DANMARKS OG GRØNLANDS GEOLOGISKE UNDERSØGELSE RAPPORT 2019/21

CO_2 Neutral energy system utilising the subsurface

WP4 Geo-model development, reservoir modelling and GIS

Karen Lyng Anthonsen, Carsten Møller Nielsen, Lars Kristensen,
Troels Laier & Peter Johannessen

GEOLOGICAL SURVEY OF DENMARK AND GREENLAND
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Content

Executive summary

This report is part of the energy research project *CO_2 Neutral energy system utilising the subsurface (CONvert)*. The overall project objective is to analyse the techno-economic feasibility of an integrated energy system, where the subsurface is utilised for thermal energy production and storage, as well as temporary CO_2 storage (Figure 1).

WP4 will identify subsurface geological structures and reservoir sandstones and will select the most attractive sites for storage of CH_4/CO_2, hot water, CO_2 and geothermal production. Productivity and injectivity are vital for the usability of the subsurface and governs the configuration of the individual subsurface installations. Subsurface reservoir modelling allows for simulation of both energy extraction (geothermal energy production) and storage. Different scenarios can be examined, and potential synergy effects can be optimized in the operating phase, but also facilitates the costly and uncertain exploration and installation phase. The WP4 aims at facilitating strategic decision making regarding early and future use of the subsurface as an active. All relevant data will be transferred to a GIS geodatabase.

Subsurface mapping and site selection

Successful subsurface storage of gasses as CO_2 and CH_4, and thermal energy storage and production of heated formation water requires several geologic conditions are met. As the geological environment can be highly variable this is important to localise the areas with optimal geological conditions for storage of gasses or heated water.

The geology of Denmark is characterised by a up to 10 km thick cover of sedimentary rocks of Late Palaeozoic to Cenozoic age. Formations containing sandstone layers (aquifers) with potential for storage of CO_2 and thermal energy and geothermal production in the Danish Basin are the Skagerrak/Bunter Sandstone Formations, the Gassum Formation, the Haldager Sand Formation and the Frederikshavn Formation.

Geological recommendations for Deep Aquifer Thermal Energy Storage (>1000 m) are the same as for geothermal production, a minimum porosity of 15%, a maximum clay content of 30% and a minimum thickness of 20 m for the reservoir aquifer (Kristensen et al. 2016). Regarding depth and reservoir properties the Gassum Formation are the most favourable formation for thermal heat storage in the Aalborg area.

The ReSOC (Reversible Solid Oxide Cells) operates with two separate gasses, a fuel gas with a composition close to natural gas, consisting mainly of methane (CH_4), and a CO_2 gas with a high content of hydrogen (H_2). In aquifers the presence of methanogenic bacteria capable of producing methane and the ReSOC's demand for fast access to dry gasses, which requires a gas-drying facility and intermediate gas storage, makes the aquifer storage of the CO_2-H_2 gas mixture unfavourable. However, it is possible to store a CO_2-H_2 gas mixture in salt caverns, but it should be noted that undesirable processes, such as methane and sulphide (H_2S) formation can take place. Furthermore, the risk of unwanted methane formation is estimated to be greater for a CO_2-H_2 gas mixture than for pure H_2 gas.

Storing supercritical CO_2 require several geological conditions to be fulfilled:

- Storage depth 800-2500 (in some cases 3000) m
- Preferable a geological structure (trap)

- Reservoir porosity min. 10% and permeability above 100 mD
- A tight seal (caprock) thicker than 20 m
- No large faults

The Gassum Formation are regarded the most attractive CO_2 storage formation with respect to depth and reservoir properties and the formation is overlaid by more than 650 m Fjerritslev Formation in the Vedsted-1 well, forming the primary seal. Based on seismic mapping of the Danish subsurface (the Geothermal WebGIS portal http://data.geus.dk/geoterm/) several structures on the Top Gassum Formation level were identified. The Langerak (unofficial name used in the project) structure located only 3 km from SE of Nordjyllandsværket was selected as the most prospective trap despite poor seismic data availability. The Vedsted-1 well was evaluated as representing the Gassum Formation in the Langerak structure.

Reservoir model construction and dynamic modelling

To assess the use of the subsurface for both energy extraction and storage, detailed static (geological) and dynamic (reservoir simulation) modelling are required. Reservoir simulation methodology can help quantify the performance of the various subsurface operations that is examined in the present project, i.e. CO_2 storage (CCS), thermal energy storage (DATES) and geothermal energy production (GE). The modelling methodology and workflow outlined in the present report is mainly based on experiences from the oil & gas industry, but similar conclusions could be obtained from other workflows.

The productivity and injectivity are vital properties for the usability of the subsurface and governs how the individual subsurface installations are to be placed in the ground; i.e. well spacing and well configuration together with optimized operation management.

The modelling procedure falls in two steps. A static model is constructed based on the geological knowledge and available geophysical and petrophysical data for the subsurface. A 3D dynamic model is subsequently build based on the geological model. Reservoir performance is evaluated through the dynamic modelling but in an iterative process with modification of the static model, especially if real production/performance data is available to calibrate the models.

For the three subsurface operations that are evaluated, CCS, GE and DATES the static modelling procedures are identical. The dynamic modelling methodology are different in order to model and replicate the different physical processes for the three operations.

The main difference for the CCS operation compared to the other two is the mandatory closure of the reservoir formation, i.e. a sealing caprock above the reservoir and a trapping mechanism to secure that the CO_2 stays in the subsurface. A depth constraint of minimum 800m for the shallowest part of the CCS reservoir is required. Below 800 m the hydrostatic pressure of the formation secures that the CO_2 is in supercritical state with a volume reduction of 300 times compared to CO_2 at surface conditions, which significantly increase the storage capacity.

For the GE and DATES the reservoirs must be in a fairly restricted depth interval; as the subsurface temperature increases with depth a certain minimum depth is required in order to extract sufficient heat. The minimum depth is much controlled by the heat demand in the individual geothermal projects/plants, i.e. the product of production rate and temperature. The hardest restriction on the depth of the reservoirs is how deep the reservoir can be located. The permeability of the reservoir rock deteriorates with depth due to the overburden compressing the rock and to geochemical processes in the rock and formation water (diagenesis). For the sandstone formations available in the Danish subsurface a maximum depth of around 2500 m is recommended

In general, the operations can benefit from reservoirs with high porosity and high permeability; a high porosity ensures a high storage capacity, whereas a high permeability provides a high productivity/injectivity.

When injecting a large volume of CO_2 in to the reservoir formation the initial formation water is displaced by the CO_2, but the process is slow, meaning that the pressure will increase from the injection well and radially out in to the reservoir. The pressure increase can potentially be managed by producing some of the formation water to surface, i.e. reducing the total volume in the reservoir. The operator of a CO_2 storage operation may meet regulatory issues concerning the pressure increase. The heat from the produced water can potentially be extracted and supplied to the district heating grid. This additional heat is not included in the overall energy calculations in the project but can be assessed as an upside.

Reservoir simulations are performed for a subsurface structure, the Langerak structure located east of Aalborg city, to assess the pressure development during CCS operations. Different well configurations are examined. It is found that 1 to 2 water production well can balance the pressure increase for the CCS operation of injection of 1 MM tonnes CO_2/year. No definite numbers are concluded for the volume of water production, because of lack of definite regulatory restrictions.

The objective for the simulation study of GE and DATES was to evaluate the geothermal production potential for the greater Aalborg area. In order to maximize the total geothermal production, it is essential to place the individual geothermal plants as close as possible without the individual plants are “stealing” production from the neighbouring plant.

In order to optimize the number of plants that can be located in the area of Aalborg simulation were run with smaller distance between the individual plants. Simulations were run for a distance of 7 km, 5 km and down to 3 km.

It was found that GE plants (doublets) can be distributed in a grid with only 3 km separation between the individual plants, without any indluence on production performance. further, the well distance in the individual doublets can be narrowed down from 1500 m to 1200 m with out any impact on the production temperature.

The DATES system was simulated for a total period of 60 years with an equal charging/discharging cycle of 5.5 month, a two weeks period with no flow were simulated to mimic any practicalities during shifting of charging mode. The production temperature profiles show that an efficiency of almost 90% is obtained within 4 – 5 years.

Introduction to WP4 Geo-model development, reservoir modelling and GIS

This report is part of the energy research project *CO_2 Neutral energy system utilising the subsurface (CONvert)*. The project was submitted to the ForskEL research program in 2016, but ForskEL was closed in December 2016 and the project was transferred to the Danish research program for energy development and demonstration (EUDP). The project began in May 2017 and has been finalised in September 2019.

The overall project objective is to analyse the techno-economic feasibility of an integrated energy system, where the subsurface is utilised for thermal energy production and storage, as well as temporary CO_2 storage (Figure 1). This will be achieved by modelling the technical feasibility, efficiency and economy of three subsurface technologies:

1. *Electricity-to-heat storage* by deep aquifer (>1000 m) thermal heat storage with injection of heated water using surplus electric energy produced by renewables and in combination with low enthalpy geothermal energy production.

2. *Electricity-to-gas storage* by chemical reactions of CO_2/CH_4 stored in subsurface geological structures and later re-electrified.

3. *Storage of CO_2* captured from biomass fired combined heat and power plant (CHP) or industry and temporarily stored for future reuse, e.g. production of sustainable synthetic fuels.

The subsurface has large available storage volumes for gasses or heated water and the advantage of a geothermal heat gradient. But the utilisation of the subsurface depends on the local geological environment, and for that reason the CO_2 neutral energy system has been modelled for the Aalborg municipality. Using a specific case area has the advantage of being able to apply realistic energy consumption profiles and economic data from existing energy producing facilities and a geological subsurface environment. As the subsurface environment is variable depending on location, generic recommendations for favourable geological conditions will be provided together with procedures to characterise the subsurface.

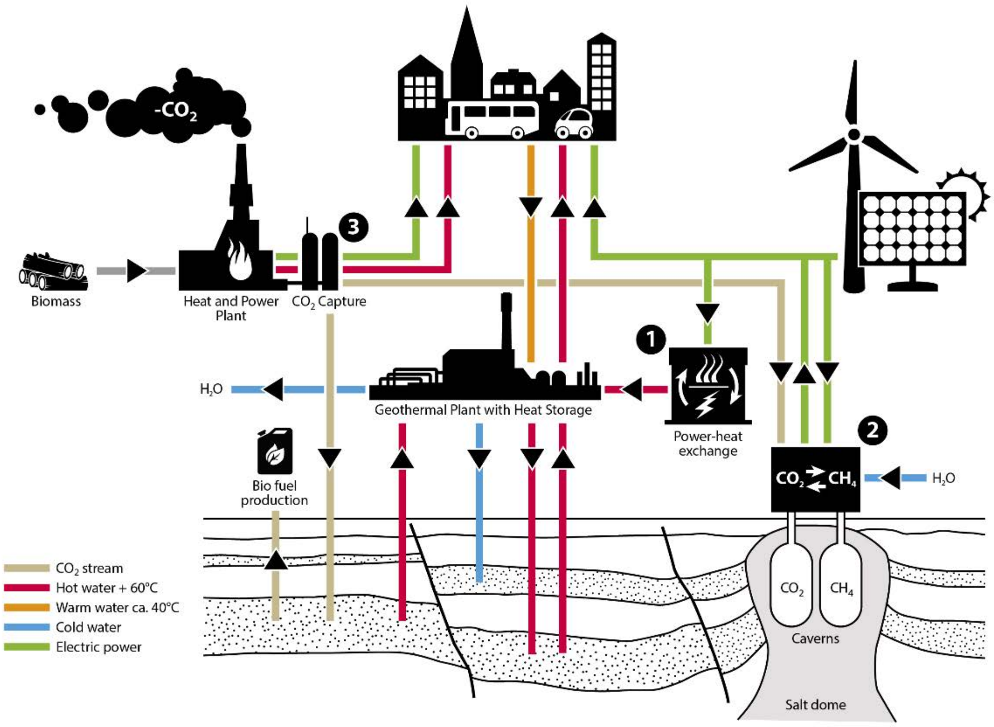

Figure 1. Schematic overview of the three technologies analysed in the project.

Scenarios will look at the effect of the system components (energy storage, geothermal, CO_2 capture) and will be related to the green transition development plans for the Aalborg area. The choice of Aalborg as model area is based on the existence of several subsurface sandstone dominated geological formations, with suitable reservoir properties for storage and geothermal production.

Objectives for WP4

Utilisation of the subsurface will depend on the local geological environment and because the geological conditions can be highly variable it is important to localise the areas where storage is possible. Detailed seismic mapping and interpretation of the subsurface including well log interpretation and correlation. The mapping will identify subsurface geological structures, potential reservoir sandstones and faults. The geological mapping of the subsurface will result in selection of the most attractive sites for storage of CH_4/CO_2, hot water and CO_2 and geothermal production. All relevant data will be transferred to a GIS geodatabase (WP4).

To assess the use of the subsurface for both energy extraction and storage detailed static (geological) and dynamic (reservoir simulation) modelling are mandatory. State of the art modelling methodology will be used subsequent to a detailed reservoir characterization building upon the results from WP3.

Setting up a subsurface reservoir model allow for simulation of both energy extraction (geothermal energy production) and storage, i.e. both storage of heat and storage of CO_2. Different scenarios can be examined; potential synergy effects can be optimized in an operating phase but also in the somewhat often costly and uncertain exploration and installation phase. The WP4 aims at facilitating strategic decision making regarding early and future use of the subsurface as an active.

The productivity and injectivity are vital properties for the usability of the subsurface and governs how the individual subsurface installations are to be placed in the ground; i.e. well spacing and well configuration together with optimized operation management.

As several unit operations can take part in the project and are to be assessed in both different combinations and timescales a GIS (Geographic Information System) model/platform will be constructed to give an overall picture of the various process-streams and units to be modelled. The GIS model will provide overview both for the subsurface as well as for the above ground installations.

Description of work
Task 4.1 Reservoir model construction. All relevant geological (WP3) and geophysical data will be analysed to characterise and delineate the reservoir(s). Geological model(s) will be constructed in the Petrel software and the reservoir simulation model(s) will be constructed in the Eclipse software, both software is licenced by Schlumberger SIS, which provide state of the art software to the oil and gas industry. Sedimentological and stratigraphic understanding of the subsurface on a regional and local scale will help constrain the model(s).

Task 4.2 The CO_2 storage operation will first be examined in an individual task as the reservoir configuration is somewhat different to the reservoir configuration for heat storage and geothermal energy production (Task 4.3). For safe geological storage of $CO_{2,}$ the reservoir must be overlaid by a tight caprock that effectively secures that CO_2 remains in the reservoir. Further a trap configuration for the reservoir is needed so the CO_2 phase can be temporarily but still securely stored. GEUS has long time experience with modelling and reservoir characterization for CO_2 storage and capacity estimation. The task will also examine any synergetic benefits when combining both CO_2 storage, thermal energy storage and geothermal energy production.

Task 4.3 Both geothermal energy production and deep aquifer thermal energy storage (DATES) are to be simulated; both as standalone unit operation as well as in combination. Synergetic benefits will be examined and optimized. Reservoir temperature development will be examined to give instructive information on project lifetime and efficiency. Subsurface flowrates and wellbore configurations will be assessed.

Task 4.4 Geographic information system (GIS) geodatabase will be build and maps of the project area, the subsurface geological formations and related surfaces facilities including their attribute data.

WP4 Reservoir modelling and GIS	*Coordinated by GEUS*
Task 4.1	Reservoir model construction
Task 4.2	Dynamic modelling of CO_2 injection/storage
Task 4.3	Dynamic modelling of geothermal energy production and deep aquifer thermal energy storage
Task 4.4	Subsurface mapping, site selection and GIS model
	Report on reservoir modelling – model construction and dynamic flow modelling

1. Subsurface mapping, site selection and GIS model

Successful subsurface storage of gasses as CO_2 and CH_4, and thermal energy storage of heated formation water requires various geologic conditions are met. As the geological environment can be highly variable this is important to localise the areas where storage is possible. Basic data to map the subsurface geology and geometry are detailed seismic mapping and interpretation, including well log interpretation and correlation. The mapping can identify subsurface geological structures, potential reservoir sandstones and faults. The geological mapping has resulted in selection of the most attractive sites for storage of CH_4/CO_2, hot water and CO_2. All relevant subsurface and on-ground facilities data are compiled in GIS geodatabase

1.1 Geological setting

The geology of Denmark is characterised by a thick cover of sedimentary rocks of Late Palaeozoic – Cenozoic age. In the Danish Basin the sedimentary succession is up to 10 km thick (Fig. 1.1). The basin is bounded to the north and north east by the Fennoscandian Border Zone (Sorgenfrie-Tornquist zone and Skagerrak-Kattegat Platform) and to northwest–southeast by the basement high, the Ringkøbing-Fyn High. The sedimentary cover on this structural high is relatively thin (1–2 km). The North German Basin is situated south of the Ringkøbing-Fyn High with sediment thickness comparable to the Danish Basin.

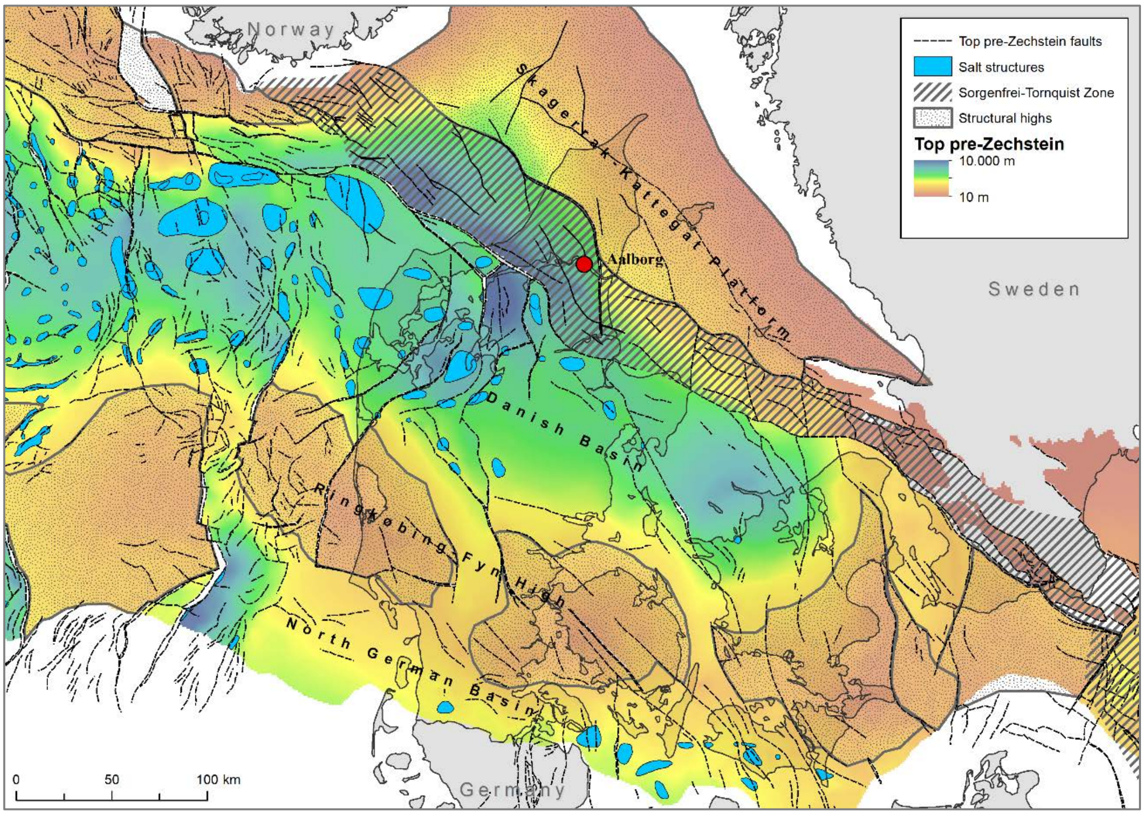

Fig. 1.1. Map showing major structural elements and depth to top Pre-Zechstein in Denmark. Modified from Vejbæk & Britze (1984).

