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SANDSTONE QUALITY ASSESSMENT FROM CORE DATA OF SANTUL FORMATION, TARAKAN BASIN BASED ON PETROGRAPHY AND ROUTINE CORE ANALYSIS

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ABSTRACT
This study analysis the quality of sandstone as reservoir in Sentul Formation, Tarakan Basin, based on petrography and routine core analysis. The aim of this study is to evaluate the sandstone reservoir in Tarakan Basin especially the rock quality information for development exploration. The quality of the sandstone in facies A (depth of 1743.75–1747.28m) is moderate. This assessment is based on the porosity value of routine core analysis from 19.48% to 27.88%, and permeability value from 25mD to 213 mD. The sandstone quality of facies B (depth of 1741.80 m–1743.75m) is good, this is based on the value of the porosity from routine core ranges from 23.34% to 26.71% and 83-359 mD of permeability value. The quality of sandstone in facies C (depth of 1737.65m–1737.75m) is good. The differences of the quality affected by the various level of compaction, sorting, and contact between the grains. The presence of carbon material and laminated clay also led to differences in the quality of the reservoir through inter-granule space filling. Sandstone mineral composition of each facies dominated by mono crystalline quartz which is chemically relatively stable, so that the cementation and replacement processes do not overly affect the porosity and permeability.
Keywords: *petrography, core, sandstone, Santul Formation*

INTRODUCTION

One of basins in Indonesia that has good petroleum industry prospects is Tarakan Basin, East Borneo Province. This basin bordered by the Celebes Sea in the east, Kuching Ridge in the west, Samporna Ridge in the north, and Mangkaliat Ridge in the south as well as separator between Tarakan Basin and Kutai Basin(Nugroho et al., 2018).

There are 14 oil and gas field sin Tarakan Basin (Darman & Lentini, 1999). In this regard, some chains of core analysis which is targeted as reservoir derived from Tarakan Basin in order to assess the quality of sand stones at the core sample. Interpretation of the depositional environment, origin, and sediment transport mechanisms can be determined by integrating facies analysis, lithology, and grain size analysis of the sedimentary layers(Kasim et al., 2023).

An adequate understanding of the porosity and permeability of the rock is an important factor in assessing the quality of reservoir(Allen & J.R. Allen, 1990), which is generally controlled by the type of rock that shields the composition and the texture of the rock as long as the product of depositional environment. However, the primary porosity and permeability would be changed by means of diagenesis process that works on the reservoir rock. Applied petrology is an essential tool for evaluating natural rocks and recycled materials used in a variety of useful applications, such as concrete and energy storage applications(Petrounias et al., 2020).

This study analysis the quality of sandstone as reservoir in Sentul Formation, Tarakan Basin, based on petrographic data and routine core data. The results of this research hare expected to provide an overview of reservoir quality that can be taken into consideration in the development effort and the exploration of new oil fields(Kasim et al., 2023; Petrounias et al., 2020).

RESEARCH AND SETTING

A.Tarakan Basin

Tarakan Basin is a sedimentary basin that located in the north eastern part of Borneo Island, precisely in the area of East Borneo Province. The form of Tarakan Basinto the east is bordered by the Celebes Sea, Kuching Ridge in the western part, SampornaRidge in the northern part, and MangkaliatRidge in the southern part as well as separator between Tarakan Basin and Kutai Basin.

Tarakan Basin can be divided into four sub-basins (Darman & Lentini, 1999; Nugroho et al., 2018), those are:

Tidung Sub-Basin, located in the northern part, filled with sediment of Late Oligocene to Miocene, separated with Berau Sub-Basin in the southern part by Sekatak Ridge.

Berau Sub-Basin, in the northern part filled by sediment aged from Late Eoceneto Late Miocene.

Tarakan Sub-Basin, the youngest sub-basin that is located in the middle part. The most northern part develops toward offshore and filled with thick enough sediment from Tarakan Formation and Bunyu Formation in Late Miocene.

Muara Sub-Basin, the most southern of deposition place toward off shore sediment development (near Mangkaliat Ridge). This sub-basin separated with Berau Sub-Basin in the north by Suiker broad Ridge, a mountainous geomorphology with east-west trending.

