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Enhancing Coal Bed Methane Recovery in Deep Raniganj Seam, Kulti Block: A Comparative Simulation Study

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ABSTRACT

This investigation assesses the efficacy of horizontal wellbores within a deep, low-permeability coal seam for Coal Bed Methane (CBM) extraction, contrasting conventional (unfractured) horizontal wells with hydraulically fractured multi-lateral horizontal wells. The evaluation of performance focused mainly on the ultimate gas recovery factor and the incremental recoverable reserves. The results of the reservoir simulation indicate a significant advantage of the fractured horizontal well configuration. In the base scenario, unfractured horizontal wells extracted the reservoir with a recovery factor of merely 42.14%, resulting in 20.89 million cubic meters (MCM) of recoverable methane throughout the project's duration. The restricted pressure depletion to near-wellbore regions was a result of limited reservoir contact and poor connectivity within the tight cleat system, which left a significant amount of gas-in-place stranded. The successful propagation of the fracture network enhanced the stimulated reservoir volume and created conductive pathways deep within the coal matrix. As a result, the recovery factor increased to 86.13%, resulting in an additional 21.81 MCM of methane being unlocked and elevating total recoverable reserves to 42.70 MCM from the same seam volume.

.***Keyword***: CBM, In-situ gas content, Adsorption isotherm, Gas recovery, Simulation, Gas analysis

1. Introduction

CBM gas reservoirs are garnering considerable attention in India due to the significant potential of coal resources, which demonstrate promising gas content in coal seams. Many years ago, coal bed methane was considered an unviable source for methane production. Nonetheless, it is currently acknowledged as one of the most advantageous and promising sources for methane extraction [1-2]. The insufficient advancement of the cleat system may result in reduced gas extraction from reservoirs. The original gas in place denotes the amount of gas present in the reservoir before production begins [3-4]. This offers valuable insights regarding the deliverability of a CBM reservoir. The gas composition of discarded coal samples contributes to the assessment of the recovery factor [5-6]. The recovery factor indicates the percentage of gas that can be extracted from a CBM reservoir. This investigation seeks to evaluate the efficacy of horizontal wellbores, considering both fractured and non-fractured conditions [7-8]. The evaluation of both wells has been conducted with a focus on their gas recovery factors.

This investigation encompassed various analyses, such as an adsorption isotherm study aimed at evaluating the gas adsorption capacity of coal samples, a gas composition analysis to identify the exact quantity of methane that can be generated from the reservoir, a gas content study to assess the actual gas available in the reservoir, and simulation studies designed to forecast the gas and water production profile over time [9-10]. The production behavior of CBM reservoirs is significantly distinct from that of conventional oil and gas reservoirs. In CBM systems, methane is predominantly retained in an adsorbed form on the internal surfaces of the coal matrix, rather than existing as free gas within the pore spaces. To facilitate the flow of the adsorbed gas toward a wellbore, it is essential to first reduce the reservoir pressure, typically achieved through the extraction of formation water during the dewatering phase. The reduction in pressure leads to the desorption of methane from the coal surface, allowing it to diffuse through the matrix and subsequently flow through the natural fracture network, referred to as the cleat system, to access the well. The development and connectivity of the fracture (cleat) system significantly impact the effectiveness of gas production [11-12]. An effectively structured and interconnected cleat network serves as a high-permeability conduit that significantly improves gas deliverability. On the other hand, inadequately designed or insufficiently linked cleats lead to bottlenecks that significantly hinder flow and ultimately diminish the total gas recovery from the reservoir [13-14]. A key factor in evaluating any CBM reservoir is the Original Gas In Place (OGIP). OGIP denotes the complete quantity of methane that was initially present in the coal seams prior to the commencement of any extraction activities [15-16]. This is usually represented in standard cubic feet per ton (scf/ton) or billion cubic feet (Bcf) for a complete block, acting as the theoretical maximum of recoverable resources. The precise estimation of OGIP is essential for understanding the reservoir's deliverability potential and plays a pivotal role in field development planning, economic assessment, and reserve booking [17-18]. At the far end of the production life cycle lies the abandonment gas content — the residual methane that remains adsorbed in the coal even when the well is no longer economically feasible to operate. The recovery factor is determined by normalizing the difference between the original gas content and the abandonment gas content against the original gas content. The recovery factor, represented as a percentage, is arguably the most critical metric for evaluating the performance of various wells, completion strategies, or stimulation techniques in CBM reservoirs. In commercial CBM fields around the globe, recovery factors generally vary between 20% and 70%. However, many Indian pilots and initial commercial projects tend to be on the lower end of this spectrum due to geological complexities and less-than-ideal well designs [19-20].

