

## Integrating Multi Purpose Geothermal Systems with Local City Heating Grids

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### ABSTRACT

Not only high heat flow regions with volcanic activity, but also other regions such as sedimentary basins are suitable for geothermal energy. In the Netherlands, with a low thermal gradient however, there are no governmental incentives for such developments, making geothermal heat and electricity production at best marginally economical. Therefore, smart solutions are needed as to economize geothermal systems, such as integration into existing heating grids, exploitation of synergies with fossil-fuel based systems, and innovation on well-construction technology. In the presence of existing grid-heating networks, geothermal heat can be included in the gross energy mix. By combining a geothermal system with a power/heat co-generation plant, a peak shaving effect on the economical risks of a combined investment can be created, making city heating grids more favourable. By combining the geothermal system with co-injection of CO<sub>2</sub> captured from the co-generation plant it is possible to create an economically feasible, environmentally sustainable multipurpose energy system. To enable the drilling of deep geothermal wells in urban areas with limited operational space, new full composite casing drilling technology with back of the truck operations have been developed at TU Delft and local based companies. As the composite material is corrosion resistant, the co-injection of 15.000 ton CO<sub>2</sub> annually becomes feasible without reducing the integrity of the wells,

### 1. INTRODUCTION

Following two geothermal projects in Bleiswijk (for glasshouses, 1700 m depth) and the Hague (6000 houses), students of Delft University, Department of Applied Earth Sciences, started a feasibility study where the commercial production of geothermal energy is combined with innovative casing drilling technology using composite materials and CO<sub>2</sub> co-injection. Currently, the Delft University campus is powered by a 79 MW power plant holding two cogeneration units for base-load and three gas boilers for peak demand. Produced energy is delivered through the public electricity grid, and through the Campus high-temperature grid heating network. Now, the municipality of Delft is developing a low-temperature heating grid in conjuncture with local housing corporations and an energy utility company. This new grid is planned to heat 22.000 newly constructed and redeveloped buildings and houses. The feeding points of the new low-temperature heating grid (80 degrees Celsius in, 30 degrees Celsius return) and the existing university campus high temperature network (130 degrees Celsius in, 80 degrees Celsius return) will be co-located through the situation of two separately owned power plants on one location. Adding a geothermal system to the energy mix could save large amounts of CO<sub>2</sub> emissions is it possible to implement this commercially. If

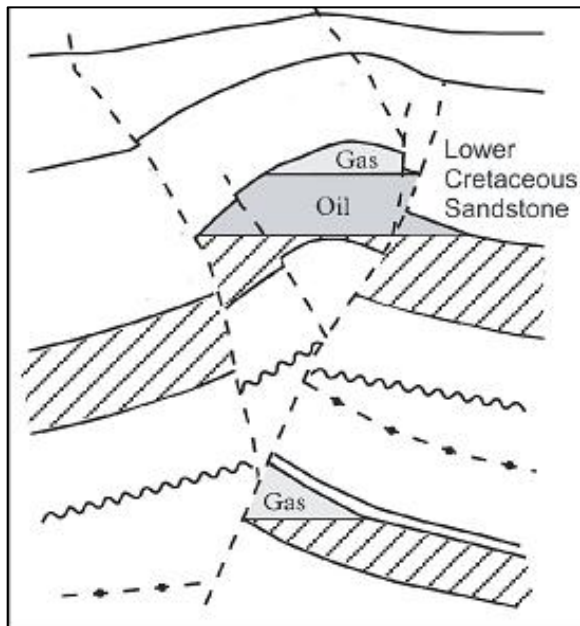
geothermal energy provided any benefits, for example being independent of gas prices, it could be made interesting for the university and local energy companies to combine a geothermal system onsite with a cogenerating heat power plant. Hence a commercial feasibility study was preformed for a multi purpose power plant. (DAP, 2008) For optimal heat gain and minimum transport costs and losses, the geothermal production- and injection well have to be located near the power-plant. This imposes spatial constraints on operations, hence the drilling of 2.5 km deep "large-diameter" holes with heavy equipment should be avoided. Therefore, light weight newly developed drilling alternatives are to be used to operate on small footprints. Furthermore, sufficient geothermal water must be available to provide the desired amounts for heat exchange, i.e. 120 to 150 m<sup>3</sup> per hour. The water is available on the flank of an anticlinal structure below the campus, which holds the Jurassic aged Rijswijk sandstone and the highly permeable Delft sandstone. These sandstones are situated at a depth between 1.8 and 2.5 km. Both members are favourable for geothermal energy production. In general, geological information on saline aquifers is sparse. Nevertheless, from oil exploration geophysical information and exploration wells in the area, we can determine the geological structure below Delft. It is more difficult to obtain reliable and specific reservoir information, i.e. the environmental details of the down-dip target sands. This problem can be solved by using reservoir information derived from wells and information of depleted oil reservoirs in the vicinity. This data is critical to first construct a static geological model of the reservoir, which can later be used for dynamic simulation of reservoir fluid behaviour, i.e. the behaviour of cold and warm water and the addition of CO<sub>2</sub>. Apart from the economics, the geology and the possibility of CO<sub>2</sub> co-injection also, some aspects of the composite drilling technology and the well construction will be explained. Finally this appraisal is discussed and combined with conclusions.

