Model to Predict Tight-gas Sands Porosity of West Depression in Liaohe Basin, China*

Wei Wei¹, Xiaomin Zhu¹, and Yuanlin Meng²

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Abstract

The Eocene–Oligocene Es3 member of the Shahejie Formation in our study area is a feldspathic, debris-rich and tight gas sandstone reservoir (porosity 2.4–10.4%, permeability 0.09 - 0.38 md), a consequence of depositional attributes (grain composition, size and sorting) acted upon by diagenesis (significant mechanical and chemical compaction, precipitation of carbonate cements and authigenic clays, and deep-burial cementation by quartz) throughout the time. Considering these parameters, a comprehensive porosity prediction model is developed based on the correlation between sedimentary facies and diagenesis. The result could also provide for the exploration of other tight gas reservoir. Based on the analyses of sedimentology and petrography data of 80 cored wells, the study investigated the distribution and influences of porosity, established a model by the following steps:

1. Diagenesis index (ID) was established integrating with temperature, Ro, quartz overgrowth, I/S, depth, and its relationship with sandstone porosity was determined to build the exponential porosity model.
2. Sedimentary facies index (IF), which was higher in the advantageous sedimentary facies, was calculated by the distribution of porosities in different sedimentary facies during each diagenetic stage.
3. The ultimate porosity model based on the relationship between the exponential porosity model and sedimentary facies (IF) was developed since the porosity was the cumulative effects of sedimentary facies and diagenesis.

This improved model can also restructure the evolving history of the reservoir aside from predicting present porosity. The improved model was applied to 16 wells from slope to sag throughout the field. A comparison of predicted and measured porosities showed 1.84% average absolute error with the pore filling of 16%. This indicates the model may be used elsewhere to predict porosities. The results show that porosity decreased sharply by compaction during the early diagenetic stage. In addition, secondary porosity developed in the middle diagenetic stage A1-A2 and the reservoir became tighter with the continuous compaction alongside with quartz and carbonate cement. The reservoir in the middle diagenetic stage A1 can be described as conventional and stage A2 unconventional.
ABSTRACT

The Eocene–Oligocene Es3 member of Shahejie formation in our study area is a feldspatic, debris-rich and tight gas sandstone reservoir (porosity 2.4-10.4%, permeability 0.09 -0.38 md), a consequence of depositional attributes (grain composition, size and sorting) acted upon by diagenesis (significant mechanical and chemical compaction, precipitation of carbonate cements and authigenic clays, and deep-burial cementation by quartz) throughout the time. Considering these impacts, a comprehensive porosity prediction model is developed based on the correlation between sedimentary facies and diagenesis. The result could also provide for the exploration of other tight gas reservoir.

Based on the analyses of sedimentology and petrography data of 80 cored wells, the study investigated the distribution and influences of porosity, established a model by the following steps:
1. Diagenesis index (ID) was established integrating with temperature, R0, quartz overgrowth, $\delta^{13}C$ and depth and its relationship with sandstone porosity was determined to build the exponential porosity model;
2. Sedimentary facies index (IF), which was higher in the advantageous sedimentary facies, was calculated by the distribution of porosities in different sedimentary facies during each diagenetic stage;
3. The ultimate porosity model based on the relationship between the exponential porosity model and sedimentary facies (IF) was developed since the porosity was the cumulative effects of sedimentary facies and diagenesis. This improved model can also restructure the evolving history of the reservoir aside from predicting present porosity.

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HIGHLIGHTS

- Build porosity model about diagenetic index, a function of $T$, $R_o$, $\delta^{13}C$, $\delta/S$ and $S$%;
- Build porosity model based on compaction curve of $z$ and sedimentary facies index (IF);
- Build final porosity model about diagenetic index (ID), $z$ and sedimentary facies index (IF);
- This model not only predicts present porosity, also reconstructs porosity history.

