Sulu Sea – East Palawan Basins: Frontier Basin Case Study

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September 2002
Abstract

The Sulu Sea – East Palawan Basins case study would deal with the resource evaluation, development strategies and management of petroleum resources of frontier or less mature basin.

The Sulu Sea basin consists of the Sandakan sub-basin while the East Palawan basin is divided into the Balabac and Bancauan sub-basins. The Sulu Sea basin extends to the northeast portion of Sabah where there have been gas discoveries. The three petroleum play types identified in the basin are carbonate reef build-ups, anticlines and fault blocks. The anticlines and fault block plays have been confirmed by the discoveries made in the Malaysian side of the basin. The total estimated resource ( undiscovered) in the Sulu Sea Basin is around 203 million barrels of oil equivalent (MBOE).

On the other hand, the plays identified in the East Palawan basin are the anticlines, stratigraphic and carbonate reef build-ups. All these are unconfirmed. The basin has been estimated to contain a total of 443 MBOE.
1. Introduction

The Sulu Sea basin that was originally proposed by the Department of Energy (DOE) and later on chosen to be one of the four case studies for the Petroleum Policy and Management Project (PPM) of the Coordinating Committee for Geoscience Programmes in East and Southeast Asia (CCOP) spans three sub-basins, namely, the Balabac, Bancuan and Sandakan sub-basins. However, with the redelineation of the country’s sedimentary basins under the recently concluded Philippine Resource Assessment Project (PhilPRA), the three sub-basins are now covered by two basins, the East Palawan basin (Bancuan and Balabac sub-basins) and the Sulu Sea basin (Sandakan sub-basin).

With this development, the DOE would like to redefine its proposal for the case study to cover both basins (Sulu Sea and East Palawan basins). Although there will be a considerable change in terms of aerial coverage (from 60,000 sq km for the original Sulu Sea basin to a total of 207,000 sq km covering 115,000 sq km for the present Sulu Sea basin and 92,000 sq km for the East Palawan basin), the work program originally proposed essentially remains the same as the prospects and leads identified by the PhilPRA team are well within the confines of the three sub-basins.

The Sulu Sea – East Palawan Basins case study represents a frontier area for the PPM Project. The main objective of this case study will be to address the geological uncertainties of such an area; to evaluate the existing incentives and to propose changes; to establish strategies to attract companies to explore in such frontier areas; and to evaluate the potential impact of the changes and strategies to the petroleum industry in the country.

The basins were selected because of the following reasons: the resource assessment results of the PhilPRA project can be used; it covers a large offshore area in the Philippines and most of it is in deep water; the area is densely covered with seismic data including some 2,000 square kilometers of 3D and additional 5,740 line kilometers of newly acquired 2D data; the basin has a complex geology; part of the basin is on the Malaysian side; and the possibility of Malaysia, a CCOP member country, participating in this case study.

This presentation will show the result of the basin evaluation. It will be divided into several topics that include the basin description, tectonic history, stratigraphy, and petroleum system, play types, the resource assessment results and the data available for this study. The fiscal regime in the Philippines will be briefly discussed including the existing gas infrastructure in the Philippines.
2. Basin Description

The Sulu Sea – East Palawan Basins are located at the southwest portion of the Philippines (covered by the blue polygon in Figure 1). The basins are bounded to the northwest by the Palawan Island, to the southeast by the Sulu Archipelago and to the southwest by the continental island of Borneo. The total area of the basins is about 207,000 sq km representing the 115,000 sq km Sulu Sea basin with maximum sediment thickness of about 6.0 kilometers and 92,000 sq km East Palawan basin with maximum sediment thickness of 3.5 kilometers.

The Sulu Sea-East Palawan Basins are oriented northeast-southwest. The Balabac and Bancauan sub-basins of the East Palawan basin are divided by the Banggi Ridge and separated from the Sulu Sea basin’s Sandakan sub-basin by the Keenapusan Ridge. These basins are within the 200-meter bathymetric contour except for the northeast and southeast portion where water depth ranges from 1,000 - 2,000 meters to as much as 5000 meters near the Sulu Trench.

The East Palawan basin is considered a forearc basin that resulted from the subduction of the Palawan Trench with the Cagayan Ridge which is the related volcanic arc (Taylor & Hayes; 1980, 1983). The northeast portion extends near the Mindoro-Cuyo Platform and Panay Island. The Sulu Sea basin, on the other hand, is a delta superimposed on a back-arc basin. It extends from the northeast portion of Sabah on the Malaysian territory to Negros Trench in central Philippines. The northeast deeper portion of the basin is oceanic crust; relatively flat and overlain by thin sedimentary cover.

