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Lessons Learned from 14 years of CCS Operations: Sleipner, In Salah and Snøhvit

Ola Eiken, Philip Ringrose, Christian Hermanrud,
Bamshad Nazarian, Tore A. Torp and Lars Høier

Statoil ASA, Technology and New Energy,Trondheim, N-7005, Norway

Abstract

In the paper we share our operational experience gained from three sites: Sleipner (14 years of injection), In Salah (6 years) and Snøhvit (2 years). Together, these three sites have disposed 16 Mt of CO_2 by 2010.

In highly variable reservoirs, with permeability ranging from a few milliDarcy to more than one Darcy, single wells have injected several hundred Kt of CO_2 per year. In the reservoirs, the actual CO_2 plume development has been strongly controlled by geological factors that we learned about during injection. Geophysical monitoring methods (especially seismic, gravity, and satellite data) have, at each site, revealed some of these unpredicted geological factors. Thus monitoring methods are as valuable for reservoir characterisation as they are for monitoring fluid saturation and pressure changes.

Current scientific debates that address CO_2 storage capacity mainly focus on the utilization of the pore space (efficiency) and the rate of pressure dissipation in response to injection (pressure limits). We add to this that detailed CO_2 site characterisation and monitoring is needed to prove significant practical CO_2 storage capacity – on a case by case basis. As this specific site experience and knowledge develops more general conclusions on storage capacity, injectivity and efficiency may be possible.

"Keywords: carbon; storage; operations; Sleipner, In Salah, Snøhvit"

1. Introduction

There are many technical issues confronting ambitions for global-scale implementation of Carbon Capture and Storage (CCS) as a greenhouse gas mitigation action. Injection capacity (injectivity) in each well and reservoir storage capacity / storage efficiency are key performance parameters for the storage cost. While pre-injection models are used to qualify and design a storage project, monitoring and model updates will learn us how close to reality the initial models were, and give us better predictions. Also, it is important for CCS that we can assure ourselves, the regulators and the public that the CO_2 can be safely stored in the long term, as it is still being debated whether the technology is a propriate greenhouse gas mitigation tool.

Considerable experience has been gained by the pioneering field-scale CCS projects which have been testing and proving this technology. In the paper we share our operation experience gained from three industrial-scale sites, which have succeeded in disposing of over 16 Mt of CO_2 since 1996. The sites span a large variety of natural environments as well as cost environments and site histories, and these experiences could therefore be useful for getting insight into the future of this potential new industry.

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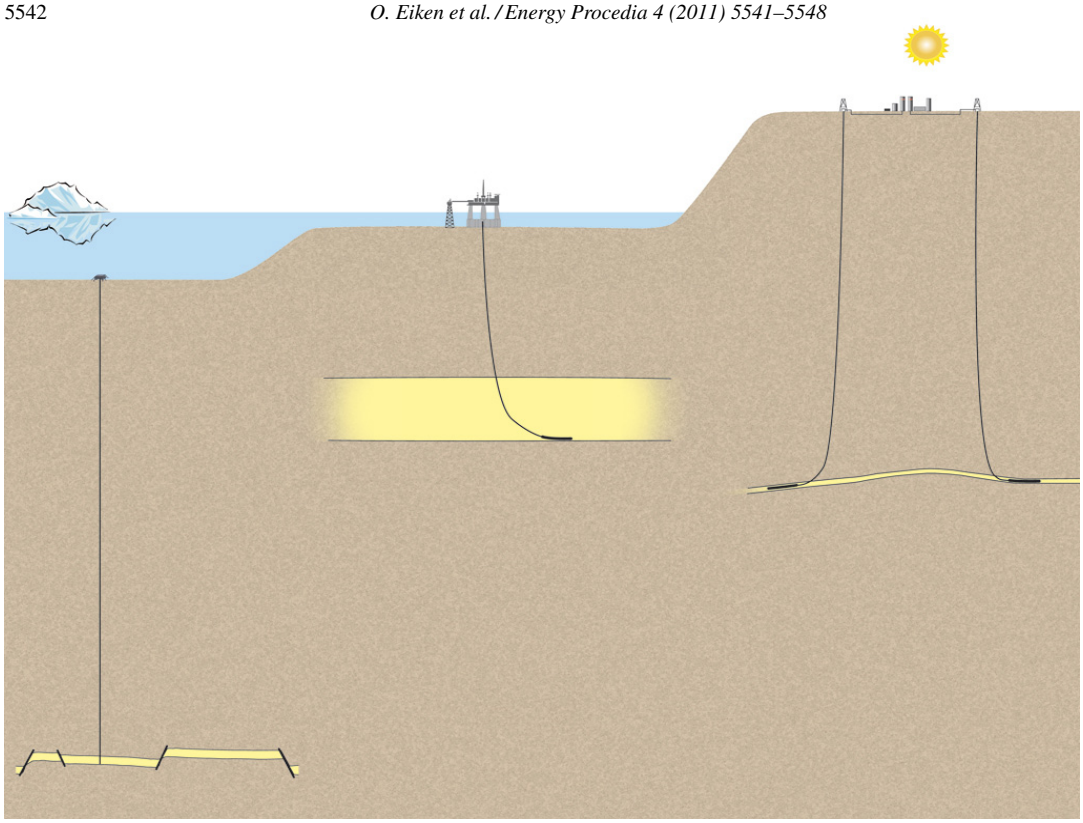

