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Energy Procedia 1 (2009) 3221–3228

Energy Procedia

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GHGT-9

Long-term simulation of the Snøhvit CO_2 storage

Audrey Estublier[a], Alf S. Lackner[b]

[a] IFP, 1-4 avenue Bois Preau 92852 Rueil Malmaison, France
[b] StatoilHydro, Rotvoll Arkitekt Ebbells vei 10 7005 Trondheim, ,Norway

Abstract

The purpose of this study is to simulate and evaluate the long-term (1000 years) consequences of carbon dioxide injection into a deep (2700 m) saline formation in the Snøhvit field located offshore in the northern Norwegian Sea. During the 30-year-lifetime of the project, which began in summer 2007, approximately 23 million tons of CO_2 are injected through one well.
In order to analyse different possible CO_2 migration pathways, several scenarios have been assumed and simulated. They deal with the sealing capacity of the main faults and of the saline formation cap rock.

Keywords: Castor, Snøhvit, carbon dioxide, storage, long-term simulation, COORES, migration, faults

doi:10.1016/j.egypro.2009.02.106

1. Introduction

Nowadays, the environment protection leads to recommend the acid gas injection and storage in geological formations as one of the solution to reduce greenhouse gas emissions into the atmosphere. It is the case for carbon dioxide, which represents about 50% of greenhouse gas.

Three options are considered to store carbon dioxide into geological formations: oil and gas reservoirs, deep saline formations and coal seams. At the present time, some geological storage projects are in operation. Most are research, development or demonstration projects like In-Salah (Algeria) and K12B (Netherlands). Several are part of industrial facilities in commercial operation like Weyburn (Canada). In Norway, the environment policy leads industrials to reduce their greenhouse gas emissions. Sleipner and Snøhvit are two StatoilHydro examples of storage into a saline formation.

In order to determine if the Snøhvit site is suitable for carbon dioxide storage, one of the main necessary points to analyse is the behaviour of an injected CO_2 plume on a long-term scale. As a part of the European CASTOR project, the purpose of this study was to simulate and evaluate the long-term (1000 years) consequences of carbon dioxide injection into the deep (2700 m) saline formation from a flow point of view at the reservoir scale.

2. Snøhvit presentation

2.1. Gas production and CO_2 storage

The Snøhvit Unit Area is located offshore in the northern Norwegian Sea (the Barents Sea) (see Figure 1) where the average water depth ranges from 250 to 330 m. It is constituted of three gas reservoirs (Figure 2), Snøhvit, Albatross and Askeladd, which were discovered between 1981 and 1984. The initial gas in place (Figure 2) is assessed to 317 GSm^3, the condensate to 34 MSm^3 and the oil to 73 MSm^3. The natural gas contains five to eight percent CO_2. At the onshore plant on Melkøya, CO_2 is separated from the natural gas and piped back to a formation at the edge of the Snøhvit reservoir, where it is stored 2700 m beneath the seabed. The CO_2 injection rate will be 700 ktons per year, thus, approximately 23 million tons of CO_2 will be stored a the end of the 30 years lifetime of the LNG project. Injected at 4°C (well head conditions), CO_2 stream meets reservoir conditions (98°C and 285 bar) where it is supercritical.

The production strategy is a phased development starting with eight gas producers and one CO_2 injector F-2H on the Snøhvit field. The Askeladd field and thereafter Albatross are phased in when required to maintain plateau gas production. A total of 21 gas producers are planned. A total of 194 GSm^3 of gas and 19 MSm^3 of condensate will be produced over the field life.

On 21 August 2007, the operator StatoilHydro opened the valves on the Snøhvit wells and gas flowed through the 143-km pipeline to land and into the plant at Melkøya (near Hammerfest). After five years of development, production of liquefied natural gas (LNG) at the Hammerfest LNG plant started on 13 September 2007. Concerning CO_2 reinjection, it started on 22 April 2008.

