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March 2005

# Case History 2.1
# HDC MARK II
# ESP – OBM Blockage UKCNS

- **Horizontal EV – ESP**
- **Pre-Packed Screen Completion**
- **OBM – Dolomite / Barite Mud Solids**
- **Bull-Head Operation**

*The well treated here was drilled as an EV installation with a Baker Centralift ESP set above approximately 900' of horizontal sand screens. The ESP and facilities were constantly blocked off with mud solids feeding through the screens – and probably lodged inside them as well. Cleaning with HCL/HF and competitor barite dissolvers had proven ineffective in cleaning the well up. The client decided to use HDC MARK II behind a PentaFlow pre-flush. This was done with the ESP cleaning up to 22,000 bpd (up from a previous high of 11,000 bpd with blockages causing shutdown) without blockages and solids.*

This well was drilled and completed in May 2004. It was suspended in heavy synthetic based drilling fluids for several weeks before being displaced to a "clean" SBM and completed with pre-packed screens. The well never cleaned up properly with the ESP constantly overloading with solids which testing indicated were carbonate and barite sourced from the drilling fluid.

Very large volumes of HCL were used to remove the carbonate solids with U104/U105 pumped to remove the barite. As these failed a competitor barite dissolver was pumped with no improvement seen.

The operational program using HDC MARK II and PentaFlow was quite straightforward as it entailed bull-heading PentaFlow ahead of the HDC MARK II with a small spacer in between. The PentaFlow was allowed to soak across the target for 90 minutes then displaced into the well with HDC MARK II behind. The HDC MARK II was divided into two soak stages.

The first HDC MARK II soak was designed to lie inside and just outside the well bore for 8 to 12 hours. The second volume of HDC MARK II was designed to push the first soak outwards (being theoretically still active) with the new volume displaced fully into the well bore so coverage was extended outside and inside the screens – up to 24 inches from the bore itself. After the last displacement the fluids were allowed to soak for 24 hours.

The ESP was started with the well cleaning up gradually (the HDC MARK II being denser is harder to lift), and the well eventually cleaning up to 22,000 bpd – up 10,000 bpd from the previous best production seen. This was and is being maintained without solids and ESP pump over loading since the job was done in March 2005.

***Subsequent to this operation, two more ESP's in the same condition were fully recovered for the same client between 2006 and 2007 contributing to a total of 60,000 bfpd during II operations.***

July 2001

## Case History 2.2
## HDC MARK II: Injector- Schielhalen

- **New Drilled Well With SBM**
- **Moderate temperature (148ºF)**
- **Gravel Packed Water Injector**
- **HDC MARK II  Breaker System**

*This well was drilled using synthetic oil based mud in the North Sea off Shetland. The concept of the field trial was to attempt to inject through the oil based mud cake without the normal procedures of producing the well conventionally to remove the filter cake by placement of the HDC MARK II chemical in the screens.*

This was deemed to be particularly challenging as this had never been successfully done before and the BHT of the well at 148° F was deemed to be very low for an unconventional or conventional dissolver of any sort.

The well was completed and the HDC MARK II placed across the screens using coiled tubing. The CTU was pulled and the chemical was allowed to soak for 24 hours before injection was attempted.

When the well was put on injection, it was established at a high back pressure (± 2000 psi) with a constant rate. The pressure was deemed to be higher than expected although this part of the field and this formation had not been injected before and the productivity of the operation was still largely in doubt.

In order to determine if the filtercake had indeed been removed, the well was cleaned up conventionally using CTU/EDTA/Acid and produced – with poor results. Injectivity went to zero indicating that the acid treatment had in all probability compromised the formation and the EDTA had no effect as well.

The decision was made to perforate through the screens to establish exactly what the injectivity of the formation was. This was done and it was found that the injection rate perforated was identical to the rates and pressures established with the original clean up of the HDC MARK II product – indicating that it had in fact, yielded total Cake dissolution and maximum injectivity at the outset.

Although the well was not in an ideal location for a injector, the establishment of the HDC MARK II as a filtercake dissolver which could eliminate the need for CTU use and conventional flow back and clean out using OBM, has been established – even at low bottom hole temperatures.

