International Journal of Engineering Sciences and Technologies

Int. J. Eng. Sci. Technol.
2026.4(3).3
ISSN: 2960-0960
https://doi.org/10.58531/ijest/4/3/3

Article

Mechanisms of Acid-Gas Contamination of Drilling Fluids and Mitigation Strategies—A Case Study of the Penglai Gas Area, Sichuan Basin

Tian Heng

CNPC Chuanqing Drilling Engineering Company Limited, Chengdu Sichuan, China

Abstract: The Sichuan Basin contains multiple hydrocarbon-bearing formations, and oil and gas development in the basin is challenged by complex subsurface conditions, including highly variable formation lithologies, diverse reservoir fluids, and irregular formation-pressure systems. During drilling operations, influxes of acid gas commonly contaminate drilling fluids. Acid-gas contamination can severely impair drilling-fluid performance and quality. Once a certain amount of acid gas enters the wellbore, drilling-fluid rheology deteriorates and filtration performance worsens, which may adversely affect drilling tools, formations, and wellbore stability. Accordingly, there is an urgent need to investigate the mitigation of acid-gas contamination in drilling fluids. This paper reviews the current status of acid-gas contamination of drilling fluids in the Penglai Gas Area of the Sichuan Basin, discusses the mechanisms and origins of carbon dioxide (CO_2) contamination, investigates mitigation methods, and summarizes field practices and experience. The results are intended to provide an important scientific basis and technical reference for controlling drilling-fluid performance and quality when acid-gas influx occurs during drilling operations.

Keywords: Penglai gas area; drilling-fluid contamination; acid gas; carbon dioxide; performance and quality control; contamination mitigation

---

1. Introduction

In recent years, as oil and gas exploration has progressively advanced toward deeper formations and drilling technologies and techniques have continued to improve, deep and ultra-deep hydrocarbon resources have emerged as an important frontier for energy exploration. Meanwhile, acid gases have been encountered with increasing frequency in

Citation: Tian H. Mechanisms of Acid-Gas Contamination of Drilling Fluids and Mitigation Strategies—A Case Study of the Penglai Gas Area, Sichuan Basin. *Int. J. Eng. Sci. Technol.*, 2026, 4(3), doi: 10.58531/ijest/4/3/3

subsurface formations, and contamination of drilling fluids has occurred from time to time. The acid gases entering the wellbore mainly include H_2S and CO_2. When CO_2 enters a drilling fluid, it generally exists as H_2CO_3, HCO_3^-, and CO_3^{2-}, depending on the pH of the fluid [1]. Such contamination can damage drilling tools, corrode equipment, and destabilize the wellbore, thereby increasing drilling risks and engineering costs [2] and posing environmental hazards. Efficient mitigation of CO_2 contamination has therefore become an operational requirement in drilling engineering and is of considerable practical significance.

2. Current Status and Genetic Analysis of CO_2 Contamination

2.1 Current Status of CO_2 Contamination in the Penglai Gas Area

The Penglai Gas Area is located on the northern slope of the Central Sichuan Paleo-Uplift in the Sichuan Basin and belongs to the stable tectonic domain of the western Yangtze Craton. Its tectonic framework was developed during the evolution of the Deyang–Anyue rift trough from the Late Sinian to the Early Cambrian [3]. Influenced by the far-field effects of uplift along the eastern margin of the Tibetan Plateau, the region has evolved from a marine sedimentary basin into a continental foreland basin since the Late Triassic, accompanied by the development of multiple phases of fold-and-thrust structures (Fig. 1).

