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New process of parameter calculation and production prediction in heavy oil well

For heavy reservoirs with different rheological fluid, the diverse phenomena may appear in the fluid flow. Based on the rheology experiment, the actual rheological equations are figured out in district A. With the detailed type of fluid, the fundamental formulas about pressure loss and temperature are reasonably selected, by which, the model for production prediction are defined as the basis for the calculation of pressure distribution along the pipe. As Beggs-Brill method has just made a prominent contribution to the slippage area, the wellbore pressure distribution is obtained through basic momentum equations, in which the pressure drop is calculated only based on the average parameters, such as density, viscosity. The impact caused by slippage between steam-liquid phases has yet been neglected. Particularly, when the steam dryness is relatively low, and the slippage does exist, the result is obviously not scientific. Therefore, with some modified parameters, this paper proposes a new process by the involvement of Beggs-Brill method, and describes the process in detail with on-site data to test and verify the feasibility. It turns out that BeggsBrill method is suitable to calculate pressure distribution, where the process and the model for production prediction are also applicable in this district.

Keywords: *Beggs-Brill, downhill, steam flooding, slippage.*

1. Introduction

As the development of the heavy oilfields are distinct from that of normal reservoirs, its fluid pattern is not similar under various temperatures. The kickoff pressure exists in nearly all the low-temperature reservoirs, which cause much trouble in the effective utilization of heavy oil[1].

As steam injection and steam flooding are generally applied in the developing heavy reservoirs, the models have sprung up for calculating the pipe parameters, such as the downhill and the uphill flows. The pipe pressure distribution precision is the key to optimizing the steam-injection parameters for steam simulation and steam flooding in heavy oilfield. It is therefore required to obtain the accurate pressure gradient. The previous scholars have done long-term studies on the multiphase pipe flow, and put forward several prediction models, like, Dun-Ros [2], Hagedorn-Brown [3], Orkiszewski [4], Aziz [5], Hasan [6], Liao Ruiquan [7], Beggs-Brill [8], Beggs-Brill modified [9], Mukherjee-Brill [10], Ansari [11], Zhang [12] and so on. Most of these models are based on the uphill flow in vertical pipe, like Dun-Ros, Hagedorn-Brown, Orkiszewski, Aziz, Hasan, Ansari and Liao Ruiquan. With the wide application in deviated wells, horizontal wells, and various enhanced recovery, like water flooding and gas flooding, these prediction models are found not practical, of which only a few rely on the downhill flow in deviated pipe, such as Beggs-Brill, modified Beggs-Brill, and Mukherjee-Brill. The Beggs-Brill method is however the only one capable of calculating the complete pressure gradient through indoor multiphase flow experiment against deviated pipe, including the uphill flow, the horizontal flow and the downhill flow.

The steam simulation in heavy oil wells attributes to the calculation process for downhill flow, so that the Beggs-Brill method is chosen for pressure calculation for this reason. While, there are some other reasons, (1) the steam-liquid flow has no fundamental difference with gas-liquid flow; (2) the other methods [13, 14] use the homogeneous model to obtain the pressure gradient with the constant density regardless of impact of slippage between the steam-liquid phases, while the Beggs-Brill method can fix the problem. On this basis, this paper proposes the BeggsBrill method for the pressure parameter calculation, and also conducts a test on this method and the calculation process.

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2. Characteristics of calculation process in heavy oil well in district A

2.1 Flow performance in block 1# and 2# of district A

2.1.1 Fluid pattern

Based on the dehydrated crude rheology experiment, we have studied the relationship between its shear rate and shear stress, and examined the primary kickoff pressure. The characteristics of crude oil are shown in Table 1.

The experimental result is shown in Fig.1.

The rheological relationships can be obtained in Table 2. where, γ is the shear rate, S^{-1}, τ is the shear stress, Pa.

