Discussion of dynamic adjustment approach for slightly Alkaline-Surfactant-Polymer flooding

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Abstract. Slightly Alkaline-Surfactant-Polymer flooding in the development process of the second oil reservoir of Daqing Oilfield had strong injection and production capability and high production rate, but dynamic response and adjustment method of each well group in different effective stages had differences. According to the development characteristics of the B area of the second class reservoir and dynamic characteristics of oil wells in different period, for unbalanced response problems of single well group, in-depth analysed the main contradiction of the effective phases, formed a comprehensive adjustment mode with injection scheme adjustment of "increasing viscosity by gradient" equilibrium,supplemented by fracturing of production well and injection well and optimization of displacement scheme and other adjustment technology.In order to further expand the swept volume, improved the producing status of middle and low permeability layers and achieved a better effect of development.

The Alkaline-Surfactant-Polymer (ASP) flooding technology shows great outcomes when the ASPpilot test conducted in 1993 in AAA oilfield with the incremental oil recovery of 20% compared to the water flooding. The technology has been continuously improvedand developed and recently the researchersuccessfully conducted the pilot test using weak base ASP(petroleum sulfonate surfactant) instead of strong base ASP (ABS; alkylbenzenesulfonate) surfactant.The use of petroleum sulfonate surfactant for ASP pilot test conducted in the BBB blocksecond-classreservoir was the first implementedpilot test using weak base surfactant. Based on philosophyof"Quick development in compound flooding, 2014 full field industrialization promotion", the27.82% of incrementaloil recovery was targeted and it was a great achievement. The optimization of the displacement projects, reasonable well pattern and arrangement and the compatibility between the chemical and the reservoir were the key factors for the successful project. On top of that, the timing, and flexibility to change the recipe of chemical is also play a role for the success.

1.Introduction of B block

The area of B is 1.17km2, which is five spot well patterns. It was consisted of 35 injection and 40 production wells, including 20 central wells. The target layer is SⅡ10-12. The average thickness of sandstone is 8.0m. the effective thickness is 6.4m, the effective permeability is0.527μm2.the geologic reserves is 115.27×104t. the pore volume is217.35×104t..

The area B was put into operation on November 2006, the area was in prepositive slug injection in August, 2008. The area was in main slug injection in December, 2009. The area was in sub slug injection in March, 2011. The area was in protective slug injection in November, 2012. The area was in the follow-up water flooding in November, 2013.The composite water went down at 0.12PV. The composite water was lowest at 0.32PV. At the end of July, 2013,The composite water cut of center was 95.5%，which is lower 1.92% than mathematic model. Periodical recovery percent of reserves is 34.11%,The recovery factor is up to 27.82% during chemical flooding，which is higher than mathematic model4.77%.

2. "EnhanceViscosity" improved the sweep efficiency in medium & high permeability layers.

The researchers indicate that reducing the interfacial tension and enhancing the viscosity of the displacement fluid was the effective method to enhance oil recovery for the non-homogeneous formation. The ultra-lowInterfacial Tension (IFT) is require to recover the residual oil which left after the water flooding but the impact is not much compare to the enhanced/control the viscosity which guaranteehigher oil recovery. These are due to the high displacement efficiency only occur at high permeability layers, however the high sweep efficiency mainly occur at low to medium permeability layers. Normally, the sweep efficiency cover about 67% from total enhance oil recovery efficiency and the rest are from displacement efficiency.

From the result of core flooding, gradually increase viscosity during pre-polymer slug, main ASP slug, auxiliary ASP slug and subsequent polymer sluginjection would gradually increase injection pressure thus enhance oil recovery. Comparing between ordinary pressure increase method and gradually decrease pressure method, the gradually increase ininjection pressure would increase oil recovery up to 1.7% and 4.65% higher than these two methods.

In this pilot, 387 scheme modifications was carried out due to different stage dynamic and main problem.There were more than 91.27% well's parameters was modified such ascontrolling injection velocity and injection viscosity to improve EOR result.

At the stage of no response from surrounding wells,68 scheme modifications were carried out including 51 injection volume modifications and 17 viscosity modifications to balance the injection pressure and modify VRR.

