The testing of Qp and QsQp equation in Kujung I Formation, East Java, Indonesia

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Abstract. Hydrocarbon-bearing reservoir shows attenuation on seismic section, but the use of attenuation in hydrocarbon exploration is less popular than other attributes. This is due to the sophisticated and advanced technology required to measure attenuation. Meanwhile, some studies were designed to estimate attenuation by formulating rock quality factor equations from a wire-line log, although others run on sandstone samples. Therefore, this study aims to estimate rock quality factors in carbonate rock of Kujung Formation using three different methods, discriminate hydrocarbon-bearing reservoir, and identifying the impact of carbonate facies. The results showed the P-wave quality factor method is sensitive to discriminate high gas saturation on facies A. Meanwhile, the QsQp ratio is sensitive to discriminate shale and carbonate. The SQp and SQs methods are sensitive to discriminate hydrocarbon-bearing reservoirs and less affected by carbonate facies. The novelty of this is to estimate the rock quality factor from various methods and identify the impact of facies in hydrocarbon identification, especially for carbonate reservoirs in Northeast Java Basin. Therefore, a new understanding of facies impact on rock quality factor contributes to choosing the best methods in discriminating pore-filling fluid identification.

1. Introduction
The application of attenuation in hydrocarbon exploration is gradually known and is sensitive to identify fluid saturation, porosity, and fracture [1]. The dimensionless rock quality factor, Q, is used to measure the degree of seismic wave attenuation. Meanwhile, to measure the attenuation, full-waveform acoustic logging [2], vertical seismic profile with advanced processing technique [3], or core measurement [4] are required. These issues made seismic wave attenuation to become less popular than other attributes such as amplitude and frequency. An alternative option to estimate it is the use of a wire-line log. Also, some equations have been formulated to estimate rock quality factors in hydrocarbon exploration. Therefore, this study aims to estimate rock quality factors using three different methods, discriminate hydrocarbon-bearing and wet reservoir, as well as identify the impact of facies of Kujung I Formation.

2. Regional Geology
Kujung I formation is well known as the main producer in Northeast Java Basin, Indonesia, and it was deposited in shallow marine settings during the early Miocene. The tectonic quiescence took place during Kujung I time, and it consists of thick and massif carbonate succession. On the Northwestern edge of the basin, it is still underexplored, but the gas discovery of Lengo-1 has more exploration opportunity [5].
3. Material and method
This study was conducted in Northwestern Edge of Northeast Java Basin, Indonesia. Eight explorations wells were used to penetrate the Kujung I Formation. Only three were proven to contain hydrocarbon, while others were wet reservoirs. Furthermore, they were completed by wire-line logs, such as total gamma-ray (GR) and uranium-corrected gamma-ray (CGR), resistivity, density, neutron, and compressional slowness. Meanwhile, two wells were completed by a shear slowness log. The routine core data measurement used to calibrate the petrophysical analysis is analog to the nearest proven oil field. Also, there were no measured core data to validate the attenuation.

The facies identification was conducted using a type of gamma-ray and density log. Furthermore, the petrophysical analysis was conducted to determine the volume of shale, porosity, and water saturation. This was calculated by the deterministic approach. Subsequently, the compressional and shear slowness logs, as well as density logs play a significant role in calculating elastic rock properties.

The Q factor was calculated using three different methods. The first is the P-wave quality factor proposed by Klimentos and McCann [4], which was obtained from the rock sample measurement in the laboratory. It measured the magnitude of rock physic parameters, including attenuation under 40 MPa and 1 MHz. The result showed a linear relationship between porosity, shale content, and coefficient attenuation. Hence, the equation:

\[
Q_p = (\pi f)/(0.0315PHIE + 0.241VSH - 0.132Vp)
\]

where: \(Q_p\) = P-wave quality factor; \(PHIE\) = effective porosity; \(VSH\) = volume of shale; \(f\) = frequency, and \(Vp\) = P-wave velocity.

