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The Importance of Reservoir Geomechanic Modelling for Carbon Sequestration, Storage, and Utilization: A Case Study from East Natuna

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Abstract - East Natuna is well known for its huge natural gas reserves with a very high CO_2 content. The appearance of CO_2 content in an oil and gas field is always considered as waste material, and will severely affect the economic value of the field. The higher the content, the more costly the process, both technically and environmentally. In this research, the newly proposed reservoir management approach called CSSU (Carbon Sequestration, Storage, and Utilization) method is trying to be applied to change the paradigm of CO_2 from waste material into economic material. The CSSU method is an integration of geological, geophysical, reservoir engineering, and engineering economics with the determination of technical and economic optimization of the use of CO_2 produced as the working fluid in a power generation system that has been conditioned through an injection-production system in geological formations. Reservoir simulation modeling is done by three models, namely: Compositional, Compositional + Geomechanical Coupling, and Compositional + Geomechanical Coupling + Thermal. There is a difference in the the total injection between Compositional + Geomechanical Coupling and ordinary Compositional simulations of 1-2 % due to factors such as Modulus Young, Poisson's Ratio, Angle of Internal Friction, and Biot's Coefficient which affect the reservoir pore volume calculations and the total CO_2 fluid injection calculation. The changes in geomechanical parameters will affect the CSSU techno-economic analysis where a 30 % change in the rock compressibility and poisson ratio parameters will effect changes in the electrical energy amounts being produced by 0.01 MW or 0.33 %, and in an economic value of 4 MMUS $ or 2.24 %.

Keywords: CSSU, reservoir simulation, geomechanics, East Natuna, CO_2

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Introduction

The demand for natural gas in Indonesia keeps increasing as the population grows. In order to keep up with the need, the oil and gas industry has to go back and re-evaluate untapped potential that has been sleeping for ages due to technical and economic reasons. In the last few decades, one of the biggest discoveries was made in East Natuna Basin which is located in North Natuna Sea (Figure 1). The resources in the area were estimated to be around 222 TCF with 70 % of it is carbon dioxide (Dunn *et al* ., 1996), which leaves ± 40 TCF of methane to be extracted. However, the development of the gas prospects was inconceivable due to the high content of carbon dioxide which is highly corrosive, requires edge cutting separation technology, and also has to be safely disposed without releasing it into the atmosphere.

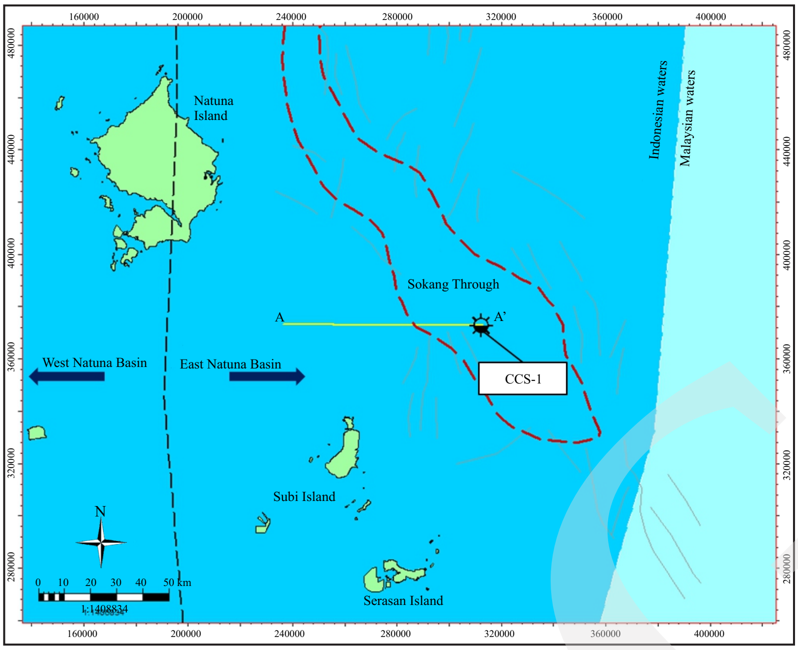


Figure 1. Location of the CCS-1 well in the North Natuna Sea.

Carbon Capture and Storage (CCS), where the captured CO_2 is safely stored in subsurface reservoir, has significantly improved to the point where it has become economically feasible. The world first CCS operation, Sleipner CCS Project, was even done in the North Sea, offshore area of Norway and the Tomakomai CCS Project in Japan which started injecting CO_2 since 2016 with the injection rate of 220,000 tons CO_2 per year (Tanase *et al*, 2013; Tanase, 2017).

A new scheme called Carbon Sequestration, Storage, and Utilization (CSSU) was proposed in order to increase the economic feasibility of the operation that will enable the development of gas resource in East Natuna, by changing the paradigm of CO_2 from waste material into economic material. Schematically, the CSSU method can be seen in Figure 2, where a gas field with CO_2 content is being produced. Then, after the CO_2 content is separated, the CO_2 fluid is flowed and injected into the storage reservoir. The gas separation process can be carried out at offshore platform production facility or taken onshore and separated on land. After it is stored for some period of time, the CO_2 fluid in the reservoir is produced, and is empowered as the working fluid in a power generation plant.

Methods

The flow of thought for CSSU method begins with an integration of geological, geophysical, and geomechanic characterization for the creation of a static reservoir model. After creating a static reservoir model, a reservoir injection simulation model of CO_2 fluid is carried out into the reservoir with three models, namely compositional, compositional + geomechanics, and compositional + geomechanics + thermal. After the CO_2 reservoir injection simulation model, then an evaluation of the injection ability and CO_2 storage capacity is carried out. To prove the CSSU method, the CO_2 fluid will be produced as a working fluid and evaluated. Finally, the whole process of the CSSU method will be economically evaluated and optimized.

There are several important variables in the CSSU system, where one of them is a geomechanic variable that depends on pressure and temperature factors. The geomechanic variable will influence the nature of the CO_2 working fluid, reservoir zone factors, seal zones, and fractures which are the main factors in subsurface modeling. Thus, the appropriate reservoir geomechanic modeling approach will be useful to optimize the reservoir management process in a CSSU study. One of this

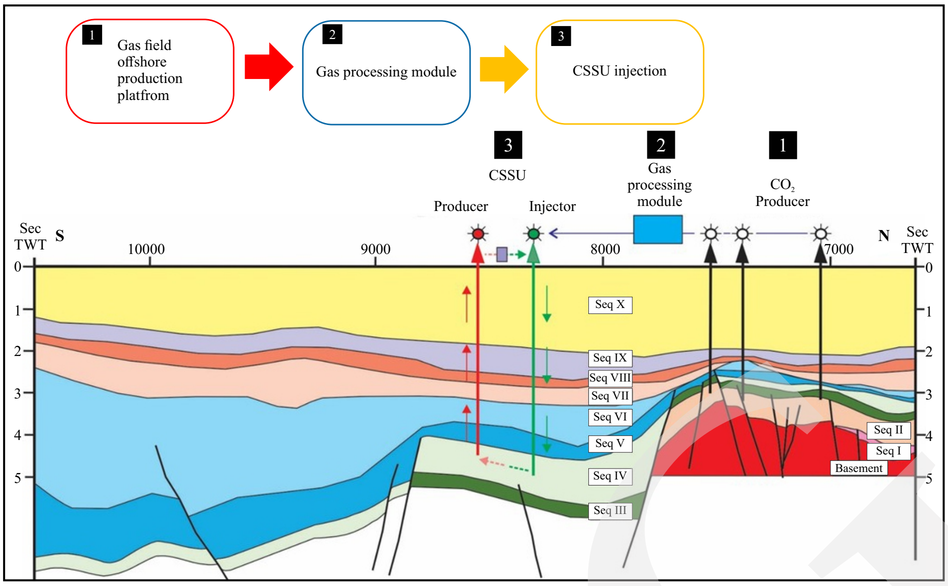


Figure 2. Systematic scheme of Carbon Sequestration Storage and Utilization (CSSU) study.

study purposes is to determine the relationship between geomechanic parameter and its impact into a techno-economic analysis of CSSU study

Reservoir Static Model and Storage Capacity

Stratigraphic Setting and Potential Capacity

The regional stratigraphy of East Natuna Basin is shown by Figure 3. The shale prone Muda Formation acts as the regional seal, while the reservoir can be found in the Upper Arang Formation or Sokang Sandstone Unit. Figure 4 shows the geological cross section of CCS-1 well, a wild cat exploration well with the total depth of 7,740 ft. (2,359 m), where the target was a four-way-dipping anticline that was discovered through subsurface imaging using seismic data. The CCS-1 well is penetrated the Muda Formation and the Upper Arang Formation.

Based on the petrophysical studies at CCS-1 well, there are several zones identified as poten-

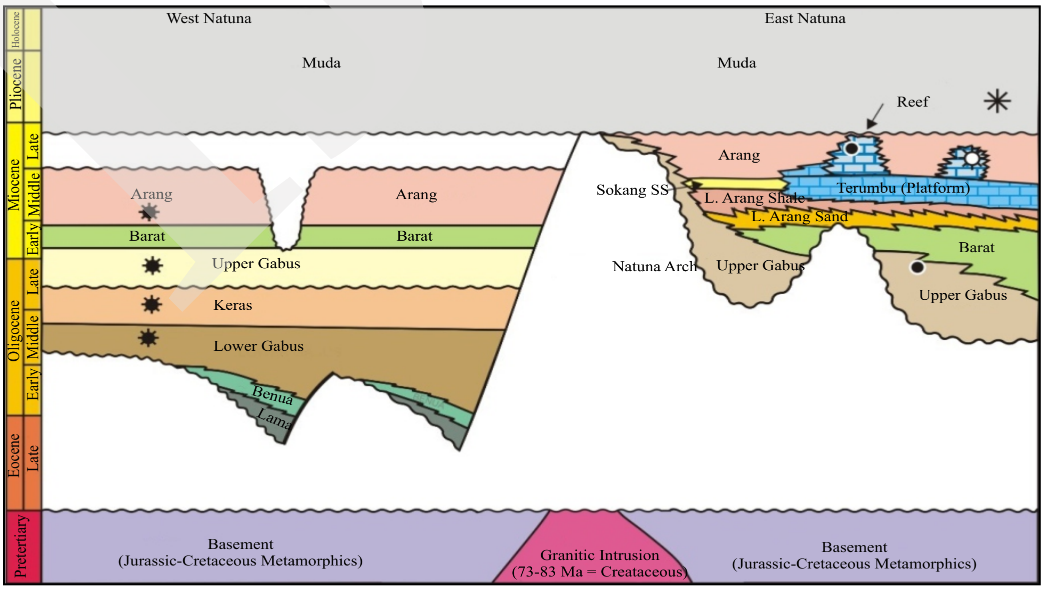


Figure 3. Regional stratigraphy of East Natuna Basin (Darman, 2017).

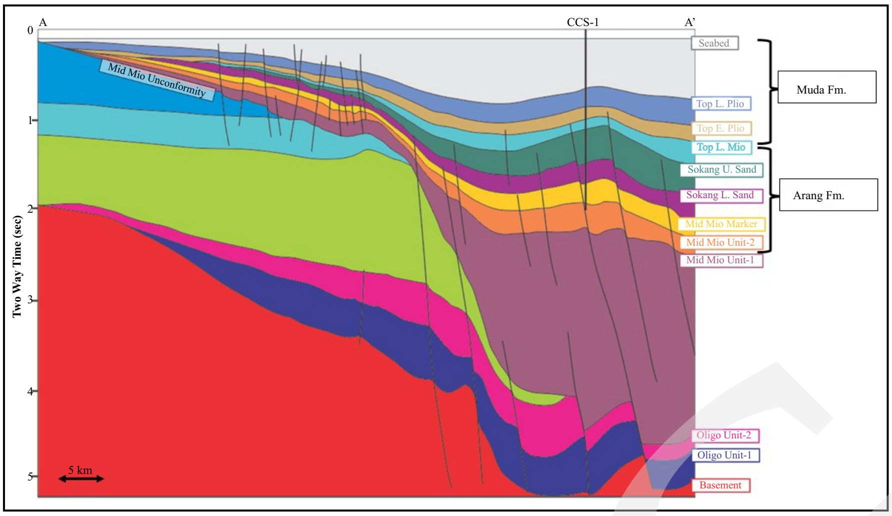


Figure 4. Cross section of the CCS-1 well and its target structure (redrawn from Raharja *et al.*, 2013; Cherdasa *et al.*, 2018).

tial reservoir intermittent between the depth of 6,200 to 7,700 ft. The most potential reservoir is determined to be called CSSU-2, and that is located between 6,816-6,831 ft. The sandstone is also overlain by 15.17 ft. thick shale that would act as its primary seal. The petrophysical property summary for CSSU-2 zone of both the reservoir storage and seal is shown in Figure 5 and summarized in Table 1.

