



**Faculty of Engineering Science and Technology  
Department of Petroleum Engineering and Applied Geophysics**

# **Temperature calculations in production and injection wells**

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## Preface

This report is the product of the project work part of the subject TPG4705 Petroleum Production Specialisation that is compulsory the last year of the Master of Technology education at NTNU. The subject consists of one part of theory subject modules of in total 7.5 credits, and the project work part of 15 credits. The project work has been performed at the Department of Petroleum Engineering and Applied Geophysics, with Jón Steinar Guðmundsson as supervisor.

The project work has consisted in learning to use TempEnn, HYSYS, setting up an organized spreadsheet, acquire theoretical knowledge about all aspects involved, analysing the results, and writing this report.

I want to mention that I have been selective in presenting raw data in the appendix, since the files generated by the programs (and spreadsheets of the equation) are very similar. I have tried to point out the important details and what are the changing parameters from time to time.

I would like to thank Jón Steinar Guðmundsson for guiding me in the process of finding the best method of temperature calculations.

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## Abstract

Temperature development in wells is a field with very few publications. It is nonetheless a field with major implications. To be able to predict where hydrate plug formation might occur in a gas pipeline, and then to know where to put in the hydrate inhibition action, it is of great importance to know the gas temperature at the wellhead. Also in exploitation of geothermal energy it is important to know how the temperature of the injected water will develop. This paper presents three methods for well temperature calculations. The methods are; an analytical steady state equation; a stand-alone Fortran program, TempEnn; and HYSYS, a commercial steady state process simulation and modeling application. The objective of this project is to apply these three totally different methods for temperature calculations on two case studies, and compare their performance. A minor goal was also to put in place necessary instructions so that students easily can run TempEnn. The case studies involve injection of water in an onshore well (case 1), and production of gas from one of the Ormen Lange gas wells (case 2).

The steady state equation and TempEnn do not include the Joule-Thomson (JT) effect. This effect involves cooling of gas when the gas expands. The neglect of the JT effect can lead to a too high calculated temperature, when calculating the pressure profile in a producing gas well. This is a major drawback when calculating in a gas well, like in case study two, but is insignificant when calculating the temperature profile in a well with incompressible liquid, like water in case study one. In the first case study, the performance of TempEnn and the steady state equation are compared. They give pretty much the same results. In the second case study, the equation and TempEnn follow each other close, but the results from these two methods deviate from the HYSYS results. This is probably caused by the neglect of the Joule-Thomson effect in both TempEnn and the steady state equation.

TempEnn is written as a non-steady state program, but still needs new time-input for every change in time. It will however, calculate its own overall heat transfer coefficient, which is a major advantage compared with the two other methods. HYSYS is a steady state program, like the steady state equation. In this paper, the only input parameter changing with time is the U-value, besides the time span itself. Both HYSYS and the equation are somewhat impractical, because they are steady state, and do not handle changing time spans very well. Using TempEnn is also somewhat impractical, as the time-input needs to be changed manually.

When calculating the temperature profile in a well with incompressible fluids, TempEnn seems to be the best alternative, because it calculates its own U-values, and it can manage a time-dependent temperature change. When calculating the temperature profile in a well with compressible fluids, HYSYS seems to be the best alternative, but it has to be fed with time-changing U-values. A combination of TempEnn and HYSYS might seem like the best way to continue. If it was possible to implement the transient solution of the temperature equation in HYSYS, this would be the best way to continue.

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## 1 Introduction

When a fluid flows in a pipe, the properties of the fluid will be affected by the rate of flow, pipe diameter, pipe roughness, the angle of the pipe and the properties of the surroundings etcetera. When calculating the temperature profile of a well fluid, the friction is not so important (ref Ivarrud), but the temperature in the surrounding formation is of great importance for the temperature development in well fluid. Also the heat flow properties of the surrounding formation and of the casing, cement and so on are important factors.

When it comes to temperature calculations of well flow, little has been published, to the authors' knowledge. It is of great importance however, both in the prevention of hydrate plug formation and exploitation of geothermal energy. When designing production equipment it is also important to know the temperature of the well flow to be able to maximize the performance.

Hydrate plug formation in a well is not something that happens often. But it is of great interest to know the well flow temperature at the wellhead to be able to predict if there is a chance of hydrate plug formation in the subsea pipeline. And if so; where in the pipeline it is most likely that this formation will occur. [Sloan]

This project is not aimed to find the exact temperature profile of one specific field. But rather to test different methods and to figure out which one is best to use in which situation. Three methods have been used:

- A steady state equation
- TempEnn
- HYSYS.

The steady state equation was developed for calculating the pipeline temperature in the end of a pipe, when the temperature of the fluid flowing into the pipe was known. The equation was meant to be used in a pipeline with a fixed ambient temperature and a non-compressible fluid. The equation has been adapted to be used in an environment with a changing ambient temperature. The changing temperature is calculated stepwise in this method.

The TempEnn program is a program developed in the Fortran language at the NTNU in the autumn of 1995. The development was done for offshore oil wells and includes an algorithm that calculates convective heat loss. [Ivarrud]

HYSYS is a steady state process simulation and modeling application with a graphical user interface. It will be used for steady state calculations of the temperature of the well fluid at different depths in one of the Ormen Lange wells.

Before the comparison of the methods was done, the steady state equation and TempEnn program were tested with an imaginary case. After this all three methods are compared by applying them on two case studies. The case studies include two vertical geothermal exploitation wells and one of the wells in the Ormen Lange gas field. The two geothermal wells are both imaginary but the figures in the calculations are realistic in the sense that the wells might be drilled for this purpose [NN, personal communication].

## 2 Literature review

As mentioned in the introduction there is not much published in the field of well flow temperature calculations. However there is the classical work of H.J. Ramey who in 1962 presented an approximate solution to the transient heat conduction problem involved in movement of hot fluids through a well bore. His solution assumes that heat transfer in the well bore is steady-state. Ramey's solution also assumes that heat transfer to the earth will be unsteady radial convection and it also considers the affect of thermal resistance in the well bore. The solution permits estimation of the temperature of fluids, tubing and casing as a function of depth and time. In 1967 G.P. Willhite improved the heat transmission model. He provided a detailed method for calculating the overall heat transfer coefficient ( $U$ ) for the completion in terms of natural convection, conduction and radiation. This coefficient is critical for estimating the temperature profile in the well.

In 1991 Alves et al. apply steady state mass, momentum and energy balance to the differential control volume. This approach leads to their unified model for predicting flowing temperature distribution in wellbores and pipelines. They claim that the model can be used for all inclination angles for either single phase or two phase flow. The equation can be simplified to the one Ramey derived in 1962 (for ideal gas or incompressible flow) under the appropriate conditions. Alves et al. acknowledge the need for an overall heat transfer coefficient which incorporates the resistance to heat flow in the well bore due to the presence of the tubing wall, tubing insulation, fluid in the casing-tubing annulus, casing wall and cement. They do not, however, make any effort to find a model for this coefficient, but refer to Willhite and others who have suggested methods for the determination of this coefficient. Several groups have tried to find simple expressions for the overall heat transfer coefficients, and also calculated the  $U$ -value under different conditions. These are listed in Table 1. Two of these groups found a single  $U$ -value, while Hasan and Kabir found a  $U$ -value indirectly dependent on the well depth. They claim that the overall heat transfer coefficient is much smaller at the bottom hole than at the wellhead. The marked variations in  $U$ -values with well depth is a direct result of the contribution of the natural convective heat transfer coefficient. Because of small temperature differences between the tubing fluid and the soil near the bottom hole, the temperature difference across the annulus is small. This leads to a smaller value of  $U$ . At the wellhead, the reverse is true, resulting in a much larger overall heat transfer coefficient (see also Table 2).

Also in 1991, Hasan and Kabir found an approximate algebraic expression for the rigorous integral solution of dimensionless formation temperature,  $T_D$ . The results of their analysis are in agreement with the classical work of Ramey for large times (dimensionless time,  $t_D > 10$ ). However, significant differences are noted between the proposed solution and that of Ramey's log-linear approximation at small ( $t_D < 10$ ) times. [Hasan, part I] This conclusion is supported by J. Hagoort in his 2004 paper.

In Part II of Hasan and Kabir's 1991 paper they come to a method that incorporates a new solution of the thermal diffusivity equation. This equation was developed in Part I. The method also incorporates the effect of both conductive and convective heat transport between the well bore and the formation. A sensitivity study showed that significant differences exist between the predicted wellhead temperature and the surface temperature, and that the fluid temperature gradient is nonlinear. Their study further shows that an increase in free gas causes a lowering of wellhead temperature due to the Joule-Thomson (JT) effect. In such cases, the expression for fluid temperature developed by Ramey for single-phase flow should not be applied, they say, when multiphase flow is encountered.

In April 2005 I. Marić presented in his paper a numerical method to calculate the Joule-Thomson coefficient of a natural gas. He says that the magnitude of the JT coefficient of a natural gas depends on the natural gas composition and varies with temperature and pressure. His calculations on a natural gas containing 86% methane can be seen in Figure 1. [Marić]

### 3 Calculation methods

Three calculation methods are tested in this project to see which method is best applied in which situation. An analytical steady state equation was first tried. This steady state equation has been developed for calculating temperature in pipeline flow. A stand-alone Fortran program, developed in 1995 for temperature calculations in oil wells, was the second method tried. HYSYS a steady state process simulation application was the last method to be tested. In this chapter, the different methods are introduced, some tested separately and all compared in case studies.

#### 3.1 Steady state equation

A steady state equation has been developed for calculating temperature in pipeline flow. This steady state equation will be applied in computing well flow temperature to see if that will yield satisfying results.

Temperature in the formation will be influenced by well flow. A pipeline on the sea bed will, in contrast, not influence sea temperature. Ambient temperature in a well increases with depth. This increase is dependent on the geothermal temperature gradient,  $\alpha$ , expressed in °C/km. A Typical value for  $\alpha$  in the North Sea is 30°C/km [Ivarrud]. This geothermal gradient will be assumed independent of rock type, density and other parameters, and will therefore be the same all the way from sea bed to bottom hole. Given this geothermal gradient in a 3000 meter deep well, the ambient temperature in the bottom hole is about 90°C while at the wellhead it will be around 4°C, the typical sea temperature at the sea bed. This equation is dependent upon the overall heat transfer coefficient (U), which in the pipeline flow calculations will be considered constant. As shown in the literature review, this is not necessarily true for well temperature calculations, but will, for this case, be considered correct. The equation is further dependent on the temperature of the fluid flowing into the pipe or the well; the mass flow rate; the diameter of the pipe; and the heat capacity of the fluid flowing in the pipe. The temperature of the fluid flowing out of the well will also be affected by pipe length or well depth.

The equation is written for pipeline flow, and not meant for well flow. The fact that it is a steady state equation makes it inadequate for use over time. Whilst seawater has the ability to compensate for temperature changes, the rock formation has not. Thus, the formation temperature will be influenced by well flow. The temperature change in the formation will arise in close proximity to the production or injection well and will be dependent on the exposure time.

Formation fluid temperature will, in most cases, be equal to the temperature of the formation it originates from. The difference between the *formation* temperature at bottom hole and at wellhead is bigger than difference between *fluid* temperature at bottom hole and wellhead (Figure 2). While the fluid is moving towards the wellhead it will lose heat to the formation. This heat transfer is smaller at the bottom hole than at the wellhead. The

temperature difference, between fluid and formation, is small at the bottom hole and large at the wellhead. Even if temperature in the fluid is decreasing on the way up, the increasing difference in temperature between formation and fluid gives rise to an increasing heat transfer. This increase in heat transfer can be described by an increase in the overall heat transfer coefficient (U). U: overall heat transfer coefficient, considers the net resistance to heat flow offered by fluid inside the tubing, the tubing wall, fluids or solids in the annulus, and the casing wall. Several groups have tried to derive U and some of these are summarized in Table 1. Hasan and Kabir have derived a depth dependent U value, shown in Table 2.

It was expected that iterations were necessary. So the first part of this project was to set up a hypothetical situation to find out if this is true. The iteration with the equation was done for an injection case where well depth, mass rate and so on, were picked more or less at random. Different heat transfer coefficients could/should have been used while calculating with the steady state equation, to take in account the changing temperature difference. According to Hasan and Kabir's model, different heat transfer coefficients should have been used at different depths, in the steady state equation. This could be done since iterations are used in the calculations. However, deriving different values for U was outside the scope of this project. Therefore, the single value calculated by TempEnn was used in the calculations with the steady state equation.

What is done in the iteration? The well is split into x amount of segments.  $T_x$  is the temperature of the fluid coming *out* of one segment and becomes the *in* temperature for the next segment ( $T_{x-1}$ ). The equation from Guðmunsson has been adapted for use with a changing ambient temperature ( $T_{amb}$ ):

$$T_x = T_{amb} + (T_{x-1} - T_{amb}) \exp\left[\frac{-U\pi d}{mC_p} \Delta L\right] \quad (3.1)$$

where d is the well diameter, m is the mass rate of the fluid,  $C_p$  is the heat capacity of the fluid and  $\Delta L$  is the segment length.

$$T_{amb} = T_{sb} + \alpha L \quad (3.2)$$

Here L is the length from the sea bed to the middle of each segment,  $\alpha$  is the geothermal temperature gradient and  $T_{sb}$  the water temperature at the sea bed.

Even though the equations mentioned above are relatively easy to understand, it is hard to use them in a program like Microsoft Excel. To make working with them easier, the following adaptations have been made:

$$T_x = (T_{sb} + \alpha L_B) + (T_{x-1} - [T_{sb} + \alpha L_B]) \exp\left[\frac{-U\pi d}{mC_p} L_s\right] \quad (3.3)$$

$$L_B = \left(\frac{L_s}{2} + (x-1) * L_s\right) \quad (3.4)$$

$$L_s = \frac{L}{\#segments} \quad (3.5)$$

Where  $L_B$  is the length from the sea bed to the middle of each segment ( $L$  before),  $L_s$  is the segment length, and  $x$  is the amount of segments/iterations.

The first thing to do is to find the  $L_s$ , which is the total length of the well divided on the amount of segments in the particular calculation. In Figure 3 a 3000 meter deep well is split in three segments. The wellbore is shown to the left, with the geothermal gradient to the right. Where  $T_{amb}$  expresses the mean ambient temperature of that particular segment, and  $T$  is the temperature of the fluid flowing out of the same segment. The next step is to find the average temperature for the specific segment, by finding the mean length of the segment. Then the out-temperature for that specific segment can be calculated, and this temperature becomes input as the in-temperature for the next segment. The results of these iterations can be seen in Figure 4 and Table A-1. In this particular example the temperature increase is so small that it makes almost no difference whether 1 or 30 iterations are used. In the case studies this is different: as shown in Appendix A-2 it seems necessary to split the well in around five segments to achieve an accuracy of 1°C.

When the produced fluid loses heat, the heat loss might not only be due to heat transfer between the fluid and the formation. The Joule-Thomson (JT) coefficient ( $\mu$ ) determines the amount of heating or cooling caused by pressure changes within a fluid flowing up the well. For the typical range of temperatures, pressures, and two-phase fluid mixtures encountered in a flowing well, JT cooling is much more significant than JT heating. Joule-Thomson heating would typically occur in some gas condensate systems and could be determined from the mixture composition. Joule-Thomson cooling is usually associated with a higher gas component in the two-phase mixture. The general conclusion that can be drawn from these trends is that wells having relatively high liquid hold-ups, caused by either lower gas/liquid ratios or higher wellhead pressures, will experience little JT cooling or heating. However, for wells operating with low liquid hold-ups, Joule-Thomson cooling could be much more significant. [Sagar, 1991]

This is a steady state equation, and will therefore not yield results in time. Another disadvantage of the equation is that it does not take in account the Joule-Thomson effect.

