The effects of dissolved sodium chloride (NaCl) on well injectivity during CO_2 storage into saline aquifers

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Abstract

Saline aquifer formations seem to be promising candidates for carbon dioxide (CO_2) storage due to their wide availability as well they have large storage capacity. Once CO_2 is injected into saline aquifer variety of processes will take place, among of them is the formation dry out and salt precipitation phenomenon, the main driver of this phenomenon is the salinity in the form of Halite (NaCL), this considers a major challenge of CO_2 injection into saline aquifers, it causes the risk of formation clogging and will effect on the well injectivity and lead to pressure build up. The selected candidate for carbon dioxide (CO_2) storage should meet the technical requirements of sealing integrity, storage capacity (potential) and containment. After the commencement of carbon dioxide (CO_2) injection into high salinity formations, formation dry out due to salt precipitation in the near wellbore will take place and this cause permeability and injectivity reduction. This work will focuses on experimental work. The experimental work investigations studied the effectiveness dilution of high sodium chloride NaCl solutions with sea water and its contribution in improving the injectivity. After saturating the sandstone core samples with different brine solutions, linear core flow tests using nitrogen gas (N_2) were carried out. The saturated samples in diluted solutions for castlegate sandstone sample showed increase in the flow rate from 4 L/min at 50 psi to 5 L/min at the same pressure, experimentally it was confirmed that dilution of brine solutions by seawater will assist in improving the sandstone core samples porosity , permeability and the injectivity.

Keywords- CO_2 storage, seawater, CO_2/Brine/Rock, Salinity, porosity, permeability CO_2 injectiviy,

1. Introduction

CO_2 has the highest contribution in global warming[1]. Carbon capture & sequestration (CCS) is a good and viable option for reducing CO_2-emissions because it can be implemented on a large scale[2]. The target of the mitigation of its effect is always at the forefront, and this can be achieved through the storage of CO_2 underground instead of venting to atmosphere, the underground storage of CO_2 is considered the better option[3]. The main hurdle to widespread deployment of CCS is cost, public acceptance and fear of leakage. CO_2 considers one of the hazardous greenhouse gases causing significant changes in the environment [4] . The negative effects of CO_2 emissions in the atmosphere could be solved by sequestering CO_2 in a suitable environment. The process of storing CO_2 underground can be divided into three major steps: capture, compression and transport, and injection into the subsurface. Halite precipitation takes place in gas wells producers and affects their productivity[5] CO_2 storage into deep saline aquifers is one of the possible promising solutions .Engineering design aspects of CO_2 storage into saline aquifers should be investigated. Sensitivity analysis should be performed by analyzing the effects of parameters such as vertical to horizontal permeability ratio, aquifer porosity, well injectivity, initial reservoir pressure conditions, injection rate and salinity on the sequestration process. Salt precipitation (halite) phenomenon and the near well bore formation dry out could be indicated through falloff pressure tests.

2.0 Experimental set up / Methodology

Description of Laboratory experiment and CT - Scan

The experimental set up used to investigate the effects of dissolved sodium chloride (Nacl) on well injectivity during CO_2 storage into saline aquifers is shown in figure 1. The components of the experimental set up are: pressure regulator (0 -60 psi), fancher core holder, glass tube gas flow meter, pressure gauge and two gate valves, the main purpose of the experimental set up is to carry out core flow test through different sandstone core samples saturated with different salinities using nitrogen gas (N_2).

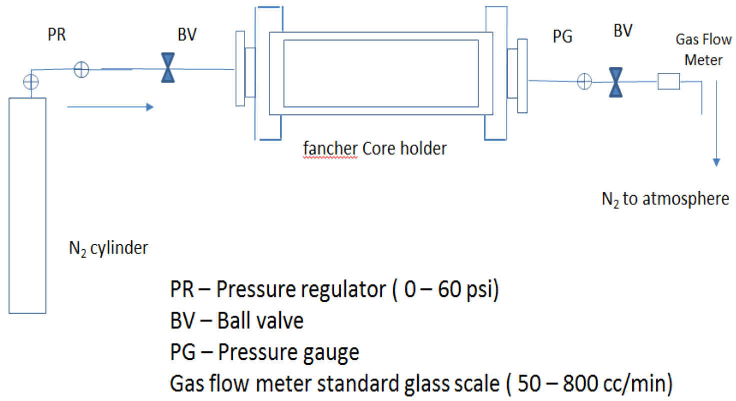


Figure1: Experimental set up

Methodology

Core flood flow tests were carried out for sandstone core samples (Idaho gray, castlegate, Benthemier) at different pressures (psi) and gas flow rates were recorded, after saturated with different brine solutions. Then the same samples were saturated in brine solution (3.5 % NaCl), dried in oven at (100 ^{0}C) and the flow tests were re-carried out, the obtained results were recorded. CT scanner was utilized to calculate the core samples porosity; the results to be compared with the results obtained from conventional methods.

The porosity and permeability of the core sample

Table 1 shows the sandstone core samples porosities and permeabilities obtained from the core samples supplier Kocurek Industries, Inc.

Table 1: Porosity and permeability of the core samples

Core Name	Porosity (%)	Permeability (md)
Idaho gray	29	2200
castlegate	27	750
Bentheimer	24	1200

In order to delay the onset of salt precipitation in the near wellbore, periodic flush of the core samples with the following waters, this could be very effective solution:

1- Periodic flush the formation with low brine salinity. 2- Periodic flush the formation with seawater.

