

Hydrocarbon Accumulation Conditions and Main Controlling Factors of Intracratonic Carbonate Rocks in Russia

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Abstract

Research objectives and scope: Taking intracratonic carbonate rocks in Block S as the research object, this paper aims to clarify the complex hydrocarbon accumulation rules, define the core controlling factors and hydrocarbon migration-accumulation mechanisms, and fill the research gaps in relevant fields. **Research methods:** Based on drilling, seismic and core test data, integrated seismic-geological interpretation, tectonic-sequence evolution restoration and accumulation element coupling analysis were adopted to systematically analyze source-reservoir-cap assemblage characteristics and hydrocarbon migration-accumulation laws. **Research results and conclusions:** An efficient hydrocarbon accumulation system consisting of high-quality hydrocarbon source rocks, high-energy reef-beach reservoirs and thick gypsum-salt cap rocks was identified. A dual-mode migration pathway network dominated by inherited paleo-uplifts as well as faults and unconformities was developed. Hydrocarbon accumulation was jointly controlled by the three-dimensional coupling of paleo-uplifts, reef-beach reservoirs and source-connected faults, and the corresponding hydrocarbon accumulation model was established. **Innovation and application value:** The established model further improves the accumulation theory of intracratonic carbonate reservoirs, provides important analogical references for the exploration of similar reservoirs in Tarim Basin, Sichuan Basin and other basins, and has important guiding significance for oil and gas exploration practice.

Keywords

Intracratonic Carbonate Rock; Inherited Paleo-uplift; Dual-mode Migration and Accumulation; Reef-beach Reservoir; Block S.

1. Introduction

Platform-margin reef-beach belts have long been the key exploration targets for carbonate oil and gas reservoirs, while their limited spatial distribution restricts further exploration potential. By contrast, widely distributed intracratonic zones with low exploration maturity have become important successive exploration fields[1]. Although domestic researches have achieved certain progresses, there are still insufficient understandings on the main controlling factors and migration-accumulation mechanisms of hydrocarbon accumulation within platforms. Block S in Russia is a typical area with well-developed intracratonic carbonate sequences and possesses high geological analogy value[2]. In this study, multiple geological data and comprehensive research methods were applied to systematically analyze hydrocarbon accumulation conditions, establish hydrocarbon migration-accumulation models and optimize favorable exploration targets, which can provide practical references for hydrocarbon exploration in similar sedimentary basins in China.

2. Regional Geological Setting

Block S is tectonically located at the junction between the southeastern Volga-Ural Basin and the northern fault terrace zone of the Pre-Caspian Basin. The Volga-Ural Basin covers an area of about 90×10^4 km², which is the second largest petroliferous basin in Russia[3]. The Pre-Caspian Basin spans approximately 55×10^4 km² and ranks among the basins with the largest subsidence amplitude and thickest sedimentary succession[4]. The main study area belongs to the southeastern Volga-Ural Platform, and its southern part extends to the marginal zone of the Pre-Caspian Basin, where peripheral uplift zones are rich in oil and gas resources[5]. Tectonically, the study area is a large-scale monocline developed on stable platform basement, which is divided into ladder-like structural units by nearly EW-trending faults. The main target strata including Middle-Upper Devonian and Middle-Lower Carboniferous are dominated by semi-restricted to open carbonate platform deposits with widely developed layered reef-beach reservoirs, and the hydrocarbon reservoirs are mainly structural-lithologic composite reservoirs.

3. Hydrocarbon Accumulation Conditions of Intracratonic Carbonate Reef-Beach Reservoirs

3.1 Stratigraphic Development Characteristics

Drilling and seismic data indicate that sedimentary strata with a total thickness over 5 000 m are developed above the crystalline basement in the study area. From bottom to top, the stratigraphic sequence is composed of Archean-Proterozoic crystalline basement, Middle-Lower Devonian transitional deposits, thick marine carbonate sequences ranging from Upper Devonian to Lower Permian, nearly 1 000 m thick evaporitic gypsum-salt rocks of Lower Permian Kungurian Stage, Middle-Upper Permian transitional strata and shallow Mesozoic-Quaternary continental clay deposits. Oil and gas reservoirs are mainly distributed in the sub-salt marine carbonate strata from Middle Devonian to Lower Permian beneath Kungurian gypsum-salt rocks, among which the upper Famennian–Tournaisian interval and Bashkirian Stage are the dominant production intervals.

