



Well-controlled dynamic hydrocarbon reserves calculation of fracture–cavity karst carbonate reservoirs based on production data analysis

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Abstract

Fracture–cavity karst carbonate reservoirs have multiple storage space with irregular geometry and various scales, and this caused strong heterogeneity and complex flow characteristics. Accurately calculating the well-controlled dynamic reserves of this kind reservoir effectively is the basis to optimize oil field development plan and making the transformation measures of production well. In order to solve the problem that conventional well-controlled dynamic hydrocarbon reserves calculation method is not suitable for such type reservoirs, we applied a method based on production data analysis. Classification standard of oil well types is established based on the fracture–cavity reservoirs geological static and production dynamic characteristics. Conceptual characteristics of geological model and fluid flow pattern for different types of production wells are assumed. Calculation workflow for well-controlled reserves of fracture–cavity reservoir is established. In the process, some technical key points are proposed to improve accuracy of curve fitting, such as converting the bottom hole pressure from wellhead pressure, correcting the well control range and converting the PVT parameters at the pseudo-steady state. We verified correctness of this method by comparing the calculated results with numerical simulation results of actual production well. This method is well used to Tahe Oil field of Tarim Basin in China. The result shows that the well-controlled reserves quantitative calculation results through this method are in conformity with oil field actual understanding, and the remaining dynamic reserves mainly exist in the drainage area of the wells that drilled different reservoir bodies with good connectivity, especially at the top of large karst caves, and that is the target of further adjusting.

Keywords Fracture–cavity karst reservoir · Production data analysis · Well-controlled reserves · Dynamic reserves · Remaining oil

Introduction

Well-controlled dynamic reserves refer to the total reserves within the range of pressure transmission in the production process, and the size of dynamic reserves is the important basis to evaluate reservoir development level and remaining oil potential, for adjusting the direction of potential tapping, and also is the material basis for single well measures to improve the development effect. However, how to evaluate the well-controlled reserves of fracture–cavity reservoir is a difficult problem, because this type reservoir is very different

from conventional reservoir. Tahe Oil field of Tarim Basin is a typical fracture–cavity karst carbonate reservoir, and the storage space mainly includes large karst caves and small scales dissolved pores and multi-scale fractures with different geometry (Zhang et al. 2004). The spatial distribution of reservoir body is complex, and the scale of storage space ranges from a few microns to tens of meters. Drilling data have proved karst cave height ranges from 1–2 to 72 m, and it is difficult to characterize accurately. The matrix is non-effective reservoir for low porosity and poor permeability. Physical properties of matrix have huge differences of different karst caves and pores, the range of porosity is from 1.8 to 100%, and the value of permeability is from several mD to hundreds of Darcy in the large karst cave; the fractures are the main flow channels with high permeability (Chen et al. 2005a, b; Li 2013). These factors lead to strong heterogeneity of this kind reservoir, and physical

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property, thickness and well-controlled range have large uncertainty, so it is difficult to evaluate a large number of single well-controlled reserves by means of volumetric or geological modeling method (Lyu et al. 2017). At the same time, oil–water flow law of this type reservoir is extremely complicated, and the mainly flow characteristics include Darcy flow, non-Darcy flow and N–S flow. (Yao and Wang 2007; Zhang and Li 2009). It has big challenge for numerical simulation by couple multiple flow forms and calculation speed of the numerical simulation of actual fracture–cavity reservoir unable to meet oil field application demand. Conventional classical concept model for describing the fluid flow characteristics cannot depict the flow condition of this reservoir accurately (Warren and Root 1963; Lee et al. 2001; Huang et al. 2010; Aljehani et al. 2017). Therefore, it is hard to calculate well-controlled hydrocarbon reserves accurately by means of actual reservoir numerical simulation. Many scholars have supplied various reserves calculation method for fracture reservoir and such reservoirs (Fetkovich et al. 1996; Chen et al. 2005a, b, 2007; Yang and Jin 2011). These methods are applied in local area which has obtained certain effects, but due to the uncertainty of fracture–cavity reservoirs makes it difficult to apply them calculate the reserves of a large number of wells completely (Zhang et al. 2012; Jenabidehkordi 2019).

Production data analysis is a method to evaluate single well-controlled reserves with the appropriate theory models, through history matching the typical interpretation chart with series of single well production, pressure and other dynamic changing over time data. At present, reservoir engineers commonly use Fetkovich (Fetkovich 1980), Blasingame et al. (1989, 1991), and Agarwal and Gardner method (1998) to analyze the production dynamic. These methods analyze the production data using typical curves combing pressure and production data and evaluate the single well-controlled reserves based on the analytical solution. This method can get the reservoir information and the value of the single well-controlled reserves without making special well test, such as shut in waiting for pressure to recover. These caused its rapid development and being used widely in reservoir analysis process (Clarkson 2013; Wang et al. 2013; Li et al. 2018).