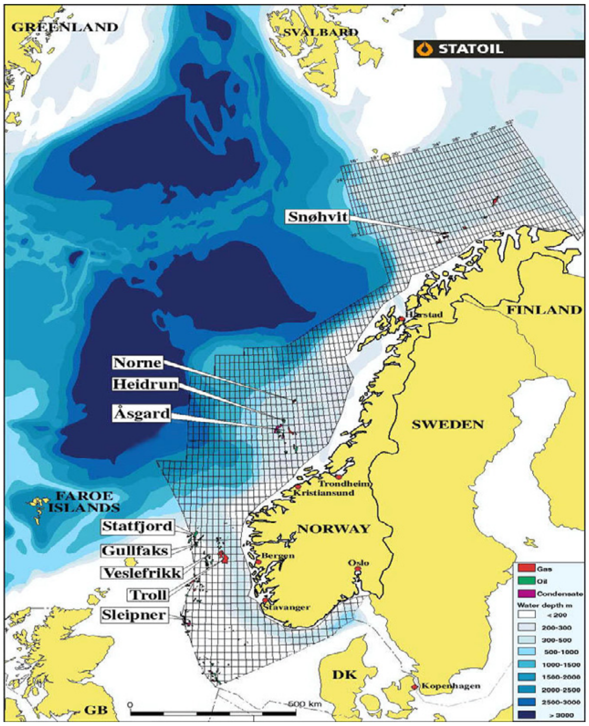


Figure 1 The Snøhvit Unit Area location

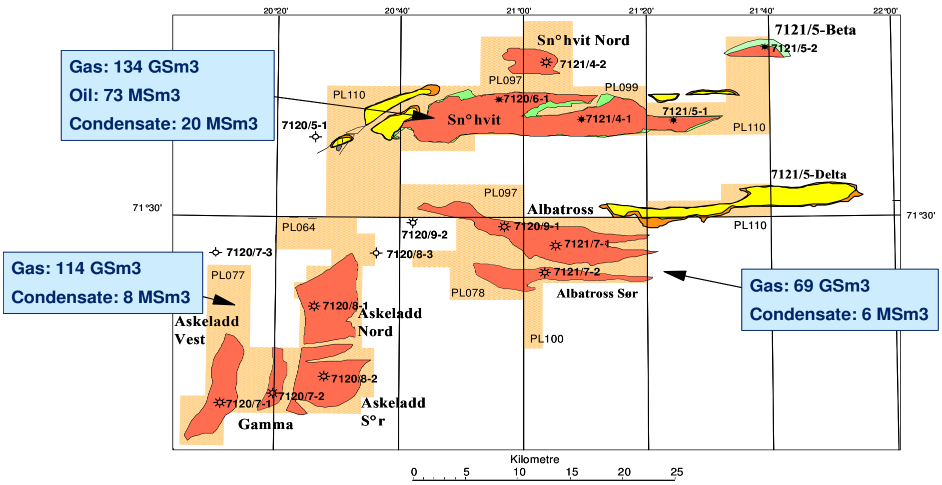


Figure 2 The Snøhvit Unit Area [1]

2.2. The lithostratigraphic formations [2]

The Snøhvit Unit Area is located in the south-western Barents Sea in the central part of the Hammerfest Basin (Figure 3). Most of the structures in the Barents Sea are overlain by upper Jurassic shales and thick Cretaceous shales that act as a seal/cap rock for the structures in the region.

The Late Triassic - Middle Jurassic lithostratigraphic formations (see Table 1) named Fruholmen, Tubåen, Nordmela and Stø consist mainly of sandstones interbedded with thin shale layers. The 45-75m-thick Tubåen is dominated by sandstones with subordinate shales and minor coals. The 60-105m-thick Nordmela formation is divided into a lower unit with very poor reservoir characteristics forming the cap rock of the underlying CO_2-bearing Tubåen formation (Nordmela2) and an upper with reservoir qualities ranging from poor to moderate (Nordmela1). The gas-bearing Stø formation is 70-100m-thick. It consists of thick sandstones alternating with thin shales and mudstones. It has been subdivided into 5 reservoir zones, Stø1-Stø5, of which the Stø5 is the lowermost, thickest and best reservoir zone.

