Depositional features of the Middle Jurassic formation of Field N and their influence on optimal drilling schedule

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Abstract. The Middle Jurassic formation of Field N represented by 4 hydrodynamically connected layers (J5-6, J4, J3 and J2) contains 42% of the field STOIIP. The J2-6 formation is characterized as a gas-oil-condensate massive lithologically and tectonically screened accumulation with a gas cap (J2, J3 layers) and bottom water (J5-6 layer). Oil is predominantly in the J3 and J4 layers. There is a high risk of early gas coning from gas-bearing layers to oil producing wells determined on the basis of production test results, which can significantly decrease the life of the well. To select a more optimal drilling schedule, it is necessary to take the risk of early gas coning into account and determine distinctive features within the gas-saturated zone that can reduce it. The presence of a thick shale barrier between the J2 and J3 layers with thicknesses varying from 0 to 30 m is recognized as the beginning of a transgression cycle, and if the gas cap is only in the J2 layer, this barrier with the thickness of more than 5 m can extensively prevent early gas coning into oil producing wells. The integration of geological information represented by the probability map constructed and petrophysical information represented by the \( kh \) map provide the more precise determination of an optimal drilling schedule.

1. Introduction

Field N is the one of the largest gas-oil-condensate fields on the Yamal Peninsula that was discovered in 1964 and has not been developed yet. Field N comprises 19 hydrocarbon-bearing formations within which the J2-6 formation of the Middle Jurassic age contains 42% of the STOIIP and is the target object of this study. This formation is described as a tectonically and lithologically screened united stratified massive accumulation with a gas cap and bottom water and characterized by the high level of compartmentalization due to the presence of discontinuous shale streaks.

Gas coning is the critical issue for oil wells with a gas cap drive, and in the case of early gas invasion, associated gas production increases and consequently the life of this well shortens. Gas invasion can be inhibited by a natural barrier and its distribution depends on a depositional environment. Consequently, the determination of depositional environments of sediments, recognition of typical facies that control such geological features as compartmentalization and the presence of impermeable barrier can help choose the most appropriate areas for drilling where the risk of gas coning is minimal and hence can extend the production life of a field.

This paper implies the following order: providing general information about the field and target object, determining the depositional environment, defining distinctive geological features and their influence on the risk of gas coning with a gas invasion probability map, integrated analysis of the \( kh \)
map and the probability map with determining the optimal field drilling schedule and evaluating the main uncertainties and recommendations on how to reduce them.

2. General information
Geographically, the field is located in the southeast part of the Yamal Peninsula, Yamal-Nenets Autonomous District, Western Siberia. Field N was discovered in 1964. The geological section of the field is comprised of Pre-Jurassic basement rocks and Jurassic, Cretaceous, Paleogene and Quaternary sedimentary rocks. The sediments of the J2-6 layer are referred to the Middle Jurassic Leontyevskaya and Malyshevskaya formations and were accumulated in a transition coastal marine environment.

The area of the field is located within the Novoportovskoe crestal location that commands a large share of similarly-named second-order structures that are, in turn, part of the higher first-order structure of the South-Yamal megalithic bank. The top of the Middle Jurassic formation has absolute elevations from -1,870 to -2,240 m and is complicated by four crestal locations (figure 1). There are many multi-directional faults and cracks of various amplitudes within the field area being sufficient for screening the Jurassic formation. The basic fault indicated on the seismic time section from the basement to the Lower Cretaceous sediments separates the area of the field into eastern and western parts.

As for the field hydrocarbon potential, Field N is located in the South-Yamal petroleum bearing region of the Yamal petroleum area in the Western Siberian petroleum province. The J2-6 hydrocarbon reservoir of the Middle Jurassic age is referred to the second hydrocarbon-saturated zone and contains 42% of the STOIIP. In compliance with the fluid content, the J2-6 formation is described as a gas-oil-condensate accumulation with a gas cap and bottom water.

Basically, the Middle Jurassic formation is characterized as a massive lithologically and tectonically screened accumulation consisting of J2, J3, J4 and J5-6 layers being hydrodynamically connected and having common GOC and WOC. Gas is contained in J2 and J3 layers, oil – predominantly in J3 and J4, whereas, J5-6 is a water-bearing layer (figure 2).