RESULTS

Porosity Model

Porosity model based on sedimentary

$$\phi_I = (IF \times 5.8 + 31.7) \times \exp (-0.0041324 \times z/IF)$$

Porosity model based on diagenesis

$$\phi_D = (IF \times 5.8 + 31.7) \times \exp (-3.1466 \times ID)$$

Improved porosity model:

$$\phi = 0.57 \times \phi_I + 0.44 \times \phi_D + 0.5$$

$$\phi = (IF \times 5.8 + 31.7) \times (0.57 \times \exp (-0.0041324 \times z/IF) + 0.44 \times \exp (-3.1466 \times ID) + 0.5)$$

Predicted Porosity

- burial depth $z$
- temperature $T$
- Diagenetic index $ID$
- Facies index $IF$

Reservoir porosity

Pore evolution and diagenetic history of Es33 reservoir sandstone from well Shuang3
Model to Predict Tight-gas Sands Porosity of West Depression in Liaohe Basin, China

Wei Wei¹, Xiaomin Zhu¹, Yuanlin Meng²
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2. Northeast Petroleum University, Daqing, Heilongjiang, China.

INTRODUCTION

The Liaohe Basin is located in northeast China, adjacent to Bohai Sea, and divided into several depressions such as Eastern and Western. The western depression contains Cenozoic lacustrine sediments deposited under varying water chemistries. The Eocene-Oligocene Shahejie Formation (Es) is of prime importance for petroleum exploration. Moreover, the difficulty of exploration in Shahejie Formation is increased by complex facies distributions and diagenetic alterations. In the tight sandstones, knowledge of the influence of sedimentology and paleogeography on the diagenetic patterns is also a key element for improved understanding and prediction of reservoir quality.

Significant progress has been made in recent years toward the successful application of models (e.g., Exemplar, Touchstone) to predict sandstone. However, these models are established on the basis of the sedimentary characteristics such as grain size and composition or diagenesis such as quartz overgrowth, overpressure, oil inhibition of quartz, and chlorite coatings.

RESEARCH METHOD

In this study, we have established an improved porosity model to predict porosity by analyzing the influences of sedimentation and diagenesis on porosity. Modeling processes are demonstrated as follows:

- Establish diagenesis index (ID) the function of temperature, Ab, quartz overgrowth, I/S, depth and time
- Calculate sedimentary facies index (IF) on the basis of the distribution of porosities in different sedimentary facies during eogenetic stage, and the value of IF is higher in the sedimentary facies with higher porosity
- Build the final porosity model based on the relationship between the exponential porosity function of ID and the compaction curve of IF and depth by the linear regression method
- This model could also reconstruct the porosity evolving history

GEOLOGIC SETTING

Liaohe basin is located in northeast China adjacent to the northeast of Bohai Sea (Fig. 1) and approximately 65 km in width and 470 km in length. Based on the structural position and the present distribution of oil and gas, the Liaohe Basin is subdivided into the Eastern Depression, the Damintun depression in the north, and the Western Depression. The southern part of the Western Depression is the main objective of this study.

Stratigraphic Column

The southern part of the Western Depression is the main objective of this study, which mainly contains Cenozoic sedimentary thickness of 3000-4000 m overlaying a Paleozoic carbonate platform (Fig. 2). Its Paleogene stratigraphic record consists of, in ascending order, Fangshenpao Fm. (Ef), Shahejie Fm. (Es) and Dongying Fm. (Ed)

Generalized stratigraphic column showing the lithology, tectonic history, sequences, sedimentary facies and source-reservoir-seal combination of the study area.
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Sedimentary Facies
Sublacustrine fans within Es3 are the most typical depositional system in a deep-water setting (Fig. 3).

Fig. 3

Depositional environment exerted an essential control on the composition (Fig. 4) and texture of the sandstones (Fig. 5), influencing subsequent diagenesis and quality.

Fig. 4  Fig. 5

Diagenetic Stage
The assessment of diagenetic level in Es3 reservoir was divided into eogenetic and mesogenetic stages (Table 2). The diagenetic strengthen increases with burial depth.

