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Study on Development of Shale Gas Horizontal Well With Time-Phased Staged Fracturing and Refracturing: Follow-Up and Evaluation of Well R9-2, A Pilot Well in Fuling Shale Gas Field

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ABSTRACT In the development of the Fuling shale gas field, for the first time, Well R9-2 was selected for a test of time-phased staged fracturing and refracturing treatments to study the effectiveness of fracturing at each stage for a novel development approach exploration. This paper introduces the design of the experiments, analyzes the results, and provides a follow-up evaluation of the entire development process. As of 9 August 2020, the well had gone through three phases of development. Phase I: time-phased staged fracturing and development for Stages 1–2, 3–4, 5–6, and co-development for Stages 1–6; Phase II: Stages 1–6 were developed once more after refracturing; Phase III: sealing the sections in Stages 1–6, then fracturing and development of Stages 7–19. Pressure build-up tests were conducted during the development of Stages 1–2 and 3–4, and gas production profile logging and microseismic monitoring were performed during the co-development of Stages 1–6. The results show that the combination of time-phased staged fracturing and refracturing treatments can fracture each stage more effectively. The pressure build-up test can effectively obtain the reservoir parameters of developed shale gas wells. The potential of refracturing treatment in a developed well can be identified from the gas production profile logging and microseismic monitoring. The findings are of this study productive for enhanced shale gas recovery; the combined pattern of time-phased staged fracturing and refracturing acts as a direct guideline to future shale gas production.

INDEX TERMS Shale gas development, time-phased staged fracturing, refracturing, pressure build-up test, gas production profile logging, Fuling shale gas field.

I. INTRODUCTION

Shale gas reservoirs are characterized by low porosity, extremely low permeability, and no natural productivity [1], [2]. Horizontal well fracturing is usually required to establish commercial productivity, which depends on the development of hydraulic fracturing in long horizontal wells for a long time afterward [3], [4]. The development of shale gas horizontal well technology has led to staged fracturing technology in horizontal wells. In longer horizontal well sections, staged fracturing technology is often used for stimulation treatment and can be divided into the staged fracturing patterns of the pump-down bridge plug, "sleeve + packer", cementing sleeve, and hydraulic jet of coiled tubing [5]–[8]. To improve the efficiency of shale gas development, the "multi-well pad" fracturing pattern is adopted in the development of horizontal well fracturing technology [6], [9]. The pattern is characterized by continuous operation, which can greatly improve the utilization rate of fracturing equipment and reduce the frequency

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of equipment movement and installation, decreasing the labour of personnel. Depending on field conditions and program concepts, "multi-well pad" fracturing patterns include single-well sequential fracturing operation, multi-well "zipper" fracturing operation, and multi-well synchronous fracturing operation [10]–[13]. At present, China's shale gas is developed commercially using a combination of pump-down bridge plug staged fracturing technology and multi-well "zipper" fracturing operation.

The technology is aimed mainly at the first fracturing treatment of a shale gas horizontal well. There is normally insufficient fracturing stimulation for the first fracturing treatment of a shale gas well; after a phase of production, the pressure decline is significant, making further production difficult [14], [15]. Refracturing in horizontal wells increases the production of a shale gas well, reactivates a low-production well, and improves the contact area of the gas reservoir [16]–[18]. Compared with the first fracturing treatment, the process of refracturing is relatively simple and cost-effective, and is becoming an effective means of reducing cost and increasing efficiency in shale gas development [13], [17]. Currently, typical refracturing in shale gas wells includes diversion with sealers, mechanical sealing, and coiled tubing refracturing [19]–[21]. Refracturing is still being researched in China, predominantly through diversion with sealers.

In terms of fossil energy development, reducing cost and increasing efficiency through management optimization, and improving oil (gas) recovery through technical means are important research directions in this period [22], [23]. Optimizing the development pattern and improving the recovery are the key research directions nowadays in the shale gas field. In the past, shale gas wells were produced directly after gas tests following multi-stage fracturing in the long horizontal section [24]–[26]. Due to cost considerations, no oil and gas companies have conducted development tests for time-phased staged fracturing. To investigate a novel pattern and provide a basis for subsequent large-scale commercial development, this study performs a development test of time-phased staged and refracturing treatments using Well R9-2 in the Fuling shale gas field as the research object. In addition, a pressure build-up test, gas production profile logging, and microseismic monitoring were conducted to provide detailed shale gas development data. The test results show that the combination pattern of time-phased staged fracturing and refracturing can be used to develop each stage more effectively and further improve shale gas recovery. The pressure build-up test is an effective means to obtain reservoir parameters of developed shale gas wells. The gas production profile logging combined with the microseismic monitoring can be used to identify the refracturing potential of the development well.

This paper has conducted the follow-up and evaluation of Well R9-2. Firstly, it introduces the summary of the study area and the well, and then the purpose and method of the test design of time-phased staged fracturing and refracturing of the well; finally, it analyzes the development effect of time-phased staged fracturing and refracturing of the well in detail, so as to provide an actual example and significant reference for exploring more effective fracturing approaches of shale gas wells, and a new direction for the subsequent development of the Fuling shale gas field.

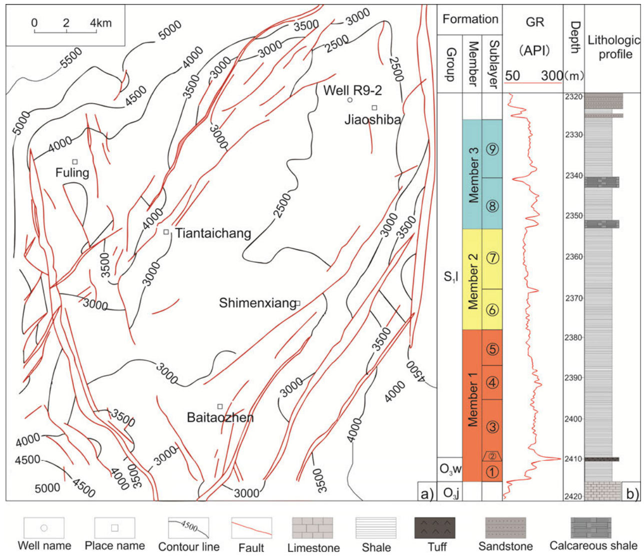

FIGURE 1. Structure of the Jiaoshiba block and target zone division in the Fuling shale gas field: (a) main structure of the area; (b) target zone division profile [27].

II. GEOLOGICAL SETTING

A. STUDY AREA BACKGROUND

The Jiaoshaba block of the Fuling shale gas field is located in the town of Jiaoshi in the Fuling district, Chongqing, and is part of the northern margin of the Baoluan–Jiaoshaba anticline zone in the southeast of the high-steep fold belt in East Sichuan (Fig. 1a). The shale in the lower part of the Upper Ordovician Wufeng Formation–Lower Silurian Longmaxi Formation in the Jiaoshiba block is the main target zone. Its thickness is 83 m–102 m; its lithologies are dominated by carbonaceous, siliceous, silty shale; its organic carbon content (TOC) is 0.5%–8.5%, averaging 5.0%; its porosity is 1.2%–8.0%, averaging 4.6%. Based on the geological drilling data, well logging data, mud logging data, and core observations in the study area, the shale section is divided into three members (nine sublayers) from bottom to top (Fig. 1b). In sublayers 1–5, the primary shale gas layers traversed by the horizontal well, the TOC of high-quality shale gas is 1.3%–5.1%, averaging 3.4%; the porosity is 2.4%–7.7%, averaging 5.6%; the total gas content is 2.1 m^3/t–9.0 m^3/t, averaging 6.8 m^3/t; the content of brittle minerals is 50.9%–83.4%, averaging 65.6%; the pressure coefficient is 1.40–1.55 and the formation temperature is 80.0 °C–90.0 °C.