The result of the subsurface mapping in Figure 6 shows the depth structure map of the CSSU-2 top which the mapping product of available seismic datasets in the studied area. From the depth structure map, the injection point of CCS-1 well located at 6,850 ft. depth has an average pressure of 3,543 psi and a temperature of 335°F. While the top of the anticline is located at the depth of ±6,000 ft. having the average pressure of 2,647 psi and the temperature of 300°F (Cherdasa, 2018).

Table 1. Petrophysical Properties Summary of CSSU-2 Storage and Seal Properties at CCS-1 Well

CSSU	Reservoir	Seal
Lithology	Sandstone	Shale
Depth (ft)	6,831-6863	6816-6831
Thickness (ft)	32	15
VClay	0.261	0.606
PHIE	0.188	0.088
PHIT	0.199	0.112
SW	0.83	0.93
Pressure (psi)	3,543	3,365
Temperature (°F)	335	335

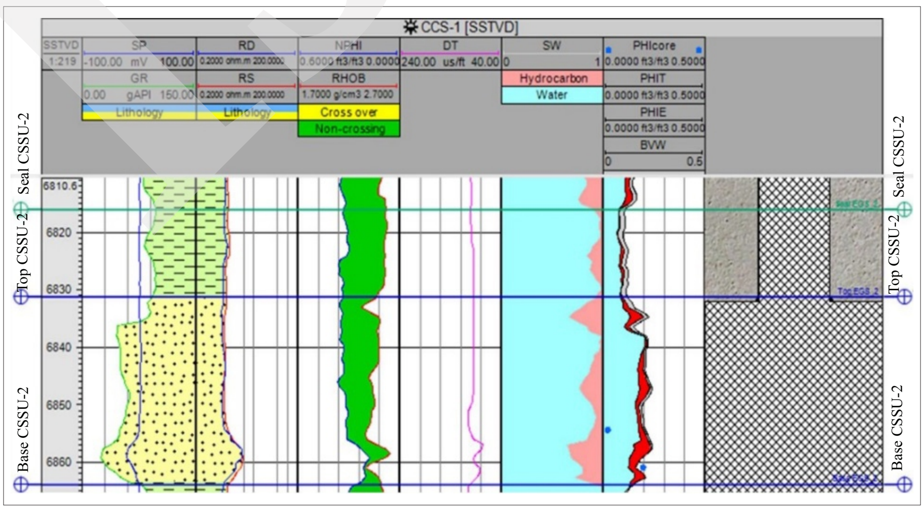


Figure 5. Proposed CSSU reservoir zone and seal section (modified from Cherdasa *et al.*, 2018).

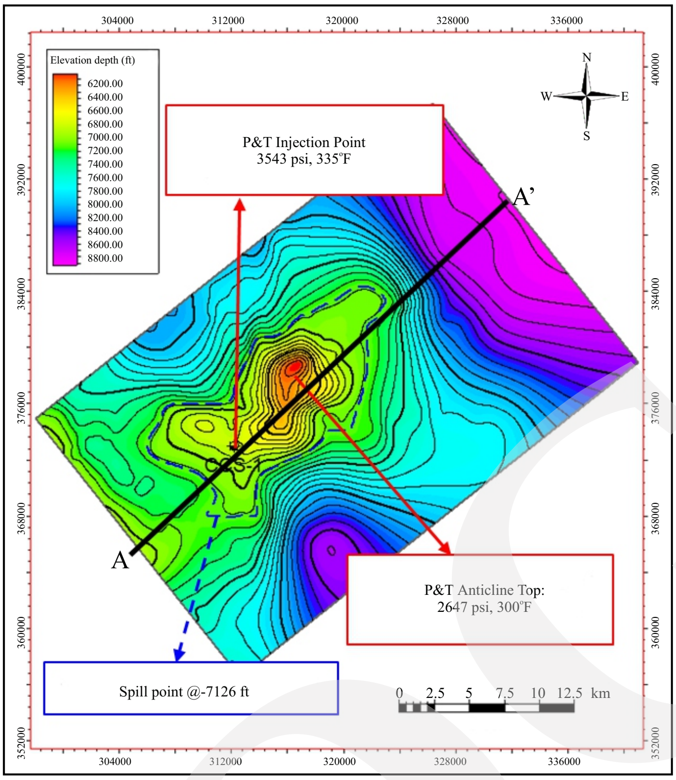


Figure 6. Top CSSU-2 Depth Structure map (Cherdasa *et al*., 2018).

The results of 1D geomechanical analysis in the studied area are obtained from the analyses of several existing wells as shown in Figure 7. The stress gradient equation is then obtained: Vertical Stress (Sv): 0.94 psi/ft., Maximum Horizontal Stress (SH Max): 0.54 psi/ft., Minimum Horizontal Stress (Sh min): 0.46 psi/ft., and Pore Pressure (PP): 0.43 psi/ft. From the gradient results, the study gets Sv> SH Max> Sh min. Referring to Anderson Theory (Zobach, 2007), the researched area is in a normal regime condition. This is supported by the geological structure of a normal fault.

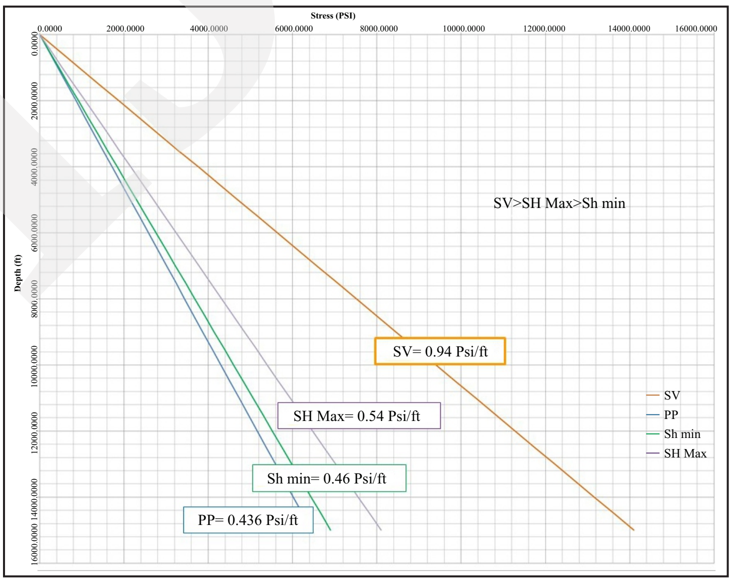


Figure 7. 1D Geomechanic analysis in the researched area.

The calculation results of the strength analysis for the seal rock and reservoir storage are shown in Table 2 and 3. With the sealing zone at a depth of 6,014 ft. MD, a thickness of 190 ft., and a gradient gas of 0.102 psi/ft., the seal zone can hold a gas column of up to 1,769 ft. high in the case of 100 % gas as shown in Table 2. As for the case of 80 % gas and 20 % water, the insulating zone can hold a gas column of 1,415 ft. in height. Table 3 shows the reservoir zone with a depth of 6,831 ft. MD, a thickness of 33 ft., and the maximum gas column within the reservoir zone attains 566 ft. The analysis above demonstrates that the seal rock has enough strength capacity to hold the reservoir storage until it is filled with 100 % gas.

The static reservoir modeling is created to calculate the CO_2 storage capacity in the reservoir using the volumetric method. The reservoir target for static model is CSSU-2 zone, and the process is started by pillar gridding as the model foundation based on the depth structure map for seal and storage zone. Following pillar gridding process, the lithological facies modeling is built by using seismic attribute data as soft data to control the facies distribution. The result of facies model will become the soft-data basis of Petrophysical Model (Porosity and Vclay). The Net to Gross (NTG) Model is made by applying the petrophysical cut-off, while the Permeability Model is made by using the Rock-Type Clustering method as the distribution basis (Figure 8).

The results of static modeling are shown in Figure 9, while Figure 9a displays a distribution of lithology for sealing zones dominated by clay rocks with an average thickness of 15.17 ft., and storage zones dominated by sandstone with the average thickness of 32.67 ft. Figure 9b exhibits the porosity distribution results where the average porosity value in the cap rock zone is 0.09 and in the storage zone is 0.20. Figure 9c shows the results of Net to Gross modeling where the cap rock zone is 0 and the storage zone is 1, whilst Figure 9d shows the results of water saturation (S_w) modeling where the average value of S_w in the cap rock zone is equal to S_w = 0.92, and the average value of S_w in the storage zone is 0.83.

The storage capacity of the CSSU method is calculated with the volumetric method. The volume of the storage structure area is calculated using a structure map of the top and bottom depth of the storage zone. Afterward, the contingent amount of the storage capacity is calculated by multiplying the total area volume with the value obtained from the evaluation formation analysis. The gas reservoir zone and shale rock layer zone located above the target zone are used as the refer-

Table 2. Seal Strength Capacity Calculation at CCS-1 Well

GEOMECHANIC Parameter		SEAL Strength Analysis			GAS CASE	HC Column (ft)
PP (psi/ft.)	0.4300	Top (ftss)	6014		100%	1769
Sh Min (psi/ft.)	0.4600	Isopach (ft.)	190		80%	1415
SH Max (psi/ft.)	0.5400	Bottom Structure	6204		60%	1061
SV (psi/ft.)	0.9400	Sh min (psi)	2826.58	2915.88	40%	708
Gas Gradient (psi/ft.)	0.1020	PP Water (psi)	2646.16	2729.76	20%	354
OIL Gradient (psi/ft.)	0.3690		180.42	186.12	0%	0
		SH Max (psi)	3127.28	3226.08		

Table 3. Reservoir Strength Calculation at CCS-1 Well

GEOMECHANIC Parameter		RESERVOIR Strength Analysis			Gas trend from SH_Min	PSI	Depth (ft)	Gas Column (ft.)	Gas Column (m)
PP (psi/ft.)	0.4300	Top (ftss)	6831			3142	6831		
Sh Min (psi/ft.)	0.4600	Isopach (ft.)	33			3200	7397	566	173
SH Max (psi/ft.)	0.5400	Bottom Structure	6864						
SV (psi/ft.)	0.9400	Sh min (psi)	3210.57	3226.08					
Gas Gradient (psi/ft.)	0.1020	PP Water (psi)	3005.64	3020.16					
OIL Gradient (psi/ft.)	0.3690		204.93	205.92					
		SH Max (psi)	3552.12	3569.28					

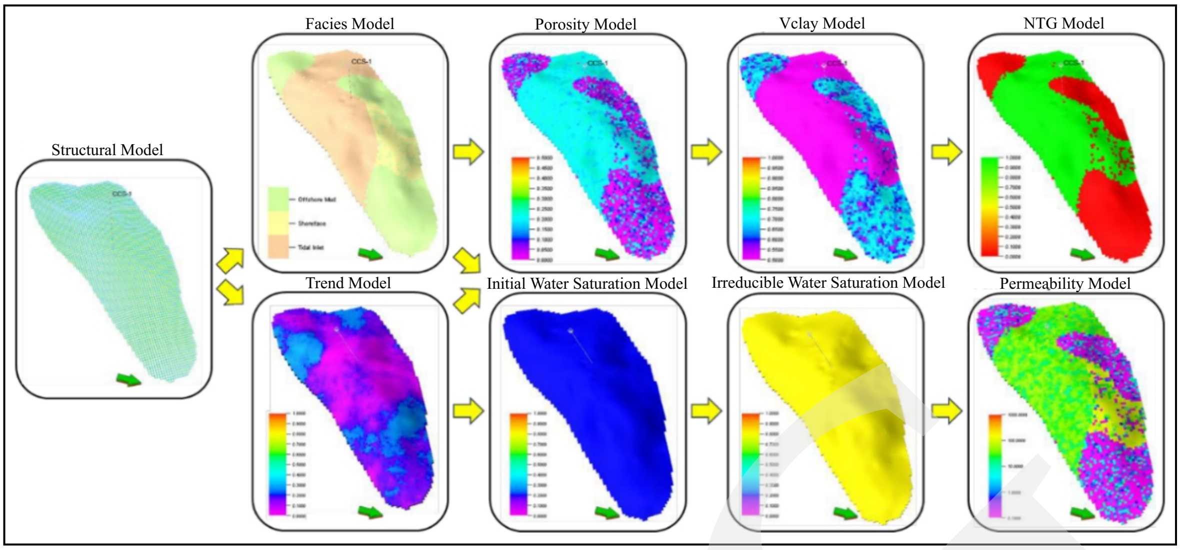


Figure 8. Static Reservoir Model workflow in the studied area.

