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# Thermal maturity modelling for the source rocks in blocks 10 and 11.1, Nam Con Son basin

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ABSTRACT

*Blocks 10 and 11.1 are located at the western boundary of the Nam Con Son basin, offshore southern Vietnam. Hydrocarbon shows have been encountered in many wells as the Gau Chua (GC), Ca Cho (CC), Gau Ngua (GN), Phi Ma (PM), Than Ma (TM), etc. In the CC and GN fields, the oil and gas were discovered in Miocene sandstone reservoirs and in fractured granite basement. The Cau and Dua formations are active source rocks in this area. Oil and gas discovered in wells were generated from coal and coaly claystone sediments which deposited under oxidation conditions to weak reducing in fluvio-delta to estuarine environments, in which land plants develop very abundantly. The 2D modeling results suggested that hydrocarbons discovered in the study area mainly derived from the local source rocks. The large quantity of hydrocarbons yields from source rocks in deeper part of southeastern kitchen migrated both vertically and laterally into the overlaying formations. Hydrocarbon strongly migrated lost through open fault. Prospects located near kitchen can trap hydrocarbons if they have a good seal. Block 10 and western block 11.1 face high risk of hydrocarbon charge due to the distance from the kitchen, weak top seal and fault seal. Of seal scenario, the composition of hydrocarbons accumulated in GC structure contains 87.5% volume of liquid and 12.5% volume of gas that derived from local Oligocene source rock. The composition of hydrocarbons in accumulation in CT (Ca Ty) structure of contains 99% volume of liquid and 92.5% volume of gas that derived from local Oligocene source rock.*



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## 1. Introduction

Blocks 10 & 11.1 are situated on the western margin of the Nam Con Son Basin, which is separated from the Cuu Long Basin in the north by the Con Son Swell (Figure 1) (Nguyen et al., 2009). Four (4) first exploration wells in structure BM (Bao Ma), PM, TM, DP (Dai Phong) Block 10 were drilled by Shell during the exploration phase from 1993 to 1994. In 2003, Gau Ong GO)- 1X well was drilled to total depth of 3957 mMD getting through the granite basement by ConSon JOC. In 2004, Gau Den Dong (GDD)-1X well was drilled as a deviated well that reached a total depth of 4489 mMDSS (4245.5 mTVDSS). The target of these wells was to test the hydrocarbon potential of Lower to Middle Miocene sandstones and basement rocks in a large horst block. Hydrocarbons are discovered in BM, PM and GO structures (Con Son JOC, 2011; EPC/TNK Joint Study, 2018).

In Block 11-1 there are four (4) exploration wells in structure CC, Ca Ty (CT), Ca Pecca Dong (CPD) and Ca Heo (CH) drilled by Shell during the exploration phase from 1994÷1996. The primary objective was to test the hydrocarbon potential of Lower to Middle Miocene sandstones. Oil and gas shows were encountered mainly from 3100÷3680 mMD in the Middle Miocene sandstone reservoirs in CC structure; oils are generated by source rock containing resinitic organic matter with kerogen Type III; without being contributed by algal lacustrine material as the other oils in Nam Con Son basin. Three wells in CT, CPD, CH structures failed. The reason for the failure of these wells is also assigned for insufficient hydrocarbon charge (Con Son JOC, 2011; EPC/TNK Joint Study, 2018).

In 2007, ConSon JOC drilled the vertical wildcat well in GC prospect. The main objective is to evaluate the potential of the Lower Miocene sandstone and the secondary objective is fractured

