Lessons Learned from Stimulation of Dibei Tight Gas Reservoir with Strong Heterogeneity in Tarim Basin

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Abstract. The Dibei gas field is a naturally fractured tight sandstone gas reservoir in the Tarim Basin, West China. It is characterized by large depth (4600–5200 m), huge thickness (100–200 m), low abundance, low matrix permeability, high pressure (80–95 MPa), high temperature (140 – 150°C) and strong heterogeneity. Different stimulation techniques were applied to improve well production. For the wells with good development of natural fractures, matrix acidizing, acid fracturing or conventional hydraulic fracturing is used. For the wells with low fracture density and huge thickness, separate-layer acid-fracturing, massive separate-layer hybrid fracturing or composite diverting agent is applied to improve stimulation efficiency. The low-damage high-temperature weighted fracturing fluids are used to reduce the effect of reservoir sensitivity and the treatment pressure, and high-strength proppant is used at the same time to keep high fracture conductivity. Meanwhile, large-diameter fracturing string with 3-1/2” and 4-1/2” connections is used to decrease pump pressure and increase pump rate. The above technologies were applied in more than twenty treatments in seven wells, of which more than half witnessed production increase. The matrix acidizing or conventional hydraulic fracturing is well performed for the wells with natural fractures, but inefficient for the extremely tight gas wells. In Well A without fractures, the massive separate-layer hybrid fracturing was used. In the treatment, a total of 1,328 m³ fracturing fluid was used, with 50 m³ proppant; the pump rate was 8 m³/min and the maximum pump pressure was 92 MPa. Unfortunately, the post-frac production was not as expected, mainly due to the damage of killing well. In Well B with fractures, high gas production was achieved by acid fracturing, but the gas rate dropped from 258,000 m³ to 51,000 m³ after killing well, and the gas rate never recovered even by acid fracturing, hydraulic fracturing and relieving damage with methanol. The development of natural fractures is the key controlling factor for gas production. Well C, less than 800 m from well B, the development of natural fractures is quite different from Well B, and 98,000 m³ gas rate was acquired after hydraulic fracturing with more than 1,000 m³ low damage high-temperature weighted fracturing fluid and 30 m³ proppant. The development of natural fractures is the key controlling
factor for gas production and killing well damage is the fatal blow to the gas production, so the stimulation techniques and working fluid system should be prudently optimized.

1. Introduction
The Dibei gas reservoir lies in the No.1 Dibei faulted nosing structure in the Dibei slope zone in the northern structural belt of the Kuqa sag. In this structure, the Jurassic Ahe Formation and Yangxia Formation reservoir rocks are dominant, and they are characterized by wide and stable distribution in horizontal direction, low porosity, low permeability, existence of fractures, strong heterogeneity, pervasive gas accumulation and low gas abundance, and high yield in sweet spots.

There are 15 wells in this area, which were drilled by the techniques of nitrogen drilling, oil-based mud drilling, and water-based mud drilling. However, they failed to achieve satisfactory production, in spite of the conventional stimulation treatments and large-scale composite fracturing. Only 5 wells yielded commercial oil and gas flow due to reservoir complexities.

We assessed the technology, size, and result of stimulations in the Dibei gas reservoir and examined the controlling factors for stimulation using log, formation test, and production performance data. We finally made suggestions about reservoir stimulation in this area.

2. Reservoir features
The Jurassic Ahe Formation in Dibei consists of braided river deltaic plain and deltaic front deposits. The reservoir beds comprise 7–9 normal cycles extending stably in the lateral direction. Sands thickness ranges from 260m to 300 m.

2.1. Lithology
The Jurassic Ahe Formation is composed of lithic sandstone and some feldspar lithic sandstone. Coarse-grained rocks mainly include conglomerate, conglomeratic coarse sandstone, and sandstone with varied particle size. Sub-angular to sub-rounded grain-supported sandstone particles are moderately sorted in linear to concavo-convex contact and with porous cement. Component maturity and textural maturity are moderate to good. Average quartz content is 33.7%; average feldspar content is 13.0%; average debris content is 37.2%. The average content of interstitial materials, including calcite, silicon, and clay, is 12.4%. The average content of clay minerals, including hair-like illite and some flake-like illite and illite/smectite, is 5.6%.