B. WELL R9-2 OUTLINE

Well R9-2 is a pilot development well on Pad 9 of the Jiaoshiba block in the Fuling shale gas field. The well was successfully drilled in the Longmaxi Formation with a measured depth of 4088.0 m. In the horizontal section of this well, target A has a measured depth of 2558.0 m, a vertical depth of 2293.3 m, and a well inclination of 89.63°. Target B has a measured depth of 4058.0 m, a vertical depth of 2300.8 m, and a well inclination of 93.30°. The horizontal section between target A and target B is 1550.0 m (Fig. 2). The major traversed section contains three or four sublayers.

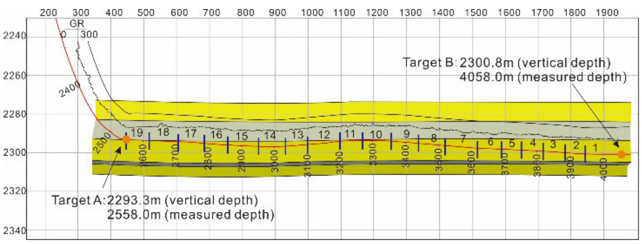

FIGURE 2. Horizontal section traversed in Well R9-2.

The reservoir of the horizontal section of Well R9-2 has good gas show and accumulation properties. The total hydrocarbon content from gas logging increases from 2.0% to 63.0%, and the methane content from 1.0% to 57.7%. The porosity ranges from 1.2%–8.5%, 5.4% on average; TOC ranges from 0.6%–4.3%, 3.0% on average. The well is prone to stimulation treatment due to its brittleness index of 30.5%–75.2%, averaging 55.5%. The formation pressure gradient is 1.41 MPa/hm–1.45 MPa/hm, the formation fracture pressure gradient is 2.10 MPa/hm–2.30 MPa/hm, and the net pressure required to open a natural fracture is 26.15 MPa. Stimulation treatment of a gas reservoir in a horizontal section tends to establish a complex network of fractures.

Starting on 26 March 2013, Well R9-2 underwent drilling, mud logging, well logging, time-phased staged fracturing in Stages 1–6, co-development in Stages 1–6, refracturing in Stages 1–6, secondary co-development in Stages 1–6, and fracturing in Stages 7–19, which encompassed the fracturing test, well test, gas production profile, and refracturing (Fig. 3). The data were abundant and representative, fully exhibiting the entire development test process of Fuling shale gas. As of 9 August 2020, the well was directly produced using casing, with a cumulative gas production of 1.003×10^8 m^3.

III. METHOD AND DATA

A. DATA SOURCES

The Fuling shale gas field is the first national-level shale gas development demonstration area in China and the first commercial shale gas field outside of North America [27]–[30]. Well R9-2 is a horizontal well used for a development test in this shale gas field, and worldwide is the first to undergo time-phased staged fracturing and refracturing tests. The researchers in this study were involved in the design of the development test and also investigated the entire process. The fracturing data, pressure build-up test, gas production profile logging, and microseismic monitoring are mainly from the Fuling shale gas field of Sinopec.

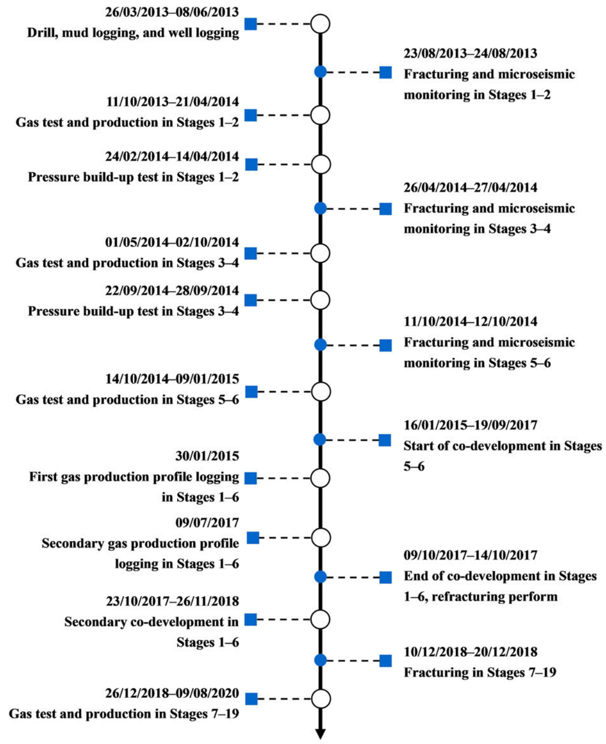

FIGURE 3. Overview of development test process in Well R9-2.

B. DESIGN AND METHOD OF THE TEST

1) PURPOSE AND TEST PLAN

Nowadays, all fracturing stages are subject to full production after multi-stage fracturing of the long horizontal section in shale gas wells. In the early stage of development in the study area, to understand the actual development of shale gas horizontal wells after fracturing in each stage and explore the possibility of a new development pattern, Well R9-2 was selected for the time-phased staged fracturing test. After time-phased staged fracturing and exploitation, when the pressure is greatly reduced and the output is difficult, the refracturing test is designed.

According to the fractured interval length design concept of "each stage is the same or similar to the vertical thickness of the reservoir", Well R9-2 can be divided into 19 stages for fracturing. To understand the development status of the horizontal well and the output of each stage in detail, and to compare these with the traditional mode after first fracturing treatment of the whole well, the well is divided into three phases for the test: the first phase is the time-phased staged fracturing and development, and co-development for Stages 1–6; the second phase is the refracturing and re-production after a period of production for Stages 1–6; the third phase is the fracturing and development for Stages 7–19. A pump-down bridge plug is planned in all three phases.

In addition, to understand the reservoir conditions and the production performance of each fracturing stage for the developed well, pressure build-up tests, gas production profile logging, and microseismic monitoring are planned on the basis of the overall development test.

TABLE 1. Design of fracturing operation parameters in Stages 1–6.

Stage	Depth of start (m)	Depth of end (m)	Stage length (m)	Number of Clusters	Fluid volume (m^3)	Sand volume (m^3)
1	3948	4018	70	3	2100	100
2	3882	3948	66	3	2100	100
3	3816	3882	66	2	1580	65
4	3752	3816	64	3	1580	65
5	3687	3752	65	2	1680	65
6	3622	3687	65	3	1680	65

TABLE 2. Main operation parameters of refracturing design in Stages 1–6.