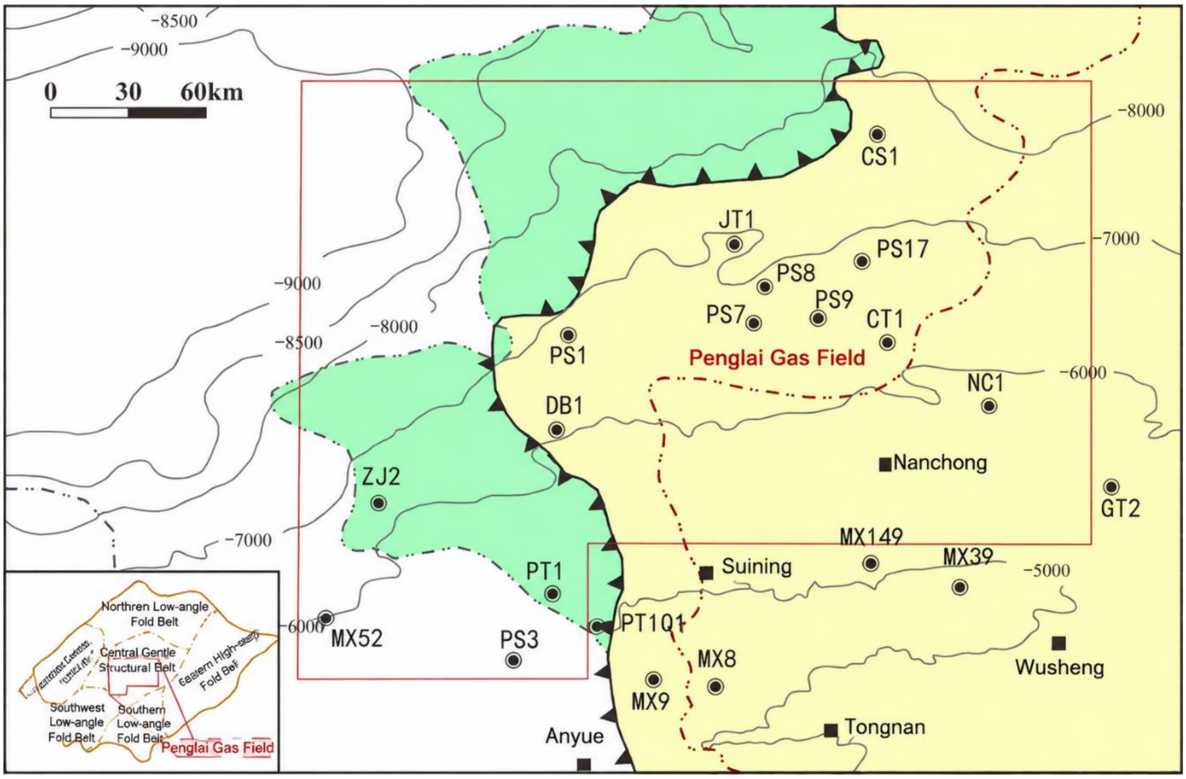

Figure 1 Structural setting and well locations in the Penglai Gas Area (modified after Yang Yu et al., 2022)

The Penglai Gas Area is an important exploration area for increasing hydrocarbon reserves and production in the Sichuan Basin. With the continuous expansion of exploration activities, CO_2-induced drilling-fluid contamination has been encountered in multiple formations within the area. By the end of 2025, a total of 28 wells had experienced CO_2 contamination (Table 1). Consequently, large volumes of contaminated drilling fluid had to be displaced or treated, substantially prolonging drilling operations and resulting in considerable economic losses. CO_2 contamination has occurred in formations ranging from the Lower Cambrian Qiongzhusi Formation to the Lower Jurassic Ziliujing Formation. Among them, the Permian Changxing, Longtan, and Maokou formations are the principal intervals associated with contamination, with a total of 16 contamination events, accounting for 67% of the reported occurrences.

Table 1 Statistics of CO_2 contamination in the Penglai Gas Area

Well area	No. of wells	Formations in which contamination occurred
Jiaotan-1 Well Area	5	Longtan–Maokou formations; Meitan–Longwangmiao formations
Pengtan-1 Well Area	9	Changxing–Maokou formations
Zhongjiang–Pengtan Well Area	14	Ziliujing–Xujiahe formations; Jialingjiang–Feixianguan formations; Changxing–Maokou formations; Canglangpu–Qiongzhusi formations

2.2 Discussion of CO_2 Origins in the Penglai Gas Area

CO_2 generation zones are commonly associated with geothermal activity, faulting, and magmatic activity. Globally, natural gas with high CO_2 contents is mainly distributed in countries and regions around the Pacific Rim where magmatic and fault activities are particularly frequent [4]. The sources of CO_2 can generally be divided into two major categories: organic and inorganic origins. Organically derived CO_2 is mainly associated with decomposition of organic matter and bacterial activity [5]. Based on the different geochemical processes experienced during the evolution of organic matter, some researchers have further classified organically derived CO_2 into five genetic types: microbial degradation of organic matter, oxidation of organic matter, thermal degradation of organic matter, cracking of organic matter, and processes involving thermochemical sulfate reduction (TSR) and bacterial sulfate reduction (BSR) [4]. Previous studies have shown that CO_2 in natural gas from the Sichuan Basin is predominantly of organic origin [6]. Through geochemical analyses, Cai et al. demonstrated that part of the CO_2 in natural gas from the Feixianguan Formation in eastern Sichuan was generated through TSR [7]. Based on the carbon isotopic characteristics of natural gas, Hu Anping et al. suggested that the CO_2 in the Wolonghe Gas Field is of organic origin [8].

