# COMPARATIVE STUDY OF POROSITY DETERMINATION METHODS FOR OGIP IN FRACTURED BASEMENT RESERVOIR

## STUDI KOMPARASI METODE PENENTUAN POROSITAS UNTUK OGIP PADA RESERVOAR BATUAN DASAR TEREKAH

**Usman**

"LEMIGAS" R & D Centre for Oil and Gas Technology
Jl. Ciledug Raya, Kav. 109, Cipulir, Kebayoran Lama, P.O. Box 1089/JKT, Jakarta Selatan 12230 INDONESIA
Tromol Pos: 6022/KBYB-Jakarta 12120, Telephone: 62-21-7394422, Faxsimile: 62-21-7246150
E-mail: upasarai@lemigas.esdm.go.id

First Registered on August 5th 2014; Received after Corection on August 25th 2014
Publication Approval on : August 29th 2014

**ABSTRAK**

Penentuan porositas reservoar batuan dasar yang terekah akan selalu menjadi tantangan karena kompleksitas proses pembentukan struktur pori rekahan tersebut serta keragaman litologi batuannya. Akibatnya, terdapat ketidakpastian yang cukup besar dalam estimasi isi awal gas ditempat (OGIP). Tujuan studi ini adalah mengevaluasi metode paling efektif untuk menentukan porositas rekahan sehingga mengurangi ketidakpastian volume OGIP pada reservoar batuan dasar yang terekah. Evaluasi dilakukan berdasarkan komparasi dengan hasil pengkuran porositas batuan inti sebagai titik acuan. Metode yang dievaluasi meliputi *secondary porosity index* (SPI), *dipole share imager* (DSI), *dual laterolog* (DL), dan *formation micro imager* (FMI). Porositas rekahan hasil interpretasi log SPI dan DSI sangat optimistik dibandingkan porositas rekahan batuan inti. Porositas rekahan hasil log FMI relatif sama dengan data batuan inti. Hasil dari log DL sangat seuai dengan porositas batuan inti dan karenanya dianggap sebagai metode perhitungan porositas rekahan terbaik pada reservoar batuan dasar terekah yang diinvestigasi dalam studi ini. Hasil-hasil tersebut di atas selaras dengan data yang dikumpulkan dari publikasi sejumlah literatur. Diperoleh bahwa nilai porositas rekahan kurang dari 1% adalah tipikal untuk batuan dasar terekah. Studi komparasi ini membantu dalam mengurangi ketidakpastian terkait dengan pengembangan reservoar batuan dasar yang terekah.

**Kata Kunci**: Porositas rekahan, reservoar batuan dasar terekah, porositas log, porositas batuan inti, isi awal gas ditempat, ketidakpastian

***ABSTRACT***

*Determination of porosity in fractured basement reservoirs has always been a challenge due to the complexity of processes involved in the generating of pore structure as well as the rock heterogeneity. As a result, estimate of original gas in place (OGIP) is subject to substantial uncertainty. Intention of this study is to evaluate the most effective method to determine fracture porosity and hence reducing uncertainty of OGIP volume in the fractured basement reservoir. The evaluation is based on comparison to the core derived porosity as the point of reference. Included in this evaluation are the techniques of secondary porosity index (SPI), dipole share imager (DSI), dual laterolog (DL), and formation micro imager (FMI). The SPI and DSI logs derived fracture porosities are found over optimistic to the core reference. The FMI determined fracture porosities are considered in fair agreement with core data. Results from the DL technique compare very favorably with core data and thought to be the best calculation of porosity in the fractured basement gas reservoir investigated in this study. Those results supported by data that have been collected from the published literatures. Found that typical value of fracture porosities in the fractured basement rocks is less than 1%. The comparative study presented here helps in reducing uncertainty related to the fractured basement reservoir development.*

**Keywords:** *Fracture porosity, fractured basement reservoir, log derived porosity, core derived porosity, original gas in place, uncertainty*

## I. INTRODUCTION

Determination of porosity is paramount because it determines the ultimate volume of a rock type that can contain hydrocarbons. The value and distribution of porosity, along with permeability and saturation, are the parameters that dictate reservoir development and production plans. There are a number of independent approaches that can be used to estimate fracture porosity for OGIP estimates. The complication is that these different approaches lead to somewhat different in the calculation results that may cause to considerable differences in the OGIP volume. The challenge is to resolve and to understand the differences among the values obtained, and to arrive at the best calculation of porosity in the fractured basement gas reservoir.

