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Recovery Of An Oil Producer Severely Damaged By OBM Using An Advanced Barite Dissolver System

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Abstract

BP in the U.K. North Sea attempted to drill a horizontal oil producer in the Harding field in 2006. Designed to produce an initial 10,000 blpd from 2000 feet of reservoir section before water break through, the well was compromised by the collapse of the lower hole due to chronic shale instability. This also resulted in the pre-drilled liner being stuck and set higher than initially planned. With less than 200 feet of reservoir sand exposed at the heel of the well (in close proximity to the water leg), the initial expectations were of 4,000 blpd. However the well was found to be badly impaired and produced 400 blpd. Although the well had been displaced to a carbonate based low solids oil based mud (LSOBM) prior to completion, a significant quantity of the barite weighted drilling system was still in the well.

The damaging mechanism was determined to be synthetic oil based mud compressed around the screen completion as well as the mud from the uncompleted horizontal lower hole being squeezed into the screens as the open hole gradually collapsed with time. A Coiled tubing (CT) intervention was carried out in late 2006 with solvents and multiple attempts with an acidic nano wash solvent system, this was not successful in restoring well productivity.

In 2007 BP chose to use an advanced chelate based barite/carbonate dissolver system behind a proprietary pre-flush system in an attempt to recover well productivity. Four operations have now been performed since September 2007 without CT, all as simple bull head operations. As a result of these treatments the well productivity (PI) has increased from 1.5 up to 12 blpd/psi. Current well rates are between 4000 to 6000 blpd depending on well stability and slugging caused by increasing water cuts.

Introduction To The Harding Field

The Harding Field, in Block 9/23b of the U.K. North Sea (Figure 1), consists of 2 main reservoirs (Central and South) developed with horizontal wells, and several satellite pools accessed via extended reach wells (Figure 2). The 2 main reservoirs currently contain 13 horizontal producers, 3 water injectors and in the central reservoir, a single gas injection well. Both main reservoirs are overlain by large gas caps so well location and production were carefully managed to minimize excessive gas production through gas coning. As aquifer support is negligible, the reservoir pressure is maintained via re-injection of the produced water supplemented by water from a shallow aquifer zone.

The South reservoir has excellent static properties but the fluid quality is less favourable. The wells are all located in the Balder Formation which is a massive homogeneous sandstone up to 150 feet thick. It is poorly consolidated, with an estimated permeability of 8 to 10 Darcies, porosities of 32 to 35%, and a net to gross (NTG) of 93 to 95%. However, the viscous oil (23 ° API, 5 centipoise) leads to unfavourable mobility ratios which tend to promote coning. The wells are operated with low drawdown's (typically less than 20 psi) to minimize water and gas coning. It was possible to achieve this and still produce at high rates due to the very high productivity of the wells, which was often in the range of 500 to 1,200 blpd/psi.

The Harding Field came on stream in April 1996 and the south reservoir was initially developed over a 2 year period with 3 horizontal producers and 1 horizontal water injector, all in the high quality NTG sand. Sidetracks of the original producers have occurred to improve reservoir recovery, the 3rd being the IS3 well which was drilled as a sidetrack from a multilateral producer which had watered out during late 2005. Multiple sidetracks of the IS3 well target eventually led to the well being named IS3x.

Well IS3x Problem Origins.

Previous Harding wells had primarily targeted the high net to gross Balder sandstone; however the IS3 sidetrack targeted reservoir sand which was expected to contain 50% shale. This led to a basis of design (BOD) for the well which would mitigate the risk of drilling and completing of the shale's which historically had compromised the deployment of completions due to poor hole conditions. Previous experience of this had been encountered with the IC3 well in the central reservoir. To this end, oil based mud (OBM) was selected to drill the section with the intention of stabilizing the shale. The use of a pre-drilled liner (PDL) and sand screens within this PDL was also incorporated into the BOD.

Unlike the IC3 reference well, severe hole instability was encountered in the 12 ¼" as well as the 8 ½" sections. These events resulted in two sidetracking operations before the eventual completion of the IS3x penetration.