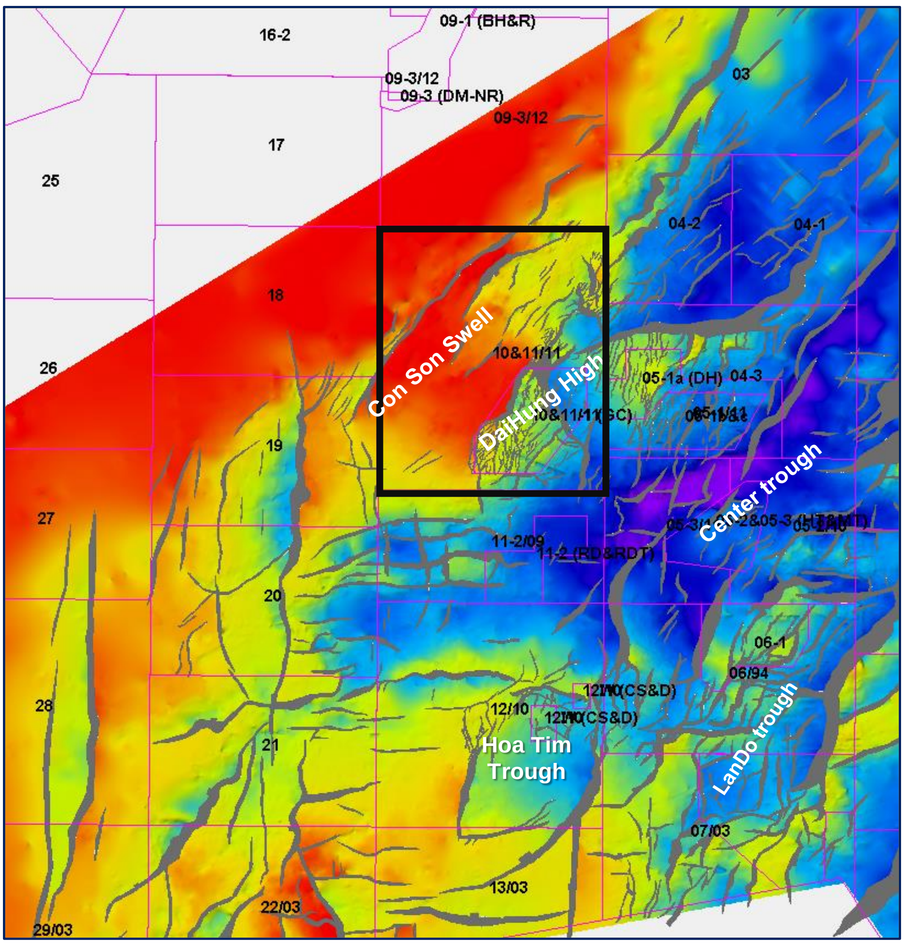



*Figure 1. Structure map of Blocks 10 & 11.1 in Nam Con Son basin. (Con Son JOC, 2011).*

granite basement. The well reached total depth at 4329 mMD and encountered oil and gas in both of two targets. Sidetrack well in GC structure was drilled to test hydrocarbon potential of Middle Miocene in GN prospect and the up-dip potential of GC clastic. In the GN prospect, oil and gas shows were encountered continuously and stronger than in GC prospect. More new oils bearing reservoirs in CC and GC structures have been found in the appraisal wells in CC, GC structures.

The aims of this article are to asscess the thermal maturity history of source rocks, to check drainage area for trap and to define the role of seal of the petroleum system in blocks 10 & 11.1.

*Geological setting*

In Block 11.1, the existence of the first rifting phase is not apparent as this is a footwall area of the significant E-W fault running through Block 04-3 to the north of Block 11.1. The Oligocene sediments could be absent or very thin on the structure highs toward the north and east and thickening toward the south as encountered in the CPD structure. In block 10, to the north of the mentioned above E-W fault, there is a nearly E-W graben formed during the first rift phase with thick Oligocene sediments (Figure 2).

Second rifting phase in blocks 10 & 11.1 began in the early beginning of the Early Miocene; the extensional faults have been developed as growth faults since Early Miocene until Late Middle Miocene, resulted >1000 m differential relief of basement in both sides of the significant faults. During the extension, there are several times of faulting ceased and reactivated again as implied by parallel or divergent of seismic pattern toward the fault plane on the hanging wall side (Nguyen et al. 2009; EPC/TNK Joint Study, 2018).

During the early Miocene, the morphology of most southern areas in block 11.1 was controlled by large listric faults running nearly north - south (N-S) and north east - south west (NE-SW), dipping toward each other to form a graben shape. Up to the Middle Miocene, the large listric fault tended to develop to the east of the block, dipping toward the SE, the consequence is the whole study area became a large hanging wall side and tilting to the SE .

The Middle Miocene unconformity (MMU) is the last regional unconformity surface in the study area, where most of the growth fault stopped underneath it. Some large faults kept developing to upper Miocene mostly due to gravity and different compaction on the two sides of the faults. Upper Miocene to present day is thermal subsidence phase with overall progradation of marine sediment toward the basin centre (Figure 2).

The fault patterns of blocks 10 & 11.1 can be divided into three systems: the N-S and NE-SW directions developed during the second rift phase from lower to middle Miocene. The N-S fault system tends to dominant toward the west while the NE-SW one controls to the east and northeast; this is due to the stronger influence of the East seafloor extension. The E-W fault system that is observed in block 10 is activated in the first rift phase and dies out during late of Oligocene period (Figure 1) (EPC/TNK Joint Study, 2018). T85 (Upper Miocene) regional seal widely distributes

