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Rock Compressibility Characteristics of Oil and Gas Sandstone Reservoirs in the Western Part of Indonesia

Bambang Widarsono[1], Junita T. Musu[2], and Yohanes D. Wangge[2]

[1]National Agency of Research and Innovation - BRIN, Indonesia
M.H. Thamrin Street NO. 8, Menteng Subdistrict, Central Jakarta City,10340, Indonesia.

[2]Testing Center for Oil and Gas LEMIGAS
Ciledug Raya Street No. 109, Kebayoran Lama District, South Jakarta City, 12230, Indonesia.

Corresponding author: Bambang Widarsono (bambang.widarsono@brin.go.id)

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ABSTRACT - Rock compressibility is one of rocks' properties that is closely related to their response to changes in effective stresses. Various Earth's subsurface-related processes involve rock compressibility. In petroleum production, for instance, it provides reservoir energy needed for the process. Studies on rock compressibility for Indonesian reservoirs are very limited. Therefore, a study has been carried out to investigate rock compressibility characteristics of Indonesian reservoir rocks, sandstones in particular. A total of 205 sandstone samples of various types have been collected from 34 oil/gas fields in nine productive sedimentary basins in Indonesia. The samples are prepared and laboratory tested for their basic properties and pore volume compressibility following the universally adopted standard methods. Results of this study indicate unclear trends in the rock property of concern in relation to porosity. However, with careful grouping and cluster analyses, clearer trends representing their intrinsic characteristics can be spotted, and appropriate correlations based on a generalized model can be established. The established correlations of maximum effective rock compressibility versus porosity offer opportunities to understand the characteristics of reservoir sandstone compressibility. Special cautions have been discussed, and special suggestions have also been offered for selecting the most appropriate correlations.

Keywords: rock compressibility, sandstones, oil and gas reservoirs, porosity, characteristics, correlations.

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INTRODUCTION

In primary stage of oil and gas production, withdrawal of reservoir fluids are always accompanied by pore pressure declines, because of which the ability of the reservoir porous rocks to sustain *in situ* stresses (both overburden and tectonic stresses) is reduced. In this condition, effective stresses born by reservoir increase leading to shrinkage in the rock's pore volume. This pore shrinkage behavior in reservoir rocks is known to be represented by a rock property called rock compressibility. This rock compressibility is often also known as bulk compressibility that is composed by solid/grain compressibility and pore volume compressibility. However, since it is always assumed that pore compressibility is much larger than solid/grain compressibility, it is therefore common to take pore volume compressibility as also representing rock compressibility aka bulk compressibility. As put by Fetkovich et al. (1991), this rock compressibility may serve as important source of reservoir energy for driving oil and gas production from reservoirs. In extreme cases such as shallow gas pockets, rock compressibility of the friable sandstones reservoir pockets often provide the only source of energy, and for many oil and especially gas reservoirs this rock behavior also contribute to overal reservoir energy.

Various aspects of upstream petroleum production involves information of reservoir rock compressibility. Estimation of hydrocarbon in place and reserve volumes using material balance methods (see Dake 1978; and Bradley 1987; for instance) requires rock compressibility data, including its applications in cases of fractured reservoirs (e.g Aguillera 2008; Widarsono 2009). Activities such as studies on production-related stress path (e.g Ruistuen et al. 1999), determination of well drainage radius using well testing data (Pinzon et al. 2001), reservoir dynamic model – geomechanics model coupling through reservoir simulation (e.g Guiterrex 1998; Tran et al. 2004), presence of subsidence due to petroleum production (e.g Geertsma 1973; Ruddy et al. 1989), and pressure maintenance for supporting field production and preventing subsidence (e.g Sulak & Danielsen 1988) rely heavily on reservoir rock compressibility data.

Awareness over rock compressibility's importance had led to a great deal of studies and investigations over it. As early as in 1950s studies presented by Hall (1953); Geerstma (1957); Fatt (1958), and later in Newman (1973), had produced various facts, conclusions, correlations over rock compressibility. Deeper investigations in rock compressibility have also been performed such as one by deWall & Smits (1988) who investigated rock compressibility's non-linearity behavior. Later studies involving attempts to establish correlations for rock compressibility of samples used in studies such as by Yale et al. (1993); Harari et al. (1995); Li et al. (2004); Liu et al. (2009); Betts et al. (2011); Myers & Hatton (2011); Bakhtiari et al. (2011); Zhu et al. (2018); Das et al. (2020), and Farahani et al. (2022). Attempts have also been spent to study compressibility of unconventional reservoir rocks of coal and shale hydrocarbon (e.g Tan et al. 2019).

Studies on rock compressibility for Indonesian reservoir rocks have also been made, albeit very limited. For instance, Pathak et al. (2007) studied on the use of laboratory-derived rock compressibility to investigate and understand pressure anomaly in NSO field of Aceh region, Fardiansyah et al. (2010) investigated rock compressibility of outcrop rocks aimed at establishing analogy for reservoir study purposes, and Widarsono (2009) observed the crucial effect of rock compressibility in material-balance based gas in place validation. Widarsono (2014) also studied Indonesian reservoir limestones' rock compressibility and observed the most suitable correlations accordingly. Studies on Indonesian reservoir rock compressibility need to go further, and this article is focused on studying compressibility characteristics of some Indonesian reservoir sandstones based on laboratory measurements on rock samples. It is hoped that this study may further enrich understanding over reservoir rock compressibility characteristics in general, not only for sanstone reservoirs in Indonesia but also for ones worldwide.

Rock compressibility

Rock compressibility, defined as a ratio between amount of change in rock volume with change in pressure and the rock's original volume, that prevails under constant reservoir temperature (isotherm) can be expressed as (e.g Zimmerman 1991):

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

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), respectively, under constant temperature marked by T. When an oil or gas field is undergoing production production process under primary recovery mechanism (i.e production process that relies solely on the reservoir's own natural energy) under isotherm condition, reservoir pore pressure declines naturally leading to reservoir rocks' shrinkage due to increase in effective stresses exerted by the constant overburden mass and tectonic stresses. The rock's characteristics and magnitude of shrinkage are dependent on the rock's compressibility behavior. The rock compressibility – controlled much by its pore volume compressibility – is in turn controlled by the rock's governing features such as mineral composition, grain size variation, state of rock cementing, and pore type/characteristics. Different rocks may have different pore volume compressibility characteristics in terms of magnitudes, their response to changes in pressure, and their behavior when related to other rock properties such as porosity.