To obtain exact values for the fracture porosity is essentially impossible. Extensive information is available in the literature concerning techniques to evaluate naturally fractured reservoirs in general. Little is known however, about approaches to calculate porosity in fractured basement reservoirs with minor or no matrix porosity. This type of reservoir is classified into Type 1 of Nelson's classification (Nelson, 2001). Fractures provide the essential storage capacity and permeability in the reservoir as illustrated in Figure 1. Reservoir quality depends on the development of secondary porosity (Aguilera, 1980). It is related to, and controlled by fracturing, cooling, hydrothermal, and weathering processes. Secondary porosity may be divided into two main kinds by origin, i.e.: (i) tectonic porosity such as joints, faults, fractures, at a range of scales from microfractures to seismic scale faults, and (ii) dissolution porosity ranging from solution effects in weathering zones or fault zones to effects associated with hydrothermal circulation. The resulting pore structure heterogeneity within complex lithology makes porosity evaluation extremely challenging in this type of reservoir. Thus, this parameter remains uncertainty and the economic feasibility of fractured basement reservoirs is always questionable. Improvement of their evaluation technique represents an important subject for many areas of study.

As commonly practiced for gas bearing sedimentary reservoirs, the neutron-density log method is used to derive porosity. In case the presence of bad-hole effect, the sonic porosity is applied. The core derived properties obtained from laboratory measurements on the representative core samples are the essential data to validate the log derived porosities. In fractured basement reservoir, since no matrix porosity presence, therefore the log derived porosities should be used with care. Evaluation of core porosity is also difficult with whole core analysis because core usually breaks along the natural fracture planes. Only the tighter unfractured parts can normally be recovered in a core barrel and subjected to core analysis. But the core is too tight to be used for capillary injection experiments. These situations pose formidable difficulties for determining fractured rock porosity.

A fractal discrete fracture network model was developed to honour highly uncertainty in determining fracture porosity (Tae et al, 2009). The modelling technique enables the systematic use of data obtained from image log and core analysis for estimating fracture porosity. Rather than using modeling approach, this paper presents a comparative study of various techniques to evaluate the most effective method in determining fracture porosity and hence OGIP in a fractured basement reservoir. Application to the fractured basement gas reservoir which is unconformably overlain by fractured sedimentary sequences is presented. The log derived porosities are constrained by comparison to core measurement. Critical comments are made on all techniques and results are shown on a comparative basis, with the purpose to narrowing down the porosity range for this reservoir rock.

## II. METHODOLOGY

A comparative study is presented to evaluate the most effective method in determining fracture porosity and hence OGIP in fractured basement reservoir.

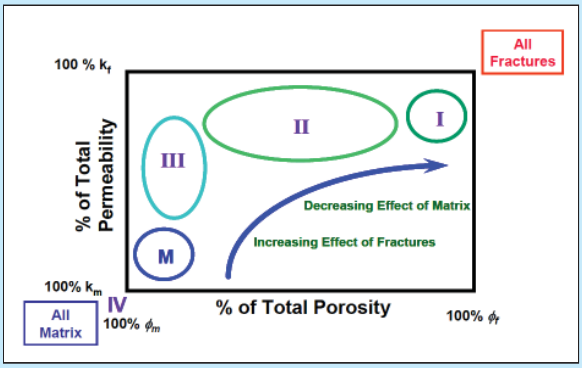


**Figure 1**
**Type 1 reservoir of Nelson's classification dominated by fracture (Nelson, 2001)**

The evaluation is based on comparison to a core measurement, which in this case is assumed to be the point of reference. Application to a case study is included. Calculation methods and data used in this evaluation are described in the following section.

