Reservoir Simulation of CO_2 Storage using Compositional Flow Model for geological formations in Frio Field and Precaspian Basin

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March 8, 2021

Abstract

CO_2 storage is a greenhouse gas mitigation instrument for many countries. In this paper, we investigate the possibility of CO_2 storage in the region of the Precaspian basin using the compositional flow model that was verified by the data of the Frio pilot project, USA. We use local grid refinement in the commercial reservoir simulator. In the reservoir simulation for data of the Frio Pilot project, we have achieved a good history matching of the well pressure. The different scenarios were tested and post-injection migration was shown for both case studies. The long-term reservoir simulation shows the potential amount of trapped CO_2 by residual and dissolved trapping mechanisms in the Precaspian basin.

***K*eywords** CO2 storage · compositional flow model · reservoir simulation

1 Introduction

In the last few years there has been a growing interest in studying many mechanisms to achieve the reduction of the CO_2 concentration in the atmosphere. The growing infrastructure of countries requires more consumption of fossil fuels that can lead to the greenhouse effect. Efforts of many countries in controlling Greenhouse Gas emissions were documented in the Paris agreement. One of the ways to mitigate the risk caused the CO_2 emissions is to inject CO_2 into depleted oil and gas reservoirs or aquifer formations for the geological storage. The injection of CO_2 should be at sufficient depth to allow the CO_2 to be in the supercritical state (in general, approximately the depth should be larger than 800 meters so that the pressure is above 7.4MPa and the temperature is above 31 degrees by Celsius) in which the storage capacity is maximized. CO_2 has a liquid-like density and gas-like viscosity in the supercritical state and occupies approximately one hundredth of the volume it does as a gas, at standard conditions. The recognition of viable role of the carbon sequestration is increasing and the implementation of such technologies can be found in many projects of the world from the USA, UK, China, Norway, etc. In [25], it was proposed the method for evaluation of the CO_2 storage capacity in the global context in order to achieve “two degree scenario" objective.

The assessment of the storage capacity is sophisticated since there are many trapping strategies. We highlight main four trapping mechanisms of carbon dioxide in the aquifer such as the hydrodynamic trapping when CO_2 migrates upwards and remains just below the cap rock (a structural or stratigraphic trap must exist), as immobile phase as a residual gas saturation during the imbibition process, dissolution in water, and the mineral trapping. The first three trapping mechanisms are the most important instruments as the mineral trapping effects can be observed only after a long time (many years, maybe even thousand of years). The most desirable mechanisms for trapping are immobile phase and dissolution in water, because hydrodynamic trapping is risky as the cap rock can be partially sealing, hence, CO_2 can migrate through it and the storage efficiency can be reduced.

To address the modeling of the CO_2 storage in the subsurface, many researchers have proposed various the numerical models with different realistic data [25, 7, 21, 24]. There are many case studies of such mechanisms around the world such as Johansen formation [11], Utsira formation [22], Cranfield pilot project [9, 20], Frio pilot project [13] and others. The large-scale modeling helps to evaluate the behavior of the injected CO_2 in the various scenarios and the models were verified by using the additional sources of field project including the pressure measurements, seismic surveys, etc.

Kazakhstan's plan on fulfilling the Paris agreement may require additional actions to be able to achieve the goals to achieve the 25% emission reduction strategy. According to [18] the current mitigation activities in Kazakhstan may not be enough to reach reduction 15% (unconditional target) based on the BaU model. CO_2 sequestration can be a solution for the country in the reduction of CO_2 emission. Potential locations in Kazakhstan for CO_2 storage was discussed in [14, 23] and it was estimated around 1003 Mt CO_2 storage capacity of the gas reservoirs of Kazakhstan in [1]. However, most of previous studies do not take into account numerical reservoir simulation of the CO_2 storage in Kazakhstan.

In this study, we investigate the reservoir simulation of CO_2 storage in 3D using the compositional flow model for the Frio CO_2 project in the USA and the Precaspian Basin in Kazakhstan. We study the effect of parameters that can be essential in the modeling of CO_2 storage evaluation in a potential subsurface of Kazakhstan. The model verification is performed by the history matching of the well pressure profile based on the data of Frio field experiment. We utilize the commercial simulator Eclipse 300. To authors' knowledge, 3D numerical simulation of CO_2 sequestration in the Prescaspian formation has been scarcely investigated from the point of view evaluation of capacity. We propose the potential place of the CO_2 storage and demonstrate the possible amount of trapped CO_2 and present also the plume migration in the post-injection period.

The remainder of the paper is organized as follows. Section 2 describes settings in the compositional flow reservoir simulation. We use the data from the Frio CO_2 project as a case study. Reservoir simulation results for regions from the Frio and the Precaspian formation are presented in Section 3. The compositional flow model was verified and applied to Frio CO_2 Project and then was applied to the Precaspian formation, Kazakhstan. Section 4 summarizes the results of this work and draws conclusions.

2 Model Description

In this section, we make an overview of the upper part of the Frio formation in USA and describe the compositional flow model set-up and input parameters for simulation.