Diagenetic Modeling System (DMS)
Diagenetic Modeling System (DMS) is a software based on the Petromod-IES, originally developed by Dr. Meng Yuanlin, to realize the numerical simulation of diagenesis and diagenetic process. Based on the burial history reconstructing, the variations of paleogeotemperature (T), vitrinite reflectance (Rg), sterane isomerization index S/(C29 S+S+T), smectite content in I/S of clay mineral (S%) and authigenic quartz (Vq%) with geological time are simulated by the software DMS and are combined to establish diagenetic index (ID) to reflect the diagenetic strength:

\[ I_D = \frac{\sum_{i=1}^{n} P_i \times Q}{\text{max}Q} \]

Where, \( I_D \) is diagenetic index; \( n \) is the number of diagenetic parameter; \( n=5 \); \( Q \) is the calculated result of the (i)th diagenetic parameter, (i.e. \( T \)); \( \text{max}Q \) is the maximum value of the (i)th diagenetic parameter in the middle B diagenetic stage.

RESULTS
Reservoir Lithology
Es3 reservoir rocks are mostly lithic arkose with subordinate feldspatic litharenite and arkose (Fig. 6).

Fig. 6

Reservoir Porosity
Porosity tended to decrease with increasing depth and appeared to be depth controlled with three zones from top to bottom (Fig. 7).

Fig. 7

Table 2

<table>
<thead>
<tr>
<th>Reservoir Lithology</th>
<th>Characteristic</th>
<th>BC</th>
<th>DPBC</th>
<th>BRC</th>
<th>OF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lithology</td>
<td>Sandy</td>
<td>34.15(441)</td>
<td>25.7(35)</td>
<td>19.8</td>
<td>15.4</td>
</tr>
<tr>
<td>Rigid grain content</td>
<td>39.3(96)</td>
<td>19.8</td>
<td>15.8</td>
<td>12</td>
<td>8</td>
</tr>
<tr>
<td>Clay matrix</td>
<td>3.97(39)</td>
<td>6.6(67)</td>
<td>15.8(3)</td>
<td>/</td>
<td></td>
</tr>
<tr>
<td>Median grain diameter</td>
<td>1.96(1.3)</td>
<td>1.6(1.3)</td>
<td>3.3(1.2)</td>
<td>/</td>
<td></td>
</tr>
<tr>
<td>Sorting coefficient</td>
<td>1.65(1.74)</td>
<td>1.7(1.17)</td>
<td>1.78(1.8)</td>
<td>/</td>
<td></td>
</tr>
<tr>
<td>Porosity</td>
<td>1.6(1.2)</td>
<td>1.2(1.24)</td>
<td>15.3(1.24)</td>
<td>/</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;2250</td>
<td>20.7%</td>
</tr>
<tr>
<td>2250-3900</td>
<td>11.64%</td>
</tr>
<tr>
<td>&gt;3900</td>
<td>4.24%</td>
</tr>
</tbody>
</table>
DISCUSSION

Influence Factors of Porosity

Table 3. The average porosity of each sedimentary facies in each diagenetic stage.

<table>
<thead>
<tr>
<th>Diagenetic Stage</th>
<th>Sedimentary Facies</th>
<th>Average Porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eogenetic stage A</td>
<td>LFBC</td>
<td>20.15(2)/18.15-21.8</td>
</tr>
<tr>
<td></td>
<td>BIC</td>
<td>19.13/10.1-33.3</td>
</tr>
<tr>
<td></td>
<td>BC</td>
<td>24.7410/6.3-38.4</td>
</tr>
<tr>
<td>Eogenetic stage B</td>
<td>LFBC</td>
<td>22.3168/4.5-35.7</td>
</tr>
<tr>
<td></td>
<td>BIC</td>
<td>21.4124/4.1-34.1</td>
</tr>
<tr>
<td></td>
<td>OF</td>
<td>12(1)/12</td>
</tr>
<tr>
<td></td>
<td>SSL</td>
<td>7(1)/7</td>
</tr>
<tr>
<td>Mesogenetic stage A1</td>
<td>LFBC</td>
<td>13.9651/1.9-37.4</td>
</tr>
<tr>
<td></td>
<td>BIC</td>
<td>12.3452/7.2-20.9</td>
</tr>
<tr>
<td></td>
<td>OF</td>
<td>11.27510/8.3-26</td>
</tr>
<tr>
<td></td>
<td>SSL</td>
<td>5.434/9.5-7</td>
</tr>
<tr>
<td>Mesogenetic stage A2</td>
<td>LFBC</td>
<td>3.8124/2.2-6.4</td>
</tr>
<tr>
<td>Mesogenetic stage B</td>
<td>LFBC</td>
<td>4.113/2.4-5.8</td>
</tr>
</tbody>
</table>