Inorganically derived CO_2 is formed from inorganic minerals or elements through various chemical processes [4] and can generally be divided into mantle-derived/magmatic and rock-chemical origins. Mantle-derived or magmatic CO_2 is mainly generated by degassing associated with subsurface magmatic activity [9], whereas rock-chemical CO_2 is primarily related to two processes: thermal decomposition and dissolution of carbonate rocks. CO_2 generated by the thermal decomposition of carbonate rocks results from the heating of carbonate rocks under high-temperature conditions, such as those associated with magmatic activity. Based on thermal-history reconstruction, Wu Xiaoqi et al. suggested that some areas of northeastern Sichuan were affected by the activity of the Permian Emeishan mantle plume. Heating by high-temperature magma induced decomposition of carbonate rocks and the generation of CO_2, indicating an origin associated with carbonate thermal decomposition [5]. In contrast, CO_2 generated through carbonate-rock dissolution exhibits more complex geochemical characteristics and may have diverse origins and sources. Huang Sijing et al.

proposed that, during the early stage of reservoir evolution, CO_2 was generated in the Feixianguan Formation reservoirs of eastern Sichuan under the influence of TSR and incorporated into authigenic calcite. During the subsequent burial stage, continued basin uplift and related processes promoted carbonate dissolution and further CO_2 generation, indicating a carbonate-dissolution origin [10]. Other researchers have suggested that CO_2 generated by early-stage TSR was predominantly dissolved in water or precipitated as carbonate minerals in association with metal ions, whereas subsequent corrosion of reservoir rocks by acidic fluids led to additional CO_2 generation [11–12]. In general, CO_2 associated with carbonate-rock dissolution is commonly accompanied by early-stage TSR processes.

CO_2 contamination in the Penglai Gas Area occurs over a wide stratigraphic interval, suggesting that the CO_2 may have multiple genetic origins. The paleogeographic framework of the Sichuan Basin was strongly influenced by Emeishan mantle-plume activity during the Middle and Late Permian. Previous electron-probe studies have suggested that the mantle involved in Emeishan basaltic magmatism had an anomalously high mantle potential temperature [13]. Under the influence of complex thermodynamic and geochemical processes involving deep mantle materials [14], mantle degassing, thermal decomposition of carbonate rocks, and TSR may all contribute to CO_2 generation.

3 Mechanistic Analysis of CO_2-Contaminated Drilling Fluids

During drilling, interaction with formation water may cause the drilling fluid to absorb a certain amount of CO_2, increasing the CO_2 content of the fluid. In addition, high temperature and high pressure can promote CO_2 release from the drilling fluid, further intensifying the degree of gas contamination. CO_2 contamination of drilling fluids is mainly realized through absorption and permeation [2], and the principal chemical reactions are as follows:

3.1 Reaction of Carbon Dioxide with Water

After carbon dioxide enters the drilling fluid, CO_2 molecules react with H_2O to form carbonic acid (H_2CO_3), which ionizes in water to form bicarbonate ions (HCO_3^-) and hydrogen ions (H^+). This lowers the drilling-fluid pH and affects its performance and quality.

$$\mathrm{CO_2 + H_2O \rightleftharpoons HCO_3^- + H^+}$$

3.2 Reaction of Carbon Dioxide with Sodium Ions

To inhibit corrosion and bacterial growth, optimize drilling-fluid properties, and maintain the effectiveness of treatment agents, drilling-fluid pH is typically controlled within 8.5–9.5, corresponding to a weakly alkaline to alkaline environment. When CO_2 enters an alkaline fluid containing Na^+, the initial reaction preferentially forms sodium carbonate (Na_2CO_3).

$$\mathrm{2Na^+ + CO_2 + H_2O \rightleftharpoons Na_2CO_3 + 2H^+}$$

As CO_2 influx continues, Na_2CO_3 further reacts with CO_2 to form sodium bicarbonate ($NaHCO_3$). When CO_2 becomes excessive and $NaHCO_3$ continues to form, its relatively low solubility may result in precipitation, thereby affecting drilling-fluid performance and quality.