TABLE 1: CHARACTERISTICS OF CRUDE OIL SAMPLE

District	Density g/cm^3	Ground viscosity mPa.S	Formation viscosity mPa.S	Freeze point °C	Wax content %
A	0.9533	11013	350	32.4	7.3

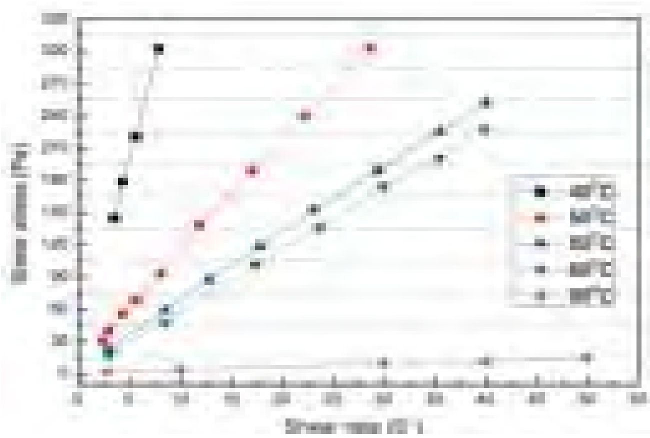

Fig.1 Rheology curve of crude oil in A district

TABLE 2: RHEOLOGICAL RELATIONSHIPS

Temperature °C	Rheological relationships
40	$\tau = 2.4+46\times\gamma^{0.9}$
50	$\tau = 0.7+13.8\times\gamma^{0.93}$
55	$\tau = 0.53+7.6\times\gamma^{0.95}$
60	$\tau = 6\gamma$
90	$\tau = 0.3\gamma$

According to the type of the rheological relationships, the fluid pattern of this district belongs to the pseudoplastic fluid if the temperature is less than 60°C, while Newtonian fluid if the temperature is more than 60°C. Therefore, the pressure prediction should take sectionalized procedures when the temperature is over 60°C to make the fluid pattern different.

2.1.2 Primary kickoff pressure

Based on the indoor experiments on extremely shear stress τ_0 of crude oil and temperature, their relationship can be obtained in Fig.2.

Through the matching method, the equation of above relationship can be available as follows.

If the temperature is over 60°C, τ_0 = 1.266×1016t-9.898, while $\tau_0 = 0$ if the the temperature is less than 60°C.

These experiments show the crude oil can flow easily if the driven force is greater than the extremely shear stress.

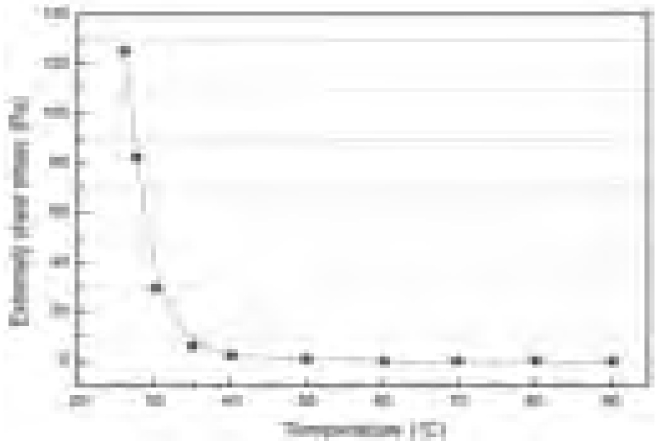

Fig.2 Relationship of extremely crude oil and temperature

Along with the rise of temperature shown in Fig.2, the extremely shear stress decreases, and approaches to be relatively low when the temperature exceeds 35°C, while approaches to zero if the temperature is more than 60°C.

According to the normal kickoff pressure Eq(1)[15], the actual primary kickoff pressure of district A can be calculated, as shown in Fig.3.