3. Tectonic Evolution

Good understanding of the tectonic history and the resulting geometry of the basin are imperative for the definitions of workable play models in resource assessment. The basins have a complicated history of rifting and compressive deformation that only a comprehensive interpretation can reveal the structural relationship (Figure 2). We
have used for these basins the already established models of the tectonic evolution of South China Sea and Sulu Sea Basin made by Taylor and Hayes (1980 and 1983), Holloway (1982), Rangin, et. al. (1990), Hinz, et. al (1991), and Schluter, et. al. (1996).

A Mesozoic Proto-South China Sea (PSCS) existed between the North Palawan Continental Terrane (NPCT) in the north and the Borneo microcontinental plate (BMP) in the south. The NPCT was a fore-arc area of Asian mainland from Middle Jurassic through Middle Cretaceous while the BMP comprised southern Sabah, Cagayan Ridge and the Sulu Archipelago.

Back-arc rifting of the NPCT and thermal uplift and erosion occurred in the Late Cretaceous. Stretching of NPCT presumably stopped in the Early Paleocene prior to the formation of an oceanic lithosphere in the South China Sea. The failed rift basin was abandoned, subsided and was filled with clastic, paralic to shallow marine sediments from Paleocene to Middle Eocene. Rifting of the NPCT and anticlockwise rotation of the BMP induced subduction of the PSCS in Late Eocene.

Continued plate convergence along the eastern margin and marked change of direction of Pacific Plate movement caused the jump of the subduction zone along the western proto-China margin towards the south Mesozoic oceanic crust and the change of subduction direction to the south. There was obduction of ophiolites and other igneous oceanic rock of the Chert-Spillite Formation.

Further rifting and stretching led to additional thinning of the continental crust in the Late Eocene-Middle Oligocene. Spreading in South China Sea since the Middle Oligocene intensified subduction north of the approaching BMP. Rotation of the microcontinent and collision of the northeast portion with the central Philippines initiated the opening of the Sandakan sub-basin by splitting into the southern Sulu Ridge and the northern Cagayan Ridge presumably during Late Oligocene. The collision resulted in the formation of the Borneo-Sulu collisional belt. The Crocker sediments were deposited on the leading edge of the southward drifting microcontinental margin between west Mindoro, Palawan, and Borneo.

Collision of the Cagayan Ridge with the NPCT in the late Early Miocene and with central Philippines in the Middle or Late Miocene initiated subduction of the
Sandakan sub-basin along Sulu Trench and Negros Trench. South China Sea spreading ceased at the same time with the right-lateral movement along the Ulugan Fault System at around 15.5 Ma year.

Development of imbricated oceanic crustal sheets in the Balabac and Bancauan sub-basins, their piercing into the wedge of the Crocker and Chert-Spillite Formations, their obduction further onto the microcontinent between Mindoro and northeast Borneo including back-thrust formation were the main events during the Middle Miocene. The inferred northward continuation of the Sandakan sub-basin through Panay was closed during Late Miocene and Pliocene.
4. Stratigraphy

The chronostratigraphic relationship is a key knowledge in the analysis of a basin. This allows for the identification of play elements, reservoir, source and seal and analyzes their relationship. For both basins, the formation names were adopted from the stratigraphic nomenclature used by the Malaysian Geological Survey in Borneo Region (BED et al., 1986).

Figure 3a. Generalized Stratigraphy of the Sulu Sea Basin
Crystalline Basement is found in the northeast and central Tawi-Tawi and neighboring island consisting of serpentinites and peridotites. These basement rocks are pre-Tertiary.

Chert Spillite Formation (Economic Basement) termed by Fitch (1955) outcrops in Balambangan and Banggi Islands, which is estimated to be 9000 meters thick. It also outcrops in South Palawan and Balabac area. It is Late Cretaceous to Early Eocene in age and unconformably overlies the crystalline basement.

Crocker Formation was originally proposed by Wilson (1961) and was extensively observed in outcrops in Labuk Bay and Banggi area. The thinly bedded sandstones and shale ranges in thickness from 6000 to 9000 meters and is of Late Eocene to Oligocene in age.
Segama Group consists of three (3) formations where the majority is found in the area of the Dent Peninsula. These are the Ayer Formation, Libong Formation and Tongku Formation. The group is characterized by the presence of abundant submarine pyroclastic rocks of intermediate to basic composition interbedded with marine clastic sediments. The Segama Group was derived from the Crocker Formation with contribution from volcanic activities during their deposition.