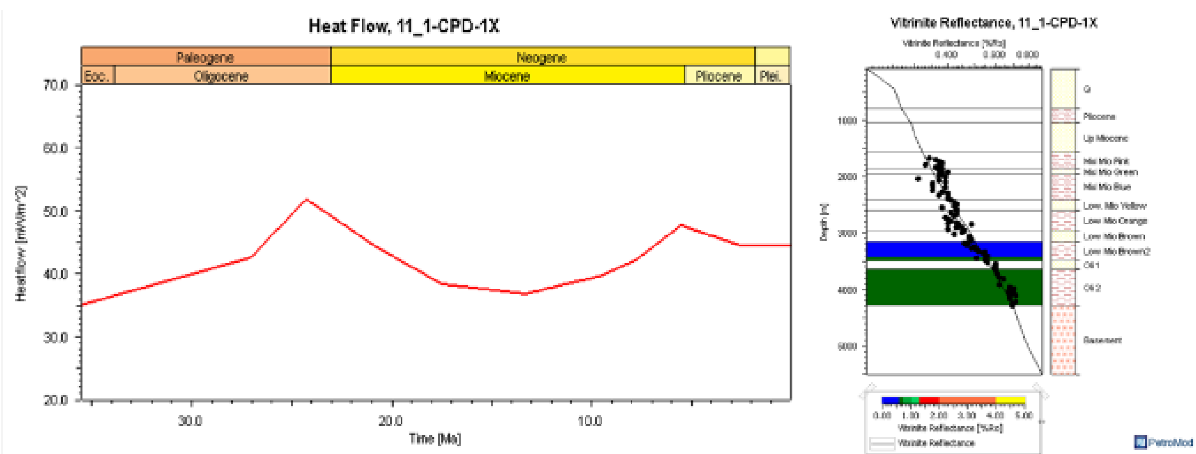



*Figure 2. Summary of tectonic history of Nam Con Son Basin and Blocks 10 & 11.1 (Con Son JOC, 2011).*

in central Nam Con Son basin with hundreds of meters in thickness. However, it is restricted in the west as in blocks 10, 11.2 and 11.2 with a thickness of tens of meters. Sediments in T85 sequence are sand - shale interbeds deposited in shoreface/deltafront environment (EPC/TNK Joint Study, 2018).

## 2. Data and research methods

### *2.1. Source rock properties*

This study discusses source rock data collected from geochemical analytical reports and previous regional studies. Oligocene and Early Miocene organic-rich sediments are the source rocks in Nam Con Son basin (EPC/TNK Joint Study, 2018).

Oligocene (T20) claystone samples are only at 11-1-CPD-1X well. The interval of Oligocene formation that this well drilled through is from fair to good in source rock quality (TOC = 0.6÷1.7% wt; $S_2$ = 0.2÷3 mg/g). Coal/coaly shale samples also were encountered with very high TOC, $S_2$ values (TOC, $S_2$ up to 19.5% wt, 64 mg/g, respectively). Source rocks mainly contain kerogen Type III - mixed generation potential of oil and gas.

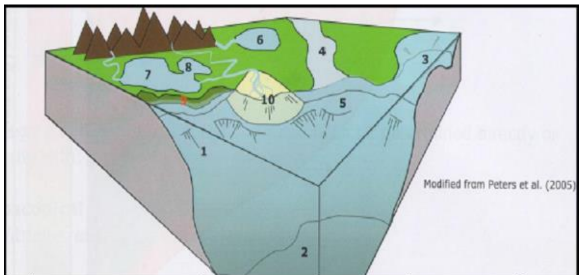
Lower Miocene sediments: Most samples of fine-grained sediments are fair to good in organic matter richness and hydrogen index values (HI) less than 400 mgHC/gTOC in blocks 10&11-1. Coal/coaly shale samples are predominant with high TOC, $S_2$ values (TOC >10% wt, S2 >20 mg/g). The source rock contains mainly kerogen Type III and Type II for oil-gas generating potential. The source rock is immature to mature zone ($410^0$C < Tmax < $445^0$C) and is of lower maturity level than Oligocene source rock.

Because of T10 is not found out in any wells in the study area, the source rock distribution was predicted by sedimentary facies.

Extracted samples collected from shale source rock are reserved in oxidation environment to weak reducing in blocks 10 & 11.1 (Pris/Phy > 3.0). Predominance distribution of $C_{29}$ sterane compared to $C_{27}$ and $C_{28}$ indicates that source rocks deposited in fluvio-delta to estuarine environment, in which land plant develop very abundantly. Discovered oils in block 11.1 and adjacent blocks have low sulphur content (%S < 1.0), high ratios of Pris/Phys (Pr/Ph > 3.0) and medium to high wax content, suggesting to reserved oil in oxy rich environment. Based on their properties, oils are classified typical for terrestrial origin oil (non-marine).

