Petroleum resource assessment of the East Greenland Basin

LI Bin1,2, LIU Chenglin1,2*, ZHAO Yue3, HONG Weiyu1,2, PING Yingqi1,2 & LIANG Dexiu1,2

1 State Key Laboratory of Petroleum Resource and Prospecting, China University of Petroleum, Beijing 102249, China; 2 College of Geosciences, China University of Petroleum, Beijing 102249, China; 3 Institute of Geomechanics, Chinese Academy of Geological Sciences, Beijing 100081, China

Received 25 June 2017; accepted 30 December 2017

Abstract The onshore and offshore parts of the East Greenland Basin are important areas for petroleum exploration at the North Pole. Although assessments by the US Geological Survey suggest a substantial petroleum potential in this area, their estimates carry a high risk because of uncertainties in the exploration data. This paper compares the reservoir-forming conditions based on data from the East Greenland Basin and the North Sea Basin. The petroleum resources of the East Greenland Basin were assessed by geochemical and analogy methods. The East Greenland Basin was a rift basin in the late Paleozoic–Mesozoic. Its basement is metamorphic rock formed by the Caledonian Orogeny in the Archean to Late Ordovician. In the basin, Devonian–Paleogene strata were deposited on the basement. Lacustrine source rock formed in the late Paleozoic and marine source rocks in the Late Jurassic. Shallow-marine sandstone reservoirs formed in the Middle Jurassic and deep-marine turbiditic sandstone reservoirs formed in the Cretaceous. The trap types are structure traps, horst and fault-lock traps, salt structure traps, and stratigraphic traps. The East Greenland Basin possesses superior reservoir-forming conditions, favorable petroleum potential and preferable exploration prospects. Because of the lack of exploration data, further evaluation of the favorable types of traps, essential amount of source rock, petroleum-generation conditions and appropriate burial histories in the East Greenland Basin are required.

Keywords East Greenland Basin, North Sea Basin, stratigraphy, analogy method, resource assessment


1 Introduction

In 2007, the US Geological Survey (USGS) released the results of North Pole petroleum resources evaluation, covering a total of 33 basins. Estimates of the undiscovered resources in the North Pole region amount to $9 \times 10^{10}$ barrels of oil, $1.669 \times 10^{15}$ cubic feet of gas and $4.4 \times 10^{10}$ barrels of condensate gas; 84% of these petroleum resources are in marine areas. The East Greenland Basin is very rich in petroleum resources, accounting for 10%, 5% and 18% of the total oil, gas and condensate gas of the North Pole petroleum resources, respectively (Zhao et al., 2014; Gautier, 2007). In the northeastern part of Greenland, resin-rich, high-sulfur coal was found, which confirmed the hydrogen index of up to 700 units of high-quality source rock (Bojesen-Koefoed et al., 1999). However, the East Greenland Basin has not been thoroughly explored, with only a few wells providing exploration data. The degree of exploration has a great influence on resource assessment; therefore, it is important to study the petroleum resource potential of the poorly explored East Greenland Basin.

* Corresponding author, E-mail: 851887838@qq.com
Resource assessment methods have developed rapidly since the 1950s, because of the increased demand for petroleum products worldwide. From statistical forecasting in the 1950s to basin modeling in the 1980s, to the development of expert systems and decision analysis in the 1990s, petroleum resource assessment has become an established research field with advanced assessment theories and many assessment methods. In this study, the petroleum resources of the East Greenland Basin were analyzed by reviewing the geological characteristics of the basin presented in previous studies and using petroleum geology analysis methods. The petroleum resources in the East Greenland Basin were evaluated by using the North Sea Basin as an analogy scaled area, and the petroleum potential was analyzed to determine the relevant geological background of the East Greenland Basin.

2 Structural background

Greenland, the largest island in the world, belongs to Denmark. The island is located in the Arctic Circle, close to the northeastern coast of North America, the Arctic Ocean and the Atlantic Ocean. Greenland has an area of about 2.16 × 10^6 km², most of it covered by inland ice, ice sheets and glaciers. The East Greenland Basin is located between 60°N and 80°N, with an area of about 3 × 10^5 km², accounting for 13.9% of Greenland's total area (Figure 1). The USGS divides the East Greenland Basin into seven tectonic units: the North Danmarkshavn Salt Basin, the South Danmarkshavn Basin, the Thetis Basin, the Jameson Land Basin, the Liverpool Land Basin, the Jameson Land Basin Subvolcanic Extension and the Northeast Greenland Volcanic Province (Figure 2).

The tectonic pattern of the East Greenland Basin is dominated by the evolution of the North Atlantic (Feng et al., 2013). The dominant tectonic feature in East Greenland is the Caledonian orogen, part of the 6000-km-long Caledonian–Appalachian orogenic belt, the original width of which is estimated to have been 700–800 km in the North Atlantic region (Schiffer et al., 2014). The opening of the North Atlantic region was one of the most important geodynamic events that shaped the present-day passive margins of Europe, Greenland and North America (Schiffer et al., 2017). The initiation of the Atlantic rift system between Greenland and Norway that run eastwards through the North Greenland and Spitsbergen to the Sverdrup Basin, took place during the latest Devonian and earliest Carboniferous (Stemmerik et al., 1991). This latest Devonian–early Carboniferous rift pulse was characterized by non-marine sedimentation in narrow, isolated half-grabens. The rifting is well documented in East Greenland, Spitsbergen and Bjørnøya, where sedimentation started during the latest Devonian, and in eastern North Greenland, where sedimentation began in the Visean (Stemmerik, 2000; Stemmerik et al., 1991).

