Abstract: The reservoir quality of sandstones is significantly impacted and transformed by sedimentation and diagenesis. It is necessary to clarify the internal relationship among them to precisely predict the sweet reservoir. In this study, five types of sedimentary microfacies are recognized through core observation and logging data: submerged distributary channel (fan delta), submerged interdistributary bay, submerged distributary channel (braided delta), distal bar, and turbidite fan. The major diagenetic processes, including compaction, cementation, and dissolution, have been analyzed based on petrography, scanning electron microscopy, and X-Ray diffraction. The dominant diagenetic cement includes calcite, smectite, kaolinite, illite, and I/S mixed-layer minerals, with small quantities of chlorite, pyrite, siderite, feldspar, and quartz cement. The reservoir quality is best in the submerged distributary channel (fan delta) sandstones, followed by submerged distributary channel (braided delta). Submerged interdistributary bay, distal bar, and turbidite fan are of poor reservoir quality. The grain size is the primary reservoir quality controlling factor, highly affected by sedimentary microfacies. Subsequent controls are diagenetic processes such as mechanical compaction, clay minerals formation, grain replacement, and dissolution that collectively influence the porosity and permeability.

Keywords: reservoir quality; sandstone diagenesis; sedimentary microfacies; detrital mineralogy; Nanpu Sag

1. Introduction

Reservoir quality is generally evaluated by porosity and permeability, which are key parameters for oil and natural gas exploration and production [1,2]. The economic viability of hydrocarbon accumulation is significantly impacted by reservoir porosity and permeability, which restrict the hydrocarbon storage and production capacity, respectively [3–5]. Discovering reservoirs with adequate quality to allow commercial exploitation is a crucial factor determining the success of oil and gas exploration [6]. The sedimentary and diagenetic process plays a significant part in influencing reservoir porosity and permeability. Understanding the composition and texture of sediments as well as the occurrences of diagenetic changes within a reservoir is crucial for predicting porosity and permeability, leading to increased oil and gas exploration accuracy [3,7,8].

The impacts of sedimentation and diagenesis on sandstone reservoirs have been widely discussed over the past few years. Detrital components such as quartz, feldspar, and rock fragments have a certain impact on reservoir porosity and permeability [9]. Sandstones with higher quartz content are more favorable for pore development because of their stronger resistance to compaction [9]. Porosity generally deteriorates with the increase of rock fragments content [10]. Due to different energy settings in different sedimentary environments, the grain size, sorting and clay content of sediments are significantly different,
which affects the porosity and permeability of the reservoir [11]. As for the relationship between sedimentation, diagenesis and reservoir quality, sedimentary factors can indirectly control reservoir quality by determining diagenetic preference and intensity [12]. For example, grain size, sorting and sedimentary thickness control reservoir quality by affecting compaction strength, cement content and dissolution [12]. Diagenetic processes such as mechanical compaction directly deteriorate the reservoir quality [11,12]. Overall, sedimentary and diagenetic processes jointly control reservoir quality and heterogeneity [11–15].

Nanpu Sag is a petroliferous sag in the Bohai Bay Basin and it has produced a significant quantity of industrial oil flows in shallow to deep layers (depth ranges roughly from 2500 m to 4000 m) [16,17]. In recent years, geologists have published fruitful studies on regional geology, sedimentary and structural evolution, and reservoir modeling of Nanpu Sag. The tectonic evolution and structural geological complexity of Nanpu Sag have been clearly addressed [18,19]. The sedimentary system of Nanpu sag has been systematically studied [20–22]. Other studies have been conducted on the pore types, diagenetic evolution, formation mechanism of reservoirs and factors controlling hydrocarbon enrichment in Nanpu Sag [17,23–26]. However, there are few studies on the relationship among sedimentary microfacies, diagenesis and reservoir quality of sandstones in Nanpu Sag. Based on that, core samples from 10 wells in the No. 1 structural belt of Nanpu Sag have been selected as the research objects to systematically investigate the sedimentary features and diagenesis of sandstone reservoirs and their influence on reservoir quality. The sedimentary, diagenetic and reservoir physical features of sandstones are analyzed by thin section, SEM, XRD and routine core analyses. The specific research aims to: (a) define the sedimentary microfacies existing in the No. 1 structural belt sandstones; (b) illustrate the sedimentary characteristics of these sandstones; (c) address reservoir physical properties of sandstones in different sedimentary microfacies; (d) demonstrate the effect of the diagenetic process after deposition on reservoir physical properties; (e) discuss the controlling factors of sandstone reservoir quality in the No. 1 structural belt.

2. Geological Background

2.1. Stratigraphy

Nanpu Sag is a Meso-Cenozoic lacustrine sub-basin situated northeast of Huanghua Depression in the Bohai Bay Basin, with a size of roughly 1932 km² (Figure 1A) [25,27,28]. The sedimentary fill of Nanpu Sag consists of large segments of clastic rocks intercalated with volcanics on the whole, depositing 5000–9000 m-thick Cenozoic strata [29,30]. The strata developed in Nanpu Sag include Shahejie and Dongying Formation in the Paleogene, Guantao and Minghuazhen Formation in the Neogene, and Pingyuan Formation in the Quaternary, from bottom to top (Figure 2). Shahejie and Dongying Formation are divided into three members separately. The 4th member of Shahejie Formation and Kongdian Formation is missing or undeveloped in Nanpu Sag (Figure 2). During the Paleogene, the sedimentary environment of Nanpu sag was mainly alluvial fan, delta, fluvial and lake environment, where Shahejie Formation and Dongying Formation were deposited. Guantao Formation and Minghuazhen Formation were developed in braided river and meandering river environments, respectively (Figure 2). Overall, the sedimentary system of Nanpu Sag is a combination of four sedimentary facies types. It is a continental faulted lake on the whole, with the fan delta formed by the alluvial fan from the steep slope in the north, and the braided delta formed by the braided river from the gentle slope in the south, and gravity flow deposits within the lake, surrounded by argillaceous deposits and scattered in front of the delta [20]. The lithology of Nanpu Sag mainly includes delta sandstone, fluvial sandstone and lacustrine mudstone.