**A. Fracture Porosity**

SPI is commonly used to interpret the magnitude of fracture porosities assuming the fractures as a dual secondary system (Jun Y et al, 2009, Marie et al, 2012, Thaimar et al, 2011). The SPI represents the differences between the total of matrix and fracture porosities registered by neutron-density logs and the matrix porosity obtained from sonic log. The concept relies on the fact that the neutron and density logs register total porosity, whereas a sonic log is only affected by matrix porosity. The SPI equation is (Bassiouni, 1994):

$$\phi_{f\_\mathrm{SPI}} = \phi_{\mathrm{total}} - \phi_{\mathrm{sonic}} \quad (1)$$

Dipole Shear Imager (DSI) sonic has also been utilized to evaluate the reservoir properties of the basement (Marie et al, 2012). The DSI dipole shear sonic imager combines monopole and dipole sonic acquisition capabilities for the reliable acoustic measurement of compressional, shear, and Stoneley slownesses, instead of merely the compressional wave as on conventional sonic log. Analysis of acoustic Stoneley waves offers a way assessing the permeability of fractures and porous beds. While traveling along the borehole wall, the wave propagates without much energy loss. However, the wave decays when it encounters a permeability change or a break in the wall. The absence of shear arrivals is sure signs of fractures. The porosity estimated by this tool is based on shear travel time as (Bassiouni, 1994):

$$\phi_{f\_\mathrm{DSI}} = \frac{\Delta t_{\mathrm{slog}} - \Delta t_{\mathrm{sm}}}{\Delta t_{\mathrm{sw}} - \Delta t_{\mathrm{sm}}} \quad (2)$$

where $\Delta t_{slog}$, $\Delta t_{sm}$, $\Delta t_{sw}$ stand for travel time of shear log reading, shear reading in 100% matrix, and fictitious shear reading in 100% water. Shear travel time is more sensitive to porosity than compressional data.

Detection of fracture in brittle rocks around boreholes has been treated by DL technique ((Jun Y et al, 2009, Marie et al, 2012, Sibbit et al, 1985, Tarek et al, 2013, Vasvari, 2011). DL resistivity reading showed some deviation from the normal conditions in front of fractures, where the presence of open fractures, mud easily displaces the original fluid. As a result, a contrast difference between shallow and deep resistivity readings of DL is well observed. Such deviations can be used to determine fracture porosities, apertures, and dipping and has been used as the key fracture indicator (Creties, 2009). Estimation fracture porosity using the empirical correlation from these resistivity readings is applied in this study. The formula is (Sibbit, 1985):

$$\phi_{f\_\mathrm{DL}} = \left[ R_{mf} \left( \frac{1}{R_{LLS}} - \frac{1}{R_{LLD}} \right) \right]^{\frac{1}{m}} \quad (3)$$

where $m$ is Archie's exponent usually around 2/3 to 3/4, $R_{mf}$, $R_{LLS}$, and $R_{LLD}$ are the mud filtrate, laterolog shallow, and laterolog deep resistivity responses respectively.

FMI is commonly used to interpret fracture porosity as well as fracture type, fracture intensity, fracture dip and orientation (Khalil et al, 1993, Louis, 1980). The interpreted porosities using Formation Micro Imager (FMI) logs acquired from three of wells intersecting the fractured basement are also presented. Fractures observed on the FMI are generally assumed to be open and, therefore permeable. The porosity is derived from the fracture aperture, trace length, and the borehole coverage of the images. This fracture porosity value applies only to the fracture void space and not with matrix porosity. The equation is:

$$\phi_{f\_\mathrm{FMI}} = \mathrm{Width} \times \mathrm{Trace\ Length} \times 1/\mathrm{Coverage} \quad (4)$$

The estimated fracture porosities from each log data are compared to available core derived porosity ($\phi_{f\_CORE}$) taken from the basement rock. Once the appropriate method has been identified, the fracture porosity can be populated in the inter-well space of entire reservoir for OGIP estimation. A literature survey is also integrated to indicate the range of fracture porosity encountered. Noted, fracture porosity in the basement rocks may reflect a regional character (Louis, 1980).

**B. Data Availability**

Fracture porosity was inferred on 8 (eight) wells completed in the basement reservoir using several tools and approaches. The approaches differ not only in the output parameters but also in the input for the evaluation. DL log was recorded in the all wells, so these data are available for making fracture porosity calculation within the whole wells. Porosity evaluation by other techniques is limited due to lack of the input-data required. The SPI method is allowed in two wells. DSI data is available in three wells. FMI porosity can be derived from two wells. Core porosity was only recoverable from one well. This sparse amount of data is most likely due to the problems of taking cores and log runs in the highly fractured nature of basement reservoir targeted.