The sediments are affected by mainly northwest–southeast striking normal faults. In the Danish Basin and North German Basin post depositional flow of Permian salt formed large domal structures, which strongly influenced later deposition. Locally the overlying sedimentary succession is deeply truncated over the top of rising salt domes and minor faults often accompany the salt structures.

1.1.1 Storage formations in the Danish Basin

The city of Aalborg is located at the north-eastern rim of the Danish Basin (Fig. 1.1). The formations containing sandstone layers (aquifers) with potential for storage of CO_2 and thermal energy in the Danish Basin are (Figure 1.2):

- Skagerrak and Bunter Sandstone Formations (Triassic)
- Gassum Formation (Upper Triassic–Lower Jurassic)
- Haldager Sand Formation (Middle Jurassic)
- Frederikshavn Formation (Upper Jurassic–Lower Cretaceous)

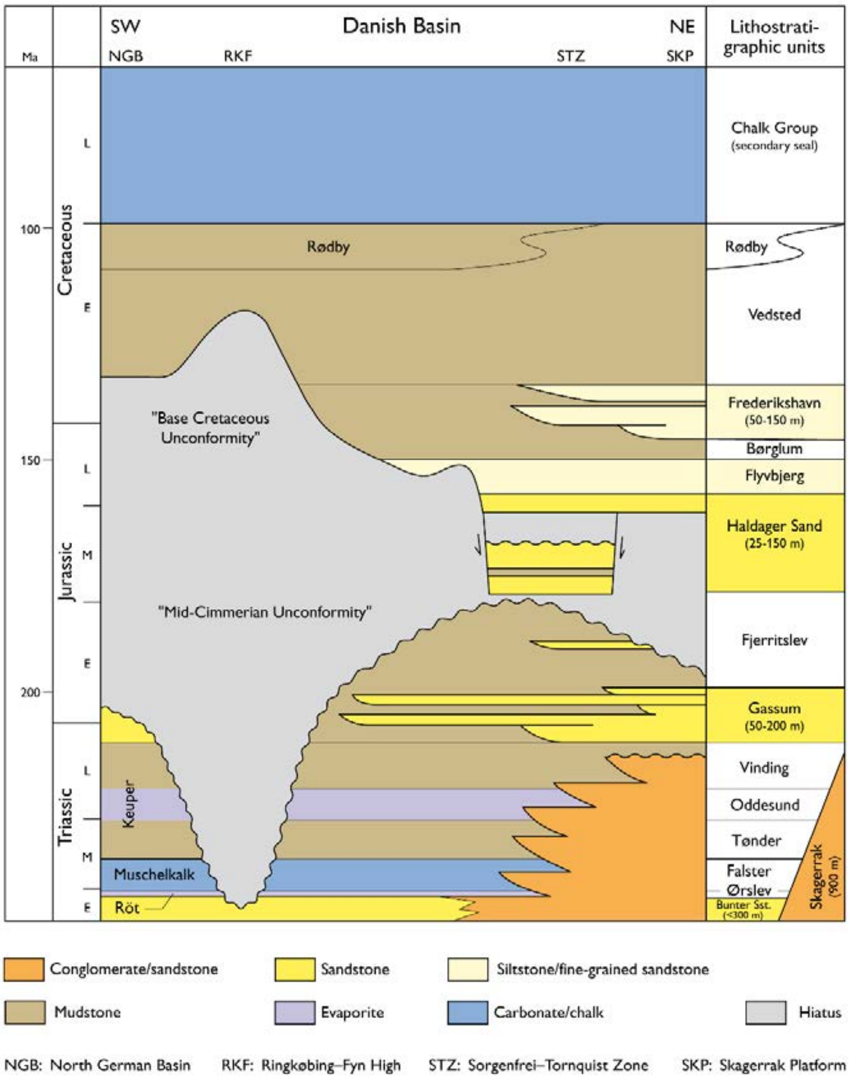

Fig. 1.2. Simplified stratigraphy and lithostratigraphy of the sedimentary succession in the Danish Basin. (Based on Bertelsen, 1980, Michelsen & Clausen, 2002; Michelsen et al., 2003).

1.1.1.1 Skagerrak/Bunter Sandstone Formations (Triassic)

The Skagerrak Formations/Bunter Sandstone are present throughout the Danish area. Sandstones of the Bunter Sandstone Formation are dominant in the southern, western and central part of the Danish area and are gradually replaced by the Skagerrak Formation towards the north eastern basin margin. The Skagerrak Formation is buried below 3000 m in the Aalborg area, only north-east of the Sorgenfrie-Tornquist zone and in connection with salt diapirs, the Formation is found above 3000 m (Fig. 1.3).

The Lower Triassic sandstone dominated succession (Bunter Sandstone and Skagerrak) forms a widespread unit with thickness around 300 m although it may reach 900 m in the central part of the Danish Basin. The succession is thin and locally absent across the Ringkøbing-Fyn High. It is anticipated that no strong primary hydraulic barriers exist within the sheet sandstone (Sørensen et al., 1998). Reservoir properties are poorly known and often based on estimates from petrophysical logs (Michelsen et al., 1981). The porosity estimates range between 0–24% (maximum 38%) whereas the permeability is generally low (10–100 mD) due to the relatively deep burial depth causing diagenetic changes and cement formation.

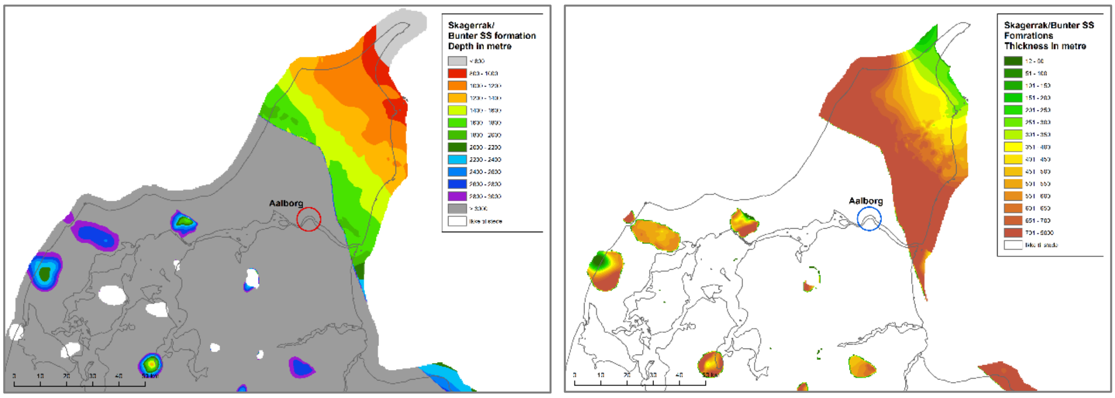

Fig. 1.3. Distibution and thiskness of the Skagerrak/Bunter Sandstone Formations.

1.1.1.2 Gassum Formation (Late Triassic – Early Jurassic)

The formation is present in the Danish Basin and it shows a remarkable continuity with thickness between 100 and 150 m throughout most of Denmark, reaching a maximum thickness of 300 m in the Sorgenfrei-Tornquist Zone (Fig. 1.1). As Aalborg is located within the Sorgenfrei-Tornquist Zone the thickness of the Gassum Formation reaches 350-450 m (Fig. 1.4).

The Gassum Formation consists of fine- to medium-grained, locally coarse-grained sandstones interbedded with heteroliths, claystones and locally thin coal beds (Michelsen et al., 2003; Nielsen, 2003). In general, the reservoir properties are excellent with porosity 18–27% (maximum 36%) and permeability up to 2000 mD.

The Gassum Formation forms the reservoir in the Stenlille natural gas storage and has been studied in great detail (Nielsen et al., 1989; Hamberg & Nielsen, 2000; Nielsen, 2003). The studies illustrate the facies complexity and the lateral variability present within the reservoir units. Each of these units may act as discrete reservoir units and is characterised by a set of porosity/permeability parameters. Based on paleogeographic reconstructions it is anticipated that the sand content will decrease towards the northwest.

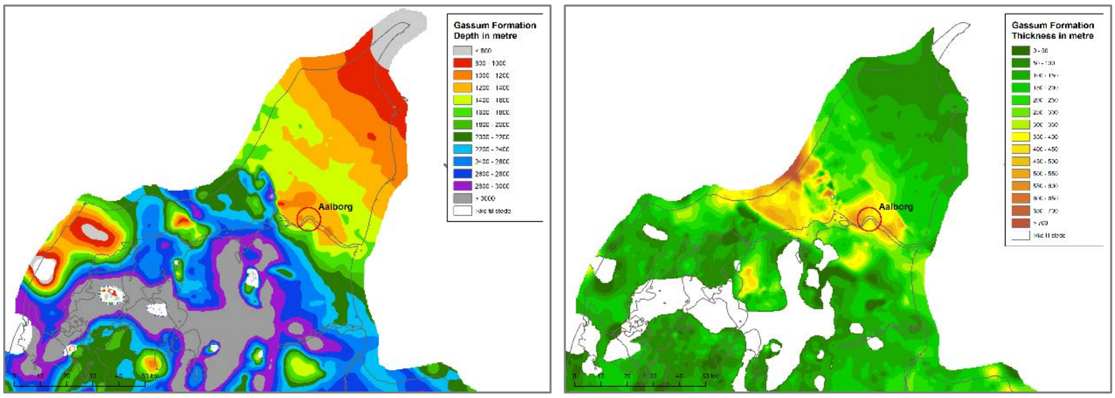

Fig. 1.4. Distibution and thickness of the Gassum Formation.

1.1.1.3 Haldager Sand Formation (Middle Jurassic)

The formation is present in the central and northern part of the Danish Basin, in the Sorgenfrei-Tornquist Zone and on the Skagerrak-Kattegat Platform reaching a maximum thickness of 150 m. The porosity varies between 12 and 33% (maximum 42%) whereas permeability has only been estimated in two wells having 600 and 2000 mD respectively. In the Aalborg area the formation is found in a depth of approximately 900 m and the thickness is around 70 m (Fig. 1.5).

The Haldager Sand Formation consists of thick beds of fine- to coarse-grained, locally pebbly sandstones intercalated with thin siltstone, claystone and coal beds. Deposition was locally affected by movements of underlying salt structures.

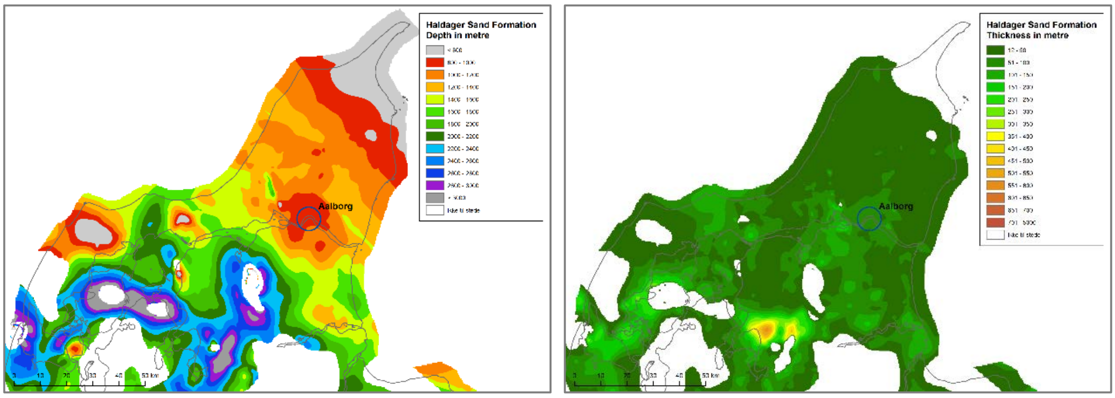

Fig. 1.5. Distibution and thickness of the Haldager Sand Formation.

1.1.1.4 Frederikshavn Formation (Late Jurassic – Early Cretaceous)

The formation is present in the northern part of the Danish Basin and reaches a maximum thickness of more than 230 m in the Sorgenfrei-Tornquist fault zone. Local faults and salt tectonics mainly control thickness variations. The formation is not present in the Aalborg area, but reaches a considerable thickness of 400-600 m south-west of Aalborg (Fig. 1.6).

The formation consists of siltstones and fine-grained sandstones forming 2–3 coarsening-upwards units separated by claystones (Michelsen et al. 2003). The most coarse-grained parts of the formation are present in the northeast towards the Skagerrak-Kattegat Platform whereas the formation interfingers with the fine-grained Børglum Formation towards the west (Michelsen et al., 2003).

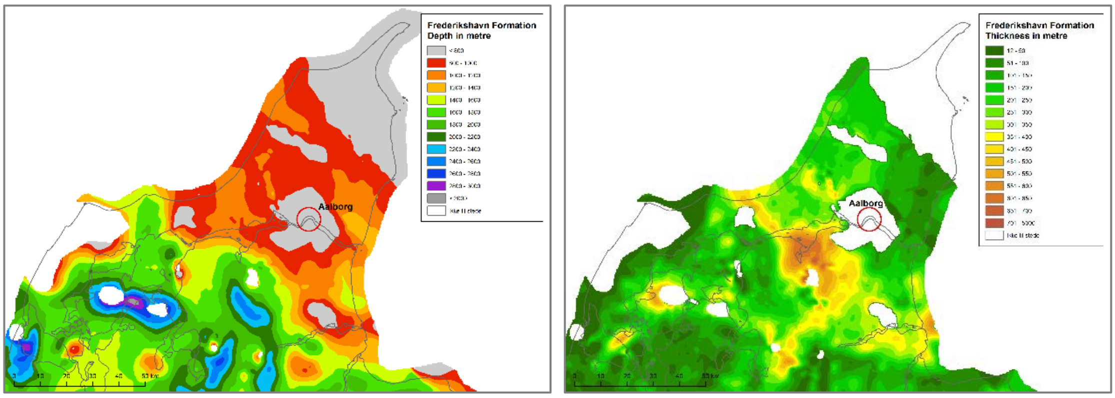

Fig. 1.6. Distibution and thickness of the Frederikshavn Formation.

1.1.2 Formations with caprock properties in the Danish Basin

Because CO_2 is buoyant the gas will move upwards after injection and therefore aquifer storage of CO_2 is dependent not only on the properties of the reservoir, but also on the integrity of the sealing formation (caprock). Geological formations in Denmark with sealing properties are lacustrine and marine mud rocks, evaporites and carbonates. The most important sealing rock type in the Danish area is marine mudstone, which is present at several stratigraphic levels. Detailed site surveys will be needed in order to test the integrity of the seal at future storage sites.

1.1.2.1 Ørslev, Falster and Oddesund Formations (Triassic)

The Ørslev Formation (Early Triassic) is transitional to the coarse-grained deposits of the Skagerrak Formation forming the northern edge of the depositional system. The fine-grained Ørslev Formation reaches 100–400 m in thickness south of the Ringkøbing-Fyn High.

The Falster Formation (Middle Triassic) is described as a unit characterised by intercalated limestones, claystones and halites. Fine-grained sandstones are locally present in the upper part of the formation. The formation reaches 100–200 m in thickness and forms a secondary seal for the Bunter Sandstone Formation in the Rødby and Tønder structures.

The Oddesund Formation (Late Triassic) is described as a unit characterised by calcareous, anhydritic claystones and siltstones intercalated with thin beds of dolomitic limestone. In the central part of the Danish Basin two prominent units of halite is present dividing the formation into three informal members. The formation varies in thickness due to local up lift of the underlying Zechstein salt and reaches a maximum thickness of 1500 m.

1.1.2.2 Fjerritslev, Flyvbjerg and Børglum Formations (Jurassic)

The Fjerritslev Formation (Early Jurassic) is characterised by a relatively uniform succession of marine, slightly calcareous claystones, with varying content of silt and siltstone laminae. Siltstones and fine-grained sandstones are locally present being most common in the north-eastern, marginal areas of the Norwegian-Danish Basin (Michelsen, 1975, 1978; Michelsen et al., 2003). The formation is present over most of the Danish Basin with a thickness of up to 1000 m although this varies significantly due to mid-Jurassic erosion.

The Flyvbjerg Formation (Late Jurassic) consists primarily of siltstones and fine-grained sandstones with poor reservoir quality and is neither regarded as a reservoir formation nor as a seal. However, it directly overlies the Haldager Sand Formation and thus may act as a transitional formation into the sealing claystones of the overlying Børglum Formation.

The Børglum Formation (Late Jurassic) consists of a uniform succession of slightly calcareous claystones (Michelsen et al., 2003). The Børglum Formation is present in most of the Danish Basin and reaches a maximum thickness of 300 m towards the Fjerritslev Fault. It rapidly thins towards the northeast, south and southwest.

1.1.2.3 Vedsted and Rødby Formations (Cretaceous)

The Early Cretaceous marine mudstones of the Vedsted and Rødby Formations form the primary sealing formation for the Frederikshavn Formation.

1.1.2.4 Chalk Group (Late Cretaceous – Early Palaeocene)

In most of the Danish area a several kilomm thick succession of carbonate rocks forms a possible secondary seal. The sealing effect is dependent on chemical reactions between dissolved CO_2 and the carbonate rock.

