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REPORT

TITLE

SACS – 2, work package 4.

Monitoring well scenarios.

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SUMMARY

Monitoring well scenarios for the Sleipner field CO_2 storage have been evaluated. Wells provide the only means for direct information access to storage aquifer and overburden parameters. Major objectives are to provide data for improved storage facility characterisation, as input to simulations and to calibrate and complement the time-lapse seismic measurements. Well information will contribute to secure that recommendations and measures are met for a safe and environmentally acceptable gas storage.

A program of two subsea vertical wells (No.1 and No.2) are proposed – one penetrating the gas cloud above the injection point (No.1) and one drilled into a connecting aquifer (No. 2) not yet reached by the injected gas. Both wells will have a comprehensive logging and sampling program. Well No.1 will be plugged and permanently abandoned after data collection. Well No. 2 will also be prepared for permanent monitoring purposes controlling lateral spreading of the injected gas. A system with resistivity sensors for saturation measurements will be established in addition to a system for pressure and temperature gradient measurements. Sonic and 3D component seismic sensors are optional to add information to the surface seismic monitoring system. Monitoring of the storage reservoir pressure is not a key issue due to the shape and size of the reservoir cap with the associated low pressure build up.

Subsea wells give most observation options and will not interfere with the Sleipner A platform operations. A slender well programme is proposed with a 9 5/8" surface casing into the top Utsira storage formation allowing an option of a 7" liner and/or an instrumented tubing to be installed. A capital cost of NOK 35 mill. for well No.1 and 70 mill. for well No.2 is anticipated.

KEYWORDS ENGLISH	KEYWORDS NORWEGIAN
CO_2 storage	CO_2 lagring
Offshore	Offshore
Leak scenarios	Lekkasjescenarier
Monitoring	Monitorering
Observation wells	Observasjonsbrønner

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1. Introduction

1.1 SACS CO_2 injection project

Since October 1996 Statoil has started to inject CO_2 coming from the Sleipner Vest Field in the southern Viking Graben area into a saline aquifer at a depth of approximately 900 m. The injection point is in the North East direction at a distance of approximately 3 km as shown in Figure 1.1. This is the first case of industrial scale CO_2 storage in the world (1 million tons per year). Careful monitoring of the behavior of the storage facility is hence required.

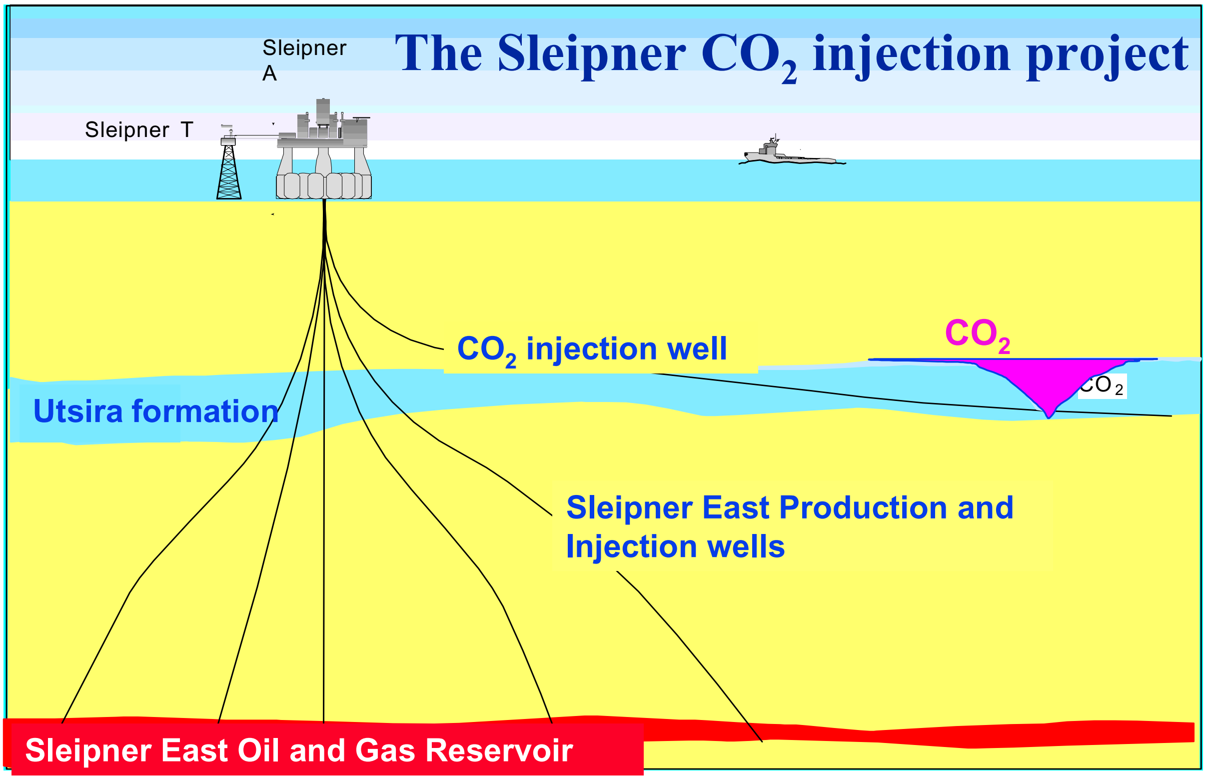

Figure 1.1 Overview of the Sleipner area with CO_2 injection.

1.2 Work package 4 – "Evaluate monitoring well"

Work package 4 is described in the "DESCRIPTION OF WORK" for the SACS 2 project:

<u>Objectives</u>
Assess need for and cost of a monitoring well or wells to provide direct access to the storage reservoir rock, cap-rock, overlying formations and formation fluids. Evaluate optimal instrumentation in the well. Study feasibility of obtaining data from the existing injection well and suggest what modifications would be needed. Determine the overall cost and performance of an observation well.

Description of work
Based on the results from Work Packages 2, 5, and other reservoir information, the possibilities of monitoring a gas cap by observation well and seismic will be evaluated. A preliminary recommendation on the need for a monitoring well will be submitted. A programme of sampling and measurement will be proposed. Different methods to drill an observation well and to equip the well will be studied.

Deliverables
Report summarizing whether a monitoring well is needed and what the investment cost will be. Specifications and costs for a sampling methodology and programme.

1.3 Norsk Standard NS-EN 1918: 1998 – "Gas supply systems / Underground gas storage"

The European Standard EN 1918 1-5: 1998 has been adopted as the Norwegian Standard NS-EN 1918 1-5. The European Standard was approved by CEN on 22 January 1998 and given status as a national standard by August 1998. The standard covers functional recommendations for design, construction, testing, commissioning, operation and maintenance of underground gas storage facilities. It specifies common basic principles for gas supply systems and complements more detailed national standards that also may exist in CEN member countries.

The standard basically describes on-land underground cycling gas supply systems as a mean for adjusting distribution supply to demand. Although the standard does not directly reflect the offshore conditions as put forward in the SACS CO_2 injection project and the Sleipner field, the standard specifies useful procedures and practises for a safe and environmentally acceptable gas storage.

In the following, guidelines set forward in part 1 and 2 are referred and reflected.

Part 1: Functional requirements for storage in aquifers
Part 2: Functional recommendations for storage in oil and gas fields.

General
The operator shall control the behaviour and ensure confinement of the storage facility by regularly using monitoring systems. The monitoring system shall be designed to verify gas containment and storage reservoir integrity while the storage facility is operating. The design should require the collection of data such as representative storage and annuli pressures, injected and withdrawn (outlets) volumes and gas qualities and, if applicable, saturation logging results. The most appropriate monitoring system shall be individually established for each project.

Some definitions
Aquifer – reservoir, group of reservoirs, or part thereof that is fully water-bearing
Upper aquifer – any aquifer overlying the caprock in the storage area

Caprock – oiltight and gastight layer covering a porous and permeable formation
Connected aquifers – aquifers that are connected to the storage aquifer and thereby subject to changes of pressure caused by the storage operations
Closure – vertical distance between the top of the structure to the spill-point
Spill-point – highest structural position within a reservoir, above which hydrocarbons could leak and migrate out
Overburden – all sediments or rock that overlie a geological formation
Minimum thickness of overburden – shortest vertical distance separating the base of the caprock from the surface
Operating well – newly drilled well or existing well converted for injection, production or both
Monitoring well (or observation well) – newly drilled well or existing well converted and completed for the purposes of observing subsurface phenomena such as pressure fluctuation, fluid flow, temperature, etc

Key requirements

Maximum operating pressure (MOP) for the storage facility shall be determined so that following risks are avoided;

the risk of mechanical disturbance
the risk of gas penetration through the caprock
the risk of uncontrolled lateral spreading of gas

Maximum operating pressure is defined by the lower of "*limit to avoid mechanical failure*" and "*limit to avoid the gas penetration through caprock* ".

It is essential that the changes in pressures and stresses do not cause mechanical failures in the layers or in the faults. The maximum pressure limit $\rho_{max,1}$ to avoid mechanical disturbance is given by:

$$p_{max,1}=XH_{min}$$

where:

$p_{max,1}$ is the maximum pressure limit in megapascals

X is he maximum pressure gradient, in megapascals per metre

H_{min} is the minimum thickness of overburden calculated from the base of the caprock, in metres

Gas shall not penetrate the caprock by displacement of water. The maximum pressure limit $p_{max,2}$ not to avoid exceed the capillary threshold pressure is given by;

$$p_{max,2}= p_w + CTP$$

where:

$p_{max,2}$ is the maximum pressure limit in megapascals

p_w is the initial pressure of the water in the base of the caprock in the dome area of the storage formation, in megapascals

CTP is the capillary threshold pressure of the caprock, in megapascals

It is assumed that geological knowledge combined with modelling techniques provide the most appropriate monitoring systems to prevent risks;

defects of vertical sealing
lateral gas outlets

In cases where gas containment is certain for geological reasons, the need for monitoring wells can be significantly reduced.

Monitoring wells
Monitoring wells are used for two purposes;

to prevent lateral gas discharge from the controlled area
to increase knowledge of gas distribution inside the reservoir

Monitoring of upper aquifers is essential to ensure either that the storage facility is gastight or that any leakage is limited and controlled. It requires accurate knowledge of the situation prevailed before the gas was introduced inside the aquifer. Both pressure measurements, water analysis and gas logging are possible measurements depending on the actual situation.

Knowledge of the lateral extension is important to avoid lateral gas discharge to sensitive zones.

The pressure in the storage formation shall be monitored to ensure that it is kept below the maximum operation pressure in the zone chosen to control. An open well shall be drilled either into this zone or to a point from which it is possible to extrapolate the pressure.

Comments to the monitoring of Sleipner CO_2 storage case
The Sleipner CO_2 storage facility is not an ideal case for active monitoring wells as described and recommended in the standard, i.e.;

monitoring of the storage reservoir pressure is not a key issue as the shape and size of the storage reservoir cap and spill points will only lead to minor pressure build up
an upper aquifer suitable for leak monitoring is not present

Wells should nevertheless be drilled to meet;

the need for improved storage facility characterisation
the need for calibration data and supplement measurements for the time-lapse seismic monitoring system in use
to check the lateral spread

2. Sleipner CO_2 storage process

The description in this chapter is a summary of work published under other work packages in the SACS project, with relevance for the monitoring well discussion. For a more complete presentation we refer to Zweigel et.al (2000), Arts et.al.(2000), Lindeberg et.al (2000), Breivik et.al (2000)

2.1 Simplified geological model

The Utsira Formation is a sandstone formation of Tertaty age, found in the Viking Graben area. The formation consists of fine grained, high permeability, mainly homogenous sands with microfossile fragments, deposed on a shallow marine shelf. In the Sleipner area the top of the formation is located at approximately 800 m true vertical depth. The thickness of the formation varies between 150 and 250 m. The formation is originally water filled and the pressure is hydrostatic. The Utsira sand is overlaid by thick Nordland shale. The shale is widely distributed and impermeable, and is thus believed to function as a barrier hindering the CO_2 to leak back out to the atmosphere. Figure 2.1 shows a schematic representation of the Sleipner storage system.

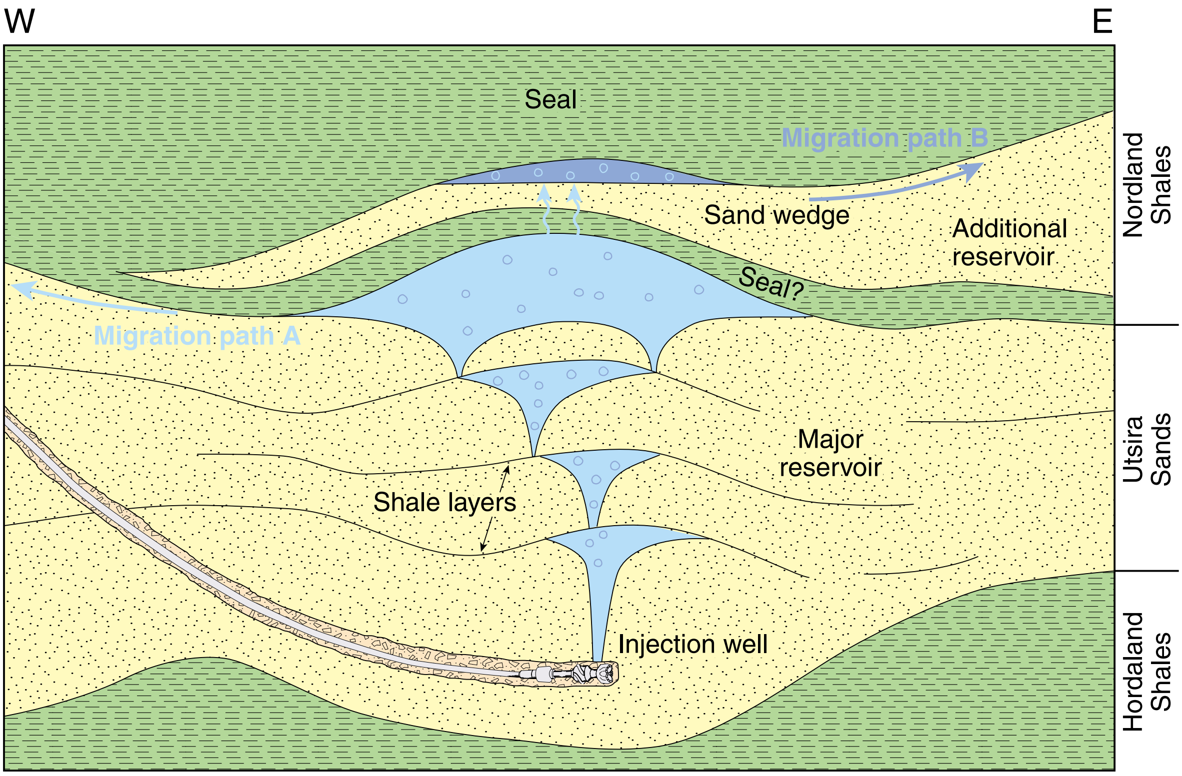

Figure 2.1 Conceptual schematic representation of the Sleipner storage system (non linear depth scale).