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References: Alan Austin – BHI 01224 – 720000 or 01224- 226000
Alistair Roy – BP 01224-832000
Alan Twynam - BP TwynamAJ@bp.com

September 2001

## Case History 2.3
## HDC MARK II – Kerr McGee – Gryphon P4 – Gravity Feed via FPSO

- **Sub-Sea Well Head**
- **Horizontal**
- **BOT Excluder Screens**
- **Acid Damage – 100% Production Loss**
- **Gravity Feed Deployment**

*The P-4 well was drilled in 2002 being badly damaged in the process using oil based mud with high losses. The well was subsequently acidised after producing circa 600 bopd – 2 x 10,000 gallon treatments. The net result was full production loss. The well was tied back via the sub-sea manifold as programmed before bringing the FPSO on with the well standing idle until late 2004 when an attempt to recover some production was made using HDC MARK II. The operation was a partial success but the lifting of the well had to be discontinued due to problems with gas lift and the subsea choke. The well was flowed from zero to 750 bopd when lifting stopped – with a build rate of 50 – 80 bopd when the operation was halted.*

The Gryphon wells are located in a high permeability, high porosity sand reservoir with enough clay elements to make acid use a high risk operation. The problems on P4 were initially caused by high volumes of oil based mud being lost during the drilling phase, then aggravated by severe acid incompatibility with the oil mud and the formation itself- resulting in the well being killed.

**HDC MARK II** and **PentaFlow** were compatibility tested and selected for a trial never attempted before which consisted of a gravity displacement from the FPSO through the production riser. Lab simulations were made which indicated that the PentaFlow and the HDC MARK II being far heavier than the seawater currently in the string would “flip” and displace themselves into the well over a relatively short period of time. However, as the well was nearly 3000’ horizontal, the exact location and ability of the fluids to access the toe of the well was questionable. Lab simulations indicated that in fact if displaced at two distinct time frames (a day apart), the Heavier HDC MARK II would almost certainly hydraulically push the PentaFlow into the well through the toe.

The displacements were performed as programmed, however it was necessary to leave the fluids soaking in the well for over two weeks due to production issues on other wells. When the well was lifted, using gas lift from an adjacent well, the well flowed back some HDC MARK II and liquids and gradually began to flow oil – building up to 450 bopd. Although 1000 psi differential pressure could be applied to the well – the design of the gas lift was such that sustained differential could not be maintained and the well could not be shocked or unloaded which was deemed necessary to really clean the heavier fluids from the deeper horizontal sections. Due to operational problems the lift had to be

abandoned with the well unable to flow on it's own. The well was re-accessed in January 2005 and gas lifted – with immediate oil flow building up to 750 bopd at a steady increasing rate from 50 bopd when the gas lift again had to be abandoned due to subsea manifold choke problems.
As work-overs and major maintenance was due, it was decided to side track the well when the rig arrived. Although the well could not be cleaned up due to operational issues, the exercise was considered a success with the well theoretically able to produce at its peak had sustained gas lift been available.

Ref: dcorkey@kmg.com

# Case History 2.5
## HDC MARK II Production Recovery – Kerr McGee CNS

- **Recent Well**
- **Moderate temperature (148ºF)**
- **Damaged By OBM**
- **Bull Head**

*This well was drilled and put on line as an oil producer in 2000. The well was completed conventionally with BOT screens. The well was thought to be impaired by the OBM drilling fluid used blocking the screens or the skin as well.*

The well was bullheaded with 4,000 liters of HDC MARK II and allowed to soak overnight. The well was opened and allowed to cleanup under its own pressure. The well cleaned up within 48 hours, doubling the production from the pre-job levels and attaining a theoretical 90% rate for the well at that time.

The well was a high angle oil producer short screen completion.

