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Optimization of Production Layer Combinations in Multi-Superposed Coalbed Methane Systems Using Numerical Simulation: A Case Study from Western Guizhou and Eastern Yunnan, China

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Abstract

Coalbed methane (CBM) reservoirs in southwestern China are characterized by thick, multi-layered coal sequences partitioned into several independent pressure systems by impermeable strata. Commingled production from multiple coal seams in such multi-superposed CBM systems often suffers from severe inter-layer interference, leading to suboptimal gas recovery. To address this challenge, we developed a systematic four-step optimization workflow integrating geological data screening, pressure compartmentalization analysis, and numerical reservoir simulation. The workflow identifies the key "main" coal seams and evaluates various co-production layer combinations to maximize gas recovery while minimizing negative interference. We applied this method to a CBM well (LC-C2) in the Western Guizhou–Eastern Yunnan region, which penetrates three discrete CBM pressure systems. In the case study, single-layer simulations first revealed that one seam (No. 7 + 8) contributed over 30% of the total gas potential, with a few other seams (e.g., No. 18, 13, 4, 16) providing moderate contributions and many seams yielding negligible gas. Guided by these results, we simulated five commingling scenarios of increasing complexity. The optimal scenario was to co-produce the seams from the two higher-pressure systems (a total of six seams) while excluding the low-pressure shallow seams. This optimal six-seam configuration achieved a 10-year cumulative gas production of approximately 2.53×10^6 m^3 (about 700 m^3/day average)—roughly 75% higher than producing the main seam alone, and even about 15% greater than a scenario involving all available seams. In contrast, including all three pressure systems (ten seams) led to interference effects where the high-pressure seams dominated flow and the low-pressure seams contributed little, resulting in lower overall recovery. The findings demonstrate that more is not always better in multi-seam CBM production. By intelligently selecting a moderate number of compatible seams for co-production, the reservoir's gas can be extracted more efficiently. The proposed quantitative optimization approach provides a practical tool for designing multi-seam CBM wells and can be broadly applied to similar geologically compartmentalized reservoirs.

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1. Introduction

Southwestern China's coal-bearing basins contain unusually thick coal sequences with dozens of seams, which often form multi-superposed independent CBM systems due to intervening impermeable strata [1]. Prior studies by Qin et al. [2] first recognized that in the Western Guizhou region, dense clastic aquitards (e.g., argillaceous ironstone layers) partition the coal measures into multiple vertically separated fluid pressure systems [3]. Each system can trap CBM semi-independently, preventing pressure communication between seams in different systems [4,5]. This concept of multi-layer, superposed CBM systems has since been documented in Late Permian coalfields of Western Guizhou and Eastern Yunnan, where 2–4 discrete CBM-bearing systems commonly coexist in a single coal-bearing succession [6,7].

CBM wells in this region traditionally targeted single thick seams, but individual seams here are relatively thin and often water-saturated, yielding sub-economic gas rates. Therefore, commingled (multi-seam) production via segmented fracturing and co-production has become the dominant development strategy in Western Guizhou and Eastern Yunnan [8]. Over the past decade, numerous pilot wells have been drilled to test various multi-seam combinations, with each well intersecting anywhere from one up to four distinct CBM systems [9,10]. However, field results have been generally disappointing—commingled wells exhibit low peak gas rates, short plateaus, and rapid declines [9]. For instance, 9 trial wells in the Tucheng block, each producing from different sets of 8–13 coal seams, achieved initial peak gas rates of only 288–760 m^3/d and unstable production with frequent water surges [11]. The average gas output per meter of coal thickness in these wells was very low, indicating inefficient use of the reservoir thickness [12,13]. Geological analyses have linked these outcomes to suboptimal layer selection and severe inter-layer interference (pressure drawdown competition) in multi-seam wells [14,15]. Guo et al. [16] reported that the lack of stable, high gas rates in local CBM wells is largely due to indiscriminate commingling of too many layers, especially across different pressure systems, leading to $1 + 1 \ll 2$ effects where adding more seams actually yields diminishing or even lower total production [16]. A striking example is well X2 in western Guizhou: when produced from two close seams within the same gas system, it achieved a peak of 2800 m^3/d and sustained >1200 m^3/d [16]. But when re-completed to produce six seams spanning two systems (well X2N), the combined peak was <500 m^3/d—even lower than the single-system case, i.e., $1 + 1 < 1$ [16]. This inter-layer negative interference arises because the higher-pressure, higher-permeability seams dominate flow to the well, suppressing contribution from lower-pressure/low-perm seams, as confirmed by physical experiments [17]. Figure 1 illustrates the general trend: as more seams (and systems) are commingled, the gas production per unit coal thickness drops off in a power-law fashion. This behavior, observed in dozens of pilot wells, underscores that simply maximizing the number of co-produced seams is counterproductive—an optimal combination must balance accessing more gas-in-place with minimizing inter-seam flow interference.

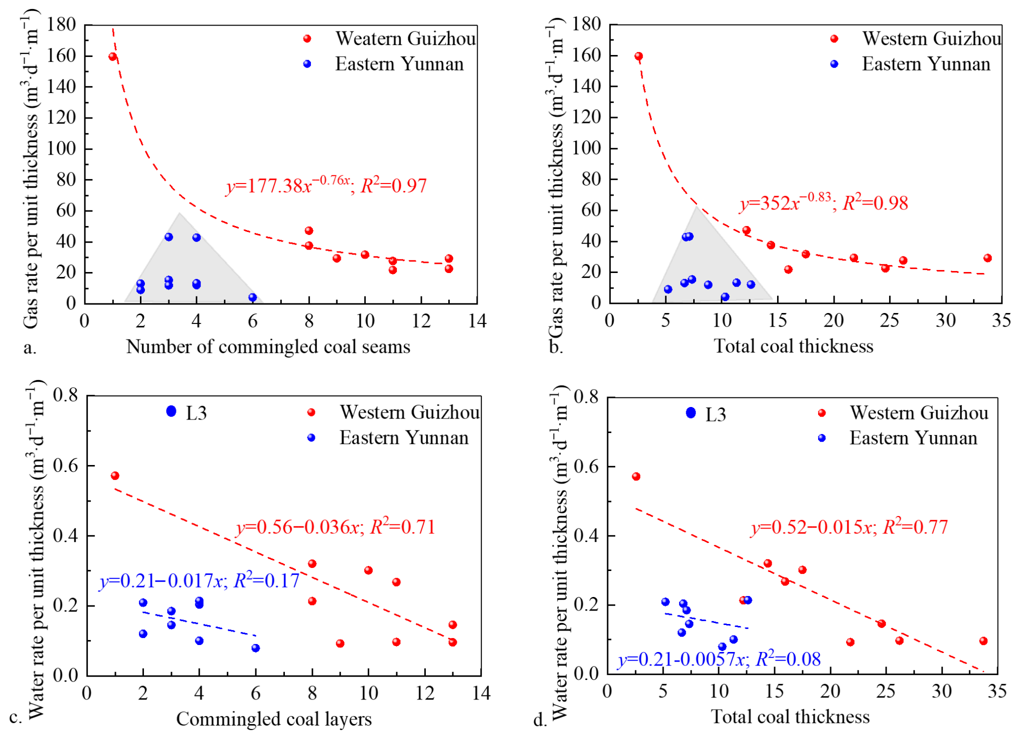

Figure 1. Well production performance per unit coal thickness under varying coal seam combinations: (**a**) number of commingled seams vs. gas production; (**b**) total coal thickness of commingled seams vs. gas production; (**c**) number of commingled seams vs. water production; (**d**) total coal thickness of commingled seams vs. water production.

In summary, the key challenge in multi-seam CBM development is to identify which subset of seams should be co-produced to maximize total gas recovery while avoiding excessive inter-layer interference. Some prior studies proposed qualitative guidelines for multi-layer selection (e.g., favoring seams in the same pressure system or with similar permeability [10]), but a rigorous, quantitative optimization method has been lacking [18]. The purpose of this study is to develop and validate a systematic four-step optimization workflow for selecting production layer combinations in multi-superposed CBM systems. A case study from the Western Guizhou–Eastern Yunnan region is used to demonstrate the applicability and practical significance of the method. This method innovatively integrates geological data screening, pressure/system partitioning, and numerical simulation of different seam combinations—providing a data-driven decision workflow rather than trial-and-error field tests. We demonstrate the method on a case study well (LC-C2 in the Laochang block), showing how it identifies the main gas-bearing seams and the optimal multi-seam configuration. The outcomes not only validate the approach's effectiveness (by matching observed production and improving performance) but also offer insights into inter-layer interference mechanisms and how to mitigate them through informed layer selection. The study thus contributes a practical optimization strategy for multi-seam CBM production, relevant to similar coal basins globally that feature stacked coal-bearing sequences.