Figure 1: Sketch of the geological settings of the Snøhvit (left), Sleipner (middle) and In Salah (right) storage reservoirs.

2. Site characteristics

The three sites, Sleipner, In Salah and Snøhvit, are contrasting in many respects (Figure 1). Surface conditions vary from the Snøhvit field situated in the Barents Sea in a fully subsea development at ~330m water depth, Sleipner in the more accessible North Sea with a production and drilling platform in 80 m water depth, and In Salah in a rocky part of the Sahara desert at ~470 m altitude. Storage depths range from ~700m below seafloor (Sleipner) to 1700 m below surface (In Salah) and 2400m below seafloor (Snøhvit). Corresponding pressure and temperature ranges all give CO_2 at supercritical conditions (Figure 2), but much closer to the critical point for Sleipner than for the others.

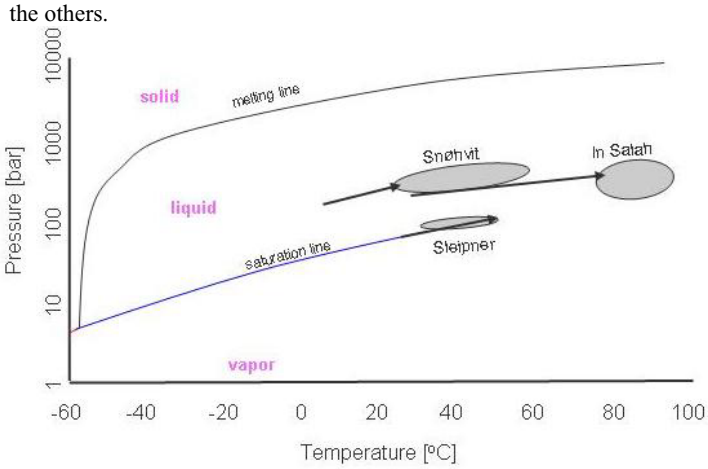

Figure 2: Phase diagram of pure CO_2 as function of pressure and temperature, with well head and bottom hole situations for Sleipner, In Salah and Snøhvit shown as arrows, and reservoir conditions indicated as shaded areas. At Sleipner, the CO_2 cools down in the reservoir, while it warms up at In Salah and Snøhvit.

All these reservoirs are sandstones, but geological settings vary widely. The shallow and unconsolidated sands in Utsira Fm. at Sleipner were deposited as basin-restricted marine lowstand deposits [1]. A sand rich succession is in the Sleipner area 200-300 m thick and has a net-to-gross ratio of 95%, interbedded with thin (<1 m) shale stringers. Porosities are 35-40% and permeabilities above 1 Darcy (Figure 3). The Utsira Fm. covers an area of about 26 000 km^2 [2], in an area with several gas pipelines to the European continent, and could potentially store Gigatons of CO_2 [3] in the future.