This study seeks to methodically assess and contrast the performance of horizontal wellbores in CBM reservoirs across two different scenarios: (1) horizontal wells operating without hydraulic fracturing, depending entirely on the natural cleat system for productivity, and (2) horizontal wells that have undergone hydraulic fracturing (multi-stage fractured horizontal wells). The main criterion for evaluating performance in this study is the ultimate gas recovery factor attained by each well type throughout its productive lifespan.

2. Materials and method:

2.1 Sample collection and preparation: The coal core samples were collected from lower seam of one bore hole located in Kulti block of Raniganj coal field, west Bengal, India. The samples were going through many analyses for finding the input parameters of CBM simulator, like porosity, permeability, volume of adsorbed gas, in-situ gas content are shown in table 1 and 2 below.

Table 1 :Average Properties of Coal Samples.

Parameter	
Depth of reservoir, ft	3808
Reservoir temperature,^{0}F	146.30
Reservoir pressure, psi	1629
Porosity, %	0.005
Permeability, mD	3.81
Coal density, gm/cc	1.35
Thickness Seam (m)	13

Table 2 :The Estimated Gas Content of the Samples.

Seam no.	Q_1 (cc/gm)	Q_2 (cc/gm)	Q_3 (cc/gm)	ΣQ (cc/gm)
As received	0.432	6.074	0.279	6.785
Dry ash free basis	0.555	7.808	0.359	8.722

2.2 Gas Composition Analysis: Molecular gas compositional analysis was carried out following Standards ASTM D 1945. The gas samples thus collected at different time intervals were analyzed for molecular compositions on Chemito GC, Model 8610 by using modified Fisher Thermal Conductivity Detector at 400C. The molecular concentrations are reported as percentages on air free basis.

2.3 Estimation of Gas Content: The gas content measurements in the core samples were performed following modified USBM Direct Method. Gas content is estimated at NTP conditions in cc/g.

2.4 Adsorption Isotherm Study: The adsorption isotherm study is carried out to find the gas storage capacity of a coal sample at reservoir temperature and pressure. This study was done in the CSIR laboratory of Central Institute of Mining and Fuel Research, Dhanbad.

3. Result and discussion

3.1 Estimation of Gas content: Canister desorption experiments were employed for determining gas desorption rate and gas content of the coal samples. The in-situ gas content in the coal were estimated by adding lost, measured and residual gas volumes divided by mass of coal sample. The desorption study is performed by sealing coal sample in a canister and measuring the volume of gas evolved from the sample as a function of temperature, time and pressure. The volume of gas which is released from the coal sample is measured by displacement of water from a graduated cylinder. The average gas content of coal samples was given below, it was found that the lost gas content of coal samples has been found in the range of 0.432 to 0.555 cc/g at STP on as receive basis to dry ash free basis.

The Residual gas of the coal samples of the study area varies from 0.279-0.359 cc/gm at STP on as receive basis to dry ash free basis. Similarly, the desorbed gas content values were found to be 6.074-7.808 cc/gm at STP on as receive basis to dry ash free basis.

3.2 Original Gas in Place and Recovery Factor: The thickness of the collected sample was 13 m. The Estimated gas reserve and recovery factor was calculated from Eq. (2) and Eq. (3), given below:

$$\text{OGIP} = \text{Coalzone thickness} \times \text{Area} \times \text{Density} \times \text{Gas content} \quad \textbf{(1)}$$

$$\text{Recovery Factor (\%)} = \left[\frac{Gci - Ga}{Gci}\right] \times 100 \quad \textbf{(2)}$$

The thickness of the coal seam was 13 m with gas content 8.72 cc/g and 80 acre area, estimated reserve was 49.58 MCM. The recovery factor is 90.25% with a recoverable resource 44.74 MCM.

3.3 Adsorption Isotherm Study: The Langmuir volume shows the gas storage capacity of the coal sample at infinite pressure, and Langmuir pressure is the pressure at which the gas storage capacity of the coal sample is half the Langmuir volume. From experiments, it was seen that the coal is having the higher adsorption capacity. The values are varying from 14.47-16.60 cc/gm at moisture equilibrated and dry ash free basis. However, the sample also has sufficient gas content varying from 6.78 to 8.72 cc/gm on as receive to dry ash free basis. The reduction of gas in the coal sample shows that there is any fault or fracture present in the area. The methane adsorption isotherm and Langmuir constant curves are shown in Figure 1 and 2.

