

# Diagenetic Facies Division of Different Types of Sandstone Reservoirs and Their Differentiation

Dalong Zhang

School of Petroleum Engineering, Xi'an Shiyou University, Xi'an, Shaanxi, 710065, China

## Abstract

**In response to the increasing proportion of low-porosity, low-permeability, and tight sandstone reservoirs in current oil and gas exploration, this paper conducts a systematic study on diagenetic facies division. First, the development stages and existing problems of diagenetic facies research are reviewed, with an emphasis on the objective of establishing a scientific classification system. The study highlights the core criteria for facies division, including types and intensities of diagenesis, petrographic characteristics, pore and petrophysical features, as well as logging responses and quantitative models. Differentiated emphasis is proposed for reservoirs of different types. Finally, a general methodological framework is constructed, progressing “from micro to macro, from qualitative to quantitative,” providing systematic ideas and methodological support for diagenetic facies research and favorable zone prediction in various types of reservoirs.**

## Keywords

**Diagenetic Facies Division; Sandstone Reservoirs and Their Differentiation; Different Types of Reservoirs; Quantitative Models; Logging Responses; Overall Methodological Framework.**

## 1. Introduction

Oil and gas exploration has now entered a new stage that seeks resources from deeper formations and reserves from more complex geological settings, with the proportion of low-porosity, low-permeability, and tight sandstone reservoirs continuing to increase. These reservoirs have typically undergone multiple diagenetic modifications and exhibit strong heterogeneity, with reservoir properties within the same depositional facies belt varying by one to three orders of magnitude [1–2]. By integrating mineral composition, pore characteristics, and diagenetic intensity, diagenetic facies analysis can accurately reveal the controlling mechanisms of reservoir quality variations and provide a direct basis for predicting favorable zones [3–5].

Research on diagenetic facies originated in the 1990s and has undergone three main developmental stages: (i) a qualitative descriptive stage, in which facies types were classified primarily through petrographic observations under the microscope; (ii) a semi-quantitative stage, marked by the introduction of parameters such as apparent compaction rate; and (iii) a quantitative stage, integrating well logging and seismic inversion to enable regional prediction [6–7]. However, several key issues remain unresolved, including: lack of unified classification standards, which hinders cross-regional comparisons; insufficient investigation into the coupling relationship between diagenesis and pore evolution; and limitations in the accuracy of planar prediction due to seismic resolution [8–9].

Establishing a robust and systematic framework for diagenetic facies division is therefore of great significance. Such a framework can (i) clarify the mechanisms by which diagenetic processes modify reservoir properties and improve the interpretation of reservoir quality

variations, (ii) optimize favorable zone prediction methods to reduce exploration risks, and (iii) provide a geological basis for reservoir heterogeneity characterization during the development stage.

## 2. Core Criteria for Diagenetic Facies Division

The scientific division of diagenetic facies requires the comprehensive integration of multi-dimensional geological information. The core criteria include the types and intensities of diagenesis, fundamental petrographic characteristics, pore–petrophysical responses, and quantitative characterization through well logs. These criteria cross-validate each other, jointly forming a complete framework for “qualitative–quantitative” diagenetic facies classification[10–11].

### 2.1. Types and Intensities of Diagenesis

Diagenesis is the key geological process that reshapes reservoir properties, with its types, intensities, and combinations directly determining the composition and structural features of diagenetic facies[12–13]. Practice in various basins shows that compaction, cementation, and dissolution are the three fundamental diagenetic processes controlling sandstone reservoir evolution, while fracturing in tectonically active regions can significantly improve permeability, serving as an important supplementary criterion for facies division.

Compaction is the primary mechanism responsible for pore loss in reservoirs, and its intensity can be characterized by grain contact relationships and apparent compaction rate. Qualitatively, the evolution from point contacts (weak compaction) to line contacts (moderate compaction), to concavo–convex or sutured contacts (strong compaction) directly reflects increasing compaction intensity. Quantitatively, an apparent compaction rate >70% with line–concavo–convex contacts indicates strong compaction, while 30%–70% with point–line contacts corresponds to moderate compaction.

Cementation determines the degree of reservoir densification, depending on both the type of cement and its abundance. Based on mineral composition (e.g, clay minerals, carbonates, silica) and cementation style (basal, pore-filling, or syntaxial overgrowth), its impact on porosity can be evaluated. Quantitatively, apparent cementation rate (cement volume as a proportion of residual intergranular pores and cement) is used to classify intensity. Chlorite and illite films, with apparent cementation rates of 30%–50%, typically protect primary pores and are considered constructive cementation. In contrast, kaolinite and carbonate pore-filling cements, with apparent cementation rates >70%, severely reduce permeability, representing destructive cementation. Carbonate cementation facies often exhibit apparent cementation rates >80%, with syntaxial calcite nearly filling all intergranular pores, leading to tight reservoirs.