IS3x was the first well in the Harding development to use OBM while drilling the reservoir section due to the shale reactivity in the 50% sand/shale reservoir. A horizontal 8 ½" hole was successfully drilled and under-reamed to 9 ½" down to 12,145 feet measured depth (MD), but despite using OBM, the 8 ½" bottom hole assembly (BHA) got stuck whilst pulling out after multiple pack-off events. Following numerous unsuccessful jarring attempts to free, the BHA was subsequently severed and cut-off with the charges detonated at 11,055 feet MD and the drill pipe was recovered. As drilling to the target depth had found 1,000 feet of net sand in the 2,000 feet long section, losing the BHA meant abandoning 1,000 feet of the reservoir that had been exposed.

When running the PDL, the string could not get past a shale section at 10,733 feet resulting in the PDL being set at that depth and an actual completion length of only 374 feet with only 200 feet of sand in this completed section. During these operations barite sag was exhibited in the mud. Attempts were made to condition and establish uniform mud properties. At the end of the final cleanup run, the PDL completed horizontal open hole was displaced to LSOBM (with 20 pounds per barrel (ppb) sized calcium carbonate additions for bridging to mitigate losses). Conditioned OBM was spotted above the fluid loss control valve.

As a result of these two stuck pipe incidents, 1,412 feet of 9 ½" horizontal hole, filled with 11.4 ppg barite / calcium carbonate containing OBM, were left below the PDL shoe non-isolated as no cement plug or any other sort of barrier was set (Figure 3).

Completion and Initial Production.

During the initial running of the 5 ½" sand screens weight loss was encountered as the screens were entering the PDL. Despite several attempts to work the screens through, the completion run was aborted with only the bottom 2 to 3 screen joints believed to have entered the PDL. Sagging was exhibited in the mud during these operations. After retrieving the screens it was determined that the screens couplings and shroud had been compacted with mud solids due to mud sag (Pictures 1, 2 and 3). The top section of screens also contained small pieces of shale in the screen shroud (less than 1% overall). After a cleanup trip the screens were successfully re-deployed and installed in the PDL, with the SC-2R packer successfully set and tested.

Production from the well started on the 4th August 2006 and it was apparent within a few days that even considering the short completion length, the well productivity was poor and was decreasing over the initial days of production. Pressure build up (PBU) tests conducted during the 1st month of production indicated severe impairment of the well. At this point the expert conclusion of the PBU data was that this was due to low reservoir flow capacity (i.e. producing length and vertical thickness) rather than damage. Subsequent testing of solids flowed from the well did not particularly contradict this conclusion as 75% of the shale and mud barite found could pass through 200 mesh screens. It was concluded that these solids in viscous mud or possibly even larger solids behind the PDL and between the PDL and the screens could be preventing communication with the reservoir.

In addition, the uncompleted open hole was suspected to be gradually collapsing with time and the mud was being squeezed slowly into the screens setting area. Despite the expectation that the major volume of suspended particles in the uncompleted open hole would settle down due to drilling fluid degradation, some particles could be still trapped in the screens area: it was suspected the main components of the damage were barite and calcium carbonate-based particles trapped between completion screens and reservoir sands.

During well startup, the drawdown had been tightly controlled to ensure optimum clean up of the horizontal hole. However, due to mud damage, the well was suspected as only producing from 10 to 20 ft of sands at the heel of the well. A higher drawdown on the well was not implemented because of 2 main concerns; to avoid bringing in further mud and solids from the uncompleted open hole (until an intervention had been performed) and to avoid accelerating gas and water coning into the open sands at the heel of the well.

The production for this length of completion was anticipated to be 4,000 blpd; it began at 800 blpd but dropped rapidly to 400 blpd. Due to the very poor results, an intervention was planned based on the results of extensive laboratory testing of chemical solutions to remove the OBM solids from the well. Lab testing was based on the analysis of deposits recovered from the aborted first set of screens, which found the deposits to be 60 to 65% barite and 15% calcium carbonate with solids sizing less than 90 microns, most sized below 45 microns.

Remedial Well Interventions.