### 2. REGIONAL GEOLOGY, STRUCTURAL FRAMEWORK AND RESERVOIR CHARACTERISTICS

#### 2.1 Regional Geological History

The subsurface below the Delft University of Technology belongs geologically to the West Netherlands Basin. This basin is bordered by the Zandvoort ridge and the IJmuiden high in the north and the London-Brabant Massif in the south. It merges with the Roer-Valley Graben in the south-east. The geological history of the relevant reservoir rocks covers the last 255 million years. According to De Jager (2007), the basin started to develop during the Late Permian on top of the Campine basin, and it continued to expand till the Late Cretaceous. Tectonic movements during the middle and Late Triassic resulted in extensive rifting, creating large-scale half-graben structures with NW-SE faults patterns. However, the strongest rifting occurred throughout the Late Jurassic to Early Cretaceous (Van Balen et al, 2002) and tilted faults block were formed.

During the Late Cretaceous compressive forces reactivated the older faults creating complex inversion structures and NNW-SSE trending fault systems. Thereafter, the basin slowly subsided to find its present-day configuration. During this continued subsidence, all previous structures have been covered under more than 1 km of sub-horizontal sets of alternating claystones, sands and coal/peat layers. These sets are associated to transgressive and regressive depositional environments. For geothermal energy implantation a subsurface aquifer with a good quality reservoir is needed. During the Jurassic, thick fluvial sediment packages were deposited in the half-grabens (Fig.1), which have formed the locations of most of the oil, gas and water reservoirs (De Jager et al, 1996).



**Figure 1: Characteristic trap situation in the West Netherlands Basin (WNB) revised after De Jager et al., (1996): Hydrocarbon traps show the potential layers for aquifers (hatched parts)**

For the purpose of geothermal energy, because of the temperature, the Lower Triassic and the Lower Cretaceous sandstones (Lokhorst & Wong, 2007) are the most favourable. They include our formation of interest, which is one of the deepest sandstone members, the Delft sandstone Member. This sandstone consists of stacked distributaries-channel deposits with massive sandstone sequences, (Van Adrichem Boogaardt & Kouwe, 1993) in a synrift tectonic setting.

## 2.2 Determination of the Geological Structures in the Delft Concession

In the past decades, 2D and 3D seismic data have been acquired to primarily explore the regionally oil bearing Rijswijk formation, about 200 meters above the Delft sandstone. For the geothermal concession below the Delft University campus grounds, the Nederlandse Aardolie Maatschappij (NAM), a major Dutch oil company, kindly provided pre-stack depth migrated seismic data. These were combined with well data of over 45 regional wells as well as other data; and integrated in a 3 dimensional earth model. This has been done using PETREL™ (PC-software that combines geophysical, drilling and geological reservoir data from various sources). This 3D model was then used to create a first static geological model (Fig. 2.).(Figure 2 can be found at the end of the paper.) Based on clear impedance

differences, the base North Sea group (top Chalk) and the Texel Marl member have been interpreted. They provide a first impression on the overall structure of the subsurface. Thereafter, the Delft sandstone was interpreted. Since most of the wells drilled did not penetrate the target sand, the exact depth is not easy to map. However, the conformably overlying Rodenrijs Claystone can be discriminated due to impedance differences with the underlying sandstone. (Van Adrichem Boogaardt and Kouwe, 1993). The top of the Delft sandstone is estimated with a geostatistic determination of the thickness of the Rodenrijs Claystone (about 50 meters), but the underlying Delft Sandstone is not always visible on seismic. The image shows an anticlinal structure of the Rijswijk sandstone member (Smits, 2008). The results reveal other tectonic features, such as regional faults, block faulting, erosion planes and other discordances that cross the stratigraphic zone in the area of interest. The overburden (1650 m) consists of Cretaceous, Tertiary and Quaternary chalks, limestones, claystones, clays, siltstones, and sandstones. No major structural elements, like faults, block faulting, erosion planes, etc., cross the Delft sandstone in the area of interest.

## 3. DETERMINATION OF THE AQUIFER DIMENSIONS AND TEMPERATURE

Several hydrocarbon exploration wells have been drilled around Delft, of which one on the University Campus. However, the Moerkapelle oil field, about 10 km north-east of Delft is considered to have a similar geological structure and situated in the Delft Sandstone as the Delft concession. Van Eldert, (2008) made an initial petrophysical study by combining and correlating the gamma ray log, neutron log, density log and resistivity logs of nine wells. This reservoir geological study provides detailed information about properties and characteristics of the Delft sandstone as a reservoir. These logs give results on reservoir mineral compositions, thickness of sand and claystone layers per well, variations in porosity and permeability per well and an assessment of the lateral continuity of the sand members. The preliminary results give for the Delft sandstone an average sand column of 51.25 m, with an average porosity of 15%. For a first appraisal, these numbers can be used for the Delft concession. When using these figures for the concession (61 km<sup>2</sup>), an enormous water volume for the Delft sandstone alone of ca.  $4.8 \cdot 10^8 \text{ m}^3$  will be available. The in-situ temperature of the area can be estimated by using the yearly average temperature (10°C) and geothermal gradient (ca. 3°C/100 m). For the concession it gives a temperature of 70°C to 82°C. To come to an accurate determination of the target temperature gradient, three approaches are used to determine a gradient (Fig.3). Bottom hole temperatures from the Moerkapelle wells, bottom hole temperatures from wells surrounding Delft and temperatures derived from TNO studies for a geothermal project in Den Haag and Bleiswijk, based on various data sources.(Smits, 2008). A temperature regression made with the bottom hole temperatures from the shallow (less than 1000 m depth) wells from the Moerkapelle field resulted in a gradient of 2.81 °C per 100 meter. They are not representative for the expected depth of the Delft sandstone (ca. 2300 m) due to the nonlinearity of the temperatures in the shallow subsurface. At greater depths the temperature gradient is linear and a regression based on bottom-hole temperatures of wells in the vicinity of Delft resulted in a gradient of 2.9 °C/100 m. However, due to the circulation of the drilling mud during drilling operations, some cooling occurs in the near well-bore area. Hence this bottom hole temperature linear curve predicts temperatures which are conservative, but based on hard-data. In TNO studies