Previous studies have found that source rocks are developed in the 3rd and the 1st Member of Shahejie Formation, and the 3rd member of Dongying Formation in Nanpu Sag [25,30,31]. The widely distributed delta sand deposits in Shahejie Formation and Dongying Formation, and fluvial sand deposits in the Neogene provide good conditions for hydrocarbon storage, while the extensively developed mudstones and volcanics in the
Neogene act as regional caprocks [25,32]. In this study, core samples are mainly from the Dongying Formation.

2.2. Tectonic Setting

Nanpu Sag is half-graben with steep faulting (Xi’nanzhuang fault and Baigezhuang fault) in the north and an overlap in the south (Figure 1B,C) [18,24]. The internal faults are very developed and dominated by normal tensile faults and some tensile-torsional faults striking mainly in NE and ENE (Figure 1B). Based on the structural characteristics of Nanpu Sag, it is divided into three sub-sags and seven secondary structural belts, including the No. 1, No. 2, No. 3, No. 4, No. 5, Gaoliu and Laoyemiao structural belts, and Liunan, Linque and Caofeidian Sub-sags (Figure 1B). Previous studies have found that the uplifted areas, as source areas, around the Nanpu Sag delivered sediments into the basin based on the depositional system distribution and seismic reflection analyses [33].

The No. 1 structural belt is located in the southwestern Nanpu Sag, mainly developing a NE trending main fault (named the No. 1 fault) and ENE-orientated comb faults (Figure 1B) [34,35]. This area mainly receives provenance from the northern fan delta and southern braided delta. The main oil-bearing strata are the middle and deep Dongying Formation and Shahejie Formation [21,36,37].

Figure 1. (A) Regional and location map of Nanpu Sag in Bohai Bay Basin [18,30]; (B) Tectonic setting of Nanpu Sag, and sampling wells are marked by red dots with well names attached next to them [18,25]; (C) Schematic geological cross-section representative of the structural setting of Nanpu Sag [38].
Figure 2. General Paleogene-Neogene stratigraphy of Nanpu Sag with information about depositional environment and hydrocarbon system elements [30,39].
3. Data and Methods

To fully understand reservoir characteristics in the No. 1 structural belt and possible factors affecting reservoir physical properties, we used an approach integrating core and wireline logging data, thin-section analysis data, porosity and permeability data, scanning electron microscope and X-ray diffraction. To understand the relationship between sedimentary microfacies and reservoir physical properties, it is critical to combine sedimentary and logging information to accurately define the sedimentary microfacies for each core section sample to correspond to the porosity and permeability data.

3.1. Core and Logging Data

Core photos and logging data from 10 wells (see the well locations in Figure 1B) in Nanpu Sag are obtained from the Petro China Jidong Oilfield Company. Sedimentary microfacies of different depth intervals from each well are determined through core observation and analysis of GR (gamma ray) and SP (spontaneous potential) logging curves.

3.2. Optical Microscopy (Thin-Section Analysis)

Rock composition data for all samples are collected from the Petro China Jidong Oilfield Company. Using the DM4500P optical light microscope, 451 thin section samples were inspected and point counted to gain information about petrography, including rock composition, sorting, roundness, and grain size. The thin sections were dyed with blue epoxy to clearly show pores. Optical photomicrographs were captured using an optical light microscope fitted with a digital camera.

3.3. Routine Core Analysis

Routine core analysis was performed by the Exploitation Laboratory of Research Institute of Petroleum Exploration & Development of PetroChina Huabei Oilfield Corporation immediately after wells were drilled, following the Chinese industry-standard “Method of core routine analysis” (SY/T5336-1996). Core plugs were originally taken every 10–20 cm. The core routine analysis was performed in a 22 °C room with a 32% humidity level, and an atmospheric pressure of 103,200 Pa. Helium porosity and horizontal permeability of 560 samples and carbonate content of 378 samples were measured. The porosity was measured using the Ultrapore-200A helium porosimeter. The permeability was measured using the ULTRA-PERM™200 permeameter. The carbonate content was measured using the TSY-1 rock carbonate content tester.

3.4. Scanning Electron Microscopy

Representative samples were analyzed using a TESCAN VEGA II scanning electron microscopy under 22 °C and 30% RH conditions at the Sedimentary Laboratory of Research Institute of Petroleum Exploration & Development of PetroChina Huabei Oilfield Corporation.

3.5. X-ray Diffraction

Clay mineral total and relative contents can be accurately determined using XRD examinations of bulk rock and clay minerals. The XRD analysis was performed by the Sedimentary Laboratory of Research Institute of Petroleum Exploration & Development of the PetroChina Huabei Oilfield Corporation. A total of 164 sub-samples of core plug samples were obtained for clay mineral analysis using an XD-610 X-ray diffractometer. The XRD analysis was performed in a 20–22 °C room with a 30–35% humidity level.

3.6. Error and Limitation Analysis

Given the limitations of sampling and data acquisition, the distribution of samples in different sedimentary microfacies may be uneven, which is beyond our control. The porosity and permeability are often affected by various factors at the same time, but we cannot unite other variables to study the influence of one single factor on porosity and permeability, which is the limitation of this study.
4. Results

4.1. Sedimentary Characteristics

There are two types of sedimentary facies in the No. 1 structural belt: fan delta and braided delta [20,25,34]. Combined with sedimentary logging, core observation, and logging curve features, five types of sedimentary microfacies are identified: submerged distributary channel (fan delta), submerged interdistributary bay, submerged distributary channel (braided delta), distal bar, and turbidite fan.

4.1.1. Submerged Distributary Channel (Fan Delta)

Submerged distributary channel (fan delta) (FSDC) is the continuation part of the fan delta channel after entering the lake. It makes up the majority of the fan delta front subfacies. Due to sampling limitations, most samples in this study belong to the submerged distributary channel (fan delta) with relatively coarse grain sizes, which are mainly medium sandstone and fine sandstone (Figure 3A). The sandstone is relatively clean, light-colored, and contains little argillaceous content. The grain size presents fining upward vertically through the log. Its GR value is often relatively low, with a general box or box-bell shape.

4.1.2. Submerged Interdistributary Bay

Submerged interdistributary bay (SIB) is the depositional part between submerged distributary channels. The lithology of sediments from submerged interdistributary bay is relatively fine, which is mainly very fine and fine sandstone (Figure 3B). The color is relatively dark. Due to submerged distributary channels’ active and frequent migration, the sediments between channels are often eroded and damaged, thus relatively less retained. The GR curve of this microfacies is generally finger-shaped.

