THE ROCK COMPRESSIBILITY CHARACTERISTICS OF SOME INDONESIAN RESERVOIR LIMESTONES

Karakteristik Kompresibilitas Batuan dari Batugamping Reservoir-reservoir Indonesia

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ABSTRAK

Kompresibilitas batuan adalah suatu sifat fisik batuan formasi yang penting. Sifat tersebut mempengaruhi berbagai proses di reservoir dan batuan formasi yang mencakup dari mulai sebagai sumber energi pendorong di reservoir, perannya yang dapat mengubah sifat-sifat fisik batuannya, sampai dengan pengaruhnya yang menyebabkan penurunan permukaan tanah. Berbagai studi telah dilakukan dan dipublikasikan, tetapi belum pernah ada studi yang komprehensif atas batugamping Indonesia, terutama karena perannya sebagai batuan reservoir yang telah menyumbang secara berarti terhadap produksi minyak dan gas nasional selama beberapa dasawarsa yang lalu. Studi ini dilakukan untuk mempelajari karakter kompresibilitas batugamping dalam hubungannya dengan porositas batuan. Sebanyak 84 sampel batugamping yang berasal dari lima formasi produktif di Indonesia dipakai dalam studi. Beberapa korelasi/model matematis yang ada dan telah dikenal secara meluas juga dipakai sebagai pembanding. Hasil studi memperlihatkan bahwa model-model yang ada tidak selalu dapat mewakili semua data yang ada sehingga sebuah model yang baru telah diusulkan untuk mewakili batugamping berkekerasan sedang dan berporositas *vuggy*. Hasil studi juga memperlihatkan bahwa karakter kompresibilitas batugamping tidak berhubungan dengan tipe batuan tapi lebih kepada tingkat kekerasan batuan dan tingkat kehadiran rongga (vug) dalam batuan.

Kata kunci: kompresibilitas batuan, batugamping, porositas, karakter

ABSTRACT

Rock compressibility is an important formation rock properties. It influences various processes in reservoir and rock formations that encompass from sources of reservoir driving energy, changes in other reservoir properties, to land subsidence. Various studies have been performed and published, but no comprehensive studies have ever been performed on Indonesian reservoir rocks. This article presents results of such studies on Indonesian limestones, reservoir rocks that have contributed much to Indonesia's national oil and gas production for decades. The study was carried out in order to study the characteristics of limestone in its relation to rock porosity. A set of 84 limestone samples taken from five productive formations in Indonesia is used in the study. Some existing and widely known mathematical correlations/models are also used to assist the study. Some of the results show that the existing models are not always valid for some of the rocks, and therefore a new model is proposed for medium-hard and vuggy limestones. The results also show that limestone characteristics are not related to rock types and place of origin, but instead to rock hardness and degree of vuggy pore presence.

***Keywords:** rock compressibility, limestone, porosity, characteristics*

I. INTRODUCTION

As reservoir pressure declines, and effective stress increases, during production reservoir rocks also tend to shrink in its pore volume. The shrinkage – and expansion due to decrease in effective stress – behavior is known to be represented by a rock property named rock compressibility. There are actually three type of rock-related compressibility: pore volume compressibility, matrix compressibility, and bulk compressibility (rock compressibility). A bulk compressibility is by principle a combination between pore volume compressibility and matrix (grain) compressibility. However, since pore volume compressibility is much larger than matrix compressibility a rock compressibility is therefore much more controlled by pore volume compressibility and accordingly the term of rock compressibility is simply interchangeable with pore volume compressibility. In overpressured oil – and especially gas – reservoirs rock compressibility can often be regarded as even the most important source of driving energy (Fetkovitch et al. 1991).

The effect of changes in effective stress on reservoir rock porosity – and permeability – has long been acknowledged and various studies have been performed in order to investigate its impact on various aspects. Rock compressibility is an important data required for cross-checking hydrocarbon in place and reserves in relatively mature fields using material balance method (e.g. Dake 1978; Bradley 1987). Study over the use of material balance method is further studied through incorporating fracture rock compressibility (Aguillera 2008) and its application for an Indonesian case (Widarsono 2009). The application has confirmed difficulty due to the lack of representative rock compressibility data but proved accurate in determining original gas in place when the right data is being used.

Studies in other area of reservoir characterization have also shown various facts, such as dependence of rock compressibility on production-related stress path (Ruistuen et al. 1999), uncertainties in well test-derived rock compressibility that needs comparison with real data from laboratory (Cox et al. 2000), and the important role of rock compressibility data for determination of well drainage radius from well test data (Pinzon et al, 2001). In broader scales of reservoir evaluation through reservoir simulation, Gutierrex (1998) recognised the relation between geomechanics and reservoir productivity, and stated that it is only rock compressibility that can be used to compensate the lack of coupling between the two mechanisms in most reservoir simulators. In a later study, Tran et al. (2004) described various ways possible for coupling the two mechanisms but they nonetheless stated the still considerable role played by rock compressibility.

Reservoir shrinkage due to hydrocarbon production also affects other areas of activities indirectly related to the production itself. Subsidence is an example, in which as early as in 1920s its occurrences in oil fields were felt and observed (Geertsma 1973). More recent studies on some fields confirmed the subsidence in Valhall field (North Sea) (Ruddy et al. 1989) due to massive production from its soft chalk reservoir, and subsidence in Ekofisk field (also North Sea) that led to a conclusion over the importance of rock compressibility information for helping pressure maintenance operation (Sulak & Danielsen, 1988). The difference between field and laboratory-measured rock compressibility due to non-linearity in rock behavior was reported by (deWall & Smits 1988) prompting to more thorough understanding over a field’s rock compressibility.

