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Controls on the Hydrocarbon Production in Shale Gas Condensate Reservoirs of Rift Lake Basins

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Abstract: The production of gas and condensate from liquid-rich shale reservoirs, particularly within heterogeneous lacustrine systems, remains a critical challenge in unconventional hydrocarbon exploration due to intricate multiphase hydrocarbon partitioning, including gases (C_1 – C_2), volatile liquids (C_3 – C_7), and heavier liquids (C_{7+}). This study investigates a 120-meter-thick interval dominated by lacustrine deposits from the Lower Cretaceous Shahezi Formation (K_1sh) in the Songliao Basin. This interval, characterized by high clay mineral content and silicate–pyrite laminations, was examined to identify the factors controlling hybrid shale gas condensate systems. We proposed the Hybrid Shale Condensate Index (*HSCI*), defined as the molar ratios of $(C_1$ – $C_7)/C_{7+}$, to categorize fluid phases and address shortcomings in traditional *GOR/API* ratios. Over 1000 samples were treated by geochemical pyrolysis logging, X-ray fluorescence (XRF) spectrum element logging, SEM-based automated mineralogy, and in situ gas desorption, revealing four primary controls: (1) Thermal maturity thresholds. Mature to highly mature shales exhibit peak condensate production and the highest total gas content (*TGC*), with maximum gaseous and liquid hydrocarbons at $T_{max} = 490$ °C. (2) Lithofacies assemblage. Argillaceous shales rich in mixed carbonate and clay minerals exhibit an intergranular porosity of $4.8 \pm 1.2\%$ and store $83 \pm 7\%$ of gas in intercrystalline pore spaces. (3) Paleoenvironmental settings. Conditions such as humid climate, saline water geochemistry, anoxic bottom waters, and significant input of volcanic materials promoted organic carbon accumulation (*TOC* reaching up to 5.2 wt%) and the preservation of organic-rich lamination. (4) Laminae and fracture systems. Silicate laminae account for 78% of total pore space, and pyrite laminations form interconnected pore networks conducive to gas storage. These findings delineate the “sweet spots” for unconventional hydrocarbon reservoirs, thereby enhancing exploration for gas condensate in lacustrine shale systems.

Keywords: shale; gas condensate; hydrocarbon; fluid phase; thermal maturity; laminae; lithofacies; lake; rift basins; volcanism



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1. Introduction

Hybrid condensates require refining processes to eliminate higher-boiling-point hydrocarbon fractions ($>CH_4$). Upon isolation, these residual hydrocarbons undergo liquefaction, yielding natural gas condensate [1]. Such reservoirs exhibit complex thermodynamic responses marked by sub-dew-point pressures that drive condensate precipitation and compositional alteration of reservoir gases [2,3]. Contemporary classification frameworks

categorize hybrid shale gas condensate resources into two distinct groups: liquid-lean and liquid-rich systems. Both groups predominantly comprise C_1 – C_{33} n-alkanes, with the C_1 – C_7 fraction persisting in gaseous states under reservoir conditions [4]. Volatile light hydrocarbons (C_3 – C_7) critically control the generation of liquid-lean condensate through phase partition processes [2,3,5–7].

Recent exploration efforts in continental basins have exposed critical knowledge gaps in characterizing shale gas condensate reservoirs. The interplay between elevated clay mineral content and heterogeneous organic inputs introduces substantial uncertainties in hydrocarbon distribution patterns [8–11]. Hybrid shale gas condensate systems in continental basins represent a critical frontier in unconventional hydrocarbon exploration, given the complexity of multiphase fluid behaviors (gas, volatile liquids, and condensate) with the challenges of heterogeneous lithofacies and diagenetic alterations. While marine shale systems (e.g., Bossier and Haynesville shales) have been extensively studied [12,13], lacustrine systems, particularly those characterized by high clay mineral contents and strong inputs of volcanogenic materials, remain underexplored. Recent advances highlight the role of lamina architectures in enhancing hydrocarbon storage and connectivity [14], the influences of bottom-water redox conditions on organic matter preservation [15], and the development of novel indices to quantify phase partitioning [16]. However, key questions persist regarding the combined effects of volcanic inputs, salinity fluctuations, and laminae-induced fractures in controlling hybrid condensate “sweet spots” within lacustrine shales.

Overall, two principal challenges have been identified in reservoir evaluation:

1. Hydrocarbon phase dynamics. Drilling-induced perturbations of pressure and temperature tend to trigger phase transitions, particularly when reservoir pressures decline below dew-point thresholds near wellbores [17–19]. Differential retention mechanisms further complicate the associated analysis. C_1 – C_2 alkanes demonstrate sluggish diffusion kinetics, while volatile light hydrocarbons (C_3 – C_7) and liquid-phase components (C_{7+}) persist in metastable configurations within fracture networks and matrix porosity [6,20,21]. These phenomena limit the efficacy of conventional C_1 – C_7 advanced mud gas logging for quantitative hydrocarbon assessment.
2. Lacustrine reservoir heterogeneity. Compared to marine shales, lacustrine systems exhibit amplified variability of lithofacies due to abrupt facies changes [22,23], multi-scale beddings [24], and lamina-induced fracture systems [25–27] that induce strong anisotropic hydrocarbon distribution and condensate productivity [28–31]. Additional complexity stems from dynamic phase behavior modulated by thermal maturity gradients, in situ P-T conditions, and near-wellbore condensate banking effects [29,31,32]. Consequently, these factors impede the reliable identification of hydrocarbon sweet spots in continental shale reservoirs.

The China Geological Survey implemented a multidisciplinary exploration project of continental shale gas resources based on the Cretaceous Shahezi Formation (K_1sh) within the Songliao Basin (JLYY1 borehole, Figure 1). A 120-meter-thick, lacustrine-dominated interval at >3000 m depth was analyzed through an integrated analytical protocol.

- High-resolution geochemical profile via systematic sampling and measurement at a 0.5 to 1 m interval (more than 1000 samples) employing multiple methods such as geochemical logging, in situ gas desorption, and electron microscopic mineralogy.
- Phase-specific hydrocarbon characterization using S_1 (C_7 – C_{33}) parameters and total gas content (TGC), with speciation of gaseous (C_1 – C_2) versus volatile (C_3 – C_7) components.
- Lithofacies discrimination through the correlation of total organic carbon content (TOC) and mineral composition, augmented by elemental proxies for paleoenvironmental reconstruction.

- Nanoscale rock fabric analysis utilizing ultra-high-resolution scanning electron microscopes (SEMs) to detect the occurrence of organic matter and mineral particles, elemental migration pathways, and hydrocarbon–bitumen associations.
- Phase behavior modeling via a proxy termed Hybrid Shale Condensate Index (*HSCI*), incorporating T_{max} values to map maturity-controlled phase distributions across C_1 – C_{33} hydrocarbons.
- Multivariate statistical integration of *HSCI*, S_1 , TGC , T_{max} , TOC , and rock compositional datasets to delineate dominant hydrocarbon distribution controls.