(Simmelink et al., 2007) for the geothermal projects in Den Haag and Bleiswijk corrected bottom-hole temperatures were used. These depths can be associated with the Delft concession, giving a geothermal gradient of 3.11 °C/100 m (surface temperature: 10 °C). Plotting bottom hole temperatures with depth (Fig. 3) gives comparable results; about 81°C at 2300 m.

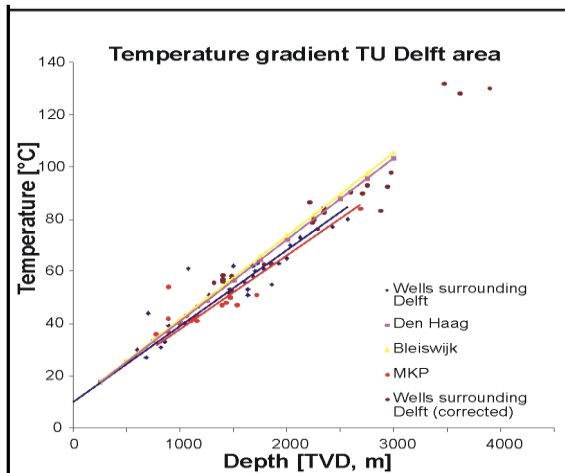


Figure 3: Different temperature gradients for the WNB from Smits, (2008)

#### 4. ECONOMICS OF A MULTIPURPOSE POWER PLANT

In the Netherlands geothermal heat has a long time not been more economically attractive compared to conventional heat from a Cogeneration Heat Power (CHP) plant. In order to compare the price for heat from a geothermal source to that from a conventional CHP plant it is critical to recognize that the price of a Giga Joule of thermal energy from CHP is related to the gas and electricity price at a certain moment in time. In a CHP plant gas is converted to electricity and heat. The electricity is sold on to the electricity grid and the heat is supplied to a local city heating grid. The cost of the thermal heat from a CHP plant is the sum of gas and operational expenditures minus the value of the electricity sold. (Bakker, 2008)

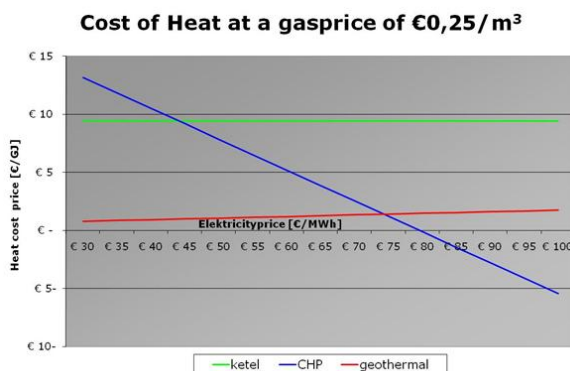


Figure 4: Different cost prices of heat at a set gas price for different heat sources. (Bakker, 2008)

Figure 4 presents the difference in cost price of heat, expressed in Euros per GJ of thermal energy for different sources versus the variable electricity price at a set gas price. Over the last 5 years the price for industrial gas and electricity in the Netherlands has fluctuated rapidly which badly effected the price of heat from CHP systems.

Industrial gas prices ranged from 19 euro cents up to 41 euro cents per cubic meter of gas. (Bakker, 2008) The cost of thermal heat from a geothermal source is only indirectly coupled to the fluctuation of the electricity price, through the electricity consumption of the pumps. Figure 5 presents the cost of heat throughout the day, in connection with the spot-market price of electricity, and visualizes a number of issues.

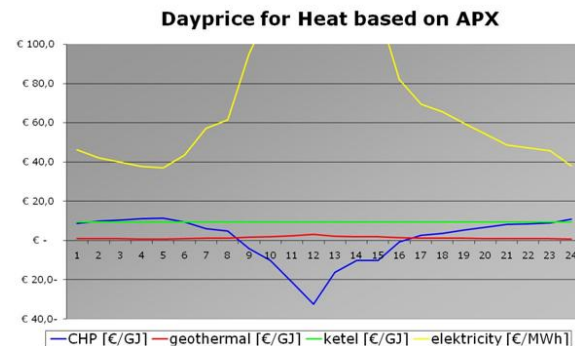


Figure 5: Different cost prices of heat based on daily profile APX for different heat sources. (Bakker, 2008)

