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DETERMINATION OF SHALE GAS POTENTIAL OF NORTH SUMATRA BASIN: AN INTEGRATION OF GEOLOGY, GEOCHEMISTRY, PETROPHYSICS AND GEOPHYSICS ANALYSIS

PENENTUKAN DAERAH POTENSI SHALE GAS INTEGRASI ANALISIS GEOLOGI, GEOFISIKA, DAN GEOKIMIA CEKUNGAN SUMATERA UTARA

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ABSTRAK

Kajian geologi dan geofisika terkombinasi secara rinci di cekungan Sumatera Utara menunjukkan bahwa formasi-formasi yang memiliki prospek sebagai play serpih yang mengandung sweet spot gas adalah serpih dari Formasi-formasi Bampo, Belumai, dan Baong. Formasi Bampo menunjukkan kualitas potensi gas serpih yang kurang baik, dengan kandungan material organik umumnya sangat rendah hingga sedang, tingkat kematangan kurang matang hingga matang, dan tingkat kerapuhan tidak rapuh hingga cukup rapuh. Batuan dikategorikan sebagai reaktif hingga sangat reaktif terhadap air dengan tingkat swelling sedang. Porositas bervariasi pada 5.8 - 7.4% dengan permeabilitas pada 0.37 - 3.2 mD. Area-area sweet spot pada formasi ini di sekitar sumur Basilam-1 dan Securai-1 menempati sekitar 21% dari keseluruhan formasi. Di sisi lain, Formasi Belumai memiliki kualitas potensi gas serpih sedang hingga baik, dengan kandungan material organik rendah hingga tinggi, tingkat kematangan belum matang hingga matang, dan tingkat kerapuhan cukup rapuh hingga sangat rapuh. Lokasi-lokasi sweet spot pada formasi ini di sekitar sumur kedua sumur menempati sekitar 29% dari volume batuan. Untuk Formasi Baong, indikator-indikator yang sama menunjukkan kualitas potensi gas serpih yang sedang hingga baik, kandungan material organik rendah hingga sedang, tingkat kematangan belum matang hingga matang, dan tingkat kerapuhan cukup rapuh hingga rapuh. Serpih di formasi ini dapat dikategorikan sebagai reaktif hingga sangat reaktif terhadap air dengan tingkat swelling kecil hingga sedang. Sweet spot pada formasi di sekitar kedua sumur menempati sekitar 11% dari volume batuan. Pemodelan cekungan memperlihatkan pembentukan gas berada pada kedalaman 2300m pada Formasi Baong Bawah, Belumai dan Bampo. Estimasi sumberdaya sweet spot gas serpih di cekungan Sumatera Utara pada Formasi Bampo, Belumai, dan Baong adalah masing-masing sebesar 6.379 TCF, 16.994 TCF, dan 25.024 TCF dengan jumlah total 48.397 TCF. Volume sumberdaya gas yang dihasilkan dari estimasi adalah bersifat spekulatif dan belum memasukkan faktor kepastian dan efisiensi apapun.

Kata Kunci: *Gas serpih, Cekungan Sumatra Utara, kandungan total karbon organik, indeks kerapuhan, Formasi Baong, Formasi Bampo, Formasi Belumai, smektit, impedansi akustik, CWT, sweet spots, sumberdaya gas spekulatif.*

ABSTRACT

A detailed combined geological and geophysical study in North Sumatra basin has shown that prospective formations for shale play containing gas sweet spots are found to be in shales from Bampo, Belumai, and Baong Formations. Bampo Formation exhibits low shale gas potential with very low to medium in organic material contents, maturity index of immature to mature, and moderate brittleness. Rocks within the formation tend to be reactive to highly reactive to water, with a moderate degree of swelling capacity. Porosity varies within 5.8 - 7.4 % with permeability ranging from 0.37 to 3.2 mD. Sweet spots in the formation found around Basilam-1 and Securai-1wells occupy about 21% of the formation. On the other hand, Belumai Formation shows moderate to good shale gas potential, with low to high organic material contents, immature to mature levels of maturity, and moderately brittle to brittle. Sweet spot areas in the formation found around the two wells are about 29% of the formation. For Baong Formation, analysis reveals moderate to good shale gas potential, with low to medium contents of organic material, immature to mature in maturity index, moderately brittle to brittle in brittleness, and tendency of being reactive to highly reactive to water but with low degree of swelling capacity. Sweet spots in the formation found around the two wells occupies are roughly 11% of the total formation volume in the area. Basin modeling leading to gas resources estimation for Baong, Belumai and Bampo Formations has led to estimated volumes of 6,379 TCF, 16,994 TCF, and 25,024 TCF, respectively, with a total amount of 48,397 TCF. The resources figures are speculative in nature and do not incorporate any certainty and efficiency factors.
Keywords: Shale gas, North Sumatra Basin, total organic carbon, brittleness index, Baong Formation, Bampo Formation, Belumai Formation, smectite, acoustic impedance, continuous wavelet transform (CWT), sweet spots, gas speculative resouces.

I. INTRODUCTION

In Indonesia, investigation of shale gas potential is an alternative exploration activity in order to anticipate the decline in conventional oil reserves. An increasing gap between the growing needs of oil and the decline in national oil production has made Indonesia a net oil importer country. The government of Indonesia has envisioned that natural gas is a source of substitution to the oil production decline and - despite the relative abundance in reserves – encouraged its continuing exploration by the industry. One sector that has recently gained momentum throughout the world is exploration of non-conventional oil and gas accumulations, including shale gas. Successes in shale gas production and technology application in the United States (e.g Rach, 2007; Kargbo and Wilhelm, 2010; Song et al. 2011; Wang and Krupnick, 2013; Aguilera and Radetzki, 2013) and Canada (e.g Aguilera and Radetzki, 2013; Rivard et al. 2014) have inspired many countries to follow these examples. Research and applications in other countries that have followed suit, such as in China (e.g Zang, 2012; Wang, 2013), have also triggered similar interest in countries that have just started such as Indonesia.

A shale gas reservoir is a spot containing natural gas that is formed within shale formations. Having complied to a set of technical criteria, this spot is called ‘sweet spots’. Shale gas sweet spots normally occur in relatively deep formation of more than 2000m of depth, and are characterized by low permeability of less than 0.001 mD, porosity that ranges from 3 to 12%, and mostly of overpressured condition (Lewis, 2004). The United States has been developing this source of energy since the 1940s, and as a result of significant attention being given to research and development it has gained large recoverable reserves of around 500 TCF (U.S. Energy Information Administration, 2011) and a contribution to the US annual national gas production at present of around 38%. This contribution is expected to reach 53% by 2040 (International Energy Agency, 2014).

In general, Indonesia’s geological setting and conditions allow the presence of shale hydrocarbon and discovery of large scale shale gas reserves. Geological Agency of the Ministry of Energy and Mineral Resources (GA-MEMR) of the Republic of Indonesia has predicted that the resource potential of Indonesia’s shale gas resources reaches up to 574 TCF (GA-MEMR, 2011). Therefore intensive efforts are needed exploring and discovering gas reserves in shale gas reservoirs. Indonesia has plenty of potential shale formations. Preliminary studies have shown that successions of thick sedimentary shales in Indonesia have the potential to form shale gas plays. Examples are Baong and Bampo Formations in North Sumatra, Pematang and Telisa Formations in Central Sumatra, Talang Akar and Gumai Formations in South Sumatra and North West Java, Ngimbang Formation in East Java, Tanjung Formation in South Kalimantan and Klasafet Formation in Papua (U.S.

Energy Information Administration, 2015).

The aim of this study is mainly to evaluate the potential of shale gas in North Sumatra Basin based on field study results combined wih subsurface seismic cross-sections, surface core samples, and well log data. This paper is focused on detailed review on the determination of source rock quality and thermal maturity from outcrop samples, geophysical evaluation including seismic attribute analysis, artificial intelligent (AI) and continuous wavelet transform (CWT) gradient analysis, petrophysical of shale properties, and shale gas resource estimation. Research study is focused on locations around the Gebang area, Pangkalan Brandan, and Langkat - North Sumatra (Figure 1). Implementation of the studies is carried out by integrating various geoscience disciplines including sedimentology, geochemistry, geophysics, geological modeling, and shale gas system analysis. It is hoped that results of this study can pave the road to deeper studies leading to the exploration and exploitation of shale gas in the area.

A. Regional Geology

North Sumatra Basin is a complex containing a series of sedimentary basins located at the top of Sumatra Island (Figure 1). The basin has Northwest - Southeast axial geometrical direction covering an area of about 96,370 km^2, approximately 20,530 km^2 onshore and 75,840 km^2 offshore. North Sumatra Basin is a back arc basin formed by the subduction of the Indian - Australia plate under the Eurasian plate in Late Eocene - Oligocene. The basin is geologically bordered in the southwest by the Bukit Barisan Mountains, in the southeast by Asahan Arc, and in the northeast by the Malaysian Peninsula. The northern part of the basin is open towards the Andaman Sea.

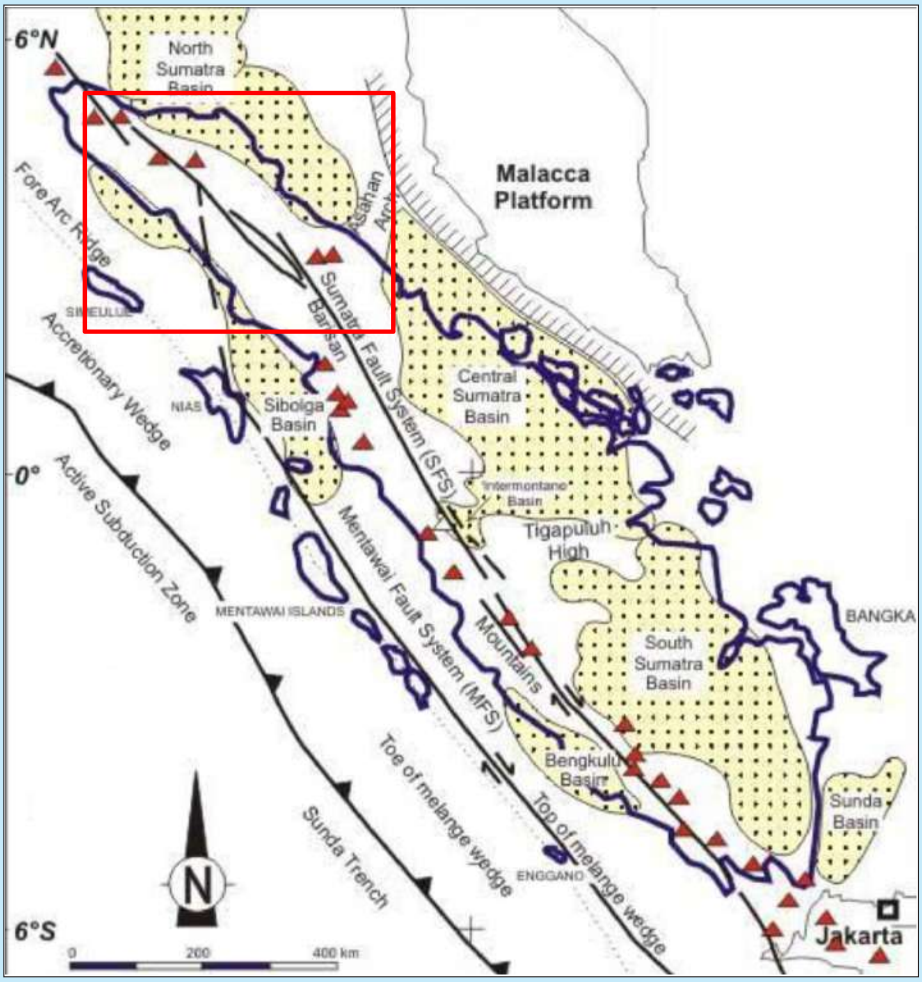


Figure 1
Location of study area and physiography of Sumatra (Darman and Sidi, 2000), shown in red-line rectangle.