In this paper, firstly we analyzed production data analysis theory proposed by Blasingame and then established the division standard of production well types combining the geological static with production dynamic characteristics. We put single wells of fracture–cavity reservoir divided into three types, assumed conceptual characteristics of geological model for the drainage area of different types of wells and used different fluid flow conceptual models to describe fluid flow law around different types of wells. On these bases, we established calculation workflow of single well-controlled reserves for fracture–cavity reservoir and proposed some

methods to improve the precision of curve fitting, through converting bottom hole pressure from wellhead pressure, correcting the well control range and calculating the PVT at the pseudo-steady state. Eventually based on production dynamic analysis method, we established the calculation method to evaluate the single well-controlled dynamic reserves of fracture–cavity reservoir and get good results when used in Tahe Oil field of Tarim Basin in China.

Production data analysis theory

Production data analysis is the method based on the theory of fluid flow in porous media and material balance equation. Using this method, we can get the reservoir information through typical curve fitting according to daily pressure and flow data. There are various pressure characteristics in the different stages of fluid flow in the reservoir. In the unstable radial flow and pseudo-steady flow stage, we can obtain the well-controlled reserves based on analytical solution for a well with continuously changing bottom hole flowing pressure in the reservoir with different boundary conditions.

Applying Duhamel's theorem to the constant-rate solution for a continuously changing flow rate, the result is

$$P_i - P_r = 141.2 \frac{B\mu}{kh} \int_0^t q(t') \frac{dP_D(t-t')}{dt} dt', \quad (1)$$

where P_i denote initial formation pressure, Pa, P_r is pressure at r position, Pa, B is formation volume coefficient, μ is viscosity, mPa·s, k is permeability, μm , h is formation thickness, m, and q is flow rate per unit time, m^3/day .

Applying the convolution theorem to Eq. (1) gives

$$P_i - P_r = 141.2 \frac{B\mu}{kh} \sum_{j=1}^m (q_j - q_{j-1}) P_D(t - t_{j-1}). \quad (2)$$

For a bounded circular reservoir, using Muskat formula (Muskat 1946), let $r = r_w$ and give this solution as

$$P_D(r_w, t) = \ln \frac{r_e}{r_w} - \frac{3}{4} + \frac{r_w}{2r_e^2} + S + 2\pi \cdot 0.0002637 \frac{kt}{\phi\mu c_t A} - 2 \sum_{n=1}^{\infty} \frac{J_0(X_n \frac{r_w}{r_e}) \text{EXP} \left(-X_n^2 \pi \cdot 0.0002637 \frac{kt}{\phi\mu c_t A} \right)}{X_n^2 J_0^2(X_n)}, \quad (3)$$

where r_w is radius of wellbore, m, r_e is drainage radius, m, $r_D = r/r_e$, S is skin factor, X_n are the positive roots of $J_1(X_n) = 0$, $t_{DA} = 0.0002637 \frac{kt}{\phi\mu c_t A}$, $A = \pi r_e^2$ is drainage area, m^2 , and C_t is comprehensive compression coefficient, Pa^{-1} . Combining Eq. (2) and Eq. (3) gives

$$\Delta P = P_i - P_r = 141.2 \frac{B\mu}{kh} \left\{ \begin{aligned} & q_m \left[\ln \frac{r_e}{r_w} - \frac{3}{4} + \frac{r_w}{2r_e^2} + S \right] + 2\pi 0.0002637 \frac{k}{\phi\mu c_t A} Q_m \\ & - 2 \sum_{j=1}^{\infty} (q_j - q_{j-1}) \sum_{n=1}^{\infty} \frac{J_0 \left(X_n \frac{r_w}{r_e} \right)}{X_n^2 J_0^2(X_n)} \text{EXP} \left(-X_n^2 \pi 0.0002637 \frac{k(t - t_{j-1})}{\phi\mu c_t A} \right) \end{aligned} \right\}, \tag{4}$$

where $Q_m = \int_0^t q(t') dt' = \sum_{j=1}^m q_j(t_j - t_{j-1})$.

We divide both sides of Eq. (4) by the final rate q_m . Letting $\bar{t} = \frac{Q_m}{q_m}$ yields:

$$\frac{\Delta P}{q_m} = 141.2 \frac{B\mu}{kh} \left[\ln \frac{r_e}{r_w} - \frac{3}{4} + \frac{r_w}{2r_e^2} + S \right] + 0.2339 \frac{B}{\phi h c_t A} \bar{t} - 282.4 \frac{B\mu}{kh} \left\{ \sum_{j=1}^{\infty} \frac{(q_j - q_{j-1})}{q_m} \sum_{n=1}^{\infty} \frac{J_0 \left(X_n \frac{r_w}{r_e} \right)}{X_n^2 J_0^2(X_n)} \text{EXP} \left(-X_n^2 \pi 0.0002637 \frac{k(t - t_{j-1})}{\phi\mu c_t A} \right) \right\}. \tag{5}$$

The infinite series in Eq. (5) can be negligible. This is true for the constant-rate case at pseudo-steady state and was shown to be approximately true for the variable-rate case at bounded reservoir flow condition using simulated examples. Therefore, we can approximate Eq. (5) by neglecting the infinite series:

$$\frac{\Delta P}{q_m} = 141.2 \frac{B\mu}{kh} \left[\ln \frac{r_e}{r_w} - \frac{3}{4} + \frac{r_w}{2r_e^2} + S \right] + 0.2339 \frac{B}{\phi h c_t A} \bar{t}, \tag{6}$$