## III. RESULTS AND DISCUSSIONS

Regional stratigraphic column of the case study area is depicted in Figure 2. The column illustrates the succession of sedimentary rocks is overlying unconformably on top of the basement rocks, where they host several economically important gas fields. Well test programs and bottom-hole measurements indicate that all reservoir sequences are sufficiently connected vertically and laterally through an extensive network of faults and natural fractures. The sedimentary reservoirs are defined to be a dual porosity consists of matrix and naturally fractured. Whereas the basement reservoir is considered to have no matrix porosity, and 100% of its permeability comes from fractures of all scales (Peter et al, 2012).

Relative to other techniques, the core derived porosity is a direct porosity approach that requires less assumption in relation to matrix lithology and mineralogical composition. Therefore, it considers that the obtained core porosity to be more representative of the fractured basement reservoir and assumed more accurate. An example of fracture photograph of slabing core taken from basement rock in the well W5 can be seen in Figure 3. Core plug depth has been assigned arbitrarily due to the core been rubble contained in one core box. Quartz grains observed in most of fracture pore, suggested that the close fractures are present. Porosity measurements under confining pressures of 2000 psi and 4000 psi on this core sample were conducted resulting in porosities of 0.5% and 0.4% respectively. Note that the reservoir pressure at origin is around of 4059 psi. Even a single core porosity data of the full basement interval, this offers significant data that can be utilized as a quality-control check on log based porosities.

Figure 4 presents the fracture porosities in basement reservoir probed for each wells using various techniques discussed in this study. Core porosity value is marked by red dot circle. The plot indicates that the fractured basement porosity probed vary with the technique employed. They could be divided into two groupings that relate to core data. The first group consists of SPI and DSI data that are not in agreement and consistently higher than core data. The second group comprises of DL and FMI data shows a fair to good agreement with core data.

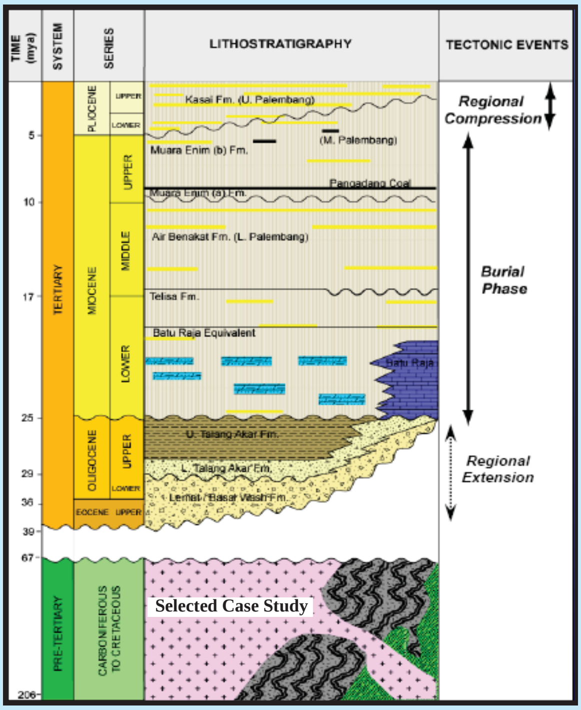


**Figure 2**
**General stratigraphic column of selected case study area**

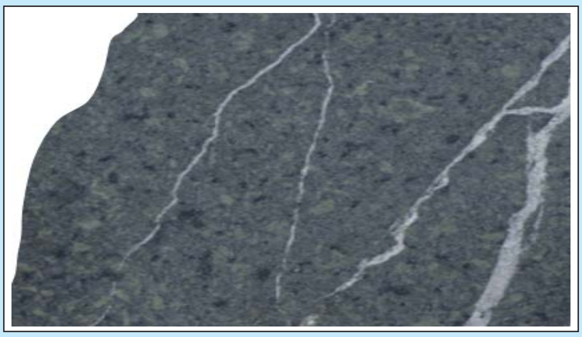

**Figure 3**
**Fracture photograph of slabing core taken from basement rock**

Fracture porosity calculated from SPI method gave higher values compared to the core derived fracture porosity, which ranged from 1.69 to 3.96%. The fracture porosity evaluated using these conventional logs may not be accurate as these logs are mainly affected complex lithology or minerals effect. The basement rocks probed here are comprised of shallow intrusive to extrusive volcanic igneous rock, associated volcanoclastic sedimentary, coarse crystalline plutonic igneous, and metasedimentary rocks. Volcanic rocks are of andesite, rhyolite, and dacite composition. Plutonic rocks are primarily of granite, whereas metasedimentary rocks consist of quartzite, argillite, and marbleized limestone. This non-uniform lithology is attributed as the main sources of inaccuracy when evaluating fracture porosity by SPI method. Another is contributed by the sonic response to the basement rocks. Failure to correct the absent of no matrix porosity such as encountered in the basement rocks may result in underestimated calculated porosities and hence produce optimistic SPI estimation. The SPI technique is a relative indicator of fractures more than quantifying facture porosity.