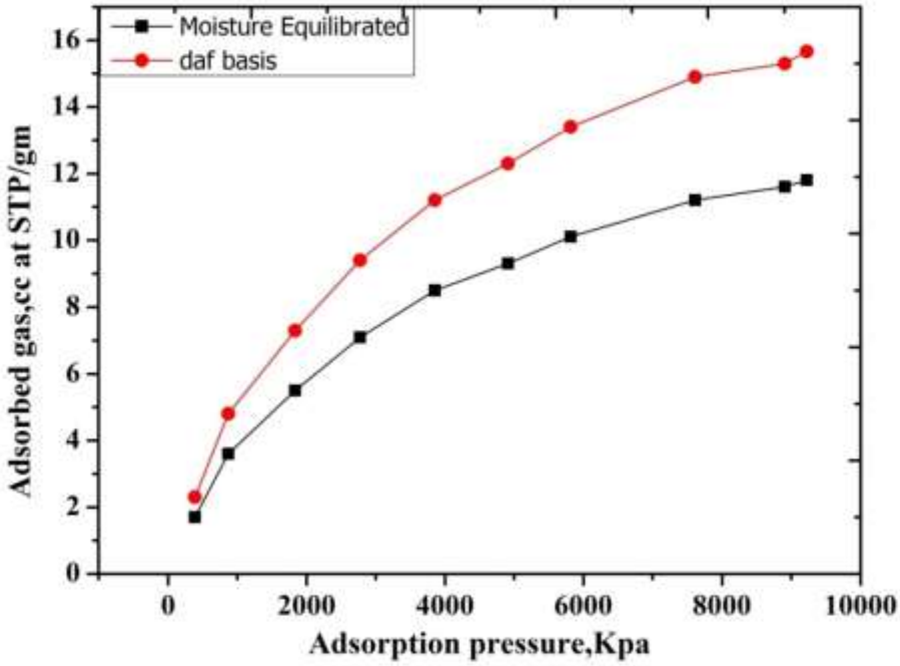

Figure 1 Methane adsorption isotherm curve of coal sample.

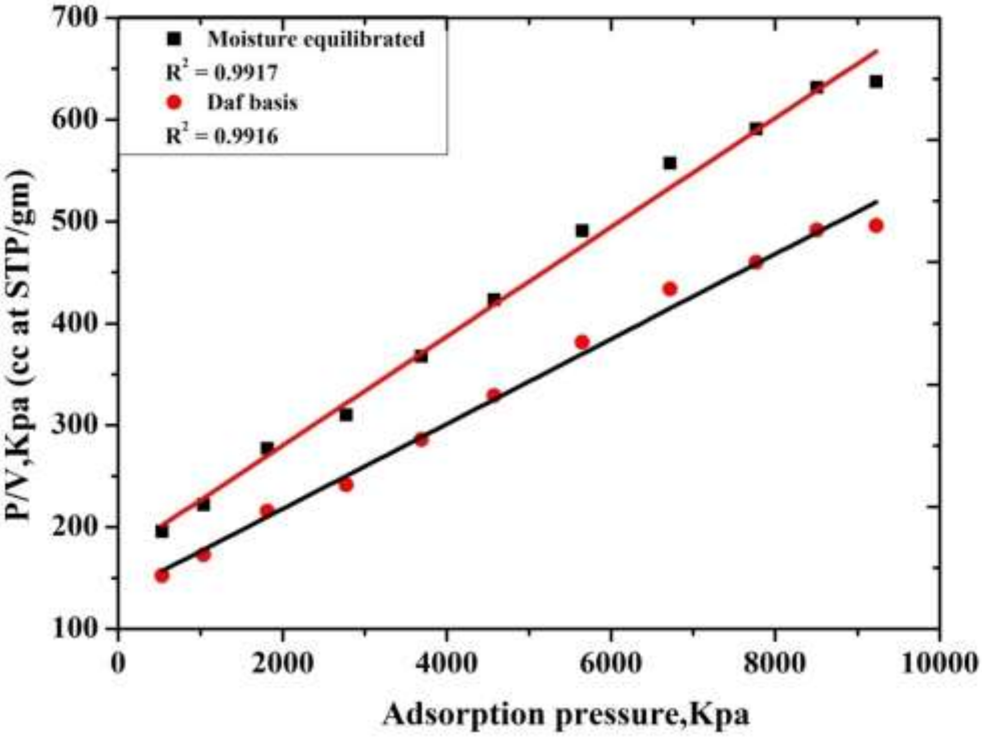

Figure 2 Langmuir constant curves of coal sample.