### *2.2. Source rock model*

Based on the concept model showing relationship among common depositional environments, lithofacies and kerogen type for petroleum source rocks (Figure 3) (Pepper and Corvi, 1995; Peters et al., 2005) organic matter in Oligocene source rock for the given geological model contains mainly mix of Type II/III and Type III kerogen with organofacies D/E and F. Coal and coaly-shale are discontinuous in paralic, coastal swamp and contain Type III - III/IV kerogen with organofacies D/E and F.




| No | Environment | Lithofacies | Organofacies | Redox | Kerogen |
|---|---|---|---|---|---|
| 1 | Upwelling shelf | Shale, carbonate, chert, phosphate | A, B | Anoxic-dysoxic | II-S, II |
| 2 | Open ocean, prodelta | Prodelta shale | B, D/E | Suboxic-aerobic | II/III |
| 3 | Restricted, silled basin | Shale | B, D/E | Anoxic-dysoxic | II |
| 4 | Epicontinental sea | Shale, carbonate | A,B | Anoxic-dysoxic | II-S, II |
| 5 | Restricted basin | Carbonate | A | Anoxic-dysoxic | II-S |
| 6 | Fluvial, marginal lacustrine | Siltstone, shale | C, D/E | Dysoxic-aerobic | I/III |
| 7 | Open lacustrine | Shale | C, D/E | Anoxic-dysoxic | I |
| **8** | **Restricted lacustrine** | **Shale** | **C, D/E** | **Anoxic-dysoxic** | **I** |
| **9** | **Paralic, coastal swamp** | **Shale, Coal** | **D/E, F** | **Dysoxic-aerobic** | **II/III, III** |
| 10 | Paralic, deltaic | Coal, shale | D/E,F | Dysoxic-aerobic | II/III, III |

*Figure 3. Relationship among common depositional environments, lithofacies and kerogen types (modified from Peters et al., 2005).*

Restricted lacustrine (T10) contains Type I kerogen with organofacies C, D/E. Early Miocene source rock deposited in deltaic- coastal zone contains mainly Type III kerogen. For this model, kerogen in Early Miocene source rocks was assigned as Type III kerogen with organofacies D/E and F. Coal and coaly-shale are in paralic, coastal swamp and contain Type III - III/IV kerogen with organofacies D/E and F.

### *2.3. Boundary conditions*

Paleo water depth (PWD), sediment water interface temperature (SWIT), and heat flow (HF) require boundary conditions to determine the basic energetic conditions for the thermal development and maturation of organic.

Estimation of paleo-water depth is sometimes complicated especially when high resolution biostratigraphic data are not available like the case of this study. The PWD was inferred from the interpreted paleo depositional environment by following relationships: Aluvial: 0 m; Swamp: 5÷10 m; Lacustrine 10÷20 m; Coastal: 0÷10 m; Shelf: 20÷200 m.

Sedimentary water Interface Temperature or Paleo-water interface temperature in this modeling was calculated using the reconstruction map of paleo-water by Wygrala (Wygrala, 1989). The location of the study area is in Northern Southeast Asia with latitude of $80^0$. Present-day SWIT is collected from wells .

Because Nam Con Son basin is a rifting basin, the heat flow model is a modification of the classic McKenzie model (McKenzie, 1978). The heat flow profiles have been well calibrated with measured vitrinite reflectance and temperature values from wells (Figure 4).

The modeling was done using the PetroMod Petroleum System Modeling software by Schlumberger (1D and 2D).

### 3. Results

Line 1 tests the role of local kitchen next to Phi Ma structure. Aluvial/Fluvial Oligocene sediment does not act as source rock in this area. Lower Miocene coastal plain shale and swamp were assigned as petroleum source rocks. The modeling results show the present-day maturity level and transformation state for the lines with calibration to well data.

Oil generation and migrated evolution are shown in Figure 5. The maturation of source rock started at 15.5 Ma when it was buried to 2500 m; main oil phase (0.7÷1.0% Ro) started at 11.3 Ma; late oil phase (1.0÷1.3% Ro) started at 9.2 Ma. The primary migration of hydrocarbon in Early