Two proprietary systems were tested which used substantially differing clean up theory and chemistry. System A was a solvent dispersant system based on "nano"-sized solvent particles in an acidic wash. The theory behind the system being that the nano-solvent could penetrate the tight compaction of the mud caked in and around the screens and the acidic wash would dissolve the calcium carbonate from the LSOBM displaced into the well prior to completion. System B was a known chelate based barite dissolver system with a tailored pre-flush system designed to penetrate the mud solids, and then dissolve the carbonate and barium sulfate solids.

System A was chosen based on the theory that the predominant solids should be carbonate based rather than barite based. In addition, the dispersing effect of the nano-wash system was thought to be ideal to break up the viscous mud recovered from the well during the sampling period.

Intervention 1 – System A: Nano-wash and Acid.

Coiled tubing was used to perform the first well intervention on IS3x. The well was entered and jetted down to 10,672 feet (bottom of the well) using 8.6 ppg brine across the lower completion. Once 400 bbls of brine had been circulated, 40 bbls of brine was bullheaded through the CT into the well to displace any oil remaining in the lower completion. After this, 60 bbls of the nano-wash fluid was jetted and bull headed into the lower completion. Once this was done the CT was pulled and the well shut in. It was notable that upon retrieval to surface that mud was stuck to the CT BHA indicating poor dispersing and more mud than anticipated being present.

On the flow back 730 bbls of fluid was returned in 24 hours with the last returns being 90% oil. The well was shut in after a 2nd nano-wash treatment with no mud seen on the CT BHA after this deployment. The well was flowed back slowly using greater than 500 psi drawdown over a period of 32 hours with 2,053 bbls of fluid returned during that period. Once the clean up after the 2nd nano-wash treatment was deemed to be complete, 2 attempts with the CT jetting base oil washes across the lower completion were performed with no observed increase in well performance before the 3rd and final nano-wash treatment was made.

As with the earlier nano-washes, the last clean up attempt was started slowly until the nano-wash and brine were removed. The flow rate of the well remained poor. A subsequent CT memory production log indicated even flow contribution along the completion and that the well PI was approximately 1.5 blpd/psi. It was concluded that the damage remaining was well distributed along the completion length, some flow was coming from behind the shale section, and mud was probably still intact beyond the screens and PDL.

After the end of the intervention, the well continued to perform poorly at approximately 300 to 400 blpd.

Intervention 2 – System B: Barite Dissolver System.

A second attempt to recover the well was planned for September 2007 using the chelate based barite dissolver system. Due to significant cost challenges, deployment of the chemicals using CT was not possible, so it was decided to make the attempt using a simple bull head operation. The operation was performed in three stages (a description of the intervention 2 chemicals is summarized in Table 1).

The bull heading was done slowly and under minimum rate to avoid any shunting of fluids into weaker thief zones. The displacement volumes were calculated considering the different hydrostatic pressures of the fluid column and expected leak off into the formation. The downhole pressure gauge in the well was used together with the known fluid densities to control fluid placement. During the operation, the surface pumps did go onto vacuum during the later stages, so the downhole pressure gauge became critical in ensuring optimum placement of the limited chemical volume.

Stage 1

An initial mutual solvent pre-flush was performed to displace as much crude away as possible from the well and near wellbore area. The system application was based on the theory that the pre-flush of System B could break through any sealed wall cake and remove any residual oil and in effect, prepare the area for the high performance barite dissolver that followed. The initial mutual solvent pre-flush was to reduce the oil in the well and avoid reducing the effectiveness of the system B pre-flush.

Stage 2

Calcium carbonate dissolver system was pumped and soaked for 3 hours across the calculated target zones. Although the barite dissolver was able to both calcium carbonate and barite, the dedicated calcium carbonate dissolver was intended to remove any calcium carbonate present and leave the barium dissolver to primarily attack the barite particles present.

2 hrs soak periods, each of 1 ½ hours with the calcium carbonate dissolver positioned across the screens were performed. The product volume pumped into the tubing was calculated to be enough for 2 soak periods and allow for the uncertainty of fluid leaking off into the reservoir. For the 1st soak period calcium carbonate dissolver was partially displaced from the tubing into the screens, and then it was displaced into the well and replaced with the fresh product for the 2nd soak period.