## Case History 2.6
## HDC MARK II – BP – Harding ISX13

- **Oil Based Mud Blocked Screens**
- **Failed Acid Nano Wash Operations**
- **Bull Head operation**

*BP in the UKCNS drilled a horizontal oil producer in the Harding field in 2006. Designed to produce an initial 10,000 bopd from a 2000' reservoir section before water break through, the well was compromised due to the collapse of the lower hole because of chronic shale instability. With less than 400' of reservoir exposed (and that included the water leg), the initial expectations were of 4000 bopd. However the well was found to be badly impaired and produced 400 blpd.*

The damaging mechanism was determined to be whole synthetic oil based mud (SOBM) compressed around the screen completion, combined with possible solids drop out. Coiled Tubing intervention was carried out in late 2006 with solvent/acid based Nano wash systems. Eventually multiple attempts with an acid/surfactant/ solvent system were unsuccessful. This treatment fluid was aimed at disrupting and removing any oil wet solids and / or calcium carbonate. Although the well had been displaced to a carbonate based SOBM prior to completion, contamination by the original barite weighted drilling fluid was was determined to be the main causative blocking agent in the well.

In 2007 BP chose to use an advanced **HDC MARK II** based barite/carbonate dissolver system behind a **PentaFlow** pre-flush system in an attempt to recover the well. The operation was performed in September 2007 without CTU in a simple bull head operation. The well immediately improved in productivity and the PI increase from the start of the operation has been increased from 1.5 to a current PI of 7.5.

The stimulation using HDC MARK II was repeated with the PI doubling until no gain in PI was seen. Overall the operation was deemed a huge success with the well producing 4000 bfpd up from 400 bfpd previously. The fact that this was accomplished with a bull head operation made the result that much more outstanding.

BP co-authored an SPE paper on this well and is listed in the archives as SPE 120762.

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## Case History 3.1
## HDC MARK II Mobile Bay

- **Vertical Gas Producer**
- **Conventional Completion**
- **Total Scale Blockage Above Perforations**

The client's deep hot gas well in Mobile Bay has a history of complex scale formations. Typically, the scales have been removed using acid complexes. But it was known that not all the scales were acid soluble. This led up to an increased volume of acid insoluble solids building up in the well until production failed completely with CTU and/or wire line unable to access the well perforations at all. Bailer samples confirmed what the fluid modeling predicted, that barium scales were present with a variety of other complex minerals such as fluorites and carbonates.

Laboratory testing indicated that **HDC MARK II** would be the product of choice for removing these particular scale species. CTU was used to place the chemicals above the obstruction where it was allowed to soak in excess of 24 hours. During the latter phase of the soak periods, the well began to pressure up indicating that communication with the perforations had been re-established.

At the end of the soak period, the well was cleaned and the blockage totally removed. The well was producing at its best gas rate possible.

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## Case History Shell USA 3.2
## HDC MARK II, Offshore Louisiana –Oil and Gas Well Recovery

- **Aged Oil and Gas Producer**
- **Vertical Conventional Liner**
- **Perforated with Pre-Packed screen**
- **Dual Stage Perforation Bull-Head**
- **CTU Placement & Well Flow Back**

The client's well had lost some production capability through apparent scale build up. From the well history, it was apparent that the scale build up had been gradual. The drop off and failure of the well suggests (theoretically) that some seed scale or process may have accelerated the damaging process resulting in the decline. Having stated this, it was also possible that the build up through the life of the well may have been a direct or contributing factor to the loss of production.

The chemistry of the scale was determined to consist of Barium/Strontium oxides, sulphate. The program implemented was built around the use of several staged placements and soaks of **PentaFlow** and **HDC MARK II**. This dissolver was used to access the well at the perforations and near well bore from 18,006'- 18,246'.

Initially coil tubing was run with a jet blasting tool and the well was jet blasted to the bottom of the prepacked screen assembly. This procedure provided for the cleanup of the inside of the production assembly while allowing the chemical to clean up the outer portion of the screens, gravel pack, perforations and perforation tunnels.

The soaks were done in stages through the coiled tubing as this allowed direct spotting of the dissolving chemicals, without having to bullhead a lot of fluid back into the formation.

The different soak periods were required during the placement of the two chemicals as a single stage bullhead would be unlikely to achieve a uniform placement of the fluid over the severely scaled area. In addition, the **HDC MARK II** could become depleted before the area was totally cleaned. By staging displacements, cleaning and access was optimized.

The program was implemented with the zone being cleaned – with large amounts of scale removed from the well – and production restored, achieving an increase of 1.5 mmcfpd of gas, 1400 bopd and 100 psi of pressure.