Equation (6) is the variable-rate approximation for stabilized flow for a well centered in a bounded circular reservoir. Because reservoir radius is much bigger than wellbore radius, if we neglect $r_w^2/2r_e^2$ in Eq. (6) and use the effective wellbore radius to model the skin effect, we obtain:

$$\frac{\Delta P}{q_m} \cong 70.6 \frac{B\mu}{kh} \ln \frac{r_e}{r_w^2 e^{3/2}} + 0.2339 \frac{B}{\phi h c_t A} \bar{t}, \tag{7}$$

Letting $m_{vr} = 0.2339 \frac{B}{\phi h c_t A}$, $b_{vr} = 70.6 \frac{B\mu}{kh} \ln \frac{r_e}{r_w^2 e^{3/2}}$ and $A = 0.2339 \frac{B}{\phi h c_t m_{vr}}$ yields

$$\frac{\Delta p(t)}{q(t)} = m t_{cr} + b \left\{ \begin{aligned} & t_{cr} = \frac{1}{q(t)} \int_0^t q(\tau) d\tau = \frac{Q(t)}{q(t)} \\ & m = 0.2339 \frac{B}{\phi h c_t A} \\ & b = 70.6 \frac{B\mu}{kh} \ln \frac{r_e}{r_w^2 e^{3/2}} \end{aligned} \right. . \tag{8}$$

We introduce the concept of material balance time and normalized pressure, where the normalized pressure is

defined as $\frac{\Delta p}{q_o}$, and the expression of the material balance time is $t_{cr} = \frac{1}{q(t)} \int_0^t q(\tau) d\tau = \frac{Q(t)}{q(t)}$. The normalized pressure $\frac{\Delta p}{q_o}$ is function of t_{cr} at linear relationship with the slope of 1. We can get a series of reservoir parameters from the

slope and intercept, including the well-controlled reserves, the permeability, the skin factor, the cross-flow parameter, the storativity ratio and the drainage radius of the well.

Single well classification and characteristics

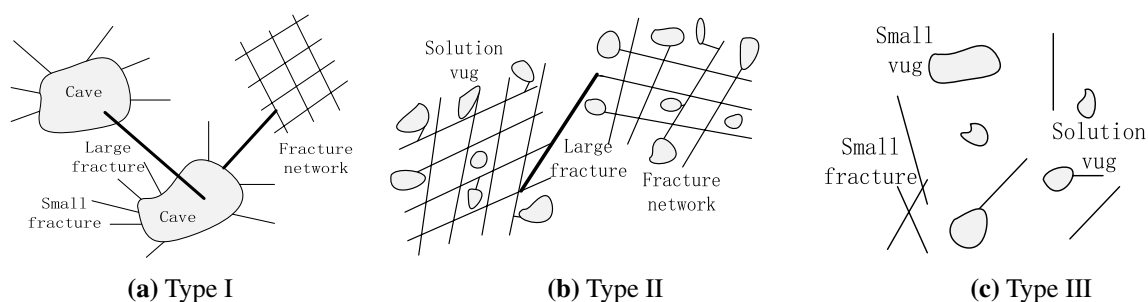
Fracture–cavity karst reservoirs have various types of fracture–cave combination with different dynamic characteristics. This makes it difficult to determine pseudo-steady state and then will directly affect the calculation accuracy of the reserves. Consider on specialties of fracture–cavity reservoirs and fully using geological static data with the long-term production dynamic data, in order to improve the calculation accuracy, we establish geological concept mode and fluid flow mode of different production wells, respectively.

Production well-type classification

Mainly based on the geological static and dynamic characteristics, fine geological model as reference, we establish classification standards of production wells, combining qualitative analysis with quantitative analysis, as shown in Table 1. We divide the production wells into three categories. In the type I well’s drilling area, the fracture and karst cave develop very well with good connectivity, and the productivity performance is very good. In the type II well’s drilling area, the fracture and dissolved pore are well developed with general connectivity, and the productivity performance is modest. In the type III well’s drilling area,

Table 1 Production well classification standard

Well type/Distinguish basis	Type I well (the fracture and karst cave develop, good connectivity)	Type II well (the fracture and dissolved pore are well developed, general connectivity)	Type III well (the fracture is well developed, bad connectivity)
Geological static characteristics	Venting while drilling Drilling fluid leakage Beads in the seismic profile	Well logging shows that fracture is well developed Some show well leakage phenomenon Small caves in the cores	Well logging shows that fracture is not developed It is hard to observe the fracture No effect in several acid fracturing
Production dynamic performance	Pump pressure reduces while acid fracturing Early productivity > 100 m ³ Oil pressure changing amplitude < 5%. Long-term steady production, above 3 years	Early productivity between 10 and 100 m ³ Small productivity index Medium time steady production, 1–3 years Production decline rate < 5%	Early productivity < 10 m ³ Dry well, special stripper well Cumulative oil production < 1 million m ³
Fine geological model	Well drill the large cave or fracture area At least one high-angle fracture around The karst caves connect to multiple fractures	Well drill the small cave and pore At least five high-angle fracture around well At least 20 microfractures connected	Solution pore develops around the well. At least 20 microfractures The connectivity is very bad

**Fig. 1** Schematic representation of reservoir bodies conceptual model: **a** type I; **b** type II; **c** type III

the fracture is well developed with bad connectivity, and the productivity performance is not so good.