3.3 Reaction of Carbon Dioxide with Calcium Ions

Similarly, when CO_2 enters an alkaline fluid containing Ca^{2+}, calcium carbonate ($CaCO_3$) is preferentially formed and precipitated during the initial stage, while a portion of H^+ is released.

$$Ca^{2+} + CO_2 + H_2O \rightleftharpoons CaCO_3\downarrow + 2H^+$$

As CO_2 continues to enter the wellbore and the drilling-fluid pH decreases below 9, $CaCO_3$ in the fluid is gradually converted to $Ca(HCO_3)_2$. Consequently, the precipitation method based on calcium treatment agents gradually loses effectiveness. The continued release of H^+ during this process further decreases the drilling-fluid pH.

In summary, CO_2 contamination of drilling fluids mainly occurs through absorption and permeation and involves chemical reactions between CO_2 and components such as H_2O, Na^+, and Ca^{2+}. These reactions can markedly reduce the drilling-fluid pH and adversely affect its performance and quality.

4 Mitigation Methods for CO_2 Contamination of Drilling Fluids

4.1 Selection of an Appropriate Drilling Fluid

Before drilling, an appropriate drilling-fluid formulation should be selected according to formation conditions and drilling-fluid performance requirements. A suitable drilling fluid can not only improve drilling efficiency and safety but also reduce the absorption and release of CO_2. The drilling-fluid types summarized below can be used to reduce CO_2 absorption and release.

4.1.1 Oil-Based Drilling Fluid

Oil-based drilling fluids exhibit relatively low CO_2 solubility and diffusivity, thereby reducing the amount of CO_2 absorbed into and released from the fluid. In addition, oil-based drilling fluids provide excellent stability and sealing capacity and can effectively protect the wellbore wall.

4.1.2 High-Density Drilling Fluid

High-density drilling fluids can reduce CO_2 absorption and release by increasing the solute concentration in the fluid. They can also increase fluid consistency and viscosity, improve sealing capacity and stability, and thereby further reduce CO_2 absorption and release.

4.1.3 Alkaline Drilling Fluid

Alkaline drilling fluids have relatively high pH values and can neutralize acidic substances in the fluid, thereby reducing CO_2 generation and absorption. In addition, alkaline drilling fluids can reduce the O_2 content of the drilling fluid, further decreasing CO_2 absorption and release.

4.2 Control of Drilling-Fluid pH

Analysis of the chemical reaction mechanisms indicates that CO_2 influx and contamination lower the drilling-fluid pH and consequently impair drilling-fluid performance and quality. Therefore, alkaline agents such as lime and sodium hydroxide can be added to neutralize acidic substances and maintain a stable drilling-fluid pH.

4.2.1 Use of Sodium Hydroxide to Control pH

First, in an alkaline fluid, sodium hydroxide (NaOH) reacts with CO_2 to form Na_2CO_3 and H_2O, as shown below:

$$2NaOH + CO_2 \rightarrow Na_2CO_3 + H_2O$$

After NaOH in the fluid is completely consumed, excess CO_2 molecules further react with the generated Na_2CO_3 to form $NaHCO_3$, as shown below:

$$Na_2CO_3 + CO_2 + H_2O \rightarrow 2NaHCO_3$$

In drilling fluids, NaOH can neutralize acidic substances and react with CO_2 to form $NaHCO_3$, releasing a large amount of heat and thereby increasing the drilling-fluid pH.

4.2.2 Use of Lime to Control pH

Lime (CaO) is a commonly used alkaline material for treating CO_2 contamination. The treatment mechanism is that CaO hydrolyzes upon contact with H_2O to form calcium hydroxide, $Ca(OH)_2$, which subsequently reacts with CO_2 to form a $CaCO_3$ precipitate. The reactions are as follows:

$$CaO + H_2O \rightarrow Ca(OH)_2$$

$$Ca(OH)_2 + CO_2 \rightarrow CaCO_3\downarrow + H_2O$$

The addition of lime can neutralize acidic substances and increase drilling-fluid pH. At the same time, lime reacts with CO_2 to form solid calcium carbonate, thereby removing CO_2 from the drilling fluid.

When using the alkalinity provided by lime, the drilling-fluid pH should generally not exceed 11. A highly alkaline environment may adversely affect drilling operations, formation stability, and drilling-fluid properties. For example, it may accelerate electrochemical corrosion of metallic equipment such as drilling tools, pumps, and valves; dissolve silicate minerals, causing wellbore instability, formation collapse, or dissolution cavities; promote excessive dispersion of clay minerals such as bentonite, thereby reducing gel strength and filtration-control capability; and weaken the effectiveness of polymer treatment agents such as PAC and CMC.

4.3 Control of Oxygen Content in Drilling Fluid

Oxygen (O_2) can promote the release of CO_2 from the drilling fluid. Therefore, controlling the O_2 content of the drilling fluid is also a means of preventing CO_2 contamination. Reducing agents are generally added for this purpose, such as sodium sulfide (Na_2S).