4.1.3. Submerged Distributary Channel (Braided Delta)

Submerged distributary channel (braided delta) (BSDC) is the continuation part of the braided delta channel after entering the lake. It is similar to the submerged distributary channel of the fan delta. The difference is that its sediments are transported by long-distance braided river, resulting in relatively finer grain size and higher structural maturity, with rounded grains in good sorting. Its lithology is mainly fine sandstone, with some medium sandstone and argillaceous laminae. The bottom of the channel sand body may contain some gravel when close to the source area in their proximal position (Figure 3C). The identification mark of this microfacies on the logging curve is box shape.

4.1.4. Distal Bar

Distal bar (DB) is the end deposit at the edge of the delta front, where the hydrodynamic conditions are relatively weak. It consists of thin, coarsening-upward sandstones interbedded with mudstone. The sandstones are generally fine-grained, with parallel laminations (Figure 3D). Its identification mark on the GR logging curve is finger-shaped or funnel-shaped.

4.1.5. Turbidite Fan

Turbidite fan (TF) is formed by the occurrence of hyperpycnal flow in the study area due to the accumulation of sufficient sediment supply on the slope provided by the fan delta and braided delta. The lithology of turbidite fan identified in the study area is mostly fine to medium sandstone. Mudstone-clast and slump structures are commonly within this microfacies (Figure 3E). GR logging curve is tooth-shaped.
Figure 3. Core photographs of different sedimentary microfacies recognized in the No. 1 structural belt with a sketch and logging information attached to them. (See the well locations in Figure 1B.)

(A) Np1, depth: 2676.17 m, submerged distributary channel (fan delta); (B) Np1, depth: 3777.82 m, submerged interdistributary bay; (C) Np1-7, depth: 2676.17 m, submerged distributary channel (braided delta); (D) Np1-4, depth: 3791.94 m, Distal bar; (E) Np1-4, depth: 3848.49 m, Turbidite fan.
4.2. Rock Composition and Texture

4.2.1. Rock Composition

The composition of sandstones within five sedimentary microfacies is summarized in Table 1. Samples from various sedimentary microfacies show no discernible differences in the detrital components, with detrital lithics making up the majority of the composition. Alkali constitutes the majority of detrital feldspars, with a tiny percentage of plagioclase. Lithics are mostly of volcanic and metamorphic types. Small quantities of mica and tuff rock fragments are among the other detrital components (Table 1). Cement and argillaceous matrix make up the majority of the sandstones’ interstitial materials. With a small quantity of quartz overgrowths, pyrite, and siderite, the cement is primarily composed of clay minerals and carbonates, such as calcite and dolomite (Table 1).

Table 1. Sandstone composition of different sedimentary microfacies in the No. 1 structural belt (Derived from thin-section point count). (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan.).

|                  | FSDC | SIB | BSDC | DB | TF |
|------------------|------|-----|------|----|----|
| **Detrital grains (vol.%)** |      |     |      |    |    |
| Quartz (vol.%)    | 30   | 34  | 44   | 31 | 37 |
| Alkali feldspar (vol.%) | 17  | 37 | 30   | 37 | 34 |
| Plagioclase (vol.%) | 1   | 2   | 3    | 1  | 3  |
| Lithics (vol.%)   | 33   | 42  | 47   | 37 | 42 |
| Acid extrusive rock fragments (vol.%) | 14  | 23 | 35   | 18 | 27 |
| Intermediate-basic extrusive rock fragments (vol.%) | 1   | 3   | 5    | 2  | 3  |
| Sedimentary rock fragments (vol.%) | 1   | 7   | 9    | 1  | 7  |
| Metamorphic rock fragments (vol.%) | 8   | 22  | 13   | 12 | 17 |
| Tuff rock fragments (vol.%) | 1   | 3   | 1    | 1  | 4  |
| Mica (vol.%)      | 1   | 5   | 1    | 4  | 0  |
| **Interstitial material (vol.%)** |      |     |      |    |    |
| Argillaceous matrix (vol.%) | 1   | 1  | 12   | 1  | 2  |
| Micritic carbonate matrix (vol.%) | 0   | 0  | 0    | 0  | 0  |
| Calcite (vol.%)   | 1   | 12  | 8    | 9  | 0  |
| Dolomite (vol.%)  | 1   | 9   | 7    | 2  | 1  |
| Clay minerals (vol.%) | 1  | 6   | 1    | 3  | 0  |
| Quartz overgrowths (vol.%) | 0   | 0  | 0    | 0  | 0  |
| Siderite (vol.%)  | 1   | 8   | 0    | 3  | 1  |

4.2.2. Sorting and Roundness

According to the results of thin-section observation, the sandstones of all sedimentary microfacies are mainly moderately-sorted, and there are a few well-sorted and poorly-sorted in FSDC, SIB, BSDC, and DB (Figure 4). There are only moderately-sorted sandstones in turbidite fan, which may be a result of small sampling quantity and the limited sampling location of thin-sections. Based on thin-section observation, there are no discernible variations in the degree of roundness among all sedimentary sandstones. The roundness of all sedimentary microfacies is mainly sub-angular to sub-rounded.
Figure 4. Sorting distribution of sandstones from each sedimentary microfacies, where “n” is the number of samples. (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan). 4.2.3. Grain Size

Different from sorting, the grain sizes of samples from five sedimentary microfacies can identify relatively noticeable variations (Figure 5). The FSDC and TF have relatively coarser grain sizes, with median values of 0.34 mm and 0.31 mm, respectively. The median grain size value of BSDC and DB is at the medium level, which is 0.23 mm and 0.26 mm, respectively. The median grain size value of SIB is obviously the lowest, which is 0.16 mm.

Figure 5. Boxplot of grain size data of each sedimentary microfacies derived from point count, where “n” is the number of samples. Each box displays data between the upper and lower quartile, and the black line represents the median. The highest and lowest values are revealed by the whiskers. Over 1.5 times the upper or lower quartile are considered outliers marked by black dots. (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan).
According to the lithology distribution of sandstones from five sedimentary microfacies, FSDC and turbidite are mainly medium sandstone, followed by fine sandstone. SIB mainly consists of very fine sandstone and fine sandstone. Fine sandstone and medium sandstone make up the majority of DB. With small amounts of medium sandstone, fine sandstone predominates in BSDC (Figure 6).