Typical rock compressibility is nomally small, in the magnitude of 10^{-6} per pound per square inch (psi) change in pressure (10^{-6} psi^{-1}). Satter (2007) put normal reservoir rocks compressibility within the range of $2x10^{-6}$ to $15x10^{-6}$ psi^{-1} @ initial reservoir pressure, while in a more detailed fashion Newman (1973) put that consolidated sandstones are usually within the range of $1.5x10^{-6}$ – $20x10^{-6}$ psi^{-1}, while friable sandstones and consolidated sandstones are within the ranges of $2.5x10^{-6}$ – $45x10^{-6}$ psi^{-1} and $5.5x10^{-6}$ – $85x10^{-6}$ psi^{-1}, respectively. This study, however, has observed soft sandstone compressibility of even higher than $100x10^{-6}$ psi^{-1}. Being much controlled by characteristics of rock's pore configuration, rock compressibility is much related to porosity even though their relationships generally differ from one rock type to another. In other words, there is probably no unique correlation that generally relates rock compressibility to porosity. Despite the non-uniqueness investigators spent tremendous efforts to establish correlations. In 1953, H.N. Hall (as presented in Baker et al, 2015) through experimental studies on sandstone and limestone samples established a general empirical correlation of

$$C_f = 1.87 \bullet 10^{-6} \emptyset^{-0.415} \tag{2}$$

where f is porosity (in fraction), 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 different correlations. Newman (1973) – as being presented in Tiab & Donaldson (2016) – established general hyperbolic correlations for both sandstones and limestones based on 79 laboratory samples used in the study. For consolidated sandstones the correlation is

$$C_f = \frac{97.32 \bullet 10^{-6}}{1+55.8721 \bullet \emptyset^{1.429}} \tag{3}$$

results of a later study by Horne (1995) – as presented in Farahani et al (2022) – yielded empirical exponential correlations of

$$C_f = exp(5.118 - 36.26\emptyset + 63.98\emptyset^2) \bullet 10^{-6} \tag{4}$$

for consolidated sandstones, and

$$C_f = exp(4.026 - 23.07\emptyset + 44.28\emptyset^2) \bullet 10^{-6} \tag{5}$$

for uncosolidated sandstones. The above correlations are to be tested and fitted on rock compressibility data of the sandtone samples used in this study.

METHODOLOGY

Pore volume compressibility measurements performed on core plug samples have been made following the standard core laboratory method. After core plugging, cleaning, oven-drying, and visual geological description, the 1.5-inch diameter core plugs underwent basic petrophysics measurements of porosity (and permeability). Grouping of sandstone types and rock hardness was made in this stage. The pore volume compressibility (PVC) tests were carried out after the basic measurements, in which samples were evacuated and fully saturated with brine.

In each PVC measurement, the brine-saturated core plug within the core holder (Figure 1) was subjected to the lowest confining pressure of 200 psig to ensure grip on the plug. From this starting condition the confining pressure (i.e overburden pressure) was raised up to pre-determined pressure levels while pore pressure at initial reservoir pressure remained constant. As changes in pore volume at each pressure level was estimated, the PV compressibility was calculated using Equation 1. This volumetric change estimate (C_{hyd}) was then

Table 1. Number of sandstone samples obtained from oil/gas fields in nine productive sedimentary basins. The geological formations are geological units containing the reservoirs of origin.

No.	Sedimentary basin	Geological formation	Oil/gas fields (sample quantity)	Hard sandstone	Med-hard sandstone	Soft sandstone	Total samples
1	North Sumatra	Keutapang	Rantau (4), Perapen (2), Paluh tabuan Barat (5), Basilam (4)	6	7	2	15
2	Central Sumatra	Sihapas Group, Bekasap, Menggala, Telisa, Duri, Pematang	Bekasap (15), Pungut (10), Zamrud (9), Kotabatak (18), Jorang (7), Kopar (8), Libo SE (1), Minas (10), Balam South (8), Kulin (2), Telinga (1), Bangko (6), Petapahan (8)	51	33	19	103
3	South Sumatra	Talang Akar	Benakat (4), Limau (4), Jirak (13), Raja (5), Air Serdang (3), Ogan (9), Talang Jimar (9)	24	17	6	47
4	West Natuna	Gabus	Kakap (8)	1	7	-	8
5	West java	Talang Akar	Karang Enggal (3)	3	-	-	3
6	East Java	Wonocolo, Ledok	Kawengan (3), Semanggi (2)	-	3	2	5
7	Barito	Tanjung	Tapian Timur (8), Tanjung (4)	6	4	2	12
8	Kutei	Balikpapan	Attaka (3), Semberah (4)	3	4	-	7
9	Tarakan	Tarakan	Bunyu (5)	-	5	-	5
	Total samples			94	80	31	205

converted to effective overburden stress (C_Z) under uniaxial condition using theoretical formula proposed by Teeuw (1971) of

$$C_Z = \frac{1}{3}\left(\frac{1+\nu}{1-\nu}\right) C_{hyd} \tag{6}$$

with n is Poisson's ratio, which for consistency reason is taken as the average value of 0.3, as suggested in Teeuw (1971). Figure 2 exhibits examples of pore volume compressibility (i.e rock compressibility) versus effective uniaxial overburden stress. Note that terms of 'stress' and 'pressure' here are interchangeable for practical purposes.

In data presentation, compressibility values at reservoir initial pressure, hence minimum effective overburden presure, is taken in accordance with depths at which the core samples were taken. By assuming uniform bulk overburden pressure (P_{OB}) and reservoir pressure (P_{res}) gradients of 1 psi/ft and 0.5 psi/ft, respectively, an effective overburden pressure gradient of 0.5 psi/ft is used following.

$$Effective\ P_{OB} = P_{OB} - \alpha P_{res} \tag{7}$$

with a is the Biot coefficient representing rock's poroelasticity tendency. In order to avoid complication a is taken as unity implying maximum effect of pore pressure on effective stress.

