GEOMECHANICAL STRESS PROFILE AT GUNDIH FIELD: STRESS QUANTIFICATION AND ANALYSIS IN RESERVOIR FOR CO$_2$ INJECTION

Harya Danio$^1$, Benyamin Sapiie$^2$, Oddy Adnan$^2$, Takeshi Tsuji$^3$, Mohammad Rachmat Sule$^4$

$^1$ Geological Engineering Study Program, Universitas Pertamina Jakarta 12220, Indonesia

$^2$ Geological Engineering Study Program, Institut Teknologi Bandung, Jl Ganesha 10, Bandung 40132, Indonesia

$^3$ International Institute for Carbon-Neutral Energy Research (I2CNER), 744 Motooka, Nishi-ku, Fukuoka 819-0395, Japan

$^4$ Geophysical Engineering Study Program, Institut Teknologi Bandung, Jl Ganesha 10, Bandung 40132, Indonesia

Email of Corresponding Author : Harya Danio, harya.danio@gmail.com

ABSTRACT

Geomechanical analysis is performed at Gundih Field to obtain detail stress condition and mechanical properties from interval of interest. Ngrayong Formation is targeted as CO$_2$ injection interval of Gundih Field. The detail interval is determined using multi-mineral modelling and calibrated using XRD and petrographic data. Overpressure is detected from this well at Ngrayong Formation. Stress direction from adjacent well showed NE – SW direction of maximum horizontal stress. Stress magnitudes and mechanical properties are calculated using available log data through well-established empirical equation resulted thrust faulting regime acting on this area. Injection capability of formation is examined from Mohr – Coulomb diagram with input from calculated stress.

Keywords: Geomechanics; Gundih Field; Ngrayong Formation; Reservoir; overpressure.

INTRODUCTION

The role of geomechanical analysis on CCS is to assess the in situ stress, pore pressure condition, and reservoir mechanical properties to solve injection related potential risk. The focuses of this study is only to estimate the maximum ability of reservoir to contain the build-up pressure caused by injection of super critical CO$_2$ for preventing leakage. The stress and pore pressure measurement are critical to describe the current reservoir condition. Reservoir requires the seal to limit the vertical migration.

The Gundih Field is situated at Blora District, Central Java Province, Indonesia. This field is part of North East Java Basin. Gundih is part of a major oil production area, Cepu Area, which contains 27 oil fields on this area. The operator of this field is state-owned oil company, Pertamina. Productions come from two major intervals, the Pliocene Mundu Formation sandstone and the Middle Miocene Ngrayong Formation sandstone. Both intervals are deposited on post rift phase of East Java Basin. Ngrayong interval become a target injection interval of this CO$_2$ capture and storage project because this interval is proven as a good reservoir interval.

GEOLOGICAL SETTING

East Java Basin is a back-arc basin on the southern part of Sunda Shelf. It has started to develop since Late Cretaceous period with the northeastward movement of Australian Plate. The movement resulted subduction under Sundaland along Java-Meratus suture. It created magmatic activity ranging from northeast Sumatra through Java to the southeast Kalimatan. During Oligocene to Early Miocene, there was a rapid reduction of Australian Plate and resulted steeper angle of subduction. During Middle Miocene to Late Miocene period, the whole Java island occupied by magmatic activities. It generated the back-arc basins that devided into several sub-basin
separated by basement high (Sribudiyani, 2003).

The Ngimbang Formation deposited clastic unit of East Java during Middle Eocene. This unit distributed along the NE-SW Meratus trend and the E-W Sakala trend. It is a syn-rift deposit of East Java basin. The Ngimbang Formation records a transgression with a passage from terrestrial sands, through shallow marine limestone to deep marine shales (Ebanks and Cook, 1993). This sequence recognized as carbonate and shale member of Ngimbang Formation that deposited during Late Eocene to Early Oligocene. This transgressive sequence is terminated by intra-Oligocene unconformity overlain by extensive carbonates of the Kujung and Prupuh Formation. Kujung Formation is covered by terrigenous sediments of Tuban Formation. Ngrayong is the member of Tuban Formation that dominated by quartz rich sandstone. The reefal dominated Bulu Formation developed after the deposition of clastic sequence. During late of Middle Miocene to early of Late Miocene, East Java Basin deposited Wonocolo Formation. This formation is characterized by marl dominated interval with rare intercalation of calcarenite. The Ledok Formation was conformably overlain Wonocolo that characterized by an increasing frequency of calcarenite intercalation within the marl (Susilohadi, 1995) (Figure 1).