In the North Sea and Norwegian Sea, crustal movements that had begun in the late Permian continued into the Early Triassic (Ziegler et al., 1982). During the Triassic, Pangea started to fragment, and the Tethys Ocean opened in a westerly direction from the present-day Middle East and separated the new Europe from Africa (Nøttvedt et al., 2008). During Early and Middle Jurassic times, the rift axis propagated progressively northwards, with formation of the central Atlantic Ocean. In the Late Jurassic, seafloor spreading in the Mid-Atlantic progressed north-eastwards, leading to major rifting between East Greenland and Norway, with a branch extending southwards into the North Sea (Peace et al., 2016). Following the earliest Cretaceous South Atlantic opening, break-up and seafloor spreading progressed into the North Atlantic between Europe and North America in the Late Cretaceous, and culminated with continental separation and formation of the Norwegian and Greenland seas in the early Cenozoic.

In the Paleogene, breakup of the Greenland region occurred in three stages: (1) Paleocene separation between North America and Greenland, which was still attached to Eurasia; (2) continued separation between Greenland and North America during the Eocene, at the same time as separation between Eurasia and Greenland (with Greenland moving as a separate plate); and (3) continued separation between Eurasia and Greenland since the Oligocene, with the latter attached to North America (Peace et al., 2017; Mjelde et al., 2008). Cenozoic compressional structures constitute potential hydrocarbon traps, either as four-way dip closures or closure along-strike of pre-existing fault blocks and terraces, which are potential targets for petroleum exploration (Dore et al., 1996).

3 Stratigraphy

The post-Caledonian geology of East Greenland comprises a nearly complete succession of Devonian to Upper Cretaceous strata deposited in continental to deep-marine environments. These strata are unconformably overlain by Paleocene–Eocene sediments (Larsen et al., 2014; Noehr-Hansen et al., 2011; Jolley and Whitham, 2004), which are more regionally overlain by Eocene tholeiitic plateau basalts (Pedersen et al., 1997; Hald, 1996; Upton et al., 1980). Figure 3 shows the distribution of stratigraphic units in East Greenland between latitudes 71°N and 74°N.

Devonian strata in the Traill Ø (Traill Island) region are exposed at the western end of Traill Ø and Geographical Society Ø. These strata belong to the Kap Kolthoff and Celsius Bjerg Groups (Olsen et al., 1993). They have a minimum thickness of 2700 m and were deposited in a fluvial–lacustrine environment. This unit comprises sandstone and conglomerate, siltstone, shale and volcanic rock. The base of the unit is not exposed (Larsen et al., 2008; Clack and Neininger, 2000; Olsen et al., 1993; Surlyk, 1990).

Figure 2  Tectonic units of the East Greenland Basin. The solid brown line outlines the East Greenland Basin; the green lines indicate unit boundaries (Gautier, 2007).
Carboniferous strata exposed in the western parts of Traill Ø and Geographical Society Ø belong to the Traill Ø Group (Vigran et al., 1999). They have a minimum thickness of 3000 m and were deposited in alluvial-fan, fluvial, alluvial-plain and lacustrine environments. The unit consists largely of sandstone and mudstone, coal, and conglomerate. The basal contact is an angular unconformity with the Devonian strata (Surlyk, 1990; Surlyk et al., 1986).

Permian strata of the Foldvik Creek Group (Christiansen, 1990), with a thickness of 90–125 m, are exposed on central Traill Ø. Deposited in a marine environment, this unit consists of conglomerate, sandstone, mudstone, carbonates and evaporites. The basal contact has a 4°–12° angle with the underlying Carboniferous strata (Stemmerik et al., 2001; Christiansen, 1990; Surlyk, 1990; Clemmensen, 1980).

Triassic strata are found across central Traill Ø and in Tvaerdal and around Laplace Bjerg on Geographical Society Ø (Parsons et al., 2017). This unit has a thickness of ≥ 1800 m; this is a minimum estimate because a complete section of the entire group has not been observed (Bjerager et al., 2006). This unit consists of mudstone and sandstone overlain by gypsiferous mudstone and sandstone. The basal contact is observed on Traill Ø and is conformable with the underlying Permian strata (Parsons et al., 2017; Decou et al., 2016; Andrews et al., 2014; Stemmerik et al., 2001; Surlyk, 1977).