4.4 Improvement of Drilling-Fluid Sealing Capacity

Because contamination is caused by the influx of formation fluids, CO_2 contamination can be prevented by improving the ability of the drilling fluid to seal formations exposed by the wellbore (Liu Xiang et al., 2009), thereby maintaining drilling-fluid performance and quality. Increasing drilling-fluid density can increase viscosity and surface tension while ensuring that hydrostatic pressure in the wellbore exceeds formation pressure. Under such conditions, formation fluids have greater difficulty entering the drilling fluid, thereby reducing CO_2 absorption and release from the formation. Therefore, increasing drilling-fluid density can effectively reduce the severity of CO_2 contamination.

4.5 Periodic Monitoring of CO_2 Content in Drilling Fluid

Periodic monitoring of CO_2 content in drilling fluid is also an important measure for preventing CO_2 contamination. Common methods include the following:

(1) Field testing: Chemical reagents, such as phenolphthalein and bromocresol green indicators, are added to the drilling fluid, and the color change is observed to estimate the CO_2 content. Detailed measurement procedures can be found in GB/T 16783.1-2014, Petroleum and natural gas industries—Field testing of drilling fluids—Part 1: Water-based fluids.

(2) Electrochemical method: Electrochemical sensors or electrodes are used to induce electrochemical reactions in the drilling fluid. The electrode potential or current is measured and used to estimate the CO_2 content.

(3) Infrared absorption method: An infrared analyzer is used to measure the degree of infrared absorption by CO_2 in the drilling fluid, from which the CO_2 content is calculated.

(4) Spectroscopic method: A spectrometer is used to measure the spectral characteristics of CO_2 in the drilling fluid, from which its concentration is calculated.

By monitoring changes in the CO_2 content of the drilling fluid and taking corresponding measures in a timely manner, the severity of CO_2 contamination can be effectively controlled.

5 Field Application of CO_2 Contamination Mitigation

From 2022 to 2025, the author participated in the treatment of CO_2-contaminated drilling fluids in several wells in the Penglai Gas Area, including wells PS7, PS9, and PS17. The contamination was concentrated mainly in intervals such as the Longtan–Maokou formations and the Longwangmiao–Canglangpu formations. The principal treatment measures included dilution and displacement, increasing pH, supplementing calcium content, increasing drilling-fluid density, converting to an oil-based drilling fluid, and adding high-temperature colloidal stabilizers. The following discussion uses the treatment of contamination encountered in the Maokou and Canglangpu formations of Well PS7 as a case study.