Secondly, the \(Q_s/Q_p\) ratio formulated by Mavko et al [6] was obtained from Hudson’s crack theory which proposed three theorems. The first theorem assumed that aligned crack orientation causes an anisotropy effect in reducing the propagated P-wave. The Equation is as follows:

\[
\frac{Q_s}{Q_p} = \frac{1}{4} \left[ \frac{3 (V_P/V_S)^2 - 2}{(V_P/V_S)^2 - 1} \right] \left[ \frac{(V_P/V_S)^2}{(V_P/V_S)^2 - 2} + \frac{(V_P/V_S)^2}{(V_P/V_S)^2 - 1} \right] \]

(2)

The second theorem assumed that the crack is randomly distributed to introduce isotropy. The Equation is:

\[
\frac{Q_s}{Q_p} = \frac{5}{4} \left[ \frac{(V_P/V_S)^2 - 2}{(V_P/V_S)^2 - 1} \right]^{1/2} \left[ \frac{2 (V_P/V_S)^2}{3 (V_P/V_S)^2 - 2} + \frac{(V_P/V_S)^2}{3 (V_P/V_S)^2 - 1} \right]^{-1}
\]

(3)

The third theorem assumed that the distribution of crack is random and the isotropy effect introduced causes a reduction of S-wave modulus. The Equation is as follows:

\[
\frac{Q_s}{Q_p} = \frac{1}{3} \left[ \frac{4 \frac{(V_P/V_S)^2 - 2}{3} \left( \frac{(V_P/V_S)^2}{3} - \frac{4}{3} \right)^2}{\left( \frac{(V_P/V_S)^2}{3} - \frac{8}{9} \right)} \right]
\]

(4)
where: $Q_P = P$-wave quality factor; $Q_S = S$-wave quality factor; $V_P = P$-wave velocity; and $V_S = S$-wave velocity.

The last method is scaled $P$-wave ($SQ_P$) and scaled $S$-wave quality factor ($SQ_S$) proposed by Hermana et al [7]. This was adopted from Mavko et al first theorem which suggested that anisotropy is introduced by crack orientation. The equation was formulated by expanding the crack density factor into porosity and crack aspect ratio of sandstone. Hence, the equation is:

$$SQ_P^{-1} = \frac{5}{6} \rho \left( \frac{V_P}{V_S} \right)^2 \frac{(V_P/V_S)^2 - 2}{(V_P/V_S)^2 - 1}$$

(5)

$$SQ_S^{-1} = \frac{10}{3} \rho \left( \frac{V_P}{V_S} \right)^2 \frac{(V_P/V_S)^2 - 2}{3(V_P/V_S)^2 - 2}$$

(6)

where: $SQ_P = $ scaled $P$-wave quality factor; $SQ_S = $ scaled $S$-wave quality factor; $\rho = $ Bulk density; $V_P = $ $P$-wave velocity; and $V_S = $ $S$-wave velocity.

4. Results and discussion

Facies of Kujung I Formation can be distinguished into two types, namely A and B based on gamma-ray log type, shale content, and density log character. This is analog to the nearest well with conventional core data in figure 1a. Facies A is characterized by low and blocky gamma-ray log, massif, and thin reservoir with higher shale content and high-density log reading found interbedding with shale. Furthermore, the A was interpreted as backreef facies, meanwhile, B was characterized by low and blocky type gamma-ray log, massive and thick reservoir with lower shale content, and low-density log reading. Facies B was interpreted as reef flat. The facies of Kujung formation wells are seen in Figure 1b.

![Figure 1. a) Facies analog used to determine A and B. b) Well to well correlation showed the distribution of facies A and B each.](image)

Shale volume was calculated by averaging gamma-ray and density-neutron logs calculation method. Subsequently, porosity calculation was conducted through the density-neutron log method. According to SAKA unpublished internal study (2020), tortuosity factor, cementation, and saturation exponent parameters used for water saturation are 1, 1.8-2, and 1.96-2 respectively. The water salinity was measured from sample analysis, which showed low saline water (20,000-30,000 ppm). Furthermore, the water saturation was calculated using the Archie equation model, and the result of the petrophysical
analysis is seen in Figure 2. Furthermore, the estimation of rock quality factor was conducted by firstly calculating dynamic elastic rock properties using a combination of compressional slowness, shear slowness, and density logs. This resulted in p-wave modulus (M), s-wave modulus (G), and VpVs ratio, and there is no measured core sample to validate the result.

