Introduction

Effective evaluation of reservoir efficiency is consistent with knowledge of reservoir history designation. As a new approach to reservoir management, local hazard zoning focused on geomechanical assessment, integrated fracture analysis, facies construction, reservoir development and pore pressure data could be implemented. This field study consists of round flat domestic structures created by rudest reef build-ups in the Middle Cretaceous-Mishrif formation in southern Iran. In this study, originally structural reconstruction analysis and lateral – vertical facies shifts are described using well findings and the connection between productivity factor and average permeability within wells, then the permeability variability in the drainage area is measured over a specific period of time for all manufacturing wells (19 wells). Thus, strain phenomenon is determined as a product of geomechanics (compaction analysis) based on permeability – strain empirical equations and finally, field-scale mapping was performed during the production phase, which is the basis for future strain frequency prediction. The key outcomes of this research are priority labelling of the threat zone, which enhances non-porous areas towards fractures and leads to increased permeable digenetic components, respectively, and emphasizes the importance of field classification based on results of strain maps to make the best decision for future field performance.

Method and Theory

The studied field is located in the Southern part of Iran and lies about 70 Km from the Iranian main land. Based on Alsharha et al. (Alsharhan & Salah, 1997) Studies, early and late cretaceous and mid tertiary diapiric movements are the most effective factors on reservoir characteristics of the salt-related oil fields. Salt-related oil fields area is characterized by Domal-shaped structures, independent closures, and parallel faults within the structures with the following trends: Sub circular, NNE-SSW and N-S Domal anticlines trends (Figure 1).

![Figure 1 Underground contour maps of some parts of this Field on Mishrif horizon.](image)

Variation of reservoir performance can be seen according to well testing data and productivity index trend. The average permeability of the reservoir around each drainage area can be estimated by measuring the pressure response at the bottom hole or well head during the test and shut-in period. The pressure variation related to the changes in fluid and rock properties that affected the stress/strain over the reservoir can lead to altering basic reservoir properties. The average reservoir pressure can be calculated by transient pressure well testing analysis and high-risk hazard regions will be recognized by comparison of permeability maps in different periods. Having built up or fallen off test, permeability variation trend can be obtained. Build up/Fall off tests in two periods of time (1977-1992) have been analyzed for obtaining permeability across drainage area for 19 wells. Flow equation indicated in equation 2 which is obtained from the diffusivity equation 1. All parameters in equation 2
are from field and laboratory data. The curve of $P_{ws}$ versus $(t_p + \Delta t)/\Delta t$ was plotted using equation 2 and equation 3 between 1977 and 1992 from well-testing information.

\[
\frac{1}{r} \left( \frac{\partial (\rho \phi c / \partial t)}{\partial r} \right) = \left( \frac{\mu c \phi}{k} \right) \frac{\partial (P_{ws} - P)}{\partial t}
\]

(1)

\[
P_{ws} = p_i - 162.2 \times (\frac{qB \mu}{kh}) \times \log((t_p + \Delta t) / \Delta t)
\]

(2)

\[
J = \frac{P_I}{Q} = \frac{(P - P)}{P - P}
\]

(3)

\[
K_h = 162.6 \times (\frac{qB \mu}{m})
\]

(4)

\[
\frac{k}{k_o} = \left[1 + \frac{(\varepsilon / f)}{3} \right] \times \left[1 + \varepsilon \right]
\]

(5)

\[
\phi = \phi^0 + \alpha(\varepsilon_v - \varepsilon_v^0) + \frac{1}{Q} \times (p - p^0)
\]

(6)

\[
k = \left[\frac{\phi^3}{(1 - \phi^3)} \right] \times \left[1 / (F \tau S_g) \right]
\]

(7)

In equation 4, $m$ is the slope of the Horner plot curve in buildup test for production wells and slope of the curve in fall off test for injection wells. There are different empirical equations for permeability and volumetric strain relation, predominant equation (Tortike & Ali, 1993; Wang & Xue, 2002) is as equation 5. Equation 6 and equation 7 (Kozeny-Carmen Equation) can be used to calculate porosity and permeability of the second state reservoir. Considering an isotropic linear elastic analysis, the porosity equation for full coupling scheme is written as equation 6 (Li, C. Zienkiewicz, & Xie, 1990).