The CO_2 is injected close to the base of the Miocene-Pliocene Utsira Sands (Fig. 2.1). Wireline-log analysis (Fig. 2.2) shows the presence of several thin (usually less than 1 m thick) shale horizons within the Utsira Formation. These shales were predicted to affect CO_2 migration, and this has been confirmed by time-lapse seismic data (Arts, 2000). However, we expect the shale layers to contain fractures and holes, partly due to differential subsidence and partly due to erosion during deposition of the interlayering sands. The sands are weakly consolidated, highly permeable and have porosities ranging from 27 % to ca. 40 % . Figure 2.2 shows wireline log profile through the Sleipner area, and Figure 2.3 shows topography of the top Utsira sand from seismic interpretation.

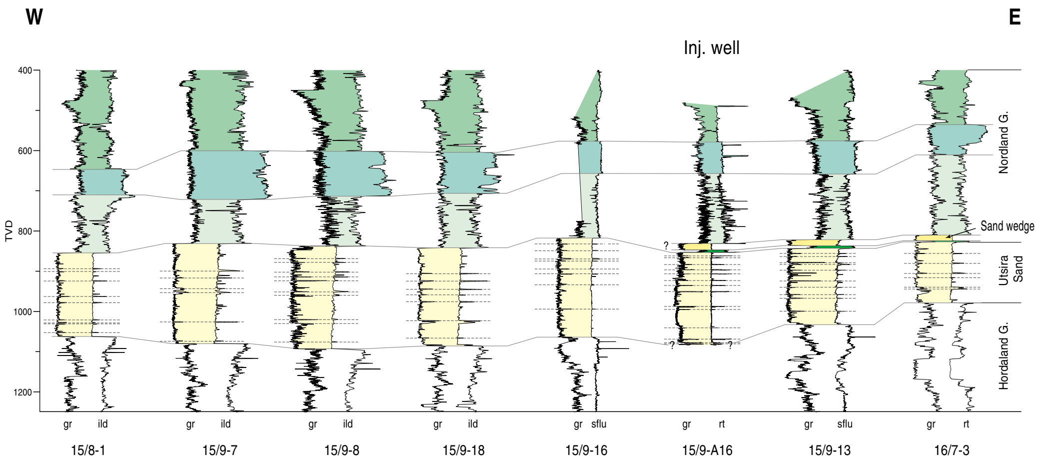

Figure 2.2 Wireline log profile through the Sleipner area, illustrating lithologies, the presence of shale layers in the Utsira Sands, and a sand wedge in the lowermost part of the Nordland Shales.

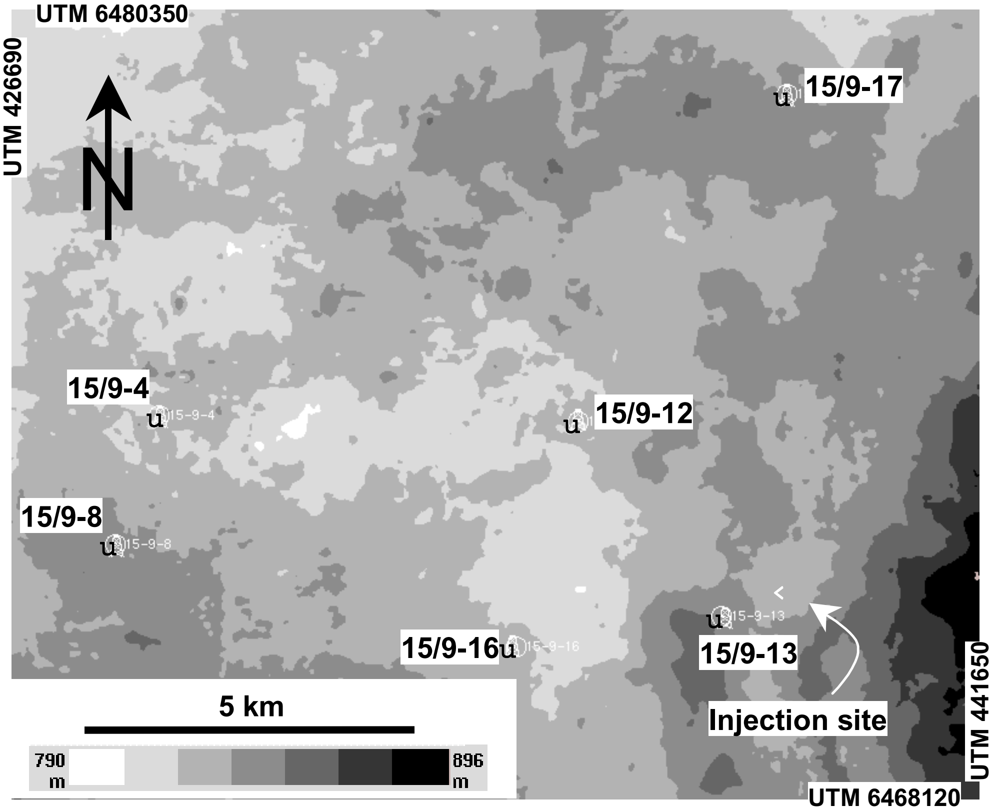

Figure 2.3 Topography of the top Utsira Sand from seismic interpretation, strongly smoothed. Contour interval: 15 m.

The Utsira Sands are overlaid by the Pliocene Nordland Shales, which are several hundred meters thick and which are assumed to act as seal. The top of the Utsira Sands has been mapped based on wireline logs and 3D seismics in the injection area. This surface has a weak regional dip towards south, but has an irregular topography with several linked domal and anticlinal structures that are caused by subsidence anomalies (Fig. 2.3). These are due to mud mobilisation edifices at the base Utsira Sand. Above the top Utsira Sands, separated by a 5 m thick shale layer, exists an eastward thickening sand wedge (Fig. 2.1) identified in wireline-log data (Fig. 2.2) and mappable in the 3D seismic data.

The Top Utsira Sand is relatively flat, but exhibits some domal and anticlinal structures linked by saddles. The injection site is located below a dome with a diameter of approx. 1600 m and a height of approx. 12 m above its spill point.

2.2 Expected CO_2 distribution

2.2.1 Distribution near injection point

The CO_2 is being injected close to the base of a high permeable, highly porous Utsira Sand. In an iterative process between seismic surveys and reservoir simulations, a reservoir model featuring the major controlling heterogeneities has been developed.

Well-data and seismic data prior to injection shows that the sand is divided by nearly horizontal, discontinuous shales. From the 3-D seismic image after three years of injection, strong reflectors can be interpreted as CO_2 accumulations identifying the major shale layers that control the vertical migration of CO_2 from the injection point to the top of the formation. By modelling this flow in reservoir simulations, it can be inferred that the CO_2 is transported in distinct columns between the shales rather than as dispersed bubbles over a large area. Improvement of the geological model increases the confidence of predictions based on simulation of the long-time fate of CO_2. A possible natural aquifer flow can have a pronounced effect on the location of CO_2 accumulations due to the relatively flat topography of the trapping shales. This effect has been quantified by simulation and this phenomenon was used to adjust the localisation of the CO_2 bubbles to better fit the seismic images. Figure 2.4 shows a seismic picture of CO_2 bubbles compared with simulations.

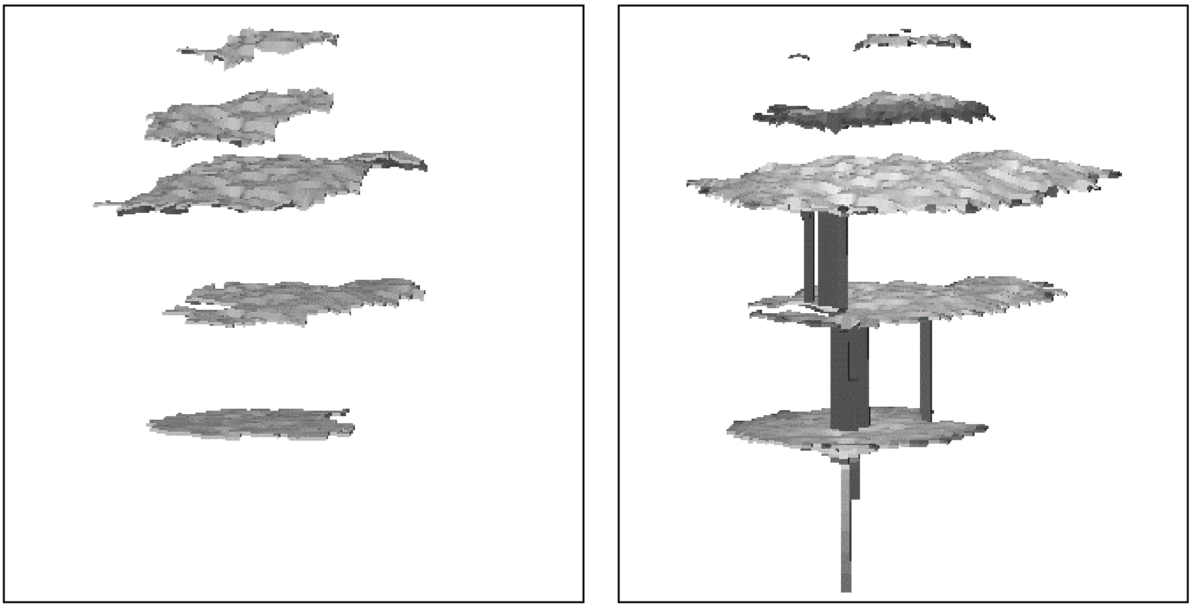

Figure 2.4 Seismic picture of CO_2 bubbles (left) compared with simulated CO_2 saturations after 3 years of injection

2.2.2 Distribution under a near horizontal seal

CO_2 is expected to reach the top Utsira, fill up the injection dome and distribute further laterally along the spill point.

Gravity-controlled migration below barrier levels has been simulated employing SINTEF's in-house developed secondary hydrocarbon migration tool SEMI (Zweigel, 2000).

The simulation results of the final distribution of CO_2, after a total quantity of 20 Million metric tons injected (total volume: ca. $30 \cdot 10^6$ m^3 CO_2), fall into two major groups:

a.) If the top Utsira Sand acts as a long-term barrier, migration occurs primarily north-westwards, reaching a maximum distance of ca. 12 km to the injection site as seen in Figure 2.5, grey outline. This maximum distance depends strongly on the porosity and the net/gross ratio of the Utsira Sands and we rate the used values to be conservative estimates.

b.) If the 5 m thick shale layer above the top Utsira Sand leaks, and CO_2 invades the sand wedge above, migration occurs primarily north- to north-eastward. A prediction of the maximum migration distance was not possible in that case because the CO_2 would then leave the area of the studied 3D seismic survey at a point ca 7 to 10 km NNE of the injection site. The volume stored within the modelled area is in the order of 4 to $7.4 \cdot 10^6$ m^3 CO_2, equalling to the total amount of CO_2 injected during 2.5 to almost 5 years (Figure 2.5, black dotted outline).

Preliminary interpretations of a time-lapse survey acquired in autumn 1999 (see Arts 2000) suggest that a small fraction of CO_2 had already then migrated into the sand wedge. A quantification of the distribution between these reservoirs is, however, not yet possible.

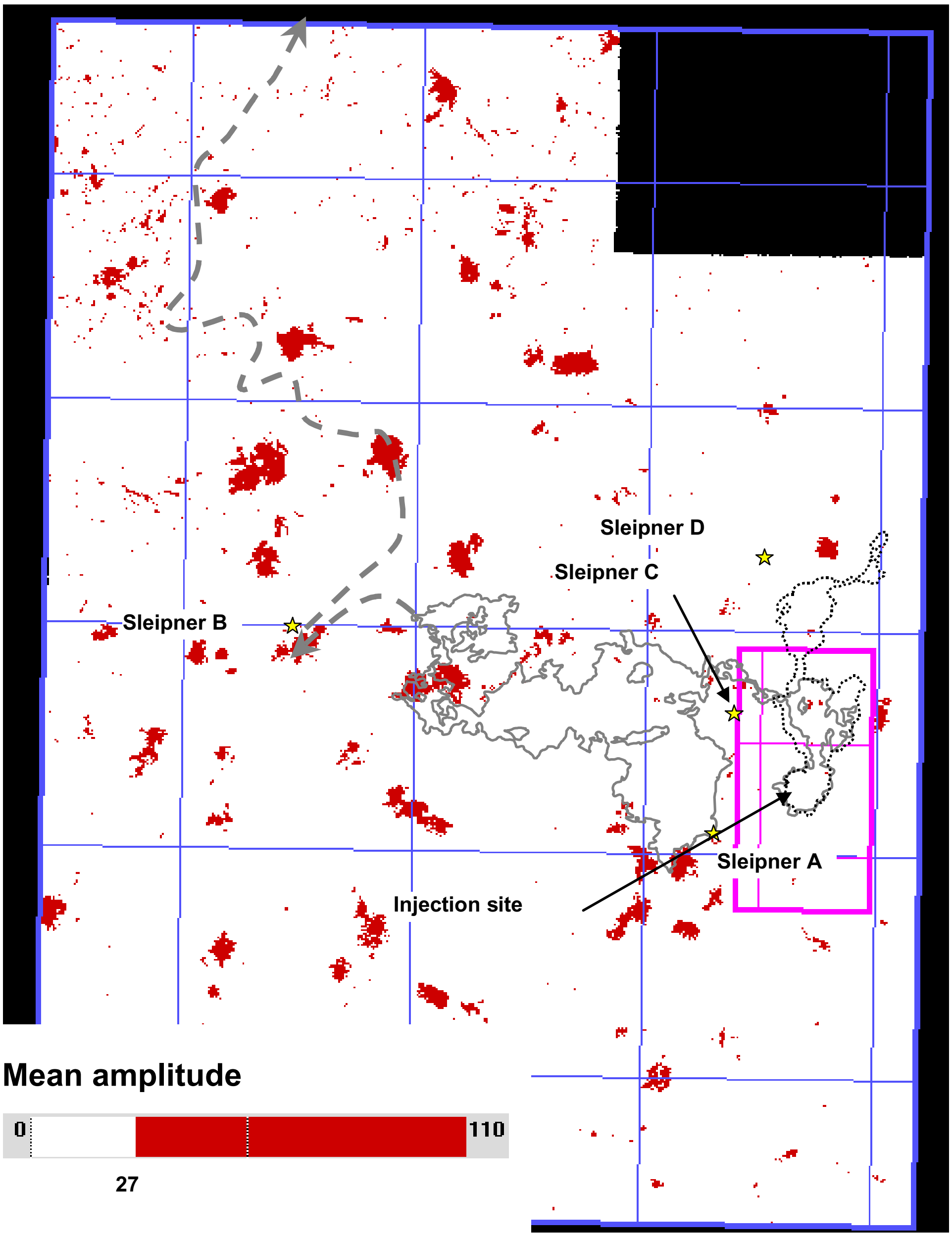

Figure 2.5 ***Grey outline:*** *maximum extent of CO_2 accumulation after injection of 20 Mill tons CO_2 and migration beneath top Utsira. Grey arrows: migration path if injection continues.* ***Black, dotted outline:*** *margins of CO_2 accumulations in survey area in case of migration within sand wedge* ***Red:*** *Mean amplitude magnitude in interval from 50 ms to 20 ms above Top Utsira (where no sand wedge present) or from 45 ms to 15 ms above top sand wedge (where present).*

2.3 Seismic anomalies in overburden

The Pliocene shales of the cap rock can be subdivided into 2 units. The lower one, directly overlying the Utsira Sand includes at its base a shale drape that can be distinguished on a regional scale. This lower unit exhibits locally anomalously high amplitudes. The upper Pliocene prograding unit is characterized by irregular internal reflectors and frequently occurring very high amplitudes. The amplitude anomalies in these units might be due to isolated high-velocity lithologies, or alternatively to the presence of shallow gas (Arts, 2000).