The Jurassic strata in this region consist of the Jameson Land Group overlain by the Hall Bredning Group. The Jameson Land Group is found across Traill Ø and Geographical Society Ø (Therkelsen and Surlyk, 2004; Engkilde and Surlyk, 2003; Price and Whitham, 1997). This group has a combined maximum thickness of between 990 m (Bjerager et al., 2006) and 1790 m (Birkelund and Callomon, 1985) and consists of sandstone, mudstone, subordinate conglomerate, shale and coal. The Jameson Land Group was deposited in fluvial and shallow-marine environments. The Hall Bredning Group is exposed in eastern Traill Ø, the exposed sections have a maximum thickness of 300 m. This unit consists of black, micaceous, organic-rich shale with subordinate sandstone. The basal contact is conformable with the Jameson Land Group (Vosgerau et al., 2004; Engkilde and Surlyk, 2003; Whitham et al., 1999; Birkelund and Callomon, 1985; Donovan, 1957).

Cretaceous strata are found in the northern part of the Traill Ø region, in Hold with Hope. This unit has a minimum thickness of 2400 m. The strata were deposited in a continental–marine environment. This unit consists of black mudstone with subordinate sandstone and conglomerates. The basal contact is conformable with the Jurassic strata (Engkilde and Surlyk, 2003; Donovan, 1957).

Figure 3  Geological map of the area between Jameson Land and Clavering Ø. The inset map shows major structural elements in the Traill Ø area. TRZ: Tvaerdal relay zone; MRZ: Månedal relay zone; SBRZ: Svinhufvud Bjerge relay zone (Stemmerik et al., 1997).

4 Assessment methods and processes

Analogy, genetic and statistical methods are the most commonly used petroleum resource assessment methods (Zhang et al., 2014). The analogy method is often used in less-explored areas such as the East Greenland Basin. The analogy method is carried out as follows: statistical analysis of the geological parameters of mature oil and gas exploration areas analogous to the prospective areas is conducted; the analogy factor is determined through various scores; and the petroleum resources are estimated. In this study, the analogy method was used to calculate the amount of petroleum resources in the East Greenland Basin.

When using the analogy method, we must first understand the geological conditions in the assessment area to select an analogous scaled area. The scaled area can be used as an assessment area analogy standard for the evaluation of the basic geological unit when we evaluate the petroleum resources (Guo et al., 2006; Hu et al., 2005). The selection of the scaled area is an important step that directly affects the outcome of the assessment. The scaled area should be well-explored with extensive geological data and contain large amounts of confirmed petroleum resources. After selecting the scaled area, a comprehensive investigation is performed to determine the oil geology conditions, the correlation coefficients of the resources and the amount of resources in the scaled area. Based on this information, the petroleum conditions in the assessment
Petroleum resource assessment of the East Greenland Basin

area are investigated and studied. The geological parameters and petroleum conditions of the assessment area and the scaled area are summarized and categorized, then the parameters are scored according to the unified analogy standard, and the analogy coefficient between the scaled area and the assessment area is obtained. The amount of resources in the assessment area is calculated using the resource abundance and other correlation coefficients of the scaled area. Finally, the data are summarized, and the results are obtained (Liu et al., 2012; Zhao et al., 2005; Zhou et al., 2005). The formula is as follows (Liu et al., 2012):

\[ Q = S \times \sum_{i=1}^{n} \left( \frac{K_i \times a_i}{n} \right) \]

- \( Q \): amount of resources of the assessment area (unit: \(10^8\) boe),
- \( S \): area of the assessment area (unit: \(10^4\) km²),
- \( K_i \): resource abundance of the scaled area (unit: \(10^4\) boe·km\(^{-2}\)),
- \( a_i \): analogy coefficient,
- \( a_i = \frac{\text{analogy total scores of the assessment area}}{\text{analogy total scores of the scaled area}} \)

5 Establishing the scaled area

Based on the selection criteria mentioned above and the tectonic evolution characteristics, we selected the North Sea Basin as the scaled area in this analogy assessment.

5.1 Geological location

The North Sea Basin is on the western side of Europe, with the Norwegian Sea to the north, the Strait of Dover to the south, and the Shetland Islands to the northwest. The North Sea Basin is surrounded by the United Kingdom, Denmark, Norway, Holland, Germany, France and Belgium, and covers an area of about \(57.5 \times 10^4\) km². Based on global tectonics, the early North Sea Basin is a late Paleozoic rift basin that evolved into a Paleogene–Neogene basin after a prolonged geological process (Ye and Yi, 2004). The basin is situated on the northwest Europe Craton, and can be divided into multiple tectonic units (Figure 4).

5.2 Hydrocarbon distribution characteristics

At the end of 2009 there were 1731 petroleum fields in the North Sea Basin (Stemmerik et al., 1997). The proven reserves of petroleum are about \(1504.26 \times 10^8\) boe; of these, \(994.17 \times 10^8\) boe are in the northern North Sea Basin and \(510.09 \times 10^8\) boe are in the southern North Sea Basin, accounting for 66.1% and 33.9% of the total reserves, respectively (Table 1). Classifying reserves by the hydrocarbon type, the North Sea Basin oil reserves are \(608.00 \times 10^8\) boe while the gas reserves are \(851.10 \times 10^8\) boe.