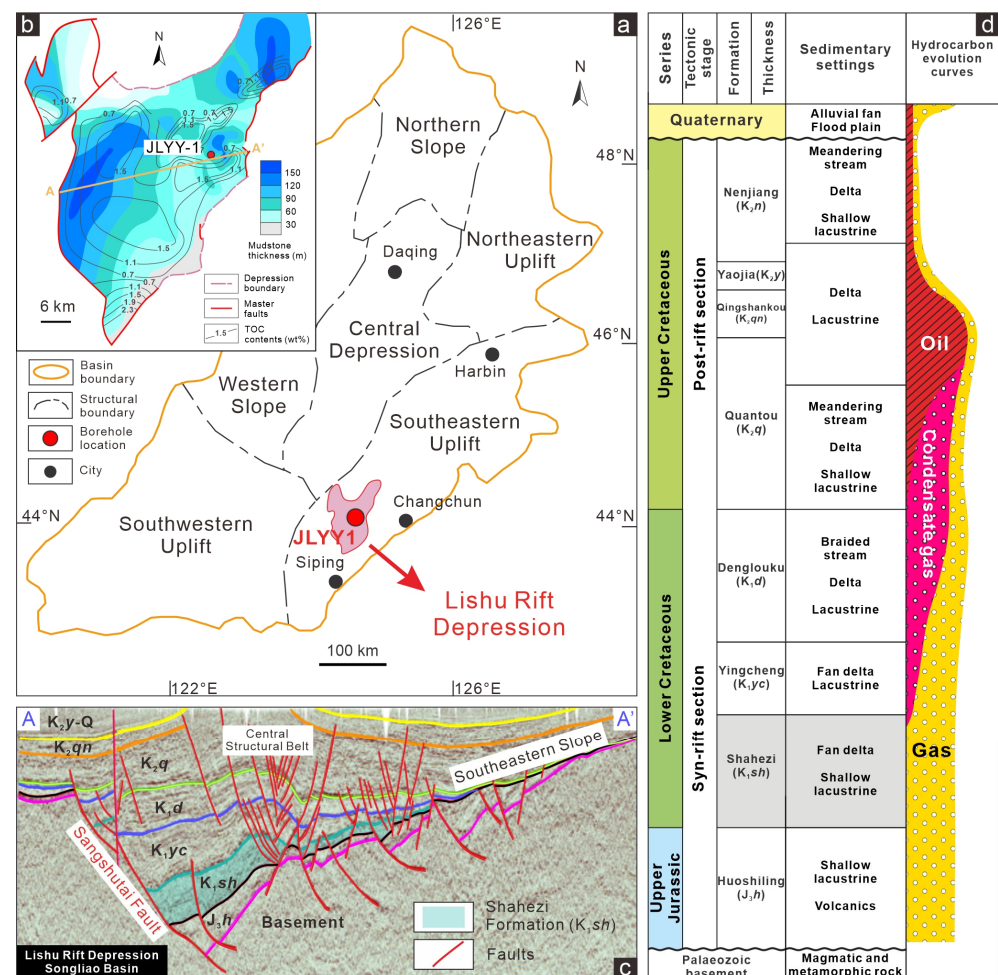


Figure 1. (a) The tectonic units of the Songliao Basin in northeastern Asia and the location of the Lishu Rift Depression. (b) Spatial distribution of mudstones and total organic carbon (TOC) concentrations within the Lishu Rift Depression. (c) An interpreted seismic reflection profile A–A' showing the basin geometry, major faults, and depositional filling of the Lishu Rift Depression. The profile location is illustrated in panel (b). (d) A stratigraphic section measured from drilling boreholes, illustrating the tectonostratigraphic evolution, sedimentary settings, and hydrocarbon phase changes of the Lishu Rift Depression.

Currently available methods for the evaluation of hybrid shale gas condensate systems, e.g., *GOR/API* classifications (*GOR*: gas-to-oil production ratio; *API*: American Petroleum Institute gravity), struggle to capture multiphase fluid behavior in lacustrine systems due to their dependence on surface fluid properties. This study addresses this gap by proposing the Hybrid Shale Condensate Index (*HSCI*), which integrates in situ gaseous (TGC) and liquid (S_1) components to quantify fluid-phase maturity for complex unconventional reservoirs rich in clay minerals. This approach uses S_1 and TGC as robust proxies for liquid

and volatile hydrocarbon phases, respectively, while providing a systematic framework to decipher hydrocarbon occurrence mechanisms in complex lacustrine shale gas condensate systems influenced by volcanic activities, paleoenvironmental settings, water geochemistry, and laminae–fracture synergy.

2. Geological Background

The JLYY1 borehole investigated in this study is situated in the eastern slope zone of the Lishu Rift Depression within the Southeast Uplift of the Songliao Basin (Figure 1). The Lishu Rift Depression, covering a total area of 2822 km², is notable for having the longest rifting period, the most complete stratigraphic development, the thickest sedimentary deposits, and the deepest burial in the southeast uplift area of the Songliao Basin. This depression contains two primary sets of strata: the syn-rift and post-rift sections (Figure 1d). The syn-rift section has a thickness ranging from 0 to 8000 m, with a maximum burial depth exceeding 10,000 m. This section contains the Cretaceous Huoshiling Formation (K_{1h}), Shahezi Formation (K_{1sh}), Yingcheng Formation (K_{1yc}), and Dengloulou Formation (K_{1d}), filled with lacustrine and fan delta deposits [22,33]. The post-rift section mainly consists of the Cretaceous Quantou Formation (K_{2q}), Qingshankou Formation (K_{2qn}), Yaojia Formation (K_{2y}), Nenjiang Formation (K_{2n}), and Quaternary strata, characterized by fluvial, deltaic, and lacustrine facies deposition [34]. The Shahezi and Yingcheng Formations are the primary intervals of thick shales developed during the significant rifting subsidence period.

From top to bottom, the JLYY1 borehole drilled through the Quaternary, Upper Cretaceous K_{2qn} and K_{2q} Formations, Lower Cretaceous K_{1d}, K_{1yc}, and K_{1sh} Formations. The measured reservoir pressure of the Shahezi Formation ranges from 19.38 to 26.56 MPa, with a reservoir pressure coefficient ranging between 0.84 and 1.0, averaging approximately 0.98. The reservoir temperature gradient in the Shahezi Formation is between 3.3 °C/100 m and 3.5 °C/100 m, indicating a normal temperature system. The formation temperature at the bottom of the JLYY1 borehole is approximately 120 °C.

3. Materials and Methods

3.1. Geochemical Pyrolysis-FID Logging and In Situ Gas Desorption

The thermal maturity of source rocks and hydrocarbon fluid properties have been rapidly evaluated by the geochemical pyrolysis-FID (flame ionization detector) logging. The generated hydrocarbons and kerogens can be volatilized and cracked at different temperatures by heating sample powders within an inert gas atmosphere [31,35,36]. The light hydrocarbons (<C₇) in the samples are measured as the S₀ peak, while the liquid hydrocarbons (C₈–C₃₃ n-alkanes) are pyrolyzed in the temperature range of the S₁ peak. The measured S₂ values represent the kerogen and heavy hydrocarbons (greater than C₃₃), and the S₄ values are contributed by the residual carbon within rocks. The in situ total gas contents (TGC, m³/t) of the Shahezi Formation rocks were tested in the well site once the core segments were recovered by pressure coring and sealed in airtight desorption canisters. The coalbed methane and shale gas pulse-type intelligent tester (HTG-Pulse-6, Hengtaishanghe Energy Technology Co., Ltd., Beijing, China) was used to measure the lost gas, desorption gas, and remaining gas. Detailed information on the experimental procedure and equipment can be found in Wang et al. (2023) [31]. In this study, the content of movable liquid hydrocarbons is indicated by S₁ values in the geochemical pyrolysis logging, whereas the content of light and gaseous hydrocarbons (C₁–C₇) is represented by the TGC values in the gas desorption tests.

3.2. X-Ray Fluorescence (XRF) Spectrum Element Logging

Major and trace element concentrations of the Shahezi Formation were measured by the X-ray fluorescence (XRF) spectrum element logging (CIT-3000SY XRF element analyzer, Sichuan Xinxianda Measurement & Controlling Co., Ltd., Chengdu, China). The XRF elemental capture energy spectrum technology is based on the interaction between high-energy X-rays and the sample. When the X-rays bombard the sample, electrons are released from the outer layers of the atoms, creating electron vacancies. Subsequently, electrons from higher energy levels fall into these vacancies, emitting characteristic X-rays. The variation in energy and wavelength of these emitted X-rays depends on the element involved. Hence, the type and quantity of elements present in the samples can be determined by analyzing the energy and wavelength of the emitted X-rays. The measured elements can be classified into five types: (1) highly migrated elements (Cl, Br, and S); (2) easily migrated elements (Ca, Mg, Na, F, Sr, K, Zn, and P); (3) migrated elements (Cu, N, Co, Mo, V, Mn, P, and S in silicates); (4) stable elements (Fe, Al, Ti, and Se); and (5) hardly migrated element (Si). In this study, twenty elements, including Na, K, Al, Si, Fe, Ca, Mg, Ti, Mn, S, P, Cl, Th, U, Ba, Sr, V, Ni, Cr, and Zr, are measured across the entire shale gas condensate interval to investigate the influence of the paleoenvironmental conditions on the in situ content of shale gas condensate.