Yulianto and Situmorang (2002) mentioned that there are three structural elements in North Sumatra Basin (Figure 2); including the Northwest - Southeast structures parallel to the axis of the basin such as the Aceh Sub-basin, structural elements such as high and depression trending north - south (Yang Besar High and Tamiang Sub-basin/Tamiang Graben), and highs trending northeast - southwest (south of Yang Besar High). They also explained that there are two major fault systems of North Sumatra Basin, the Sumatra fault system/ SFS in northwest – southeast direction and fault systems in north - south direction. The north - south trending fault system is a major fault that controls the development of the Tertiary basin of Sumatra Island.

B. Stratigraphy

North Sumatra Basin stratigraphy is divided into Pre-Tertiary and Tertiary sediments. The Pre-Tertiary sediment consists of basement of North Sumatra Basin, which is composed of low-grade metamorphic rocks of Permian and Jura - Cretaceous (Cameron and Aspden, 1982), igneous intrusion of Paleozoic and Mesozoic, and dolomite/ limestone of Early Tertiary (Eocene). Tertiary sediment was unconformably deposited on basement as described in stratigraphic column according to Yulihanto and Situmorang (2002) (Figure 3). Basal sandstones and conglomerates of Oligocene-Early Miocene Bruksah/Parapat Formation are early rift-valley sediment infill and were deposited as fluviatil – alluvial sediments. Finer grain size on the upper part of the formation contained local coal, lignite and tufa. The Parapat/ Bruksah Formation is laterally and vertically interfingering with shallow marine sediment (restricted) - lacustrine of Late Oligocene - Early Miocene Bampo Formation. Oligocene - Early Miocene Bampo Formation consists of claystone and massive calcalreous dark gray shale. Fossil contents is limited as it is interpreted that this formation was deposited on euxinic environment, and conformably deposited above the Bruksah/ Parapat Formation.

Peutu Formation, which is equivalent to Belumai Formation in the eastern part of the basin, was deposited at the initiation of the transgressive phase during Early Miocene - Middle Miocene. At the top of basement highs, Peutu Formation is observed as limestone reef, but it is also found as calcareous claystone and calcareous siltstone (containing high amount of glauconite). Baong Formation was

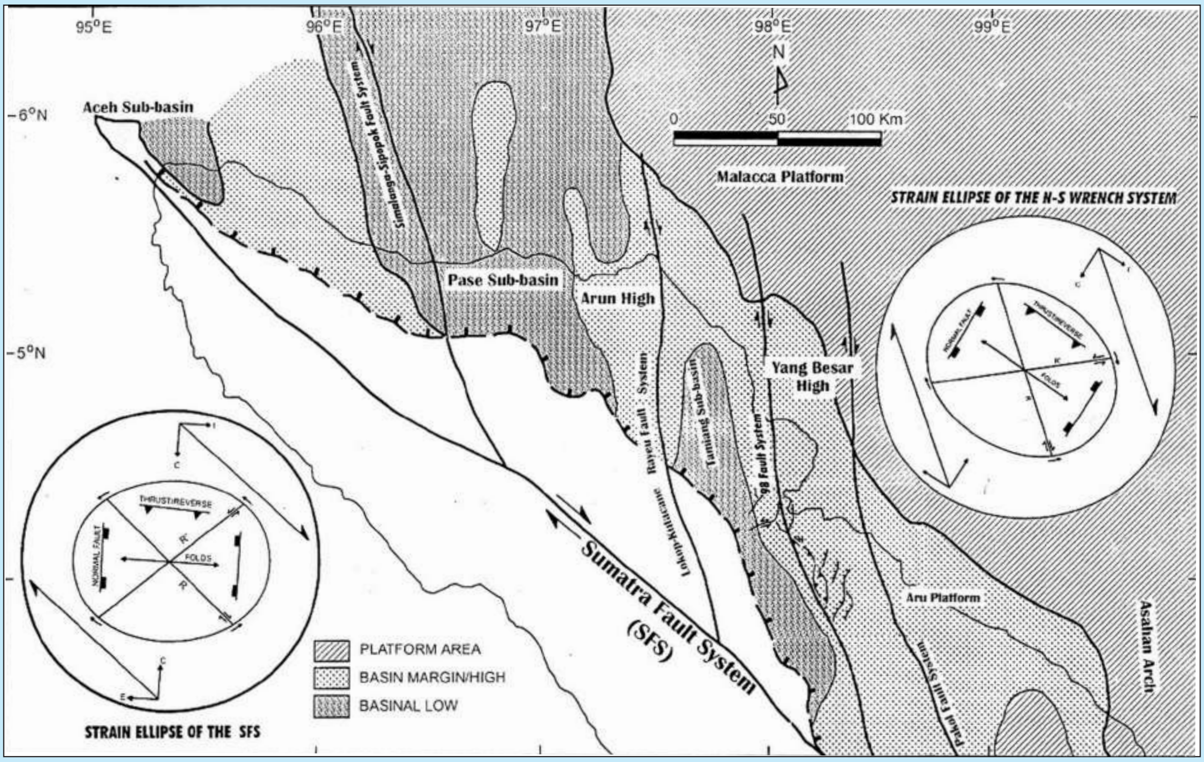


Figure 2
The main fault system and the North Sumatra Basin tectonic elements (Yulihanto and Situmorang, 2002).

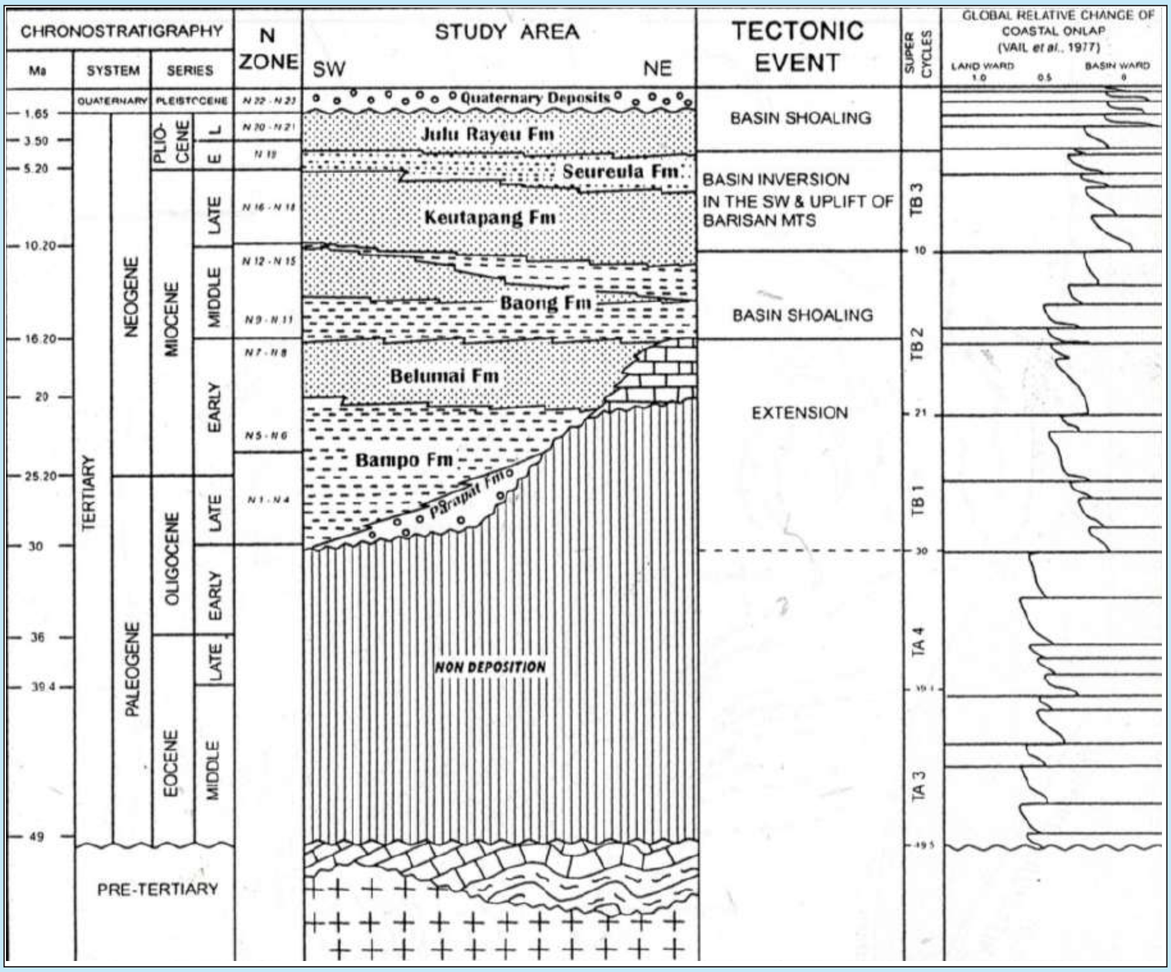


Figure 3
Simplified stratigraphy of North Sumatra Basin (Yulihanto and Situmorang, 2002).

deposited in Middle Miocene - Late Miocene in neritic environment (dark gray, massive, calcareous, rich in foraminifera). The formation is overpressured and is considered as source rock.

Locally, shale facies changes into siltstone and sandstone (Lower Baong, Middle Middle and Penulin) which is essentially a turbidite deposition. In Late Miocene to Plio - Pleistocene, compression caused onset on regressive cycle that resulted in the deposition of Keutapang, Seurula and Julu Rayu Formations. Keutapang and Seureula Formations are of deltaic and shallow deposits.

C. Geology Model of Bampo and Baong Formations

Previous studies performed by several researchers (Kingston, 1978; Courtney et al. 1989; Yulihanto and Situmorang, 2002) assumed that Baong and Bampo are potential formations for shale gas reservoirs. Bampo Formation is mainly exposed in the northern part of the basin. Its lithology is characterized by calcareous mudstone and shale, poorly-bedded, pyritic, and slight carbonaceous material. It was deposited during transgression in euxinic - pelagic environment, and conformably lies above Parapat Formation, with thickness ranging from 36 to 2,700m. On the other hand, Bampo silt sequence contains residual organic materials and potential as source rock, deposited on lacustrine environment, which is similar to Oligocene sediments of Central and South Sumatra Basins. The Baong Formation consists of Lower Baong Shale, Middle Baong Sandstone (MBS), and Upper Baong Shale. Lower Baong Shale is dominated by calcareous shale, dark gray, rich of forams, and was deposited in a marine environment. Maximum thickness of the Lower Baong Shale is 764m. MBS unit is composed of light gray sandstone, very fine grained, calcareous and glauconitic. This unit is commonly found in the Aru area (Pertamina Block). The upper part of the member is characterized by sandstone layers and the bottom part refers to sandstone just above the Lower Baong Shale. Thickness of this sandstone sequence varies within 315 m to 928 m. Baong and Bampo Formations are considered suitable as shale gas reservoir. Both of them are of overpressured shale and considered as source rocks (Kingston, 1978), have high level of maturity with Ro values > 1.3, total organic contents (TOC) that reaches 1.50%, and are of marine sediment type (Courteney et al. 1989).