Figure 4 Schematic map of the principal geological structures of the North Sea Basin (Zabanbark, 2012).

5.3 Petroleum geological conditions

5.3.1 Source rocks

The most widely distributed source rocks in the northern North Sea Basin are the Upper Jurassic Kimmeridge Clay Formation shales, which are a set of marine source rocks that occur over the entire area (Yang et al., 2014; Yang et al., 2011; Ye and Yi, 2004; Cooper et al., 1995). The Upper Jurassic sequence contains another set of source rocks, the Heather Formation shales, with a more limited distribution than that of the Kimmeridge Clay Formation shales. The main kerogen in the Kimmeridge Clay Formation and the Heather Formation is type II and the average total organic carbon (TOC) value is 2%.

The source rocks of the southern North Sea Basin are Carboniferous Westphalian coal-bearing strata and are the most important source rocks in this area (Keym et al., 2006; Gormly et al., 1994). The TOC of the coal beds is more than 60%; the shale layers contain mainly type III kerogen and >1% TOC; the average TOC is 75% overall (Zhang et al., 2011; Li and Jin, 2005; Kubala et al., 2003; Leeder and Hardman, 1990). The vitrinite reflectivity (Ro) is up to 1.5% and the maturity decreases from the center of the basin to the margin (Kubala et al., 2003). Ro of the Westphalian coal-bearing source rocks in the southern North Sea Basin is generally more than 2% (Doomenenbal and Stevenson, 2010). Based on the maturity of the source
rocks, the northern North Sea Basin mainly generated oil and the southern North Sea Basin mainly generated gas.

Table 1 Distribution of proven hydrocarbons in the North Sea Basin (Yang et al., 2014)

<table>
<thead>
<tr>
<th>Tectonic division</th>
<th>Geomorphology</th>
<th>Number of oil and gas fields</th>
<th>Oil Reserves /(%(×10^8 t)</th>
<th>Oil Occupancy /%</th>
<th>Gas Reserves /(%(×10^8 m^3)</th>
<th>Gas Occupancy /%</th>
<th>Oil equivalent Reserves /(%/(×10^8 boe)</th>
<th>Oil equivalent Occupancy /%</th>
</tr>
</thead>
<tbody>
<tr>
<td>The northern North Sea Basin</td>
<td>Viking Graben offshore</td>
<td>254</td>
<td>37.86</td>
<td>40.8</td>
<td>20446</td>
<td>16.4</td>
<td>412.39</td>
<td>27.4</td>
</tr>
<tr>
<td>Central Graben offshore</td>
<td>242</td>
<td>26.58</td>
<td>28.7</td>
<td>13605</td>
<td>10.9</td>
<td>284.55</td>
<td>18.9</td>
<td></td>
</tr>
<tr>
<td>Moray Firth Basin offshore</td>
<td>101</td>
<td>9.33</td>
<td>10.1</td>
<td>2511</td>
<td>2.0</td>
<td>84.95</td>
<td>5.6</td>
<td></td>
</tr>
<tr>
<td>Horda Platform offshore</td>
<td>38</td>
<td>9.57</td>
<td>10.3</td>
<td>14844</td>
<td>11.9</td>
<td>168.08</td>
<td>11.2</td>
<td></td>
</tr>
<tr>
<td>Other areas offshore</td>
<td>53</td>
<td>4.08</td>
<td>4.4</td>
<td>2151</td>
<td>1.7</td>
<td>44.20</td>
<td>2.9</td>
<td></td>
</tr>
<tr>
<td>Sum offshore</td>
<td>688</td>
<td>87.42</td>
<td>92.4</td>
<td>53556</td>
<td>42.9</td>
<td>994.17</td>
<td>66.1</td>
<td></td>
</tr>
<tr>
<td>Anglo-Dutch Basin</td>
<td>offshore</td>
<td>424</td>
<td>0.99</td>
<td>1.1</td>
<td>24972</td>
<td>19.9</td>
<td>171.96</td>
<td>11.4</td>
</tr>
<tr>
<td>onshore</td>
<td>119</td>
<td>0.61</td>
<td>0.6</td>
<td>1024</td>
<td>0.1</td>
<td>11.21</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>subtotal</td>
<td>543</td>
<td>1.60</td>
<td>1.7</td>
<td>25996</td>
<td>20.8</td>
<td>183.18</td>
<td>12.2</td>
<td></td>
</tr>
<tr>
<td>Northwest basin of Germany</td>
<td>offshore</td>
<td>62</td>
<td>0.51</td>
<td>0.5</td>
<td>31546</td>
<td>25.3</td>
<td>211.91</td>
<td>14.1</td>
</tr>
<tr>
<td>onshore</td>
<td>438</td>
<td>3.24</td>
<td>3.5</td>
<td>13834</td>
<td>11.0</td>
<td>115.01</td>
<td>7.6</td>
<td></td>
</tr>
<tr>
<td>subtotal</td>
<td>500</td>
<td>3.75</td>
<td>4.0</td>
<td>45380</td>
<td>36.3</td>
<td>326.92</td>
<td>21.7</td>
<td></td>
</tr>
<tr>
<td>Sum offshore</td>
<td>486</td>
<td>1.50</td>
<td>1.6</td>
<td>56518</td>
<td>45.2</td>
<td>383.87</td>
<td>25.6</td>
<td></td>
</tr>
<tr>
<td>onshore</td>
<td>557</td>
<td>3.85</td>
<td>4.2</td>
<td>14858</td>
<td>11.9</td>
<td>126.22</td>
<td>8.3</td>
<td></td>
</tr>
<tr>
<td>subtotal</td>
<td>1043</td>
<td>5.35</td>
<td>5.8</td>
<td>71375</td>
<td>57.1</td>
<td>510.09</td>
<td>33.9</td>
<td></td>
</tr>
<tr>
<td>Total offshore</td>
<td>1174</td>
<td>88.92</td>
<td>95.8</td>
<td>110074</td>
<td>88.1</td>
<td>1378.04</td>
<td>91.6</td>
<td></td>
</tr>
<tr>
<td>onshore</td>
<td>557</td>
<td>3.85</td>
<td>4.2</td>
<td>14858</td>
<td>11.9</td>
<td>126.22</td>
<td>8.4</td>
<td></td>
</tr>
<tr>
<td>subtotal</td>
<td>1731</td>
<td>92.77</td>
<td>100</td>
<td>124932</td>
<td>100</td>
<td>1504.26</td>
<td>100</td>
<td></td>
</tr>
</tbody>
</table>

