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Optimal Practices To Remediate and Control Fines Migration in Inland-Water Wells in the Maracaibo Basin, West Venezuela

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Abstract

This paper summarizes the following aspects of a comprehensive program intended to develop optimal practices for the stimulation of wells in the Ceuta field, a developing area located in Lake Maracaibo, West Venezuela: lab testing to diagnose formation damage mechanisms and to qualify proposed treatments; operational practices including injection sequence, treating volumes for optimal radial penetration and diversion techniques for uniform placement; recommended safety and environmental practices.

Also, detailed examples of treatments performed in six inland-water wells in the Ceuta, Area 8 South Central area within this field are provided. The average production rate for these wells before the implementation of these practices was 419 BOPD. The implementation of the guidelines provided in this paper resulted in an average post-production rate of 2100 BOPD with a twelve-month average decline rate of 1.6 BOPD.

The enhanced methodology has been implemented with success in other fields in the Maracaibo Lake area known as CentroLago, Lagotreco and Lagocinco. Results from treatments in these areas are also summarized and discussed.

Introduction

The Ceuta Field is a developing oilfield located in the Maracaibo Lake area, West Venezuela (see **Figure 1**). Hydrocarbons of ca. 20-37 º API are produced in this field from sandstone layers with permeabilities ranging between 25-115 mD in a gross interval of approximately 700 feet that includes the reservoir units commonly referred to in the Maracaibo Basin as units Misoa B 3.4 to B 6.0. Bottomhole temperatures range between 290-310 ºF and reservoir pressures range between 4000-6500 psi with depths of about 16,500 ft. The stimulation of wells in this field is a challenging task from technical and operational standpoints due to the diversity of formation damage mechanisms (chiefly fines migration, with deposition of clays, organic compounds and scales also occurring), bottomhole temperatures and large pressure gradients between producing sandstone layers.

The purpose of this paper is to report recent innovations in the matrix stimulation strategy for the Ceuta field that have resulted in improved production results over previously reported stimulation protocols. Specifics regarding typical fluid formulations, operational practices for injection sequence, treating volumes for optimal radial penetration, diversion techniques for uniform placement and recommended safety and environmental practices are described and discussed. The recommended stimulation protocol, with is referred within PDVSA as “Liquid HF”, has been successfully implemented in other fields in the Maracaibo Lake area Centro Sur Lago, Lagotreco and Lagocinco. Results from stimulation jobs in these fields with the Liquid HF protocol are also summarized and briefly reviewed.

Near-wellbore Damage Mechanisms

Laboratory studies performed on crude oil and core samples from the areas of interest allow determining the prevailing mechanisms that impair well production.

A previous study[1] determined that fines migration is a key impairing near-wellbore area for the Ceuta field. This assessment was achieved via mineralogical analyses by means of X-ray diffraction, flow tests on representative cores from the field and scanning electron microscopy. These studies concluded that there are clay particles, specifically kaolinite and smectite/illite (“mixed layer”), that can be dispersed with relative ease and migrate with fluid flow to further deposit in the pore throats, thus reducing the effective permeability of the porous media.

Comprehensive discussions about migrating fines and fines migration control theory are reported in the general literature[2,3]. It is proper to mention here that migrating fines can be a variety of different materials, including clays (phyllosilicates with a typical size less than 4 μm) and silts (silicates or aluminosilicates with sizes ranging from 4 to 64 μm). Dissolution of phyllosilicates, silicates and/or aluminosilicates that act as migratory fines and impair productivity is known to be achieved by the chemical reaction of hydrofluoric acid with these materials. For example, for kaolinite ($Al_4Si_4O_{10}(OH)_8$), the stoichiometric relationship:

$$Al_4Si_4O_{10}(OH)_8 + 4(n\text{-}m)\ HF + (28\text{-}4(n+m))H_3O^+ \leftrightarrow 4\ AlF_n^{(3-n)-} + 4\ SiF_m^{(4-m)-} + (46\text{-}4(n+m))H_2O \qquad (1)$$

where $0 \leq n < 6$ and $m = 4$ or 6 has been proposed[4]. Species $AlF_n^{(3-n)-}$ and $SiF_m^{(4-m)-}$ are water-soluble and therefore can be removed from the formation during flowback. However, such removal must be performed in a timely manner because these chemicals can undergo additional reactions that eventually lead to the precipitation of silica gel and other insoluble by-products[4].