The more deeply buried and tighter formations at In Salah and Snøhvit have much lower porosities and permeabilities [4, 5], caused by both compaction and diagenesis effects, as well as the more muddy primary depositional environment. Tubåen Fm. at Snøhvit is fluvial, and observed open fractures may have been caused by late Cenozoic uplift [6, 7]. Permeabilities > 500 milliDarcy have been measured from cores, but the lateral extent of such good sands is uncertain. The up to 110 m thick formation contain several shaly intervals, and the degree of vertical communication throughout the reservoir was uncertain prior to injection. Deposition was tidal deltaic at In Salah, where the formation best can be described as a fracture-influenced, matrix-dominated reservoir [5]. The low matrix permeabilities at In Salah could pose the largest challenges on injection capacity in each well, but this could be helped by fracture permeability. Both the Sleipner and In Salah storage reservoirs are gentle domed four-way dip closures, while the Tubåen Fm. at Snøhvit is situated in a faulted block with >200 m throws, but not completely sealed off according to the seismic mapping [4].

Sleipner reservoir properties will clearly give the easiest flow of CO_2 through the reservoir, with the highest single-well injection capacity (maximum rate). How the geology of these three sites will affect the volumetric sweep and storage mass per unit area (storage efficiency) can not be found out from pre-injection modeling studies, however. Significant restrictions and heterogeneities such as stratigraphic and fault barriers within the reservoirs could on the one hand cause larger injectivity challenges, but on the other hand a better distribution of CO_2 in the storage reservoir cannot be ruled out for such a case.

The cap rock succession above the In Salah and Snøhvit reservoirs is thicker and more consolidated than at Sleipner, with alternating shales and sandstones. At Snøhvit there is even a producing gas reservoir above the storage formation, as illustrated in Figure 1, and a leakage up to this level would close the circle for the travelling CO_2.

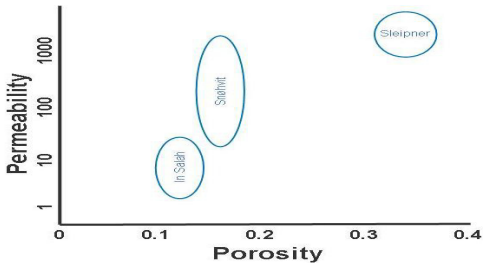

Figure 3: Estimated porosity and permeability ranges of the three sites.

3. Well and injection experience

On Sleipner, the CO_2 is wet [8], while the Snøhvit and In Salah CO_2 is dried down to <50 ppm water content. A 0.5% - 2% methane fraction is present in all injections. The CO_2 passes through four compression stages at all three sites, in order to reach the required well head pressure. During prolonged shut-in periods at Sleipner, the temperature at the top of the well may drop to 5°C and the pressure to 40 bar, which is within the hydrate formation envelope and requires hydrate inhibition. The injection well is drilled highly deviated (83°) from the platform; 2.4 km laterally at 1 km depth [8], underneath a gentle anticline with relief of only 10-20 m and possible spill points in three directions. High-quality stainless steel (25 % Cr) was used for the 7" tubing and exposed parts of the 9 5/8" casing to prevent corrosion [9]. After the initial well perforation had been done, a 38 m long section was re-perforated using a gravel pack containing 200-micron sand screens, and this has proved to be sufficient for high and stable injection rates since 1996, as shown in Figure 5. By September 2010, 12 million tons of CO_2 had been injected. At the Sleipner well head, CO_2 is just at the phase transition between gas and fluid (Figure 2), in a two-phase flow. Wellhead

temperature is controlled to be stable at 25°C, and pressure has consequently been stable at the phase transition (around 62-65) bar during all these years. Bottom hole pressure is not measured, but the stable injection and 4D seismic images (see below) suggest only small pressure buildup in the reservoir, implying pressures only marginally above hydrostatic. Bottom-hole temperature of the injected CO_2 is estimated at about 48°C, some 13°C higher than the virgin reservoir temperature. Injection has been regular, with major interruptions only during the typically ~4-week work-over periods of the platform every second year. A insignificant portion of the captured CO_2 has been vented to the atmosphere.