Dissolution is the most constructive diagenetic process that enhances reservoir quality, and its intensity is reflected by the development of dissolution pores and apparent dissolution rate. Secondary pores, such as intergranular dissolution pores and feldspar moldic pores, directly indicate dissolution intensity. Quantitatively, the ratio of dissolution pore area to total pore area is used for classification. For example, in the Wenchang Formation of the Lufeng Depression, the medium-compaction, weak-cementation, and strong-dissolution facies exhibit apparent dissolution rates >70%, with feldspar and lithic dissolution forming honeycomb-like pores and an average porosity of 4.51%[14]. In the Chang-8 Member of the Longdong HQ block, apparent dissolution rates of 50%–80% are observed, with feldspar dissolution pores accounting for over 60%, serving as the primary oil and gas storage space[15].

Fracturing, formed under tectonic stress or diagenetic stress, enhances dissolution by providing fluid pathways. Its intensity is characterized by fracture density and filling degree. For instance, in the Ahe Formation of the Tarim Basin, dissolution microfracture facies exhibit

a network of tectonic and diagenetic fractures, with unfilled fractures exceeding 70%, significantly improving permeability and making it the most favorable reservoir facies in the study area[16].

## 2.2. Petrographic Characteristics.

The mineral composition and textural maturity of rocks provide the material basis for diagenesis, directly influencing the evolutionary pathway and final characteristics of diagenetic facies, and thus serve as an important supplementary criterion[17].

In terms of mineral composition, the types and proportions of detrital grains and matrix determine resistance to compaction and susceptibility to dissolution. Quartz sandstones, with high quartz content and abundant rigid grains, resist compaction and preserve primary pores, often undergoing silica cementation. Feldspathic litharenites, with higher feldspar and lithic content, are more prone to dissolution. Matrix-rich sandstones (>10% clay matrix) are more susceptible to compaction, whereas chlorite coatings can reduce intergranular friction and mitigate compaction.

Grain sorting, roundness, and size also control diagenetic intensity by influencing fluid permeability. Well-sorted (sorting coefficient <1.5), sub-rounded to rounded sandstones have better pore connectivity, promoting dissolution fluid migration. Poorly sorted (sorting coefficient >2.0), angular fine sandstones are prone to strong compaction due to matrix filling. Medium-coarse sandstones (0.5–2 mm) have larger pore spaces and stronger dissolution potential, whereas siltstones (<0.0625 mm) are easily cement-filled.

## 2.3. Pore and Petrophysical Characteristics.

Pore types, pore structures, and related petrophysical parameters directly indicate the effects of diagenetic modification and serve as key markers for diagenetic facies division. Favorable facies are dominated by residual intergranular pores and secondary dissolution pores, with high porosity, whereas unfavorable facies are characterized by intercrystalline pores and microfractures, with low porosity.

Quantitatively, favorable diagenetic facies generally exhibit porosity >10% and permeability >1 mD, while unfavorable facies typically show porosity <8% and permeability <0.1 mD. Additionally, porosity-permeability correlations can be used to verify the rationality of facies classification.

## 2.4. Logging Responses and Quantitative Models.

Well logs, due to their continuity and cost-effectiveness, provide a crucial link for extending diagenetic facies classification from cored intervals to uncored sections and across the reservoir plane. By establishing the correspondence between logging responses and diagenetic facies, quantitative identification becomes possible.

Conventional log responses show systematic differences among diagenetic facies. Favorable facies, with well-developed porosity and low clay content, are typically characterized by low natural gamma, low density, high acoustic travel time, and high resistivity. Unfavorable facies, in contrast, show the opposite responses due to high compaction or clay content.

Quantitative identification models are developed by correlating logging parameters with diagenetic facies, allowing for quantitative recognition. Discriminant functions can be established using multiple log curves (e.g, natural gamma, acoustic travel time), enabling diagenetic facies identification.

### 3. Key Considerations for Diagenetic Facies Division in Different Reservoir Types

Sandstone reservoirs formed under different geological settings exhibit distinct diagenetic evolutionary pathways, controlling factors, and reservoir characteristics. Therefore, diagenetic facies division must emphasize different aspects depending on the reservoir type, so as to accurately reveal the relationship between diagenesis and reservoir quality. The following sections elaborate on the core considerations and methodological features for low-permeability reservoirs, tight sandstones, unconsolidated sandstones, and deep tight sandstones.

Low-permeability reservoirs are commonly developed in deltaic and fluvial depositional environments, where reservoir properties are jointly controlled by depositional microfacies and diagenesis. The matching relationship between dissolution and depositional microfacies serves as the key to facies division. These reservoirs typically experience moderate diagenetic modification, with compaction and cementation causing significant loss of primary pores. Dissolution becomes the critical process for enhancing reservoir quality, and the permeability of dissolution fluids is closely linked to the hydrodynamic conditions of depositional microfacies. Hence, for low-permeability reservoirs, the emphasis is placed on the coupling between diagenesis and depositional microfacies.

Tight sandstone reservoirs are mainly controlled by the constructive versus destructive effects of cementation. Strong cementation and/or compaction usually cause severe loss of primary pores. Thus, facies division should focus on distinguishing cement types and their impacts on reservoir quality—whether constructive cementation (pore-protecting) or destructive cementation (pore-blocking). At the same time, the compensatory role of dissolution in generating secondary porosity should also be highlighted.