Based on the deposition cycle and deployment of sedimentation facies, the regional stratigraphic sequence can be divided into five cycles of deposition consisting of two transgressive cycles and three regressive(Achmad & Samuel, 1984). The cycles discussed sequentially starting from the old to the young as follows:

Cycle 1: Sebakung Formation, Sujau Formation, Seilor Formation, Mangkabua Formation.

Cycle 2: Tempilan Formation, Talabar Formation, Naintufo Formation.

Cycle 3: Meliat Formation, Tabul Formation, Sentul Formation.

Cycle 4: Tarakan Formation.

Cycle 5: Bunyu Formation.

Tarakan sub-basin stratigraphy divided into 5 depositional cycles, intimately dictated by interplay between Kuching High episodic uplift as the clastic provenance and the regional eustasy(Z & L. Samuel, 1984). The first cycle was starting from regional transgression in the Late Eocene to Late Oligocene during deposition of Sujauclastics, Seilor carbonates, and Mangkabua marls. The second cycle took place during latest Oligocene to early Middle Miocene, where Tempilanclastics interfingered with Tabalar limestones and overlaid by Naintupo shales. The third cycle occurred during Middle to Late Miocene, marked by tremendous supply of Meliat deltaic sediments followed by deeper marine clastics of Tabul and Santul. The fourth cycle was deposited during Pliocene by the occurrence of Tarakan deltaic sequences. The fifth cycle occured from early to late Pleistocene by deposition of Bunyu deltaic succession during the on going sea-level rise.

The Tarakan Formation is composed of sand, shale and coal interbeds that belong to the Sesayap delta system. It is characterized by the increasing number of sandstones and coals upward. The lowest thick coal bed is arbitrarily taken as the base of the Tarakan Formation. Eastward they gradually change into shale and limestone facies of a prodelta or marine environment. Total thickness reached 1,000 m in the north (Mengatal Field) up to 3,000 m in the south (Mamburungan Field)(S. Courteney et al., 1991)

The tectonic history of this subbasin began with a rupture and was interrupted by periods of uplift ending in the late Eocene, mid-Oligocene, and mid-Miocene. These uplifts were controlled by volcanic activity during the same period. The interaction of these processes led to the formation of the five geological blocks that we recognize today(Biantoro et al., n.d.).

B. Petroleum System of Tarakan Basin

The Tarakan Basin is a complex multi-layered basin. According to the stratigraphic record, the basin began to fracture in the Early Tertiary, followed by the development of a passive margin and foreland basin toward the end of the Tertiary. The complexity of the basin is more pronounced due to deltaic tectonic movements, especially in the eastern part of the basin. An inverted thrust fault closure of Pliocene-Pleistocene crustal compression products was developed in several parts in and served as one of the proven hydrocarbon-bearing traps in this basin(Noeradi & Djuhaeni, 2005).

Source Rock

Coal and shales aged from Pleistocene to Pliocene are sediments that rich in organic material in this area. Late Miocene sequence has source rocks with moderate to good qualification contained in the coal and supra-littoral shales that sometimes still immature, except in the northern part of Tarakan Basin (it has been entering the early stage of maturation). Late Miocene coal facies is a potential source. It had been reworked when entering deep sea turbidity. Sequence in the Early to Middle Miocene contain enough material that rich in organic and demonstrate the potential to produce hydrocarbons in the Tarakan Sub-Basin. Meanwhile, the existed sequences in the Early Eocene to Middle Miocene generally show poor source rock potential(Doust & Noble, 2008).

Reservoir Rock

Reservoir rock found in nearly all levels aged from Oligocene to Pleistocene of Tarakan Basin. Tarakan Basin is a delta system. Delta plain reservoir generally produces a commercial reservoir with tight carbonate that formed in little amount, mostly as the result of diagenesis. Hydrocarbons produced in Tarakan Basin commonly found in estuaries or grooving sandstone. Lateral relationship of each layer shows the spread of the reservoirs (sandstone) are very limited and lensing. The spread of sandstone is strongly influenced by the direction in which the delta sedimentation as well as the type of sandstone is formed. The percentage of sandstone which is calculated on the Santul Formation and Tarakan Formation look for changes in the direction of sedimentation and progradation during both of formation forming process(Doust & Noble, 2008).