At In Salah, the three wells all inject down flank in the same ~20 m thick reservoir zone as on the gas fields, with horizontal sections up to 1.8 km long. Injection started 2004. Injection pressures are significantly higher than at Sleipner. All three wells are operated at a common wellhead flowing pressure, mostly ranging between 140 and 180 bar. De-hydration was found to be less costly than using stainless steel in the well completions [10]. Injection temperature fluctuates between 25°C and 55°C (winter – summer). Estimated flowing bottom hole pressures are around 290 bars (based on extrapolation from surface data), considerably higher than the initial 180-190 bars. The horizontal wells were designed to cross the prevailing natural fracture direction (NW-SE) and hydraulic stimulation of fractures within the reservoir has probably occurred [11, 12]. Together the injection wells have taken most of the captured CO_2.

At Snøhvit, CO_2 is compressed to 80 - 140 bars at the onshore LNG plant and transported offshore in a 153 km long 8” pipeline [13]. Subsea injection occurs via a seafloor template and a near-vertical well with currently three perforation zones covering in total ~30 m of the 110 m thick Tubåen Fm. The injection zone is underlying the water zone of the gas reservoir, close to the rim of the field. The Tubåen Fm. within the fault block comprising the Snøhvit field is estimated to contain a pore volume of about 1 billion m^3 with further possible communication to neighbouring downfaulted blocks. Pressure is expected to rise in a closed volume environment [14], with storage capacity depending on the actual volume in communication with the well. Injection commenced in April 2008, and 0.8 million tones have been injected by September 2010 (Figure 4). Injection has been intermittent, due to start-up challenges for the onshore LNG plant. Only small quantities of CO_2 have been vented to the atmosphere.

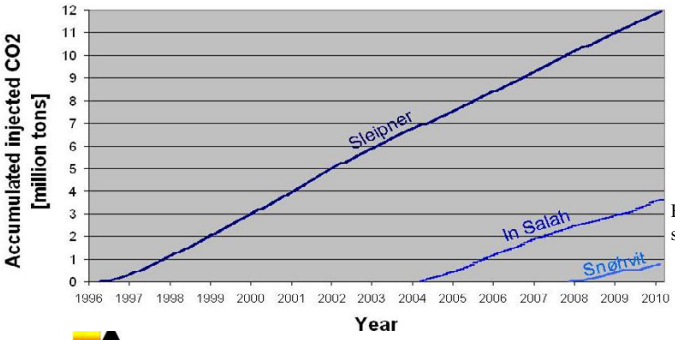

Figure 4: Cumulative injected mass of CO_2 at the three sites.

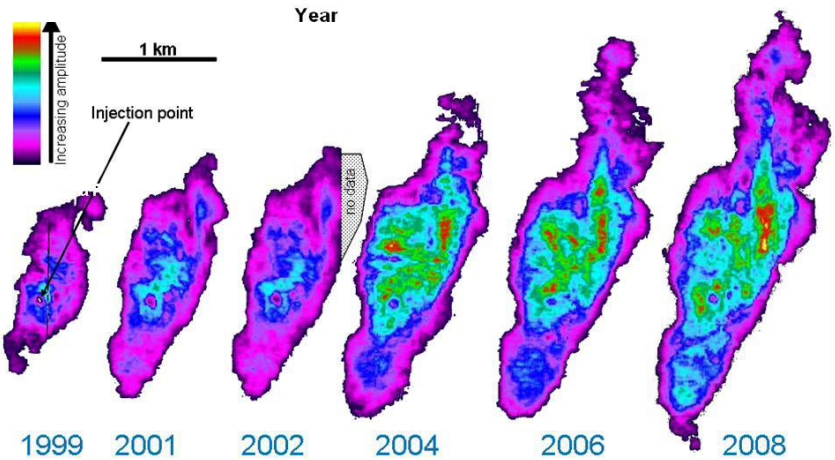

Figure 5: Time-lapse seismic difference reflection amplitude maps at Sleipner, cumulative for all layers. Expansion of the plume in all directions is observed, as well as intensified reflections in the central part of the plume.