2.1 Overview of the Frio CO_2 model

The injection pilot project in Frio brine formation is used as a case study for reservoir simulation of CO_2 sequestration. The Frio brine field is a sandstone formation with high porosity and permeability located in Houston, Texas, USA. In this pilot project it was injected about 1600 tons of CO_2 during 10 days into the formation 1500 m below the surface in [15]. The target for injection was upper Frio Formation ("C" sandstone) which is 23-meters thick brine-bearing interval above oil production zone. The upper part of "C" formation has porosity of 30 to 35% and permeability of 2000 to 2500 md. There is also some finer grained sandstone with porosity of 24 to 28% and permeability of 70 to 120 md in the middle of this zone. Finally, there is a cap rock (seal) at the top of "C" formation and that's why the injected CO_2 can be trapped through a hydrodynamic trapping mechanism. The project consisted of two wells: one injection and one observation. The existing oil production well was plugged and recompleted in "C" formation as observation well. A new injector was completed in "C" formation for CO_2 injection. There are no faults or fractures b/w injection and observation wells. The distance between wells is about 33 m and the dip angle is approximately 16 degrees.

2.2 Compositional reservoir simulation model set-up

The compositional reservoir simulation was designed using ECLIPSE 300 simulator and was used to investigate the development of the larger scale CO_2 storage experiment. There were two components present in the model: CO_2 and water. In ECLIPSE 300 simulator, the solubility of CO_2 in water was calculated using the procedure of Spycher and Pruess [28] which was based on fugacity equilibration between water and CO_2. The fugacities for water and CO2 were calculated using Henry's law and the Redlick-Kwong equation of state respectively. The compositional model takes into account the important processes happening during the interaction of CO_2 with water, namely the process of CO_2 dissolution in the water, density changes of CO_2-water mixture, trapping of the gas as the residual saturation and gas gravity effects leading to the hydrodynamic trapping by the cap rock.

The corner point geometry grid was implemented using a Python script. Angle of 16 degrees was chosen during the construction of the grid, see Figure 1.

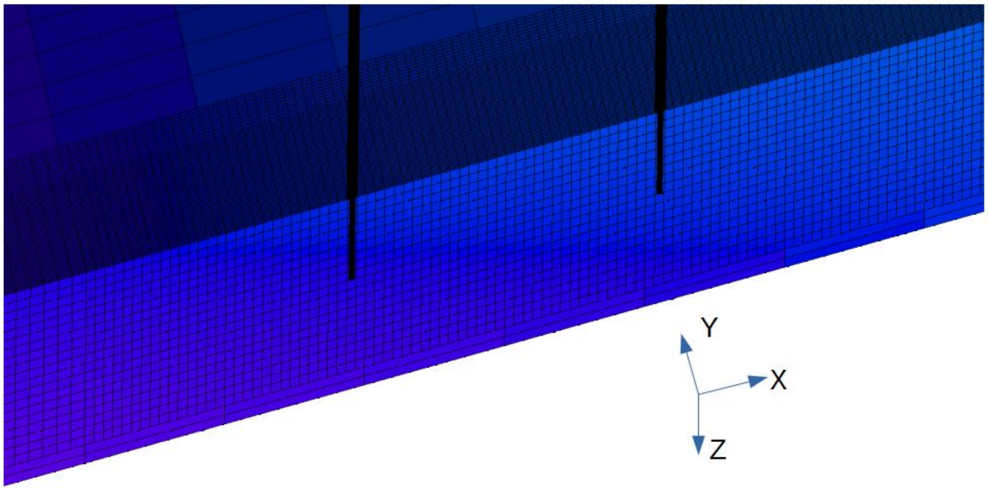


Figure 1: Grid for Frio project

The domain of the model was discretized by 150×150×23 cells. The lateral width of each grid cell was 15 meters and layer thickness was 1 meter. As there were two sealing faults and salt dome based on the Frio geological model, the no-flow boundary conditions were applied from all sides. The further description on the configuration of the grid could be found in Section 3.

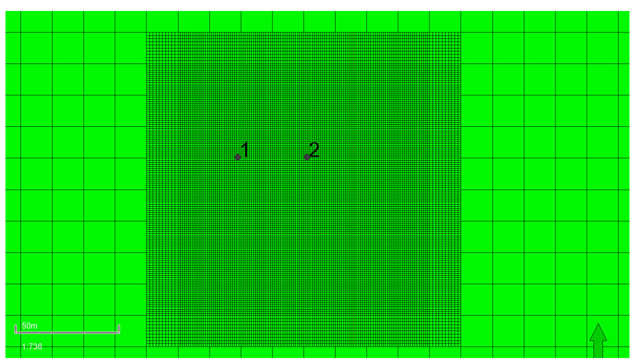
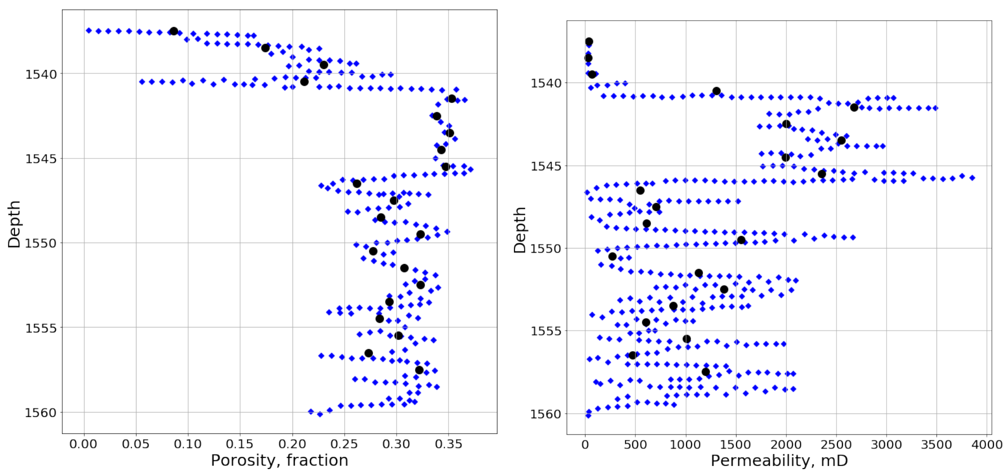