3.4 Gas Composition Analysis: The composition of the gas samples which are collected from the field shows that the methane concentration is high and it varies from 97.833 to 97.621% (air-free basis). The huge amount of methane (42.187MCM) is recovered from the fracture well method. The higher hydrocarbon components (C_2+) constituting up to 0.735% with 0.315MCM of gas resource. The concentration of CO_2 varies from 1.145 to 1.354%, which shows that large amounts of CO_2 is produced and can be recovered for ECBM recovery prospects. The methane, carbon dioxide and higher hydrocarbon production with time is shown in Figure 3.

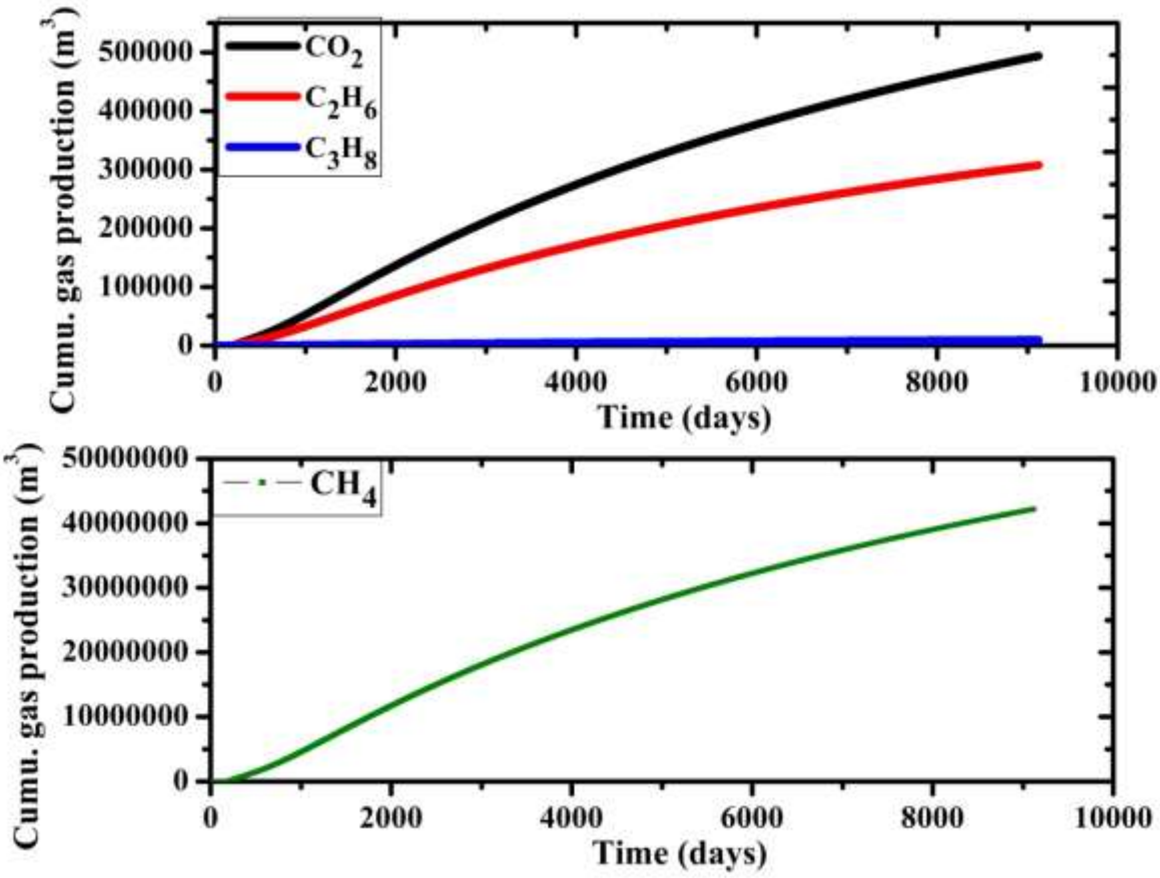

Figure 3 Cumulative methane, carbon dioxide and hydrocarbon production with time.