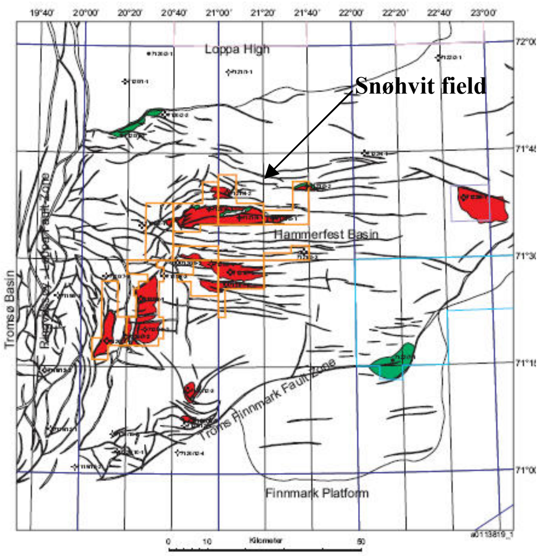


Figure 3 Structural setting of the Snøhvit Unit Area in the Barents Sea [2]

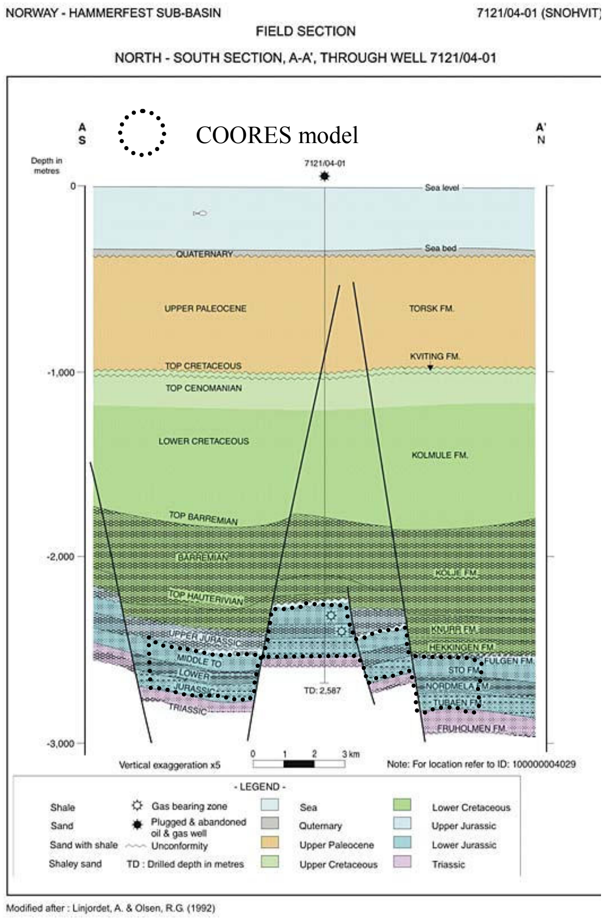


Figure 4 Stratigraphy of the Hammerfest Basin in the Snøhvit zone [3]

The Middle and Upper Triassic strata (e.g. the Fruholmen formation) are characterized by a lower sequence of interbedded shales and sandstones that occasionally are carbonaceous and contain coal fragments, overlain by a shaly and silty unit that has increasingly more interbedded sandstones upward.

Table 1 Horizontal permeability, Net-to-Gross and porosity [4]

Formation	Porosity [%]	Permeability [mD]	Net/gross	Type
Stø 1	14	16-186	0,930	gas-bearing formation
Stø 2	15	110-290	0,989	
Stø 3	12	1-9	0,837	
Stø 4	13	2-7	0,994	
Stø 5	17	217-659	0,992	
Nordmela1	13	4-39	0,494	cap rock
Nordmela2	13	1-23	0,152	
Tubåen	10-15	185-883	0,666	Aquifer used for CO_2 reinjection

3. Long-term simulations [5]

This section presents the results of the long-term carbon dioxide storage simulation in a limited area composed of three formations: Tubåen , Nordmela and Sto (Figure 4). In order to analyse the different possible pathways of CO_2 migration, several scenarios were assumed and simulated. They focus on the sealing capacity of existing faults (Figure 4) and the physical properties of Nordmela (capillary pressure and relative permeability).