![Figure 1. Structural map of J2 top. Field N](image-url)
3. Deposition environment determination
According to the structural and lithological features distinguished within the core, three main lithotypes can be recognized for the J4 and J3 layers. Typical structures and features are illustrated in figure 3.
Lithotype 1 is represented by medium to fine sandstone with argillaceous and calcite cement. There are mud clasts and clasts of siderite and traces of slump at the bottom of the sediments (figure 3, a) and an upward change in the structure from large cross-bedding to current ripples and herringbone stratification (figure 3, b). Double mud drapes can be recognized and indicate tidal activity (figure 3, c) [3]. There is also the bioturbation of sediments (figure 3, d) at the top and the upward trend towards an increase in the shale content (probably, channel abandonment). Ichnofacies recognized in the core is referred to Scolithos and indicates marine conditions of sedimentation [4]. Also, there are plant debris within the core samples. Lithotype 2 is characterized by the interbedding of sandstone and siltstone with the abundance of a lenticular, wave and flaser structure and mudstone with a planar structure (figure 3, e). Besides, the sediments of Lithotype 2 are highly bioturbated. The change in lithology and typical structures indicate a condition with a frequent variation from a passive environment to the high activity of currents. Lithotype 3 is represented by the thin interbedding of shale, siltstone and sandstone with bioturbation and a planar-bedding structure (figure 3, f) and indicates little or no current activity.

The sediments of the J2 layer can be divided into two types: grey to green marine shale (lithotype 4), thin interbedding of siltstone, sandstone and mudstone highly reworked by the storm activity with high bioturbation and a lenticular and wavy structure and the presence of such ichnofacies as scolithos and palaeophicus that shows a marine environment (lithotype 5). Figure 4 illustrates the basic features of the J2 lithotypes.

Figure 3. Typical sedimentary structures and features of J4 and J3
Figure 4. Typical sedimentary structures and features of J2

For the recognition of log motif types, the shape of an SP curve is chosen due to the fact that GR does not illustrate the change in the lithological composition sufficiently, as the shape of resistivity curves is subjected to the influence of hydrocarbons. In compliance with the lithotypes identified within the J4, J3 and J2 layers, four main types of log motifs (electrofacies) based on the shape of the SP curve can be recognized. Type 1 electrofacies is referred to Lithotype 1 and characterized by a predominantly square shape with a sharp horizontal base that gives evidence of erosion in the underlying sediments, a gently or slightly notched vertical curve and gently decreasing top that indicates a change in the size of grains and an increase in shale components in the sediments. Such a shape of the SP curve is typical of channel facies. The standard value of $\alpha_{SP}$ for this electrofacies is 1.0-0.6. Electrofacies 2 is described by the shape of a rectangular triangle with the high level of notch that can be explained by the frequent variation of sandstone and mudstone, the maximum value of $\alpha_{SP}$ is equal to 0.4-0.6. This electrofacies is characterized by the high intensity of compartmentalization due to the frequent changes in conditions from active to passive and typical of Lythotype 2. Electrofacies 3 is characterized by the high level of notch with the maximum value of $\alpha_{SP}$ equal to 0.2-0.3. Such a type of an SP curve shape is typical of Lithotypes 3 and 4. Electrofacies 4 describes the presence of Lithotype 5 within J2 and is characterized by an upward coarsening trend, often has an oblique notch side line. The value of $\alpha_{SP}$ varies from 0.6 to 0.8.[2].

On the basis of the lithotypes distinguished from the core data, log motifs and main vertical trends, the following conclusions about facies and depositional environments can be made.

The sediments in the J4 and J3 layers have similar typical features and are characterized by Lithotypes 1, 2 and 3. There are traces of tidal activity represented by the herringbone structure and mud drapes within Lithotype 1 that can be interpreted as a tidal channel and is characterized by a small thickness, however, with a high level of amalgamation [1]. Away from the areas of strong tidal currents, there are tidal mudflats (Lithotype 3). The succession is predominantly of mud with thin sand sheets present if very high tides or storms were washing the coarser material across the flats. The evidence of vegetation is normally abundant. The same is relevant to bioturbation by the fauna living on the nutrient-rich mudflats [3]. Also, the interdistributary bay facies (Lithotype 2) is widely
developed within the area of the field. The dominant position of the lenticular to wavy structure identifies the features of distributary bay sediments. With due account of these features, the sediments of the J4 and J3 layers are referred to as tidal-dominated delta deposits. Tidal processes form sandbodies being parallel to the directions of the tidal currents; they are roughly perpendicular to the regional shorelines [7]. Figure 5 illustrates the modern analog of a tidal-dominated delta.