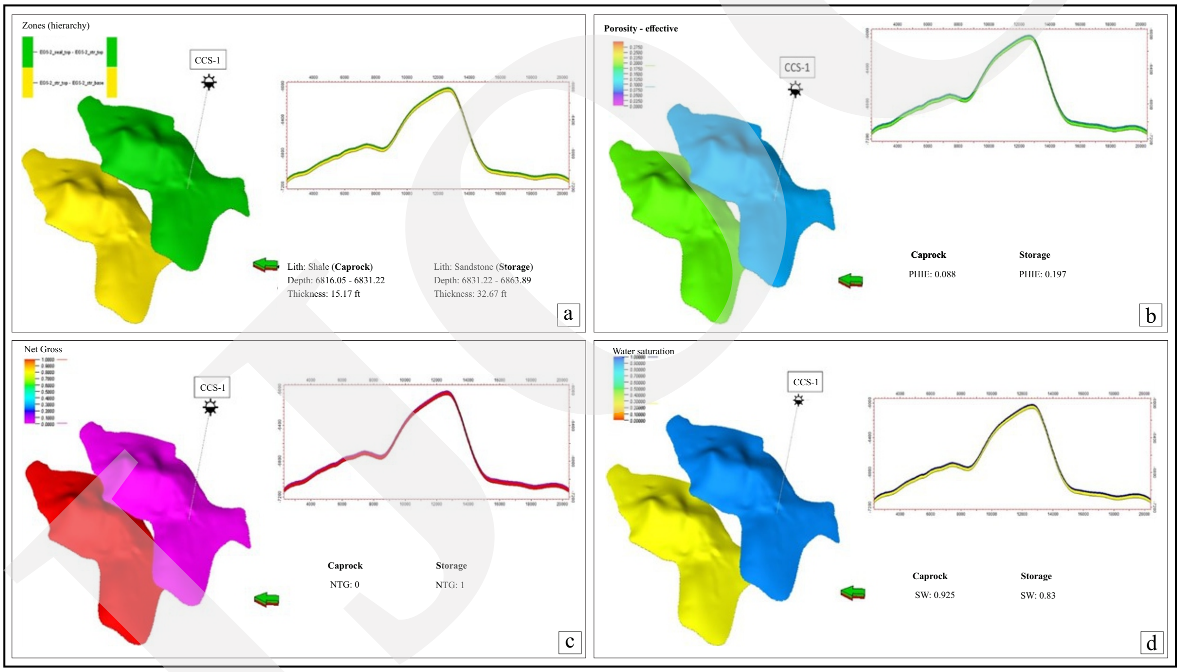


Figure 9. Reservoir Static Modeling results of the studied area where (a) Results of lithology modeling, (b) Results of porosity modeling, (c) Results of Net To Gross modeling, and (d) Results of water saturation modeling (S_w).

ence for calculating the storage zone. The lowest water saturation value of the gas reservoir zone is assumed to be the maximum gas capacity that can be injected into the storage zone. The shale rock property above the gas reservoir is also considered adequate as the cap rock, because it can hold the gas reservoir below it with CO_2 levels up to 87 %.

Based on the depth structure map of CSSU-2 zone (Figure 7), the spill point in the CSSU-2 zone structure is at a depth of 7,126 ft., and the injection zone of the CCS-1 well is at a depth of ± 6,825 ft. At a depth of 6,825 ft. where the magnitude of pressure is 3,543 psi and the temperature is 335 °F (see Table 1), the characterization of the existing gas fluid for the formation volume factor (Bg) and gas density (ρg) values is 0.005 cf/scf of 0.393 gr/cc.

The parameters used for calculating CO_2 storage capacity are shown in Table 4 and the

Table 4. Input Parameter for Storage Capacity Volumetric Calculation of CSSU-2 Zone

Parameter	Value	Description
Net to Gross	1	
Porosity	0.188	Average Effective Porosity Value
Water Saturation	0.830	S_w
Formation Volume Factor (cf/scf)	0.005	Bg @3543 psi
Gas Density (g/cc)	0.393	Gas density @ 3543 psi and 335 °F
	0.00189	Gas density @ 14.67 psi and 60 °F (STP)

storage capacity volumetric calculation result of the CSSU-2 interval zone is presented in Table 5 which is 1,467.78 Bscf or 78.89 MMTon.

Formation and Well Injectivity Analysis

After calculating the amount of CO_2 storage capacity in the CSSU-2 zone at a depth of 6,813 - 6,831 ft. in the CCS-1 well of 1,485.47 Bscf or 79.84 MMTons of CO_2 gas, the next step is analyzing the injection rate for CO_2 fluid to subsurface. This requires a number of controls such as flow rate and pressure in the injection well. The targeted CO_2 fluid object is a super critical CO_2 fluid which needs a specific pressure and temperature limits in order to keep the CO_2 fluid stays in the super critical phase. Figure 10a shows a diagram of a CCS-1 well with a CSSU-2 target zone.

Table 5. Volumetric Estimation Result of CSSU-2 Storage Capacity

Volumetric Results	Value
Bulk Volume (BCF)	44.21
Pore Volume (BCF)	8.31
CO_2 *Volume* (BCF)	6.98
Storage Capacity (BSCF)	1,467.78
Storage Capacity (MMTon)	78.89

The magnitude of the pressure limit on the wellhead must be greater than the CO_2 pressure at the super critical point which is above 73.82 bar or 1071 psi, and greater than the minimum pressure that can cause the CO_2 fluid flow into the formation. The temperature at the wellhead and the bottom hole should be greater than the CO_2 temperature under super critical phase conditions which is above 31 ° C or 87.98 ° F. Based on these limits, the pressure and temperature conditions at the wellhead are set to be at least 1,100 psi and 90 ° F. Figure 10b presents a diagram of the CO_2 phase where the wellhead condition is in the direction of the reservoir condition (pressure= 3,543 psi and temperature of 350 ° F).

Nodal analysis is carried out to see the wellhead pressure and the amount of CO_2 fluid under

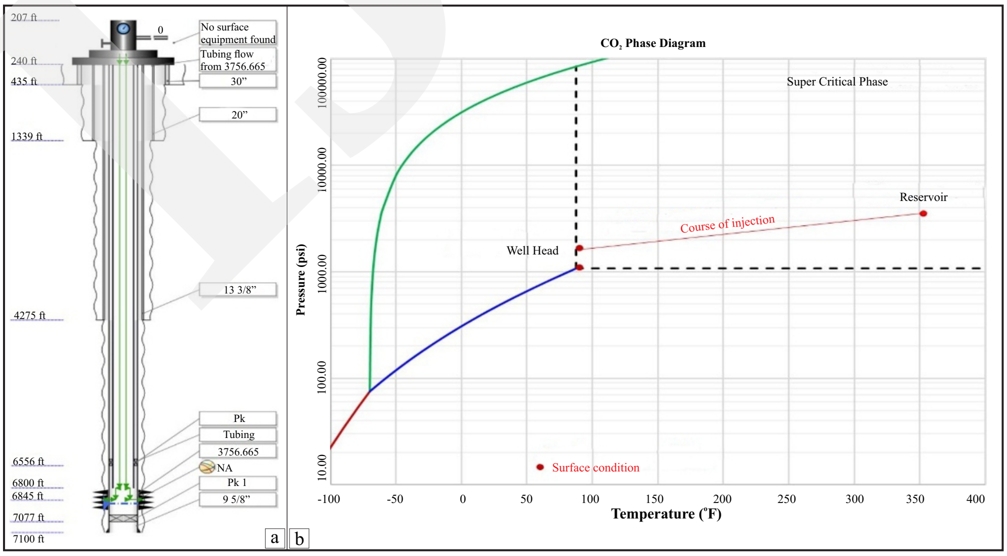


Figure 10. Operational and conditional limitation of CO_2 fluid injection into the reservoir where (a) The CCS-1 well schematic diagram with CSSU-2 zone in it, (b) CO_2 phase diagram and the injection fluid condition from the well head into the reservoir.

super critical phase conditions that can be injected into the CSSU-2 zone. Figure 11 represents the relationship between the pressure at the wellhead, the magnitude of the existing flow rate, and the amount of pressure at the bottom of the well. Figure 11a shows that at 1,100 psi wellhead pressure there was no injection flow obtained at all. The new flow occurs when the wellhead pressure is 1,650 psi and produces a flow of 16.7 MMscfD with a bottom hole pressure of 3,733 psi (Figure 11b). Figure 11c exhibits that in a wellhead pressure condition of 2,000 psi, an injection flow of 60.1 MMscfD was obtained, and a bottom well pressure of 4,268 psi was reached. Figure 11d illustrates that the wellhead pressure of 3,000 psi is obtained with the injection flow of 142 MMscfD and the bottom well pressure of 5,337 psi.

The amount of CO_2 fluid daily injection calculation depends on the overall storage capacity. For this study, a time period of fifty years is used. Therefore, the amount of storage capacity can be divided equally with the length of operation time. For the storage capacity of 1.47 TSCF, it can be filled with a daily injection capacity of 80 MMscfD for fifty years.

When the CSSU-2 reservoir is injected with a super critical CO_2 fluid, the reservoir pressure will increase. Figure 12 shows the nodal analysis with the reservoir pressure ranges from 3,500 - 7,000 psi, variations in wellhead pressure of 1,650 - 4,500 psi and the amount of vertical pressure (Sv) or overburden of 6,500 psi as the pressure limitation under subsurface conditions. For wellhead pressure of 1,650 psi, the injection of fluid into the reservoir can only occur in the condition of reservoir pressure of 3,500 psi (Figure 12a). For wellhead pressure of 2,650 psi the injection of fluid into the reservoir can only occur at a condition of reservoir pressure of up to 4,500 psi (Figure 12b). Whereas the 3,750 psi wellhead pressure for the injection of fluid into the reservoir can only occur at conditions of reservoir pressure of up to 6,000 psi, although it is still below the vertical pressure (Sv) of 6,500 psi, and already within the maximum threshold (Figure 12c). At 4,500 psi pressure, the process of fluid injection

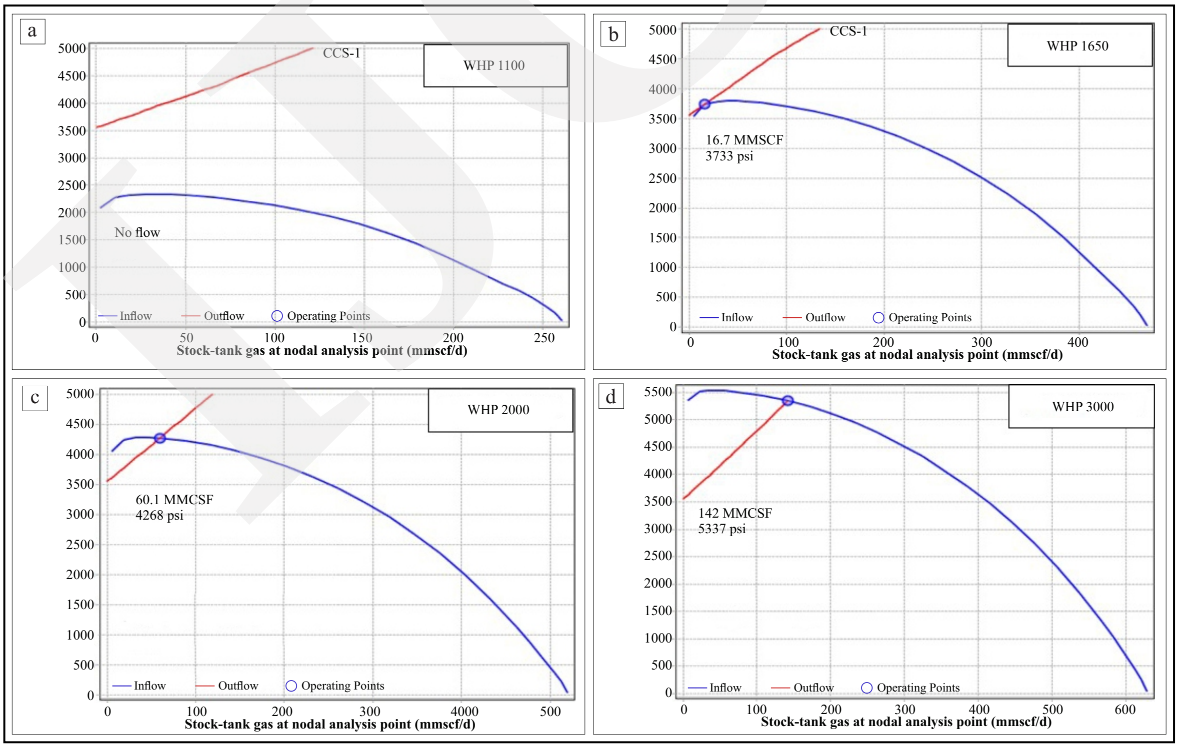


Figure 11. Nodal analysis with some variations in wellhead pressure which causes variations in operational conditions in the CSSU-2 reservoir zone. (a) Condition at wellhead pressure of 1,100 psi, (b) Condition at wellhead pressure of 1,650 psi, (c) Condition at well head pressure of 2,000 psi, and (d) Condition at well- head pressure of 3,000 psi.