1.2 Deep aquifer thermal energy storage site selection

The geothermal gradient in Denmark is c. 25–30°C per kilom (Mathiesen et al., 2009) and the average annual surface temperature is approximately 8°C, which implies that a temperature close to 35°C is expected in 1 km depth.

Deep aquifer thermal energy storage (DATES) is a subsurface thermal energy storage at depths deeper than 1000 m, and functions as energy storage by injection of heated formation water. The energy is stored as water with temperatures higher than the *in-situ* formation water of the deep geothermal aquifer. The technology is in principle like shallow aquifer thermal energy storage (ATES), but DATES utilises that the geological formation is already heated to some extend and under pressure in 1000 m depths or deeper.

In the Danish Basin the widely distributed Gassum and Skagerrak/Bunter Sandstone formations constitutes major geothermal reservoirs, but also formations with more local distribution as the Haldager Sand and Frederikshavn formations have geothermal potentials (Røgen et al., 2015; Mathiesen et al., 2010; Nielsen et al., 2004).

Based on Kristensen et al. (2016), the required reservoir properties for geothermal aquifers are:

- Porosity min. 15%
- Clay content max. 30%
- Aquifer layer thickness min. 20 m

Quantification of reservoir permeability, which is the single most critical factor for geothermal fluid extraction is complicated, as very few in-situ measurements are available, and no permeability logs are available from wells in the Danish onshore area (Kristensen et al., 2016). However, it is possible to make a qualified prediction of the reservoir permeability based on methodology as described in Kristensen et al. (2016).

The porosity and permeability generally decrease with increasing burial depth, due to mechanical compaction and diagenetic alterations (Olivarius et al., 2015 a,b). Generally, the porosity and permeability will have decreased to level that's unattractive for geothermal production at a depth below 3000 m. This makes the Skagerrak/Bunter Sandstone formations unattractive for DATES in the Aalborg area (Fig. 1.3).

1.2.1 The Gassum Formation

Data from deep wells and seismic interpretation results show that the Gassum Formation is present in most parts of northern Jylland, and this formation forms a suitable geothermal reservoir in this part of Denmark (Fig. 1.4). The following deep wells represent the study area: Farsø-1, Vedsted-1, Børglum-1, Flyvbjerg-1, Vendsyssel-1 and Sæby-1 (Fig. 1.7 and 1.8).

The depth the top of the Gassum Formation varies considerably within the study area e.g. 2740 m in the Farsø-1 well, but only 1080 m in Sæby-1. The Farsø-1 well is located in the Danish Basin, whereas the Vendsyssel-1 and Sæby-1 wells are located on the Skagerrak-Kattegat Platform, and Flyvbjerg-1 and Børglum-1 are located in the Fjerritslev trough. The Gassum Formation thins towards the Skagerrak-Kattegat Platform area (Fig. 1.1).

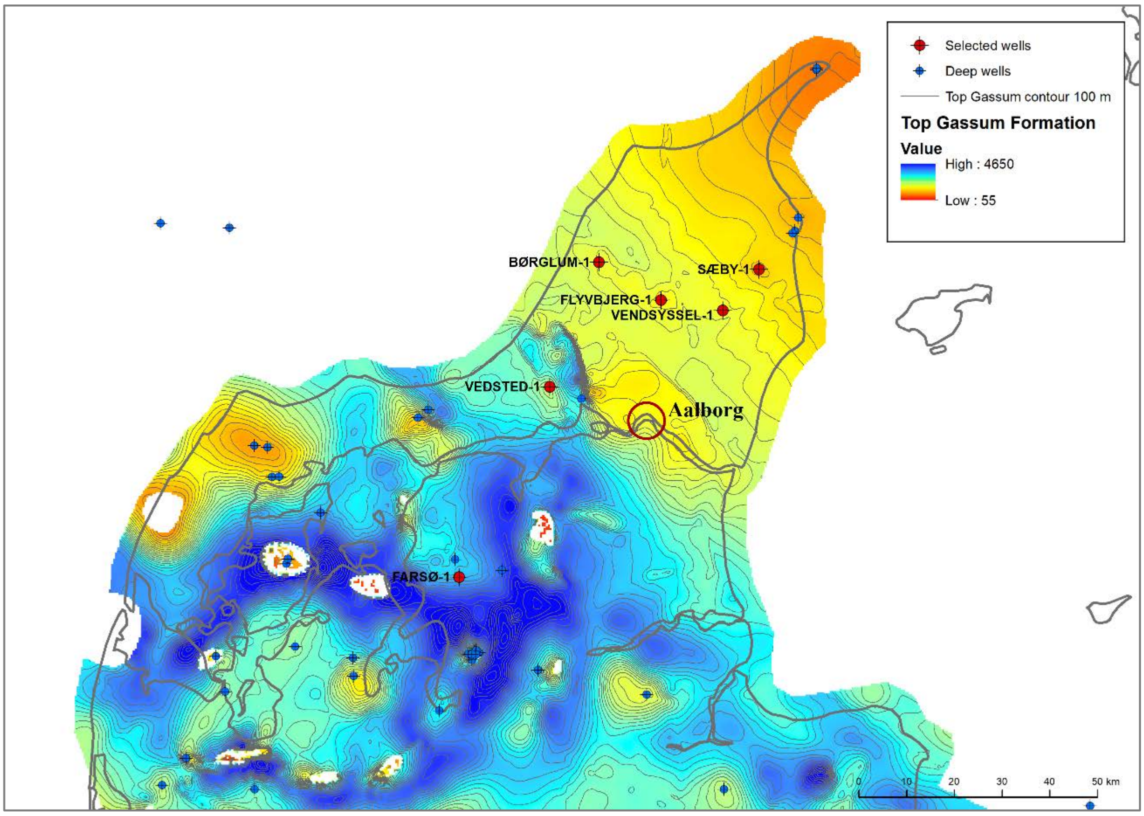

Fig. 1.7. Location of the deep wells selected for the project.

In the Aalborg area the depth to the Gassum Formation is between 1000-1400 m. The closest well where the Gassum Formation is reached is the Vedsted-1 well, ca. 30 km northwest of

Aalborg. In Vedsted-1 140 m of Gassum Formation is logged and sandstone layers are dominating the top and in the bottom of the well, separated by a clay/mud interval (Fig. 1.8). The Gassum Formation is overlaid by 674 m of the claystone dominated Fjerritslev Formation (Nielsen and Japsen, 1992).

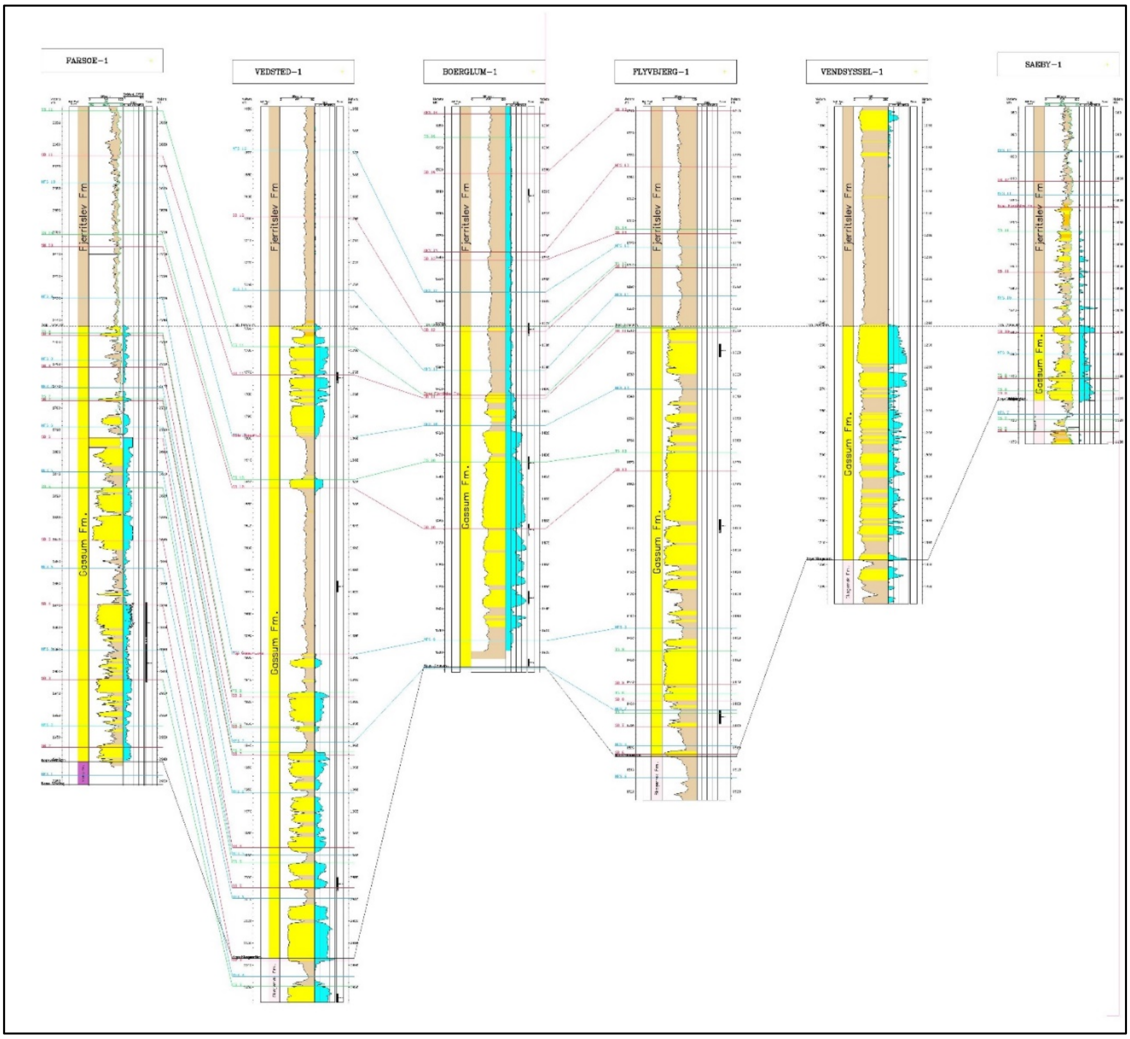

Fig. 1.8. Profile showing the wells Farsø-1, Vedsted-1, Børglum-1, Flyvbjerg-1, Vendsyssel-1 and Sæby-1 using Top Gassum Formation as datum line. The lithological interpretation is plotted in between the GR (SP) log to the left and the sonic log to the right. The lithology colour codes are: Yellow: sandstone, Brown: shale/clay and Siltstone: orange. The blue colour-filled curve corresponds to an interpreted porosity (PHIE curve; scaled 0–40%). The black bars indicate cored intervals. The PHIE curve is supplemented by core porosity data, if available. Selected sequence boundaries as also plotted.

1.2.2 Conclusion deep aquifer thermal energy storage site selection

Deep Aquifer Thermal Energy Storage (DATES) utilises the geothermal gradient to minimize the heat loss to the surroundings. A good reservoir quality for storage of heated water is characterized by minimum porosity of 15%, maximum clay content of 30% and minimum thickness of 20 m for the reservoir aquifer. Regarding depth and reservoir properties the Gassum Formation have the most favourable thermal heat storage aquifers.

1.3 CH_4 / CO_2 storage site selection

The ReSOC (Reversible Solid Oxide Cells) operates with two separate gasses a fuel gas with a composition close to natural gas, consisting mainly of methane (CH_4), and a CO_2 gas with a high content of hydrogen (H_2).

1.3.1 Storage of CO_2-H_2 gas mixture

Fuel gas used in the ReSOC (Reversible Solid Oxide Cells) processes is close to have the same composition as natural gas and can be stored directly in the existing natural gas network. However, as shown in the table 1, the CO_2 is mixed with a lot of hydrogen and a significant amount of CO. The question is whether this CO_2 gas can be stored either in subsurface aquifers or in salt caverns, and which of the two options are the preferred storage.

Table 1. Molar composition of the fuel gas and the CO_2 gas used in the ReSOC.

	H_2	CO	CO_2	CH_4
fuel gas	0.022	~0	0.006	0.972
CO_2 gas	0.416	0.094	0.461	0.029

1.3.1.1 Storage of coal-based town gas in deep aquifer - closest practical experience with CO_2-H_2 gas mixture

At first, it must be mentioned, that it has not been possible to find literature examples of CO_2-H_2 gas mixture storage in salt caverns. The closest practical experience of storing and recovering a CO_2-H_2 gas mixture as shown in Table 2, is the storage of town gas in Lobodice in the south-eastern Czech Republic which has taken place since the late 1960s. The gas is stored in aquifer of lower Miocene age at a depth of 400-500 m, and the caprock is located approx. 300 m below sea level. The total volume of the stored gas is 400 million m^3 STP (Buzek et al., 1994). The town gas is extracted from coal and contains the same four gases as the gas mixture in table 1, although the relative CH_4 content is significantly higher, 22% against approx. 3%, see table 2 from Smigan et al. (1990).

Table 2. Town gas storage in a > 300 m deep aquifer at Lobodice.

	H_2	CO	CO_2	CH_4	$\delta^{13}C_{CH4}$ ‰
Injected gas	0.54	0.09	0.117	0.219	-34.5
Produced gas	0.37	0.033	0.087	0.40	-80

1.3.1.2 Partial conversion of town gas in aquifers due to bacterial methane production

Studies from the late 1980s showed that the gas produced from the storage had a significantly higher CH_4 content (40%) than the original city gas (22%) after approx. 7 months in the storage, see table 2. Carbon isotope analysis of CH_4 showed significantly lower delta 13C value for the gas produced (-80 ‰) compared to the original town gas (-34.5 ‰). Laboratory tests analysing water samples from the aquifer layer confirmed the presence of methanogenic bacteria (Smigan et al., 1990) capable of producing methane (like in formula 1) is characterized by low delta 13C value.

(1) $4H_2 + CO_2 = CH_4 + 2H_2O$

(2) $3H_2 + CO = CH_4 + H_2O$

Theoretically, one could imagine that CO also is converted to CH_4 by bacteria (like formula 2), but no evidence of this has been found at the gas storage facility in Lobodice. In contrast, there was evidence of catalytic conversion of CO to CH_4 in the wells shortly after injection of the town gas (Buzek et al., 1994). The catalytic conversion of the gas resulted in a loss of energy, and this was studied more closely by Panfilov (2010), who found a complex pattern with respect to the spatial distribution.

1.3.2 Storage of H_2 gas

H_2 storage related to renewable energy based on wind power and solar cells has been the subject of several recent research projects (Panfilov, 2016) to ensuring a stable supply from these sources. H_2 is produced by electrolysis of water and can either be used directly as an energy source or converted to electricity as needed. Conversion (of electricity) to and from H_2 causes an energy loss, which according to Jensen et al. (2015) can be reduced by using reversible fuel cells and a combination of CO_2 and CH_4 (plus H_2) cf. table 1. The CH_4-rich fuel gas and the H_2-containing CO_2 gas must be stored in separate storage units e.g. salt caverns (Jensen et al., 2015).

Although the mentioned research projects only concern pure H_2 gas stored in salt caverns (Panfilov, 2016), the experience gained from this study, is considered to be relevant for the CO_2-H_2 gas mixtures used for the ReSOC.

Existing and abandoned H_2 underground storage sites in Europe and America is shown in table 3 from Panfilov (2016) and present a short overview of each site. The table primarily concern storing of H_2 for use in the chemical industry and refineries, and at present no large-scale facilities in connection with electricity generation from renewable sources have been implemented. The two German plants at the top of the list have been converted into natural gas storage and the storage in Kiel has been in use since 1971.

Table 3. Underground storage of hydrogen worldwide (Panfilov, 2016)

	Type	% H_2	P, T	Depth (m)
Bad Lauchstädt, Germany	Salt cavern		150 bar	820
Kiel, Germany	Salt cavern	60–64	80–100 bar	1330
Teesside, UK	Salt cavern	95	50 bar	400
Texas: Air Liquid, USA	Salt cavern	95		
Texas: ConocoPhillips, USA	Salt cavern	95		850
Texas: Praxair, USA	Salt cavern			
Beynes, France	Aquifer Aq-	50		430
Ketzin, Germany	uifer Aqui-	62		200–250
Lobodice, Czech Di-	fer Natural	50	90 bar, 34 °C	430
adema, Argentina	Gas	10	10 bar, 50 °C	600

There are not many scientific publications on the storage of H_2-rich gases in a geological environment besides the already mentioned studies of the gas storage in Lobodice. Some researchers have mentioned the risk of leakage due to diffusion, because of the small size of the H_2 molecule, but no practical problems have been reported to indicate this is the case (Panfilov, 2016).

Preliminary studies of possible large-scale H_2 gas mixture storage connected with renewable energy storage, includes former natural gas fields (Amid et al., 2016; Tarkowski, 2017) and salt caverns (Lord et al., 2014; Orzarlan, 2012; Tarkowski, 2017). Mixing with natural gas in existing underground storage is also mentioned as a solution (Reitenbach et al., 2015). However, the latter possibility is limited by the industry's requirement that the relative H_2 amount must not exceed 6-15% (Panfilov, 2016) of the natural gas composition. The studies evaluate the possible undesirable reactions with H_2 in the geological environment, which additionally to the bacterial methane formation mentioned earlier, also include sulphide formation via sulphate reducing bacteria (Amid et al., 2016; Panfilov, 2016) and iron oxide release (Henkel et al., 2014).

Bacterial activity is generally considered to be less significant in a salt-saturated environment e.g. in salt caverns, although salt tolerant bacteria are known. This implies, that when storing H_2, one should consider the possibility of both methane and sulphide (H_2S) can be formed, the latter being the most serious nuisance.

1.3.3 Conclusion CH_4 / CO_2 storage site selection

The question of whether it is possible to store a CO_2-H_2 gas mixture in salt caverns in connection with electricity production from renewable sources can be answered with a yes. However, it should be noted that undesirable processes, such as methane and sulphide (H_2S) formation can take place. Furthermore, the risk of unwanted methane formation is estimated to be greater for a CO_2-H_2 gas mixture than for pure H_2 gas.

The presence of methanogenic bacteria in aquifers capable of producing methane and the ReSOCs demand for fast access to dry gasses, requiring a gas-drying facility and intermediate storage, makes the aquifer storage of the CO_2-H_2 gas mixture less favourable.