Asphaltene deposition has also been found to contribute to production impairment in this area. Asphaltene contents for crude oils produced from the Ceuta field typically range between 8 wt. and 11 wt.%, as determined by standard solubility analyses[5]. These asphaltene contents rank high among those found in typical crude oils worldwide[6]. Also, **Figure 2** shows a photograph of organic deposits collected from the production tubing of a well in Ceuta field. The deposits shown in this picture exhibited 95% solubility in standard solubility tests performed at 140 ºF during one hour with a blend of aromatic solvents. These figures illustrate the propensity that is observed in wells in this area to render asphaltene precipitation issues.

Finally, several wells in the area have shown presence of calcite (calcium carbonate), which is most likely present as residual damage from completion fluids. For example, **Table 1** shows X-ray diffraction and solubility tests results for samples collected in two wells of the Ceuta field at depths that are representative of the pay zones of interest. Solubility tests reported in this table were conducted at 150 ºF during 1 h, and the percentages of solids that were solubilized were determined via gravimetry.

Results for well 1 are typical of those found for most wells in the Ceuta field. Results from well 2 are clearly indicative of near-wellbore damage due to invasion of completion fluids, as noted by the atypically high content of calcite and also by the presence of barite in the sample.

Removal of calcium-bearing minerals prior to the injection of hydrofluoric acid is a critical step for the success of matrix stimulation treatments comprising HF in their composition, because unwanted secondary reactions could occur. For example, calcite would react with hydrofluoric acid according to the stoichiometric relationship:

$$CaCO_3 + 2HF \leftrightarrow CaF_2 + H_2O + CO_2 \qquad (2)$$

Firstly, this reaction reduces the availability of HF for the dissolution of formation fines. More importantly, calcium fluoride (CaF_2) is a highly insoluble material (solubility = 1.6 mg/100 cm^3 of water at room temperature[4]) that would precipitate and block flow channels, thus impairing well production.

Matrix Stimulation Protocols

A previous study for this field[1] pinpointed via laboratory and field tests fines migration as the most influential formation damage mechanism for production impairment. The same study describes the implementation of a stimulation strategy comprising the use of matrix treatments with fluoboric acid to improve well responses in terms of production rates and sustaining of such rates over time. Such strategy was compared favorably with previous practices considering the use of HF/HCl blends only.

The recommended stimulation strategy described in Ref. (1) for the Ceuta field consisted of consecutive injection into the formation of the following fluids:

1. *Solvent:* Injected into 25-30 gal/ft of treated sand
2. *Pre-flush:* 10% HCl injected into 25-30 gal/ft of treated sand.
3. *Regular mud acid medium:* (6% HCl + 1.5% HF) injected into 100-150 gal/ft of treated sand. The RMA is intended to dissolve migrating fines in the formation and near-wellbore area.
4. *Spacer*: Ammonium chloride brine is injected to displace the RMA out of the 3 - 5 ft critical matrix area.
5. *Main fluid:* comprising fluoboric acid (HBF_4) and injected at 100 – 150 gal/ft. Fluoboric acid hydrolyzes to generate HF according to the stoichiometric relationship:

$$HBF_4 + 3\ H_2O \leftrightarrow H_3BO_3 + 4\ HF \qquad (3)$$

The generated HF further reacts with phyllosilicates, silicates and/or aluminosilicates present in the formation. The boric acid (H_3BO_3) was claimed to bond and stabilize clays in the formation and consequently to control further fines migration.

An alternative protocol that has been termed “Liquid HF” within PDVSA was developed and implemented in recent years to improve on several areas not considered by the initial methodology:

(a) HCl was replaced with organic acids blends (acetic + formic acid) to prevent destabilization of clays in the presence of HCl at high temperatures as described in Ref. [7].

(b) Removal of organic and inorganic deposits is addressed in independent stages before the injection of HF. This is done with the goal of improving removal of organic deposits and calcareous residues that would otherwise impair the ability of HF to react with the target fines. These independent stages address the fact that both organic and inorganic deposits may also have an important role in production impairment as discussed previously.