2. Geological Setting and Production Challenges

2.1. Geological Setting

The focus area lies in the Western Guizhou–Eastern Yunnan region, on the southeastern margin of the Sichuan Basin. Geologically, it consists of Permian coal measures deposited in a platform to paralic setting, later deformed into gentle synclines and faulted blocks. The coal-bearing strata (e.g., the Late Permian Longtan Formation) are highly stratified, containing tens of thin coal seams (generally 0.3–3 m thick each) interbedded with mudstones, shales, and sandstones. Regionally, the coal rank varies from medium-volatile to low-volatile bituminous (Ro ≈ 0.8–1.2%) in Western Guizhou to semianthracite (Ro > 2.0%) in Eastern Yunnan, indicating a complex thermal and tectonic history [19]. A notable feature is the pervasive development of argillaceous ironstone bands (also called "mudstone with siderite") within the coal measures—these are laterally continuous, compact layers with extremely low permeability that act as aquitards [20]. As a result, the vertical fluid continuity in the coal-bearing sequence is disrupted, giving rise to multiple independent CBM-bearing systems stacked atop one another [21].

Independent CBM pressure systems were identified using multiple indicators: (1) measured formation pressure gradients that showed abrupt discontinuities across sealing mudstone layers, (2) well interference tests confirming lack of communication between adjacent seams, and (3) lithological evidence of thick, dense rhodochrosite-bearing mudstones acting as effective seals. Together, these indicators confirmed hydraulic isolation of the pressure systems. Field measurements corroborate the existence of these discrete pressure systems. In a single borehole, one would expect coal reservoir pressure and gas content to increase monotonically with depth under a unified hydrostatic system; instead, oscillating profiles are observed [22–24]. For example, in well TC-1 (Tucheng block), coal gas content first rises with depth from Seam 4 to 12, then drops from Seam 12 to 16, and rises again in deeper seams 22 to 29 (Figure 2a). Correspondingly, drill-stem tests show abnormally high reservoir pressures in some mid-depth seams (e.g., Seam 16, pressure coefficient 1.40) but near-normal pressure in shallower and deeper seams. Such non-monotonic gas content and pressure profiles indicate at least 2–3 distinct pressure compartments (gas-bearing systems) in the vertical sequence. The boundaries of these systems align with the thick, laterally continuous mudstone or carbonate layers, which effectively seal off gas and water communication between the coal groups. Shen et al. identified similar key sealing strata in the Late Permian coalfield of western Guizhou, confirming that depositional cyclicity created independent CBM systems separated by low-permeability layers [23,25]. In the Enhong syncline of eastern Yunnan, for instance, three coal sequences separated by regionally extensive sideritic mudstones behave as independent CBM systems: the coal seams immediately above each mudstone have locally low gas contents and form the base of each system. Notably, the Enhong block's coal seams exhibit much lower reservoir pressures (most seams are sub-hydrostatic, pressure coefficients ~0.8–1.1) compared to Tucheng's (Figure 2b), reflecting different hydrological conditions and perhaps active water recharge in shallower systems [26]. In the Laochang block, coal gas content and saturation are generally low (average saturation ~38%) and show no clear depth trend (Figure 2c), also pointing to multiple independent systems and a complicated permeability distribution [27,28].

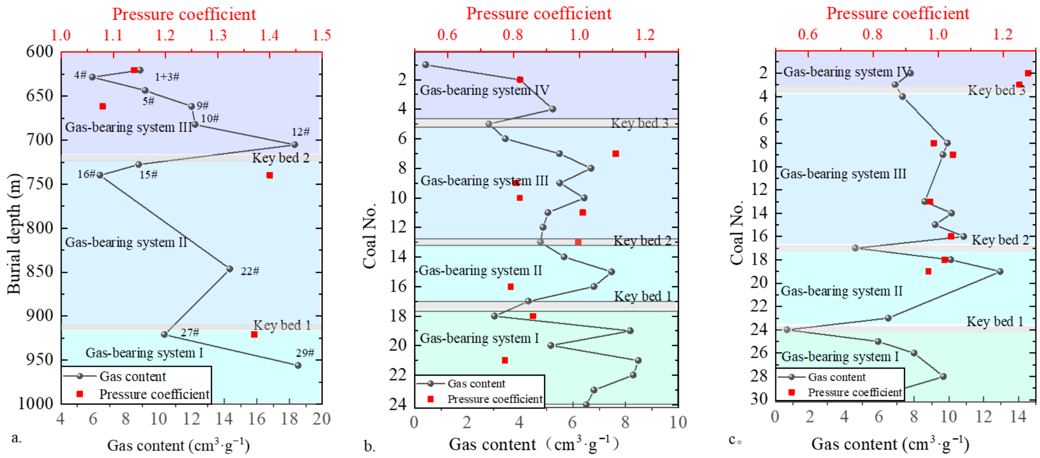

Figure 2. Key stratigraphic horizons and division of CBM systems: (**a**) Tucheng Block; (**b**) Enhong Block; (**c**) Laochang Block.

2.2. Production Challenges in Commingled CBM Wells

Because of these geological features, CBM occurrence in the study area is characterized by multiple small, isolated "pods" of gas rather than one large continuous reservoir. Each pod (system) can have different pressure, saturation, and permeability characteristics. The practical implication is that a single coal seam on its own often cannot sustain economic gas production, as it may be thin and quickly drained or lack sufficient pressure drive. This has motivated the widespread use of multi-seam commingled production wells, which attempt to simultaneously extract gas from several seams to aggregate sufficient flow rates. However, as noted in the Introduction, this approach introduces the risk of interference between seams, especially when seams from different pressure systems are combined. The study area's pilot production history provides clear evidence of such interference.

In the Tucheng block, 9 vertical production wells (T1–T9) were completed, each targeting a different set of seams out of ~40 total seams in the local coalfield. All wells were frac-stimulated in each target seam and then produced together. The results were generally poor—for example, well T6 (which tapped 13 seams across three systems) showed the highest performance, yet even it could only sustain an average ~760 m^3/d in the first 1000 days. The gas production curves fluctuated strongly with time and none of the wells achieved stable, high gas rates. Figure 3 shows the actual production (gas and water) rates of a representative Tucheng well producing multiple seams. The erratic gas rate and relatively high water production indicate that pressure drawdown was not uniformly achieved in all layers, likely because certain seams dominated the flow. Indeed, a comparison of a single-seam test vs. multi-seam production in the same borehole (well TC1N vs. TC1) highlights the interference effect (Figure 4): TC1N, fractured only in Seam 1 + 3 (total 2.6 m of coal), produced 859 m^3/d peak gas; whereas TC1, which added 9 more seams (total 17.5 m coal across 3 systems), only raised the peak gas to ~1196 m^3/d—far less than proportional. Moreover, TC1's water production was over five times higher than TC1N's, indicating that adding many seams mostly resulted in excess water influx without commensurate gas gain.

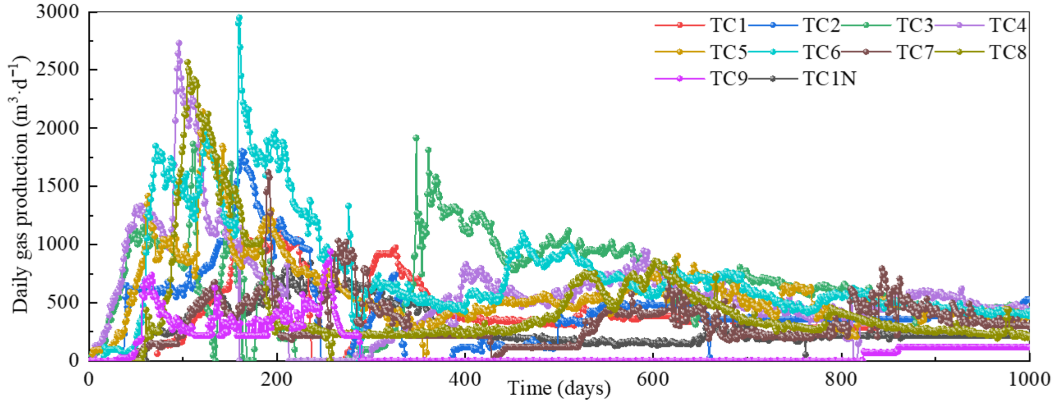

Figure 3. Actual drainage curves of CBM co-production wells in Tucheng block.