1.4 CO_2 storage site selection

When localising a suitable storage site for CO_2 several geological conditions must be met. At first, the storage aquifer (reservoir) should be in the depth range of 800m – 2500 m, in some cases down to 3000 m depth if the reservoir properties are favourable. The CO_2 changes phase from a gas to a supercritical fluid at a pressure of 73 atm and a temperature of 31°C (Fig. 1.9a) and the volume of CO_2 is hereby reduced to 1% of the volume as gas, but depending on the chemical composition of the formation water (brine). In Denmark a general rule, the pressure will drop 1 bar/10 m and the temperature will rise by 30-40°C every 1000 m. The conditions for CO_2 to be supercritical will normally be met in depth of 800 m.

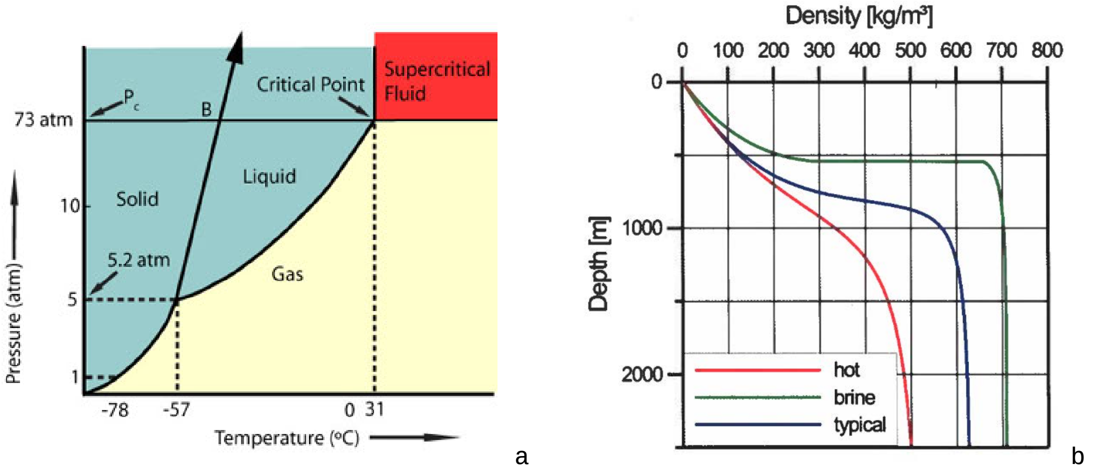

Figure 1.9. a) CO_2 Phase diagram. b) CO_2 density variation with depth assuming hydrostatic pressure and typical temperature gradients in sedimentary basins (blue); elevated geothermal gradients of 45°Ckm^{-1} (red) and hydrostatic pressure gradient of highly concentrated brines 12.5 MPakm^{-1} (green). (Chadwick el al., 2008)

Secondly, the reservoir must have good porosity and permeability. Porosity should be more than 10%. A permeability of at least 100 mD is considered good although the work by Chadwick el al. (2008) recommend 200 mD, and values of 500 mD or more are good (Table 4). At depths of more than 2500 m, the porosity and permeability of the rock usually have deteriorated significantly, and the CO_2 storage efficiency considered to be poor.

Thirdly, the CO_2 will migrate upwards after storage and therefore, the reservoir must be covered by a seal (caprock). The seal must be impermeable and have a recommended minimum thickness of 20 m (Table 4). Structural geological traps are considered essential, at least initially, when considering aquifer storage onshore Denmark. Storing CO_2 in defined traps in the subsurface allow continuous monitoring of the fate of the injected CO_2 and eventually meets the demand for future recovery of all or parts of the injected gas (Larsen et al., 2003). In addition, there must be no major faults in the sail, as the presence of faults can increase the risk of CO_2 can leak out of the storage reservoir.

The size of the reservoir must have a storage capacity that correspond the CO_2 emission and the lifetime of the point source(s) expected to supply the storage site. The GESTCO report recommends a minimum storage capacity of 100 mega tons (Larsen et el., 2003).

Tabel 4. Key geological indicators for storage site suitability (Chadwick el al., 2008).

	Positive indicators	Cautionary indicators
RESERVOIR EFFICACY		
Static storage capacity	Estimated effective storage capacity much larger than total amount of CO_2 to be injected	Estimated effective storage capacity similar to total amount of CO_2 to be injected
Dynamic storage capacity	Predicted injection-induced pressures well below levels likely to induce geomechanical damage to reservoir or caprock	Injection-induced pressures approach geomechanical instability limits
Reservoir properties		
Depth	>1000 m <2500m	< 800 m > 2500 m
Reservoir thickness (net)	> 50 m	< 20 m
Porosity	> 20%	< 10%
Permability	> 500 mD	< 200 mD
Salinity	> 100 gl^{-1}	< 30 gl^{-1}
Stratigraphy	Uniform	Complex lateral variation and complex connectivity of reservoir facies
CAPROCK EFFICACY		
Lateral continuity	Stratigraphically uniform, small or no faults	Lateral variations, medium to large faults
Thickness	> 100 m	< 20 m
Capillary entry pressure	Much greater than maximum predicted injection-induced pressure increase	Similar to maximum predicted injection-induced pressure increase

The sandstone reservoirs forming a potential for recovery of geothermal energy are identical to the deep aquifers suitable for CO_2 storage, however the combination of CO_2 storage with geothermal return water may result in conflicts of interest. On the contrary, the pressure built-up by CO_2 injection can assist geothermal water production.

1.4.1 Mapping of potential CO_2 storage sites near Aalborg

Geological structures (traps) are preferred as CO_2 storage sites and the Gassum Formation is evaluated as the most attractive storage formation with respect to depth and reservoir properties. Consequently, has mapping of geological structures on the Top Gassum Formation level been carried out. Interpretation of seismic surveys based on the most resent onshore mapping of the Danish subsurface (the Geothermal WebGIS portal http://data.geus.dk/geoterm/) has been used for the screening of traps (Fig. 1.10)

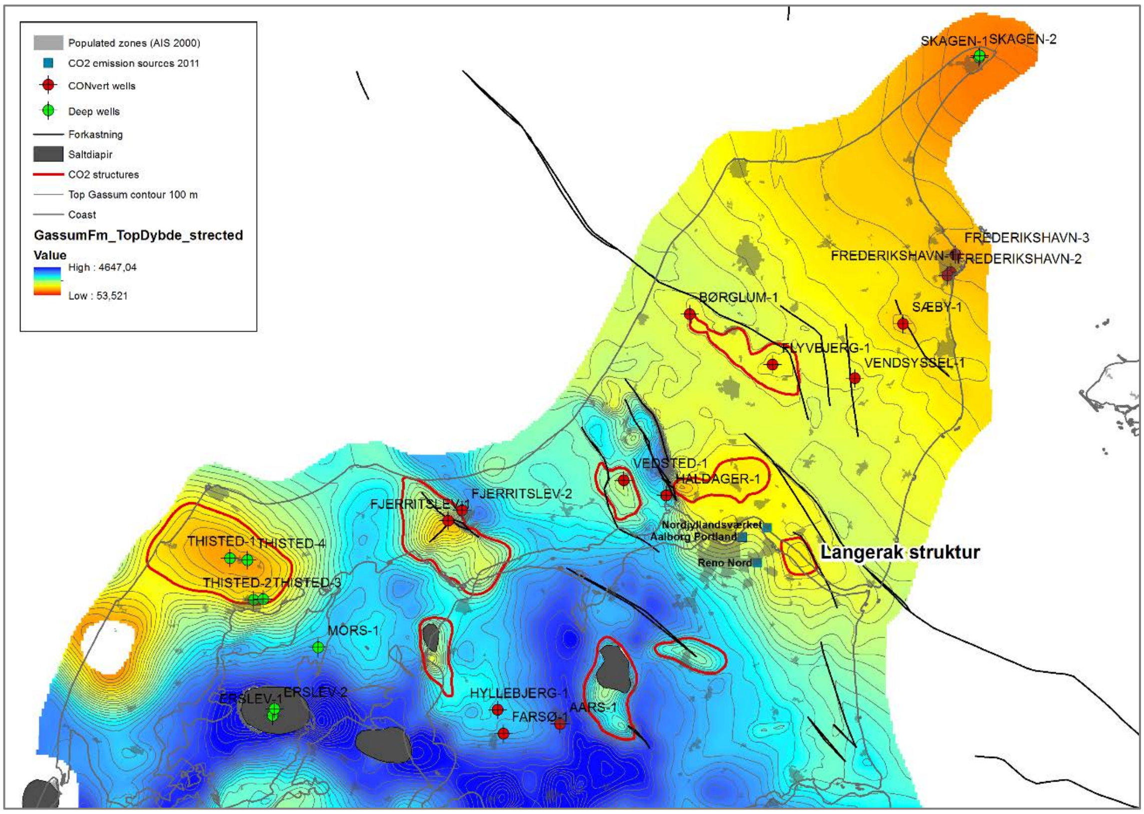

Fig. 1.10. Map of the Top Gassum Formation from the Geothermal webGIS portal with the mapped CO_2 structures (traps).

After mapping of geological structures, selected seismic lines were reinterpreted in order to evaluate the mapped traps. The reinterpretation resulted in selection of a preferred trap for CO_2 storage near Aalborg, the Langerak structure (named after the narrow sound between Aalborg and Kattegat) which is located just 3 km southeast of Nordjyllandsværket, although the seismic quality in the area is poor (Fig. 1.11). The second option is the Vedsted structure ca. 30 km northwest of Aalborg. Opposite the Langerak structure the Vedsted structure has been thoroughly surveyed by Vattenfall 2008-2010, since it was chosen as storage site for CO_2 from Nordjyllandsværket which was owned by Vattenfall at the time. Some of the mapped structures were rejected as potential CO_2 storage sites due to weak seismic evidence for the existence of a suitable trap.

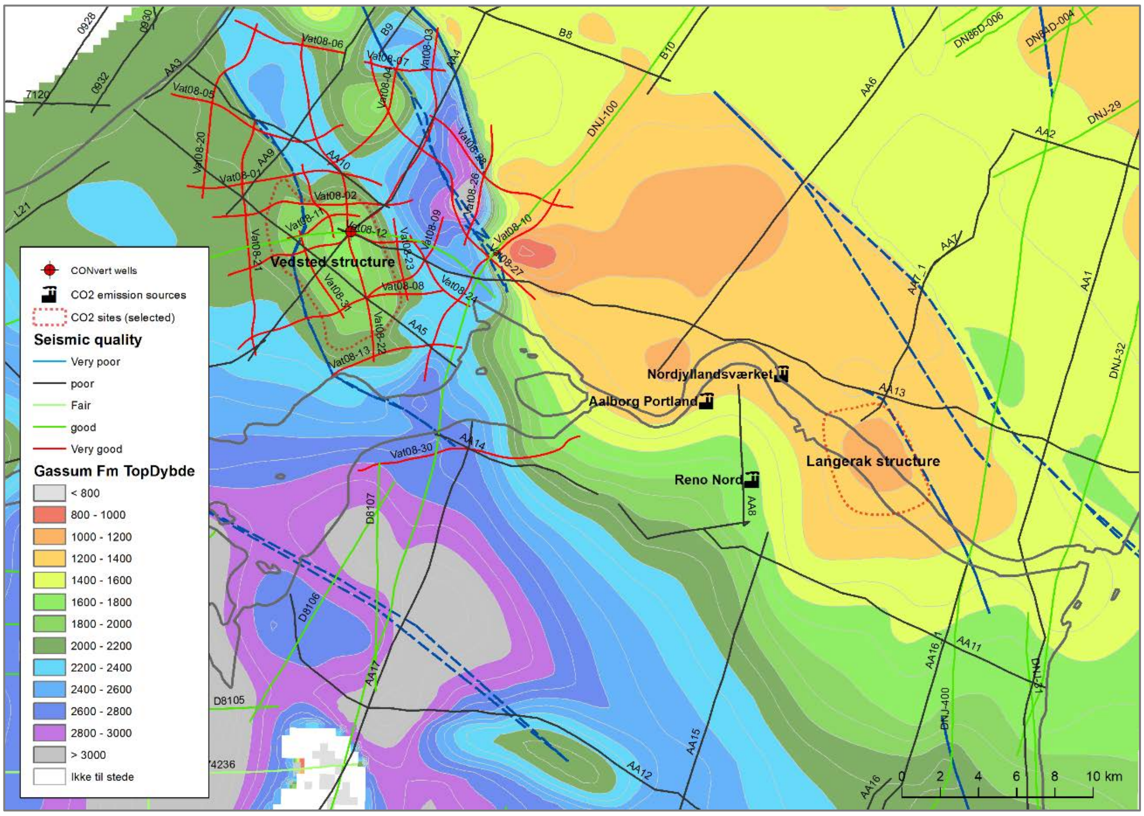

Fig. 1.11. Top Gassum Formation map with the seismic survey lines and the two selected structures Langerak and Vedsted.

1.4.2 Prediction of Gassum Formation sand in the Langerak structure

The Vedsted-1 well is probably the closest well in this area representing the sand of the Gassum Formation expected to be present in the Langerak structure, and log data from the Vedsted-1 well has been extrapolated and used for the reservoir model of the Langerak structure. The Vedsted-1 well contains sandstones deposited in an estuarine environment. The Gassum Formation is overlaid by 650+ m Fjerritslev Formation forming the primary seal.

The line between the Vedsted-1 well and the Langerak structure probably lies parallel with the orientation of the paleo-coastline (NW-SE). The line between the Vedsted-1 well and the Langerak structure probably lies perpendicular to estuarine channel sandstones.

1.4.3 Conclusions CO_2 storage site selection

Storing supercritical CO2 require several geological conditions to be fulfilled:

- Storage depth 800-2500 (3000) m
- Preferable a geological structure (trap)
- Reservoir porosity min. 10% and permeabilities above 100 mD
- A tight seal (caprock) thicker than 20 m
- No large faults

The Gassum Formation are regarded the most attractive storage formation with respect to depth and reservoir properties and the formation is overlaid by more than 650 m Fjerritslev Formation in the Vedsted-1 well, forming the primary seal. Based on seismic mapping of the Danish subsurface (the Geothermal WebGIS portal http://data.geus.dk/geoterm/) several structures on the Top Gassum Formation level were identified. The Langerak structure located only 3 km from southeast of Nordjyllandsværket was selected as the most prospective trap despite poor seismic data availability. The Vedsted-1 well was evaluated as representing the Gassum Formation in the Langerak structure.

1.5 GIS model

As several unit operations in combination with the subsurface are to be assessed in both different combinations and timescales a GIS (Geographic Information System) model and database was created providing an overview of the subsurface as well as the above ground installations. The GIS application used is ArcGIS by ESRI. Most of the figures in this report section 1 are produced on basis of the CONvert ArcGIS database.

2. Reservoir model construction

Reservoir simulation methodology can help quantify the performance of the various subsurface operations that were examined in the present project, i.e. CO_2 storage, thermal energy storage and geothermal energy production. The methodology is widely used in the oil & gas industry as well as in groundwater modelling. The modelling methodology and workflow outlined in the present report is mainly based on experiences from the oil & gas industry, but similar conclusions could be obtained from other workflows.

The modelling procedure falls in two steps. A geological (or static) model is constructed based on the geological knowledge and available geophysical and petrophysical data for the subsurface of the area of interest (AOI). A 3D reservoir simulation (or dynamic) model is subsequently build based on the geological model. Reservoir performance is evaluated through the dynamic modelling, but in an iterative process with modification of the static model, especially if real production/performance data is available to calibrate the models.

For the three subsurface operations that are evaluated in task 4.1, 4.2 and 4.3, i.e. CO_2 storage (CCS), thermal energy storage (DATES)and geothermal energy production (GE) the static modelling procedures are identical. The dynamic modelling methodology are different in order to model and replicate the different physical processes for the three operations.

The Petrel software (Petrel 2015) is used for the static model construction and the Eclipse 100 software (Eclipse 2017) is used for the dynamic modelling part.

Figures 2.1 to 2.3 illustrate differences and similarities for the three subsurface operations. The main difference for the CCS operation compared to the other two is the mandatory closure of the reservoir formation, i.e. the caprock and curvature of the reservoir (cf. fig. 2.1). A depth constraint of minimum 800 m for the shallowest part of the reservoir is also required. Below 800 m the hydrostatic pressure of the formation secures that the CO_2 is in supercritical state with a volume reduction of 300 times compared to CO_2 at surface conditions, which significantly increase the storage capacity (cf. fig. 1.9).

Below 800m the density of the supercritical CO_2 is still smaller than the formation water so buoyancy will force the CO_2 in upwards direction, where the overlying caprock prevents the CO_2 for further migration to surface. Besides the physical capture of the CO_2 by the caprock other effects help to immobilize and permanent store the CO_2 in the subsurface (cf. fig. 2.4); capillary forces will stop part of the migrating CO_2 (residual CO_2 trapping), some part of the CO_2 will dissolve in the formation water and part of the CO_2 will react with the reservoir rock and be chemical bounded (e.g. Benson et al., 2005).

In CCS the requirement for the reservoir formation is high porosity and high permeability; a high porosity ensures a high storage capacity whereas a high permeability provides a high injectivity, i.e. how easy it is to press the CO_2 in to the formation and displace the formation water. In contrast the caprock must have a very low permeability and high capillary entry pressure to secure that no CO_2 can escape through the caprock.

When injecting a large volume of CO_2 in to the reservoir formation the initial formation water is displaced by the CO_2, but the process is slow meaning that the pressure will increase from the injection well and radially in to the reservoir. The pressure increase can potentially be managed by producing some of the formation water to surface, i.e. reducing the total volume in the reservoir. As illustrated on figure 2.1 the heat from the produced water can potentially be extracted and supplied to the district heating grid (Nielsen et al., 2013). This additional heat is not included in the overall energy calculations in the project but can be assessed as an upside.

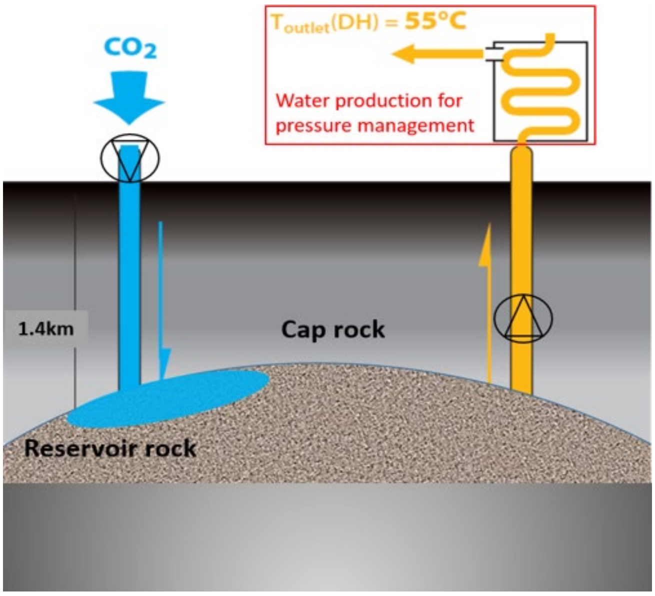

Fig. 2.1. CCS operation. CO_2 is injected in to the reservoir formation. Due to buoyancy the less dense supercritical CO_2 will migrate to the shallowest point of the reservoir closure. The caprock will prevent any CO_2 migration to surface. Pressure build up can be managed by water production – potentially the heat from the produced water can be extracted.