![Tidal-dominated delta in Papua New Guinea](image)

**Figure 5.** Tidal-dominated delta in Papua New Guinea (according to Boyd)

There is a shale barrier between J3 and J2 sand bodies that indicates a rise in the sea level. The J2 layer is represented by rare sand lenses within the shale background and is interpreted as tempestites (Lithotype 5) – sands reworked by the storm activity. The abundance of marine bioturbation including phycosiphon and paleophicus ichnfacies indicates that they are probably shallow marine tempestites. These sediments are usually characterized by the presence of hummocky cross stratification as the most distinctive feature, but since this structure is big-sized, it is difficult to recognize it within the core data [4]. These marine sediments indicate the beginning of a transition cycle.

In case of vertical facies distribution, the following features can be distinguished. There is a frequent variation of muddy flat, channel and interdistributary bay facies in the vertical direction. The channel facies has a significant thickness varying from 5 to 30 m due to the vertical accretion and amalgamation of the channels. Thin shale laminae within the channel facies are interpreted as a boundary between the channels, and these facies are usually interchanged by interdistributary bay facies or muddy flat facies that can indicate channel abandonment. The proportional quantity of interdistributary bay and muddy flat facies increases at the top of the J3 layer.

It is necessary to point out that there is shale barrier between the J3 and J2 sediments with a thickness varying from 0 to 30 m. This shale is recognized as marine and can be interpreted as the indicator of transgression beginning. With due account of the vertical trends that are recognized in the correlation panel, it can be concluded that the traces of continental and marine depositional conditions exist simultaneously and the main trend towards a change from a more continental to a more marine environment is distinguished.

Laterally, there are the following trends: within the J4 and J3 layers, channel facies and interdistributary bay facies are predominant. The orientation of the channel facies distribution is from the west-southwest to the east-northeast that corresponds to the main source area location. The J2 layer is characterized by the presence of rare sand lenses within a marine shale background (figure 6).
4. Determining an optimal drilling schedule

Gas coning is the critical issue for oil wells with a gas cap drive, therefore, the main problem for the cost-effective development of Field N is the high risk of early gas coning and selecting such a drilling schedule that takes it into account and reduces the risks of early gas invasion. Reservoir sand continuity, the presence and distribution of continuous and discontinuous barriers, the level of compartmentalization are referred to a distinctive geological feature that can reduce the risk of gas coning in some way, they are controlled by the depositional environment and facies distribution. Therefore, apart from the STOIIP quantity and reservoir quality, to choose the most optimal drilling schedule, it is necessary to take into account the geological features of the identified facies that can be a possible constraint to gas invasion and reduce the risk of coning.

As it has already been mentioned, three reservoir facies and two non-reservoir facies can be distinguished within the gas-bearing zone including the J3 and J2 layers.

J3 is characterized by the variation of tidal channels and interdistributary bay reservoir facies that can contain hydrocarbons. The non-reservoir facies is rare within J3. There is a tempestite facies represented by rare lenses within the J2 shale background.

From the petrophysical point of view, the facies identified have relatively similar petrophysical properties. There is a difference in the lithological composition between the reservoir facies of the J3 layer controlled by the conditions of a depositional environment. The channel facies is represented by sandstone with the absence or rare thin layers of carbonate sediments or siltstone indicating channel abandonment by the finer-grained material that can be reworked by the next stage channel activity, while the interdistributary facies is characterized by the high level of compartmentalization represented by the interbedding of sandstone, siltstone and mudstone accumulated during the slack periods of the tidal cycle. The big number of mudstone layers in the interdistributary bay facies can prevent or deter a vertical flow between reservoir compartments. Where these layers are
discontinuous, they act as baffles for flow, and hence, the probability of early gas coning through this facies is lower vs. in case of the channel facies [6]. The net to gross ratio is the quantitative representation of shale presence. The channel facies is characterized by a range of NTG from 0.46 to 1, while the measured value of NTG for the interdistributary bay facies varies from 0.20 to 0.58.