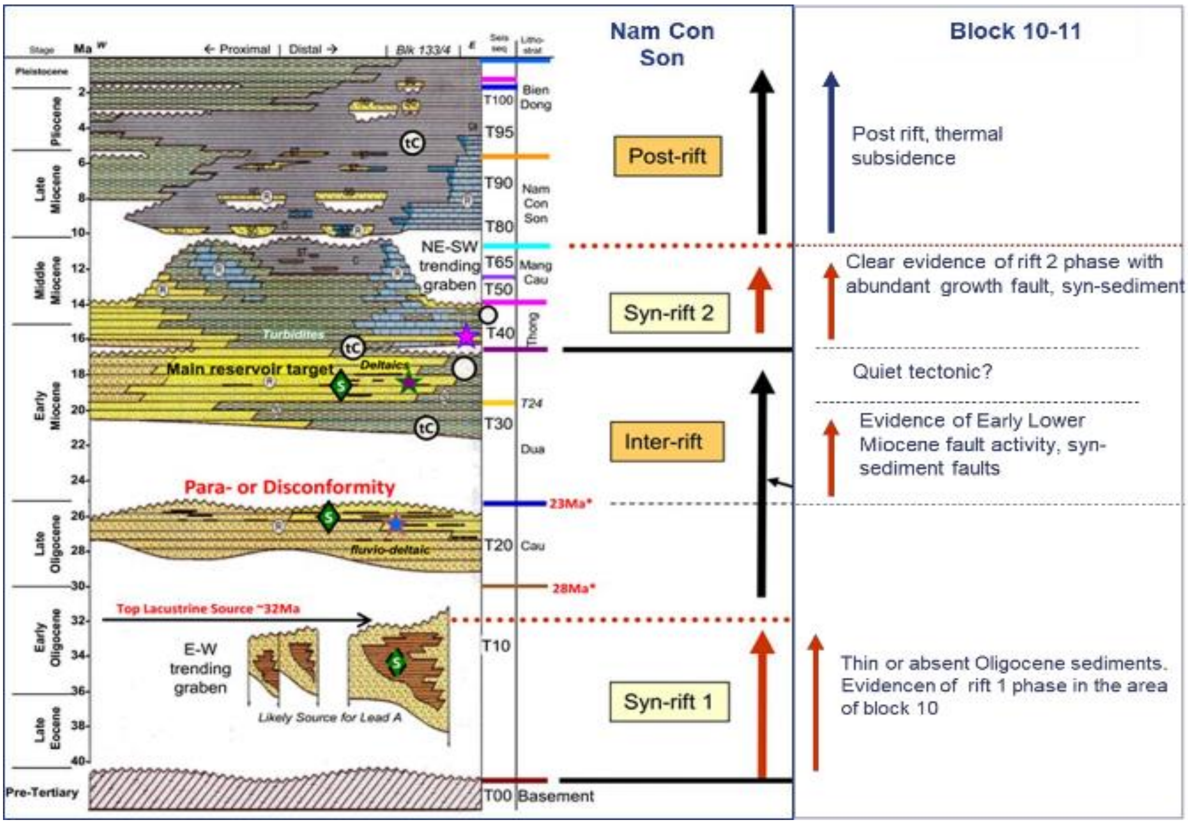



*Figure 4. Heat flow trends calibrated by temperature and vitrinite reflectance data from 11.1-CPD-1X well (Con Son JOC, 2011).*