The importance of rock compressibility led various investigators to spend attention on the rock property’s underlying theory and its relations with other properties. Early studies like ones reported by Hall (1953), Geertsma (1957), Fatt (1958), and Newman (1973) resulted in some important conclusions, as well as correlations attempted to provide practicians with practical sets of equations for predicting rock compressibilities. Latter studies by Yale et al. 1993), Harari et al. (1995), Li et al. (2004), Liu et al. 2009), Betts et al. (2011), Myers and Hatton (2011), and Bakhtiari et al. (2011) attempted to produce some correlations based on the samples they used in the study. Most of the studies reported inaccurate predicted values using past correlations and yielding discussions over various factors that may serve as the cause of the misprediction.

Rock compressibility studies for Indonesian rock samples are very limited, to author’s knowledge. Pathak & Wirya (2007) used rock compressibility data from laboratory successfuly to explain pressure anomaly in NSO field-Aceh and Fardiansyah et al. (2010) studied rock compressibility data from outcrop samples for the purpose of analogy. The rarity of such study and a complete absence of comprehensive studies on reservoir rocks in Indonesia have underlined the need of such studies. This paper reports results of a study on rock compressibility of Indonesian reservoir limestones; characteristics, general trends, relation with rock types, and correlations with other properties.

II. METHODOLOGY

A. Rock Compressibility

With considering under constant temperature condition, compressibility of a rock formation is defined as a ratio of an amount of change in volume with change in pressure to its original volume, or can be expressed as (Zimmerman, 1991):

$$C_f = \frac{1}{V_P}\left(\frac{\partial V_P}{\partial P}\right)_T \qquad (1)$$

with C_f, V_p, and P are formation compressibility (usually in psi^{-1}), pore volume (in cu-ft), and pressure exerted on the formation (in psi). T is to mark that the condition is under constant temperature. In reality in the formation, when a reservoir is being produced for its hydrocarbon the reservoir pressure declines resulting in – while overburden pressure remains constant – increase in effective stress. The formation's contraction characteristics in response to the increasing (or decreasing) effective stress reflects the formation's compressibility. Different pore types and structures may respond differently toward compression, and their pores and permeability may also decrease in different manners. However, for most reservoir rocks the volume change is actually small, in the magnitude of 10^{-6} psi^{-1}, and normally within the range of $2x10^{-6}$ to $15x10^{-6}$ psi^{-1} @ initial reservoir pressure (Satter, 2007).

Similarly to its relation to pore structure also relates closely with porosity. However, there is a wide range in compressibility for a particular porosity, and furthermore, may behave differently for rocks with different porosities. This led to the need to understand the relationship and seek correlation(s) that link the two. In 1953, Hall established a general empirical correlation of

$$C_f = 1.87x10^{-6}\phi^{-0.4} \qquad (2)$$

where ϕ is porosity, usually at atmospheric or overburdened conditions. Since the correlation was established based on a certain number of samples only and is unlikely to be valid for reservoir rocks in general other later investigators attempted to establish other correlations. Newman (1973) established general hyperbolic correlations for both sandstones and limestones based on 79 samples put in the study. For limestones, the correlation is

$$C_f = \frac{0.8535}{[1+2.367\phi]}x10^{-6} \qquad (3)$$

Results of a more recent study also yielded correlations of (as shown in Horne, 1995)

$$C_f = \exp\left(4.026 - 23.07\phi + 44.28\phi^2\right)x10^{-6} \qquad (4)$$

for limestones. Figure 1 shows the three ϕ-C_f existing correlations. All three correlations infer lower compressibility for higher porosity rocks. Using the correlations presented above comparisons are to be made on the characteristics of Indonesian reservoir sandstones.

B. Data Measurements

Analysis on core samples were initiated by core plugging and cleaning, after which smples underwent

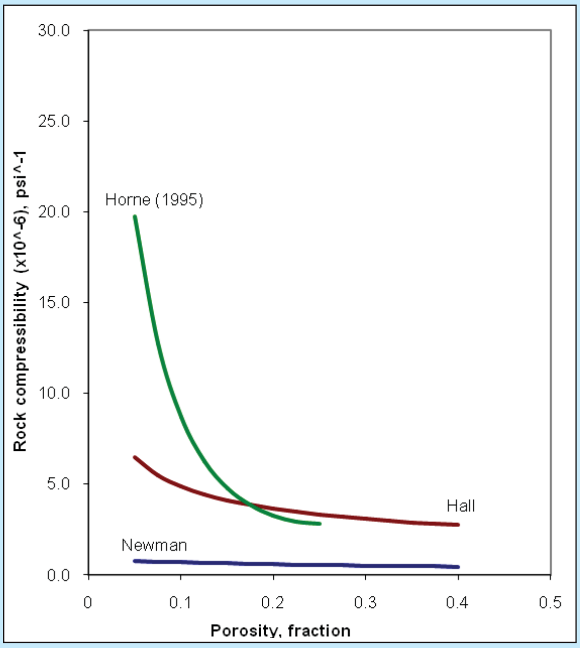

Figure 1
The existing rock compressibility correlations for limestones

geological visual description and basic properties measurements of porosity and permeability. The PVC test was performed by evacuating and fully saturating the samples with brine and then both pore and confining pressures were elevated up to a certain pressure level (i.e 200 psig). Using this as a starting point the overburden pressure was raised further up to pre-determined pressure levels while the pore pressure was kept constant. After estimating changes in pore volume at each pressure level the was calculated using Equation 1. For converting hydrostatic loading condition into uniaxial condition, that is more representing reservoir under overburden loading, theoretical formula proposed by Teeuw (1971) was used. Figure 2 presents an exemplary set of measurement results, in the standard form of versus effective overburden pressure.

As many as 84 limestone samples were used in the study (Appendix). The samples were taken from 11 productive oil and gas fields in Indonesia. They represent various limestone types, and belong to five important limestone formations in Indonesia; the Baturaja of South Sumatra basin, Belumai and Peutu of North Sumatra, Minahaki of Banggai basin, and Kujung of Northeast Java basin. Figure 3 presents the locations of the Tertiary sedimentary basins. Through the use of these representative samples, valuable information is expected to be revealed about the compressibility characteristics of carbonate rocks of Indonesian reservoirs.