The oldest sedimentary unit observed from JEPON-1 well is Tawun Formation. This unit was characterized by interbedded limestone and siltstone with marl intercalation on this well. Ngrayong Formation was identified over Tawun Formation from JPN-1 well. Ngrayong Formation recognized by interbedded siltstone with limestone and sandstone.

The present-day of East Java Basin encompasses three major structural provinces, the Northern Platform, Central High, and the Southern Basin. There are two dominant structural trends on this basin, the E – W trend and the NE – SW trend. The E – W trend interpreted to relate with basement grain of the East Java Basin. The NE – SW related to collision trend of Luk Ulo – Meratus Complexes during Late Cretaceous. Northward movement of Indian – Australian Plate during Middle – Late Miocene reactivated the E – W structural trend to strike-slip fault (e.g. Sakala Fault Zone). The Northern Platform develops the NE – SW structural trends. The E – W structural pattern dominates the Central High with Sakala Fault Zone control the deformation on this province.

Figure 1. The regional stratigraphy of East Java Basin (Sapiie et al., 2015)

METHODOLOGY

TARGET PROPERTIES

The target reservoir for CO₂ is identified through regional study data and detailed by petrophysical analysis of JEPON-1 well. This target is interval on Ngrayong Formation. This is based on the geological history and the composition of Ngrayong Formation. The sandstone from this formation is known to compose almost entirely by quartz-rich sandstone. The sandstone reported having average porosity 15.08% and average permeability 203.8 millidarcies (mD) (Rianda et al., 2015). Moreover, the CO₂ that will be injected to the well is supercritical phase. The supercritical temperature of CO₂ is 304.25 K and its critical pressure is 7.39 MPa. Assuming the pore pressure are hydrostatic condition (10
MPa/km), the depth to satisfy the condition is 739m or below.

Petrophysical analysis was performed at JEPON-1 well. In general, Ngrayong Formation from this well exhibits high density, low velocity, and high neutron porosity interval. Crossplots between some rock properties are performed to identify the lithology of formation. The crossplots show the complexity of Ngrayong Formation of this well since it gives different lithology trend result from one another (Figure 2). The high fluid content and complex carbonates porosity possibly caused the uncertainty on this well.

Mineral modelling was conducted to obtain the conclusive result. Mineral modelling is a petrophysical technique to acquire the percentage of mineral content through combining rock petrophysical data. There are four XRD data and 20 thin sections from side wall cores (SWC) to calibrate the mineral percentage and lithology. The log data that used for modelling are gamma ray, neutron porosity, and sonic velocity. Those parameter are the inputs to model quartz, dolomite, calcite, clay, water, and hydrocarbons content of the formation. The 40% quartz content is used as a cut-off to identify the quartz sandstone on Ngrayong Formation.

The result from mineral modelling, Ngrayong Formation on JEPON-1 well is dominated by shale and carbonates. It confirmed the cutting description. Ngrayong Formation is described as a shale dominated formation with interbedded sandstone and limestone (Figure 3). The model identified the dolomite on limestone probably derived the high density on this formation. The sandstone intervals presented as a small portion of this well and indicated the marine incursion on this area. It seems Ngrayong Formation on this area deposited a paralic sequence like some places on East Java (Ardhana, 1993) and result relatively thin sandstone layer.

As mentioned before, the sandstone determination used the quartz content cut-off. The sandstone intervals actually present on some interval of this well but mostly have thin layer. The most prominent interval is identified at depth 854 – 862m. It is the thickest among all sand interval on Ngrayong Formation and supported by cutting report of JEPON-1 well.