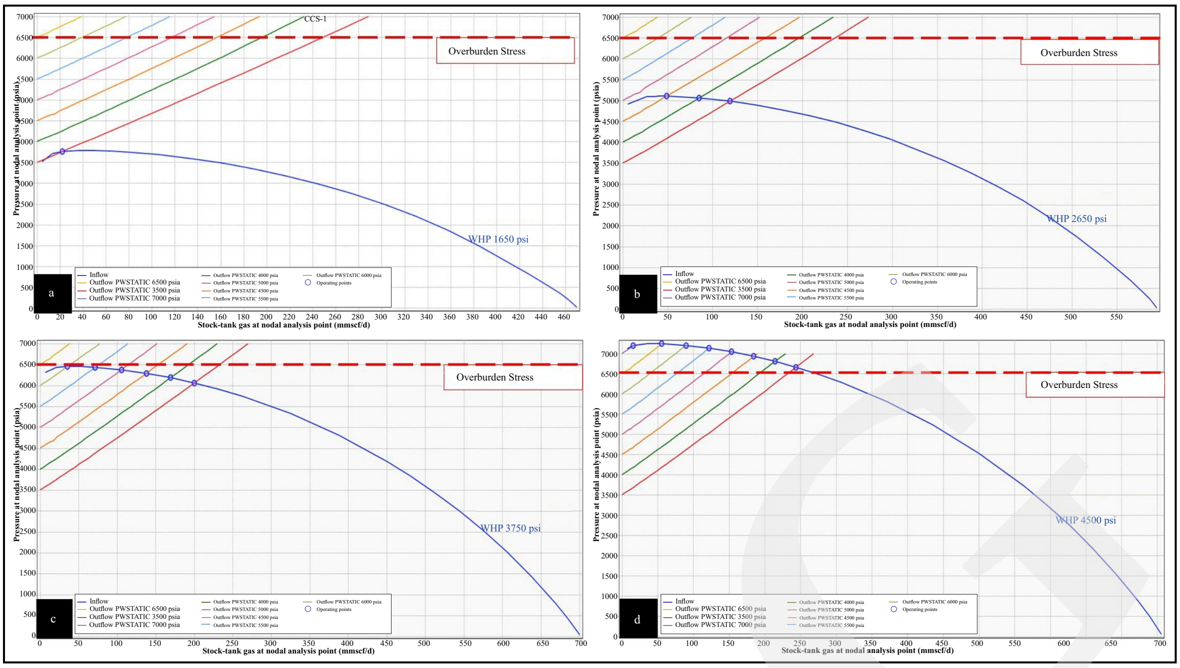


Figure 12. Nodal analysis with some variations in wellhead pressure which causes variations in reservoir pressure conditions in the CSSU-2 reservoir zone. (a) Condition at wellhead pressure of 1,650 psi, (b) Condition at wellhead pressure of 2,650 psi, (c) Condition at wellhead pressure of 3,750 psi, and (d) Condition at wellhead pressure of 4,500 psi.

into the reservoir will occur at reservoir pressure conditions of up to 7,000 psi. However, even at the lowest reservoir pressure condition of 3,500 psi, there is a pressure magnitude in the exceeding amount of vertical pressure (Sv) of 6,500 psi in the reservoir. This condition may indicate the flow of supercritical CO_2 fluid from the reservoir into the upper zone due to the seal above CSSU-2 reservoir zone broke or cracked. (Figure 12d).

Dynamic Reservoir Modeling

The specification of the reservoir simulation model built in this study is as follows: the size of each cell is 200 m x 200 m with a thickness of 1.65 m, and the total number of 3D cells is 207,350. As a comparison, the geological static models have a size of each cell of 200 m x 200 m and a thickness of 0.48 m, so that the total number of 3D cells is 715,000. While the lateral size is not changing, but the vertical size is. However, it is crucial to have a good upscaling in order to preserve the reservoir properties defined in the static model.

The dynamic reservoir modeling is conducted by employing several methods and case studies as set out in Figure 13. The first simulation method is carried out with a compositional simulation method. This compositional simulation method is done to understand what happens in the reservoir during the CO_2 injection process. The final goal of this compositional simulation is to find out how much CO_2 can be injected, and how much CO_2 is trapped in the subsurface. The main data in this compositional simulation are the reservoir porosity and permeability data obtained from the static modeling. The fluid data in the reservoir are gas (CO_2 and CH_4) and water (H_20) obtained from CCS-1 well data. For the simulation purpose, a 100 % CO_2 injection fluid is injected within the operational limitation. The first limit is the maximum bottom hole pressure of 5,500 psi assuming the vertical stress limit (S_v) in the reservoir zone is equal to 6,500 psi. This limit is used to accommodate the resistance of sealing rocks (seals), so that no CO_2 leakage occurs to the surface or to the upper zone. The second limit is the maximum CO_2 injection flow through the wellhead which is 90 BscfD. This is made to be able to meet the initial target of CO_2 injection in the pilot area of 80 BscfD.

Methods	Cases (Sw)	Cases (Injection Wells)	Cases (Injection + Production Wells)
Compositional	Sw = 1 Sw = 0.83	2, 3, 5 Inj. Wells	N.A.
Compositional Geomechanics	Sw = 0.83	2, 3, 5 Inj. Wells	20 yrs = 3 Inj. Wells 5 yrs = 2 Inj Wells + 1 well Shut-in 25 Yrs = 2 Inj Wells + 1 well Production
Compositional Geomechanics Thermal	Sw = 0.83	2, 3, 5 Inj. Wells	20 yrs = 3 Inj. Wells 5 yrs = 2 Inj Wells + 1 well Shut-in 25 Yrs = 2 Inj Wells + 1 well Production

Cases (Field Sw)	
Sw = 1	All Reservoir is purely 100% Saline Brine
Sw = 0.83	Based on CCS-1 Petrophysics results

Cases (Wells)	
2 Inj. Well	CCS-1, Well-2
3 Inj. Well	CCS-1, Well-2 , Well-3
5 Inj. Well	CCS-1, Well-2 , Well-3, Well-5, Well-6

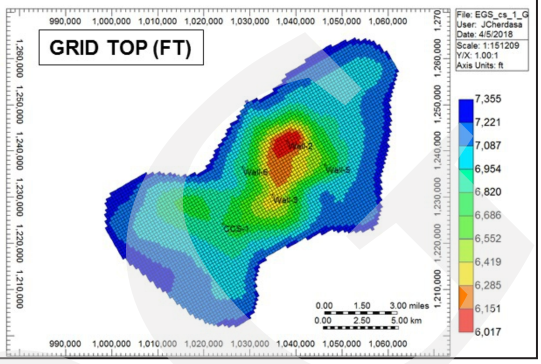


Figure 13. Methods and case studies to be carried out on dynamic modeling of CSSU-2 reservoir and injection well plots in the pilot area.

The compositional simulation method is carried out using two cases of water saturation. The first case is the water saturation value equal to 1 (S_w= 1) considering that the CSSU-1 reservoir zone is brine. The second case has a water saturation value of 0.83 (S_w= 0.83) based on petrophysical results of the CCS-1 well in the CSSU-2 zone. From the two S_w cases, several development cases were carried out based on the number of injection wells with the total of three cases using two, three, and five injection wells. Case 2 injection wells using wells CCS-1 and Well-2, case 3 injection wells using wells CCS-1, Well-2 and Well-3, and case 5 injection wells using wells CCS-1, Well-2, Well-3, Well-5, and Well-6. The choice of well position is based on the geometry of the depth structure and the average value of the existing permeability. The CCS-1 well is the existing reference well, Well-2 is at the top of the structure, Well-3 is in the middle of the height amongst CCS-1 and Well-2, Wells 5 and 6, well selected as peripheral wells with the relative height is the same as the CCS-1 well.

The second method is a compositional simulation method that uses geomechanic modeling parameters as the simulation input. The same with the previous explained method, the final goal of this method is to predict how much CO_2 can be injected, and how much CO_2 is trapped in the subsurface. However, one of the fundamental differences between the compositional methods and the compositional methods with geomechanic coupling is the calculation changes in the pressure and temperature within the formation due to changes in pressure and temperature by changing with in the fluid flow in the reservoir whether it is due to injection or production from a well. The end result of this geomechanic-coupled-method is supposed to be able to better represent the conditions in the subsurface.

The geomechanic parameters used in the geomechanic coupling method comprise the rock compressibility, Young's Modulus, Poisson's Ratio, Angle of Internal Friction, and Biot's Coefficient. The mathematical model used in this geomechanic coupling is The Mohr-Coulomb Model. It is a model commonly used in determining the limits on the strength of an object, especially rocks. In the Mohr-Coulomb Method the basic data by assumption of a material or existing rock formation is cohesion, having an angle of Internal Friction of 30° and the Biot's Coefficient number is one. Hence, the rocks in the existing formation will experience interaction with full of pore pressure and external pressure. The injection fluid parameter is 100 % CO_2 where the simulation of CO_2 injection into the reservoir made operational limits. The first limit is the maximum bottom hole pressure of 5,500 psi and the maximum CO_2 injection flow through the well head of 90 BscfD.

For compositional simulation with geomechanic coupling, the water saturation case is 0.83 (S_w= 0.83), and the injection wells are two, three, and five wells. In addition to this simulation, one case was added where there was a production of super critical CO_2 fluid that would later be the differentiator and the core of the CO_2 critical superfluity utilization scheme in the CSSU process. This additional case uses three wells, namely CCS-1, Well-2, and Well-3, where in the layout time during the first twenty years Well-3 became the injection well. Then, in the next five years Well-3 was closed (shut- in), and CCS-1 and Well-2 are still using CO_2 injection. This is based on the preparation for the phase of CO_2 fluid production in Well-3. In the next twenty-five years, the CCS-1 and Well-2 wells continue to inject CO_2, while Well-3 begins to produce CO_2 as part of the CO_2 worker fluid utilization process (Figure 13). The process of producing CO_2 fluid is only carried out in the twenty-five year, because it takes time for the CO_2 fluid that has been injected to absorb and to store heat from the reservoir. As time goes by, the production will increase the period of a field. Obviously the flow rate will decrease, and the field operation cost will increase further. Thus, the CSSU method is expected to produce more positive economic impacts for further field development.

The third method is a more advanced compositional simulation using geomechanic modeling parameters, and in addition the thermal modeling parameters. The thermal modeling takes into account factors such as heat capacity of existing reservoir rocks, value of thermal conductivity in the reservoir zone, and existing fluids. The final goal of compositional simulations coupled with geomechanic and thermal coupling is to know the quantity of CO_2 that can be injected, and the amount of CO_2 trapped beneath the surface. At the time the CO_2 worker fluid is produced, this shows how hot is the CO_2 fluid produced after being injected and stored, so that the heat from CO_2 fluid can be used and converted into electrical energy.

Compositional simulations with geomechanic and thermal coupling are conducted with a case of water saturation of 0.83 (S_w= 0.83) and injection well cases of two, three, and five wells . In addition to this simulation case, a super critical CO_2 production fluid is also conducted. This additional case uses three wells, namely CCS-1, Well-2, and Well-3, where in the first twenty years Well-3 became the injection well and then in the next five years Well-3 were closed (shut- in), while CCS-1 and Well-2 wells continue to inject CO_2. This is based on the preparation for the phase of the production of CO_2 fluid in Well-3. The next twenty-five years is where the CCS-1 and Well-2 wells continue to inject CO_2, and Well-3 begins to produce CO_2 fluid as part of the CO_2 working fluid utilization process (Figure 13).

The results of the dynamic modeling is shown in Figure 14. While Figures 15 and 16 show the modeling results of reservoir properties such as water saturation (S_w) and reservoir pressure through time from 2020 - 2070 with the compositional and geomechanic coupling, water saturation (S_w) value which is 0.83, and three injector wells case for the example.

The results of compositional simulations with cases of water saturation of 1 and 0.83 (S_w= 1 and S_w = 0.83) using two, three, and five super critical CO_2 fluid injection wells are:

First, under conditions with water saturation of 1, then after ten good injection years with two, three, and five injection wells. The total cumulative CO_2 injected is ± 90 Bcf, and after ten years which is in 2030 onwards there will be no additional CO_2 injection into the reservoir anymore due to the reservoir pressure is equal to wellbore injection pressure.