![Figure 2. The petrophysical analysis result and its estimation of attenuation.](image)

The result of the estimated rock quality factor can be seen in figure 3. The P-wave rock quality factor (Qp) by using Klimentos and McCann method showed discrimination of hydrocarbon-bearing and wet reservoirs on facies A in cross plot between Qp and VpVs (Figure 3b). Also, the reservoir with 20-50% water saturation was easily recognized from a cross plot in Figure 3b with Qp and VpVs ranging from 2-11 and 1.3-1.8 respectively. Although, in facies B, it was difficult to discriminate between hydrocarbon-bearing and wet reservoirs rocks as seen in Figure 3c. Furthermore, the VPVS ratio was more sensitive to discriminate the two reservoirs than Qp.

By using 3 theorems from Mavko et al method, the Qs/Qp ratio can be estimated through 3 different equations. The result in Table 1 showed Qs/Qp ratio was less sensitive to identify hydrocarbon reservoirs,
as shown by a wide range value. However, facies A has a lower value and narrower range of QsQp ratio than B. Hence, the QsQp ratio is more sensitive to identify reservoir and non-reservoir lithology such as shale. The shale has a high QsQp ratio with 100% volume and water saturation.

Figure 3. P-wave rock quality factor result using Klimentos and McCann Equation. a) well-based rock quality factor results and the cross plot between VpVs ratio and P-wave quality factor on b) facies A, and c) facies B which point color means water saturation.

|            | Facies A | Facies B | Hydrocarbon reservoir | Shale |
|------------|----------|----------|-----------------------|-------|
| QsQp       | 0-90     | 0-50     | 0-90                  | 35-50 |
| QsQp2      | 0-10     | 0-5      | 0-10                  | 4-12  |
| QsQp3      | 0.8-18   | 0.8-10   | 0.8-18                | 8-15  |
Figure 4. SQp and SQs result. a) well-based SQp and SQs results and the cross plot between SQp and SQs on b) facies A, and c) facies B which point color means water saturation.

The estimated inverse scaled-Q factor proposed by Hermana et al looks like the first equation result of the Mavko et al method in Figure 2. To discriminate between hydrocarbon-bearing and wet reservoirs, it is necessary to plot SQp and SQs values. In Figure 4b, SQp and SQs method gradually changed due to the reduction of water saturation on facies A. The hydrocarbon-bearing reservoir with 20-50% water saturation of SQp and SQs value ranges from 0.05-3 and 0.58-1 respectively. Meanwhile, the wet reservoir has SQp and SQs values ranging from 0.05-3 and 0.48-0.6. On facies B, a thin hydrocarbon-bearing reservoir was detected that SQp value ranges from 0.05-1 and SQs from 0.6-1. From all these facies, it is seen that SQs value was sensitive to detect water saturation and hydrocarbon indication. Therefore, with this method, facies give less impact to discriminate the hydrocarbon indication. In Figure 4b and 4c, both lithofacies shows gradual change as reduction of water saturation and increase in SQs value, even though facies B in (Figure 4c) looks more irregular than A (Figure 4b).

The facies affect the result of the estimated rock quality factor, and B will tend to produce a poor-quality result than A. Furthermore, low water saturation makes reservoir discrimination easier to identify, and the presence of high gas content affects wire-line log reading, especially for porosity and...
sonic logs. This directly affects the result of the estimated rock quality factor as seen in Qp, SQp, and SQs methods.

5. Conclusion
All the methods are applicable to estimate rock quality factors in carbonate reservoirs but only Qp, SQp, and SQs can discriminate pore-filling fluid. Furthermore, facies affect the estimated rock quality factor, and the QsQp ratio is sensitive to discriminate shale and carbonate. Therefore, a new understanding of facies impact on rock quality factor contributes to choosing the best methods to discriminate pore-filling fluid.

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