Geological concept and flow model hypothesis

Depending on the types of production wells combined with characteristic of fracture–cavity karst reservoirs, we establish the reservoir’s geological concept and hypothesis of fluid flow model around the wells. As shown in Fig. 1a, type I wells drill the areas with large karst caves and fractures, where the fluid diversion fracture exists and the connectivity is very good. As shown in Fig. 1b, type II wells drill the fracture developed area, where small pores, caves and large fracture exist, and with good connectivity. As

shown in Fig. 1c, type III wells drill the areas, where only isolated caves, pores and small fractures exist, the connectivity is bad and the fluid cannot flow.

For type I wells, we adopt triple-porosity media model to describe the fluid flow condition, as shown in Fig. 2a, where we consider cavity system, fracture system and small pore matrix system as the triple medium, respectively. When the pore matrix system and fracture system both supply fluid to cavities, we adopt the triple-porosity singular-permeability hypothesis to describe the cave fluid supply condition, where pore matrix–cave’s cross-flow coefficient and fracture–cave coefficient exist. When the pore matrix system and cave both supply fluid to fracture, and the pore matrix system supplies fluid to karst cave, we adopt the triple-porosity dual-permeability hypothesis to

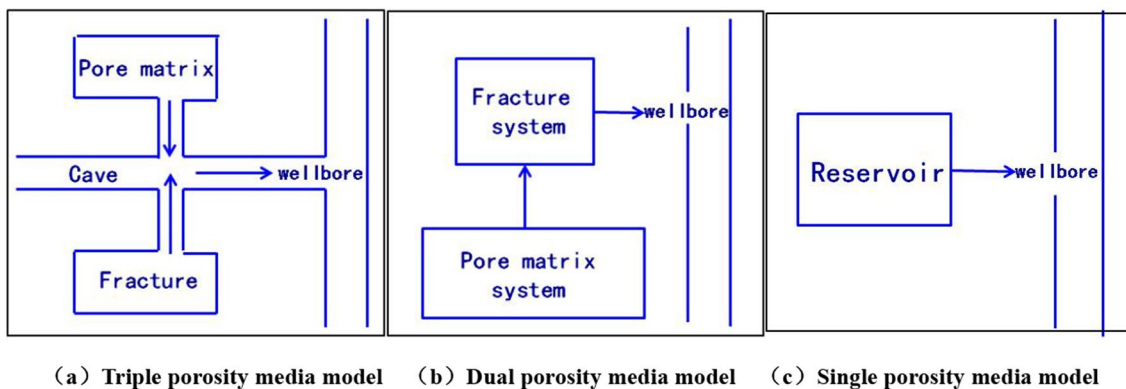


Fig. 2 Flow pattern hypothesis

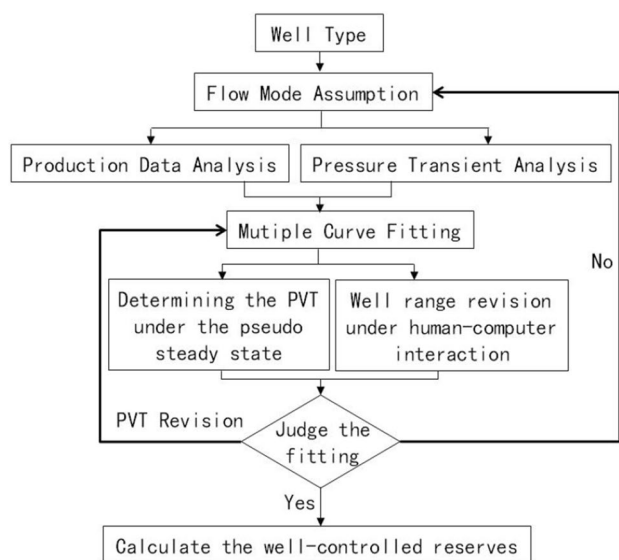


Fig. 3 The workflow of well-controlled reserves calculation

describe the condition of both the cave and fracture fluid supply. For type II wells, we adopt the dual-porosity media model to describe the fluid flow condition, as shown in Fig. 2a, where we put fracture as one media and the small cave and pore matrix as another media. When the pore matrix system and small cave both supply fluid to the well, and the pore matrix system supplies fluid to the fracture, we adopt dual-porosity media dual-permeability hypothesis to describe this condition. When only the fracture system supplies fluid to the well, we adopt dual-porosity singular-permeability media model. For type III wells, we adopt the single-porosity media model to describe the fluid flow condition, as shown in Fig. 2c, where the drilling area supplies fluid to the well, the supply radius is small, and the cross-flow does not exist.

