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An Impressive Impact on Well Productivity by Hydrochloric Acidizing of Vuggy Carbonate Reservoir: A Case Study

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Abstract

Hydrochloric acidizing is a routine operation in oil fields to reduce the mechanical skin. In this paper, practical acidizing in a typical carbonate oil reservoir located in the southwest of Iran is practiced, which shows an unexpected improvement after acidizing. To understand the acidizing effect on reservoir rock, the formation rock is analyzed on different scales. An acidizing laboratory test is also carried out on formation core samples to understand the acidizing performance. The results show that the main feature of this reservoir is its dominated secondary porosity and its special pattern of distribution. Practically, this porosity percolation has caused high mechanical skin during drilling and a large productivity improvement after acidizing. The acidizing increased the ultimate recovery of the reservoir with existing wells and prolonged the production plateau.

Keywords: Acidizing, Carbonate Reservoirs, Paleokarst, Porosity Distribution Pattern, Productivity Improvement.

1. Introduction

It is a fact that the acidizing performance of the carbonate is directly related to the development of flow channels in the rock. As Xiong (1994) stated, when acid is injected into a carbonate, the acid flows preferentially into the highly permeable regions, namely the large pores, vugs, or natural fractures. The rapid dissolution of the matrix material enlarges these initial flow paths; thus the acid soon forms large, highly conductive flow channels called wormholes. Wang (1993) reported that large pore sizes should be present in the virgin rock so that wormholing can be initiated. Moreover, if all pores in the formation are small, acid will dissolve the rock uniformly and wormholes will not form until some of the pores have reached a critical size. Based on the work of Wang (1993), if large pore sizes are available in intact rock, then the first criterion for the large effect of acidizing is granted. The large increase of productivity after acidizing treatment was first studied by Clason, 1935. He first suggested that crevices (fractures) must be present, and only through the enlargement of the crevices and/or removal of drilling fluid or other deposits from crevices or fractures could large increases in productivity be explained. Sharaf (2000) ascribed the unexpected high production rates after acidizing

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treatment to opening natural fractures. Harris (1966) introduced factors of pressure, temperature, acid flow velocity, acid concentration, type of acid, formation composition, and by-product formation as the main parameters affecting acidizing performance. Nierode (1971) added surface-area-to-volume ratio which is the surface of rock which comes in contact with a given volume of acid.

Iran has a very long history as an oil producing country, following the first commercial petroleum find in Masjid Soleyman in 1908. Normally, matrix acidizing is conducted after a well has been drilled, put into production, and when production declined to maintain production. Accordingly, to evaluate an acidizing job some factors such as productivity index, skin factor, pressure drop around the well bore and flow rate (before and after stimulation job) are performed in Iranian oilfields. The history of matrix acidizing in some of the southern Iranian oilfields has been introduced Zoveidavianpoor (2010) to which the reader can refer. He evaluated the matrix acidizing in the south of Iran and investigate that the majority of these acidizing operations have inefficient outcome. However, there is no evidence of any crevices (fractures) in most of the Iranian fields. Adding to these factors, based on different acidizing experiences in Iranian carbonate oil fields, at a constant concentration of acid, porosity distribution pattern in carbonate rocks can make a significant difference.

In this paper, practical acidizing in a typical DV oil field located in the southwest of Iran and the impressive improvement on production is presented. To understand the mechanism of acid in this field, the formation rock is analyzed on different scales and valuable features of the rock are introduced. An acidizing laboratory test is also carried out on formation core samples to understand the acidizing performance.

2. Results and discussion

2.1. Reservoir characteristics

The studied oil field, called DV, is one of the heterogeneous carbonate reservoirs in the southwest of Iran with a north-south elongation. This gentle symmetrical anticlinal structure is about 10 km wide and 25 km long. The producing interval consists of three separated layers, namely A, B, and C, which are pure limestone with a total thickness of about 500 m. The DV reservoir is at the depth of more than 4000 m and at a temperature of about 150 °C. The initial reservoir pressure is 9000 psi and contains light oil with an API of 40 degree. The oil production is started with 3500 STB at year 2000 with one well and building up gradually to 160,000 STB at the beginning of year 2010 with 22 producing wells. The associated gas reinjection is kicked off one year later at a surface pressure of 7500 psi.

Undoubtedly, the special effect of acid on this reservoir is related to the porosity distribution and rock typing, so the reservoir characterization is presented in a wide range from micro scales to petrophysical log scales. The most dominant facies are wackstone/packstone, peloidal packstone, ooidal grainstone, and packstone/grainstone. These features are recognized from scanning electron microscope images shown in Figures 1-4. These images are thin section images coming from core cut samples in one well. It is difficult to predict the acidizing effect from these images, but they can be used to characterize the reservoir. The lateral and vertical distributions of such facies are controlled by the high frequency sea level variations generating stacked transgressive/regressive sedimentary cycles.

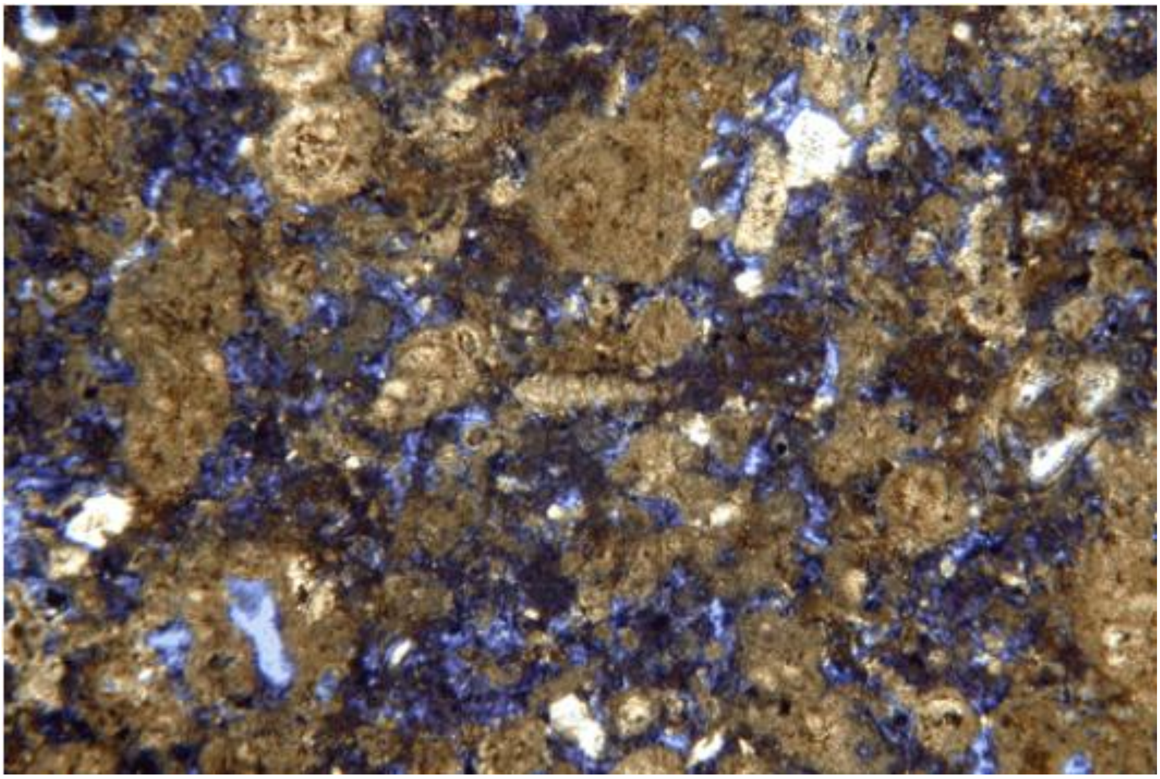


Figure 1
Packstone/grainstone and the main pore types are represented by intergranular and vugs.