Figure 2: Local grid refinement around wells, 1- injection well and 2 - observation well

The local grid refinement (LGR) was used where finer grids were set in the area where the CO_2 plume migration may occur in order to obtain accurate calculation, see Figure 2. The LGR allows to improve accuracy of the model and it was reported in many studies of the flow and transport problems with error evaluations [5, 26, 4, 19, 6]. The 8 cells in the area of injection and observation wells were refined laterally by the factor of 15 giving cells 1 meter in width and the further 2 cells from each side by the factor of 10 giving cells 1.5 meters in width.

Rock compressibility value of 1.28e-4 1/bar was applied to the model [10]. The realistic porosity and permeability were digitized from [15] and were averaged over each 1 meter in the z-direction using Python script, see Figure 3. As there is data only from one well, the permeability and porosity is the same along the layers. Moreover, the horizontal permeability in both directions x and y were assumed to be the same, i.e. there was no anisotropy in x and y directions.



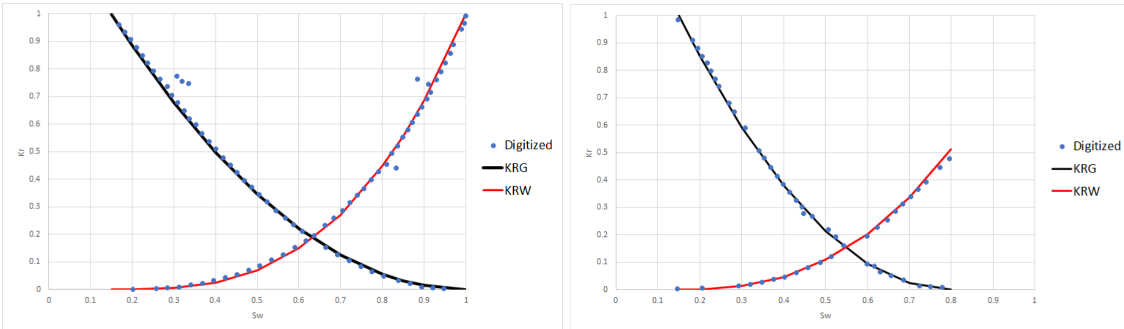
(a) Porosity

(b) Permeability

Figure 3: The porosity and horizontal permeability curves from Frio field and averaged values per meter

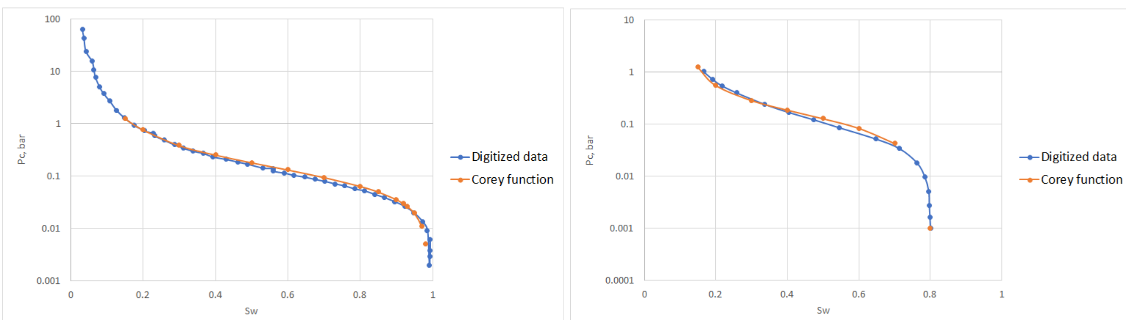
The 3-parameter Peng Robinson equation of state was used in the model. Two components were considered in the model such as CO_2 and water with density of 1026 kg/m3. The initial pressure and temperature were set as 152 bars and 57°C, respectively. All equation of state parameters for CO_2 component including Tcrit, Pcrit, ACF, MW, PARACHOR, SSHIFT and BIC were standard in the simulator that were specified in previous study [13].