III. RESULTS AND DISCUSSION

In performing evaluation over the results of measurement, two angles of approach are adopted; evaluation through rock type grouping and evaluation through their geological place of origin (i.e rock formation). For rock type grouping, Dunham classification is used. Dunham (1962) established a stratified classification starting from the top by recognising ‘crystalline’ and ‘non-crystalline’, dividing the ‘non-crystalline’ into ‘components bound’ and components not bound’, dividing further the ‘components not bound’ into ‘containing mud’ and not, down to division of the rocks classified as ‘containing mud’ into ‘mud dominated’ and ‘grain dominated’. These definitions, based clearly on rock fabric, classify carbonate rocks into rocks types of crystalline, boundstone, grainstone, packstone, wackstone, and mudstone. In this study, only data of rock samples belonging to boundstone, grainstone, packstone, and wackestone is available for evaluation.

For data presentation compressibility values at reservoir initial pressure, hence minimum effective overburden presure, are used. By assuming uniform overburden pressure (P_{OB}) and reservoir pressure (P_{res}) gradients of 1 psi/ft and 0.5 psi/ft, respectively, an effective overburden pressure of 0.5 psi/ft is used following

$$effective P_{OB} = P_{OB} - P_{res} .$$

As effective overburden pressure has been determined, the needed compressibility values are obtained from the rock compressibility curves (e.g Figure 2).

The tendency of relation between rock compressibility and porosity for the 84 rock samples are depicted on Figure 4. Although no clear trend can be observed, the data population still provide a semblance of decrease in initial rock compressibility for higher porosity limestones. The lack of sharp – a general trend is also still visible – trend is also shown and reinforced by their porosity – permeability relationship (Figure 5). This lack of obvious trend is expected and analysis on lower levels is required.

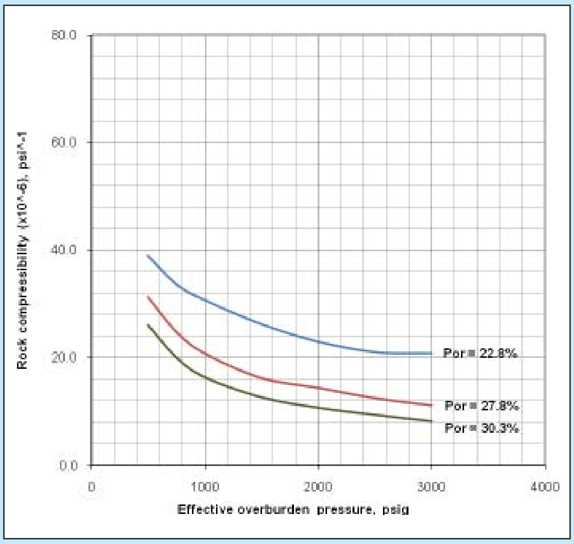

Figure 2
Example of pore volume compressibility results (Kujung)

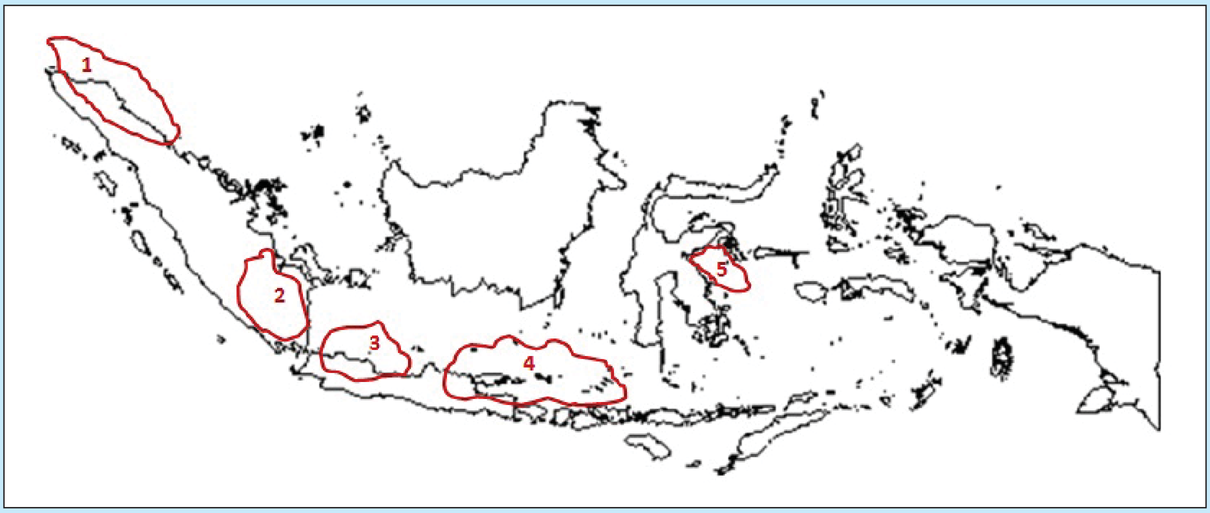

Figure 3
Tertiary sedimentary basins, the place of origin of the limestone core samples used in this study: (1) North Sumatra basin, (2) South Sumatra basin, (3) Northwest Java basin, (4) Northeast Java basin, and (5) Banggai basin