It is necessary to point out another important geological feature of the Middle Jurassic sediments accumulation: there is an explicit continuous shale barrier between the J2 and J3 layers indicating the beginning of a transgression cycle and separating the tempestites of J2 from the reservoir facies of J3. In the case when gas is contained only in J2, this shale plays the role of a barrier that can prevent gas coning. The thickness of the shale barrier varies from 0 to 30 m within the area of the field. This shale is not a hydrodynamic barrier for J2 and J3 accumulation due to the connectivity between these layers where the thickness of the barrier is small and the shale is discontinuous.

In compliance with the identified geological features that can potentially reduce the risk of early gas invasion, a gas coning probability map can be created. When gas is only in the J2 layer, the shale barrier indicating a transgression cycle can prevent gas invasion from J2 to oil-bearing J3. Figure 7 demonstrates the thickness map of the shale barrier between the J2 and J3 layers. The critical value of the shale thickness above which the risk of early gas coning is minimal depends on such factors as drawdown pressure that can vary during field development. Thus, it is assumed that the critical value is equal to 5 m, this choice will be explained later.

Figure 7. Shale barrier thickness map

When gas is contained in J2 and J3 (the predominant part of the field), the main factor influencing the risk of gas coning is the presence and distribution of discontinuous shale within the gas-saturated zone. To determine a zone with the minimal risk of gas coning, an NTG map above GOC is created (figure 8). Critical values for zonation of the NTG map according to the level of gas coning probability are chosen on the basis of the production test results for appraisal wells. In compliance with the
production test results, it can be concluded that when gas is in the interdistributary bay facies characterized by the low value of NTG, gas rates from the perforated oil zone are minimal or absent (the low value of GOR near the gas solubility), while when gas is in the channel facies with high NTG, there are high gas rates and, consequently, the high value of GOR (up to 5,000). The integrated analysis of the production test results and NTG values allows determining the critical values of NTG for each facies. For the interdistributary bay facies, the maximum value at which there is no gas coning is equal to 0.40. For the channel facies, the critical value is equal to 0.53, which means that there is the high probability of gas coning above this value (figure 9). As for well 167 with NTG being 0.40, the thickness of shale is equal to 5 m, and it is enough for preventing early gas coning. Due to the absence of other data that could characterize the critical thickness of the shale barrier in the J2 layer, this value is assumed as a limit for a ranging area in accordance with the thickness of shale barrier. Figure 10 illustrates the ranging of the territory by the level of gas coning probability according to the determined critical value of NTG and the thickness of the shale barrier. Red color illustrates the areas where the risk of gas invasion is lowest, blue color – highest.

Figure 8. NTG map of J3 gas bearing zone
Figure 9. Results of production tests for appraisal wells

Figure 10. Gas coning probability map

Usually the most optimal drilling schedule is determined on the basis of kh maps that indicate the quantity of STOIIP and reservoir quality simultaneously. When it comes to Field N, one of the basic criteria for selecting a schedule is the quantity of both gas and oil. In compliance with that, a kh map
for the oil-bearing and gas-bearing zone was reconstructed. The net gas thickness map was created on the basis of seismic (correlation with a dynamic attribute) and well data. The net oil thickness map was created on the basis of only well data. To determine permeability maps, porosity maps reconstructed with Gaussian simulation based on the variogram analysis results and poroperm relationship from the core data were used. Figure 11 demonstrates the mapping results for the oil-saturated and gas-saturated zones.

Figure 11. Kh map above GOC (left) and below GOC (right)

The complex analysis of the obtained data, including the kh maps of gas-bearing and oil-bearing zones, and the gas coning probability map, allows determining the most optimal drilling schedule that takes into account the qualitative characteristic of STOIIP indicated by the kh-values, gas cap thickness and the risks of gas invasion into a production well that considerably reduces oil production. As it can be seen from figure 12 that illustrates the results of mapping with an identified promising area for drilling, such a factor as the probability of gas coning plays the role of a controlling factor for taking the final decision. Conditionally, the territory of the field can be divided into three parts: the southern and northern parts being promising for oil production and the central part that is not promising due to the significant thickness of the gas cap and small effective oil thickness. The most promising territory for field development beginning is the southern part and Area 1 where the following factors can be recognized simultaneously: a gas cap is absent or has an insignificant thickness, there is a large anomaly on the kh map below GOC that is the evidence of the high value of STOIIP and improved reservoir quality, the probability of early gas coning is extremely low due to the domination of the interdistributary bay facies. Area 2 is characterized by the presence of a gas cap, but this gas is predominantly in the interdistributary bay facies that implies the low risk of gas coning. The least promising area within the southern part of the field is Area 3, despite the fact that there is
sufficient STOIIP and the quantity of gas is the same as for Area 2. Because of the development of the channel facies within this area, and, consequently, the high probability of gas invasion, only the oil reservoir on the edge is promising, as there gas is in the J2 layer that is characterized by the presence of a shale barrier being thick enough to prevent gas invasion.