Phase	Fluid volume (m^3)	Sand volume (m^3)	Temporary blocking ball (qty)	5–8mm sealer (kg)	60–80 mesh sealer (kg)
Squeeze test	1170	–	–	–	–
Section 1	2150	130	205	50	300
Section 2	2150	130	440	50	300
Section 3	2150	130	657	50	300
Section 4	1950	110	844	50	300

2) TIME-PHASED STAGED FRACTURING AND DEVELOPMENT IN STAGES 1–6

The design for Stages 1–6 adopts the pattern of three fracturing treatments and separate production in Stages 1–2, 3–4, and 5–6. A single stage is designed to have two or three clusters (Table 1). After three separate development phases in Stages 1–2, 3–4, and 5–6, co-development in Stages 1–6 is conducted. The gas production profile logging is tested during the co-development to analyse the production performance in Stages 1–6 and compare with the time-phased staged fracturing.

3) REFRACTURING AND DEVELOPMENT IN STAGES 1–6

A refracturing test can be conducted to re-stimulate the perforating clusters with no gas or less produced gas, increasing the stimulated reservoir volume (SRV) and enhancing the recovery. It can also provide information and lay the foundation for production of the old well in later stages of development [17]. The test for Well R9-2 is designed to conduct the refracturing treatment and secondary co-production following the pressure drop after a period of co-production in Stages 1–6.

Well R9-2 adopts the technique of diversion with sealers, currently the predominant refracturing technology. It uses the principle of temporary plugging before diversion and then fractures reservoirs in turn as per the sequence of formation opening pressure. During fracturing, the fracturing fluid carries sealers into the main fracture. Degradable particles build up, temporarily plugging the entrance of the fracture, causing the fracturing fluid to enter the unfractured area, forming new fractures and boosting the SRV [17], [31]. With the gradual degradation of the particles, the temporary plugging of fractures is removed. The technique of diversion with sealers can usually achieve multiple diversions, improving the effects of refracturing and maximizing the SRV [32]. For the refracturing in Well R9-2, the technique of diversion with "temporary blocking balls + sealers" was used several times to maximize the overall SRV. According to the principle of diversion with sealers, the refracturing can stimulate three to four clusters for each stage and be used in four sections for the repeated fracturing treatments in Stages 1–6 (Table 2).

Moreover, to form a more complex fracture network in the fracturing stage, after the sealers and temporary blocking balls are added as per the design, gel is added to produce temporary plugging in the fractures. New fractures are opened after the temporary plugging of pores and fractures in some stages to achieve re-stimulation of the refracturing stages and increase the stimulation effect.

4) FRACTURING AND DEVELOPMENT IN STAGES 7–19

After secondary co-development of Stages 1–6 for a period of time, the wellhead pressure is equal to the gas transmission pressure and the output is difficult. Sealing the sections in Stages 1–6 with plugs provides pressure recovery. The next phase of fracturing is conducted on Stages 7–19 of the initial fracturing design. There are six clusters for each stage in Stages 7–19, with a fluid volume of 2400 m^3 and a sand volume of 121.5 m^3 for each stage.

5) PRESSURE BUILD-UP TEST

A pressure build-up test is usually performed after a well has been shut down for a period of time to obtain continuous bottom hole pressure [33], [34]. For a shale gas reservoir, a pressure build-up test can identify the reserves and reservoir contamination, and quantitatively analyse the variation in formation coefficients and the effect of fracturing [35], [36]. During the development of Well R9-2, a pressure build-up test was conducted to better understand the characteristic parameters and the development effect of the formation and wellbore.

6) GAS PRODUCTION PROFILE LOGGING

For staged fracturing, the effect after fracturing in a shale gas horizontal well is critical information. Gas production profile logging can be used to determine the critical fluid-carrying capacity and the production of a fracturing stage [37], [38]. To determine the actual fracturing effect and the production of the fracturing stage, gas production profile logging was undertaken under different operating conditions during the co-development in Stages 1–6.

7) MICROSEISMIC MONITORING TEST

Microseismic monitoring can effectively evaluate the effect of stimulation of a horizontal section in the fracturing of a shale gas horizontal well [39]–[42]. To determine the actual fracturing effect of the well and provide the basis for subsequent fracturing and refracturing, microseismic monitoring is applied to obtain the length, width, and height of a fracture in the stimulated section as well as the SRV.

TABLE 3. First phase fracturing and production data.

Stage	Fluid volume (m^3)	Sand volume (m^3)	Choke (mm)	Flame height (m)	Wellhead pressure (MPa)	Production (10^4 m^3/d)	Open flow rate (10^4 m^3/d)	Flowback rate (%)
1–2	4404.6	200.6	8	5–6	7.7	5.6–5.9	5.7	3.6
3–4	3525.8	130.9	6	4–5	6.1	1.3–2.3	2.2	10.9
5–6	3692.5	145.2	4	2–3	2.4	0.8–1.6	2.0	3.2

IV. TEST RESULTS AND ANALYSIS

A. FIRST PHASE OF DEVELOPMENT TEST

The first phase of the development test started on 23 August 2013 and ended on 19 September 2017. The first phase included three fracturing treatments and separate production in Stages 1–2, 3–4, 5–6, and co-development in Stages 1–6. The pressure build-up tests were conducted during separate production of Stages 1–2 and 3–4. Gas production profile logging was conducted twice in Stages 1–6. The production duration was 1489 days, with a cumulative gas production of 2830.3 × 10^4 m^3.

1) FRACTURING AND DEVELOPMENT IN STAGES 1–2

From 23 August 2013 to 24 August 2013, Stages 1 and 2 were divided into three perforating clusters for fracturing. The operation pressure for Stage 1 was 54 MPa–80 MPa, the flow rate was 12.8 m^3/min–14.4 m^3/min, and the maximum sand ratio was 23%. The operation pressure for Stage 2 was 58 MPa–80 MPa, the flow rate was 12.4 m^3/min–14.6 m^3/min, and the maximum sand ratio was 23%. The fracture pressure for both stages was 80.0 MPa (Fig. 4a). The completion rates for fluid added in Stages 1 and 2 were 109.6% and 100.1%, respectively; the completion rates for sand added in Stages 1 and 2 were 100% and 100.6%, respectively, and were generally consistent with the design.

From 11 October 2013 to 14 October 2013, a gas test was conducted in Stages 1–2. An 8 mm choke was used to control the fluid discharge through the separator. The gas production was 5.6 × 10^4 m^3/d–5.9 × 10^4 m^3/d, the outlet flame height was 5–6 m, and the open flow rate was 5.7 × 10^4 m^3/d (Table 3).

From 15 October 2013 to 21 April 2014, the wellhead pressure was reduced from 15.15 MPa to 5.98 MPa during production for Stages 1–2, which was essentially the same as the gas transmission pressure; the gas production decreased from 6.2 × 10^4 m^3/d to 1.4 × 10^4 m^3/d (Fig. 5a). The production duration in Stages 1–2 was 189 days, with a cumulative gas production of 483.3 × 10^4 m^3 and water production of 114.8 m^3. The average daily gas production was 3.38 × 10^4 m^3, not including the shut-in duration.

In the development for Stages 1–2, a pressure build-up test was conducted to know the reservoir situations after fracturing when the well was shut in from 24 February 2014 to 14 April 2014. The testing duration was 1212 hours and the length of the tested section was 135.3 m. The obtained characteristic parameters of wellbore storage, post-frac permeability, and elastic storage capacity ratio are presented in Table 4. The characteristic curve (upslope) is shown in Fig. 6.