The results from the calculations with the steady state model are, in Figure 5, compared to the results from the program TempEnn. After an introduction to this program this comparison will be discussed.

### 3.2 TempEnn

TempEnn is a Fortran program that was created at NTNU in 1995 by the master of science student Endre Ivarrud. The program is written in Fortran 77 language for use in a Unix environment. The program was created for calculating temperature in production wells; this program was extended for use in injection wells in 1996. How to use the program is explained in Appendix B3. The program is based on a model that calculates temperature in production wells. The new model is built on an analytical solution. The model calculates transient heat loss semi analytical in the formation. A new algorithm that calculates convective heat loss in annulus has also been implemented. Sensitivity analysis shows that production rate is the dominating factor in temperature calculations. Friction has small effect on decrease in temperature at normal rates. [Ivarrud]

Ivarruds model for calculation of well fluid temperature includes heat transfer in the formation, in the riser in sea and in the riser in air. In this project only onshore wells and wells going to the sea bed will be considered. There are different heat transferring mechanisms that causes heat transfer in each of the different parts. Ivarrud assumes that conduction is the dominating heat transfer mechanism in the formation and that convection is the dominating mechanism in water and air. But as in this project only production to the sea bed has been considered, only conduction has been used.

The overall heat transfer coefficient calculated by TempEnn is dependent on time and the heat conductivity of each of the substances like steel in tubing and casing, cement and water that isolates the well fluid from the formation.

$$U_{TOT} = \frac{1}{\frac{1}{U_T} + \frac{1}{U_K}} \quad (3.6)$$

Where  $U_{TOT}$  is the overall heat transfer coefficient and

$$U_T = \frac{k_E}{r_w} * f(t) \quad (3.7)$$

$f(t)$  is the transient solution of the temperature equation;  $k_E$  is the conductivity of the formation;  $r_w$  is the well radius. And the conduction through the completion is based on a general formula for conduction through radial geometry [Ivarrud]

$$U_K = \frac{1}{r_0 \sum_i \frac{1}{k_i} \ln\left(\frac{r_{i+1}}{r_i}\right)} \quad (3.8)$$

Here  $i$  indicate different layers with their own heat conductivities.

In Ivarrud's paper he explains that in a production well the temperature difference between formation and well fluid will increase towards the wellhead. This he says will lead to an increase in the heat transfer rate. It is thought that this increase in heat transfer coefficient will lead to an increase in the overall heat transfer coefficient, this is supported by Hasan and Kabir [Hasan, part II]. But in TempEnn the U-value is calculated to be independent of the temperature difference between the formation and the well fluid (which again is indirectly dependent on the depth) and only changes with time (shown in Figure 5).

The fluid model in TempEnn assumes single phase incompressible flow. So like the steady state equation, Ivarrud's model does not take into account expansion cooling (Joule-Thomson cooling). This assumption should make the results for a gas well invalid. The program will still be tried against the other two methods to calculate the temperature profile of the well stream from one of the gas wells at Ormen Lange. The hydrostatic pressure will decrease as the fluid is moving towards the wellhead. This pressure decrease will cause some cooling because the fluid expands when pressure decreases. Because of this, the temperature at the wellhead calculated with TempEnn is likely to be too high compared to what it actually will be in reality.

The same parameters that were used in testing the steady state equation were used to test TempEnn. By keeping all the input parameters constant, except time, it became visible that the temperature of the injected water in the imaginary test case would increase less as time goes by. This trend can be seen in Figure 6, where the results of testing TempEnn and the steady state equation are compared. The observed trend was expected; as the formation will be cooled when it is transferring "heat" to the water, the heat transfer from the formation will decrease with time.

As mentioned earlier TempEnn was first developed for producing oil wells, and later expanded to also be used in injection wells. Practically this means that the program is divided in two parts, a production and an injection part. In TempEnn the input time has to be changed manually every single time. This means that the program is a cumbersome method when working with a large time span. In TempEnn development, focus has been on functionality, not on user friendliness. It is for example not that easy to keep track of all the different input data files (see Appendix B Table B-1). A big advantage over the steady state equation is that TempEnn calculates its own U-value, assuming this value is correct.

Figure 6 also contains the result from the steady state equation. This result was calculated with the overall heat transfer coefficient calculated in TempEnn after 1 day injection. The graph from the steady state equation shows pretty much the same trend. The difference between the two is that TempEnn calculates an overall higher temperature profile than the steady state equation. Further comparison of TempEnn with the other methods is done in the case studies, Chapter 4.

### **3.3 HYSYS**

HYSYS is a steady state process simulation and modeling application with a graphical user interface. This interface makes it fairly easy to build process simulation models. The program is attributed Hyprotech, a subsidiary of Aspen Technology.

In Aspen's information brochure about HYSYS they claim that "HYSYS is built to ensure accurate calculation of physical properties, transport properties and phase behavior"[Aspentech]. If this claim is legit, then HYSYS should contain a tool to calculate the Joule-Thomson effect. Though it is likely that JT is built into the temperature and pressure calculations done by HYSYS, the author has not succeeded to find the exact temperature change caused by the JT effect in the HYSYS calculations. HYSYS is also supposed to be able to calculate the U-value by itself, but this was not achieved in the project. This U-value would however, be time-independent; it would not consider the time span.

HYSYS will be calculating the case study with two different pipe flow correlations; Beggs & Brill (B&B) and HTFS Homogeneous (HTFS) flow. In short the B&B method is based on work done with an air-water mixture at many different conditions, and is applicable for inclined flow. The HTFS model has been validated for horizontal, and both upward and downward vertical flow using a wide range of data held by the Harwell data bank.

The first thing the user has to do in HYSYS is to define the molecular composition of the streams, what thermodynamic processes he/she wishes to use in the calculations and the process flow chart. In the process flow chart objects required for most simulations are available. These objects include streams, unit operations and logical operations. Examples of these could be heat transfer equipment, separators, compressors, piping equipment and so forth. The objects can be placed in the simulation basis environment according to the user's wishes, and connected in a logical order. (see Appendix C2) When this is done, and HYSYS has all the info it needs, it will calculate the missing parameters by its own.

Comparison of HYSYS with the other methods will be done in the case studies.

## 4 Case studies

To be able to see how the three different methods work, and see if there is a significant difference in the results from each of them, two case studies has been set up. The case studies include two vertical geothermal exploitation wells and one of the wells in the Ormen Lange gas field. The two geothermal wells are both imaginary but the figures in the calculations are realistic in the sense that the wells might be drilled for this purpose [NN, personal communication].

### 4.1 Water injection-well

The temperature development in two imaginary wells will be looked closer upon with both TempEnn and the steady state equation. These wells are 4000 meter and 6000 meter deep vertical, onshore, monobore wells. A monobore well is a well with a uniform radius all the way down to the bottomhole. In both imaginary wells the water injection takes place in the outer tube while the water is transported back to the surface in the inner tube (Figure 7). As can be seen in the figure, the flow area is decreased compared to what it would have been with one way transportation in the tube. Because of this smaller flow area, the fluid has to move faster to provide the same flow rate as it would with transportation in one direction (only an “outer” tube). Flow rate can be described as

$$q = A * v \quad (4.1)$$

where  $q$  is flow rate,  $A$  is area and  $v$  is velocity. It should be clear that when  $A$  decreases,  $v$  has to increase to maintain the same  $q$ . The increased velocity gives the fluid less time to be in contact with the formation, and therefore less time to be transferred heat to. This means that the inner diameter of the casing can not be used directly to calculate the temperature of the well fluid. An equivalent inner diameter has to be found to use in these calculations. See Appendix D for the derivation of this diameter. This equivalent diameter has to be used in both the TempEnn and the steady state equation calculations.

The water injection calculations will be done with different flow rates. When the flow rate increases, it is likely that the increase in water temperature will be smaller. As can be seen in equation 4.1; when  $q$  increases in the same flow area,  $v$  also has to increase. This increase in velocity with a large  $q$  compared to a smaller  $q$  will also lead to less contact time for the fluid, thus providing a smaller temperature increase in the water.

Both the wells are going to be calculated with these properties [NN, personal communication]:

- Water temperature before injection,  $T_i$  : 20 and 40 °C
- Injection rate,  $q$  : 4, 15 and 33 kg/s. This is equal to 346, 1296 and 2850 Sm<sup>3</sup>/day
- Time after first injection: 1 day and 1, 8 and 16 years

However, the steady state equation will not be used to calculate the well temperature for all these different conditions. The calculations will be done for both the wells with two different flow rates after one day of injection. Because calculations are done after one day, the  $U$ -value used in the equation was the one calculated in TempEnn after one day of

injection. This is assumed to be representative for the overall picture. In TempEnn all parameters were used, which means that a total amount of 48 calculations had to be carried out. The injection part of TempEnn was used here. Since calculations in HYSYS would also acquire 48 scenarios, this was considered unmanageable and was therefore not performed.

Figures 8 and 9 show that when the well depth is given, the most significant parameters are the injection rate and the time span of the injection. Whether the temperature of the injected water is 20 °C or 40 °C before injection does not really matter. The increase in the water temperature is mostly the same. This is not the case for changes in injection rates. When the rate increases, the water temperature will not increase as much as it would with lower rates. This can be observed in Figures 10 and 11. While the increase in water temperature in the 4000 meter deep well is 70 °C after one day with an injection rate of 346 Sm<sup>3</sup>/day, the increase is only 17 °C with an injection rate of 2850 Sm<sup>3</sup>/day. After 16 years (5840 days) of injection the temperature increase is only 30 °C (instead of 70°C) and 4 °C (instead of the original 17°C), respectively. The same development can be seen if Figures 12 and 13 for the 6000 meter deep well. Whether this is a too small temperature increase to give profitable exploitation is outside the scope of this project.

When the calculations are done with the steady state equation, the temperature developments are mostly the same as in the one day calculations with TempEnn. This can be seen in Figures 10 through 13. The deviation is relatively small between the results, but again TempEnn calculates an overall higher temperature profile. The relative deviation, however, grows smaller with increasing flow rate. This applies for both the 4000 and the 6000 meter well.

One thing not accounted for in both the steady state equation and TempEnn is the return of the injected water to surface. As shown in Figure 7 the return takes place in the inner tube. Even if the inner tube would be well insulated, it is likely that there will be a small heat transfer between the water going down and the water going up. This will be discussed further in Chapter 5

## 4.2 Ormen Lange well

The Ormen Lange gas field outside the western parts of Norway is the second largest gas field in Norway. The gas will be produced from two sea bed templates in the central area of the field. Each of these templates will have room for eight wells. The templates will be located at water depths of 800 – 1100 meters. Each template will have four 9 5/8" and four 7" wells. The 9 5/8" wells will have a maximum production capacity of 10 MSm<sup>3</sup>/d. [Heskestad] For the calculation of temperature development in the well, one of the 9 5/8" wells will be used as an example. It will be assumed that the wellhead is located at 900 meters water depth, and that it is a monobore well. The elevation profile of the well can be found in Figure E-1. For more well properties see Table 3.

All three methods will be used in this case study to be able to compare the results. It is likely that the results from TempEnn and the steady state equation will be much the same, while HYSYS might yield somewhat different results. This is due to the mentioned neglect of the Joule-Thomson effect by TempEnn and the steady state equation.

The well stream is gas saturated with water, Table 4. To be able to achieve this in HYSYS, the gas has to be mixed with water and then brought into a separator. The product from the vapor outlet becomes the well stream while the product from the liquid outlet is not considered. (see Appendix C2) Input for HYSYS is gas and water rate, temperature and pressure as well as gas composition before mixing. HYSYS calculates the volume flow in well conditions and density in well conditions. These are necessary properties in TempEnn and the steady state equation and were taken from HYSYS directly instead of being calculated manually. In HYSYS both of the pipe flow correlations (described in Chapter 3.3) will be used. Each of the four straight sections of the well in Figure E-1 will be treated as single pipes in HYSYS. Each of them is given a length, a change in vertical depth, a corresponding mean ambient temperature, and the heat transfer coefficient as calculated in TempEnn after 1 day of injection. In this case study, the production part of TempEnn has been used.

The results from TempEnn and the steady state equation show small temperature drops for the well flow (Figures 14 and 15) while the results from HYSYS (Figure 16) show bigger temperature drops for both pipe flow correlations (Beggs & Brill and HTFS Homogeneous flow). Again the results from TempEnn show a bigger temperature difference from starting point to end point compared to the equation, like it was mentioned for case 1. The shape of the graph from HYSYS might look different from the TempEnn and steady state graphs because there is only 4 points in the HYSYS calculations.

As stated before TempEnn assumes incompressible well flow. The main difference in calculating temperature drop for incompressible and compressible well flow is the Joule – Thomson effect (This is explained in Chapter 2 and 3.1). This effect involves a temperature drop when gas expands from high to low pressure at constant enthalpy. Most of the pressure drop the well flow experiences is the static head ( $\rho gh$ ). But it is the belief

of the author that some of the pressure drop is caused by Joule-Thomson expansion. This expansion causes the Joule-Thomson cooling.

The overall heat transfer coefficients used in HYSYS is the one calculated by TempEnn after one day production, 6.6, and 0. When the U-value equals 0, no heat should be lost to the formation (see also Table 5 and Appendix C1). This is totally hypothetical and was done to see if it would be possible to figure out the heat loss because of the Joule-Thomson effect. This was done to see if it would be possible to match the results from TempEnn to the results from HYSYS. If that was the case, it would not be an unfair guess that the only factor not accounted for in TempEnn and the equation was the Joule-Thomson effect. The results are as can be seen in Figure 15. As can be seen, the temperature drop only changes with 1.5 – 2 degrees C with both the fluid models, when the U-value changes from 6.6 to 0. This means that HYSYS somehow calculates the heat loss from the produced fluid to the surrounding formation to be less than 2 degrees C.

A simple calculation was done to see if it was possible to find the cooling caused by the Joule-Thomson effect. The following equation was used:

$$\mu = \left( \frac{\delta T}{\delta P} \right)_H \quad (4.2)$$

$\mu$  is the JT coefficient,  $\delta T$  is the temperature drop because of JT expansion and  $\delta P$  is the pressure drop because of JT expansion.

As can be seen from this equation, to be able to find the temperature drop because of JT expansion, it is necessary to know the pressure drop caused by the expansion. The total pressure drop is of course bigger, because it involves the gravitational pressure loss ( $\rho gh$ ) from well bottom to the wellhead. Separating the JT expansion from the static head was not achieved. To show this, the temperature drop was calculated anyway and resulted in far too high values. This is shown in Appendix C1.

Even if the gas composition in the Ormen Lange well is not totally the same as the one Marić uses, the JT coefficients found in these simple calculations seem to agree with Marić's for about the same temperature and pressure (Figure 1).

## 5 Discussion

The three methods tested in this project are very different. While the steady state equation and HYSYS are steady state models, TempEnn is built to be used under non-steady state conditions. Despite the differences between the TempEnn program and the steady state equation, the results seem to be quite the same. The similarity in results between these two methods shows that the steady state equation can be used to calculate temperature under non-steady state conditions provided the correct U-value with time.