Firstly, heat from a CHP plant is cheaper compared to geothermal heat when the electricity prices are high and the gas prices are low; such as during peak-demand of electricity during the summer when gas prices are low. Secondly, when the opposite happens, i.e. the gas prices are high and the electricity prices are low such as during the night in a cold period, geothermal heat is more economical. Seasonal fluctuations were taken in to account in the feasibility study. (Bakker, 2008) This counter balancing effect of heat price sparked the concept of a multi purpose power plant combining geothermal energy with a CHP plant to supply a mix of heat into the city: the so-called power hub. In this variation the geothermal energy is put into the gross energy mix as a base load of the heat generation as can be seen in figure 6. Because of this price and cost balancing effect, the higher investment on the combined CHP with geothermal system is compensated by the gains of the 30-years life-time of such a project. However, the model does not account for risk of geologic failure and complicated price forecasts for energy, but high gas prices favour geothermal. (DAP, 2008)

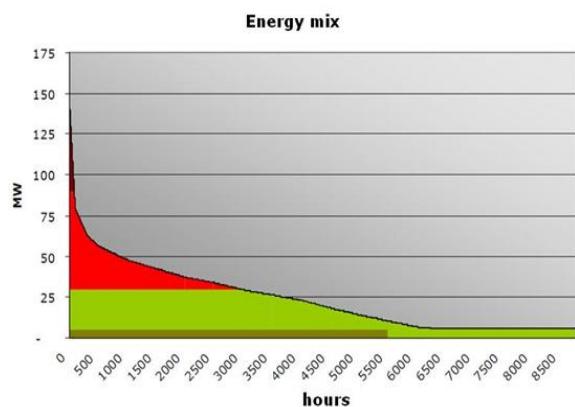
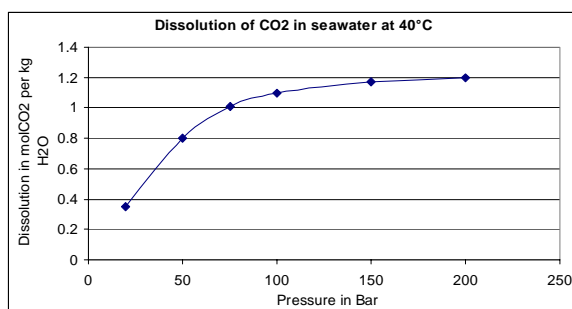


Figure 6: gross energy mix; heat supply in MW over time, Dark green is heat supplied by geothermal source, Light green by CHP, Red by gas boilers, Dark red by peak and backup gas boilers. (Bakker, 2008)

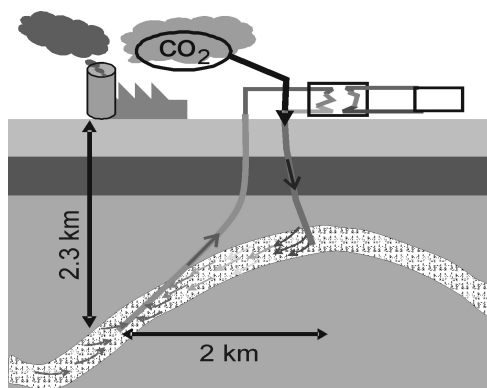
## 5. SURFACE INFRASTRUCTURE COMBINED WITH GEOTHERMAL ENERGY AND CO<sub>2</sub> CO-INJECTION

The University Campus has an on-site 79 MW power plant with two cogeneration units for base-load and three gas boilers for peak demand. Annually, Delft University consumes about  $11 \cdot 10^6$  m<sup>3</sup> of gas and produces circa 21605 tons of CO<sub>2</sub> of which ca. 15 ktons caused by electricity production. Now the heating system uses a distribution temperature ratio of 130°C-supply/80°C-return and a few percent distribution losses. When changing this ratio to more efficient lower temperatures of 90°C/70°C or even 55°C/40°C, distribution losses are lower and geothermal energy can contribute to the power supply. When implementing geothermal energy, the heat will contribute up to 5 MW continuously (95000 GJ), cutting CO<sub>2</sub> emission, while reducing costs for base-load heat production. A reduction of gas consumption of 3500 ton (and the associated emission of 9625 tons of CO<sub>2</sub>) can be achieved. To realize this reduction, the water production rate has to be ca. 150 m<sup>3</sup>/hr. When CO<sub>2</sub>, SO<sub>x</sub> and NO<sub>x</sub> are separated from the flue gas, they can be co-injected with the geothermal water. Assuming that the remaining produced 11980 tons of CO<sub>2</sub> can be separated and can be injected without seasonal effects, then the dissolution will be 0.2 mol/l or  $9 \cdot 10^{-3}$  kg/l. According to Duan and Sun (2003) these concentrations are very stable under in-situ conditions



**Figure 7: Maximum dissolution versus fluid pressure for CO<sub>2</sub> in seawater at 40 °C (After Duan & Sun, 2003)**

Duan and Sun (2003) found for seawater, at 40°C and 200 bar a CO<sub>2</sub> fluid pressure dissolution of 1.2 mol/kg of water, which is about six times higher as supposed to be injected. If capture is possible and well integrity and injectivity are satisfactory, it will result into the development of a Zero Emission Power Plant (ZEPP) (Fig.7), (Fig.8.).