II. METHODOLOGY

To localise the prospect area of shale gas, an integrated geological, geophysical, and petrophysical study has been carried out in order to reduce any acompanying uncertainties normally encountered in subsurface studies. From the geological side, the analyses used also include geochemical study for determining source rock quality and thermal maturity following indicators used in previous studies (Lewis, 2004; Passey et al. 2012). Data from petrographic analysis also serves as additional information.

In addition to its traditional role in assisting the generation of structural sub-surface model, geophysical studies are focused on the prospect area to determine the distribution of potential shale gas layers, through the use of acoustic impedance (AI), continuous wavelet transform (CWT) gradient method (seismic frequency texture; a base color of red - green - blue "RGB"). Petrophysical study is conducted based on well log data including data quality control, and determination of parameters such as volume of shale (V_{sh}), water resistivity (R_w), porosity (ϕ), water saturation (S_w), and cut-off values. Through the use of geochemistry and well log data a AI - TOC transform is generated using which AI data from seismic interpretation is transformed into TOC spatial data. By converting the AI from seismic data to TOC data determination of sweet spots – with additional support from CWT data and geology

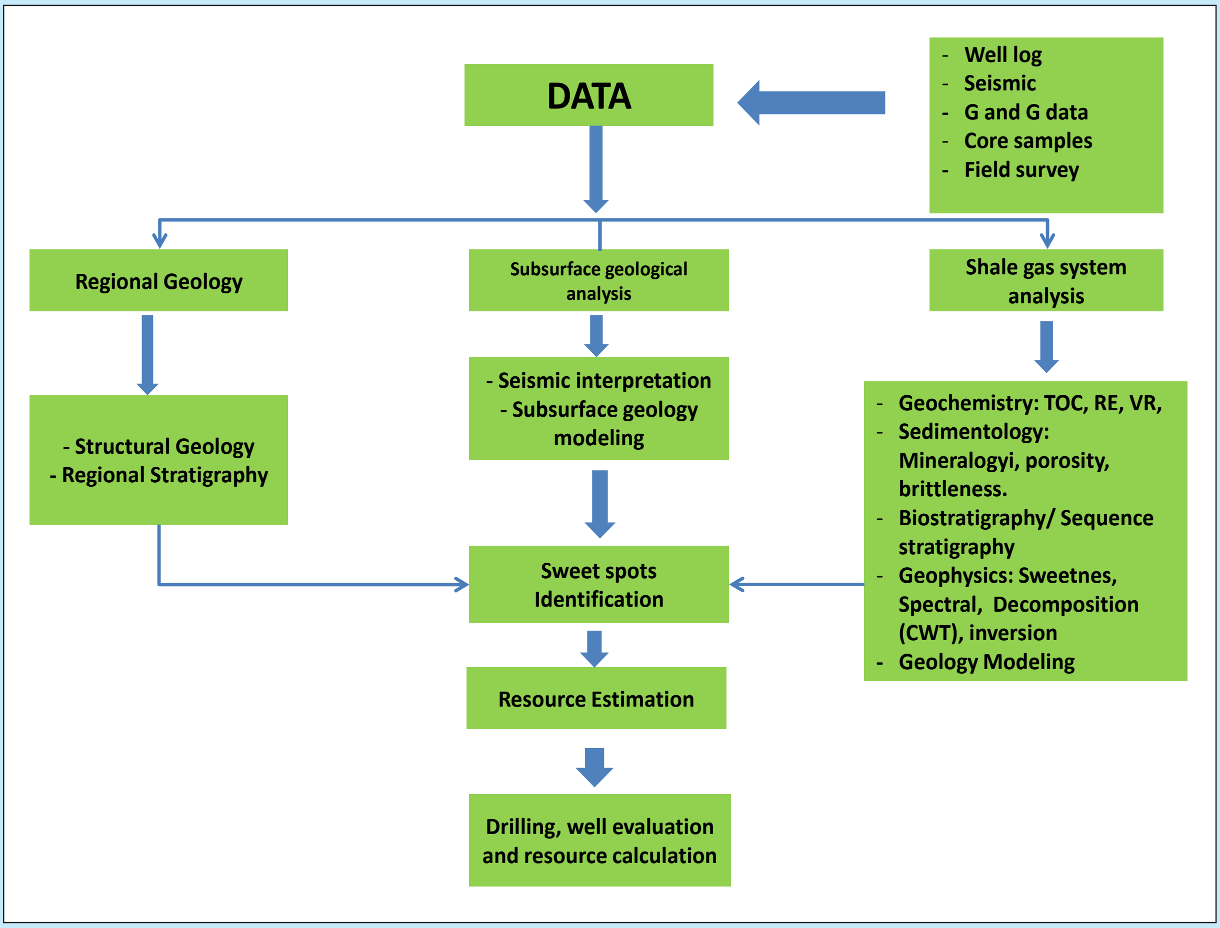
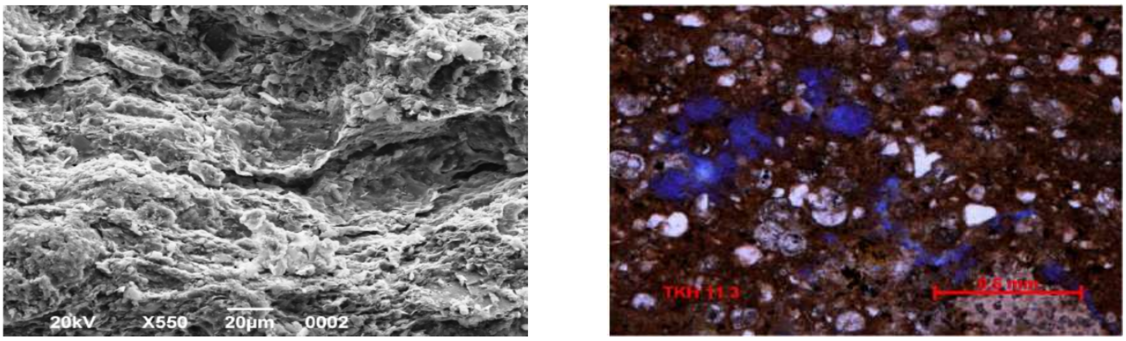
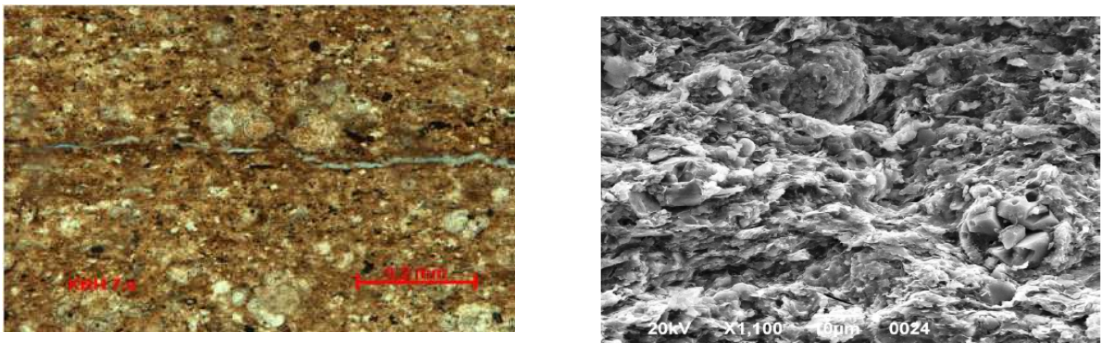


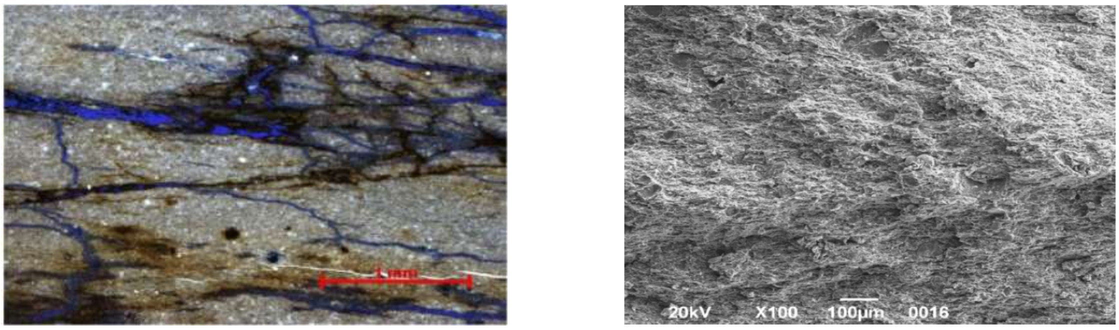
Figure 4
Flow chart of shale gas study.



Baong Formation – Fossiliferous Claystone



Belumai Formation – Fossiliferous Claystone



Bampo Formation – Claystone

Figure 5
Photomicrographs of thin section petrography and SEM.

analysis – is made both in vertical and horizontal directions. Gas in Place (*GIP*) estimation is made using (Ambrose et al. 2010) (Figure 4).

$$GIP = G_{ST} \; x \; Rock\ Volume \times Shale\ Density \quad (1)$$

with

$$G_{ST} = G_{f\,+}\, G_a \quad (2)$$

and

$$G_f = \frac{32.0368}{B_g}\left[\frac{\emptyset(1-S_w)}{\rho_b} - \frac{1.318\times10^{-6}\times M}{\rho_s}\left(G_{SL}\frac{P}{P+P_L}\right)\right] \quad (3)$$

In the above equations B_g, G_a, G_f, G_{ST}, G_{SL}, M, P, P_L, S_w, r_b, ρ_s are gas formation volume factor (reservoir volume/surface volume), adsorbed gas storage (scf/ton), free gas storage (scf/ton), gas total in-place (scf/ton), Langmuir storage capacity (scf/ton), apparent natural gas molecular weight (lbm/lb-mol), formation pressure (psia), Langmuir pressure (psia), water saturation (fraction), formation bulk density (gr/cm^3), and sorbed phase (dry shale) density (g/cm^3), respectively.

III. RESULTS

A. Shale Gas Potential from Laboratory Tests

To determine the potential of shale gas, several laboratory tests have been conducted in order to determine the quality and suitability of the shale formation to act as sweet spots. The tests include mineralogy composition, maturity of source rock, brittleness, sensitivity of rocks to water, porosity and permeability (i.e storativity and conductivity), determination of sweet spots, and resources estimation. Laboratory tests are applied for Bampo, Baong and Belumai Formations, although several previous research activities concluded that only Baong and Bampo have good shale gas potential (Murtrijito et al. 2013; Ardhi et al. 2013; Bahesti, 2013).