Stage 3

After completion of the 1 ½ hour soak periods the calcium carbonate dissolver was displaced into the formation by the barite dissolver. The dissolver was deployed and soaked in two stages. The first stage was soaked for 16 hours when in theory, the dissolver would be half spent at the bottom hole temperature (BHT) of the well. This still active dissolver was bull headed into the well by an identical volume of new barite dissolver fluid and the well shut in for 24 hours. The basis of the two stage soaking theory was that having active dissolver on both sides of the well bore skin would effectively double the contact surface area as well as ensure any mud solids in fractures and fissures were removed during the operation.

The Intervention 2 System B operation and volume summaries are shown in Table 2. During pumping operations, it was noted that the injectivity of fluid into the reservoir was an order of magnitude higher than the productivity.

Cleanup

The well was flowed back and cleaned up (the gas lift system had been commissioned between intervention 1 and intervention 2). The well cleaned up from 300 to 400 blpd to 2,000 blpd (at 45% oil). The initial well flow was irregular due to the slugging behaviour of the multiphase flow from the well. The slugging frequency reduced quickly as the water from the treatment was flowed back. Well tests performed a few days after treatment flowback showed the PI had increased from 1.5 to 4.5 blpd/psi.

Flow back sample analysis showed considerable amounts of dissolved barium sulfate estimated to be between 350 to 500 kilograms as well as calcium and other mineral species found in the drilling fluid solids.

In the analysis it was notable that the uptake of the clay stabilizing component inbuilt in System B had been extremely high indicating that the shale and clay in the reservoir had been substantially damaged by the previous CT intervention if not the water phase of the OBM itself at some stage.

Intervention 3 – System B: Barite Dissolver System.

Based on the results of the initial chemical deployment it was decided to treat the well again using just mutual solvent pre-flush and barite dissolver system. For the intervention 3 bullheading operations it was agreed not to pump calcium carbonate dissolver as it was assumed that most of the calcium carbonate particles had been removed in the intervention 2 treatment.

During March 2008 treatment the well was bull headed as before, pumping mutual solvent pre-flush followed by the barite dissolver placed and soaked in two stages (22 and 36.5 hrs). A description of the intervention 3 chemicals is summarized in Table 1 and the operation and volume summaries are shown in Table 3. Only a short displacement volume was pumped before the 2nd soak period as it was determined that the heavy column of barite dissolver left in the well during the 1st soak had been slowly leaking off into the well.

After treatment cleanup the productivity of the well increased yet again from a PI of 4.5 to 7.5 blpd/psi or an effective increase to 3,500 blpd (45% oil) which was sustained over several months.

Subsequent analysis of the dissolved solids again showed barite in quantity in the returns, but these could not be accurately determined due to the high water cut in the samples.

Interventions 4 and 5 – System B: Barite Dissolver System.

The significant increase in well productivity and cost effectiveness of the initial bull head treatments enabled a further 2 bullhead operations to be executed in November 2008 and February 2009. Water cut had increased during 2008 up to 75% and well slugging was an issue causing a reduction in production and issues in the surface facilities. Further increases in the well PI were predicted to allow greater well stability at the higher well rates. This also provided support for the additional interventions.

The intervention programmes were almost identical to intervention 3 using the same chemicals with very slightly different volumes and soak times.

After intervention 4, the well productivity increased from 7.5 up to 11 blpd/psi. This allowed a stable well rate to be sustained at 3500 to 4000 blpd at 75% water cut. Subsequent analysis of the dissolved solids again showed barite in quantity in the returns. Exact quantities were not known at the time of writing this paper.

After intervention 5, the well productivity increased from 11 to approximately 12.5 blpd/psi. This was a smaller increase than earlier interventions although analysis of the dissolved solids again showed barite in the returns. Exact quantities were not known at the time of writing this paper.