3.3. SEM-Based Automated Mineralogy and Petrography

The RoqSCAN system is a quantitative and automated SEM-EDS (scanning electron microscopy and energy-dispersive X-ray spectroscopy) developed by Fugro Robertson Ltd. (Leidschendam, The Netherlands) and Carl Zeiss Microscopy Ltd. (Jena, Germany) [37,38]. It can not only be used in the laboratory but can also be prepared as portable, durable core analysis equipment in the field. The RoqSCAN used in this study is equipped with a Carl Zeiss EVO 50 SEM (Carl Zeiss Ltd., Jena, Germany), a Bruker AXS X-ray detector (Bruker Corporation, Billerica, MA, USA), a Bruker Pulse Processor (Bruker Corporation, Billerica, MA, USA), and Zeiss SmartPI™ software (version 1.0, Carl Zeiss Ltd., Jena, Germany) [33], allowing for mineralogical and petrographic analysis of rock cuttings, cores, sidewall coring, and thin sections. It provides data on element concentrations, mineral types, rock fabrics, and petrophysical parameters (e.g., porosity, pore-size distribution, fracture numbers, and fracture density) by analyzing high-resolution SEM-EDS images (pseudo-color mineral images with a maximum resolution of 250 nm) [39–41]. Besides these data, the RoqSCAN system can also give information about bulk-rock density, brittleness, and elasticity [42,43]. In this study, the RoqSCAN is used to quantify the mineral composition and determine the rock fabrics. The images of laminated mudstones, composed of various mineral compositions, help to investigate the influences of lithofacies and laminae-induced fractures on shale gas condensate gas contents.

Besides RoqSCAN technology, an ultra-high-resolution FEG (field emission gun)-SEM (Zeiss GeminiSEM 450, Carl Zeiss Ltd., Jena, Germany) was utilized to detect dispersed organic matter and mineral particles across scales ranging from μm to nm, at the SEM Shared Research Facility, University of Liverpool. Backscattered (BSE, 20 kV accelerating voltage, 1 nA current) and secondary electron (SE, 5 kV, 1 nA) microscopy were performed on the Ar-ion beam-milled rock blocks to produce photomicrographs. Details of sample preparation and experimental procedure can be found in Wang et al. (2023 and 2025) [22,33].

3.4. Hybrid Shale Condensate Index (HSCI)

The fluid types on the surface are typically determined based on the gas-to-oil ratio (GOR) and oil viscosity (API), as illustrated in Table 1 and previous studies [9,29,31]. Both GOR and API are determined by the light hydrocarbon components ($\text{C}_1\text{--C}_7$) and heavy

hydrocarbon components (C_{7+}) [44–46]. The content of gaseous hydrocarbons ranges from mixtures of methane and ethane with very few other constituents (dry gas) to mixtures containing a range of hydrocarbons from methane to pentane, and even hexane (C_6H_{14}) and heptane (C_7H_{16}) (wet gas). In both cases, some carbon dioxide (CO_2) and inert gases, including helium (He), are present along with hydrogen sulfide (H_2S) and trace amounts of organic sulfur [47–49].

Table 1. Measured fluid composition and fraction properties for typical condensate gas regions. Separator gas and oil samples were captured and recombined to the reported GOR in the laboratory.

GOR (scf/STB) ¹	3000–4000	4000–5000	5000–8000	8000–15,000	15,000–50,000
Specific gravity (°API)	52.1	55.5	N/A ²	54.58	N/A
Reservoir pressure (psi)	11,025	10,630	10,000	9300	N/A
Reservoir temperature (°F)	321	328	300	290	275
Dew point (psi)	4312	4165	4050	3892	3310
CO ₂	1.07	0.69	1.57	1.971	1.10
N ₂	0.15	0.07	0.09	0.092	0.10
C ₁	61.88	64.17	67.97	69.722	72.60
C ₂	11.64	11.22	11.61	11.791	12.95
C ₃	5.58	5.46	4.57	4.165	3.79
I-C ₄	1.32	1.53	1.38	1.316	1.25
N-C ₄	2.35	2.39	1.90	1.67	1.46
I-C ₅	1.20	1.35	1.24	1.188	1.14

¹ scf/STB: cubic feet of gas per barrel of oil or condensate. ² N/A: not available.

In this study, the fluid type of drilling-associated hydrocarbons is classified by using the in situ hydrocarbon components based on the surface fluid classification. While C_1 – C_7 advanced mud gas logging methods are employed during drilling, testing the gaseous hydrocarbon content of hybrid shale gas condensates is challenging. This difficulty arises because the liquid phase formed in the matrix typically remains below residual oil saturation. Moreover, the heavier hydrocarbon components (C_{7+}) will be permanently trapped in the matrix unless enhanced oil recovery techniques are applied. This is especially true under drilling conditions where only small quantities of C_1 – C_2 hydrocarbons can flow to the gas content tester due to the density of the drilling fluid. Therefore, the hybrid condensates cannot be fully evaluated without considering the concomitant oils.

As a result, a new index, the Hydrocarbon Saturation Classification Index (*HSCI*), was proposed using the molar components of C_1 – C_7 and C_{7+} to classify the fluid type, as described in Equation (1) [50]. The ratio values are calculated according to the molar ratio of hydrocarbon components, as shown in Table 1. The *HSCI*, as defined in Equation (1), offers an advantage in representing the occurrence of equal and elevated maturity levels in both gaseous and liquid components of condensates, particularly for hybrid condensates. Since the C_{7+} fraction is the only liquid-phase component available in gas condensate PVT analytical data, it is often spuriously increased by depressurization, making a reliable liquid index generally unavailable.

$$\left\{ \begin{array}{l} \text{Liquid hydrocarbons : } \frac{n_{C_1-C_7}}{n_{C_{7+}}} < 10 \\ \text{Gas condensate : } 10 < \frac{n_{C_1-C_7}}{n_{C_{7+}}} < 60 \\ \text{Wet gas : } 60 < \frac{n_{C_1-C_7}}{n_{C_{7+}}} < 128 \\ \text{Dry gas : } \frac{n_{C_1-C_7}}{n_{C_{7+}}} > 128 \end{array} \right. \quad (1)$$

Here, some modifications were made to fit the light hydrocarbon component ratio as Equation (2), where *TGC* is used to indicate the volume content of desorbed gas, and *S₁* is used to indicate the mass content of movable hydrocarbon in shales.

$$HSCI = \frac{n_{C_1-C_7}}{n_{C_7+}} = \frac{m_{C_1-C_7} M_{C_8-C_{33}}}{M_{C_1-C_7} m_{C_8-C_{33}}} = \frac{10^3 m_{rock} TGC}{M_{C_1-C_7} \rho_{C_1-C_7}} \cdot \frac{M_{C_8-C_{33}}}{m_{rock} \cdot S_1} = \frac{10^3 TGC \cdot M_{C_8-C_{33}}}{M_{C_1-C_7} \rho_{C_1-C_7} S_1} \quad (2)$$

where n indicates the molar content, m indicates the mass for special hydrocarbon components, M indicates the molar mass, and ρ indicates the hydrocarbon density. Additionally, the fitting parameters of $\rho_{C_1-C_7}$, $M_{C_1-C_7}$, and $M_{C_8-C_{33}}$ are settled as 0.739 g/cm³, 16 g/mol, and 78 g/mol, respectively. Note that the $HSCI$ is only proposed according to the fluid type classification during production, especially related to the hydrocarbon components. However, any kind of hydrocarbon components could not be used separately to illustrate the in situ fluid phase. Thus, a further hydrocarbon phase work using the $HSCI$ and the geochemical pyrolysis logging data will be discussed in the following sections.

4. Results

4.1. Lacustrine Shale Components and Lithofacies

Quantitative mineral analysis utilizing RoqSCAN and rock pyrolysis reveals distinct compositional zonation in lacustrine shales (Figures 2 and 3). The ternary diagram in Figure 3a delineates bulk-rock mineral composition into three endmembers: carbonates, clay minerals, and non-clay mineral silicates. Detailed mineral speciation maps (Figure 3b,c) employ standardized symbology: solid circles denote high-TOC samples (>2 wt%), squares represent medium-TOC (0.5 to 2 wt%), and triangles mark low-TOC zones (<0.5 wt%). The associated clay mineral classification chart identifies seven species through diagnostic X-ray diffraction peaks: mixed clay (MC, 14 Å), illite/muscovite (I/M, 10 Å), kaolinite (K, 7 Å), mixed calcareous clays (MC(C), 12–14 Å composite), chlorite (Ch, 14 Å and 7 Å), glauconite (G, 10 Å and 4.5 Å), and biotite (Bio, 10 Å and 3.3 Å). Core analysis identifies three vertically stacked units marked by different mineral compositions: (1) argillaceous zone (3080–3115 m): clay mineral content > 75 vol% with homogenous fabric (lamination index < 0.15); (2) laminated and organic-rich unit (3115–3165 m): peak TOC (5.2 ± 0.8 wt%) coincident with pronounced bedding-parallel anisotropy (lamination index > 0.65); (3) calcite-fractured mudstone (3170–3200 m): $89 \pm 4\%$ calcite content exhibiting conjugate fracture sets (fracture density: 12 ± 3 fractures/m) and pressure solution crumples.