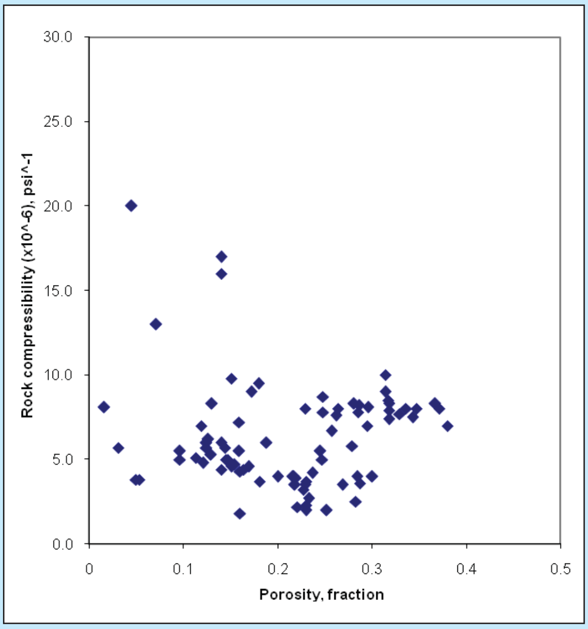

Figure 4
Plot between rock porosity and rock compressibility of all data (84 samples)

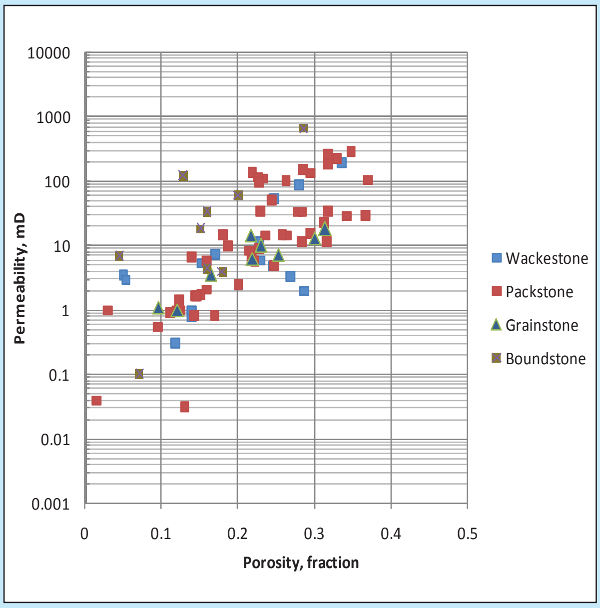

Figure 5
Porosity – permeability plot for all limestone samples (84 samples)

A. Rock Compressibility and Rock Types

As rock typing has been established through visual description, samples and the corresponding data are groupped into rock type-based groups. For boundstone (9 samples) the data is presented on Figure 6. In this limited amount of samples no sharp trend is indicated and no one of the correlations can represent all data population, even though Horne (1995) model appears to be the closest model to fit some of the data points. Apart from the limited sample number, this inconclusive data plot probably reflects the reefal nature of boundstone along with its associated heterogeneity.

Despite the similarly limited sample number (9 samples), data for grainstone samples is clearly different compared to the boundstone group (Figure 7). Hall model appears to agree well with the data. Interestingly, the nine samples are actually from five fields and three formations located in three different sedimentary basins; North Sumatra, South Sumatra, and Banggai (Sulawesi), The good agreement between data and the Hall model reflects the less variation in pore structures among the samples classified as grainstones, all characterized by presence of forams and pin-point vugs.

Packstone make the bulk of the sample population with its 48 samples. Plot in Figure 8 present a fair degree of scatter even though the general trend show decrease or at least constant in compressibility with the increase in porosity. However, a more careful analysis may show that the lower part of the data cluster agree well with both correlations with Hall model appears to represent better. On the other hand, the data on the upper cluster of the data is likely to be represented by other model other than the three existing models. A closer look on the data with regard to physical features show difference between the two clusters. The lower cluster is predominantly Arun limestone that are characterized by presence of forams, algae, stylolites, and pin-point vugs at most while the upper cluster's Kujung limestones show presence of larger vugs. Different environment and development during the rock forming may have some relation to place of origin.

In a way similar to packstone, data showing for the wackestone group (18 samples) yields agreement between either Hall or Horne (1995) model and only a part of the data populations (Figure 9). In this case, this is also apparent that the lower and upper data come from different place of origin, Banggai and North Sumatra basins, respectively. Overall evaluation over data based on rock typing have shown that some of the data agree with Hall and/or Horne (1995) models, while Newman model for limestones predicts too low compressibility values for the same porosity range. The fact that some of the data do not fit with the models also lead to need for an alternative of evaluation approach.

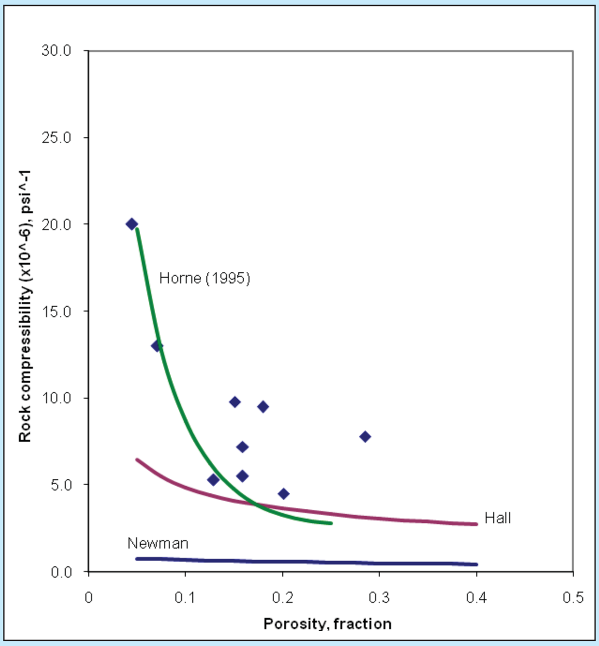

Figure 6
Rock compressibility data for boundstone (9 samples). Most of the data fall beyond the three corelations