Calculating productivity changes between interventions 4 and 5 was difficult as a very limited amount of quality well tests were performed between the interventions. There were several well tests where the well was not stable so calculation of the PI could have a significant error. There is evidence that intervention 5 contributed to an increase in well productivity. Figure 4 shows a graphical summary of the well PI changes during the bull head operations.

Cleanup Criteria During Backflow After Bullhead Operations.

When backflowing the well after the bullheading jobs, it was of very high importance to backflow all the non-spent chemicals out of the well through the test separator avoiding the main plant, in order not to introduce the treatment chemicals into the main plant separators. Failure to do that could result into severe emulsions issues in the main plant separators. A route was established from the test separator to the gravity based crude storage tanks bypassing the platform process facilities. Harding does not have an export oil line and utilizes these storage tanks and shuttle tankers to export oil.Only when all the chemicals were flowed out completely from the well through the test separator could the well be diverted back to the main plant separators. Criteria for flowback completion were established to be as following:

- Water cut expected to remain constant within 3 consecutive samples taken every 50 bbl (+/- 5%),
- No Barite Dissolver chemical detected in neat form (pH would be highly alkaline for neat Barite Dissolver chemical)
- Well flow conditions remain stable (downhole pressure gauge, wellhead flowing pressure and rate steady)

When backflowing the well, samples of the returns were taken downstream of the test separator: samples appearance, water cut and pH of the water phase were noted. Samples were also taken for lab analysis in town (for ions concentrations). For all well interventions, when backflowing the well, drillwater was coming first, followed by treatment fluid (high pH), followed by treatment fluid / oil emulsion and finally oil was coming with the expected water cut (neutral pH of water phase).

During intervention 2 and 4 well backflows, a high amount of solids / mud debris was noted in the residual treatment fluid coming out of the well.

The last water-cuts tested in the offshore production lab during the September 2007 treatment backflow were as following: 30%, 26%, 34% and 33%, pH 7.5 with 1,932 bbls backflowed in total; however some emulsion was reported in the main plant separators after the treatment. Table 4 summarizes the intervention 2 backflow volumes.

The last water-cuts tested in the offshore production lab during the March 2008 treatment backflow were as following: 32%, 31%, 33%, 34% and 40%, pH 7.5 with 1,500 bbls backflowed in total. Table 5 summarizes the intervention 3 backflow volumes. Well flow conditions (downhole pressure gauge, wellhead flowing pressure and rate) remained stable. No emulsion issues on the main plant have been reported after the treatment, so all the chemicals were circulated out successfully before the well flow was diverted back to the main plant.

For interventions 4 (November 2008) and 5 (February 2009), an identical flowback procedure was adopted as per intervention 3 (March 2008). Analysis of the flow back samples onshore has indicated that barite continues to be removed from the well. No emulsion issues were reported after completion of the intervention 4 and 5 flowbacks.

Conclusions

The application of this chemical system through bullheading has proved to be both a cost effective and efficient system for increasing well productivity which has been impaired through mud damage. A chart summarizing the step changes in well productivity is shown in figure 4. Other key conclusions are:

- The barite dissolver system as used in System B proved to be a very effective OBM solids and debris removal agent and was recommended for well remediation on other BP projects worldwide.
- The deployment through a simple bull heading operation and the success without coiled tubing indicated that the system could have wide application in interventions where CT units are not available or practical.
- The effectiveness of the system in the horizontal section of this well via bull heading whilst having been validated on other wells using the system, makes it particularly appealing from a cost perspective on future interventions.
- The relatively low BHT of the Harding field also means the system which has no known upper temperature limitation could have wide application in fields where cooling through injection and or shallow plays inhibits the performance of similar chemicals.