2.2. Pore structure
The reservoir space is composed of micropores in argillaceous rock, intragranular dissolved pores, intergranular dissolved pores, and microfractures; primary pores may seldom be observed (Figure 1). Reservoir displacement pressure ranges 0.14–2.51 MPa. The maximum throat radius ranges 0.29–5.25 μm. The median pressure ranges 0.89–46.80 MPa. The median throat radius ranges 0.02–0.83 μm. The throat radius mainly ranges 11–40 μm. In general, pore-throat structure is poor.

Structural fractures and microfractures in the Ahe Formation constitute an efficient network for fluid flow and hydrocarbon accumulation. This is a factor for high yield from the Dibei gas reservoir. But fractures are heterogeneous in the vertical and lateral directions.

![Figure 1. Pore types and geometries](image-url)
2.3. Reservoir properties
The matrix porosity of Ahe sandstone ranges 0.3–12.2% with an average of 5.6%; the permeability ranges 0.01–2670 mD with an average of 0.76 mD. Reservoir rocks are generally of ultra-low porosity and low to ultra-low permeability (Figure 2).

![Figure 2. Histograms of core properties](image)

2.4. Sensitivity
The Ahe reservoir rocks feature high velocity sensitivity, weak acid sensitivity, moderate to high alkali sensitivity, moderate to high water sensitivity, and moderate to high salinity sensitivity.

2.5. Temperature and pressure
The Ahe gas reservoir is an abnormal-high pressure reservoir in view of the pressure coefficient of 1.4–1.82. The original formation temperature normally ranges 136–145°C.

3. Reservoir stimulation
Matrix acidizing, small-scale fracturing, large-scale acid fracturing, and large-scale composite fracturing were used for 21 treatments of 8 wells among 15 wells drilled in Dibei. Such treatments included 7 acidizing treatments, 2 acid fracturing treatments, 11 fracturing treatments, and 1 methanol de-plugging treatment. Reservoir stimulation was mainly accomplished through acidizing and small-scale sand fracturing before 2005 and through acid fracturing and large-scale sand fracturing after 2005 (Figure 3).

Some pilot tests on acidizing, as well as fracturing, were made before 2005. Totally, 11 treatments were carried out for two wells, including 7 acidizing treatments and 4 fracturing treatments, using the 3-1/2″+2-7/8″ completion strings and conventional fracturing fluid systems. Due to the limitation of strings and fracturing equipment, the displacement was less than 3.0 m³/min, and the treatment scale was small, with the maximum sand volume in a single layer less than 15 m³.

Fracturing became the major stimulation technique after 2005 due to the application of 4-1/2″ and 5″ large-diameter completion strings and KCL weighted fracturing fluids, together with the improved equipment. Totally, 10 treatments were conducted, including 2 acid fracturing treatments and 7 fracturing treatments, with the techniques of large-scale acid fracturing, packer layered fracturing, and large-scale composite fracturing. The maximum displacement reached 11.1 m³/min; the maximum volume of fluids reached 1,328 m³; the maximum sand volume reached 80.74 m³ per well or 60.59 m³ per layer. According to the statistical data, reservoir stimulation after 2005, especially sand fracturing, did not get good results at some wells. The increase in gas production was limited. There is no evident correlation between production and stimulation scale (Table 1).