At the stage of gradually responded surrounding wellsperiod, the polymer distribution profile modifications and production stimulationswere carried out to improve the injection pressure and sweep volume. 61 parameters modificationswere carried out at this stageincluding 16 injection volume modifications and 45viscosity modifications.

Decreasing in water cut was thecritical period for this pilot. The total liquid production was decreasing thus some of the wells will not benefit from the ASP injection. At this critical stage, the parameters modifications were focus on how to control areal heterogeneity and how to improve areal sweep efficiency. 148 parameters modificationswere carried out at this stage including 37 injection volume modifications and 97viscosity optimizations and 14 combination of injection volume and viscosity modifications.

The last period which are very important in ASP flooding are when the water cut begin to increase. Controlling areal heterogeneity and water cut were very crucial at this stage. Water break through may occurs at some of the wells at this period that may lead to high amount chemical production (polymer, alkaline and surfactant). Huge amount of chemical concentration wererequire to continue the chemical flooding at this stage. So controlling the water break through and chemical productionis necessary at this period. 110 scheme modificationswere carried out at this stage including 22 injection volume modifications, 65 times viscosity modifications and 23 combination of volume and viscosity modifications.

So, in overall there are two kinds of scheme modifications which areinjection volume modifications and viscosity modifications. The purpose of injection volume modifications are to control areal heterogeneity and control well groups VRR while forviscosity modification are to control vertical heterogeneity and enhance sweep volume. Due to these modifications, Block B viscosity had increase gradually from 19mPa·s to 61mPa·s. The injection pressure had increase from 5.92MPa (pre-water flooding) to 10.42MPa (middle stage of water cut increasing). The well groups injection pressure difference were from 5.11MPa (pre-water flooding) to 2.12MPa (subsequent stage of polymer slug) and in the stage of main slug, the well groups injection pressure difference was kept between 2 to 3MPa in order to ensure the producers can benefit from ASP injection from all direction.

As we all know, sweep volume is the result of sweep area times with vertical sweep thickness. Sweep volume can be improve by two factors.The first factor is by increasing the flowing bottomholepressure differences between injectors and producers. By increasing theviscosity, the flowing bottomhole pressure differences between producers and injectors will also gradually increase thus improve the sweep area. At different stage, flowing bottom hole pressure differences between injectors and producers was keep changing, for example, the bottomhole pressure differences during pre-water injection was 8.02MPa, the pre-polymer flooding was 8.93MPa, the main ASP slug was 12.44MPa, the auxiliary ASP slug was 12.70MPa while atsubsequent polymer slugwas 13.97MPa.Secondly, by improving thePolymer/ASP distribution profile may lead toimprove in vertical sweep thickness.The ratio of working layer number over total layer numberbetween pre-water injection stage with pre-polymer slug, main ASP slug and auxiliary ASP slug stage increased 6.76%, 11.32% and 13.53% respectively. While the ratio of working thickness over total thickness between them also increased 6.65%, 9.01% and 11.57% respectively. The ratio of working thicknessover total thickness for the group of net pay thicknesslower than 1m and permeability less than 100mD formationhaveincreased 12.3% and group of net pay thicknessof 1-2m with permeability range of 100-200mDformation have also increased by 22%. The increase in ratio in some small thickness and permeability formation give an indication that ASP flooding increased sweep volume.

3. To use the high concentration Polymer solution to control the polymer distribution before ASP injection.

After the water injection, the difference of the injection pressure and the water distributionamong the wells are high due to the reservoir heterogeneity. There are 22 wells injection pressure lower than 6 MPa and the percentage is 62.9% while there are only 2 wells injection pressure higher than 7 MPa and the percentage is 2.9%. Polymer injection distribution profile shows most Polymer injected into SII-12 formation and the percentage is 45.63%.

In order to balance the differences of the injection pressure and the water distribution profile among the wells,7 wells were selected to inject high concentration of polymer solution, due to its high net pay thickness, low injection pressure and serious interlayer heterogeneity.

The average net pay thickness of the 7 wells is 9.3m with permeability of 675 mD. Average injection volume of the 7 wells is 53.4 m3and injection pressure is 5.23MPa. Average start-up pressure is 2.81MPa and average PI is 10.16MPa. Ratio of working thickness over total thickness is 74.03% and the main working thickness ratio is 30.4%. Average produced liquid of 8 surrounding wells is 46 t, produced oil is 0.69 t and water cut is 95.81%.