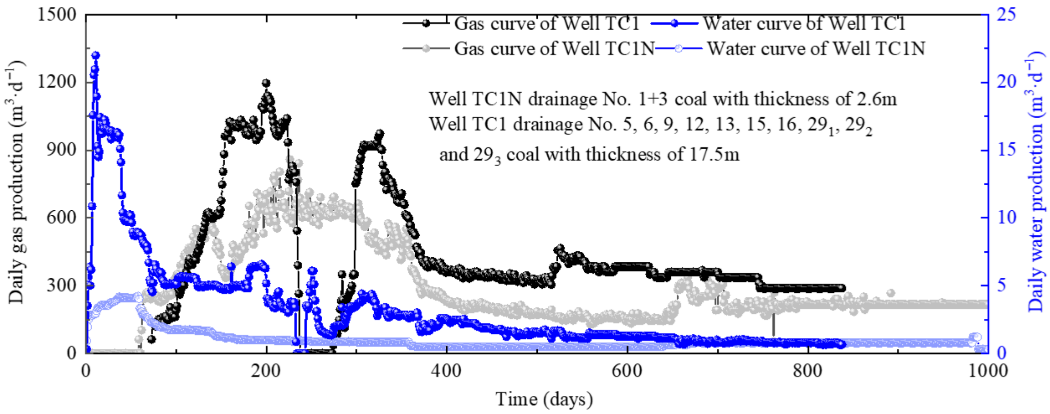

Figure 4. Comparison of drainage effect of different developing target layers in TC1 well.

In the Enhong block, two pilot wells (E6 and E7) were drilled for commingled production (Figure 5). Well E6 was perforated in six seams across three pressure systems, whereas E7 was perforated in only two seams within the same system. E6's multi-system approach yielded a peak gas rate of only 116 m^3/d and an average ~40 m^3/d over 1000 days, whereas E7 (fewer seams in one system) reached 314 m^3/d peak and ~72 m^3/d average. Although both wells had low absolute production, E7's performance was nearly double E6's, suggesting that reducing the number of systems being co-produced can lessen interference and improve gas rate. Similarly, in the Laochang block, eight trial wells (LC1–LC8) completed with various seam combinations showed that wells with fewer target seams tended to have slightly better gas rates. Half of the Laochang wells produced <80 m^3/d (very low), largely due to operational issues (frequent shutdowns, etc.), but even the better-performing wells rarely exceeded 150–200 m^3/d average in the first three years. Water production in these wells was generally low to moderate (<2.5 m^3/d, dropping below 1 m^3/d after some time), which indicates that, unlike Tucheng, the Laochang and Enhong coals are relatively dry (low initial water saturation) but suffer from low gas content and pressure, making absolute production limited.

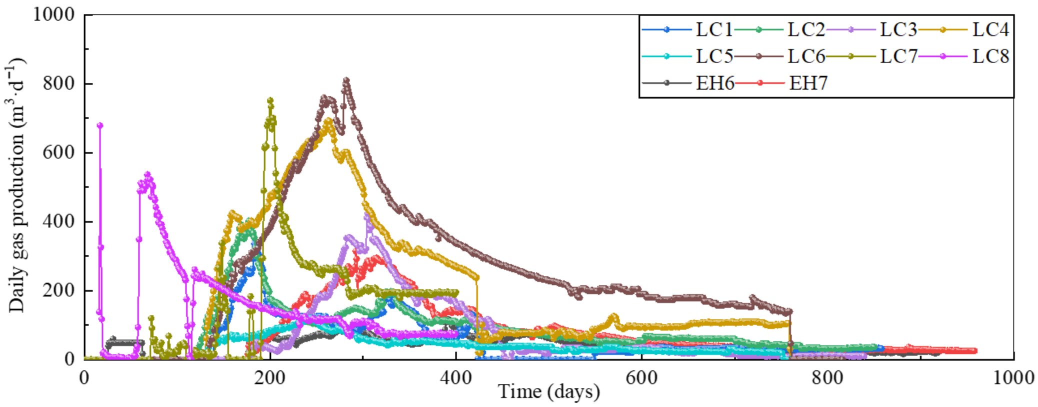

Figure 5. Actual drainage curves of CBM co-production wells in Laochang and Enhong blocks.

In summary, Western Guizhou–Eastern Yunnan CBM reservoirs present a complex multi-layer system where careful optimization is required to achieve economic gas production. The geological setting provides both the opportunity (abundant coal seams and gas resources) and the challenge (compartmentalization and interference) for CBM development. In the following sections, we outline a systematic methodology to address this challenge, and we validate it using a detailed case study in the Laochang block.

3. Methodology

We developed a systematic four-step optimization workflow (summarized schematically in Figure 6) to select the best combination of production layers in a multi-seam CBM well. The workflow progresses from data gathering and model calibration to simulation-based evaluation of different commingled production scenarios. The main steps are as follows:

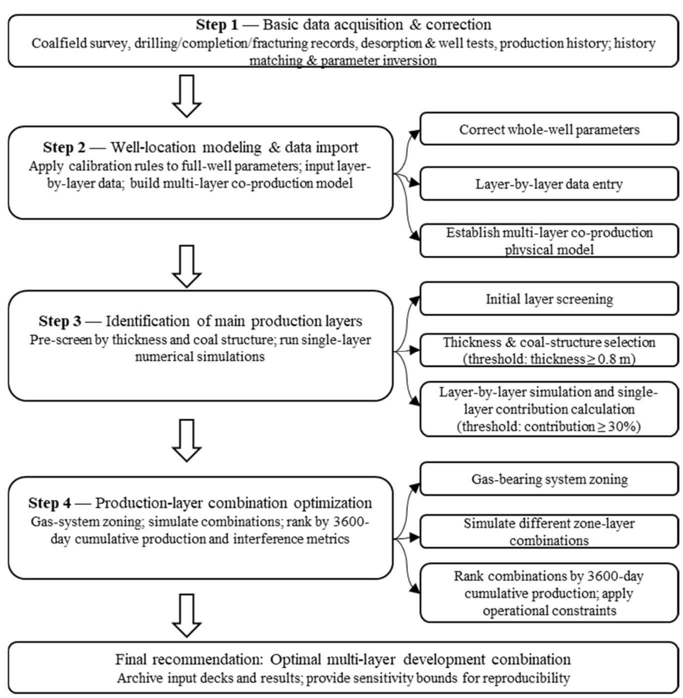

Figure 6. Schematic illustration of the four-step optimization workflow for selecting commingled production layers in a multi-superposed CBM system.

3.1. Data Collection and Calibration

Gather all necessary geological and engineering data to characterize the reservoir, then calibrate uncertain parameters via history matching. Key data include coal seam depths, thicknesses, gas content (from exploration cores), reservoir pressures (drill-stem tests), permeability estimates, fracture treatment reports, and production histories of any existing wells. These data are quality-checked and corrected as needed (e.g., standardizing units, filtering outliers). Using an initial reservoir model, we perform a history match against observed production (especially early-time pressure drawdown and gas rate behavior) to adjust critical parameters (permeability, gas desorption properties, fracture characteristics, etc.) within realistic ranges. This calibration ensures the model can reproduce field behavior and effectively "corrects" the raw data for use in predictive simulations.

3.2. Well Model Construction

Numerical simulations were conducted using the COMET3™ Reservoir Simulator, developed by International Advanced Energy Company, USA. . Gas adsorption/desorption was modeled using the Langmuir isotherm, while permeability variation with stress was captured by a standard exponential stress-sensitivity function. These constitutive models are widely applied in CBM reservoir simulations and ensure reproducibility of results. Build a numerical reservoir model of the target well that explicitly represents all pertinent coal seams and intervening strata using the calibrated parameters from Step 1. In practice, we construct a radial grid model encompassing the well and surrounding reservoir (extending sufficiently far, e.g., ~1000 m radius, to capture drainage). The vertical grid is finely layered to honor each coal seam's thickness and depth, with intervening impermeable rock layers included to prevent cross-flow between seams except through the wellbore. Each coal layer is assigned its specific properties (thickness, porosity, permeability, initial gas content, critical desorption pressure, etc.) from the corrected dataset. The initial conditions (pressure and saturation) are set layer-by-layer according to depth and any known pressure gradient for each gas-bearing system. The well completion is then configured in the model: typically, only the target seams are "open" to flow (perforated/fractured) initially, while other seams can be added or kept isolated in different simulation scenarios. A constant bottomhole pressure (e.g., 500 kPa) production constraint is applied to simulate a pumped well that continuously draws down pressure.