As it is obvious, an equation of volumetric strain is cubic, so it has 3 different responses. Two of them are complex and only one is real. So the volumetric strain curve is not linear. This issue is justified from equation 5 which can be the basis of future reservoir geomechanics. It prospects that volumetric strain is negative regarding permeability decreases. Volumetric strain changes are a function of length variation over a premier length which is obtained according to structural geology. From reservoir geology and rock laboratory studies point of view, length variation is considered equal to oil layer thickness and assumption of negligible expansion of rock and fluid is not far away from reality.

Examples

Build up testing has been done for gathering reservoir data in the early life cycle of field’s development. Build-up test has been done for production and the fall-off tests were done for injection wells. From productivity index, permeability over drainage area of each well was calculated according to the curve of semilog $P_{ws}$ versus $(t_p + \Delta t)/\Delta t$ (slop curve is in psi/cycle).

By introducing the fluid characterization, we found that permeability reduction is not due to skin’s fluid compositions challenges. In addition, sand production was not observed in all wells during the reservoir producing life cycle. However, PI decreasing is justifiable with some parameters such as Pressure change, skin, well completion and other dynamic parameters. But decreasing of permeability can lead to a geomechanical challenge in case of pore pressure variation. After 15 years, well testing was performed again. The curve of semilog $P_{ws}$ versus $(tp + \Delta t)/\Delta t$ plotted for new well-test data (build-up test for production wells and fall-off test for injection wells).

Three regions are calculated by volumetric strain trend. The first region is a high volumetric strain rate area (Region a), the second area has a medium volumetric strain rate (Region b) and the third one shows a low volumetric strain level (Region c). Figure 2-a represents these three regions. These regions are distinguished by the permeability reduction. Reservoir permeability variation and state of porous media can be good evidence for heterogeneous performance in reservoir life cycle according to geomechanical effects. Reducing the trend of permeability is not same in different areas. Furthermore, 19 wells of volumetric strain drainage are calculated from equation 5. For volumetric strain modelling, the first 3D geomechanical model should be built and then volumetric strain map in different wells around its drainage area interpolated by geostatistical methods (Figure 2-b). This map can be a good indication of field scale reservoir compaction, and it can also be the basis of future reservoir operation strategies such as Production/injection well placement and IOR/EOR.
Three different areas on the strain map are divided based on initial permeability, the amount of permeability reduction and permeability reduction ratio (permeability modulus) are as follow:

Region a; high-risk hazard zone: in some parts of the reservoir, strain map indicates severe compaction which must be prioritized for reservoir characterization improvement. Considering acidizing job can be good reasons for sharp variation in the reservoir. It is noticeable that 19 wells drainage area are diminishing in the secondary well testing. Permeability reduction and permeability modulus are high (more than 7) and generally initial permeability is good.

Region b; medium risk hazard zone: In comparison to the region (a), this area has a mediocre risk hazard compaction over depletion history. Medium compaction, middle fracture network density, being far from faults rather than previous region and poor connection between vuggy and caves network are good reasons for lower compaction. Reservoir compaction in chalks filling fractured network is medium. These regions generally have good initial permeability, medium permeability reduction and medium permeability modulus (between 3 and 7).

Region c; low-risk hazard zone: these areas almost have a poor/fine fracture network, initial well porous media and disconnect vuggs and caves network. less acidizing job in this region can be lower skin indication around each well. So this area has a minimum priority for preserving reservoir compaction. These regions generally have low initial permeability, low permeability reduction and low permeability ratio (between 1 and 3).