Anomalously strong amplitudes occur occasionally within the lower part of the Pliocene shales and in the Utsira Sand and are abundant in the upper Pliocene shales (Figure 2.6). Most of the anomalies in the Utsira Sand were identified as probable artifacts (multiples), coinciding with the anomalies observed in the lower Pliocene. However, a small number of anomalies just below the Top Utsira as well as the anomalies in the Pliocene shales are considered to be real phenomena, which might be at least partially due to the presence of shallow gas (Figure 2.6). These anomalies seem in some cases to be linked to mud volcanoes by zones of weak amplitudes ('gas chimneys'). Many of the anomalies, however, can not be linked to features at the base of the Utsira Sand. By using interval attributes based on the amplitude of the seismic signal the occurrences of these anomalies have been successfully mapped This is shown in Figure 2.5. The strongest anomalies are not observed within the modelled CO_2 distribution

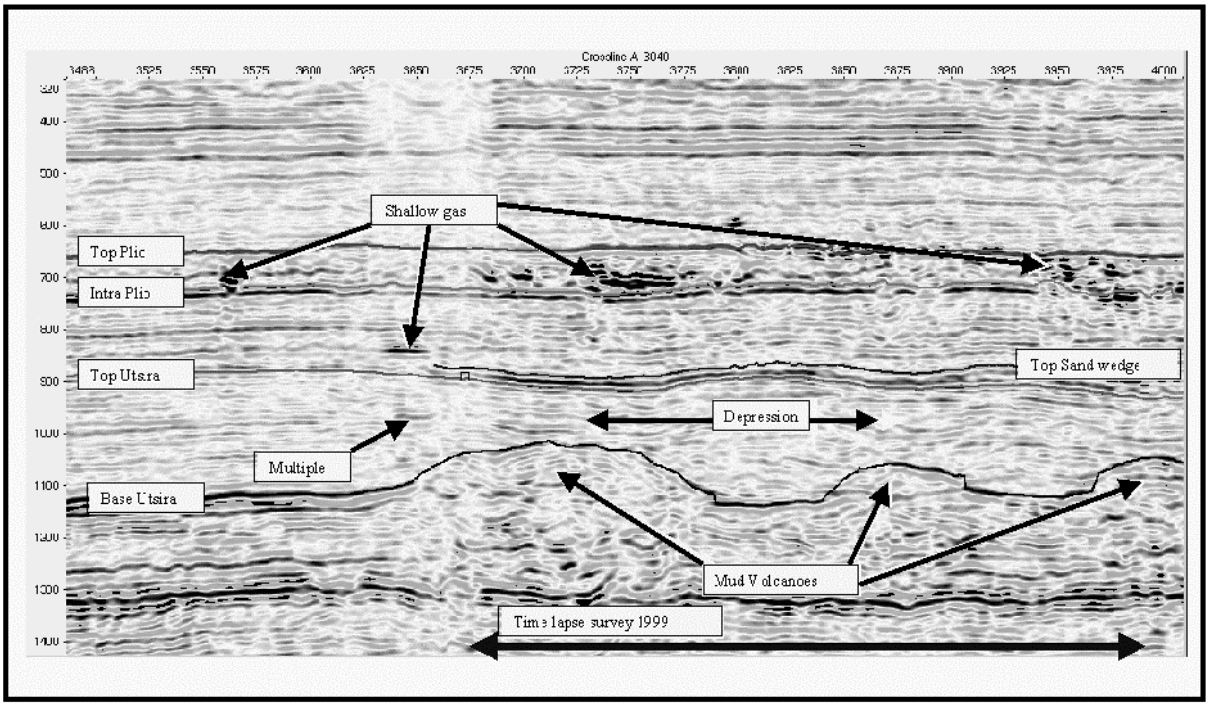

Figure 2.6 Seismic line (east to west) from the 3D seismic survey ST98M11 showing amplitude anomalies.

2.4 4D seismic monitoring

4D seismic monitoring was selected as the primary monitoring technique in the SACS project. A good-quality pre-injection 3D seismic survey was shot in 1994. A repeated 3D seismic dataset was acquired in 1999, after about 3 years and 2 million metric tons of CO_2 injection.

The interpretation of the repeated survey confirmed the principles of CO_2 distribution predicted by the reservoir flow simulations and by adjusting the vertical spacing and lateral size of the shale layers a good match between the seismic images and the model output was achieved as seen in Figure 2.7 and Figure 2.8. The interpretation also indicated that some CO_2 had passed the 5m thick shale layer at the top Utsira sand and was accumulating in the sand wedge mentioned in chapter 2.1.

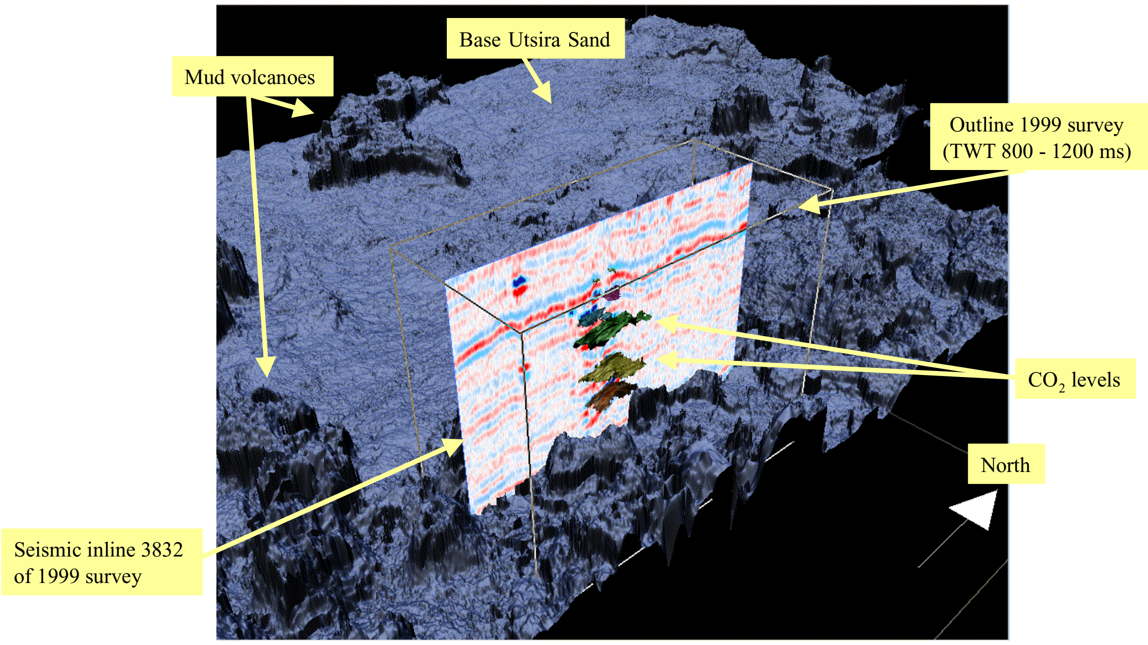

Figure 2.7 The base Utsira interpreted horizon (blue), seismic inline 3832 of the 1999 survey and the 6 levels of CO_2.

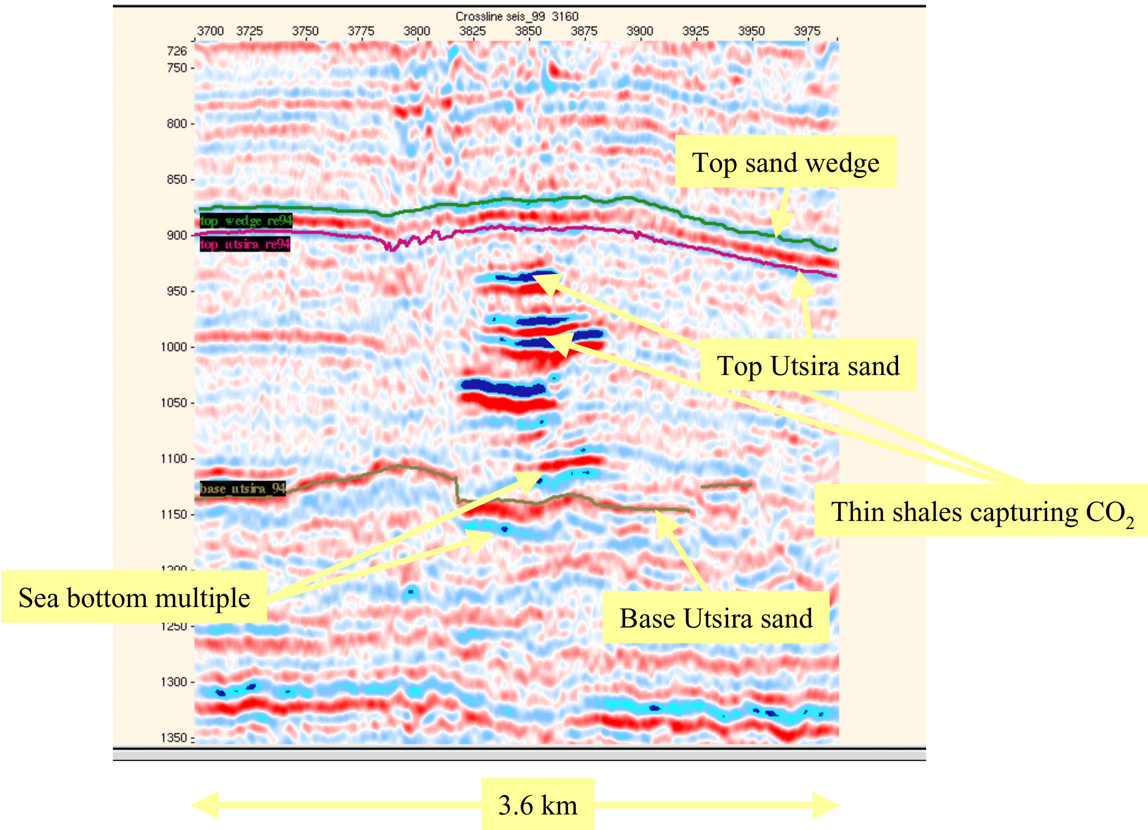

Figure 2.8 Seismic crossline 3160 of the time-lapse seismic survey showing the different CO_2 levels.

The advantage of time lapse seismic as monitoring technique is excellent aerial coverage and moderate cost for a repeated survey. Although the first repeated survey for monitoring of CO_2 injection into the Utsira sand seem to bee successful, seismic is an indirect measurement. The resolution is limited and a quantitative interpretation of seismic response into CO_2 saturation is doubtful and monitoring of the cap rock sealing capability is poorly addressed.

Better cap rock data obtained during the drilling of an injection or monitoring well, also will benefit the accuracy and credibility of the seismic monitoring

There is, however, a need to consider alternative monitoring techniques as complementary information.

3. Well monitoring objectives and methods

3.1 Relevant monitoring issues

Fundamental monitoring issues for the Utsira CO_2 injection are:

monitor leaks of CO_2 into or through the overburden
monitor the distribution of CO_2 in the aquifer around the injection area
monitor the lateral spread of CO_2 as the injection volume increases
monitor to what extent CO_2 is dissolved in the formation water

Pressure monitoring has high focus in conventional gas storage projects. Utsira is high permeable with enormous pore volume compared to injection volume. The cap has domes giving free gas columns of only 15-25 m. The pressure increase in the aquifer due to CO_2 injection is expected to be in the sub bar area, far below estimated limits to avoid mechanical failure or gas penetration through undisturbed cap-rock (ref. ch 2.3).

The Pliocene shales overlaying the Utsira sands were expected to have good sealing properties. The presence of seismic anomalies in the cap-rock, interpreted as shallow gas (Chapter 2.3) and the observation of CO_2 in the sand wedge (Chapter 2.4) indicate, however, that the possibility of CO_2-leakage through the cap can not be excluded . A direct observation of a leak from a dedicated observation well is unlikely. A leak will probably occur in a weak or fractured zone in the cap. Although such zones could be observed as anomalies on the seismic, the probability of penetrating the zone with a well is minimal. So far no significant anomalies are observed in the primary injection dome. Any observation well will however give the opportunity for extensive coring, logging and fluid sampling. Acquiring this type of data, followed by careful analysis, is probably the best approach for a better understanding of the sealing properties.

Indications of gas leakage through the overburden can sometimes be observed at the sea floor. Repeated site survey with inspection of the seafloor can be considered to look for development of pock marks on the seafloor indicating possible leaking gas. An active sonar surveillance of the sea column can likewise give indications of leaking gas.