3.3. Main Production Layer Identification

Not all coal seams contribute significantly to gas production; very thin or low-permeability seams may yield negligible gas but can complicate production (e.g., by introducing excess water or simply adding cost). In this step, we identify the key coal seams ("main layers") that should be prioritized. First, a geological screening is applied: we exclude seams below a thickness cutoff following Chinese CBM development guidelines (GB/T 29119–2023) and those known to be tectonically deformed (mylonitic or friable coals with ultra-low permeability), since such seams are poor candidates for stimulation. Next, for each remaining seam, we perform a single-layer production simulation; using the calibrated model, we simulate 10 years (3600 days) of production from that seam alone (all other layers are shut in, with the well at constant bottomhole pressure). This yields the isolated gas production capacity of each seam. We record the cumulative 10-year gas volume and the percentage contribution of that seam relative to the sum of all single-seam cases (i.e., its share of the total gas that would be produced if every seam were produced individually with no interference). In addition, seams contributing more than 30% of the total simulated single-seam production were defined as "main seams". This threshold ensures that only dominant seams are prioritized, consistent with field practice and previous optimization studies [29].

3.4. Optimization Method for Layer Combinations

Finally, we evaluate various commingled production scenarios using the model to determine the optimal layer combination. Generally, the candidate combinations are built around the main layer(s) identified in Step 3, progressively adding additional layers and even entire pressure systems. We group coal seams by their independent CBM pressure systems and formulate scenarios such as producing only the main seam; producing all seams within the main seam's system; adding seams from one additional system; or adding seams from all available systems. Each scenario is run in the simulator for the specified production period (10 years here) under identical well conditions. We then compare the simulated cumulative gas recovery and production rate profiles for all scenarios. The optimal combination is selected as the one yielding the highest gas recovery (unless a smaller combination produces nearly as much with a simpler completion). This approach allows a quantitative assessment of the trade-offs; for example, whether adding a particular group of seams (especially from a different pressure system) helps or hurts overall production. The result of Step 4 is a recommended set of coal seams to co-produce in the well to maximize performance while minimizing inter-layer interference. Compared with existing CBM development guidelines in China, which provide general principles for seam selection in multiple coal areas, the proposed workflow extends these practices by offering a quantitative optimization process based on calibrated numerical simulation. This integration bridges qualitative field guidelines with quantitative predictions, thereby facilitating practical adoption.

4. Case Study: Well LC-C2

4.1. Well Overview and Data Collection

Well LC-C2 is located in the Laochang block (Yuwang area) of Eastern Yunnan (see Figure 7). The well intersects over 20 coal seams in a ~800 m thick coal-bearing sequence. Based on exploration data, three seams (No. 16, 18 and 19) were initially selected as the primary targets due to their relatively greater thickness and high gas content. Basic reservoir parameters for these three seams are given in Table 1. Seam 16, for example, is at ~699 m depth with 1.40 m thickness and had an initial reservoir pressure of 7.73 MPa (pressure gradient ~1.11 MPa/100 m, slightly above hydrostatic). All three target seams are bituminous coal of primary (intact) structure, with low matrix permeability on the order of 10^{-1}–10^{-2} mD. The critical desorption pressures (0.59–0.80 MPa) were fairly high relative to reservoir pressure, indicating these seams were initially under-saturated with gas (estimated ~30–40% gas saturation).

Table 1. Basic reservoir parameters of Well LC-C2.

Coal Seam	Depth (m)	Thickness (m)	Pressure (MPa)	Pressure Grad. (MPa/100 m)	Critical Desor. P (MPa)	Permeability (mD)	Coal Structure
16#	699.2	1.40	7.73	1.11	0.79	0.0771	Primary (intact)
18#	724.8	2.90	7.47	1.03	0.59	0.1126	Primary (intact)
19#	734.7	1.80	7.62	1.04	0.80	0.0869	Primary (intact)

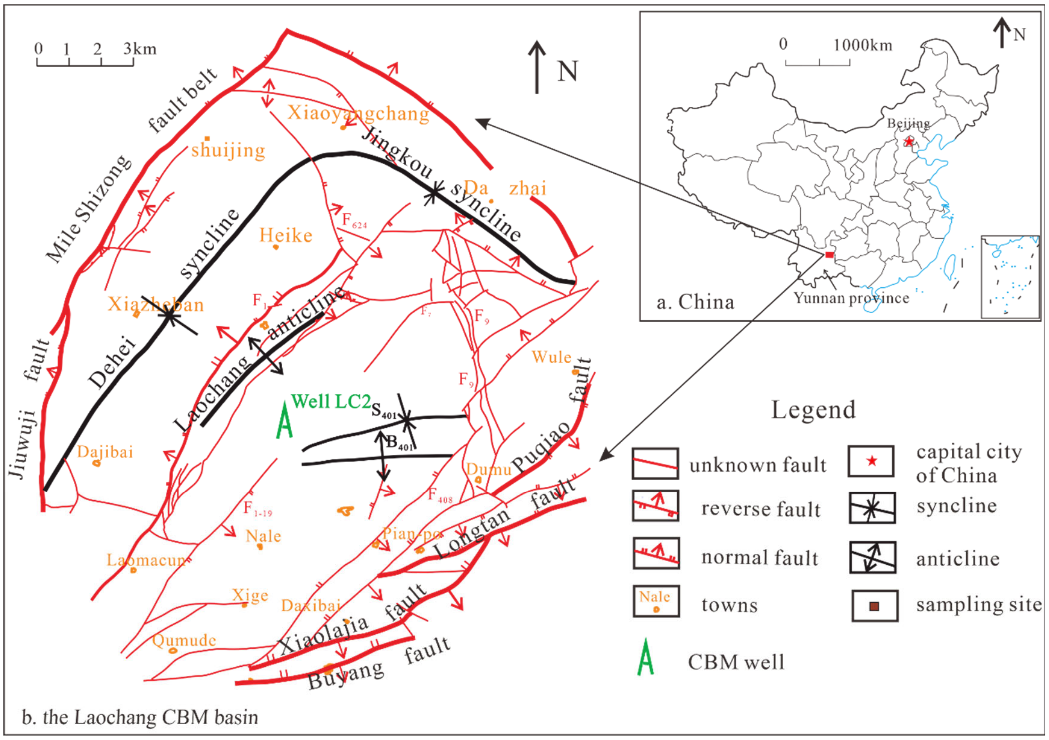

Figure 7. Structural framework of the study area and location map of Well LC-C2 (modified from Ref [27]. Licensed under CC BY 4.0. (**a**) Geographical location of the Laochang Block in China; (**b**) Structural outline map of the Lao-chang coalbed methane basin.

Well LC-C2 was drilled and completed with a segmented hydraulic fracturing treatment in the three target seams (16, 18, and 19). After completion, a commingled production test was conducted for about six months to gauge well performance. The production history (shown in Figure 8) exhibited two distinct stages: (a) an initial dewatering stage (approximately the first 123 days) where water was produced and bottomhole pressure fell steadily from ~6.8 MPa to ~1.4 MPa, but no measurable gas flow occurred; and (b) a gas production stage after the bottomhole pressure dropped below the critical desorption threshold (~1.4 MPa), during which gas breakthrough was achieved. Gas rate rose to a peak of 402 m^3/d around day 175, accompanied by a decline in water rate and a lowering of the fluid level, but after this peak the gas production declined rapidly. The low peak gas rate and its quick decline indicated suboptimal performance, likely due to the low initial gas saturations (<35%) in these seams and the need for prolonged dewatering. Essentially, the three fractured seams did not supply sustained gas flow, implying limited gas-in-place or permeability constraints.