Seal Rock

The top seal for the potential reservoir is thick of claystone that "works" as sandstones during flooding events. The silty part overlies with the sandy part of older delta. The presence of hydrocarbons in sandstone below the Pliocene-aged shales characterizes that this layer works as an effective seal(Doust & Noble, 2008).

MATERIAL AND METHOD

The object of research is the core, precisely on sandstone (as reservoir) located in the Santul Formation, Tarakan Basin. The core that used as data source of this study located in the depth interval of 1737.65–1747.28 m, then some are for petrographic and routine core analysis at certain depth. Thin section of petrographic analysis amounted to fourteen samples were located at a depth of 1737.70 m, 1741.60 m, 1742.33 m, 1742.78m, 1743.00 m, 1743.30m, 1743.63 m, 1743.93 m, 1744.32 m, 1744.75 m, 1745.06 m, 1745.35 m, 1746.04 m, and 1746.35 m.

The purpose of petrographic analysis is to identify the mineralogical composition of rocks from the grains, to know the texture and the relationship between minerals, as well as determining the porosity and diagenesis of rocks(Walker & James, 1992). Routine core analysis includes results of total porosity and permeability of each sample. The amount of porosity resulted from routine core analysis will be different with the result of petrographic analysis. Routine core analysis yields the total porosity and permeability from helium shooting to calculate the sample of micro-porosity. Porosity and permeability data of each sample was made in the form of cross-plot between porosity to depth and permeability to depth, and then was made the cross-plot between the porosity and permeability to look at the relationship between the distributions of porosity-permeability to depth for illustrated the changing of properties of rock in depth factor(Odigi & Momta, 2015). If the trend line (R2) close to one (1), then there is a closer relationship between porosity and permeability which means that any increase or decrease in porosity values will be kept up followed by an increase or decrease in permeability values(Adams et al., 1984). In addition to porosity and permeability data, routine core analysis also produced the SW data (water saturation) to be used as an element of quality assessment of the reservoir.

RESULT AND DISCUSSION

Based on the assessment, overall main composition of sandstone is dominated by mono crystalline quartz (49% to 62%) which is composed of plagioclase (1% to 2.5%), K-feldspar (0.25% to 1.25%), and rock fragments (4% to 7.5%). Other minerals are also present as mica (0.25% to 1%), heavy mineral (0.25% to 0.5%), carbon material (0.5% to 10%), and laminated clay (5% to 18%). The matrix is dominated by clay detritus (3% to 7.5%) and artificial matrix (1.5% to 5%).

Based on core description, it can be inferred that the core sample specified on sandstone divided into three facies: facies in the depth interval of 1743.75m to 1747.28m, facies Bin depth interval of1741.80 m to 1743.75m, and facies C in the depth interval of1737.65mto 1737.75m. Based on the assessment, the depth interval of 1737.75 to 1741.80m doesn’t contain any sand stone and predicted as seal rock.

Facies A

Based on the result of petrographic analysis on the six sample in facies A, visual porosity values obtained are classified as poor until moderate that ranges 8%–15%. Most of the porosity is secondary porosity formed by dissolution. Routine core analysis results porosity valued from 19.48% to 27.88%, horizontal permeability valued from 25mD to 213mD, and water saturation ranged between36.97% and 43.45% (Table I). From these data, there are differences in porosity values between petrographic analysis and routine core analysis. These are due to the kaolinite mineral resulted from diagenesis, cementation, and replacement.

Table I. Porosity And Permeability Values Of Facies Afrom Petrography And Routine Core Analysis

Depth (m)	Petrography		Routine core				
	Porosity (%)		Porosity (%)		Permeability (mD)		Saturation (%)
1744.32	10	Moderate	19.95	Good	25	Good	40.08
1744.75	15	Good	27.88	Preferential	213	Very good	37.84
1745.06	8	Poor	20.30	Very good	25	Good	36.97
1745.35	10	Moderate	22.68	Good	36	Good	39.92
1746.04	12	Moderate	19.48	Good	25	Good	43.45
1746.35	12	Moderate	18.85	Good	35	Good	42.36

Based on the porosity and permeability graph of facies A (Fig.1), it appears that the porosity on good level (depth of 1744.32 m, 1746.04 m, and 1746.35 m), on very good level (depth of 1745.06 m and 1745.35 m), and on preferential level (depth of 1744.75). Permeability is on good level (depth of 1744.32 m, 1745.06 m, 1745.35 m, 1744.04 m, and 1746.35 m) and on very good level (depth of 1744.75 m). In the graph, the relationship between porosity and permeability (Fig.1 c) shows theR2 value of 0.8646 (close to 1) which means that the porosity and permeability of this facies are generally interconnected, wherein the increase or decrease in porosity values will always be followed by an increase or decrease in permeability values. It occurs at any depth, except at 1746.35 m.