Utsira has a nearly horizontal seal, trapped gas columns below the cap are not expected to exceed 15-20 m. Over time the injected CO_2 will be distributed over a large area (ref. Ch 2.2.2). Seismic is the only known method where a full 3D mapping of the CO_2 distribution is feasible, and the results from the first repeated survey are promising (ref. ch 2.4). Monitoring wells will have an important impact on calibration of the seismic data, with respect to CO_2 saturation and volumetric resolution. Monitoring wells may be drilled near by the injection point, where CO_2 has been exposed for a long period, or in a virgin area were CO_2 is expected to migrate. Monitoring wells can be applied for instantaneous data gather (cores, logs, fluid samples) or trend observations through permanently installed equipment.

3.2 Main well objectives

The main well objectives are to provide direct information access to the storage aquifer, connected aquifers and overburden. Well data will give input to;

the understanding of the behaviour and movements of the stored CO_2
calibration of the time-lapse seismic monitoring system
to verify the quality of vertical sealing
to monitor the lateral spread

Drilling observation wells will provide data from;

downhole formation logging
measurements on cores and cuttings
Vertical Seismic Profile (VSP)
analysis of fluid and gas samples
storage aquifer permanent monitoring

State of the art logging while drilling (LWD) will together with wireline logging and formation testing give physical properties knowledge about the formations. A proposed logging program is indicated Table 3-1. Laboratory investigation and measurements on core and cutting samples will give geological knowledge and add information of both geophysical properties and the rock strength. After the hole is cased and cemented, a detailed Vertical Seismic Profiling (VSP) will together with surface seismics allow the observations made in the hole and cores to be scaled up and extrapolated away from the borehole. To extend observations over time and to monitor the lateral spreading a range permanent well sensors will be installed.

Table 3-1 Proposed logging program for observation well (ref. Figure 5.2)

MWD/LWD	12 1/4”	Gamma (GR), Resistivity, MWD
	8 1/2”	Gamma (GR), Resistivity, MWD
Wireline logging	12 1/4”	Caliper, Gamma, Resistivity (laterolog), Neutron, Density, Sonic, Formation imager (FMI), VSP?
	8 1/2”	Caliper, Gamma, Resistivity (laterolog), Neutron, Density, Sonic, Formation imager (FMI), VSP?
Form.test	8 1/2”	Formation tester, Fluid samples
Coring	12 1/4”	2 4” core sections á 30 m
	8 1/2”	2 4” core sections á 30 m

3.3 Monitoring methods

Methods and equipment for permanent well monitoring, with relevance for the Utsira CO_2 injection is described in the following. A sensor overview is given in Table 3-2

Table 3-2 Overview over permanent well monitoring sensors

Sensor type	Observed Parameter	Benefit	Availability	Comment
Pressure	Formation pressure or pressure gradient	CO_2 column hight	Systems commercial available and proven (expected lifetime 10-20 years)	Limited resolution, sensor drift
Temperature	Formation temperature	Input to models	Systems commercial available and proven (expected lifetime 5-10 years)	
Resistivity	Formation resistivity	CO_2 saturation	Commercial system available	Limited experience
Seismic (VSP)	Seismic velocities, seismic reflectors	Improved seismic resolution	Commercial systems available	
Seismic monitoring	Microseismic activity (and position)		Commercial systems available	Microseismic activity not expected
Sonic	Sonic p- and s-wave interval velocities	Calibrates surface seismics	Commercial systems not available	

3.3.1 Pressure and temperature

The presence of a CO_2 cap in the aquifer will influence the formation pressure. A cap of 10 m is estimated to increase the pressure with 0.3 bar. A pressure build-up as a function of time is modelled in Appendix A.1.

Figure 3.1 indicates that a permanently installed pressure sensor with 10 bar full measurement range typically will drift off $\pm$ 0.01bar over a life span of 20 years. Such sensors will soon be available off-the-shelf and ready for installation, - demonstrations are seen via similar sensors available for other applications. The main challenge is to protect the relatively “soft” membrane needed for 10 bar measurement range during installation. The drift of sensors are normally a portion of full range (<1% for the sensor referenced above), so 10 bar full range seem to be a maximum with today’s sensors.

Pressure monitoring (combined with temperature), or differential pressure monitoring between top and bottom of cap, can be utilized for CO_2 monitoring purposes. A pressure change may be difficult to interpret. An observed pressure reduction may be due to sensor drift, leak into cap-rock or CO_2 solubility in brine. The measurement should thus be combined with other observations.

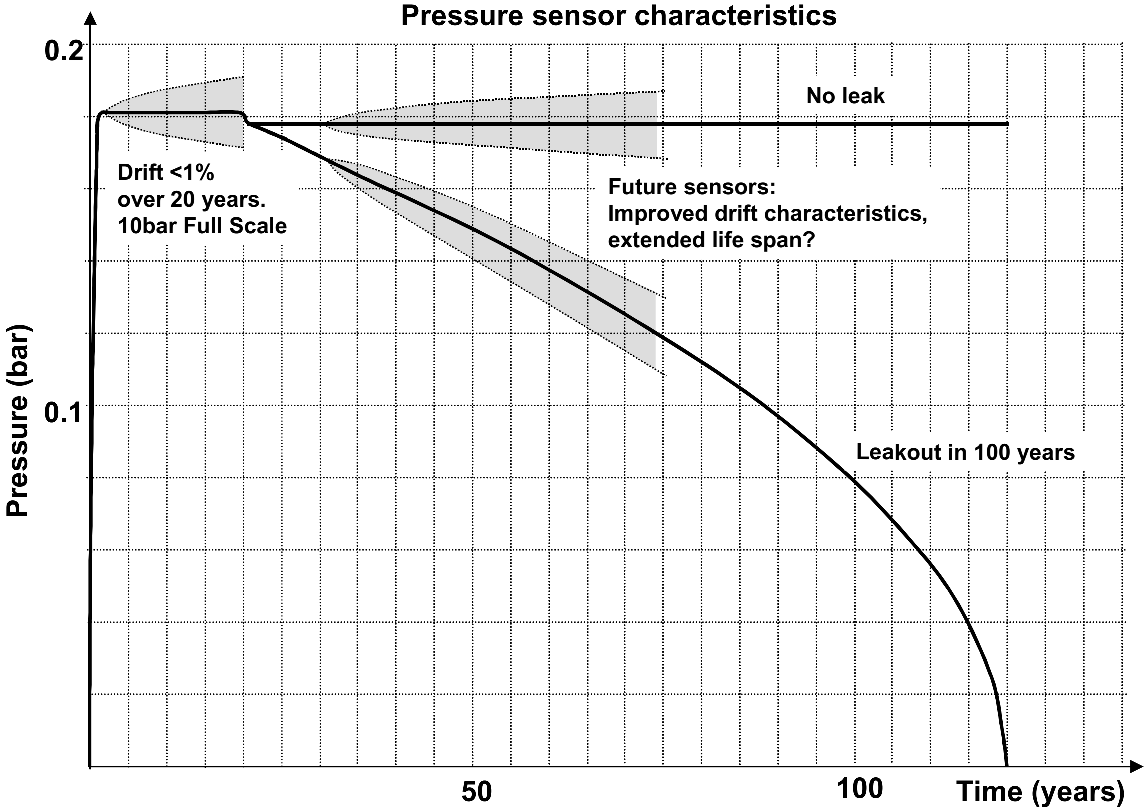

Figure 3.1 Permanent pressure sensors and the uncertainty due to drift in output signal. The drift characteristics are derived from a one month test on permanent well sensors from Weatherford (preliminary data).

Permanent pressure gauges are available from several vendors.
Figure 3.2 shows a downhole instrumentation set up proposed by Roxar. Budget prise is 250-350 kNOK pr sensor. A similar system is proposed by Weatherford (Appendix A.2). The differential pressure sensors proposed are of the type described above.

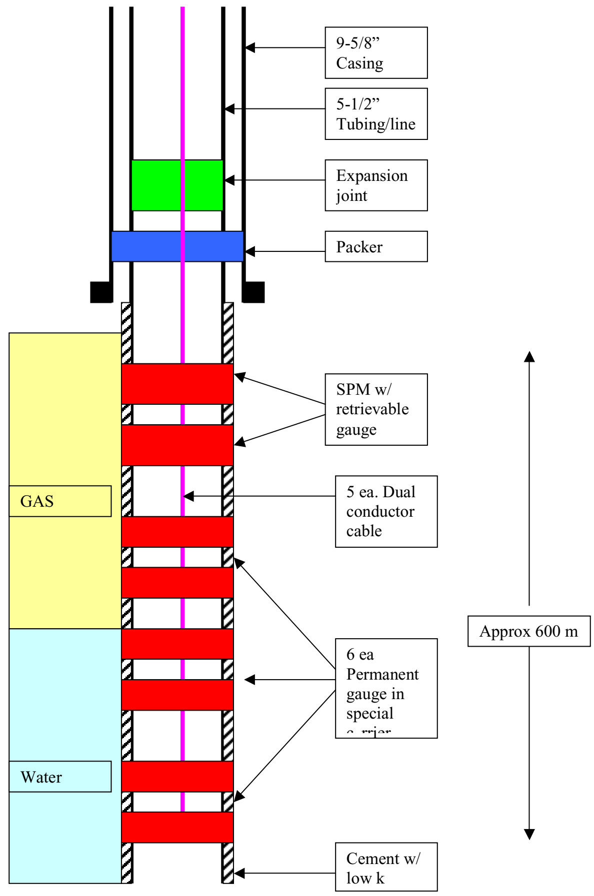

Figure 3.2 Permanent downhole instrumentation set up proposed by Roxar.

3.3.2 Resistivity

The formation water in the Utsira formation has a salinity comparable to sea water. The water resistivity is measured to 0.22 m @ 20^{o}C (a water sample from Oseberg). CO_2 in the formation has isolating electrical properties. Resistivity or conductivity measurements are thus well suited for estimation of CO_2 saturation in the formation (when the porosity is known). Saturation models commonly applied in wire-line logging for estimation of hydrocarbon saturation (i.e.Archie equation) can be directly applied. Permanently installed sensors have the capability of monitoring time developing trends with high resolution.

Two basic sensor principles are available, electrodes in galvanic coupling to the formation or induction sensors. A conducting casing will dramatically influence formation electrical measurements from a borehole.

The spatial resolution and detection range depends on sensor geometry and frequency.

The technology for permanent electromagnetic formation monitoring is under development. One commercial system is currently available and several other systems are under prototype testing.

The Roxar WMR system as shown in Figure 3.3 is based on an induction transmitter and a receiver pair, similar to wireline and logging while drilling induction logging tools. The tool can be mounted in a fibreglass casing section or as a cemented liner section. Up to 32 sensor nodes can be combined with a single cable to surface.

When calibrated against wireline logs the saturation estimate will have an accuracy within 5%. An array of 8 sensor nodes, carefully distributed in the well would probably give sufficient lateral resolution.

Expected lifetime of a permanent sensor system is typically 5 years. Budget costs for a system is typically 500kNOK for each node.

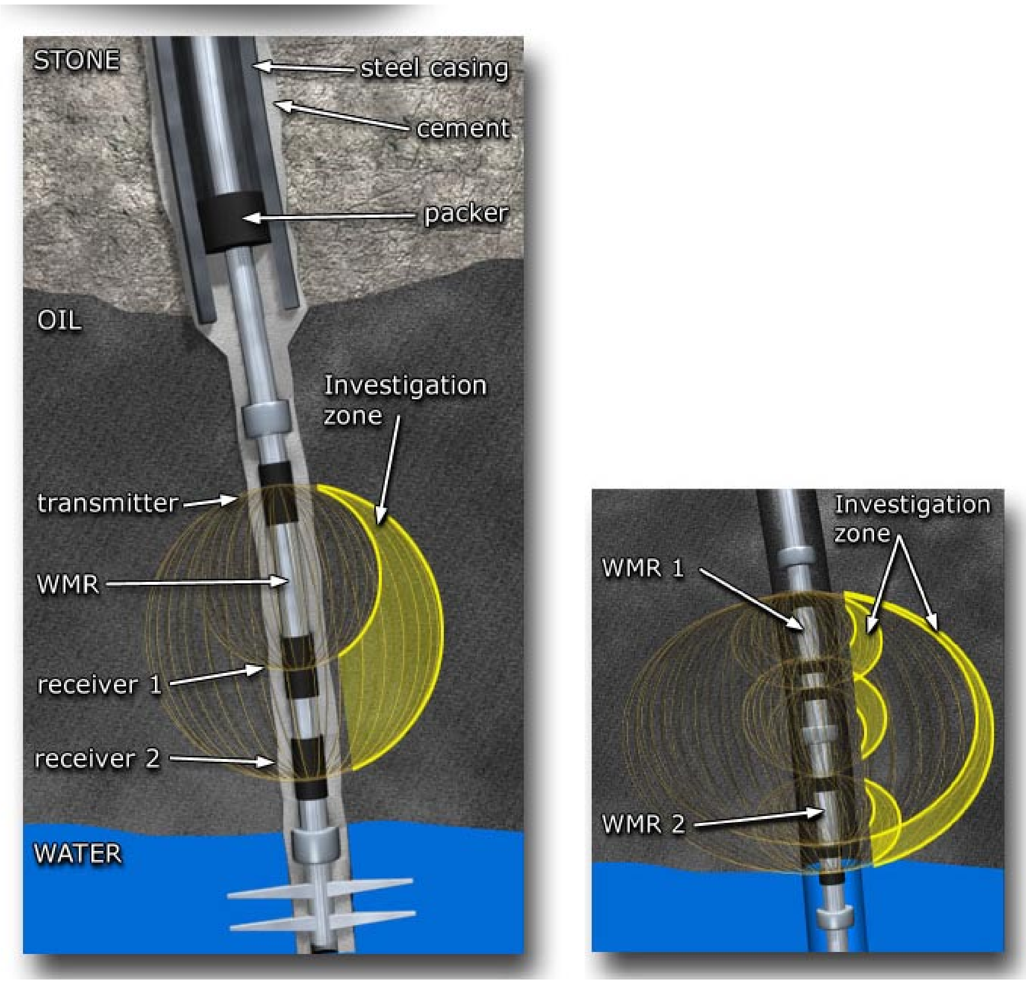

Figure 3.3 Roxar WMR electromagnetic saturation monitor.