Using the > 40% volume of quartz cut-off, it would be clean 6.2m thick sandstone interval. The average effective porosity of this interval is 16% and average permeability is 38.7 mD.

HORIZONTAL STRESS DIRECTIONS

Horizontal stress directions interpreted from vicinity wells in the southern part of Gundih Field (Figure 4a). Image log from KDL-1 and KTB-2 were analyzed to receive stress information. Image log of KDL-1 well acquired from depth 3497m-3669m specifically on Kujung Formation. KTB-2 well image obtained from Kujung Formation interval at depth 2824m-3014m. Both images showed carbonate facies on Kujung Formation.

Dominant stress indicator for KDL-1 is drilling induced tensile fractures. The tensile fractures have dominant azimuth N50°E – N70°E. Conductive fractures generally have N30°E and N80°E strike azimuth. The dip of fractures is dominated by high angle dip around 50° – 60°. Low angle plane appeared to have NW – SE strike azimuth and interpreted as limestone bedding. Drilling induced tensile fractures and natural fractures data exhibit horizontal stress maximum from around N50°E on KDL-1 well (Figure 4b).

The image log from KTB-2 well displayed similar pattern. Conductive fractures from this well have N20°E and N80°E strike azimuth but show more variation in dips. Dominantly, fractures have dips around 40° – 60°. Drilling induced tensile fractures observed to have N60°E. There are no breakouts interpreted to present in this well. Horizontal stress maximum direction from this well interpreted to N60°E direction (Figure 4c).

Both wells indicated the maximum horizontal stress direction from around N50° – 60°E. Assuming stress directions remain consistent along depth and stress direction on JPN-1 well consistent with direction from KDL-1 and KTB-2 thus JPN-1 well maximum horizontal stress direction is from NE – SW direction.

VERTICAL STRESS

The magnitude of vertical stress ($S_v$) is the pressure exerted by the overlying volume of rocks. Vertical stress ($S_v$) was calculated through bulk density from logging data along depth (z) (Eq. 1).
\[ S_v = \int_0^Z \rho(z) g \, dz \approx \rho g z \]  

(1)
Figure 2. Crossplots of well logs data from Ngrayong Formation interval.

Figure 3. Mineral content modeling result and petrographic description on Ngrayong Formation.

Figure 4. (a) Image logs from KTB – 2 and KDL – 1 appeared drilling induced tensile fracture from around N60°E direction. (b) Fracture, bedding, and stress orientations KTB – 2 and KDL – 1. (c) Well positions of KTB – 2 and KDL – 1 (Pertamina, 2004 and Pertamina, 2005).
In many cases, shallow density data is not available. The data on shallow depth should be known to acquire correct value of vertical stress since the overlying rock volume should be completely included to calculation. Missing density data at shallow depth extrapolated using density – depth trend line generated from available density data. The vertical stress gradient acquired from calculation around 21.48 MPa/km.

There are two leak-off test (LOT) measurements from well JPN-1. The LOT test initially conducted to determine the fracture pressure of formation. This test usually tells the minimum horizontal stress value of formation. First LOT data measure at depth 302m. Pressure required to reach leak-off pressure at depth 302m estimated 17.93 ppg (5.34 MPa). This result exhibited the very high values of leak-off test. The high value of the test gives wide mud weight window for drilling operations. The careful investigation of LOT result concluded the result close to vertical stress of the interval. Vertical stress estimated at this depth is 5.58 MPa. Second LOT data measure at depth 828m. Leak of pressure at second point measured 16.39 ppg (15.96 MPa) and vertical stress calculated 17.09 MPa. Both LOT data values nearly reached vertical stress values. It indicates the LOT values is vertical stress magnitude rather than minimum horizontal stress. The near vertical stress LOT values actually could be used to investigate the minimum horizontal stress value through observation of multi cycle instantaneous shut-in pressure (ISIP) (Zoback, 2007). This observation cannot be done since the LOT tests not reached the ISIP.