Acknowledgements

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References

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Tables

Table 1: System B (Interventions 2,3,4 and 5) Chemicals Description

Product	Product Description
Pre-Flush	Mutual solvent / squeeze enhancer product, aims in removing oil droplets and making solids water-wet; acts to condition the rock matrix to accept higher loading of scale inhibitor and can also be used as a stimulation aid for water block removal or emulsion resolution in the near wellbore
Calcium Carbonate Dissolver	Carbonate scale dissolver which works by dissolving carbonates, polymers with an aggressive action while drying and cracking clays as well as it contains a surfactant for removing glycol and oily inhibitors in water based or oil based fluid filter cakes
Barite Dissolver	Chelating agent to dissolve barite, drilling fluid additives, scale and some formation deposits which may be embedded in casings

Table 2: System B (Intervention 2) Operations and Volumes Summary

Chemical	Volume, bbls
Pre-Flush	20
Drillwater	15
Calcium Carbonate Dissolver	46
Drillwater	10
Barite Dissolver	62
Drillwater	69
Soak Calcium Carbonate Dissolver for 1.5 hrs	
Drillwater	20
Soak Calcium Carbonate Dissolver for 1.5 hrs	
Drillwater	20
Soak Barite Dissolver for 16 hrs	
Drillwater	30
Soak Barite Dissolver for 24 hrs	

Table 3: System B (Intervention 3) Operations and Volumes Summary

Chemical	Volume, bbls
Pre-Flush	20
Drillwater	15
Barite Dissolver	101
Drillwater	75
Soak Barite Dissolver for 22 hrs	
Drillwater	3
Soak Barite Dissolver for 36.5 hrs	

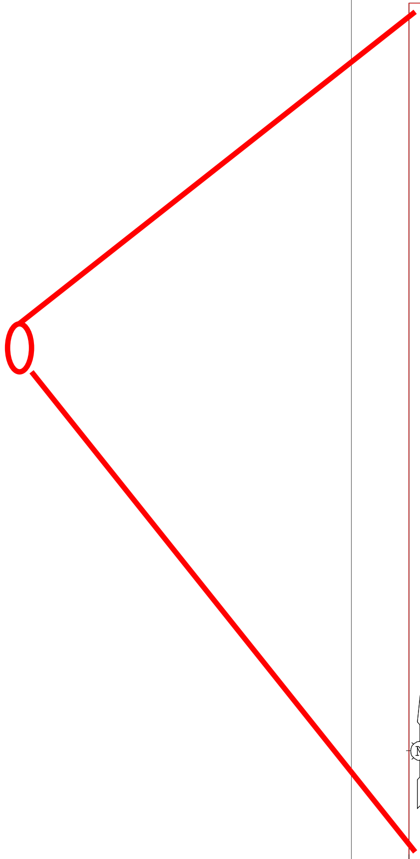
Table 4: Well Backflow during Intervention 2

Volume of Fluid Backflowed, bbls	Sample Observations	pH	WC
226	Dirty treatment fluid	14	-
300	Dirty treatment fluid	11	-
326	Dirty treatment fluid	10	-
586	Oil Emulsion	-	-
635	Oil with WC	-	30%
685	Oil with WC	-	26%
735	Oil with WC	-	34%
785	Oil with WC	-	33%
1932 bbls flowed in total			

Table 5: Well Backflow during Intervention 3

Volume of Fluid Backflowed, bbls	Sample Observations	pH	WC
210	Dirty treatment fluid	14	-
230	Dirty treatment fluid	13	-
290	Oil Emulsion	12	50%,
590	Oil Emulsion	-	-
610	Oil with WC	8	37%
660	Oil with WC	8	50%
710	Oil with WC	8	32%
769	Oil with WC	8	31%
810	Oil with WC	8	33%
860	Oil with WC (Quick separation)	8	34%
910	Oil with WC (Quick separation)	7.5	40%
1500 bbls flowed in total			