Based on core and seismic fracture studies totally 4 types of fractures are classified as High Open Fracture Network (HOFN), High Partially Open Fracture Network (HPOFN), High Close Fracture Network (HCFN) and Rarely Close Fracture (RCF). Acoustic impedance studies showed a well porous media condition in the crest of anticlines and toward the saddle. It is expected to
increase reservoir compaction with incremental of porous media status. Adaption of acoustic impedance map is compatible with resulted strain map and subsequently reservoir regional compaction. By increasing rock density, the compaction has become lower and vice versa (Figure 4). Table 1 shows the final results of this study.

<table>
<thead>
<tr>
<th>Regions</th>
<th>Wells</th>
<th>Distance from Major Fault [m]</th>
<th>Fracture Impress/vuggy and cave</th>
<th>High rock density</th>
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<tbody>
<tr>
<td>Region a</td>
<td>D9</td>
<td>Toward Saddle</td>
<td>HOFN* + Vuggy</td>
<td>Porous Area</td>
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<td></td>
<td>D3</td>
<td>140</td>
<td>HOFN + Vuggy</td>
<td>Porous Area</td>
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<td></td>
<td>D8</td>
<td>560</td>
<td>HOFN + Vuggy</td>
<td>Porous Area</td>
</tr>
<tr>
<td></td>
<td>E1</td>
<td>310</td>
<td>HOFN + Vuggy</td>
<td>Porous Area</td>
</tr>
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<td></td>
<td>A4</td>
<td>280 (B T.F)</td>
<td>HOFN + Vuggy</td>
<td>Porous Area</td>
</tr>
<tr>
<td>Region b</td>
<td>A5</td>
<td>46</td>
<td>HOFN + Vuggy</td>
<td>Porous Area</td>
</tr>
<tr>
<td></td>
<td>D4</td>
<td>250 (B T.F)</td>
<td>HPOFN + Rarely Vuggy&amp; Cave</td>
<td>Transition Area</td>
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<tr>
<td></td>
<td>B4</td>
<td>93 FEP</td>
<td>HPOFN + Rarely Vuggy&amp; Cave</td>
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<td>20 FEP</td>
<td>HPOFN + Rarely Vuggy&amp; Cave</td>
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<td></td>
<td>F14</td>
<td>1590</td>
<td>HCFN + Disconnect Vuggy</td>
<td>Non-Porous Area</td>
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<td>A2</td>
<td>238</td>
<td>HCFN + Disconnect Vuggy</td>
<td>Transition Area</td>
</tr>
<tr>
<td></td>
<td>A6</td>
<td>500</td>
<td>HPOFN + Rarely Vuggy&amp; Cave</td>
<td>Transition Area</td>
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<tr>
<td></td>
<td>B3</td>
<td>Cross Fault</td>
<td>HCFN + Disconnect Vuggy</td>
<td>Non-Porous Area</td>
</tr>
<tr>
<td>Region c</td>
<td>F3</td>
<td>735</td>
<td>RCF + Without Vuggy&amp; Cave</td>
<td>Non-Porous Area</td>
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<tr>
<td></td>
<td>E2</td>
<td>500</td>
<td>RCF + Without Vuggy&amp; Cave</td>
<td>Non-Porous Area</td>
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<td>F12</td>
<td>400 FEP</td>
<td>RCF + Without Vuggy&amp; Cave</td>
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<td>F13</td>
<td>253 FEP</td>
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</table>

Conclusions

Investigation of Field-scale reservoir compaction as a reservoir Geomechanical studies can be the main factor for reservoir management decision making. Well test data can be a good indication for actual reservoir condition. In this article, permeability is obtained by interpretation of buildup and fall off test around 19 wells and then by introducing an empirical equation for obtaining volumetric strain. Regional risk hazard zonation was the classified basis of permeability reduction ratio, calculated volumetric strain and amount of permeability reduction. The main factors that exacerbated reservoir compactions are; distance to fault, fractures network status, vuggy and caves and initial porous media condition. Depiction of the strain map indicated that all reservoir regions have not the same behaviour over reservoir depletion, so compaction in different reservoir areas will be heterogeneous and strain map shows this matter obviously.

References