PORE PRESSURE

Pore pressure is pressure of fluid within an interconnected pore space. This parameter takes important role in carbon capture storage since it affects the subsurface stress conditions, the injection capability, and the field operation. Pore pressure (\(P_p\)) model was built using Eaton (1975) equation (Eq. 2) and integrated with drill stem test (DST) data, mud weight, and drilling events.

\[
P_p = S_v - (S_v - P_{\text{hyd}})(\frac{\Delta \text{P}}{\Delta \text{t}_{\text{log}}})^3
\]

Eaton (1975) method compares the values of sonic, density, or resistivity logs with the normal values on mudrock interval. The normal values is the trend that exhibited by mudrock interval through compaction process on the basin. The log values that deflected from the normal compaction values is consider having an abnormally pressure. This study emphasized the behavior of sonic log since it gives clearer picture of the abnormally pressure behavior on JEPON-1 well.

The top section of the well is exhibited hydrostatic pressure. There is no significant log deflection from the top log interval until depth 850mMD. The sonic deflection data appeared around depth 850mMD. This interval exhibited anomalously low sonic slowness. It was not to consider as abnormally pressure since the DST data slightly below this interval showed normal hydrostatic pressure with gradient 10.17 MPa/km. The deflection continues until the total depth (TD) of the well.

Kick and loss happened during drilling at depth 1407mMD indicated abnormally high pressure (overpressure). Overpressure interval was inferred start from depth 990mMD according to Eaton formula. On the top of overpressure interval, pore pressure gradient deflect to 10.40 MPa/km. Overpressure reached 16.06 MPa/km at the total depth (TD). Pore pressure still elevated and not observed back to hydrostatic at TD of the well.

HORIZONTAL STRESS MAGNITUDES

Horizontal stress minimum \(S_{h_{\text{min}}}\) and maximum \(S_{h_{\text{max}}}\) measured using Blanton and Olson (1999) equation. It is used poroelastic deformation assumptions to acquired horizontal stress magnitudes. The advantages of this method are the involvement of tectonic and thermal effects in addition to overburden and pore pressure as source of horizontal stress. The parameters that used on this method are Poisson ratio, Young modulus, overburden, Biot constant, pore pressure, geothermal gradient, and coefficient of thermal expansion.

Overburden, pore pressure, Poisson ratio, Young modulus are calculated based on method that mentioned on the previously section. Geothermal gradient used 34°C/km (32.06 °F/m). The Biot constant assumed 1 in this study. In the absence of measured values for
thermal coefficient of expansion, 5.56E-6°F used for sandstone, 5.00E-6°F for shale, and 4.44E-6°F for carbonates (Blanton and Olson, 1999).

The $S_{h_{\text{min}}}$ gradient from Eq. 4 is 30.08 MPa/km for normal hydrostatic pore pressure. There are deflection of horizontal stress magnitudes on the overpressure interval. The gradient of $S_{h_{\text{min}}}$ is decrease to 28.27 MPa/km on the overpressure interval. It is very common behavior of stress on the overpressure interval. Stress commonly approached to vertical stress magnitudes on the overpressure interval to satisfy the ratio of the largest principle stress ($\sigma_1$) and the least principle stress ($\sigma_3$) cannot exceed the crustal strength of the earth (Jaeger and Cook, 1979; Zoback, 2007). The $S_{h_{\text{max}}}$ exhibited the same behavior as $S_{h_{\text{min}}}$. The $S_{h_{\text{max}}}$ gradient on normal hydrostatic interval is 36.64 MPa/km. The gradient decrease to 31.44 MPa/km on the overpressure interval (Figure 5).