3- Periodic flush the formation with pure water. The most obvious and the cheapest source of water is seawater for offshore fields, shallow aquifers for in onshore fields. River water is used only when no other source is available due to high content of suspended matter. In all cases the prior condition for good injection water is that must improve the well injectivity and the reservoir characteristics

Porosity calculation methods

a) Liquid saturation method

Porosity is a measure of storage capacity of a reservoir. It is defined as the ratio of the pore volume to bulk volume, and is may be expressed as either a percent or a fraction. In equation form

$$\phi = \frac{pore\,volume}{bulk\,volume} = \frac{bulk\,volume - grain\,volume}{bulk\,\,volume} \tag{3}$$

Table2: Dimensions and physical properties of the core samples used in the study

Core name	**Length [cm]**	**Diameter [cm]**	**Bulk volume V_b [cm^3]**	**Wet weight W_s [g]**	**Dry weight W_d [g]**	**Grain volume VG [cm^3]**	**Pore volume PV [cm^3]**	**Porosity Φ [%]**
Castlegate	2.54	2.54	12.87	27.4	23.9	9.608	3.262	25.3
Bentheimer	2.51	2.71	13.38	28.6	25.5	10.49	2.89	21.6
Idaho gray	2.54	2.54	12.87	23.7	20.5	9.89	2.98	23.2

b) Helium gas expansion porosimeter

One of the most used methods of pore volume measurement is the helium technique. This employs Bayle’s law. The helium gas in the reference cell isothermally expands into sample cell. After expansion the resultant equilibrium pressure is measured. The Helium porosometer apparatus is shown schematically in figure 2.

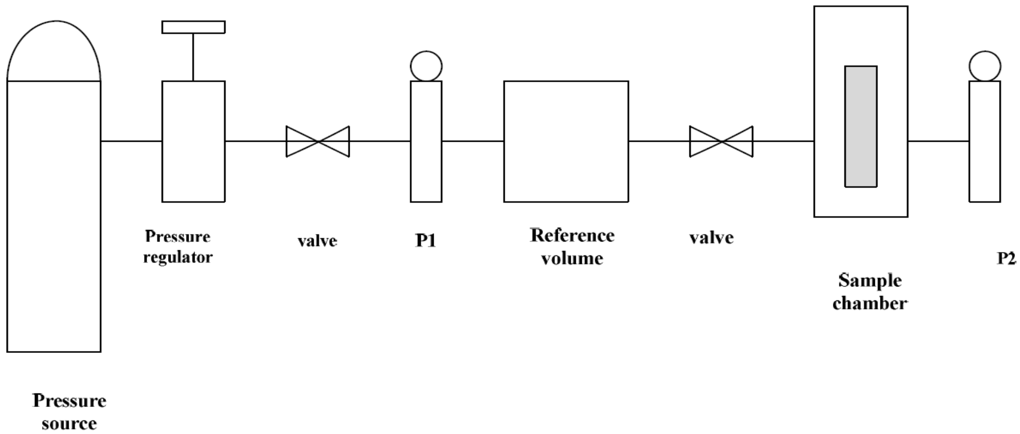


Figure.2: Schematic diagram of helium porosimeter apparatus.

Principles of Grain Volume Determination

The PORG-200™ uses the general gases Law to determine grain volume from the expansion of a known volume of helium into a calibrated sample holder (Matrix Cup).

General gases law: $$\frac{p_1 v_1}{T_1} = \frac{p_2 v_2}{T_2}$$

Where:

p_1 = Initial Absolute Pressure

v_1 = Initial Volume

T_1 = Initial Absolute Temperature

p_2 = Expanded Absolute Pressure

v_2 = Expanded Volume

T_2 = Expanded Absolute Temperature

The reference volume is pressured to 95 Psig and expanded into a Matrix Cup sample holder containing the sample to be analyzed. A second pressure is read, and used to compute the unknown volume. The following equation is often used to derive grain volume:

$$V_g = V_c - V_r \left(\frac{P_1 - P_2}{P_2 - P_a} \right) + V_v \left(\frac{P_2}{P_2 - P_a} \right)$$ Where:

v_g = Grain Volume , v_c = Sample Chamber Volume

v_r = Reference Chamber Volume , v_v = Valve Displacement Volume

P_1 = Absolute Initial Reference Volume Pressure

P_2 = Absolute Expanded Pressure

P_a = Absolute Atmospheric Pressure Initially in Sample Chamber.

It is known that the bulk volume vb = vg + vp, $\Phi = \frac{vp}{vb} = \frac{vb - vg}{vb} = 1 - \frac{vg}{vb}$,

$vp = pore\ volume = (vb - vg)$, Φ is the effective porosity.

C) CT scan method for porosity determination

Micro and Nano-CT scanners produce 2D representations of a slice of an object based on material density, measured by X-ray transmissions. The resulting slice is made up of 3D pixels, known as 'voxels'. The micro CT scan carried out is a non-destructive technique that creates digital slices of the core sample using penetration radiation. The sandstone sample is rotated inside a beam of x-rays and two dimensional radiographs are collected from many directions. The computer is used to line up and center the x-ray images in a radial pattern. The images are then sectioned (sliced) horizontally to produce a stack. Segmentation on the image for the scanned sample was done to reduce computational time enhance image reconstruction resolution. A section of the sample was segmented and used for the image extraction and volume analysis. After segmentation the image is extracted and a 3D visualization of the extracted geometry of the processed CT scans of the sandstone sample. Porosity of the scanned samples was then calculated using the complex computational algorithm in the software package, figure 11 shows the visualization of the scanned samples.

Table3: Shows comparison between porosity computed by helium gas method (A), liquid saturating method (B) and CT –Scan method (C)

No	Core Name	Porosity (A) ϕ (%)	Porosity (B) ϕ (%)	CT scan(C) ϕ (%)	Average ϕ (%)
1	Cstlegate	25.5	24.4	24.29	24.93
2	Bentheimer	20.7	23.6	20.66	21.7
3	Idaho gray	23.8	22.4	24.56	23.6

The three core samples considered were subjected to linear core flow tests using the experimental setup in figure 1. The effect of pressure on flow rates of different NaCl concentrations on each of the samples were measured and tabulated in tables 5 to 10. The effect of NaCl concentration on permeability of core samples was then investigated.

