HYDROCARBON RESOURCES ASSESSMENT IN THE NORTH SUMATRA BASIN

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ABSTRACT

The assessment of undiscovered oil and gas potential is a critical aspect of oil exploration, especially in the unexplored basins, although it is also important as a basis for appraising the national's energy policies and can assist long term economic planning.

In the North Sumatra basin, the Tertiary sediments can be grouped into three stratigraphic sequences, based on which, the hydrocarbon play types can be classified. The play type is the basic unit that contains all elements for hydrocarbon generation and entrapment. The classification of the plays in the North Sumatra Basin, from bottom to top, are as follow:

- stratigraphic sequence I,
  - clastic wedge base (Parapat Fm), as type I,
- stratigraphic sequence II,
  - carbonate wedge base (Arun/Malacca/Belumai Fm), as type II,
- stratigraphic sequence III,
  - clastic wedge middle (Middle Baung Sandstone Member of Baung Fm), as type III,
  - clastic wedge top (Keutapang and Seurula Fm), as type IV.

The hydrocarbon potential of the play types is then evaluated by using the so-called IUGS method, to assess the total resources of the North Sumatra Basin. The result can be continuously updated in line with additional and development of the structural, stratigraphic and geochemical controls and concepts are available.

I. INTRODUCTION

The geological and geophysical data level in the North Sumatra Basin are varied from the point of view of exploration density activities and their quality. Nearly mature exploration activities have already done in the southern part of the basin, especially in the onshore area, which is the most producing hydrocarbon region of the basin. How ever, the value of the undiscovered hydrocarbon is still significant, since the deposit is accumulated in the clastic sedimentary and carbonate reservoir rocks, in the form of stratigraphic and structural traps. On the other hand, the data level in the northern part of the basin, towards the Andaman Sea, is scarce compared to the southern part, i.e. regional data. In optimizing the achievement of the hydrocarbon resources on the basin, the effort of discovering new hydrocarbon accumulation has to be continued, regardless the condition of the data level.

There are several methods that can be applied for assessing the resources, which estimate and calculate:

*) PPPTMGB "LEMIGAS"
- the hydrocarbon potential in the basin on any data level,
- the probable size of the resources and the probability of their existence.

In using the method, the degree of uncertainty for parameters used in the calculation should be identified and quantified. The method employed is able to guide the management in making decisions, developing exploration strategies, and evaluating opportunities. One promising method is the so-called USGS resources assessment method.

The application of the USGS method in the North Sumatra Basin is expected to solve the problem on the probability of the hydrocarbon potential, which is approximately the real potential of the basin.

II. GEOLOGIC SETTING

II.1. General

The North Sumatra Basin is an asymmetric NW-SE trending and steep block faulted basin. The SW flank is bordered by the Barisan Mountain that was uplifted since the Middle Miocene, while in the SE part the basin is bounded by the Asahan arc. The Malaysian Peninsula limits the basin in NE flank. In the northern part, the basin is opened towards the Andaman Sea. Two structural trends prevailed in the basin, i.e., the Pre-Tertiary N-S fault pattern and Pleistocene NW-SE and NE-SW strike-slip fault pattern, which were developed since the Middle Miocene (Fig. 1).

The Pre-Tertiary structural grain appears to control the sedimentation during the Tertiary times (Fig. 2).

II.2. Tectonic and Sedimentation

The Pre-Tertiary rocks consist of volcanoclastic sedimentary rocks, that have been metamorphosed and folded, and batholithic intrusions (Fig. 3).

During the Late Oligocene, block faulting took place in the North Sumatra basin, and the coarse clastic sediments of the Parapat Formation were deposited in fluvial to paralic environments, unconformably overlain the basement. The basin was later on subsided gradually and an isolated marine environment was formed in which the black phytic carbonate nodule of the Bampo Formation were deposited in restricted and anoxic conditions. The Bampo Formation conformably overlain the Parapat Formation.

In the Early Miocene, compressional stresses were reactivated which had lasted until Middle Miocene time. The northern part of the basin was uplifted, whereas in the southern part a shallow marine conditions prevailed. The subsidence of the basin occurred followed by the deposition of shale and reeal limestone of the Peutu Formation, unconformably upon the Bampo Formation. To the south, the Peutu Formation is dominated by glauconitic sandstone and calcarenite, which was deposited conformably on the Bampo Formation. After the Peutu Formation was deposited, the North Sumatra region was uplifted, due to the collision between the Asian and Australian Plate and this resulted the wrench sumatran fault system.

In the Middle Miocene, the Baong Formation was deposited unconformably on the Peutu Formation, except in the southern part where the Baong Formation conformably overlain the Peutu Formation. The Middle Baong Sand Member was deposited in the southern part of the basin and appears as the lower part of the Keutapang Formation towards the S-E.

Uplifting continued which resulting in the shallowing of the environment of deposition during the Late Miocene, followed by the deposition of the clastic sediments of the Keutapang, Seurula dan Julu Rayeu Formations.