As effective overburden pressure has been determined, the needed compressibility values for the samples are obtained from the rock compressibility curves (e.g Figure 2). Pairs of porosity at initial condition (i.e at reservoir initial pressure aka maximum effective overburden) and its corresponding uniaxial rock compressibility value are then obtained, using which the whole study has been carried out.

A total of 205 sandstone core samples taken from 34 oil/gas fields in nine productive sedimentary basins in western Indonesia (Figure 3) are used in this study. They are North Sumatra, Central Sumatra, South Sumatra, West Natuna, West Java, East Java, Barito, Kutei, and Tarakan basins. All of the sandstone samples have been taken from productive geological formations. Table 1 presents information regarding sample quantity, origin, and hardness category. The sandstones samples consist of 94 hard, 80 medium-hard, and 31 soft/friable sandstones. It must be noted, however, that the hardness categories are solely

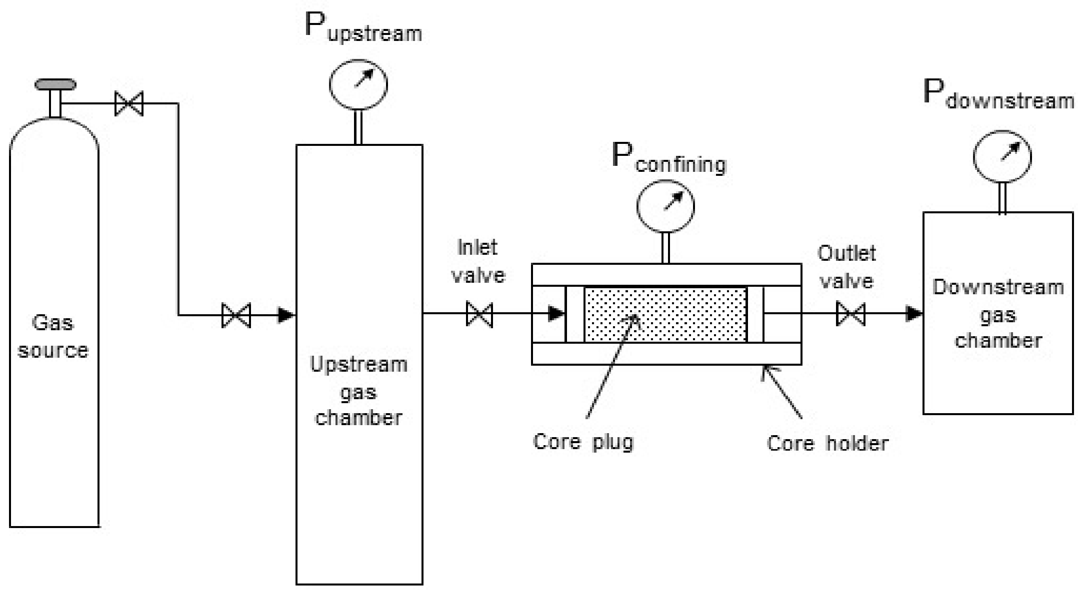

Figure 1. A simplified schematic diagram of the Temco RCA 841 apparatus used for pore volume compressibility measurement.

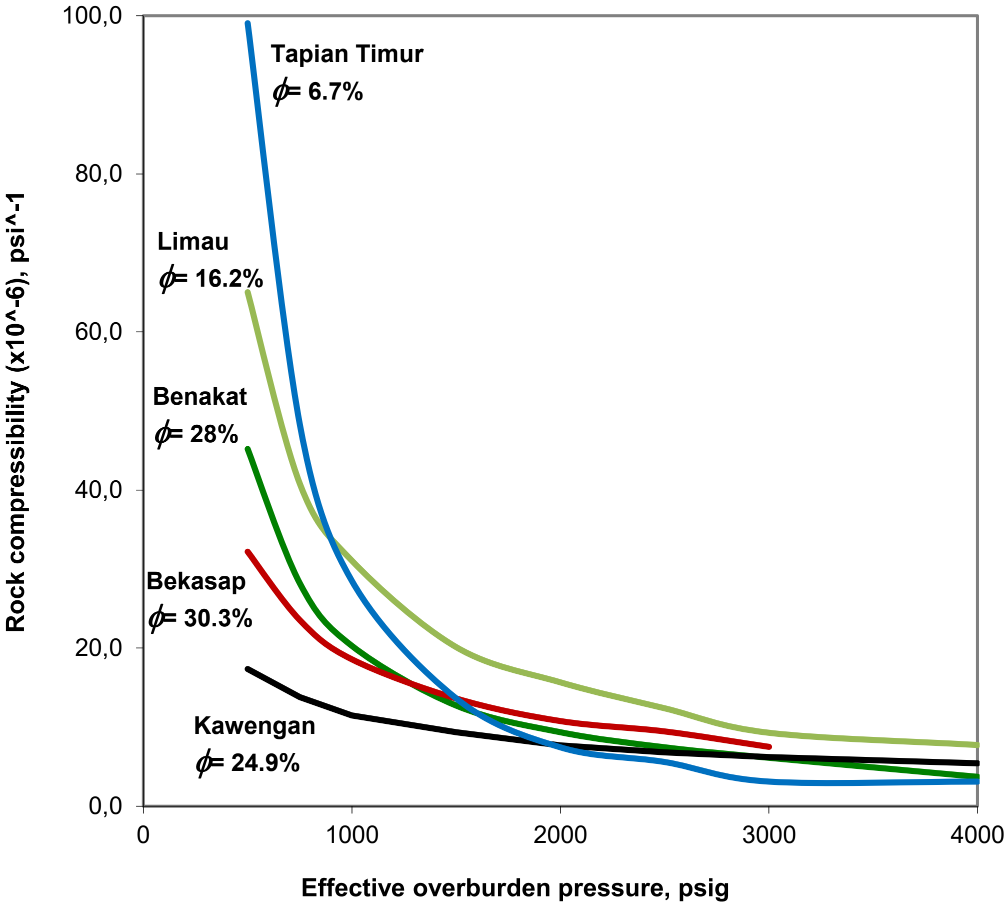

Figure 2. Examples of pore volume compressibility (i.e rock compressibility) of some sandstone samples. Field of origin and average porosity values mark each of data curve.