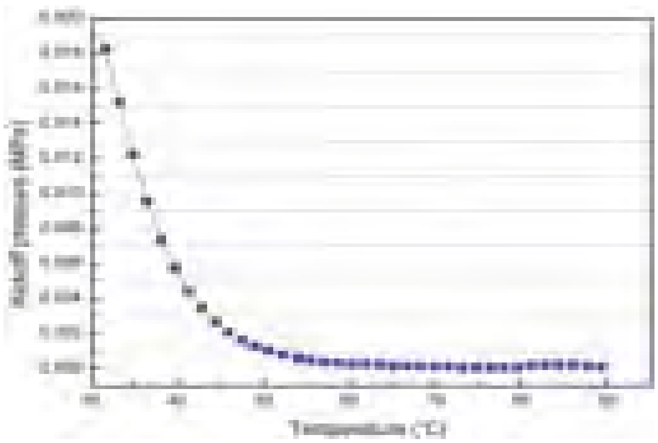

Fig.3 Cure of kickoff pressure in district A

$$P_{\tau_0} = 2_{\tau_0}L/r \quad \ldots \quad (1)$$

where, P_{τ_0} is the kickoff pressure, Pa; *L* is the length of tube, m; *r* is the tube diameter, m.

The heavy oil of this district can flow easily when the temperature approaches 60°C, and its properties are similar to thin oil, of which the pressure can be calculated by the normal models. Seen from Fig.3, it turns out the kickoff pressure would approach zero if the temperature reaches 60°C, it means the heavy oil can move easily during this situations.

2.2 PRESSURE LOSS

Based on the indoor experiment and basic constitution of pressure loss, the usual pressure calculation model can be figured out in Eq(2), and the bottom hole pressure can be available step by step.

$$P_h = P_d + \Delta P + P_g \quad \ldots \quad (2)$$

where, P_h is the bottom hole pressure, MPa; P_d is the wellhead pressure, MPa; P_g is the gravity of liquid column, MPa; ΔP is the fractional pressure loss, MPa.

The pressure distribution has a close relationship with the type of reservoir fluid, and is also affected by the phase flow in the pipe. The phase pattern of district A should be studied based on the Newtonian fluid or pseudoplastic fluid types respectively.

2.2.1 Type of pseudoplastic fluid

The block 1# belongs to pseudoplastic fluid if the block temperature is less than 60°C. The phase pattern can be predicted through Eq(3)[16].

$$R_e = \frac{D^n v^{2-n} \rho}{m} \quad \ldots \quad (3)$$

where, $m = \frac{k}{8}\left(\frac{6n+2}{n}\right)^n$. k is the consistency coefficient; n is the flow index; v is the speed, m/s; D is the pipe internal diameter, m; ρ is the fluid density, kg/m^3.

The Reynolds number and daily liquid production are calculated as shown in Fig.4.

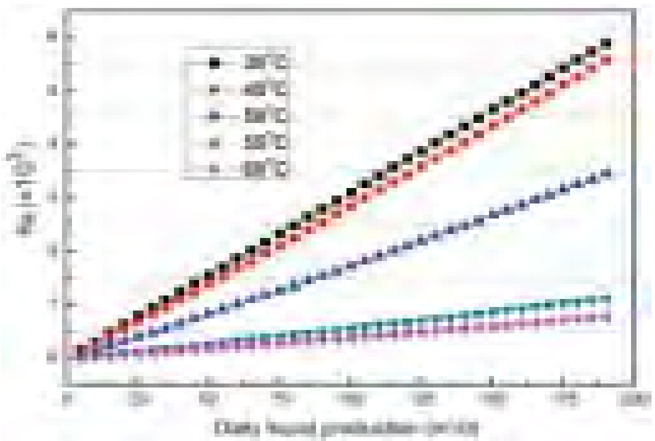

Fig.4 Phase pattern prediction

The fluid production of this block is 5~40m^3/d; the temperature is below 60°C; the Reynolds number is less than 2000, which means the phase pattern belongs to structural flow. Then it can be approached to the pressure loss as below.

According to the definition of pseudoplastic fluid [17], the shear stress can be obtained in Eq(4).

$$\tau = \tau_0 + k\left(-\frac{du}{dr}\right)^n \quad \ldots \quad (4)$$

where,

$$\tau_0 = \frac{pr_0}{2L}, \tau = \frac{pr}{2L} \quad \ldots \quad (5)$$

where τ_0 is the extremely shear stress, Pa; τ is the internal frictional stress per area, Pa; u is the speed at the distance r, m/s; r is the radius, m; r_0 is the radius of flow core, m; p is the pressure drawdown of liquid column, Pa; L is the liquid column, m; k is the consistency coefficient; n is the flow index.