II.3. Hydrocarbon Occurrences

II.3.1. The Source Rocks

The Bampo, Peutu, Belumai and Lower Baong Formations are considered to be the source rocks in the basin, with depth varied from 2000 to 4000 m. To the southwest, these formations are cropping out. The geothermal gradient ranges from 36.4°C to 45.5°C/km, and the Total Organic Contents of those formations are 0.5%. The thermal maturity zone is located approximately in the central part of the basin.
with average depth to the top of oil window 1500 m (Fig. 4).

II.3.2. The Reservoir Rocks
The reservoir rocks are clastic and carbonate sediments, i.e. the Parapat Formations, Middle Baong Sand Member, Keutapang, Seurula Formations, and Belumai Formation, Arun Limestone of the Peutu Formation.

The porosities and permeabilities range from 13-25% and 50-100 md respectively.

II.3.3. Hydrocarbon Migration
The hydrocarbons that have been generated since Miocene time in the Bampo, Peutu and Lower Baong Formations migrated through the fault system and accumulated in the Arun LS, Belumai Formation, Middle Baong Sandstone Member and Keutapang Formation (Fig. 5). The over-pressure of the Baong shale also affected the migration of the hydrocarbon.

II.3.4. Cap Rocks
The Parapat Formation is sealed by the shale of the Bampo Formation, while the basal Miocene carbonates are capped by the Lower Baong Formation. The sandstones of the Keutapang Formation are sealed by the shaling out of the formation itself.

II.3.5. Traps
Several types of traps can be observed in the basin, i.e. anticline faults, fault related structures, drape overs, stratigraphic traps in the carbonate deposit (build up, pinnacle) and clastic sediments (sand lenses, wedge out, unconformity).

III. RESOURCE ASSESSMENT METHOD

III.1. Definition

The equality of understanding about several terms used in the assessment method is very useful, because these terms have been variously defined in the literature. The terms of prospect, pool, field and play are often used interchangable, without clear defination. Podruski et al. (1988) composed definition of that terms as follows:

- a pool is a discovered accumulation of hydrocarbon typically within a single stratigraphic interval, that is hydraulically separated from any other oil accumulation. Any number of pools can exist within a field.
- a prospect is an untested exploration target, usually within a single stratigraphic interval.
- a field is used to designate an area that produces oil without stratigraphic interval restrictions.
- a play consist of a family of pools and/or prospects that share a common history of hydrocarbon generation and migration, reservoir development, and trap configuration.

III.2. The Play Concept

By practical definition, a play is a group of prospects with geologically similar source, reservoir and trap control of oil and gas occurrence and this have geographic and stratigraphic limits.

Geologists try to recognize, within a certain interval of geological evolution, a condition of stratigraphical, sedimentological or structural model that are then to be translated into the play definition. Due to the geological change that usually occurs in the basin, the play definition is inconsistent that does not fit and can not be applied in the whole basin.

In reality, the play analysis method is more applicable in the restricted and interested area, such as a geological trend consisting of reef of specific age or turbidite sandstone along major fault. The increasing of the geological understanding as a result of the exploration activities, leads the plays to be subdivided into better predefined elements, in order to get a more reliable estimate.

III.3. Hydrocarbon Appraisal

In any assessment method, there are several parameters which usually cause the decisions to be subjective. The minimizing of this subjectivity depends on the sense of the geological knowledge of the
area. The existing data must be comprehensive, such as type of maps, cross-section charts, and graphs of the geological, geophysical and geochemical analyses, in order to obtain an efficient and reliable assessment.

The application of the USGS resources assessment method requires data, i.e. the existing discoveries within the play. All the available data are then quantified and recorded in the oil and gas appraisal data form (Fig. 6).

This form is organized by three main categories:
- Play attributes,
- Prospect attributes,
- Hydrocarbon volume parameters.

The quantification recorded can be calculated manually or by computer simulation, and yields a probability of resource appraisal and pool size distribution of the play in the studied area.

III.3.1. Play attributes

The play attributes consist of hydrocarbon source, timing, migration and potential reservoir facies attribute. The hydrocarbon attribute determines whether the conditions of the play are favourable for occurrences of oil and gas.

The conditional deposit probability expresses the probability that any randomly selected prospect is an accumulation, given that the play parameters are favourable.

The marginal play probability expresses the probability that all of the first four play parameters are currently favourable somewhere in the play.

III.3.2. Prospect attributes

The determination of the nature of the prospect needs three parameters, i.e. trapping mechanism, effective porosity and hydrocarbon accumulation. Evaluation of these parameters is accomplished by recording a single value between 0 (total certainty that the parameters is absent), and 1 (total certainty that the parameters is present) for the probability that the parameters is generally favourable in a randomly selected prospect within the play area.

III.3.3. Hydrocarbon volume parameters

The parameters are consist of reservoir lithology, hydrocarbon mixture and reservoir parameters. The reservoir parameters include area of closure, reservoir thickness, effective porosity, trap fill, and reservoir depth. The parameters describe the range of possibility value of the generic reservoir characteristics that determine the volume of the hydrocarbon present in an individual accumulation within the play. So, the hydrocarbon volume parameters quantifications are conditional on the play attributes and the prospect attributes of being favourable.