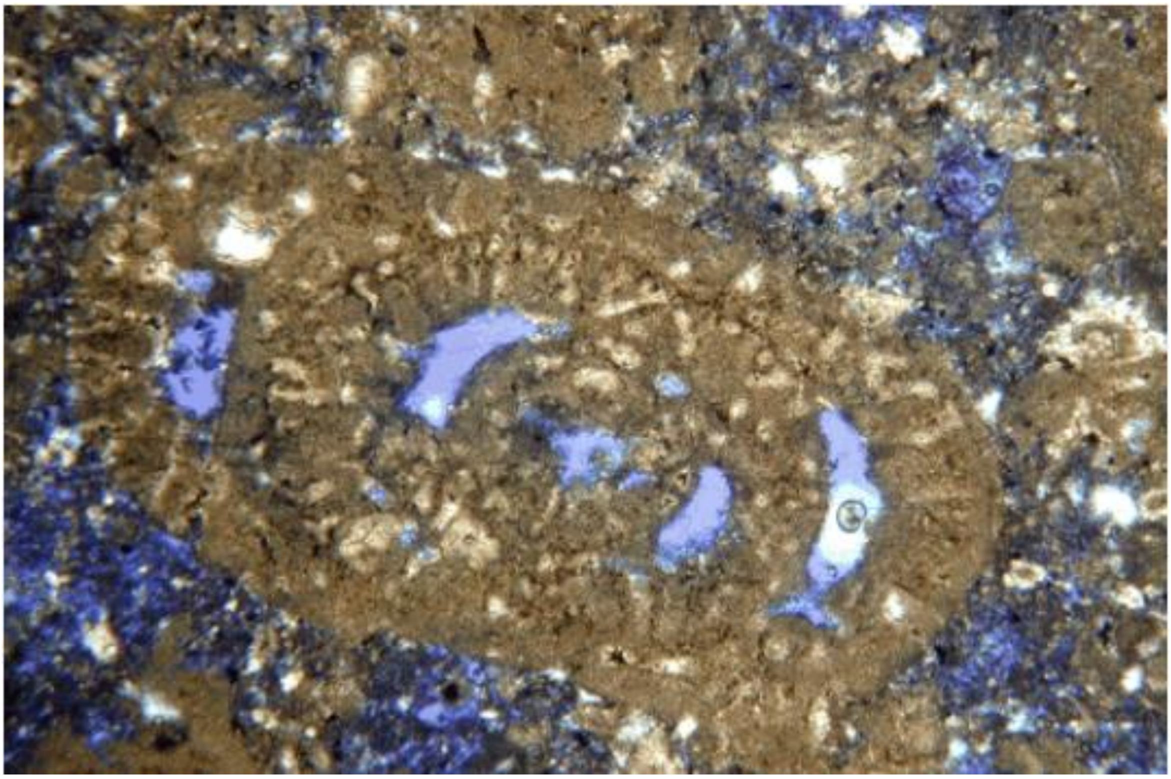


Figure 2
Wackstone/packstone, with benthic foram.

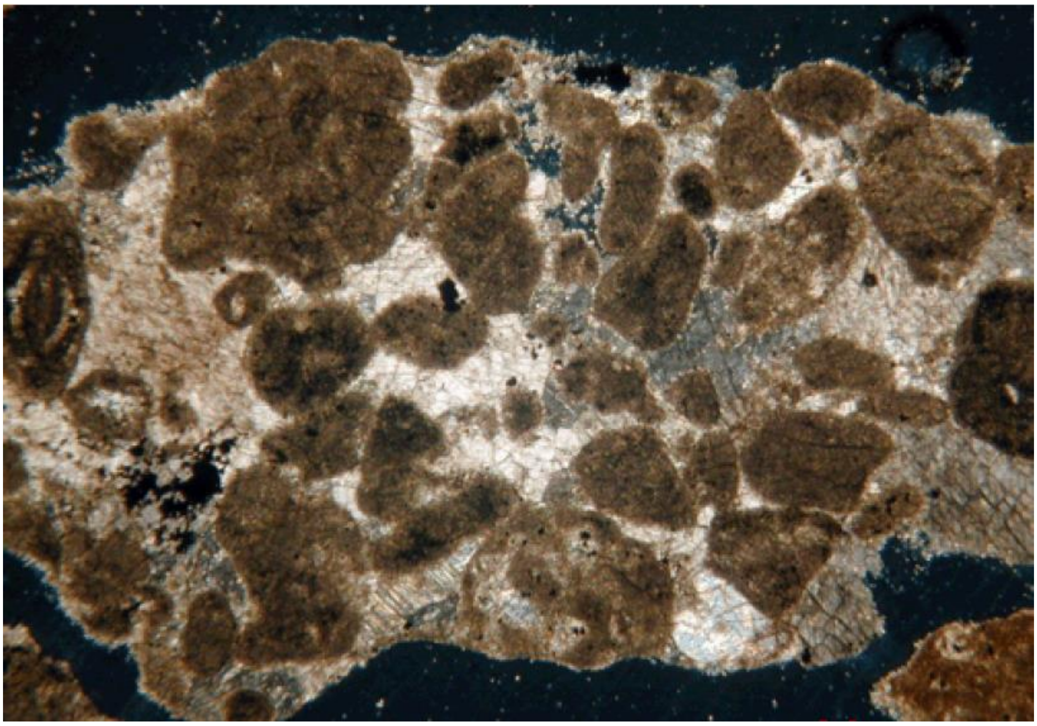


Figure 3
Ooidal grainstone, the primary porosity is filled by calcite cements.

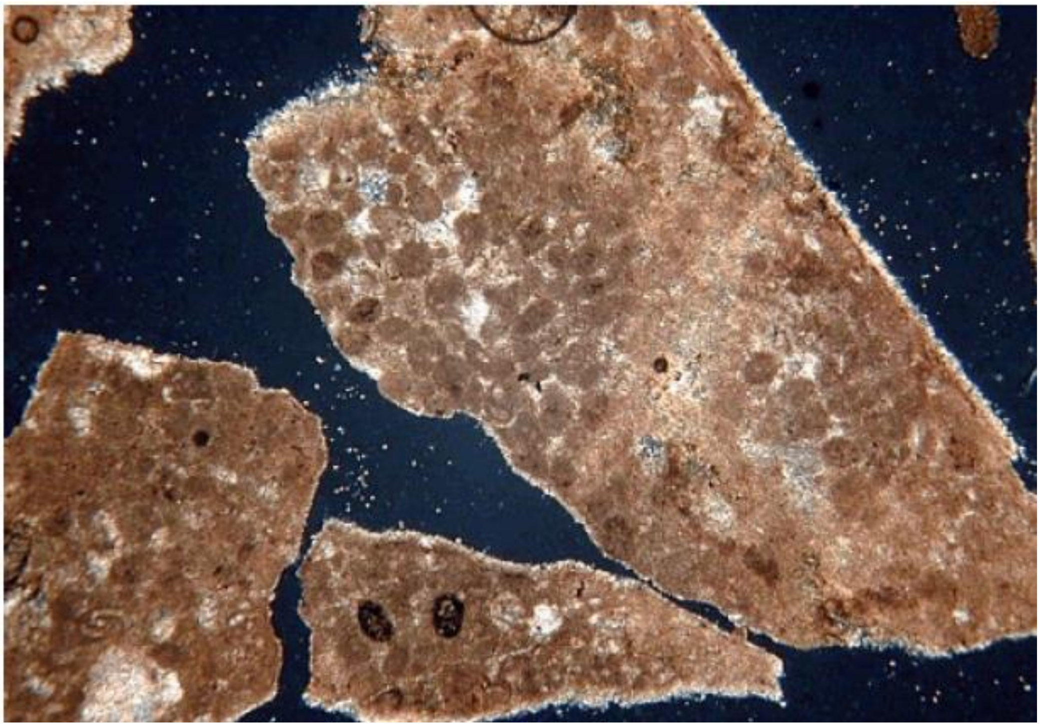


Figure 4
Well-sorted peliodal packstone; the primary porosity is filled by calcite cements