Figures



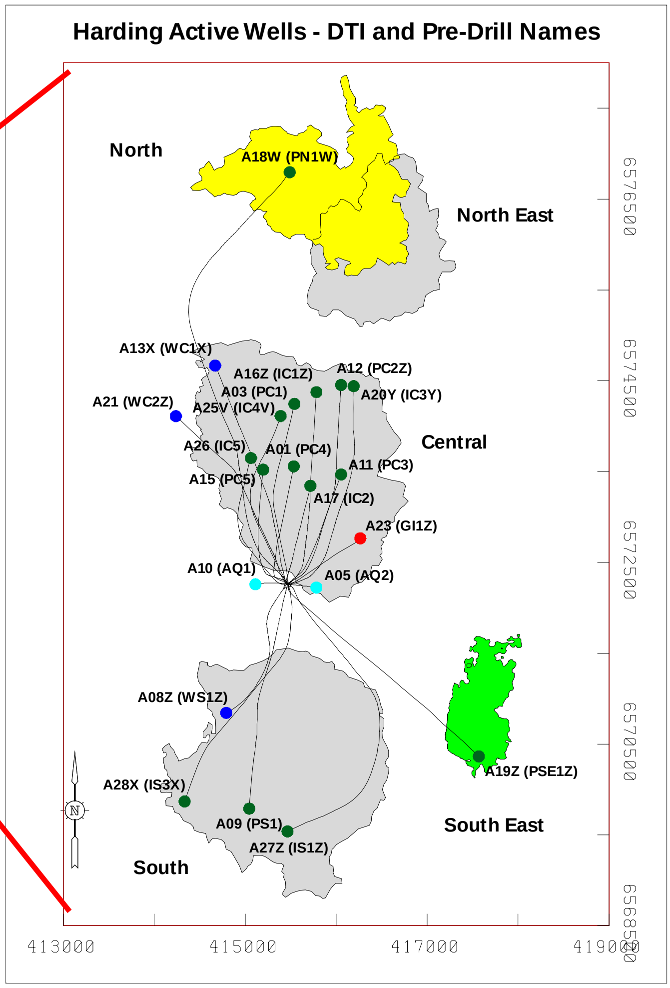


Figure 1: Haring Field location in U.K. North Sea

Figure 2: Field Map showing active wells

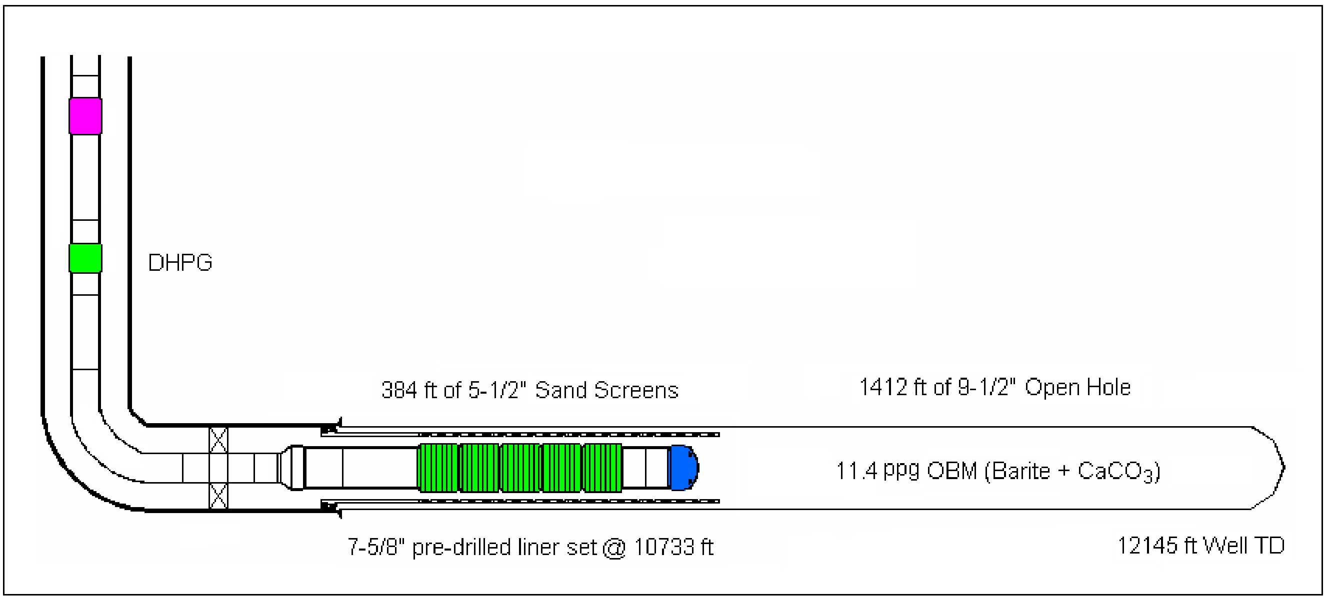


Figure 3: IS3x Well Actual Completion Schematic (Simplified)