Differences in porosity values in each depth of the facies are due to differences in the level of diagenesis working process. At a depth of1744.75mhas a porosity value that is on preferential level (27.88%) and permeability values that are on very good level (213 mD). This is caused by inadequate compaction strength, characterized by contact between the grains which is dominated by the point contact, furthermore the carbon material is presents lightly (1%). Carbon material swill reduce the porosity value because it will fill the pores between the grains.

The strong enough compaction found at a depth of 1744.32m, 1745.06m, 1745.35 m, 1744.04m, and 1746.35m which caused the value stay on good level. The fairly strong level of compaction is seen at the point contact which is dominated by an elongated contact. Besides the presence of carbon material that is sufficiently large (1% -7.5%) also cause a reduction in the value of porosity.

Matter that caused the value lowering of porosity and permeability are sorting and roundness level; at a depth of 1744.32 m, 1745.06 m, 1745.35 m, 1744.04 m and 1746.35 m have moderate–poor sorting and sub-angular–very angular roundness. These are different with a depth of 1744.75 m which has good–moderate sorting and angular–sub-angular roundness, so that it has bigger space of porosity and permeability (Fig.1). In general, it can be concluded that the quality of sandstones at facies A is moderate.

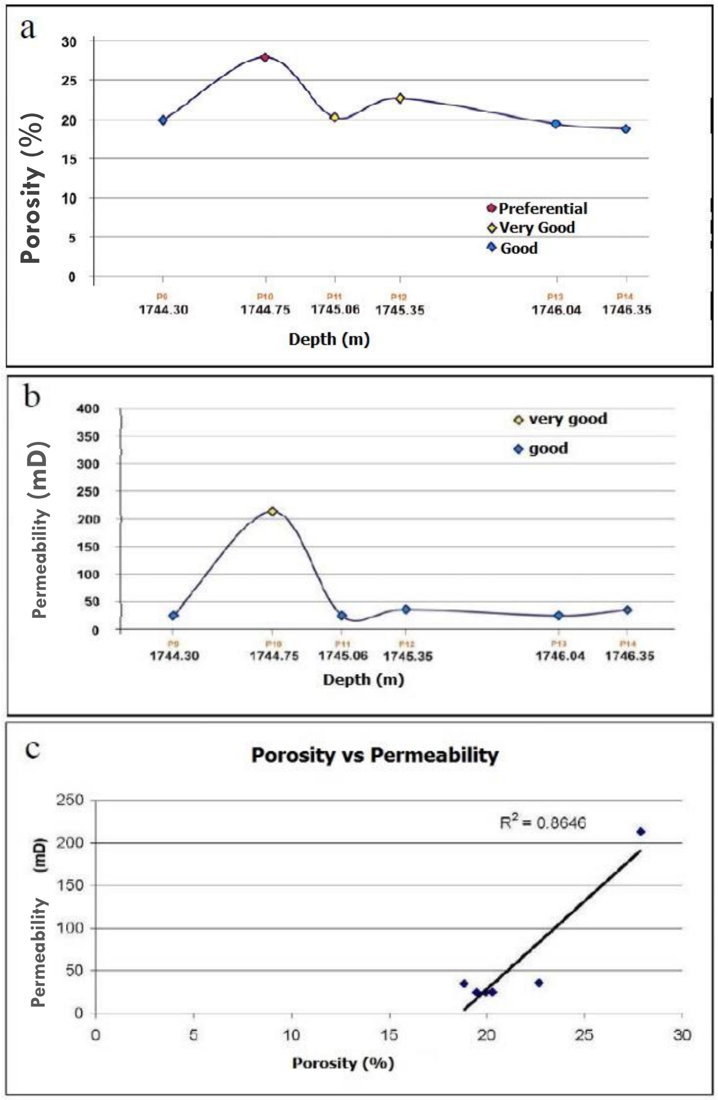


Fig.1. Cross-plott graph of porosity and permeability of facies A

Sandstone at depth of 1744.75 m, routine core analysis shows porosity 27.88% (preferential). Large porosity caused by good–moderate sorting, so that it creates the bigger inter-granule space, morover it has angular–sub-angular roundness. The happened compaction is not too strong, it is characterized by the present of point contact type between the granules.