The depositional environment of DV reservoir is of a ramp type carbonate platform. The facies belts of inner, outer, and middle ramp can be recognized. The middle ramp is characterized as a carbonate build-up that could be associated with prograding facies and shoals with primary porosity such as intergranular and framework porosity. The inner and outer ramp facies are represented by wackstone and mudstone with primary poor reservoir quality properties. The main lithology of this reservoir is limestone interbedded with mudstone to shaly limestone. During geological time, two important dissolution events have occurred: early diagenetic developing intercrystalline/micro porosity, molds and vugs up to 1 mm in size in the upper half of the reservoir (layer A and B), and paleokarst creating secondary pores in the form of large molds and vugs up to 2 cm in size with solution enlarged features and solution pipes most dominant in the lower half of the reservoir (Layer C).

2.2. Reservoir porosity analysis

In order to have samples of formation rock, coring operation is performed in appraisal wells. Figure 5 shows an X-ray tomography image indicating the distribution of secondary porosities (dark areas) in 6 slices of the plug. This is an indication of spatial secondary porosity distribution also in the formation. As shown in this figure, secondary pores are abundance and well connected along a core plug.

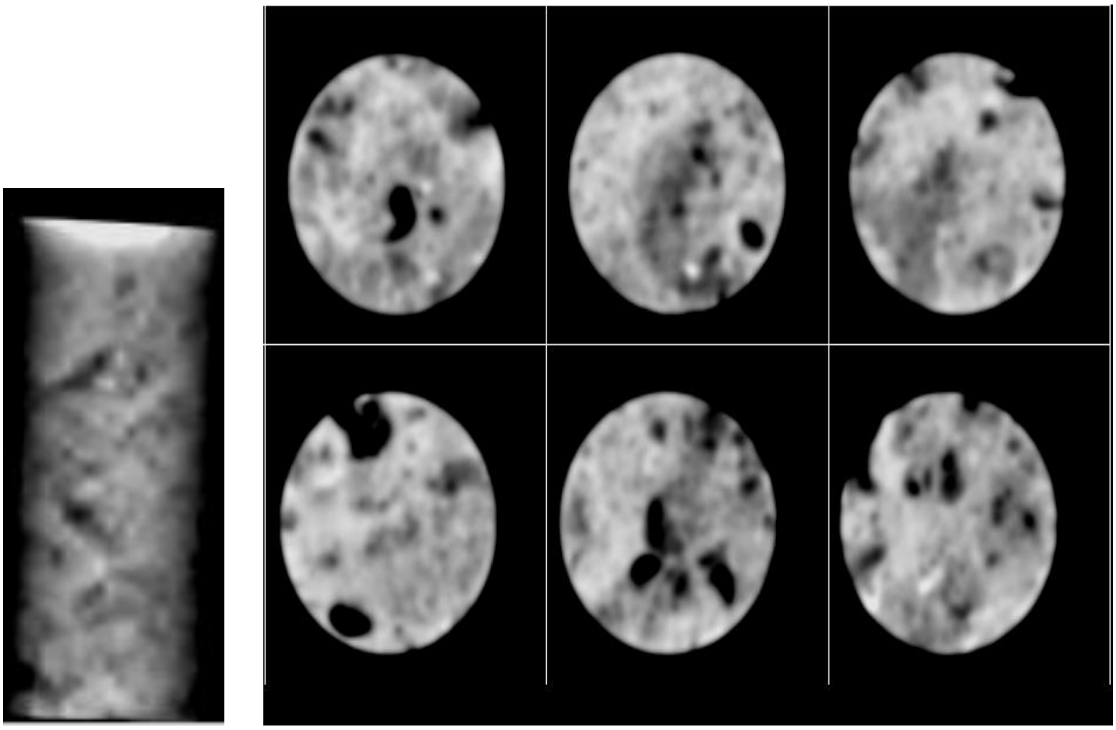


Figure 5
X-ray tomography images.

Ditch cutting samples in vuggy intervals are also analyzed using an optical microscope. Figure 6 shows the pore network characteristics of cuttings in DV field. As detected, there are some microfractures (yellow arrow), which can connect the moldic porosity (red arrow) to other sections of the media. The mcirofracture is not quite open, but probably exposing to enough acid can make a conduit between moldic porosities.

Moreover, Schlumberger has introduced the new approach of variable density log (VDL) to utilize borehole electrical images in the analysis of carbonate reservoir porosity system (Newsberry, 1996). Through this technique, porosity distribution and quantity of vugs/molds fraction around the wellbore at each depth can be obtained. The resistivity data from electrical images are transformed into porosity map of the borehole after their calibration with the shallow resistivity and log porosity (preferably effective porosity). At every specified sampling rate (generally 0.1 inch for oomoldic porosity system or 0.3 inch or bigger for formations having large size vugs or molds), porosity distribution histograms are computed. Figure 7 shows different porosity distributions in homogenous and heterogeneous carbonates. As shown in Figure 7 (a), for homogenous intervals, the porosity distribution has a bell shape frequency, which is called unimodal distribution (homogenous carbonate). In vuggy carbonates, highly skewed unimodal or bimodal distribution of porosity is observed. While in most heterogeneous carbonates where cementation, primary porosity, and vuggy porosity are present, highly skewed and broad, or bimodal/trimodal porosity distribution may be observed (Figure 7 (b and c)). On such histograms, the points from the high porosity ends represent leached pores (vugs or molds) and fracture fractions of porosity, whereas the points from the low porosity end belong to the dense or cemented areas of the host rock. The area under the high porosity tails of porosity histograms gives the quantity of secondary porosity.