In my opinion, however, the equation is impractical in use: Because the set-up in the spread sheet has to be changed for every change in well depth and well profile, it is too time consuming to be used for practical purposes. But there might be easier ways to do these calculations.

As already mentioned TempEnn is built for use under non-steady state conditions. But as with the equation TempEnn also needs to be run with new input-values for every time the conditions change and to see progress with time. This is a time-consuming process; not only running the program over and over, but also the data processing takes a lot of time. Even if the calculations seem to be correct, at least for incompressible fluids, the program is impractical in use. This is also visible in Appendix B3, there are many files (both input, output and programfiles) that confuse the user and similar parameters have to be supplied in different places. So even though a procedure for using the program is presented, I feel that the program still is impractical in use.

While TempEnn calculates the overall heat transfer coefficient on its own, the steady state equation and HYSYS needed it as input. HYSYS is also supposed to be able to calculate its own U-value, but this was not achieved in the project. However, this U-value would not be considering the time span. So even though the internal U would have helped, it would be preferable to have the transient solution of the temperature equation implemented in HYSYS.

The results from the first case study in Chapter 4.1 are as expected. The temperature increase is quite large in the first few days of injection. It is also larger for smaller injection rates than for higher rates. The temperature increase is also as expected decreasing with time. This has been shown using TempEnn, but could also have been shown with the steady state equation, if correct time-dependent U-values were used as input. It should be stressed that in these tests the return to surface of the injected water has not been taken into account. As mentioned in Chapter 4.1 the inner tube would be well insulated. Even so it is likely that there will be a somewhat small temperature exchange between the water in the inner tube and the water in the outer tube. It might be that this heat transfer has very small implications. The water moving up would be warmer than the water moving down, this means that heat is transferred from the upward moving water to the downward moving water. Is it likely that the returning water is colder than it would be if the return pipe was totally isolated (read: absolutely no heat transfer). Maybe not, because the heat leaving the upward moving water is transferred to the downward

moving water, so no heat should be lost. Of course this would be in an ideal situation, but it seems likely that this heat transfer does not have a big significance. If this is true, then the temperature of the produced water would be about the same as the calculated temperature at the bottom. In this case, the Joule-Thomson effect is considered negligible as the fluid is virtually incompressible.

Throughout the test and case 1, TempEnn and the steady state equation produced similar results, with TempEnn being consistent a bit higher temperature than the equation. However, by comparing the different flow rates of the same well (either 4000 or 6000 m), with increasing flow rate a decreasing deviation was found. The reason and importance of this is not known at this point.

Then there is the question about the results in the second case study: There is quite a big difference between them, so which of the results are correct? If the well fluid temperature at the wellhead is 80 °C, as given in Heskestad, there should be no doubt. The result from HYSYS is closest to the “correct” result. This seems plausible as the fluid temperature drops from both TempEnn and the equation are low. The low temperature drop is most likely caused by the negligence of the Joule-Thomson effect (which because of the compressible well fluid is very important) in both the equation and TempEnn. This theory was tested (Chapter 4.2 and Appendix C1) by supplying both the TempEnn calculated U-value (6.6 W/m<sup>2</sup>°C) and a U-value of zero. When U equals zero, all the heat loss is caused by heat transfer to the formation. It seems like the results from HYSYS contradict this fact (Figure 16 and Table 5). The difference in temperature drop is not even two degrees Celsius, for both the flow correlations. These results imply that “all” the heat loss is caused by the Joule-Thomson cooling. It should be clear that the contradiction of the results to a physical fact gives rise to more questions, and makes one wonder how large the JT effect really is.

There is at least one more uncertainty in the calculations done. Hasan and Kabir believe that the U-value will change with formation depth as shown in Table 2 (see for more explanation Chapters 2 and 3.2). It is understood that this change comes from the increasing temperature change between the surrounding formation and the well fluid as the fluid ascend. If this is true, the U-value calculated in TempEnn seems to be calculated under false pretences. TempEnn calculates a single U-value from top to bottom or the other way around. Not, as Hasan and Kabir say it should, changing with increasing difference in the gradients (= temperature difference between fluid and formation). Maybe TempEnn calculates a U-value which is some kind of average heat transfer coefficient?

The U-values calculated in TempEnn seem to be far too low, when comparing them to the values in Table 1 (see figure 5). It is unsure how the different groups calculated the presented U-values compared to how Ivarrud told TempEnn to calculate them. Some differences in this, would of course lead to different results. But the difference seems to be very large. The results in the first case study seem nevertheless reasonable (Chapter 4.1). Also the second case study, where the TempEnn-calculated U-value has been used in the HYSYS calculations, seems to give reasonable results.

## 6 Conclusion

When estimating the temperature profile in a well with incompressible fluids (water in this case), TempEnn and the steady state equation give plausible results. TempEnn is favorable over the equation, because of the programs' non-steady state performance. The results are not as good, when estimating the temperature profile in a well with compressible fluids with these two methods. HYSYS seems to give more plausible results than TempEnn and the equation, with compressible well fluids.

Both the equation and TempEnn give a far too small temperature drop when producing gas. This is probably caused by the total neglect of the Joule-Thomson effect.

The fact that TempEnn calculates its own overall heat transfer coefficient is a strong benefit with this program, but because it needs to be run again for every time the time span changes it is not very practical. HYSYS would perform better if it was able to calculate the U-values by itself, and also if the application managed to calculate over a time span.

Both TempEnn and HYSYS have their strong sides, but need further development. The steady state equation is impractical in the form it exists now, the results for incompressible fluids are promising, but the programs have clear user advantage over the equation. Implementing the transient solution of the temperature equation in HYSYS would make it possible to calculate the time-dependent U-values. This would probably then become the best way to do this type of calculations.

## 7 Future work

A closer look should be taken on the calculations in HYSYS regarding the U-values, since the difference in temperature drop with  $U=6,6$  and  $U=0$  was so small. Beside this, a solution should be found for the time-dependent U-value and/or time span. Implementing the transient solution of the temperature equation in HYSYS would be of great benefit. If it was possible to write a “plug-in” for HYSYS where it is possible to tell the program that it should calculate the temperature profile over several years, and for example give a result for each passing year. This would make it very much more practical to work with, and save a lot of time for the user.

From the results produced by HYSYS, it would be of interest to calculate the actual temperature drop in the well fluid caused only by the Joule-Thomson effect. Comparing this to the results from TempEnn, could clear up exactly how big the JT effect actually is. Note that this is only of importance with compressible well fluids, like gas, and not for incompressible well fluids.

Some modifications to TempEnn would be beneficial. The questions around the Joule-Thomson effect should be cleared up, and most likely this function has to be implemented in the program. A procedure for using TempEnn has been presented in this paper, and this should be made accessible for students. This will help students to run TempEnn. It is, however, still believed that the program should be adjusted to become more user friendly.

## Nomenclature

|                  |  |   |
|------------------|--|---|
| $\alpha$         | geothermal gradient  | $^{\circ}\text{C}/\text{km}$                                    |
| $A_i$            | inner tube flow area   | $\text{m}^2$  |
| $A_o$            | outer tube flow area   | $\text{m}^2$  |
| $C_p$            | heat capacity  | $\text{J}/\text{kg}^{\circ}\text{C}$                            |
| $D$              | diameter   | $\text{m}$  |
| $K$              | conductivity   | $\text{W}/\text{m}^{\circ}\text{C}$                             |
| $M$              | molecular weight   | $\text{kg}/\text{kmole}$  |
| $P$              | pressure   | $\text{bar}, \text{Pa}, \text{MPa}$                             |
| $q$              | flow rate  | $\text{kg}/\text{s}, \text{m}^3/\text{s}, \text{Sm}^3/\text{d}$ |
| $\rho$           | density  | $\text{kg}/\text{m}^3$  |
| $r_i$            | inner tube radius  | $\text{m}$  |
| $r_o$            | outer tube radius  | $\text{m}$  |
| $T$              | temperature  | $^{\circ}\text{C}$  |
| $T_{\text{amb}}$ | ambient temperature  | $^{\circ}\text{C}$  |
| $T_i$            | Temperature of the water before it is injected               | $^{\circ}\text{C}$  |
| $T_{\text{sb}}$  | sea bed temperature  | $^{\circ}\text{C}$  |
| $T_x$            | temperature of the liquid coming out of a particular segment | $^{\circ}\text{C}$  |
| $T_{x-1}$        | temperature of the liquid going into a particular segment    | $^{\circ}\text{C}$  |
| $U$              | overall heat transfer coefficient                            | $\text{W}/\text{m}^2^{\circ}\text{C}$                           |

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## Tables

**Table 1** Overall Heat Transfer Coefficient-values

| Source                | Btu/hr ft <sup>2</sup> °F | W/m <sup>2</sup> K | Comment   |
|-----------------------|---------------------------|--------------------|---|
| Hasan & Kabir         | 30,29                     | 171,99             | Value at bottom hole, see table 2 for more  |
| Willhite              | 3,14                      | 17,8               | Steam at 600 °F is injected down 3 1/2 “ tubing set on a packer in 9 5/8” casing the annulus contains a stagnant gas at 14,7 psia and the casing is cemented to surface in a 12” hole. Mean subsurface temp of 100 °F = 38°C and reservoir at 1000 ft |
| Sagar, Doty & Schmidt | 8,44                      | 47,92              | Natural flowing well in west Texas. Excellent agreement between the predicted and measured temperature profiles. Mass flow rate: 0,19lbm/sec = 0,086 kg/s   |

**Table 2** Overall heat transfer coefficients dependent on depth

*“The table shows that the overall heat transfer coefficient is much smaller at the bottom hole than at the wellhead. The marked variations in U-values with well depth is a direct result of the contribution of the natural convective heat transfer coefficient. Because of small temperature differences between the tubing fluid and the soil near the bottom hole, the temperature difference across the annulus is small. This leads to a smaller value of U. At the wellhead, the reverse is true, resulting in a much larger overall heat transfer coefficient.” [Hasan, part II]*

| Well depth<br>ft | U                        | U                   |
|------------------|--------------------------|---------------------|
|                  | Btu/hrft <sup>2</sup> °F | W/m <sup>2</sup> °C |
| 0                | 30,29                    | 171,99              |
| 500              | 30,11                    | 170,97              |
| 1000             | 29,88                    | 169,67              |
| 1500             | 29,59                    | 168,02              |
| 2000             | 29,23                    | 165,98              |
| 2500             | 28,75                    | 163,25              |
| 3000             | 28,12                    | 159,67              |
| 3500             | 27,26                    | 154,79              |
| 4000             | 26,02                    | 147,73              |
| 4500             | 24,09                    | 136,79              |
| 5000             | 20,3                     | 115,27              |
| 5355             | 3,53                     | 20,04               |

**Table 3** Input data for Ormen Lange calculations

| <b>From Heskestad</b> |       |                  |
|-----------------------|-------|------------------|
| $P_{res}$             | 290   | bar              |
| $U_{well}$            | 4     | $W/m^2\text{°C}$ |
| $T_{sb}$              | -1,2  | $\text{°C}$      |
| $T_{res}$             | 96    | $\text{°C}$      |
| $\alpha$              | 48,3  | $\text{°C/km}$   |
| Depth sea bed         | 900   | M                |
| $C_{p,wellflow}$      | 3379  | $J/kg\text{°C}$  |
| $q_{max}$             | 10    | $MSm^3/d$        |
| $D_{well}$            | 12    | ''               |
| $OD_{casing}$         | 9 5/8 | ''               |
| $ID_{casing}$         | 8 1/2 | ''               |
| $OD_{tubing}$         | 7,656 | ''               |
| $ID_{tubing}$         | 6,276 | ''               |
| <b>From HYSYS</b>     |       |                  |
| $q_{wellflow}$        | 44256 | $m^3/d$          |
| $\rho_{wellflow}$     | 174,5 | $kg/m^3$         |
| M                     | 17,45 | $kg/kmole$       |
| <b>From Ivarrud</b>   |       |                  |
| $\rho_{formation}$    | 2600  | $kg/m^3$         |
| $C_{p,formation}$     | 900   | $J/kg\text{°C}$  |
| $K_{formation}$       | 1,8   | $W/m\text{°C}$   |
| $K_{steel}$           | 60    | $W/m\text{°C}$   |
| $K_{water}$           | 0,6   | $W/m\text{°C}$   |
| $K_{cement}$          | 7     | $W/m\text{°C}$   |

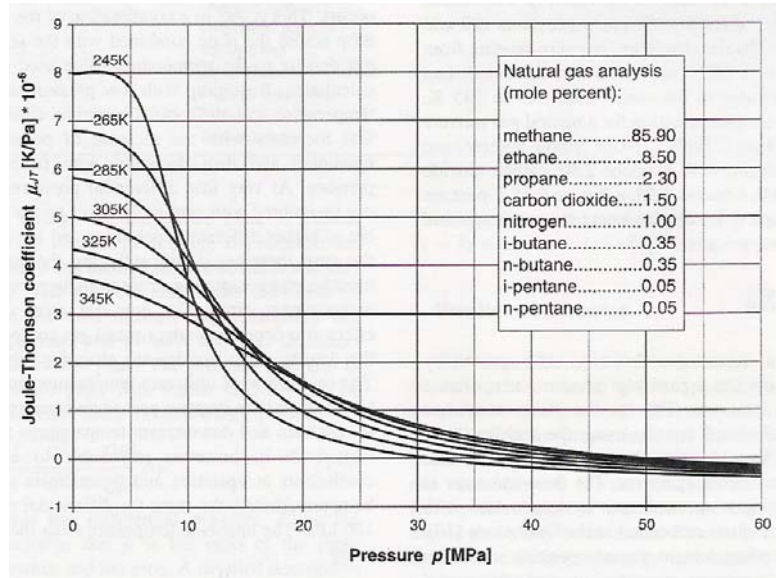
**Table 4** Wellstream Composition at Ormen Lange

| <b>Component</b> | <b>Mole fractions</b> |
|------------------|-----------------------|
| N <sub>2</sub>   | 0,003411              |
| CO <sub>2</sub>  | 0,004080              |
| H <sub>2</sub> O | 0,005931              |
| Methane          | 0,930927              |
| Ethane           | 0,034719              |
| Propane          | 0,012177              |
| i-Butane         | 0,002717              |
| n-Butane         | 0,003220              |
| i-Pentane        | 0,001510              |
| n-Pentane        | 0,001308              |

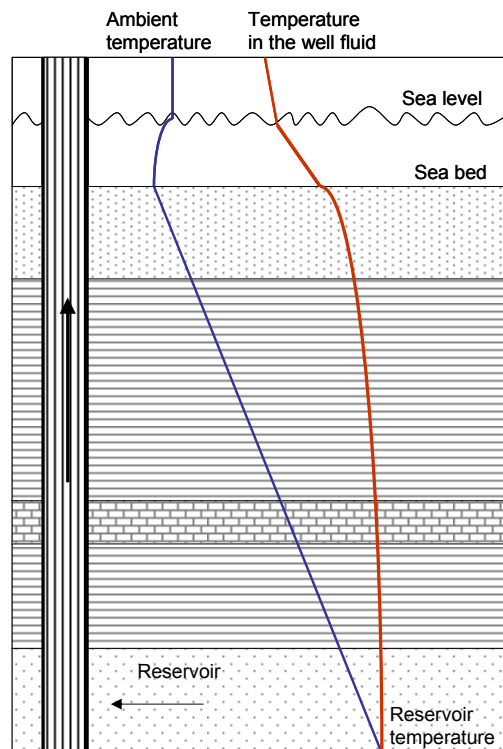
**Table 5** Temperature calculations for Ormen Lange in HYSYS with different flow models and U-values. As can be seen in the table, the temperature profile is about the same when the overall heat transfer coefficient is 6.6 or 0 W/m<sup>2</sup>K. This is not what was expected and is discussed in Chapters 4.2 and 5.