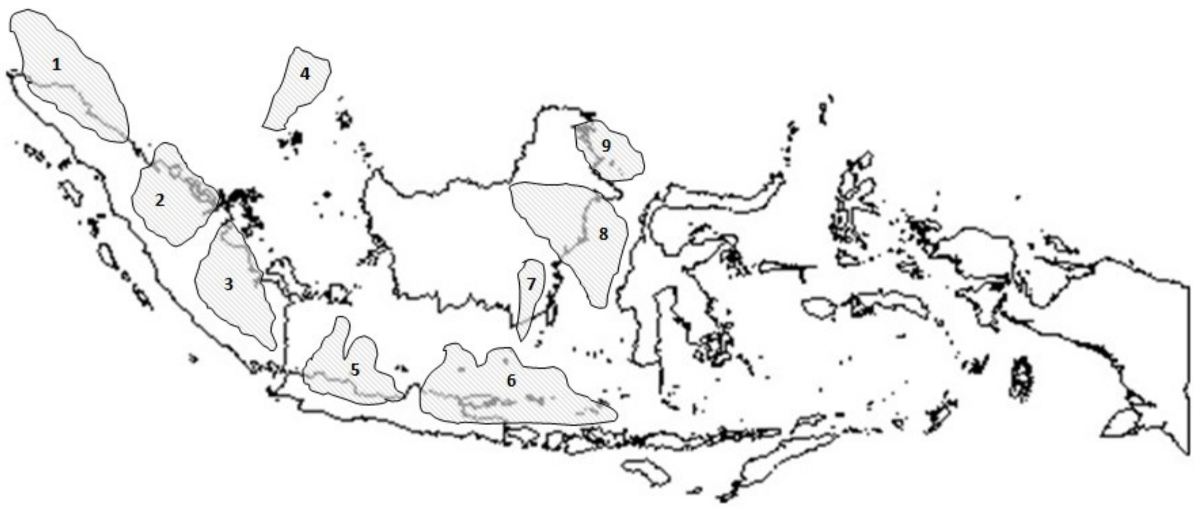

Figure 3. The nine productive sedimentary basins from which the sandstone samples are taken; 1) North Sumatra, 2) Central Sumatra, 3) South Sumatra, 4) West Natuna, 5) West Java, 6) East Java, 7) Barito, 8) Kutei, and 9) Tarakan.

based on geological visual/physical inspection and are not based on any mechanical properties data whatsoever.

Apart from samples that have descriptive features belonging to clean and relatively homogeneous sandstones, some of the sandstone samples also notably display specific structural characteristics in the form of coglomeratic sandstones (20 samples), laminated/stratified sandstones (41 samples), and argillaceous sandstones (29 samples). This total number of 90 samples are actually among the total samples of 205, regardless of fields/basin of origin. These categorization on rock hardness and structural/ mineralogical aspects serve as sample grouping in the analysis over the samples' rock compressibility. Application of the existing correlations was to be made on these sample groups, which eventually leads to new understandings and needs of modifications.

RESULTS AND DISCUSSION

The rock compressibility to be presented is stress dependent, which means that the rock samples behave differently even under same stress path. Therefore, it is crucial to present all of the data on the same ground. This common ground is that all rock compressibility data is taken at effective uniaxial overburden pressure and is paired with initial porosity at virtually zero net pressure. Figure 4 depicts plot of the pairs of data for the 205 core plugs grouped under hard, medium-hard, and soft/friable hardness characteristics.

Rock compressibility versus rock hardness

The plot of of effective uniaxial compressibility versus initial porosity shown on Figure 4 has clearly exhibited a substantial degree of scatter, both for all data in general and for when the data is grouped into the three rock hardness characteristics. A rather visible tendency is shown

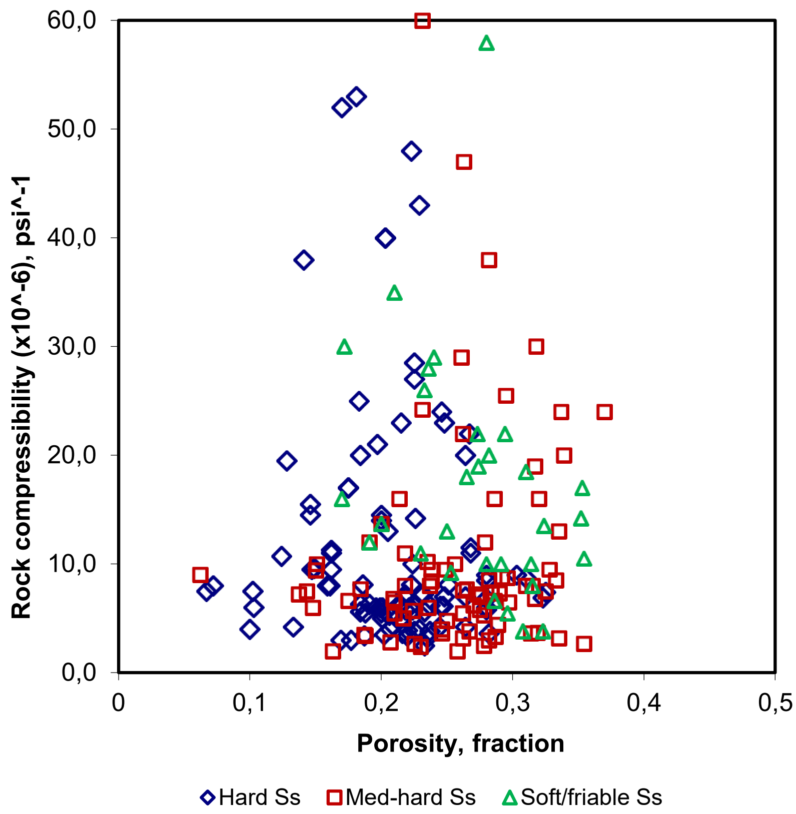

Figure 4. Plot of maximum rock compressibility versus initial porosity (@ zero net overburden stress) for all sandstones samples devided into hard, medium-hard, and soft/friable types.

by porosity characteristics of the hard sandstones, which is in general lower than porosity of the medium-hard and soft sandstones. The rock compressibility data itself, however, does not reflect any clear trends with respect to porosity. Instead, rock compressibility for a single chosen porosity value may come up with several values within the three rock hardness groups.