In the model, the relative permeability and capillary pressure values were digitized and fitted based on the data from [10] and the Corey function, for more details see equations (1)-(3), was used to reproduce these data for usage in reservoir simulation model and it was illustrated in Figures 4 and 5. The saturations of connate water and critical water were defined to equal 15%, the Corey coefficient for drainage and imbibition gas curves (C_g) was 2, for drainage water curve was 3 and for imbibition water curve (C_w) was 2.5. Relative permeability and capillary pressure hysteresis options (both curves drainage and imbibition were used in the simulation model) were switched on



(a) Drainage relative permeability (b) Imbibition relative permeability

Figure 4: Relative permeability curves CO_2 and water where $S_w = 0.15$. Corey function fitted to drainage and imbibition relative permeability curves from [10]



(a) Drainage capillary pressure (b) Imbibition capillary pressure

Figure 5: Corey function fitted to drainage and imbibition capillary pressure curves from [10]

in the reservoir simulation model. The critical gas saturation was assumed to be 5%. The formulas of the relative permeability ([8]) and the capillary pressure ([27]) were as follows,

$$k_{rg} = k_{rgmax} \left[\frac{1 - s_w - s_{gcr}}{1 - s_{wi} - s_{gcr}} \right]^{C_g} \tag{1}$$

where S_w is the water saturation, S_{wi} is the intial water saturation, S_{gcr} is the critical gas saturation, C_g is the Corey gas exponent,

$$k_{rw} = k_{rwmax} \left[\frac{s_w - s_{wcr}}{s_{wmax} - s_{wcr}} \right]^{C_w} \tag{2}$$

where S_w is the water saturation, S_{wmax} is the maximum water saturation, S_{wcr} is the critical water saturation, C_w is the Corey water exponent,

$$p_c = \frac{c_w}{\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{a_w}} + \frac{c_g}{\left(\frac{S_g - S_{gr}}{1 - S_{gr}}\right)^{a_g}} \tag{3}$$

where S_w is the water saturation, S_{wr} is the critical water saturation, S_g is the gas saturation, S_{gr} is the critical gas saturation, S_w is the water saturation, a_w and a_g are pore-size distribution coefficients for water and gas (a_w = 0.4 and a_g = 0.03 for drainage curve; a_w = 0.34 and a_g = 0.06 for imbibition curve), C_w and C_g are the entry capillary pressures for water and gas (C_w = 0.347 and C_g = -0.307 for drainage curve; C_w = 0.33 and C_g = -0.3 for imbibition curve).

3 Numerical Results

In this section we describe the history matching results of the compositional flow model for the injection well pressure and CO_2 plume migration for the Frio project in the USA. Moreover, we show the possibility of CO_2 storage in proposed region of the Precaspain basin and provide compositional model set-up and simulation results.

3.1 History matching of the well pressure for Frio project

The initial grid for the reservoir simulation of Frio project was set as square with equal sides of 2250 m (150 cells in each direction with lateral width of 15 meters) for the x -y direction, see Figure 6. We should note that based on geological model of Frio field in [10, 13], there are no-flow boundary conditions from 3 sides of the reservoir (salt dome from one side and two main faults from the remaining two sides). To improve the history matching, we tested different values of pore volume multiplier.

As can be seen from Figure 8, the width of the reservoir seems to be ambiguous, as when the width of the reservoir is shortened to 855 meters (Figure 7), the BHP of injector started to deviate from the historically recorded pressure which was also observed in [17]. It seems that the width should be larger than width based on the geological model, and the deviation of BHP is shown in Figure 8.

To achieve the history matching on injector's BHP and to receive a consistent CO_2 plume shape with width = 2250 meter, the different parameters were varied which are discussed below.

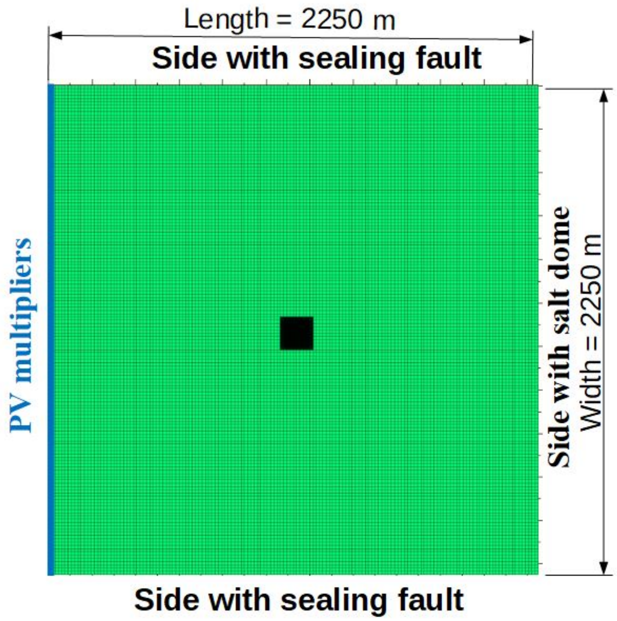


Figure 6: Square model with length and width of 2250 m

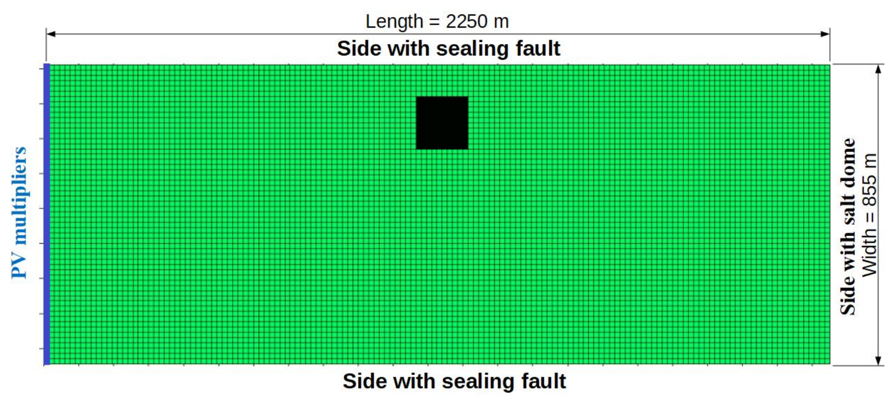


Figure 7: Rectangle model with width of 855 m and length of 2250 m

Due to uncertainty of the permeability in reservoir, we conducted numerical experiments for the vertical to horizontal permeability ratio (kv/kh) from 0.01 to 0.1. We should note that the vertical direction of CO_2 plume flow towards the reservoir top can be impacted by this ratio. The various numerical experiments showed a small impact of kv/kh variation on injector's BHP. Finally, the value of 0.1 was kept as a base case because it is commonly used in the industry ([12]) to account for vertical flow restrictions.