5.3.2 Reservoirs

Several sets of reservoirs formed in the North Sea Basin from the Paleozoic to the Cenozoic. Regional reservoirs formed in the northern North Sea Basin in the Early Jurassic, Late Cretaceous, Paleocene and Eocene (Wilkinson et al., 2006; Ye et al., 2004). The main reservoirs are the Lower Jurassic Statfjord Formation and the Middle Jurassic Brent Group (Wilkinson et al., 2006).

The Middle Jurassic Brent Group sandstone reservoir of the East Shetland Basin has an average thickness of more than 150 m, an average porosity of 18% and an average permeability of about 650 mD (Ehrenberg, 1997; Beydoun et al., 1990).

The Lower Jurassic Statfjord Formation is a fluvial–delta facies sandstone reservoir with shale interlayers. The average porosity of the reservoir is 13.5% and the average permeability is 330 mD (Sun and Zhao, 2012; Ramm and Ryseth, 1996).

The main reservoir in the southern North Sea Basin is the lower Permian Rotliegende sandstone. The maximum thickness of the reservoir is more than 300 m (Nagtegal, 1979), the maximum porosity is 30% and the permeability varies from 1 to 3000 mD (Glennie and Provan, 1990).

5.3.3 Cap rocks

The main cap rocks in the northern North Sea Basin are the source rocks of this region, the Upper Jurassic Kimmeridge Clay Formation shale and Heather Formation shale, which cover the Middle Jurassic reservoirs and prevent hydrocarbon diffusion. As regional cap rocks, the two sets of cap rocks are widely distributed, and are approximately 150–1000 m thick (Yang et al., 2014).

The cap rock of the southern North Sea Basin is the salt rock of the Permian Zechstein Formation (Yang et al., 2014; Ye et al., 2004; Ramm and Ryseth, 1996). The Zechstein Formation is a set of regional cap rocks with a wide distribution and a thickness of about 200–1000 m.
5.3.4 Petroleum migration and reservoir characteristics

The source rocks of the Kimmeridge Clay Formation in the northern North Sea Basin matured in the Late Cretaceous; at the same time, the thickness of the Cretaceous strata reached 1700 m. The Kimmeridge Clay Formation shale in the Viking graben reached its peak hydrocarbon generation in the Paleogene (Grabinski, 1983). The hydrocarbon migration distance was short (2–30 m), and the migration was generally vertical (Liu et al., 2012; Isaksen and Ledje, 2011). Based on previous studies, hydrocarbons in the northern North Sea Basin were either generated in older strata and accumulated in younger strata or generated in younger strata and accumulated in older strata (Zhang et al., 2011). In general, hydrocarbons in the southern North Sea Basin were generated in older rocks and migrated to younger strata.

6 Petroleum geological conditions of the assessment area

6.1 Source rocks

There are four sets of source rocks in the East Greenland Basin: the Upper Permian Ravnefjeld Formation, the Upper Triassic–Lower Jurassic Kap Stewart Formation, the Middle Jurassic Fossilbjerget Formation and the Upper Jurassic Hareelv Formation (Feng et al., 2013; Stemmerik et al., 1998) (Figure 5).

The Upper Permian Ravnefjeld Formation is a set of marine shales that was deposited in a hypoxic shallow sea. In the central area of the Jameson Land basin, dark shale with rich organic matter is widely distributed. The kerogen type is mainly type II and a small amount of type III, which have good hydrocarbon generation potential (Nielsen et al., 2008). The average TOC is 4.5%, and the hydrogen index is 300–400 mg HC·g⁻¹ TOC (Wignall and Twitchett, 2002; Christiansen et al., 1962). Based on previous studies of more than 20 cores, the average $R_a$ is 1.75%, which indicates mature source rock (Karlsen et al., 1988).