3.2 Tectonic-Sequence Evolution Process

Combined with tectonic-sequence evolution reconstruction, stratigraphic correlation and seismic profile interpretation, the tectonic-sedimentary evolution of the study area can be divided into four key stages:

- (1) Sedimentation initiated in the Emsian Stage of Early Devonian and was dominated by continental deposits in the early period; seawater invasion occurred in the Eifelian Stage of Middle Devonian to form carbonate platform sedimentary environment, and continental sedimentary system prevailed again in the Givetian Stage.
- (2) Large-scale marine transgression occurred during the Frasnian–Famennian Stage of Late Devonian and restored carbonate sedimentation. The Domanik-facies strata in the lower Frasnian Stage constitute major high-quality hydrocarbon source rocks. The long-term paleohigh of southern Kosha Uplift exerted significant control on reef body development.
- (3) Sea-level fluctuation and drop occurred in the early Visean Stage, leading to obvious denudation of carbonate rocks on the top of Tournaisian strata; marine transgression expanded from the middle-late Visean Stage to Serpukhovian Stage, forming another set of effective hydrocarbon source rocks. Platform uplift took place in the Bashkirian Stage and facilitated the development of high-energy shallow beach deposits; carbonate weathering and denudation in the late Bashkirian Stage were favorable for reservoir pore development.
- (4) Shallow marine sedimentary system migrated southward during the Kungurian Stage of Lower Permian, and evaporative lagoon environment was widely developed in inland areas, depositing nearly kilometer-scale gypsum-salt sequences acting as high-quality regional cap rocks.

3.3 Development Features and Hydrocarbon Generation Potential of High-quality Hydrocarbon Source Rocks

Organic geochemical tests and regional geological correlation confirm that the primary effective hydrocarbon source rocks in the Volga-Ural Basin are Domanik-type bituminous limestone and argillaceous carbonate rocks developed in Frasnian–Tournaisian strata[6]. The total organic carbon (TOC) content ranges from 4% to 6% on average, with the maximum value up to 20%. The kerogen is mainly Type II, and vitrinite reflectance (R_o) varies from 0.65% to 1.15%. These source rocks are mainly distributed in the Kama-Kinel Graben with the maximum cumulative thickness of 400–500 m[7].

In Block S, such hydrocarbon source rocks are mainly developed in the middle-lower Frasnian Stage and transgressive cycles of Visean Stage. The single-layer thickness ranges from 2 m to 10 m with large cumulative thickness (50–200 m for Frasnian strata and 20–100 m for Visean strata), showing superior hydrocarbon generation potential. The R_o values of Frasnian source rocks range from 1.0% to 1.15% belonging to high thermal evolution stage, while those of Visean source rocks are 0.65%–0.85% in mature stage, jointly forming the dominant hydrocarbon generation assemblage.

3.4 Development Rules and Formation Mechanism of High-quality Intracratonic Reef-Beach Reservoirs

3.4.1 Stratigraphic Distribution and Lithologic Characteristics

Core observation, logging facies identification and seismic facies interpretation reveal that reef-building organisms flourished globally during the Late Paleozoic Devonian–Carboniferous periods[8-9]. Three large-scale marine transgressions on the southeastern margin of the East European Platform formed semi-restricted carbonate platform sedimentary settings in Block S, which provided favorable conditions for the development of reef-beach facies reservoirs. Intracratonic reef-beach reservoirs in the study area are mainly developed in Zavolzhye Formation (Upper Devonian Famennian) – Lower Carboniferous Tournaisian strata and Upper Carboniferous Bashkirian strata, while thin-layer reservoirs are locally developed in Middle Devonian and Lower Permian sequences.

Reservoirs in Famennian–Tournaisian strata are mainly composed of biogenic limestone, and local microfractures effectively improve reservoir permeability. Bashkirian reservoirs are dominated by high-energy grain limestone with intense penecontemporaneous dissolution, and dissolution vugs, intergranular pores and intragranular pores are well developed. Different from intensely dolomitized deep carbonate reservoirs in China, favorable reservoirs in Block S only experience weak local dolomitization[10-11], with calcite as the dominant mineral and dolomite content generally lower than 5%, and even lower in high-quality reservoir intervals.