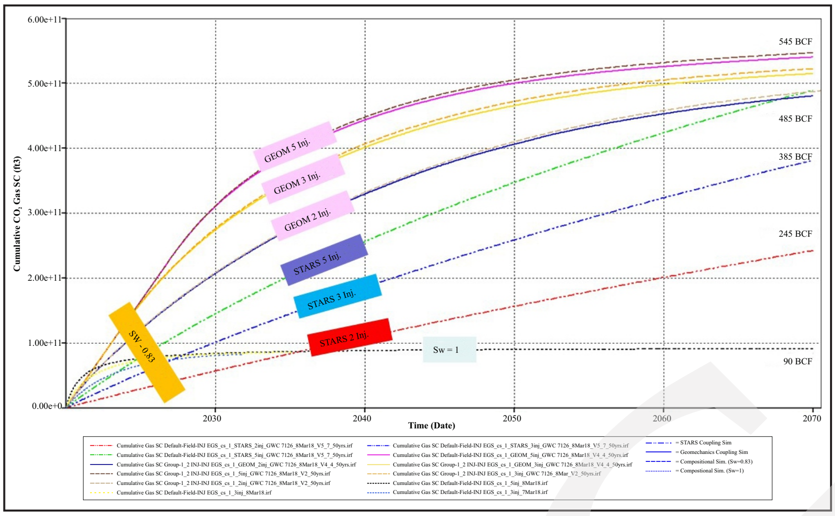


Figure 14. Cumulative total of super critical CO_2 fluid that was injected from 2020 to 2070 using a compositional, geomechanic and thermal coupling methods for dynamic reservoir simulation with initial water saturation conditions of 0.83 ($S_w = 0.83$) and $S_w = 1$ through two, three, and five injection wells.

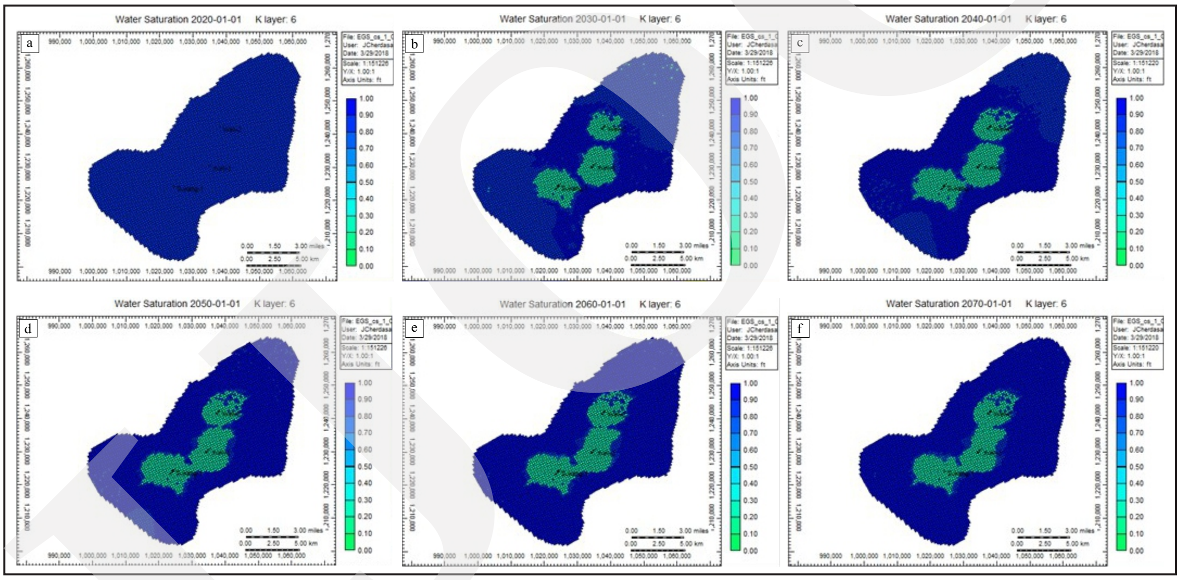


Figure 15. Compositional plus geomechanic coupling method reservoir simulation result under initial water saturation conditions of 0.83 ($S_w = 0.83$) and three injection wells; changes in water saturation property through time from (a) 2020, (b) 2030, (c) 2040, (d) 2050, (e) 2060, and (f) 2070.

Second, at water saturation condition is 0.83 with two injection wells. The total cumulative CO_2 injected is ± 485 Bcf, S_3 injection wells are ± 520 Bcf, and five injection wells are ± 545 Bcf (Figure 14).

For the compositional plus geomechanic coupling simulation with a case of water saturation of 0.83 ($S_w = 0.83$) using two, three, and five super critical CO_2 fluid injection wells, the following results are obtained:

Under water saturation of 0.83 with two injection wells, the total cumulative CO_2 injected is ± 480 Bcf, three injection wells are ± 515 Bcf, and five injection wells are ± 540 Bcf. For the compositional plus geomechanic and thermal coupling simulations with a case of water saturation of 0.83 ($S_w = 0.83$) using two, three, and five super critical CO_2 fluid injection wells, the following results are obtained:

Under water saturation conditions of 0.83 with two injection wells, the total cumulative CO_2

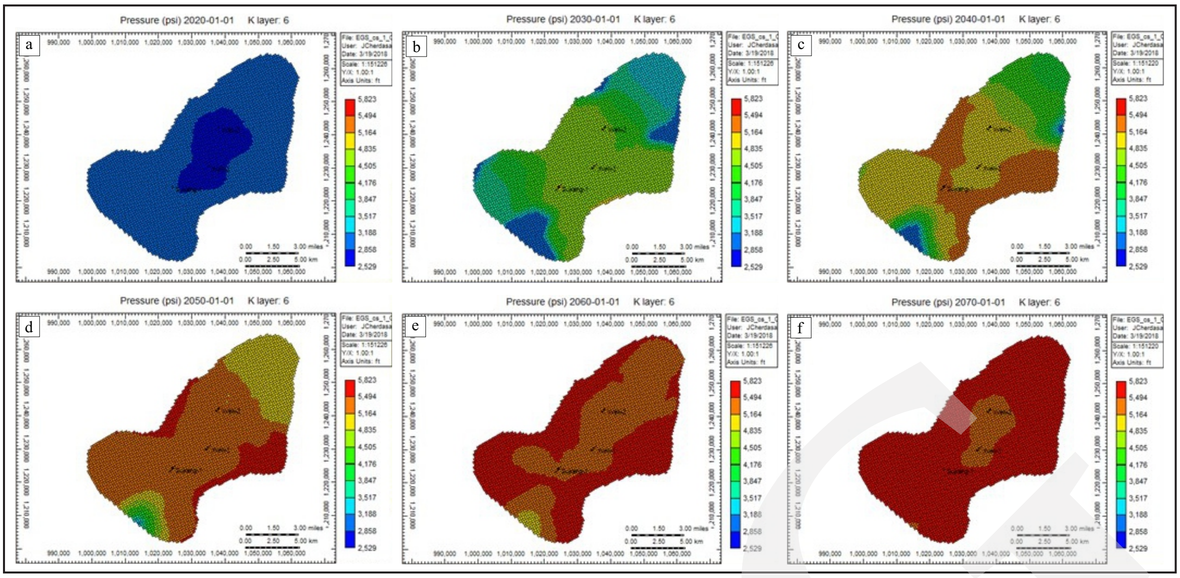


Figure 16. Compositional plus geomechanic coupling method reservoir simulation result under initial water saturation conditions of 0.83 (S_w= 0.83) and three injection wells; changes in reservoir pressure properties through time from (a) 2020, (b) 2030, (c) 2040, (d) 2050, (e) 2060, and (f) 2070.

being injected is ± 245 Bcf, three injection wells are ± 385 Bcf, and five injection wells are ± 485 Bcf (Figure 14).

The change in water saturation property parameters over time is due to the process of super critical CO_2 fluid injection from three injection wells as shown in Figure 15 . The water saturation map scale from low to high is green for water saturation at 0 (S_w= 0) and blue for water saturation at 1 (S_w= 1). The initial condition of the CSSU-2 reservoir is in 2020 with a value of S_w= 0.83 (Figure 15a) , then along with the injection process in three wells.There is a change in saturation value, especially around the well being green, which indicates that the injection process can be seen in Figure 15b by showing a map of water saturation in 2030. Figure 15c shows the water saturation in 2040 that the radius of change in the value of water saturation is expanding more than that in 2030, almost 1.5 times wider. Whereas Figure 15d displays a map of water saturation in 2050. Figure 15e shows a map of water saturation in 2060, and Figure 15f illustrates a map of water saturation in 2070 where the changes in saturation values are not significant but greater than in 2020 to 2040. This is due to the effects of changes of pressure in reservoir due to the injection process that becomes smaller in 2050 to 2070 compared to 2020 to 2040. Starting from 2050 it can be seen that the saturation value of water amongst the three wells has begun to relate and increasingly influences. The change in time for the reservoir pressure property parameters is due to the injection process of the three wells (Figure 16). The scale of the reservoir pressure map from low to high is blue for pressures valued at 2,529 psi and red for reservoir pressures valued at 5,781 psi. The initial condition of the CSSU-2 reservoir in 2020 with an initial reservoir pressure of 2,500 - 3,000 psi is shown on the map with the majority in blue (Figure 16a). The reservoir pressure map in 2030 (Figure 16b) shows that as the injection process in both wells progresses, there will be a change in the amount of pressure in the reservoir, especially around the well to yellow or around 5,000 psi. In general, the reservoir pressure will increase to 4,000 psi or around 500-1,000 psi compared to the initial conditions. T his is indicated by the change in colour from blue to green which indicates the injection process is running.

The reservoir pressure in 2040 (Figure 16c) can increase where conditions around the well turn to dark yellow and orange or around 5,300 psi. In general, reservoir pressure increases up to 4800 psi or around 800 psi from year 2030 and 1,800 - 2,300 psi compared to initial conditions. This is indicated by the colour change from dominant green in 2030 to yellow and orange in 2040. Whereas Figure 16d shows a map of reservoir pressure in 2050 where conditions around the wells are 5,400 psi or orange in colour. Around the reservoir, in general reservoir pressure increases to 5,300 psi or around 500 psi from 2040 and 2,300-2,800 psi compared to the initial conditions. This is indicated by the changing in colour in the reservoir unit to become dominantly orange.

The reservoir pressure map is presented in Figure 16e, in 2060, where the conditions around the well are 5,500 psi or red, and around the reservoir in general reservoir pressure increases to 5,400 psi or around 100 psi from 2050 and 2,400-2,900 psi compared to initial conditions. This is indicated by the changing in colour in the reservoir unit to be dominant orange and red. Figure 16f shows a reservoir pressure map in 2070 where the conditions around the well are 5,500 psi or red, and around the reservoir in general reservoir pressure increases up to 5,500 psi or about 100 psi from 2060 and 2,500 - 3,000 psi compared to the initial conditions, indicated by the changing-in colour in the reservoir unit to be dominant red.

After the process of CO_2 injection into the subsurface through a wellbore, it is expected that the CO_2 fluid is in a super critical phase which has a greater density than the gas phase. Most of the CO_2 fluid being injected will be in the mobility phase, which is free to move laterally and vertically until it is blocked by the seal rock and trapped following the geometry of the subsurface structures. This trapping mechanism is called as structural and hydrodynamic trappings (Figures 17a and 17b). The process of capturing CO_2 as a residual gas occurs when the CO_2 trapped in the subsurface structures interacts with formation water. This process is known as a residual trapping (Figure 17c). As CO_2 moves to the main subsurface structure, one of the interactions from the CO_2 fluid is with the formation water, then the CO_2 will dissolve or be dissolved with the existing aqueous phase. This is known as solubility trapping (Figure 17d). In addition, the CO_2 fluid interaction will not only occur with the formation water, but also with the surrounding rocks.

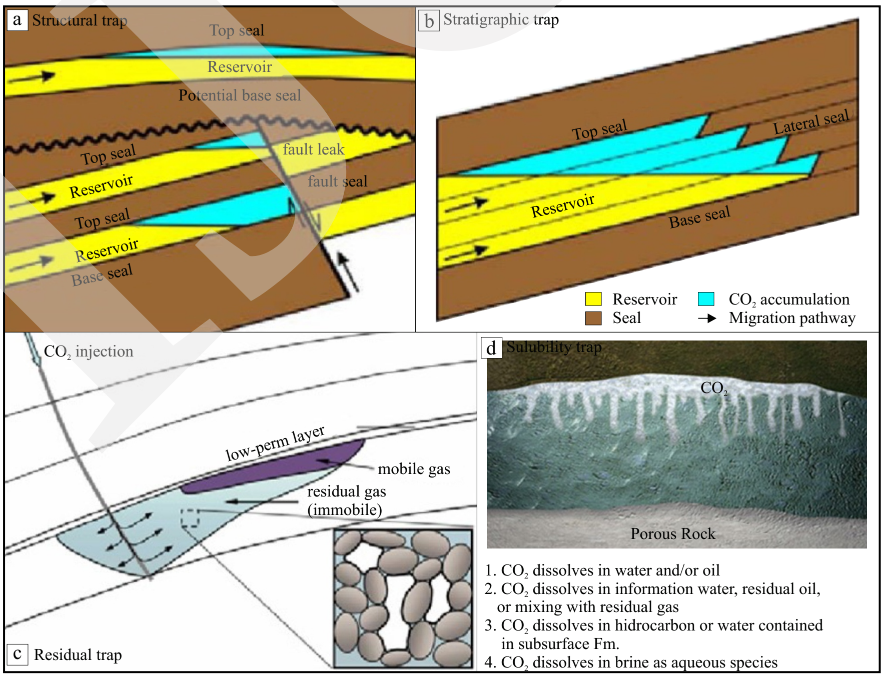


Figure 17. CO_2 trapping mechanism within subsurface conditions where (a) Structural trap, (b) Structural trap, (c) Residual trap mechanism due to the interaction of CO_2 with subsurface formation water, (d) Solubility trap where CO_2 interacts with fluids below the surface such as formation water, hydrocarbons (Oil and Gas), and residual hydrocarbon (Zhang and Song, 2013).