DSI was logged over the interval of fractured basement to evaluate the reservoir properties of the basement. As shown in Figure 4, the DSI resulted in average fracture porosities of between 3.26% and 7.26% which are much higher than the core reference. The presence of abundant conductive fractures and mineral changes throughout the basement interval probably causes false increases in recorded shear travel time resulting in optimistic porosity. Figure 5 visualizes a section of FMI image taken from the well W3 that appears abundant conductive continuous fractures, with relatively good fracture porosity and relatively large open fractures.

Interpretation results from the resistivity reading of DL compare very good with core measurement. The all wells indicate a range of average fracture porosities of 0.38% to 0.80%. Dual Laterolog known has good tolerance to bad-hole conditions in a brittle rock environment. It also provides a continuous fracture aperture estimate which includes all the electrically conductive fractures, including those which are too small. Hence, this method provides more realistic porosity fractures value rather than conventional derived fracture porosity from SPI and shear-compressional sonic methods. DL technique

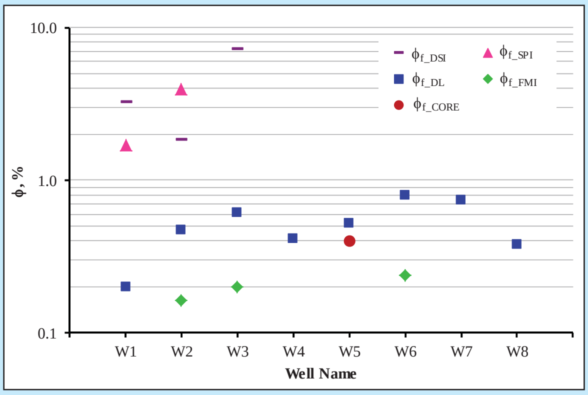


**Figure 4**
**Porosity of fractured basement reservoir evaluated by various techniques**

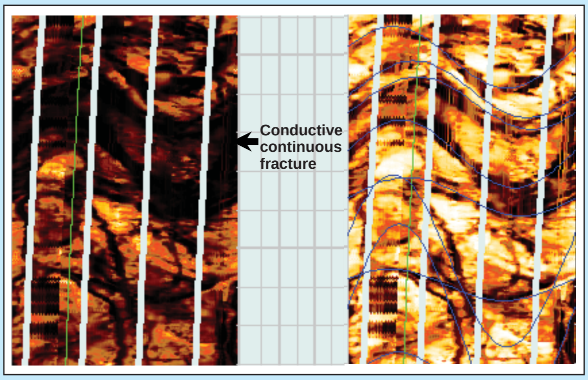


**Figure 5**
**Highly conductive continuous fractures associated with relatively good porosity in basement reservoir**

is also considered comparable with FMI results qualitatively and quantitatively. As seen in Figure 4, the DL results in three wells evaluated are in agreement with trend in the FMI analysis. Thus, the DL technique thought to be the superior method for evaluating fracture porosity in basement reservoir with no matrix porosity. A section of interpreted wells in Figure 6 shows the calculated porosities inferred from SPI, DSI, and DL techniques with SPI porosity omitted in the well W3.

FMI determined fracture porosities are considered in good agreement with core measurement. The estimated porosities have range values of 0.16% to 0.24% in W2, W3, and W6 consecutively and are slightly less than core porosity and is mostly lower than the fracture porosities from other techniques. This is due to the fact that the FMI log only represents fracture porosities intersected by wells while other