4D seismic has already proven successful as monitoring technique in the SACS project (ref ch. 2.4). The limited seismic resolution and the uncertainty in the relation between

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seismic response and CO_2 saturation, makes permanent resistivity monitoring an excellent calibration for the observed seismic time lapse responses.

3.3.3 Borehole seismics

Systems with seismic sensors for permanent borehole installation are available from several vendors. 3 component geophones are clamped to the casing or cemented into the borehole. The geophones can be applied for continuous monitoring of microseismic events or for acquisition of repeated VSP.   Figure 3.4 shows an example of permanent seismic sensors from IFP/Gaz de France, with up to 24 levels of 3C geophones. A similar system is operated by CGG. Halliburton is developing a new system with up to 200 levels with variable spacing.

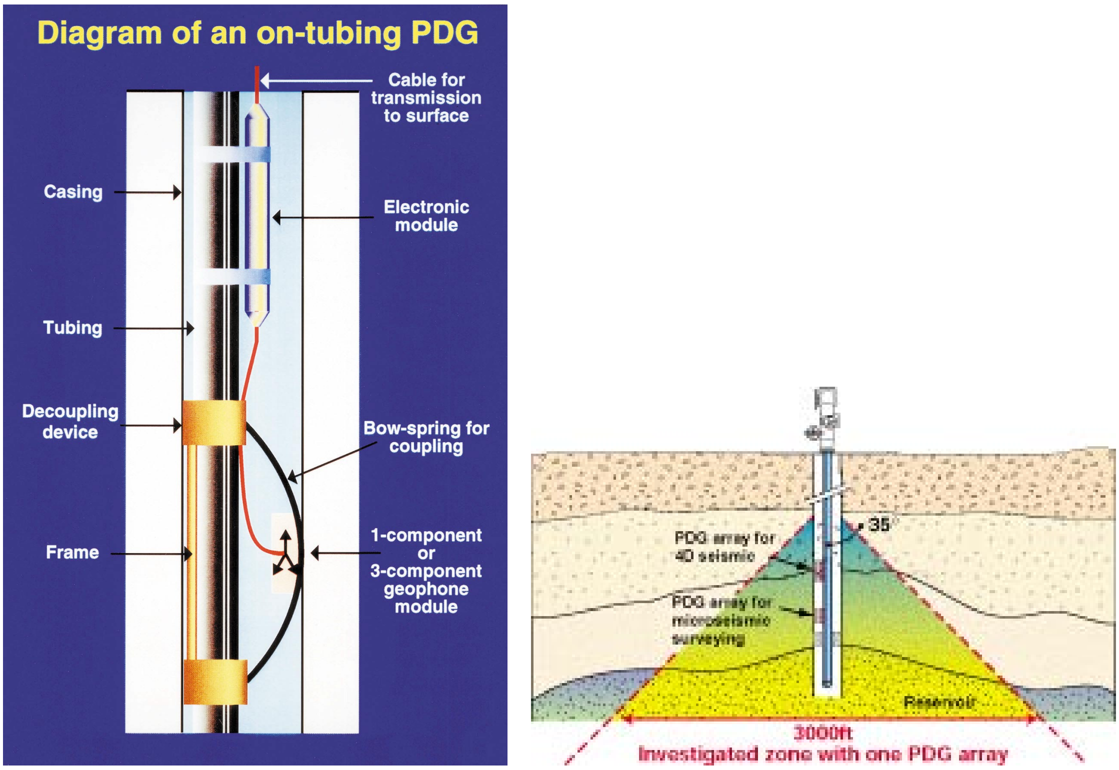

Figure 3.4   Example of permanent seismic sensors (IFP)

The advantage of time-lapse VSP compared to surface seismics is improved signal to noise ratio, good repeatability and improved resolution near the borehole. When multiple source offsets and azimuths are employed with multiple borehole receiver array installations, it becomes possible to develop a 3D image of the reservoir whose area xtent meets whatever objective is specified.

3.3.4 Sonic

Sonic logs are frequently used for calibration of seismics. Monitoring of changes in sonic velocities at different depths is thus relevant for interpretation and calibration of 4D seismics.

Equipment for permanent sonic measurements are to our knowledge not commercially available today. The complexity of a system is comparable to a permanent resistivity monitoring system (ref ch.. 3.3.2). Each sensor node would consist of one piezoelectric source and two (or more) receivers in an array. 8-16 nodes would typically be sufficient for a monitoring well.

3.3.5 Borehole gravimetry

Gravity prospecting is a common geophysical method. It involves the measurements of the variations of the gravitational field of the earth. These variations are due to density changes and typically quite small. Instruments are therefore most sensitive (1 mgal compared to the absolute acceleration of gravity with 1000 gal). In gravity prospecting various corrections are necessary to compare measurement form different points: latitude correction, free-air correction, Bouguer correction, terrain correction.
For logging purpose logging gravimeter exist, e.g., the borehole gravity meter BHGM by LaCoste & Romberg. Their accuracy corresponds to a density resolution of 0.01 g/cm^3. Repeatability of gravity difference measurements in boreholes is about 2-3 mgal. The gravity method has two strong advantages:

1. The depth of investigation is great (several meter up to tenth of meters)
2. The measurements are not influenced by casing

The disadvantages are that the gravimeters are most sensitive and available tools are only applicable for small borehole inclination.
However, few case examples of reservoir monitoring by gravity exists. Gravity measuring devices for permanent monitoring is currently not available.

3.3.6 Fluid sampling

Measuring the amount of CO_2 dissolved brine solution over time is a relevant monitoring objective. A reliable measure of this parameter requires fluid sampling on a regular basis. With existing technology fluid sampling can only be performed with direct access to the well (through a wire-line operation) or with a producing well. These options are not available within reasonable technical and economical frames today.

4. Well options

4.1 General

Various options of observation wells can be thought of as sketched in Figure 4.1. Possible well configurations are;

1. Down to caprock
2. Partly through caprock
3. Into storage aquifer
4. High angle / sidetrack into upper aquifer (if found)
5. Into connected aquifer to check lateral spreading
6. Use of injection well / sidetrack
7. New multipurpose injection / monitoring well

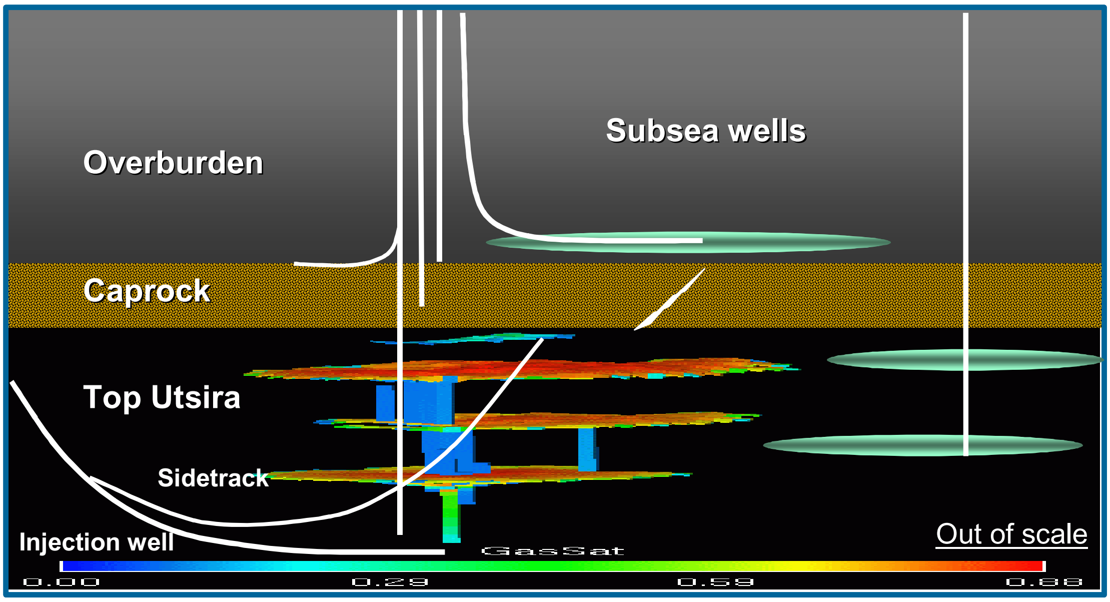

Figure 4.1 Observation well scenarios

4.2 From Sleipner A

Three well options from the Sleipner A platform can be thought of;

1. The use of the injection well itself (15/9-A-16)
2. Drilling of a sidetrack from the injection well
3. Drilling of a new multipurpose monitoring and spare injection well

The first option is rather limited as it will only be for cased hole logging purposes and for measurements at the injection point. This option could be performed within a timeframe of a few days, and will not interfere with the gas injection program . Due to the extended reach and high angle of the well, the logging and measurement operations will need coiled tubing or other pipe conveyance adding some operational risk.

The second option is a sidetrack from the injection well kicking off after the 13 3/8" casing shoe. It will give some flexibility to the well monitoring program, but will add too much operational risk and with a danger of losing this important well for a long time. A window has to be milled in the casing and the Utsira formation is also poor consolidated thus making it difficult to build up a well angle to reach higher up in the gas cloud for measurements. Appendix B.1 and B.2 show the CO_2 injection well, 15/9-A-16, and a possible sidetrack from this for monitoring purposes.

The third option combining a spare injection well and a monitoring solution could be a viable solution. Such a well, if properly planned for, gives several interesting possibilities with also sidetrack / multilateral options using preinstalled casing windows. However, the need for a spare injection well has been thoroughly discussed earlier by the Sleipner drilling and well team, concluding that there is not a need for a spare well at this time. The existing well has a 7" monobore design ensuring good access for remedial actions in this important well if a problem should occur. High quality duplex steel has been used for the injection tubulars and exposed parts of the surface casing. Spare tubulars and equipment also exists for repair purposes.

Wells drilled from the Sleipner A platform will have to be of an extended reach and high angle design to meet monitoring objectives. The distance to the injection point is 3 km away and the most obvious storage reservoir spill points indicate monitoring of lateral spread even further away. A platform centre drilled well will interfere with daily platform operations and will not offer as flexible monitoring options as possibly wanted. It will also require a separate slot if not a sidetrack from an existing well is possible. A platform operated permanent monitoring well will, however, be easier to support over time and can also be drilled without penetrating the caprock above the storage aquifer.

4.3 From rig

Subsea wells drilled from a rig are distance independent from the Sleipner platform centre and will open for most options for subsurface characterisation and monitoring objectives. Simple vertical wells can be drilled both above the injection point and further away for checking of the lateral spreading. Drilling of these wells will also be independent from the operations at the platform center and not interfere with the CO_2 injection. They will penetrate the caprock and special care has therefore to be taken not to induce leakages. An option could also be to drill high angle wells penetrating the caprock outside the stored gas plume. Another option briefly looked into is to drill an high angle well above the caprock for a possible upper aquifer monitoring as schematically demonstrated in Appendix B.3.

Wells drilled for characterisation purposes only can be sealed off under the seafloor and permanent abandoned after use. Wells equipped for permanent monitoring applications, however, have to be subsea completed and with a trawler protection arrangement. For signal transmission from the wells a hydroacoustic link to the surface or a cable on the seafloor back to the platform centre can be used.

A simple slender well design can be applied with a 30" conductor for BOP support and two x-overs to a 9 5/8" surface casing. Drilling, logging and sampling of these wells should be fairly straight forward, but care has to be taken not to induce leaks. Most uncertainty is related to the installation and testing of the permanent monitoring systems. Although other field cases can be referred to, not much industry experience have been gained within this field yet.

4.4 Cost estimates

Sleipner daily platform rate has been referred to be NOK 1.2 – 1.5 mill. Although a cheaper rate than for a rig, wells will take much longer time to drill. The cost of the existing CO_2 injection well has been referred to be NOK 60-70 mill., where much of the capital cost was related to the need for expensive high quality steel tubulars. This indicates that a multipurpose well as sketched above will cost in the range of NOK 100 mill.

Subsea wells have to be drilled from semi-submersible rigs or drillships with current daily rig rates of 2 – 2.5 mill. The rig market is expected to be tight for still some years and there is yet not much other option than using a standard semi-submersible. Although new cost effective concepts are being developed for slim exploration drilling and intervention in deep waters, these options will not be available for some time. Drilling of the wells should be fairly straight forward with a drilling campaign of 1 – 1.5 weeks time per well. Two days should be added for the coring operations and the same for wireline logging and testing – summing up to a total of approximately two weeks for “characterisation wells” indicating a cost of NOK 35 mill. as shown in

Table 4-1.

Most uncertainty is related to the time needed for the completion of a permanent monitoring well. Normally one week of operation should be enough, but two weeks should be counted for if installation and equipment problems should occur. Typical equipment cost of the monitoring system is NOK 10 – 15 mill. It is an alternative to drill and complete the permanent monitoring well in two operations using a cheaper rig or ship for the completion, but the availability of smaller rigs are uncertain as indicated above. A total of up to four weeks operations indicates a total cost of NOK 70 mill. for a combined characterisation and permanent monitoring well as shown in

Table 4-1.

The highest cost is associated to the rig rates and the time needed. The second important issue is the cost of an instrumented permanent monitoring system. Drilling and completion of an monitoring well only without an extensive logging and sampling program will cost in the range of NOK 55 – 60 mill.

Table 4-1 Cost estimate subsea observation wells

Cost estimate of subsea observation wells (NOK)					
Sequence	**Equipment**	**Rate**	**Days**	**Cost**	**Sum**
Drilling	Rig	2.200.000	10	22.000.000	**24.500.000**
	Drillbits (36”, $12\frac{1}{4}$”, $8\frac{1}{2}$”)	500.000		500.000	
	Casing/ liner/tubing etc. (30”, $9\frac{5}{8}$”, 7”)	1.000.000		1.000.000	
	Consumables & services	1.000.000		1.000.000	
Coring	Rig	2.200.000	2	4.400.000	**4.900.000**
	Drillbit ($8\frac{1}{2}$”)	100.000		100.000	
	Equipment etc.	400.000		400.000	
Logging	Rig	2.200.000	2	4.400.000	**5.600.000**
	MWD / LWD / mud log	500.000		500.000	
	Wireline log. / RFT / VSP	700.000		700.000	
Subtotal characterisation wells					**35.000.000**
Permanent monitoring	Rig	2.200.000	10	22.000.000	
	Monitoring equipment	12.000.000		12.000.000	
	Consumables & services	1.000.000		1.000.000	
Subtotal permanent well monitoring completion					**35.000.000**
Grand total characterisation & permanent monitoring wells					**70.000.000**

5. Recommendations

5.1 General

The Sleipner CO_2 storage project is an important effort addressing an alternative solution to reduce the environmental impact from oil and gas production. Observation wells will give a substantial contribution to the basic needs;

- characterise
- calibrate
- control

A well program is recommended combining characterisation and permanent monitoring objectives;

- for improved storage facility characterisation
- to calibrate and complement the time-lapse seismic monitoring system
- to check the lateral spread

A direct observation of a leak from a dedicated observation well is unlikely.