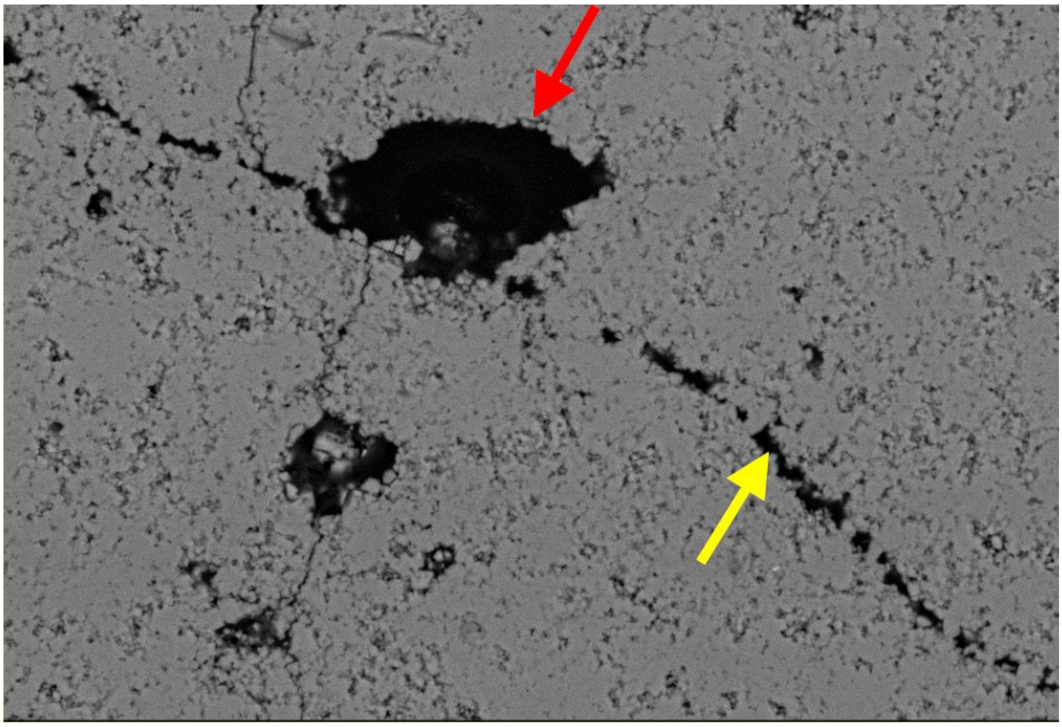
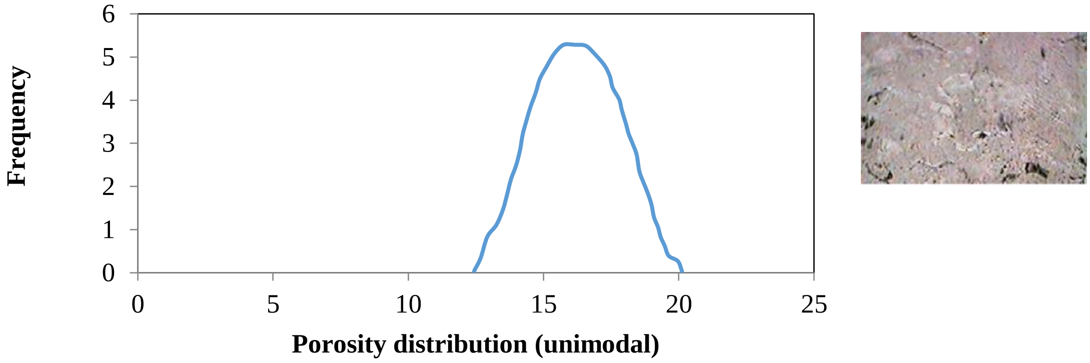


Figure 6
The porosity is relatively high and made up by molds (red arrow), and incompletely healed microfracture (yellow arrow).

a)



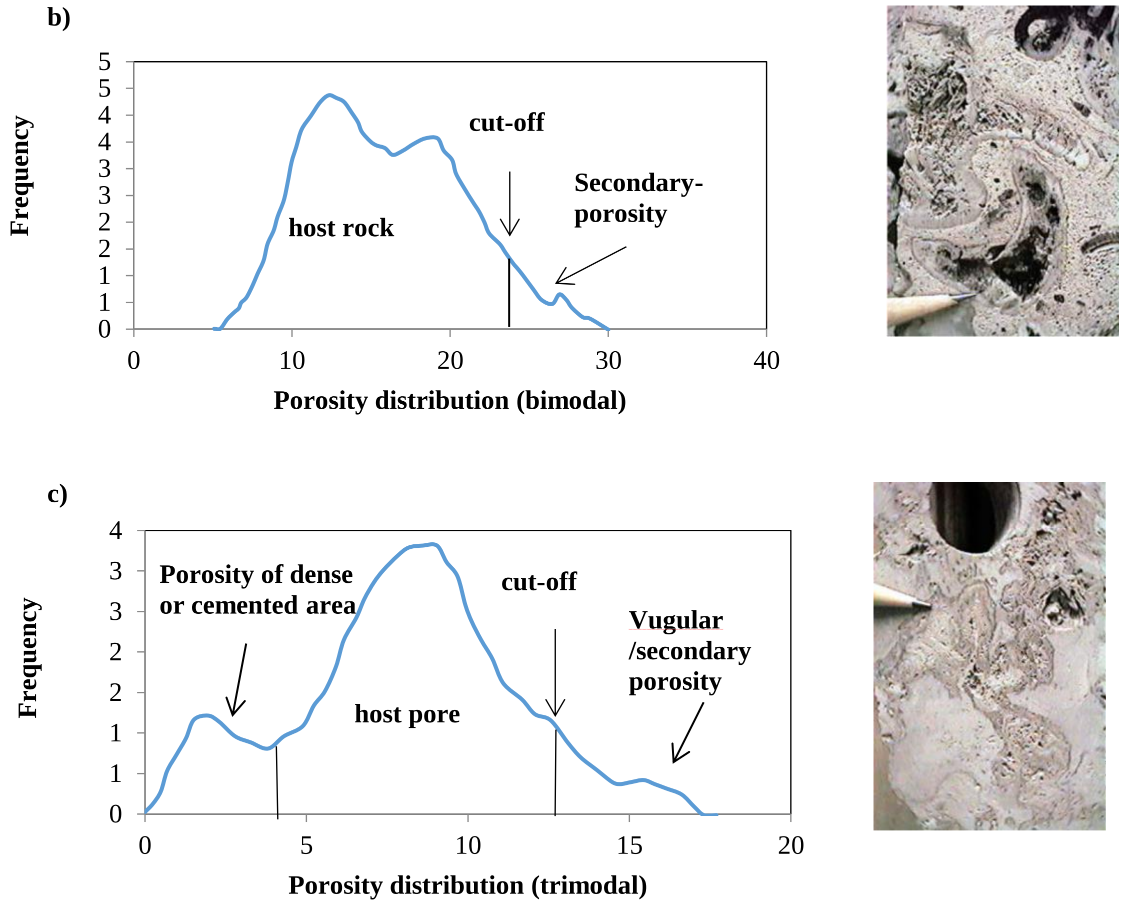


Figure 7
Typical FMI/FMS porosity histograms showing porosity distribution in homogenous and heterogeneous carbonates; unimodal distribution is found in homogenous carbonates (a); bimodal to trimodal distributions are found in heterogeneous carbonates (b and c).

Figure 8 displays porosity histograms, variable density log (VDL) along with FMS images. The porosity analysis revealed the presence of secondary porosity in most section of the reservoir. The porosity histogram shows that the upper section of the interval has a broad/skewed porosity distribution as a sign of more secondary porosity, which is mainly composed of vugs/molds. In the lower interval of Figure 7, the heterogeneity seems to be less, but an asymmetric porosity distribution is still visible. The secondary pores are also visible on the FMS display. The FMS images revealed varying amount of heterogeneity in the form of conductive and resistive (dense) areas across the whole interval. The conductive heterogeneities are due to porous areas (i.e. patches of intergranular and intercrystalline porosity, moldic/ vuggy porosity and, short discontinuous open fractures) of different sizes, shapes, and conductivities. The resistive heterogeneities are due to dense cemented areas of lower or zero porosity. As can be seen, no evidence of open fractures having a continuous conductive trace could be found in log data. The same results were obtained when investigating well test and seismic traces. Delving into the production logging data showed that secondary porosity intervals have the most contribution in production.