3.1. COORES model

For this study, IFP software dedicated to CO_2 simulation, named COORES version 1.1.2, was used. In order to reduce the CPU time of the long-term simulation, two assumptions were considered. Firstly, the flow model is a two-phase model: water and gas phases. Secondly, the migration model simulates the non reactive mass transfer of two components: CO_2 and CH_4-N_2.

Moreover, in order to study the migration of the dissolved CO_2 plume, the CO_2 dissolution in water is modelled by a constant as a function of temperature, pressure and salinity. Hysteresis phenomena are not taken into account, thus, the critical gas saturation (Sgc) is equal to the residual gas saturation (Sgr) in all the scenarios. Only a study of sensitivity to the residual gas saturation (Sgr=4% and 25%) in Tubåen has been performed to highlight the capillary trapping.

3.2. Results

The simulations showed the following results.

If the faults are assumed to be sealed, the simulations indicate that the CO_2 plume mainly migrates westward in the Tubåen formation (Figure 5) but doesn't reach the boundaries of the model. CO_2 remains trapped in the saline formation (Figure 6) and the only observable impact is a strong pressure increase in the aquifer during the injection period. Therefore, the CO_2 storage capacity is limited and inferior to the desired 23 Mtons. With a threshold fracture pressure of 390 bar, about 4 Mtons can be injected in 6 years ; with a threshold pressure of 1.5 times the reservoir pressure, the injection of 17 Mtons is possible in 30 years. If the Nordmela sealing capacity is reduced, about a third of the mass of injected CO_2 migrates up to the gas reservoir through Nordmela over 1030 years but without reaching its top.

If the faults are assumed to be permeable, CO_2 mainly migrates along two faults to the gas reservoir (n°1 and 2 on Figure 7) and slightly to the North boundary (n°3 on Figure 7) of the model even if the sealing capacity of Nordmela is reduced. At 1030 years (Figures 8 and 9), the major part of the injected CO_2 mass migrates up to the gas reservoir. Only 7% of which a part is trapped by capillary (Sgr=4%) remains in Tubåen. Whatever the scenarios, the North boundary is the only migration pathway at the Snøhvit model scale (Figure 9). The migrated proportion through the North boundary ranges between 5.2% and 6.4 % of the mass of injected CO_2. If the residual gas saturation is considered equal to 25% instead of 4% (see Figure 10), the amount which does not migrate to the gas reservoir and remains in Tubåen is higher (20% instead of 7%) and only 4.6% of CO_2 compared to 5.2% migrates through the North boundary.

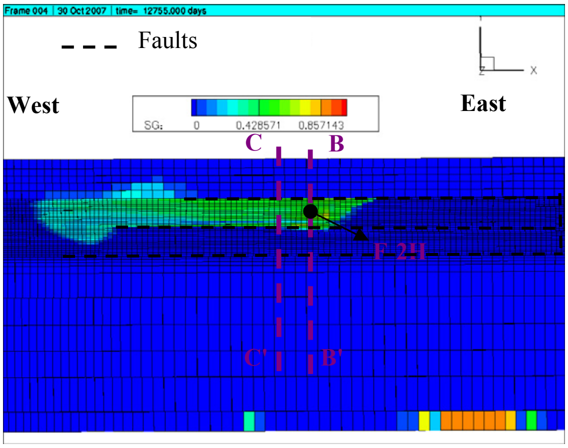


Figure 5 Gas saturation in the Tubåen formation, 30 years, 17 Mtons of injected CO_2 in the closed fault model

