Petrophysical properties analysis of a carbonate reservoir with natural fractures and vugs using X-ray computed tomography.
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  1. Permeability porosity analysis
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Introduction

• Compared with siliciclastic rock, the diversity of the pore type and structure in carbonate reservoirs makes the petrophysical and fluid flow properties complex.
• Describing the pore type and structure is very important for petrophysical properties analysis.
• Disadvantages of other methods (Intrusive mercury curve method, thin section identification, SEM)
  – Core sample will be destroyed
  – Core experiments in lab needed (time-consuming)
Introduction

• Literature Review
  – Flow behavior/distribution
    • Combined Use of X-ray CT scan and local resistivity measurements: a new approach to fluid distribution description in cores (Durand, 2003)
    • Analysis of multiphase flow behavior in Vugular carbonates using X-ray CT scanning (Olivier et al., 2005)
    • X-ray CT Based numerical analysis for fluid flows through vuggy carbonate cores (Kusanagi et al., 2014)
Introduction

• Literature Review

  – Porosity

    • X-ray CT evaluation of poorly consolidated, thin-bedded core. (Brancolini et al., 1995)
    • Use of X-ray CT to measure pore volume compressibility of Shaybah carbonates (Siddiqui et al., 2010)
    • An X-ray CT study of multidimensional imbibition in dual porosity carbonates (Alshehri and Kovscek, 2012)
Introduction

• Literature Review
  – Relative Permeability
    • Application of X-ray CT scanning to determine gas/water relative permeabilities (MacAllister et al., 1993)
    • Analysis of the effect of residual oil on particle trapping during produced-water reinjection using X-ray tomography (Saraf et al., 2010)
  – Others
    • An experimental study of miscible displacements in heterogeneous carbonate cores using X-ray CT (Hicks et al., 1994)
    • Carbonate petrophysical properties: computed tomography (CT) for experimental WAG Design under reservoir conditions. In: Offshore Technology Conference Brazil (Laboissiere et al., 2013)
Introduction

- Few studies applied X-ray CT to carbonate reservoirs with both fractures and vugs.
- This paper will investigate the different effects of fractures and vugs on the petrophysical properties with X-ray CT.
X-ray CT

• A CT scan makes use of computer-processed combinations of many X-ray images taken from different angles to produce cross-sectional images of specific areas of a scanned object.

• To see inside the object without cutting
X-ray CT

- Beer’s Law (比爾定律)
  \[ I = I_0 e^{-\int \mu(s) ds} \]

  I : Transmitted intensity (穿透強度)
  I_0: Incident beam intensity (入射光束強度)
  s: Ray path (射線路徑)
  \( \mu(s) \): Local linear attenuation coefficient (局部線性衰減係數)
- \( \mu \) is dependent on the density.
X-ray CT

- CT number: defined to quantitatively evaluate the attenuation of X-rays in the transmitting material

\[
\text{CTN} = \frac{\mu_{\text{Matrix}} - \mu_{\text{Water}}}{\mu_{\text{Water}}} \times 1000
\]

\(\mu\) : linear X-ray attenuation

\(\mu_{\text{water}}\): linear X-ray attenuation when core sample is full of water

- Define: Air = -1000, Water = 0
- Higher \(\mu\) → Higher density → Larger CTN
Y field

- There are two formations:
  - S formation
    - 191 core samples (3 wells)
    - more fracture
  - F formation
    - more vugs

Fig. 3. The number of matrix, fractured and vuggy core samples.
X-ray CT images

- Three different core types: matrix, fractured, vuggy

(a) Matrix sample  
(b) Fractured sample  
(c) Vuggy sample

Homogeneous High density  
Lineal or stripy deep region  
Dark blocks
X-ray CT images

• Diameter of the scanned core sample: 38mm
• CT images:
  8 cross-section images (8個橫切面影像)
  2 longitudinal-section (2個縱切面影像)
  Neighboring cross-section images distance: 6mm
• Images consists of 512*512 pixels (Each pixel is 0.2*0.2 mm)
• Grey scale: 0(dark)~255(bright)
Measuring Method

- The porosity and permeability of all of the core samples were measured in the laboratory.
- Equipment: Auto Pore III-9420

<table>
<thead>
<tr>
<th>Porosity</th>
<th>How to measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ultraporosimeter</td>
<td>Using Helium injection. Pore volume is calculated from Helium expansion using Boyle’s law.</td>
</tr>
<tr>
<td>Air Permeability</td>
<td>Ultrapermeameter. Darcy’s equation is applied to calculate air permeability from the measured air flow rate and upstream and downstream pressures.</td>
</tr>
</tbody>
</table>
The permeability-porosity relationship in the carbonate reservoir is poor due to the existence of fractures and vugs.

Fig. 4. The porosity and permeability of all of the core samples in the S formation.
Fracture density
Fracture width
Fracture orientation

**Abstract**

**Introduction**

**Methodology**

**Results and Discussions**

**Conclusions**

**Future Works**

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Fig. 5. The porosity and permeability of all of the core samples in the S formation.
• Measured porosity v.s CTN

\[ \phi = -0.0324 \times CTN + 85.296 \]

• Only valid for pure limestone without other minerals

\[ \sigma = \sqrt{\frac{\sum_{i=1}^{n} (CTN_i - \overline{CTN})^2}{n}} \]

Fig. 6. The porosity and CT number of all of the core samples in the A1 well.
Fig. 6. The porosity and CT number of all of the core samples in the A1 well.