The outcrop samples of Bambo Formation are mainly composed of claystone and silt, dark grey in color, relatively massive, and grains are locally

Table 1
XRD analysis for outcrop samples of Baong, Bampo and Belumai Formations

NO.	SAMPLES	FORMATION	CLAY MINERALS (%)					CARBONATE MINERALS (%)			OTHER MINERALS (%)					TOTAL (%)			BRITTLENESS INDEX/ BI (Wang & Gale, 2009)
			SMEC-TITE	ILLITE SMEC-TITE	ILLITE	KAOLIN-ITE	CHLO-RITE	CALCI-TE	DOLO-MITE	SIDE-RITE	QRTZ	K-FELDSPAR	PLAGIO-CLASE	PYRI-TE	GYP-SUM	CLAY	CARBO-NATE	OTHER	
1	TKH II 3		-	-	8	-	8	40	4	-	34	-	2	4	-	16	44	40	0.78
2	TBN 3		15	5	5	8	-	20	-	-	42	-	5	-	-	33	20	47	0,62
3	TBN 4		8	6	4	8	-	32	-	-	40	-	2	-	-	26	32	42	0,72
4	BK-29		3	-	7	12	-	44	-	-	30	-	1	2	1	19	44	34	0,74
5	BK-32		7	-	7	9	-	40	-	-	32	-	1	3	1	16	40	37	0,72
6	BK-25		8	-	5	17	-	30	1	-	30	-	2	3	4	22	31	39	0,61
7	BS-02A	Baong	33	-	5	10	-	17	-	-	27	-	2	6	-	15	17	35	0,44
8	S.BKL-22		12	-	5	18	-	26	2	3	30	-	1	3	-	23	31	34	0,61
9	S.BKL-20		30	-	6	8	-	20	-	-	30	-	2	4	-	14	20	36	0,5
10	S.BKL-18		-	3	5	18	-	40	-	-	32	-	2	-	-	26	40	34	0,72
11	KG-1A		10	-	10	12	5	20	-	-	38	-	-	5	-	27	20	43	0,58
12	KG-1B		13	-	6	8	6	22	-	-	40	-	1	4	-	20	22	45	0,62
13	KG-1C		15	-	6	10	5	30	-	-	30	-	2	2	-	21	30	34	0,6
14	TKH II 4		10	-	10	-	12	18	-	-	36	-	8	6	-	32	18	50	0,54
15	TKH II 5	Belumai	6	-	5	-	10	30	-	-	40	-	4	5	-	21	30	49	0,7
16	KBL 3		-	-	-	-	-	99	-	-	1	-	-	-	-	-	99	1	N.C.
17	KBL 7A		-	4	8	8	-	26	-	-	52	-	2	-	-	20	26	54	0,78
18	S.BKL-13		-	-	17	26	-	10	5	-	40	2	-	-	-	43	15	42	0,55
19	S.BKL-12		-	5	15	12	-	2	6	-	58	2	-	-	-	32	8	60	0,66
20	S.BKL-11		-	-	10	16	-	6	-	-	66	2	-	-	-	26	6	68	0,72
21	S.BKL-16 (9)		-	-	16	32	-	8	-	-	40	4	-	-	-	48	8	44	0,48
22	LK-1		-	-	30	4	-	-	-	-	56	1	1	8	-	34	0	66	0,56
23	LK-3		-	-	26	-	20	2	5	-	40	2	5	-	-	46	7	47	0,47
24	LK-6		-	-	35	5	20	-	-	-	34	1	5	-	-	60	0	40	0,34
25	LK-8	Bampo	-	-	30	-	30	-	3	3	30	-	4	-	-	60	6	34	0,36
26	WP-4.1		-	-	20	-	26	-	-	-	48	3	3	-	-	46	0	54	0,48
27	WP-4.4		-	-	30	-	30	-	-	-	48	3	3	-	-	60	0	54	0,48
28	WP-4.7		-	-	24	-	22	-	-	-	46	2	6	-	-	46	0	54	0,46
29	WP-4.9		-	-	30	-	28	-	-	-	33	3	6	-	-	58	0	42	0,33
30	WP-4.11		-	-	20	-	26	-	-	-	44	3	7	-	-	46	0	54	0,44
31	SKB-7A		26	-	8	12	-	-	-	5	40	2	3	4	-	20	5	49	0,45
32	TKH-05		10	-	8	8	-	14	1	4	47	-	5	3	-	26	19	55	0,66
33	S.BKL-7		5	-	6	-	-	-	-	-	87	2	-	-	-	11	0	89	0,87
34	S.BKL-5	Parapat	-	-	6	-	8	34	-	3	46	3	-	-	-	14	37	49	0,83
35	S.BKL-3		-	-	10	-	8	-	-	-	75	4	3	-	-	18	0	82	0,75
36	S.BKL-2		-	-	10	-	10	-	-	-	75	3	2	-	-	20	0	80	0,75
37	KBL 5		-	-	30	-	-	-	-	-	20	-	50	-	-	30	-	70	N.C.
38	KBL 11A	Butar ?	-	-	30	-	-	-	-	-	65	-	-	-	-	35	-	65	0,65
39	KBL 13B		-	-	20	6	-	-	-	-	72	-	-	-	-	28	-	72	0,72

Table 2
TOC and Rock Eval Pyrolysis Data

No.	Age	Formation	Traverse	Sample No.	Analised Lithology	TOC	S1	S2	S3	PY	S2/S3	PI	PC	Tmax (°C)	HI	OI
						(% wt)	mg/g									
1	Middle - Late Miocene	Baong	Sungai Berkail (Bahorok)	S.BKL-22	Clyst, dkgy, calc	1,25	0,39	3,73	0,21	4,12	17,76	0,05	0,34	421	298	17
2				S.BKL-20	Clyst, dkgy, calc	1,76	0,49	8,44	0,62	8,93	13,61	0,03	0,74	429	480	35
3				S.BKL-18	Clyst, med.dkgy, calc	0,67	0,17	1,46	0,26	1,63	5,62	0,06	0,14	423	216	39
4			Kota Gajah-Kutambaru	KG-1A	Sh, brngy, calc	1,74	0,54	7,73	0,36	8,27	21,47	0,03	0,69	423	444	21
5				KG-1B	Sh, brngy, calc	1,59	0,54	6,51	0,28	7,05	23,25	0,04	0,59	425	409	18
6				KG-1C	Shale	1,3	0,47	5,29	0,14	5,76	37,79	0,04	0,48	425	407	11
7			Bahorok	BK-25	Shale	0,86	0,11	1,92	0,31	2,03	6,19	0,05	-	425	222	36
8				BK-29	Shale	1,18	0,18	4,29	0,36	4,47	11,92	0,04	-	433	364	31
9				BK-32	Shale	1,36	0,13	3,71	0,31	3,84	11,97	0,03	-	434	272	23
10			Besitang	BST-02A	Shale	1,4	0,23	4,41	0,95	4,64	4,64	0,05	-	426	315	68
11				BST-03A	Shale	0,63	-	-	-	-	-	-	-	-	-	-
12			Tiga Binanga	TBN-3	Shale	0,77	0,09	0,27	0,35	0,36	0,77	0,17	0,03	438	35	45
13				TBN-4	Shale	0,53	-	-	-	-	-	-	-	-	-	-
14			Tangkahan	TKH-113	Shale	0,56	-	-	-	-	-	-	-	-	-	-
15			Sumur DRU-1A	1928-1930m	Shale, dkgy-dkgy/v.dkgy	1,35	0,54	2,87	0,35	3,41	8,2	0,16	0,28	428	213	26
16				2328-2330m	Shale, dkgy	1,34	0,43	2,41	0,27	2,84	8,93	0,15	0,24	433	179	20
17	Early Miocene	Belumai	Selundur	SKB-2	Shale	0,84	0,12	0,68	0,39	0,8	1,74	0,15	-	425	81	46
18			Batang Sarangan	BS-4	Shale	0,8	0,25	2,25	0,02	2,5	112,5	0,06	0,21	427	281	3
19				BS-5	Shale	0,69	0,23	1,85	0,08	2,08	23,13	0,06	0,17	423	268	12
20			Kuta Buluh	KBH-7A	Shale	1,4	0,85	1,71	0,24	2,56	7,13	0,25	0,21	440	122	17
21				KBH-13B	Shale	1,45	0,1	0	0,6	0,1	0	-	0,01	*	0	41
22			Tangkahan	TKH-16	Shale	0,87	0,19	1,28	0,65	1,47	1,97	0,13	-	437	146	74
23				TKH-114	Shale	0,8	0,25	2,25	0,02	2,5	112,5	0,06	0,21	427	281	3
24				TKH-115	Shale	0,69	0,23	1,85	0,08	2,08	23,13	0,06	0,17	423	268	12
25	Late Oligocene	Bampo	Sungai Berkail (Bahorok)	S.BKL-13	Sltst, brn.gy, calc, hd	0,06	-	-	-	-	-	-	-	-	-	-
26				S.BKL-12	Clyst, purplishmbrn.dkgy, slty	0,07	-	-	-	-	-	-	-	-	-	-
27				S.BKL-11	Sltst, yell.ltgy, hd	0,06	-	-	-	-	-	-	-	-	-	-
28			Lokawar - Kutambaru	S.BKL-09	Clyst, wht.ltgy, calc	0,12	-	-	-	-	-	-	-	-	-	-
29				LK-1	Sh, dk.gy	1,59	0,08	0,77	0,08	0,85	9,63	0,05	0,07	438	48	5
30				LK-3	Sh, dk.gy, hd	0,12	-	-	-	-	-	-	-	-	-	-
31				LK-6	Sh, dk.gy, hd	0,2	-	-	-	-	-	-	-	-	-	-
32				LK-8	Sh, dk.gy, hd	0,21	-	-	-	-	-	-	-	-	-	-
33			Sungai Wampu - Kutambaru	WP-4.1	Clyst, gy, hd	0,39	0,01	0	0,24	0,01	0	0	0	*	0	61
34				WP-4.4	Clyst, gy, hd	0,4	0	0	0,1	0	0	0	0	*	0	25
35				WP-4.7	Clyst, gy, hd	0,39	0,03	0	0,09	0,03	0	0	0	*	0	23
36				WP-4.9	Clyst, gy, hd	0,46	0	0	0,11	0	0	0	0	*	0	24
37				WP-4.11	Clyst, gy, hd	0,42	0	0	0,04	0	0	0	0	*	0	10
38			Sumur DRU-1A	3080-3082m	Shale, gy-dkgy	0,48	0,24	0,31	0,16	0,55	1,94	0,44	0,05	437	64	33
39				3100-3102m	Shale, gy-dkgy	0,53	0,24	0,31	0,19	0,55	1,63	0,44	0,05	437	58	36
40				3148-3150m	Shale, gy-dkgy	0,54	0,33	0,31	0,19	0,64	1,63	0,52	0,05	441	58	35
41	Late Eocene - Early	Parapat/ Basal SST	Sungai Berkail (Bahorok)	S.BKL-7	Sltst, yell.brngy, calc	0,21	-	-	-	-	-	-	-	-	-	-
42				S.BKL-5	Sltst/vf.Sst, brngy, calc	0,11	-	-	-	-	-	-	-	-	-	-
43				S.BKL-3	Sltst, ltgy, hd	0,26	-	-	-	-	-	-	-	-	-	-
44				S.BKL-2	Vf Sst, brngy	0,09	-	-	-	-	-	-	-	-	-	-

Remarks :

TOC : Total Organic Carbon
S1 : Amount of Free Hydrocarbon
S2 : Amount of Free Hydrocarbon released from kerogen
S3 : Organic Carbon Dioxide
PY : Amount of Total Hydrocarbon = (S1 +
PI : Production = (S1/S1 + S2)
PC : Pyrolysable Carbon
Tmax : Maximum Temperature (°C) at the top of S_2 pea
HI : Hydrogen Index = (S_2/TOC) x 100
OI : Oxygen Index = (S_3/TOC) x 100
NDP : No Determination Possible
* : Erroreneous Tmax Readings due to lack of S2

replaced by calcite. Petrographic analysis reveals that the samples mostly are silty shale consisting of mainly monocrystalline quartz (3.5-25.0%), feldspar in lesser proportion, metamorphic and sedimentry rock fragments, carbonaceous material, and mica. Matrix is abundant (51.25-87.5%), porosity is low (0.25-3.0%) mostly made by intergranular and fine fissures type of pores (Figure 5). X-ray diffraction (XRD) results show that samples are mainly composed of quartz (30-66%), with minor amount of feldspar (0-4%), plagioclase (0-7%), and pyrite (0-8%). Carbonate minerals are observed in moderate amount including calcite (0-14%), dolomite (0-6%), and siderite (0-5%). Clay mineral occurs in relatively high amount covering smectite (0-26%), illite (8-35%), kaolinite (0-26%), and chlorite (0-30%) (Table 1). Geochemical analysis shows very low to medium contents of organic material (TOC: 0.07 to 0.54%), mature maturity index (Tmax: 437 - 441^{o}C) (Table 2), and low to moderate brittleness (BI: 0:33 - 0.72). The rocks tend to be reactive to highly reactive to water (Capillary Suction Time - CST: 29.5 - 85) with moderate degree of swelling (3.3 - 10.6 %). Porosity varies between 5.8% and 7.4% with permeability ranging from 0.37 mD to 3.2 mD.