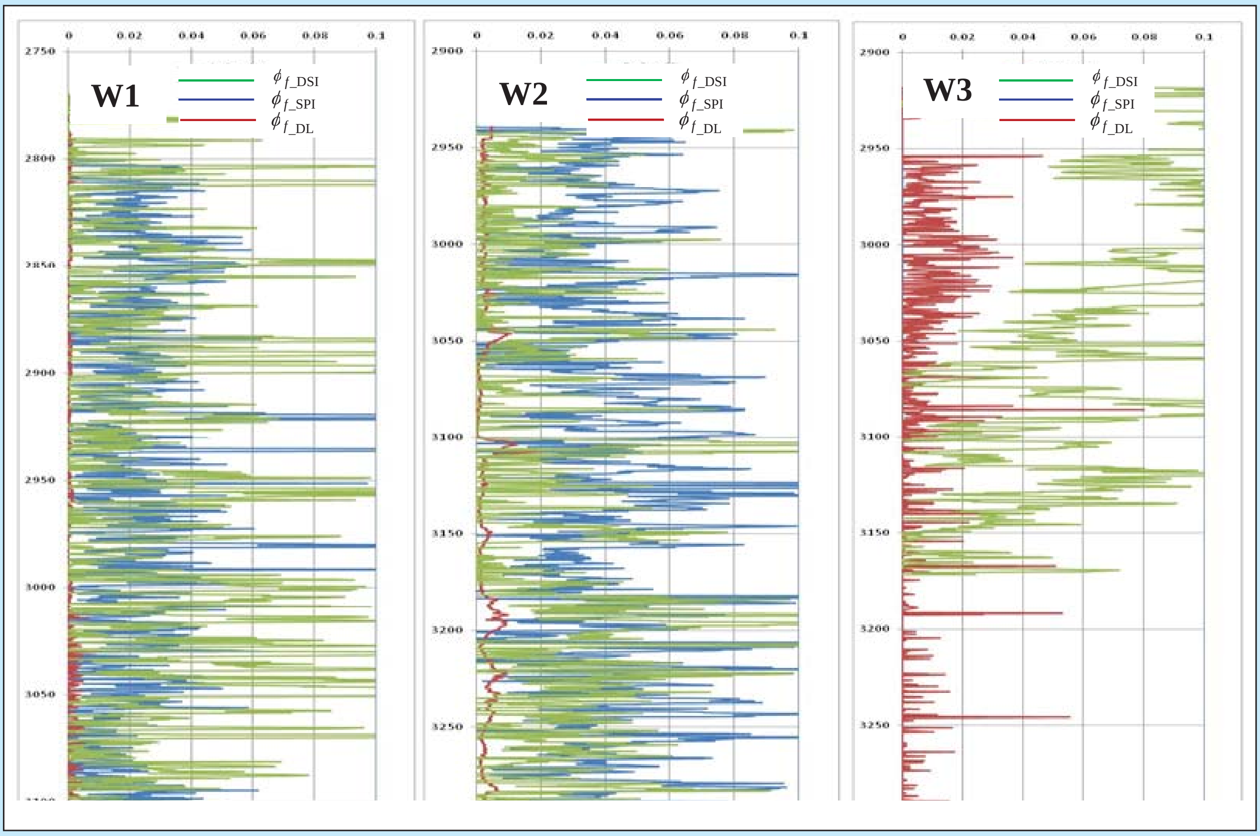


**Figure 6**
**Composite log of fracture porosity inferred from SPI, DSI, and DL in basement reservoir**

techniques are measuring fractures which extend far enough from the borehole. Porosity values represented here are an average number within a well. In fact the interpreted FMI fracture porosity is highly variable and zoned, but does not show a consistent relationship with depth. For instance, the FMI porosity in the well W3 reaches a maximum of 0.40 % and is generally between 0.01 % and 0.25% with mean of 0.24%. As revealed in Figure 5, the section of FMI image shown relatively good fracture porosity and relatively large open fractures but poorest gas shows indicated from mud log reading. Caution must be taken with the calculated fracture porosities as clay-filled fractures will also appears as open fractures on the FMI, and erroneously contribute to estimated fracture porosity.

The results from all techniques discussed above are summarized in a stock plot depicted in Figure **7**. This plot shows the range of high-low fracture porosity values and its mean yielded by each method. It is clear that the SPI and DSI techniques tend to be overly optimistic compared to the core reference. Interpretation results from the DL technique compare very favorably with core data, whereas the FMI results display less than the core porosity but both are comparable quantitatively. As core data are infrequently acquired, the DL derived fracture porosities that have been validated with core data were used to define the fracture porosities distribution in the studied basement reservoir vertically and laterally for OGIP calculation. Results of the DL technique were satisfactory in terms of the OGIP history matched and were successfully in reproducing the reservoir pressure depletion.