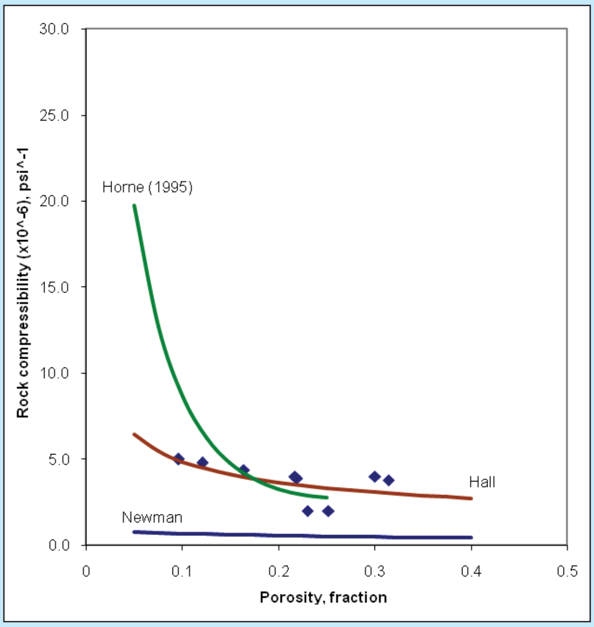

Figure 7
Rock compressibility data for grainstone (9 samples) showing good agreement with Hall correlation

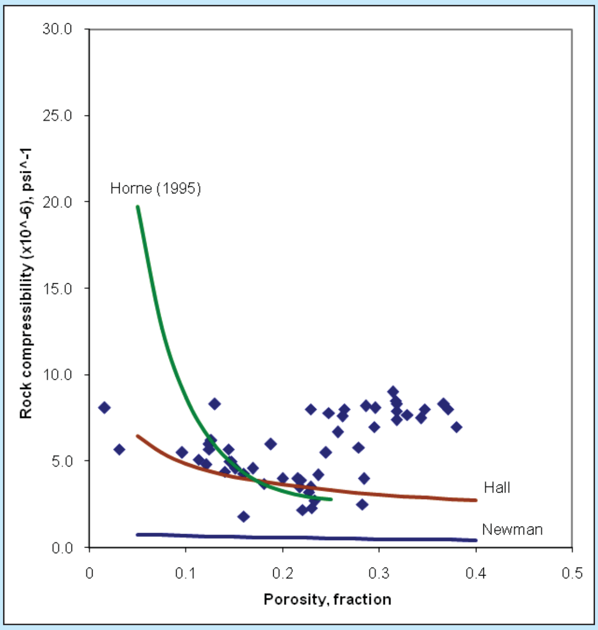

Figure 8
Rock compressibility data for packstone (48 samples) showing two clusters of data, with the lower cluster tends to agree with Hall correlation

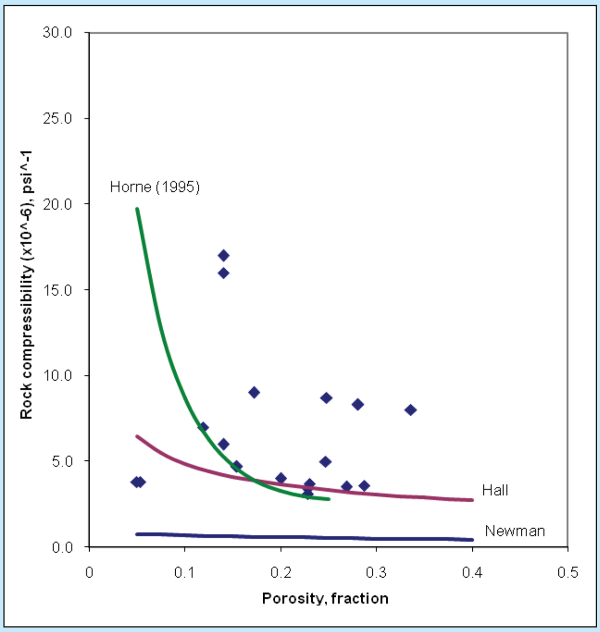

Figure 9
Rock compressibility data for wackestone (18 samples) depicting similar trends to packtone with some of the data in reasonably good agreement with Hall model

B. Rock Compressibility and Rock Formations

As put earlier, the 84 limestones used in the study have been taken from four limestone formations in four productive sedimentary basins. Each locations may have different environment and rock forming path that affect rock compressibility characteristics. Figure 10 depicts plot for the Baturaja limestones (South Sumatra).The *f*-C_f plot (17 samples) some degree of scatter even though agreement with Hall model (or Horne (1995)?) is evident for most of the data. When compared to data plot for Minahaki limestones (18 samples) a stronger agreement to the Hall correlation is indicated under a much better degree of tolerance (Figure 11). This agreement to Hall correlation has to be underlined since the Horne (1995) model is valid only up to porosity of 23%. The two data showings from two places of origin strongly indicate that the existing models, derived using samples from other places, can be proved valid for some Indonesian limestones belonging to some specific places, in this case Baturaja (South Sumatra) and Minahaki formations.

For the limestone samples (36 samples) from North Sumatra basin the plot between rock compressibility and porosity is presented on Figure 12. From the data, a separation into two groups is visible. The lower cluster – all from Peutu formation – appears to reasonably agree with either Hall or Horne (1995) models. A more careful examination, however, tend to lean on Hall model as the more representative correlation for the Peutu samples. On the other hand, the upper cluster – all samples from Belumai formation – apparently fall out of all three correlations. By observing the clear trend shown by the samples it can be concluded that the data are not of false ones but instead should be represented by other model. A new correlation is therefore required.