Unconsolidated sandstone reservoirs are primarily governed by the balance between grain support and clay filling. These reservoirs, usually shallowly buried, experience weak compaction. Therefore, diagenetic facies division should focus on the dynamic balance between grain-supported frameworks and clay mineral filling. Grain support strength determines resistance to compaction, while the degree of clay filling controls pore connectivity. Together, these factors influence reservoir stability and hydrocarbon-bearing potential[18].

Deep tight sandstone reservoirs (buried deeper than 3000 m) are jointly modified by strong compaction and cementation, with primary pores nearly eliminated. The key to facies division lies in the superimposed effects of fracturing and dissolution. Fractures not only directly improve permeability but also provide pathways for dissolution fluids, resulting in composite storage spaces of fracture–dissolution pore systems[19–20].

In summary, diagenetic facies division for different reservoir types must focus on their dominant controlling factors: dissolution–microfacies coupling for low-permeability reservoirs, cementation effects for tight sandstones, grain support–clay filling balance for unconsolidated sandstones, and fracture–dissolution interplay for deep tight sandstones. Such a differentiated approach enhances both the accuracy and applicability of diagenetic facies prediction.

### 4. Methodological Framework and Application Cases of Diagenetic Facies Division

The division of diagenetic facies requires a systematic workflow that integrates multi-source data to achieve accurate characterization from single-well to regional scales. The core logic of this workflow follows a progressive approach of “from micro to macro, from qualitative to quantitative,” and consists of the following steps:

Step 1: Data acquisition and preprocessing.

A comprehensive database must be established through core analysis, laboratory experiments, and well logging. Core samples are analyzed using thin-section casting, scanning electron microscopy (SEM), and petrophysical testing to quantify pore types, cement content, clay mineral occurrence, dissolution features, porosity, and permeability. Well logs, including natural gamma, acoustic travel time, density, and resistivity, are collected and corrected for borehole size and depth matching to ensure continuity, which is essential for model construction[21].

Step 2: Quantitative characterization of diagenetic intensity.

Based on experimental data, diagenetic parameters are calculated and intensity grades are classified. Apparent compaction rate is derived from the difference between original porosity and post-compaction porosity. Apparent cementation rate is defined as the volume ratio of cement to the sum of residual intergranular pores and cement. Apparent dissolution rate is calculated as the ratio of dissolution pore area to total pore area.

Step 3: Preliminary facies classification and nomenclature.

By integrating diagenetic intensity, pore types, and petrographic features, diagenetic facies are qualitatively named. The naming convention combines diagenetic intensity with dominant mineral or pore type, such as “medium-compaction, weak-cementation, strong-dissolution facies” or “residual intergranular pore–feldspar dissolution facies.” Facies with similar petrophysical properties are then grouped into broader categories.

Step 4: Logging response modeling and whole-interval identification.

Correspondence between diagenetic facies and well log responses is established to extend facies identification to uncored intervals. Logging calibration involves statistical analysis of parameter ranges for different diagenetic facies. Quantitative models, such as Fisher discriminant analysis and backpropagation (BP) neural networks, are then trained using multiple logging parameters. For example, in the Ahe Formation, a BP neural network trained with seven logging parameters achieved a diagenetic facies recognition accuracy of 87.9%[16].

Step 5: Regional prediction and validation.

The spatial distribution of diagenetic facies is predicted by integrating seismic inversion results with depositional facies constraints. Facies-sensitive seismic attributes are optimized, and production data are used for validation. Well testing and production performance are compared with predicted diagenetic facies to evaluate hydrocarbon potential.

The general framework for diagenetic facies division is applicable to various reservoir types, provided that key parameters are adjusted according to reservoir characteristics (e.g., dissolution rate and depositional facies for low-permeability reservoirs; fracture parameters for deep tight reservoirs). Multi-dimensional data validation ensures accuracy and reliability.

## 5. Summary

Research on diagenetic facies has undergone several developmental stages, yet challenges such as the lack of unified classification standards remain. Establishing a scientific division framework is therefore of great significance, as it clarifies the mechanisms of diagenetic modification, optimizes favorable zone prediction, and provides a geological basis for reservoir heterogeneity characterization.

The division of diagenetic facies should be based on four core criteria: types and intensities of diagenesis, petrographic characteristics, pore and petrophysical features, and logging responses with quantitative models. These factors complement one another and together form a complete classification system.

Different reservoir types require distinct emphases in diagenetic facies division. For low-permeability reservoirs, the focus lies on the coupling of dissolution and depositional

microfacies; for tight sandstones, on the constructive or destructive role of cementation; for unconsolidated sandstones, on the balance between grain support and clay filling; and for deep tight sandstones, on the interplay between fracturing and dissolution. This differentiated approach significantly enhances the precision of facies prediction.

A general methodological framework for diagenetic facies division has been established, following the logic of “from micro to macro, from qualitative to quantitative.” Through systematic data acquisition, diagenetic intensity quantification, facies classification, logging model construction, and regional prediction, accurate reservoir characterization can be achieved. This framework is applicable to a wide range of reservoir types, with parameter optimization and multi-dimensional validation being the key to improving accuracy and reliability.

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