(c) HF is added as a reagent, and not generated through the decomposition of fluoboric acid. Clay stabilization is achieved instead by using a proprietary polyelectrolyte that is able to adsorb on the pore walls and prevent further detachment of migratory clay particles.

(d) Injected volumes were optimized for more adequate treatment costs and reduced product handling.

Specifics for the treatment sequence are as follows:

Stage 1:

1. *Solvent*: Injected into 15 - 60 gal/ft of treated sand in order to dissolve organic residues such as paraffins and asphaltenes, set the wettability of the formation to water wet and break down possible emulsions within 2 to 4 feet of the critical matrix region. Radial penetration is calculated according to the expression:

$$V/H = 23.50\, D\, (D + R/6)\, \phi \qquad (4)$$

were V/H is the volume of fluid that is injected per foot of treated sand (gal/ft), D is the target radial penetration from the wellbore (ft), R is the wellbore radius (inches) and ϕ is the average porosity of the target sand.

2. *Flowback* of injected fluids, aided with gas and/or nitrogen lifting.

Stage 2:

3. *Solvent*: Injected into 5 -15 gal/ft of treated sand (1 to 2 feet penetration).

4. *Organic acid blend* (13 % acetic acid + 9 % formic acid): injected into 30 - 60 gal/ft of treated sand (3 to 4 feet penetration) to dissolve any calcareous materials in the formation, thus preventing precipitation of calcium fluoride (CaF_2).

5. *Flowback* of injected fluids, aided with gas and/or nitrogen lifting.

Stage 3:

6. *Pre-flush*: Organic acid blend (6% acetic acid + 5% formic acid) injected into 15-30 gal/ft (2 to 3 feet penetration) of treated sand to condition pH of the formation and remove any calcareous residues that may have remained after stage 2.

7. *Main fluid*: HF/Organic acid blend (2% HF + 13% acetic acid + 9% formic acid) injected into 30 - 60 gal/ft of treated sand (3 to 4 feet penetration) to dissolve migrating fines in the formation and near-wellbore area.

8. *Post-flush*: Organic acid blend (6% acetic acid + 5% formic acid) comprising a proprietary clay stabilizing polyelectrolyte and injected into 30 - 60 gal/ft of treated sand (3 to 4 feet penetration) for fines migration control.

9. *Flowback* of injected fluids, aided with gas and/or nitrogen lifting.

Use of coiled tubing units is preferred for these operations, because (a) more uniform fluid placement can be achieved along the target intervals; (b) nitrogen lifting is available to remove the HF treatment promptly and to avoid occurrence of secondary and tertiary reactions and the formation of unwanted by-products.

Intercalated sandstone layers with perforated intervals typically higher than 20 feet may require the use of diverging methods to improve fluid placement. This is particularly true is significant differences in reservoir pressure and/or permeability are observed between intercalations. Nitrogen foams and viscoelastic fluids such as those described in Ref. [8] have been successfully used to promote divergence during these treatments.

Quality, Health, Safety and Environmental Considerations

The success of matrix stimulation treatments is bound to efficient quality control. The Liquid HF protocol requires the presence of an experienced lab technician before the job to perform quality assurance/quality control of the raw materials before shipment, and also at the wellsite before and during mixing and pumping operations to verify compliance of the chemical blends with parameters previously measured in the laboratory. Personal protective equipment must be worn as required by the material safety data sheet of each reagent. In particular, Nomex suits, hardhats, safety glasses, steel toed boots, face shields, neoprene gloves, and special suits for handling of HF solutions were made available for each operation.

The Liquid HF protocol includes a contingency plan that requires the presence of a paramedic from the loading of HF solution in the barges to the completion of the operation, including the flowback of the last stage. The transportation time of individuals from the barge to the closest medical center via (a) fast boat plus ambulance trip, and (b) helicopter trip, are estimated before the job and arrangements are made to have the fastest option available during the execution of the job (**Figure 3**).

Finally, the protocol requires for the barges used for these operations to count with zero-discharge systems. In this way, potential chemical spills are contained within the barge and are prevented from falling into the sea and therefore from affecting the environment.