Three genetic classes are defined based on the following TOC thresholds:

- Type I (TOC > 2 wt%): S_1 (C₇–C₃₃) = 1.8 ± 0.3 mg/g, TGC (C₁–C₂) = 1.6 ± 0.2 m³/t.
- Type II (0.5–2 wt%): S_1 = 0.9 ± 0.2 mg/g, TGC = 1.1 ± 0.3 m³/t.
- Type III (<0.5 wt%): S_1 = 0.3 ± 0.1 mg/g, TGC = 0.7 ± 0.2 m³/t.

Figure 3d demonstrates S_1 maxima (>1.5 mg/g) in shales of 50–75% clay mineral content, correlating with MC(C) abundance ($R^2 = 0.82$, $p < 0.01$). Pore network modeling reveals MC(C)-rich zones develop $4.8 \pm 1.2\%$ intergranular porosity (Figure 4a, blue clusters) versus $1.2 \pm 0.5\%$ in I/M-dominated regions.

Furthermore, spatial correlation analysis (Figure 4b,c) shows TGC maxima (>1.5 m³/t) overlap with high- S_1 intervals but lack TOC dependence ($R = 0.18$, $p = 0.32$). SEM-EDS mapping confirms < 2% organic porosity, with $83 \pm 7\%$ gas stored in intercrystalline pores within the clay mineral matrix (Figure 4d, marked by yellow).

Integrated analysis identifies optimal reservoirs as (1) liquid phase hydrocarbon: MC(C) > 25%, I/M:K < 1.5:1, TOC > 2 wt% (Figure 4a, red zones); (2) gaseous phase hydrocarbon: clay mineral content = 50–75%, illite crystallinity < 0.35 $\Delta^\circ 2\theta$ (Figure 4c).

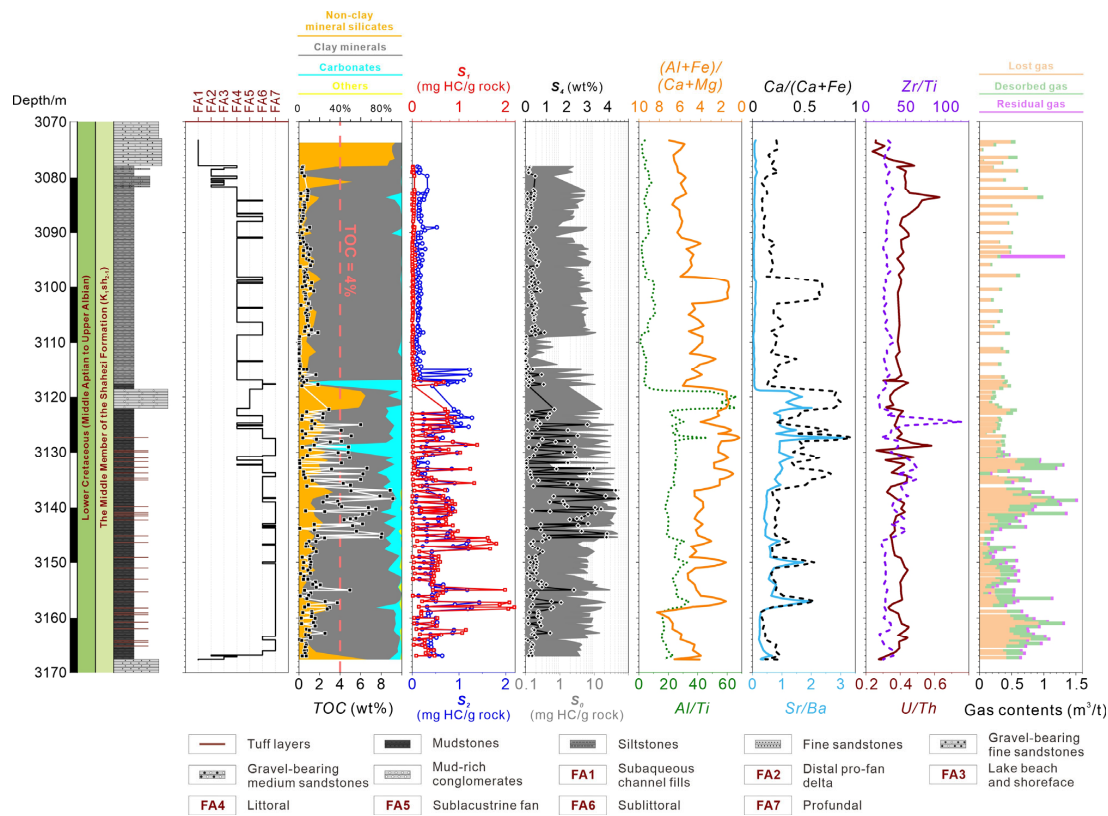


Figure 2. Comprehensive stratigraphic section of the lacustrine-dominated interval within the Shahezi Formation (JLYY1 borehole, Lishu Rift Depression), illustrating the vertical variations in lithology, facies associations (FA1–FA7, after Wang et al., 2025) [22], mineral composition, total organic carbon (TOC) content, pyrolysis logging proxies (S_0 , S_1 , S_2 , and S_4), geochemical indicators, and total gas content (TGC). The Al/Ti ratio is used to infer paleoclimate conditions (humid vs. dry), while the $(Al + Fe)/(Ca + Mg)$ proxy reflects paleowater depth. Sr/Ba and $Ca/(Ca + Fe)$ ratios are employed to differentiate paleosalinity (freshwater vs. saline lake), the Zr/Ti ratio indicates the input intensity of volcanic materials, and the U/Th ratio serves as an indicator of bottom-water paleoredox conditions.

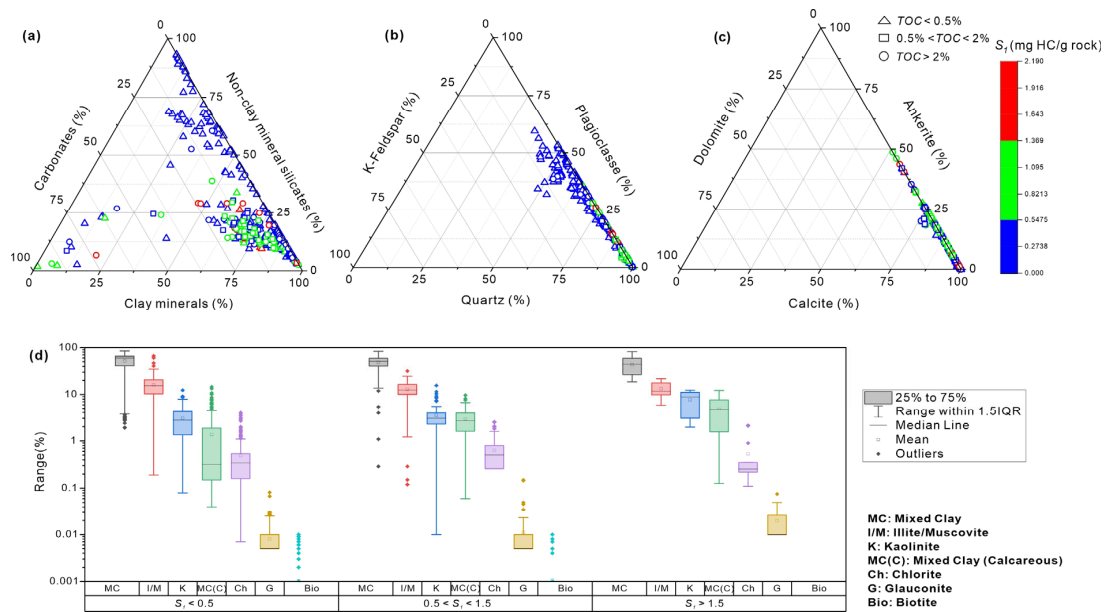


Figure 3. Ternary (a–c) and box (d) diagrams showing the correlation between RoqSCAN mineral composition, total organic carbon (TOC) concentrations, and pyrolysis S_1 values. S_1 values are used to indicate the contents of liquid hydrocarbons.