Subsiquently it will lead to the mineral trapping (Zhang and Song, 2013).

The amount of CO_2 trapped by solubility, structure, and residual in the case of initial water saturation is 0.83 with two, three, and five injection wells (Figure 18 and Table 6). It can be seen that the solubility trap is the most dominant one, equal to ± 100 MMTon of CO_2 or 77 % of the total CO_2 trap available. Structural trap is equal to ± 20 MMTon of CO_2 or 15 % of the total CO_2 trap, and the residual trap is ± 10 MMTon of CO_2 or 8 % of the total CO_2 traps.

After composional simulation plus geomechanic coupling with cases of two, three, and five injection wells, the simulations are performed with the same method for the case of three wells (CCS-1, Well-2, and Well-3) with two injection wells and one production well with the detailed timeframe as follows:

- 2020 - 2040 : three injection wells (CCS-1, Well-2, and Well-3)
- 2040 - 2045 : two injection wells (CCS-1 and Well-2)
- one shut-in well (Well-3)
- * 2045 - 2070 : two injection wells (CCS-1 and Well-2)
- one CO_2 production well (Well-3)

This simulation is conducted within the operational limits of the existing production wells, along with the surface facility limits at the time of injection and the minimum bottom hole which is 150 psi, assuming this production well uses a pump to assist the production.

The two injection wells and one production well case is run in order to prove the CSSU method for the utilization side in terms of using the CO_2 supercritical fluid as the working fluid in an electricity generation system.

The reservoir simulation results are explained sequentially in Figures 19-22. The result of two injection wells and one production well with water saturation (S_w), reservoir pressure, and gas mass density parameter from year 2020 at the initial condition, year 2040 at the end of three injection wells, year 2045 at the end of

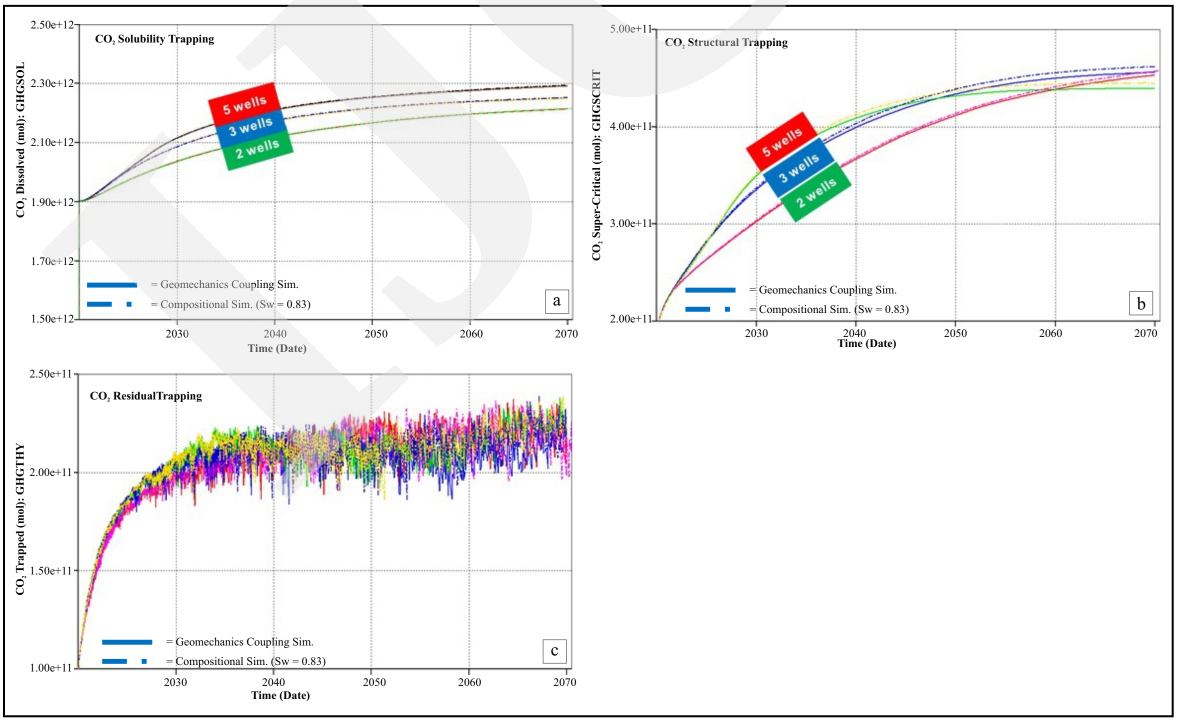
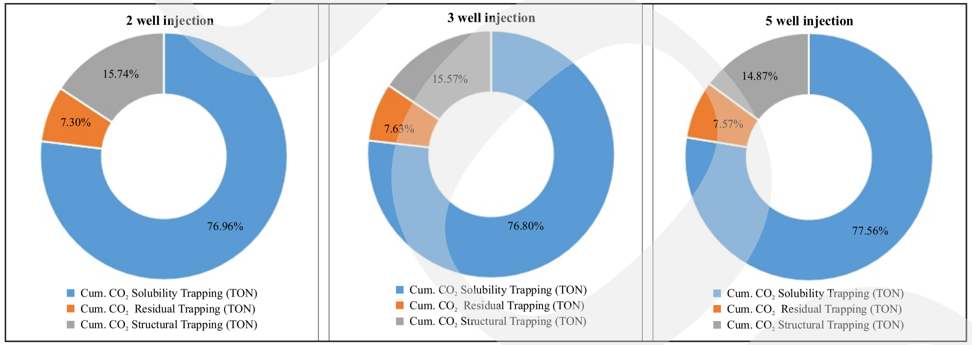


Figure 18. The amount of CO_2 fluid trapped through the (a) solubility, (b) structural, and (c) residual mechanism due to the injection process from 2020 to 2070 using a dynamic reservoir simulation compositional plus geomechanic coupling method with initial water saturation conditions of 0.83 (S_w= 0.83) and two, three, and five injection wells.

Table 6. Results of CO_2 Amount Being Trapped by Solubility, Structural, and Residual

			Cum. CO_2 Solubility Trapping (Mol)		Cum. CO_2 Solubility Trapping (TON)			Cum. CO_2 Residual Trapping (Mol)		Cum. CO_2 Residual Trapping (TON)			Cum. CO_2 Structural Trapping (Mol)		Cum. CO_2 Structural Trapping (TON)		
			COMP	GEOM	COMP	GEOM	Diff (GEOM-COMP)	COMP	GEOM	COMP	GEOM	Diff (GEOM-COMP)	COMP	GEOM	COMP	GEOM	Diff (GEOM-COMP)
Cases	Sw = 0.83	2 Inj. Well	2.21E+12	2.21E+12	9.75E+07	9.74E+07	-0.034%	2.18E+11	2.10E+11	9.61E+06	9.24E+06	-3.916%	4.57E+11	4.53E+11	2.01E+07	1.99E+07	-0.894%
		3 Inj. Well	2.25E+12	2.25E+12	9.91E+07	9.90E+07	-0.121%	2.21E+11	2.24E+11	9.72E+06	9.84E+06	1.153%	4.62E+11	4.56E+11	2.03E+07	2.01E+07	-1.288%
		5 Inj. Well	2.29E+12	2.29E+12	1.01E+08	1.01E+08	-0.124%	2.27E+11	2.24E+11	9.99E+06	9.84E+06	-1.441%	4.45E+11	4.39E+11	1.96E+07	1.93E+07	-1.193%

Molar Mass (Mol) CO_2 = 44.01 gram/mol



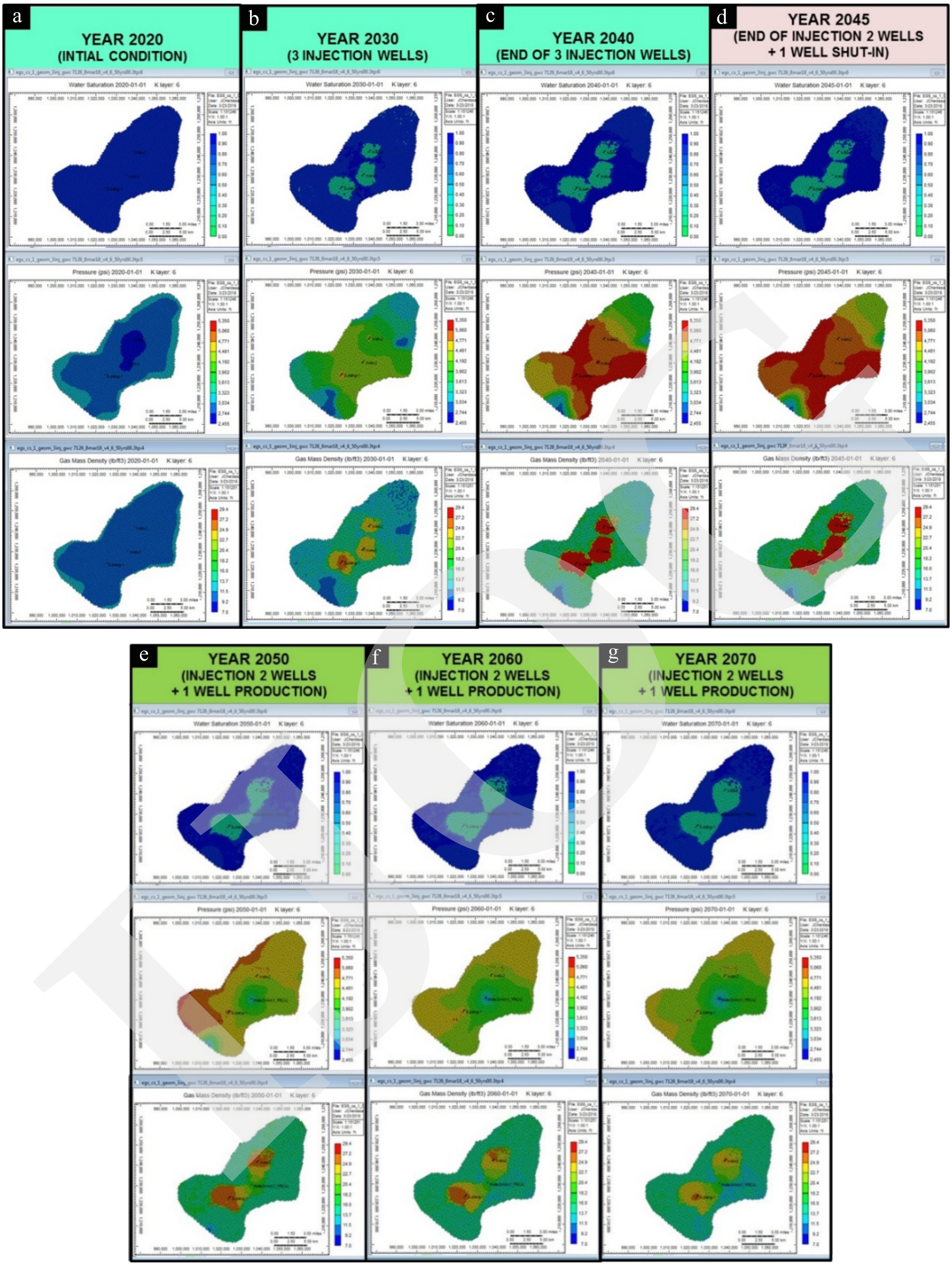


Figure 19. Result of a dynamic reservoir simulation compositional plus geomechanic coupling method within the changes of water saturation, reservoir pressure, and gas mass density parameter in (a) Year 2020, (b) Year 2030, (c) Year 2040, (d) Year 2045, (e) Year 2050, (f) Year 2060, and (g) Year 2070 showing the effect of one CO_2 production well.

two injection wells and one well shut-in, and year 2050 to 2070 two injection wells at one production well can be seen in Figure 19. T he initial conditions in 2020 for the water saturation property parameter value is 0.83 (S_w= 0.83) with water saturation map scale from low to high is green for water saturation value of 0 (S_w = 0) and blue for water saturation is 1 (S_w= 1) as seen in Figure 19a. The initial conditions for reservoir pressure parameter that are 2,500 - 3,000 psi with a scale of reservoir pressure maps from low to high are blue for pressures valued at 2,455 psi and red for pressures valued at 5,350 psi. The initial conditions for the gas density property parameter which is 8 lb/ft^3 showing a map scale density from low to high is blue for the gas density value which is 7 lb/ft^3 and red for the gas density value which is 29.4 lb/ft^3. The condition in 2030 with the injection process of three wells (Figure 19b) and the water saturation property in the area around the well has changed to 0 (S_w= 0). The injection area has changed to reach a radius of 2 km, but there is no visible relationship amongst the wells. The reservoir pressure property parameter value conditions is at 4,000 - 4,500 psi near the injection well, and the conditions for gas density property parameters are at 23-25 lb/ft^3 in the vicinity of the injection well.