The horizontal permeability far from the injection well trajectory was key parameter for variation in order to match the injector's BHP and CO_2 plume migration. The simulations indicate that the value of BHP is increased when the value of horizontal permeability is decreased. Moreover, this slows down horizontal migration of CO_2 plume from injector towards producer. The horizontal permeability in x and y directions was multiplied by 0.5 outside the injection well (but not for cells perforated by well, because the data in the well area is measured and known) to reach history match on injection well flowing BHP. The alternative option is the change of productivity index (PI) of the well instead of changing horizontal permeability. However, the PI application will impact the perforated cells, which should be untouched because permeability was taken directly from the measured permeability curve. The critical gas saturation was one of the main parameter to history match the CO_2 plume migration, as it can impact the movement of gas and the amount of gas left as a residual saturation. The values of this parameter such as 0, 1%, 5%, 10%, 20% were tested using end point scaling (3-point scaling) in order to achieve a comparable CO_2 plume to that of the conducted seismic survey from [16]. The value of 5% was chosen as the best one to match available data.

The pore volume multiplier on the edge cells of the model was the second most influential parameter on injectors' BHP trend. The application of pore volume multiplier made the BHP trend consistent with observed BHP trend. Its value of 1000 was chosen based on the iteration process to get a BHP trend consistent with an observed one. The multiplier was applied only to edge cells at the opposite side of the salt dome.

As shown in Figure 8 the excellent matching between measured and modeled BHP (black line) was achieved. It is important to note that the history match was improved by utilizing width of 2250 m.

The CO_2 plume from the history-matched reservoir simulation of the current study at different days is shown in Figure 9. The results are similar to CO_2 plume migration from Fig. 7 of [17].

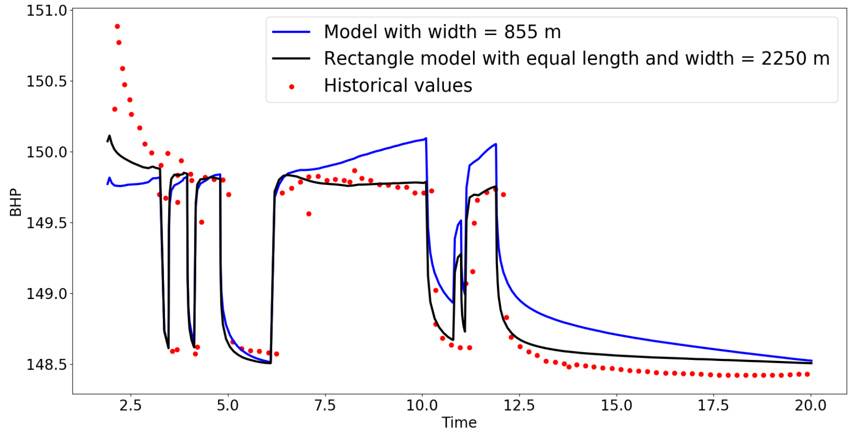


Figure 8: History match of injector's BHP with width = 2250 m (black line) and width = 855 m (blue line)