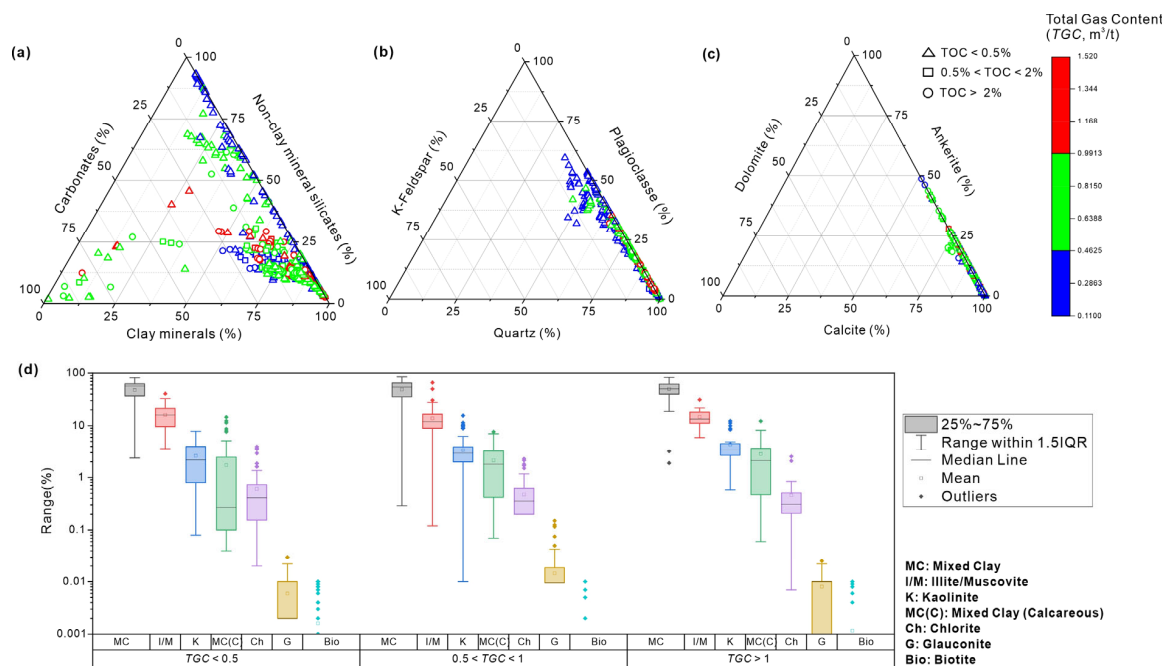


Figure 4. Ternary (a–c) and box (d) diagrams showing the correlation between RoqSCAN mineral composition, total organic carbon (TOC) concentrations, and total gas contents (TGC). TGC values are used to indicate the contents of liquid hydrocarbons.

4.2. Thermal Maturity and Hydrocarbon Phases

T_{max} values are used to indicate the thermal maturity between 450 °C to 510 °C in a mature and highly mature stage for the vertical shale section from 3080 m to 3165 m of JLYY1 well. The liquid friction, as mentioned in Section 3.4, is depicted by the $HSCI$ in Equation (2), such that $HSCI$ is valued between 0 to 140 for the vertical shale section. Generally, gas friction in gaseous and volatile phases controls the shales from 3080 m to 3115 m, where $HSCI$ is valued between 60 to 140. Hydrocarbon content increases with the heavier components from 3115 m to 3165 m, which are controlled by the hybrid shale gas condensate phases.

To illustrate the influence of thermal maturity and hydrocarbon phases on the hydrocarbon content, parameters of S_1 , TGC , and $HSCI$ are used to make a statistical scatter chart where T_{max} is settled as the x-axis, black points indicate the S_1 values, and blue points indicate the TGC values, as shown in Figure 5.

Here, S_1 and TGC are parameters tested just following the drilling process, indicating the hydrocarbon phases upon the ground, and T_{max} and $HSCI$ are the in situ indicators of the subsurface conditions for the JLYY1 well. In detail, T_{max} is valued from 460 °C to 500 °C and associated with a gaseous and liquid hydrocarbon peak (highest TGC and S_1 values) around 490 °C. Here, $HSCI$ was used to distinguish the shale hydrocarbon resources in the gas condensate, wet gas, and liquid states, respectively. Moreover, a further thermal maturity system was taken into consideration in this study. The hydrocarbon phases of the Shahezi Formation shale reservoir could be classified into six types: (1) the wet gas in mature shale ($T_{max} < 480$ °C, $HSCI > 60$); (2) wet gas in highly mature shale ($T_{max} > 480$ °C, $HSCI > 60$); (3) gas condensate in mature shale ($T_{max} < 480$ °C, $10 < HSCI < 60$); (4) gas condensate in highly mature shale ($T_{max} > 480$ °C, $10 < HSCI < 60$); (5) liquid in mature shale ($T_{max} < 480$ °C, $HSCI < 10$); and (6) liquid in highly mature shale ($T_{max} > 480$ °C, $HSCI < 10$). As indicated by the $HSCI$ values in Figure 5, the red points indicate that shale gas condensate in mature and highly mature shale, acting as the major hydrocarbon phases, contributes mostly to the hydrocarbon content of the in situ hybrid shale gas condensate resources. Unlike marine

shales (e.g., Haynesville, Marcellus), where biogenic silica and high thermal maturity dominate, the *HSCI* framework uniquely resolves fluid-phase ambiguities in lacustrine systems by accounting for volcanism–clay mineral interactions and lamina architectures. This approach reduces reliance on depressurization-distorted C_{7+} data, offering a higher accuracy in sweet spot prediction compared to traditional *GOR/API* methods. Section 5 provides microscopic evidence for the influence of volcanism–clay mineral interactions and lamina architectures on hydrocarbon production in shale gas condensate reservoirs.

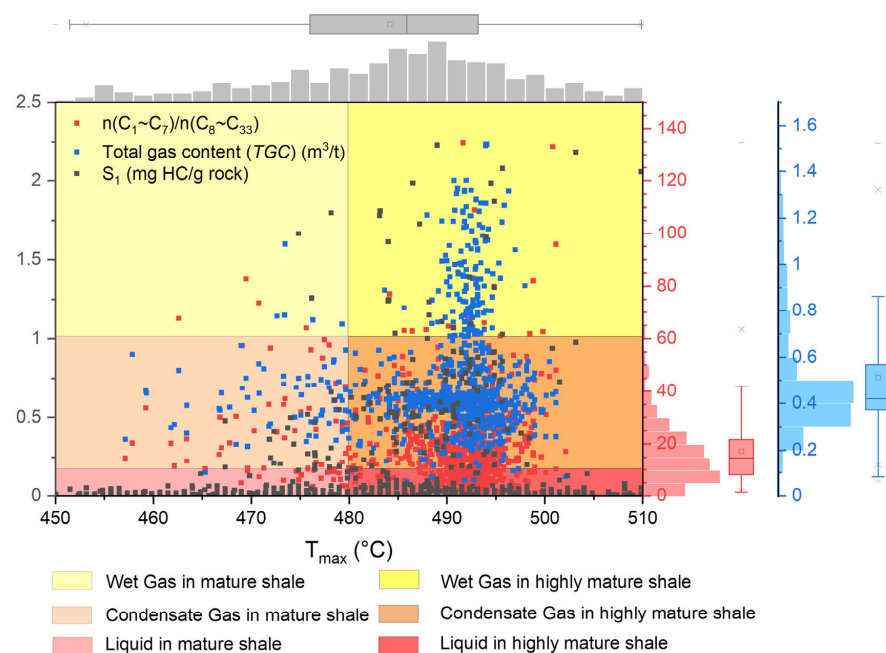


Figure 5. A scatter diagram of thermal maturation (T_{max}), Hydrocarbon Saturation Classification Index (*HSCI*), pyrolysis S_1 , and total gas content (*TGC*), illustrating the changes in hydrocarbon fluid phase with evolving thermal maturation in the Shahezi Formation shales (JLYY1 borehole, Lishu Rift Depression, Songliao Basin). Frequency distribution histograms and box-and-whisker plots for T_{max} , *HSCI*, and *TGC* are also provided, showing data distribution, outliers, and confidence intervals for these variables.