Sandstone at depth of 1746.35 m, routine core analysis shows 18.85% of porosity (classified as good). This is caused by poor sorting and roundness ranged between angular–sub-angular. The happened compaction were strong enough, visible from the relationship between the grains which is dominated by elongated contact type and the presence of artificial matrix (5%). The presence of laminating clay inserted between the grains also causes the declination of porosity at this depth interval.

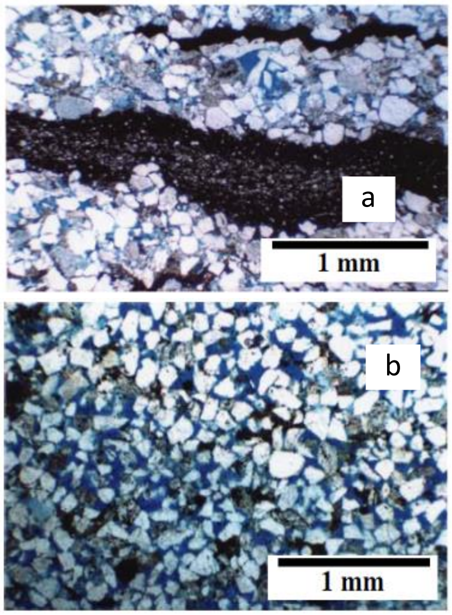


Fig. 2. The relation between sandstone micro-texture and diagenesis process to the permeability in facies

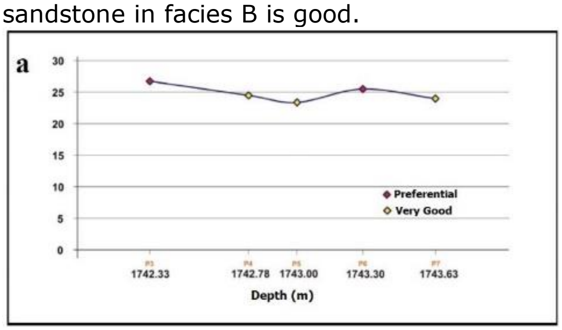
Facies B

At this facies seen that the value of a relativelygoodvisualporosityrangingbetween1 5-17%. Most of the porosity is secondary porosity formed by dissolution. Routine core analysis results the porosityvalues23.34%–26.71%, the horizontal permeability ranging on 83mD–359mD, and water saturation ranging on 35.46%–41.99% (Table II). Of these, there are differences in porosity values between petrographic analysis and routine core analysis due to the present of kaolinite formed during diagenesis, cementation, and replacement.

Table II. Porosity And Permeability Values of Facies B from Petrography And Routine Core Analysis

Depth (m)	Petrography		Routine core				
	Porosity (%)		Porosity (%)		Permeability (mD)		Saturation (%)
1742.33	17	Good	26.71	Good	359	Very good	35.81
1742.78	17	Good	24.45	Preferential	126	Very good	40.30
1743.00	5	Good	23.34	Very good	83	Good	41.99
1743.30	70	Good	25.46	Good	128	Very good	35.46
1743.63	15	Good	23.96	Good	141	Very good	39.75

In the graph of Fig.3, it appears that the porosity varies on preferential level (depth of 1742.33 m and 1743.30 m) and on very good level (depth of 1742.78 m, 1743.00 m, and 1743.63 m). Permeability stays on good level (depth of 1743.00 m) and on very good level (depth of 1742.33 m, 1742.78 m, 1743.30 m, and 1743.63 m). In the graph, the relationship between porosity and permeability (Fig.3c) has R2 value of 0.7423 (close to 1) which means that the porosity and permeability of this facies are generally interconnected, wherein the increase or decrease in porosity values will always be followed by an increase or decrease in permeability values. This occurs at any depth, except at a depth of 1743.63 m. Different value of permeability levels occurred at a depth 1743.00 m which is on good level and the others on very good permeability level. This is due to the occurrence of higher compaction in the depth of 1743.00 m than in the four other samples. At this depth, the contact between the grains is dominated by elongated contact, so that it narrows the porosity and spoils the inter-pore contact that eventually reduces the permeability value (Fig.3) It can be concluded that the quality of sandstone in facies B is good.