Effect of injected water quality

The presence of impurities in the injected water such as suspended solids cause formation

Plugging, also, the presence of iron (uncoated pipe) and bicarbonate in the injected water causes the precipitation of iron oxides and formation of scale deposits that in turn plug the formation. These materials plug the pore spaces within the rock and consequently reduce the flow path of injected CO_2 and water; As a result, injectivity declines if the water quality is not maintained**.** Seawater should be treated at the plant before it is distributed to the various injection stations. The treatment should be designed to meet the water quality standards listed in Table.1 to prevent and minimize formation plugging from accumulated solids. The presence of solid particles in the injected water causes the precipitations and scale deposits that is turn plug the formation. These materials plug the pore spaces within the rock and consequently reduce the flow path of injected water. As a result injectivity declines if water quality is not maintained [10]. The vaporisation process results in halite drop-out with a consequent reduction in permeability. In consolidated cores vaporisation could be catastrophic for permeability; a reduction of about 50% was measured in this laboratory study for high salinity brine[11].

Table 4: Seawater treatment specifications [6]

Parameter	**Maximum acceptable**
Total suspended solids	0.2 mg/l
pH	7.2
Iron	0.1 mg/l
Sulphide	14 mg/l
Dissolved Oxygen	10 PPb
Particles number > 2 μ	200 particles per ½ ml of water

Theoretical effect of injectvity index

Darcy’s Law for the linear model is shown in equation (1)

$$q = \frac{k\,A}{\mu}\frac{\Delta p}{l} \qquad (1)$$

Changing the temperature of the flowing fluid will only affect the viscosity. Rearranging the above equation to solve for II, it gives equation 2

$$II = \frac{q}{\Delta p} = \frac{k A}{l} \frac{1}{\mu} \qquad (2)$$

Equation (2) says that II is inversely proportional to the viscosity of the injected water which in turn is directly related to its temperature[6]. In this work II will increase if the core permeability increases. A prerequisite for the proper operation of all CO_2 storage sites is a highly injectivity of their injection wells because the cost of drilling new wells is very high. Hence the operators tend to keep the number of wells as low as possible[7]. Salt precipitation reduces formation porosity, and consequently also permeability and injectivity[8]. Horizontal well can significantly increase CO_2 injectivity in brine formations of lower permeability. Injection rates can be increased 4-5 times over that for a vertical for realistic injector lengths with no increase in injection pressure[9]. In highly saline environments, formation dry-out around the injection well is a concern because it may induce precipitation of salts with attendant loss of porosity, permeability, and injectivity[8]. Adverse effects on injectivity caused by bacteria cannot easily be excluded in injection wells of other CO_2 storages[7].

3. Analysis of results:-

1- The average results of the core porosities were compared with that of the core supplier (Kocurek Industries, Inc.) and found that almost the same as shown in table 3.

2- The effects of pressure on flow rate for different brine concentrations were plotted for each core sample, it was observed that as the brine concentration increases the flow rate will decrease as shown in figures 4 – 9.

3- The effects of NaCl concentration on permeability show that the permeability damage % increases as the brine concentration increases as shown in figure 10.

4- Diluting of brine concentration by sea water can eliminate or delay the onset of salt precipitation phenomenon and assist to improve the well injectivity during CO_2 storage into saline aquifers.

Study carried out involved

- Flow of different concentrations of NaCl to investigate the effect of dissolved NaCl on the injectivity performance.

- To investigate how the seawater water could assist in improving the petro physical characteristics (porosity and permeability) of the storage aquifer as well the well injectivity could be improved if it is periodically pumped.

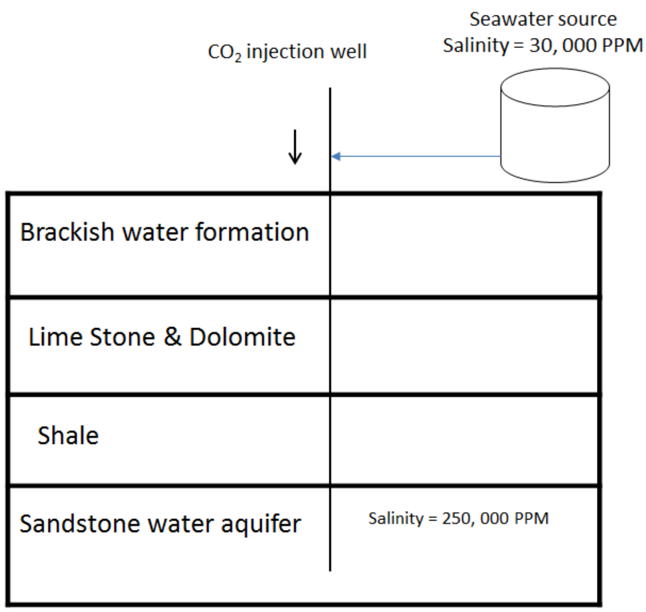


Figure 3: Pumping sea water to storage formation

Table 5: linear core flow test results of Castlegate sandstone core samples

Na Cl Brine concentration							
10%		15%		20%		26.4%	
Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)
10	2.5	10	2	10	1	10	0.3
20	3.5	20	3	20	2	20	1
30	4.5	30	4	30	3	30	2
40	5.5	40	4.5	40	4	40	3
50	6	50	5.5	50	5	50	4