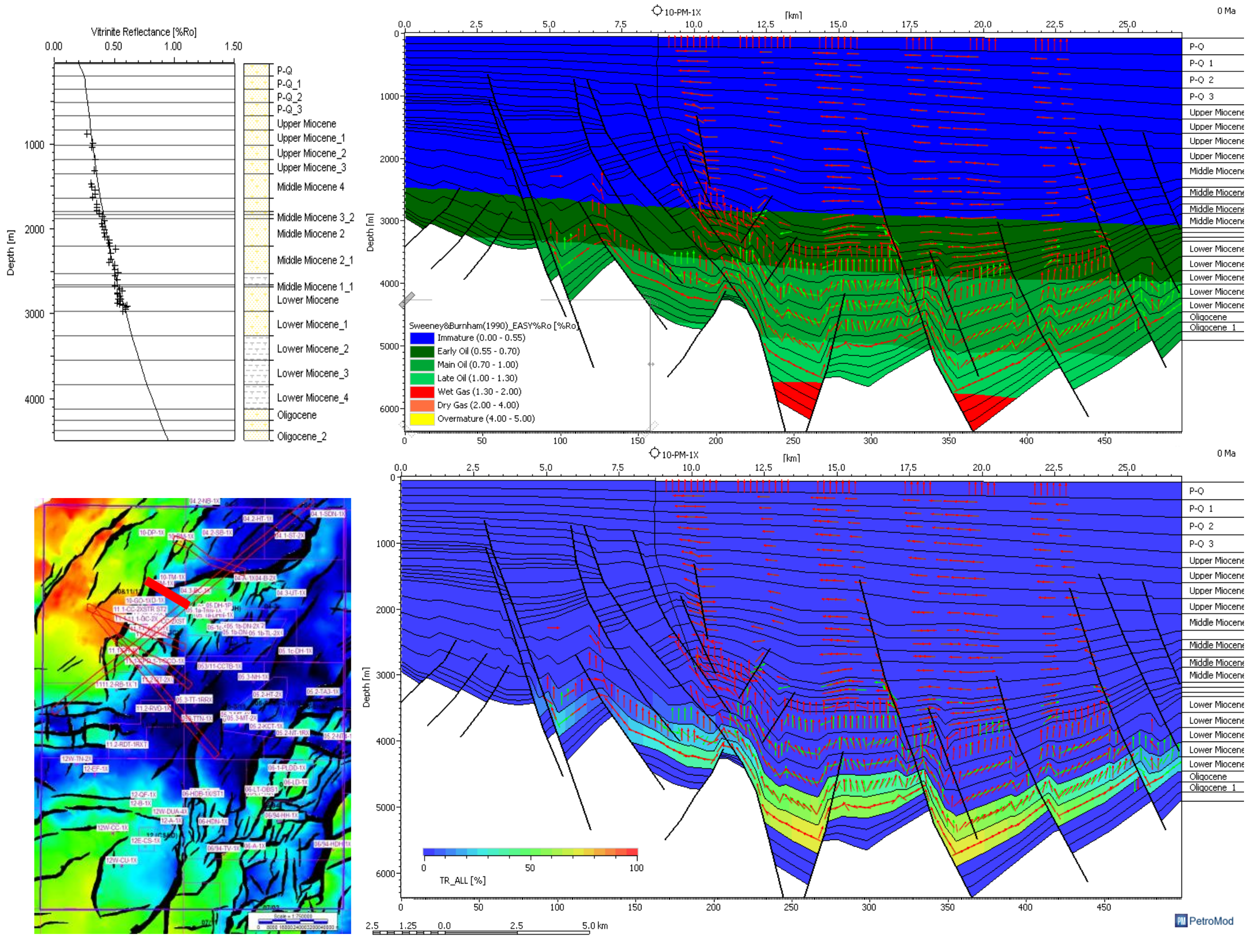



*Figure 5. Present day maturity (upper) and transformation ratio of OM in sediment (lower) - line goes next to PM structure block 10.*

Oligocene source rock started at that time along the open faults. At 9 Ma, gas started migrating along the open faults. Hydrocarbon was lost while migrating along the big faults because of lack of seal layers. Wet gas phase started at 1.4 Ma. At present, all of Lower Miocene source rocks are in the oil window.

Line 2 modeling runs for tracking hydrocarbon in CT area (Figure 6). Oligocene lacustrine, Oligocene and Lower Miocene swamp, and Lower Miocene coastal plain shale were assigned as source rock for oil and gas. The modeling results show the present day maturity level and transformation state for the lines with calibration to well data. It is indicated that large quantity of hydrocarbons yield from source rocks in deeper part migrated both vertically and laterally into the overlaying formations.

Since 26.9 Ma, source rock at deepest area has started to be matured and reached to main oil phase at 24.5 Ma; late oil phase started at 19.1 Ma (Figure 6). The first hydrocarbon migrated along open fault at that time. At present, Oligocene source rocks are over mature and Lower Miocene source rocks produce dry gas. Source rock in CT structure are in oil window phase now. CT source rock started to be matured at 20.9 Ma and reached main oil phase at 15.5 Ma. The first hydrocarbon migrated from Oligocene source rock in CT area took place when it reached the late oil phase from early 7.5 Ma but was lost through unseal fault.

Regarding the role of seal in petroleum system within the study area, Upper Oligocene - Lower Miocene swamp and Lower Miocene coastal plain shale were assigned as source rock. Middle Miocene coastal plain shale was assigned as seal layers. The modeling result indicated the significant difference between two scenarios (Figure 7 & 8).

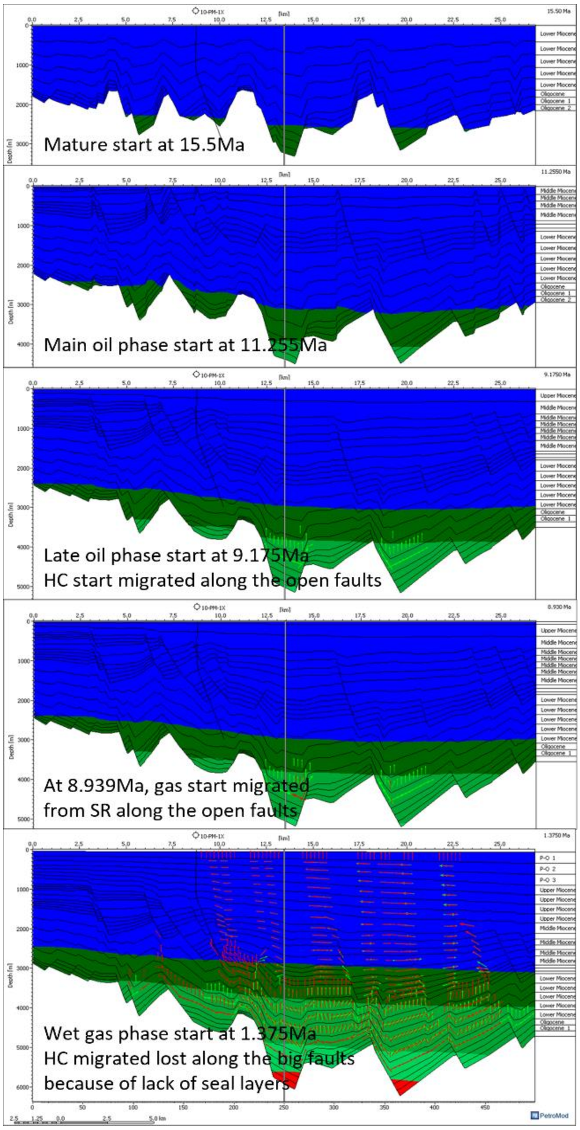



*Figure 6. Hydrocarbon generation and migration at line 2 through well drilled in CT structure. Hydrocarbon migrates along unseal faults.*