In order to confirm the stress configuration of the well, it is important to constraint the stress. The upper limit of $S_{H_{\text{max}}}$ was constrained by frictional strength of the crust (Jaeger and Cook, 1979). LOT values close to vertical stress therefore vertical stress was the least principle ($\sigma_3$) and consequently the largest principle stress ($\sigma_1$) is maximum horizontal stress ($S_{H_{\text{max}}}$). It is the greatest possible horizontal stress acting on this well. The lowest possible of horizontal stress is limited using tensile failure equation. It is chosen because tensile failure will be occurred on the greatest different on horizontal stress. Assuming tensile failure existed during drilling along wellbore wall and $S_{H_{\text{max}}}$ value was known from upper limit equation thus lower limit of $S_{h_{\text{min}}}$ could be calculated using tensile strength equation (Zoback, 2007) (Eq. 15 and 16).

\[
\frac{\sigma_1}{\sigma_3} = \frac{S_{H_{\text{max}}} - P_p}{P_V - P_p} = \left[(\mu^2 + 1)^{1/2} + \mu \right]^2 
\]  

(3)

\[
S_{h_{\text{min}}} = \frac{S_{H_{\text{max}}} + 2P_p + \Delta P + T_0 + \sigma_{\Delta T}}{3}
\]  

(4)

The upper boundary limit of $S_{H_{\text{max}}}$ showed around 44.33 MPa/km on the normal hydrostatic interval and deflected to around 37.55 MPa/km in the overpressure interval. The $S_{h_{\text{min}}}$ gradient of lower boundary stress is 23.52 MPa/km in the normal hydrostatic interval. $S_{h_{\text{min}}}$ values for lower bound affected by overpressure with small deflect became 22.84 MPa/km (Figure 5).

The vertical stress values become the smallest value of principal stress. It gives sense of current stress regime is thrust faulting regime. The implications of stress regime is very wide especially on injection of CO$_2$. Thrust fault regime will propagate horizontal plane on tensile fracture rather than vertical. Apparently, it gives an advantage on the injection since on the worst case of reservoir unable to contain the injection pressure, the tensile fracture will propagate to the reservoir layer rather than damaging overlying and underlying layers.

**DISCUSSION**

This study has observed the overpressure from this well on the Ngrayong Formation. It is very hard to predict top of overpressure of this well. The common well logs data to predict overpressure such as density, resistivity or sonic logs not having very distinct deflection to indicate top of overpressure. Since there are kick 1470mMD, it is strong indicator of overpressure and the top of this abnormally pressure should be determined. Sonic log gives small deflection thus the top of overpressure is predicted around 990mMD.

Unpublished thesis work from Jufriansyah (2016) has well documented overpressure evidence on East Java Basin. Five wells had examined to identify the pore pressure behavior around East Java Basin. Those five wells documented the presence of overpressure on this basin at various depth. However, all the top of overpressure observed in the middle of Ngrayong Formation. It is strengthen the study result that overpressure occurred on Ngrayong Formation. The target of CO$_2$ injection is around 150m shallower from the top of overpressure however drilling this area should do with careful since the spatial distribution is poorly documented.

Thrust fault is present on this well. It is very common to have thrust fault around anticline like the one at Gundih Field. Stress calculation resulted the thrust faulting regime on this well and it gives very similar result with the geological condition of this area. In other words, the stress condition when the anticline and faults formed not much altered until the
Present day. The stress regime result directly implicated the injection behavior of this well. The horizontal plane of tensile fracture propagation and the ductile interval of Ledok Formation give a secure sense that propagated failure will not result damage on adjacent formation. The more concern should be addressed to the fractures and faults reactivation of this well since it can be the conduit for fluid to reach surface and cause environmental problems. The 2.5 MPa (see Figure 6) of stress is not very big value so it is very important to monitor the injection process over the time.

The stress and mechanical properties calculation is very critical of this study. The limitation of data may influenced the result. However, the geomechanical analysis should be performed to consider the risk of injection CO₂ to the formation. This study will give the insights of general workflow to convert standard oil and gas dataset to become comprehensive geomechanical analysis.

**CONCLUSION**

The interval target is chosen at interval 854 – 862 mMD within Ngrayong Formation based on petrophysical analysis and multi-mineral model. Using the > 40% volume of quartz cut-off, it would be clean 6.2m thick sandstone interval. The average effective porosity of this interval is 16% and average permeability is 38.7 mD

Geomechanical analysis has conducted on Gundih Field. Pore pressure exhibited to abnormally high at depth around 990m from JPN-I well. According to image log data from adjacent well, the horizontal stress maximum direction is from around N60°E. The stress condition on Gundih Field interpreted to be thrust faulting regime. Vertical stress appeared to be the least principle stress on this field. It is supported by LOT test values that showed close to vertical stress.