**Figure 8: Concept of a zero emission heat power plant, supported by geothermal energy supply, CO<sub>2</sub>-capture and sequestration in a aquifer**

## 6. WELL CONFIGURATION AND UNCONVENTIONAL DRILLING

The geothermal production well is planned to produce in the order of 150 m<sup>3</sup>/hr of water. For these amounts, a large-diameter well will be essential. A wire wrapped screen will be placed to prevent reservoir sand production. The water is brought up through an electrical submersible pump (ESP) hung off in the top part of the well at 300-500 m depth. It is lowered on its electrical power supply with a winch. Formation fluid is produced through the well, circulated through a heat exchanger and re-injected at about two km distance in the same subsurface formation. In this way a closed circulation of the water with minimum electrical energy consumption is obtained. For optimal heat gain, the production- and injection well have to be co-located with the power-plant. However, in urban environments small operational footprints are essential for drilling a production- and injection well. This gives spatial constraints and the drilling of conventional 2 to 2.5 km deep large-diameter holes requiring heavy equipment should be avoided. Nevertheless, by using new light-weight composite materials for wells in combination with casing drilling technology, only small drilling rigs are required. The composite material (Fig.9) is less susceptible to corrosion and enables the co-injection of CO<sub>2</sub> with the returning water (Wolf et al., 2008).



**Figure 9: Composite tubing developed by Delft University, WEP and Airborne and proposed by Acquit, to be used as an innovative alternative drilling/well option for steel tubing**

The mentioned casing drilling with composite pipe finds its origin at Delft University together with WEP and Airborne, and is further developed by an industrial consortium (Acquit BV). It is a light weight concept where a composite casing pipe is combined with the casing drilling methodology. This almost buoyant casing pipe needs considerably less working space and existing civil pile drilling units can be used to drill wells (Leijnse, 2008). The application of the casing drilling technique can be very time efficient. However, the risk of getting differentially stuck is considerably higher than with conventional drilling techniques. Casing drilling does have a 'smearing effect'; the collars passing the formation reinforce the borehole wall, reducing losses and differential sticking. In all, the composite casing reduces hole and circulation friction. However, the casing is more flexible, making directional control of the well more difficult. The composite casing pipe has a better insulation, improved skin and a better endurance for corrosion (CO<sub>2</sub>-rich return water). In addition, for long term monitoring purposes it is possible to implement P,T-sensors. Overall construction and operation costs can be significantly reduced over the life-time of a project, but the composite casing itself will be more expensive.

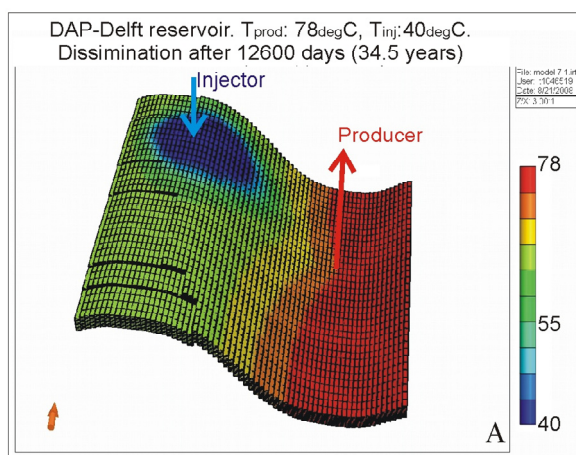


## 7. TWO PHASE PLAN FOR CO<sub>2</sub>-INJECTION

Delft University has applied for the geothermal exploration license under and around its campus grounds. The “first phase” exploration is focusing on the construction of a conventional geothermal system with innovative material and drilling technology. In the second phase, a research program for CO<sub>2</sub> capture and storage will be realized. For removing the CO<sub>2</sub> from the power plants’ flue gas, several capture techniques are studied. One of the options is adding CO<sub>2</sub> at low pressure (about 20 bar) as being maximal 10 vol.% of the re-injected water volume (Smits, 2008). Gas will diffuse into the water achieving undersaturated conditions before it reaches the target member (Duan & Sun, 2003). Since the local sedimentological characterization of the reservoir is not fully comprehended yet, it is considered as a homogeneous sheet without interruption by faults or environmental discontinuities. In the first phase, geothermal water will be used to contribute up to 5 MW continuously (95000 GJ), cutting CO<sub>2</sub> emission with 9625 tons, while reducing costs for base-load heat production. In a second phase, it is planned to start co-injection of CO<sub>2</sub> together with the re-injected water. This suggestion follows the idea of Pruess (2006) to inject high pressure CO<sub>2</sub> in a geothermal reservoir in order to mine heat. The ambitions in this project are less pronounced, i.e. heat mining with water and co-storage of low pressure dissolved CO<sub>2</sub> with re-injected water. The method of CO<sub>2</sub> capture is a major research project at Delft University. As an alternative for the use of a conventional amines process, alternatives are proposed such as membrane technologies (Scholes et al., 2009). Another option is co-injection of CO<sub>2</sub>-clathrates at appropriate depths (Golombok et al., 2008).

