Classification and features of single-well flow units in a carbonate reservoir - Taking the NT oil field at the eastern edge of Pre-Caspian Basin as an example

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Abstract. Identifying the carbonate reservoirs has always been a challenge to geological exploration, while reasonable classification of flow units is the bottleneck in this exploitation. While taking the NT oil field at the eastern edge of Pre-Caspian Basin as an example, this paper proposes the classification of flow units into five categories based on previous flow-unit classification theory and actual oilfield features by using the pore throat radius at the mercury injection saturation of 35% as the main judging criterion. In this paper, the features of various flow units have also been analyzed. The type-I flow units, mainly found in dolomite and algal reef limestone reservoirs, have the highest production capacity. Given the existence of corrosion and dolomitization, they are mainly fracture-cave composite reservoirs or fracture pore reservoirs. As far as the type-I flow units are concerned, the flow index is > 1.42 for KT-I stratum and > 1.55 for KT-II stratum. The production capacity and reservoir quality of type-II-IV flow units would decline in turn. The type-V flow units are argillaceous limestone, with a very low production capacity and a flow index being 0.01-0.05 for KT-I and 0.03-0.05 for KT-II.

1. Introduction
From the perspective of microcosmic origin, these flow units constitute a rock mass with basically similar pore-throat properties determining the fluid flow and are much different from other units among porous media. As the diagenesis of carbonate reservoirs has a great influence on the type and growth characteristics of reservoir space, this study has classified the flow units from the perspective of microcosmic reservoir-space origin through the comprehensive use of research results on core, physical property analysis, capillary pressure, diagenesis, and sedimentary microfacies.

The classification of flow units is based on core analysis data, through which the calculation of R35 and its RQI and FZI can obtain the average FZI reflecting different flow units. When multiple flow units exist, the whole FZI distribution function will be the total contribution of single FZI distribution functions. The identification of single FZI functions (namely flow units) needs to break the whole FZI distribution down into different components. As a result, cluster analysis is needed.

The flow units relate to the distribution of sedimentary microfacies and diagenetic facies, but may not comply with the boundaries of sedimentary microfacies. The most important factor influencing the fluid flow is the geometric feature of pore throat, which is controlled by the mineral composition (type, position, and amount) and structure (size, shape and sorted behavior of granules) of rocks. Different combinations of these properties can lead to totally different fluid flow characteristics. Therefore, a
flow unit may contain different types of lithofacies with different sedimentary textures and mineral compositions.

By taking the NT oil field at the eastern edge of Pre-Caspian Basin as an example, this paper describes the method of classifying the flow units of carbonate reservoirs.

2. Regional profile
The NT oil field lies at the eastern edge of Pre-Caspian Basin, including two sets of carbonate strata, namely carboniferous KT-I and KT-II, with a MKT stratum about 300 m thick in between and 6000 m deep at most. The MKT is divided into two sets of strata consisting of 14 substrata, while the KT-I into 9 substrata and the KT-II into 6 substrata. After the sedimentation, the carbonate reservoirs on the target stratum experienced various diagenetic environments, multi-stages of diagenesis, as well as several tectonic activities. Due to the influence of multiple factors such as diagenetic epigenesis, structural fracturing and dissolution on reservoir space, the reservoirs are complexly distributed, strongly anisotropic and badly connected. Therefore, the research on flow units is of great importance to comprehensive reservoir evaluation while providing a basis for the development and adjustment of oilfield flooding. Especially, the correct identification of single-well flow units is the key of overall reasonable assessment of carbonate reservoirs.

3. Classification method of flow units

3.1. Pittman R35 model
R35 was proposed by using the relationships among porosity, air permeability and pore throat radius (at the mercury injection saturation of 35%). A mass of previous findings show that, R35 can reflect better the type of reservoir space and the seepage characteristics of carbonate reservoirs to promote better research on flow units (Amaefule, et al,1993; Ebank,1987; Hearn,et al,1984).

As R35 can reflect not only sedimentary and diagenetic environments but also flow behavior and reservoir performance, it has been widely accepted by geologists and reservoir engineers to calculate R35 through the combination of Winland model with core-related data or by directly using the capillary pressure curves. The flow units of reservoirs can be classified in accordance with the range of R35 variation.

Winland R35 model was only robust to the rocks in the form of pores and pore throats, which are intergranular pores related to rock texture (such as sandstone)(Fan, et al,2014; Liu,et al,2000; Wang,et al ,2010). But for those carbonatites containing not merely intergranular pores, Winland may not correctly evaluate the reservoir quality, so the modified Winland R35, namely Pittman model, can be used to calculate the carbonate reservoirs:

$$\log R_{35} = 0.255 + 0.565 \times \log k - 0.523 \times \log \phi_e$$

Where: $k$ is air permeability to the core, in mD; $\phi_e$ is core porosity, in %.