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# Case History 4.1
# HDC MARK II - OBM Barite Dissolving
# Petronas Carigali – Resak A10S

- **HT Gas Well (325ºF)**
- **Deviated**
- **Dual String Completion**
- **OBM – Settled Barite + Acid Damage**
- **Conventional Perforated Liner**
- **Multi-stage Bull Head Through Short String**
- **CTU $N_2$ Gas Lift**

*Summary: Resak A10 was designed to produce 25 mmscfd, but only produced 10 mmscfd and falling. After pumping 13.0 ppg OBM to kill the well, 250 bbls of acid was pumped. Production dropped to below 1 mmscfd. Besides damage from acid, it was also believed that some of the barite from the OBM had settled and covered some of the perforations. In an attempt to recover some production, a year later almost 70 bbls of HDC MARK II was bullheaded into the well over 26 hours resulting in production of 7 mmscfd.*

Resak A10 is a dual string gas producer drilled by Carigali offshore Terengganu in 1999. The well was completed as a dual string completion to isolate a higher pressure reservoir at the bottom from intermediate production zones above.

Due to communication between the completions and lack of heavy brine, the well was killed and suspended in 13.0 ppg OBM. On re-entry, it was found that most of the perforations (in both zones) were partially buried under settled barite and OBM.

In the upper zone, coiled tubing could not be used to attempt a wash out, so the zone was acidized with 250 bbls of SWIK Halliburton formulation.

The zone was originally designed to produce 25 mmscfd. At the time of acidizing, the zone was producing between 10 and 7 mmscfd and falling. After acidizing, the production dropped to less than 4 million, dwindling to less than 1.5 mmscfd by June 2002 with over 200 bpd water.

In preliminary meetings and subsequent lab confirmation by Petronas, it was agreed that a cost effective trial using HDC MARK II would entail attempting to recover some of the buried perforations, and reversing if possible some of the HCL damage. Due to the high volume of acid used it was felt that attempting to reach the complete step out radius of the acid impact on the initial treatment stage was too expensive on an experimental basis.

The HDC MARK II job design was a staged bullhead operation through a cement unit. The job design was based on staged displacements of HDC MARK II over three hour intervals in a “dissolve” – “wash” – “dissolve” sequence to induce removal of barite from the lower perforations and flowing through them as the chemical depleted. The final stage consisted of displacing the entire volumes into the formation and static soaking for 12 hours. The entire operation was completed in 26 hours.

At the end of 26 hours, a partial nitrogen gas lift was used although the well began cleaning up naturally. Within 24 hours of lifting, the well was producing 4.5 mmscfd, going up to 6 mmscfd within 96 hours and over 7 mmscfd after five days, with 80 bpd water, and 5 cubic meters per day of condensate. The production has continued in excess of 7 mmscfd on a 19% choke through to the last tests held 45 days after the well was stimulated. The condensate production results indicate a clear response from the previously buried perforations although the actual gas production source remains questionable.

The actual mineral species and weights dissolved as analyzed from the returns are tabulated in Table 1. (Note: The Barite used contained high volumes of Hematite)

Based on the average specific gravity of the dissolved compounds, the mass of solids indicate that theoretically 63’ of settled barite and mud could have been removed from the well. That stated, the figure of 63’ is erroneous however, as it is impossible for the HDC MARK II to have uniformly contacted sufficient surface area during the stage displacements to address the bulk solids in the 7”. Basing the active HDC MARK II on a 25% to 50% activity within the 7”, over the period of each displacement, it is estimated with a high degree of confidence that between 19’ and 30’ of perforations in the lower liner was re-exposed.