| <i>MD (m)</i> | <b>Beggs and Brill</b> |              | <b>HTFS Homogeneous</b> |              |
|---------------|------------------------|--------------|-------------------------|--------------|
|               | <i>T (°C)</i>          |              | <i>T (°C)</i>           |              |
|               | <i>U = 6,6</i>         | <i>U = 0</i> | <i>U = 6,6</i>          | <i>U = 0</i> |
| 4200          | 97,13                  | 97,13        | 97,13                   | 97,13        |
| 3500          | 96,62                  | 96,63        | 96,64                   | 96,64        |
| 3000          | 86,09                  | 86,77        | 89,61                   | 90,41        |
| 100           | 82,22                  | 83,22        | 86,53                   | 88,01        |
| 0             | 75,16                  | 76,82        | 81,88                   | 83,81        |

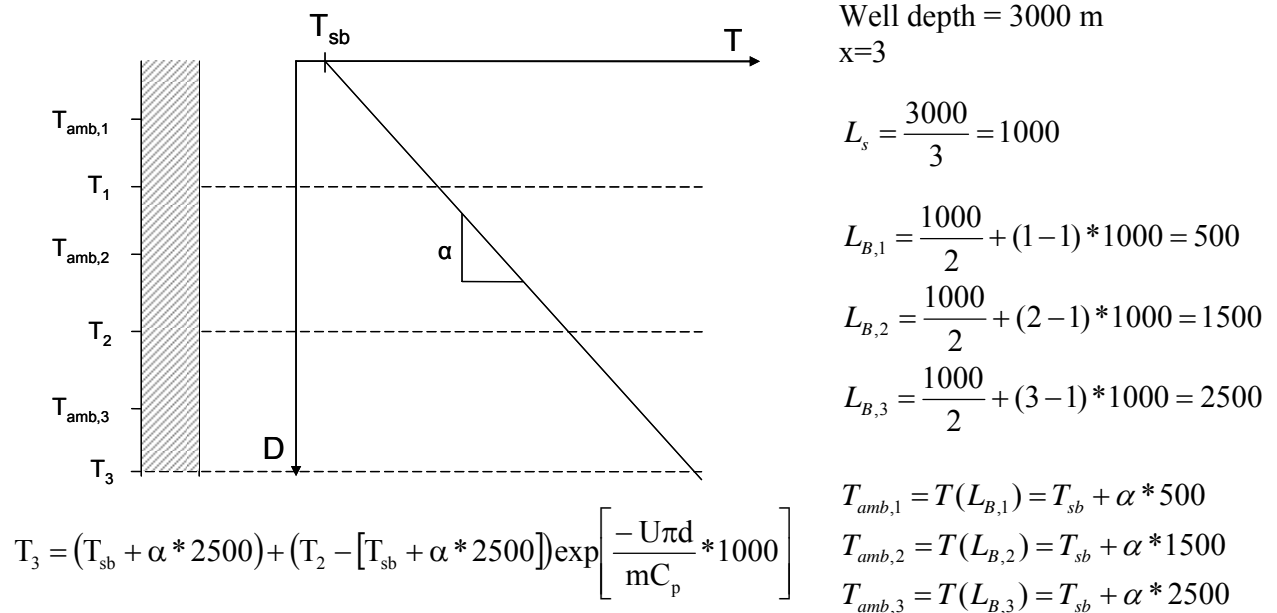
## Figures



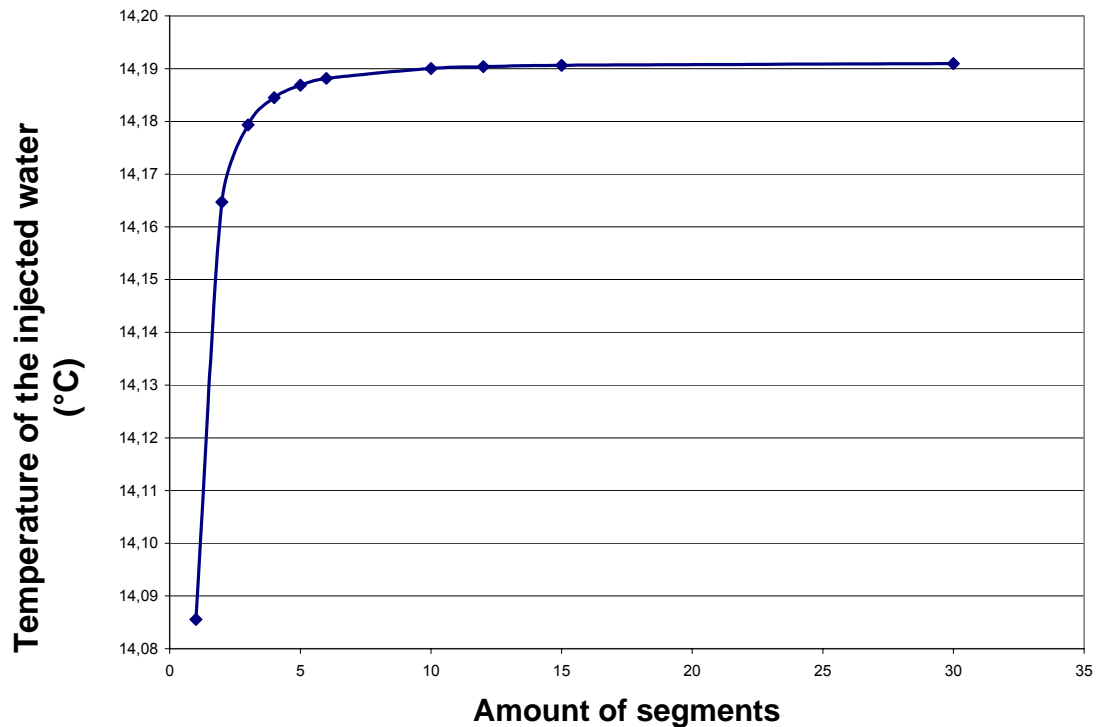
**Figure 1** The Joule Thomson coefficient for natural gas [Marić]



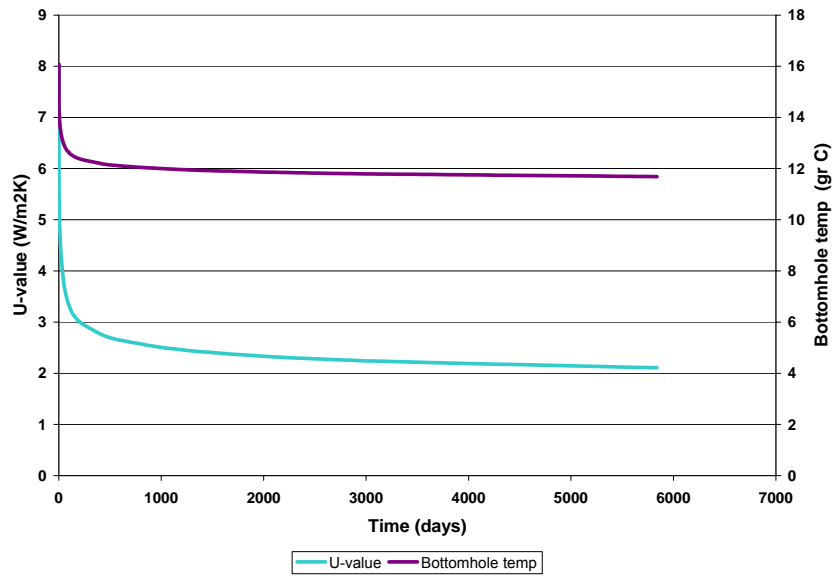
**Figure 2** Formation temperature gradient and produced/injected fluid temperature gradient. Modified from Ivarrud



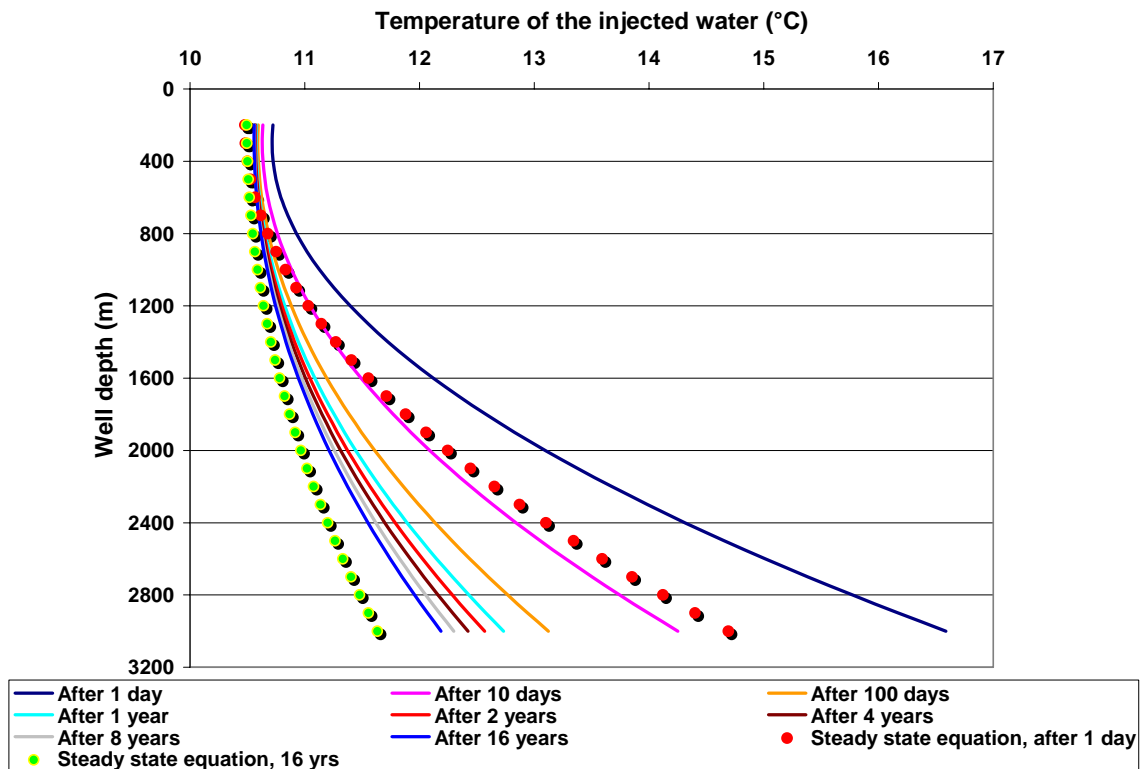
**Figure 3** An example of a calculation with the steady state equation. See text for details (Chapter 3.1)



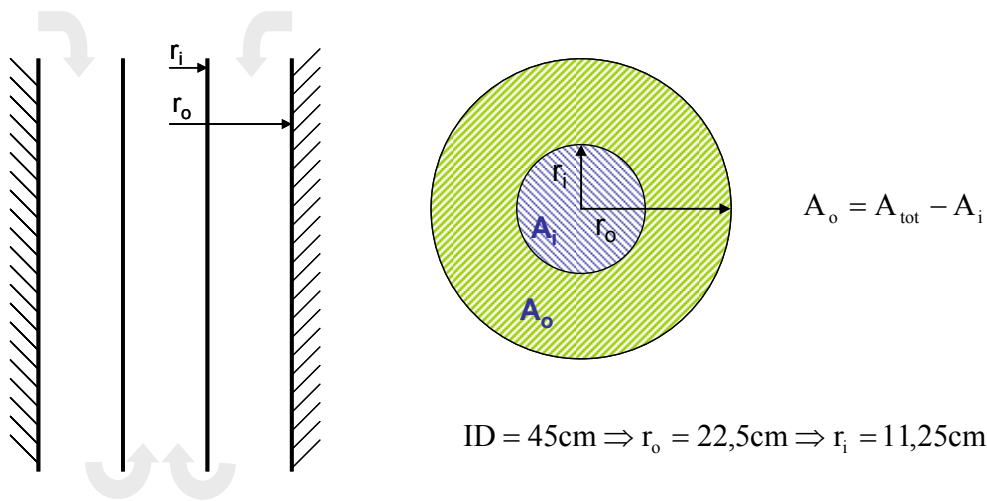
**Figure 4** Temperature development at bottom hole. The development of temperature at bottom hole is dependent on the number of segments the well was divided in.



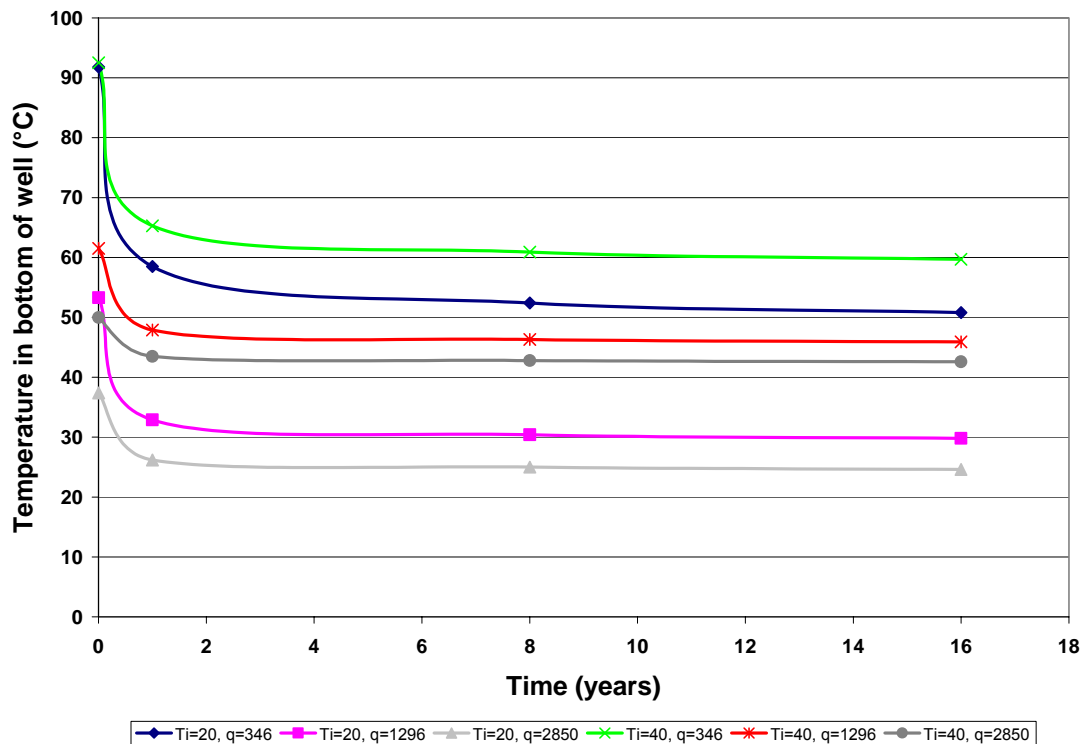
**Figure 5** U-values calculated by TempEnn. The results shown here are from the test case, but are also representative for the case studies. As can be seen, the U-values TempEnn calculates are time dependent and much lower than the values found in the literature, presented in Table 1.