The Middle Jurassic Fossilbjerget Formation is equivalent to the Heather Formation of the North Sea Basin and is a set of marine shales with about 1%–4% TOC (Feng et al., 2013; Ehrenberg et al., 1990).

The Upper Jurassic Hareelv Formation is a set of marine dark shales in the Jameson Land basin, with type II kerogen, a thickness of 200–500 m and an area of more than 4500 km². Based on samples analyzed in previous studies, the TOC content is 6%–12% and $R_a$ is 0.5%–0.7%, indicating mature source rock, and the hydrogen index is 200–300 mg HC·g⁻¹ TOC (Surlyk and Noe-Nygaard, 2001; Requejo et al., 1989).

The Upper Triassic–Lower Jurassic Kap Stewart Formation shale mainly occurs in the Jameson Land Basin of the East Greenland Basin. The rock represents delta-plain facies, and extends over an area of 1.19 × 10⁶ km². The organic matter includes algae and higher plant debris, with type I and type III kerogen. The total thickness of the formation is 155–400 m, and the source rock with hydrocarbon-generation capacity is about 15 m thick. The density of the source rock is 2400 kg·m⁻³ and the TOC varies from 0.5% to 10.3%. In the middle of the formation, a set of shales with a thickness of about 10–15 m has good oil-generation potential. The TOC of this shale is about 10%, the hydrogen index is up to 700 mg HC·g⁻¹ TOC, and the sulfur content is very low. The average $R_a$ is less than 1.0%, indicating low-maturity to mature source rock (Krabbe, 1996; Ehrenberg et al., 1990).

6.2 Reservoirs

Several sets of reservoirs are developed in the East Greenland Basin: the upper Permian Wegener Halvø Formation reef limestone; the Upper Triassic–Lower Jurassic Kap Stewart Formation sandstone; the Lower Jurassic Neill Klinter Formation sandstone; the Middle Jurassic Pelion Formation sandstone and the Upper Jurassic Olympen Formation.

The Upper Jurassic Olympen Formation contains a set of shallow-marine and fluvial deltaic sediments with a thickness of less than 250 m and a depth of more than 2500 m. The lithology is quartz lithic sandstone. The porosity varies from 7% to 27%, the average porosity is 20% and the maximum permeability is 622 mD (Price and Whitham, 1997).

The Upper Triassic–Lower Jurassic Kap Stewart Formation sandstone is equivalent to the Staffjord sandstone of the North Sea Basin, with similar physical properties. Some studies have shown that the porosity in the East Greenland Basin ranges from 10% to 30% (Cheatwood et al., 1986). Further research on the other reservoirs and potential reservoirs is required.

6.3 Cap rock

The cap rock in the East Greenland Basin can be categorized as inner cap rock, most of which is mudstone and shale, and occurs over the entire region; however, the thickness of the cap rock is thinner than in the North Sea Basin (Li and Tong, 2010).

6.4 Petroleum migration and reservoir characteristics

The Late Jurassic to Early Cretaceous was an important developmental period of the source rocks of the sedimentary basins in the Atlantic (Schiffer et al., 2014); it
Figure 5  Stratigraphic column and petroleum plays in the East Greenland Basin (Feng et al., 2013).
is estimated that hydrocarbon generation peaked in the East Greenland Basin after the Late Cretaceous. Studies of fluid inclusions indicate that the petroleum migration pathways were microcracks, faults and unconformities. Petroleum accumulated mainly through vertical migration pathways rather than lateral migration pathways into anticline traps, fault traps and some stratigraphic traps formed by tension and salt structures; the migration distance was short (Spencer et al., 2011; Baron and Parenell, 2007; Jonk et al., 2005).

Based on the source rock, reservoirs and the development horizons of the cap rocks, hydrocarbons in the East Greenland Basin were generated in older rocks and accumulated in younger rocks.

### Calculation and comparison of resources

#### 7.1 Calculating petroleum resources

After determining the scaled area and analyzing the petroleum geological conditions in the assessment area, the scores were calculated based on the standard presented in Liu et al. (2012). Table 2 lists the assessment parameters for the East Greenland Basin, the northern North Sea Basin and the southern North Sea Basin.