The lithology of Belumai Formation is commonly fossilferous claystone, dark grey, massive and occasionally with parallel lamination and fractures. Petrographic analysis shows the Belumai Formation in general is fossiliferous claystone dominated by detrital clay matrix and planktonic foraminifers, minor benthonic forams, monocrystalline quartz, carbonaceous material, plagioclase, glauconite, and indeterminite bioclasts. Visual porosity is low (4.00-4.50%) and consisting mainly of fine fractures, minor dissolution, and micropores (Figure 5). XRD analysis reveals that the rocks' main composition is quartz (36-52%), calcite (18-30%), clay minerals - illite (5-10%), chlorite (0-12%), smectite (0-10%), and kaolinite (0-8%), plagioclase (2-8%) - and pyrite (0-6%) (Table 1). Samples from Belumai Formation generally shows moderate to good shale gas potential, with low to high organic material (TOC: 0.69 to 1.45 %), immature to mature maturity index (Tmax: 423 - 440^{o}C) (Table 2), and relative brittle to very brittle (BI: 0.33-0.72).

Baong Formation lithologically shows light grey, contains fossils, massive and brittle with burrows. The bedding thickness varies within 10-20cm. Petrographic analyses show that the fossiliferous claystone is mainly composed of detrital clay matrix (15.0-68.25%) and planktonic foraminiferas (2.5-37.75%) and also by subordinate benthonic forams (1.5-10.0%), monocrystalline quartz (2.75-10.0%), carbonaceous materials (0-3.0%), and plagioclase (0-1.0%). Other components occur in very minor amount of less than 1% are glauconite, mica, rock fragments, and indeterminate bioclasts. Visual porosity is low (1.25-6.5%) mainly consisting of dissolution, intraparticle, and fine fractures (Figure 5). Results of XRD analysis show the claystone of the formation is dominated by quartz (27-42%), calcite (17.0-44%), and clay minerals composing of smectite (0-33%), illite (4-10%), kaolinite (8-18%), and chlorite (0-8%) with minor amount of plagioclase (0-5%), pyrite (0-6%), and gypsum (0-4%) (Table 1). The samples have low - medium contents of organic material (TOC: 0.53 to 1.76%), immature to mature maturity index (Tmax: 421 - 438^{o}C) (Table 2), brittleness of relatively brittle to brittle (BI: 0.44-0.78), and reactive to highly reactive to water (CST: 25.8-59.7) with low degree of swelling tendency (1.6-7.9 %).

B. Geophysical Analysis - Top Structure Mapping

Seismic interpretation covers Langkat, Pangkalan Susu and Pangkalan Brandan lines with the control of well log data from Basilam A-1, Pantai Pakam Timur-3, Besitang-1, and Securai-1 wells. Seismic interpretation is completed by picking 7 horizons as formation boundaries. This study is narrowed to shale of Bampo, Belumai, and Lower Baong Formations. Green horizon for top Bampo Formation, orange horizon for top Belumai Formation, pink horizon for top Lower Baong Formation, and yellow horizon top Middle Baong Formation, red horizon for top Baong Formation.

Based on geological modeling of North Sumatra Basin, gas was formed at a depth of 2300m. Bampo, Belumai and Lower Baong with gas content should occur below 2300m. Lower Baong Formation, Belumai, and Bampo occur between depths 800 - 6,700m, with an average thickness of Bampo Formation ranging from 300 to 550m, indicated by blue - green contours, while the thick Bampo Formation as showed by dark blue - purple contours reached depth of 800m, which is located in north direction of Well Basilam-A1, distributed from west to east (Figure 6).

Belumai Formation is thinning to the south and thickening to the north. Southern part is shown by yellow – orange with various values between 250 - 350m, while the north part has average thickness between 350-600m, which is shown by light blue - green contour. Lower Baong Formation shows thinning to the south and thickening to the north. The average thickness in the south is indicated by orange - green contours with value of 600 - 1,000m, present around Besitang-1, Securai-1, Basilam-1, Batu Mandi-1 and Pantai Pakam Timur-3. To the north (Aceh) the thickness of formation reaches up to 1,000 - 2,000m as shown by light blue - purple contour (Figure 7).

C. Distribution of Gas Content Within Bampo, Belumai and Lower Baong Formations

Based on gas maturity window in the area - as determined through geochemistry laboratory tests - that is applied on the top structure maps generated earlier gas content distribution is determined for the three formations. All gas distribution maps for the three formations, therefore, show gas contents that

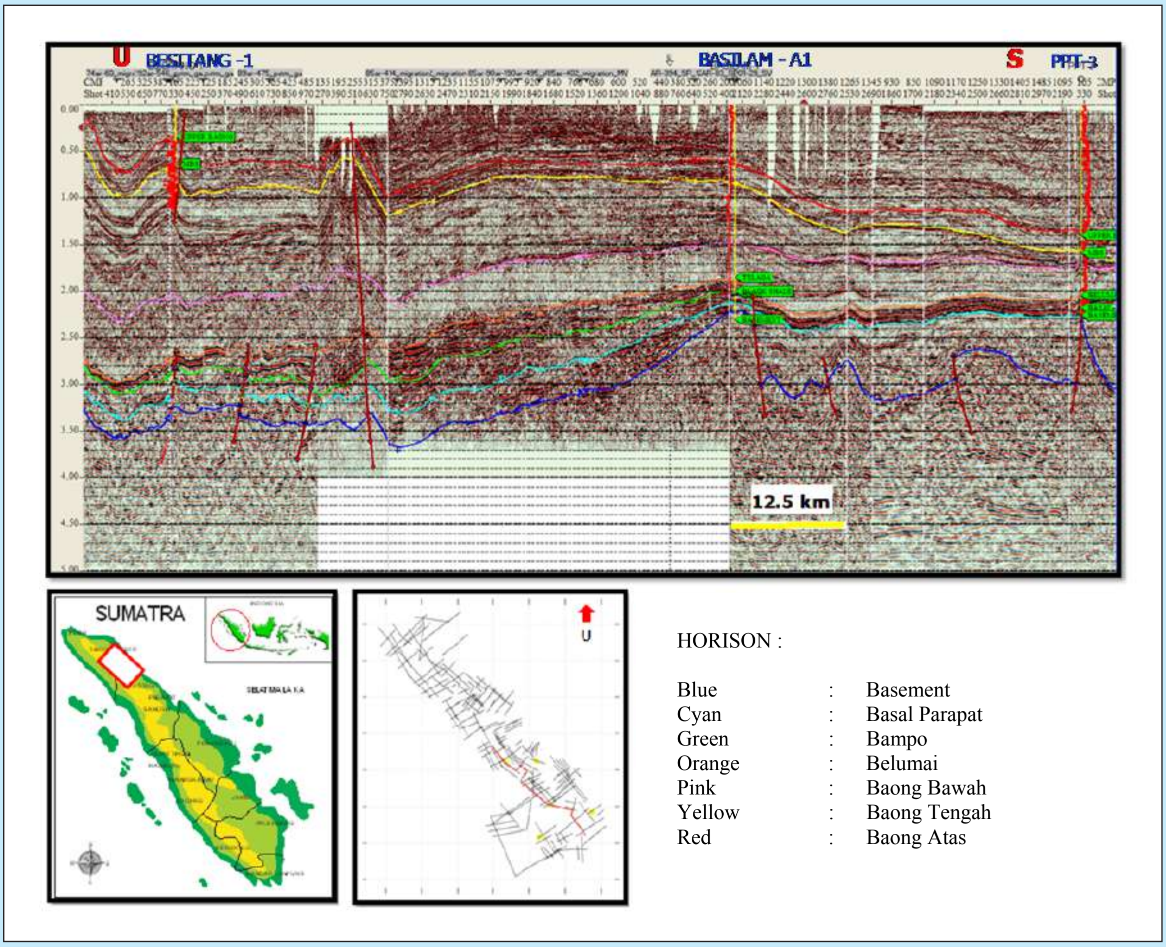


Figure 6 ?
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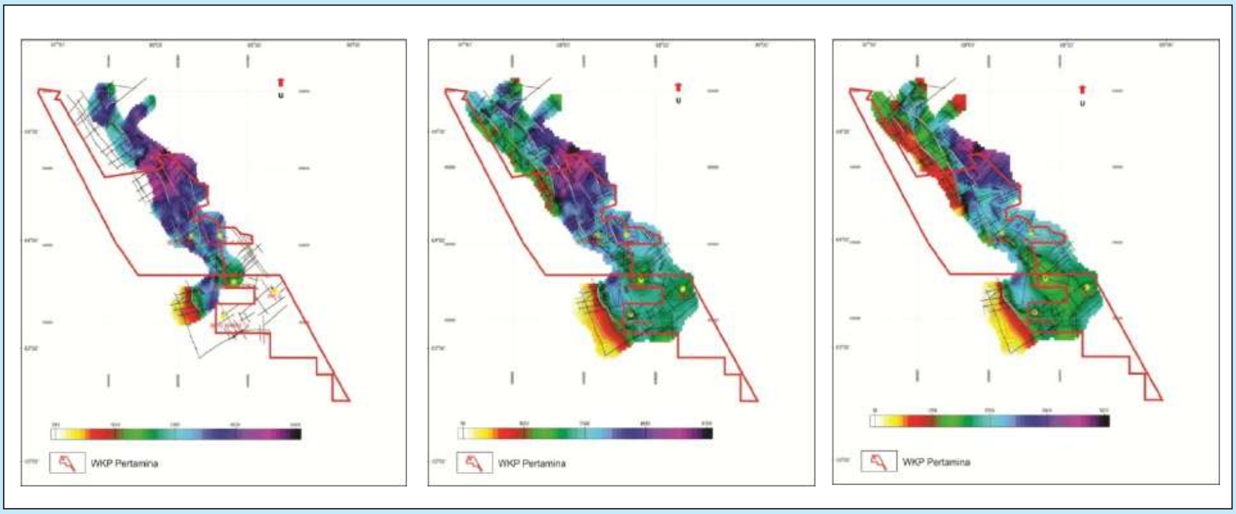

Figure 7
Isopach Maps of Bampo Formation, Belumai Formation and Lower Baong Formation (left - right).