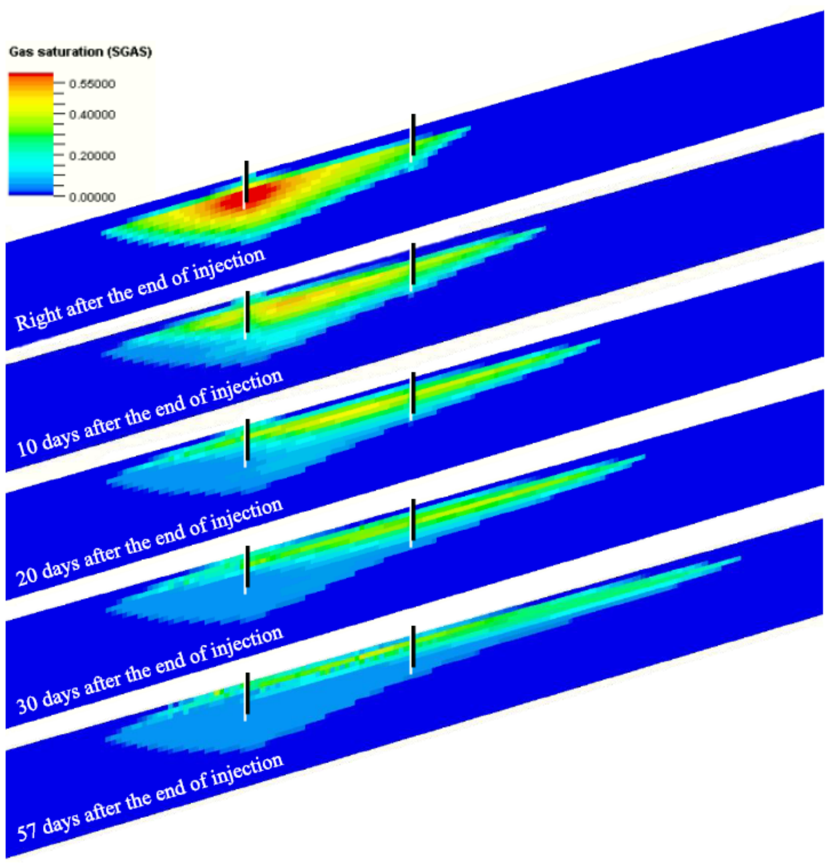


Figure 9: CO_2 plume migration for the Frio project based on the history-matched simulation model

3.2 Application of the CO_2 storage model using data from Kazakhstan

Kazakhstan has many sedimentary basins or formations which can be used for potential CO_2 storage [1]. The largest basin among them is Precaspian basin which has a huge storage capacity compared to other basins and it was chosen for modelling to show the CO_2 storage efficiency using the compositional flow simulation. In the reservoir modeling, we consider a region of the postsalt formation, which is a good target for CO_2 sequestration with the good reservoir characteristics where porosity is higher than 20 $\%$ and permeability varies from 30 mD to several hundred millidarcies [1], and with a presence of a good cap rock. As shown in figure 10, the proposed region is located in Cretaceous reservoir at depths of approximately 1000-2000 meters. As its depth is more than 800m, hydrostatic pressure is above 7.4 MPa and the temperature is above 31°C, CO_2 should be in supercritical state in which the storage capacity is maximized. Another advantage of the proposed region is from economic point of view as the potential cost for drilling a new well is lower with lower formation depth.

In our model, the width and height of the region were set as 14 km and 450 m, respectively. A constant porosity value of 20$\%$ and permeability of 100 mD were taken as input for reservoir model. PVT (equation of state) and the SCAL (relative permeability and capillary pressure curves) data were used based on analysis of the Frio field model, since they were verified by the history matching process, and were applied to the Precaspian basin model.

Similarly to Frio model, the local grid refinement around the injector and potential CO_2 distribution & migration area was used for the the Precaspian basin model to achieve a good resolution and accurate movement of CO_2 plume, see Figure 11.

Using digitization tool, the depth of the reservoir top was taken as 1073 m, see Figure 10. The pore pressure of 109 bar at that depth was calculated by the hydrostatic formula using the brine density of 1035 kg/m3. The reservoir temperature was taken as homogeneous in the reservoir, i.e. constant of 55.7°C. It was calculated assuming the ambient surface temperature of 20°C and average geothermal gradient of 27.5°C/km. The gas injection rate was set as 120000 m^3/day (223 tons/day). This value is approximately equal to the injection rate in the Frio CO_2 project. The consideration of