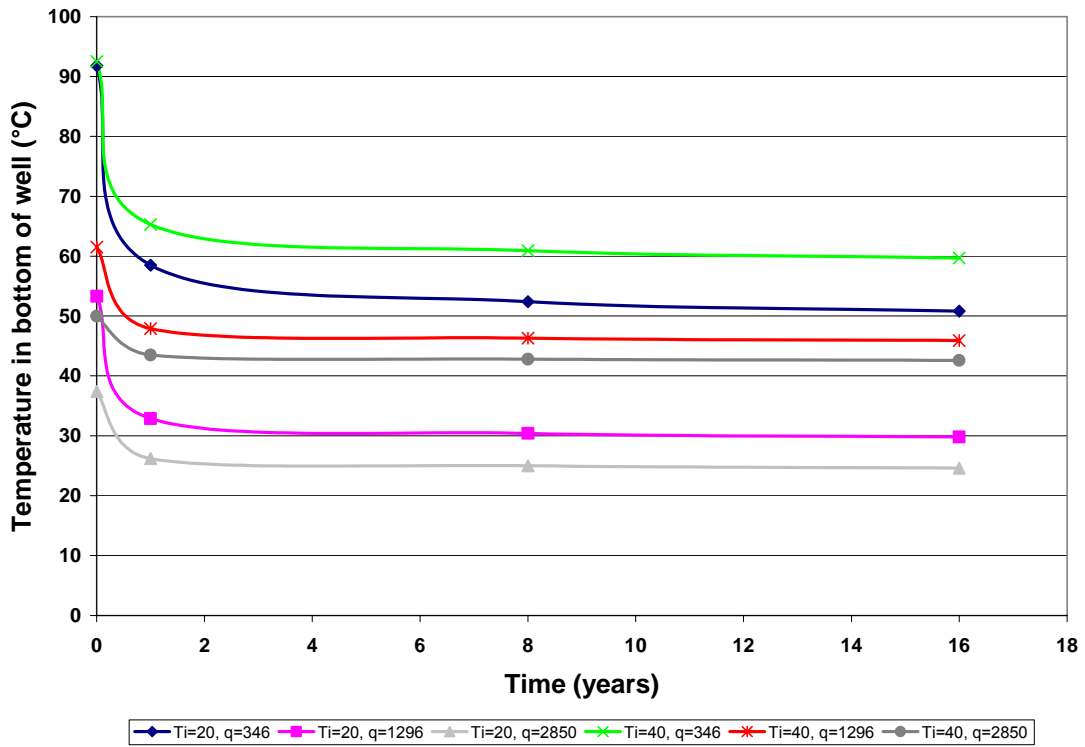
**Figure 6** Temperature of the injected water vs depth. Temperature of the water before injection,  $T_1 = 10\text{ }^\circ\text{C}$ .



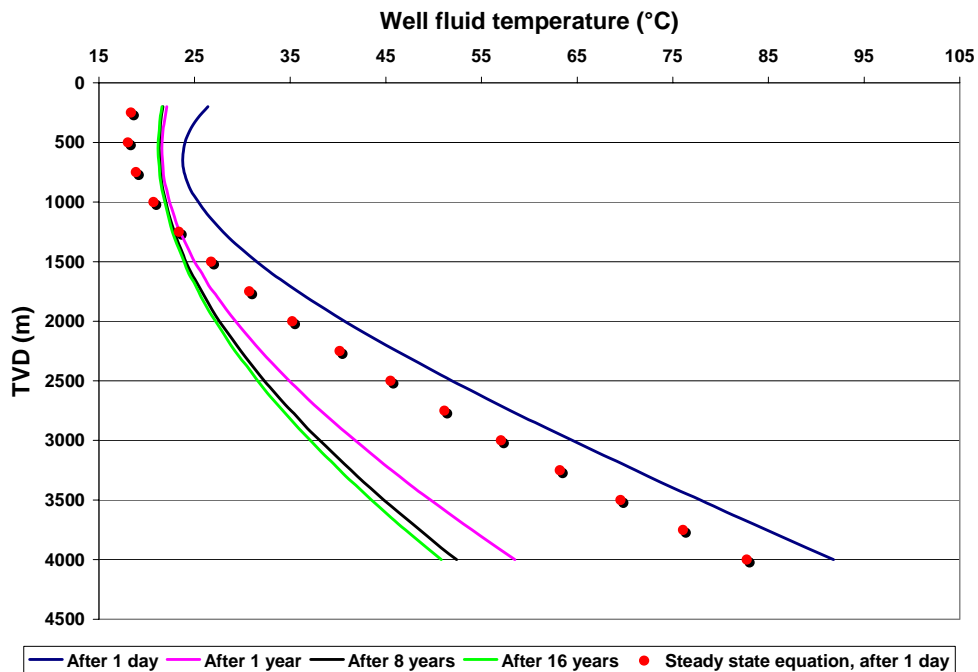
**Figure 7** Diagram of the geothermal injection well. Injection is done in the outer tubing (green), the returning water comes up in the inner tubing (blue).  $A_o$  is the flow area of the outer tube,  $A_i$  is the flow area of the inner tube, and  $A_{tot}$  is the total area.  $r_o$  is the radius of the outer tube and  $r_i$  from the inner tube.



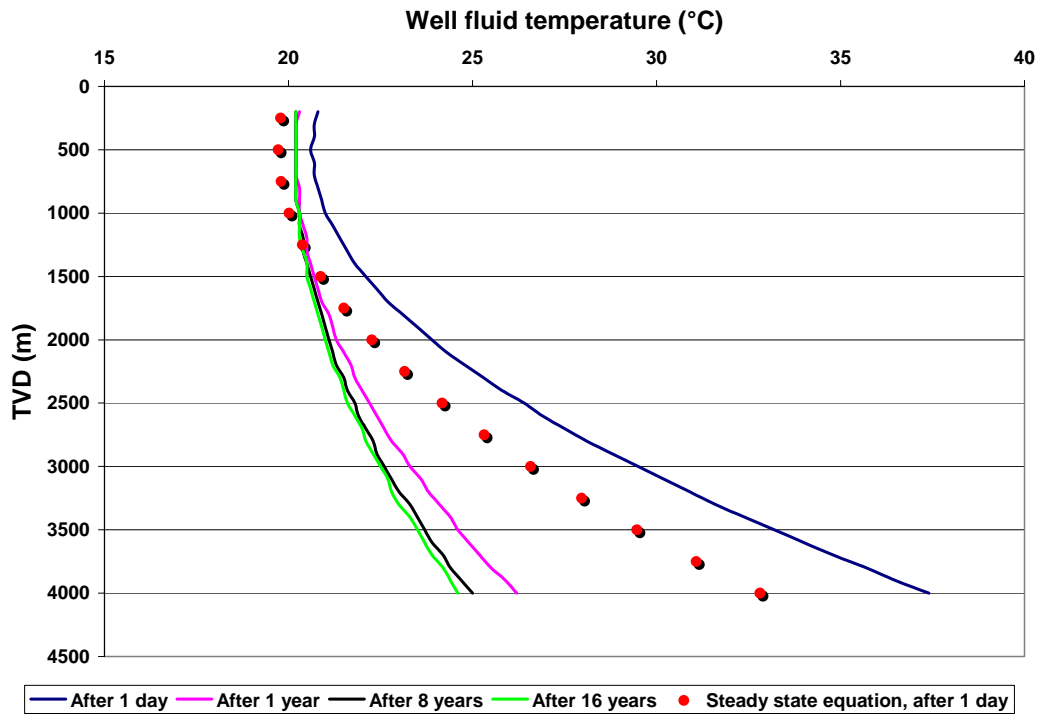
**Figure 8** Development of bottom hole temperature in the 4000 meter deep injection well, with different flow rates and injection temperatures.  $T_i$  is the water temperature before injection ( $^{\circ}\text{C}$ ),  $q$  is the water flow rate ( $\text{Sm}^3/\text{d}$ )



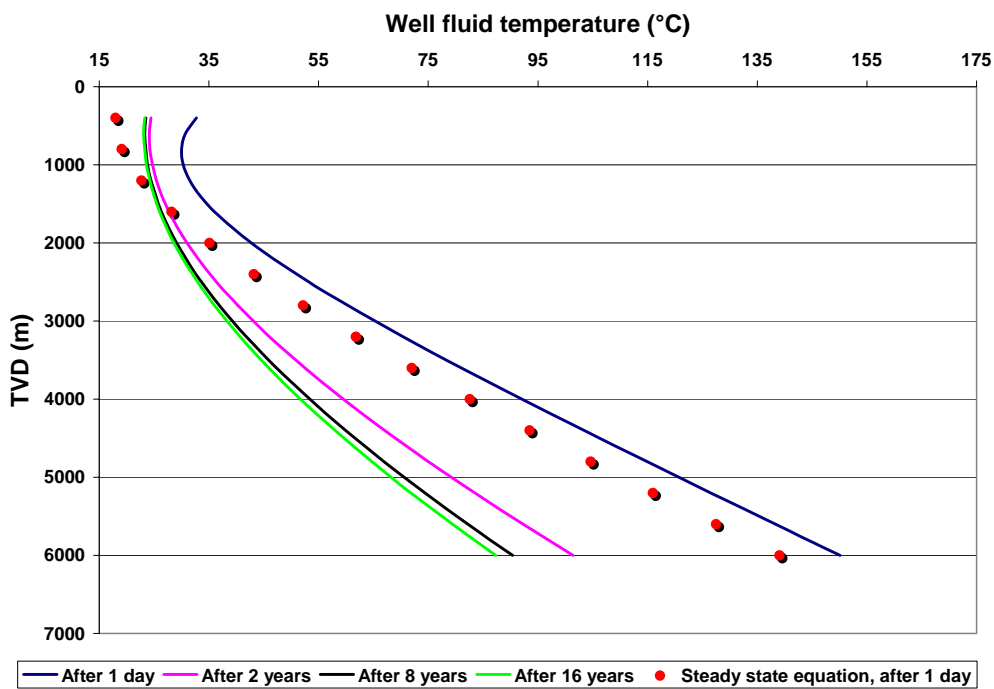
**Figure 9** Development of bottom hole temperature in the 6000 meter deep injection well, with different flow rates and injection temperatures.  $T_i$  is the water temperature before injection ( $^{\circ}\text{C}$ ),  $q$  is the water flow rate ( $\text{Sm}^3/\text{d}$ )



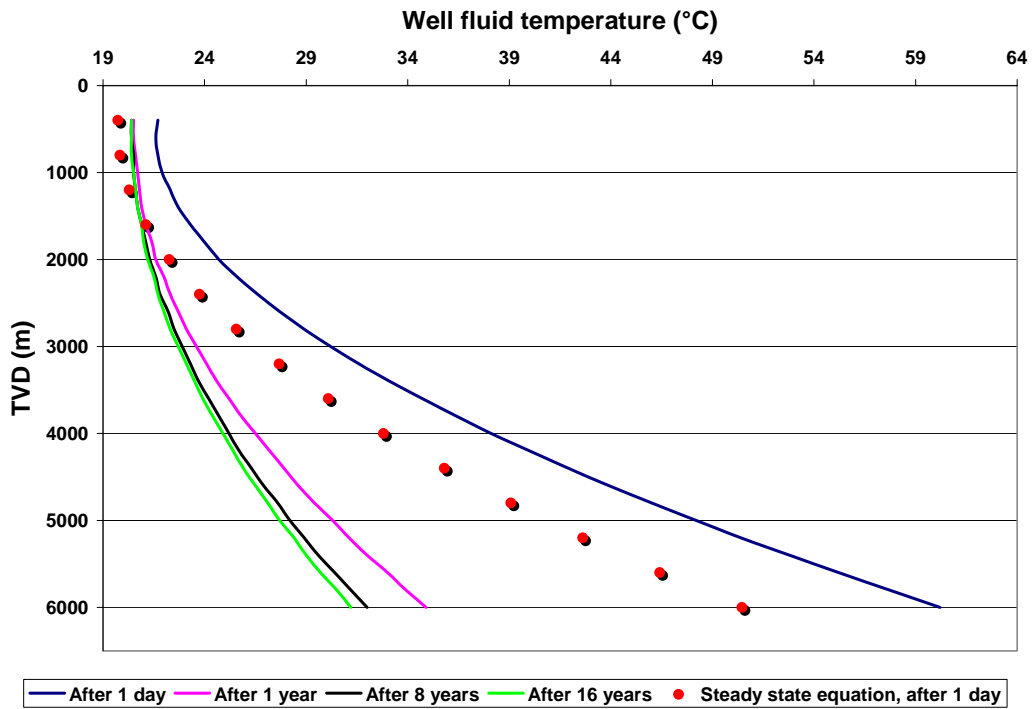
**Figure 10** Temperature increase in the 4000 meter deep injection well,  $q$  is  $4 \text{ kg/s}$  ( $= 346 \text{ Sm}^3/\text{d}$ ) and  $T_i$  is  $20 \text{ }^{\circ}\text{C}$



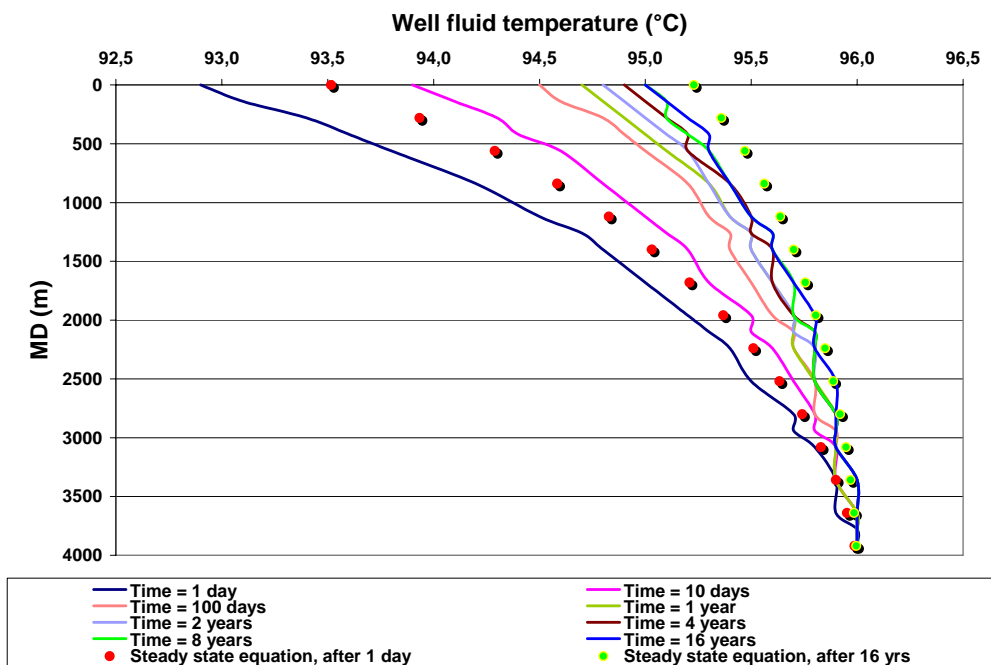
**Figure 11** Temperature increase in the 4000 meter deep injection well,  $q$  is 33 kg/s (= 2850 Sm<sup>3</sup>/d) and  $T_i$  is 20 °C. It is important to notice the difference in temperature increase between this figure and figure 9.