Within the northern part of the field, there are two promising areas that were also chosen because of the most optimal combination of the smaller gas thickness, sufficient oil thickness and reservoir quality, and the lowest probability of gas coning.

### 4. Main uncertainties and recommendations

In compliance with the identified geological features that control the risk of gas coning, the following main uncertainties can be recognized.

Firstly, it is the critical value of NTG that depends on facies determination and production test results. The facies were determined manually and subject to the interpreter’s opinion. Besides, there is no explicit discrimination between the values of NTG for a particular facies and the typical ranges are overlapped. The production tests results also imply uncertainty connected with the intervals of perforation. In addition, as it has already been mentioned, the largest value of NTG at which there is no gas production is equal to 0.4, while the lowest value of NTG for the channel facies at which gas invasion occurs is 0.52, so the range of 0.4 to 0.52 comprises values for which there are no production test results and it can indicate the presence or absence of gas coning with equal probability. In this study, the value of critical NTG equal to 0.52 was used as an optimistic scenario, as it is assumed that the channel facies cannot prevent gas invasion sufficiently and the range of NTG typical of this facies is 0.46-1, which does not include the pessimistic critical value of 0.40. Figure 13 illustrates a probability map with the critical value of 0.4. It should be noted that the most promising area (Area 1) does not change, while there is a reduction in the territory within Area 2. The territory of the area within the northern part of the field is also decreasing. As a recommendation for uncertainty reduction, it is necessary to perform production tests for newly drilled wells in order to determine the critical value of NTG more precisely.
The second uncertainty is shale barrier thickness. The change in the critical value by 10% does not have a significant impact and there is only a small area with the high risk of gas coning. Basically, the critical value of thickness depends on certain conditions of field development, including the value of drawdown pressure. With due account for this fact, it is recommended to find a correlation between the critical barrier thickness at which gas invasion is prevented and the drawdown pressure.

Figure 13. Probability map of gas coning with the critical value of NTG=0.4

4. Conclusions
To determine an optimal drilling schedule, it is necessary to take the risk of early gas coning into account. The classical usage of the kh map for determining an optimal drilling procedure cannot predict the places where the gas coning probability is minimal to the full extent. Thus, the recognition of a depositional environment in order to distinguish geological features that can significantly reduce the risk of gas invasion was carried out. The J4 sediments saturated with predominantly oil and the J3 sediments containing oil and gas are interpreted as tidal-dominated delta sediments and the reservoir is represented by two facies: channel facies and interdistributary bay facies. J2 is represented by the rare sand lenses of tempestites within a marine shale background.

The presence of discontinuous shale in the interdistributary bay facies characterized by the low value of NTG (0.2-0.58) can prevent or inhibit early gas coning. Also, there is a shale barrier between the J3 and J2 layers. The results of the production tests for appraisal wells confirm the conclusion that the interdistributary bay is able to prevent the risk of early gas coning. The critical value of NTG that divides the territory of the field into areas with the high and low probability of gas coning was determined on the basis of the production test results and data on the NTG value for the facies. It varies from 0.4 to 0.52.

To determine the most optimal drilling schedule, the kh maps and the gas coning probability map were used. This integrated analysis allows determining that Area 1 is most appropriate for field development beginning, as it is simultaneously characterized by the high quantity of STOIIP and the best reservoir quality, a small gas cap and the low probability of early gas coning.
An uncertainty analysis was also performed. There are two main uncertainties connected with the critical values of NTG and the shale barrier thickness that are used for probability map reconstruction. This map is very sensitive to the critical value of NTG. There is a sufficient reduction in the territory where the risk of gas coning is minimal based on the probability map with the critical value of NTG being equal to 0.40. It is recommended to perform production tests for the newly drilled wells with the purpose of determining the critical value of NTG more precisely.

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