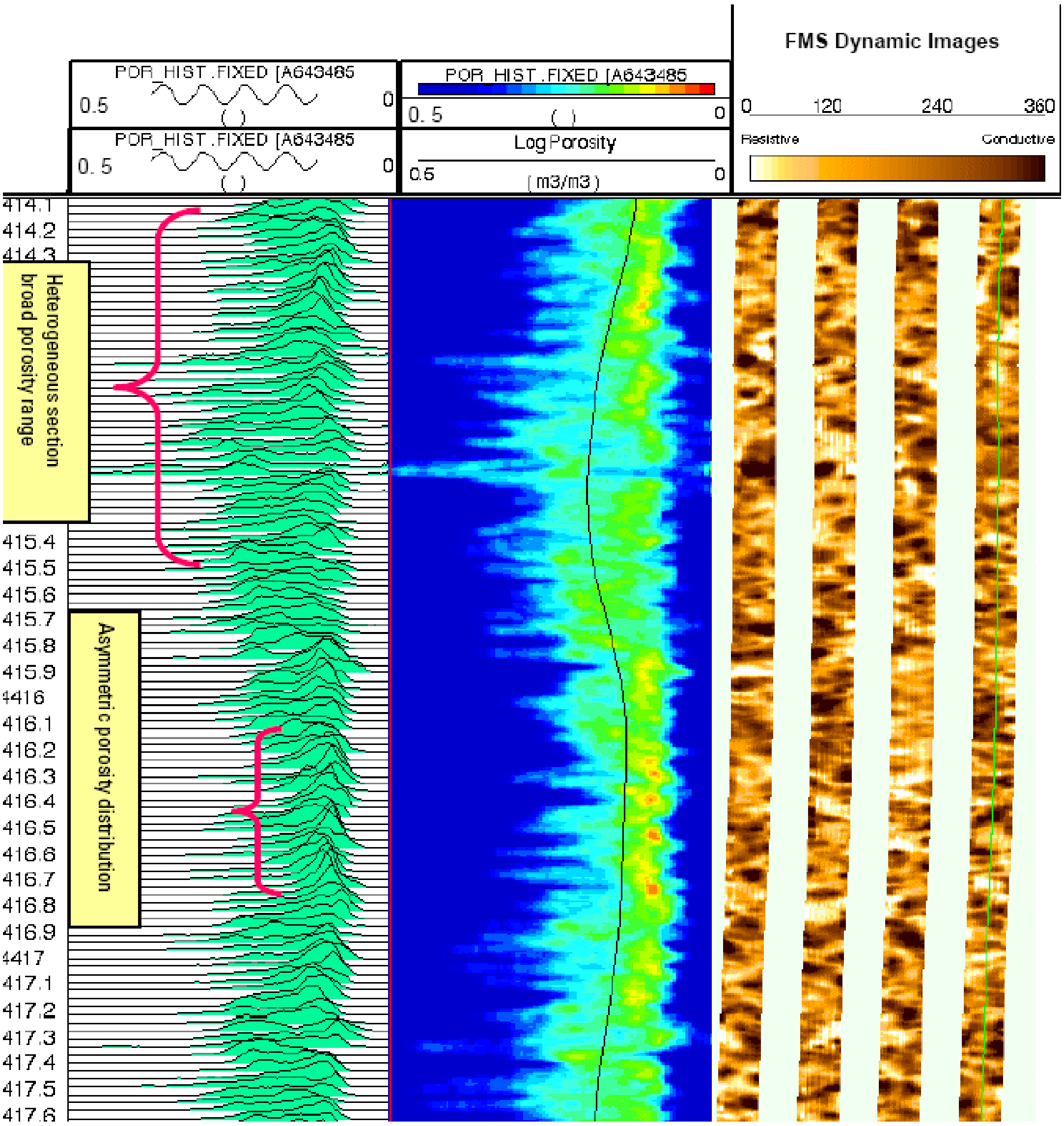


Figure 8
FMS porosity histograms and VDL (variable-density-log) display over a section showing heterogeneous (broad porosity range) and asymmetric porosity distribution.

Ghafoori (2009) went through the petrophysical log of this reservoir and concluded that there is a honeycomb pattern of secondary pores/channels in the dense host rock of this carbonate reservoir. They refer to the production logging data as the fact that the dissolution event caused by paleokarst has a positive effect on reservoir productivity. Most sections of layer C in DV field have heterogeneous trimodal porosity (as shown in Figure 8); layer B is fairly affected with this distribution, and layer A has the least porosity heterogeneity according to Schlumberger log interpretation.

2.3. Method of practical acidizing in DV oil field

Basically different techniques were used to introduce acid to the formation in DV oil field. Since the formation is deep (more than 4000 meters), the utilization of coil tubing is risky and all the acid is bullheaded to the well. In the early acidizing jobs, sequences of acid and viscous diverting agent

(VDA) were injected; supposedly, VDA should divert acid to less permeable intervals. In the later cases without using VDA, diversion pumping technique was practiced; acid injection rate was increased in several steps, and the well head pressure drop was checked in each step. If the pressure was stable at a constant injection rate, it means that the acid has lost its reactivity, and it is the end of pushing acid further into the formation. Latest jobs were performed by just delivering acid to the formation at a constant rate in order to remove the high skin evaluated from early well tests. Pumping is continued until displacing fluid fill up the wellbore and production tubing.

Acidizing campaign was performed in DV oil field, and the amount of fluid and the results of acidizing are shown in Table 1. For each well, completion status, producing layer, thickness of the formation, evaluated skin from well test, injecting fluid per meter, final pressure, and rate and amount of productivity index before and after acidizing are shown in Table 1. As can be seen, the amount of acid per meter of producing intervals are different, but comparing with categories mentioned with different authors, it is not a high volume acidizing (Sharaf, 2000, Halliburton, 1998, King, 1986).

Table 1

Matrix stimulation summary of wells in the field studied.

Well No.	Completion type	Production Layer	Exposed Thickness (m)	Skin	Acid/m (bbl/m)	VDA (bbl)	Final Pressure (psi)	Final Rate (bpm)	PI-pre (stbd/psi)	PI-post (stbd/psi)
xx5	Perf.	A.2	20	-	1.3	0	4200	0.5	-	0.1
xx5	Perf.	A.1,2	45	-	4.1	0	4160	6.4	0.1	7.5
x2	O.H.	B	110	7	1.9	0	3850	3.4	2.4	4.1
x6	S.L.	B	51	12	2.7	0	1750	4.5	2.6	6.0
x0	Perf.	B	43	0	4.2	0	-	-	1.5	2.6
x0	Perf.	B	43	-	4.7	0	2380	7.6	2.6	4.5
xx6	Perf.	B	40	13	5.0	0	2400	8.7	2.5	11.0
x07	O.H.	C.1,2,3	134	22	0.9	0	2810	4.0	8.0	9.1
x08	O.H.	C.1,2,3	173	35	1.7	0	1720	6.0	4.9	4.5*
xx2	S.L.	C.1,2,3	166	10	1.9	125.0	1450	6.0	3.0	14.0
xx9	Perf.	C.1,2	91	95	2.7	187.0	1490	4.7	2.4	15.0
x4	Perf.	C.1,2,3	98	40	2.9	187.0	1194	6.2	3.4	18.0
xxx1	Perf.	C.1,2	74	39	3.9	0	-	-	1.0	26.2
x5	Perf.	C.1,2	70	480	4.0	0	2500	7.0	1.3	41.0

* Well is nearby injector and, due to acidizing, its GOR increased from 2500 scf/stb to 7000 scf/stb.