3.2. Flow unit classification based on both R35 and PTT
By relating R35 values with the size of pore system, pore throat type (PTT) can reflect better the reservoir quality, seepage characteristics and production capacity of different flow units.

Type I (Megaport): $R_{35}>10\mu m$. This is the best reservoir with the best reserve and seepage and normally the highest output. In such a flow unit, given the consistency between stratum thickness and other conditions, tens of thousands of barrels of medium-gravity crude oil can be output every day.

Type II (Macroport): $2\mu m<R_{35}\leqslant10\mu m$. This reservoir has good quality and high output. Given the consistency between stratum thickness and other conditions, this type of flow units can yield thousand of barrels of crude oil every day.

Type III (Mesopore): $0.5\mu m<R_{35}\leqslant2\mu m$. This reservoir has average quality and high output. If other conditions are desirable, this type of flow units can yield hundreds of barrels of crude oil every day.
Type IV (Microport): 0.1 < R35 ≤ 0.5 um. This reservoir has average quality. Although many dense gas reservoirs have such a R35, their production, in most cases, is very low because of small stratum thickness as well as average quality and heavy gravity of crude oil.

Type V (Nanoport): R35 < 0.1 um. This reservoir has bad quality and normally very low output (or mostly dry).

By using the 4249 sample point data of 13 wells in the NT oil field for physical property analysis, this paper classifies the flow units into five types (see the Fig. 1 and 2, and the Table 1) according to the R35 Pittman model.

Figure 1. Porosity-permeability crossplot for KT-I with different pore throat radii

Figure 2. Porosity-permeability crossplot for KT-II with different pore throat radii
Table 1. List of different pore throats for KT1

| Stratum | Type of pore throat | Number of data points | Percentage (%) | Number of data points | Percentage (%) |
|---------|---------------------|-----------------------|----------------|-----------------------|----------------|
| I       | KT-I               | 19                    | 1.35           | 69                    | 2.46           |
| II      | KT-I               | 231                   | 16.37          | 617                   | 21.99          |
| III     | KT-I               | 377                   | 26.72          | 535                   | 19.07          |
| IV      | KT-I               | 431                   | 30.55          | 609                   | 21.7           |
| V       | KT-I               | 353                   | 25.02          | 976                   | 34.78          |

It is observed from both Fig.1 and 2 that, the growth of fractures in the KT2 stratum is stronger than in KT1 (as there are more points with a <5% porosity and high permeability in KT2).

4. Flow index for different types of flow units in different strata

4.1. Flow index

Simulation of the flow of fluid in porous media by combining Tubular Darcy law with Poiseuille law and replacing porous medium with a series of capillaries showed:

\[ k = \frac{r^2}{8\emptyset_e} \] (1)

Simple as it is, the equation (1) relates pore size (radius) with pore throat shape, demonstrating that the relation between porosity and permeability depends mainly on pore characteristics, in particular pore throat radius.

Therefore, to describe the relation between actual porosity and permeability more relevantly, buckling factor was later introduced as hydrodynamic radius concept to obtain the Kozeny-Carmen equation, which was then converted into:

\[ 0.0314 \frac{k}{\emptyset_e} = \left( \frac{\emptyset_e}{1 - \emptyset_e} \right)^{-\frac{1}{\frac{\tau S_g v}{F_s}}} \] (2)

Through the combination with the definitions of flow unit index FZI and reservoir quality index RQI and the introduction of \( \emptyset_e \) as normalized active porosity, the following equation can be obtained:

\[ FZI = \frac{RQI}{\emptyset_z} \] (3)

After taking the logarithm on both sides, the following relation can be derived:

\[ \log RQI = \log \emptyset_z + \log FZI \] (4)

In the log-log coordinates of FZI and \( \emptyset_z \), the intercepts of different straight lines mean the FZI values of different flow units.

In an ideal case, the sample points with similar FZI values in the log-log coordinates of RQI and \( \emptyset_z \) are on the lines with an identical intercept, while the sample points with totally different FZI values are on the lines with different intercepts. The sample points on the same line have similar pore throat features, thus forming one flow unit. Every line is a specific flow unit, whose average FZI is expressed by \( \emptyset_z \) intercept.
4.2. Determination of FZI for different types of flow units in KT1 and KT2

The parameters input in this study include core porosity \( \phi_z \) (at the interval of 0.3 ~ 1.0 m), core permeability \( K \), and sample analysis data. The corrected core porosity has also been obtained. It can be seen from the equation (4) that, in the log-log coordinates of RQI and \( \phi_z \), a linear relation is found between RQI and \( \phi_z \), whose intercept is \( \log \) (Fig.3 and 4). Thereby, the FZI values for different flow units in different strata, as shown in the Table 2, can be obtained.