In a subsurface modelling context GE and DATES are described and handled similarly. Figure 2.2 and 2.3 show the conceptual setup for the two subsurface operations. There are no hard restriction to the overlying strata of the reservoir as no fluids are to be trapped. Like for the CCS operation a high porosity and high permeability for the reservoir is mandatory, i.e. a high porosity ensures a high capacity and a high permeability ensures a high productivity and in-jectivity.

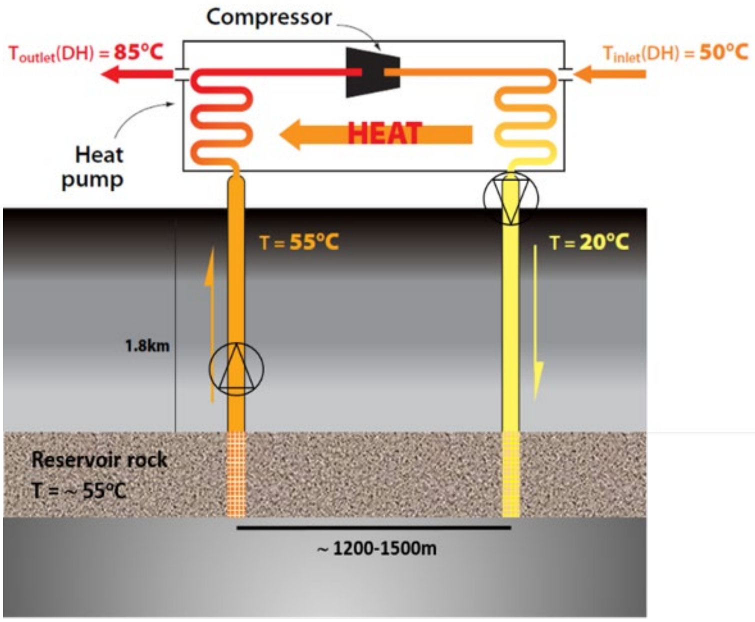

Fig. 2.2. Geothermal operation. Doublet well configuration; one production well and one injection well. The two wells are completed in the reservoir section. The heat from the produced water is extracted with heat exchanger at surface before the water is returned by the injection well.

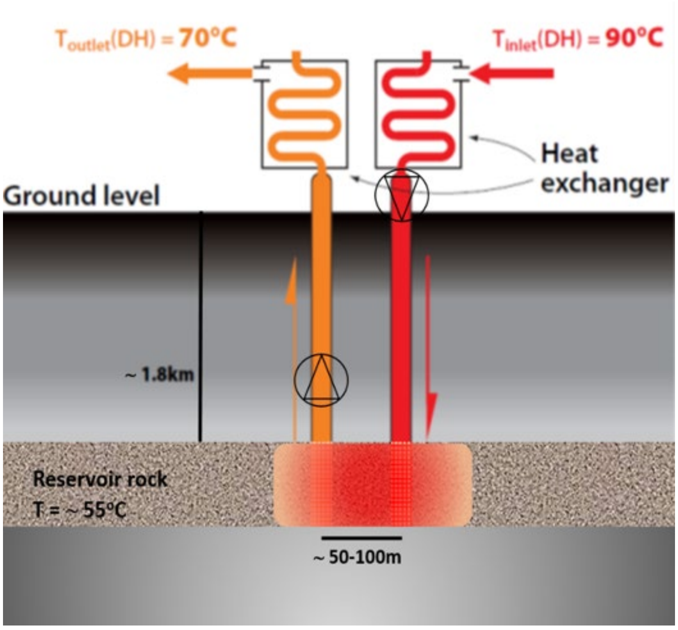

Fig. 2.3. DATES operation. Reservoir is charged with heated water during periods with excess heat. The Stored heat can be back-produced in periods with heat shortage.

The reservoirs must be in a fairly restricted depth interval; as the subsurface temperature increases with depth a certain minimum depth is required in order to extract sufficient heat. The minimum depth is much controlled by the heat demand in the individual geothermal projects/plants. In Denmark, being a low enthalpy area with respect to geothermal production, the extracted heat is used for district heating. With the recent development in heat pumps the temperature of the produced water is not as critical, as the temperature can be raised by heat pumps, it is more the effective cooling of the formation water and the production-/injection rate of the operation. The hardest restriction on the depth of the reservoirs is how deep the reservoir can be located. The permeability of the reservoir rock deteriorates with depth due to the high pressure from the overburden compress the rock and due to geochemical processes in the rock and formation water (diagenesis). For the sandstone formations available in the Danish subsurface a maximum depth of around 2500m is recommended (Kristensen et al., 2016).

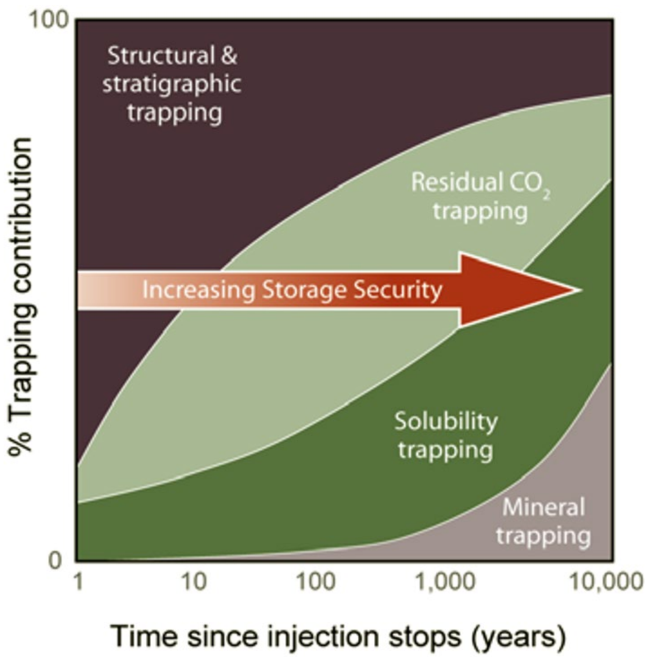

Fig. 2.4. Trapping mechanism for subsurface CO_2 storage (Benson et al., 2005)

For a GE operation the volume injected is equal to the volume produced (referred to as "full voidage replacement") so there are no pressure issues like for the CCS operation. Only pressure constraint is that the injection pressure must not exceed the fracture pressure of the formation. For the DATES operation the full voidage replacement is also obtained, but here the timeframe are a little different; the reservoir is charged with heated water in periods with excess heat and discharged in periods with a heat demand. The timeframe in combination with the charge – and discharge rates must be evaluated with respect to local pressure fluctuations.

A reservoir simulation model is subjected to uncertainty, mainly because there is large uncertainty in the reservoir paramm used to populate the model i.e. primarily the permeability estimates. Uncertainty also exist for other input data (e.g. thermal properties) as well as for the setup of the static model.

The procedure for model construction, both the static and dynamic models, is similar for the three subsurface operations studied, so in the following the procedure is exemplified with the construction of models used to simulate the CCS operation. The subsurface data coverage is often sparse, which can be a challenge to produce reliable models (Nielsen et al., 2015). The models are subjected to uncertainty, which is important to consider, especially, when the model results are used for predictive objectives.

The following sections describe the construction of the 3D reservoir model (static and dynamic) and is followed by a discussion of different simulation scenarios for the three subsurface operations, i.e. CCS, GE and DATES.

2.1 Static model

In the following the modelling procedure is outlined exemplified with the model used for modelling the CCS operation. As stated above static modelling is challenged by the sparse data coverage for the storage site area and regional geological studies are used to support the site modelling.

In the present study a structure east of Aalborg is identified on regional seismic mapping. The interpretation or identification is subjected to large uncertainty, but for the purpose of conceptual modelling in the present project it can be used. In the present project the structure is labelled “Langerak”, but this is by no means an official name. In figure 2.5 is displayed the subsurface data coverage for the area around Aalborg.

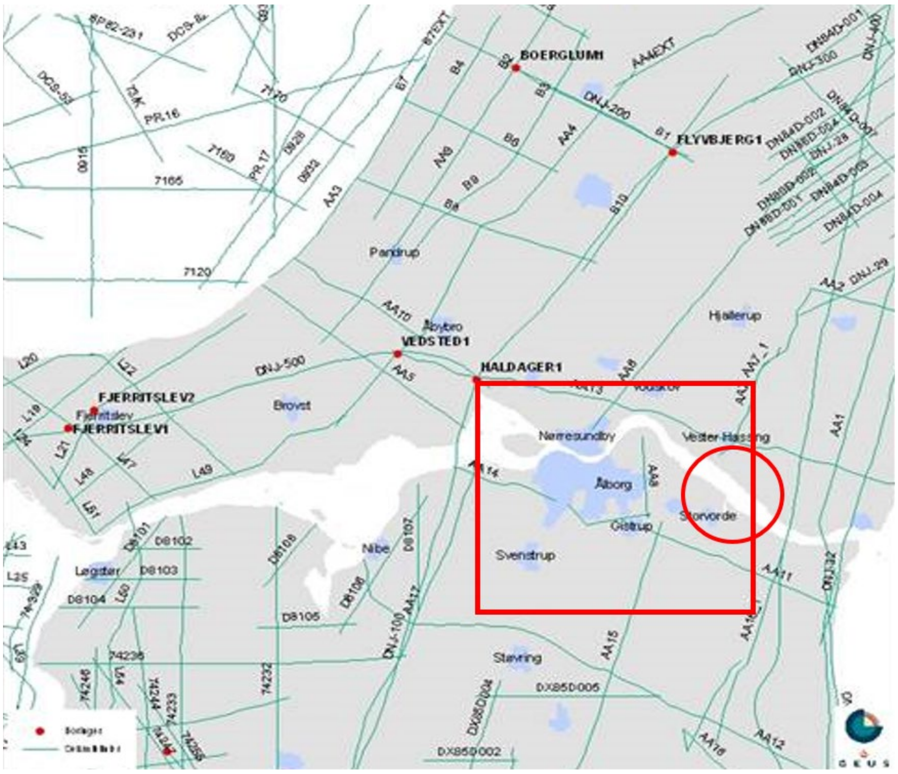

Fig. 2.5. Subsurface data coverage. Green lines are seismic lines. Red dots are deep subsurface wells. Red square is the area of interest for the geothermal energy production/storage operations. Red circle is the location of the Langerak structure.

Due to the sparse data coverage it was decided to use analogue data from the nearby Vedsted structure, placed northwest of Aalborg. The Vedsted location have previously been used to model a potential CCS operation (Nielsen et al., 2015). Data are replicated at the Aalborg and Langerak area. In figure 2.6 is shown the geological and petrophysical interpretation for the Vedsted area.

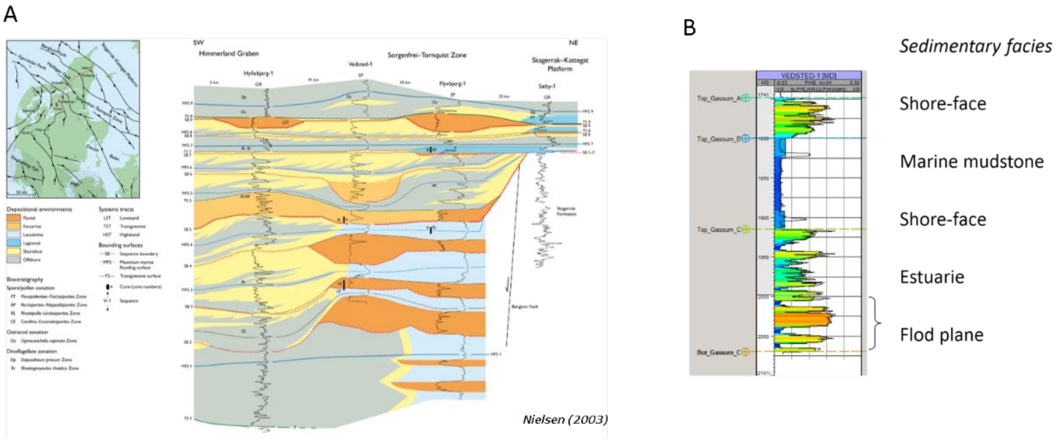

Fig. 2.6. Interpreted geology in the Aalborg (Vedsted) area. Left picture (A) interpreted variation at Gassum level. Right picture (B) interpreted porosity and lithology wireline log for the Gassum Formation in Vedsted structure.

2.1.1 Input data

This section describes the input data used for setting up the 3D static - and dynamic reservoir models along with the assumptions and constraints behind the choice of input data.

2.1.1.1 Seismic – and well data

The top Gassum surface is imported in the Petrel software from the regional seismic interpretation of the top Gassum Formation in the "Geotermiske screenings project" (Dybgeotermi, 2015). In the "Geotermiske screenings project" the top Gassum horizon is seismically pick on a regional scale, so the Langerak structure is uncertain.

The interpreted top Gassum surface is used as a proxy for the additional surfaces needed to model the area. 9 additional surfaces were added to the model based on the individual depths interpreted from the Vedsted well (cf. Fig. 2.6). The additional surfaces are depth shifted vertically relative to the relative vertical division in the Vedsted well. 8 of the total 10 surfaces are used to divide the Gassum reservoir Formation in intervals with high and low porosities. The last two surfaces are used to delineate the top (overburden) and base (underburden) of the model. 400 m of over- and underburden are used to delineate the model and to ensure proper vertical boundary conditions for the dynamic modelling of pressure and temperature (to be described later). The 3D frame of the model is illustrated in figure 2.7 for the Langerak structure.

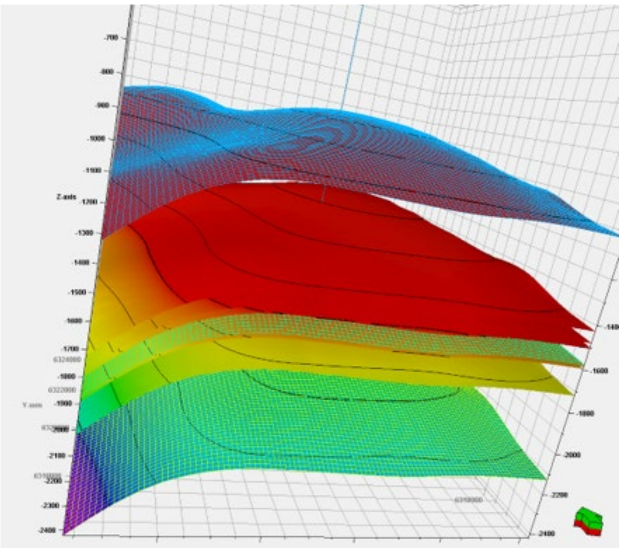

Fig. 2.7. The stacked surfaces encompassing the 3D model.

2.1.1.2 Model delineation

For the CCS modelling an area of interest (AOI) is defined around the Langerak structure on the top Gassum surface. The AOI is 10 km x 10 km, which is sufficient to cover the flanks of the structure in order to model the structural closure to secure the trapping of the CO_2 (Fig. 2.8).

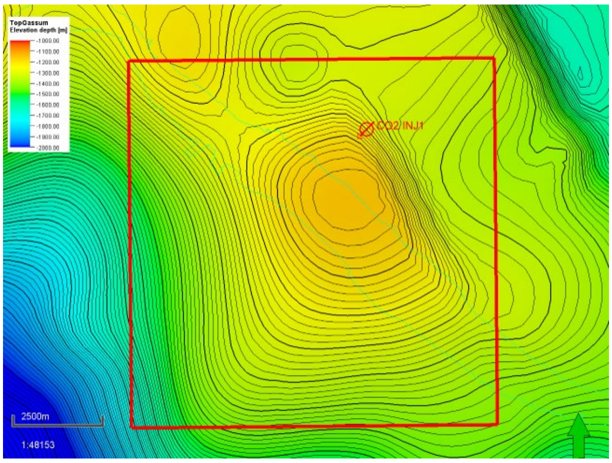

Fig. 2.8. Area of interest (AOI) for the CCS modelling. A 10 km x 10 km polygon (red square) is placed on the top Gassum Fm. map for the Langerak structure.

For the GE and DATES modelling an AOI of 36 km x 30 km is used in order to encompass a number of individual GE/DATES operation for optimizing the use of geothermal energy in the greater Aalborg area.

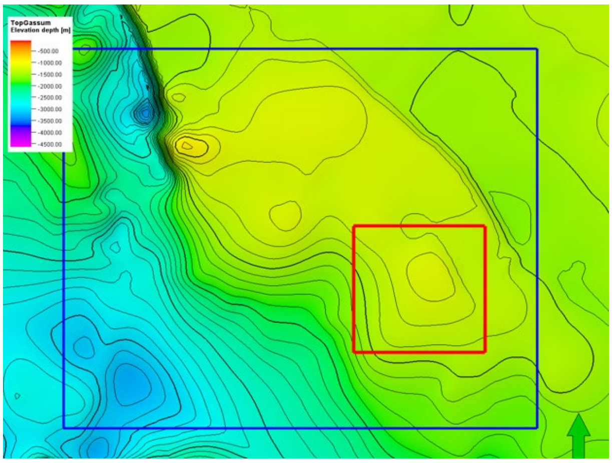

Fig. 2.9. 36 km x 30 km AOI for the GE and DATES modelling (blue square). Red square is the AOI for the CCS modelling.

2.1.1.3 Grid

A 3D corner point grid is constructed from the imported and adjusted surfaces. A total of 105 layers in the z direction are used to ensure a high vertical resolution of the reservoir intervals. The same vertical resolution is used for both the CCS and the GE/DATES models, the resolution is approximate 2 m in the reservoir interval and varies to much larger resolution in the over- and underbuden to minimize number of grid cells.