<table>
<thead>
<tr>
<th>Table 2</th>
<th>Geological characteristics of the assessment area and the scaled area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basin</td>
<td>The East Greenland Basin</td>
</tr>
<tr>
<td>Trap conditions Type</td>
<td>Anticline, fault and a few stratigraphic traps</td>
</tr>
<tr>
<td>Thickness/m</td>
<td>Less than the thickness of the North Sea Basin</td>
</tr>
<tr>
<td>Lithology</td>
<td>Mudstone and shale</td>
</tr>
<tr>
<td>Area factor</td>
<td>Regional</td>
</tr>
<tr>
<td>Damage degree of fracture Small</td>
<td>Small</td>
</tr>
<tr>
<td>Sedimentary facies</td>
<td>Shallow sea, deep sea turbidity</td>
</tr>
<tr>
<td>Average thickness</td>
<td>—</td>
</tr>
<tr>
<td>Porosity</td>
<td>20%</td>
</tr>
<tr>
<td>Permeability/mD</td>
<td>&lt;622</td>
</tr>
<tr>
<td>Depth/km</td>
<td>&gt;4.7</td>
</tr>
<tr>
<td>TOC</td>
<td>7%</td>
</tr>
<tr>
<td>Type of organic matter</td>
<td>Type II, type III</td>
</tr>
<tr>
<td>Maturity</td>
<td>Low mature—mature</td>
</tr>
<tr>
<td>Peak time of hydrocarbon generation</td>
<td>After the Late Cretaceous</td>
</tr>
<tr>
<td>Migration distance</td>
<td>Short</td>
</tr>
<tr>
<td>Transportation conditions</td>
<td>Cracks, faults, unconformities</td>
</tr>
<tr>
<td>Play formation and hydrocarbon generation peak</td>
<td>Play formation was earlier</td>
</tr>
<tr>
<td>Migration mode</td>
<td>Vertical migration mainly, lateral migration less</td>
</tr>
<tr>
<td>Pattern of generation, Reservoir and cap rock</td>
<td>Generation in lower zone and storage in upper zone</td>
</tr>
<tr>
<td>Resources</td>
<td>Oil/(10^8 boe) — 127.64 1.43</td>
</tr>
</tbody>
</table>
From Table 2, the petroleum conditions of the East Greenland Basin are very similar to those of the North Sea Basin. So, analogy can be used to calculate the amount of resources in East Greenland Basin. But there are some differences, which are as follows: (1) the sedimentary facies of the East Greenland Basin are marine, but those of the North Sea Basin are terrestrial; (2) the depth of the East Greenland Basin reservoir is deeper than that of the North Sea Basin; and (3) the source rocks of the East Greenland Basin are low-maturity to mature and in the phase of oil generation, but in the North Sea Basin, the source rocks are high-maturity to over-mature and in the phase of condensate gas–gas generation.

Table 3 lists the scores of the parameters based on the scoring standard, and the resource abundance for oil, gas and condensate gas. Scoring standards without data were deleted. From the scores, we calculated the analogy coefficient:

\[
\alpha_1 = \frac{S_{\text{EGB}}}{S_{\text{NNB}}} = \frac{49.5}{52.3} = 0.95
\]

\[
\alpha_2 = \frac{S_{\text{EGB}}}{S_{\text{SNB}}} = \frac{49.5}{54.8} = 0.90
\]

\[\alpha_1: \text{analogy coefficient between the East Greenland Basin and the northern North Sea Basin}\]
\[\alpha_2: \text{analogy coefficient between the East Greenland Basin and the southern North Sea Basin}\]
\[S_{\text{EGB}}: \text{total analogy score of the East Greenland Basin}\]
\[S_{\text{NNB}}: \text{total analogy score of the northern North Sea Basin}\]
\[S_{\text{SNB}}: \text{total analogy score of the southern North Sea Basin}\]

Using the formula given above, the oil, gas and condensate gas resources of the East Greenland Basin can be calculated. Table 4 shows the results of the analogy calculations and the evaluation results of undiscovered petroleum resources in the northern North Sea Basin, southern North Sea Basin and East Greenland Basin, which were published by the USGS in 2007.