Attempts were then spent to have a closer observation on individual sandstone hardness group. In the observation, the plot is accompanied by attachment of the three exsting correlations of Hall (1953), Newman (1973), and Horne (1995) in order to see their degree of fitness/agreement with the plotted data. A cluster analysis was then performed. Upon a closer look on the data plot for the hard sandstone group (Figure 5), it is apparent that the scatter remains visible. Nonetheless, when the data trend is judged through the shapes of existing correlations (i.e decreasing compressibility with increasing porosity) and through the clustering way of observation, the data appears to belong to clusters.

For the hard sandstone group, clustering on the plotted data results in four visible clusters with trends are somewhat similar to the trend shown by Newman (1973) curve. When the Newman correlation of Equation 3 is turned into

$$C_f = \frac{97.32 \cdot 10^{-6}}{1+55.8721 \cdot \emptyset^{x}} \tag{8}$$

in which the $f^{1.492}$ is replaced by f^{x}, allowing the x-factor to vary in accordance with the need to fit to data set within the clusters. This course of action appears to have worked well, which through uses of x-factor of 2 and 1 result in two modified Newman correlations, the curves (a) and (b) on Figure 5, respectively. There are therefore three Newman curves with three x-factor of 2.0, 1.492 (original), and 1.0, plus the Hall correlation that fits to the lowest cluster. These four correlations correspond to porosity ranges of 17%-26%, 11%-33%, 11%-28%, and 5%-28%, respectively. What implications this facts would bring are to be discussed in later parts of this article.

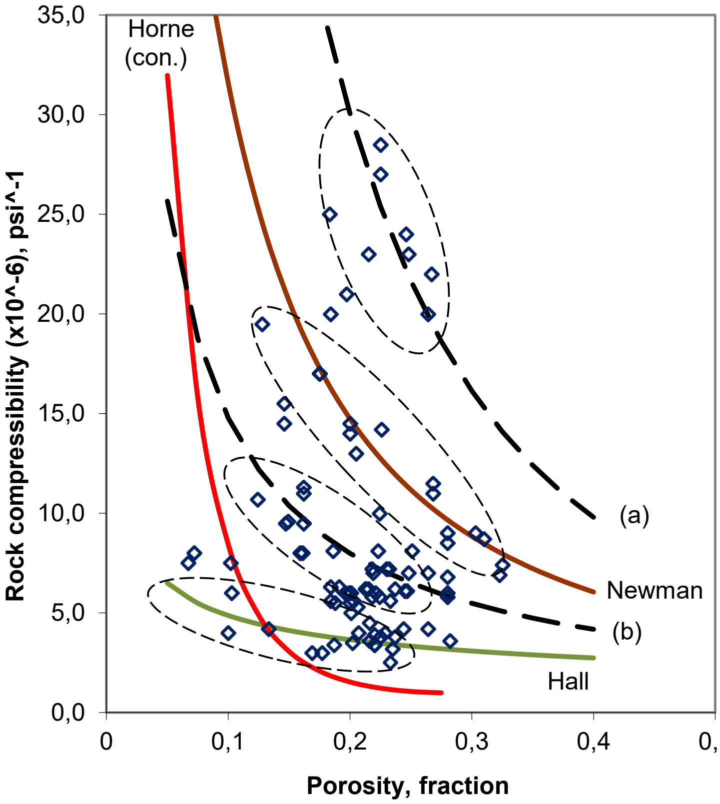

Figure 5. Cluster analysis on hard sandstones indicates four groups of (a) Newman with x-factor of 2.0, original Newman model, (b) Newman with x-factor of 1.0, and Hall model.

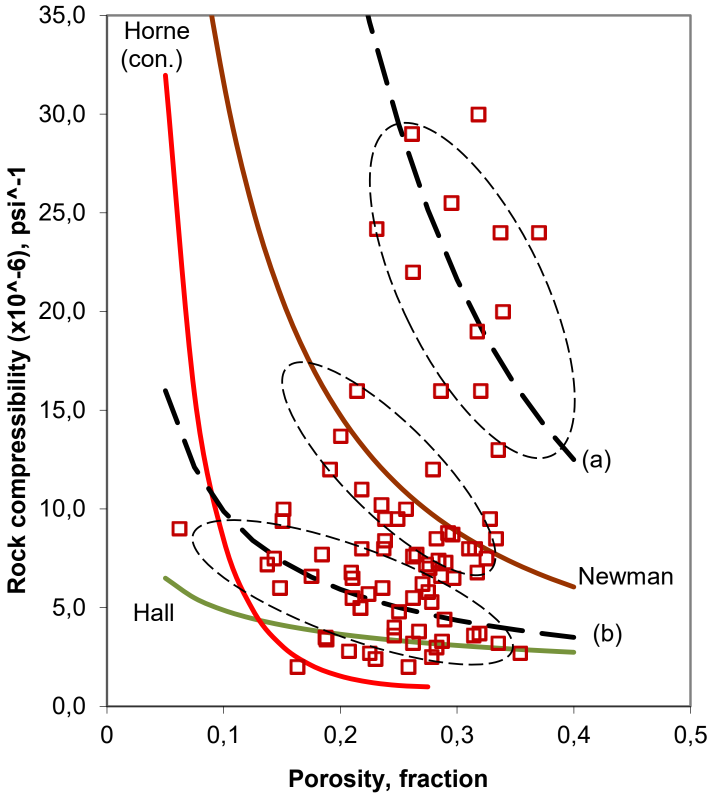

Figure 6. Cluster analysis on medium-hard sandstones indicates three groups of (a) Newman with *x*-factor of 2.3, original Newman model, and (b) Newman with *x*-factor of 0.8. Note that Hall correlation maybe of usable but it is preferably replaced by curve (b).

Similar to the case of hard sandstones, data for the medium-hard sandstone samples also show apparent scatter with three clusters are indicated (Figure 6). For the data points within the three clusters, three Newman correlations appear to fit them; the curve (a) with *x*-factor of 2.3, original Newman with *x*-factor of 1.492, and curve (b) with *x*-factor of 0.8. These three curves relate to respective porosity ranges of 24%-39%, 18%-34%, and 7%-36%.