Through observing trend of the Belumai samples the required correlation could bear a resemblance to any of the three empirical correlations. As reformulation of the three correlations have been undertaken, it came out that the most approprate correlation for the Belumai samples is

$$C_f = \frac{85.43}{\left[1 + 15.35\phi^{0.385}\right]} x10^{-6} \qquad (5)$$

which is mathematically a modification of Newman model but with similar curve shape, except in

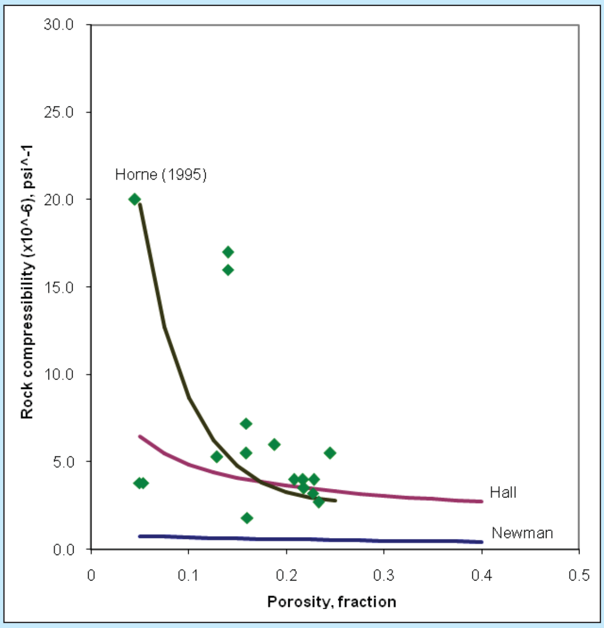

Figure 10
Rock compressibility data for Baturaja formation limestones (17 samples) presenting in reasonably good agreement between data and Hall (and/or Horne, 1995 (?)) model(s)

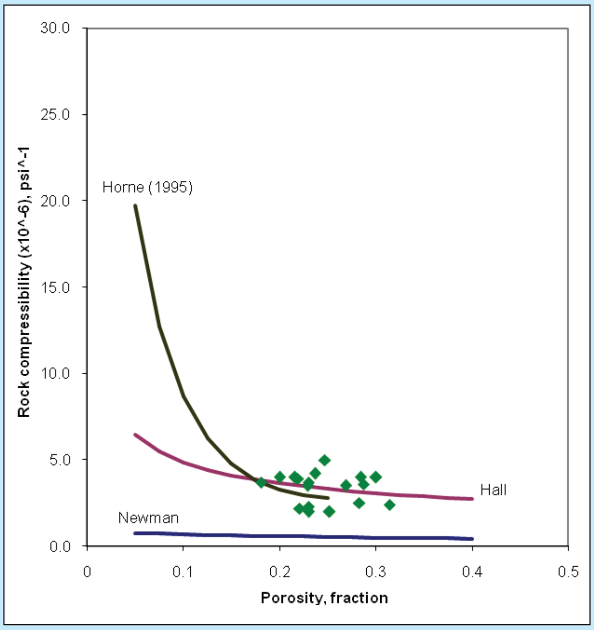

Figure 11
Rock compressibility data for Minahaki formation limestones (18 samples) showing good agreement between data and Hall model. Presence of data with porosity higher than 24% defies association to Horne (1995) model

the order of magnitudes, with Hall model. Upon observing the newly proposed ϕ-C_f empirical correlation the presence of $\phi^{0.385}$ implies that effect of porosity difference at higher porosity diminishes. In other words, the higher the porosity values the lesser the compressibility variation among them.

Application of Equation 5 on Belumai data is presented on Figure 13. The equation shows no limit of validity at least up to porosity of 50%. Agreement between the proposed correlation with the Belumai data appears very good, with gentler slope at higher porosity that well represents the less variation in within that porosity range.

Plot for the Kujung Formation (Northeast Java basin) data (13 samples) is shown on Figure 14. In the manner similar to Belumai samples, the Kujung samples also fall out of the three existing correlations. However, when the newly proposed correlation is applied, it fits the data reasonably well. Although the data comprises only data for higher porosity values, and no evidence whether the correlation is also valid for lower porosity values, the model works well for the available data. The newly proposed model can therefore be considered valid since it can represent two data groups taken from two far separated regions.

IV. DISCUSSIONS

As has been observed in the application of the new model, it agrees well with two sets of samples taken from two sedimentary basins that are not linked in every way. This leads to the need to compare aspects of the two sets of samples. Attempts to compare the two at scales larger than core scale – field- or basin-scale depositional and diagenetic aspects – are simply too complicated and may be considered as irrelevant to the theme of this article.

Comparison between the physical nature of the two sets show that the Kujung samples are almost entirely medium hard packstone with porosity made mainly of vugs, while the Belumai samples are also mainly medium hard with 9 packstones, 3 wackestones, and 3 boundstones (see Appendix). The samples' porosity is mainly made of pin-point to mottled vugs/med vugs. Considering the mostly medium hard nature of the limestone samples analysed, it is probably the hardness of the two sample sets provides the similarity in the rock compressibility characteristics. This becomes more

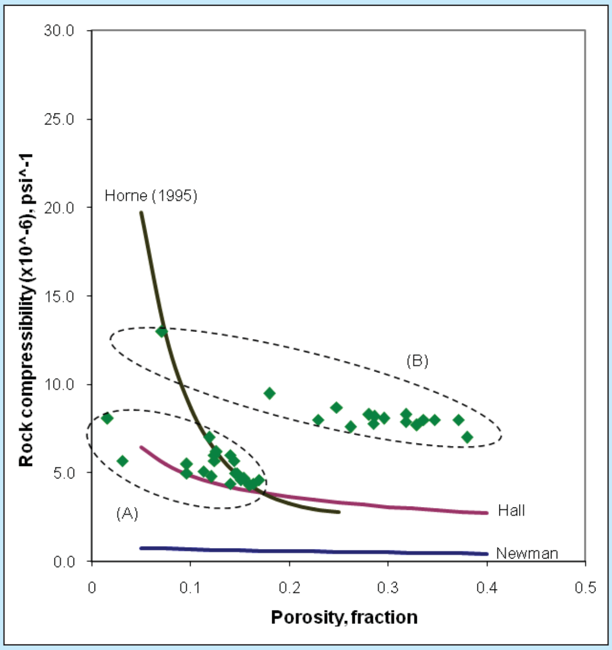

Figure 12
Rock compressibility data for North Sumatra basin limestones (36 samples) depicting two data clusters of data from (A) Peutu formation and (B) Belumai formation. The Peutu data appears to agree more to Hall rather than to Horne (1995) model due to presence of some low porosity samples that tilt to the former model