Dent Group in the southeastern Dent Peninsula also consists of three (3) formations. The Sebahat, Ganduman and Togopi Formations. The Sebahat Formations has a thickness of up to 2300 meters along the western flank of the Sebahat anticline. This deltaic deposit was accompanied by distal reef growth sometimes on subsiding volcanic high (Che Mat Zin, 1994). This was followed by the deposition of the sandy southeast prograding Ganduman Formation. After a phase of major uplift and erosion in the Early Pliocene, the marine Togopi Formation was deposited. Ganduman and Togopi Formation have estimated thickness of 1400 meters and 400 meters, respectively. The provenance for both the Sebahat and Ganduman is believed to be the Older Sebahat or Tanjong Formation Equivalent. The age of the Dent Group ranges from Late Miocene to Pleistocene and unconformably overlies the Segama Group.
5. Petroleum System

The petroleum system is defined as the set of geological factors that when combined give the conditions necessary for hydrocarbon accumulations. By understanding the petroleum system in the basin, the potential resources generated, migrated and trapped can be assessed properly.

5.1 Source Rocks

Potential source rocks in the basins consist of Early to Late Miocene sediments. These sections penetrated by the wells drilled in the basins have been analyzed for total organic content (TOC), pyrolysis and visual kerogen analyses.

The Early Miocene section shows very poor source quality with very lean organic carbon content.

The gray shales in the Middle Miocene section show average to above average organic content with vitrinitic kerogens present. It has fair to good hydrocarbon generating potential if it reaches optimum maturity.

Results of analysis from Coral–1 well indicate a different proportion with oil-prone amorphous kerogen predominating over the gas-prone vitrinites. They are marginally mature in the analyzed section of Coral-1 well. Lateral equivalents of these shales in a deeper more thermally mature regime could be considered as fair to good oil and gas source rocks.

The Late Miocene section contains predominantly humic kerogen with poor to fair hydrocarbon source potential at optimum maturity. In Clotilde-1, 389-1 and Coral-1 wells, the analyzed shales are rich in organic carbon containing herbaceous-woody kerogen with fair quantities of waxy sapropel capable of generating gas and heavy oil. These source rocks are at an early mature stage but if lateral equivalents were sufficiently buried, it could generate fair to good quantities of gas and heavy oil.

5.2 Reservoir Rocks

Sulu Sea Basin

Early to Middle Miocene quartzose sandstone section penetrated by 333-1 well with gross thickness of 1300m show porosities in the range of 17-18% and permeabilities between 30 and 107md based on core analysis. The oil show logged in this well occurred in this interval. The 409-1 well also encountered thick inner neritic porous sandstone with thickness of 1650m and measured porosities of sidewall cores between 18 to 24%. Log calculations indicate 12 to 21% with the wet gas shows recorded within this section. Porosities of 13 to 22% were calculated from log of the Sentry Bank-1 well. These data are all from the wells drilled in Sandakan sub-basin.

Late Miocene rocks encountered in Sandakan sub-basin showed measured or log derived porosities of 19-35% in 333-1 well; 11-26% in 409-1 well; 18-25% in Clotilde-1 well and 20-34% in Sentry Bank-1 well.

East Palawan Basin

In the Balabac sub-basin, predominantly fine-grained elastic facies were encountered in Coral-1 well. Potential reservoir rocks from Sulu Sea A-1 well in Bancauan sub-
basin gave porosity estimates of 22-30% and low permeability on the drill stem test conducted on the thin Middle Miocene sandy limestone. Middle Miocene sandstone from Sulu Sea B-1 well sidewall cores showed porosities in the range of 27 to 31%.

5.3 Seals

Potential seals are mostly interbedded claystones and siltstones overlying the Sebahat Formation or its equivalent for the Early to Middle Miocene reservoir rocks. Interbedded sections of claystones, shales and siltstones encountered in the Sandakan sub-basin wells are all potential seals for the Late Miocene reservoir rocks.

6. Petroleum Play types

The petroleum play types identified in the Sulu Sea basin are the carbonate reef build-up (RB), anticline (AN) and fault block (FB) plays. The confirmation of the AN and FB plays was based on the Nymphe North – 1 oil and gas discovery and Nymphe – 1 gas producer which are both on the Malaysian side of the basin. The RB play is yet to be confirmed in the basin.

In the East Palawan basin, the three petroleum play types identified are the carbonate build-up (RB), anticline (AN) and stratigraphic (ST) plays. None of these has been confirmed in the basin.

6.1 Prospect and Leads

The PhilPRA Project compiled 21 structures in the Sulu Sea basin consisting of 18 prospects (10 FB, 4 RB and 4 AN) and 3 leads (1 FB and 2 RB). The average probability of discovery in the basin is 5%.