Well-controlled reserves calculation

According to the special characteristics of the fracture–cavity karst reservoirs, we design the well-controlled reserves calculation workflow, as shown in Fig. 3. Firstly, we determine the type of the single well geological concept and choose the different fluid flow models, respectively. Then, we adopt PDA method to fit the semilog curve, double logarithmic derivative curve and Blasingame curve in order to determine equivalent parameters and the well-controlled range and further calculate the well-controlled reserves. In order to fit multiple curves accurately, we deeply consider the characteristic of the fracture–cavity reservoir. As a result, our first choice is the production data, where the water cut is less than 5%, which we can approximately think the fluid as the single phase. Then, we calculate the bottom hole flowing pressure, determine the well-controlled range through human–computer interaction and choose the flow concept model.

In addition, the well-controlled range under pseudo-steady state is closer to the actual scope. When we use the parameters under the pseudo-steady state, we can get more accurately well-controlled hydrocarbon reserves. Therefore, we can correct the parameters through curve fitting. In detail, we first get the time range of the pseudo-steady state through curve fitting and then get the average pressure of this segment, and then, we correct the parameters using this average pressure. The calculation workflow requires repeated adjustment and correction in order to achieve a better fitting effect. Finally, we can get the well-controlled reserves reflecting the real situation underground.

Bottom hole pressure conversion

There are lack of static pressure and flowing pressure test data of the single well or unit during the fracture–cavity reservoir’s production. However, there are rich data of the

well production, oil and casing pressure and their changes, which can reflect the changes of the bottom hole flowing pressure and can reflect the pressure loss from bottom hole to wellhead pressure. Because the fluid in the case is static during the production, when the water cut is less than 5%, assuming that the case is filled with crude oil, and the oil pipe is put under the production level, the factor affecting the difference value between flowing pressure and casing pressure is the pressure difference from static oil column. Therefore, we can calculate the changes of the bottom hole pressure using the casing pressure and production data.

For water injection fracture–cavity carbonate reservoir with closed and no bottom water, when the reservoir pressure is higher than saturation pressure, material balance equation can be simplified as Eq. (9):

$$N_p B_o = N B_{oi} C_t (P_i - P) = E (P_i - P), \quad (9)$$

where N_p is the cumulative oil production, 10^4 m^3 , N is the geologic reserves, 10^4 m^3 , P is the current reservoir pressure, MPa, P_i is the original reservoir pressure, MPa, B_o is volume factor of formation crude oil under current pressure, B_{oi} is the volume factor of formation crude oil under original reservoir pressure, C_t is the total compressibility of the reservoir, MPa^{-1} , and E is defined as the elastic index of the fracture–cave unit, which is the produced fluid volume when the fracture–cave unit's pressure drop is 1 MPa.

The process of the oil well production yields Eq. (10):

$$q_o = J(P - P_{wf}) = J \left(P_i - \frac{N_p B_o}{E} - P_{wf} \right), \quad (10)$$

where q_o is the well production rate, m^3/s , J is the productivity index, $\text{m}^3/(\text{s}\cdot\text{Pa})$, and P_{wf} is the bottom hole flowing pressure, MPa.

Solving Eq. (10) for $P_i - P_{wf}$ gives

$$(P_i - P_{wf}) = \frac{N_p B_o}{E} \frac{q_o}{J}. \quad (11)$$

From Eq. (11), we can see that the difference between the original pressure and bottom hole flowing pressure is composed of two parts, namely the total pressure drop and producing pressure drop. Under the condition of little or no flow pressure test data, we can get the flowing pressure, using the relationship between the casing pressure and the flowing pressure, as shown in Eq. (12):

$$P_{wf} = P_c + P_h, \quad (12)$$

where P_c is the casing pressure, MPa, and P_h is the differential pressure caused by the hydrostatic oil column, MPa.

Combining Eq. (11) and Eq. (13) yields

$$P_c = (P_i - P_h) - \frac{N_p B_o}{E} - \frac{q_o}{J}. \quad (13)$$

Using the data of the casing pressure, daily production and cumulative production, we establish the multivariate regression equation. Solving the equation, we can get several parameters, such as $(P_i - P_h)$, E and J . In this way, we establish the method to calculate the bottom hole flowing pressure and the productivity index, under the condition of lacking the hydrostatic pressure and flowing pressure data.

Well-controlled range revision

Through production data analysis, we can get the reservoir shape, the boundary properties and the distance between the well and the boundary, and further, we can determine the well spacing. However, because of the strong heterogeneity of the fracture–cavity reservoir, the well spacing only based on the dynamic method is difficult to represent the actual control area. Therefore, we determine the well spacing using the result of inter-well connectivity discriminant and the positional distribution of the cave and fracture determined from fine 3D geological model. This human–computer interaction mode can get a more accurate well spacing and can improve the precision of the curve fitting.