A literature survey is also integrated in this study to highlight the range of fracture porosities encountered in the basement reservoir around the world. The literature sources and pertinent data characterizing each of the surveyed sites are summarized in Table 1. Surveyed data show that the fracture porosities of basement rocks are generally very small. Values less than 0.01 of rock volume or 1% are typical. Fracture-related porosity caused by surface weathering or hydrothermal solution may attain much larger values, but the porosity in the actual facture is still very small (Nelson, 2001). Numerous techniques were established to examine fracture porosity in basement reservoirs. The survey results show that the core measurements and FMI/FMS analysis produced accurate values. Conventional logs of LDT and MM derived fracture porosities are over estimate by several orders of magnitude (Khalil et al, 1993). Surveyed data support our finding in this study. Where results from the core and FMI yield satisfactory values. While the SPI and DSI logs resulting in over optimistic values. The DL log showed a favorable comparison to the typical fracture porosity observed in this literature survey.

## IV. CONCLUSIONS

Various methods of fracture porosity calculation in a fractured basement reservoir have been evaluated. The evaluation is based on comparison to the core derived porosity as the point of reference. Found that conventional logs of SPI and DSI derived fracture porosities are over estimate by several orders of magnitude to the core reference. Non uniform lithology is attributed as the main source of inaccuracy when evaluating fracture porosity by

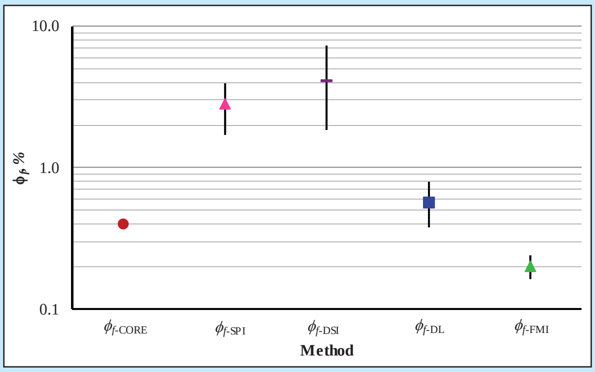


**Figure 7**
**Range of fractured basement porosity values derived from all techniques evaluated in this study**

**Table 1**
**Fracture porosities in basement rocks around the world**

| Field / Reference | Fracture Porosity | Rock |
|---|---|---|
| Case Studied | 1.69 - 3.96% from SPI<br>3.26 - 7.26% from DSI<br>0.20 - 0.80% from DL<br>0.16 - 0.24% from FMI<br>0.40% from CORE | volcanic igneous, volacnoclastic sedimentary, coarse crystalline, plutonic igneous, metasedimentary basement |
| White Tiger - Vietnam (Huy, 2012) | < 0.2%<br>0.4 - 0.5%<br>0.6 - 4.0% | in diorite basement<br>in granodiorite basement<br>in granite basement |
| Zeit Bay - Egypt (Khalil, 1993) | 0.4 – 2.0% from CORE<br>3.0 – 15.0% from LDT*<br>1.0 – 8.0% from MM*<br>0.2 – 2.0% from FMS* | granite, metavolcanics, metasediments basement |
| Anonymous - Austria (Tarek *et al*, 2013) | 0.5% | crystalline and volcanic basement |
| Nagylendel - Hungary (Louis, 1980) | 1.0% | not available |
| Ruby - Indonesia (Suardana, 2013) | 0.15 – 0.30% | metamorphic of marble and slate basement |
| Anonymous (Nelson, 2001) | 0.1 – 1.0% | crystalline basement |

*LDT = Litho-Density Tool; MM = Multimineral Log; FMS = Formation Micro Scanner

SPI method. The presence of abundant conductive fractures and mineral changes caused the higher fracture porosity calculated by DSI method. The FMI results display less than the core porosity due to the fact that this method only represents fracture porosities intersected by wells, but both are found comparable quantitatively. Calculation results from the DL technique compare very favorably with core data and thought to be the best calculation of porosity in the fractured basement gas reservoir probed. Results from this study supported by the published data collected from the published literatures. Comparative studies to evaluate the most applicable method in determining fracture porosity and hence OGIP estimates help to reduce uncertainty in developing a fractured basement reservoir.