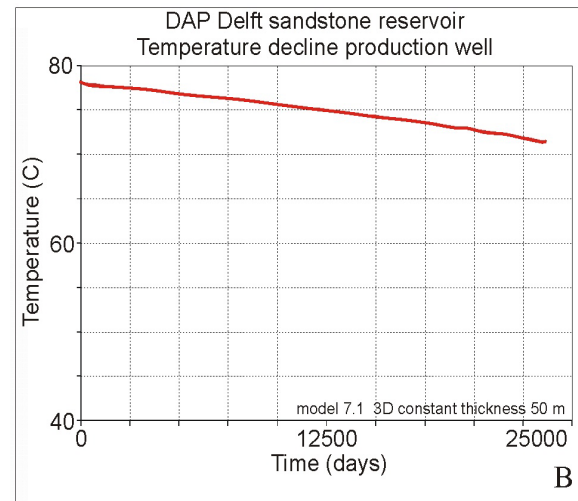
### 7.1 Reservoir Behaviour without CO<sub>2</sub> co-Injection

Smits (2008) modelled the reservoir on its caloric capacity. For modelling reasons, the size of the reservoir for the Delft Geothermal project is represented by a 3600 by 3300 meter area, and it was calculated that the thermal breakthrough fully depends on the well spacing when less than 2000 meters. The geophysical interpretation suggests that the Delft sandstone may vary in thickness, having thinner layers at the colder top of the anticline-like structure and thicker ones at the warmer bottom. A series of scenarios with variations in layer thickness and permeabilities were modelled using the dynamic reservoir simulator (STARS).



**Figure 10: Reservoir modelling; example of Geothermal water production and CO<sub>2</sub>-enriched water injection. Temperature distribution after 34.5 years in a homogeneous layer (Smits, 2008)**

All scenarios used the same basic parameters; injection point - top anticline temperature, 76°C; production point - bottom anticline temperature, 80°C; well distance, 2000 m; production area, 3600 m x 3300 m (Fig. 10); temperature dependent density and CO<sub>2</sub>-sorptions were ignored. The models show that the largest effect on the thermal breakthrough is realized when a thickness variation is applied in the models. An assumed larger thickness at the bottom of the anticline gives a considerable increase in the volume of the caloric source, and by that a slower cool down (Fig. 11).



**Figure 11: Example of temperature decline versus time at the production well (Smits, 2008)**

For a homogeneous reservoir, it results after 65 years in an irrelevant temperature drop at the production well of 1.5 °C. To assess the importance of heterogeneity 3-D simulations were run with a high-permeability layer parallel to the flow direction. This creates an earlier thermal breakthrough and a temperature drop of 2°C after 28 to 30 years.

### 7.2 Reservoir Behaviour with CO<sub>2</sub> co-Injection and the Cool Down Effect

When co-injection of 12 ktons of CO<sub>2</sub> annually is feasible, we have to add the 0.2 mol/l or 9·10<sup>-3</sup> mg/l of CO<sub>2</sub> dissolved. Further, in our models we have to include that the injected colder water is heavier (22 kg/m<sup>3</sup>) than the original water and that it migrates downward along the anticline. Den Boer (2008) developed with COMSOL a reservoir simulation model, following Stopa et al. (2006) and studied the mechanisms occurring during injection and the prediction of the thermal breakthrough. The aquifer fluid is a brine with a high salinity (table 1) (Because of the size table 1 can be found at the end of this paper), corresponding with a 8 wt% NaCl aqueous solution. Hence, the 9 ppm dissolved CO<sub>2</sub> is not included as a part of the gravity issue. For the reservoir and a 2000 m well distance, it is calculated that flow driven by the density difference between the cold injected water and the warm reservoir water occurs. The results are comparable with the production temperature predictions of Smits (2008). When considering fluid flow and heat transfer between the wells in the reservoir, it is calculated that the currently planned 2000 meters will give an initial temperature change in the production well after circa 44 years. With a lifetime of the wells of 30 to 40 years the calculated optimal spacing can be reduced to 1500 m to 1600 m. When the use of temperature dependent rock and fluid properties is included (Fig. 12), the results give the same thermal breakthrough time.

However, they also give a better post-breakthrough behaviour, in terms of a higher temperature for a longer period. An initial study on reservoir heterogeneity shows that the thermal front movement follows the fluid flow with a certain lag. It was found that the combination of heterogeneity and temperature dependant fluid properties shows viscous cross flow which slows down the thermal breakthrough itself.

## DISCUSSION AND CONCLUSIONS

This preliminary study shows the feasibility of the Delft Sand reservoir below Delft, to contain ample water and geothermal energy to produce continuously warm water of about 80°C and to co-inject CO<sub>2</sub>, continuously for a lifetime of 40 years. A commercial feasibility study shows that a geothermal system can be added to a cogeneration heat power plant to enhance the economical performance and peak shave the risk caused by fluctuating gas and electricity prices, making a energy mix heated city heating grid from a multi purpose power plant promising. When capture of CO<sub>2</sub> is feasible, it means that the power plant of Delft can be considered a zero emission power plant. The intention is to prepare a zero emission power plant. Still, not all energy consuming activities have been included. Power needed for the production and injection of geothermal water and the energy required for CO<sub>2</sub> capture and transport have been ignored. We assume that this increase will be in between 10 to 20 % of the total. The additional amount of CO<sub>2</sub> can easily be co-injected without exceeding the maximum amount that can be absorbed by the water. In this way, the co-located energy systems become fully sustainable and a zero-emission power-hub is achieved. The geophysical and reservoir geological data combined with the initial reservoir modelling results made clear that gravity effects and heterogeneity of the reservoir are no show stoppers. However, several aspects, which may hamper the production and injection of water, have to be discussed. Following the IPCC-report on CO<sub>2</sub> Capture and Storage (2005), several questions have to be answered and solved before CO<sub>2</sub> co-injection can start.