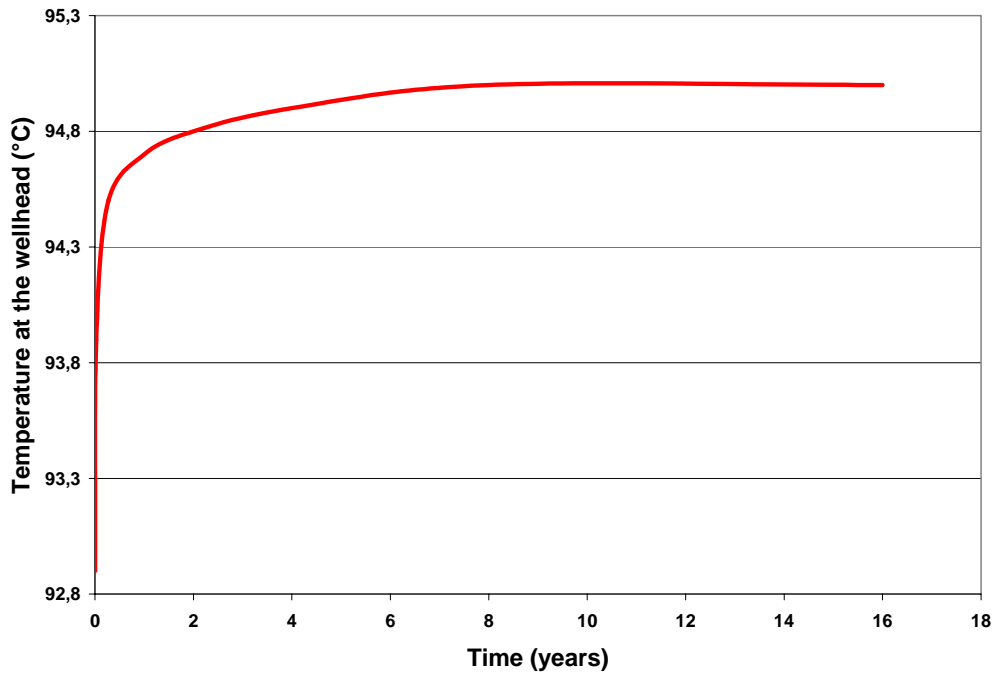
**Figure 12** Temperature increase in the 6000 meter deep injection well,  $q$  is 4 kg/s (= 346 Sm<sup>3</sup>/d) and  $T_i$  is 20 °C.



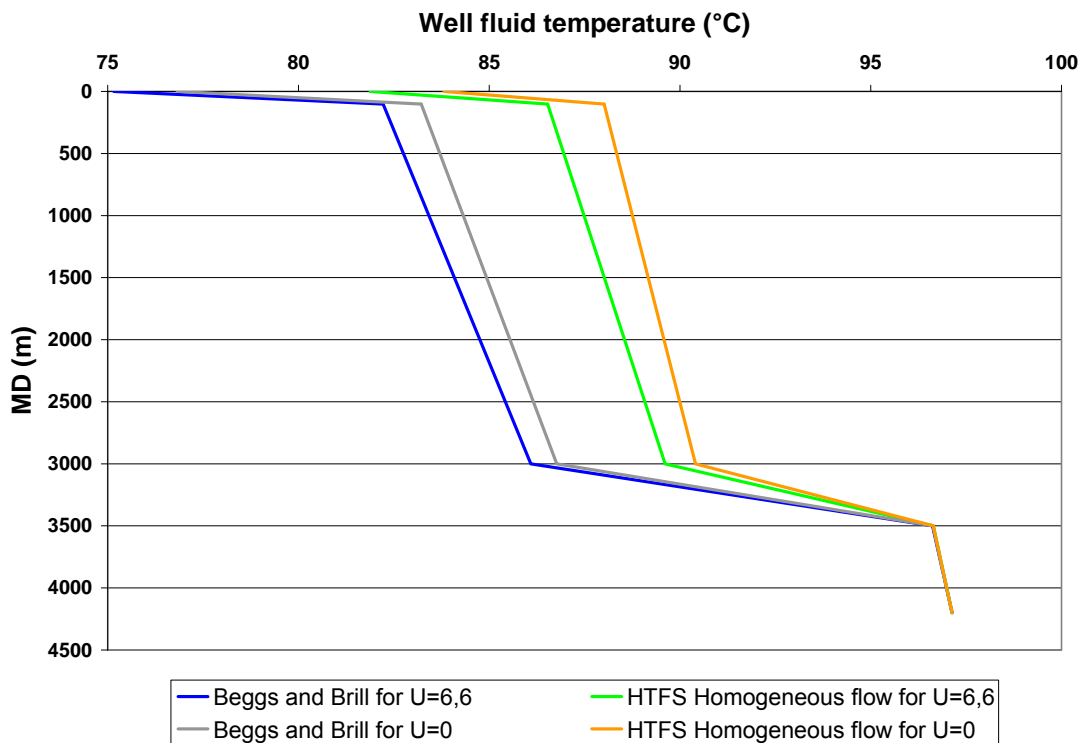
**Figure 13** Temperature increase in the 6000 meter deep injection well,  $q$  is 33 kg/s (= 2850 Sm<sup>3</sup>/d) and  $T_i = 20$  °C. It is important to notice the difference in temperature increase between this figure and figure 11.



**Figure 14** Temperature development in the Ormen Lange production well vs time, calculated in TempEnn.



**Figure 15** Temperature development at the Ormen Lange wellhead vs. time calculated in TempEnn



**Figure 16** Temperature development in the Ormen Lange production well vs time, calculated in HYSYS

## Appendix A: Steady State Equation

### Appendix A1: the iteration process

**Table A-1** the iteration process for the steady state equation.

| Ls (m) | 3000  | 1500  | 1000  | 750   | 600   | 500   | 300   | 250   | 200   | 100   |
|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| L (m)  | 1     | 2     | 3     | 4     | 5     | 6     | 10    | 12    | 15    | 30    |
| 100    |       |       |       |       |       |       |       |       |       | 9,98  |
| 200    |       |       |       |       |       |       |       |       |       | 9,98  |
| 250    |       |       |       |       |       |       |       | 9,98  |       |       |
| 300    |       |       |       |       |       |       | 9,98  |       |       | 9,98  |
| 400    |       |       |       |       |       |       |       |       | 10,00 | 10,00 |
| 500    |       |       |       |       |       | 10,03 |       | 10,03 |       | 10,03 |
| 600    |       |       |       |       | 10,07 |       | 10,07 |       | 10,07 | 10,07 |
| 700    |       |       |       |       |       |       |       |       |       | 10,12 |
| 750    |       |       |       | 10,14 |       |       |       | 10,15 |       |       |
| 800    |       |       |       |       |       |       |       |       | 10,18 | 10,18 |
| 900    |       |       |       |       |       |       | 10,25 |       |       | 10,25 |
| 1000   |       |       | 10,33 |       |       | 10,33 |       | 10,33 | 10,33 | 10,33 |
| 1100   |       |       |       |       |       |       |       |       |       | 10,43 |
| 1200   |       |       |       |       | 10,53 |       | 10,53 |       | 10,53 | 10,53 |
| 1250   |       |       |       |       |       |       |       | 10,59 |       |       |
| 1300   |       |       |       |       |       |       |       |       |       | 10,65 |
| 1400   |       |       |       |       |       |       |       |       | 10,77 | 10,77 |
| 1500   |       | 10,89 |       | 10,90 |       | 10,91 | 10,91 | 10,91 |       | 10,91 |
| 1600   |       |       |       |       |       |       |       |       | 11,05 | 11,05 |
| 1700   |       |       |       |       |       |       |       |       |       | 11,21 |
| 1750   |       |       |       |       |       |       |       | 11,29 |       |       |
| 1800   |       |       |       |       | 11,38 |       | 11,38 |       | 11,38 | 11,38 |
| 1900   |       |       |       |       |       |       |       |       |       | 11,56 |
| 2000   |       |       | 11,74 |       |       | 11,74 |       | 11,74 | 11,75 | 11,75 |
| 2100   |       |       |       |       |       |       | 11,94 |       |       | 11,94 |
| 2200   |       |       |       |       |       |       |       |       | 12,15 | 12,15 |
| 2250   |       |       |       | 12,26 |       |       |       | 12,26 |       |       |
| 2300   |       |       |       |       |       |       |       |       |       | 12,37 |
| 2400   |       |       |       |       | 12,60 |       | 12,60 |       | 12,60 | 12,60 |
| 2500   |       |       |       |       |       | 12,84 |       | 12,84 |       | 12,84 |
| 2600   |       |       |       |       |       |       |       |       | 13,09 | 13,09 |
| 2700   |       |       |       |       |       |       | 13,35 |       |       | 13,35 |
| 2750   |       |       |       |       |       |       |       | 13,48 |       |       |
| 2800   |       |       |       |       |       |       |       |       | 13,62 | 13,62 |
| 2900   |       |       |       |       |       |       |       |       |       | 13,90 |
| 3000   | 14,09 | 14,16 | 14,18 | 14,18 | 14,19 | 14,19 | 14,19 | 14,19 | 14,19 | 14,19 |

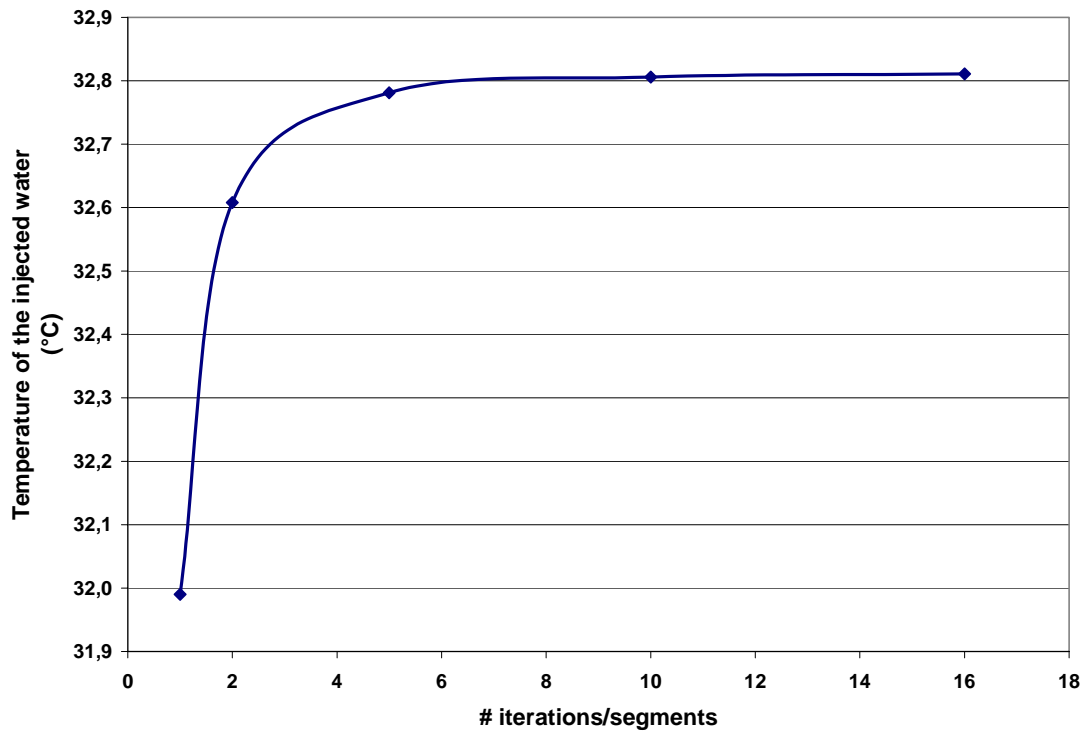
The number of iterations are marked in the table. Every column has to be set up manually; this is, of course, a time demanding task. The determination of the number of necessary iterations is shown in Figure 4 and Appendix A-2.

This type of spreadsheet has been set up for each calculation done with the steady state equation, even though only one example is shown here. The numbers are different from time to time, but the principle is the same. For explanation of the calculations see Chapter 3.1 and Figure 3.



## **Appendix A2: determination of the number of iterations**

Opposed to the test case where only one iteration (or segment) is enough to get inside a 1 degree range (as shown in figure 4), in the case studies about five will suffice. This is shown in this figure.



**Figure A-2** Necessary amount of segments/iterations

When the steady state equation was used in case 1, 16 iterations were used to produce the reported results, since this gave more data-points and therefore a clearer trend.

## Appendix B: TempEnn

### Appendix B1: input TempEnn

**Table B-1** Input parameters in the different input files of TempEnn. All three input files had to be filled out correctly before running the program.

| Input file   |                       | Symbol                              | Unit         |                   |
|--------------|-----------------------|-------------------------------------|--------------|-------------------|
| Nrc.dat      | Casing size           | Outer diameter                      | ODC1         | "                 |
|              |                       | Inner diameter                      | IDC1         | "                 |
|              | Tubing size           | Outer diameter                      | ODA          | "                 |
|              |                       | Inner diameter                      | IDA          | "                 |
|              | Well size             | Bit diameter                        | DW           | "                 |
|              | Conductivities        | Water                               | KW           | W/mK              |
|              |                       | Steel                               | KS           | W/mK              |
| Cement       |                       | KC                                  | W/mK         |                   |
| wellNR.dat   |                       | Amount of well data                 | N            | -                 |
|              | Temperatures          | Bottomhole                          | TBH          | °C                |
|              |                       | Seabed                              | TSB          | °C                |
|              |                       | Sea                                 | TAS          | °C                |
|              |                       | Air                                 | TAA          | °C                |
|              |                       |                                     |              |                   |
|              | Depths                | Ocean level (RKB)                   | ZSL          | m                 |
|              |                       | Seabed                              | ZSB          | m                 |
|              |                       | True vertical depth (from RKB)      | TVD          | m                 |
|              |                       | Measured depth                      | MD           | m                 |
|              | Completion type       | COMPLETION                          | -            |                   |
| innput.dat   | Program specific data | Name of analyser                    | ANALYST      | -                 |
|              |                       | Name of well                        | NAME         | -                 |
|              |                       | Name of well input file wellNR.dat  | PROFILE      | -                 |
|              |                       | Name of completiondata file Nrc.dat | COMPFILE     | -                 |
|              |                       | Name of file data is written to     | OUTFILE      | -                 |
|              | Fluid properties      | Production/injection rate           | RATE         | m <sup>3</sup> /d |
|              |                       | Density                             | DENSITY@WELL | kg/m <sup>3</sup> |
|              |                       | Watercut                            | WC           | -                 |
|              |                       | Production/injection time           | TID          | days              |
|              | Formation properties  | Density                             | ROE          | kg/m <sup>3</sup> |
| Conductivity |                       | KE                                  | W/mK         |                   |
| Heatcapacity |                       | CPE                                 | J/kgK        |                   |

## Appendix B2: output TempEnn

Table B-2: An example of the output from TempEnn.