Case Study – Well VLG-3865

This section summarizes relevant information for the intervention of well VLG-3865 (B-superior, VLG-3729 reservoir in Ceuta field) following the Liquid HF protocol. **Figure 4** illustrates key components of the completion for well VLG-3865. This completion is typical of wells in the Ceuta field: 3-1/2” tubing provided with gas lift mandrels and packer fixture near the tubing end, set over 7” production liners. For this well, perforations were open over 106 ft of sandstone layers with average characteristics summarized in **Table 2**. Produced crude oil exhibited a density of 22.6 ºAPI and a BWS below 1%. Bottomhole temperature was 300 ºF.

A NODAL analysis was performed for this well to assess expected production rates from implementing the Liquid HF protocol described in the preceding section. Specifics on NODAL analysis are reported in the literature[9,10]. Results from such analysis are shown in **Figure 5**. The production of the well before the intervention was 756 BNPD with a bottomhole flowing pressure of 3900 psi. The reservoir pressure had been measured previously via static pressure test to render 6400 psi. The calibration of the estimated inflow performance relationship curves (IPR) with the outflow (also vertical lift performance, VLP) curve to match the initial production and flowing pressure render a skin (damage) factor of 46.

The proposed treatment for the well consisted of injecting via coiled tubing (a) a first stage comprising 35 bbl of a solvent blend (14 gal/ft) to achieve radial penetration of 2 ft within the critical matrix, followed by activation of the gas lift system and flowback; (b) a second stage comprising a pre-flush of the solvent blend used in the previous stage (10 bbl) followed by 70 bbl (28 gal/ft) of an organic acid blend comprising 13 vol.% acetic acid and 9 vol.% formic acid to achieve radial penetration of 3 ft within the critical matrix, followed by activation of the gas lift system and flowback; (c) a third stage comprising 35 bbl of pre-flush (organic acid blend 6 vol.% acetic acid and 5 vol.% formic acid), followed by 70 bbl of a HF/organic acid blend (2 vol.% HF, 13 vol.% acetic acid, 9 vol.% formic acid), and by 70 bbl of a post-flush solution comprising 6 vol.% acetic acid, 5 vol.% formic acid and 0.3 vol.% of a proprietary polymeric clay stabilizer. Conventional additives such as demulsifiers, iron reducing agents, asphaltene dispersants and mutual solvents were added as deemed necessary and required by compatibility tests performed prior to the job.

The effect of the proposed matrix treatment on near-wellbore damage removal was simulated with the software StimCADE (v.4, Schlumberger). Results from such simulation are summarized in **Figure 6**. This figure shows the evolution of the average skin (damage) factor over the treated interval as function of the treatment volume penetrating the formation during stage 3 of the sequential treatment. The simulation suggested that a final skin of 5.4 could be achieved with this treatment. This residual skin value was then used to generate the expected IPR curve after the treatment, which is also shown in **Figure 5**. It can be seen in this figure that the NODAL analysis rendered an expected production rate of 2217 BNPD.

The stimulation job was performed as designed. Production tests were performed before and after the well intervention as reported in **Figure 7**. It is seen in this figure that production tests within the month following the intervention rendered production rates ranging between 2300 – 2515 BOPD (average = 2410 BOPD = 2434 NBPD with 1% BWS). The inferred residual near-wellbore damage (skin) with this post-stimulation production rate was 3 as shown in **Figure 5**. The resulting production compares favorably with the expected production for the well from NODAL analysis, thus confirming that the calibration of the model was adequate to predict expected performance for wells in this area.

Importantly, **Figure 7** shows that the well continued to produce at a rate of ca 2000 BOPD one year after performing the matrix treatment. The observed average production decay rate was 1.1 BOPD. These features are indicative of the effectiveness of the treatment in regards to fines migration control.

Summary of Results for the Ceuta Field

The case study described above corresponds to one of the first six field trials that were performed in Ceuta field for the enhanced methodology during 2004. **Figure 8** summarizes production results for the other initial five trials that were performed in this area, along with those for well VLG-3865. It is seen in this figure that a consistently favorable production response was obtained in all cases. In summary, the average production rates for these wells were (a) 419 BOPD right before the interventions; (b) 2100 BOPD right after the stimulation jobs; (c) 1863 BOPD six months after the interventions; and (d) 1505 BOPD one year after performing matrix stimulations. The average one-year decline rate for the six wells was 1.6 BOPD.