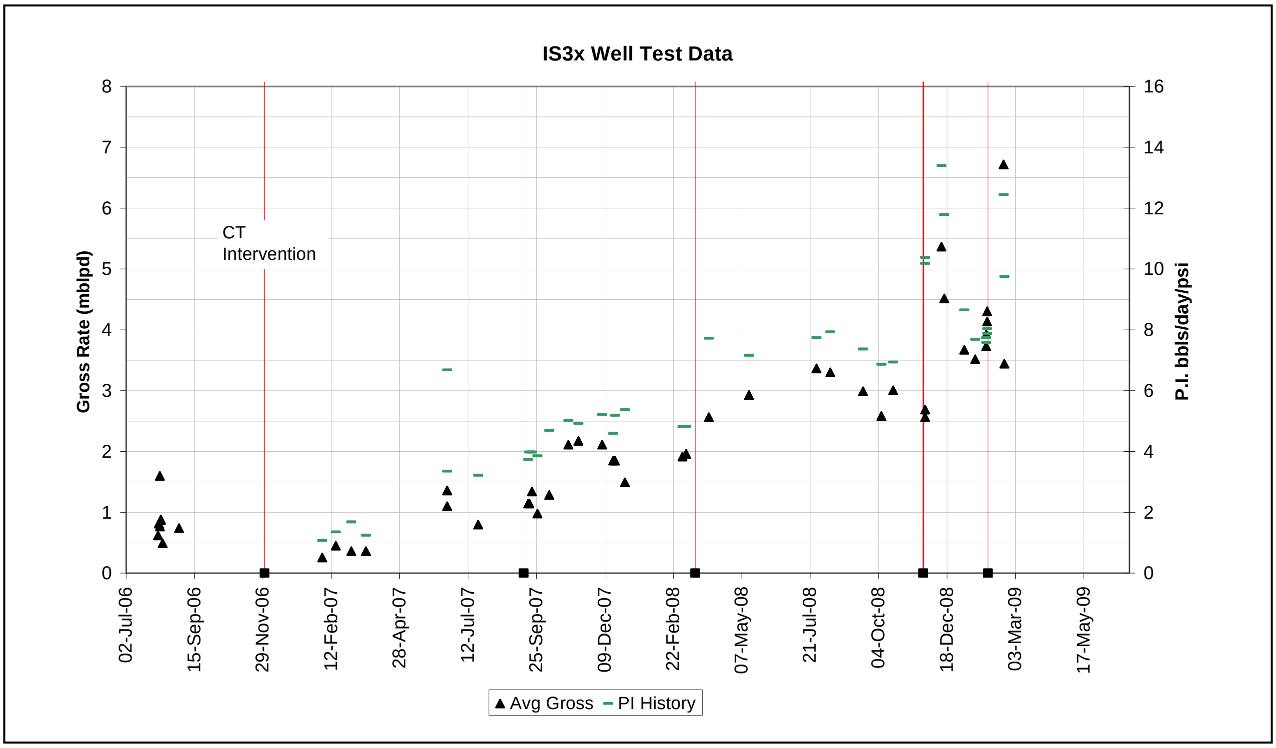


Figure 4: Chart summarizing average gross well rates and increases in well productivity over the period of bull head operations from September 2007 to February 2009. The CT intervention date is also shown.

Pictures

Picture 1: Screens that were pulled out from the aborted 1st completion run with shroud covered with mud solids. The picture on the left shows one of the lowest screen joints as it was removed from the well. A higher joint shown in the right picture which had not entered into the PDL showed slightly less mud coating but the screen shroud was still blocked.

Picture 2: mud coated on inner section of screens shroud from aborted 1st completion run.

Picture 3: sample of mud solids being retrieved from the base pipe of the screen from the aborted 1st completion run for lab analysis.