5.2 Well program

A program of two subsea vertical observation wells, No.1 and No.2, is proposed – one penetrating the gas cloud above the injection point (No.1) and one drilled into connecting aquifers (No. 2) not yet reached by the injected gas. The map in Figure 5.1 indicates the location of the wells. Well No.1 will be drilled for sampling and logging purposes only, providing data for improved characterisation of the storage facility and will be sealed off beneath seafloor and permanently abandoned after use. Well No.2 will penetrate two possible migration paths as described in Chapter 2.2.2. After the sampling and logging programme, it will also be permanently equipped with an instrumented tubing. A capital cost of NOK 35 mill. for well No.1 and 70 mill. for well No.2 is anticipated.

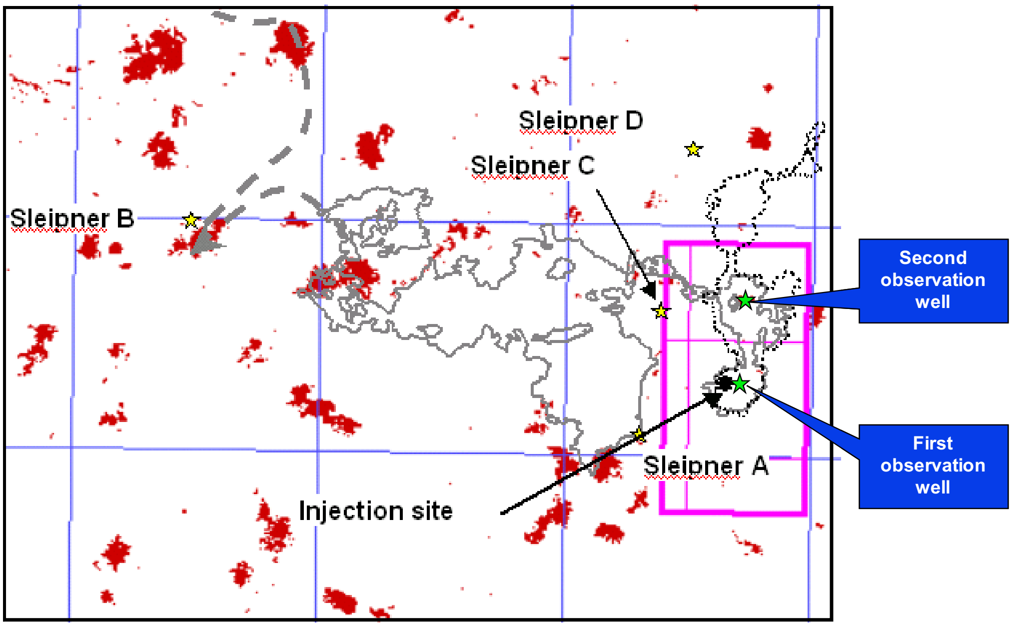

Figure 5.1 Proposed location of observation wells

A comprehensive logging and sampling program should be planned for both wells as described in Chapter 3.2. The main objective of well No. 2 is to control lateral spreading of the injected gas. A system with resistivity sensors for saturation measurements will be established in addition to a system for pressure and temperature gradient measurements. Sonic and 3D component seismic sensors are optional to add information to the surface seismic monitoring system. Monitoring of the storage reservoir pressure is not a key issue due to the shape and size of the reservoir cap with the associated low pressure build up.

Subsea wells give most observation options and will not interfere with the Sleipner A platform operations. A proposed well design is schematically shown in Figure 5.2. The basic well design can be applied for both the proposed wells. A slender well programme is proposed with a 30" conductor 90m below seafloor for BOP support and a 9 5/8" surface casing into the top Utsira storage formation. A 12 ¼" hole for setting of the 9 5/8" casing will be drilled through the overburden and the caprock. An 8 ½" hole will be drilled in the storage formation allowing an option allowing an option of a 7" liner and / or an instrumented tubing to be installed. Alternatively a 6" open hole will also be drilled for the instrumented tubing. The coring sections will be drilled with an 8 ½" bit with a successive 12 ¼" hole opener in the overburden and caprock. Coring in the Utsira can be difficult but nevertheless should be tried.

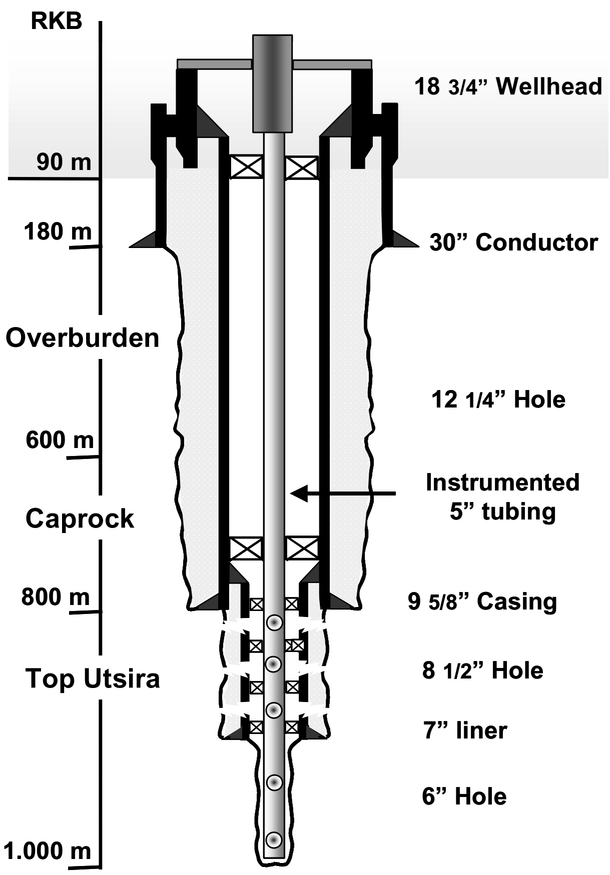

Figure 5.2 Schematics of proposed subsea well design

The wells need careful design not to introduce leaks. High quality packers and tubular steel have to be used where exposed to CO_2. Gas tight cement for cement plugs and casing bonding need likewise to be used. A cement bond log (CBT) and ultrasonic cement imager (USI) will be run to ensure that the cement has filled the annulus between the casing and borehole and that the cement and casing are well bonded.

The drilling campaign should be synchronised with a 3D surface seismic survey for the time-lapse seismic monitoring program. In this way the subsurface information collected in the well can be directly correlated to the surface seismic observations. VSP seismic sensors in the well is an option to add overall seismic information. Also a site survey with inspection of the seafloor should be considered to look for pock marks on the seafloor indicating possible leaking gas. An active sonar surveillance of the sea column can likewise give indications of leaking gas.

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Appendix A Aspects of Pressure monitoring

A1 The pressure development in a spherical storage cap during gas accumulation and storage of CO_2 gas.

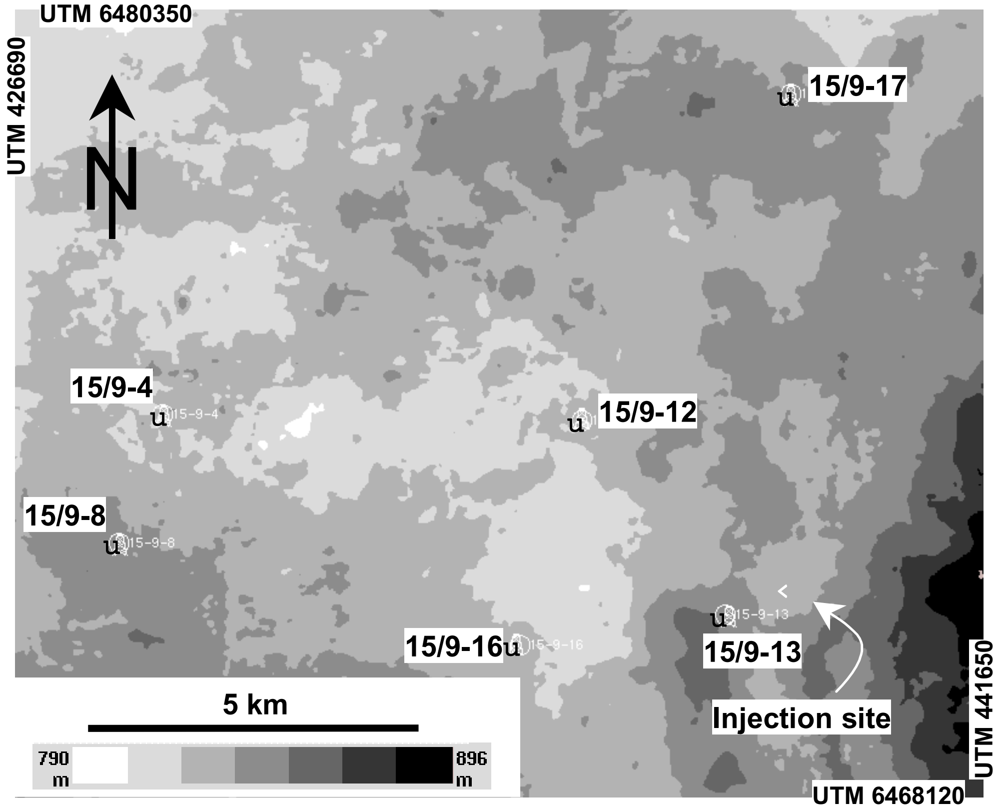


Figure A1: Topography of the top Utsira Sand from seismic interpretation, strongly smoothed.
Contour interval: 15 m. For a corresponding seismic section refer to Arts et al. (this volume).

Gas may enter volumes of different shapes and sizes in the aquifer, see figure 1. From the topography contour plot it is indicated that the CO_2 gas is initially injected into a volume with a 'round' contour and a possible outflow towards northeast.
In the following discussion on the pressure development in gas volumes, a spherical cap shape is used as an approximation to the shapes found in the Utsira reservoir.
Let the radius of a sphere be r (see Figure 2), while the height of the spherical cap is h.
The cap volume is: $volume_{cap} = \frac{1}{3}\pi h^2(3r - h)$. (eq.1)

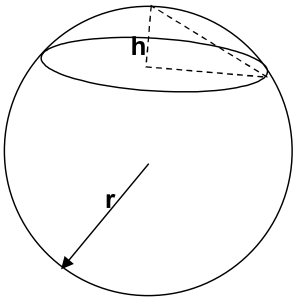


Figure A2: *A spherical cap.*

Assuming that h<<r, the cap 'ceiling' is assumed to be close enough to actual cap shapes in the Utsira aquifer.

Gas entering the cap volume will build up from the top, until the volume is filled up and the gas starts to drain out.
The height of the gas bubble will increase as shown on figure 3 (a plot of eq. 1). Here, a sphere with radius 40 000 m is used. Assuming that the gas volumetric inflow is constant, we see that the height will increase most rapidly in the beginning. With an injection rate of 1 Mill metric tons / year and a reservoir gas density of 700 kg/m^3, the volumetric injection rate to the storage gas bubble is around 1.4 10^6 m^3/year. If this was injected into the spherical cap described here, the gas bubble height would be app. 6 m after one year of injection. <u>Note that the case discussed here is generic and will not necessarily correspond with the more detailed reservoir geology and migration modelling performed elsewhere in the SACS project documentation.</u>

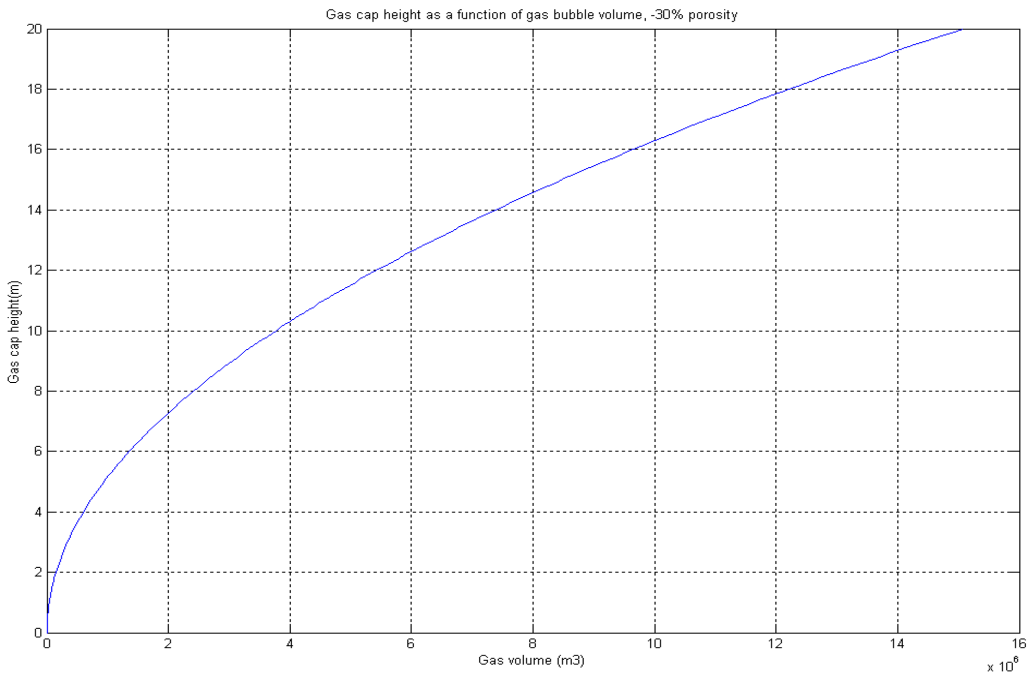


Figure A3. *The height of a gas bubble in a spherical cap as a function of injected gas volume.*

As the height of the gas bubble increases, the width of the bubble will also increase, see figure 4. The figure indicates a bubble radius of 700 m after a year of injection.