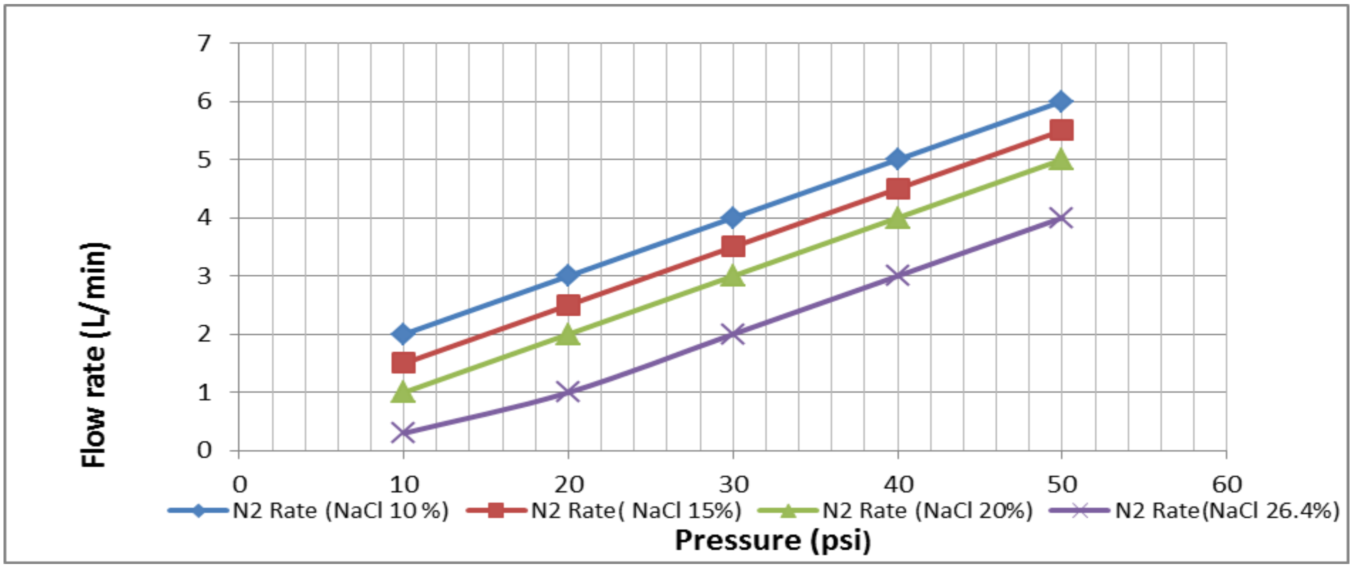


Figure 4: The linear core Flow test of castlegate sandstone

Castlegate core samples, saturated with different brine solution (10%, 15%, 20%, 26.4%), the same samples were saturated with 3.5% brine solution to dilute the concentration and investigate the effect of dilution on injection rate (L/min).

Table 6: The castlegate core flow test results after saturating the samples with 3.5 % NaCl.

All the samples saturated with 3.5 % NaCl							
10%		15%		20%		26.4%	
Pressure (Psi)	**N_2 rate (L/min)**	**Pressure (Psi)**	**N_2 rate (L/min)**	**Pressure (Psi)**	**N_2 rate (L/min)**	**Pressure (Psi)**	**N_2 rate (L/min)**
10	2.5	10	2	10	1.5	10	1
20	3.5	20	3	20	2.5	20	2
30	4.5	30	4	30	3.5	30	3
40	5.5	40	5	40	4.5	40	4
50	6.5	50	6	50	5.5	50	5

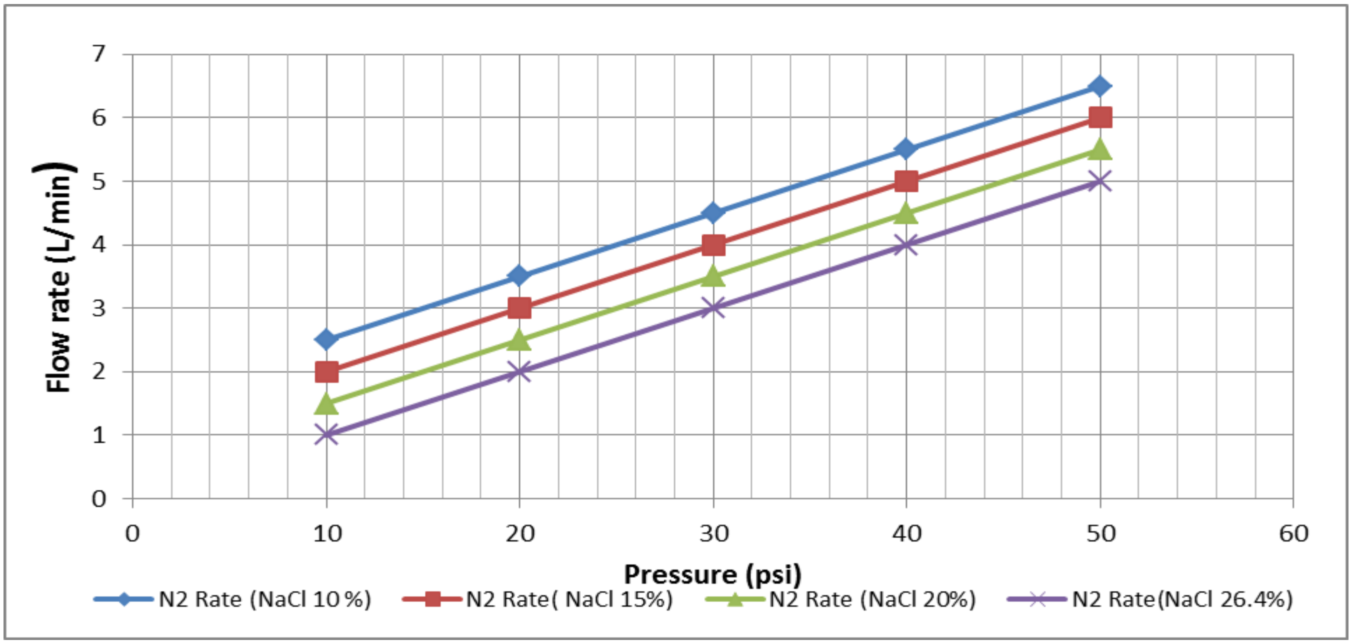


Figure 5: Flow test for castlegate sandstone core samples, after saturating with 3.5% NaCl

Bentheimer sandstone linear core flow test, the core flow test was carried out for each saturated core sample, the obtained result are tabulate in table 7.