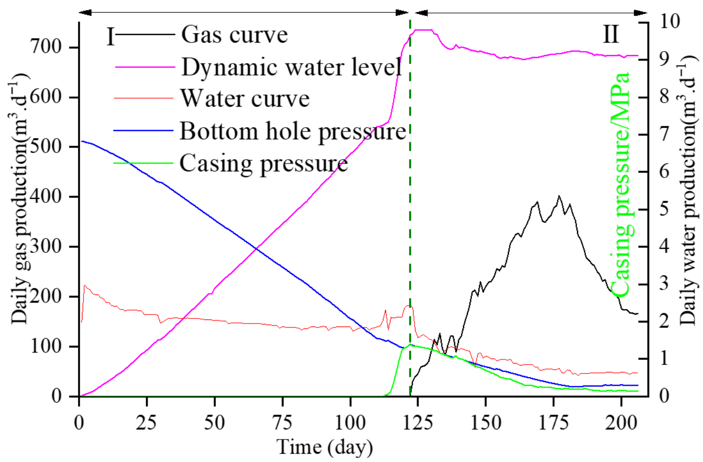

Figure 8. Production history of Well LC-C2.

Using the early production data from LC-C2, we performed history matching to calibrate the reservoir model parameters for the target seams. By tuning the coal permeability and fracture properties in the simulation, we achieved a reasonable match to the observed gas ramp-up and decline (the modeled vs. actual performance is compared in Figure 9). The final adjusted parameters from history matching are summarized in Table 2. Notably, the effective permeability of each main seam had to be reduced significantly from initial estimates to reproduce the slow gas onset and low peak (for example, Seam 16 permeability was adjusted from an initial 0.27 mD down to 0.077 mD). During history matching, coal permeability values were reduced (e.g., from 0.27 to 0.077 mD for Seam 16). This discrepancy may arise because laboratory measurements overestimate in-situ permeability due to stress relief, or because fracture damage and skin effects reduce effective permeability in the reservoir. Such reductions are consistent with observations in other CBM fields. We also introduced finite-conductivity fractures of approximately 80 m half-length in each target seam to match the relatively rapid pressure drawdown (fracture half-length was assumed to be 80 m in the base case due to lack of direct measurements). Sensitivity simulations with half-lengths of 60 m and 100 m indicated that although absolute gas volumes varied, the relative ranking of optimized combinations remained unchanged. This demonstrates that the conclusions are not strongly dependent on the assumed fracture length. In addition, the critical desorption pressure for seams 16 and 18 was slightly adjusted (e.g., from 0.79 down to 0.75 MPa for Seam 16) to better align the timing of gas appearance in the simulation with the observed 123-day dewatering period. After this calibration, the model could faithfully reproduce the key features of LC-C2's early production, indicating that the reservoir parameters for the seams were consistent with field behavior.

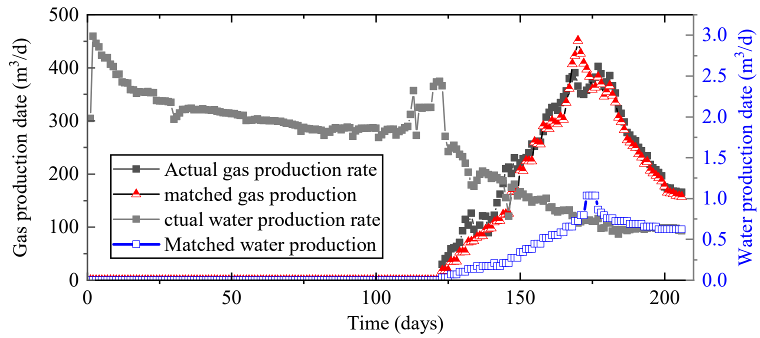

Figure 9. Actual production and fitting production of LC-C2 Well.

Table 2. List of history matching parameter adjustment.

Parameter	Seam 16 (Initial)	Seam 16 (Matched)	Seam 18 (Initial)	Seam 18 (Matched)	Seam 19 (Initial)	Seam 19 (Matched)
Permeability (mD)	0.270	0.077	0.394	0.113	0.304	0.087
Fracture half-length (m)	/	80	/	80	/	80
Fracture permeability (mD)	/	0.50	/	0.50	/	0.50
Critical desorption P (MPa)	0.79	0.75	0.59	0.54	0.80	0.75

Figure 9 presents the history match of gas and water production. The simulated gas production is in close agreement with the observed data. For water production, the early stage shows a mismatch because actual production included the backflow of fracturing fluid and non-reservoir water. After this initial phase, the simulated and measured water rates converge and remain consistent. The updated figure confirms that the calibrated reservoir parameters reproduce both gas and water production behavior reliably. After matching, the reservoir model for LC-C2 was considered calibrated and ready for predictive analysis. The calibrated parameters confirm that the targeted coal seams have very low permeability (on the order of 0.1 mD or less) and were initially under-saturated with gas (desorption did not occur until significant pressure drawdown, consistent with ~30% initial gas saturation). With a reliable well-scale model in hand, we proceeded to the next steps of identifying the main productive seams and optimizing the layer combination.

4.2. Building the Full Well Model

Using the data from Steps 1 and 2, we constructed a multi-layer radial reservoir model for LC-C2 encompassing all significant coal seams. The model included 21 coal layers (all seams ≥ 0.3 m thick, from Seam 1 down to Seam 21) separated by impermeable rock layers. The initial reservoir pressure in each seam was assigned based on its depth and the pressure gradients measured in the block; in LC-C2's case, three distinct pressure regimes were identified: the deepest seams (System I) around 7.6 MPa, intermediate-depth seams (System II, including Seam 7 + 8 and its neighbors) around 7.1 MPa, and shallower seams (System III) around 5.3 MPa. The well's completion was represented by opening the layers corresponding to seams 16, 18, and 19 (which had been fractured) for flow into the wellbore, while all other seams were initially kept closed. A constant bottomhole pressure of 500 kPa was applied to simulate continuous pumping. The model thus captured the essential features of the LC-C2 well: multiple coal seams with separate pressure systems, and a well that can be selectively completed in different layers.

With the full well model established and validated against the trial production, we moved on to analyze the production potential of individual seams and combinations of seams using numerical simulation. These steps correspond to Steps 3 and 4 of the methodology and are presented in the next section, along with the results and interpretation for well LC-C2.

5. Results and Discussion

5.1. Main Coal Seam Identification

Well LC-C2 penetrated a total of 21 coal seams, of which 10 seams met the basic screening criteria (≥0.8 m thick and primary coal structure) and were retained for production analysis (the others were very thin or otherwise unviable seams). We performed single-layer production simulations for each of these 10 candidate seams, producing each one in isolation for 10 years under identical conditions. Table 3 summarizes the simulated gas recovery and performance metrics for each seam. The results immediately show that Seam 7 + 8 (a merged coal seam of combined thickness ~3.4 m) is the dominant contributor, with an estimated 10-year recovery of ~1.45×10^6 m^3 and an average of ~403 m^3/d if produced alone. This corresponds to about 31.5% of the total gas that would be produced by all 10 seams in isolation, making Seam 7 + 8 by far the largest single contributor. The next-highest yielding seams in isolation are Seam 18 (~836×10^3 m^3, 18.2% of total) and Seam 13 (~445×10^3 m^3, 9.7%). Several seams contribute only a marginal amount of gas individually (e.g., Seam 2, Seam 3, and Seam 9-2 each < 3% of the total). Applying a 30% contribution threshold to define a “main” production layer, Seam 7 + 8 is the only seam in LC-C2 that qualifies as a primary main layer. In practice, however, relying on a single seam would not capture all available gas, so we also consider the next tier of seams. If we include all seams that individually contribute on the order of 10% or more, we bring in Seams 18, 13, and 4 (each around 9–18%) and Seam 16 (~8.9%). In fact, the top five seams (7 + 8, 18, 13, 4, and 16) together account for roughly 78% of the total single-layer gas potential of the well. We therefore identify Seam 7 + 8 as the core main coal seam for LC-C2, and seams 4, 13, 16, and 18 as important secondary layers to prioritize in combination building. The remaining candidate layers (Seam 2, 3, 9-1, 9-2, and 19) have relatively low individual yields and would only be considered for production if needed to complement the main seams within a particular gas-bearing system.

Table 3. Simulated gas production performance of each single coal seam in well LC-C2 (10-year production in isolation).