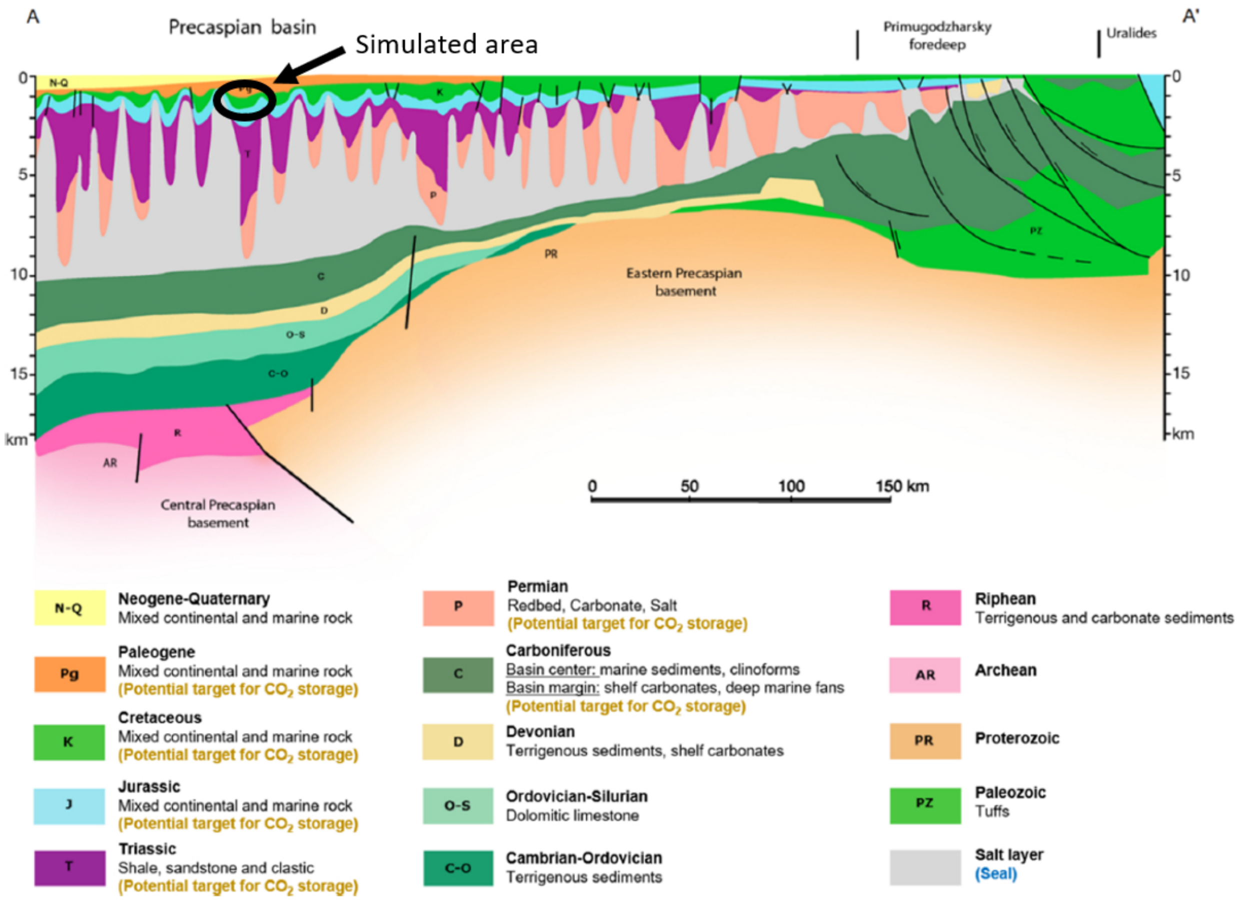


Figure 10: Potential reservoirs for CO_2 storage in Precaspian basin adopted from [1]

Table 1: Setting for Precaspian model

Parameter	Value
Depth of reservoir top, m	1073
Top perforation depth, m	1121
Pore pressure at reservoir top depth, bar	109
Overburden pressure at 1073 m and 1121 m, bar	232, 242
Reservoir temperature, C	55.7
Porosity, %	20
Horizontal permeability, mD	100
Kv/Kh ratio	0.1
Number of cells in I and J directions	90
Number of layers	15
Cell dimensions in I and J directions, m	150
Layer thickness, m	30
Injection rate, tons/day	223
Injection period, years	100
Post injection period, years	130
Total amount injected, millon tons	8.14

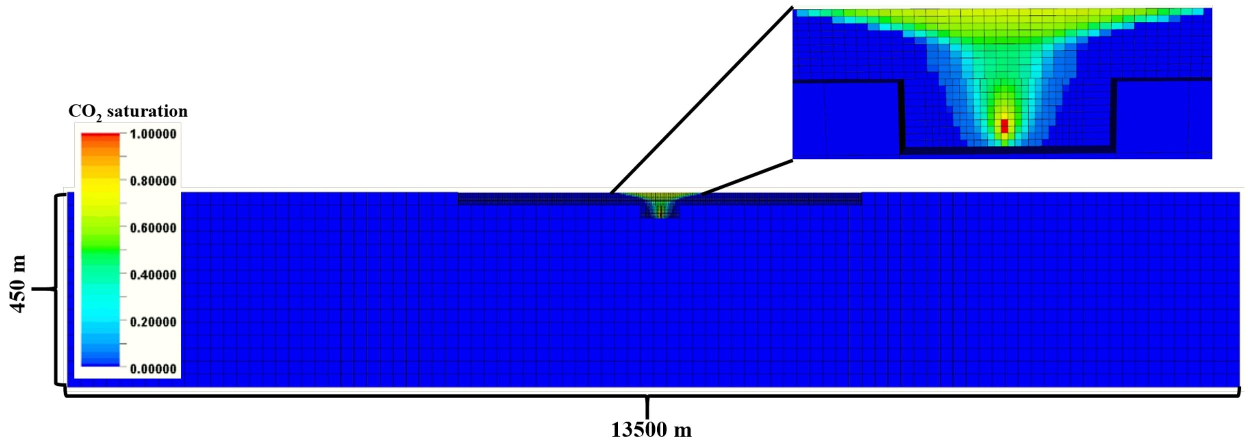


Figure 11: Grid with local grid refinement in the center of the Precaspian model

fracture pressure should be taken into account while injecting the CO_2 into the Precaspian basin in order to avoid a generation of fractures around the well, which can act as a potential path for CO_2 migration upwards to the surface. For several years, a great effort has been devoted to study of the properties of the fractured system such as pressure, geometry and other factors [3, 2]. The fracture pressure was assumed as 65% from overburden pressure. The 65% of overburden pressure is potentially the minimum fracture pressure in the reservoir, but can be higher than this, achieving the overburden pressure itself. As Cretaceous formations are mostly consisted of clastic rocks, the average rock density was taken as 2200 kg/m^3. The approximate overburden pressure at perforation depth of 1121 m is about 242 bar, hence, the minimum fracture pressure is 157 bar. In other words, the bottomhole pressure of injector should not increase the pressure of 157 bar.

The amount of trapped CO_2 which includes the dissolved CO_2 in water, immobile residual gas saturation and remaining amount of CO_2 in mobile phase, was computed using the reservoir model and is illustrated in figure 13. The most of the CO_2 was left in immobile phase after 100 years, i.e. 80% of all injected CO_2 (6.5 Mtons). 12% of injected CO_2 was dissolved in water (0.97 Mtons) and 8% was trapped as residual gas (0.68 Mtons). The reason for such amount of trapped residual CO_2 is that the saturation table of CO_2-water has only 5% of irreducible gas saturation. Here, it should be noted that the residual CO_2 saturation is one of the uncertain parameters and can be higher than 5%, which will definitely lead to the increased amount of trapped gas by capillary forces.