3.5 Simulation Results: The simulation study which was carried out by using COMET3 software. The simulation study shows that the recovery factor has been improved from 42.14% to 86.13% by fractured well approach with a recoverable resource of 20.89 to 42.70 MCM. As the simulation values are very close to the experimental values, so this data can be used to predict the future production of the reservoir. The predicted future Cumulative and production rate of the recoverable gas and water has been shown in Figures 4, and 5.

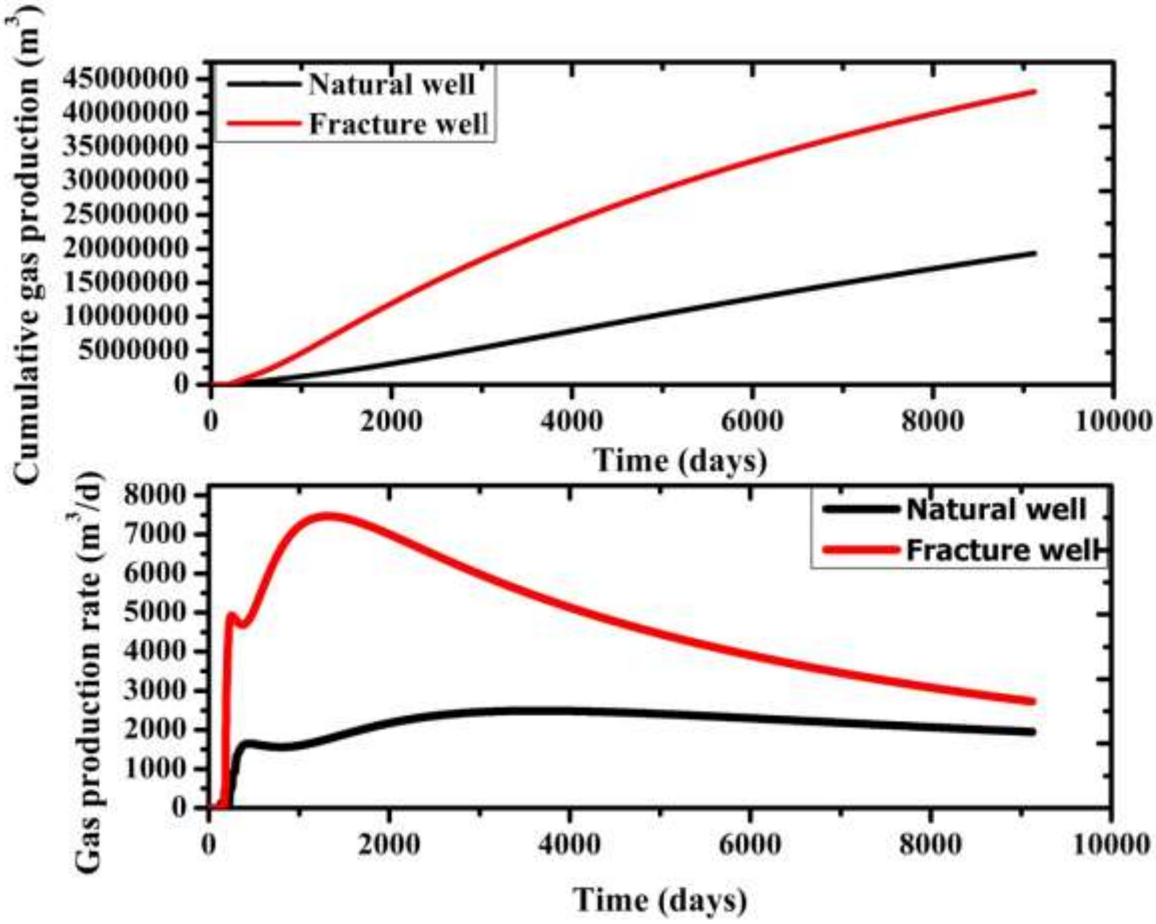

Figure 4 Cumulative and production rate of Gas with time.