4. Monitoring and modelling

On Sleipner a set of six repeat 3D seismic surveys have been acquired, giving a unique set of monitoring data [15]. The CO_2 plume yields highly-reflective layers, and outlines the plume well (Figure 5). The mapped plume area reached 3.1 km^2 by 2008, which means that about 5% of the pore space under that area is occupied by CO_2. This volume ratio has remained fairly constant during the last ten years. The area has been steadily growing, as has the sum of seismic amplitudes (Figure 6). In spite of this good linear relation, quantitative estimates based on seismic amplitudes and travel time changes are challenging [16], and currently the seismic data are not able to estimate, for example, the amount of CO_2 dissolved in the water. No leakage to levels above the Utsira Fm. has been observed by inspection of time-lapse difference sections. High data repeatability has been obtained by dedicated seismic acquisition and processing, and the detection threshold may be of order one Kt of CO_2.

Three time-lapse seafloor gravity surveys have been carried out, in 2002, 2005 and 2009. CO_2 pushing away denser water reduces gravity, and inversion for average density using geometry constraints from seismic give 675-715 kg/m^3 of this supercritical fluid [17]. Combining this with recent temperature measurements to determine the CO_2 density distribution within the plume, the data may be inverted for the amount of CO_2 absorbed in the formation water, which cause an increase in gravity. Data and model precision gives a detectability level of 1.8 % absorption per year, and no absorption (above this level) has been observed so far [17]. In addition a trial Controlled Source Electromagnetic (CSEM) survey was carried out 2008, but no interpretable signal from the CO_2 plume has been detected in the analysis so far, probably due to pipeline noise and moderate CO_2 response. The seafloor has been mapped with multibeam echo sounding and side-scan sonar. Videos have been taken by ROV, as a routine precaution, and as expected no seafloor changes (pockmarks, bubbles) have been observed.

Detailed interpretation and flow modeling for matching and prediction purposes has been a challenge on Sleipner. Clearly much of the flow is controlled by the topography. The injected CO_2 flows in nine distinct high-saturation layers not more than a few meters thick, capped by thin intra-sand shales above. Strong gravitational segregation causes CO_2 to flow upward in the reservoir and plume shape mainly resembles the top reservoir topography. This is challenging to capture by finite element modeling (Eclipse), which then requires high-resolution grids [17]. An alternative simulation method, using invasion percolation, appears to capture the topographic control adequately, but neglects some of the near-well time-dependent effects dominated by viscous forces [18]. Straight extrapolation based on the mapped topography suggest that the plume will continue to expand in the northerly direction and mostly in the middle and upper layers (layer 5 and 9) in the years to come, while some of the modeling has suggested faster front movement across the western spill point than has been observed so far.

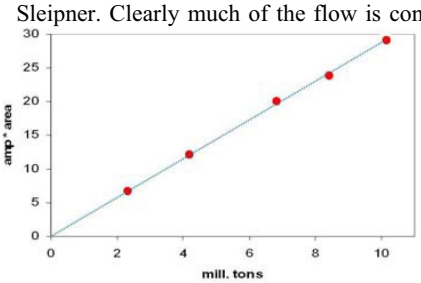

Figure 6: The area-integrated seismic amplitudes for all layers cross-plotted against injected mass at Sleipner.

At In Salah, a wide range of monitoring techniques have been deployed [19]. Due to the challenging and remote onshore setting, the seismic dataset is limited to a pre-injection baseline 3D seismic (1997) and one good quality time-lapse dataset (2009) over the northern area, covering two of the injectors. InSAR satellite data has however been acquired over the entire injection period, with survey intervals of between 30 days and 8 days, depending on the satellite and bandwidth. Elevation of the ground has been monitored to mm-precision in pioneering work on InSAR processing [11]. Above the injection wells, uplift of 1-2 cm has been observed (Figure 7), and this has been inverted to infer sub-surface pressure expansion [20]. Time-lapse processing and analysis of the 2009 repeat seismic survey is challenging, due to limitations in the baseline survey. However, amplitude changes probably related to pressure effects at the reservoir level are observed around the KB-503 well, while KB-502 which had injected less CO_2 and was shut in during the repeat seismic acquisition shows a less clear response. Passive microseismic recording started in July

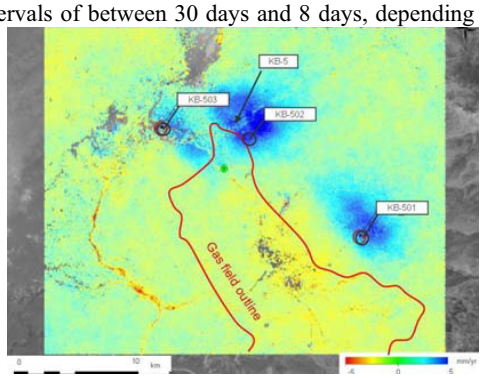

Figure 7: InSAR surface elevation map of In Salah [20, 21].