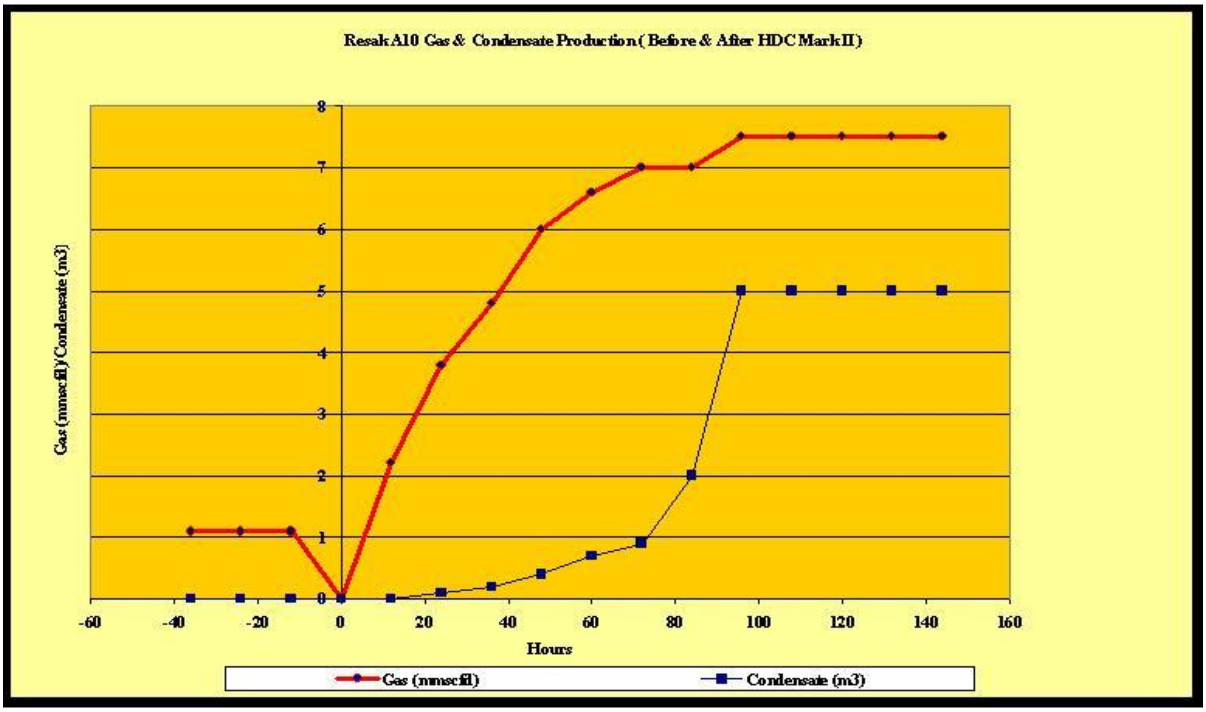
Table 2 reveals the actual analytical breakdown of the liquid volume flow back and dissolving rate of the HDC MARK II in each volume.

**Table 2: Separator Volumes, Weights Dissolved/HDC MARK II Capacity**

| Sample | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Volume bbls | 40 | 40 | 160 | 40 | 40 |
| Cum. Volume bbls | 40 | 80 | 240 | 280 | 320 |
| g/l dissolved minerals | 24.24 | 22.34 | 32.50 | 10.83 | 4.82 |
| Total Litres | 6392 | 6392 | 25568 | 6392 | 6392 |
| Total Grams | 154,949.62 | 142,794.72 | 830,960.00 | 69,247.35 | 30,781.32 |
| Total Kilograms | 154.95 | 142.79 | 830.96 | 69.25 | 30.78 |

| | | | | | |
|---|---|---|---|---|---|
| % SD27X In Sample | 28.00% | 24.65% | 31.50% | 10.65% | 5.00% |
| Litres SD27X | 1,789.76 | 1,575.63 | 8,053.92 | 680.75 | 319.60 |
| Dissolved g/l | 86.58 | 90.63 | 103.17 | 101.72 | 96.31 |

Chart 1: Production Gas Rates Before & After HDC MARK II Treatment




Reference: Kasim Selamat - Senior Production Engineer
kasimse@petronas.com.my

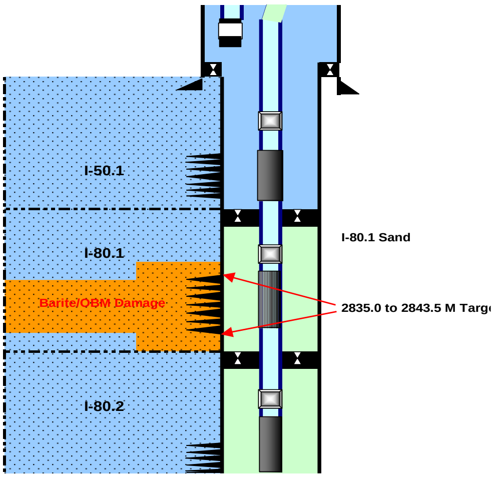
# Case History 4.2
# HDC MARK II - OBM Barite Dissolving
# Petronas Carigali – Resak A3