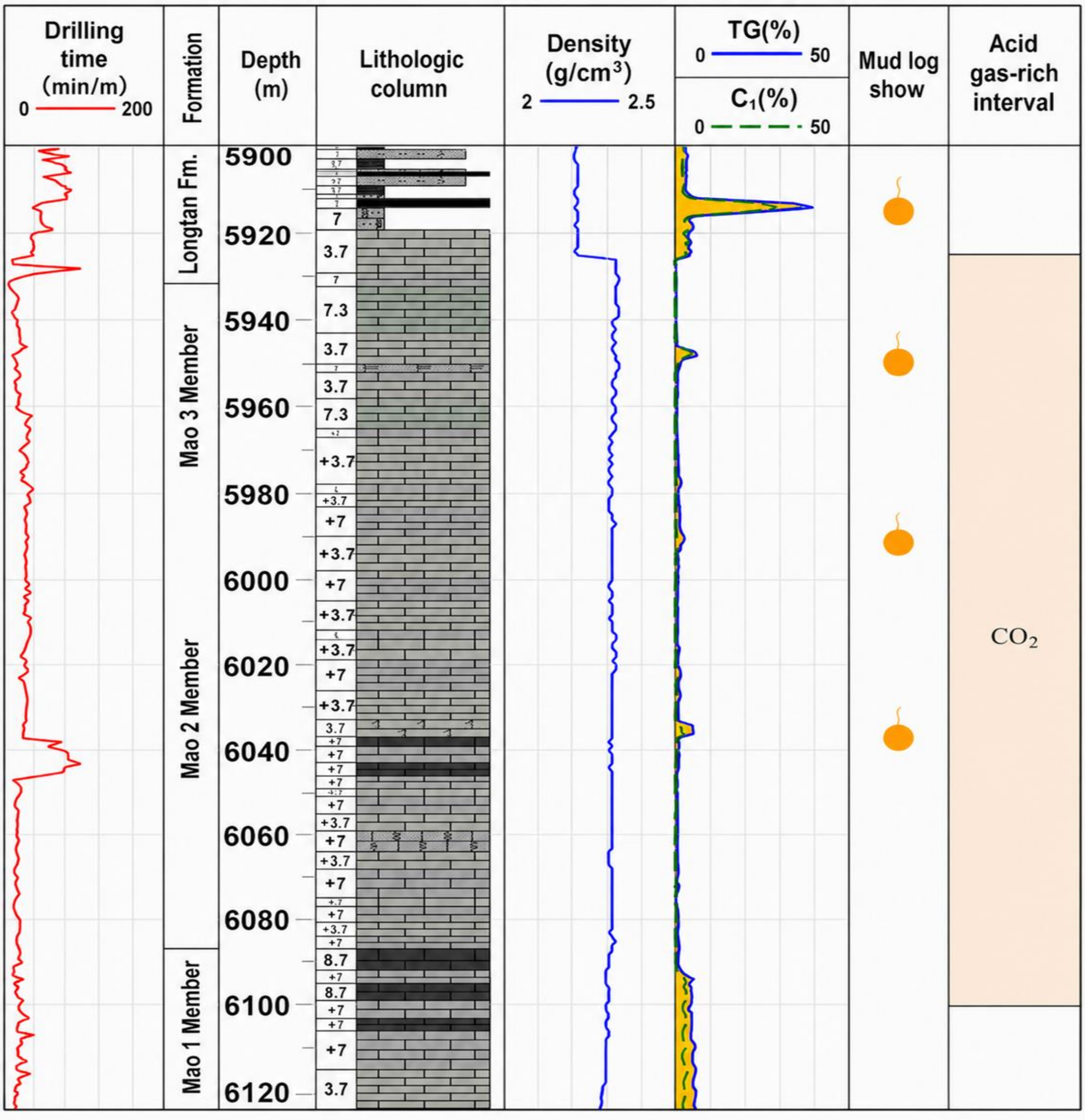

Figure 2. Composite mud-logging plot for the Maokou Formation in Well PS7 (including gas-logging response)

5.1 Treatment of CO_2 Contamination in Well PS7

Well PS7 is located on the slope zone of the central Sichuan Basin. With a planned well depth of 7,520 m, it was deployed as an appraisal well to investigate the development of shoal-facies reservoirs and the gas-bearing extent along the platform-margin belt of the fourth member of the Dengying Formation in the Penglai Gas Area.

5.1.1 Overview of the Contamination Event

On February 4, 2022, Well PS7 was being drilled with an organic-salt polysulfonate drilling-fluid system at a density of 2.32 g/cm³. During coring at a well depth of 6,045 m (Member 2 of the Maokou Formation; Fig. 2), the total hydrocarbon reading reached 6%, and the rheological properties of the drilling fluid deteriorated. Filtrate analysis showed that Ca^{2+} decreased from 880 to 0 mg/L, while CO_3^{2-} increased to 4,125 mg/L and HCO_3^- increased to 2,184 mg/L. These changes indicated acid-gas contamination of the drilling fluid by CO_2.

5.1.2 CO_2 Contamination Treatment Process

(1) Contamination identification followed by dilution and displacement. A complete set of drilling-fluid performance tests and filtrate analyses confirmed CO_2 contamination. A total of 80 m³ of active drilling fluid was diluted and displaced, calcium ions were supplemented, and high-temperature stability was adjusted. The drilling fluid subsequently returned to normal. The changes in measured properties are shown in Table 2.

Table 2. Drilling-fluid performance during treatment of CO_2 contamination in Member 2 of the Maokou Formation, Well PS7

Drilling-fluid condition	**Density, g/cm³**	**Viscosity, s**	**Plastic viscosity, mPa·s**	**Gel strength, Pa**	**pH**	**HTHP, mL/mm**	**CO_3^{2-}, mg/L**	**HCO_3^-, mg/L**	**Ca^{2+}, mg/L**
Design specification	2.29–2.44	48–75	50–75	2–8/8–20	8–18	≤12/3	/	/	/
Before contamination	2.32	58	23	1/6	10.5	11/3	/	/	800
At 6,045 m	2.32	79	62	6.2/24	9.3	15/4	4,125	2,184	0
After displacement	2.32	64	52	2.0/12	10.5	13/3	/	/	240