### Reservoir Geology:

A more detailed sedimentary environment has to be established. Already concluded from De Jager. (2007), the Moerkappelle reference oil field is located near the horst on the northern boundary of the basin. The Delft concession is

situated more central in the basin. Here the sedimentation rate was higher, and more channel sands can be expected. Wiggers, (2009) shows that the thickness of the Delft Sandstone member in the Delft Concession is approximately twice as thick as the Delft Sandstone Member in the Moerkappelle oil field. Furthermore, the burial history below the concession is of importance, for example; what will be the degree of compaction or degree of cementation in the sandstone caused by percolating ground water?

### Geology-Petrology:

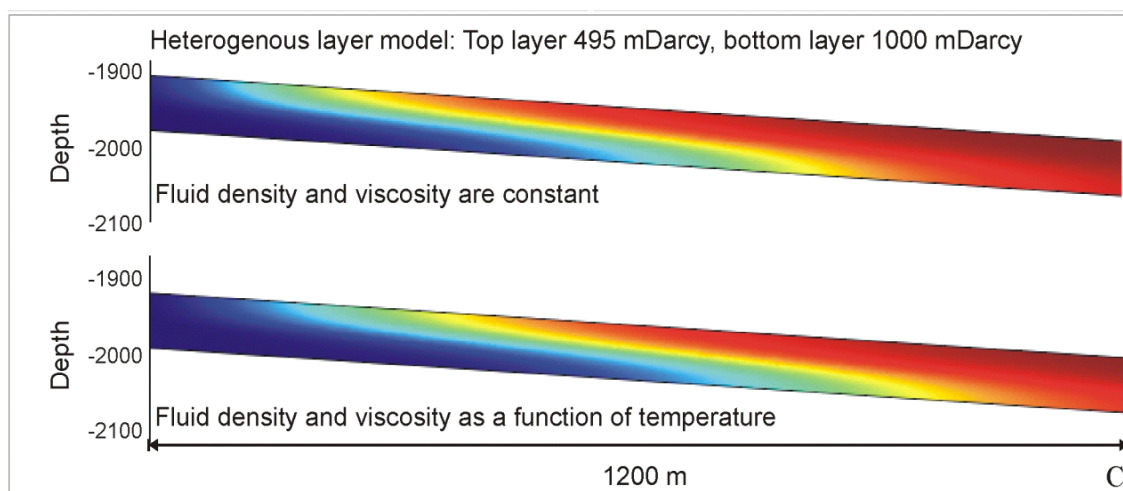
What is the effect of CO<sub>2</sub>-enriched water on the reservoir rock and overburden? Will there be dissolution and remineralisation; when, how and where? Mineralization of CO<sub>2</sub> with Fe-minerals into Fe-carbonates can be an advantage since CO<sub>2</sub> will then be extracted from the injected water.

### Well Integrity and Production/Injection:

The high production rates may induce sand and fines production. What will be the effect of these particles in the production well and in the injection well? Do the fines induce clogging and by that loss of injection? The first studies show that an average production and injection rate is feasible. Since the power plant has seasonal fluctuations in CO<sub>2</sub> production, variations in CO<sub>2</sub> co-injection must be feasible. About six times the average concentration (Duan and Sun, 2003) can be injected before dissolution of CO<sub>2</sub> stops. It means a lowering of the pH, which may affect the injection point. Increase in CO<sub>2</sub> concentration does not mean that it can escape and migrate through the cap rock to the surface; the gas is stable sorbed into the water.

### Drilling Technology:

We propose several technical novelties for drilling and CO<sub>2</sub>-injection. The first study shows that the concept is feasible. The application of the new techniques, the casing drilling, and drilling with composite pipe make it possible to reduce the total well cost, making the use of geothermal energy more interesting in comparison to natural gas. However, the drilling of a well is associated with several risks, such as H<sub>2</sub>S, shallow gas, differential sticking, mud losses and well control. Also, long term injection has to be investigated; the time effect of CO<sub>2</sub> on the tubing, (surface) infra structure and pumping equipment.



**Figure 12: Differences in gravity flow between the injection and production well in an inclined heterogeneous reservoir, without (top) and with (bottom) temperature dependency (Den Boer, 2008)**

For the drilling safety the blow out preventers are vital. Testing has been done on closure around composite pipe. The shearing aspect also has to be tested. The connection procedure is another focus point; simulation studies of the string behaviour have to be done. The use of these new technologies can be very successful, reducing rig size, rig time and by that reducing the total well costs.

In all it can be concluded that the preliminary studies by Smits (2008), de Boer (2008), Leijnse (2008), Van Eldert (2008), and Wiggers (2009) show promising reservoir qualities for the sandstone member; high permeability, high porosities and ample amounts of geo-energy and CO<sub>2</sub> reservoir capacity. At a depth of circa 2300 m, it is expected to produce water with a temperature of about 75°C to 80°C. A production- and injection rate over 150 m<sup>3</sup>/hr should be feasible. With carefully planned production- and injection wells, the original warm water and colder CO<sub>2</sub>-saturated re-injected water will not interfere for at least 30 years. If the proposed technology is successful, it can be translated to small ZEPP configurations for glasshouses. Then a serious national reduction in energy consumption and CO<sub>2</sub> emission should be feasible. In that case, more doublets will use a geothermal source and multiple production and injection wells may cause interference. The reservoirs are considered to be very large closed systems where local pressure differences and interference may improve the energy efficiency. We only discussed the Delft sandstone member. Other members with even greater storage capacities are present and multi-layer exploitation could be an option. As a whole, geothermal energy combined with CO<sub>2</sub>-injection looks very interesting and a economically feasible, environmentally sustainable multipurpose plant very promising.