Seam No.	10-Year Cumulative Gas (m^3)	Average Daily Gas (m^3/d)	Percentage of Total (%)
2	179,560	50	3.90%
3	99,306	28	2.16%
4	439,189	122	9.54%
7 + 8	1,450,811	403	31.54%
9-1	367,266	102	7.98%
9-2	107,021	30	2.32%
13	444,770	124	9.67%
16	411,368	114	8.94%
18	836,432	232	18.18%
19	264,161	73	5.74%
All coal seams	4,599,884	1278	100.00%

These single-layer results confirm that LC-C2's gas potential is highly skewed toward certain seams. Seam 7 + 8 in particular stands out, consistent with it being one of the thickest coals and having a high gas content (>12 m^3/t) in this area [8]. In contrast, seams like No. 2 and 3 are very thin (0.4–0.8 m) and of lower coal rank, explaining their poor performance. Seam 18, although quite thick (2.9 m), has moderately low permeability and gas content, yielding a decent but not top-tier result. Overall, the quantitative single-seam analysis provides a rational basis for selecting which layers merit co-production. By focusing on the identified "main seams", developers can prioritize the most productive intervals and avoid expending effort on layers that contribute little.

5.2. Optimization of Layer Combinations

Guided by the above findings, we designed five commingled production scenarios of increasing complexity, all of which included the main seam (7 + 8) as the backbone. The first scenario considered production from the main seam alone, representing a baseline case within pressure System II. The second scenario extended this by adding the companion seams 9-1 and 9-2 from the same system, thereby evaluating the effect of commingling within a single pressure compartment. The third scenario combined all seams from Systems I and II, encompassing the main seam and its associated layers in System II as well as the deeper seams 16, 18, and 19 in System I. This two-system configuration ultimately proved to be the optimal choice. The fourth scenario explored commingling across Systems II and III, integrating the main seam group with the shallow seams (2, 3, 4, and 13). Finally, the fifth scenario represented the most extensive configuration, with all ten candidate seams across the three identified systems (I, II, and III) included for co-production (Figure 10).

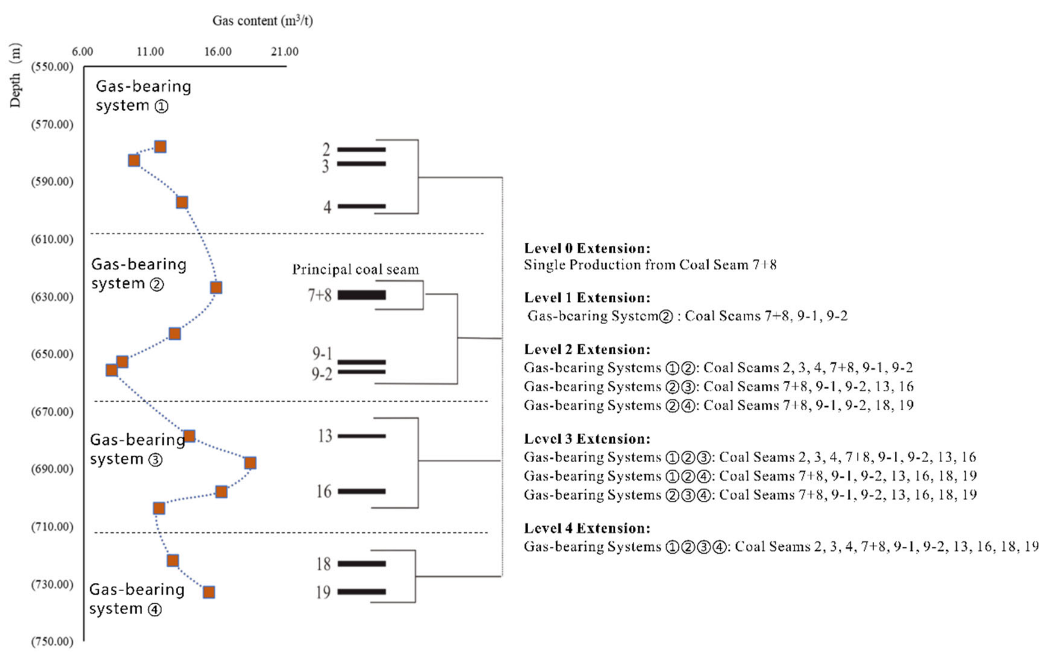

Figure 10. Production layer combination structure diagram.

Each scenario was simulated for 10 years using the calibrated LC-C2 reservoir model under identical production conditions with a constant bottomhole pressure of 500 kPa. The results, summarized in Table 4 and illustrated in Figures 11–19, reveal several clear trends. Commingling additional seams within the same pressure system yields a significant production increase: adding seams 9-1 and 9-2 alongside 7 + 8 increased the 10-year recovery to 2.44 × 10^6 m^3, approximately 68% higher than producing Seam 7 + 8 alone.

Incorporating the deeper System I seams further boosted the cumulative output to 2.53 × 10^6 m^3, making the System I + II combination the best performer, with an average gas rate of ~700 m^3/d. This optimal configuration successfully leveraged the gas-in-place of both the main seam and deeper seams without incurring excessive interference. In contrast, including the shallow System III seams reduced overall performance. The II + III combination produced 2.29 × 10^6 m^3, and the all-systems case yielded only 2.20 × 10^6 m^3, the lowest of all scenarios. The poor performance of the shallow seams, combined with their interference effects that hindered drawdown and production from deeper seams, explains the decline. These results clearly demonstrate that selective commingling confined to compatible pressure systems is superior to indiscriminate inclusion of all available seams.

Table 4. Simulated 10-year gas production for different production layer combinations in well LC-C2.

Scenario	Co-Produced Seams	10-Year Cumulative Gas (m^3)	Average Gas Rate (m^3/d)
1. Main Seam Only	7 + 8 (System II)	1,450,811	403
2. All Seams in System II	7 + 8, 9-1, 9-2 (System II)	2,437,311	677
3. Systems I + II (Optimal)	16, 18, 19 + 7 + 8, 9-1, 9-2	2,525,074	701
4. Systems II + III	7 + 8, 9-1, 9-2 + 2, 3, 4, 13	2,286,024	635
5. All Systems (I + II + III)	16, 18, 19 + 7 + 8, 9-1, 9-2 + 2, 3, 4, 13	2,200,000	610

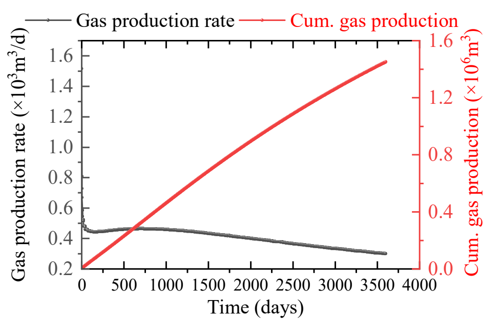

Figure 11. Level 0 extended drainage curve (Seam 7 + 8).

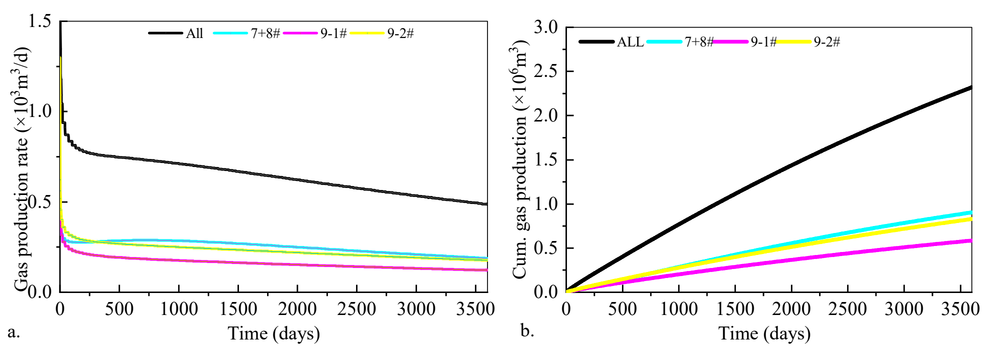

Figure 12. Level-1 extended production forecast curve (System I) (**a**) daily gas production; (**b**) cumulative gas production.

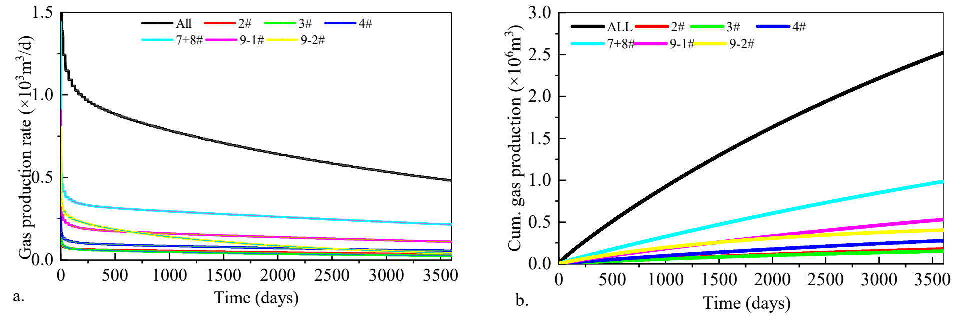

Figure 13. Level 2 extended drainage forecast curve (Systems I and II) (**a**) daily gas production; (**b**) cumulative gas production.