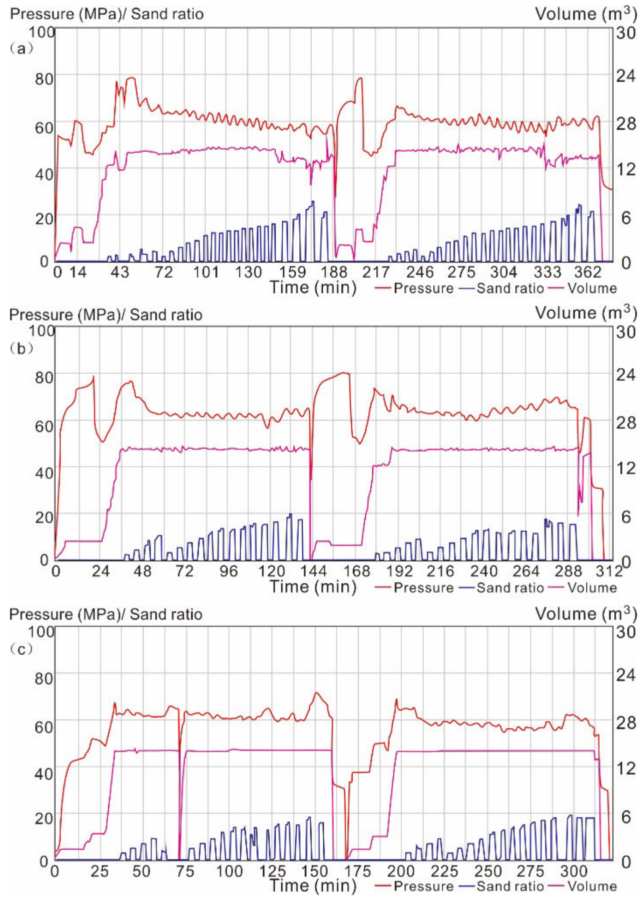

FIGURE 4. First phase of fracturing operation curves: (a) Stages 1–2; (b) Stages 3–4; (c) Stages 5–6.

The derivative pressure curve and the template derivative pressure curve are similar; the test data can be used as the gas layer reference, indicating the actual layer characteristics. The wellbore storage coefficient is the ratio of the wellbore continuous flow rate to the velocity of pressure change, which directly reflects the storage capacity. The wellbore storage coefficient for Stages 1–2 is 943 m^3/MPa, indicating that there are large reserves remaining. The skin factor indicates the integrity of a well and is an important technical index for evaluating the contamination and reservoir damage in the immediate vicinity of the wellbore. The skin factor for

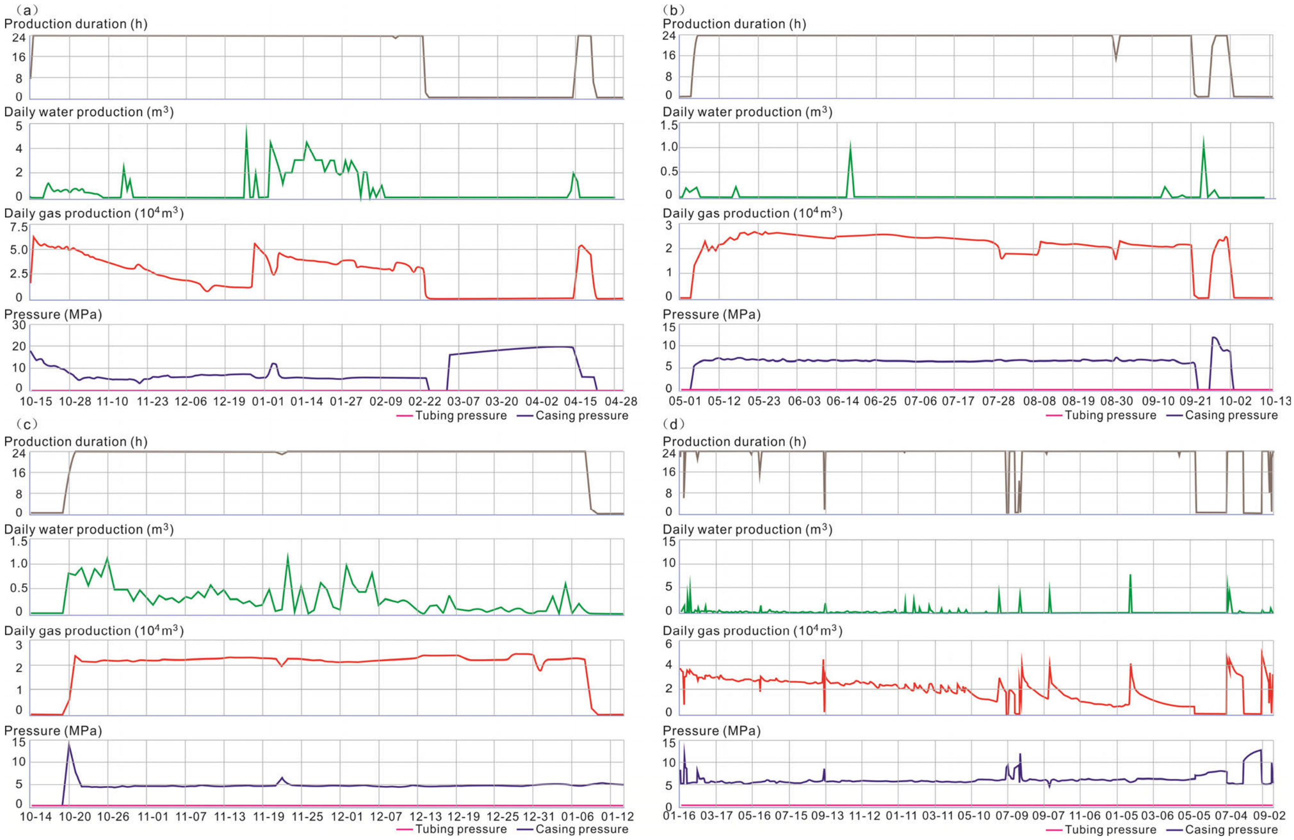

FIGURE 5. **First phase of gas production curves: (a) Stages 1–2; (b) Stages 3–4; (c) Stages 5–6; (d) Stages 1–6.**

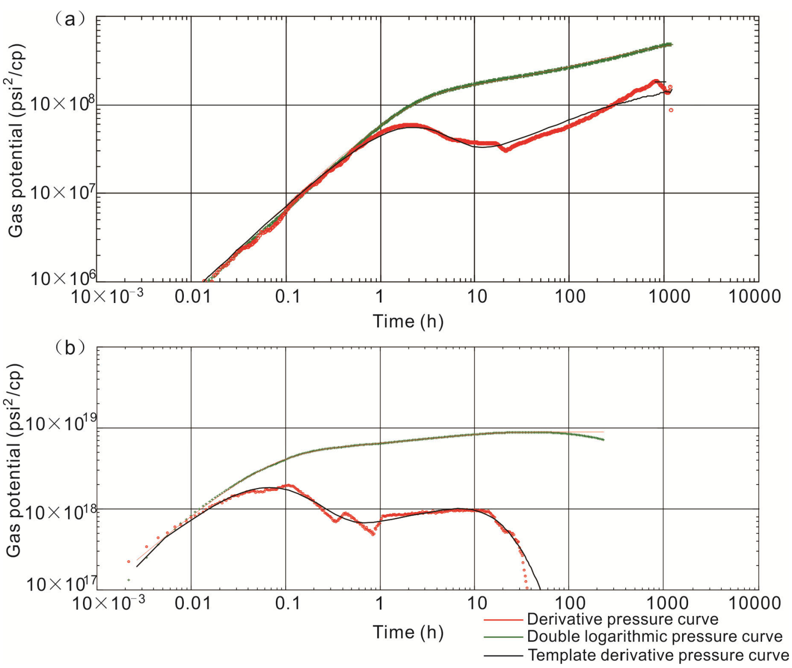

FIGURE 6. **Pressure build-up test curves: (a) Stages 1–2, derivative pressure curve is upslope type; (b) Stages 3–4; derivative pressure curve decreased to zero in the middle and late periods of testing.**