## ACKNOWLEDGMENTS

The author wishes to thank Bambang Agus Wijayanto at Core Laboratory in Research and Development Centre for Oil and Gas Technology "LEMIGAS" for his fruitful discussion and scientific support.

## REFERENCES

**Aguilera, R.**, 1980. *Naturally fractured reservoir*, Penn Well Publishing Company, Tulsa, Oklahoma, USA.

**Bassiouni, Z.**, 1994. *Theory, measurement, and interpretation of well logs*, SPE Textbook Series Vol. 4, Richardson, Texas, USA.

**Creties, J., Ahmed, O., Abdel, Z.,** & **Jeff, W.**, 2009. "Quantifying and predicting naturally fractured reservoir behaviour with continuous fracture models", *AAPG Bulletin*, Volume 93, No. 11, pp. 1597-1608.

**Huy, X.N., Bae Wisup, San, T. N., Xuan, V. T., SungMing, J.,** & **Kim, D. Y.**, 2012. **"**Fractured basement reservoirs and oil displacement mechanism in White Tiger Field, offshore Vietnam**"**, *AAPG International Conference & Exhibition*, Singapore.

**Jun, Y., Liwei, L., Rudi, L.,** & **Simon, P.**, 2009. "Petrophysical fracture identification for rock physics studies", *the 71st EAGE Conference and Exhibition*, Amsterdam, Netherlands.

**Khalil, M. M., Pigaht, J.,** & **El Wazeer, F. M.**, 1993. "Comparison of petrophysical method for STOIIP in a refined estimation of fractured basement reservoir", *paper SPE 25653*, presented at the SPE Middle East Oil Technical Conference & Exhibition, Bahrain.

**Louis, H. R.**, 1980. *The reservoir engineering aspects of fractured formations*, Technip, Imprimerie, Paris.

**Marie, L., Sherief, F., Lauren, S.,** & **Agnes, D.**, 2012. "Fractured basement reservoir characterization for fracture distribution, porosity, and permeability prediction", *AAPG International Conference and Exhibition*, Singapore.

**Nelson, R. A.**, 2001. *Analysis of naturally fractured reservoirs*, 2nd Edition, Gulf Publishing Co. Book Division.

**Peter, H., Patricia, A., Pijush, P., Chris, Z., Ray R. Jr., Hugh, A., Roand, K., Bob Lee,** & **Elliot, H.**, 2012. "Relationship between fractures, fault zones, stress, and reservoir productivity in the Suban gas field, Sumatera, Indonesia", *AAPG Bulletin*, Volume 96, No. 4, pp. 753-772.

**Sibbit, A. M.** & **Faivre, O.**, 1985. "The Dual Laterolog response in fractured rocks", *paper T, SPWLA 26th Annual Logging Symposium*, Dallas, Texas, USA.

**Suardana, M., Samodra, A., Wahidin, A.,** & **Sule, M. R.**, 2013. "Identification of fractured basement reservoir using integrated well data and seismic attributes: Case study at Ruby Field, Northwest Java Basin", *AAPG Annual Convention and Exhibition*, Pittsburgh, Pennsylvania, USA.

**Tae, H. K.** & **David, S. S.**, 2009. "Estimation of Fracture Porosity of Naturally Fractured Reservoir with No Matrix Porosity Using Fractal Discrete Fracture Networks", *SPE Reservoir Evaluation & Engineering*, Volume 12, No. 2, pp. 232-242.

**Thaimar, R. R., Jim, D. K., Ron, J. M. B.,** & **James, J. H.**, 2011. "Comparative Study of Formation Evaluation Methods for Unconventional Shale-Gas Reservoirs: Application to the Haynesville Shale (Texas)", *paper SPE 144062*, the SPE North American Unconventional Gas Conference and Exhibition, Texas, USA.

**Tarek, F. S.** & **Elhamy, T.**, 2013. "Using of Dual Laterolog to detect fracture parameters for Nubia sandstone formation in Rudeis-Sidri area, Gulf of Suez, Egypt", *Egyptian Journal of Petroleum*, No. 22, pp. 313-319.

**Vasvari, V.**, 2011. "On the applicability of Dual Laterolog for determination of fracture parameter in hard rock aquifers", *Austrian Journal of Earth Sciences*, Volume 104, No. 2, pp. 80-89.