The first job was performed on well xx5, which had not been able to produce any oil earlier. This well is the only well completed in layer A. Based on accurate petrophysical interpretation and MDT tests, this whole layer did not have significant mobility. However, it was in the contract of the developing company to complete at least one well in the most productive section of this layer. As a result, the well was completed in Layer A.2. However, after perforation, well head pressure dropped to zero and no oil could be produced. As shown in Figure 9, in early September 2011, the first job with hydrochloride acid of 15 percent concentration was performed. In this operation, the formation is first cleaned up by injecting 6 barrels of xylene, and then 26 barrels of acid was bullheaded to the formation. As tabulated in Table 1, with 1.3 barrels of acid per meter of formation at a maximum injection rate of 0.5 barrels per minute, diversion technique was used to make sure acid is exposed to all formation. However, as shown in Figure 9, the well production improved for a short period with 1000 bbl/day until asphaltene plugged the well at the end of September. After that, several asphaltene clean-ups with xylene were implemented, but the well could not produce oil for a long time before asphaltene plug it again. Second acidizing was performed after perforating a 25 meter new interval with weaker petrophysical and productivity properties. This time, 186 barrels or 4.1 barrels per meter of acid after 50 barrels of xylene was injected at maximum pumping horse power to inject at 4160 psi and 6.4 bpm the result was extraordinary. As shown in Figure 9, all production factors rocketed up. Well head pressure increased and at 3000 psi flowing well head pressure, and more than 10,000 bbls/day oil was produced. Asphaltene problem was tackled with escalated wellhead temperature, and the well productivity leapt from 0.1 to 7.5 stbd/psi.

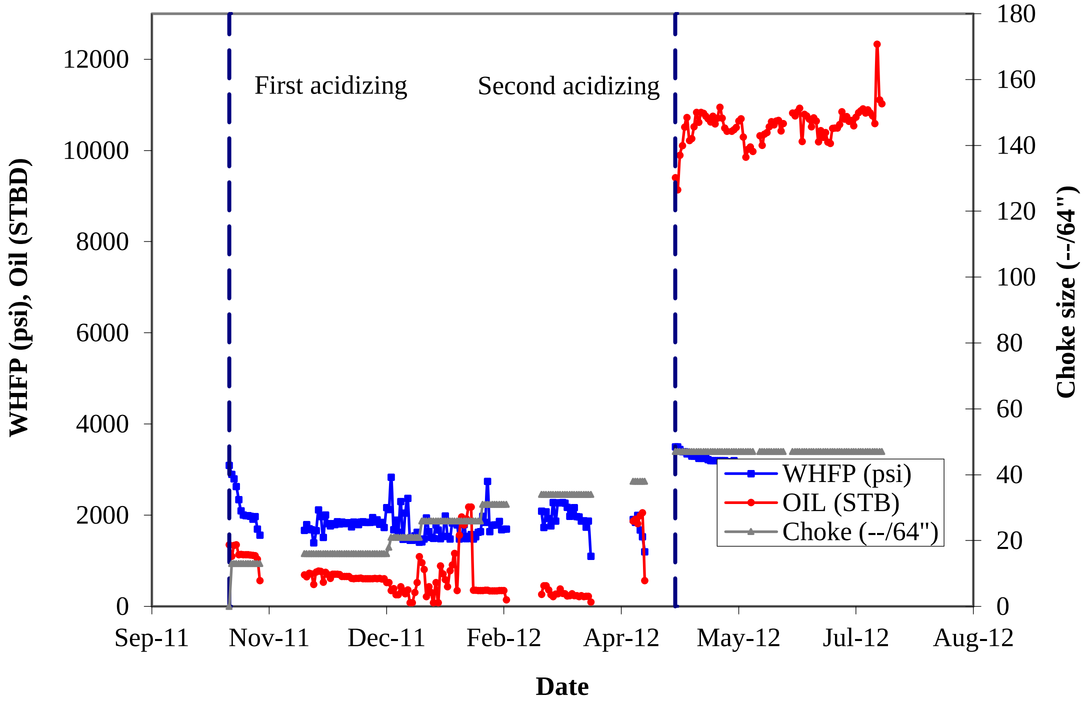


Figure 9
Wellxx5 completed in layer A, showing extensive improvement.

The productivity improvement was continued by acidizing wells in layer B as well. For example, well x0, as shown in Figure 10, had severe asphaltene precipitation problems, and it was required to perform asphaltene cleanup at least three times in a year. The well was acidized for the first time just before March 2010. As tabulated in Table 1, about 4.2 bbls/m 15% hydrochloride acid was injected, and productivity was improved from 1.5 to 2.6 stbd/psi. The well was returned to production at a well flowing pressure of more than 3000 psi and a rate of more than 1500 bbls/day. However, the problem of asphaltene plugging was not solved. One year later, the well was acidized for the second time with 4.7 bbls/m of acid at a higher injection rate of 7.6 bbls/m. As shown in Figure 10, after second acidizing, the well was producing continuously for more than a year with a daily production of more than 5000 bbls/day.

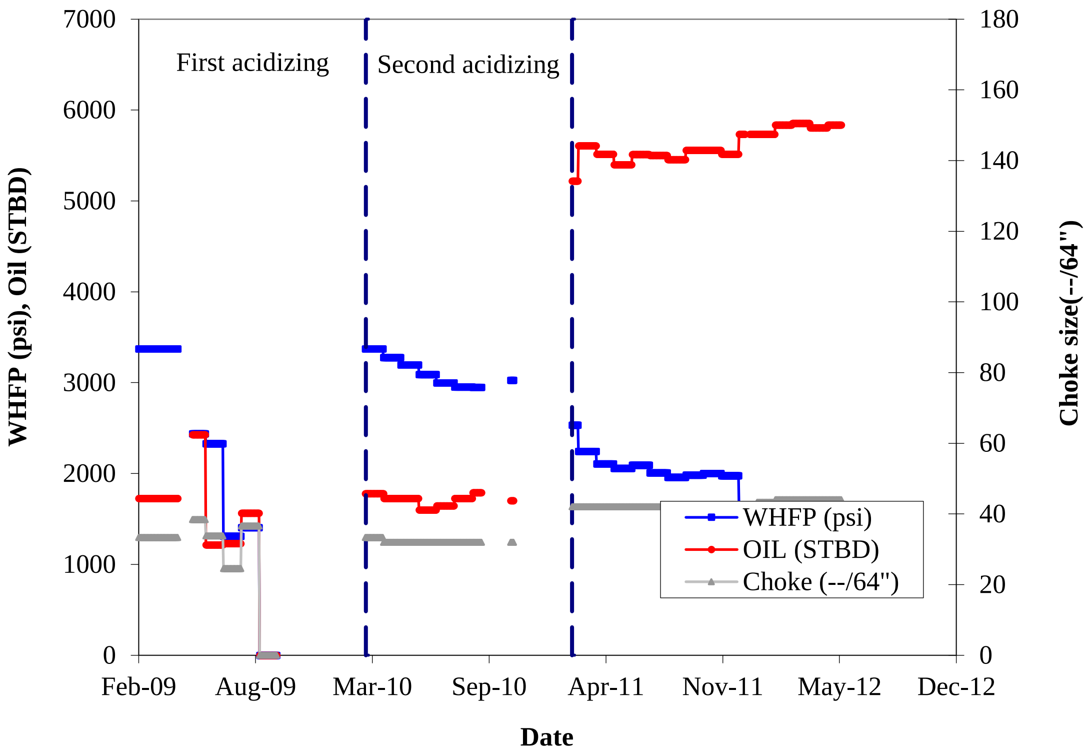


Figure 10
Well x0 completed in layer B; adding more acid resulted in higher improvement.