Figure 9 (right) summarizes the average results listed above. Averages for production results of six wells intervened with the conventional stimulation protocol described earlier are also provided for comparison (**Figure 9**, left). It is seen in this figure that the optimized protocol rendered higher post-stimulation production rates and better sustaining of such rates in time. By virtue of these results, the enhanced methodology was adopted by PDVSA for future matrix stimulations in the Ceuta field. By the end of 2006, thirty wells had been stimulated in this field following the Liquid HF methodology. Twenty nine of such wells exhibited significant gains in oil production, for which the protocol has been regarded as successful.

Summary of Results for Other Fields in the Maracaibo Basin

Table 3 summarizes pre- and post-stimulation production rates for wells located in CentroLago, Lagotreco and Lagocinco fields within the Maracaibo basin (see **Figure 1**) and for which fines migration was also assessed as the key impairing near-wellbore damage mechanism.

Gains in production due to stimulation were more moderate than those observed in the Ceuta field in all cases. This is mainly due to the fact that Centro Sur Lago, Lagotreco and Lagocinco fields are well developed oilfields that exhibit significantly lower reservoir pressures (typically in the range of 500 – 1200 psi), and therefore have significantly lower production potentials.

Conclusions

Fines migration, asphaltene deposition and residues from completion fluids that persist in the near-wellbore area are the most influential damage mechanisms that explain production impairments in the Ceuta field, West Venezuela.

A three-stage protocol intended to target each of these mechanisms individually has been optimized and adopted to perform acid stimulations in this field. The protocol comprises (a) thorough quality, health, safety and environmental considerations; (b) job design supported with NODAL analysis and laboratory data to assess compatibility with reservoir fluids; (c) the use of tailored solvent blends and organic acid blends in combination with straight HF and with a proprietary polyelectrolyte for efficient removal of organic deposits, inorganic deposits and for the dissolution and stabilization of migratory fines. The protocol has been adopted for matrix stimulation treatments in the Ceuta field due to very positive results in terms of production gains that have resulted from its implementation. More modest, yet favorable results were also obtained from using this protocol in CentroLago, Lagotreco and Lagocinco fields, which are also located in the Maracaibo basin.

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Table 1. General composition and solubility of samples colected from two wells located in Ceuta Field

	Well 1	Well 2
Sampling depth (ft)	15751	16456
Mineralogical composition[a]		
Quartz	94.1	42.0
Clays	3.9	-
Microcline	2.0	3.1
Calcite	Tr	44.9
Siderite	-	-
Magnetite	-	-
Barite	-	10.0
Others	-	-
Solubility in acids (%)[b]		
15% HCl	6.1	53.0
15% HCl + RMA (12% HCl + 3% HF)	7.0	58.0

a. Determined via X-ray diffraction
b. Test conditions: T = 150 ºF during 1 h; RMA = retarded mud acid

Table 2. Average Properties for Well VLG-3865

Permeability (mD)	52
Porosity (%)	12.0
Zone Pressure (psi)	6400
BHST (ºF)	300
Formation Lithology	
Quartz (%)	95.3
Calcite (%)	Tr
Dolomite (%)	0.3
K-Felspar (%)	0.7
Siderite (%)	0.1
Kaolinite (%)	2.8
Smectite (%)	0.2
Illite (%)	0.5
Chlorite (%)	0.1

Table 3. Summary of Results in CentroLago, Lagotreco and Lagocinco Fields

Field	Well	Pre-job Production Rate (NBPD)	Post-job Production Rate (NBPD)	Production gain (NBPD)
CentroLago	CL-216	360	514	154
	CLD-74	266	505	239
	CLA-209	244	341	97
	CLA-281	29	133	104
	CLA-320	60	154	94
Lagotreco	VLC-1375	234	417	183
	VLC-1072	179	487	308
	VLC-1457	43	373	330
	VLC-1471	135	610	475
	VLC-1396	105	403	298
Lagocinco	LRF-131	18	257	239
	VLE-1306	0	207	207
	VLE-1045	97	155	58
	VLE-1275	0	95	95
	LRF-152	41	244	203