Stages 1–2 is 0.26, indicating there is contamination in the wellbore based on the criterion of contamination for a dual-medium reservoir. The permeability is 7.28 md and the formation coefficient is 277 md·m, indicating good reservoir

TABLE 4. Comparison of parameters for two pressure build-up tests.

Test parameter	Stages 1–2 test	Stages 3–4 test
Testing duration (h)	1212	159
Length of tested section (m)	135.3	130.0
Wellbore storage coefficient (m^3/MPa)	943	1.21
Skin factor	0.26	-0.21
Initial pressure (MPa)	23.53	35.68
Extrapolated pressure (MPa)	24.30	36.06
Formation coefficient (md·m)	277	71.5
Permeability (md)	7.28	1.88
Elastic storage capacity ratio	1.17×10^{-4}	0.12
Cross flow coefficient	1.15×10^{-6}	1.29×10^{-8}

permeability and a significant fracturing effect. The elastic storage capacity ratio is the ratio between the elastic storage capacity of a fracture system and the total elastic storage capacity of an oil and gas reservoir; generally, a smaller value indicates a more abundant gas source. The elastic storage capacity ratio of the test is 1.17×10^{-4}, which indicates that the gas source is abundant and stable. The cross flow coefficient indicates the complexity of fluid exchange between the fracture system and the rock matrix system in the dual-pore reservoir. The cross flow coefficient is 1.15×10^{-6}, reflecting a good cross flow capability between the fractures and the matrix.

From analysis of the pressure build-up test, it is found that after a phase of development, the reservoir in Stages 1–2 is in good condition with significant productivity.

2) FRACTURING AND DEVELOPMENT IN STAGES 3–4

From 26 April 2014 to 27 April 2014, sealing plugs were landed in Stages 1–2 and the fracturing was launched in Stages 3–4. The two perforating clusters for fracturing were adopted in Stage 3; the operation pressure was 55.4 MPa–64.4 MPa, the flow rate was 14.1 m^3/min–14.3 m^3/min, the maximum sand ratio was 18%, and the formation fracture pressure was 79.4 MPa. The three perforating clusters for fracturing were adopted in Stage 4; the operation pressure was 59.2 MPa–70.0 MPa, the flow rate was 14.1 m^3/min–14.3 m^3/min, the maximum sand ratio was 18%, and the formation fracture pressure was 80.9 MPa (Fig. 4b). The completion rates for fluid loading in Stages 3 and 4 were 106.1% and 110.7%, respectively; the completion rates for sand loading in Stages 1 and 2 were 101.3% and 100%, respectively, indicating consistency with the design.

From 1 May 2014 to 4 May 2014, the gas test in Stages 3–4 was conducted using a 6 mm choke to control the fluid discharge through a separator. The gas production was 1.3×10^4 m^3/d–2.3×10^4 m^3/d, the outlet flame height was 4–5 m (Table 3), and the open flow rate was 2.2×10^4 m^3/d.

From 5 May 2014 to 2 October 2014, the production in Stages 3–4 was launched with an initial wellhead pressure of 5.46 MPa; the gas production decreased from 2.3×10^4 m^3/d to 1.1×10^4 m^3/d (Fig. 5b). The production duration for Stages 3–4 was 151 days, with a cumulative gas production of 333.6×10^4 m^3/d and water production of 3.6 m^3. The average daily gas production was 2.30×10^4 m^3/d, not including the shut-in duration.

In the development in Stages 3–4, the pressure build-up test was performed from 22 September 2014 to 28 September 2014. The testing duration was 159 hours and the length of the tested section was 130.0 m. The wellbore storage, post-frac permeability, and elastic storage capacity ratio obtained from the test are presented in Table 4. The derivative of the characteristic curve decreased to zero in the middle and late periods of testing (Fig. 6b).

The pressure build-up decreased later, which usually indicates encountering a constant pressure boundary. As there was a tight shale reservoir, large fracture networks were less likely. As the shale gas reservoir in the study area belonged to the same pressure system, there was no significant difference in layered pressure. In the absence of other supporting data, no constant pressure boundary was directly identified.

Combined with the production in Stages 3–4, the production and the fluid-carrying capacity in this phase were lower. Large quantities of fracturing fluid remained in the reservoir, distorting the test data and masking the original curve characteristics. The derivative curve decreasing to zero in the middle and late periods may be related to shorter production and testing duration. This type of curve indicates a poor effect; the analysed testing data are not typical and the errors of the resulting parameters are greater.

3) FRACTURING AND DEVELOPMENT IN STAGE 5–6

From 11 October 2014 to 12 October 2014, the sealing plugs in Stages 3–4 were landed and the fracturing was launched in Stages 5–6. The two perforating clusters for fracturing were adopted in Stage 5; the operation pressure was 60.0 MPa–70.0 MPa, the flow rate was 14.0 m^3/min, the maximum sand ratio was 18%, and the formation fracture pressure was 67.6 MPa. The three perforating clusters for fracturing were adopted in Stage 6; the operation pressure was 55.8 MPa–62.5 MPa, the flow rate was 14.1 m^3/min, the maximum sand ratio was 19%, and the formation fracture pressure was 65.6 MPa (Fig. 4c). The completion rates for fluid loading in Stages 5 and 6 were 115.4% and 104.4%, respectively; the completion rates for sand loading in Stages 5 and 6 were 100.2% and 123.2%, respectively, indicating consistency with the design.

From 15 October 2014 to 19 October 2014, the gas test in Stages 5–6 was conducted using a 4 mm choke to control the fluid discharge through a separator. The gas production was 0.8×10^4 m^3/d–1.6×10^4 m^3/d, the outlet flame height was 2–3 m, and the open flow rate was 2.0×10^4 m^3/d (Table 3).

From 20 October 2014 to 9 January 2015, gas production in Stages 5–6 was conducted, with an initial wellhead pressure of 14.18 MPa and without significant decrease in gas production (Fig. 5c). The production duration in Stages 5–6 was 82 days, with a cumulative gas production of 180.2×10^4 m^3, water production of 25.1 m^3, and daily gas production of 2.20×10^4 m^3.