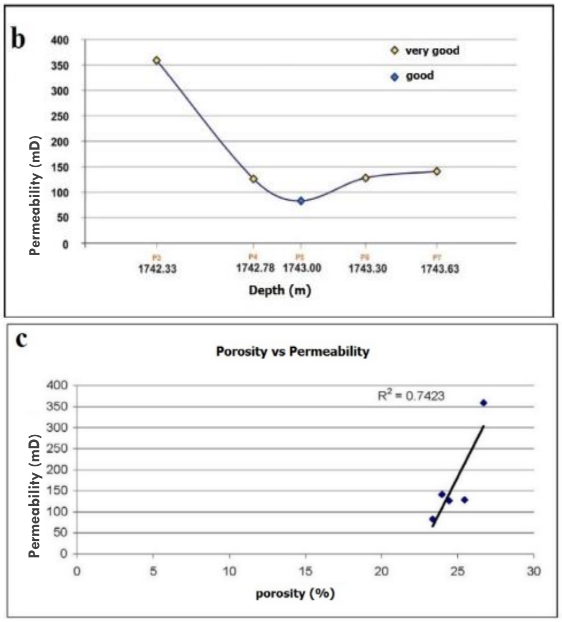


Fig 3. Cross-plot graph of porosity and permeability of facies B

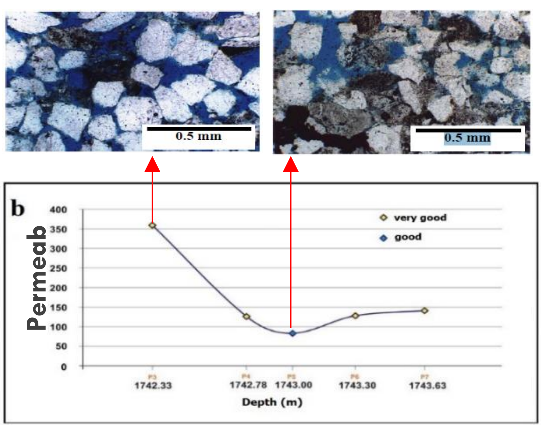


Fig.4. The relation between sandstone micro-texture and diagenesis process to the permeability in facies B

Sandstone at depth of 1742.33 m, routine core analysis shows permeability 359 mD relatively good. Great permeability due to the good relations between grains and the contact between the grains which is dominated by the point contact type that describes the level of compaction is not too high.

Sandstone at depth of 1743.00 m, routine core analysis shows the value of 83 mD (good). The reduced permeability value caused by strong enough.

C.Facies C

Porosity value of petrographic analysis on this facieses 13% (moderate), while the routine core is 26.14% (preferential). The value of permeability is 493mD (very good). Facies C is sand stone deposited on channel of delta plain and distributary channel as well sorted. The compaction that is not to strong caused the contact between the grains is dominated by point contact. Porosity result of petrographic analysis has enough quality and routine core analysis classified as preferential. The permeability shows very good quality. This is affected by the presence of good sorting and in adequate compaction strength. Based on the porosity and permeability of this sand stone facies, the quality determined as good.

CONCLUSION

The quality of sandstone in facies A is moderate based on the porosity value of routine core analysis ranging at 19.48% to 27.88%, then the permeability value ranging from 25mD to 213 mD. The sandstone quality of facies B is good, this is based on the value of the porosity from routine core ranging from 23.34% to 26.71% and permeability value from 83mD to 359 mD. The quality of sandstone in facies C is good. The differences of the quality affected by the various level of compaction, sorting, and contact between the grains. Besides that, the presence of carbon material and laminated clay also led to differences in the quality of the reservoir through inter-granule space filling. Mineral composition of sandstone in each facies is dominated by mono crystalline quartz which is chemically stable, so that the cementation and replacement processes do not overly affect the porosity and permeability.

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