Figure 6. Lithology distribution of sandstones from each sedimentary microfacies, where “n” is the number of samples. (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan).

Grain size depends on the hydrodynamic condition of the sedimentary environment and the transport distance of sediments. The hydrodynamic conditions gradually weaken with increasing sediment transport distance, and sediment grain size will gradually decrease. Therefore, the sandstones from FSDC are generally coarser than DB and turbidite fan. The grain size of SIB is the smallest because fine-grained sediments overflowing outside the submerged distributary channels make up the majority for the sandstones in SIB. The sediments in the braided delta are transported farther than those in the fan delta, so the grain size of sandstones from BSDC is smaller than that from fan delta facies. The grain size of sediments in different sedimentary microfacies shows significant differences, which may affect the physical properties of reservoirs.

4.2.4. Quartz–Feldspar–Lithic Sandstone Classification

There is no significant difference in the detrital composition of sandstones from each sedimentary microfacies based on the point count data. According to Folk’s classification scheme [40], the sandstones from five sedimentary microfacies are mainly feldspathic litharenite, with average contents for three components being $Q_{34.6}F_{23.5}R_{42.1}$, $Q_{34.2}F_{23.8}R_{42}$, $Q_{32.4}F_{25.2}R_{42.4}$, $Q_{37.6}F_{27.8}R_{34.6}$, and $Q_{35.5}F_{27.3}R_{37.2}$ (Figure 7).

The clastic composition of sandstone reflects the provenance information. The similarity of these sandstones in QFL classification indicates the consistency of provenance composition. Therefore, it can be inferred that the difference in reservoir physical properties in the study area has nothing to do with QFL classification.
4.3. Rock Porosity and Permeability

Porosity and permeability data are displayed in Figure 8, split by sedimentary microfacies in the form of scatter plot and boxplot, respectively. Core effective porosity and horizontal permeability are positively correlated with each other among all sedimentary microfacies, and the reservoir quality of the five sedimentary microfacies shows significant differences (Figure 8A). The porosity and permeability of FSDC samples are generally higher, while those of TF and DB samples are typically lower (Figure 8A). The range of core analysis porosity values is 3.8% to 34.5%, where FSDC, SIB, BSDC, DB, and TF have a median value of 25.1%, 19.6%, 23.1%, 15.4%, and 13.7%, respectively (Figure 8B). The range of core analysis horizontal permeability values is 0.06 to 3530 mD, where FSDC, SIB, BSDC, DB, and TF have a median value of 160.00 mD, 3.58 mD, 7.84 mD, 0.99 mD, and 0.78 mD, respectively (Figure 8C). The permeability and the porosity show the same general trend among samples of different sedimentary microfacies (Figure 8B,C).

According to the physical property classification standard of the clastic rock reservoir of CNPC (China National Petroleum Corporation), the porosity of a good reservoir is supposed to be greater than 15%, and the permeability is supposed to be greater than 100 mD. Sandstones from FSDC exhibit the highest porosity and permeability out of the entire collection of core plugs and belong to the good reservoir (Figure 8A–C). Almost all sandstone samples from BSDC have a porosity greater than 15%, which meets the porosity standard of a good reservoir but has poor permeability. Sandstones from other sedimentary microfacies mainly fall into the poor reservoir. The differences in reservoir physical properties shown in different sedimentary microfacies are possibly related to their differences in grain size, which will be discussed later.
4.4. Diagenesis

Thin-section analyses, SEM, and XRD show that the sandstones in the No. 1 structural belt have experienced a complex diagenetic process. Diagenesis affecting the quality of sandstone reservoirs mainly includes compaction, cementation, and dissolution. Cementation mainly includes carbonate cementation, clay cementation, quartz overgrowth, and feldspar overgrowth (Figure 9A–H).
Figure 9. Plane polarized image and scanning electron microscope images showing diagenesis in sandstones. (A) Np1-5, depth: 2717.56 m, quartz, feldspar, kaolinite, pores, and feldspar dissolution; (B) Np1-4, depth: 2438.26 m, quartz overgrowth, feldspar overgrowth, feldspar dissolution; (C) Np1-4, depth: 2510.85 m, feldspar overgrowth; (D) Np1-37, depth: 3173.50 m, calcite, illite, and I/S-mixed layer; (E) Np1-37, depth: 3174.92 m, kaolinite, and dolomite; (F) Np101 × 8, depth: 2303.99 m, feldspar overgrowth, smectite, and illite; (G) Np103 × 2, depth: 1859.65 m, pyrite, and chlorite; (H) Np105, depth: 2839.94 m, feldspar dissolution. (Q—quartz, F—Feldspar, Fd—feldspar dissolution, Cal—calcite, Do—dolomite, K—kaolinite, S—smectite, I—illite, Ch—chlorite, I/S—illite/smectite-mixed layer, Py—pyrite, Qo—quartz overgrowth, Fo—feldspar overgrowth).
Compaction: As the buried depth increases, the mechanical compaction is gradually enhanced, detrital grains such as quartz and feldspar show certain directionality (Figure 9A), and concave–convex contact between grains progressively replaces point and line contact. Ductile minerals such as mica are generally deformed.

Carbonate cementation: Carbonate cementation is a common authigenic mineral, usually found filling in authigenic intergranular pores or feldspar dissolved pores (Figure 9D). Carbonate cement mainly includes calcite and dolomite (Figure 9D,E), of which calcite is the primary type. The crystalline calcite cement occurs in the form of filling intergranular pores.

Clay cementation: XRD analysis data show that authigenic clay minerals content ranges from 0 to 45%, with an average of 9.83%. The primary clay minerals, according to XRD and SEM analyses, include kaolinite, smectite, illite, chlorite, and I/S mixed-layer minerals (Figure 9). Smectite is distributed on the particle surface in dark flakes (Figure 9D,F). Kaolinite mostly exists in intergranular pores in the form of pore filling. It is the alteration product of feldspar and forms vermicular or booklet textures (Figure 9E). Sheet-like illite mainly fills pores attached to the grain surface or filled intergranular pores in the form of bright leaf and silk hair. Microcrystals such as flakes divide the pores into smaller pores, increasing the degree of detour (Figure 9F). I/S-mixed layer minerals mainly grow as pore-filling cement, which is the mineral of the transition from smectite to illite, in the form of honeycomb, semi honeycomb, and cotton wadding (Figure 9D). Chlorite occurs along the surfaces of clastic grains as rims, in needle leaf shape, pile ball shape, and rose shape (Figure 9G). The occurrence in pores includes pore liner and pore filling. Generally, needle-like chlorite is mostly pore liner wrapped on the surface of particles, while pile-like and rose-like chlorite are filled in pores.