3.4.2 Reservoir Pore-permeability Characteristics

Based on core porosity-permeability measurement and logging interpretation model establishment, obvious physical property differences exist between the two sets of major reservoirs: ① Famennian Zavolzhye Formation – Tournaisian reservoirs: porosity is mainly 5%–15%, permeability is 0.1–100 mD, belonging to medium-low porosity and ultra-low to medium-low permeability reservoirs; ② Bashkirian reservoirs: porosity is mostly 8%–15% (partial samples >15%), permeability is mainly 1–100 mD (partial samples >100 mD), classified as medium-high porosity and low to medium-low permeability reservoirs.

3.4.3 Formation Mechanism of High-quality Reef-beach Reservoirs

The development of high-quality reservoirs is jointly controlled by sedimentary facies differentiation and post-depositional diagenetic transformation: ① Sedimentary facies control: during sea-level falling stages, high-energy reef-beach deposits were accumulated on intracratonic paleogeomorphic highs with well-sorted sediments and developed primary intergranular pores, laying a solid material foundation for reservoir formation; ② Diagenetic modification effect: reservoir exposure in late regression stage triggered strong penecontemporaneous dissolution, which enlarged primary pores

and formed abundant secondary dissolution pores and vugs. Microfractures derived from basement uplift-related faults further optimized reservoir seepage capacity.

3.5 Cap Rock Sealing Capacity and Source-reservoir-cap Assemblage Features

A dual sealing system composed of regional cap rocks and local cap rocks is developed in the study area with excellent sealing performance. ① The regional cap rock is thick massive anhydrite sequences of Lower Permian Kungurian Stage with a cumulative thickness of 1 100 m. It is characterized by dense lithology and strong sealing capacity, which can effectively prevent hydrocarbon vertical migration and leakage, and provide stable sealing conditions for Devonian–Carboniferous carbonate reservoirs in the whole study area; ② Local cap rocks are dense argillaceous limestone and compact limestone formed during marine transgression periods, which are well matched with major reservoirs developed in regression sedimentary cycles. Typical examples include dense limestone of Moscow Stage overlying Bashkirian reservoirs and argillaceous limestone of Tula Formation covering Zavolzhye–Tournaisian reservoirs. The combined sealing effect of regional and local cap rocks greatly improves hydrocarbon preservation conditions.

3.6 Dual-mode Hydrocarbon Migration and Accumulation Model of Intracratonic Carbonate Reef-beach Reservoirs

Based on hydrocarbon migration pathway tracing, migration system effectiveness evaluation and hydrocarbon accumulation numerical simulation, it is confirmed that intracratonic areas are far away from major hydrocarbon generation depressions, and hydrocarbon accumulation highly depends on efficient migration systems, which is obviously different from the near-source accumulation models of platform-margin zones. A composite migration network consisting of faults, unconformities and high-permeability layers was identified, forming a dual-mode hydrocarbon migration-accumulation pattern including vertical migration and lateral migration.

3.6.1 Vertical Migration Pattern: Lower-source and Upper-reservoir Pattern Controlled by Source-connected Faults

This accumulation pattern is mainly dominated by high-angle strike-slip faults related to basement uplifts. Major strike-slip faults penetrate multiple stratigraphic units vertically, and secondary derivative faults are widely developed on both sides, forming tree-shaped fault combination systems which act as high-efficiency vertical hydrocarbon migration channels. Hydrocarbons generated from Frasnian–Visean Domanik-type source rocks migrate upward along high-angle strike-slip faults under hydrocarbon generation overpressure, and finally accumulate in favorable reservoir intervals such as upper Famennian–Tournaisian strata and Bashkirian strata, forming typical lower-source and upper-reservoir hydrocarbon reservoirs.

3.6.2 Lateral Migration Pattern: Lateral-source and Lateral-reservoir Pattern Controlled by Unconformities and High-permeability Layers

Controlled by regional tectonic framework and unconformity distribution, the study area is located at the updip direction of the central depression of the Pre-Caspian Basin with huge hydrocarbon generation potential. Under buoyancy, hydrocarbons generated in central depression migrate towards paleotectonic highs of Block S along regional unconformities and laterally continuous high-permeability reservoir beds, and gather in various local traps to form lateral-source and lateral-reservoir hydrocarbon reservoirs.

The two migration patterns coordinate with each other effectively: vertical fault migration systems transport deep hydrocarbons to different reservoir intervals, while lateral migration systems deliver hydrocarbons from distant hydrocarbon kitchens, jointly providing sufficient oil and gas sources for intracratonic hydrocarbon reservoir formation.