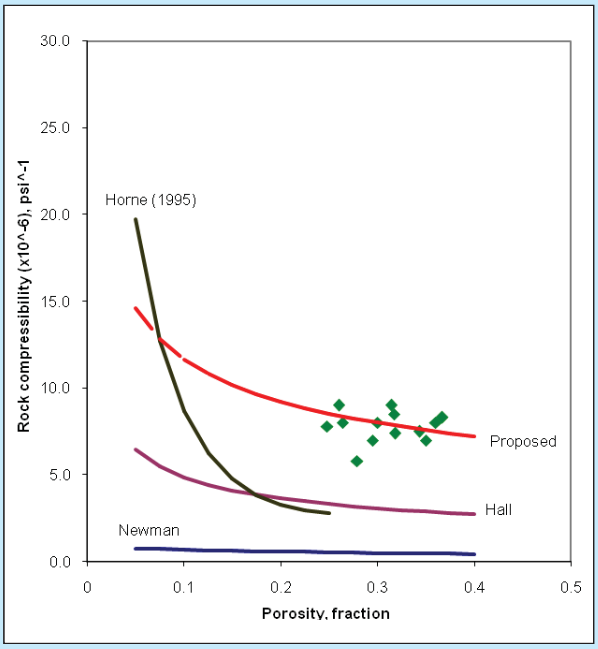

Figure 14
Rock compressibility plot showing good agreement between samples from Kujung formation (13 samples) and the the proposed model. Kujung formation (Northeast Java basin) samples are also of medium-hard and vuggy limestones

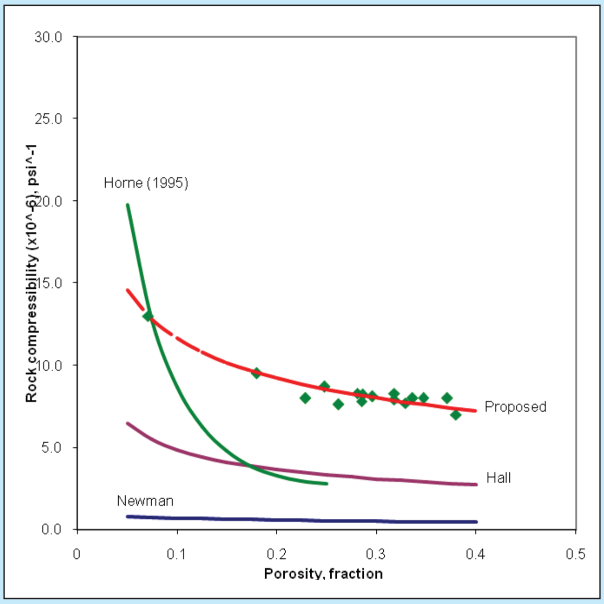

Figure 13
A newly proposed model that fits very well with the medium hard – vuggy Belumai limestones (15 samples). The model has no porosity limit in the validity

underlined when comparison is made to all other samples from all other formations that are almost entirely of 'hard' hardness and less vuggy. Therefore, it can be said that the newly proposed correlation (Equation 5) is a ϕ-C_f correlation for medium-hard and vuggy limestones, regardless of rock types.

For the rest of hard limestones, on the other hand, the models of Hall and Horne (1995) appear to represent them well. However, caution should be taken in choosing the Horne (1995) model since it has limitation of validity. The Hall model is likely to be more appropriate for Indonesian hard limestones. For the Newman model, it is apparently at odd with all data population. No explanation whether or not it can be applied for any of Indonesian limestones. It can probably be applied for 'very hard' Indonesian limestones, which may no longer be considered as productive reservoir rocks.

V. CONCLUSIONS

At the termination of the study, a set of main conclusions have been taken:

A new correlation has been proposed for Indonesian medium-hard and vuggy limestones. The model has been proved applicable for rocks taken from different sedimentary basin regardless of rock types.

Hall correlation has been found to work for Indonesian hard limestones regardless of rock types. These limestones usually have minimum presence of vuggy pores hence stressing the role of vugs – apart from hardness – in determining characteristics.

The characteristics of limestone used in this study with regard to porosity is not related to or dependent on rock types. Instead, rock hardness and significant presence of vuggy pores affect the property's order of magnitude, even though its relation with porosity may remain of the same trend.

The characteristics of limestone used in this study with regard to porosity is not related to place of origin or proximity of deposition. Belumai limestones behave more closely to Kujung limestones and differ much from Peutu limestones even though Belumai and Peutu formations are both in the North Sumatra basin.

Considering the effect of rock hardness on characteristics, the prevailing assumption of zero rock matrix compressibility – i.e PV compressibility is equal to – needs to be revisited. Further studies on rock matrix compliance to stress are required.

The hard (represented mostlyby Hall model) and the medium-hard vuggy (represented by the new model) limestones samples appear to be similar in their characteristics with regards to porosity, and only differ in their order of magnitudes. This underlines the need to carefully differentiate between the two kinds of limestones, in order to choose the appropriate model for any practical purposes.