Quartz overgrowth: Authigenic quartz is commonly generated by partial or overall secondary growth around the edge of quartz grains (Figure 9B).

Dissolution: The dissolution of the sandstone reservoir mainly occurs in feldspar, forming dissolved secondary pores, which may enhance the porosity and connectivity between pores (Figure 9B,H).

5. Discussion

5.1. Sedimentary Impact on Reservoir Quality

There is a certain relationship between reservoir quality and sedimentary microfacies (Figure 8). It has been found that particle size and morphology, sorting and roundness, as well as the content of clay and matrix in sandstones are generally the primary sedimentary factors affecting reservoir quality [41–43]. The relationship between sorting and porosity or permeability cannot be discussed, considering that the sorting of sandstones from all sedimentary microfacies is similar in the No. 1 structural belt (Figure 4). However, the grain size varies significantly (Figure 5).

To evaluate the effects of textural factors, porosity and permeability have been respectively compared to grain size split by sedimentary microfacies (Figure 10). Porosity shows no obvious correlation with grain size. Samples with great grain size differences can have similar porosity, and samples with similar grain sizes can have great differences in porosity (Figure 10A), which indicates that grain size is not a dominant factor for porosity. There is an apparent positive correlation between grain size and permeability (Figure 10B). The permeability values of the coarser-grained sandstones, particularly those from the submerged distributary channel (fan delta), are generally higher than those of the finer-grained sandstones (Figure 10B).
Figures 10. Plots of reservoir properties versus grain size derived from point count, split by different sedimentary microfacies. (A) Core effective porosity versus grain size; (B) Core horizontal permeability versus grain size. (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan).

Grain size and sedimentary microfacies roughly distinguish between good and poor reservoir quality (Figures 8A and 10). Permeability and grain size are positively correlated because of narrower pore throats and capillaries produced by finer-grained sandstones [44,45]. As packed spheres’ porosity is irrelevant to grain size, there is no straightforward relationship between porosity and grain size (Figure 10A) [46]. However, sandstones from FSDC and BSDC often have higher porosity than those from DB and TF (Figure 10A). We have already shown that the sorting of sandstones from all sedimentary microfacies is similar in the No. 1 structural belt (Figure 4), so the physical property difference might be caused by diagenetic factors, which will be discussed in the following section.

5.2. Diagenetic Impact on Reservoir Quality
5.2.1. Carbonate Cementation

The cement of the sandstones in the No. 1 structural belt includes carbonate, clay minerals, and quartz overgrowth (Figure 9). Carbonates generally grow in the form of pore-filling. It has been found that the influence of pore-filling carbonates on porosity and permeability is usually much greater than cement at the edge of particles such as quartz secondary enlargement [47,48]. The porosity and permeability are inversely correlated with the amount of carbonate cement existing in the reservoir (Figure 11). Samples with higher porosity and permeability often contain lower carbonate content. The porosity and permeability of samples with higher carbonate cement content are generally lower. Therefore, reservoir quality is significantly controlled by the carbonate cement distribution.

However, samples from turbidite fan, distal bar, and submerged interdistributary bay containing low carbonate content still have low porosity and permeability (Figure 11), which might be a result of other factors controlling reservoir quality, which will be discussed below.
5.2.2. Clay Cementation

Clay is also an essential factor affecting reservoir quality [49–51]. Plots of reservoir properties versus total clay content indicate a slight negative relationship between total clay content and the reservoir quality of sandstones (Figure 12). The formation and transformation of clay minerals might have a particular impact on reservoir properties. For example, the organic matter within the source rocks on top produced a significant amount of acid during the burial process [48]. Lots of secondary pores and authigenic kaolinite were formed as the acid flowed into the reservoirs and interacted with unstable minerals such as feldspars [52–54]. The majority of the clay found in the sandstones in the No. 1 structural belt consists of clay matrix developed during sedimentation and authigenic clay minerals generated during diagenesis. Smectite and kaolinite clay minerals typically underwent a transition into illite or chlorite during the burial phase. The reservoir quality is impacted differently by various clay minerals.

Figure 11. Plots of reservoir properties versus carbonate content derived from routine core analysis, split by different sedimentary microfacies. (A) Core effective porosity versus carbonate content; (B) Core horizontal permeability versus carbonate content. (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan).

Figure 12. Plots of reservoir properties versus total clay content derived from XRD, split by different sedimentary microfacies. (A) Core effective porosity versus total clay content; (B) Core horizontal permeability versus total clay content. (FSDC—submerged distributary channel (fan delta), SIB—submerged interdistributary bay, BSDC—submerged distributary channels (braided delta), DB—distal bar, TF—turbidite fan).
There is no discernible relationship between porosity and permeability of the sandstone and smectite relative content (Figure 13A,B), indicating that reservoir quality is not much affected by the relative content of smectite. The effects of kaolinite on reservoir quality are complex. On one hand, as a type of cement, kaolinite might fill the pores, narrowing the pore throats and degrading connectivity between pores, thus reducing the porosity and permeability [55]; on the other hand, kaolinite has intercrystalline pores itself and is transformed from feldspar, indicating the formation of secondary pores due to feldspar dissolution, which has a beneficial effect on reservoir quality [48,49]. The porosity and permeability of the sandstones in the No. 1 structural belt are positively correlated with kaolinite content (Figure 13C,D), indicating that kaolinite has a constructive effect on reservoir quality in this study. Most illites filled the pore throat of sandstone (Figure 9D,F), reducing the porosity and destroying the connectivity between pores. Therefore, the reservoir porosity and permeability are reversely correlated with illite content (Figure 13E,F). When the illite content is small, the porosity and permeability of sandstones with close illite content are significantly different due to the influence of other factors (Figure 13E,F). The porosity and permeability of sandstone also negatively correlate with I/S-mixed layer content (Figure 13G,H), indicating that the I/S-mixed layer also fills the reservoir pore space and lowers the reservoir physical properties. Chlorite on the grain surface may preserve intergranular pores by inhibiting the development of compaction and quartz overgrowths [56–58]. However, the chlorite content of the sandstones in the No. 1 structural belt is very low. Only under SEM is it possible to observe the extremely limited distribution of chlorite rims (Figure 9G). Chlorite failed to protect reservoir quality because of the low chlorite levels in those reservoirs (Figure 13I,J). Most sandstone samples have small and close chlorite content, but show a wide range of porosity and permeability (Figure 13I,J), which is supposed to be caused by other factors.