Table 7: linear core flow tests results of Bentheimer sand stone core samples

NaCl Brine concentration							
10%		15%		20%		26.4%	
Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)
10	2	10	1.5	10	1	10	0.2
20	3	20	2.5	20	2	20	1
30	4	30	3.5	30	3	30	1.8
40	5	40	4.5	40	4	40	2.5
50	6	50	5.25	50	4.75	50	3.2

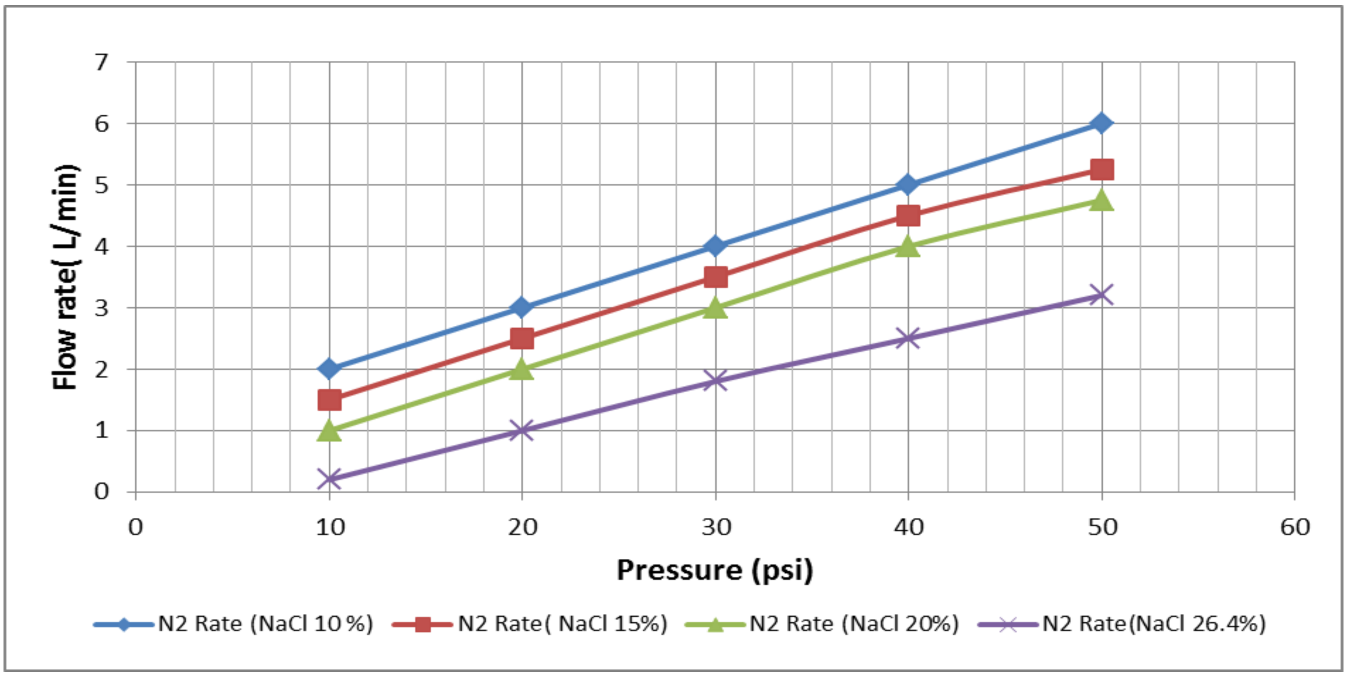


Figure 6: the linear core flow test of Bentheimer sandstone

Bentheimer core samples, saturated with different brine solution (10%, 15%, 20%, 26.4%), the same samples were saturated with 3.5 Wt. % brine solution to dilute the concentration and investigate the effect of dilution on injection rate (L/min), the obtained results are tabulated in table 8.

Table 8: The flow test results of Bentheimer core samples after saturating with 3.5 % NaCl.

All the samples saturated with 3.5 % NaCl							
10%		15%		20%		26.4%	
Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)
10	2.5	10	2	10	1.5	10	1
20	3.5	20	3	20	2.5	20	2
30	4.5	30	4	30	3.5	30	3
40	5.5	40	5	40	4.5	40	4
50	6.5	50	6	50	5.5	50	5