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Appendix

Table A1
Basic data of core samples from Baturaja formation (South Sumatra basin)

No.	Type	Porosity (fraction)	Permeability (mD)	Description	Depth (m)
1	Packstone	0.245	49	hd,sli vug, for	1502
2	Packstone	0.16	2.1	hd,for,OM streak	1502
3	Packstone	0.233	111	hd, for,OM streak	1503
4	Packstone	0.218	132	hd,sli vug, for	1504
5	Packstone	0.188	9.7	hd,sli vug, for	1506
6	Packstone	0.227	117	hrd,form	1507
7	Wackestone	0.05	3.4	hd,vug,for	1511
8	Wackestone	0.053	3	hd, vug, foram	1514
9	Wackestone	0.228	11	hd, sty, foram	1526
10	Wackestone	0.14	1	hd,for, styl	1532
11	Boundstone	0.217	14.5	hd,coral	1642
12	Boundstone	0.159	33	hd, styl	1617
13	Boundstone	0.045	6.8	hd,coral, styl	1606
14	Boundstone	0.129	119	hd,coral, sli vug	1609
15	Wackestone	0.228	11	hd,for,vug	1526
16	Wackestone	0.14	1	hd,for,vug drusy	1532

Table A2
Basic data of core samples from Minahaki formation (Banggai-Sula basin)

No.	Type	Porosity (fraction)	Permeability (mD)	Description	Depth (m)
1	Grainstone	0.252	7.3	hd, sli vug,foram	1828
2	Grainstone	0.23	10	hd, for, pp-vug	1832
3	Grainstone	0.3	13	hd,sli foss frag	1951
4	Grainstone	0.314	18	hd, vug	1954
5	Packstone	0.23	33	hd, vug	2076
6	Packstone	0.229	8.6	hd, vug	2077
7	Packstone	0.283	34	hd, vug	2077
8	Packstone	0.219	6.3	hd, vug	2080
9	Packstone	0.2	2.4	hd, sli vug	2080
10	Packstone	0.216	8.4	hd, vug	2083
11	Packstone	0.181	14.2	hd, vug	2083
12	Packstone	0.237	14.5	hd, vug	2084
13	Packstone	0.221	5.6	hd, vug	2085
14	Wackestone	0.269	3.2	hd, vug	2029
15	Packstone	0.284	11	hd, for, pp-vug	1957
16	Wackestone	0.287	2	hd,sli foss frag	1960
17	Wackestone	0.247	4.9	hd-vhd	2025
18	Wackestone	0.23	6	hd, foss, pp-vug	2028

Table A3
Basic data of core samples from Peutu formation (North Sumatra basin)

No.	Type	Porosity (fraction)	Permeability (mD)	Description	Depth (m)
1	Packstone	0.096	0.55	hd, for, algae, ppv	2758
2	Packstone	0.031	1	hd, for, alg, styl	2761
3	Wackestone	0.154	5.4	hd, for, alg, styl	2766
4	Packstone	0.151	1.7	hd, for, algae, ppv	2770
5	Packstone	0.121	1	hd, for, algae, ppv	2774
6	Wackestone	0.119	0.3	hd, algae	3301
7	Wackestone	0.14	0.76	hd, aggregate	3302
8	Packstone	0.016	0.04	hd, aggr, styl	3305
9	Packstone	0.126	1	Hd, for, pp-vug	2208
10	Packstone	0.144	0.8	hd, for, mot-vug	3311
11	Packstone	0.164	3.5	hd,for,pp-vug	2837
12	Packstone	0.113	0.9	hd,for,alg,pp-vug	2844
13	Packstone	0.096	1.1	hd,for,alg,cor,motv	2851
14	Packstone	0.14	6.5	hd,for,alg,mot v	2983
15	Packstone	0.16	5.6	as above	2985
16	Packstone	0.124	1.1	hd,cor,loc xlin	3242
17	Packstone	0.124	1.5	hd,cor,alg,for,ppv	3237
18	Packstone	0.145	1.6	hd,for,ppvug	2793
19	Packstone	0.147	1.6	hd,cor,alg,loc xlin	3231
20	Packstone	0.169	0.8	hd,cor,alg,	3216

Table A4
Basic data of core samples from Belumai formation (North Sumatra basin)

No.	Type	Porosity (fraction)	Permeability (mD)	Description	Depth (m)
1	Packstone	0.318	253	mhd,for,alg,cor,ppv	1266
2	Wackestone	0.281	85	mhd,aggr,pp-mot v	1270
3	Wackestone	0.248	52	mhd,aggr,pp-mot v	1272
4	Boundstone	0.071	0.1	vhd, coral	1276
5	Boundstone	0.18	4	hd,cor,alg,for,ppv	1279
6	Packstone	0.347	275	hd,for,alg,mot v	1946
7	Packstone	0.329	214	mhd,for,alg,ppv	1948
8	Packstone	0.318	176	mhd,for,alg,ppv	1951
9	Packstone	0.262	98	mhd,for,alg,pp m-v	1954
10	Packstone	0.296	136	mhd,for,alg,pp m-v	1955
11	Packstone	0.286	147	mhd,alg,for,m-vug	2113
12	Packstone	0.371	106	mhd,alg,for,m-vug	2114
13	Wackestone	0.336	190	mhd,cor,alg,for,ppv	2115
14	Boundstone	0.285	665	mhd,cor,alg,for,vug	2116
15	Packstone	0.229	94	mhd,cor,alg,for,ppv	2125

Table A5
Basic data of core samples from Kujung formation (Northeast Java basin)

No.	Type	Porosity (fraction)	Permeability (mD)	Description	Depth (m)
1	Packstone	0.314	22	mhd,vug, styl, for	1447
2	Packstone	0.317	11	mhd,vug, styl, for	1447
3	Packstone	0.343	29	mhd,vug, corl, for	1449
4	Packstone	0.367	28	mhd,vug, styl, for	1451
5	Packstone	0.295	15	mhd,vug, styl, for	1454
6	Packstone	0.318	33	mhd,vug calc, for	1455
7	Packstone	0.279	34	mhd,vug calc, for	1461
8	Packstone	0.248	4.8	mhd,vug, corl, for	1463
9	Packstone	0.264	14.5	hard,vug, corl, for	1527
10	Packstone	0.36	8	mhd,vug, corl, for	1528
11	Packstone	0.35	7	mhd,vug, corl	1530
12	Packstone	0.3	8	mhd,vug, styl, for	1531
13	Packstone	0.26	9	hd,vug,for	1531