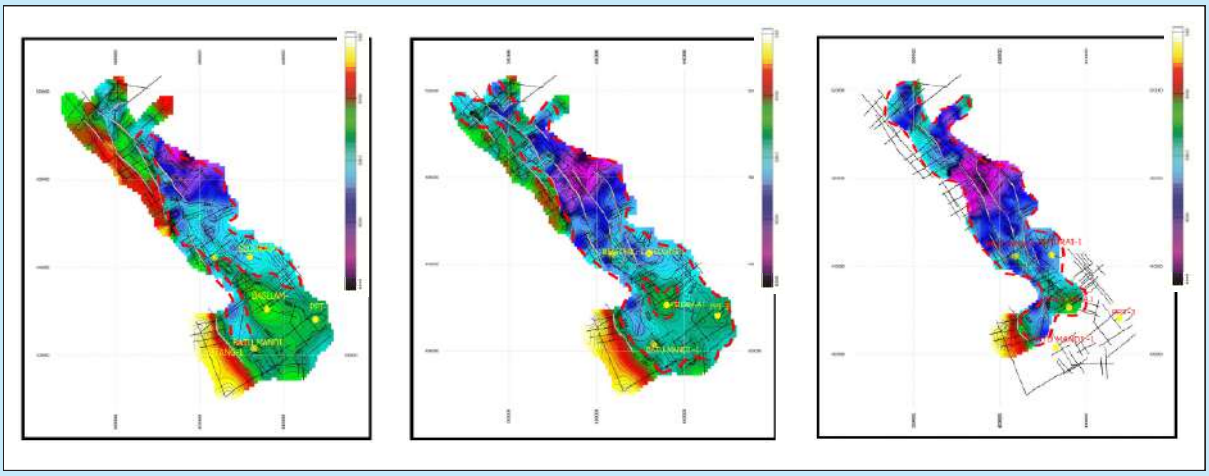

Figure 8
Depth structure of gas containing Lower Baong Formation, Belumai Formation, and Bampo Formation (left - right).

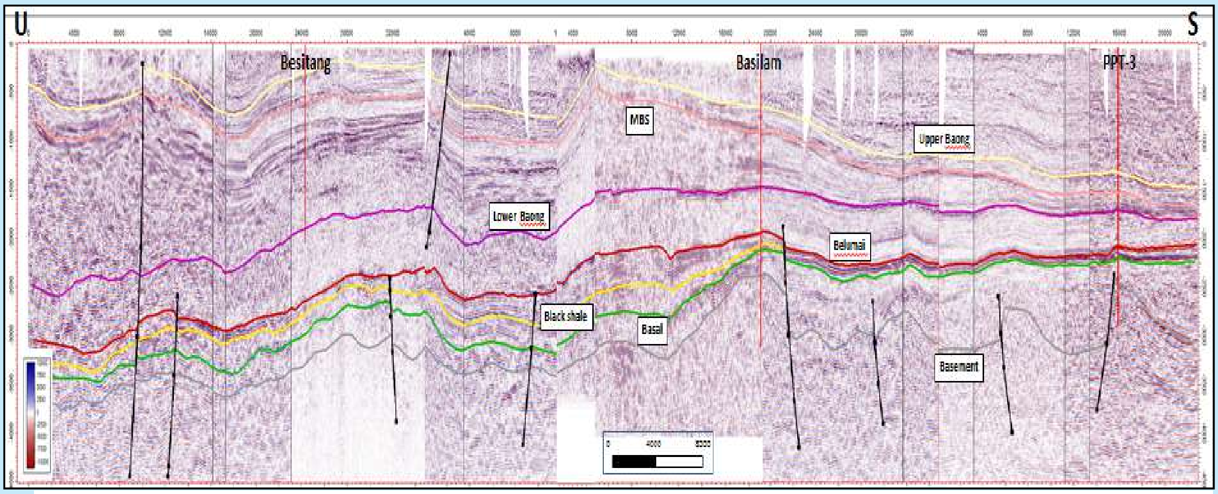

Figure 9
Composite line of north-south direction traversing Besitang-1 dan Basilam-1 well.

occur below depth of 2,300m. Figure 8 depicts the distribution of Bampo Formation containing gas where gas in the Bampo Formation reaches maturity below a depth of 2,300m. The red dashed line is the boundary of mature area for Bampo Formation, which is distributed within North Sumatra - Aceh axis. Similar to Bampo Formation, geochemistry tests have shown that gas in the Belumai Formation also reaches maturity below a depth of 2,300m. This corresponds to an area within the red dashed line that serves as boundary of the formation's mature area, spread from North Sumatra to Aceh. For its higher areas around Basilam-A1 well, Belumai Formation has not reach maturity as gas containing shale due to depths of its shale body are in general above 2300m. Using the same maturity criteria higher areas of the Bangko Formation in its western part towards the Bukit Barisan Mountains - as indicated by green/ yellow areas - has also not reached shale gas maturity for the same reason (Figure 8).

However, in a way similar to the other two formations, Lower Baong Formation is considered as containing gas since most of its shale body is situated below 2,300m. This is depicted area within the red dashed line (Figure 8). In higher areas surrounding Basilam-A1, Pantai Pakam Timur-3, and Batumandi wells, Baong Formation has not reach maturity because the depth is higher than 2,300m. This is also true for the higher areas to the west towards the Bukit Barisan and to the north, indicated by countour within green/ yellow area. While in Aceh, the Lower Baong Formation has reach maturity, as indicated by contours within blue/ purple area in Aru area (contour shallower than 3,000m) (Figure 9).

D. Identification of Sweet Spots and Resource Estimation

The geophysical approach used in this study is a standard seismic attribute using amplitude and frequency attributes - method of 'sweetness' analysis (Hart, 2008), plus application of spectral decomposition method of continuous wavelet transform (CWT) (Partyka et al. 1999; Sinha et al. 2005). Prior to the application of sweetness and CWT methods, several seismic lines were used for the amplitude balancing process. Through this process the seismic data is arranged so that seismic amplitudes are expected to have a range of similar seismic amplitude values.

Figure 10 is a composite line of north-south direction passing through the Besitang-1, Basilam-1, and PPT-3 wells, whereas Figure 10 depicts sections of sweetness (a) and CWT (b) of the composite lines in north-south direction. The applications of these two methods are employed to indicate zones of interest contained in the black shale most probably in Bampo Formation surrounding Basilam-1 and Besitang-1wells. Zones of interest are marked in yellow to red areas indicating porous areas with stronger reddish areas which are expected to contain gas. Information from well testing provides that Basilam-1well shows indication of gas in black shale that is most probably from Bampo Formation (at its top of depths around 2,576.6 m MD).

Figure 11 shows crossplots of sweetness and CWT with wireline logs of Basilam-1 including gamma ray, density, resistivity and sonic. The interesting zone has high value of sweetness and low value of CWT. Gas indication appears in shale bed. Cross plots of sweetness and CWT with well log data were not performed for Besitang-1 well due to data absence. The Besitang-1 well does not penetrate Bampo formation (Besitang-1 well: TVD 1,700 m MD).

Reservoir characterisation (seismic inversion and spectral decomposition) is performed to determine distribution of shale gas reservoir property on the seismic section. Seismic inversion informs the AI of shale lithology while spectral decomposition detects formation parts with gas saturation. As previously determined the potential of shale gas zones is indicated by the presence of sweet spots, in which values of TOC is the main parameter to define coverage of the area. Acoustic impedance (AI) is used

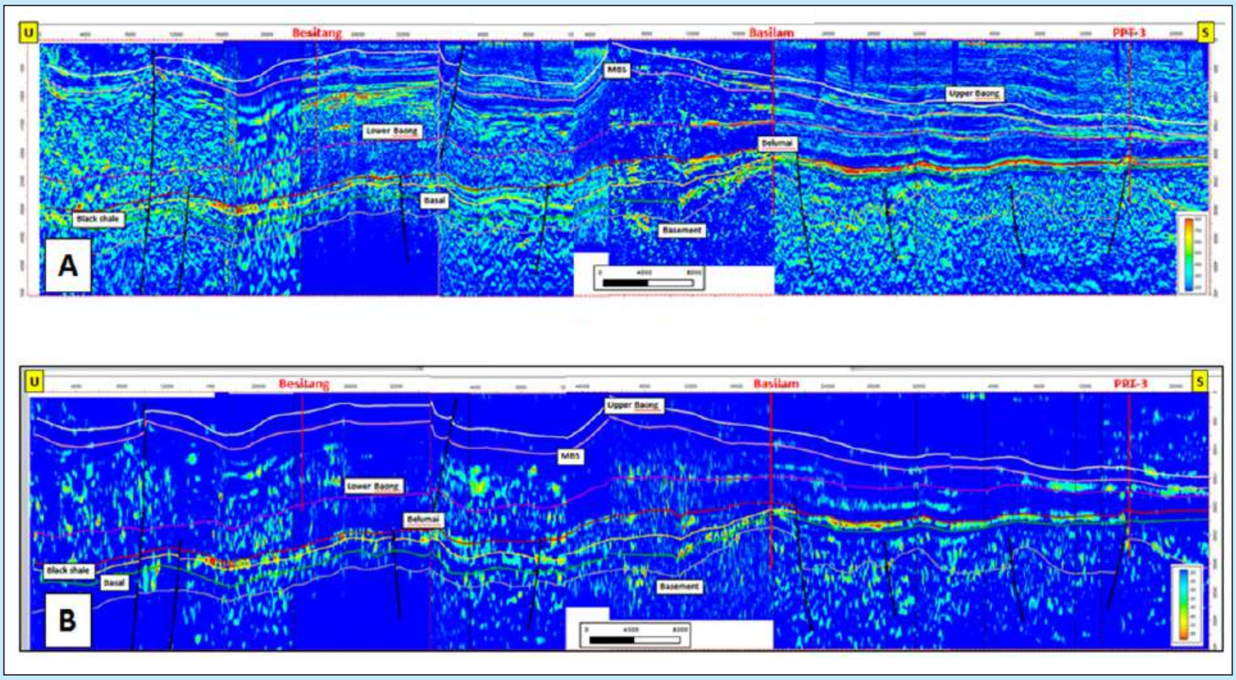

Figure 10
(a) Sweetness section and (b) CWT section of north-south direction traversing Besitang-1dan Basilam-1 well.

to determine the type of shale lithology that serves as reservoir rocks. Some researchers suggested and have managed to establish an empirical relationship between AI and the TOC using which AI distribution resulted from seismic inversion analysis can be transformed into TOC distribution (Løseth et al, 2013; Passey et al. 2012; and Liu, 2013).

Seismic inversion results (Figure 12) show that in general AI values in the shale formations range between 4,000 and 9,200 m/s*g/cc. Crossplot between TOC and AI (Figure 13) for Besitang-1 data appears to be in good correlation with correlation factor of 0.928. Note that high TOC value of around 1.5 - 1.7% - TOC levels that are considered as mature for this study – is associated with AI value of approximately 5,500 - 6,500 m/s*g/cc. Using the AI - TOC good correlation, the TOC distribution within the formations are generated. Upon using the correlation, the highest probability for sweet spots lies on AI values within 7,000 – 8,000 m/s*g/cc, which correspond to TOC values greater than 1%. Shale formations having these values are also considered as suitable for fracturing.