Substituting Eq(5) into Eq(4), we obtain the Eq(6).

$$\frac{p(r-r_0)}{2Lk} = \left(-\frac{du}{dr}\right)^n \quad \ldots \quad (6)$$

Substituting Eq(6), the Eq(7) is available.

$$u = -\frac{n}{n+1}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}\left[(r-r_0)^{\frac{n+1}{n}} - (R-r_0)^{\frac{n+1}{n}}\right] \quad \ldots \quad (7)$$

where, R is the pipe diameter, m.

When the r reaches the r_0, the velocity of flow core can be available by Eq(8).

$$u_0 = \frac{n}{n+1}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}(R-r_0)^{\frac{n+1}{n}} \quad \ldots \quad (8)$$

Thus,

$$Q_0 = \pi r_0^2 u_0 = \pi r_0^2 \frac{n}{n+1}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}(R-r_0)^{\frac{n+1}{n}} \quad \ldots \quad (9)$$

As the whole fluid rate Q includes two parts, one is of the flow core Q_0, the other is the fluid rate in gradient district Q_1, the whole fluid rate is $Q = Q_0+Q_1$. And the fluid rate Q_1 can be available by substituting Eq(10).

$$Q_1 = \int_{r_0}^{R} -2\pi \frac{n}{n+1}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}\left[(r-r_0)^{\frac{n+1}{n}} - (R-r_0)^{\frac{n+1}{n}}\right]dr \quad \ldots \quad (10)$$

After substituting the Eq(10), the Q_1 is available as shown in Eq(11).

$$Q_1 = \frac{\pi n}{n+1}(R-r_0)^{\frac{n}{n+1}}\left(R^2 - r_0^2\right) - \frac{2\pi n^2}{(n+1)(3n+1)}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}(R-r_0)^{\frac{3n+1}{n}} \quad \ldots \quad (11)$$

And the whole fluid rate Q can be available in Eq(12).

$$Q = \frac{\pi n}{n+1}(R-r_0)^{\frac{n}{n+1}}\left(R^2 - r_0^2\right) - \frac{2\pi n^2}{(n+1)(3n+1)}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}(R-r_0)^{\frac{3n+1}{n}} + \pi r_0^2 \frac{n}{n+1}\left(\frac{p}{2Lk}\right)^{\frac{1}{n}}(R-r_0)^{\frac{n+1}{n}} \quad \ldots \quad (12)$$

Eq(12) is the relationship between fluid rate and pressure loss in inner pipe for pseudoplastic fluid in structural flow.

2.2.2 Type of Newtonian fluid

The block 2# belongs to Newtonian fluid because the block temperature is more than 60ºC. The phase pattern can be predicted through Newtonian Reynolds number by Eq(13)[18].

$$R_e = \frac{vd\rho}{\mu} \quad \dots \quad (13)$$

where, v is the average velocity, m/s; μ is the kinetic viscosity, Pa.S; d is the pipe diameter, m.

Calculating the flow conditions of block 2# with various flow rates in 76mm pipe diameter, the results are shown in Fig.5.

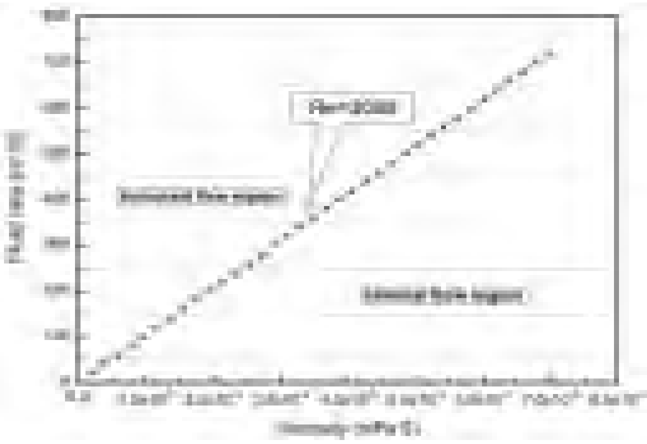

Fig.5 Critical flowing condition of heavy oil

As the fluid rate of this block is as same as block 1#, the viscosity will be 400~6000 mPa.S when the temperature in this block is not less than 60ºC. As shown in Fig.5, the R_e is below 2000, the phase pattern is laminar flow. According to the relationship between velocity and pressure loss in the effective sectional area of inner pipe, as the Newtonian fluid is laminar flow pattern, the relationship can be expressed by Eq(14).