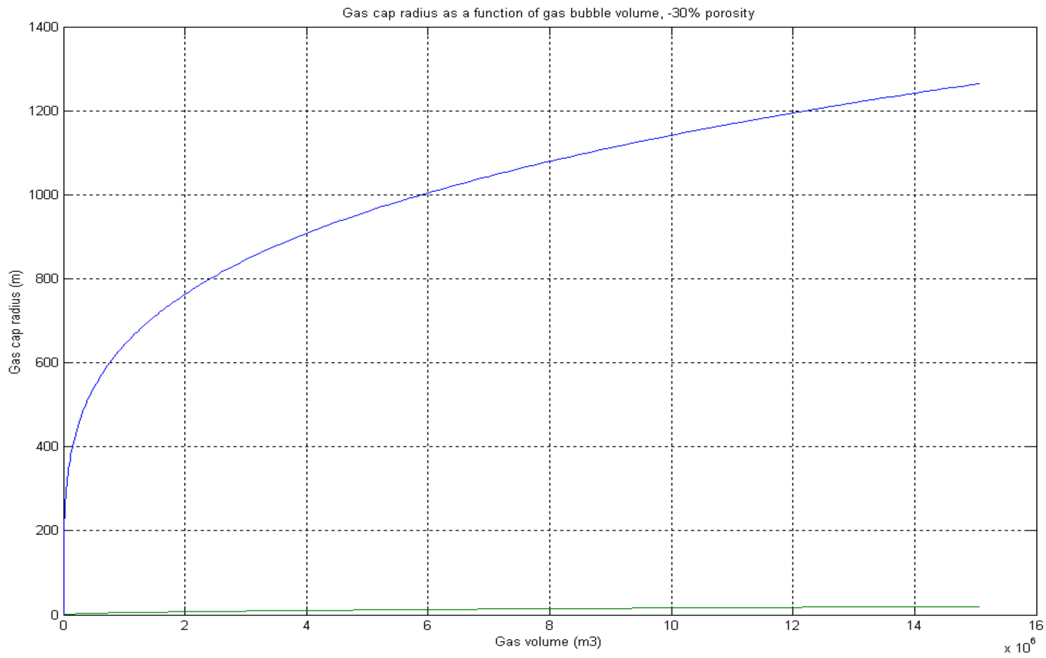


Figure A4. The gas cap radius as a function of gas volume.

The volume is assumed to be water filled before the injection starts. Displacing the water with gas means that a lighter column is displacing the heavier water. Thus, the pressure in the volume is increased relative to the initial pressure (the hydrostatic pressure is decreased). For water and CO_2, the density difference is 0.3. Measured on top of the gas bubble, the development of the pressure is seen at figure 5.

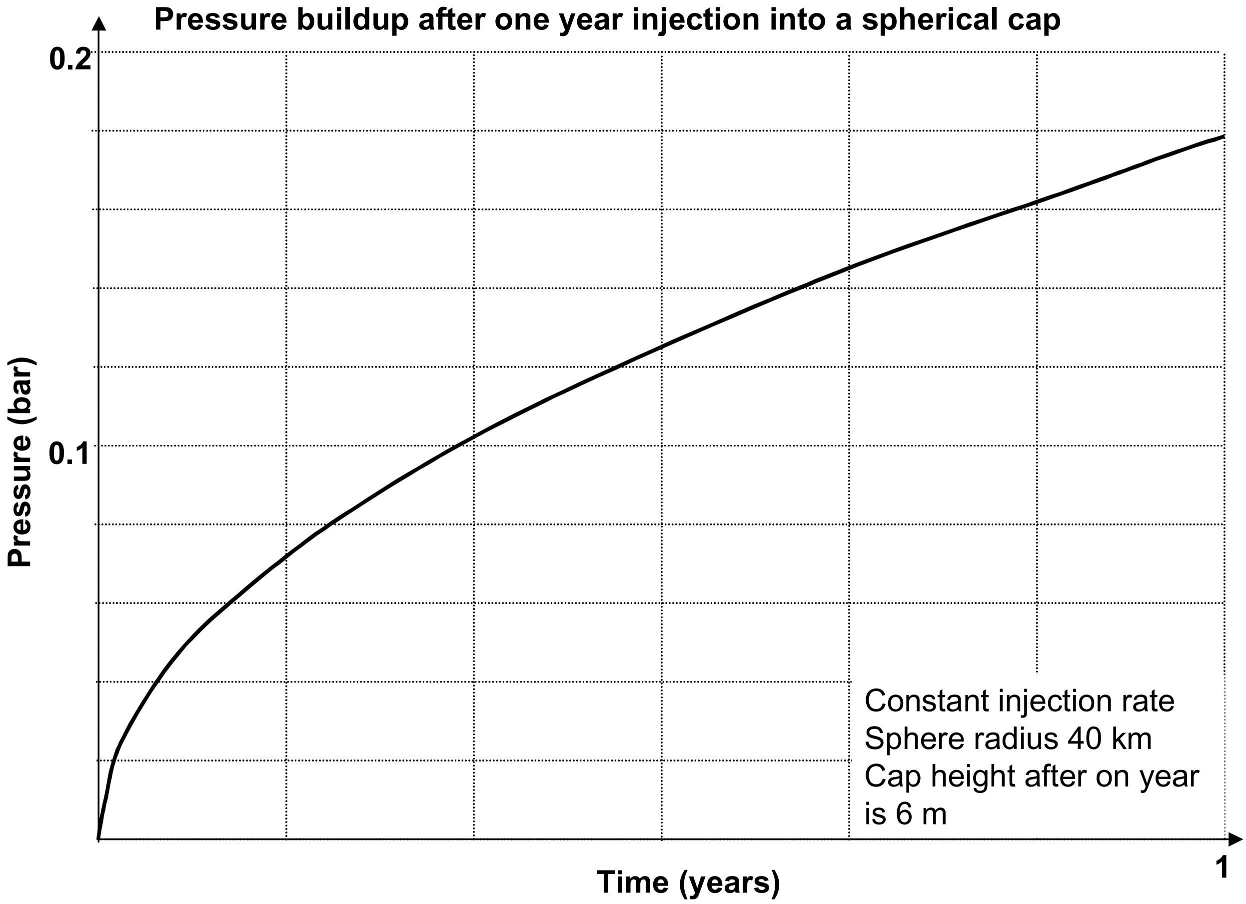


Figure A5. Pressure development on top of the gas bubble as a function of injected gas volume.

At some bubble height threshold, the sphere cap "overflows" and gas is drained along some migration path. The bubble pressure should then flatten off, with a slight "overshoot" as long as gas inflow is maintained. At figure 6, the probable pressure development of the accumulation phase and the overflow phase for a 6m bubble overflow thresholds is seen.
A spherical cap has the capability of storing a certain amount of gas, so the pressure should be fairly constant over the whole injection periode, with some variations due to variations in gas injection rate. When injection is stopped, a slight decrease can be expected, see figure 6.
For the Utsira reservoir, the time distance from the accumulation in a cap storage to the injection is stopped may be 20 years. Since the discussion is not limited to the main bubble over the point of injection, this time span is naturally dependent of the time the actual bubble starts to accumulate gas.

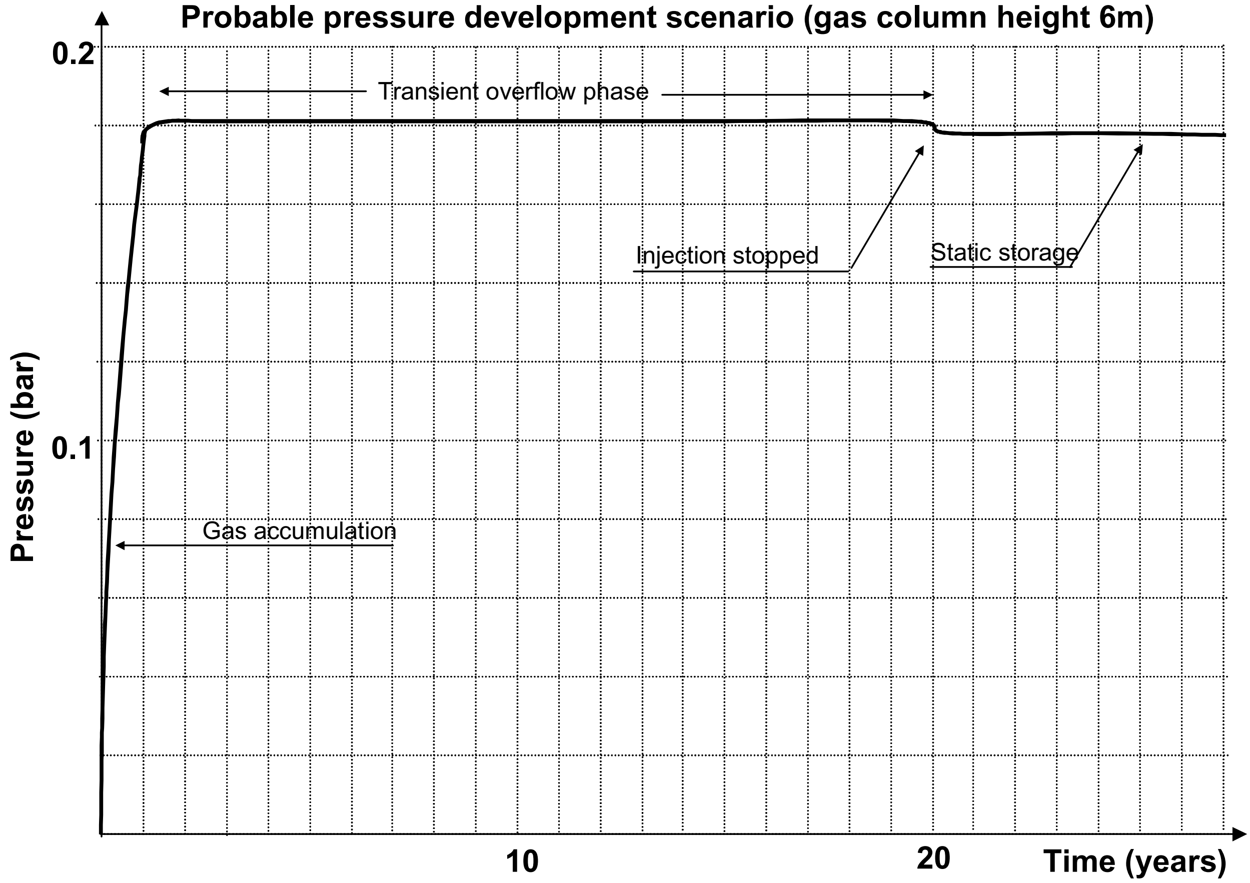


Figure A6. A probable pressure build-up through gas accumulation, gas overflow and static storage phases.

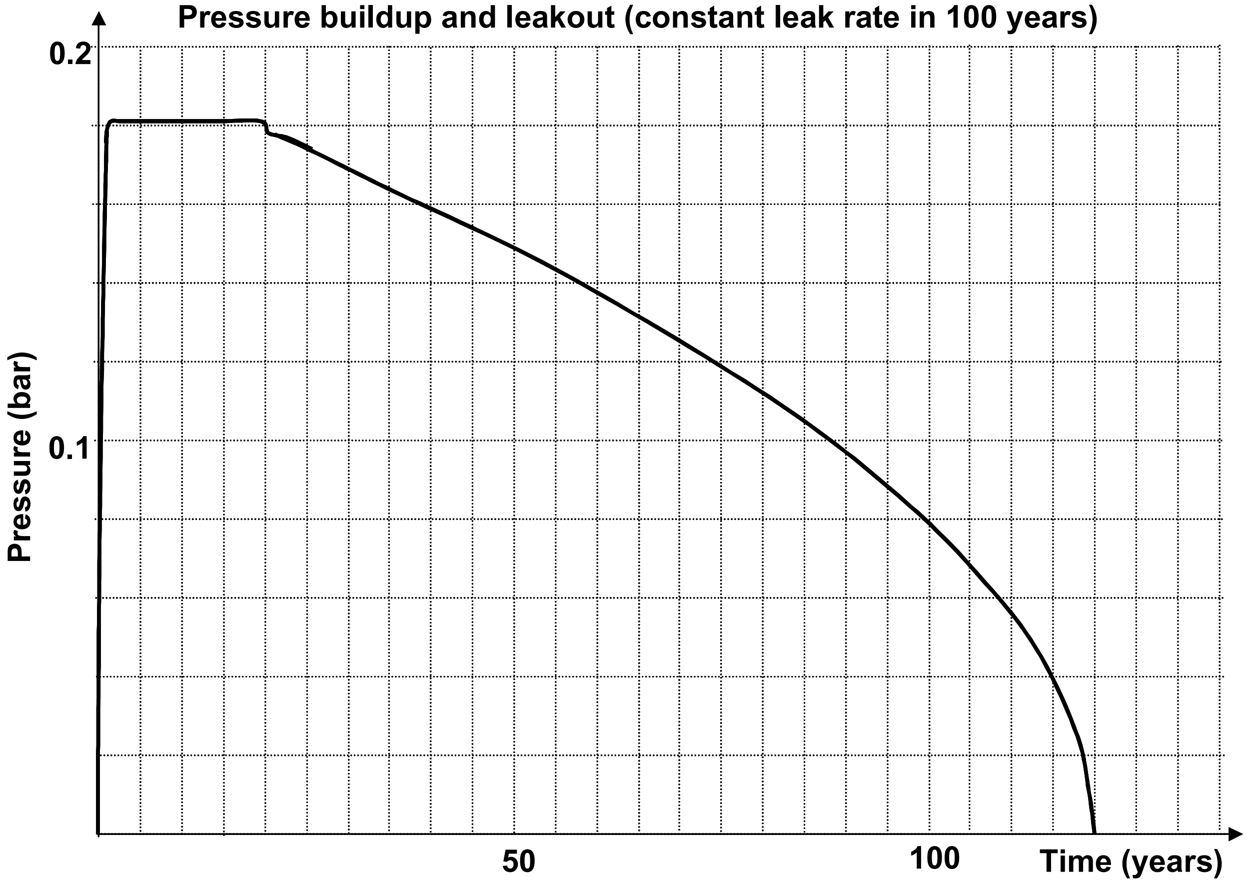
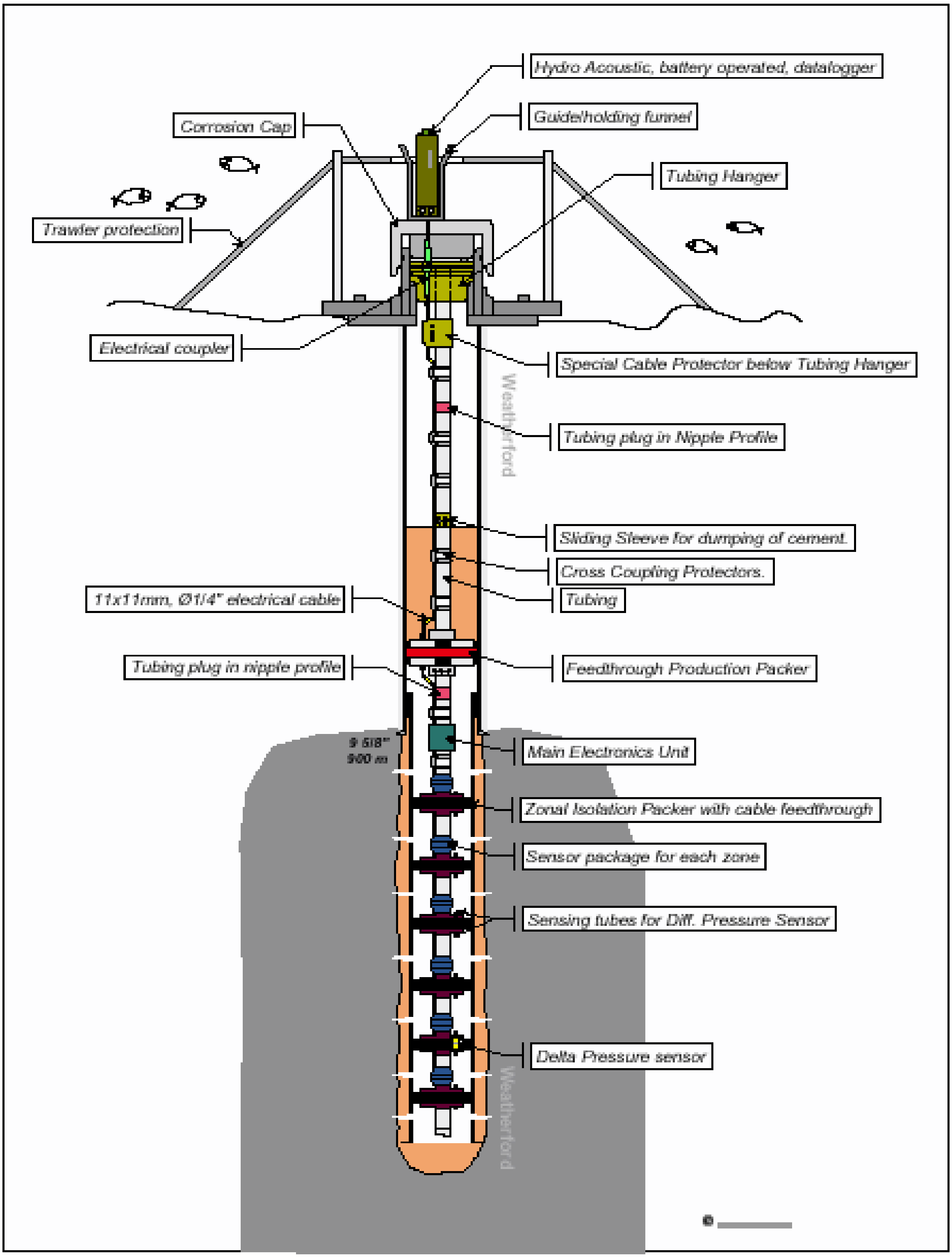