Grid resolutions in the lateral direction are different for the CCS and GE/DATES models. A grid cell resolution of 100 m x 100 m is used for the CCS modelling, resulting in a total of 1.029.105 grid cells. In order to avoid a very large number of grid cells for the larger GE/DATES model a grid cell size of 400 m x 400 m was applied resulting in a total number of grids cell of 708.750. But a grid cell size of 400 m x 400 m are to coarse to resolve the dynamic modelling of the GE and DATES process, so in order to avoid numerical dispersion local grid refinement has to be applied, this is discussed later for the dynamical modelling. The refinement has increasingly higher resolution toward the wells with a grid cell size of 10 m x 10 m in the near well area.

2.1.1.4 Grid properties

To populate the models with reservoir properties, *i.e.* porosity, permeability and thermal paramm, the vertical variation of lithology and porosity in the Vedsted well is used (Fig. 4.6). It was decided to model the AOI as a “layer-cake” model, *i.e.* no lateral variation in reservoir properties, only vertical variation. The regional seismic resolution is too low to incorporate a more detailed lateral variation in reservoir paramm. The geological understanding of the area supports this approach, even that the seismic interpretation could to some extend indicate discontinuity in the layers in the reservoir interval especially south of the centre of Aalborg city.

The porosity log from the Vedsted well is up-scaled to assign a single averaged value for each of the individual layers that the well penetrates in the grid. The up-scaled porosity values are assigned to the respective layers in the 3D grid, resulting in a layer-cake model that allows for variation in porosity values in the vertical direction but with constant values for each layer. The upscaled porosity log for the Vedsted well is displayed in figure 2.10.

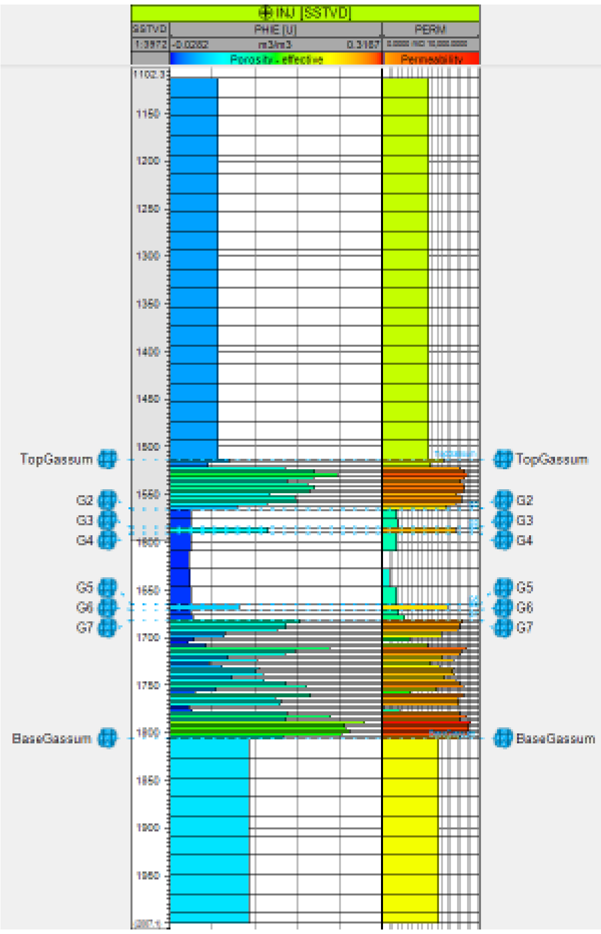

Fig. 2.10. Upscaled porosity and permeability values from the Vedsted well.

To populate the model with permeability values, a porosity-permeability relation is used. This relationship between porosity and permeability is established from laboratory flooding experiments on core samples. A general porosity-permeability relationship for the Gassum Formation is shown in figure 2.11. The selection of samples was subjected to both petrophysic and petrographic evaluation to be representative for the Aalborg subsurface area, figure 2.12. From this relationship permeability values are calculated for each of the grid cells in the model. The “new regional” trend (fig. 2.12) was used. The over- and underburden are assigned a constant value for both porosity and permeability (0.05 porosity fraction and 1 mD).

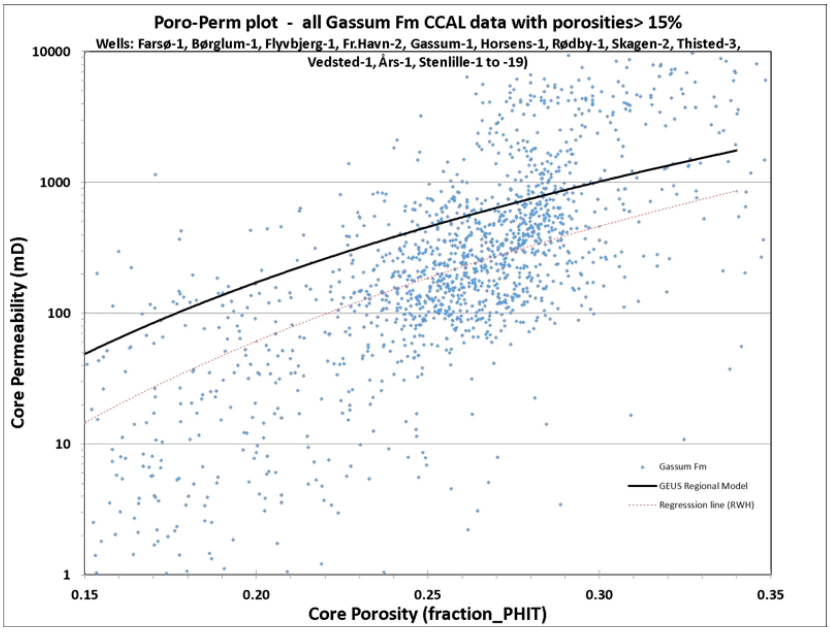

Fig. 2.11. General relationship for the Gassum Formation between porosity and permeability base on laboratory data.

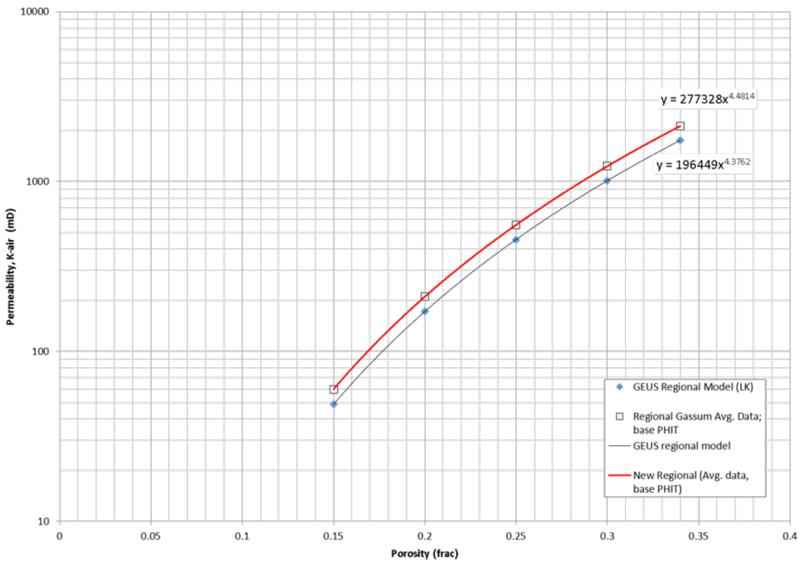

Fig. 2.12. Relationship for the Gassum Formation between porosity and permeability used in the Aalborg area.

A factor of 1.25 is multiplied on the permeability values to account for the upscaling process from core analysis data measured in the laboratory to field scale values and to convert from gas permeability to water permeability. Also based on core analysis a ratio between the vertical and horizontal permeability of 0.3 is used.

Figures 2.13 and 2.14 display the two static models for CCs - and GE/DATES modelling.

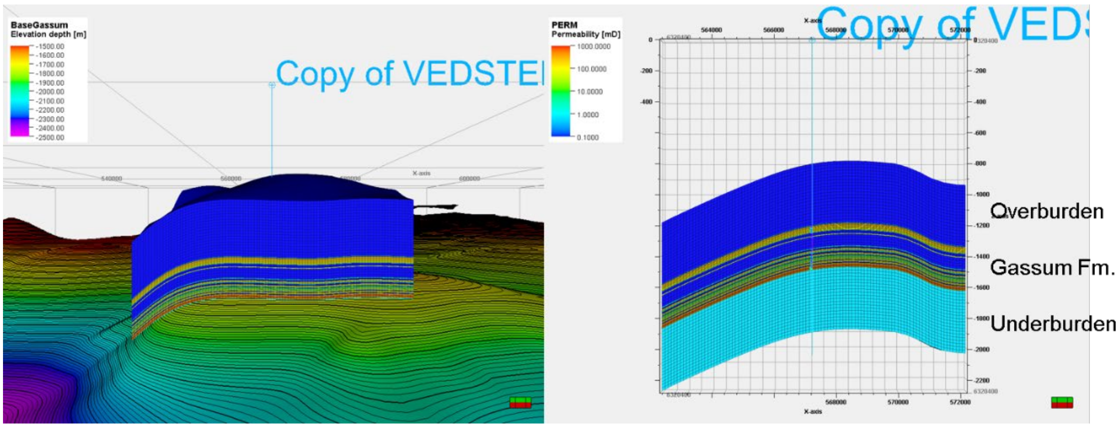

Fig. 2.13. Static model for CCS modelling in the Langerak structure. Left figure permeability values distributed in the 3D grid, model placed on top of the base Gassum surface. Right figure, 2D profile through the Langerak structure. Overburden are assigned a porosity value of 0.01 mD and underburden a value of 0.05 mD. The model is exaggerated 5X in the vertical direction.

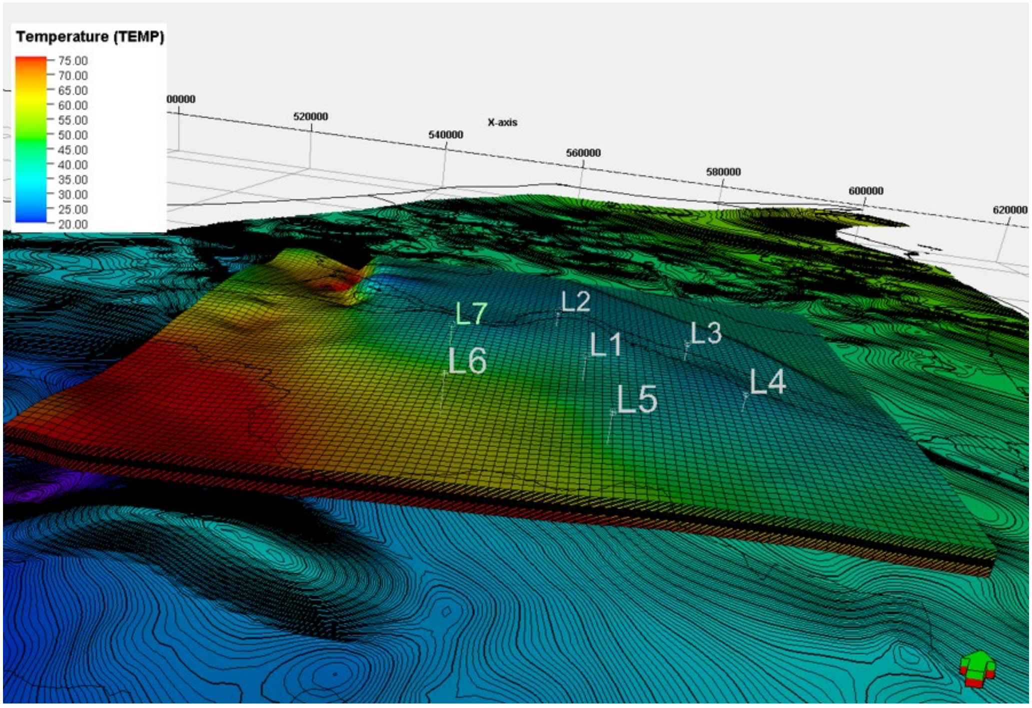

Fig. 2.14. The large 3D static model for GE and DATES modelling. The grid values are initial temperature values. L1 to L7 indicate seven locations for GE plants. The model is exaggerated 5X in the vertical direction.

Grid and grid properties as described above are exported from the static Petrel software model into the Eclipse software for the dynamic modelling.

Eclipse 100 (Eclipse, 2015) is a black-oil simulator widely used in the oil & gas industry for reservoir simulations. It is a robust and well proven numerical code based on finite differentiation of the relevant equations; *i.e.* it solves Darcy's law (flow) together with a generalized conservation equation (material balance).

Darcy equation states a relation between the flow velocity and the pressure gradient with the proportionality factor being the ration between the permeability and fluid viscosity in vector notations:

$$\boldsymbol{V} = -\frac{\overline{\overline{K}}}{\mu} \cdot \nabla P$$

$$\begin{bmatrix} u \\ v \\ w \end{bmatrix} = -\frac{1}{\mu} \begin{bmatrix} K_{xx} & K_{xy} & K_{xz} \\ K_{yx} & K_{yy} & K_{yz} \\ K_{zx} & K_{zy} & K_{zz} \end{bmatrix} \begin{bmatrix} \frac{\partial P}{\partial x} \\ \frac{\partial P}{\partial y} \\ \frac{\partial P}{\partial z} \end{bmatrix}$$

3. Dynamic modelling of CO_2 injection and storage

The static CCS model is exported to the Eclipse 100 reservoir simulator (Eclipse, 2015). Grid definition and orientation together with porosity and permeability grid values are exported. Eclipse use corner point grids in order to capture reservoir curvature.

As stated in the previous paragraph Eclipse 100 is a black-oil reservoir simulator. For simulating a CO_2 – brine system for modelling geological storage of CO_2, Eclipse 100 can be used simply by treating the CO_2 and formation water phases as the simulator gas phase and simulator oil phase, respectively. This “trick” is widely accepted in the CCS modelling community and a more exhausting description on how to setup Eclipse 100 for CCS modelling is described in detail in Frykman et al. (2008) and is not the scope of this study.

3.1 Modelling procedure

Some elements on how to setup Eclipse 100 for CO_2 storage modelling are listed below in order to illustrate the different use of Eclipse 100 when used for CCS and when used for GE/DATES modelling.

The CO_2 formation volume factor (FVF), density and viscosity are obtained from the commercial PVT software PVTsim (PVTsim, 2001). The brine data which accounts for dissolved CO_2 are obtained from Chang, Coats and Nolen (1998). The brine density is calculated by the correlation of Rowe and Chow (1970). The brine viscosity is assumed to be independent of CO_2 content and pressure and is calculated by the correlation of Batzle and Wang (Crewes, 2007).

In Eclipse 100 solubility data, FVF data and viscosities are represented in tables. This allows both solubility properties and density versus depth data to be consistently represented, as pressure variation in the model is dominated by the hydrostatic pressure gradient throughout the simulation.

3.1.1 Saturation functions

Relative permeability functions are taken from two SPE papers (Bennion & Bachu 2006a, Bennion & Bachu 2006b). The relative permeability functions are needed in order to describe the flow of two fluid phases in the porous rock. It replaces the permeability and accounts for the blocking effect each phase can have for the other phase (Fig. 3.1).

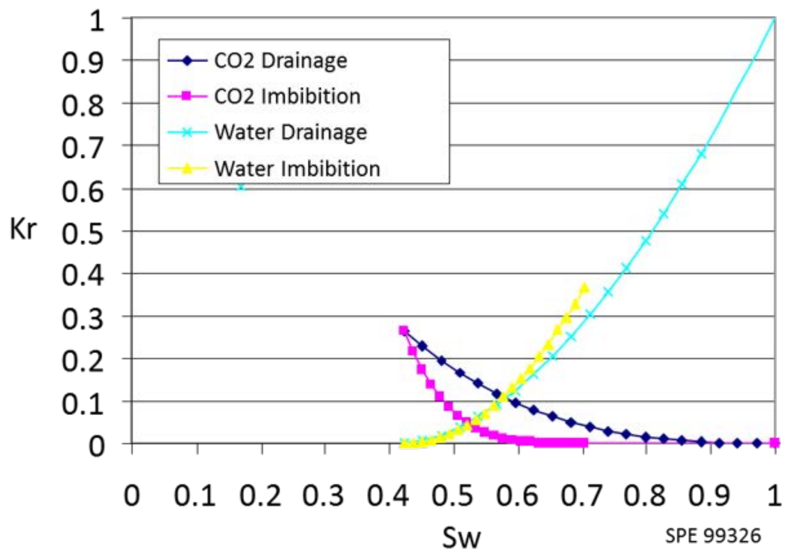

Fig. 3.1. Relative permeability functions (Bennion & Bachu, 2006 a, b).

The capillary entry pressure for the sand layers are set to 0.1 bar and for the cap rock layer it is modelled to be 100 times higher, i.e. 10 bar. The capillary pressure functions are arbitrary constructed from the entry pressures and the end points on the relative permeability curves.

3.1.2 Boundary conditions

The “pore volume multiplication” boundary conditions method is used. It is a technique to simulate how a site-specific model is connected to a large (or infinite) aquifer (Nielsen & Frykman, 2012). The MULTPV keyword In Eclipse 100 is used; the pore volume for the outermost grid cells are multiplied by a high number. For the present simulations the three outermost grid rows are multiplied by increasing values of 10, 100 and 1000.

3.1.3 Initial conditions

The initial reservoir pressure is 135 bar at a datum depth of 1200 m, i.e. hydrostatic conditions prevail before injection commences. The individual simulation runs were started from the hydrostatic equilibrium situations. For some of the runs the “restarts” option were applied.

3.2 Modelling scenarios

The objectives for the simulation study were to evaluate the CO_2 distribution and pressure development in the Gassum sandstone Formation in the Langerak structure.

The closure of the interpreted structure is large and can easily capture the planned CO_2 stream of 1E6 tonnes/year during a 30 years injection period. The critical issue is the pressure development in the reservoir formation, both the injection pressure and how fast the pressure will dissipate when the CO_2 phase displaces the formation water.

Simulations of CO_2 injection are run with;

- 1 injection well placed down flank to the north of the structure,
- 1 injection well and one water production well to manage the pressure increase by voidage replacement,
- 1 injection well and two water production wells to manage the pressure increase at different voidage replacements.

3.3 Results and discussion

Figure 3.2 shows the CO_2 plume development when injected in to the reservoir intervals. During the injection period of 30 years the CO_2 phase displaces the formation water. The injection pressure displaces the water around the injection well, but the buoyancy forces also forces the less dense CO_2 phase to migrate upwards the flank of the structure, figure 3.2.