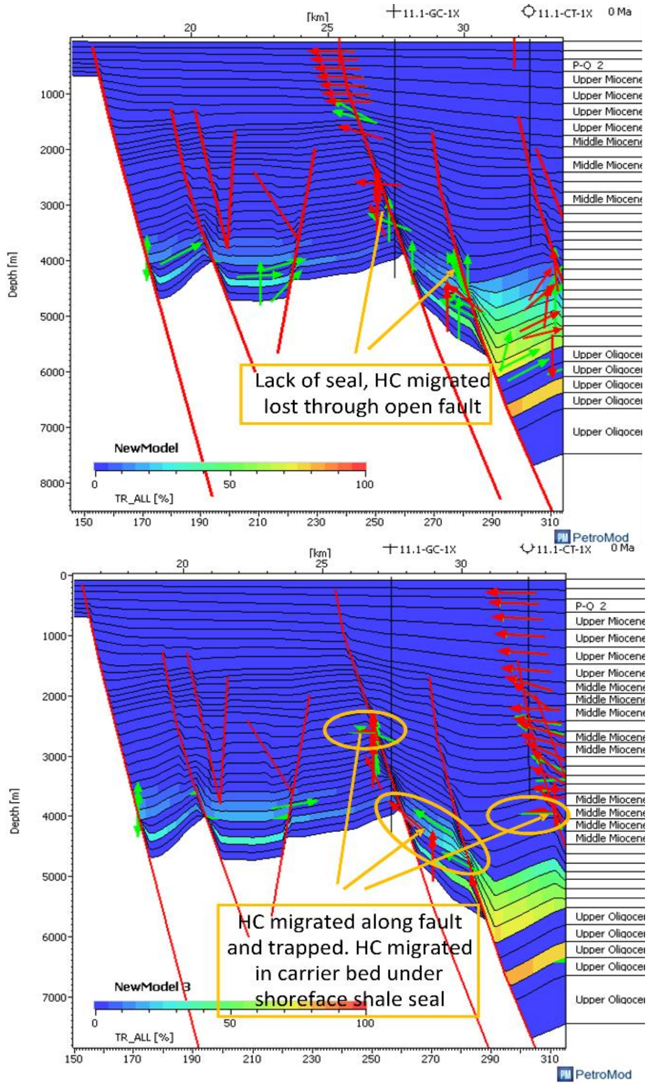



*Figure 7. Hydrocarbon composition in accumulation of scenario with seal layers. Present day transformation ratio of OM in sediment in 2 scenarios. Red arrow as gas migration, green arrow as oil migration.*

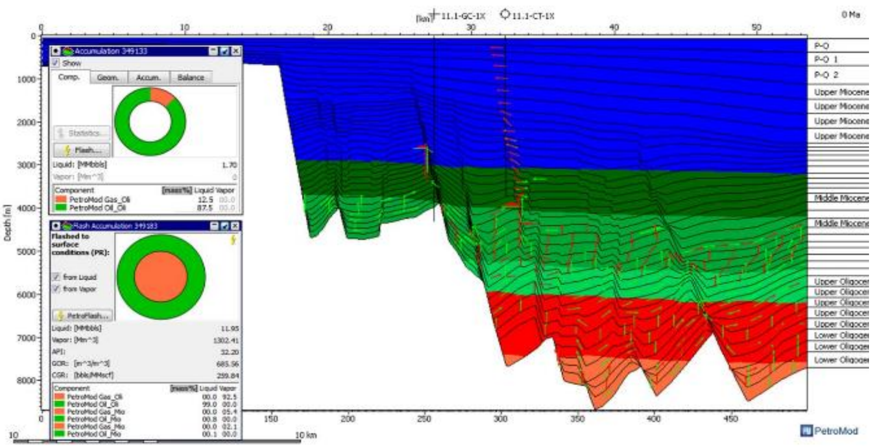


*Figure 8. Hydrocarbon composition in accumulation of scenario with seal layers.*

In the case of lack of seal, source rock is in the late oil phase, hydrocarbon strongly migrated lost through unseal fault. Meanwhile, in the case of shoreface shale acting as seal, hydrocarbon migrated in carrier bed under shoreface shale seal or migrated along the fault and trapped in close fault structure (Figure 7).

Of seal scenario, the composition of hydrocarbons accumulated in GC structure contains 87.5% volume of liquid and 12.5% volume of gas that derived from local Oligocene source rock. The composition of hydrocarbons in accumulation in CT structure of contains 99% volume of liquid and 92.5% volume of gas that derived from local Oligocene source rock (Figure 8).