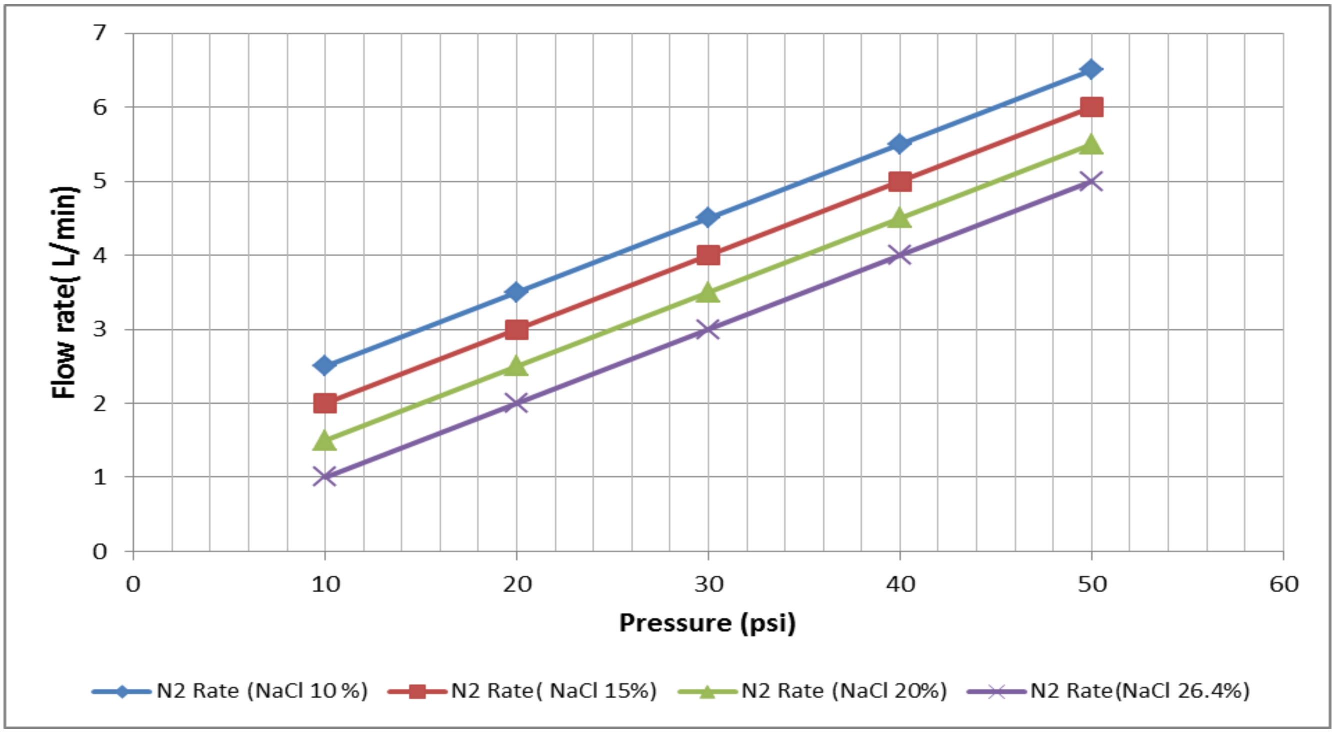


Figure 7: Flow test for Bentheimer sandstone core samples, after saturating with 3.5% NaCl

Idaho gray sandstone linear core flow test, the core flow test was carried out for each saturated core sample; the obtained results are tabulated in table 9.

Table 9: linear core flow test results of Idaho gray sandstone.

NaCl Brine concentration							
10%		15%		20%		26.4%	
Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)	Pressure (Psi)	N_2 rate (L/min)
10	2.5	10	2	10	1.5	10	0.5
20	3.5	20	3	20	2.5	20	1.5
30	4.5	30	4	30	3.5	30	2.5
40	5.5	40	5	40	4.5	40	3.5
50	6.5	50	6	50	5.5	50	4.2