$$u = \left(\frac{p}{4L\mu}\right)\left(R^2 - r^2\right) \quad \dots \quad (14)$$

Then the relationship between fluid rate and pressure loss can be expressed in Eq(15).

$$Q = \int_0^R u 2\pi dr = \frac{p\pi}{8L\mu} R^4 \quad \dots \quad (15)$$

2.3 Temperature performance

It is well-known that, the usual iterative computation for predicting the pressure gradient during oil-gas two-phase flow and oil-gas-liquid three-phase flow is shown in Fig.6.

With regard to the pipe in steam injection wells, there are several big differences in the iterative computation.

(1) Average temperature calculation in each part of pipe, firstly, physical parameters, like gas/oil ratio, oil volume factor and gas volume factor, can be available by reservoir temperature, liquid production, liquid content, special part

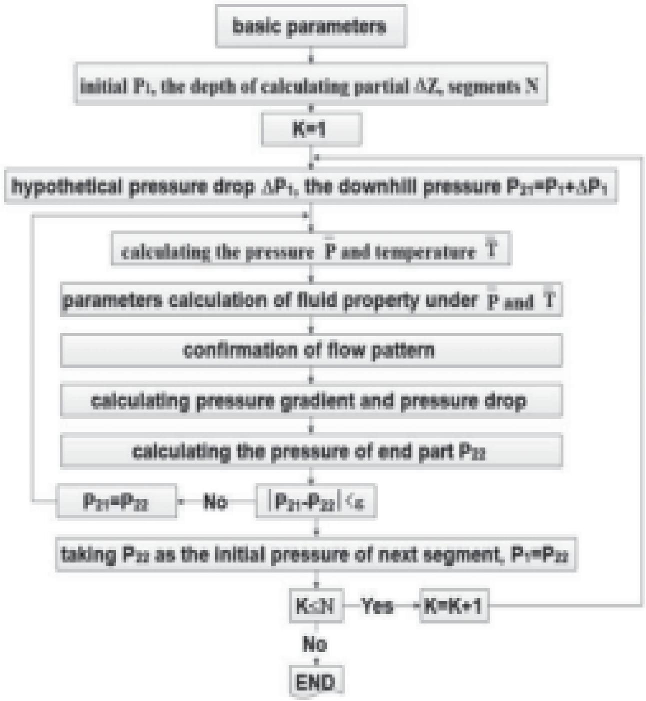

Fig.6 Common iterative process of pressure prediction

pressure and hypothetical temperature. Then, the new temperature can be calculated through iterations with Sagar method [9, 19]. When it comes to predicting the pressure gradient, the temperature system has changed. The saturated vapour temperature is only related to the vapour pressure, thus, the average temperature is available by a new way to re-calculate the average pressure.

(2) Calculation of fluid property parameters and different flowing parameters under average pressure and temperature, it is of great significance to first access the gas mass flow, liquid mass flow and outlet liquid volume content, however it is easy to calculate the volume of free gas using the physical parameters during the pressure prediction process, finally to work out the three parameters above. The steam dryness can be calculated based on the velocity of external heat loss[20], and then come to the water mass flow, gas mass flow and so on.

The speed of heat loss in pipe is calculated by Eq(16).

$$Q_s = \frac{2\pi r_{t0} U_{t0} K_e}{K_e + r_{t0} U_{t0} f(t)} \left[\left(T_s - b\right)L - \frac{aL^2}{2} \right] \quad \dots \quad (16)$$

where $f(t)$ is the heat conductivity; U_{to} is the total coefficient of heat transmission from the outface of tube to the outface of cement mantle, kcal/(m^2.h.ºC); r_{to} is the outside diameter of tube, m; K_e is the coefficient of heat conductivity of layer, kcal/(m.h.ºC); T_s is the temperature of steam, ºC; b is the temperature of land surface (layer of constant temperature), ºC; a is the geothermal gradient, ºC/m; L is the total length of injecting pipe, m.