5.2.3. Dissolution

Dissolution is an important factor in enhancing reservoir quality [59]. The mineral types and the depositional environment have an impact on the dissolving process [23,60]. Some parts of the reservoir in Nanpu Sag are adjacent to source rocks, which have released a huge quantity of organic acid during the burial process, leading to the dissolution of feldspars. The dissolution generally occurs along cleavages (Figure 9A,B,H), producing secondary pores which significantly improve reservoir quality. However, there was no observation of the carbonate cement dissolving, which could also be an essential element in the formation of secondary pores [61].

5.3. Diagenetic Sequence

The burial history has been reconstructed by Chen et al. [62] using a petroleum system simulation software, based on stratigraphic sequence, thickness, lithology, and strata denudation amount derived from the evolution of stratigraphic porosity. Based on thin section, paleotemperature, SEM, and XRD analysis, a schematic diagram of the diagenetic sequence of the sandstones in the No. 1 structural belt from Nanpu Sag is summarized in Figure 14. The diagenetic stages were divided according to the Chinese standard “The division of diagenetic stages in clastic rock” (SY/T5477-2003).
Figure 13. Plots of reservoir properties versus clay relative content derived from XRD, split by different sedimentary microfacies. (A) Core effective porosity versus smectite relative content; (B) Core horizontal permeability versus smectite relative content; (C) Core effective porosity versus kaolinite relative content; (D) Core horizontal permeability versus kaolinite relative content; (E) Core effective porosity versus illite relative content; (F) Core horizontal permeability versus illite relative content; (G) Core effective porosity versus I/S-mixed layer relative content; (H) Core horizontal permeability versus I/S-mixed layer relative content; (I) Core effective porosity versus chlorite relative content; (J) Core horizontal permeability versus chlorite relative content.
The Ed sandstones have experienced Eogenesis A stage, Eogenesis B stage, and Mesodiagenesis A stage. During the Eodiagenesis A stage, the Ed sandstones were buried shallowly and experienced temperatures up to 65 °C. Mechanical compaction gradually destroyed the primary pores. Smectite and carbonate cement began to appear. Mechanical compaction was the main control on reservoir physical properties at this point. During the Eodiagenesis B stage, the temperature ranged from 65 °C to 85 °C. Mechanical compaction further reduces porosity. The source rock near the reservoir reached the maturation threshold, and unstable minerals like feldspar were dissolved when the organic acid formed by the transformation of organic matter migrated into the sandstone, generating clay minerals such as kaolinite at the same time. With the increase of burial depth, temperature, and pressure, part of the interlayer water of smectite was released, resulting in some interlayer collapse, rearrangement of lattice, and the adsorption of alkaline cations, forming I/S-mixed...
layers. During the Mesodiagenesis A stage, the temperature reached 85 °C. The strong mechanical compaction caused the transformation of the contact mode of detrital grains from point contact and line contact to concave–convex contact, which largely destroyed the primary pores. At this stage, massive volumes of organic acid were produced from source rock for fully entering the matching threshold, which greatly dissolved feldspar to form secondary pores. The charging of oil and gas inhibited the formation of cement, thus protecting the primary pores [26,63]. The massive dissolution of feldspar formed abundant kaolinite. When the oil production peak was reached, organic acid concentration began to decrease, and the feldspar overgrowth began to form. At the same time, smectite was further illitized, and kaolinite began to transform into illite and chlorite.

6. Conclusions

1. Five types of sedimentary microfacies are recognized in the No. 1 structural belt of Nanpu Sag: submerged distributary channel (fan delta), submerged interdistributary bay, submerged distributary channel (braided delta), distal bar, and turbidite fan; The sandstone reservoir is mainly medium-fine grained feldspathic litharenite with the texture of moderately-sorted and sub-angular to sub-rounded.

2. Reservoir quality is best in submerged distributary channel (fan delta), followed by submerged distributary channel (braided delta). Submerged interdistributary bay, distal bar, and turbidite fan have poor reservoir quality. This trend is primarily controlled by grain size, with the higher permeabilities associated with the coarser-grained sandstones.

3. Reservoir quality was also controlled by diagenetic processes, including compaction, cementation, and dissolution. Compaction reduces primary porosity. Kaolinite indicates the formation of feldspar dissolved pores, which may improve reservoir porosity, while the increase in carbonate cement, illite, and I/S mixed-layer content implies a drastic decrease in reservoir quality. Dissolution produces secondary pores, thus enhancing reservoir quality.

4. The primary control on reservoir quality observed in this study are the sedimentary processes which determine the grain size. Subsequent controls are diagenetic processes such as mechanical compaction, grain replacement, clay minerals formation, and dissolution that collectively influence the porosity and permeability.

Author Contributions: Z.Y.: Conceptualization, Formal analysis, Writing—Original Draft. S.C.: Conceptualization, Methodology, Funding acquisition, Review & Editing. W.X.: Conceptualization, Methodology, Review & Editing. S.Z.: Resources. J.M.: Review & Editing. T.G.: Review & Editing. All authors have read and agreed to the published version of the manuscript.

Funding: This study was financially supported by the Fundamental Research Funds for the Central Universities, China University of Geosciences (Wuhan) (No. CUG170616), National Natural Science Foundation of China (41972117), National Science and Technology major special projects (2016ZX05006-006-002), and Fundamental Research Funds for National Universities, China University of Geosciences (Wuhan).

Data Availability Statement: The data that support the findings of this study are available on request from the corresponding authors. The data are not publicly available due to confidential restrictions.

Acknowledgments: We would like to acknowledge the support of the PetroChina Jidong Oilfield Company.