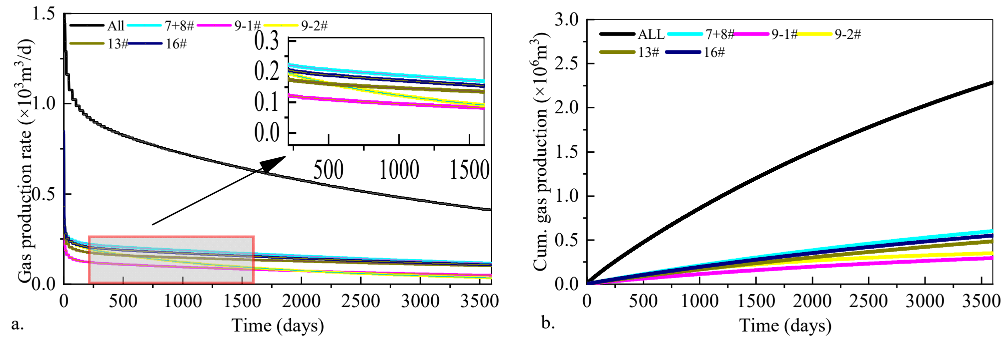

Figure 14. Level 2 extended drainage forecast curve (Systems II and III) (**a**) daily gas production; (**b**) cumulative gas production.

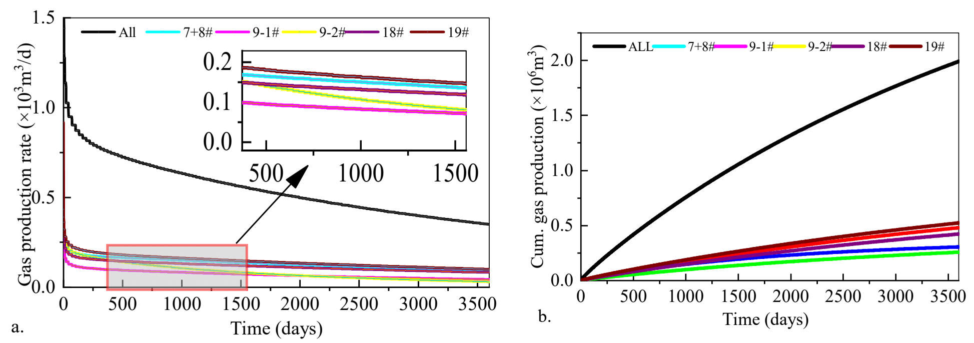

Figure 15. Level 2 extended drainage forecast curve (Systems II and IV) (**a**) daily gas production; (**b**) cumulative gas production.

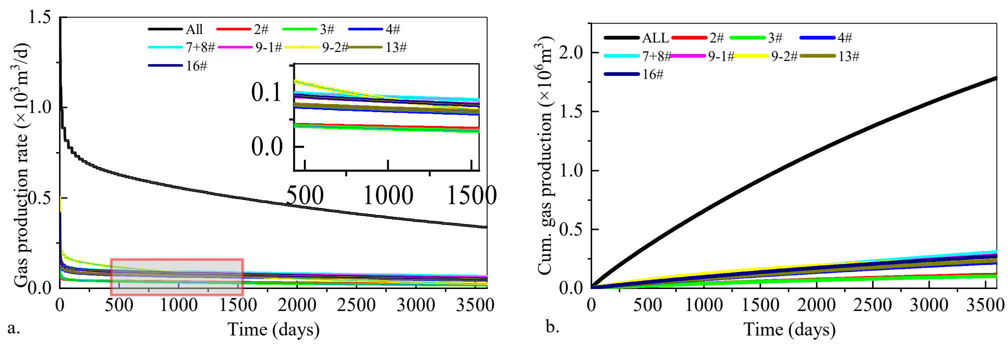

Figure 16. Level 3 extended drainage forecast curve (Systems I, II, and III) (**a**) daily gas production; (**b**) cumulative gas production.

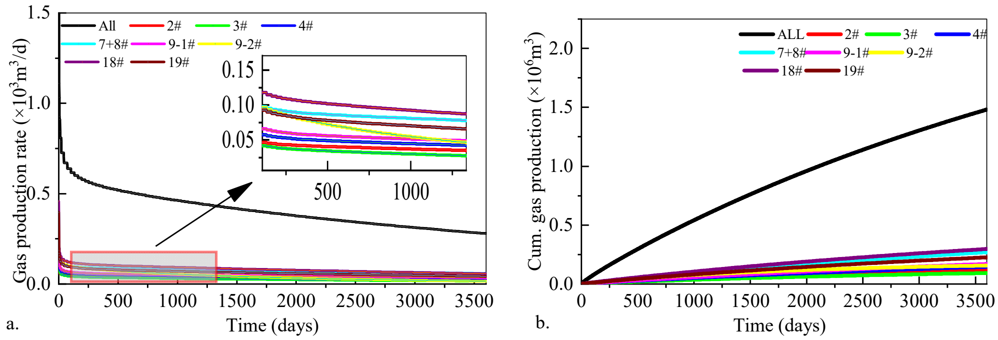

Figure 17. Level 3 extended drainage forecast curve (Systems I, II, and IV). (**a**) daily gas production; (**b**) cumulative gas production.

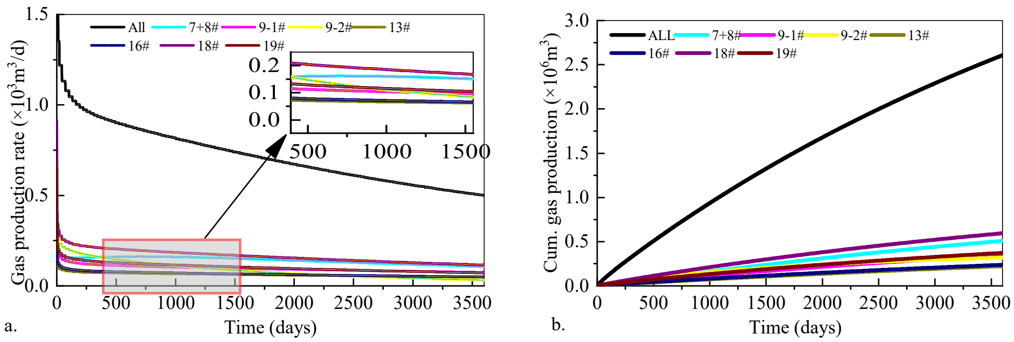

Figure 18. Level 3 extended drainage forecast curve (Systems II, III, and IV) (**a**) daily gas production; (**b**) cumulative gas production.

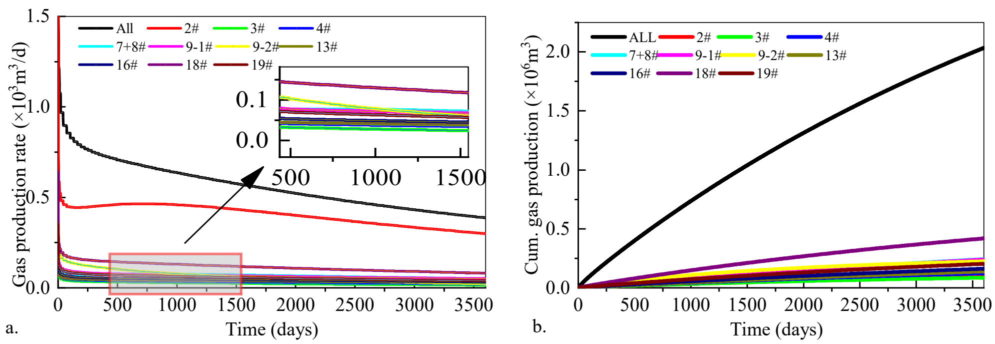

Figure 19. Level 4 extended drainage forecast curve (Systems I, II, III, and IV) (**a**) daily gas production; (**b**) cumulative gas production.