From the Mohr – Coulomb diagram, the target interval is able to contain 2.5 MPa pressure before it cause reactivation of fracture on formation. The reservoir pressure should maintain below this value to prevent reservoir damage. The more concern should be addressed to the fractures and faults reactivation of this well since it can be the conduit for fluid to reach surface and cause environmental problems.
The wellbore stability analysis can be used as a guide for development drilling for JEPON-1 well. Overpressure on Ngrayong interval proved to be major problem during JPN-1 drilling. Current geomechanical model can be utilized to predict safe mud weight window and another development program on carbon capture and storage of Gundih Field.

Geomechanical model has built for Gundih Field especially JPN-1 well. All mechanical parameter mostly derived from log data. It was produced dynamic parameter for this well. Laboratory tests to convert dynamic to static parameter are highly recommended to conduct. It will calibrate mechanical and stress result from this study.

REFERENCES

Ardhana, W., 1993. A Depositional Model for the Early Middle Miocene Ngrayong Formation and Implications for Exploration in the East Java Basin. Indonesian Petroleum Association. Proceedings 22nd Annual Convention.

Blanton, T.L. and Olson, J.E. 1999. Stress Magnitudes from Logs: Effects of Tectonic Strains and Temperature. SPE 54643. SPE Reservoir Evaluation and Engineering Vol. 2.

Eaton, B. A. 1975. The Equation for Geopressure Prediction from Well Logs. SPE 5544. SPE 50th Annual Meeting Society of Petroleum Engineers of AIME.

Jaeger, J.C. and Cook, N. G. W. 1979. Fundamentals of Rock Mechanics 2nd Edition. New York: Chapman and Hall.

Jufriansyah, M. M. 2016. Pore Pressure and Overpressure Prediction Using Wireline Log And Seismic Interval Velocity In The East Java Basin. Master Thesis, Institute of Technology Bandung.

Pertamina. 2004. FMI Analysis Results KTB-2 Interval 2824-3014m Onshore East Java, Indonesia. Pertamina Internal Report

Pertamina. 2005. FMI KDL-1 Interval 3497-3669m. Pertamina Internal Report

Rienda, F., Arisandy, M., and Bambelia, D. 2015. Prospectivity of Reservoir Potential On The Middle Miocene Ngrayong Formation In Grobogan Area: Implications For Petroleum System. Pacific Section AAPG Convention, Oxnard, California, May 3-6, 2015.

Sapiie, B., Danio, H., Priyono, A., Asikin, A. R., Widarto, D. S., Widianto, E., Tsuji, T. 2015. Geological Characteristic and Fault Stability of The Gundih CCS Pilot Project at Central Java, Indonesia. Proceedings of the 12th SEGJ International Symposium, 2015.

Smyth, H., Hall, R., Hamilton, J., and Kinny, P. 2005. East Java: Cenozoic Basins, Volcanoes and Ancient Basement. IPA05-G-045. Indonesian Petroleum Association. Proceedings 30th Annual Convention

Sribudiyani, M., N., Ryacudu, R., Kunto, T., Astono, P., Prasetya, I., Sapiie, B., Asikin, S., Harsolumakso, A.H., and Yulianto, I., 2003. The Collision of the East Java Microplate and Its Implications for Hydrocarbon Occurrences in the East Java Basin. Indonesian Petroleum Association. Proceedings 29th Annual Convention, p. 335-346.

Susilohadi. 2005. Late Tertiary and Quartenary Geology of the East Java Basin, Indonesia. Doctor of Philosophy Thesis, University of Wollongong.

van Bemmelen, R.W., 1949. The Geology of Indonesia. Govt. Printing Office. Nijhoff. The Hague

Zoback, M. D. 2007. Reservoir Geomechanics. New York: Cambridge University Press.