4.3. Paleoenvironmental Conditions

Major elements (Na, K, Al, Si, Fe, Ca, Mg, Ti, Mn, S, P, Cl) and trace elements (Th, U, Ba, Sr, V, Ni, Cr, Zr) were measured to study the paleoenvironmental conditions during the deposition of the Shahezi Formation and their influences on hydrocarbon contents of shale gas condensate layers. The Al/Ti ratios indicate paleoclimate conditions (humid vs. dry), while the Sr/Ba and $Ca/(Ca + Fe)$ proxies reflect paleosalinity (freshwater vs. saline lake). The $(Al + Fe)/(Ca + Mg)$ ratio suggests paleowater depth, and the Zr/Ti ratio indicates the input intensity of volcanic materials. The U/Th ratio helps assess bottom-water paleoredox conditions (oxic vs. anoxic) [51–56].

As shown in Figure 2, the paleoclimate shifts from humid to dry with decreasing Al/Ti values. Shales from 3080 m to 3120 m were deposited in a more arid climate, corresponding to lower hydrocarbon content. The paleo-lake environment transitions from freshwater to saline with increasing Sr/Ba and $Ca/(Ca + Fe)$ values, generating shales of 3115–3135 m suitable for hydrocarbon generation. These sections have higher hydrocarbon contents due to the saline water geochemistry [57]. Similarly, increasing $(Al + Fe)/(Ca + Mg)$ values suggest high water depths, enhanced hydrocarbon generation in the section of (3120–3140 m).

Volcanic ash preserved in the paleo-lake sediments, indicated by fluctuating Zr/Ti values of 3122–3142 m, also promotes hydrocarbon generation. As proposed by Li et al.

(2022), tuffaceous shale layers are key to the prediction of the hydrocarbon “sweet spot” created by water–rock interaction [50]. U is enriched in anoxic environments, while Th concentrations tend to be constant [58–60]. Thus, high U/Th values usually indicate anoxic bottom-water conditions. For the JLYY1 borehole, a high gas production is recorded in the shales from 3128 m to 3142 m, as well as 3155 m to 3167 m, where the highest hydrocarbon content corresponds to the most anoxic conditions.

Moreover, hybrid sedimentary factors contribute to the deposition of organic-rich shales from 3118 m to 3137 m. Under microscopes, organic matter particles are closely associated with terrigenous organic inputs (e.g., mineral particles covered by solid bitumen, Figure 6a,b), volcanogenic materials (e.g., organic-rich clay laminae derived from devitrified volcanic glass, Figure 6c–e), and terrestrial plant inputs (Figure 6f). Additionally, the migration of liquid hydrocarbon along volcanogenic silicate particles (Figure 6c,d) and the occurrence of solid bitumen within clay laminae (Figure 6e) suggest a hybrid sedimentary model contributing to hybrid condensate gas generation in lacustrine shale reservoirs.

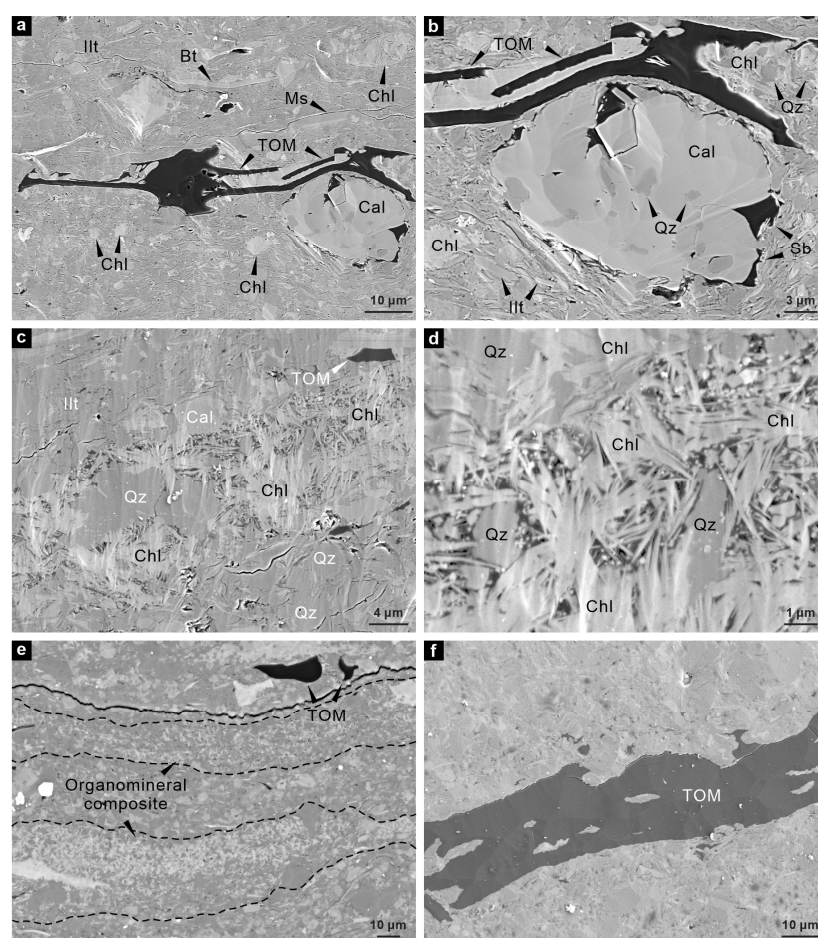


Figure 6. SEM photomicrographs of lacustrine shale samples from the Shahezi Formation (JLYY1 borehole, Lishu Rift Depression, Songliao Basin). (a–d) Secondary electron (SE) images, 3124.55 m depth. Panels (b) and (d) are magnified views of selected regions in (a) and (b), respectively. (e) Backscattered electron (BSE) image, 3128.67 m depth. (f) SE image, 3130.2 m depth. Images (c–e) show the microscopic structure and mineral composition of tuff laminae, consisting predominantly of authigenic chlorite blades, quartz, minor calcite, and pore-filling solid bitumen. These organomineral composites are interpreted as products of the devitrification of volcanic glass [22]. During this process, montmorillonite formed in early stages reacts with Fe oxide in shallow-water and alkaline conditions to produce chlorite, releasing Ca^{2+} and Si^{4+} ions that contribute to the generation of calcite and quartz. Abbreviations: Illt = illite; Bt = biotite; Ms = muscovite; Chl = chlorite; Cal = calcite; Qz = quartz; Sb = solid bitumen; TOM = terrigenous organic matter.

Overall, paleoenvironmental conditions, such as volcanic materials input, a humid climate, saline lacustrine conditions, and anoxic bottom-water promoted the deposition of shale gas condensate reservoirs, enhancing hydrocarbon content in hybrid shale gas condensate reservoirs.

4.4. Shale Lamination and Lamina-Induced Fractures

Lamina-induced fracture systems constitute critical hydrocarbon storage spaces and migration pathways in lacustrine shale reservoirs, with four distinct lithological types identified through an integration of RoqSCAN and FEG-SEM approaches (Figures 6 and 7): Silicate laminae (Figure 7b), predominantly developed in 3080–3165 m clay mineral-rich intervals, characterized by submillimeter quartz and feldspar bands (<200 μm) and accounting for 78% of total hydrocarbon storage space ($S_1 = 1.8 \pm 0.4 \text{ mg/g}$). These laminae enhance fracture connectivity through increasing fracture density and anisotropic permeability. Clay mineral laminae (Figure 7c) tend to create fractures with apertures of 50–150 μm in shales. Carbonate laminae (Figure 7a) within the same interval exhibit 20–80 μm calcite-filled fractures with $35 \pm 7\%$ spatial filling density, supported by crystalline infill textures.