2009, and an array of tilt meters was deployed in December 2009. Also a program of surface and soil gas and groundwater monitoring has been deployed, and 5 shallow aquifer monitoring wells have been drilling [12]. CO_2 breakthrough was detected in the suspended appraisal well KB-5, and tracer analysis confirmed that the CO_2 came from injection well KB-502 [21]. This observation serves as a constraint to flow models, and suggests some fracture flow. KB-5 has now been plugged and abandoned to secure this well against possible future leakage.

Down-hole pressures and temperatures are measured 800 m above the reservoir in the injection well at Snøhvit, and can be remotely accessed on line. The frequent injection stops give a unique time series of pressure build-ups and fall-offs, as illustrated in Figure 8. With current injection rates, there has been a clear trend of pressure increase over the 2 ½ years of injection history. The longest injection stop lasted for four months. Pressure did not stabilize during that period (Figure 8). This indicates moderate effective permeability (lower than initially expected from pre-injection well data), but this is not a constraint on the maximum reservoir volume which is in contact with the well. It is too early to know the storage capacity based on the observed pressure increase in the well. 4D seismic data acquired 2009 revealed clear anomalies related to both CO_2 and pressurized water, with amplitudes decaying away from the injection well and falling into the background noise level 1-3 km away from the well (Figure 8). More than 90% of the 4D amplitudes are within the lowermost zone of Tubåen Fm., connected to the lowermost perforation. This shows that only a small part of the Tubåen Fm., about 1/6 of the volume, is receiving most of the CO_2. Probably this zone is sealed off vertically from the rest by a shaly interval. The spatial pattern of high seismic amplitudes indicates presence of CO_2 in a NW-SE trending channel. The areal extent of the 4D anomaly is too large to arise from rocks saturated with 500 Kt CO_2, and forces us to interpret some of the amplitudes as pressure induced. The spatial variability (Figure 8) suggest that lateral heterogeneities play an important role. Possibly are barriers related to channeling reducing the effective permeability significantly.

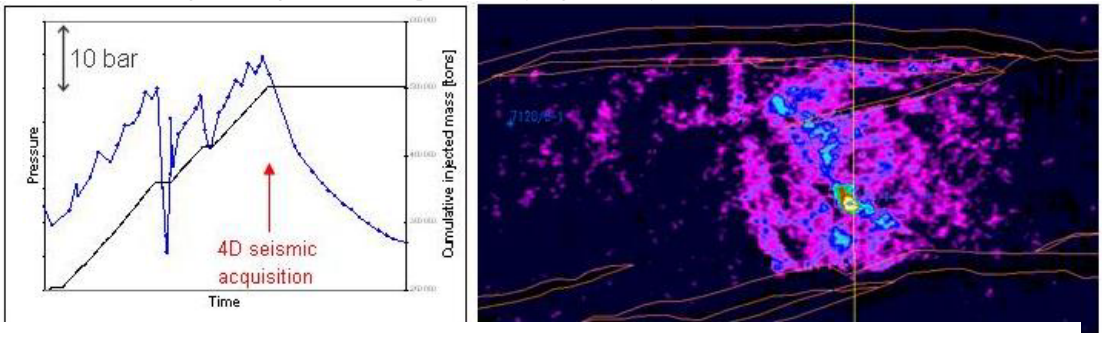

Figure 8: Portion of the injection and pressure data from Snøhvit spanning year 2009 (left), and 4D seismic difference amplitude map of the lowermost Tubåen Fm. level (right)..