- **HT Gas Well (325º F)**
- **Deviated**
- **Dual String Completion**
- **OBM Drilling Skin Damage**
- **Conventional Perforated Liner**
- **Multi-stage Bull Head Through Long String Sliding Sleeve**
- **Lifted Using Flow From LS**

*Summary: Resak A3 is a dual string gas producer which was severely damaged in the middle target of the long string (I.80 sand) and never produced from this zone. Attempts to bull head acid through the sliding sleeve proved ineffectual. In 2004 PentaFlow cake breaker mixed with PowerPickle® Oil solvent - was bullheaded ahead of HDC MARK II mud barite and solids dissolver system. After 24 hours, the zone was lifted producing 11mmscfd.*

Resak A3 is a dual string gas producer drilled by Carigali offshore Terengganu in 1998. The well was completed as a dual string completion to isolate a higher pressure reservoir at the bottom from intermediate production zones above.

The well was badly damaged by the OBM mud used with the middle (I.80 sand) totally impaired and non-responsive to acid treatments.




The zone was isolated from the lower production and bull-headed with 3500 liters each of PentaFlow/PowerPickle® (50/50) and HDC MARK II and allowed to soak overnight. The well was gas lifted from the SSD successfully producing 11 mmscfd and building.

Reference: Kasim Selamat – Senior Production Engineer kasimse@petronas.com.my

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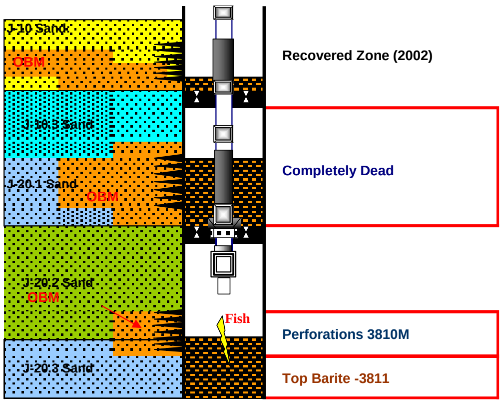
## Case History 4.5
## HDC MARK II - OBM Barite Dissolving
## Petronas Carigali – Resak A10-L

- **HT Gas Well (325º F)**
- **Deviated**
- **OBM – Settled Barite + Acid Damage**
- **Conventional Perforated Liner**
- **Multi-stage Bull Head Through Short String**
- **CTU $N_2$ Gas Lift**

*Summary: Resak A10L was designed to produce 50 mmcfd, but only produced 20 - 25 mmcfd and falling. After pumping 13.0 ppg OBM to kill the well, during a zonal communication problem in 2001 – the well was impaired badly by settled OBM and solids in the formation. Coil tubing washing was attempted with a resulting loss of the jetting head and production was resumed after a poor acid job result. In November 2004* ***PowerPickle*** *oil solvent was bull-headed as a pre-flush to* ***HDC MARK II****. The well was allowed to build up pressure naturally until it came on stream and flowed 45 mmscfd.*

Resak A10 is a dual string gas producer drilled by Carigali offshore Terengganu in 1999. The well was completed as a dual string completion to isolate a higher pressure reservoir at the bottom from intermediate production zones above. Due to communication between




the completions and lack of heavy brine, the well was killed and suspended in 13.0 ppg OBM. On re-entry, it was found that most of the perforations in the short string and long string zones were partially buried under settled barite and OBM. In the upper zone, **HDC MARK II** had been used to restore the well to productivity in 2002, so the same methodology was programmed for the deeper long string which was partially buried under OBM solids. The zone was originally designed to produce 50 mmscfd. At the time of acidizing, the zone was producing between 20 and 22 mmscfd and falling. As CTU was not available – it was decided to bull head the Power Pickle and HDC MARK II although there was no gas lift available. The decision was made expecting the well to take time to clean itself up.

Using 4,000 liters (50/50) **PentaFlow** and **PowerPickle** as a preflush, the lower zone was stage displaced to 9,000 liters of **HDC MARK II**. The well was allowed stand static as the pressure built up over time until it cleaned up and was placed on stream producing 45 mmscfd.