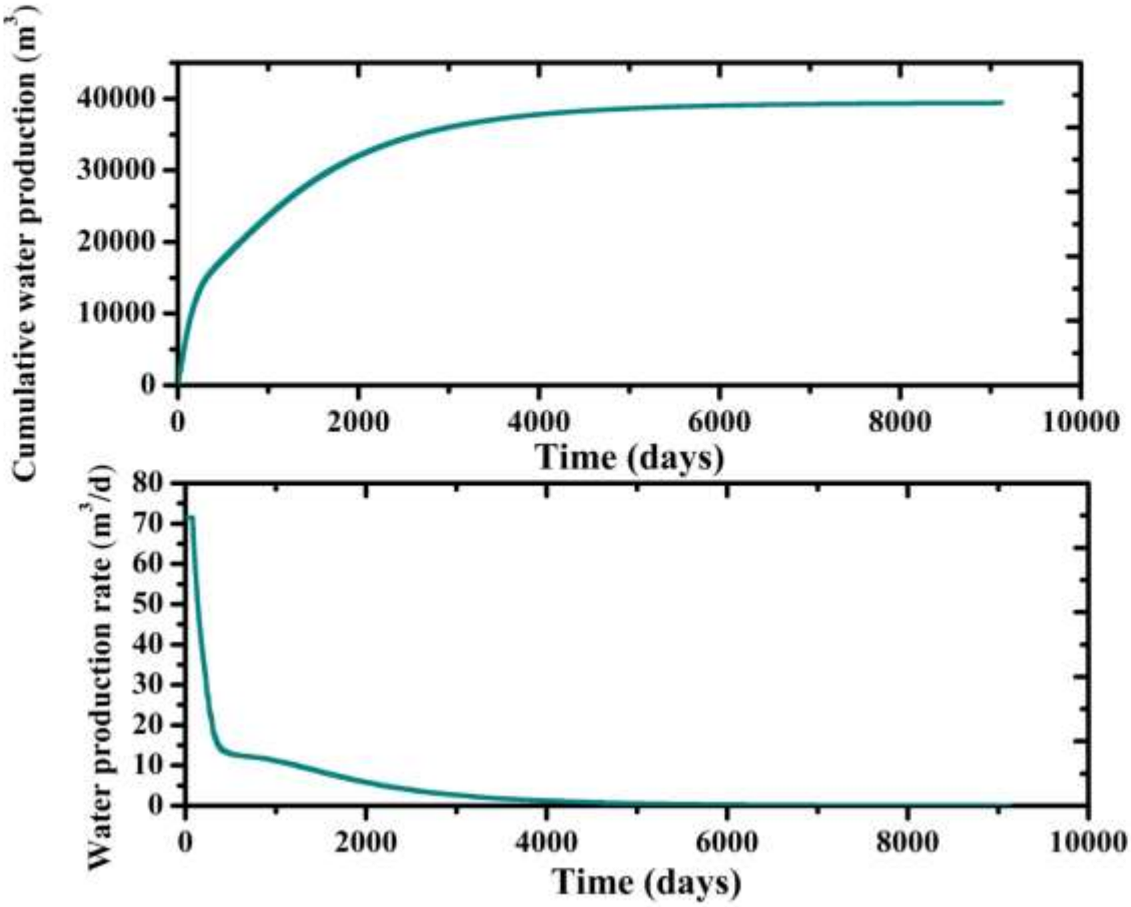

Figure 5 Cumulative and production rate of water with time.

4. Conclusion:

A comprehensive reservoir simulation study carried out on a specific deep block has highlighted the significant potential of advanced well completion techniques in accessing these previously untapped resources. Traditional vertical or directional coalbed methane wells in low-permeability, deep coal reservoirs frequently produce unsatisfactory recovery factors due to insufficient connectivity between the natural fracture network and the wellbore, along with localized reservoir pressure depletion. The investigation analyzed conventional well designs alongside a multi-lateral fractured well strategy, where several horizontal laterals are drilled from a single vertical wellbore and subjected to intensive stimulation via hydraulic fracturing. The findings were remarkable. Under base-case conditions utilizing conventional wells, the ultimate recovery factor was projected to be merely 42.14%, resulting in over half of the gas-in-place remaining unrecovered throughout the economic lifespan of the project. The fractured multi-lateral well configuration significantly enhanced the recovery factor to an impressive 86.13%. This results in a volumetric increase of recoverable reserves from 20.89 million cubic meters (MCM) to 42.70 MCM within the same seam volume, adding an additional 21.81 MCM of methane to the recoverable category. This indicates a 51.07% relative enhancement in gas recovery, highlighting the significant influence of better reservoir contact and increased drainage efficiency in tight coal reservoirs. Notably, analyses of downhole and surface gas composition indicated that the produced gas stream has a considerable amount of carbon dioxide (CO_2), with some intervals surpassing 15–20% by volume. Traditionally, CO_2 is seen as an impurity that needs to be eliminated to meet pipeline specifications; however, its presence presents an unexpected synergistic opportunity within the realm of carbon management.

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