5. CO_2 storage in a reservoir management perspective

In parallel with 14 years of CCS experience, and in fact for a much longer time period, significant experience has been gained in Statoil's offshore field developments for oil and gas production. Massive hydrocarbon gas injection (miscible and immiscible) in fields like Statfjord, Oseberg, Smørbukk Sør and Grane has resulted in world-leading recovery factors. Water injection and water-alternating-gas techniques have been implemented in fields like Gullfaks and Heidrun. The key to success has been the ability to combine reservoir characterization, monitoring technology, smart wells and innovative flooding techniques in cross-disciplinary reservoir management projects. Large-scale CO_2 storage projects will benefit from such experience from enhanced oil recovery projects. As has been demonstrated with high-resolution 4D seismic methods for a number of fields, high recovery factors normally also mean good volumetric sweep of the injectant (water, hydrocarbon gas or combinations).

This reservoir management perspective is possible to apply to CO_2 storage in geological aquifers. Future large-scale scenarios will potentially involve a number of wells, with flexibility in completion solutions and preparation for non-expensive side-tracks, since well cost will be an economical limitation. It is important to understand aspects like the combined diffusion-convective mechanisms and fluid movement on long term basis. The sweep efficiency

in the injection period will to a large degree dictate the long-term storage behaviour of the supercritical CO_2 in the reservoirs, and the injection period represents the time-window where it is possible to take actions with respect to flooding pattern alteration. Therefore, comprehensive monitoring and modelling will be important to understand the mechanisms (like diffusion, dilution, buoyancy forces and capillary trapping) occurring when CO_2 is injected in the reservoir.

At Sleipner, injection capacity as well as reservoir storage capacity is plentiful, and consequently there has been no need for reservoir management. On In Salah and Snøhvit the situations are different, and the choice of drilling three horizontal injection wells on In Salah is a response to this challenge. On Snøhvit, the pressure may increase further and could eventually reach the fracture pressure, if injection continues at current rates. A number of reservoir management options are then available, such as controlled fracturing, drilling a side-track, a new injection well or injecting in the gas bearing formation above. The choice will be based on updated models and their predictions, as well as the cost and robustness of various alternatives.

CO_2 storage capacity is not a nature-given number. Rather, it depends on the number and design of injection wells (and thus by economy), well positioning, injection strategy, and risk acceptance. Efficient utilization of CO_2 storage space will depend on all these factors. Both the CO_2 injection at Sleipner, Snøhvit and In Salah as well as general experience from oil and gas production have contributed to our knowledge of these factors. It is expected that further progress with respect to efficient use of subsurface CO_2 storage capacity will be made as more experience is gained from the ongoing injection sites, and as future CO_2 injection project are realized

6. Conclusions

In highly variable and complex reservoirs, with permeability ranging from a few milliDarcy to more than one Darcy, single wells have injected several hundred thousand tons of CO_2 per year. Injectivity has been good on Sleipner and more challenging on In Salah and Snøhvit. Surface geophysical and well pressure monitor data have been of high quality and give rich information on the storage behaviour. Down-hole measurement of pressure and temperature removes uncertainties in calculations based on wellhead conditions, and should be prioritized in future storage projects. Dynamic modeling to match the data is still challenging, and there is room for further model improvement.

In the reservoirs, the actual CO_2 plume development has been strongly controlled by geological factors which we learned about during injection. Geophysical monitoring methods (especially seismic, gravity, and satellite data) have, at each site, revealed some of these unpredicted geological factors. Thus monitoring methods are as valuable for reservoir characterization as they are for following fluid saturation and pressure changes. Together these data and models help improving predictions.

High-quality monitor data also lowers the detection threshold for any potential leakage, which increases the confidence in the storage projects. At Sleipner and Snøhvit 4D seismic monitoring is of sufficient quality to confirm that there are no signs of leakage into the overburden. At In Salah, InSAR data has proven particularly valuable in monitoring pressure distribution and containment in the reservoir. This demonstrates that CO_2 storage is clearly technically feasible, and the monitoring portfolio for verification of safe long-term storage is available and effective. Assurance and verification may be challenging, but is certainly possible.

Experience from oil and gas production shows that intelligent application of reservoir characterization and monitoring technology (e.g. high resolution geological mapping and time-lapse seismic) and advanced well solutions leads to significantly improved oil recovery. In a similar way, we expect detailed CO_2 site characterization, monitoring and well solutions to increase the sweep efficiency of the injected phase and thus CO_2 storage capacity, on a case by case basis, and as the specific site experience and knowledge develops.

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