(2) Recurrent contamination followed by large-volume displacement with freshly prepared high-calcium drilling fluid. On March 12, drilling reached 6,660 m in the Canglangpu Formation. The total hydrocarbon reading fluctuated markedly between 5% and 9%, and drilling-fluid rheology deteriorated. Field tests indicated renewed CO_2 contamination. On March 13, 150 m³ of fresh drilling fluid with a density of 2.35 g/cm³ and a Ca^{2+} concentration of 980 mg/L was prepared for large-volume dilution and displacement of the active fluid. After displacement, the density was increased to 2.37 g/cm³. Circulation monitoring showed continued deterioration of drilling-fluid performance. Based on laboratory testing, another 100 m³ of fresh drilling fluid with a density of 2.35 g/cm³ and a Ca^{2+} concentration of 1,050 mg/L was prepared and used for a second large-volume displacement. This treatment produced some improvement; however, because a large amount of CO_2 entered over a long open-hole interval, the overall mitigation effect remained unsatisfactory. The changes in drilling-fluid properties during the process are shown in Table 3.

Table 3. Drilling-fluid performance during treatment of CO_2 contamination in the Canglangpu Formation, Well PS7

Drilling-fluid condition	**Density, g/cm³**	**Viscosity, s**	**Plastic viscosity, mPa·s**	**Gel strength, Pa**	**pH**	**HTHP, mL/mm**	**CO_3^{2-}, mg/L**	**HCO_3^-, mg/L**	**Ca^{2+}, mg/L**
Design specification	2.29–2.44	48–75	50–75	2–8/8–20	8–18	≤12/3	/	/	/
Before contamination	2.33	52	51	2.5/8.5	11	8/2	/	/	680
At 6,660 m	2.34	138	52	15/32	9.1	30/8	8,256	5,340	0
Week 1 after displacement	2.34	55	52	1/5	10.9	10/3	3,169	1,546	180
Week 2 after displacement	2.37	57	51	2/9	10.4	12/4	5,459	3,918	40
After second displacement	2.37	104	51	11.5/28	10.2	22/6	6,364	4,249	220

(3) Conversion to an oil-based drilling fluid through total depth. A neighboring well drilled with a fluid density of 2.30 g/cm³ experienced lost returns at a depth of 6,770 m in the underlying Qiongzhusi Formation. Comparative analysis therefore indicated that the drilling-fluid density in Well PS7 needed to be reduced to below 2.23 g/cm³. As CO_2 continued to be released with formation pressure, the drilling fluid became severely contaminated, and large-volume dilution and displacement failed to achieve the required treatment effect. The system was therefore converted to an oil-based drilling fluid during drilling below approximately 6,600 m. After the entire wellbore was displaced with oil-based drilling fluid at a density of 2.35 g/cm³, the density was gradually reduced to 2.18 g/cm³ to relieve formation pressure and was later increased to 2.23 g/cm³. Drilling then resumed to a final depth of 6,740 m. Throughout this period, the performance and quality of the oil-based drilling fluid remained stable.

6 Conclusions and Recommendations

Acid-gas contamination of drilling fluids is widespread in the Penglai Gas Area of the Sichuan Basin, with the principal affected intervals concentrated in the Changxing, Longtan, and Maokou formations. Acid-gas contamination deteriorates drilling-fluid rheology and is accompanied by sharp increases in gel strength, thick and poorly consolidated filter cake, and excessive pump pressure. These conditions can readily lead to differential sticking, pressure-induced lost circulation, and other drilling complications. The effectiveness of contamination treatment therefore directly influences drilling cost, operational safety, and economic performance. This study analyzes the mechanisms of CO_2 contamination in the Penglai Gas Area, evaluates mitigation methods, and summarizes field application experience to provide guidance for subsequent treatment of acid-gas contamination.

(1) A variety of methods are available for treating acid-gas contamination, and field operations generally require an integrated treatment package rather than a single measure. Treatment programs should be developed by comprehensively considering downhole complexity, characteristics of the formations encountered, pressure systems, and fluid properties. Treatment materials and dosages should be optimized to achieve effective mitigation.

(2) Control of the contamination source should be prioritized. As the first field response, drilling-fluid density can be increased in a timely manner, provided that lost circulation is avoided, to prevent continued influx of CO_2-rich acid gas. Targeted anti-contamination treatments can then be applied, including high-calcium and high-alkalinity treatment, dilution, and colloidal stabilization.

(3) During the early stage of contamination, high-alkalinity agents used in dilution treatment, commonly including CaO and NaOH, can be applied while maintaining drilling-fluid pH at 10.5–11.5 and Ca^{2+} concentration at not less than 400 mg/L. This approach can provide good treatment performance. In addition, specialized polycarboxylate thinners can be introduced; they show good dilution efficiency for CO_2-contaminated drilling fluids and can maintain stable properties for relatively long periods.