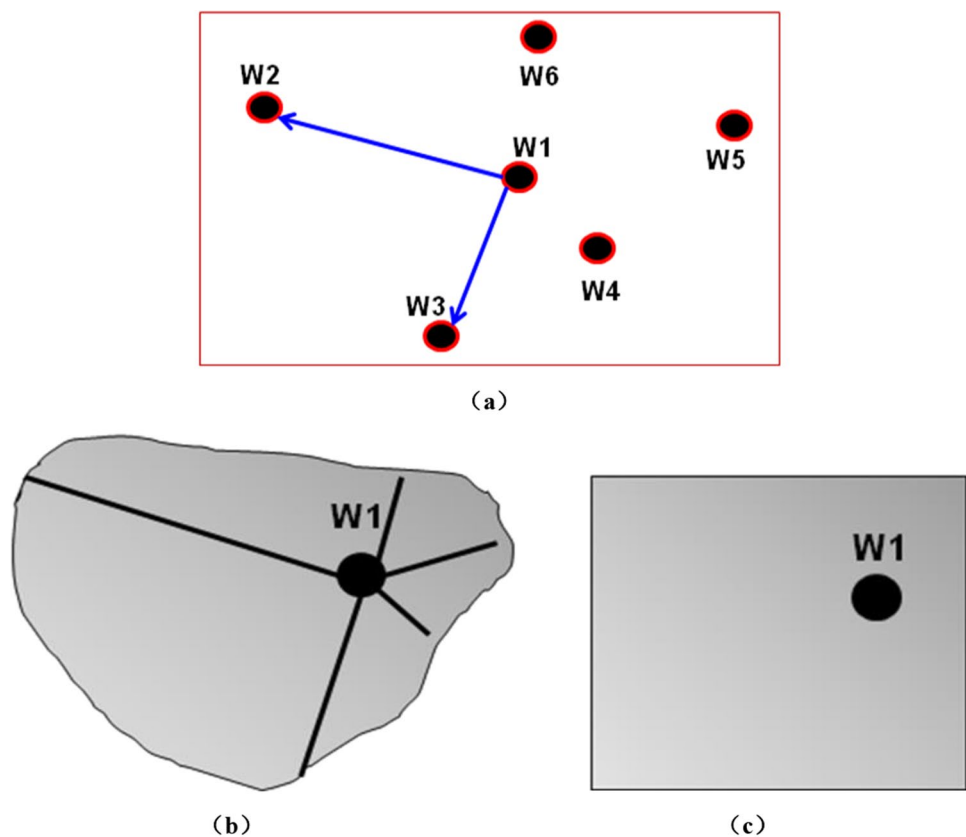
As shown in Fig. 4a, the result diagram of the inter-well connectivity discriminant shows that the connectivity between W1 well and W2 well, and W3 well is good, while the connectivity between W1 well and other wells is poor. Therefore, the W1 well's controlled area at the direction of W2 well and W3 well is much bigger. Assuming that Fig. 5b is the actual control area of W1 well, then we can get equivalent controlled area, which is rectangular or oval. We can revise the well spacing repeatedly, and then, we can get more accurately value of reserves on the premise of guaranteeing the curve fitting.

Well-controlled reserves calculation

In this section, we take W1 well as an example to calculate the well-controlled reserves. In the process of W1's drilling, venting, leaking and well kick happened. Moreover, the logging interpretation shows that the karst cave in the reservoir is several meters and cave-type reservoir well developed. This well produced $8.82 \times 10^4 \text{ m}^3$ oil totally, the production period without water lasted for 900 days, the initial production rate was $150.3 \text{ m}^3/\text{day}$, and its production was stable. The W1 well belongs to type I well.

Based on the geological understanding of W1 well, we first assume the flow pattern. After analyzing sensitivity of the flow concept model, we adopt triple-porosity singular-permeability model to describe the flowing of the fluid

Fig. 4 Schematic diagram of well equivalent control area: **a** connectivity discriminate result; **b** actual control area; **c** equivalent control area



around the well. Then, we convert the bottom hole pressure from oil pressure, adjust the well-controlled scope repeatedly and determine the PVT parameters under the pseudo-state. Then, we get fitting curve of double logarithmic pressure, semilog pressure and original pressure and obtain good fitting effect; the curve shows typical characteristics of triple medium as shown in Fig. 5. Moreover, we get the oil saturation of the drainage area through thickness-weighted average method and can determine the oil density from the conclusion of PVT tests. Finally, we get the well-controlled reserve of $66.8 \times 10^4 \text{ m}^3$.

Method verification and application

In order to verify the correctness of the calculation and process method, we established the fine 3D geological model of fracture–cavity reservoir for a typical well, then carried out reservoir numerical simulation research, matched the production historical characterization and evaluated well-controlled dynamic reserves based on numerical simulation results. Through comparing the reserves calculated by numerical simulation and production dynamic analysis, the correctness of this method is verified. This method is applied to evaluate well-controlled reserves in

the fracture–cavity-type reservoir of X block reservoir and obtained good results.

Method verification

We use the classification modeling method to establish the fine geological model of W1 well. Figure 6a shows the geological modeling result, and the orange color represents karst caves, the yellow color represents dissolved pores, the green color represents fractures and the gray color represents matrix. Figure 6b shows the numerical simulation for remaining oil distribution of karst caves reservoir in well-controlled range. We calculate the reserves included in the range of pressure drop, this reserves can be used as single well-controlled dynamic reserves, the size of reserves is $61.2 \times 10^4 \text{ m}^3$, the difference between the results of Section 3.3 of this paper is $5.6 \times 10^4 \text{ m}^3$, and the relative error is 9.15%. Considering the difficulty of dynamic reserves calculation, such error will not affect development methods and strategies, within our acceptable range. Based on this, we can prove the correctness of this method.