Figure 3. Normalized porosity and RQI for KT1

Figure 4. Normalized porosity and RQI for KT2
### Table 2. Relation between RQI and $\phi_z$ for different flow units in KT1 and KT2

| FU Type | Equation | Samples | RMSE | Average FZI (um) |
|---------|----------|---------|------|-----------------|
| KT1     |           |         |      |                 |
| FU5     | $\log_{10}RQI = 0.09132852 \times \log_{10}\phi_z - 1.902238$ | 415     | 0.26 | 0.01            |
| FU4     | $\log_{10}RQI = 0.03700668 \times \log_{10}\phi_z - 1.304759$ | 443     | 0.19 | 0.05            |
| FU3     | $\log_{10}RQI = -0.01585089 \times \log_{10}\phi_z - 0.786287$ | 345     | 0.14 | 0.16            |
| FU2     | $\log_{10}RQI = 0.01013611 \times \log_{10}\phi_z - 0.2473519$ | 228     | 0.16 | 0.57            |
| FU1     | $\log_{10}RQI = -0.1067485 \times \log_{10}\phi_z + 0.1522143$ | 19      | 0.14 | 1.42            |
| KT2     |           |         |      |                 |
| FU5     | $\log_{10}RQI = 0.2603245 \times \log_{10}\phi_z - 1.557015$ | 1294    | 0.18 | 0.03            |
| FU4     | $\log_{10}RQI = 0.05367775 \times \log_{10}\phi_z - 1.26324$  | 591     | 0.18 | 0.05            |
| FU3     | $\log_{10}RQI = 0.07655873 \times \log_{10}\phi_z - 0.6546777$ | 533     | 0.15 | 0.22            |
| FU2     | $\log_{10}RQI = 0.08281183 \times \log_{10}\phi_z - 0.1570062$ | 613     | 0.16 | 0.70            |
| FU1     | $\log_{10}RQI = -0.05277874 \times \log_{10}\phi_z + 0.1904083$ | 54      | 0.09 | 1.55            |

### 4.3. Classification result and distribution pattern of flow units

By considering the above calculation method, the flow units of 13 coring wells in the NT oil field have been classified through discriminatory analysis in accordance with sedimentary microfacies, rock type, reservoir space type, physical property parameters, and mercury-injection curve features. Moreover, the classification results have been comprehensively analyzed, as shown in the Table 3.

### Table 3. Features of different flow units in KT1 and KT2

| FU Type | $R_35$ (um) | $FZI$ (um) | Main rock type | Main reservoir space type | Main sedimentary microfacies | Main diagenesis | Oil output |
|---------|-------------|------------|----------------|--------------------------|-----------------------------|----------------|------------|
| FU1     | $R_35>10$   | $FZI>1.42$ (KT1) | Dolomite; algal reef limestone | Fracture-cave type; fracture pore type | Dolomitic flat; algal reef | IA, IB | Highest |
| FU2     | $2<R_35<10$ | $0.57<FZI<1.42$ (KT1) | Limestone; biolithite | Fracture-cave type; fracture pore type | Algal reef; intraplatform shoal | IB, IC | Higher |
| FU3     | $0.5<R_35<2$ | $0.16<FZI<0.57$ (KT1) | Calcarenite; limestone | Fracture pore type; pore type | Intraplatform shoal; grain shoal | IIA, IIB | Average |
| FU4     | $0.1<R_35<0.5$ | $0.05<FZI<0.16$ (KT1) | Limestone | Pore type | Limestone flat; grain shoal | III | Low |
| FU5     | $R_35<0.1$  | $0.01<FZI<0.05$ (KT1) | Argillaceous limestone | Pore type | Limestone flat; grain shoal | IV | Very low |

The type-I flow units, mainly found in dolomite and algal reef limestone reservoirs, have the highest production capacity. Given the existence of corrosion and dolomitization, they are mainly fracture-cave composite reservoirs or fracture pore reservoirs. As far as the type-I flow units are concerned, the flow index is $>1.42$ for KT-I stratum and $>1.55$ for KT-II stratum. The production capacity and reservoir quality of type-II-IV flow units would decline in turn. The type-V flow units are argillaceous limestone, with a very low production capacity and a flow index being $0.01-0.05$ for KT-I and $0.03-0.05$ for KT-II.

### 5. Conclusion

The NT oil field is a complex carbonatite reservoir featuring complicated sedimentary diagenesis, strong anisotropism, and difficult exploitation. The classification and identification of flow units is of great importance to the exploitation and adjustment of oil fields. The carboniferous reservoir of an oil field has five types of flow units. Among them, the type-I flow units constitute the best stratum, with the biggest flow index but the smallest proportion of only 1.35%. In contrast, the KT-II stratum
accounts for 2.46%, and the type-II-V strata for 16.37-34.78% respectively in relative equilibrium. The main contribution to the production capacity of this oil field is made by type-I-III flow units.

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