4) CO-DEVELOPMENT IN STAGES 1–6

From 16 January 2015 to 19 September 2017, the co-development in Stages 1–6 was conducted. The initial wellhead pressure was 8.57 MPa, the initial production was 3.6×10^4 m^3/d, the production duration was 875 days, the cumulative gas production was 1853.0×10^4 m^3, and the water production was 133.2 m^3 (Fig. 5d). The average daily gas production was 2.42×10^4 m^3, not including the shut-in duration. As the wellhead pressure was equal to the gas transmission pressure, the well was shut in on 13 May 2017 and opened on 4 July 2017; the wellhead pressure was 7.90 MPa and the gas production was 4.9×10^4 m^3/d.

During the commingled production in Stages 1–6, under the two operating conditions, flow scanned image (FSI) gas production profile logging was applied to analyse the production results of different fracturing stages and perforating clusters to identify the actual fracturing effect. The first gas profile logging was conducted under the operating conditions of 3×10^4 m^3/d on 30 January 2015; the second gas profile logging was conducted under the operating condition of 4×10^4 m^3/d on 9 July 2017.

It is observed from the two gas production profile logging results that the contribution rate of each fracturing stage in the two loggings is consistent (Fig. 7a). Stage 6 and Stage 4 of the two gas production profile loggings were the main contributing fracturing stages. In the first logging, the contribution rate was 51.0% for Stage 6 and 19.9% for Stage 4, and reached 70.9% for both stages. In the second logging, the contribution rate was 43.3% for Stage 6 and 22.3% for Stage 4, and reached 66.6% for both stages. The contribution rates of gas production in the first and second

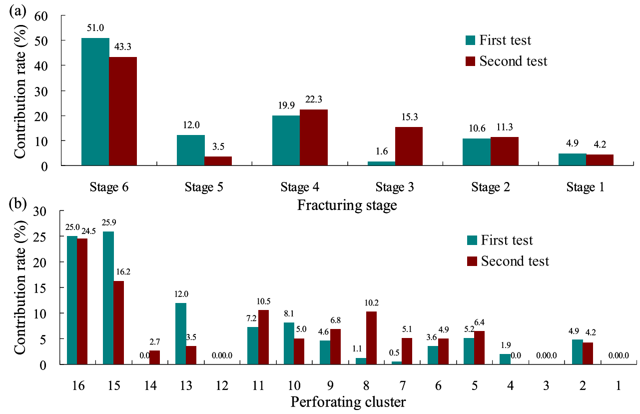

FIGURE 7. Gas production contribution rates of two gas production profile loggings: (a) comparison of contribution rates of each fracturing stage; (b) comparison of contribution rates of each perforating cluster.

tests were similar. Stage 3 and Stage 5 differed considerably in the two tests. The gas production contribution rate for Stage 3 increased from 1.62% in the first test to 15.28% in the second test. The contribution rate for Stage 5 decreased from 12% in the first test to 3.51% in the second test. Thus, the gas production contribution rates in the same fracturing stage may be different under different operating conditions.

Comparing the contribution rate of each perforating cluster in the two gas production profile loggings (Fig. 7b), the contribution of No. 15 and No. 16 perforating clusters was relatively high in both loggings. There were non-contributing perforating clusters, such as No. 1, No. 3 and No. 12 clusters. For the No. 4 and No. 14 clusters, there was a small contribution under one operating condition and no contribution under the other operating condition.

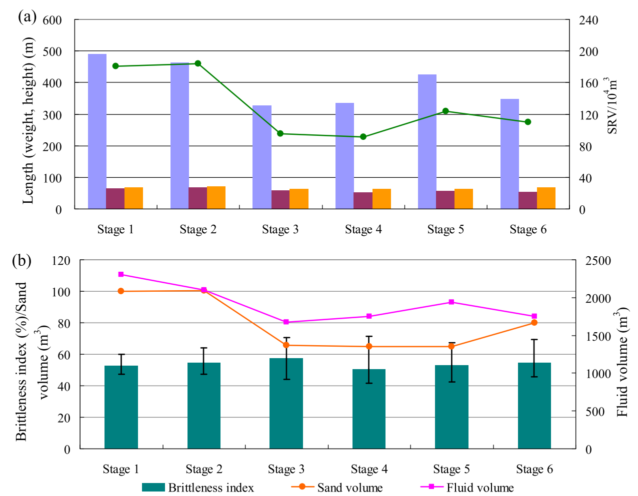

FIGURE 8. Comparison of microseismic monitoring results and engineering parameters after fracturing in Stages 1–6: (a) comparison of length, width, height, and SRV; (b) comparison of fracturing engineering parameters.

During the staged fracturing in Stages 1–2, 3–4, and 5–6, microseismic monitoring was used to obtain the length, width, and height of fractures in Stages 1–6 to calculate the SRV (Fig. 8a).

In Fig. 8a, the difference in the height and width of fractures in Stage 6 is not appreciable, but the length of fractures is considerably different. The fractures in Stages 1–2 are significantly longer than in Stages 3–6. The length, height, and width of fractures in Stages 3–4 are smaller than those in Stages 1–2 and 5–6 after fracturing stimulation. The SRV is optimal in Stages 1–2, fair in Stages 5–6, and poor in Stages 3–4, roughly corresponding to the daily production for the time-phased staged fracturing treatments in Stages 1–2, 3–4, and 5–6.

The engineering parameters of the fracturing treatments in Stages 1–6 are compared in Fig. 8b. For Stages 1–6, the traversed section contains three sublayers, and the brittleness index distribution is relatively stable. However, there was a large difference between using fracturing sand and fluid in the fracturing in Stages 1–6. Further, the total volume of fracturing sand and fluid used in Stages 1–2 was much greater than in Stages 3–6, and was more favourable for the formation of fracture networks. The total volume of fracturing sand used in Stage 5 was greater than in Stages 3, 4, and 6; the total volume of fracturing fluid used in Stage 6 was greater than in Stages 3–5. The difference in fracturing engineering parameters is an important factor in producing different stimulation results.

B. SECOND PHASE OF DEVELOPMENT TEST

1) POTENTIAL OF REFRACTURING

The second phase of development was the refracturing and re-development in Stages 1–6. The refracturing of a shale gas reservoir was aimed mainly at the stage clusters in which the initial stimulation was poor or there was no stimulation. Prior to the refracturing, the gas production profile logging and microseismic monitoring can be combined to determine whether there is potential for the refracturing.

Gas production profile logging is usually used to determine the refracturing potential and to analyse the contribution of each fracturing stage and perforating cluster to further determine if refracturing is necessary. In terms of the phenomenon that a higher recovery degree indicates a more depleted pressure and easier re-opening of fractures with repeated fracturing [43], and the results of gas production profile logging from 16 perforating clusters in Stages 1-6 of Well R9-2, the recovery degree can be divided into three categories (Fig. 7): (1) the recovery degree is higher, and the pressure is depleted, as in Clusters 15 and 16; (2) there is minimal gas production, as in Clusters 3, 4, 12, and 14; (3) some gas is produced in the clusters, but the amounts are far different from those in the major gas-producing stages.