The maturity maps of Oligocene and Early Miocene source rocks are shown in Figure 9.

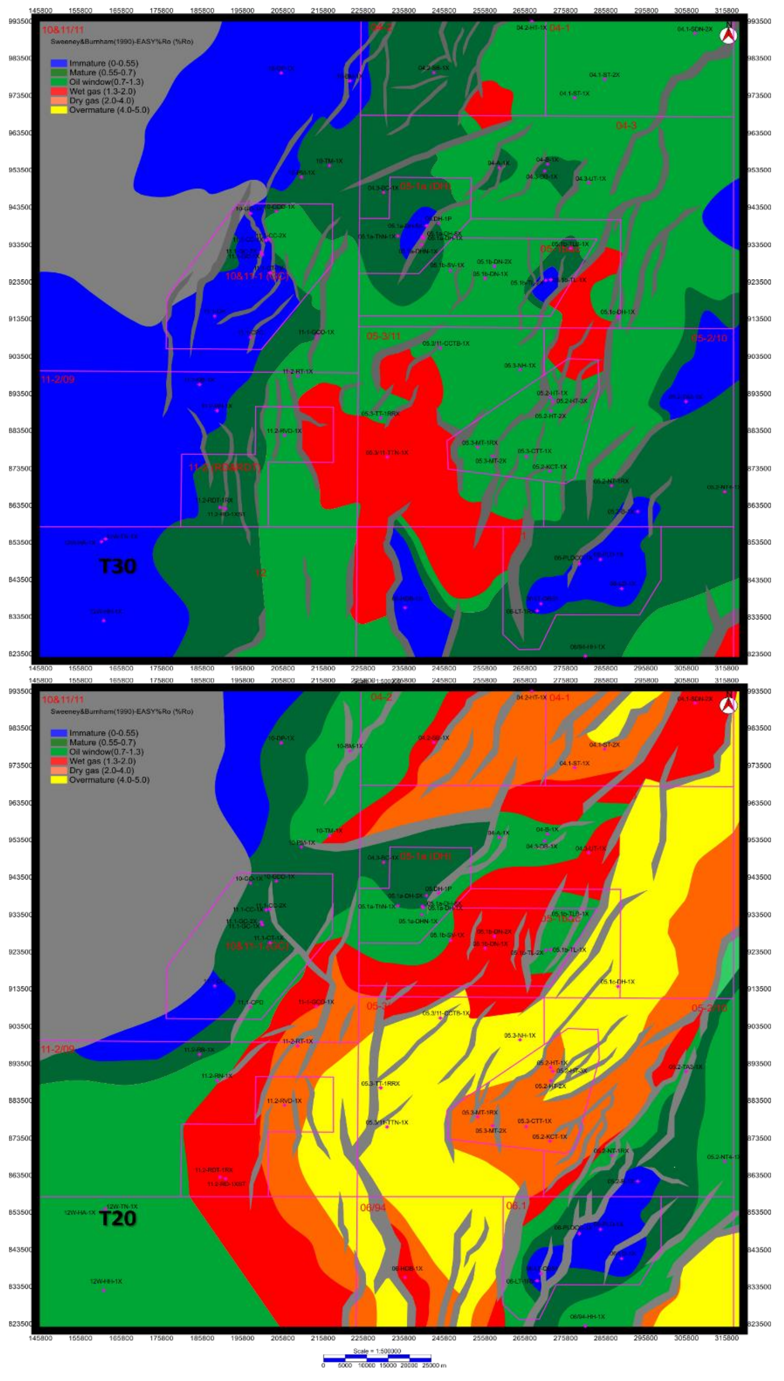



*Figure 9. Maturity distribution of Top T30 and Top T20 formations in study area at present time.*

Block 10 &11.1 lack T10 source rock. T20 (Oligocene) source rock in blocks 10 & 11.1 are in mature to oil window phase except GCO structure area (wet gas stage). Coal and coaly claystone in trough nearby can be good source rock (particularly high in TOC, $S_2$) and supply HC for the structure in blocks 10 & 11.1 if there is good seal. T30 (Lower Miocene) source rocks in block 11.1 are immature to oil window phase and can be good source rocks which supply HC for the structure in blocks 10 & 11.1.

## 4. Conclusion

The 2D modeling results suggested that hydrocarbon accumulations in the study area mainly derived from the local source rocks.

Block 10 and western block 11.1 face high risk of hydrocarbon charge due to the distance from the kitchen, weak top seal and fault seal.

Prospects located near kitchen can have accumulation if they have good seal.

## Contribution of authors

Nga Hoai Le - proposes ideas and contributes to the manuscript; Huyen Dieu Thi Pham - reviewed and edited the manuscript; Lan Tuyet Thi Nguyen - collected and analyzed the data.

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