The use of high concentration of polymer pre-slug injection was a successful and effective waywhere:

Firstly, all the 7 injected wells injection pressurewas increasedand the water distribution was improved. Their injection pressure increase from 5.86MPa to 8.79MPa, howeverother 28 injection wells pressure just increased from 5.94MPa to 8.58MPa. The water distribution was improved and theinjection volume of high permeability formation was decreased. For examplein B-2-62 well, only 51.76 % of its thickness can be injected by polymer prior to the modification, however 100% of thickness can injectedpost profile modifications.

Surrounding wells production performance

Category	No.	Before profile modification			Afterprofile modification			WC Difference (%)
		Gross (t)	Crude (t)	WC (%)	Gross (t)	Crude (t)	WC (%)	
Surrounding wells	18	86	1.1	98.69	65	14.0	78.41	-20.29
Water cut decrease>20%	12	93	1.5	98.41	69	20.2	70.90	-27.51
Other wells	26	42	0.9	97.83	47	7.0	84.89	-12.94
Total	44	66	1.0	98.45	56	10.8	80.84	-17.61

Secondly, all the surrounding wells benefit from polymer distribution modification. Post profile modifications, 18 surrounding wells oil production rate increased 14 t/d and water cut decreased 20.29% (from 98.60% to 78.41%).However,the oil rate only increased 7 t/d and the water cut decreased 12.94% (from 97.83% to 84.89%) for other producing wells which located far away from profile modification injected wells.After profile modifications,12 surrounding wells water cut decreased more than 20% (from 98.41% to 70.90%) and oil production rate increase 20.2t/d.

4. Implementation of production stimulation to improve ASP EOR result.

Block B water cut began to decrease when the chemical injection volume is 0.2269 PV. At this stage the producers began to response. The injector's injection pressure began to increase, 9 injectors were encounters difficulty to inject chemical due to the chemical absorption into the reservoir and the producers' liquid production also decreased significantly. The injection and production stimulation are necessary at this stage to cater this issue.

In order to ensure the good effectduring the pilot test, according to reservoir conditions and principal Contradiction of different stage, accurate timing and adjustment in injection and production stimulation was carried out. In the stage of water cut decrease to the bottom, 9 injectors were fractured and before water cut increase another 9 injectors were fractured. After fracturing, the injection pressure decreased to 2.99Mpa and 3.58MPa.

19 Producers were fracturedduring the ASP flooding. From the study, fracture can increase the sweep volume and enhance oil recovery up to 2.52%. When the water cut decreased to low value and reached the bottom, 13 wells were fractured. After fracturing, the oil rate increase to 10.8t/d per well and water cut decreased to 2.09%. Before water cut increased, another 6 wells were selected to be fracture in order to increase the low net pay formation sweep volume. After the fracturing, the oil production rate increased to3.5 t/d per well and water cut decreased to 1.62%. The best timing to fracture the wells is when the water cut at lowest value thus can improve oil recovery.

5. To conduct injection sensitivities analysis and parameters optimization for further enhancement of oil recovery.

Injection sensitivities analysis and parameters optimization is necessary during ASP floodingin order to further enhance oil recovery.

At the end of auxiliary slug injection, injection pressure can be further increase andthe water cut was 90.35%, 20 wells have water cut lower than 90%, and it is a possibility to further inject ASP solution into the reservoir.

From remodeling study, injection scenario was optimized and auxiliary slug change from 0.1 PV to 0.2 PV,subsequent polymer slug changed form 0.2 PV to 0.25 PV.

The ASP flooding may further enhanced oil recoveryup to 2.5% after the optimization.

6. Conclusion

(1) Improve viscosity gradually and balance the injection pressure during ASP flooding can enhanced the injection volume in second class reservoir.

(2) To use the high concentration Polymer solution to control the polymer distribution before ASP injection can significantly increase sweep volume.

(3) Implementation of production stimulation (fracturingproducer and injector)can further improve oil production and enhance oil recovery.

(4) To do the remodeling and optimize ASP flooding scenarios can further enhance oil recovery by 2.5%.

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