Conflicts of Interest: The authors declare no conflict of interest.
24. Wang, E.; Liu, G.; Pang, X.; Li, C.; Zhao, Z.; Feng, Y.; Wu, Z. An improved hydrocarbon generation potential method for quantifying hydrocarbon characteristics and expulsion characteristics with application example of Paleogene Shahejie Formation, Nanpu Sag, Bohai Bay Basin. *Mar. Pet. Geol.* 2020, 112, 104106. [CrossRef]

25. Wang, E.; Liu, G.; Pang, X.; Wu, Z.; Li, C.; Bai, H.; Zhang, Z. Sedimentology, diagenetic evolution, and sweet spot prediction of tight sandstone reservoirs: A case study of the third member of the Upper Paleogene Shahejie Formation, Nanpu Sag, Bohai Bay Basin, China. *J. Pet. Sci. Eng.* 2020, 186, 106718. [CrossRef]

26. Zhao, X.; Shi, Y.; Wen, W.; Li, L.; Zhang, B.; Lin, S.; Chen, G. Characteristics and genetic mechanism of high-quality clastic reservoirs in the 1st Member, Paleogene Shahejie Formation in the southern Nanpu Sag, Bohai Bay Basin. *Geol. Rev.* 2021, 67, 1373–1388. (In Chinese with English Abstract)

27. Chen, S.; Wang, H.; Zhou, L.; Huang, C.; Wang, J.; Ren, P.; Xiang, X. Sequence thickness and its response to episodic tectonic evolution in Paleogene Qikou Sag, Bohaiwan Basin. *Acta Geol. Sin.* 2012, 86, 1077–1092. [CrossRef]

28. Zhao, R.; Chen, S.; Wang, H.; Gan, H.; Wang, G.; Ma, Q. Intense faulting and downwarping of Nanpu Sag in the Bohai Bay Basin, eastern China: Response to the Cenozoic Stagnant Pacific Slab. *Mar. Pet. Geol.* 2019, 109, 819–838. [CrossRef]

29. Chen, S.; Wang, H.; Zhou, L.; Huang, C.; Ren, P.; Wang, J.; Liao, Y.; Xiang, X.; Xia, C. Recognition and depiction of special geologic bodies of Member 3 of Dongying Formation in Littoral Slope Zone, Qikou Sag. *J. Cent. South Univ.* 2011, 18, 898–908. [CrossRef]

30. Guo, Y.; Pang, X.; Dong, Y.; Jiang, Z.; Chen, D.; Jiang, F. Hydrocarbon generation and migration in the Nanpu Sag, Bohai Bay Basin, eastern China: Insight from basin and petroleum system modeling. *J. Asian Earth Sci.* 2013, 77, 140–150. [CrossRef]

31. Jiang, F.; Pang, X.; Li, L.; Wang, Q.; Dong, Y.; Hu, T.; Chen, L.; Chen, J.; Wang, Y. Petroleum resources in the Nanpu Sag, Bohai Bay Basin, eastern China. *AAPG Bull.* 2018, 102, 1213–1237. [CrossRef]

32. Wang, E.; Pang, X.; Zhao, X.; Wang, Z.; Hu, T.; Wu, Z.; Yang, J.; Feng, Y.; Zhang, Z. Characteristics, diagenetic evolution, and controlling factors of the ESL deep burial high-quality sandstone reservoirs in the PG2 oilfield, Nanpu Sag, Bohai Bay Basin, China. *Geol. J.* 2020, 55, 2403–2419. [CrossRef]

33. Zhang, C. Tectono-Sedimentary Analysis of Nanpu Sag in the Bohaiwan Basin; China University of Geosciences: Wuhan, China, 2010.

34. Hao, J.; Ke, Y.; Zhang, Y.; Ma, J.; Liu, K.; Li, B. Sedimentary system of lower member 3 of Dongying Formation in No.1 structural belt of Nanpu sag. *J. Heilongjiang Univ. Sci. Technol.* 2019, 30, 35–40. (In Chinese with English Abstract)

35. Wang, E.; Liu, G.; Pang, X.; Li, C.; Zhao, Z.; Feng, Y.; Wu, Z.; Li, C.; Bai, H.; Zhang, Z. Sedimentology, diagenetic evolution, and sweet spot prediction of tight sandstone reservoirs: A case study of the third member of the Upper Paleogene Shahejie Formation, Nanpu Sag, Bohai Bay Basin, China. *Earth Sci. Front.* 2020, 17, 1057–1068. [CrossRef]

36. Qing, Y.; Zhang, J.; Wang, H.; Tang, X.; Guo, Y. Exploration practices of lithologic reservoir of Paleogene Dongying Formation in Gaonan slope of Nanpu Sag. *Spec. Oil Gas Reserv.* 2013, 20, 48–51+143. (In Chinese with English Abstract)

37. Xu, A.; Dong, Y.; Han, D.; Yao, F.; Huo, C.; Wang, Z.; Dai, X. Integrated description and evaluation of reservoirs based on seismic, logging, and geological data: Taking Dongying Formation Member 1 oil reservoir of No. 1 structure, Nanpu Sag as an example. *Pet. Explor. Dev.* 2009, 36, 541–551. [CrossRef]

38. Lv, X. Characteristics of Sequence Stratigraphic Architecture and Its Response to Structural Activity of Dongying Formation in Nanpu Sag; China University of Geosciences: Wuhan, China, 2008.

39. Wang, H.; Zhao, S.E.; Lin, Z.; Jiang, H.; Huang, C.; Liao, Y.; Liao, J. The key control factors and petroleum and geological significance of extra-thick deposition in Dongying Formation, Nanpu Sag. *Earth Sci. Front.* 2012, 19, 108–120. (In Chinese with English Abstract) [CrossRef]

40. Folk, R.L. *Petrology of Sedimentary Rocks*; Hemphill: Austin, TX, USA, 1974.

41. Gier, S.; Worden, R.H.; Johns, W.D.; Kurzweil, H. Diagenesis and reservoir quality of Miocene sandstones in the Vienna Basin, Austria. *Mar. Pet. Geol.* 2008, 25, 681–695. [CrossRef]

42. Hamlin, H.S.; Dutton, S.P.; Seggie, R.J.; Tyler, N. Depositional controls on reservoir properties in a braided-delta sandstone, Tirrawarra oil field, South Australia. *AAPG Bull.* 1996, 80, 139–156. [CrossRef]