To identify the potential of a refracturing treatment, the combined surface and borehole microseismic monitoring can be used to monitor fractures while undertaking the fracturing treatment in the well pad, having the knowledge of the length, width and height of fractures and their distribution [13], [44], [45], and incorporating the information with the gas content of the fracturing stage to analyze the technically recoverable reserves and apparent recovery, so as to determine whether it is necessary to fracture again. For the three sublayers traversed in Stages 1–6, the total gas content was approximately 7.51 m^3/t, the total SRV was 785.2 $\times$ 10^4 m^3, and the technical recoverable reserves were 1.5 $\times$ 10^8 m^3. A total of 2850.1 $\times$ 10^4 m^3 of shale gas was produced during the first phase of development, with a recovery of 19.0%. At the end of the first co-development in Stages 1–6, Well R9-2 had a production casing pressure of 5.06 MPa and a gas production of 3.30 $\times$ 10^4 m^3/d. The wellhead pressure was equal to the gas transmission pressure and the production was lower than the critical fluid-carrying flow, leading to poor fluid discharge. Subsequent production of the gas well was difficult to pursue with the prevailing treatment.

The gas production profile logging results indicated that there were perforating clusters with low or no gas production after the first fracturing treatment. Based on the analysis of the microseismic monitoring results, there was still a large amount of shale gas available for production in Stages 1–6. The Fuling shale gas field has developed more than 400 wells, with an average recovery of more than 20%. Thus, it was realistic to conduct refracturing treatment to achieve sustainable development.

2) REFRACTURING AND CONTINUOUS PRODUCTION IN STAGES 1–6

From 9 October 2017 to 14 October 2017, the refracturing and gas testing in the well was completed for Stages 1–6; the completion rates for fluid loading and sand loading were 105.5% and 63.8%, respectively, essentially consistent with the design. The refracturing operation pressure was generally higher than in the initial fracturing, and at times exceeded 80 MPa. The change in operation pressure between 940 min–960 min and 1010 min–1035 min resulted from the ‘‘temporary blocking balls + sealers’’ diversion technique, opening new fractures, reaching the diversion target with sealers, and enhancing fracture complexity (Fig. 9).

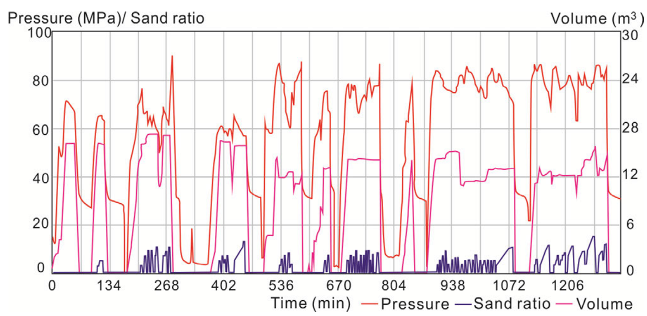

FIGURE 9. Refracturing operation curves in Stages 1–6.

An 8 mm choke was used to control the fluid discharge through a separator, with a gas production of 5.41 $\times$ 10^4 m^3/d, a wellhead pressure of 8.45 MPa, and a flow rate of 7.5 $\times$ 10^4 m^3. The initial wellhead pressure was

7.59 MPa for the secondary co-production in Stages 1–6 from 23 October 2017 to 26 November 2018. In the mid-term secondary co-production, multiple shut-ins were undertaken for pressure recovery because the wellhead pressure was equal to the gas transmission pressure (Fig. 10). The second production in Stages 1–6 lasted 400 days, with a cumulative gas production of 1072.3 $\times$ 10^4 m^3, a cumulative water production of 969.7 m^3, and an average daily gas production of 3.26 $\times$ 10^4 m^3.

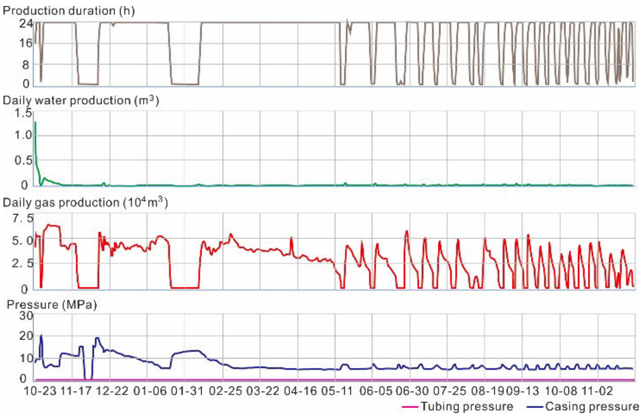

FIGURE 10. Secondary co-production curves in Stages 1–6.

After refracturing, the average daily gas production of the secondary co-production in Stages 1–6 was greater than in the first co-production, indicating that the refracturing was warranted.

C. THIRD PHASE OF DEVELOPMENT TEST

After the refracturing and continuous production in Stages 1–6, the wellhead pressure was equal to the gas transmission pressure, and the production of the gas well was lower than the critical fluid-carrying capacity. Thus, the sealing plugs were landed for pressure recovery in the well. According to the design of the time-phased staged fracturing test, the pressure recovery was conducted in Stages 1–6 during the third phase of the well development in which the subsequent horizontal section was developed. The subsequent horizontal section was 1064 m long and was divided into 13 stages according to the fractured interval length design concept of ‘‘each stage is the same or similar to the vertical thickness of the reservoir’’. The 13 stages were divided into 78 perforating clusters, with an average of six perforating clusters per stage, which was greater than the average number of clusters per stage in Stages 1–6.

From 10 December 2018 to 20 December 2018, fracturing treatment was performed in Stages 7–19; the operation pressure was 51.2 MPa–85.2 MPa, the flow rate was 12.3 m^3/min–15.1 m^3/min, the sand ratio was 4–17%, and the fracture pressure of the formation was 66.9 MPa on average (Fig. 11). The completion rate for fluid loading was 88.8%–106.6% in Stages 7–19, averaging 97.0%; the completion rate for sand loading was 61.5%–130.2%, averaging 90.2%.

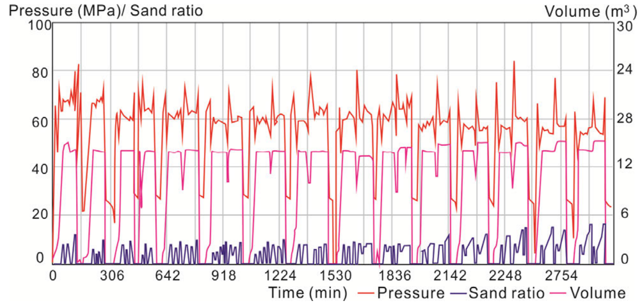

FIGURE 11. Fracturing operation curves in Stages 7–19.

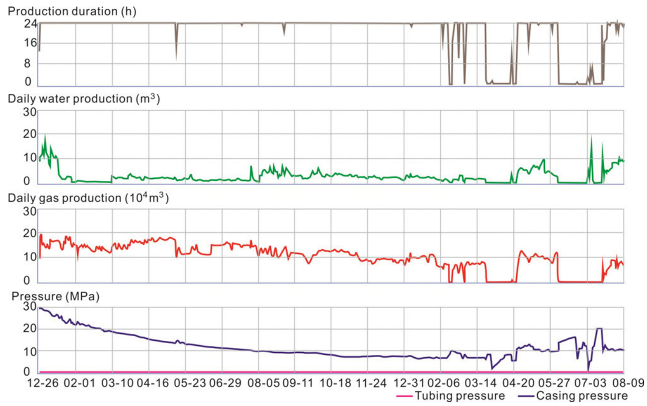

FIGURE 12. Gas production curves in Stages 7–19.