Application

According to this method, we classify 39 wells of X block reservoir, among which are 10 type I wells, 21 type II wells

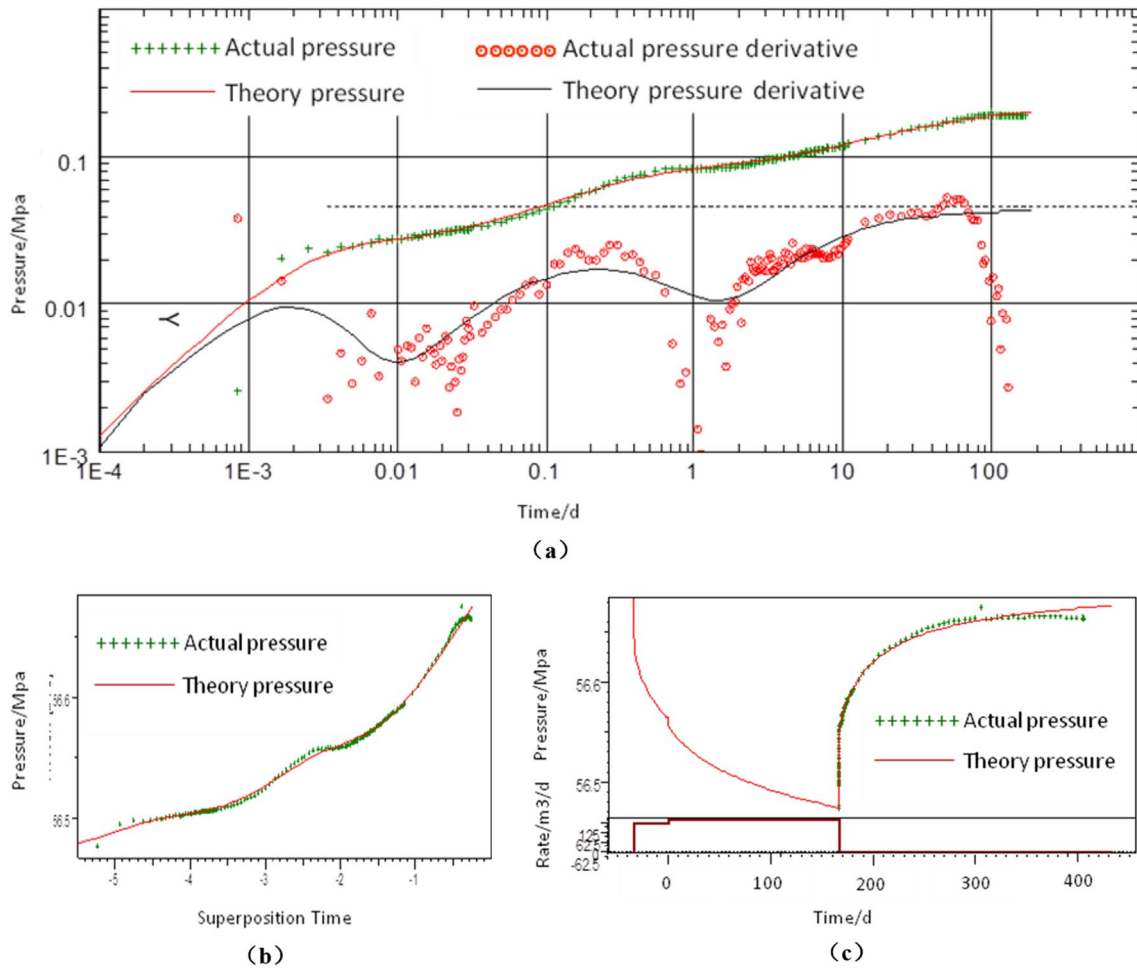
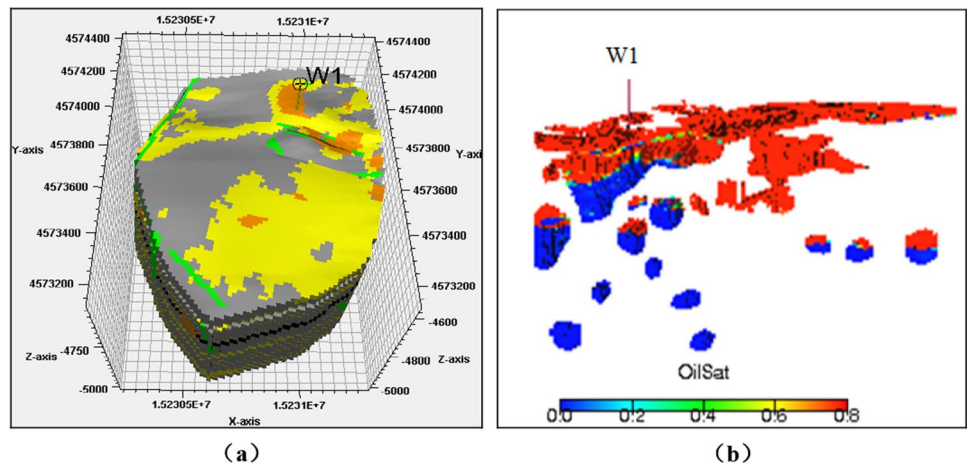