After the injection has stopped the CO_2 will be trapped under the concave structure of the caprock. Part of the CO_2 will be dissolved in the formation water and part of the CO_2 will be immobilized in the residual tail of the plume when migrated to the capex of the structure. Finally, a part of the CO_2 will be trapped by mineral trapping, but this is not modelled with the present reservoir simulation (cf. fig. 2.4).

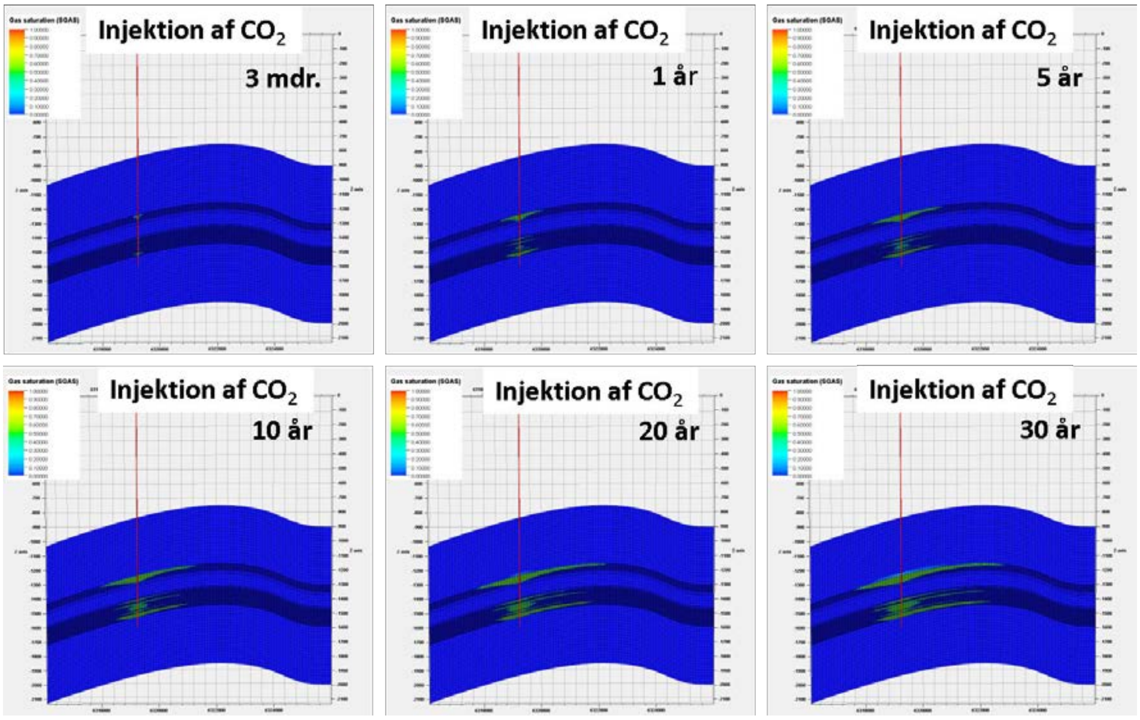

Fig. 3.2. Profiles of the Langerak structure at different times during the injection of CO_2. The CO_2 phase is distributed in the reservoir interval due to both the injection pressure and buoyancy, i.e. migration up-flank of the structure

Figure 3.3 shows the pressure development during the CO_2 injection. The pressure will increase at the injection well/point and level off with distance. Due to the balance between the injection rate, the reservoir permeability and the compressibility of the reservoir the pressure will not have time to dissipate and will continue to increase during the injection period.

The operator of a CO_2 storage operation may meet some regulatory issues concerning the pressure increase. The pressure most be below the fracture pressure of the reservoir and the overlying caprock and the CO_2 phase pressure must not exceed the capillary entry pressure of the caprock. Further, there might be some restrictions on how much the pressure are allowed to increase at the boundary of the granted license area. These issues are described in the regulatory framework and guidelines from the EU directive on CCS (EC 2009, EC 2011). The EU directive operates with a definition called the “storage complex”, which is the granted license area that an operator is responsible for.

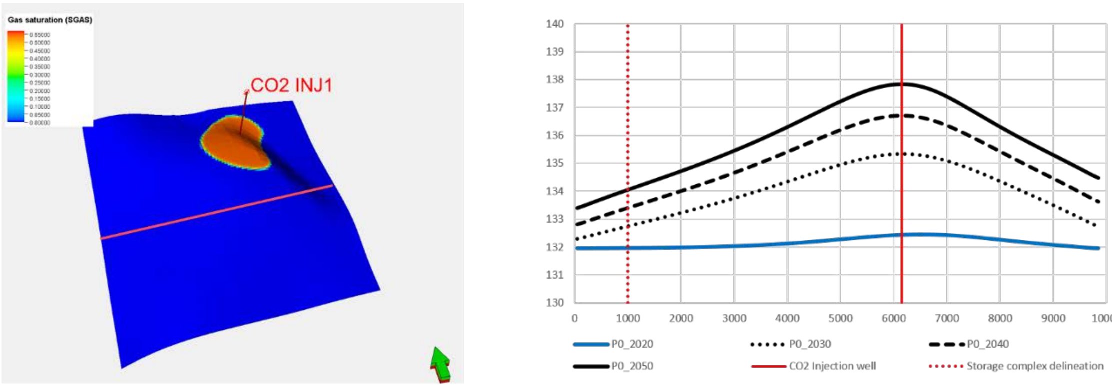

Fig. 3.3. Left picture: Top view of the CO_2 distribution after 30 years of injection. Right picture: Pressure profiles at different times of injection. Profiles are measured through the structure at the red line on the left picture. The solid vertical red line is the injection well/point. The dotted vertical red line is the delineation of the model; after some years of injection the pressure has increased several bars at the boarder of the model.

In order to mitigate and manage the pressure development during a CO_2 injection operation water can be produced to balance the injected volume of CO_2, this is referred to as voidage replacement.

Water production wells can be placed at different locations on the structure. It will be an optimization process on how many wells are needed and how much water has to be produced. Both the drilling of additional well(s) and the handling of produced water comes with a cost. Figure 3.4 shows an example on how different water production schemes can mitigate the pressure increase, both at the injection point and at the delineation of the model/license area.

For the present example the pressure at the delineation of the model/license area can be maintained at the initial pressure if the total water production equals 4800 m^3/day, i.e. 100 m^3/h/well, which is almost full voidage replacement.

If the pressure at the boundary of the storage complex/license area is allowed to increase approximate 1 bar the amount of water that needs to be produced can be halved, which of cause have direct impact on the costs for the storage operation. It has not been possible for the project to get any numbers on how much the pressure actually can be allowed to increase, neither form the EU directive or regulatory bodies.

The heat from the produced water may be utilized in the district heating system. But it was decided in the present project not to include this excess heat in the economic evaluations because of the non-resolved issues on the allowed pressure increase.

Figure 3.5 shows a conceptual model on how the storage complex is defined and which elements an operator are responsible for exemplified for the Vedsted structure (Nielsen et al., 2015)

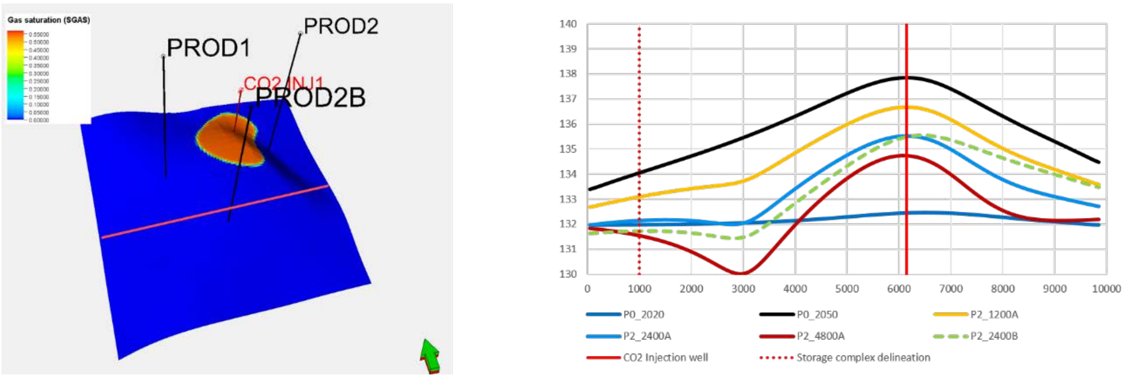

Fig. 3.4. Left picture: Different locations for the water production wells. Right picture: Simulated pressure profiles for different water production well configurations and water production rates.

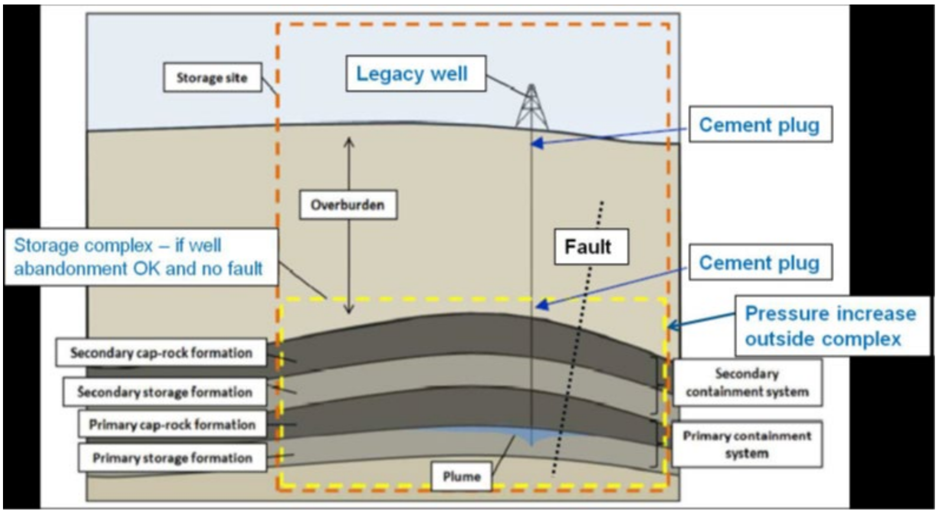

Fig. 3.5. Storage complex definition with different elements (Nielsen et al., 2015)

3.4 Summery

Conceptual modelling of CO_2 storage in the Langerak structure:

- Storage option close to Aalborg CO_2 point source(s),

- Large storage capacity in the Langerak structure,
- Trap configuration; caprock and 4-way closure,
- Delineation of the Langerak structure uncertain.

Pressure management by water production:

- Safety issues; CO_2 injection pressure must not exceed fracture pressure,
- Regulatory issues (DK regulation, EU CCS Directive); how much can the pressure increase at license boundary,
- Produced water can supplement the geothermal production – but excess water must be handled at surface
- Additional drilling costs.

4. Dynamic modelling of geothermal energy production and deep aquifer thermal energy storage

Similar to the CO_2 storage modelling procedure the static model for the GE and DATES operations are exported to the Eclipse 100 reservoir simulator. Again, it Is not the scope of the present project to detail the concept of reservoir simulation, but merely to outline the specific elements for using Eclipse 100 for geothermal reservoir simulations.

4.1 Modelling procedure

Eclipse 100 is inherently an isothermal reservoir simulator, but it has an in-build temperature option that can be used to simulate temperature distribution. The option can keep track of the injected cold water (as a tracer) and the temperature changes, when the formation water and injected water mixes in each grid cell. Furthermore, heat conduction for the geological layers is built in to this option.

Heat conduction for the geological layers is assumed to be 2 W/m/˚C for the shale layers and 4 W/m/˚C for the reservoir sandstone, together with specific heat capacity of 2.2 MJ/m^3/˚C and 4.0 MJ/m^3/˚C for the geological layers and the formation water, respectively (Balling & Bording, 2013).

A temperature profile for the Aalborg area is discussed in Vosgerau et al. (2015) and the values taken form Balling & Bording, (2013). A temperature gradient of 27˚C/km and a mean annual surface temperature of 8˚C are used in the reservoir simulations.

The viscosity of the formation water is strongly dependent on temperature and a table of viscosity as function of temperature must be entered as input in the simulation model. Table of temperature and viscosity is created from CREWES (2007) assuming a formation water density of 1150 kg/m^3 (Laier 2018, pers. com.).

4.1.1 Boundary conditions

Proper boundary conditions must be applied for the simulation model. Even though the simulation of a geothermal plant operation involves production and injection of equal volumes of water (full voidage replacement), it must be secured that the simulated pressure and temperature development is not influenced by the model boundary. For this study the pore volume multiplication was tried as a boundary condition; *i.e.* the pore volumes of the outermost grid cells of the model have been multiplied by a high number to mimic that the model area is situated in an infinite aquifer. But in contrast to the CO_2 storage model the GE/DATES model is so large (36 km x 30 km) that the pore volume multiplication had no effect on the simulation results, so it was decided to run the simulations without any multiplication.

Further, as described previously, the over- and underburden is included in the reservoir model to secure correct handling of the temperature and pressure vertical boundary conditions.

The Eclipse "well control" option is also a boundary condition for solving the differential equations describing the water flow and pressure development in the reservoir model. The build-in Eclipse well option (Eclipse, 2017) is used to describe the production and injection wells in the simulator. The wells are controlled by volume rate at surface conditions, *i.e.* a specific desired production and injection rate. The Eclipse well option balances the total through put from the wells to the reservoir for the individual grid cells by a "connection transmissibility factor".

The wells are modelled as being open in the two main reservoir intervals, i.e. each well has access to the entire thickness of the reservoir. The well diam is arbitrarily set to 0.245m with a skin factor of zero.

4.1.2 Grid refinement

The lateral size of the individual grid cells in the static model is 400 m x 400 m in order to keep the number of grid cell in the large model at a reasonable size. But when modelling a GE – or DATES operation, where the well distance can vary between 1200 m down to 50 m for the DATES well configuration it is mandatory to refine the grid cell size in the well areas in order to avoid errors from numerical dispersion.

Grid refinement can be done both in the Petrel software and in Eclipse 100. For the present study grid refinement was done in Eclipse. Figure 4.1 illustrate the refinement results; a 400 m x 400 m large grid cell is divided in to smaller grid cells until a grid cell size of 20 m x 20 m is obtained between the wells. The refinement process is optimized when the simulation results are independent on further grid refinement.

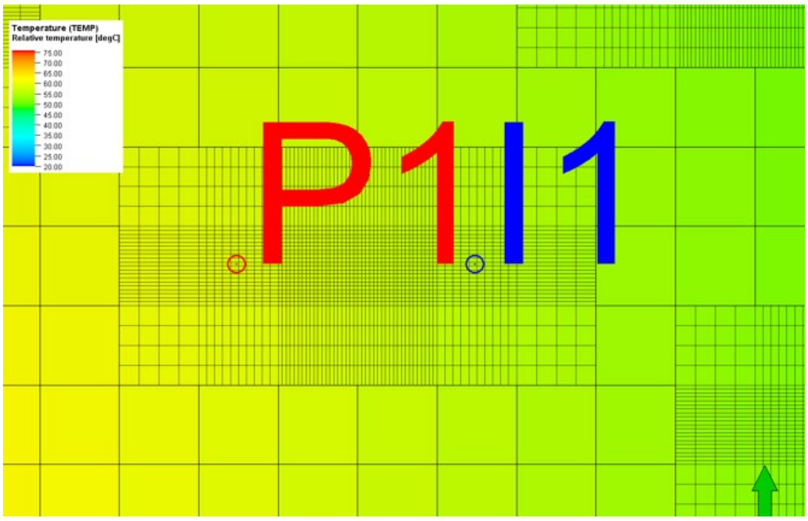

Fig. 4.1. Grid refinement around well pairs. Grid cell size are refined from 400 m x 400 m down to 20 mx 20 m between the two wells.

Initialisation of flow modelling

In the reservoir model the water phase is given properties to mimic the saline formation water in the Aalborg area, i.e. a density of 1150 kg/m^3. The initial pressure of the formation water is calculated as hydrostatic (hydrostatic equilibrium) for each grid cell from the density and the depth of the respective grid cell. Density is assumed to vary linearly with depth.

Model temperature is calculated for each grid cell from the temperature-depth relation given above (27˚C/1000 m and a surface temperature of 8˚C). It is assumed that the entire reservoir model is in thermal equilibrium and that the temperature vary linearly with depth (Vosgerau et al., 2015).

4.1.3 Modelling scenarios

4.1.3.1 GE modelling

The objective for the simulation study was to evaluate the geothermal production potential for the greater Aalborg area. In order to maximize the total geothermal production, it is essential to place the individual geothermal plants as close as possible without the individual plants are "stealing" production from the neighbouring plant.

The well distance between the production – and injection wells in a single geothermal doublet plant can also be minimized/optimized down from the "rule of thumb" value of 1500 m.

Two different grids were superimposed on a map over the greater Aalborg area; a 7 km grid and a 5 km grid. The aim was to place a least 15 individual GE doublet plants in the area. Figure 4.2 display the grid and the resulting "closest packing" of doublet plants with 7 km separation or 5 km separation. From the figure it is obvious that the 5 km separation allows the 15 plants to be packed closets around the city centre, with the upside to increase the number of plants and in the area.

Simulations were run for optimization of "closest packing"; A plant configuration was used with a centre plant located at the RenoNord location and with six neighbouring plants equal distributed around the centre plant.

The simulations were run with an injection temperature of 20ºC. Each doublet was operated at a constant flow rate of 200 m^3/h. Simulations were run for 50 years.

4.1.3.2 DATES modelling

The dynamic model for the GE was used to simulate the DATES operation. A conceptual well configuration as illustrated in figure 2.3 with a well distance of 50 m between the "hot" and "cold" well.

The hot well was charged with 90ºC hot water at a rate of 100 m^3/h. It was charged for 5.5 months and discharged for 5.5 month in order to mimic a 6/6 months charging/discharging cycle allowing for 2 weeks pause for flow reversing.