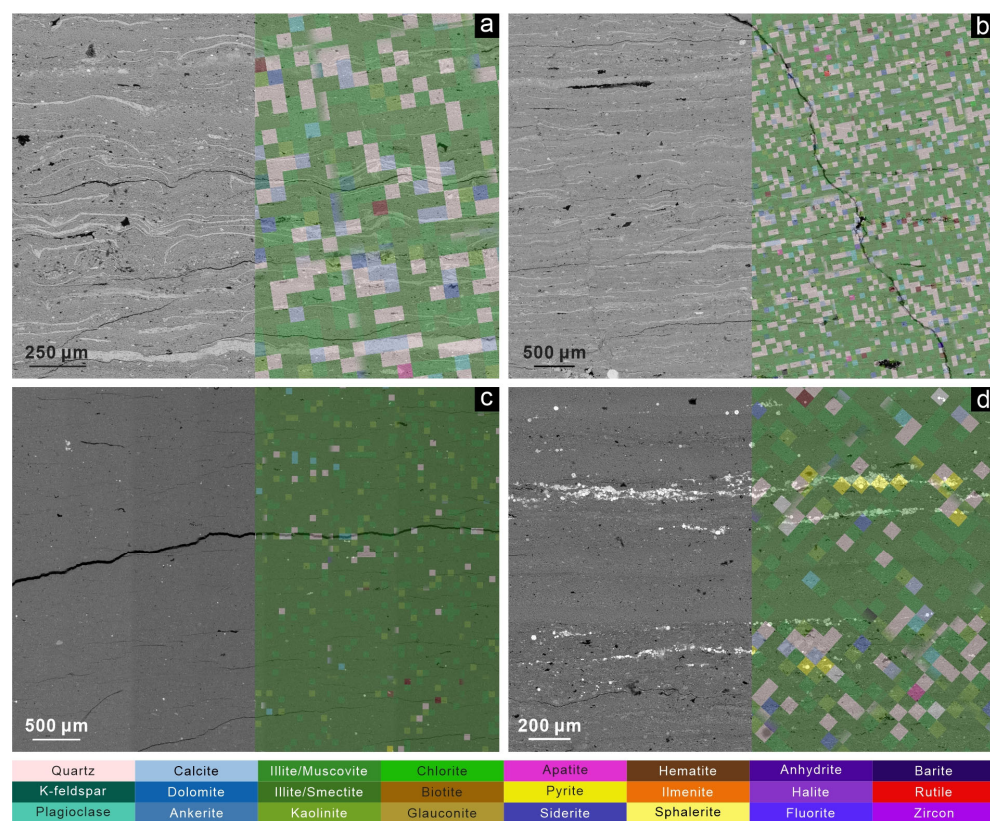


Figure 7. RoqSCAN SEM-EDS photomicrographs of lacustrine shale samples from the Shahezi Formation (JLYY1 borehole, Lishu Rift Depression, Songliao Basin), showing four types of laminae: (a) 3125.15 m depth, calcareous laminae; (b) 3125.15 m depth, non-clay mineral silicate laminae; (c) 3155.5 m depth, argillaceous laminae; and (d) 3138.4 m depth, pyrite laminae.

Pyrite laminae (Figure 7d) demonstrate a unique Fe-S diagenetic association with organic matter-hosted pore clusters (porosity $\theta = 8 \pm 3\%$), serving as robust indicators of the “sweet spot” through their strong correlation with TOC ($R^2 = 0.91$). Their development involves Fe migration along hydrocarbon flow paths and S enrichment in zones rich in solid bitumen (organic matter = $6 \pm 2 \text{ vol\%}$), particularly where silicate laminae fractures intersect pre-existing clay mineral-rich matrices. Spatial analysis confirms these lamina systems collectively create interconnected hydrocarbon storage networks, with silicate

laminae governing bulk storage capacity while pyrite laminae mark high-TOC (>2 wt%) preservation zones. The observed lamina and fracture configurations—particularly the staggered propagation of pyrite and silicate laminae in organic-rich intervals—provide diagnostic criteria for identifying hybrid shale gas condensate sweet spots.

5. Discussion

An integrated model is proposed to illustrate the hydrocarbon generation and evolution of hybrid shale gas condensate resources, considering the four key factors, rock components and lithofacies, thermal maturity and hydrocarbon phases, paleoenvironmental conditions, and lamina-induced fractures, as shown in Figure 8.

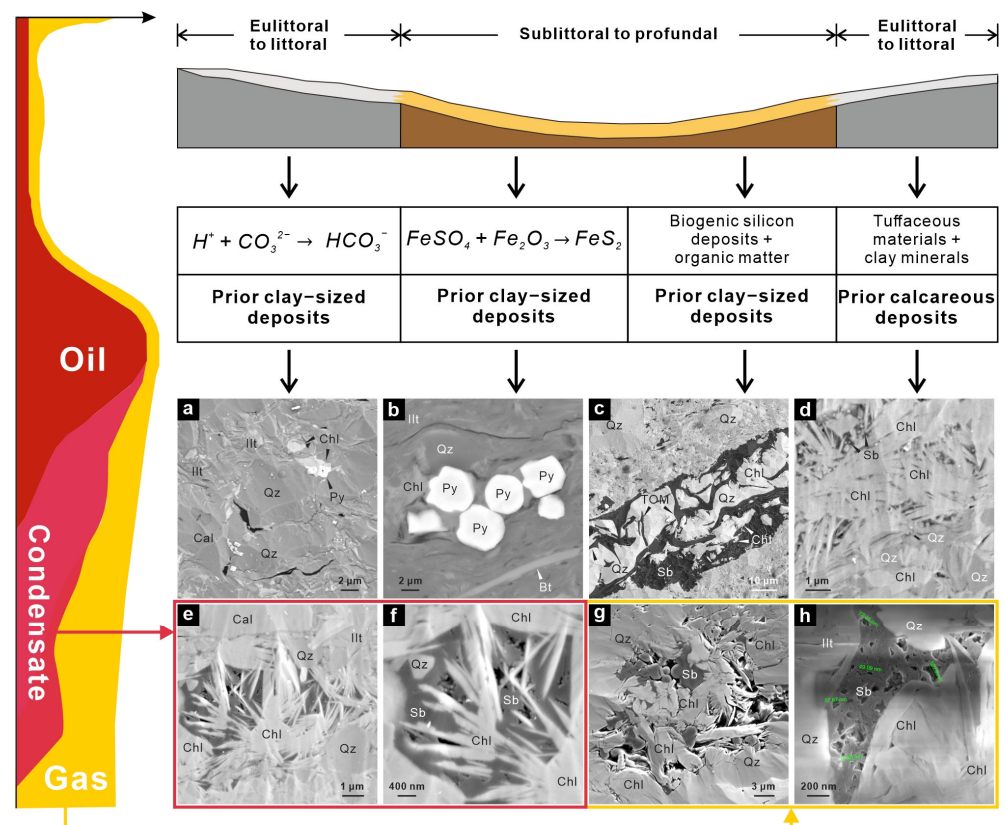


Figure 8. A schematic diagram showing the hydrocarbon generation and evolution model of the shale gas condensate reservoir in syn-rift lake basins. Four controlling factors are illustrated in this model: (1) rock components and lithofacies; (2) thermal maturity and hydrocarbon fluid phases; (3) paleoenvironmental conditions; and (4) shale lamination and lamina-induced fractures. (a) Second electron (SE) image, 3101.24 m depth. (b) Backscattered electron (BSE) image, 3166.52 m depth. (c) SE image, 3130.2 m depth. (d) SE image, 3124.55 m depth. (e,f) SE images, 3125.19 m depth. (g) SE image, 3122 m depth. (h) SE image, 3131.96 m depth. Panel (f) is an enlarged view of a region of (e).

5.1. Comparison of the Hybrid Sedimentation Model Between Hydrocarbon-Rich Shales and Hydrocarbon-Lean Shales

Volcanism commonly occurs in the syn-rift Songliao Basin, where significant volcanic activity began during the Early Cretaceous due to the subduction of the Indian and Pacific plates beneath the Eurasian plate [34]. This led to the development of grabens, particularly in the central fault block of the Songliao Basin [61]. Based on basin geometric characteristics, volcanism, and early sedimentation, a hybrid sedimentation model is proposed in Li et al. (2022), illustrating the syn-rift lake basins, affected or unaffected by volcanism, respectively [50]. The hydrocarbon-rich shales occur between 3115 m and 3165 m, while the hydrocarbon-lean section is between 3080 m and 3115 m.