4. Main Controlling Factors of Hydrocarbon Accumulation in Reef-beach Reservoirs

4.1 Analysis on Multi-factor Coupling Accumulation Mechanism

Hydrocarbon accumulation of intracratonic carbonate reservoirs in Block S is controlled by the coupling of sedimentary condition, tectonic setting and migration system. The core main controlling factors are summarized as follows:

- (1) Inherited paleo-uplift is the primary controlling factor. The paleotectonic highs of inherited paleo-uplifts show obvious sedimentary inheritance and are distributed around basement bulges. Long-term high-energy sedimentary environments promote the superimposed development of reef-beach bodies to form high-quality reservoirs, and also control the migration direction and enrichment distribution of hydrocarbons, which is well represented by the southern Kosha Uplift.
- (2) High-quality reservoir development is restricted by high-energy reef-beach facies distribution and late dissolution transformation. Reef-beach deposits formed in regression cycles have well-developed primary pores, and superimposed by exposure dissolution in late regression stage and fracture reconstruction, forming a ternary reservoir development model of reef-beach facies + dissolution + fractures. Reservoir development quality directly determines hydrocarbon enrichment degree and single-well production capacity.
- (3) Source-connected faults and multi-stage unconformities constitute the dual-mode migration system. The development scale and extension distance of faults control vertical hydrocarbon migration efficiency, while the distribution range and lateral connectivity of unconformities determine lateral hydrocarbon migration capacity. Circular faults developed around basement uplifts can directly connect hydrocarbon source rocks and reservoirs, which are the most favorable hydrocarbon migration channels.

4.2 Favorable Exploration Zones and Target Optimization

According to hydrocarbon accumulation controlling factors, regional geological characteristics and resource potential assessment, favorable exploration areas in the study area are divided into two categories:

- (1) Southern Kosha inherited paleo-uplift belt: controlled by basement uplift activities, this zone maintains long-term high paleotopography, with widely distributed superimposed reef-beach bodies, thick reservoir beds, good physical properties and complete fault migration systems, which is confirmed as the most favorable core exploration target area.
- (2) Local paleogeomorphic high zones in central and northern study area: these areas are generally dominated by low-lying paleotopography, with scattered local paleohighs controlling the development of isolated point-shaped reef-beach bodies. When matched with favorable structural traps and effective fault migration systems, independent lithologic hydrocarbon reservoirs can be formed, which are regarded as important potential successive exploration areas.

5. Conclusion

(1) Multi-disciplinary comprehensive studies prove that Block S possesses superior basic geological conditions for intracratonic carbonate hydrocarbon accumulation. The dominant hydrocarbon source rocks are Frasnian–Visean Domanik-type source rocks; high-quality reservoirs are mainly developed in high-energy reef-beach facies belts of upper Famennian–Tournaisian and Bashkirian strata; thick Kungurian gypsum-salt sequences act as stable regional cap rocks. The above accumulation elements are vertically assembled in order to form pancake-type high-efficiency source-reservoir-cap assemblages.

(2) By adopting integrated seismic-geological interpretation and paleotopography restoration technology, it is confirmed that the study area develops a dual-mode migration system composed of vertical fault pathways and lateral unconformity-high permeability layer pathways. Inherited paleo-

uplifts not only control the spatial distribution law of reef-beach reservoirs, but also dominate the migration and enrichment direction of hydrocarbons, establishing the unique accumulation framework dominated by paleo-uplift control and dual-mode hydrocarbon migration.

(3) Hydrocarbon accumulation of intracratonic carbonate reservoirs is mainly controlled by three-dimensional coupling effects, including directional migration control of inherited paleo-uplifts, reservoir storage capacity guarantee of high-energy reef-beach facies and dissolution transformation, as well as migration connection function of source-connected faults and unconformities. On this basis, the southern Kosha inherited paleo-uplift belt is determined as the optimal favorable exploration zone, and local paleogeomorphic highs in central and northern parts are defined as potential successive exploration targets.

(4) The established hydrocarbon accumulation theoretical system and corresponding exploration technical methods in this study effectively solve the key problems such as unclear accumulation rules and ambiguous exploration deployment directions in intracratonic carbonate zones. The research results can provide solid theoretical basis and practical technical references for exploration arrangement and efficient development of similar carbonate hydrocarbon reservoirs in Tarim Basin, Sichuan Basin and other petroliferous basins in China.

Acknowledgments

Fund projects: Heilongjiang Provincial Unveiling and Commanding Program (No.2022-JS-1740, 2022-JS-1853); Scientific Research and Technological Development Project of China National Petroleum Corporation (No.2021DJ1808).

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