On 26 December 2018, production was started in Stages 7–19, with an initial wellhead pressure of 29.56 MPa, an open flow rate of 30 $\times$ 10^4 m^3/d, and a daily gas production of 18.1 $\times$ 10^4 m^3/d (Fig. 12). As of August 9, 2020, the cumulative gas production in this phase was 6128.2 $\times$ 10^4 m^3 and the cumulative water production was 1532.5 m^3. The average daily gas production was 10.34 $\times$ 10^4 m^3/d, not including the shut-in duration.

V. DISCUSSION

A. NOVEL DEVELOPMENT PATTERN FOR SHALE GAS HORIZONTAL WELL

The development of shale gas horizontal wells is usually conducted based on the pattern of multistage fracturing in a long horizontal section; all fracturing stages are produced directly. In Well R9-2, the combined pattern of time-phased staged fracturing and refracturing treatments was used. In the first phase of development, separate fracturing and production tests were conducted in Stages 1–2, 3–4, and 5–6; the stable productivity was attributed to the three separate treatments. The daily gas production of Stages 1–2 was the greatest and the daily gas production of Stages 5–6 was the smallest. The daily productivity of the first co-development in Stages 1–6 was greater than the separate daily gas production in Stages 3–4 and 5–6, but was significantly smaller than the separate gas production in Stages 1–2 (Fig. 13). The gas production profile test of the first co-development in Stages 1–6 was conducted; the test results indicated that the gas production contribution rate was slightly lower in Stages 1–2. The gas production contribution rate was the greatest in Stage 6 (Fig. 7), and the gas production contribution was uneven. The gas production with time-phased staged fracturing in Stages 1–2 was significant, but contributed less with co-production in Stages 1–6. Stages 5–6 had the lowest daily gas production with time-phased staged fracturing but made a major contribution to the gas production with combined treatments in Stages 1–6.

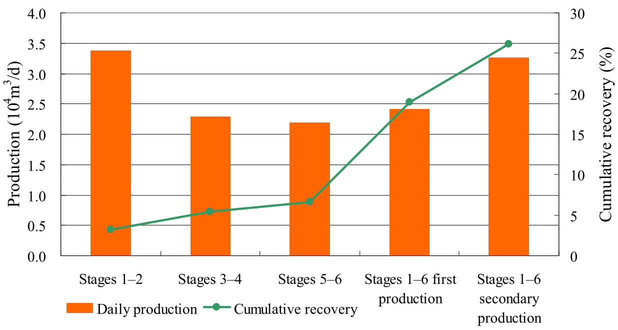

FIGURE 13. **Comparison of daily gas production and recovery in the first and second phases.**

It is concluded that when all fracturing stages are developed, some fracturing stages fail to make a contribution to gas production; time-phased staged and refracturing treatments enable those fracturing stages to be fully produced. Comparing the two treatment patterns, it is concluded that staged development can stimulate all stages more effectively, and thus enhance the recovery.

Refracturing treatment is also an effective approach to enhance gas recovery. It is observed in Fig. 13 that the daily gas production of the secondary co-development in Stages 1–6 was significantly greater than that of the first co-development in Stages 1–6, and the effect of the refracturing stimulation was significant. During the first and second phases of the development tests, the apparent recovery of Stages 1–6 reached 26.1%. It is concluded that the combination of time-phased staged fracturing and refracturing can be used to develop each fracturing stage more effectively and enhance the overall development recovery.

B. EFFECT OF PRESSURE BUILD-UP TEST ON POST-FRACTURING EVALUATION OF SHALE WELL

A pressure build-up test is an important means to effectively and economically obtain the reservoir parameters of a developed shale gas well. Pressure build-up tests were conducted in Well R9-2 in Stages 1–2 and 3–4 during the development process. The curve shape for the two tests differed considerably (Fig. 6).

The curve in Fig. 6a features a linear flow with a pressure derivative slope of 1/2, indicating the formation of fracking-induced fractures. Moreover, the derivative curve in Fig. 6a is similar to the template derivative curve, reflecting the reservoir characteristics more accurately.

Fig. 6b shows that the derivative curve decreases to zero in the middle and late periods; it is impossible to obtain the SRV boundary characteristic when the derivative decreases to zero in the actual shut-in pressure build-up because of the low permeability of the shale reservoir. The corresponding duration for obtaining formation data from these tests is positively correlated with the duration of the blowout test or the production. The scope of obtained formation data is limited, which is the result of a poor test.

Therefore, when using a pressure build-up test to obtain the reservoir data of a developed shale gas well, detailed identification based on the test curve shape is necessary. A test well with longer production duration tends to be selected, since a longer shut-in duration facilitates more accurate identification of a reservoir.

C. APPLICATION OF GAS PRODUCTION PROFILE LOGGING IN SHALE FRACTURING EVALUATION

In the development of a shale gas horizontal well, gas production profile logging can provide the critical fluid-carrying capacity and the fracturing stage production scenario to help the operation personnel determine the optimal operating conditions and reasonable proration production [46]–[49]. In the first co-development for Stages 1–6 in Well R9-2, gas production profile logging was performed under the operating conditions of 3×10^4 m^3/d and 4×10^4 m^3/d. From the two gas production profile logging results, the gas production contribution rate of the fracturing stages and perforating clusters near target A is greater than that of the fracturing stages and perforating clusters near target B, and the "near target A effect" is significant (Fig. 7).

D. FUTURE WORK

This study evaluates the entire development process of Well R9-2. Although the current research results reflect the development scenario of a well subjected to time-phased staged fracturing and refracturing, there are some limitations in this study. For example, refracturing has not yet been conducted in Stages 7–19, including the gas production profile logging and pressure build-up test. The authors will follow up and investigate the well continuously, monitor the borehole pressure recovery when sealing with a bridge plug in Stages 1–6, and share the test results in a timely manner.

VI. CONCLUSION

In the development of the Fuling shale gas field, to investigate fracturing technology and a novel pattern for shale gas horizontal wells in this block, Well R9-2 is used as a pilot well to conduct time-phased staged fracturing and refracturing tests. This study investigates the development of the well and draws the following conclusions.

1) In the Fuling shale gas field, it is possible to develop each fracturing stage more effectively through the combination of time-phased staged fracturing and refracturing treatments to achieve the goal of double-effect development.

2) A pressure build-up test is an effective means to obtain the reservoir parameters of developed shale gas wells. Choosing a well with a longer production time for the test

and a shut-in time that is as long as possible during the test is conducive to more accurate analysis of the reservoir.

3) A gas production profile test can directly show the gas production contribution of each fracturing stage and perforating cluster. The gas production contribution rates of the fracturing stage and clusters near target A are greater than those near target B.

4) Microseismic monitoring can provide the length, width, and height of a fracture, the SRV after fracturing, and predict the technically recoverable reserves of a fracturing stage combined with the gas content, and then obtain the apparent recovery of the developed wells. Combined with microseismic data and gas production profile data, the potential of a refracturing treatment can be identified under the condition that it is difficult to produce gas.

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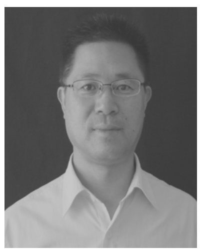

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