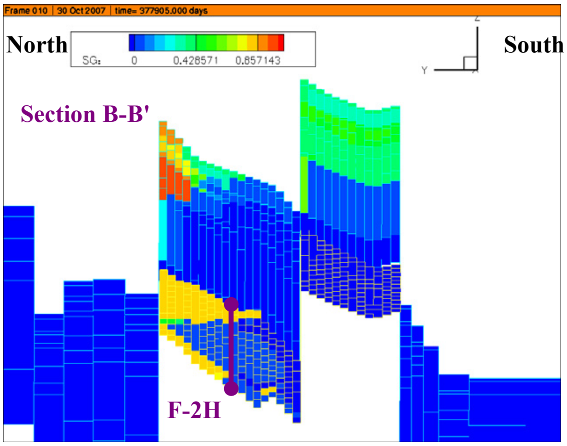


Figure 6 Gas saturation in section B-B', 1030 years, 17 Mtons of injected CO_2 in the closed fault model

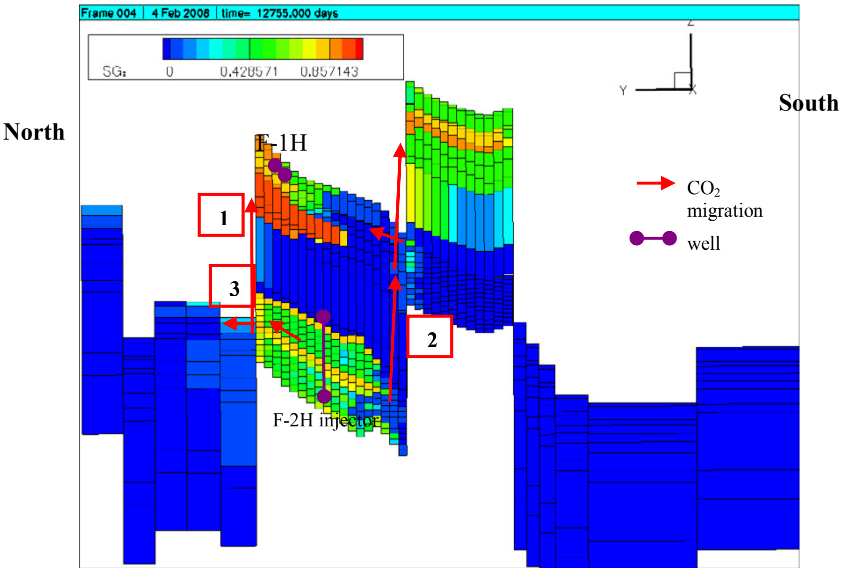
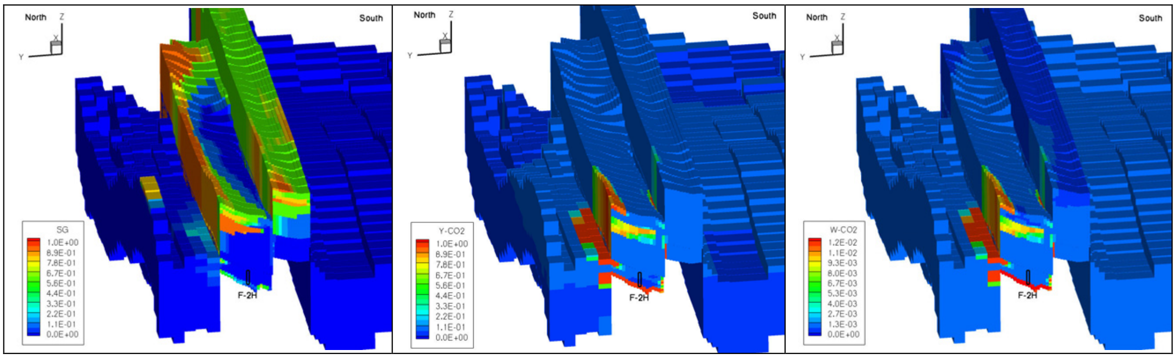