The coefficient of heat loss in pipe is calculated by Eq(17).

$$\partial = \frac{100Q_s}{M_s\left[X_i C_s + (1 - X_i)C_w\right]} \quad ... \quad (17)$$

where, M_s is the mass velocity of steam injection, t/h; C_s is the coefficient of latent heat of vaporization in wellhead, kcal/kg; X_i is the dryness fraction of steam in pipeline, %; C_w is the sensible heat of saturated steam in pipeline, the heat capacity of water phase, kcal/kg.

The dryness fraction of steam is calculated below.

The criterion that determines whether the dryness fraction of steam is greater than zero is shown in Eq(18).

$$Q_s < M_s \cdot X_i \cdot C_s \quad ... \quad (18)$$

If theEq(18) is true, the X_i can be calculated by the Eq(19).

$$\partial X_j = X_i - \frac{Q_s}{M_s \cdot C_s} \quad ... \quad (19)$$

The gas mass flow and water mass flow can be calculated by the Eq(20) and Eq(21), respectively:

$$M_g = M_s X_i \quad ... \quad (20)$$

$$M_w = M_s(1 - X_i) \quad ... \quad (21)$$

where, M_g is the steam injection speed, t/h; M_w is the water injecting speed, t/h.

2.4 Production prediction

For the normal reservoir with kickoff pressure, the law of predicting production fits with Eq(22)[21].

$$V = \frac{k}{\mu}\left(dp/dr - \lambda\right) \quad ... \quad (22)$$

where, V is the Darcy velocity, cm/s; K is the permeability, μm^2; μ is the liquid viscosity, mPa.S; dp/dr is the pressure gradient, 0.1MPa/cm; λ is the primary kickoff pressure, 0.1MPa/cm.

As seen from the Eq(5), if $|dp/dr| > \lambda$, then $V = \frac{k}{\mu}\left(dp/dr - \lambda\right)$, while $|dp/dr| \le \lambda$, V = 0. According to the law of pressure distribution, the gradient is much lower when the point approaches to the boundary, therefore there should be a location R in the layer with equal kickoff pressure gradient, that is $dp/dr = \lambda$. If the distance is greater than R, the flow pressure gradient is not less than kickoff pressure, and then the flow cannot move easily. Only if the distance is located in the R circle can the flow move easily, and this R is so-called kinematical circle. The corresponding boundary is the kinematical boundary pressure.

So says, if the reservoir has the limit of kickoff pressure (like types of Newtonian fluid or pseudoplastic fluid), the diameter cannot be calculated for the reservoir outline, but for the kinematical circle. The boundary pressure should take the appropriate kinematical value.

For most of vertical wells, the method of predicting production is Darcy's Law, which is suitable for the normal oil reservoirs. With the limit of possible kickoff pressure in heavy oil well at an underground temperature, the reservoir outline and boundary pressure are not the basic conditions for flow movement, which means the Darcy's Law no longer fits for heavy oil wells. Thus the new method for predicting production should be developed.

Suppose the heavy reservoir is homogeneous, isotropic, and has stable boundary pressure with only single phase flow. With the flowing obstacle of kickoff pressure, the fluid should overcome this pressure for movement, while the fluid flows, the rheology properties match the Newtonian.

Based on the generalized Darcy's Law, when the fluid flows, the production prediction is shown in Eq(23).

$$Q = \frac{2\pi rhK}{\mu B}\left(dp/dr - \lambda\right) \quad ... \quad (23)$$

where, Q is the liquid production, m^3/d; r is the radial distance, m; h is the reservoir thickness, m; p is the pressure at the distance r, MPa; B is the volume ratio. Take $r = R$ and $p = p_m$, we integrate the Eq(23), and come to the prediction model for heavy reservoir with kickoff pressure, as shown in Eq(24)[22].

$$Q = \frac{2\pi rhK}{\mu B \, ln \frac{R}{r_w}}\left[(p_m - p_w) - \lambda(R - r_w)\right] \quad ... \quad (24)$$

where, p_w is the bottom hole pressure, MPa; r_w is the pipe diameter, m.