The sedimentary facies index ($IF$) was established to quantify the influence of sedimentary facies:

$IF = \frac{\phi}{\phi_{max}}$

$IF$ of BC, LFBC, BIC, OF, SSL is 1, 0.9, 0.87, 0.48, 0.28.

Porosity Model Based on Sedimentary Facies

Primary porosity:

$\phi_1 = IF \times 5.8 + 31.7$

Porosity model about $IF$:

$\phi_{IF} = (IF \times 5.8 + 31.7) \times \exp(-0.000413124 \times z/IF)$

![Fig. 8](image)

Porosity Model Based on Diagenesis

Porosity model about $ID$

$\phi_{ID} = (IF \times 5.8 + 31.7) \times \exp(-3.1466 \times ID)$

![Fig. 9](image)

Improved porosity model

$\phi = 0.57 \times \phi_{IF} + 0.44 \times \phi_{ID} + 0.5$

$= (IF \times 5.8 + 31.7) \times \exp(-0.000413124 \times z/IF) + 0.44 \times \exp(-3.1466 \times ID) + 0.5$

![Fig. 10](image)

APPLICATION

Current Porosity Prediction

Porosity Evolution History

Fig. 11

Diagenetic Modeling System (DMS)

burial depth $z$

+ temperature $T$

+ Diagenetic index $ID$

Facies index $IF$

Reservoir porosity history

Reservoir porosity

Porosity evolution

Rapid decline: 30% to 43-39 Ma: 14%
Slow decline: 14% to 39-36 Ma: 8%
Stable decline: 8% to 36 Ma to present: 4.8%

CONCLUSION

1. The improved porosity model is established by using burial depth ($z$), diagenesis ($ID$) and sedimentary facies ($IF$).
2. The predicted porosity of Es33 decreases with increasing $ID$ from basin boundary to basin center.
3. Porosity evolution history of Es33 reservoir is divided into three stages: the rapid decline stage during deposition of Es33 and Es32 (30 - 14%), the slow decline stage during deposition of Es31 (14 - 8%), and the stable decline stage during the deposition of Neocene and Quaternary sediments (8 - 4.8%).
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- Build final porosity model about diagenetic index (ID), z and sedimentary facies index (IF);
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\[ \phi_s = (IF \times 5.8 + 31.7) \times \exp(-0.000413124 \times z/IF) \]
Porosity model based on diagenesis
\[ \phi_D = (IF \times 5.8 + 31.7) \times \exp(-3.1466 \times ID) \]
Improved porosity model:
\[ \phi = 0.57 \times \phi_s + 0.44 \times \phi_D + 0.5 \]
\[ \phi = (IF \times 5.8 + 31.7) \times (0.57 \times \exp(-0.000413124 \times z/IF) + 0.4 \times \exp(-3.1466 \times ID) + 0.5) \]

Current Porosity Prediction

Porosity Evolution History

Diagenetic Modeling System (DMS)

Burial depth z + Temperature T + Diagenetic index ID + Facies index IF

Reservoir porosity

Facies index IF kept constant during geological time

Porosity evolution
- Rapid decline 43-39 Ma 30% to 14%
- Slow decline 39-36 Ma 14% to 8%
- Stable decline 36 Ma to present 8% to 4.8%

CONTACT
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If you are interested in my work, if we have the same research, please contact me.