(c) $\sigma=68.27$

(d) $\sigma=156.583$
Fig. 8. The distribution of the CT number standard deviation.
Stress sensitivity analysis

• The permeability of the carbonate core samples is sensitive to the change in confining stress.

• The stress sensitivity of permeability depends on the pore type, structure and distribution.
Fig. 9. Permeability stress sensitivity in the S formation.

(b) 94H \( K = 1.1 \text{mD}; \ \phi = 12.15\% \)

(h) 183H \( K = 2.901 \text{mD}; \ \phi = 11.05\% \)
Porosity vs. Stress

This graph compares porosity to stress levels. The data shows the following:

- **Porosity vs. Stress**
  - (d) 264H K=16.102mD; φ=14.55%
  - (e) 274H K=1.622mD; φ=14.52%
  - (g) 333H K=5.005mD; φ=15.31%

The charts indicate differences in porosity across various stress levels, with specific percentages provided for each condition.
Fig. 11. The porosity stress sensitivity in the F formation.

Fig. 13. The permeability stress sensitivity in the F formation.
Oil-gas relative permeability analysis

- Oil-gas relative permeability: measured in lab (unsteady state method)

  Be saturated by water that had the same salinity as the reservoir formation water

  Be flooded with crude oil until no water was produced

  Be aged in an incubator for 30 days under reaching the reservoir temperature and pressure

- Then, gas was injected to measure the oil and gas relative permeability as a function of gas saturation with the JBN method (Johnson, Bossler, Naumann, 1958).
Fig. 15. The measured oil–gas relative permeability curve of core samples.

Fig. 17. The measured oil–gas relative permeability curve of fractured core sample.

Fig. 19. The measured oil–gas relative permeability curve of vuggy core samples.

Matrix
Average
Maximum=35%

Fractured
Average
Maximum<25%

Vuggy
Average
Maximum=29%
1. Compared with the fractured and vuggy core samples, the matrix carbonate core samples show a strong permeability-porosity relationship.

2. A fitting formula for calculating the porosity with the CT number was determined.

3. The standard deviation of the CT number can reflect the heterogeneity inside of the core, and the large standard deviation of the CT number indicates serious heterogeneity in the core.
4. The permeability of fractured samples are more sensitive to high net confining stress compared with the matrix and vuggy samples.

5. The porosity of vuggy samples are more sensitive to high net confining stress.

6. Fractures are unfavourable to gas injection in carbonate reservoirs, as the oil recovery efficiency is low due to gas channeling.
Current and Future Works
Current and Future Works
Current and Future Works

• Learn the software of image processing
• Find the best resolution of the sample
• Search for my research topic
Thank you 😊
Equipment of Experiment

- Auto Pore III-9420
- A kind of mercury porosimeter (壓汞儀)
- Pore size, specific surface area, bulk density, apparent density, porosity, particle distribution and related properties for powder or porous materials.
CT number and Grey Value

- Human tissues' CT values are divided into 2000 units.
- A person's eyes can distinguish 16 shades of gray.
  - Example: $\frac{2000}{16} = 125$ HU
  - (CT value difference less than 125 HU cannot be distinguished by the human eye)
- Window Width: CT value range must be observed in segments.
  - Window Width = 100 HU, the CT value that can be distinguished is $\frac{100}{16} = 6.25$ HU
    - → Window narrow → contrast strong, suitable for observing objects with similar density
  - Window Width = 200 HU, the CT value that can be distinguished is $\frac{200}{16} = 12.5$ HU
    - → Window wide → contrast weak, suitable for observing objects with large density differences
- Window Width's narrowness directly affects image clarity and contrast.

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毫達西(mD)

- 滲透率同時也代表流體在岩層中流動難易程度的指標，其與流體之特性無關，而與孔隙大小、分布及連通的程度有關。
- 滲透率的單位一般稱為達西(Darcy)，其定義為黏度1厘泊(Centipoise, cp)之流體，在差壓1大氣壓下，以每秒1立方公分的流率，流經長度1公分、截面積1平方公分之孔隙介質，由於以達西為單位來度量滲透率的大小，有時其度量單位過於龐大，故常用毫達西(mini-Darcy或mD)進行度量，大小為達西之千分之1

- $1\text{ cP} = 10^{-3}\text{ Pa}\cdot\text{s} = 1\text{ mPa}\cdot\text{s}$
Enhanced Oil Recovery (EOR)

Primary Recovery
- The natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface.
- Only about 10% of a reservoir's original oil in place is produced.

Secondary Recovery
- Inject water or gas to displace oil and drive it to a production wellbore
- The recovery of 20-40% of the original oil in place.

Tertiary Recovery
- Thermal recovery
- Gas injection
- Chemical injection

Enhanced Oil Recovery (EOR)

- Use gases such as natural gas, nitrogen, or carbon dioxide ($\text{CO}_2$) that expand in a reservoir to push additional oil to a production wellbore, or other gases that dissolve in the oil to lower its viscosity and improves its flow rate.
- Gas injection accounts for nearly 60 percent of EOR production in the United States.

The JBN method provides a convenient means for calculating the relative permeability curves from oil production and total fluid production data.

The method also requires other data such as the measured flow rates of each fluid and the pressure drop across the core sample or sand-pack.