The 24 structures mapped in the East Palawan basin consist of 20 prospects (16 AN, 2 ST and 2 RB) and 4 AN leads. The average probability of discovery in the basin is 4%.

7. Resource Assessment

7.1 Estimated Resources

All of the structures in the Sulu Sea-East Palawan Basins were analyzed probabilistically using GeoX software and were risked according to the Philippine Play and Prospect Risk System. The calculated resource volumes were then classified according to the Philippine Petroleum Resource Classification System.

For the Sulu Sea basin, the hypothetical (mapped) resources are estimated at 109 MBOE while the speculative (unmapped) resources is 94 MBOE for a total of 203 MBOE. For the East Palawan basin, the estimated resources (undiscovered resources) are 443 million barrels of oil equivalent (MBOE). The hypothetical (mapped) resources are 166 MBOE while the speculative (unmapped) resources have a total of 277 MBOE.
7.1.a Sulu Sea Basin Total Resources

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<tr>
<th>Resource Class</th>
<th>Total</th>
<th>Oil</th>
<th>Gas</th>
<th>Total</th>
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<tr>
<td></td>
<td>Million Sm3 o.e. (Mean)</td>
<td>Million Sm3 (Mean)</td>
<td>Billion Sm3 (Mean)</td>
<td>Million bbl o.e. (Mean)</td>
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<td>Leads (U.1.2)</td>
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<td>Speculative (Unmapped) Resources (U.2)</td>
<td>15</td>
<td>10</td>
<td>5</td>
<td>94</td>
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7.1.a East Palawan Basin Total Resources

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<td><strong>Total Resources</strong></td>
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<td>Undiscovered Resources (U)</td>
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<td>32</td>
<td>12</td>
<td>277</td>
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8. Data Availability

8.1 Seismic

The first geophysical survey conducted in the basins was in 1965 by the Visayan Exploration Company. From 1965 to 1972, the total seismic data acquired in the basin was 12,977 line-kilometers. Geophysical offshore surveys were continued periodically from 1973 to 1997. Detailed grids of 2D surveys with average line spacing of 2 kilometers cover large parts of the basin (BED, 1986). In 1998, 3D seismic acquisition was carried out by ARCO. This brought the total 2D data to about 48,200 line kilometers and 2,000 square kilometer of 3D in the Sulu Sea Basin (Figure 4). An additional 5,740 line kilometers of 2D data were acquired by ARCO recently.

![Figure 4. Seismic Coverage Map](image_url)
9. Fiscal Regime

The Service Contract system was introduced in 1972 under the Presidential Decree No. 87 also known as “The Oil Exploration and Development Act of 1972”. Under this system, the government award contracts such as the Non-exclusive Geophysical Permit (NGP), Geophysical Survey and Exploration Contract (GSEC) and the Service Contract (SC) to qualified petroleum companies to undertake petroleum exploration, development and production. This system also provides incentives to attract investors in the petroleum industry. Below are the incentives given to petroleum prospective investors:

- Service fee of up to 40% of the net production.
- Cost reimbursement of up to 70% gross production with carry-forward of unrecovered costs.
- Filipino Participation Incentive Allowance (FPIA) grants of up to 7.5% of the gross proceeds for service contract with minimum Filipino participation of 15%.
- Exemption from all taxes except income tax.
- Income tax obligation paid out of government’s share.
- Exemption from all taxes and duties for importation of materials and equipment for petroleum operations.
- Easy repatriation of investments and profits.
- Free market determination of crude oil prices’ i.e., prices realized in a transaction between independent persons dealing at arms-length.
- Special income tax rate of 8% of gross Philippine income for subcontractors.
- Special income tax rate of 15% of Philippine income for foreign employees of service contractors and subcontractors.

The Philippine Fiscal Terms in comparison with other countries is one of the most attractive in Asia. Although the company exploring for petroleum takes all the risk, the contractor’s total take may reach as high as 83% after the deduction of the government share and taxes.
Gas Infrastructure

With the start of production of the Malampaya Gas to Power Project, this ushered in the natural gas industry in the Philippines. The 500-kilometer offshore pipeline developed by Shell Philippines Exploration BV (SPEX) from the NW Palawan to Batangas is the major backbone of gas infrastructure in the Philippines. Natural gas being produced from Malampaya field powers the Sta. Rita, Ilijan, and San Lorenzo power plants located in Batangas producing a total of 2700 MW. Several other power plants are also being considered to develop the natural gas industry in Luzon.
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