(4) Because CO_2 is not readily dissolved or ionized in oil-based drilling fluids, it has no obvious effect on their rheological properties. When formation-pressure conditions prevent CO_2 influx from being controlled by increasing drilling-fluid density, timely conversion to an oil-based drilling-fluid system of the appropriate density can effectively reduce CO_2 contamination, although engineering costs will increase.

(5) During drilling operations, measures to prevent drilling-fluid contamination should be strengthened and treatment efficiency should be improved. Rheological properties and filtration/wall-building performance should be adjusted promptly, while an adequate circulation rate should be maintained to effectively scour thick, poorly consolidated filter cake from the wellbore wall. Prolonged stationary periods of the drillstring should be avoided to reduce the risk of stuck pipe and to control drilling time and engineering cost.

Conflict of interest: The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

References:

1. Liu X., Luo Y.F., Wang J., Li L. Testing methods and treatment techniques for CO_2 contamination of drilling fluids. Drilling & Production Technology, 2009, 32(6): 78–81, 144. [in Chinese]
2. Wu B.Y., Song Z.Y., Chen P. Experimental study on monitoring CO_2 corrosion and scaling in gas-well wellbores. Drilling & Production Technology, 2021, 44(1): 77–81. [in Chinese]
3. Li R., Wang Y.X., Wang Z.C., et al. Geological characteristics of the southern segment of the Deyang–Anyue rift trough in the Sichuan Basin from the Late Sinian to Early Cambrian. Petroleum Exploration and Development, 2023, (2): 285–296. [in Chinese]
4. Zuo Y.H., Zheng Z.Y., Shao D.L., Wang H.P., Yang L., Wang C.F., Zhang Y.G. Review of CO_2 genesis, main controlling factors of accumulation, and degassing models. Science Technology and Engineering, 2021, 21(29): 12356–12367. [in Chinese]
5. Wu X.Q., Dai J.X., Liao F.R., Huang S.P. Origin and source of CO_2 in natural gas from eastern Sichuan Basin. Science China Earth Sciences, 2013, 43(4): 503–512. [in Chinese]
6. Dai J.X., Xia X.Y., Wei Y.Z., Tao S.Z. Carbon isotopic characteristics of natural gas in the Sichuan Basin. Petroleum Geology & Experiment, 2001, (2): 115–121, 132. [in Chinese]
7. Cai C.F., Xie Z.Y., Worden R.H., et al. Methane-dominated thermochemical sulphate reduction in the Triassic Feixianguan Formation, East Sichuan Basin, China: towards prediction of fatal H_2S concentrations. Marine and Petroleum Geology, 2004, 21: 1265–1279.

8. Hu A.P., Chen H.L., Yang S.F., Liu Q.Y. Genesis and main controlling factors of natural gas accumulation in the Wolonghe Gas Field. Acta Petrolei Sinica, 2008, (5): 643–649. [in Chinese]
9. Song Y., Xu Y.C. Genetic types of natural gas and their identification. Petroleum Exploration and Development, 2005, (4): 24–29. [in Chinese]
10. Huang S.J., Huang K.K., Tong H.P., Liu L.H., Sun W., Zhong Q.Q. Origin of CO_2 in natural gas from the Triassic Feixianguan Formation in northeastern Sichuan Basin. Science China Earth Sciences, 2010, 40(5): 583–591. [in Chinese]
11. Wang W.C., Zhang X.B., Luo H.Y., Li L.W. Carbon isotopic characteristics and genesis of hydrocarbons and CO_2 in H_2S-rich natural gas in northeastern Sichuan. Natural Gas Geoscience, 2011, 22(1): 136–143. [in Chinese]
12. Liu Q.Y., Jin Z.J., Gao B., Zhang D.W., Hu A.P., Yang C., Li J. Genesis of CO_2 in sour gas and influence of TSR in northeastern Sichuan. Acta Geologica Sinica, 2009, 83(8): 1195–1202. [in Chinese]
13. Xu Y.G. Mantle plume tectonics, large igneous provinces and their geological effects. Earth Science Frontiers, 2002, (4): 341–353. [in Chinese]
14. Luo Z.L., Sun W., Han J.H., Wang R.J. Influence of the Emeishan mantle plume on Permian hydrocarbon accumulation conditions in the Middle–Upper Yangtze region. Earth Science Frontiers, 2012, 19(6): 144–154. [in Chinese]