### Table 3  Scores of geological characteristics and resource abundance in the assessment area and scaled area

<table>
<thead>
<tr>
<th>Basin</th>
<th>The East Greenland Basin</th>
<th>The northern North Sea Basin</th>
<th>The southern North Sea Basin</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Trap conditions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Type</td>
<td>3.5</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Thickness/m</td>
<td>2</td>
<td>3</td>
<td>3.5</td>
</tr>
<tr>
<td>Lithology</td>
<td>2.5</td>
<td>2.5</td>
<td>4</td>
</tr>
<tr>
<td>Area factor</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Damage degree of fracture</td>
<td>3</td>
<td>3</td>
<td>3.5</td>
</tr>
<tr>
<td><strong>Cap-rock conditions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sedimentary facies</td>
<td>3</td>
<td>3.5</td>
<td>3.5</td>
</tr>
<tr>
<td>Average thickness</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Porosity</td>
<td>3</td>
<td>2.6</td>
<td>2.5</td>
</tr>
<tr>
<td>Permeability/mD</td>
<td>3.5</td>
<td>3.7</td>
<td>3.8</td>
</tr>
<tr>
<td>Depth/km</td>
<td>1</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td><strong>Reservoir conditions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOC</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Type of organic matter</td>
<td>2</td>
<td>2.5</td>
<td>1</td>
</tr>
<tr>
<td>Maturity</td>
<td>2</td>
<td>2.5</td>
<td>2.5</td>
</tr>
<tr>
<td>Peak time of hydrocarbon generation</td>
<td>3</td>
<td>4</td>
<td>3</td>
</tr>
<tr>
<td>Migration distance</td>
<td>3.5</td>
<td>3.5</td>
<td>3.5</td>
</tr>
<tr>
<td>Transportation conditions</td>
<td>1.5</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td><strong>Source rock conditions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Play formation and hydrocarbon generation peak</td>
<td>3</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>Migration mode</td>
<td>2.5</td>
<td>2.5</td>
<td>3</td>
</tr>
<tr>
<td>Pattern of generation, Reservoir and cap rock</td>
<td>3.5</td>
<td>2.5</td>
<td>3.5</td>
</tr>
<tr>
<td><strong>Petroleum system</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Analogy total scores</td>
<td>49.5</td>
<td>52.3</td>
<td>54.8</td>
</tr>
<tr>
<td>Analogy coefficient</td>
<td>—</td>
<td>0.94646</td>
<td>0.90329</td>
</tr>
<tr>
<td><strong>Analogy calculation</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area/(×10⁴ km²)</td>
<td>50</td>
<td>35</td>
<td>22.5</td>
</tr>
<tr>
<td>Oil/(×10⁴ boe·km⁻²)</td>
<td>—</td>
<td>3.6468</td>
<td>0.0636</td>
</tr>
<tr>
<td>Gas/(×10⁴ boe·km⁻²)</td>
<td>—</td>
<td>1.9654</td>
<td>2.0858</td>
</tr>
<tr>
<td>Condensate gas/(×10⁴ boe·km⁻²)</td>
<td>—</td>
<td>0.5163</td>
<td>0.0284</td>
</tr>
</tbody>
</table>
Table 4 Undiscovered petroleum resources in the assessment area and scaled area

<table>
<thead>
<tr>
<th></th>
<th>The northern North Sea Basin</th>
<th>The southern North Sea Basin</th>
<th>The East Greenland Basin</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil/(×10^8 boe)</strong></td>
<td>130.99</td>
<td>1.47</td>
<td>88.99</td>
</tr>
<tr>
<td><strong>Gas/(×10^8 boe)</strong></td>
<td>70.59</td>
<td>48.16</td>
<td>160.98</td>
</tr>
<tr>
<td><strong>Condensate gas/(×10^8 boe)</strong></td>
<td>18.54</td>
<td>0.66</td>
<td>66.04</td>
</tr>
</tbody>
</table>

7.2 Comparative analysis

In general, there is good agreement between our results and those of the USGS for undiscovered oil resources; however, there is a notable difference between the estimates for undiscovered gas resources, and the largest difference is between the results for undiscovered condensate gas resources. The relative error of the three resource types is as follows:

\[
\delta_{\text{oil}} = \frac{Q_{\text{oil}} - Q_{\text{oil}}^*}{Q_{\text{oil}}^*} \times 100\% = 1.15\%, \quad (7-1)
\]

\[
\delta_{\text{gas}} = \frac{Q_{\text{gas}} - Q_{\text{gas}}^*}{Q_{\text{gas}}^*} \times 100\% = 40.16\%, \quad (7-2)
\]

\[
\delta_{\text{con}} = \frac{Q_{\text{con}} - Q_{\text{con}}^*}{Q_{\text{con}}^*} \times 100\% = 83.68\%, \quad (7-3)
\]

where \( \delta \) is the relative error, \( Q \) is the undiscovered petroleum resources of our analogy calculations and \( Q^* \) is the undiscovered petroleum resources of the USGS evaluation.

The large relative errors found in the results of undiscovered gas and condensate gas resources (Eqs. (7-2) and (7-3), respectively) may be explained in two ways. One is that there are some differences between the methods used by scholars in China and in other countries to determine the type of kerogen and the temperature and pressure of the reservoir; another may be that some standards of the geological characteristics used in China differ from those used in other countries.

7.3 Comparison of the petroleum geological conditions between the East Greenland Basin and the North Sea Basin, we have drawn the following conclusions.

Several sets of source rock developed in the East Greenland Basin, mainly shale that formed in lacustrine and marine environments. The superior petroleum geological conditions indicate a high resource potential in the East Greenland Basin.

(1) The analogy method was used to assess the undiscovered resources of the East Greenland Basin, using the North Sea Basin as an analogy scaled area. The calculation results show that the East Greenland Basin has an estimated \( 9.001 \times 10^9 \) boe of undiscovered resources of oil, \( 9.633 \times 10^9 \) boe of gas and \( 1.078 \times 10^9 \) boe of condensate gas.

(2) A comparison of our results with those of the USGS shows differences in the undiscovered gas and condensate gas resources estimates. The main reasons for the discrepancies may be that some geological data and standards of the geological characteristics used in China differ from those used in other countries.

Acknowledgments This study was supported by the Chinese Polar Environment Comprehensive Investigation and Assessment Programs (Grant no.CHINARE2016-04-03).

8 Conclusions

Through analogy and calculation of resources between the East Greenland Basin and the North Sea Basin, we have drawn the following conclusions.

References


stratigraphy and sedimentary evolution across the Permian-Triassic boundary in East Greenland. Geol Mag, 143(5): 635–656