![Figure 3. Statistical data of reservoir stimulation at different stages](image)
Table 1. Reservoir stimulation parameters and production

| Well | Depth m | Stimulation | Vfluid m³ | Pumping pressure MPa | Pumping rate m³/min | Proppant m³ | Pressure gradient MPa/m | Production before/after stimulation |
|------|---------|-------------|-----------|----------------------|---------------------|------------|------------------------|-----------------------------------|
| E    | 4969–4982 | Fracturing | 127.9     | 95                   | 2.24                | 3.2        | /5.6                   | /3.45                             |
|      | 4776–4785 | Acidizing   | 16.5      | 68                   | 0.4                 | 0.023      | /                      | /6.9                              |
| G    | 4746–4760 | Fracturing | 191       | 100.5                | 2.82                | 11.4       | 0.026                  | 0/13.1                            |
|      | 4606–4620 | Acidizing   | 27.9      | 71.4                 | 0.83                | /          | 0.26/0.16/0.16         | /21.6                             |
| H    | 4595–4615 | Fracturing | 323.4     | 78.5                 | 4.12                | 22.5       | 0.027                  | /0.15                             |
|      | 4898–4975 | Acid fracturing | 271       | 92                   | 5.05                | /          | 28.7/29.5              | 22.8/25.9                         |
|      | 4808–4975 | Acid fracturing | 530       | 86.2                 | 5.16                | /          | 10.4/20.7              | 5.1/18.5                          |
|      | 4808–4975 | Fracturing | 1058.7    | 109                 | 11.1                | 42.92      | 0.025                  | 23.3/21.7                         |
|      | 4808–4975 | Methanol   | 25        | 79.0                 | 1                   | /          | 35.5/41.79             | 12.8/14.56                        |
| M    | 4867–4985 | Fracturing | 1068      | 115.5                | 5.06                | 60.59      | 0.029                  | 0.35/4.84                         |
|      | 5053–5061 | Fracturing | 416.9     | 107.8                | 3.78                | 20.15      | 0.025                  | 0/0.15                            |
| A    | 4938–5099 | Fracturing | 1328.6    | 92.2                 | 8                   | 50.1       | 0.023                  | 9.6/11.4                          |
| C    | 4785–4840 | Fracturing | 680       | 103.4                | 5.4                 | 30         | 0.026                  | /                                 |

4. Controlling factors for stimulation

According to the production data before and after stimulation, reservoir stimulation after 2005, especially sand fracturing, did not get good results at some wells. The increase in gas production was limited even at large sand volume. The following factors are considered critical for stimulation.

4.1. Tectonic setting

The Dibei gas reservoir is a non-typical layered tight gas accumulation controlled by local structures. It is greatly variable in gas saturation, physical properties and well productivity at different structural positions.

Well D drilled at the structural high had high yield without any stimulation; its open flow capacity exceeded 1,000 MCM. Well M drilled using the nitrogen drilling technique at the structural margin was tested to be a low-yield well; its open flow capacity was 2,000 m³/d. Due to low gas saturation and poor reservoir properties, Well M did not realize economic gas production even after fracturing (Figure 4). These two wells differ greatly in matrix porosity, permeability, saturation, and fracture density. This means strong heterogeneity of Jurassic reservoir in Dibei has a great impact on well productivity.

Figure 4. Structure map of Dibei
4.2. Fractures
In the Dibei fractured-porous gas reservoir, natural fractures are developed, matrix pores and fractures serve as major storage space and flow path, respectively, and the overall connectivity is poor. As per reservoir correlation, the fracture density varies heterogeneously in the vertical and lateral directions. Natural fracture density diversely ranges 0.007–0.51/m, and effective permeability ranges 0.0018–0.85 mD (Table 2). Fracture density is large in the areas with favorable structures. For example, Well D and Well B, where there are mainly half-filled and unfilled high-angle fractures and some oblique fractures, achieved high, stable yield after well completion (Figure 5). Well C, which was also drilled at a favorable, is an exception. It is 1,250 and 790 m far away from Well D and Well B, respectively. Due to fracture heterogeneity, no natural fractures were observed in core samples acquired from Well C; there was no circulation loss during well drilling, and initial production was only 20,000 m3. Its daily gas production increased to 100,000 m3 after large-scale fracturing and quickly decreased to 35,000 m3 after six months. Some wells, e.g. Well A and Well M, were drilled at the structural margin with low fracture density or low permeability. Their initial production was low, and post-frac yield was also far from economic production. This means the well productivity is related to fracture density rather than reservoir stimulation.