43. Ommer, D.; Dalland, A.; Goggin, T.P.; Hongs, B. Depositional Environment and Diagenesis of Jurassic Reservoir Sandstones in the Eastern Part of Troms I Area. In *Petro-Leum Geology of the North European Margin*; Gaonan slope of Nanpu Sag. *Spec. Oil Gas Reserv.* 2011, 1373–1388. (In Chinese with English Abstract)

44. Cade, C.A.; Evans, I.J.; Bryant, S.L. Analysis of permeability controls: A new approach. *Clay Miner.* 1994, 29, 491–501. [CrossRef]

45. Lawton, A.Y.; Worden, R.H.; Utley, J.E.P.; Crowley, S.F. Sedimentological and diagenetic controls on the reservoir quality of marginal marine sandstones buried to moderate depths and temperatures: Brent Province, UK North Sea. *Mar. Pet. Geol.* 2021, 128, 104993. [CrossRef]

46. Beard, D.C.; Weyl, P.K. Influence of texture on porosity and permeability of unconsolidated sand1. *AAPG Bull.* 1973, 57, 349–369. [CrossRef]

47. Dutton, S.P. Calcite cement in Permian deep-water sandstones, Delaware Basin, west Texas: Origin, distribution, and effect on reservoir properties. *AAPG Bull.* 2008, 92, 765–787. [CrossRef]

48. Morad, S.; Al-Ramadan, K.; Ketzer, J.M.; De Ros, I.F. The impact of diagenesis on the heterogeneity of sandstone reservoirs: A review of the role of depositional fades and sequence stratigraphy. *AAPG Bull.* 2010, 94, 1267–1309. [CrossRef]

49. Li, Q.; Jiang, Z.; Liu, K.; Zhang, C.; You, X. Factors controlling reservoir properties and hydrocarbon accumulation of lacustrine deep-water turbidites in the Huimin Depression, Bohai Bay Basin, East China. *Mar. Pet. Geol.* 2014, 57, 327–344. [CrossRef]

50. Xie, W.; Wang, M.; Wang, H.; Ma, R.; Duan, H. Diagenesis of shale and its control on pore structure, a case study from typical marine, transitional and continental shales. *Front. Earth Sci.* 2021, 15, 378–394. [CrossRef]
51. Xie, W.; Chen, S.; Vandeginste, V.; Yu, Z.; Wang, H.; Wang, M. Review of the effect of diagenetic evolution of shale reservoir on the pore structure and adsorption capacity of clay minerals. *Energy Fuels* **2022**, *36*, 4728–4745. [CrossRef]

52. Mansurbeg, H.; Morad, S.; Salem, A.; Marfil, R.; El-ghali, M.A.K.; Nystuen, J.P.; Caja, M.A.; Amorosi, A.; Garcia, D.; La Iglesia, A. Diagenesis and reservoir quality evolution of palaeocene deep-water, marine sandstones, the Shetland-Faroes Basin, British continental shelf. *Mar. Pet. Geol.* **2008**, *25*, 514–543. [CrossRef]

53. Salem, A.M.; Ketzer, J.M.; Morad, S.; Rizk, R.R.; Al-Aasm, I.S. Diagenesis and reservoir-quality evolution of incised-valley sandstone: Evidence from the Abu Madi gas reservoirs (upper Miocene), the Nile Delta Basin, Egypt. *J. Sediment. Res.* **2005**, *75*, 572–584. [CrossRef]

54. Wang, J.; Cao, Y.; Xiao, J.; Liu, K.; Song, M. Factors controlling reservoir properties and hydrocarbon accumulation of the Eocene lacustrine beach-bar sandstones in the Dongying Depression, Bohai Basin, China. *Mar. Pet. Geol.* **2019**, *99*, 1–16. [CrossRef]

55. Swanson, B.F. Simple correlation between permeabilities and mercury capillary pressures. *J. Pet. Technol.* **1981**, *33*, 2498–2504. [CrossRef]

56. Barclay, S.A.; Worden, R.H. Effects of Reservoir Wettability on Quartz Cementation in Oil Fields. In *Quartz Cementation in Sandstones*; Worden, R.H., Morad, S., Eds.; John Wiley & Sons: Hoboken, NJ, USA, 2000; pp. 103–117.

57. Ehrenberg, S.N.; Aagaard, P.; Wilson, M.J.; Fraser, A.R.; Duthie, D.M.L. Depth-dependent transformation of kaolinite to dickite in sandstones of the Norwegian continental shelf. *Clay Miner.* **1993**, *28*, 325–352. [CrossRef]

58. Thomson, A. Preservation of porosity in the deep Woodbine/Tuscaloosa trend, Louisiana. *J. Pet. Technol.* **1982**, *34*, 1156–1162. [CrossRef]

59. Yue, D.; Wu, S.; Xu, Z.; Xiong, L.; Chen, D.; Ji, Y.; Zhou, Y. Reservoir quality, natural fractures, and gas productivity of upper Triassic Xujiahe tight gas sandstones in western Sichuan Basin, China. *Mar. Pet. Geol.* **2018**, *89*, 370–386. [CrossRef]

60. Gao, Y.; Zhang, J.; Li, H.; Yu, X. Diagenesis and porosity evolution of deep Es3 2+3 Formation in Gaoshangpu Oilfield, Nanpu Sag. *Fault-Block Oil Gas Field* **2016**, *23*, 703–708. (In Chinese with English Abstract)

61. Lai, J.; Wang, G.; Ran, Y.; Zhou, Z.; Cui, Y. Impact of diagenesis on the reservoir quality of tight oil sandstones: The case of Upper Triassic Yanchang Formation Chang 7 oil layers in Ordos Basin, China. *J. Pet. Sci. Eng.* **2016**, *145*, 54–65. [CrossRef]

62. Chen, L.; Ji, H.; Zhang, L.; Jia, H.; Zhu, Y.; Fang, Z. Effect of burial processes on the evolution of organic acids and implications for acidic dissolution from a case study of the Nanpu Sag, Bohai Bay Basin, China. *J. Nat. Gas Sci. Eng.* **2017**, *39*, 173–187. [CrossRef]

63. Jin, F.; Zhang, K.; Wang, Q.; Niu, X.; Yu, Z.; Bai, G.; Zhao, X. Formation mechanisms of good-quality clastic reservoirs in deep formations in rifted basins: A case study of Raoyang sag in Bohai Bay Basin, East China. *Pet. Explor. Dev.* **2018**, *45*, 264–272. [CrossRef]