For the soft/friable 31 sandstone samples, the clustering appear to be simpler with only two distinctly separated clusters with two fitting curves; the curve (a) of Newman model with *x*-factor of 2.1 and the original Newman correlation curve (Figure 7). The upper curve is associated with porosity upper – lower limits (porosity data range) of 18%-37%, whereas the original Newman curve is related to porosity range of 17%-33%. The overal result of rock compressibility analysis on the three sandstone hardness characteristics has shown to us that there is no specific difference in its relationships with porosity between the three groups. This is clearly indicated by the total of nine correlations – including the original Newman and Hall – to represent the whole data population.

Rock compressibility versus sandstone types

Among the 205 sandstone samples that make the total data population, a part of them show distinctive structural and mineralogical features in the form of conlomeratic sandstones (20 samples), laminated/stratified sandstones (41 samples), and argillaceous sandstones (29 samples). By definition, conglomeratic sandstones – or sometimes called gravelly or pebbly sandstones – are sandstones that have roughly 5% to 30% gravels (e.g Folk 1954), whereas laminated/bedded sandstones are sandstones that contain structural lamination as the results of genetical mechanisms of either tractional currents or turbidity currents (Packham 1954), and argillaceous sandstones are sandstones that contain clay minerals in their interstitial spaces (e.g Thomas 1978). It is to be

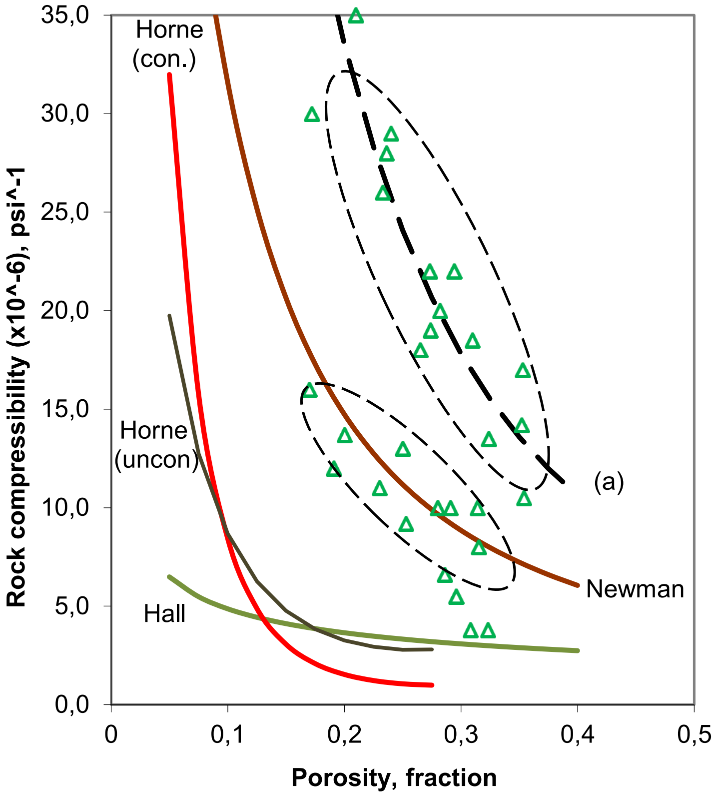

Figure 7. Cluster analysis on soft/friable sandstones indicates only two groups of (a) Newman with *x*-factor of 2.1 and the original Newman model. Note that Horne (1995) correlation for soft sandstones (left) is also included in the visual fitting, but results show very poor agreement.

observed of how different sandstone types may exhibit their rock compressibility characteristics vis a vis porosity.

The data plot for the 20 conglomeratic sandstone samples is presented on Figure 8. Despite the limited quantity of data points, at least three clusters may be indicated; the upper cluster with curve (a) of generalized Newman correlation (*x*-factor = 1.8), the middle curve (b) of another modified Newman correlation (*x*-factor = 1.0), and the lower cluster with Hall correlation that fits the data points. The three curves have porosity ranges that are roughly supplementative to each other of 28%-37%, 14%-28%, and 10%-17%, respectively. This fact may leads one to adopt the view that this conglomeratic sandstones group has three continuous porosity ranges of validity, with each porosity range has its own valid correlation. This view is certainly not true since the three clusters are separated more likely due to intrinsic differences between the conglomeratic sandstones in the three clusters.

Data plots for the other two sndstone types, the laminated/stratified sandstones and the argillaceous sandstones, are shown on Figures 9 and 10, respectively. The two data plots exhibit smilarity in clustering results, both of which have three fitting curves of curves (a), existing Newman correlation curve, and curve (b). For the modified Newman correlations that fit curve (a) and curve (b), *x*-factors of 2.0 (while 2.05 for the laminated/ stratified sandstones) and 0.8 are used, respectively. Similarity in the *x*-factor values underlines similiraty in rock compressibility characteristics of the laminated/stratified and argillaceous sandstones.

Tabel 2. Composition of samples according to sandstone types/groups and porosity ranges of samples belonging to each group. 'Equation/model' refers to correlation that represents samples within a group. Note that different *x*-factor values are needed by the generalized Newman (Equation 8) model. The *x*-factor of 1.429 represents the original Newman model.

No.	Sandstone type (Total sample)	Equation/model	Sample quantity (percentage)	Porosity range (%)
	<u>Based on hardness</u>			
1	Hard sandstone (94)	Newman, x = 2.0	13 (13.8%)	17 – 26
		Newman, x = 1.429	17 (18.1%)	11 – 33
		Newman, x = 1	30 (31.9%)	11 – 28
		Hall	34 (36.2%)	5 – 28
2	Med-hard sandstone (80)	Newman, x = 2.3	12 (15%)	24 – 39
		Newman, x = 1.429	22 (27.5%)	18 – 34
		Newman, x = 0.8	46 (57.5%)	7 – 36
3	Soft/friable sandstone (31)	Newman, x = 2.1	16 (51.6%)	18 – 37
		Newman, x = 1.429	15 (48.4%)	17 – 33
	<u>Specific features</u>			
4	Conglomeratic sandstone (20)	Newman, x = 1.8	8 (40.0%)	28 – 37
		Newman, x = 1.0	9 (45.0%)	14 – 28
		Hall	3 (15.0%)	10 – 17
5	Laminated /stratified sandstone (41)	Newman, x = 2.05	6 (15.0%)	21 – 33
		Newman, x = 1.429	6 (15.0%)	18 – 30
		Newman, x = 0.8	29 (70.0%)	9 – 34
6	Argillaceous sandstone (29)	Newman, x = 2.0	8 (27.6%)	20 – 31
		Newman, x = 1.429	9 (31.0%)	12 – 30
		Newman, x = 0.8	12 (61.4%)	7 – 23