## Case History 4.9

## Injector Well Restoration Using HDC MARK II – Monobore - Thailand

- **New Drilled Water Injector**
- **Conventional Perforated Liner**
- **Plugged With OBM – no injection**

Summary :

*The well was drilled and completed as a conventional monobore using weighted oil based mud. After cementing the casing, the well was perforated but failed to inject. Reverse flow back and CTU sampling indicated whole oil based mud was in the perforations. Acid failed to make an impact.*

The well information was examined and a treatment consisting of **HDC MARK II** was programmed. The programme called for a two stage soak inside the casing and outside into the perforations and matrix to eliminate the barite which appeared to be plugging the well bore.

Due to the urgency of the situation, the Operator decided to proceed with a trial job even though only 50% of the required chemical was available at the particular window for the operation.

CTU was used to place the **HDC MARK II** into the well. The well was bull headed with a solvent pre-flush to remove any gross oil, the followed with the first stage **HDC MARK II** soak.

The **HDC MARK II** was allowed to soak in place for 8 hours, then was displaced into the formation with nw **HDC MARK II** lying across the perforations and in the matrix, and the well shut in for 24 hours.

After 24 hours the well was gas lifted using CTU to assist a quick cleanup, then the well placed on injection. ***The well went operational with an injection rate of 8500 bfpd under 1500 psi***

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## Case History 5.1

## HDC MARK II – ADDAX: OBM Damage – Oil Producer

- **New Drill – Oil Producer**
- **Moderate temperature (140ºF)**
- **Acid Damaged – OBM Damaged – Dead Well**
- **CTU & Gas Lifted**
- **Slotted Liner – OH Completion**

*Summary: This well reservoir section consisted of 2,467' of horizontal section drilled and completed in a slotted liner/open hole configuration. With no production seen due to OBM mud solids blockage in an extremely acid sensitive formation, an intervention and well recovery operation was designed using* ***PentaFlow/PowerPickle*** *and* ***HDC MARK II****. <u>The recovery programme was implemented bringing the well from 0 BFPD production to 2700 BPD in an operation covering 48 hours.</u>*

OSSU-11H was drilled and completed in the first quarter of 2002, using a 10.7 ppg barite weighted Synthetic Oil Based drilling fluid (SOBM) with a 551 psi overbalance on the formation. An open hole completion was set in place with 9-5/8" casing to 7,630 ft MD (4564 ft TVD) and a 7" slotted liner run in the 8-1/2" open hole to TD @ 10,272 ft MD (2,642 ft of OH).

Due to the overbalance and bridging agents used with the SOBM (barite, calcium carbonate), formation damage was suspected across the near well bore area, hence the inability of the well to flow.

Two subsequent unsuccessful attempts were made to unload the well.

1. Natural gas from an adjacent well was injected down the tubing casing annulus in an attempt to unload the well via the gas lift mandrels. The inability of the gas injection pressure to displace the annular fluid to the targeted lowest GLM, coupled with the fact that flow could not be maintained and adjacent wells had to be put back on production, to mitigate production losses, forced an abandonment of this attempt.

2. Nitrogen was injected down the completion string via CTU @ 200 to 250 scf/min in an attempt to initiate flow. An initial recovery of 60 BLPH (1,440 BLPD) at 60 psi and 80% BS&W was achieved. This rate gradually declined to 30 BLPH (720 BLPD) at 85% BS&W. (450 bbls of formation fluid) and was shut in with 30 psi WHP as natural flow was not possible. Over a 30-day period the tubing pressure gradually increased to 1,100 psi. When opened to production the well flowed crude oil for 20 minutes before gassing out and the FTHP dropped to 520 psig. The well was shut in for build-up and achieved 1,000 psig in 24 hours. When re-opened it gassed out with the FTHP dropping to 500 psig and shut in.

No further attempt was made to flow the well prior to this stimulation job. The shut in tubing pressure prior to this stimulation job was 190 psi.