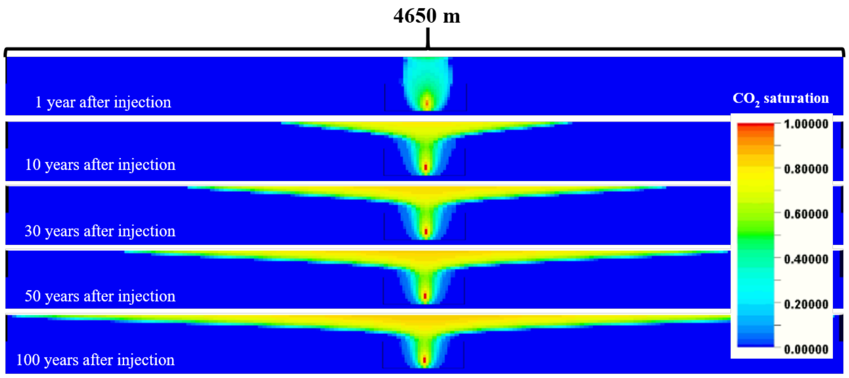
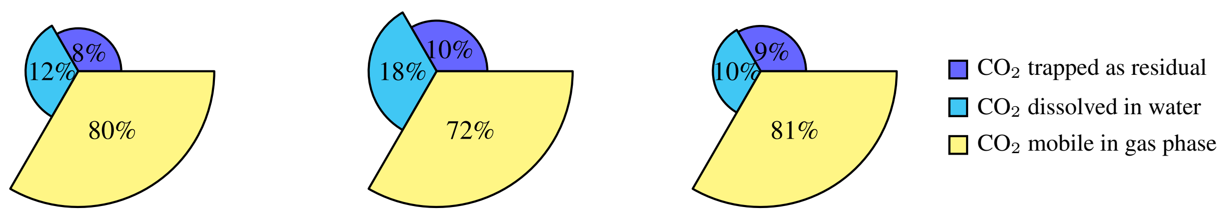


Figure 12: CO_2 migration in Precaspian model for 1, 10, 30, 50 and 100 years

To model the post injection migration, we show the possible effect of residual gas trapping within 130 years after the end of injection. After stopping the CO_2 injection, it continues to dissolve in water. From Figure 13 it can be seen that the amount of dissolved CO_2 increased over time from 12% to 18% (1.46 Mtons), and the amount of gas trapped as residual gas saturation increased from 8 to 10% (0.79 Mtons). The total of 28% of injected CO_2 is trapped permanently, which is an indication of a good potential for CO_2 storage. The remaining part of CO_2 is in mobile gas phase, but also can be trapped by a sealed cap rock. To make it happen, the impermeable cap rock should exists. Moreover, the injection pressure should be monitored in order to not fracture the cap rock. In addition, the spill points should also be monitored in order to prevent the CO_2 migration to other formations.

We also should mention that the lower the injection point (the lower the perforations) the more contact area there is between CO_2 and the formation water, leading to a better trapping efficiency. The usage of horizontal injection wells should also increase the contact area between CO_2 and the formation water, however, the drilling of such wells should be considered from economic point of view as the drilling cost is more expensive.

Another scenario for injection, is to control the well by constant bottomhole pressure of approximately 150 bars in order to be lower than fracture pressure. In this scenario with constant BHP, we can inject much more (64.6 million tons of CO_2) into the Precaspian formation. The total trapped amount of CO_2 is also approximately 19% (12.4 Mtons) from the injected amount. For that scenario, we need to know the stress state of the reservoir formation and accurate fracture pressure measurements.



(a) 100 years (b) 130 years (c) 100 years with constant BHP

Figure 13: Breakdown of CO_2 amount by trapping mechanisms after indicated years in the Precaspian basin

4 Conclusion

In this paper, we use the compositional flow simulation to model CO_2 storage process for Frio CO_2 project, USA, and a geological formation in Precaspian basin, Kazakhstan. We have a good history matching of the well pressure of the Frio project in the model. The impact of different parameters on the model behavior are studied and analyzed with provided data. The result of CO_2 migration in the Frio formation is consistent with other study [17]. Next, we built the compositional flow model for a region of the Precapsian basin using the equation of state and relative permeability curves from the verified Frio field CO_2 model. It has shown that approximately 8.14 million tons of CO_2 can be injected into the region of the Precaspian basin within 100 years with an injection rate of 223 tons/day. Furthermore, about 8% from that injected gas is trapped as residual gas saturation and 12% is dissolved in water within 100 years of injection. The next 130 years after the end of injection demonstrated that the amount of residual trapped gas increases to 10% and dissolved gas increases to 18%. If the injection rate is increased due to well control by bottomhole pressure which is below fracture pressure, we can achieve 64.6 million tons of injected CO_2. On the other hand, the results show that the most of injected CO_2 remains in mobile gaseous phase and can be trapped only by hydrodynamic trapping due to cap rock. The findings suggest that this approach could be useful for decision makers to consider a CO_2 sequestration project in Kazakhstan.

5 Acknowledgement

Authors wishes to acknowledge the research grant, No AP08052762, from the Ministry of Education and the Nazarbayev University Faculty Development Competitive Research Grant (NUFDCRG), Grant No 110119FD4502.

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