During the syn-rift period, volcanic activity raised temperatures, increased atmospheric CO₂, and caused mass mortality of organisms [22,62]. This created a unique environment for hydrocarbon-rich shales, including a quiescent water setting with volcanic inputs, a humid climate, saline lakes, and anoxic bottom-water conditions in the syn-rift lake. Both oxic and anoxic water layers contributed to hybrid organic-rich deposits [63], which contained terrigenous salt-tolerant plants, organic matter, and planktonic aerobic organisms [50]. These organic-rich deposits in the Shahezi Formation, primarily from oil-prone fractions of terrigenous organic matter [22,33], mixed with minerals and formed organic matter laminae, indicate a stable and anoxic water environment. Anaerobic bacteria helped degrade organic matter and form authigenic minerals. Dispersed terrigenous organic matter is deposited with detrital or authigenic quartz, generating the silicate- and organic-rich laminae possibly derived from the devitrification of volcanic glass in tuff [22].

The hydrocarbon-rich shales from 3115 m to 3165 m, which have higher hydrocarbon content than those from 3080 m to 3115 m (Figure 2), are key to defining “hybrid shale gas condensate”. The gas and liquid hydrocarbon states are influenced not only by in situ conditions like temperature and pressure [64–66] but also by the input of terrestrial-sourced organic matter, which contributes to the production of gas and liquid hydrocarbons in the early stages of hydrocarbon evolution [67].

As the basin evolved, volcanic activity decreased, and secondary faults formed, leading to shallow water depth, a relatively cold and arid climate, and low salinity water conditions under weak evaporation conditions. The lake environment became more stable, with an oxic layer on top and a dysoxic layer below. In this stable period, aquatic organic matter preservation was difficult due to the weak reducing environment [68]. Instead, terrigenous organic matter sourced from land plants contributed to the enrichment of Type III kerogen, which performs relatively poorly in hydrocarbon generation. This explains the lower hydrocarbon content in the shales from 3080 m to 3115 m.

5.2. The Organic–Mineral Interactions During the Diagenesis of Hydrocarbon-Rich Shales

The hydrocarbon content of hybrid shale gas condensates is influenced by organic–mineral interactions during diagenesis (Figure 8). Here, organic–mineral interactions are examined to explain hydrocarbon storage and desorption, using SEM to describe the relationship between organic matter, mineral particles, and pores (Figure 8). The test samples are horizontally stratified and finely laminated mudstones.

Organic matter, primarily composed of solid bitumen, results from kerogen evolution and often intergrows with authigenic pyrite, calcite, and non-clay mineral silicate minerals (Figure 8). In calcareous laminae (Figure 8a), calcification occurs in the presence of prior clay-sized deposits, where HCO₃[−] combines with Ca²⁺ and Mg²⁺ ions to form calcareous diagenetic minerals in slightly alkaline, oxidizing conditions [69]. Intergranular pores of calcite particles contribute to solid bitumen storage (Figure 8a), where hydrocarbons are mainly stored in the intergranular pores of clay minerals and calcareous particles, as well as in organic matter-hosted pores.

Silicate laminae are often associated with pyrite laminae (Figures 7d and 8b) due to the symbiotic relationship between organic matter and pyrite. Pyrite can either separate from organic matter or become embedded in solid bitumen, showing flow traces (Figures 7d and 8b). Pyrite is typically surrounded by detrital quartz particles and authigenic quartz overgrowth, which are possibly generated during the devitrification of volcanic glass in tuff (Figure 7d). Pyrite forms in an anoxic bottom-water environment during early diagenesis [70].

An interesting phenomenon is seen in Figure 8e,f, where the clay mineral assemblages are associated with calcite particles within micro-scale organomineral composites. These

formations resemble structures that likely result from the devitrification of volcanic glass into chlorite and illite. Although it remains uncertain whether this process directly influences organic matter evolution, it is clear that the combination of volcanic glass, organic matter, and calcite in a special diagenetic setting contributes to hydrocarbon-rich shales.

The most common mineral intergrowth with organic matter is authigenic quartz, followed by pyrite, illite, and carbonate minerals [71]. The complex microstructures formed by organic matter and authigenic minerals are similar to those found in intrusive igneous rock crystallization processes. This suggests that organic matter and authigenic minerals may have the same origin and evolutionary process according to their diagenetic pathways. The evolution of parent-rock material into solid bitumen and the crystallization of minerals hints at chemical differentiation between organic and inorganic components.

5.3. The Liquid Hydrocarbon and Solid Bitumen of the Hybrid Shale Gas Condensate Reservoirs

The organic matter in the cored shales of this study has evolved into condensate and wet gas stages, as discussed in Section 4.2. Hybrid shale gas condensate in mature and highly mature shale is the dominant fluid phase and contributes significantly to the in situ hydrocarbon content. Although the light hydrocarbons in gas or liquid states have been lost from the samples due to drilling and coring, the space left by hydrocarbon desorption, exudation, and diffusion remains detectable under SEM.

SEM images are used to indirectly illustrate the hydrocarbon state. The organic matter in the SEM photos is classified into three types: highly mature organic matter with a vesicular structure, mature organic matter with liquid mold holes and vesicular structures, and solid bitumen with no movable hydrocarbon traces (Figure 8e–h). Authigenic quartz and solid bitumen often coexist, with solid bitumen spherulites and pores present. In the SEM images, different pore types are visible, mainly formed by gas generation, accumulation, and escape of hydrocarbons from kerogen. These pores are typically round, with apertures ranging from tens to hundreds of nanometers, varying in size, depth, and shape. Solid bitumen development is particularly noticeable in intergranular pores of authigenic minerals, which protect the organic matter and allow hydrocarbons to generate and accumulate. The light hydrocarbons around these pores, along with the solid bitumen formed during hydrocarbon generation, as shown in Figure 8c–h, strongly support the accumulation of hybrid shale gas condensates.

6. Conclusions

This study establishes a multiscale framework for evaluating hybrid shale gas condensate reservoirs in rift lake basins affected by volcanism, integrating geochemical, mineralogical, and sedimentological analyses of the Shahezi Formation (Songliao Basin). By combining novel proxies (e.g., *HSCI* index) with paleoenvironmental diagnostics, a predictive model was proposed for lacustrine shale systems to distinguish them from marine analogs. Key findings include the following:

1. Argillaceous shales (50–75% clay minerals) containing mixed carbonate and clay minerals ($MC(C) > 25\%$) and organic matter ($TOC > 2 \text{ wt}\%$) exhibit high potential of hydrocarbon storage, achieving $S_1 > 1.5 \pm 0.3 \text{ mg/g}$ (C_7 – C_{33}) and $TGC > 1.5 \pm 0.2 \text{ m}^3/\text{t}$ (C_1 – C_2). These intervals develop intergranular porosity of $4.8 \pm 1.2\%$, which is higher than illite-dominated zones.
2. Six fluid phases of hydrocarbons were identified by the *HSCI* index, showing that the mature ($T_{max} = 460$ – $480 \text{ }^\circ\text{C}$) and highly mature ($T_{max} = 480$ – $500 \text{ }^\circ\text{C}$) shales are dominated by gas condensates. The production of gaseous and liquid hydrocarbon peaks at $T_{max} = 490 \text{ }^\circ\text{C}$ (highest S_1 and TGC values), which corresponds to intervals with enhanced preservation of $MC(C)$.

3. Volcanic material inputs ($Zr/Ti > 40$), humid paleoclimate ($Al/Ti > 10$), saline lake water ($Sr/Ba > 0.5$ and $Ca/(Ca + Fe) > 0.3$), and anoxic bottom-water conditions ($U/Th > 0.4$) promote hybrid silicate and pyrite laminations, elevating TOC to 5.2 ± 0.8 wt%, which is higher than intervals unaffected by volcanism.
4. Silicate laminae ($S_1 = 1.8 \pm 0.4$ mg/g) and pyrite laminae (porosity $\theta = 8\% \pm 3\%$) jointly form heterogenic seepage networks, promoting hydrocarbon generation in low-porosity shales (porosity $\theta = 1.2\text{--}4.8\%$). These systems differ from their marine analogs due to significant organic–mineral interactions.

Overall, these insights redefine “sweet spot” criteria for hybrid shale gas condensate reservoirs in rift lake basins, emphasizing volcanic–diagenetic pathways and lamina architecture as key discriminators from marine systems.

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Abbreviations

The following abbreviations are used in this manuscript:

TOC	Total organic carbon content (wt%)
TGC	Total gas content (m^3/t)
HSCI	Hybrid Shale Condensate Index
GOR	Gas-to-oil production ratio (Scf/STB)
API	American Petroleum Institute gravity ($^\circ$ API)

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