Without considering the impact of kinematical circle and kinematical boundary pressure, the Eq(24) can be changed to Eq(25).

$$Q = \frac{2\pi hK}{\mu B \, ln \frac{R_e}{r_w}}\left[(p_e - p_w) - \lambda(R_e - r_w)\right] \quad ... \quad (25)$$

where p_e is the reservoir boundary pressure, MPa, and r_w is the reservoir radius, m.

The district A belongs to pseudoplastic fluid when the reservoir temperature is less than 60ºC, while Newtonian fluid temperature is greater than 60ºC. The district A pertains to the later as the temperature of reservoir is 78ºC, and the production predication model should be chosen as Eq(8).

3. Calculation and verification for a real well

3.1 Parameters distribution

To verify the feasibility of Beggs Brill method in pressure prediction during steam injection process, this paper describes this process through an on-site well.

Parameters during the steam simulation of X well in block 1# are given below.

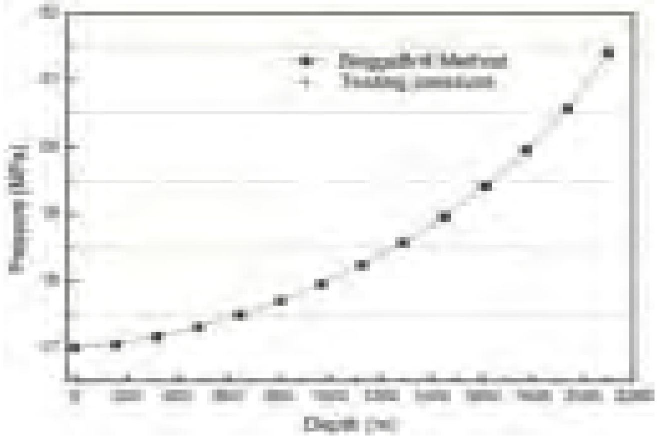

Fig.7 Pressure distributions during steam simulation

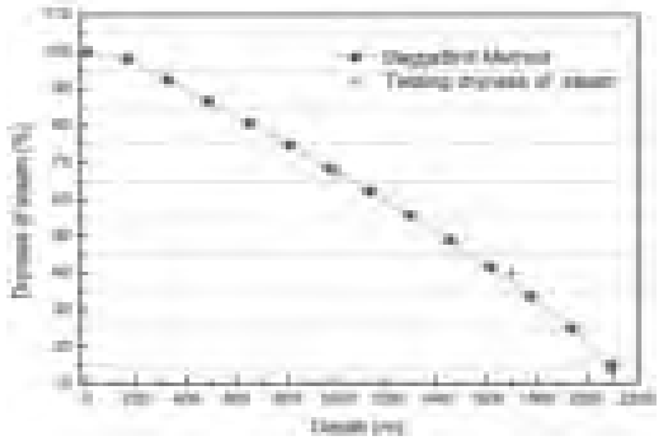

Fig.9 Dryness distributions during steam simulation

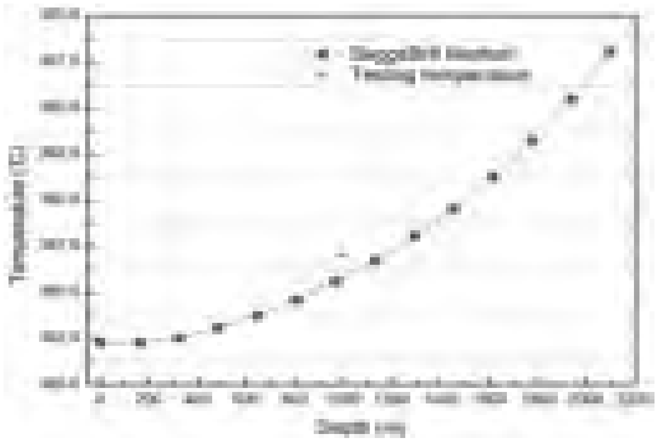

Fig.8 Temperature distributions during steam simulation

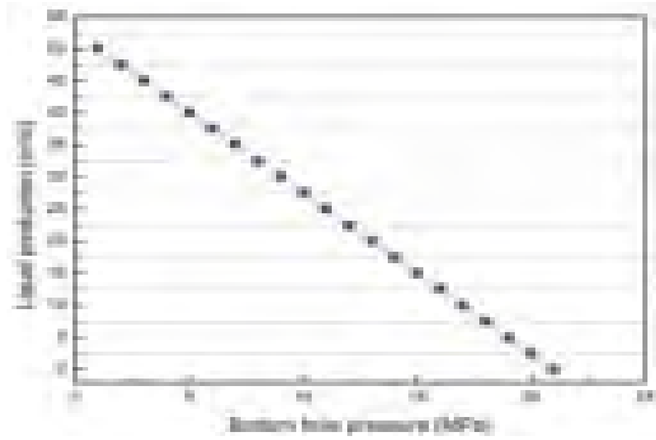

Fig.10 Production verification

(1) Reservoir parameters: temperature 78°C; depth 2,100m; surface temperature19.5°C; formation thermal conductivity 2.3 kcal/(m.h.°C); geothermal gradient 0.03 °C/m.

(2) Steam injection parameters: steam injection pressure 17MPa; the temperature is 240 t/d; steam injection time 3.0d; dryness fraction 100%.

(3) Tubing, casing and cement mantle parameters: tubing diameter steam injection, 0.062 m/0.073 m; thermal conductivity 37 kcal/(m.h.°C); casing diameter 0.1598 m/ 0.1778m; thermal conductivity 40kcal/(m.h.°C); diameter of cement mantle, 0.18 m/0.24 m; thermal conductivity 0.3 kcal/(m.h.°C); the annular is full of air with thermal conductivity of 0.006 kcal/(m.h.°C).

(4) The actual data, 357°C-1,000 m; bottom hole temperature of steam injection, 368°C; bottom hole pressure of steam injection, 21.41MPa; dryness 67 %-1,000 m, dryness 40 %-1,400 m, dryness 13 %-2,100 m.