Figure 7. A pressure buildup and leakout scenarium. The leakout is constant and is thus the opposite prosess to the pressure buildup phase.

A.2 Pressure monitoring proposal from Weatherford

Proposed concept.



DIACS 8 Weatherford Completion Systems

Description

Prior to the completion the well is drilled and the 7" liner is run and cemented in place. Perforation is performed at 5 meter intervals over the 100m section that is to be monitored.

The lower end of the completion is spaced out so that the isolation packers will end up being set between the perforations. To achieve this, a landing sub for the perforating gun and the completion might be run as a part of the liner. The lower 100 meters of the completion is build up by isolation packer sections that also contain the differential pressure sensor. The packers will be of a 'outer moving sleeve' type that not generates a lot of tubing movement during the setting sequence. There are different ways achieving positive setting of all these packers. Methods will be further explained when the project progresses.

Each section of the pressure sensors will be made up onshore. When fitted to the completion string a quick connector ensures full pressure integrity and fast mounting. At the last pressure sensor mounted a Main Electronic Unit (MEU) will be fitted. This will take care of all the multiplexed communication with the pressure sensors. It will also send the retrieved information up to the seabed datalogger. Standard downhole cable will be used to send these data. This cable can easily be run through the 'production packer' barrier and likewise fitted to the tubing hanger wet connector.

Cable protectors will be run on every joint between the lower packer and the tubing hanger. In the tubing hanger the signal will go through standard wet connectors used for permanent well instrumentation.

Two nipple profiles should be run as a part of the completion string. Plugs can be hung off in these to fulfil the NPD regulations for permanent abandonment of wells.

A sliding sleeve (mechanical or hydraulic) is proposed run in a distance above the production packer. Once the completion is landed and the packer is set, this can be opened and cement dumped above the packer.

A datalogger will be placed on the Temporary Abandonment cap (TA-Cap). This will retrieve data from all the downhole sensors at given logging intervals. The information will be stored in a non-volatile memory. This is only accessible by via the hydro acoustic communication link. This link enables the user to upload the stored data through the water from a supply or stand-by boat.

Project Schedule and Pricing

If this project goes ahead, we first of all need an initial phase where all involved parties get together and agrees on the scope, running and handling of this project.
Then an engineering phase with design and testing of critical components must take place.
Finally the equipment goes into production and is finally tested.

Item	Description	Cost [NOK]	Duration
1	Initial Phase	150.000,-	4 weeks
2	Engineering phase	1.500.000,-	16 weeks
3	Downhole Equipment	7.500.000,-	20 weeks
4	Final testing	100.000,-	2 weeks
5	Documentation	100.000,-	4 weeks

Do note that timing and pricing are very budgetary and can be subject to change.

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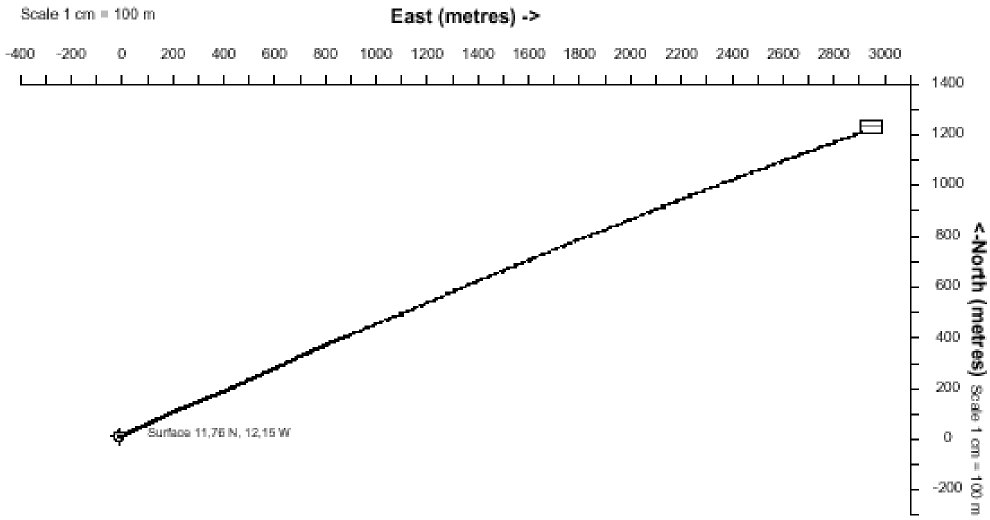
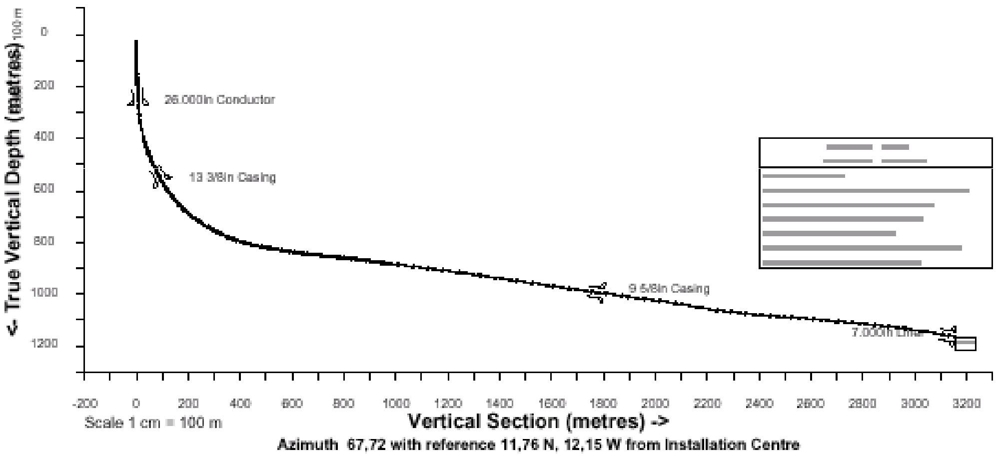
Appendix B Well profile examples

B.1 Sleipner A Well: 15/9-A-16

Statoil

Installation : Sleipner A	Well : 15/9-A-16
Field : SLEIPNER	Location : Norway





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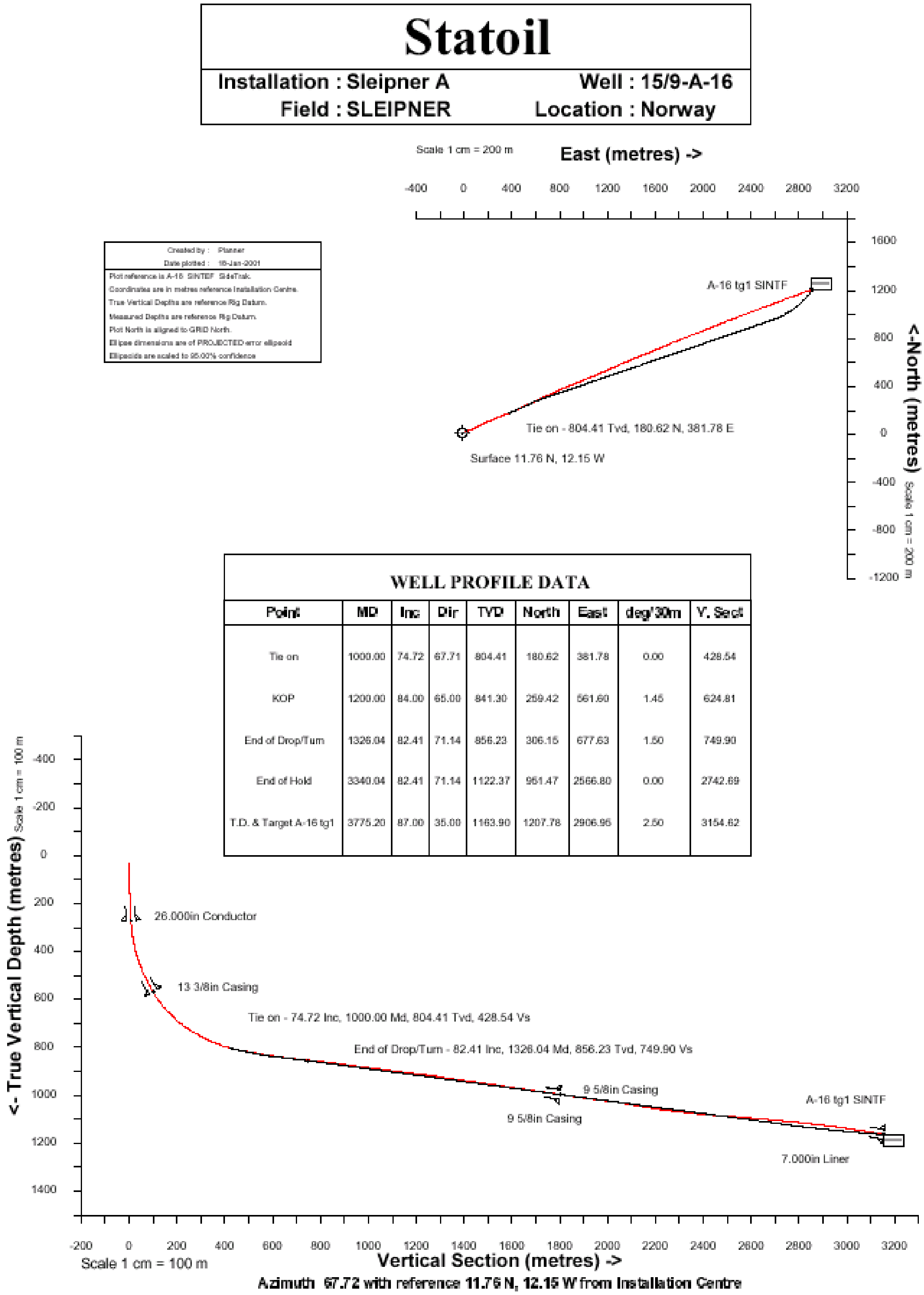
B.2 Sleipner CO_2 monitoring well sidetrack option



WELL PROFILE DATA

Point	MD	Inc	Dir	TVD	North	East	deg/30m	V. Sect
Tie on	1000.00	74.72	67.71	804.41	180.62	381.78	0.00	428.54
KOP	1200.00	84.00	65.00	841.30	259.42	561.60	1.45	624.81
End of Drop/Turn	1326.04	82.41	71.14	856.23	306.15	677.63	1.50	749.90
End of Hold	3340.04	82.41	71.14	1122.37	951.47	2566.80	0.00	2742.69
T.D. & Target A-16 tg1	3775.20	87.00	35.00	1163.90	1207.78	2906.95	2.50	3154.62

B. 3 Subsea high angle well above caprock

Demonstration Drilling

Structure : Ellipse Alpha   Well : EA-1

Field : Thursday   Location : Offshore Norway

---- WELL PROFILE DATA ----

----- Point -----	MD	Inc	Dir	TVD	North	East	V. Sect	Deg/30
Tie on	0.00	0.00	45.00	0.00	0.00	0.00	0.00	0.00
End of Hold	400.00	0.00	45.00	400.00	0.00	0.00	0.00	0.00
End of Build	1028.32	90.00	45.00	800.00	282.84	282.84	400.00	4.30
T.D. & End of Hold	1300.00	90.00	45.00	800.00	474.95	474.95	671.68	0.00