The number of drillable prospects is the play characteristic that describes the range of possible value for the number of valid targets that would be considered for drilling of the play where to be fully explored.

IV. RESOURCES ASSESSMENT IN THE NORTH SUMATRA BASIN

IV.1. Play Types

The stratigraphy of the North Sumatra Basin can be subdivided into three stratigraphic sequences, i.e. the Oligocene, Early-Middle Miocene, and Late Miocene-Pleistocene stratigraphic sequences (Fig.7,8,9).

In the northern part of the basin, each of those sequences is clearly separated by an unconformity while in the southern part, unconformity can be detected only between the first and the second sequences.

The wedge base type of the play model is made up by clastic deposit of the Parapat Formation and carbonate sediments (the Arun LS of the Peutu Formation), which can be recognized in the first and second sequences. The third sequence contains the wedge middle (the Middle Baong Sand of the Baong Formation), and wedge top (the Keutapang and Seurula Formations).
IV.2. Evaluation of Hydrocarbon Potential

IV.2.1. Parapat Wedge Base Play

The Parapat Formation is a very arenaceous clastic, usually occupied the irregular low topographic areas and thickened to the north (Fig. 10). So far, there has not been any evidence detected for hydrocarbon accumulation in the wedge base, either from outcrop or borehole data. However, in the northern part, especially in the vicinity of structural highs, the occurrence of prospect in this play type need to be carefully investigated. Actually the depth of this play is deeper than the base of the oil generation level. This means that the play tend to contain gas instead of oil.

IV.2.2. Carbonate Wedge Base Play

The carbonate rocks of the Peutu and Belumai Formations can be found in three locations, which indicate that the content of the hydrocarbon is different (Fig. 11). In the southern part, it contains oil, while in the northern part it is dominated by gas.

The Arun Gas Field data shown in Table 1 is an example of used to predict the undiscovered gas potential of this play type.

IV.2.3. The MBS Wedge Middle Play

The MBS is producing zone in the southern part (Aru area) (Fig. 12, 13 & 14). The sandstones are interpreted as turbidite deposits, and appears as the lower part of the Keutapang Formation in the southeast. The potential sandstone layers of the MBS are Besitang River, Sembilan, Susu and Aru sandstones. The over-pressure caused by diapiric structure of the Baong shales occurred in the Aru area. The discovery wells show the reservoir data as follows:

- sand layer thickness (lenses) : 50 - 75 m
- porosities : 10 - 25 %
- oil (paraffinic) : 45-52 API

The undiscovered hydrocarbon in this play is less than that estimate for the Keutapang Wedge Top Play. This due to the influence of several factors an restricted area of deposition, predominant stratigraphic traps and the shaly reservoir rocks.

The evaluation shows that the maximum undiscovered oil of this play is estimated as 2.5 MMBBL and the minimum is 0.15 MMBBL.

IV.2.4. Keutapang Wedge Top Play

The Keutapang Formation was deposited in the deltaic environment. Potential reservoir are thin sandstones layers trending NW-SE, which are dominated by stratigraphic traps. The structural traps are faulted and dome-like. The reservoirs are usually vertically sealed by shale.

The depth of this play type ranges from 800 m to 1100 m subsea. The sandstone porosities and permeabilities are approximately 15-20% and 50-100 mD respectively. The 43-51 API oil is paraffinic.

The play evaluation indicates that this is the most important oil play in the North Sumatra Basin. The maximum undiscovered oil is 504 MMBBL and the minimum is 0.37 MMBBL.

V. CONCLUSION

1. Stratigraphic wedge play concept of the North Sumatra Basin provides a logic geological process and show a simple understanding in a choosing the play type.

2. The Keutapang Wedge Top Play should be explored in detail as undiscovered potential of this play is high.

3. The resources assessment method is a tool for management to control and develop the exploration activity. This method is also very useful in estimating hydrocarbon potential of unknown areas.

REFERENCES


From Offshore Norway, 6th Meeting of the WGRA-CCOP, Bangkok, 29 Aug. - 2 Sept., 1988


Figure 2. Structural cross-section
OIL AND GAS APPRAISAL DATA FORM

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Probability of Favorable or Present</th>
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<td>Potential Reservoir Facies</td>
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<td>Hydrocarbon Accumulation</td>
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Figure 6
Oil and gas appraisal data form (Modified from US Department of Interior, 1979)
Figure 7
Time Slice Isopach Map (Oligocene Time)

Figure 8
Time Slice Isopach Map (Early-Middle Miocene Time)
Figure 9
Time Slice Isopach Map (Late Miocene-Pliocene Time)

Figure 10
Areal Distribution of Parapat Formation
Figure 11
Areal Distribution of Limestone (Peutu, Belumai Formations)

Figure 12
Areal Distribution of Middle Baong Sand (Baong Formation)
Figure 13
Middle Baong Sand Isopach Map (Mulhadijono, 1978)
Figure 14
Map of most prospective area (Mulahadijono, 1978)
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Above 10,000 for methane