| Input values                |                                   | Output |      |       |      |      |      |      |      |      |      |         |                |     |    |                |
|-----------------------------|-----------------------------------|--------|------|-------|------|------|------|------|------|------|------|---------|----------------|-----|----|----------------|
| flowrate                    | 2500 Sm <sup>3</sup> /d           |        |      |       |      |      |      |      |      |      |      | ANALYST | :Truls Valberg |     |    |                |
| wellfluid density           | 1000 kg/m <sup>3</sup>            |        |      |       |      |      |      |      |      |      |      | WELL    | :C14           |     |    |                |
| watercut                    | 1 -                               |        |      |       |      |      |      |      |      |      |      |         |                |     |    | <i>out.see</i> |
| time                        | 16 år                             |        |      |       |      |      |      |      |      |      |      | RATE    | WC             | TID | CP |                |
| formation density           | 2600 kg/m <sup>3</sup>            | MD     | TVD  | TFBDZ | UTOT | 2500 | 1    | 5840 | 4200 |      |      |         |                |     |    |                |
| formation conductivity      | 1,8 W/mK                          |        |      |       |      | UTOT | MD   | DL   | TVD  | TOZ  | TW   | DQDZ    | RW             |     |    |                |
| formation heat capacity     | 900 J/kgK                         | 200    | 200  | 10,06 | 2,11 | 2,11 | 200  | 100  | 200  | 7,6  | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| bottomhole temperature      | 80 °C                             | 300    | 300  | 10,06 | 2,11 | 2,11 | 300  | 100  | 300  | 10,2 | 10,1 | 1,6     | 0,159 SOIL     |     |    |                |
| sea bottom temperature      | 5 °C                              | 400    | 400  | 10,06 | 2,11 | 2,11 | 400  | 100  | 400  | 12,8 | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| air temperature             | 6 °C                              | 500    | 500  | 10,07 | 2,11 | 2,11 | 500  | 100  | 500  | 15,3 | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| water temp before injection | 10 °C                             | 600    | 600  | 10,08 | 2,11 | 2,11 | 600  | 100  | 600  | 17,9 | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| sea water temperature       | 4 °C                              | 700    | 700  | 10,10 | 2,11 | 2,11 | 700  | 100  | 700  | 20,5 | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| sea bottom depth            | 100 m                             | 800    | 800  | 10,12 | 2,11 | 2,11 | 800  | 100  | 800  | 23,1 | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| rotary kelly bushing        | 30 m                              | 900    | 900  | 10,14 | 2,11 | 2,11 | 900  | 100  | 900  | 25,7 | 10,1 | 0       | 0,159 SOIL     |     |    |                |
| well depth                  | 3000 m                            | 1000   | 1000 | 10,17 | 2,11 | 2,11 | 1000 | 100  | 1000 | 28,3 | 10,2 | 0       | 0,159 SOIL     |     |    |                |
| water conductivity          | 0,6 W/mK                          | 1100   | 1100 | 10,21 | 2,11 | 2,11 | 1100 | 100  | 1100 | 30,9 | 10,2 | 0       | 0,159 SOIL     |     |    |                |
| steel conductivity          | 60 W/mK                           | 1200   | 1200 | 10,25 | 2,11 | 2,11 | 1200 | 100  | 1200 | 33,4 | 10,2 | 0       | 0,159 SOIL     |     |    |                |
| cement conductivity         | 7 W/mK                            | 1300   | 1300 | 10,29 | 2,11 | 2,11 | 1300 | 100  | 1300 | 36   | 10,3 | 0       | 0,159 SOIL     |     |    |                |
| outer diameter casing       | 10 "                              | 1400   | 1400 | 10,34 | 2,11 | 2,11 | 1400 | 100  | 1400 | 38,6 | 10,3 | 0       | 0,159 SOIL     |     |    |                |
| inner diameter casing       | 8,49 "                            | 1500   | 1500 | 10,39 | 2,11 | 2,11 | 1500 | 100  | 1500 | 41,2 | 10,4 | 0       | 0,159 SOIL     |     |    |                |
| well diameter               | 12,5 "                            | 1600   | 1600 | 10,44 | 2,11 | 2,11 | 1600 | 100  | 1600 | 43,8 | 10,4 | 0       | 0,159 SOIL     |     |    |                |
| UTOT [W/m <sup>2</sup> K]   | OVERALL HEAT TRANSFER COEFFICIENT | 1700   | 1700 | 10,50 | 2,11 | 2,11 | 1700 | 100  | 1700 | 46,4 | 10,5 | 0       | 0,159 SOIL     |     |    |                |
| DL [m]                      | SEGMENT LENGTH                    | 1800   | 1800 | 10,57 | 2,11 | 2,11 | 1800 | 100  | 1800 | 49   | 10,6 | 0       | 0,159 SOIL     |     |    |                |
| TOAV [C]                    | MEAN AMBIENT ROCK TEMPERATURE     | 1900   | 1900 | 10,64 | 2,11 | 2,11 | 1900 | 100  | 1900 | 51,6 | 10,6 | 0       | 0,159 SOIL     |     |    |                |
| TFBDZ [C]                   | WELL TEMPERATURE                  | 2000   | 2000 | 10,71 | 2,11 | 2,11 | 2000 | 100  | 2000 | 54,1 | 10,7 | 0       | 0,159 SOIL     |     |    |                |
| TOZ [C]                     | TOZDZ FROM LAST CALCULATION       | 2100   | 2100 | 10,79 | 2,11 | 2,11 | 2100 | 100  | 2100 | 56,7 | 10,8 | 0       | 0,159 SOIL     |     |    |                |
| RW [m]                      | WELL RADIUS                       | 2200   | 2200 | 10,87 | 2,11 | 2,11 | 2200 | 100  | 2200 | 59,3 | 10,9 | 0       | 0,159 SOIL     |     |    |                |
| TW [C]                      | ROUNDED TFBDZ                     | 2300   | 2300 | 10,96 | 2,11 | 2,11 | 2300 | 100  | 2300 | 61,9 | 11   | 0       | 0,159 SOIL     |     |    |                |
| DQDZ [W/m]                  | TOTAL HEAT TRANSFER RATE          | 2400   | 2400 | 11,05 | 2,11 | 2,11 | 2400 | 100  | 2400 | 64,5 | 11,1 | 0       | 0,159 SOIL     |     |    |                |
| TVD [m]                     | TRUE VERTICAL DEPTH               | 2500   | 2500 | 11,15 | 2,11 | 2,11 | 2500 | 100  | 2500 | 67,1 | 11,1 | 0       | 0,159 SOIL     |     |    |                |
| MD [m]                      | MEASURED DEPTH                    | 2600   | 2600 | 11,25 | 2,11 | 2,11 | 2600 | 100  | 2600 | 69,7 | 11,2 | 0       | 0,159 SOIL     |     |    |                |
|                             |                                   | 2700   | 2700 | 11,35 | 2,11 | 2,11 | 2700 | 100  | 2700 | 72,2 | 11,3 | 0       | 0,159 SOIL     |     |    |                |
|                             |                                   | 2800   | 2800 | 11,46 | 2,11 | 2,11 | 2800 | 100  | 2800 | 74,8 | 11,5 | 0       | 0,159 SOIL     |     |    |                |
|                             |                                   | 2900   | 2900 | 11,57 | 2,11 | 2,11 | 2900 | 100  | 2900 | 77,4 | 11,6 | 0       | 0,159 SOIL     |     |    |                |
|                             |                                   | 3000   | 3000 | 11,69 | 2,11 | 2,11 | 3000 | 100  | 3000 | 80   | 11,7 | 0       | 0,159 SOIL     |     |    |                |

In the project the formation properties like density, conductivity and so on has been considered mostly the same in both the case studies. Also the casing properties have been kept constant. That means that the only properties changing are the flow rate, well fluid density, water cut, time, the water temperature before injection, and well depth (marked to the left). Of the out parameters from TempEnn, the UTOT (U-values) and the TW-values are the important ones. The TW-values are rounded well flow temperature-values (marked on the right side).

After running the program with three different input files, two out-put files are generated. This means that there are quite a lot of variables and parameters that one has to keep track off.

It has been decided only to present an example of the raw data of TempEnn, since over 50 similar files (spreadsheets like this one) were generated in this project.

## **Appendix B3: procedure for running TempEnn**

Part of this project was to create information or a procedure for how to run TempEnn. This was requested, because the program could be useful in teaching. This procedure is meant (and some part only accessible) for NTNU students. TempEnn is run in a Unix environment and has a written user interface instead of a graphical. Even though it is possible to compile, and run, the program in Windows, the description below is meant for use in the Unix environment. This is done since the necessary software for running in Windows is not accessible for students at the department. Note that the interface mentioned below is case sensitive. Some information on how to get started can be found on [www.ipt.ntnu.no/~jsgfag/programmer/TempEnn.html](http://www.ipt.ntnu.no/~jsgfag/programmer/TempEnn.html).

### **To get started**

This you have to do, to copy the necessary files into your user domain.

1. Check in *my computer* if the server *petrus* is mapped up. If not do the following
  - a. In *my computer* go to *tools* and *map networkdrive*
  - b. choose a drive and write in foldername `\\129.241.27.25\your username` press *finish*
2. On this server (you have your own user space) create a folder (f.eks TempEnn) that you will use for running the program. Create inside this folder two folders; one for injection and one for production
3. Connect to *petrus.ipt.ntnu.no* in an SSH client, like F-secure that is installed
4. Use your own username and password
5. A welcome message appears
6. Type `cd home` and press enter. As long as no error message appears, you are in the correct folder.
7. Type `ls` and you get a list of folders in the *home* folder you just entered
8. Your user should be found in the *petra1a* folder of *petra1b* folder. Access these by typing `cd petra1a` or `cd petra1b` respectively. To go back to the home folder type `cd ..` (use `ls` to check if your user is there)
9. When you have found your user; type `cd "your username"`
10. Type `ls` again, to see your folders (the ones you created in the first two steps of this procedure)
11. Type `cd "foldername"` (f. ex. TempEnn)
12. Type `cd prod` (or the name you gave to your productionfolder)
13. type `cp /localiptibm3/produksjon/Temp/prod/*`. (the period on the end is important ! and all spaces mentioned !)
14. Repeat step 11 to 13 for your injectionfolder by typing `cp /localiptibm3/produksjon/Temp/inject/*`. (don't forget the period !)
15. Now you are ready to start using the program

## How to run the program?

1. We start with organizing the input files
  - a. In windows enter the folder where you copied the files into
  - b. There are originally two sets of inputfiles: *wellb50.dat*, *wellb40.dat* and *b50c.dat*, *b40c.dat*. There is also one called *innput.dat*, this is the file were you write which of the files you want TempEnn to use.
  - c. Open the inputfiles you want to use in f.ex. Microsoft Word and change the parameters to what you want it to be. For a comprehensible list of the input parameter see Table B-1 (NR=40 or 50)
    - i. It is recommended to start with *wellbNR.dat*
    - ii. In *bNRc.dat* the listed parameters change due to changing casingsize down the well. You don not necessarily need all of them, the casing program is up to you to decide.
    - iii. In *innput.dat* you tell TempEnn which inputfiles it should use, you also name the outputfile (this has to be changed for each test !)
2. The next step is to find out which programfiles to use. There are several combinations possible, there will be presented only one example, to make sure it is easy to follow. It is suggested that when you have to do a lot of calculations and have some troubles that you find out more about the different files.
  - a. Connect to *petrus.ipt.ntnu.no* in an SSH client, like F-secure that is installed
  - b. Use your own username and password
  - c. A welcome message appears
  - d. Enter your TempEnn folder (the prod *or* inject folder)
  - e. Now you have to compile the program, this involves telling the Fortran compiler which of the programfiles it should use. An example for a production well can be: *xf -o prodtest temp4\_0.f tetahaal.f beta\_soilt.f con2.f ufunkt.f solbe.f stehfest.f lapsol.f bessfunk.f* This is an example of a well that goes up to the sea bed, that is why *beta\_seat.f* and *beta\_airt.f* is not included in the compilation (*prodtest* is an example of a name for executable file, and can be changed if you want to).
  - f. The program is run by typing *prodtest* as the second command
3. Now you get two output files: *profil.dat* and *name.see* (the name you have specified in *innput.dat*) (for a list of output parameters see in Table B-2)
4. These .dat files can be opened in f.ex Microsoft Word (for additional editing) or directly imported in a program like Microsoft Excel

How all the different program files are connected is explained graphically on the next page.

The different program files are connected as follows

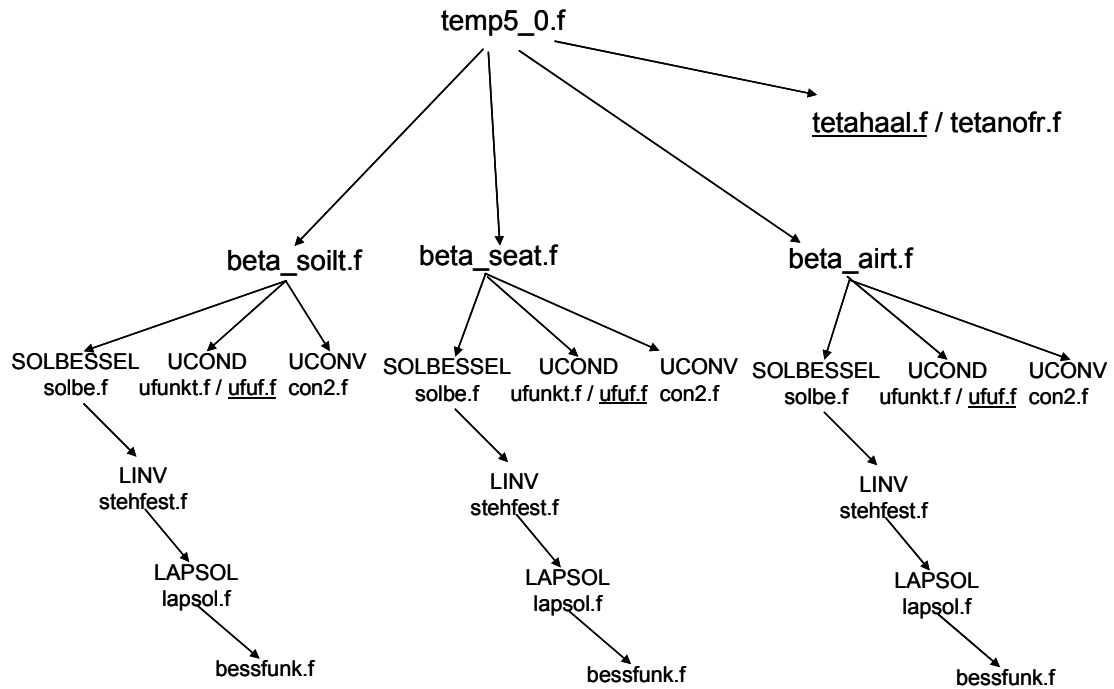


Figure B-1: The production tree

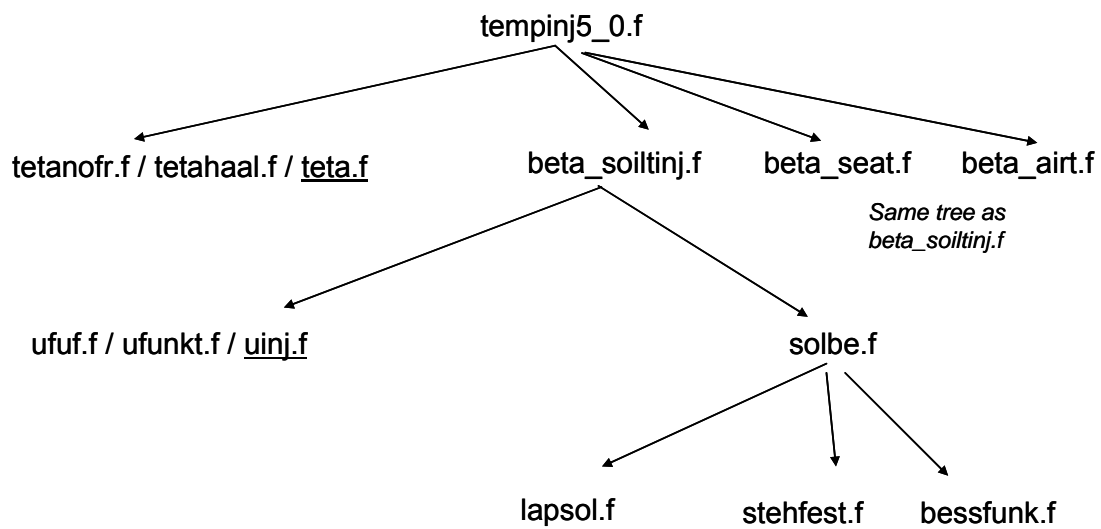


Figure B-2: The injection tree

## Appendix C: HYSYS

### Appendix C1: HYSYS and the JT coefficient

Which part of the temperature loss is due to the Joule-Thomson effect?