Understanding the rock compressibility characteristics

Summary of overal results from the clustering analysis are presented in Table 2. From the scatter exhibited by overal data when plotted together it can be easily seen that there most likely be no single correlation between rock compressibility and porosity for all sandstones (let alone including carbonates), in the sense of many previous studies that have produced many existing correlations. For certain population of samples belonging to specific origin and rock types, a single correlation representing the population may be justified. On the other hand, however, study on fairly large quantity samples obtained from varried places of origins – in the way of this study – has proved that it is impossible to establish a single correlation that represents all sandstones. A larger picture ought to be drawn from the fact.

The fact that more than one correlation is needed to fit data population in a single sandstone group/type, with overlapping porosity ranges, is the simplest evidence that there is no single correlation that can represent all. Clustering analysis results for all sandstone grouping have shown overlapping porosity ranges – except for the conglomeratic sandstones – implying that pore volume compressibility as the largest component in rock compressibility is not only related to initial pore

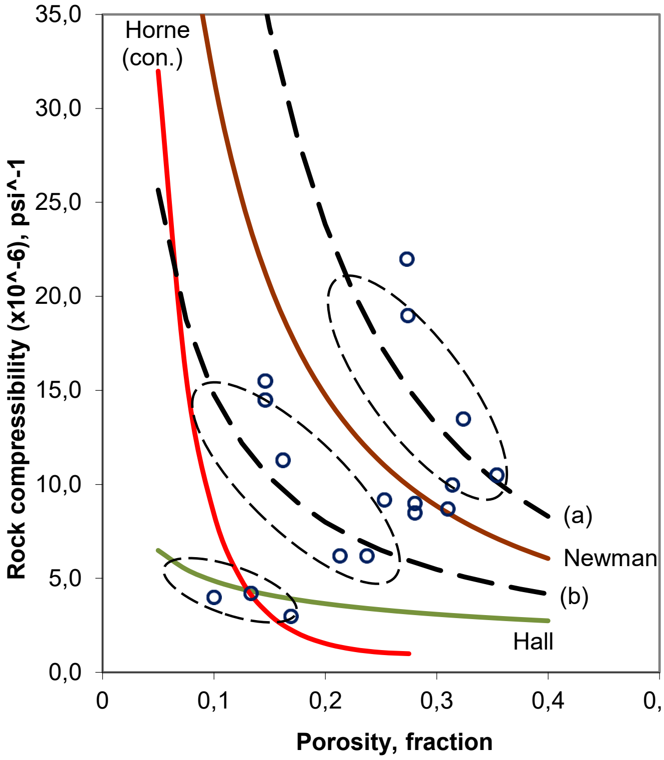

Figure 8. Cluster analysis on conglqomeratic sandstones indicates three groups of (a) Newman with x-factor of 1.8, (b) Newman with x-factor of 1.0, and Hall model. This case shows continuity in porosity ranges – from low to high – in general for the three clusters (see Table 2).

volume and porosity, but also to other factors that are intrinsically different from one rock type to another such as pore structure and presence of discontinuities.

A similar conclusion can also be drawn when one observes the x-factors needed by the generalized Newman correlation (Equation 8) and quantity of samples that are represented by them (see Table 2). The x-factors of the three hardness group clusters are indeed different. For example, clusters of curve (a) in hard, medium-hard, and soft/friable sandstone groups with their x-factors of 2.0, 2.3, and 2.1, respectively, but they are not different enough to establish three strongly distinct pore volume compressibility characteristics. Same occurence also prevails for, say, clusters of curves (b) for conglomeratic, laminated/stratified, and argillaceous sandstones that use equally similar respective x-factor values of 1.0, 0.8, and 0.8.

All evidence regarding maximum pore volume compressibility versus porosity relationships of the Indonesian reservoir sandstones under study tends to show scatter and irregularities. It is also true even when the data is grouped into groups based on rock physical and structural characteristics. Nevertheless, as the data is put into groups it appears that there has been some semblance of regularity.

Following the logic that maximum rock compressibility tends to decrease with increase in rock porosity – as suggested by all existing correlations – the data trends becomes more reasonably clear. As shown by the generalization of Newman correlation (Equation 8) and its results in just varrying the x-factor (Table 2), the data seem to become easier to fit visually. (Note that attempts have also been made to use the other two correlations, but the generalized Newman correlation seems to deliver the most practical approach). Note that the Hall correlation nonetheless also shows good agreement especially for samples with low porosity, even though use of low x-factor values in the generalized Newman correlation may also serves the purpose well. This outcome might be taken as a reference that the generalized Newman correlation could be used to well model rock compressibility characteristics for sandstones through varying the *x*-factor.

Use of correlations.

Attempts to establish correlations since Hall (1953) are indeed aimed at both to assist understanding over rock compressibility behaviors and to support practical purposes in various applications. As Table 2 depicts various *x*-factor values resulted from the cluster analysis-led curve fitting using the generalized Newman correlation, question may arise as to which one of the correlations is to be adopted. Practically, this may be answered by the following suggestion. Having determined nature and type of sandstones at disposal, one can determine which one is the most suitable through at least two approaches:

- Consideration over sample quantity and porosity ranges (could be viewed as correlation's porosity range of validity). Table 2 also presents quantity of samples (and their percentages to total sample quantity within the group) that through cluster analysis is regarded as a separate cluster represented by a correlation. Through this approach, the most representative correlation(s) may be picked. For instance, Hall correlation (sample quantity of 36.2% and porosity range of 5%-28%) and generalized Newman with *x*-factor = 0.8 (sample quantity of 57.5% and porosity range of 7%-36%) could be chosen for hard and medium-hard sandstones, repectively. The two clusters represent the largest data point quantity (i.e highest percentages) within their sandstones groups. Another example is the generalized Newman model with *x*-factor of 0.8 for the laminated/stratified sandstones group.
- Presence of minimum data at disposal. For some particular reasons, it is often that an oil/ gas field has only very limited pore volume compressibility data. One or two of this pore volume compressibility versus net uniaxial