![High-angle fractures in FMI (Well D)](image)

![High-angle fractures in FMI (Well B)](image)

**Figure 5.** Natural fractures

**Table 2.** Reservoir properties and production of wells in Dibei

| Well | Depth m | Oil (water) rate m³/d | Gas rate ×10⁴m³/d | Permeability mD | Fracture density /m | Note  |
|------|---------|----------------------|-------------------|-----------------|---------------------|-------|
| E    | 4905–4913 | 0                    | 5.6               | 0.368           | 0.074              | Well test |
| B    | 4708.5–4766 | 0                    | 4.52              | 0.0453          |                     | DST    |
|      | 4808–4878  | 70                   | 59.26             | 0.85            | 0.51               | DST    |
|      | 4808.0–5000| 31                   | 23.25             | 0.16            | 0.25               | DST    |
|      | 4808–4975  | 7.32                 | 1.18              | 0.8/6.96        |                     | Well test |
| A    | 4923–5220  | 8.2                  | 0.15              | 0.0018          | 0.06               | Well test |
| M    | 4867–4985  | 50.4 (water)         | 0.59              | 0.0283          | 0.07               | Well test |
| D    | 4768–4794.8| 42                   | 72                | 0.5             | 0.49               | PDA    |

4.3. Formation damage in well drilling and completion
Three stimulation treatments were conducted in Well D, witnessing a successively declining production. The first treatment – acid fracturing – resulted in a larger output than DST result; this indicated effective mitigation of reservoir contamination. After well killing using high-density mud (1.9 g/cm³), the gas output sharply decreased to 48,349 m³. To clear the contamination caused by workover, the second treatment (large-scale acid fracturing and sand fracturing) was performed. The post-frac production was higher than the post-workover production, but the output did not return to the level after the first treatment. Especially, the output after sand fracturing was below that after the second treatment. As per analysis, high-density mud loss and contamination caused by well killing are the primary controls on production increase, and water blocking and water sensitivity caused by liquid phase invasion are the secondary controls.
According to the electric logging interpretation, 71 conductive fractures were identified in the target interval in Well D. Fracture density, permeability, and open flow capacity varies greatly in the vertical direction. Mass circulation loss (larger than 150 m3) occurred during well drilling. Naturally open fractures may be filled with mud. The contamination caused by mud was cleared by the first treatment, but high-density mud used in well killing (for more than one month) completely plugged tubes of nearly 90 m long below the packer (Figure 6). It was anticipated that in such a case, mud would inevitably flow into and plug natural fractures and matrix pores in the reservoir and consequently lead to a sharp production decline.

![Figure 6. Tubing plugging by well killing mud](image)

In view of the matrix with low porosity, low permeability, small throats, poor pore-throat configuration, and existence of hair-like illite, liquid components are apt to invade into pore space to cause water blocking. The experiments show that water sensitivity and water blocking occurred after fluids such as fracturing fluids invaded into formations; as a result, matrix permeability decreased remarkably. About 20.0% of formation damage was caused by water sensitivity, and 40% caused by water blocking; the effect of water blocking mitigated with production time (Figure 8).

![Figure 7. Variation of water blocking damage rate](image)

The operating time shows that killing fluids, mud, and residuals from the reactions with acidizing fluids retained around the well bore were not expelled completely by bleeding after each treatment. These pollutants were pushed deeply into formations by large-scale stimulation, making the production decline.

5. Conclusion

(1) Natural fracture density is a major control on high yield. Limited production increase after fracturing was attributed to strong fracture heterogeneity.

(2) Formation fluids and pollutants flow along fractures. Well killing with high-density mud caused fatal pollution of fractured reservoirs. It was challenging to clear these pervasive pollutants by using reservoir stimulation. Water blocking caused by low permeability and poor pore-throat configuration also contributed to initial low production. It is suggested speeding up flowback to mitigate liquid invasion and damage of water blocking.

(3) Reservoirs with large fracture density at favorable structures can be stimulated using acidizing or small-scale fracturing. Reservoirs with small fracture density and low gas saturation at structure margin
may be stimulated using horizontal well multi-cluster plug & perf technique because it is difficult to realize economic production through conventional vertical well fracturing.

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