The condition in 2040 which is the end of the three-well injection process (Figure 19c) , the water saturation property in the area near the well has changed to 0 (S_w= 0), the injection area has changed to reach a radius of 2.5 km, and has visible connectivity amongst the wells. The reservoir pressure property parameter value conditions is 4,500 - 5,000 psi around the injection well. Compared to 2030, the injection effect area becomes wider, and the conditions for gas density property parameters are at 23 - , 25 lb/ft^3 in the area of the injection well. The situation in 2045 is the final conditions with two injection wells (CCS-1 and Well-2) and one shut-in well (Well-3) for preparation becoming a production well (Figure 19d) . The water saturation property in the area around the well has changed to 0 (S_w= 0), and the injection area has changed. There is a relationship amongst wells but not too much compared to 2040. The reservoir pressure property parameter conditions is at 5,000-50,000 psi around the injection well. Compared to 2040 the area of the injection effect area changed to become wider and the conditions for gas density property parameters are at 23-25 lb/ft^3 near the injection well. Compared to 2040 the injection effect area becomes wider.

The condition in 2050 is the beginning of two injection wells and one production well (Figure 19e) . The water saturation property in the area around the well has changed to 0 (S_w= 0) with a visible connectivity between the three wells. When Well-3 is being produced, the fluid movement around the Well-3 could be seen, and the injection effect area at the two injection wells is becoming bigger. The reservoir pressure property parameter conditions is 4,500 - 5,000 psi near the injection well and 3,500 - 4,000 psi around the production well. The gas density property parameter conditions are at 23-25 lb/ft^3 around the injection well and at 16-18 lb/ft^3 around the production well. The conditions in 2060 is a continuation of two injection wells and one production well as seen in Figure 19f. The water saturation property in the area around the well has changed to 0 (S_w= 0) and with a visible connectivity between the three wells. When Well-3 is produced, the water saturation value is getting larger and the injection effect area from two injection wells is getting greater. The reservoir pressure property parameter conditions is 4,500 - 5,000 psi around the injection well and 3,500 - 4,000 psi near the production well. The overall condition, the reservoir pressure declines indicated by the dominance of yellow compared to orange and red in 2050. The gas density property parameter conditions are at 23-25 lb/ft^3 around the injection well and 13-15 lb/ft^3 around the production well. The conditions in 2070 is the end of the injection process of two injection wells and one production well as seen in Figure 19g . The water saturation property in the area around the well has changed to 0 (S_w= 0) and with visible connectivity between the three wells. When Well-3 is producing, the water saturation value is getting higher, and the injection effect area from two injection wells is also getting greater. The reservoir pressure property parameter conditions is 4,500 - 5,000 psi near the injection well and 3,500 - 4,000 psi around the production well. The overall reservoir pressure decreases which is shown by the dominance of green compared to yellow in 2060. The gas density property parameter conditions are at 23-25 lb/ft^3 in the injection well and 16-18 lb/ft^3 around the production well.

In summary, it can be seen that once Well-3 starts producing, the formation pressure which was constantly increasing, begins to decrease and looking for equilibrium. Accordingly, the two existing injection wells can increase the cumulative injection of CO_2 fluid into the formation. This can be seen by the shape changes of the existing water saturation and the distribution of gas mass density parameters in formations which follow the operational developments. Based on the simulation results with compositional plus geomechanic coupling with a case of water saturation of 0.83 (S_w = 0.83) and three injection wells then continued to two injection wells and one production well. The following results are obtained that the total cumulative CO_2 fluid being injected is ± 1,150 Bcf. It is almost more than double when injected with three wells or two wells where the total cumulative CO_2 gas can be injected for ± 500 Bcf (Figures 20 and 21; Table 7). Based on the volumetric calculation results in the CSSU-2 zone, the storage capacity is 1,467.78 Bcf or 78.89 MMTon. Then, the storage efficiency which is the ratio between the total CO_2 fluid being injected into the formation and CO_2 storage capacity under the water saturation conditions of 0.83 (S_w = 0.83) is 24.45%.

The CO_2 supercritical fluid production is by one well for twenty-five years (Figure 22 and Table 8). The total amount of CO_2 produced is 115 Bcf with the average daily production over the past twenty years is 14 - 10 MMscfd. The average fluid temperature at the bottom of the well is 350 °F, and the mean enthalpy of produced fluid is 220 - 140 MMBtu/day, and the fluid temperature output at the injection well is 105 °F which means the fluid enthalpy is 42-66 MMBtu/day (the enthalpy calculation of production fluid is obtained from the reduction in temperature and the heat capacity of CO_2 fluids). Further with the 75 % efficiency at the power plant, then the calculation of electrical energy generated from the process

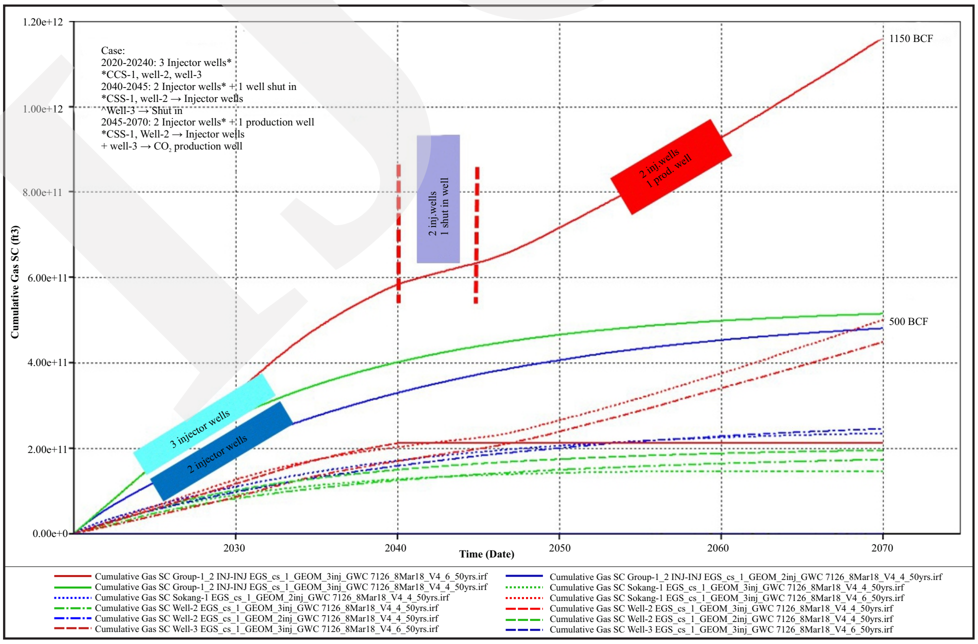


Figure 20. Cumulative total of super critical CO_2 fluid being injected from 2020 to 2070 using a dynamic reservoir simulation compositional plus geomechanic coupling method with the initial water saturation condition of 0.83 (S_w = 0.83) through three injection wells, continued to two injection wells and one production well.

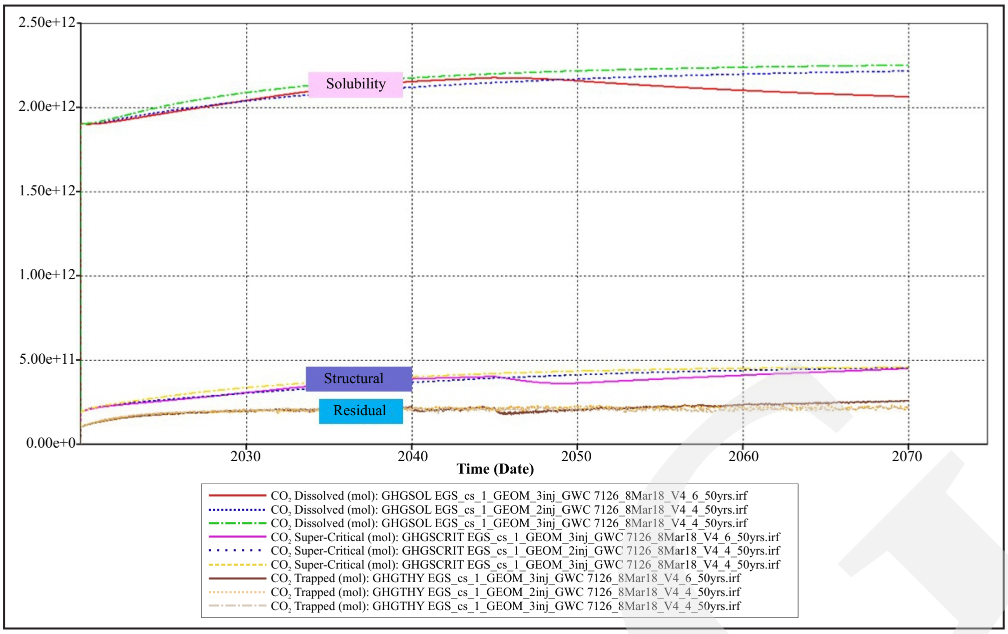


Figure 21. Amount of CO_2 fluid trapped through the solubility, structural, and residual mechanism due to the injection process from 2020 to 2070 using a dynamic reservoir simulation compositional plus geomechanic coupling method with the initial water saturation condition of 0.83 (S_w = 0.83) through three injection wells, continued to two injection wells and one production well.

Tabel 7. Calculation Results of Cumulative CO_2 Fluid being Injected from 2020 to 2070

			Cum. CO_2 Gas Surface Condition (BSCF)			**Cum. CO_2 Gas Surface Condition (TON)**			
			COMP	**GEOM (3 Inj)**	**GEOM (2 Inj + 1 Prod)**	**COMP**	**GEOM (3 Inj)**	**GEOM (2 Inj + 1 Prod)**	**Diff (GEOM-COMP)**
Cases	Sw = 0.83	3 Inj. Well	522.49	515.04	1510.00	2.81E+13	2.77E+07	8.12E+07	66%

is 55 - 133.55 MMBtu/day or 0.67 - 1.63 MW. This CO_2 supercritical fluid will be used as the working fluid in an electricity generation system.

Discussion

Geomechanic Impact on Reservoir Management

One of the questions in this study is the relationship between geomechanical parameters and their impact to the economic value. To answer this question, an experiment was carried out by changing the existing geomechanical parameters, and then observing the factor of total CO_2 fluid injection, the total CO_2 fluid production, and the amount of existing CO_2 fluid flow rate.

The total amount of CO_2 fluid injection which will affect the amount of CO_2 fluid and can be accommodated and trapped, correlates to the economic magnitude in terms of the value of carbon credits obtained. The magnitude of the total value of production and the existing CO_2 fluid flow rate will correlate to the amount of electrical energy that can be produced. The changes in these three values will certainly affect the economic value of the study.