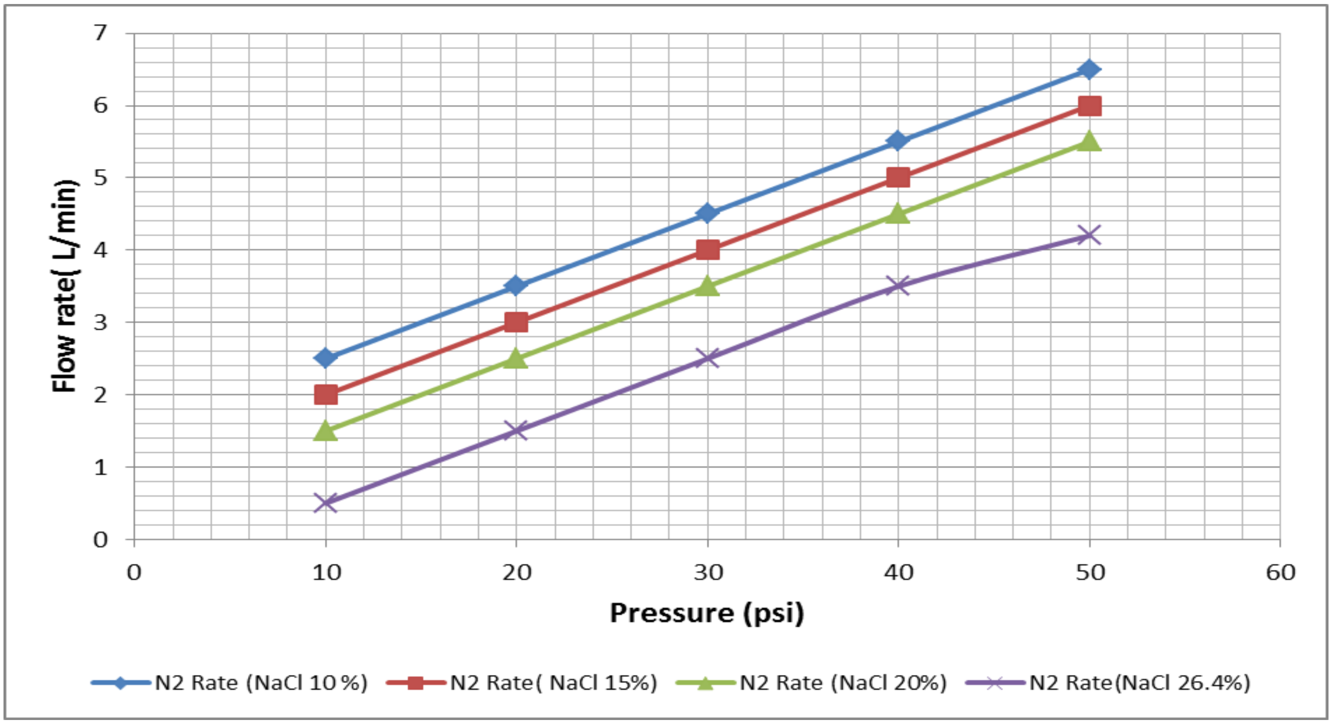


Figure 8: Flow test results of Idaho gray sandstone core sample

Idaho gray core samples, saturated with different brine solution (10%, 15%, 20%, 26.4%), the same samples were saturated with 3.5% brine solution to dilute the concentration and investigate the effect of dilution on injection rate (L/min), the obtained results are tabulated in table 10..

Table 10: The flow test results of Idaho gray core samples after saturating with 3.5 % NaCl.

All the samples saturated with 3.5 % NaCl							
10%		**15%**		**20%**		**26.4%**	
Pressure (Psi)	**N_2 rate (L/min)**	**Pressure (Psi)**	**N_2 rate (L/min)**	**Pressure (Psi)**	**N_2 rate (L/min)**	**Pressure (Psi)**	**N_2 rate (L/min)**
10	3	10	2.5	10	2	10	1.5
20	4	20	3.5	20	3	20	2.5
30	5	30	4.5	30	4	30	3.5
40	6	40	5.5	40	5	40	4.5
50	7	50	6.5	50	6	50	5.5

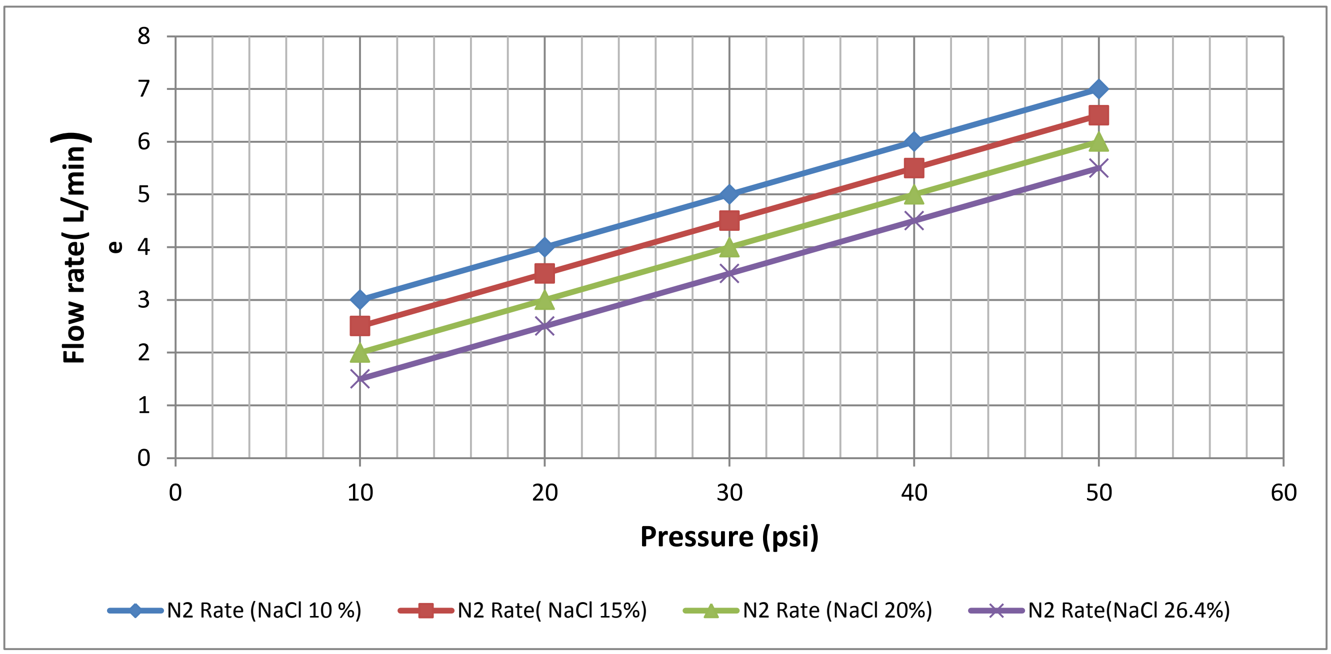


Figure 9: Flow test Idaho gray sandstone core samples, after saturating with 3.5% NaCl

Effect of NaCl (halite) concentration on core samples permeability.

An experimental work was carried out in order to investigate the effect NaCl concentration on brine permeability and below the summary of the obtained results. The apparatus PERL -200 was used to measure the brine permeability. The salinity of the initial brine: The more concentrated the brine, the more massive the salt deposit.[12]

The results in table 11 show that the permeability damage increases as the NaCl concentration increases, the damage is 2 % at 10 % NaCl and increased to 47 % at 26.4 % NaCl concentration.

Table 11: Castlegate, Bentheimer and Idaho gray sandstone core samples permeability damage due to NaCl different concentrations.