U calculated in TempEnn after one day of injection equals 6.6 W/m<sup>2</sup>°C.

When U = 0, no temperature drop will be caused by heat transfer to the formation, then only the Joule-Thomson cooling causes the temperature to drop. The results from HYSYS presented here seem to be wrong as the heat loss to the formation only constitutes 1.66 and 1.93 degrees C.

The Joule-Thomson coefficient values seem similar to Marić' values, but the calculated temperature loss will be calculated far too high. This is because the calculated pressure loss is the *total* pressure loss, not only pressure loss due to the JT expansion.

$$\mu = \left( \frac{\delta T}{\delta P} \right)_H \quad R = 8314,3 \text{ J/kmolK}$$

$$Pv = zRT \quad v = \frac{zRT}{P}$$

$$\delta Pv = zR\delta T$$

$$\delta T = \frac{\delta Pv}{zR}, \quad \delta P = \frac{zR\delta T}{v}$$

$$\mu = \frac{\delta Pv}{zR\delta P} = \frac{v}{zR} \left( = \frac{M}{Z\rho R} = \frac{\delta T}{\delta P} \right)$$

$$\Delta T = \mu\Delta P$$

| MD (m) | Stream number | Z-factor U = 6,6 |                       | Temp U=6,6 (gr C) |                       |
|--------|---------------|------------------|-----------------------|-------------------|-----------------------|
|        |               | Beggs and Brill  | HTFS Homogeneous flow | Beggs and Brill   | HTFS Homogeneous flow |
| 4200   | 4             | 0,9458           | 0,9458                | 97,13             | 97,13                 |
| 3500   | 6             | 0,9435           | 0,9436                | 96,62             | 96,64                 |
| 3000   | 7             | 0,8950           | 0,9118                | 86,09             | 89,61                 |
| 100    | 8             | 0,8847           | 0,9030                | 82,22             | 86,53                 |
| 0      | 9             | 0,8705           | 0,8892                | 75,16             | 81,88                 |
|        | Δ             |                  |                       | 21,97             | 15,25                 |

| MD (m) | Stream number | Temp U=0 (gr C) |                       | Pressure (MPa)  |                       |
|--------|---------------|-----------------|-----------------------|-----------------|-----------------------|
|        |               | Beggs and Brill | HTFS Homogeneous flow | Beggs and Brill | HTFS Homogeneous flow |
| 4200   | 4             | 97,13           | 97,13                 | 29              | 29                    |
| 3500   | 6             | 96,63           | 96,64                 | 28,71           | 28,73                 |
| 3000   | 7             | 86,77           | 90,41                 | 21,21           | 24,3                  |
| 100    | 8             | 83,22           | 88,01                 | 19,45           | 23,12                 |
| 0      | 9             | 76,82           | 83,81                 | 16,71           | 21,27                 |
|        | Δ             | 20,31           | 13,32                 | 12,29           | 7,73                  |

| MD (m) | Stream number | v U=6,6 (m3/kmol) |                       | μ (K/Pa)        |                       |
|--------|---------------|-------------------|-----------------------|-----------------|-----------------------|
|        |               | Beggs and Brill   | HTFS Homogeneous flow | Beggs and Brill | HTFS Homogeneous flow |
| 4200   | 4             | 0,10              | 0,10                  | 1,28E-05        | 1,28E-05              |
| 3500   | 6             | 0,10              | 0,10                  | 1,29E-05        | 1,29E-05              |
| 3000   | 7             | 0,13              | 0,11                  | 1,69E-05        | 1,49E-05              |
| 100    | 8             | 0,13              | 0,12                  | 1,83E-05        | 1,56E-05              |
| 0      | 9             | 0,15              | 0,12                  | 2,08E-05        | 1,67E-05              |

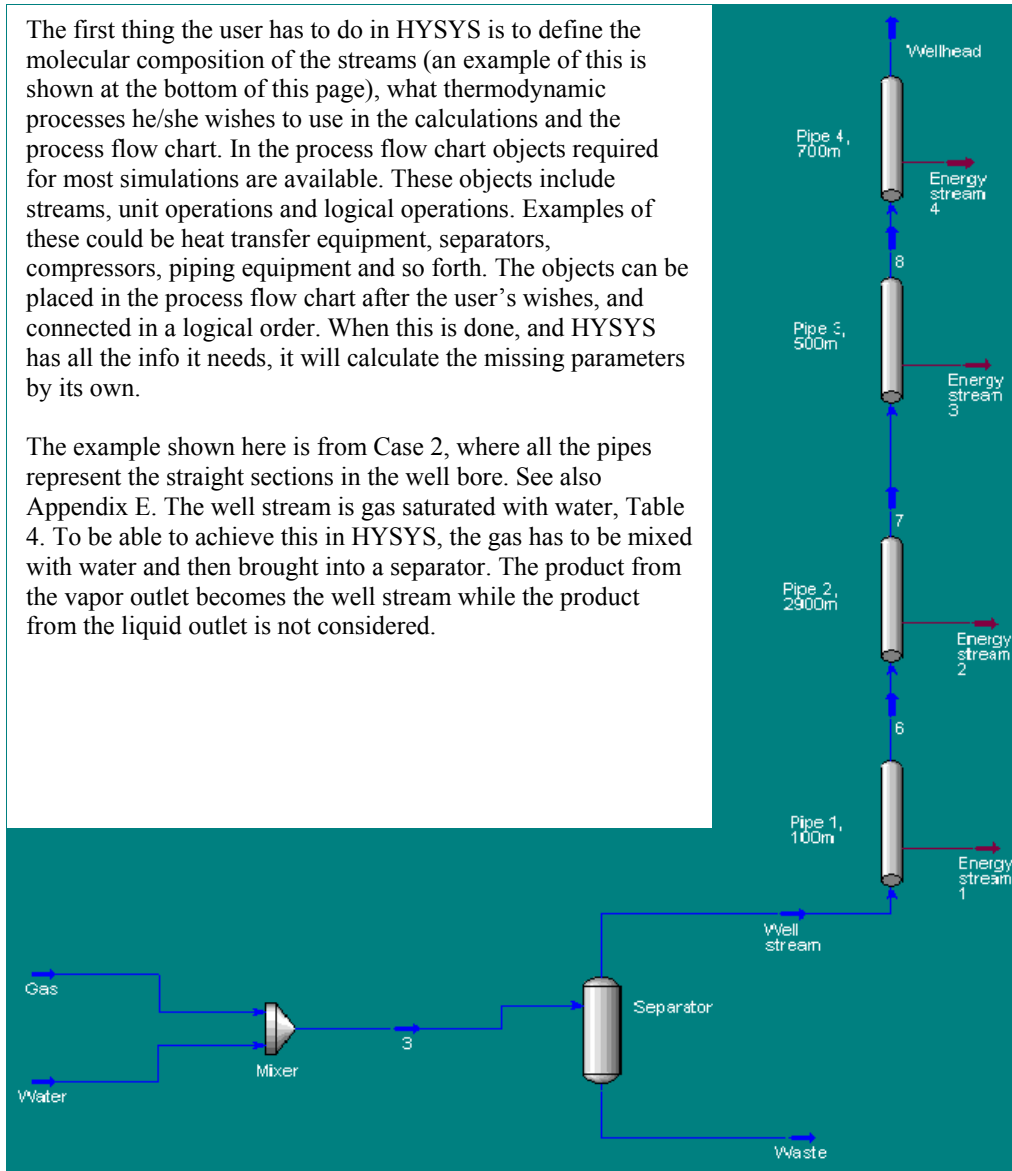
  

| MD (m) | Stream number | μ (K/bar)       |                       | ΔT (K)          |                       |
|--------|---------------|-----------------|-----------------------|-----------------|-----------------------|
|        |               | Beggs and Brill | HTFS Homogeneous flow | Beggs and Brill | HTFS Homogeneous flow |
| 4200   | 4             | 1,28            | 1,28                  | 156,86          | 98,66                 |
| 3500   | 6             | 1,29            | 1,29                  | 154,49          | 95,98                 |
| 3000   | 7             | 1,69            | 1,49                  | 76,19           | 45,21                 |
| 100    | 8             | 1,83            | 1,56                  | 50,04           | 28,77                 |
| 0      | 9             | 2,08            | 1,67                  | 0,00            | 0,00                  |

## Appendix C2: HYSYS user interface

The first thing the user has to do in HYSYS is to define the molecular composition of the streams (an example of this is shown at the bottom of this page), what thermodynamic processes he/she wishes to use in the calculations and the process flow chart. In the process flow chart objects required for most simulations are available. These objects include streams, unit operations and logical operations. Examples of these could be heat transfer equipment, separators, compressors, piping equipment and so forth. The objects can be placed in the process flow chart after the user's wishes, and connected in a logical order. When this is done, and HYSYS has all the info it needs, it will calculate the missing parameters by its own.

The example shown here is from Case 2, where all the pipes represent the straight sections in the well bore. See also Appendix E. The well stream is gas saturated with water, Table 4. To be able to achieve this in HYSYS, the gas has to be mixed with water and then brought into a separator. The product from the vapor outlet becomes the well stream while the product from the liquid outlet is not considered.



| Worksheet  | Stream Name             | Gas                           | Vapour Phase |             |
|------------|-------------------------|-------------------------------|--------------|-------------|
| Conditions | Vapour / Phase Fraction | 1.0000                        | 1.0000       |             |
|            | Temperature [C]         | 95.00                         | 95.00        |             |
|            | Properties              | Pressure [kPa]                | 2.900e+004   | 2.900e+004  |
|            | Composition             | Molar Flow [kgmole/h]         | 1.834e+004   | 1.834e+004  |
|            | K Value                 | Mass Flow [kg/h]              | 3.200e+005   | 3.200e+005  |
|            | User Variables          | Std Ideal Liq Vol Flow [m3/h] | 1017         | 1017        |
|            | Notes                   | Molar Enthalpy [kJ/kgmole]    | -7.732e+004  | -7.732e+004 |
|            | Cost Parameters         | Molar Entropy [kJ/kgmole-C]   | 141.1        | 141.1       |
|            |                         | Heat Flow [kJ/h]              | -1.418e+009  | -1.418e+009 |
|            |                         | Liq Vol Flow @Std Cond [m3/h] | <empty>      | <empty>     |
|            | Fluid Package           | Basis-1                       |              |             |

## Appendix D: Additional information Case 1

### Calculation of equivalent inner diameter

$$ID = 45\text{cm} \Rightarrow r_o = 22,5\text{cm} \Rightarrow r_i = 12,5\text{cm}$$

$$A = \pi r^2$$

$$A_{tot} = \pi * 0,225^2 = 0,159\text{m}^2$$

$$A_2 = \pi * (r_o^2 - r_i^2) = \pi * (0,225^2 - 0,125^2) = 0,110\text{m}^2$$

$$\frac{A_2}{A_{tot}} = \frac{0,11}{0,16} = 0,69$$

This change in flow area leads to this change in diameter:

$$0,16 = \pi * 0,225^2$$

$$0,69 * 0,16 = \pi * r_{eq}^2 \Rightarrow r_{eq} = \sqrt{\frac{0,69 * 0,16}{\pi}} = 0,187\text{m}$$

$$d_{eq} = 2 * r_{eq} = 2 * 0,187 = 0,374\text{m} = 37,4\text{cm}$$

A is general circle area,  $A_{tot}$  is total circle area,  $A_2$  is the outer circle area,  $r_o$  is the outer circle radius,  $r_i$  is the inner circle radius,  $r_{eq}$  is the equivalent radius and  $d_{eq}$  is the equivalent diameter of the circle.

\*1: small miscalculation with assumed small implications

## Appendix E: Additional information Case 2

### Wellbore profile

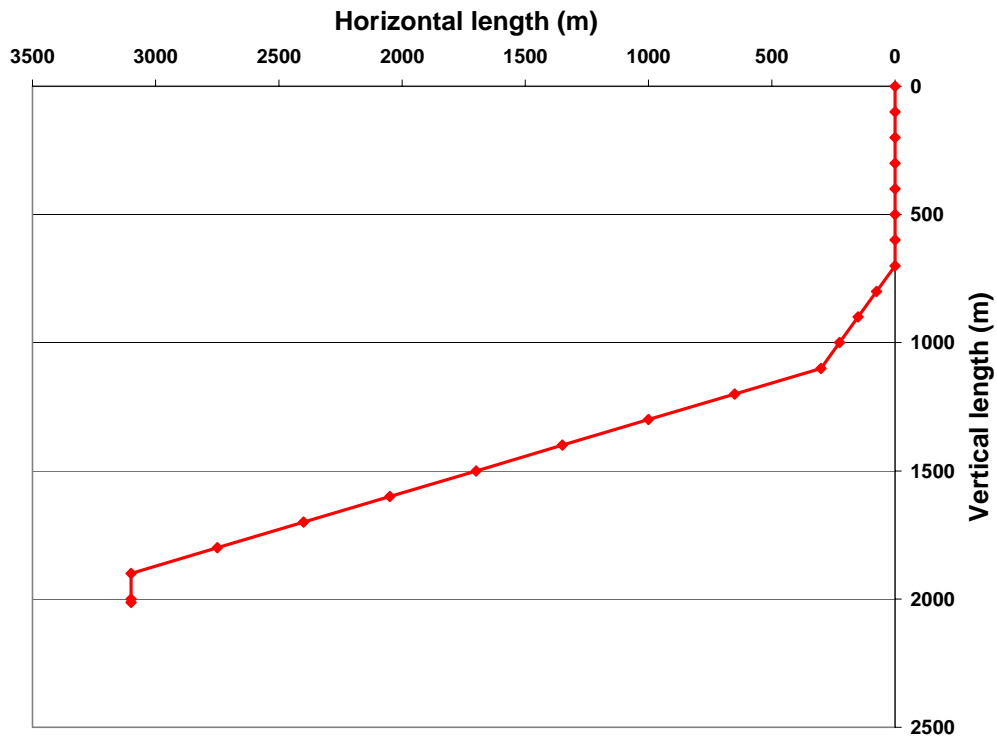


Figure E-1 Elevation profile of the Ormen Lange well