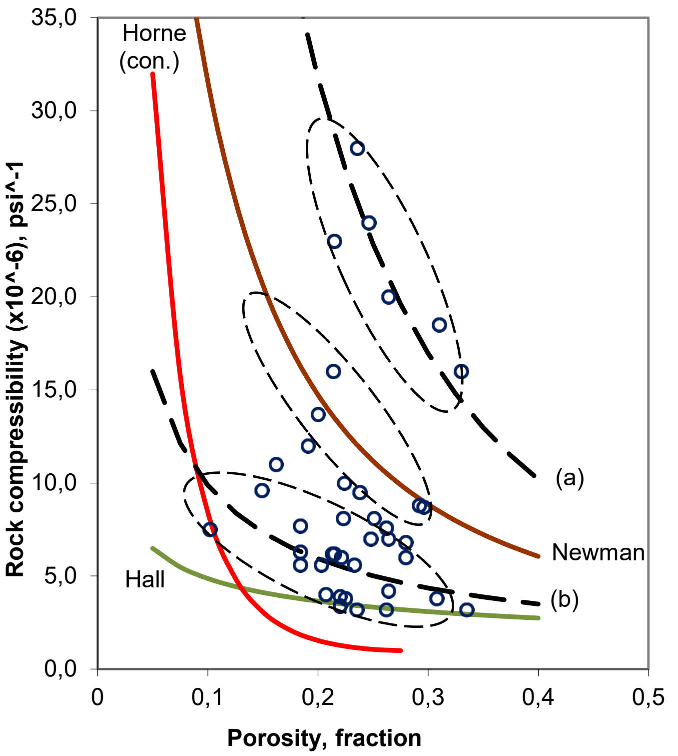

Figure 9. Cluster analysis on laminated/stratified sandstones indicates three groups of (a) Newman with *x*-factor of 2.05, original Newman model, and (b) Newman with *x*-factor of 0.8. Again, the Hall model appears to work for some data with porosity range of 20%-33%, but this may be well represented by curve (b).

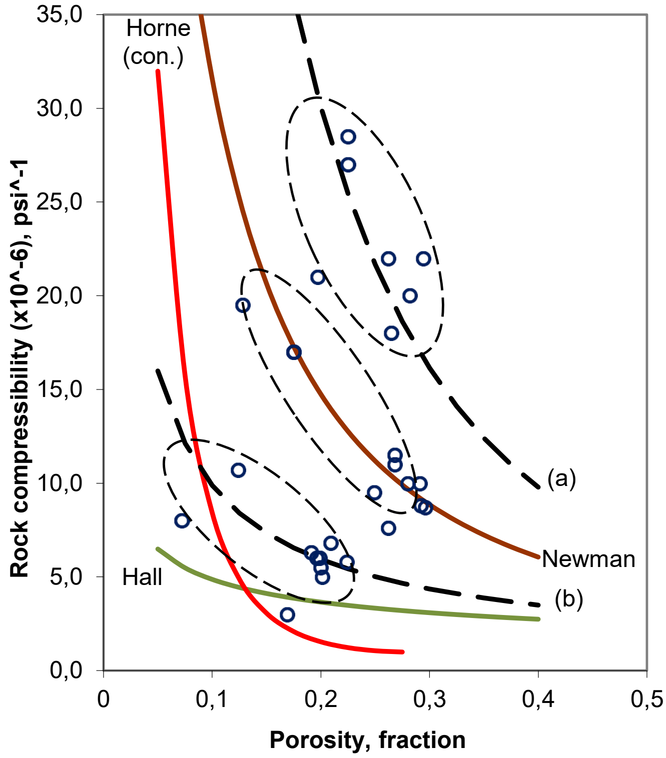

Figure 10. Cluster analysis on argillaceous sandstones indicates three groups of (a) Newman with *x*-factor of 2.0, original Newman model, and (b) Newman with *x*-factor of 0.8.

overburden stress data is useful for determining which correlation is the most representative for a specific case. Upon recognizing sandstone hardness – or sandstone structural type if it is among the three sandstone types presented here – plot of maximum pore volume compressibility at initial porosity on the right graph on Figure 5 through Figure 10 can give indication over which correlation may be the most representative one.

Attempts to observe regularities in rock compressibility characteristics of reservoir rocks are indeed challenging. Results from this study using sufficiently large volume of data quantity have proved this presumption further, even though correlations indicated from semblance of regularities have been yielded. It is hoped that this study enrich further our understanding over rock compressibility of reservoir rocks.

CONCLUSION

From this rock compressibility study using sufficiently large volume of sandstone samples from various oil and gas fields in Indonesia, it can be concluded that there is no regularity for all rocks – sandstones in this case – in their rock compressibility behavior related to porosity, even for a particular rock type. This is indicated by the high degree of scatter, even though grouping based on sandstone types and cluster analysis help much in enabling to define clearer rock compressibility characteristics.

Following the common logic in the relationship between maximum rock compressibility and initial rock porosity, it has been observed that a generalized Newman (from Newman, 1973) generated in this study – with its various *x*-factors – can be used in relative ease to model the rock compressibility behavior after a careful grouping in sandstone types. Correlations representing particular sandstone types have been produced. However, caution may still have to be taken in choosing the most representative correlation.

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GLOSSARY OF TERMS

Symbol	Definition	Unit
C_f	Formation compressibility (i.e., rock compressibility)	psi^{-1}
V_p	Pore volume	cu-ft
P	Pressure	psi
T	Mark of constant temperature	
ϕ	Porosity	fraction
C_{hyd}	Pore volume compressibility under hydrostatic pressure	psi^{-1}
C_Z	Pore volume compressibility under effective uniaxial overburden stress	psi^{-1}
ν	Poisson’s ratio	dimensionless
P_{OB}	Overburden pressure	psi
P_{res}	Reservoir pressure	psi
α	Biot constant	
x	Power factor in the generalized Newman model	

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