Castlegate				Bentheimer			Idaho gray		
Nacl %	K initial	K final	Damage %	K initial	K final	Damage %	K initial	K final	Damage %
10	750	736	2.0	1200	1184	1	2200	2153	2
15	750	668	11	1200	1031	14	2200	1981	10
20	750	506	33	1200	921	23	2200	1817	17
26.4	750	433	42	1200	715	40	2200	1169	47

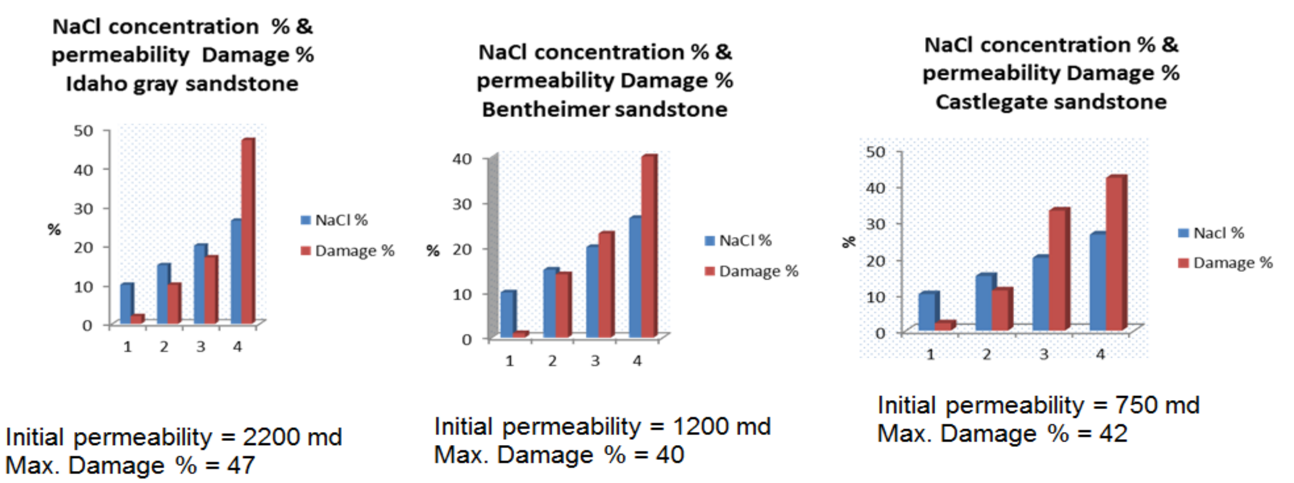
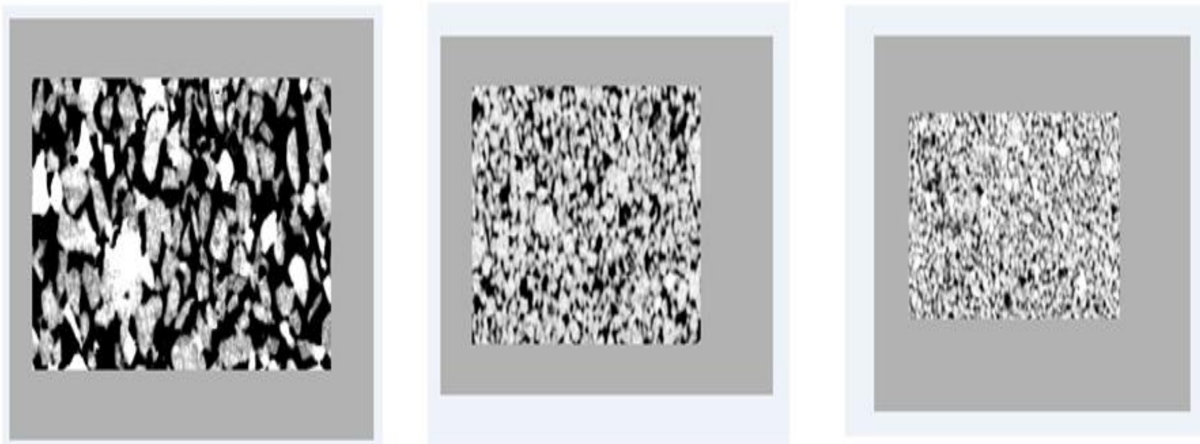


Figure 10: Castlegate, Bentheimer and Idaho gray sandstone core samples permeability alteration due to different NaCl concentration



Idaho gray sandstone **Bentheimer sandstone** **Castlegate sandstone**

Figure 11: Visualisation of the pore spaces for porosity calculation, Castlegate, Bentheimer and Idaho gray sandstone core sample.

Conclusion

In conclusion, during CO_2 injection into a saline formation, focusing only on storage capacity, or the degree to which the pore volume is reduced by halite precipitation, is insufficient, since a little precipitation in a pore-throat could have a significant effect on permeability, which is very important aspect.In this work the brine saturated core samples were subjected to linear flow test and encouraging results were obtained after diluting the brine solutions with seawater, this means the dissolved NaCl contributes to improve the porosity and permeability of core samples. Therefore the formation dry out phenomenon can be eliminated by pumping seawater to the CO_2 storage well. A periodic seawater injection can eliminate the salt precipitation phenomenon in the near well bore provided that the water quality meets the standard requirements table 1. Severe consequences and pore throat plugging can take place if the injected water has any associated solid particles such as (iron) if pipe is uncoated. As shown in figure 10 the NaCl (halite) concentration has drastic effect on core permeability, the damage is between 2 – 47 %, the damage completely dependent on the NaCl concentrations and the aquifer salinity dilution by seawater can improve the permeability and reduce the risk of damage provided that the pumped water is free of suspended particles and scale deposits, if the injected water is well treated the well injectivity will be improved and the aquifer characteristics (porosity and permeability) could remain unaffected. Quantifying the permeability reduction aids the injectivity evaluation for CO_2 sequestration.

Nomenclature

q = Flow rate (cm^3/sec)

II = injectivity index (cm^3/sec)/ (atm)

K = permeability (md)

A = cross section area of core sample (cm^2)

L= length of the core sample (cm)

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