generally been an issue. On one of the wells, a thinner zone was to be frac-packed and the pad volume was less than the work string capacity. The excess pad fluid was injected at a rate that did not create a fracture.

No excessive pressures have been observed re-establishing circulation with the VES fluid exposed to cooler temperatures in the depth from the mudline to surface while shut down to analyze the mini-frac data. The seawater temperature at the mudline is approximately 38° F, and the wells have been shut down for up to 3.5 hrs while analyzing the data.

The friction adjusted skins on the wells are similar to the previous wells, near zero to negative, indicating the revised procedures are delivering low skin wells.

CONCLUSIONS

Gravel pack design, execution:

1. Utilize screens with shunt tubes on long interval zones to ensure an annulus pack.

2. A combination of proppant, formation sand and xanthan-based solids-free fluid loss material can create a filter cake that effectively plugs a gravel pack screen.

3. Run pre-job tests to determine potential plugging issues with fluids and screens. Only pump tested recipes.

4. Sizing the gravel pack screen for expected formation particle size distribution is a good practice but does not guarantee that sufficiently small fines will not get into the system and damage the screens from plugging, collapse and/or erosion.

5. Procedural changes can be put in place to mitigate supercharging of reservoir during frac-jobs and damaging fines-laden flow from the reservoir into the wellbore.

6. Calibrate flowback on choke prior to pumping the frac job. Re-check integrity of choke and all valves if abrasive fluids are pumped through them.

7. Conduct full-scale testing of sand control screens for major projects to ensure that key mechanical properties are met (e.g., burst and collapse ratings).

8. Whenever possible, run gravel pack (density and RA tracer) logs to verify adequate annular pack.

9. Include and analyze bottomhole pressure/temperature gauges for additional information on frac-pack results.

10. When hole angle, UCS data and sand grain size indicate that inflow is likely, utilize revised frac procedures that minimize tool movements and eliminate potential for formation inflow during frac-pack operations.

11. Develop and follow detailed procedures that monitor and control drawdown versus rate during initial well unloading operations, to better identify any skin problems and to avoid failing a well.

12. Analysis of pressure drop from a non-damaged reservoir to the inside of the sand control screen can supply data on whether existing screens are acceptable for a given project.

13. The gravel pack equipment selected for Magnolia can continue to be used with confidence, as long as the proper procedural changes are implemented.

Workover Operations:

1. Consider retrievability of all completion equipment during initial well design.

2. During workover planning, prepare a "what-if" flowchart to help optimize sequence of operations and prioritize contingency planning.

3. Contact other operators and service companies for their experiences and best practices.

4. Conduct a planning meeting with the primary service companies to validate planned activities and establish appropriate contingencies.

5. When risking options, objectively assess probability and consequences of trouble. Put value on the most controllable option.

6. Have contingency plans in place. Test contingency equipment as necessary.

7. Best practices for retrieving screens:

• Don't try to jar screens out with packer.

• Consider and optimize wash fluid properties.

• 3 bbl/min wash rate. For the A1ST1BP1, this equated to 300 ft/min annular velocity for the screen by washpipe annulus and 950 ft/min annular velocity for the washpipe by casing annulus.

• Rotate 40-50 rpm while washing over screens.

• Set conservative torque limits and resist the temptation to exceed the limit as progress slows. It is better to make additional trip(s) than to damage screens or leave washpipe in the well.

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