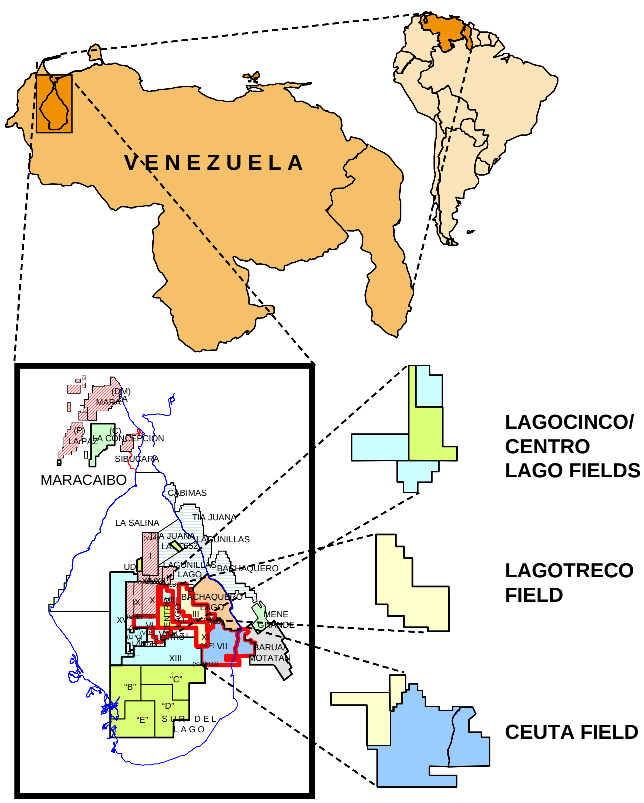

Figure 1. Location of Ceuta, Lagotreco, CentroLago and Lagocinco fields**.**

Figure 2. Picture showing organic residues collected from production tubing in a Ceuta field well.

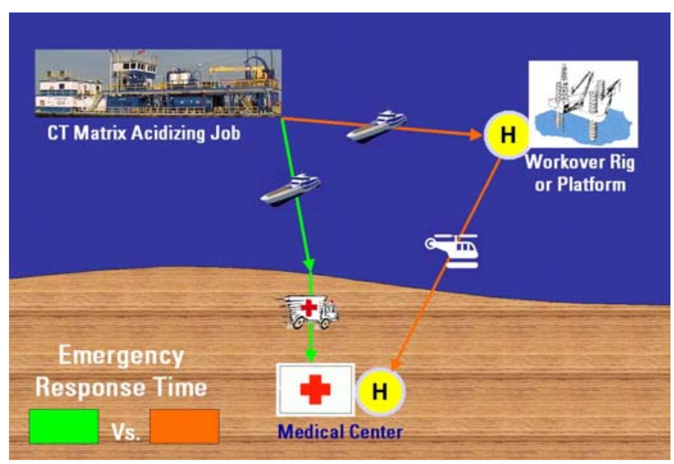

Figure 3. Medical evacuation routes are considered as part of the contingency plan.