In layer C, the acidizing results were more conclusive. As shown in Table 1, only in three wells viscous diverting agent was utilized, but, in comparison with other jobs (without VDA), no comparable improvement was detected. Except in well x08, which is close to the gas injection wells, and its GOR increased from 2500 scf/stb to 7000 scf/stb due to acidizing, other wells had unexpected responses to acidizing. For instance, Well xxx1, as shown in Figure 11, was started producing from July 2009 with less than 2000 psi flowing well head pressure and about 2500 bbls/day oil production. The well was acidized in February 2011, and a massive production enhancement was achieved. The oil production leapt to 11,000 bbls/day for the flowing wellhead pressure less than 3000 psi. In all the other wells completed in layer C, the increment in productivity, as shown in Table 1, is obvious and in direct relationship with the amount of acid per meter of formation. It seems there is no limitation; the more the acid was injected, the more the productivity was achieved. If there was not any mechanical restraints, we could test the idea of some authors that carbonate acidizing treatments can be carried out at the highest rate possibly without fracturing the reservoir rock. In this case for this special field, more productivity improvement may be foretold. In Well x5, the well testing was carried out before and after stimulation. Pre-stimulation skin was calculated to be 480 and post stimulation skin was reduced to 7. Therefore, there is more room for improvement.

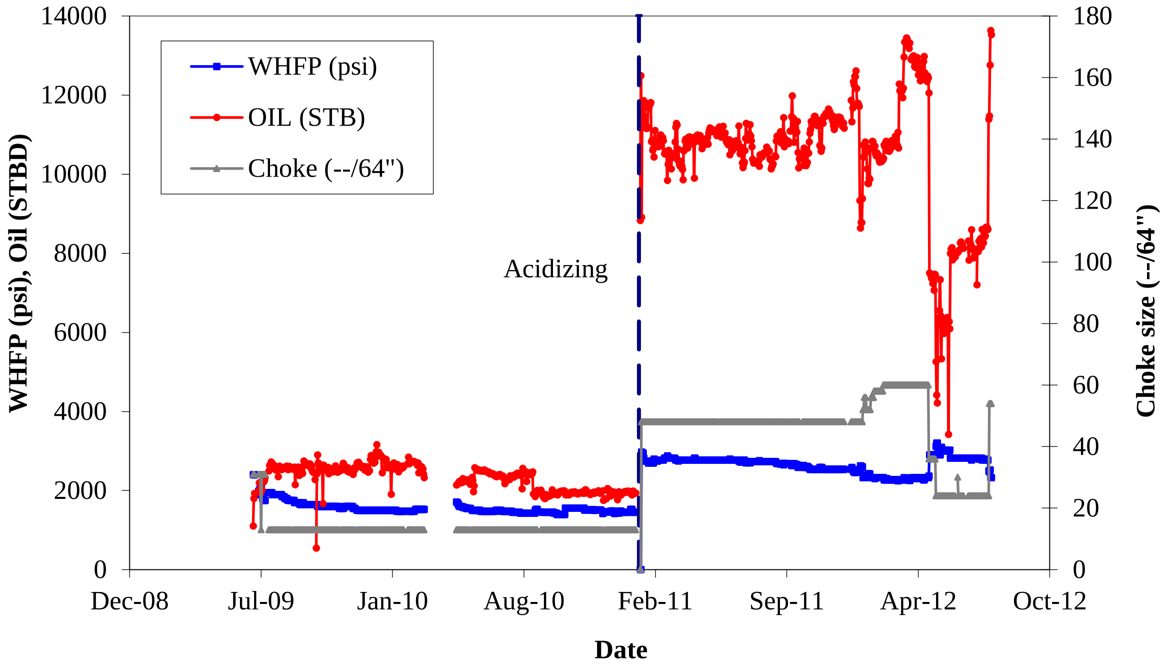


Figure 11

Well xxx1 completed in layer C produces a huge amount of oil after acidizing.

However, what is the reason for the high efficiency of acidizing and why do three layers have different responses to acidizing? As Tiab (2004) stated, the critical link between geological heterogeneity and reservoir performance is the key to understand a carbonate reservoir. Several studies from sedimentological deposition to microscopic samples have been conducted to find out the special features of this field.

2.4. Core stimulation experiment

Although it is not possible to provide a representative core from vuggy formation, some core plugs were prepared to perform acid flood experiment. Moreover, due to the highly heterogeneous nature of core, it was not possible to take long core plugs. First of all, batch test was performed on one core sample. One core was ground to powder and placed in a 15% HCl solution at room temperature, and the weight of the sample was measured continuously. The results were compared with a pure limestone sample, and a significant difference was not observed. Therefore, it was concluded that the reaction rate of reservoir rock was quite similar to pure limestone, and there was not any special composition in the mineralogy of the rock to make it different. Second, one acidizing setup was prepared to inject at a maximum pressure of 2500 psi and at an atmospheric backpressure. To start the experiment, core dimensions and porosity were measured. In order to have the in situ condition of the reservoir, the gasoil (diesel) was first injected to obtain the permeability of each core. Afterward, acid at different concentrations and injection rates was exposed to one face of the core, and the total volume injected was monitored until acid reached the other face of the core. The results are listed in Table 2. As revealed in this table, the experiment is repeated with acid concentrations of 10, 15, and

20% and at injection rates of 0.125, 0.25, and 0.5 cc/minute. In each set of the experiments, one core sample with its own porosity and heterogeneity was utilized.

Table 2
Acid injection experiments.

Length (mm)	41.45	43.15	41.85	40.35	43.15	43.8	46.4*
Diameter (mm)	37.45	37.44	37.3	37.4	37.44	37.1	37.2
Area (cm^2)	11	11	10.92	10.98	11	10.80	10.86
Porosity (%)	9.59	7.75	7.59	12.52	7.75	5.79	8.09
Permeability (mD)	0.215	0.5	0.4	0.69	0.5	0.283	1.16
Acid Type (Percent of HCl)	20	15	10	15	15	15	15
Injection Rate (cc/min)	0.25	0.25	0.25	0.125	0.25	0.5	0.25
PV acid injected before Breakthrough	0.62	0.65	3.28	1.91	0.65	1.46	0.84
Volume acid injected before Breakthrough	2.65	2.39	11.38	10.61	2.39	4	3.46

*Core was saturated with asphaltene.

Since DV reservoir has the problem of asphaltene plugging in some wells, the acidizing experiment is performed on a core saturated with asphaltene components. However, no significant effect on acidizing performance was observed. In all the cases, the wormhole, as shown in Figure 1 was detected in both side of the core. Moreover, since the number of available cores were limited, it was not possible to repeat the experiments for more cases. Also, from these data, no conclusion can be drawn because the physical properties of the rock (mainly porosity distribution) are changing in each core. This is another special feature of vuggy carbonate rock that cannot provide two core samples with the same porosity distribution.

Figure 12
Wormholes in two sides of the core after acidizing with 15% HCl and at a rate of 0.125 cc/min.