Fig. 5 W1 well curve fitting: **a** log–log plot; **b** pressure history match plot; **c** semilog plot

Fig. 6 Geological modeling and numerical simulation results of W1: **a** fine geological model of W1 well; **b** numerical simulation for remaining oil distribution of karst caves reservoir in well-controlled range



and 8 type III wells. Through analyzing the flowing mode, revising the well-controlled range and fitting the curves, we can reverse the reservoir parameters and further get the well-controlled volume. Knowing the oil saturation and weighted

average thickness analyzed from logging interpretation, we can further get the well-controlled dynamic reserves. In addition, we did the recovery calibration through optimizing the wells that have reached ultimate output of the field's

Table 2 The calculation results of type I well in X block reservoir

Well name	Geological characteristics	Cumulative production	Early production	Interpretation model	Control volume	Oil saturation	Single well-controlled reserves	Remaining recoverable reserves
	Drilling, seismic, logging	$10^4 \times \text{m}^3$	m^3/day		10^4m^3	%	10^4m^3	10^4m^3
A1	Leakage, karst cave, fracture developed	20.71	164.4	Triple-porosity double-permeability model	325.72	69.2	225.4	43.12
A2	Venting, lost circulation, kicking, weak beads, karst cave, fracture developed	8.38	142.8	Triple-porosity singular-permeability model	106	63.8	67.63	12.94
A3	Acid fracturing, fracture developed	11.88	135.2	Triple-porosity singular-permeability model	246.11	71.5	175.97	33.66
A4	Lost circulation, weak beads	19.6	148.5	Triple-porosity double-permeability model	154.08	68.5	105.54	20.19
A5	Strong reflection beads	10.41	100.2	Triple-porosity double-permeability model	279.32	65.8	183.79	35.16
A6	Kicking, lost circulation	41.5	228.9	Triple-porosity singular-permeability model	490.86	62.9	308.75	59.06
A7	Strong reflection beads	23.3	182.4	Triple-porosity double-permeability model	227.4	77.6	215.26	41.18
A8	Strong reflection beads, fracture developed in the core	9.84	226.6	Triple-porosity singular-permeability model	110.23	55.6	61.29	11.72
A9	Serious lost circulation, fracture developed	10.01	112.2	Triple-porosity double-permeability model	168.77	60.7	102.44	19.6
A10	Strong reflection beads, pump pressure drop obviously while acid fracturing	11.47	151.6	Triple-porosity singular-permeability model	100.22	63.5	63.64	12.17

three blocks. Statistically, there are 13 wells which have reached ultimate output. These wells have injected water, sidetracked or shut down. Using the result of the well-controlled reserves and the cumulative production, we get that the type I well recovery is 19.13%, the type II well recovery is 12.35%, and the type III well recovery is 5.82%. Using these recovery calibration results, we calculate the recoverable reserves and the remaining recoverable reserves of the wells in the whole area. Some of the type I wells are shown in Table 2.

Through calculation, the type I well's control reserves are $1509.72 \times 10^4 \text{m}^3$, and the remaining recoverable reserves are $288.81 \times 10^4 \text{m}^3$. The type II well's control reserves are $1230.9 \times 10^4 \text{m}^3$, and the remaining recoverable reserves are $152.02 \times 10^4 \text{m}^3$. The type III well's control reserves are $416.4 \times 10^4 \text{m}^3$, and the remaining recoverable reserves are $24.23 \times 10^4 \text{m}^3$. Based on these results, we determine the whole region's well-controlled reserves after excluding the inter-well interference effect. From the results, we can see that the remaining recoverable reserves mainly exist in the drainage area of type I and II wells. This is according to practical knowledge of the oil field. Due to the developed karst cave and fracture with good connectivity, the remaining oil mainly exists in the form

of ceiling oil, which is primary considering object in the next step development plan adjustment and technological measures of reforming.

Conclusion

According to the complex characteristics of fracture–cavity karst carbonate reservoirs, production well types division standards are established based on the geological static and production dynamic characteristics. Geological conceptual characteristics model and fluid flow pattern are assumed for each type of the wells. Long-term production dynamic data analysis is adopted to calculate the reserves. Evaluation method and workflow for single well-controlled dynamic hydrocarbon reserves of fracture–cavity carbonate reservoirs based on this analysis results are established.

In the process, this method makes full use of the single well's dynamic and static data and carries out several curve fitting for the well dynamic data and production data. We establish the method to improve the precision of curve fitting, through converting the bottom hole pressure from well-head pressure repeatedly, correcting the well control range and calculating the PVT parameters at the pseudo-steady

state. In this way, we are trying to depict the well-controlled reserves of different well types accurately.

The correctness of this method is verified by comparison with fine numerical simulation results of fracture–cavity oil reservoir. Based on this method, we evaluate the well-controlled recoverable reserves of the 39 wells in X block reservoir. In this field, the remaining recoverable reserves mainly exist in the drainage area of type I and II wells. These accords with practical knowledge of the field. The remaining oil mainly exists in the form of ceiling oil, which is primary considering object in the next step development plan adjustment and technological measures of reforming.

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