The simulation results clearly indicate that the optimal commingling strategy for well LC-C2 is to produce from the two deeper CBM systems (I and II) and exclude the shallowest system (III). In quantitative terms, the selected combination (Scenario 3) is projected to recover about 2.53×10^6 m^3 of gas in 10 years (an average of ~700 m^3/d). This represents a ~75% increase in total gas compared to producing the main seam alone, and about 15% more gas than the scenario that included all seams. In the optimal case, we can further examine the layer-by-layer contributions: Seam 7 + 8 (the main seam) accounts for roughly 39% of the total gas, seams 9-1 and 9-2 together about 37%, and the added deep seams (16, 18, and 19) contribute the remaining ~24% (Figure 20). By contrast, when the shallow system was included, its seams contributed <15% of the total gas but caused a disproportionate reduction in output from other seams; some of the gas that would have been produced from the deeper seams was never recovered within the 10-year window, likely because the shallow layers provided an easier outlet for water or temporarily diverted flow, slowing pressure drawdown in the deeper layers. This reinforces the decision to exclude those shallow seams: they added little gas of their own and interfered with the efficient production of gas from the more prolific seams. In addition, sensitivity tests indicated that variations in permeability, Langmuir volume, and fracture half-length caused changes in absolute cumulative gas forecasts by up to 20%. However, the relative performance ranking of different co-production scenarios remained unchanged, demonstrating that the optimization results are robust against parameter uncertainty.

Mechanistically, these findings support the interference hypothesis discussed earlier. When multiple isolated pressure systems are opened together in one well, the system with the highest pressure (and/or permeability) will dominate production initially, delivering most of the flow while its pressure drops. During this period, lower-pressure systems contribute very little because their pressure differential to the wellbore is smaller—effectively, the high-pressure seams "steal" the drawdown. By the time the dominant system is partially depleted and the lower-pressure seams could start producing more significantly, the overall reservoir pressure in the vicinity may have declined so much that those lower-pressure seams have lost a portion of their driving force. In other words, the opportunity for the low-pressure seams to produce is largely gone by the time the high-pressure seam is exhausted, resulting in less combined gas than if each were produced separately or sequentially. Our simulation of LC-C2 captures this behavior: including System III seams provided almost no immediate gas (because System II had higher pressure and took the lead), and later those seams could not make up for lost time, leading to a lower total recovery than if they were left out. By not commingling the lowest-pressure system, the optimal case avoided this problem; it allowed the two higher-pressure systems (which were closer in pressure) to be produced together efficiently, while leaving the troublesome shallow layers for potential separate development.

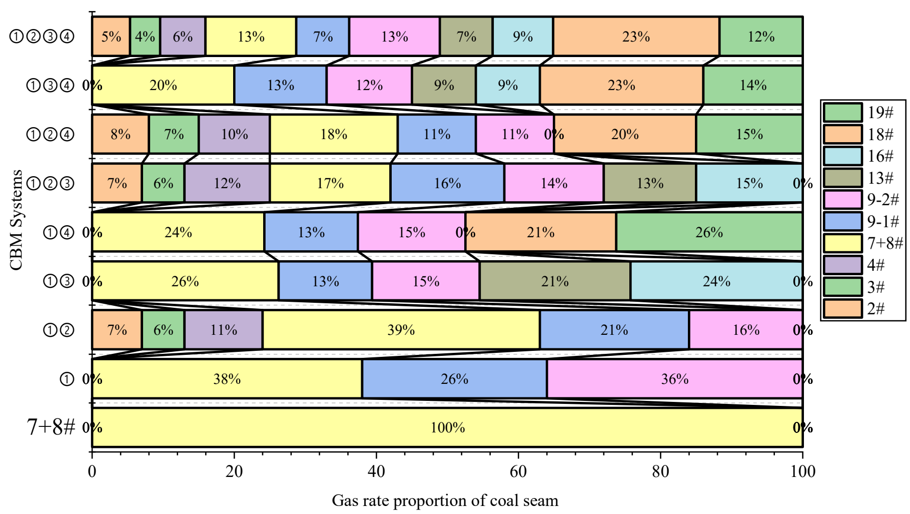

Figure 20. Proportional contributions of individual seams under different production layer combinations.

These results have important practical implications. They demonstrate that in multi-superposed CBM settings, more is not always better when it comes to choosing co-production layers. A judicious selection that targets a moderate number of seams within compatible pressure regimes can significantly outperform an all-inclusive approach. In the LC-C2 case, the optimal 6-seam combination (Systems I + II) outperformed the 10-seam combination (Systems I + II + III) despite using fewer layers. The improvement in gas output and production stability comes from mitigating inter-layer interference by avoiding seams that would contribute disproportionately to water or steal drawdown without adding much gas. This optimized strategy can serve as a model for similar multi-seam CBM wells: it suggests that operators should focus on co-producing seams from the higher-pressure (or better quality) systems and consider isolating or separately developing the lower-pressure systems. By doing so, the effective utilization of the reservoir is maximized and the “1 + 1 < 2” negative synergy is minimized. The simulations assume perfect vertical seals between independent systems, i.e., no cross-flow except through the wellbore. In reality, induced fractures or natural vertical fractures could provide limited communication between seams. This assumption should be regarded as a limitation, and future work should consider cross-flow sensitivity analysis to evaluate its potential influence. The sustainability of the proposed workflow lies in its adaptability: as new field data become available, the calibrated models can be updated, and the optimization can be refined. This iterative process ensures that the results remain relevant and applicable over long-term CBM field development.

6. Conclusions

This research presented a comprehensive four-step optimization method for selecting production layer combinations in multi-superposed CBM systems and demonstrated its effectiveness on a field case in Western Guizhou–Eastern Yunnan. The key conclusions are:

(1) Commingling too many coal seams across different pressure systems can severely impair CBM well performance. Field trials and simulations confirm that indiscriminate co-production of numerous layers (especially combining high-pressure and low-pressure systems) leads to strong inter-layer interference. In such cases, the higher-pressure seams dominate production while lower-pressure seams contribute little, resulting in total gas output far below the sum of what individual seams could produce (a “1 + 1 < 2” negative synergy effect).

(2) A systematic, simulation-based workflow was developed to optimize multi-seam production design. The proposed four-step method (data gathering and calibration, well modeling, single-seam productivity evaluation, and scenario simulation) provides a quantitative means to identify the most productive coal seams and the optimal combination for co-production. This data-driven approach moves beyond prior qualitative guidelines and trial-and-error field practices, enabling informed decision-making for layer selection in commingled CBM wells.

(3) Application of the method to well LC-C2 demonstrated that an intermediate number of compatible seams yields the best performance. In the case study, only one seam (7 + 8) was identified as a primary “main layer” (>30% of total potential), with a few others as secondary contributors (~10–18% each). The optimal production strategy was to co-produce the six seams from the two higher-pressure systems (Systems I and II), while excluding the shallow low-pressure system (System III). This optimized configuration achieved a 10-year cumulative gas recovery of ~2.53×10^6 m^3 (~700 m^3/d average), about 75% higher than producing the main seam alone and ~15% higher than commingling all three systems (ten seams).

(4) Selective co-production of seams from similar pressure regimes is recommended for multi-layer CBM reservoirs. By avoiding low-productivity seams that mainly introduce water or siphon pressure drawdown, operators can greatly improve gas recovery and well stability. The findings from LC-C2 indicate that focusing on a moderate number of high-quality seams (in terms of pressure, permeability, and gas content) can maximize gas output, whereas adding marginal seams from other pressure compartments may be counterproductive. This optimized approach to layer selection can be applied to other

CBM fields with stacked coal seams, providing valuable guidance to enhance production efficiency in geologically compartmentalized reservoirs.

(5) This study is limited to a single well in one geological setting, and uncertainties remain in assumed fracture parameters and permeability calibration. Future work will focus on applying the four-step workflow to multi-well pilot tests in different geological blocks, incorporating uncertainty quantification of fracture parameters, and assessing the applicability of the method in other CBM basins worldwide.

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Conflicts of Interest: Author Fangkai Quan was employed by the State Key Laboratory of Safe Mining of Deep Coal and Environmental Protection, Ltd. Authors Tao Song and Haiying Wang were employed by the company the First Exploration Team of Shandong Coalfield Geologic Bureau, and Shandong Engineering Research Center of Mine Gas Disaster Prevention. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest. The company State Key Laboratory of Safe Mining of Deep Coal and Environmental Protection, Ltd, the First Exploration Team of Shandong Coalfield Geologic Bureau, and Shandong Engineering Research Center of Mine Gas Disaster Prevention had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results.

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