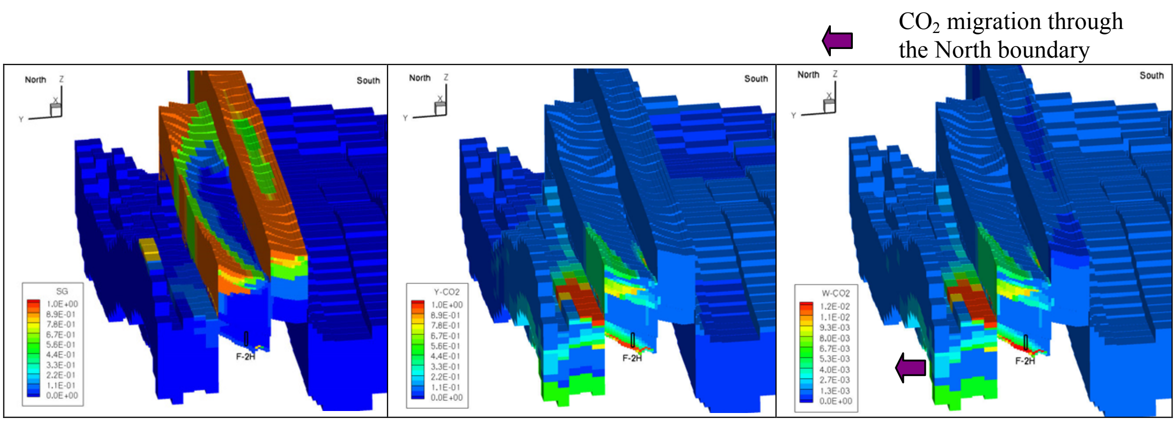
Figure 7 Gas saturation in vertical section B-B', 30 years, 23 Mtons of injected CO_2 in the permeable fault model

Section C-C'



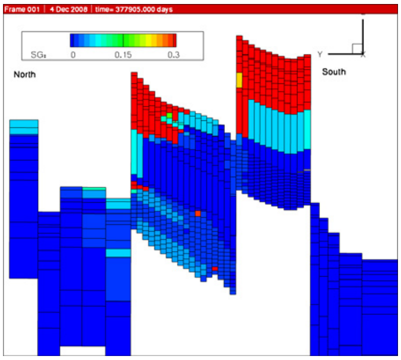
Gas saturation | CO_2 gas molar fraction | CO_2 water molar fraction

Figure 8 Permeable fault model, 30 years (injection period), section C-C'

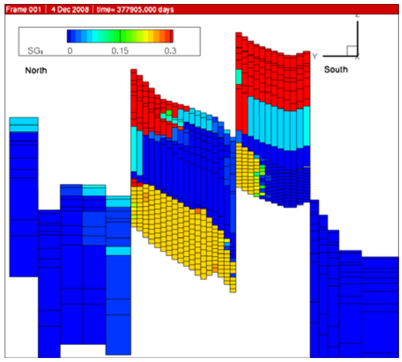


Gas saturation | CO_2 gas molar fraction | CO_2 water molar fraction

Figure 9 Permeable fault model, 1030 years (injection+storage period)



Gas saturation: Sgc=Sgr=4%



Gas saturation: Sgc=Sgr=25%

Figure 10 Permeable fault model, 1030 years (injection+storage period), two studied cases: critical gas saturation (Sgc) is equal to residual gas saturation (Sgr), 4% or 25%

4. Conclusion

The purpose of this study was to simulate and evaluate the long-term (1000 years) consequences of carbon dioxide injection into the deep (2700 m) saline formation in the Snøhvit field. The analyse of the different scenarios have showed that the CO_2 plume behaves differently according to the fault permeability. If the faults are assumed to be sealed, CO_2 remains trapped in the saline formation and the only observable impact is a strong pressure increase in the aquifer during the injection period. In the opposite case where the faults are assumed to be permeable, the major part of the injected CO_2 mass migrates to the gas reservoir, about 5 % of the injected CO_2 mass exits the computation domain and only a small amount remains in the injection domain.

The results highlighted that as a part of a risk analysis, it would be necessary to laterally and vertically extend the model domain. Indeed, the sealing capacity of the gas reservoir cap rock and the fault network can play a part in CO_2 migration.

Acknowledgements

IFP gratefully thanks StatoilHydro for providing the data [1], [2] [6] and for the permission to publish this paper.

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