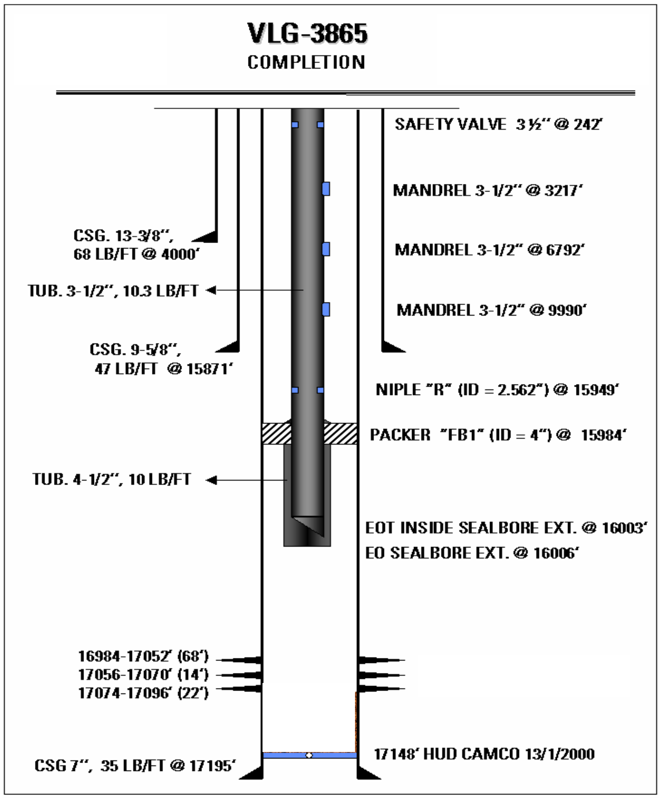

Figure 4. Schematic representation of the completion of well VLG-3865 located in Ceuta field.

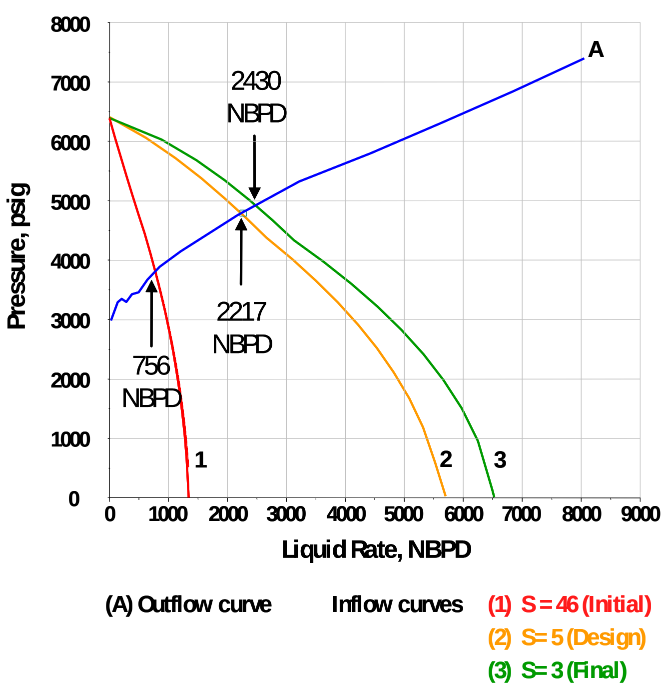

Figure 5. NODAL analysis for well VLG-3865

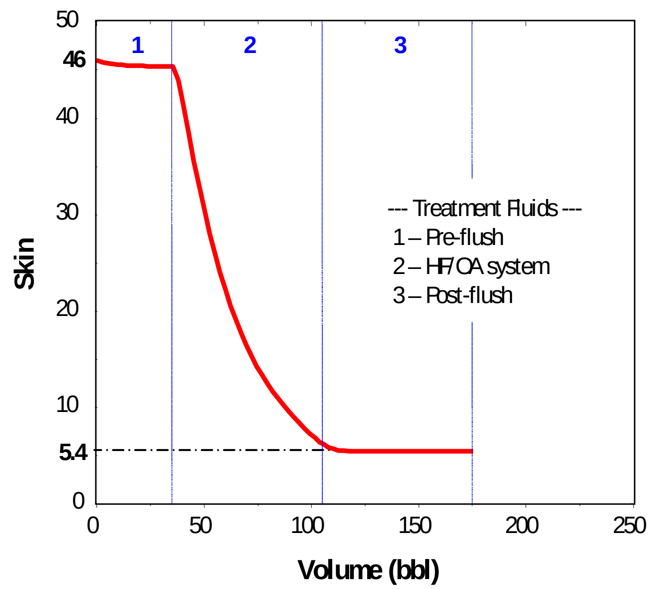

Figure 6. Simulated progression of skin damage as function of injected volume into the formation during stage 3 of the Liquid HF protocol.