Through the use of TOC – AI correlation, distribution of TOC values range in general is also found as in between 0.5% and 1.6%. High TOC values of 1.4 - 1.67% characterize the Lower Baong Formation in its low areas and in the surrounding area of Besitang wells (Figure 14). Lithology distribution modeling is shown by the spread of sand and shale in lateral direction. The modeling is based on the AI values of 5,500 – 6,500 m/s*g/cc, which corresponds to relatively large gradient frequency disparity. The bigger the disparity the greater the possibility of rocks saturated with hydrocarbons. In Figure 15, large changes of disparities are indicated by grey to black in the color spectrum.

Through combining the TOC distribution, log-core petrophysical analysis, and TOC criterion of 1.6 - 1.7% areas that are considered as sweet spots around Basilam-1 and Securai-1 wells are determined. For this TOC cut-off, average porosity values of 2%, 3%, and 5% are obtained for Bampo Formation, Belumai Formation, and Lower Baong Formation, respectively. Sweet spots in the Bampo, Belumai, and Baong formations are found around

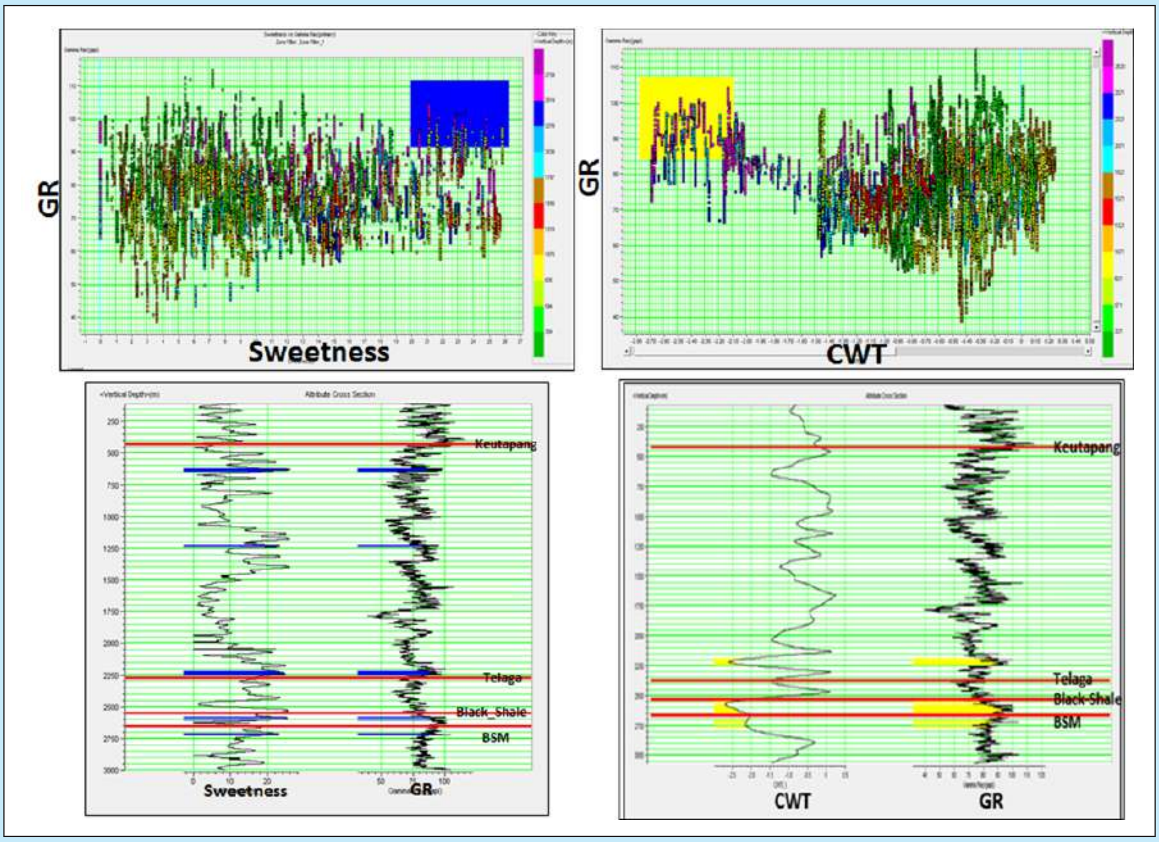

Figure 11
Crossplots of sweetness and CWT with GR logs of Basilam-1.

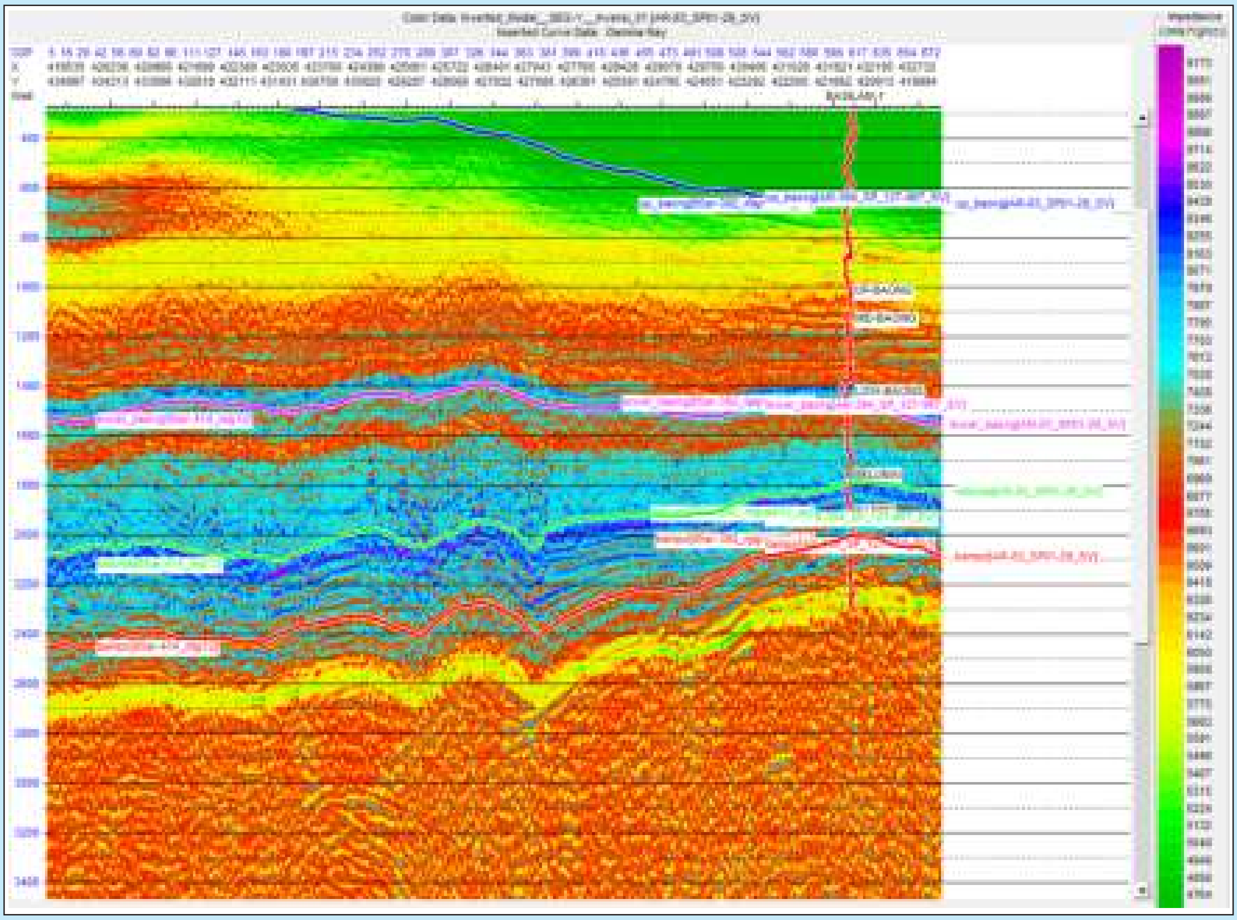

Figure 12
Acoustic Impedance (AI) cross-section through Basilam-1 well.

Table 3
Area and Volume within gas window

Formation	Area (m^2)	Area (acree)	Volume (m^3)	Volume (acree feet)
Lower Baong	1.2994E+13	3.2108E+09	8.9076E+11	7.2215E+12
Belumai	1.6879E+13	4.1708E+09	9.2094E+15	7.4662E+12
Bampo	2.3310E+12	5.7726E+09	9.3289E+15	7.5631E+12

Basilam-1 and Securai-1wells and occupy about 21%, 29%, and 11% of the formations, respectively.

With supporting parameter values used in Equations 1, 2, and 3 (Tables 3 and Table 4) shale gas resources (i.e gas in place) for the three formations are estimated. Porosity (ϕ), bulk density (ρ_b), and S_w are averaged values determined from petrophysical analyises on Basilam-1, Batumandi-1, Besitang-1, dan PPT-3 well log data, whereas B_g is derived from laboratory pressure-volume-temperature (PVT) analysis on gas samples taken from Besitang-1 well, and ρ_s was obtained from direct core laboratory measurements on outcrop dry shale samples. For G_{SL}, M, P_L values, laboratory adsorption isotherm tests were carried out on two outcrop shale samples, one represents Lower Baong and Belumai formations of depths 2,500 - 3,500m (both formations are considered as having adjacent depth intervals) and the other one is for Bampo Formation of depths 4,000 - 6,600m. Resource estimations have resulted in accumulation of shale gas present in the sweet spots found to be 6.379 trillion cubic feet (TCF) for

Table 4
Parameters for shale gas in place calculation

Parameter	Unit	Lower Baong	Belumai	Bampo
φ	%	5	0	0
Bg	res. vol/surface vol.	0.007	0.006	0.005
ρ_s	g/cm^3	0.3	0.34	0.4
ρ_b	g/cm3	2.55	2.6	2.7
S_w	%	70	60	50
M	lb/lb.mol	12	13	16
G_{SL}	scf/ton	60	70	50
P	psi	3.000	3.248	4.000
P_L	psi	1.200	1.300	1.150

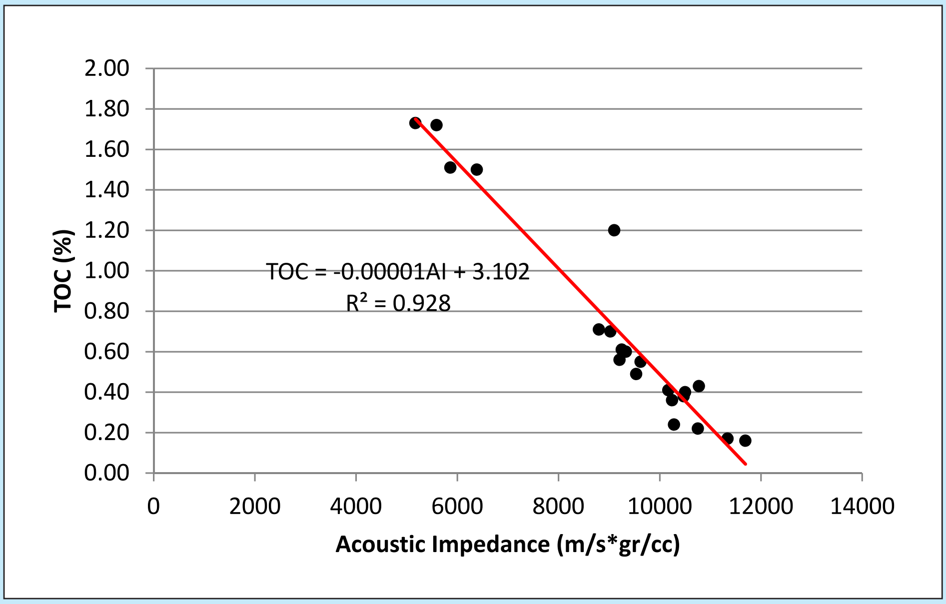

Figure 13
Cross-plot between AI and TOC in Besitang-1 well.