With oil in the hole a diesel spacer was pumped ahead of the treatment and a CTU utilized to spot the treatment across the slotted liner. While RIH the CT hung up at 8,340 ft **(the maximum depth previously attained by coil was 7,500 ft)**. Slow progress was made on attempts to wash down and the operation was suspended for the night as only daylight operations were performed. On resumption a maximum depth of **8,418 ft** was achieved. It was decided to displace the oil in the hole with diesel and spot a **Power Pickle/PentaFlow** pill (44.5 bbls) across the liner interval. The coil was pulled out of the hole, 150 psi applied at the wellhead and the treatment left to soak overnight.

Upon resumption of the operation noticed that the WHP increased to 190 psi. 22 bbls of the **Power Pickle/PentaFlow** was squeezed into the formation and the coil was run in hole to a maximum of **9,501 f**t. This suggested that the combination of **PowerPickle** and **PentaFlow** had in fact dissolved or dispersed the blockage which had caused the coil to hang up at 8,340 ft. Next 95 bbls of **HDC MARK II** was spotted across the liner interval. The coil was pulled to 7,000 ft and 44 bbls squeezed into the formation. The coil was then pulled to surface, 70 psi WHP applied and the treatment allowed to soak for **42 hrs**. Nitrogen was used to lift the well and the well flowed at **2,700 bpd** at **650 psi** with the well stabilizing to approximately 2500 bpd when completing the report.

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January 2005

## Case History 5.2
## HDC MARK II – Shell Nigeria: Ogini18st

- **New Drill – Oil Producer**
- **Moderate temperature (160ºF)**
- **OBM Damaged – Dead Well**
- **CTU & Bull-Head Above HUD**
- **Excluder Screen – OH Completion**

Ogini # 18ST was drilled in August 1999 using Synthetic mud with barite used as weighing material. The well could not be produced immediately after completions for a period of about 152 days due to community restiveness. Thereafter, it was rocked for two weeks before the completions fluid could be displaced for the well to come in. The well was kicked off on gas lift in March 2000.

The well was subject to frequent surging and from time to time would stop flowing. Diagnosis suggested that the well was not properly cleaned up and the formation was likely to be severely impaired. A clean up attempt was made in January 2001. The clean up was not completed due to encountered HUD at 8477ft.

Production however saw a slight improvement to 1080 bpd with the change in choke size from 36"/64" to open hole done in August 2003. This was not sustainable however and the well continued to drop off. The gas lift valves were changed out in October 2003. A fish was left in the well (HUD) during earlier stimulation operations with a jet blaster tool. As such the subsequent stimulation operation using **PentaFlow** and **HDC MARK II** was bull-headed past this fish. ***At the time of operations, the well was completely dead with no production what so ever***.

Coil tubing was used to run to the top of the fish from where the chemicals were bull-headed. A 50/50 mix of **PentaFlow** and **PowerPickle** was pre-flushed into the well and allowed to soak for 90 minutes. This was subsequently bull-headed into the formation by **HDC MARK II** and the lot allowed to soak for 36 hours.

Nitrogen was used to lift from the HUD. The well came on very quickly, established a stable production rate from its own pressure, at circa 3000 bpd – from 0 bpd.

It is conjectured that due to the fish in the well, it is unlikely that the **HDC MARK II** fluid accessed the total area and that further improvement to the production could be made if the fish could be retrieved and **HDC MARK II** placed uniformly in the well.

March 2005

## Case History 5.3

## HDC MARK II – Fish Recovery In HTHP Geothermal Well

- **Geothermal Well**
- **Vertical**
- **Fish Lodged in Settled WBM Barite**
- **Mud Weight 15.5 ppg**

*This well is a geothermal well which had a fish lying above and through a milled bridge plug. The fish was identified to be buried in settled water base mud solids, which was 95% barite. I t was necessary to remove the barite which could not be washed away or jetted due to the fish configuration so the Operator decided to try **HDC MARK II** barite dissolver to expose the fish.*

**HDC MARK II** was air freighted to the location and spotted into the well on top of the fish, which was located circa 2,900'. The fluid was spotted three times with soaks until an over shot was run to tag and grapple the fish if possible.

When reaching the depth of the fish – it was found that the fish had dropped completely when the barite had dissolved. The fish fell to the bottom of the well – in the rat hole where it was no longer problematic.

The Operator was very pleased with the result that saved them a vast amount of time and money on an extended milling and fishing programme.