The geomechanic parameters being sensitized are the value of Rock Compressibility and Poisson Ratio. The rock compressibility value is an assessment of the strength of a rock in holding pressure, so that the rock shape does not easily change. The Poisson Ratio is a magnitude of the ratio between the narrowing of the body to the increase in length due to a pressure, where the

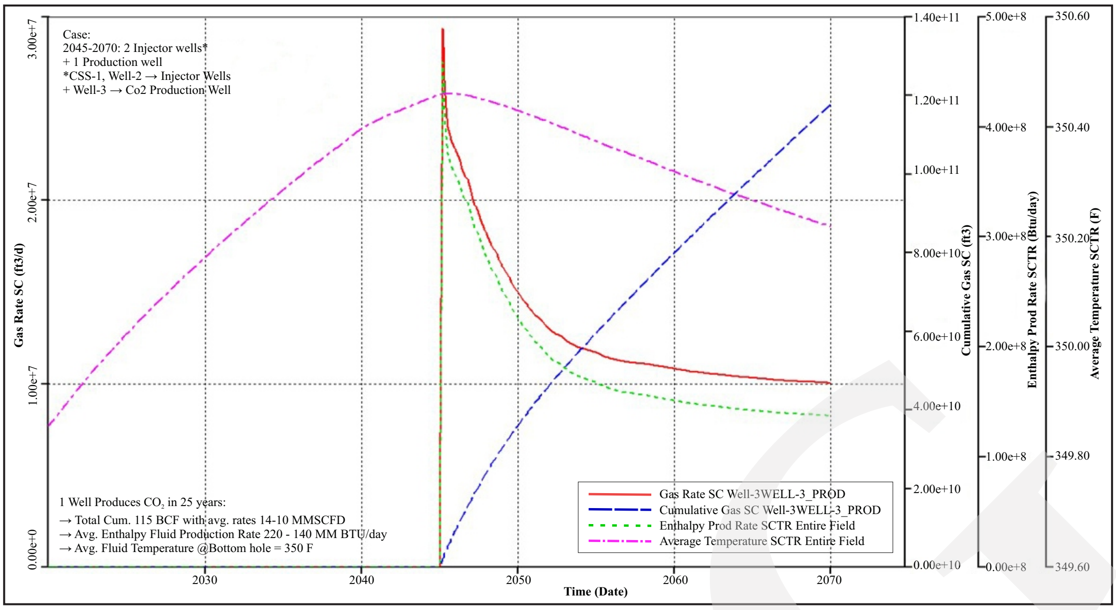
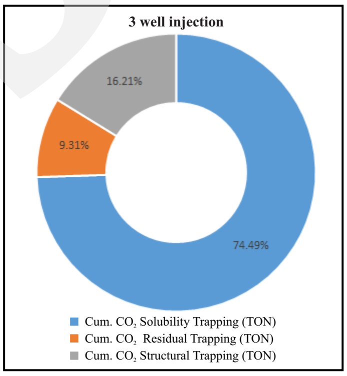


Figure 22. Amount of CO_2 fluid produced from 2045 to 2070 using a dynamic reservoir simulation compositional plus geomechanic coupling and thermal method with the initial water saturation condition of 0.83 (S_w = 0.83) through one production well.

Table 8. Calculation Results of CO_2 being Solubility, Structural, Residual Trapped

			Cum. CO_2 Solubility Trapping (Mol)			Cum. CO2 Solubility Trapping (TON)			
			COMP	GEOM (3 Inj)	GEOM (2 Inj + 1 Prod)	COMP	GEOM (3 Inj)	GEOM (2 Inj + 1 Prod)	Diff (GEOM-COMP)
Cases	Sw = 0.83	3 Inj. Well	2.25E+12	2.25E+12	2.06E+12	9.91E+07	9.90E+07	9.07E+07	-9.108%
			Cum. CO_2 Residual Trapping (Mol)			Cum. CO_2 Residual Trapping (TON)			
			COMP	GEOM (3 Inj)	GEOM (2 Inj + 1 Prod)	COMP	GEOM (3 Inj)	GEOM (2 Inj + 1 Prod)	Diff (GEOM-COMP)
Cases	Sw = 0.83	3 Inj. Well	2.21E+11	2.24E+11	2.58E+11	9.72E+06	9.84E+06	1.13E+07	13.226%
			Cum. CO_2 Structural Trapping (Mol)			Cum. CO_2 Structural Trapping (TON)			
			COMP	GEOM (3 Inj)	GEOM (2 Inj + 1 Prod)	COMP	GEOM (3 Inj)	GEOM (2 Inj + 1 Prod)	Diff (GEOM-COMP)
Cases	Sw = 0.83	3 Inj. Well	4.62E+11	4.56E+11	4.49E+11	2.03E+07	2.01E+07	1.97E+07	-1.616%

Molar Mass (Mol) CO_2 = 44.01 gram/mol



value of the poisson ratio is at 0.1 to 0.45. In the Base Case the compressibility value of rocks is 1.50 E ^ 6 psi, Low Case 1.00 E ^ 6 psi, and High Case 2.00 E ^ 6 psi. For the Poisson Ratio, the value in the Base Case is 0.36, the Low Case is 0.25, and the High Case is 0.42.

A comparison of reservoir simulation modeling results in compositional method and geomechanical coupling at water saturation values of 0.83 with two injection wells and one production well (Figure 23 and Table 9). From the simulation results, it can be seen in cases with lower compressibility values and smaller Poisson Ratios that the total amount of CO_2 which is able to be injected rises by 30 Bscf (from 1190 Bscf to 1220 Bscf), the total value of CO_2 production rises by 2 Bscf (from 599 Bscf to 601 Bscf), and the average CO_2 production value increases by 0.2 MMscf (from 59.9 MMscf to 60.1 MMscf). The rock compressibility and Poisson Ratio values are greater than the total value of the injected CO_2 that decreases by 10 Bscf (from 1190 Bscf to 1180 Bscf). The total value of CO_2 production decreases by 0.6 Bscf (from 599 Bscf to 593 Bscf), and the average production value of CO_2 decreases by 0.6 MMscf (from 65.9 MMscf to 65.3 MMscf).

By the increasing and the decreasing in the total CO_2 fluid injected results, the total CO_2 fluid produced and the average CO_2 fluid production, the difference in the amount of electrical energy produced in the Low Case, the electrical energy generated is 2.18 MW or up 0.33 %, and in the Base Case is 2.17 MW. In the High Case the electrical energy produced is smaller at 2.15 MW, down 1.30 % from the electrical energy at the Base Case. From this, it can also be seen that the impact on the economic research in the Low Case, the economic value increased by 3.88 MMUS \$ (from 172.77 MMUS \$ to 176.65 MMUS \$), and in the High Case the economic value decreased by 1.96 MMUS \$

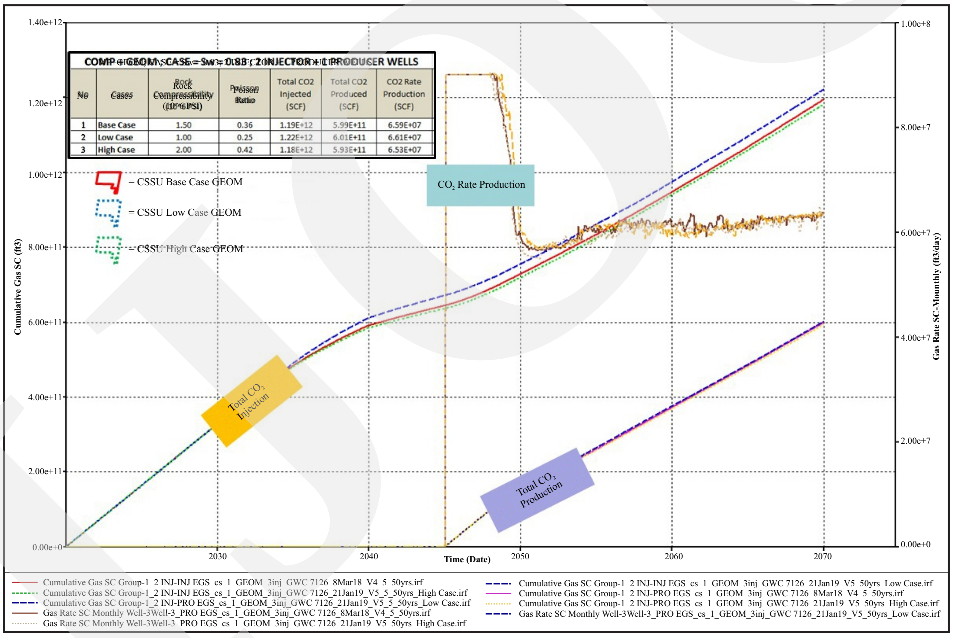


Figure 23. The plot between the total CO_2 fluid injection, the total CO_2 being produced, and the average amount of CO_2 production over time.

Table 9. Reservoir Simulation Results with The Case of Geomechanical Parameter Sensitivity

No	Cases	Rock Compressibility (10^6 PSI)	Poisson Ratio	Total CO_2 Injected (SCF)	Total CO_2 Produced (SCF)	CO_2 Rate Production (SCF)	Electricity Produced (MW)	Diff. in Electricity Prod (%)	NPV (MM US$)	Difference in NPV (%)
1	**Base Case**	1.50	0.36	1.19E+12	5.99E+11	6.59E+07	2.17	-	172.77	-
2	**Low Case**	1.00	0.25	1.22E+12	6.01E+11	6.61E+07	2.18	0.33%	176.65	2.24%
3	**High Case**	2.00	0.42	1.18E+12	5.93E+11	6.53E+07	2.15	-1.30%	170.81	-3.31%

COMP + GEOM ; CASE = Sw = 0.83 ; 2 INJECTOR + 1 PRODUCER WELLS (from 172.77 MMUS \$ to 170.81 MMUS \$) as shown in Table 9.

From the reservoir simulation results, it can be concluded that the greater the compressibility value of rocks and the higher the Poisson Ratio value, the stronger the physical rocks will be and the harder the shape to change (rigid). Hence, the physical differences caused by changes in pressure do not have too much effect. This is evident in the total value of CO_2 fluid which can be injected smaller than the compressibility value of the rock and its Poisson Ratio, which make the rock is more easily changed so as to physically there will certainly be new cavities (changes in porosity) to accommodate more CO_2 fluid as indicated by the increased total CO_2 value. Therefore, based on the simulation results, it also can be concluded that geomechanical parameters play an important role in the reservoir management process, especially within the planning phase due to its economic impact for a field development.

Conclusions

- The CSSU method is an integration of geological, geophysical, reservoir engineering, and engineering economics that is required to take into account the use of produced CO_2 fluids as the worker fluid in a power plant system that has been conditioned through an injection-production system in geological formations. This is to change the paradigm of CO_2 fluids from waste material to economical material.
- The combined optimization of the deterministic and stochastic methods with the Particle Swarm Optimization (PSO) algorithm is the novelty of this study to answer complex and nonlinear problems in the CSSU (Carbon Sequestration, Storage, and Utilization) method.
- The CSSU of the researched area is in a sedimentary basin with the pilot area selected to facilitate the evaluation of the technical and economic feasibility of the CSSU method The geological, geophysical, and petrophysical characterizations obtained:
  - Reservoir rocks in the studied area are the sequence 4 and sequence 3 zones, with the gas production reservoir zone with high CO_2 content being the sequence 5 and 4 zones.
  - The seal rock in the studied area is the 7th sequence zone or clay stone layer (shale) insertion in the 4th and 3rd sequence zones.
- Volumetric calculations in the CSSU-2 zone using the parameters of petrophysic and static modeling obtained values as follows: Bulk Volume of 44.21 Bcf, Pore Volume of 8.31 Bcf, CO_2 Pore Volume of 6.98 Bcf, and Storage Capacity of 1,467.78 Bscf or 78.89 MMTon.
- Reservoir simulation modeling is done by three methods, namely: compositional, compositional + geomechanic coupling, and compositional + geomechanic + thermal coupling. There is a difference of ~8 Bscf for a total injection between compositional simulation and geomechanic coupling plus ordinary compositional simulation. The differences in calculations is mainly due to input factors such as Modulus Young, Poisson's Ratio, Angle of Internal Friction, and Biot's Coefficient. It has an impact on the pore volume (pore volume) of the existing reservoir, so that it affects the total CO_2 fluid injection.
- The results of dynamic reservoir simulation modeling with compositional simulation with geomechanic coupling method for two injection wells and one production well show cumulative CO_2 injection fluid into the formation is almost more than double the process of three continuous injection wells, from 500 Bcf to 1,150 Bcf in total CO_2 fluid injection. As soon as Well-3 starts producing, the formation pressure which initially increases constantly decreases and tends to slow down to find equilibrium. Thus, the injection capacity of the two existing injection wells can be increased.
- Modeling result of one production well for twenty-five years to utilize the CO_2 super critical fluids as working fluids with enthalpy

in the production fluids is 220-140 MMBtu/day, and enthalpy in the fluid output into injection wells is 42-66 MMBtu/day (enthalpy calculation of production fluid is obtained from the reduction in temperature and heat capacity of CO_2 fluids). The calculation of the electrical energy produced from the process is 55-133.5 MMBtu/day or 0.67-1.63 MW. The results of this calculation are still around 1/10 compared to the electrical energy produced using hydrocarbon gas as the working fluid.

o Geomechanical parameters play an important role in the reservoir management process, such as rock compressibility and poisson ratio parameter. The greater the compressibility value of rocks and the higher poisson ratio values, the physical rocks will be stronger and harder to change its shape (rigid), so that the physical differences caused by changes in pressure become a small effect. A small compressibility value of rocks and p oisson ratio can make the rock physically have new cavities (changes in porosity) to accommodate more CO_2 fluid when there is a change in the reservoir. From the simulation results there was a change of 30 % for rock pressure compressibility parameters (from 1.50 x 10-6psi to 1.00 x 10-6psi) and p oisson ratio parameters (from 0.36 to 0.25), and there was a change in the amount of electrical energy produced by 0.01 MW or 0.33 % and changes in the economic value of 4 MMUS $ or 2.24 %.

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