Lower Baong Formation; 16.994 TCF for Belumai Formation; and 25.024 TCF for Bampo Formation, with total volume of 48.397 TCF.

IV. DISCUSSION

Lower Baong Formation occurs at depth 1,000 - 6,200m. At high areas of Basilam-A1, Pantai Pakam Timur-3 (PPT-3), and Batumandi wells, Lower Baong Formation does not reach oil window because of its depth of shallower than 2,300m. This is similar to the case of high areas in western to northern parts of studied area. In the North, Lower Baong Formation has reached oil window as marked by contour within blue to purple areas as in Aru area with contours below 3000m. Belumai Formation occurs at depths of within 1,200 – 6,300m (Figures 6 and 7), and Bampo Formation at depths of within 1,500 - 6,600m. Potential areas of shale gas are deeper than 2300m, as marked by contours within dark blue to purple area. Bampo Formation

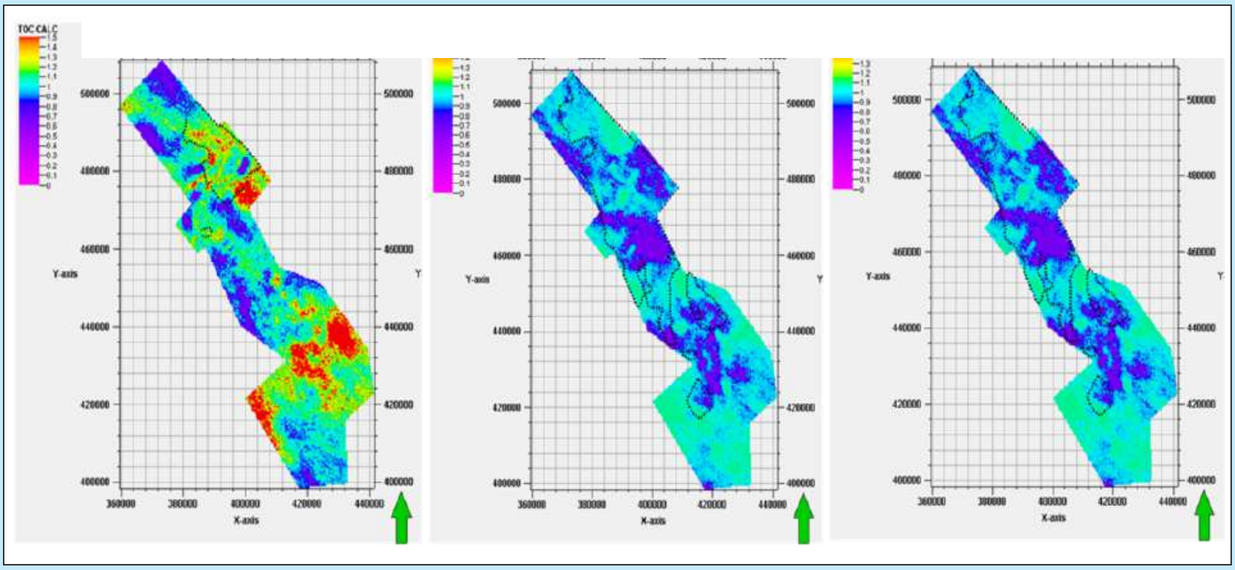

Figure 14
Distribution maps of TOC correlated through AI from (a) Lower Baong Formation (b) Belumai Formation and (c) Bampo Formation.

thins out to the South direction and in southern part from Basilam-A1 well whereas Bampo Formation does not develop sufficiently due to sedimentation limitation provided by highs and grabens to filling areas in the South.

Generally claystones of Baong Formation are described as light gray in color, contain fossils, massive, brittle, having burrow structures, and layered with thickness varies between 10cm and 20m (LEMIGAS, 2012; 2013). Lithology is commonly fossiliferous claystone, where composition is dominated by clay matrix and planktonic foraminefers with lesser benthos, monocrystalline quartz, carbonaceous material, and plagioclase. Other materials include glauconite, mica, rock fragments and indeterminate fossils (“LEMIGAS”, 2012, 2013). Porosity is poor including secondary dissolution and intraparticles, accompanied by minor microfractures. TOC values moderate to good varying from 0.53 - 1.76%, with maturity level categorized as immature to mature. Based on the analysis, it is interpreted that Baong Formation has moderate to good shale gas quality. However, the high content of smectite needs to be carefully considered since this may provide difficulties for any drilling and fracturing operations.

Claystones of Bampo Formation are fosilliferous claystone, gray - dark gray, massive with parallel lamination, and the occurence of fractures. The composition is dominated by clay matrix with planktonic foraminifers and accompanied by minor benthonic forams, monocrystalline quartz, carbonaceous material, plagioclase, glauconite, and indetermined fossils. Porosity is low, commonly fractures supplemented by a number of dissolution and microporosity. TOC values are moderate to good (0.69 – 1.45%) and immature to mature of maturity level. Belumai Formation shows moderate to good shale gas potential.

Samples from Bampo Formation shows silty clay, gray - dark, relatively compact, and locally replace by calcite. The composition is dominated by quartz monocrystalline, along with small amounts of feldspar, fragments of metamorphic and sedimentary rocks, carbonaceous material and mica. There is a high amount of clay matrix. Porosity is intergranular and fractures. The content of organic material is generally very low - medium (TOC: 0.07 – 0.54%). Bampo Formation indicates poor potential as a shale gas resource, even though the formation has apparently reached the gas window of below 2,300 m. However, the low TOC values result from absence of significant sweet spots for the formation. With regard to TOC values, it is important to understand that kerogen occupies a much larger volume percent (vol%) than is indicated by the TOC weight percent (wt%). This can be explained by the low grain density of the organic matter (typically 1.1-1.4 g/cc) compared to that of common rock-forming minerals (2.6-2.8 g/cc) (Passey, 2012). Therefore, the Bampo

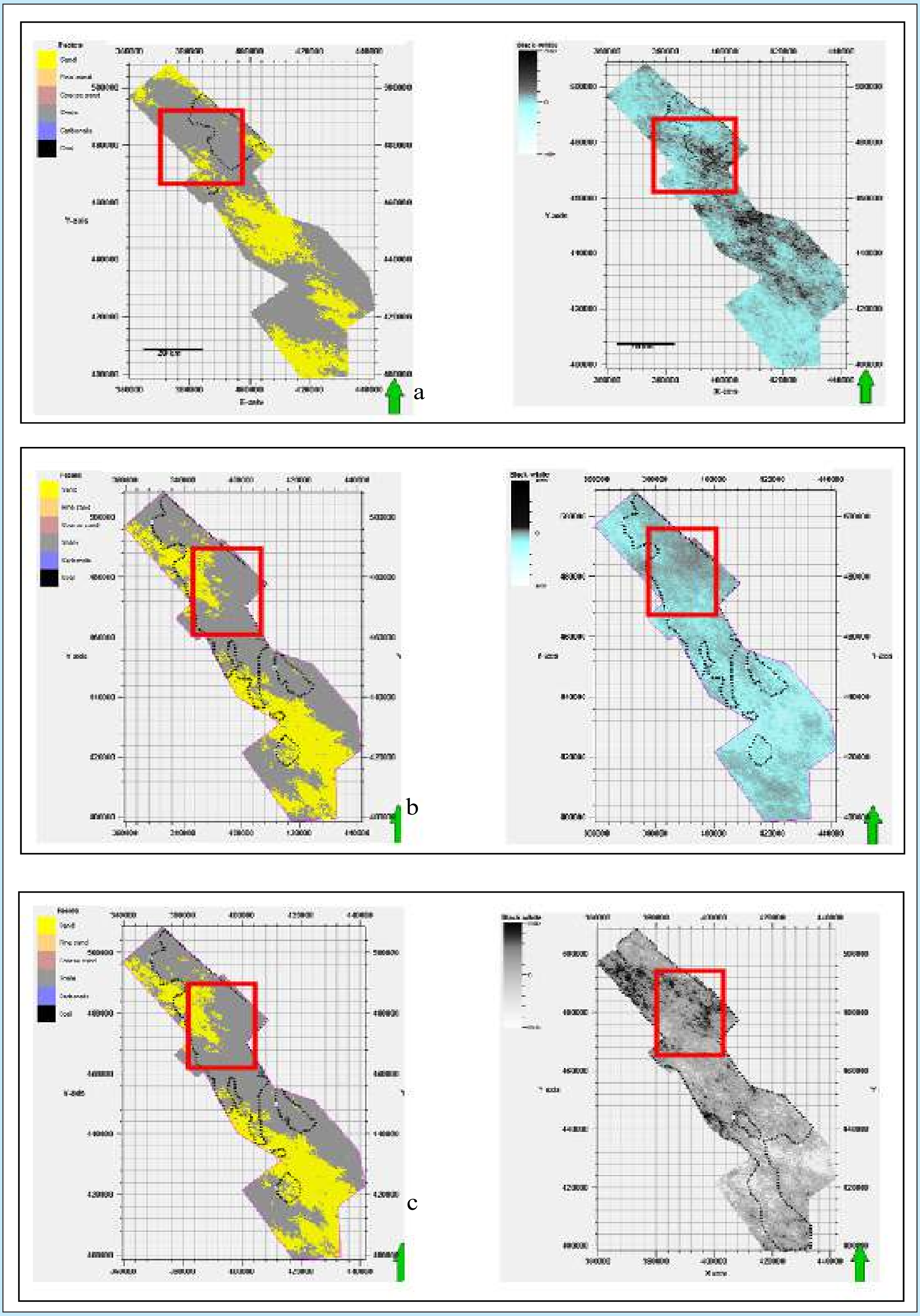

Figure 15
Modeling of lithology distribution and lateral frequency disparity of (a) Baong Formation (b) Belumai Formation, and (c) Bampo Formation.

Formation can only be interpreted as having shale gas potential that is categorized as poor to moderate. Despite poor to moderate, the large formation thickness has nevertheless led to large (25.024 TCF) gas resource volume.

V. CONCLUSION AND RECOMMENDATION

Potential of shale gas in North Sumatra Basin is from shales of Lower Baong, Belumai, and Bampo Formations, from depths of deeper than 2,300m, and with TOC values that range between 1.4 and 1.67%. It is supported by brittelness of brittle to moderately brittle (BI = 0.33-0.78), which are correlated with values of acoustic impedance (AI) that vary within 5,500 - 6,500 m/s*g/cc range. Estimation of shale gas resource potential in the Lower Baong, Belumai and Bampo Formations has yielded 6.379 trillion cubic feet (TCF), 16.994 TCF, and 25.024 TCF, respectively.

From an operational point of view, the high amount of smectite occuring in North Sumatra Basin needs to be carefully considered, and consequently research of shale gas in the North Sumatra Basin has to be focused on specific drilling and production technologies aimed at enhancing the ability to deal with problems that may be caused by high content of smectite. With regard to the existing references or studies, a detailed characterization of shale gas, including drilling, fracturing, and core analysis in accordance with the character of each sedimentary basin in Indonesia need to be carried out.

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