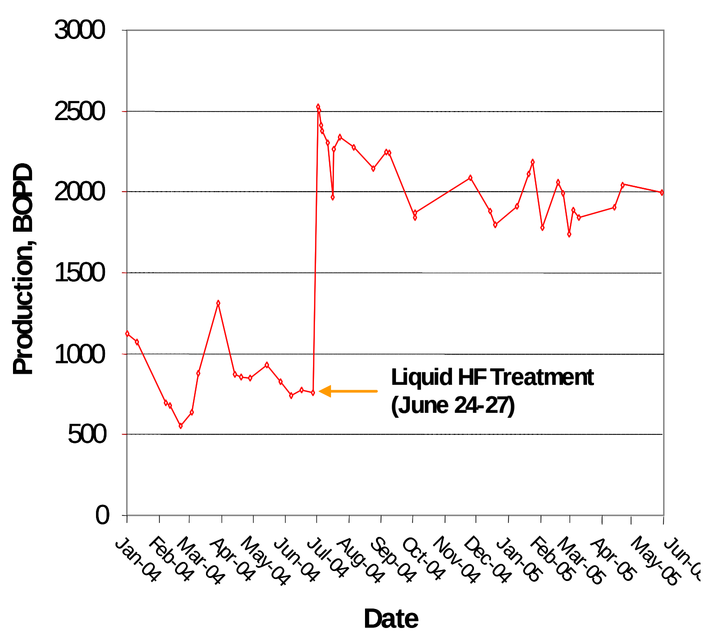

Figure 7. Production history for well VLG-3865 before and after matrix stimulation following the Liquid HF protocol.

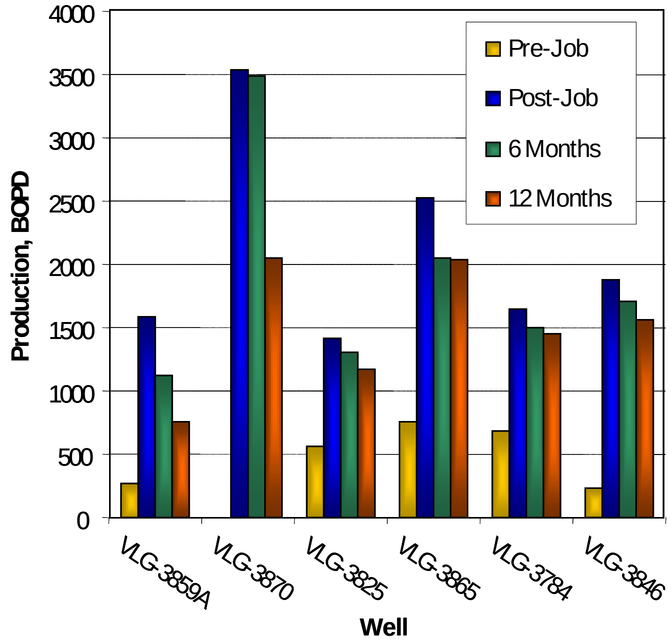

Figure 8. Summary of 2004 matrix acidizing campaign in the Ceuta field.

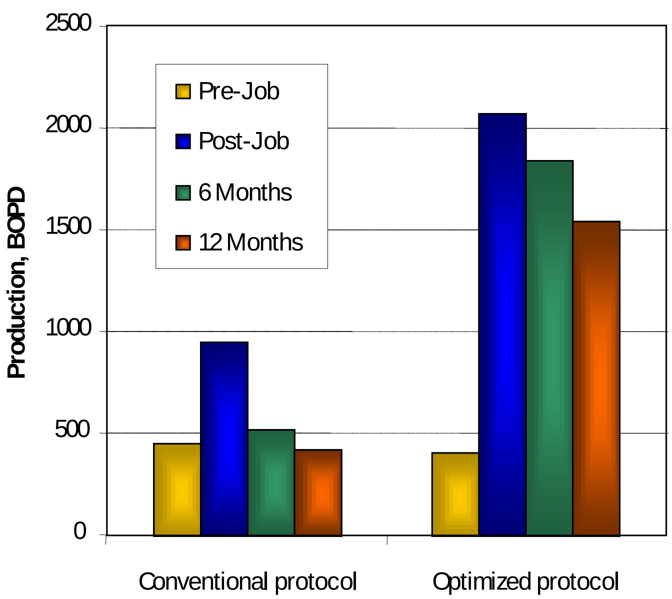

Figure 9. Comparison of production results from the implementation of the conventional (left) and optimized protocols described in the paper.