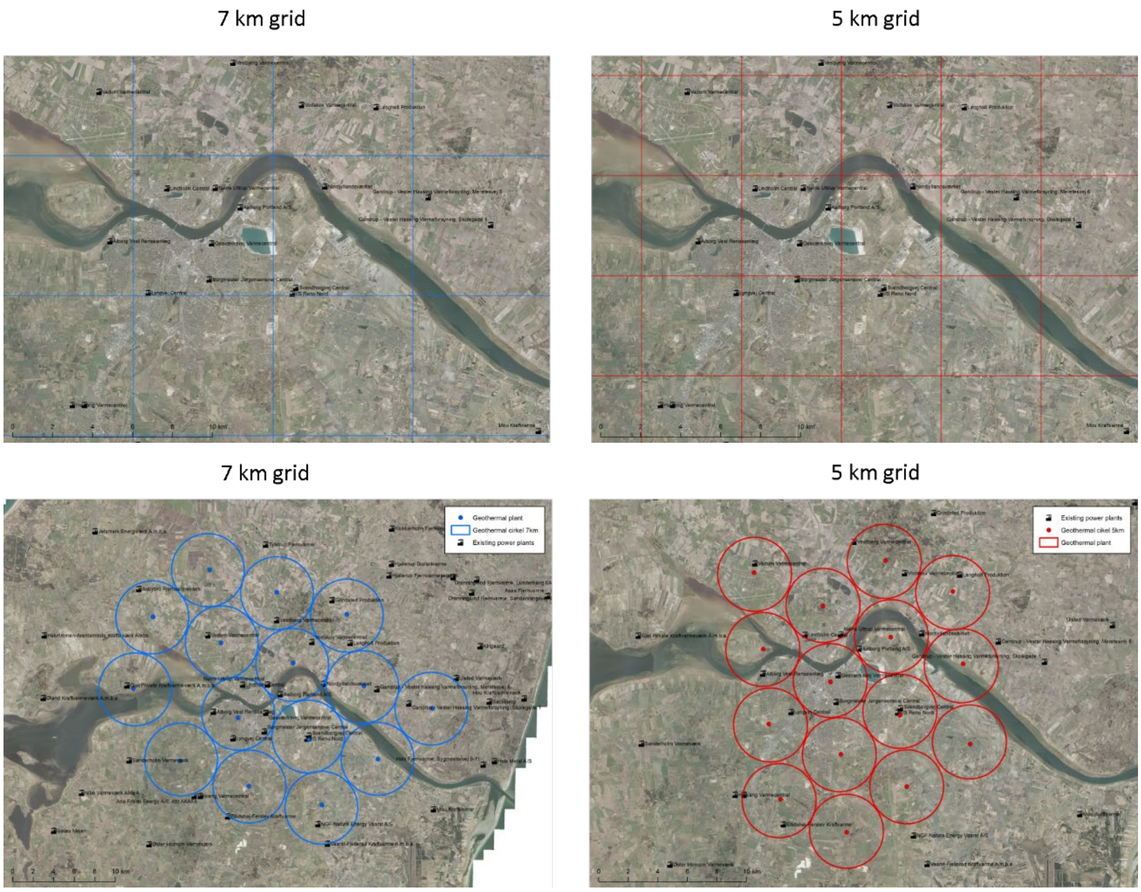

Fig. 4.2. Optimized location of individual GE doublet plants.

4.2 Results and discussion

GE modelling

Figure 4.3 shows the simulated cold water front progressing from the injection well. It is clear from the figure that the high permeability part of the reservoir is conducting most of the flow (cf. fig. 2.10).

It is important to bear in mind that, even that, the 2D profiles displayed in figure 4.3 shows that the cold-water front have reached the production well after 50 years of operation the production temperature is not dropping drastically. From figure 4.4 it is clear that the production well is producing warm formation water from an area around the well; the injected cold water is only reaching the production well in a narrow wedge. The pressure sink and source around the production – and injection wells respectively are only biased to some extend from each other.

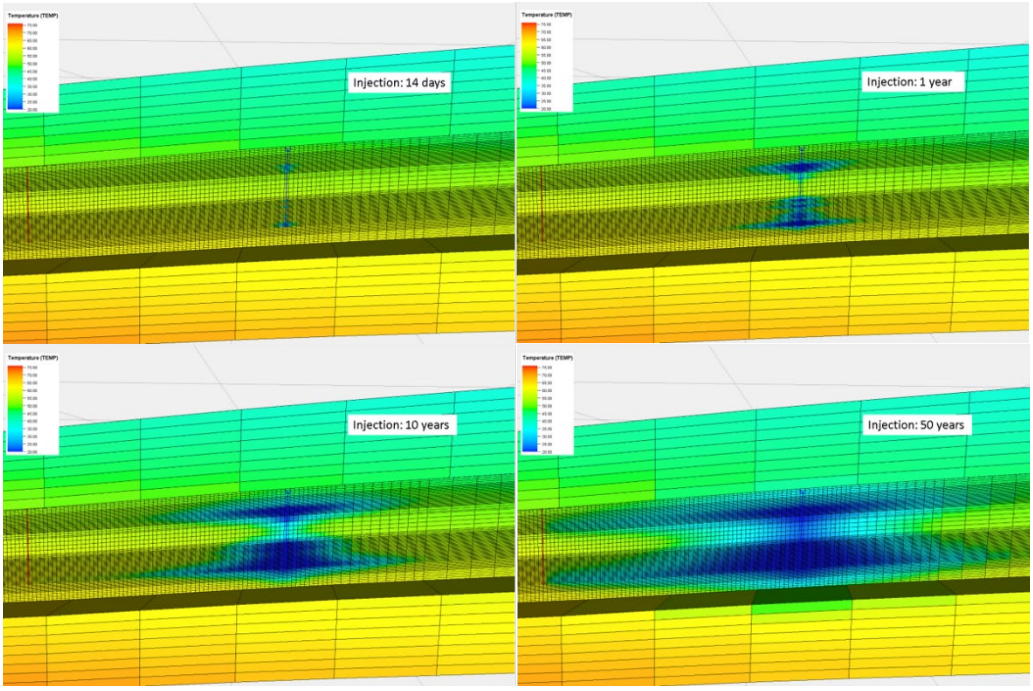

Fig. 4.3. Simulated cold water fromt at different time steps. The injection well is in the centre and the production well to the left in each picture (red vertical line).

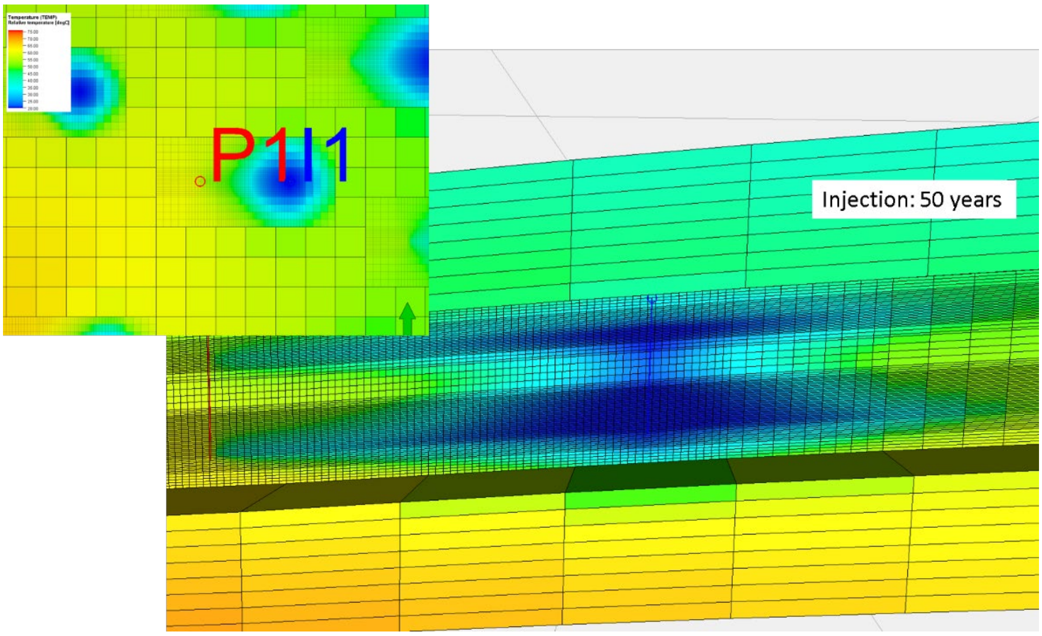

Fig. 4.4. Simulated cold water fromt at after 50 years of simulation. The small incert picture shows a top view of the cold water front; the cold water reach the production well in a narrow wedge.

The production temperature only decreases approximate 2ºC during an operation of constant flow of 200 m³/h for 50 years. Figure 4.5 shows the production profiles for the seven doublet centred around the RenoNord location. The different production temperatures are due to the different locations in the subsurface. The Gassum reservoir is dipping to the south, thereby the southernmost plants are located deep and thereby benefitting from warmer formation water.

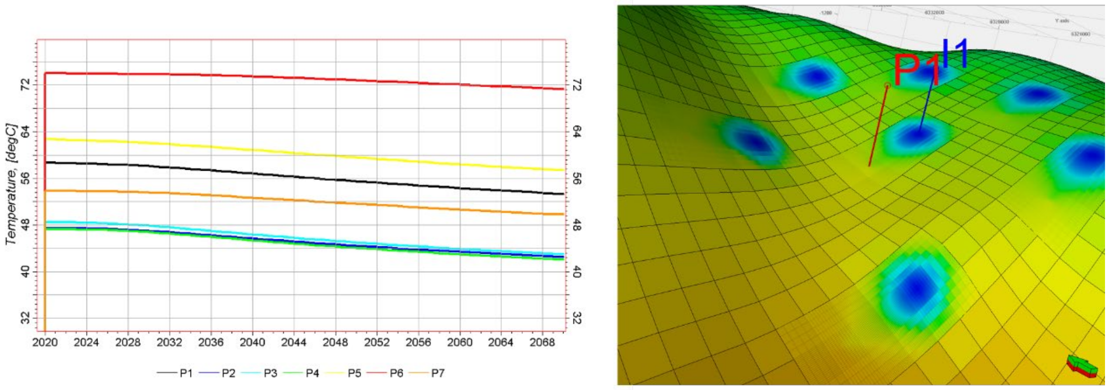

Fig. 4.5. Left: Production profiles for the 7 individual plant locations. Each plants are separated by 7 km. The P1/I1 location is the RenoNord location.

In order to optimize the number of plants that can be locatred in the area of Aalborg simulation were run with smaller distance between the individual plants. Simulations were run for a distance of 7 km, 5 km an ddown to 3 km. further, the well distance in the individual doublets were narrowed down from 1500 m to 1200 m with out any impact on the production temperature.

Figures 4.6 and 4.7 display the results of narrowing the distance between the GE plants. No distinct differences between the production temperature profiles are observed, only a very small influence on the production temperatur for some of the plants, when simulating with a distance of 3 km.

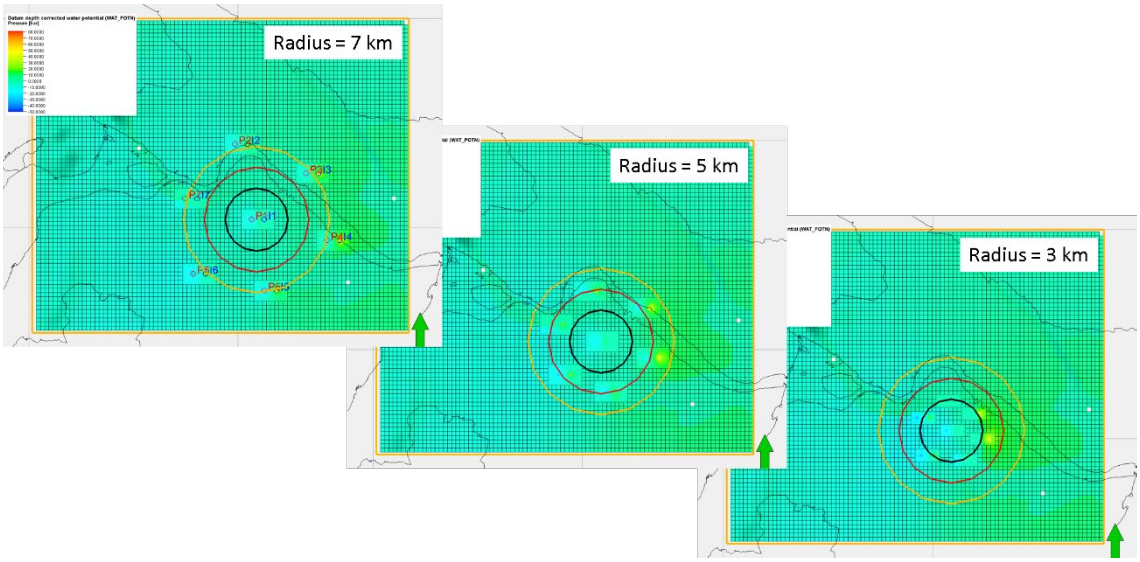

Fig. 4.6. Top view of the temperature distribution after 50 years of simulation. Distance between the individual plants varies from 7 km, 5 km and down to 3 km.

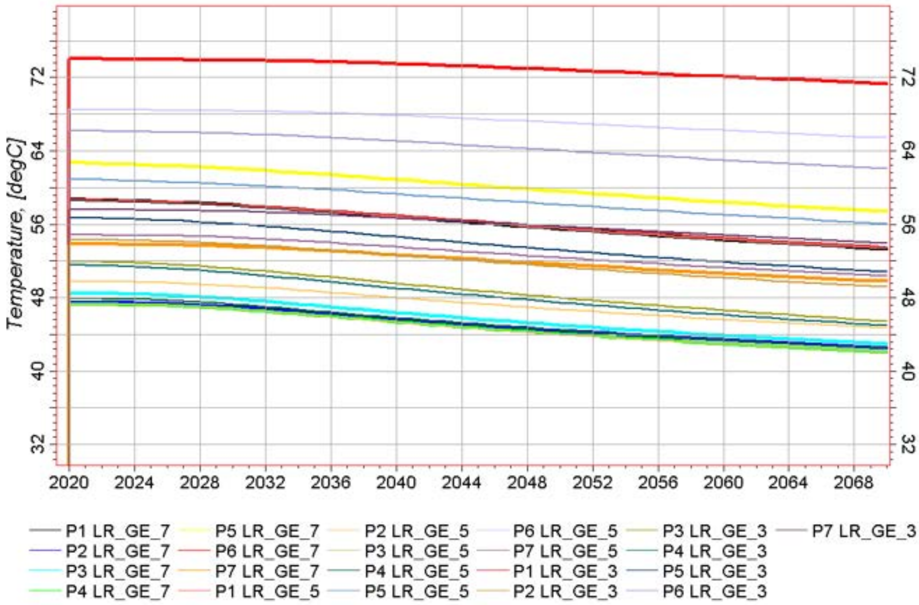

Fig. 4.7. Development in production temperature for the three plant configurations shown in figure 4.6.

4.2.1.1 DATES modelling

The DATES system was simulated for a total period of 60 years with an equal charging/dis-charging cycle of 5.5 month, a two weeks period with no flow were simulated to mimic any practicalities during shifting of charging mode.

Figures 4.8 and 4.9 show the development of the heated area around the hot well and the production temperature from the well. The system is surprisingly effective with only a narrow area around the hot well is heated, the heat loss from heat conduction seems to be minimal. Simulations show that the efficiency is higher if the DATES is located as deep as possible, i.e. the temperature difference between the charge water and the formation water is smallest returning the smallest temperature for driving heat conduction.

The production temperature profile shows that it only takes approximate 4 – 5 years for the reservoir rock to be heated so the efficiency almost 90%.

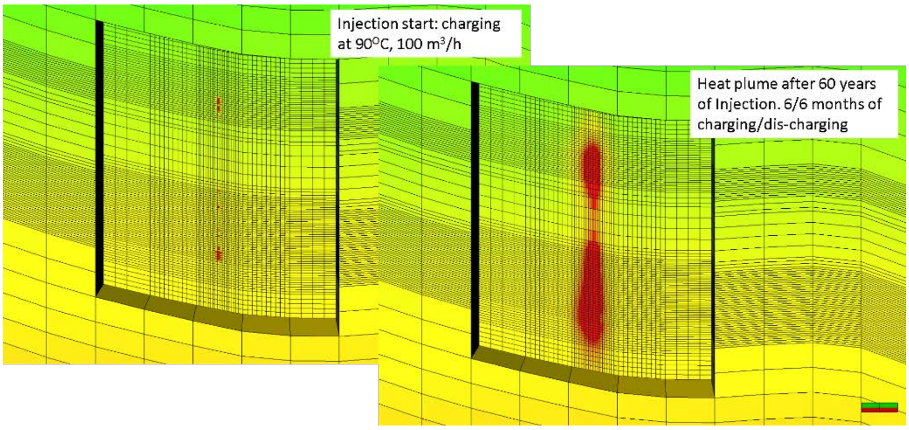

Fig. 4.8. Distribution of the heat plume for the DATES operation. Heat loss through heat conduction seems to be minimal.

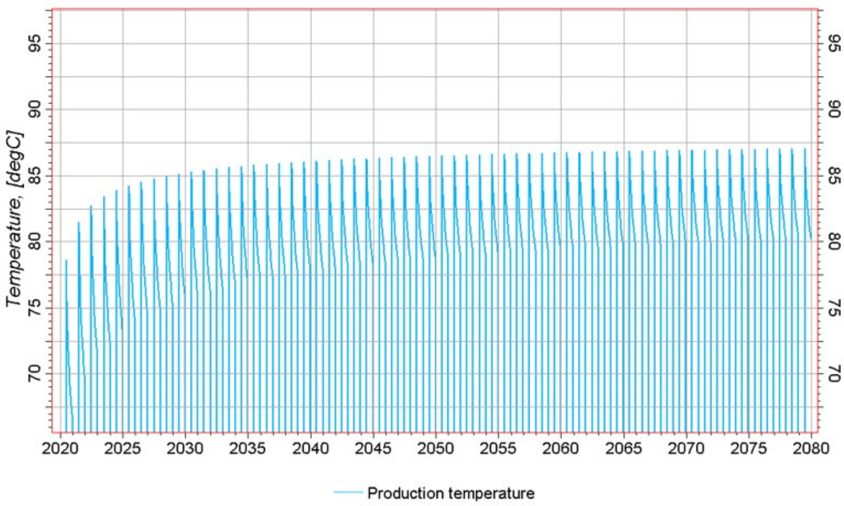

Fig. 4.9. Production temperature as function of time for the DATES system. The system is charged with 90°C water. A 6/6 charging/discharging scheme.

4.3 Summery

Findings for the GE simulation work:

- Simulations with the GE model show that individual GE plants can be located within a distance of 3 km, giving opportunities for optimizing the subsurface space,
- Simulations with the Gassum reservoir model indicates that approximate 8 MW per doublet might be achieved if operated at 200 m^3/h and produced water cooled to 20°C (subjected to uncertainty),
- Well distance in a single doublet can be minimized to 1200 m – and potentially further,

Findings for the DATES simulation work:

- Almost 90% efficiency after 4-5 years of charging/discharging
- Relative low temperature difference between injection – and reservoir water reduces heat loss from heat conduction

5. References

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