Based on related parameters, this method turns out from prediction that the bottomhole pressure of steam injection is 21.4 MPa; the bottom hole temperature of steam injection is 368.04°C; the dryness of bottom hole is 14.99 %. The pressure, temperature and dryness distribution along the pipe are shown in Figs.7-9. As shown in the figure, the relative errors of these parameters are very low.

As shown in Figs.7-9, it is feasible to predict the pressure gradient by the Beggs Brill method accurately. While, the process of calculating parameters is also applicable to the production prediction.

3.2 Production verification

According to the parameters distribution of steam injection and the production prediction model (Eq(25)), the production of X well in block 1# can be calculated as shown in Fig.10.

As seen from Fig.10, the feeding amount of liquid goes up with the decrease of bottomhole pressure. As the detailed parameters of X well have been given above, the production calculated by Eq(25) is 20.1m^3/d with just 4% relative error from real daily production. While the result of normal process with Darcy's Law is 34m^3/d, and the relative error is 62%, that is to say, the new distribution process of parameters and the production prediction model are much more feasible for block 1# of district A. similarly, the block 2# can get the accurate calculation.

4. Conclusions

(1) Although there are many models for production prediction, none is suitable for all wells. Under certain conditions, the pressure loss and the temperature performance can be diversified in different downhill or uphill flow, which is tough for the accurate calculation of relative parameters.

(2) The differences between the new process and the other common methods are as follows: 1. The calculating method of temperature in steam injection wells is unique; 2. The calculating process of fluid property and different flowing parameters under average pressure and temperature is reliable. The paper describes the calculation process and gets the final feasible model.

(3) Example calculation in a real steam injection well prefers the Beggs Brill method to predict the pressure gradient at a high accuracy, and verifies this method more feasible. The calculation process and model of production predication are more applicable to such wells.

Acknowledgments

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