## NOMENCLATURE

CHP	Cogeneration Heat Power (plant)
DAP	Delft Geothermal Project
ESP	Electrical submersible pump
NAM	Nederlandse Aardolie Maatschappij
WNB	West Netherlands Basin
Zepp	Zero Emission Power Plant

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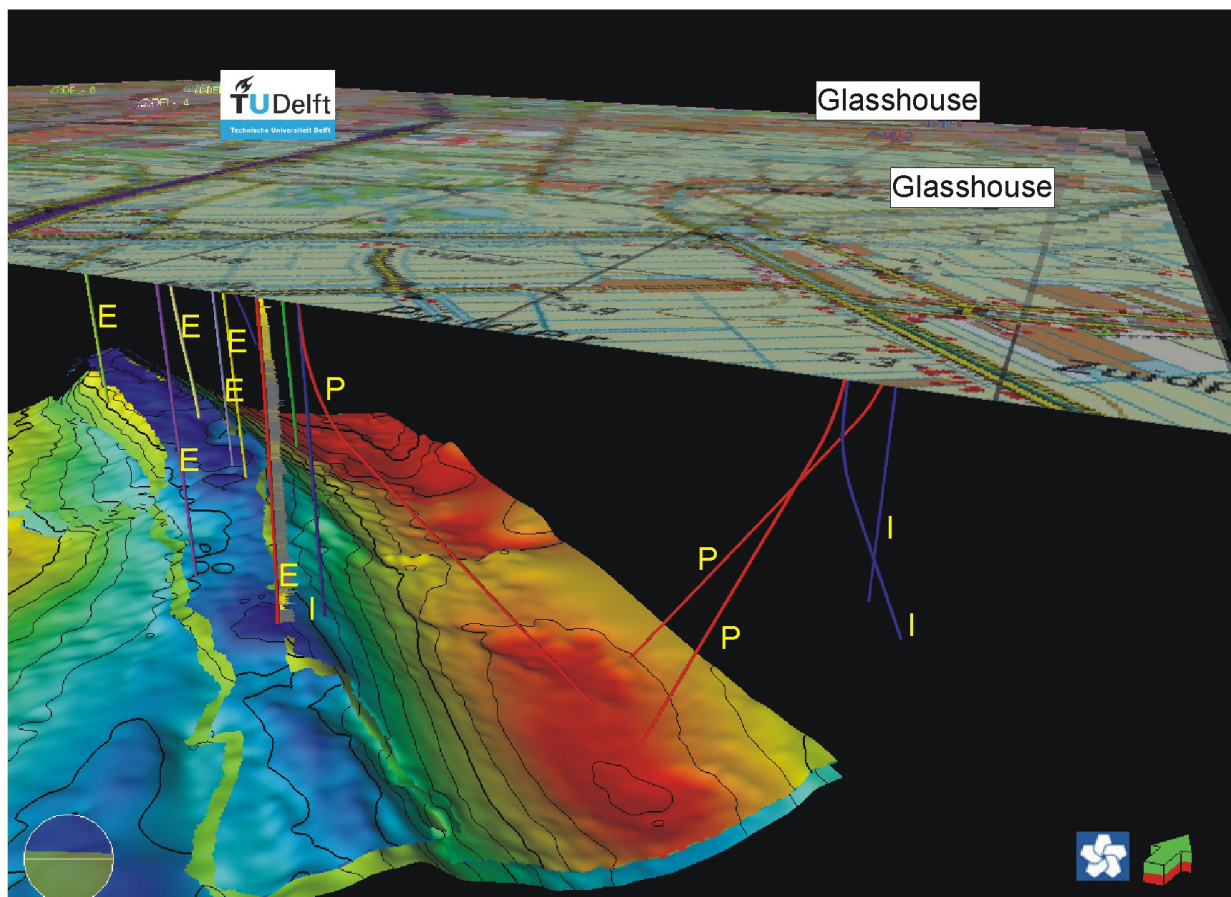
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**Table 1. Chemical Composition with the Salinity of Water as Found in Cretaceous Aquifers.**

Parameter	De Lier (Zuurdeeg 1983) [g/l]	Lower Cretaceous (Collins, 1975) [g/l]
Na+	36,3	31,0
K+	0,20	0,13
Ca <sup>2+</sup>	3,6	7,0
Mg <sup>2+</sup>	0,8	0,9
Sr <sup>2+</sup>	0,58	0,2
Ba <sup>2+</sup>	0,035	0,040
Fe <sup>2+</sup>	0,033	-
Cl-	55	62
SO <sub>4</sub> <sup>2-</sup>	0,15	0,28
H <sub>3</sub> PO <sub>4</sub>	0,02	-
H <sub>4</sub> SiO <sub>4</sub>	0,06	-
HCO <sub>3</sub>	0,02	0,26
TDS	~97	~100



**Figure. 2: Interpretation of the sub-surface based on appraisal wells (E) and seismic lines. An artistic impression of the injection (I) and production (P) wells in the sand member of relevance**