Besides, the core plugs represent only the matrix section of the specimen, and spreading the result of the experiment to the whole producing formation cannot be quite accurate. However, considering the experimental results and high temperature and pressure conditions of the field, it was decided that the optimum acid concentration of 15% at an experimental rate of 0.25 cc/minute was more efficient than 20% or higher. This concentration with retarding additives should not have any risk of corrosion.

In total, effective acidizing in DV field has increased the reserve and resolved several production challenges. First of all, after acidizing, due to significant skin reduction, expected field plateau elongated. In Figure 13, the green curve is before stimulation and the red curve is the post stimulation field production. As seen, the acidizing improvement of the wells resulted in an extension of plateau for more than 3 years. Second, after acidizing, low pressure drop was exposed to the formation face to gain a high rate; as a result, the particle production was reduced saving longer performance of the surface oil treatment facilities. Third, when production of the well increased, surface flowing temperature was increased, and consequently the asphaltene plugging (or wax deposition) both in the tubing string and surface facilities were reduced (Hasanvand, 2015). In Figure 13, the prediction shows that the oil production of post-acidizing falls below pre-acidizing prediction in 2032, which is due to the reservoir pressure drop. In case of post-acidizing, more oil is extracted from the reservoir, and consequently, in comparison, slightly less production is expected.

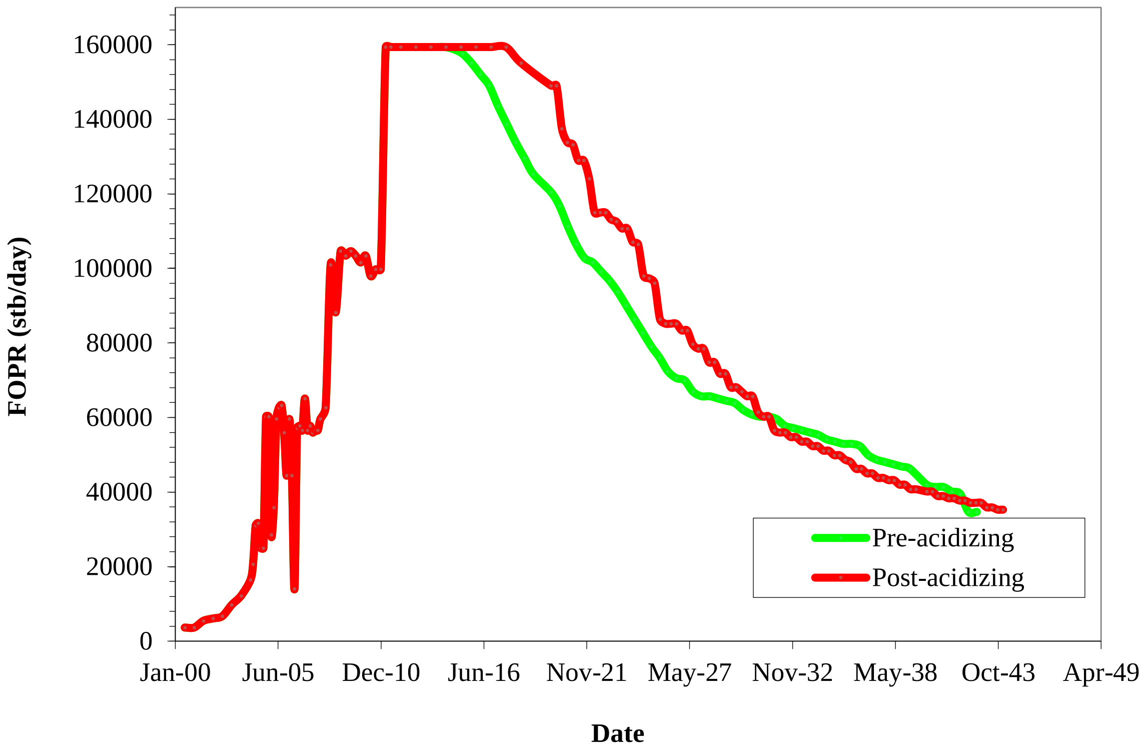


Figure 13
Production forecast before and after stimulation (from reservoir model).

There is also a drawback for acidizing in this special field. A well close to the gas injector was also acidized. The skin again reduced significantly, but, as a result, gas oil ratio increased dramatically. Thus, it is concluded that by acidizing high density vuggy carbonate, the chance of opening path between injector and producer is also augmented. Moreover, due to this increment, the operator must reduce the oil rate to prevent excessive gas production.

Frick et al. (1994) concluded that the effect of the high permeability formations would be the same as a high injection rate. In both cases, due to the development of several wormholes along the entire section, more volume of acid is required to penetrate to a certain diameter. In this studied case, the formation is highly vuggy and more acid is needed to penetrate deeper into the formation. The results of the experiments shown in Table 2 confirmed this statement. In the experiments, except for the case of 10 % hydrochloride acid, when the permeability or injection rate increases, the volume of acid to reach breakthrough will also increase. In field practices shown in Table 1 by increasing both acid volume per meter and acid injection rate productivity index was improved. The unique point about DV field case is that we could not find any limitation for improvement; in other words, the more the acid is injected, the more the improvement is achieved. It seems there is no limitation of improvement due to the percolation of vuggy porosity. Clason (1935) believed that fractures should be present for large acidizing improvement; however, in this case, fracture is not detected. Instead, abundant large pores like a honeycomb are detected Ghafoori (2009). When large pore sizes are available, as Wang (1993) stated, the first criteria for large effect of acidizing is then available. Since this presented case has lots of large pores, unlimited amount of wormholes will form if enough acid exposed.

As a result of acidizing campaign, the field plateau is elongated, and production challenges like particle production and asphaltene plugging are avoided.

3. Conclusions

Hydrochloride acidizing is an ordinary method of productivity enhancement in carbonate rock, but secondary porosity distribution as a main factor affecting formation performance should be emphasized. In DV reservoirs, a normal amount of hydrochloride acid is injected, and unexpected results are recorded. The full field study is performed, and the following conclusions are obtained:

1. A paleo karst phenomenon has distributed large pores in DV carbonate reservoir in such a high density analogous to honeycomb, which quantifies the production sharing.
2. The specific porosity distribution pattern (honeycomb pattern) caused high mechanical skin during drilling on the one hand, and helped with the percolation of the hydrochloride acid on the other hand, leading to large productivity improvement.
3. Practical results in DV oil reservoir show that by injecting a higher volume of acid higher well productivity is achieved. Since large pores are abundance, the exposure of more acid can induce further wormholes.
4. The acidizing increased the ultimate recovery of the field with existing wells and prolonged the production plateau. This will reduce the cost of field development, and it is worth characterizing the formation before finalizing field development plan. Furthermore, it has mitigated some production challenges like asphaltene (or wax) precipitation and particle production. This finding helped with reducing the cost and risk of well unplugging operations.

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Nomenclature

API	:American Petroleum Standard
bbls/day	:Barrels per day
bbls/m	:Barrels per meter
bpm	:Barrels per minute
cc/minute	:Cubic centimeter per minute
cm^2	:Square centimeter
DV field	:One oil field south west of Iran
FMS	:Formation Micro Scanner
HCL	:Hydrochloride acid
km	:Kilometer
m	:Meter
mD	:Milli Darcy
MDT	:Modular dynamic formation tester
mm	:Milli meter
psi	:Pound per square inch
STB	:Stock Tank Barrel
stbd/psi	:Stock barrels per day per pound per square inch
VDA	:Viscous diverting agent
VDL	:Variable density log
X-ray	:X-radiation

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