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A COUPLED WELLBORE-RESERVOIR SIMULATOR UTILIZING MEASURED WELLHEAD CONDITIONS

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ABSTRACT

The main objective in this study is to develop a coupled wellbore-reservoir simulator to allow for more integrated modeling and to use wellhead conditions to a greater extent than has been done so far by defining them as main inputs to the coupled model. The program TOUGH2 is used to simulate the behavior of a reservoir while a new model, FloWell, is designed to simulate two phase flow in a wellbore. Finally, a detailed numerical model of the Reykjanes geothermal field in Iceland is constructed, including the coupled FloWell-TOUGH2 model.

FloWell produced simulations in good agreement with pressure logs from wells at Reykjanes and Svartsengi geothermal fields. An inverse estimation with iTOUGH2 was effective in finding new permeabilities for the Reykjanes reservoir, providing a reasonable match for the natural state of the reservoir as well as the observed pressure drawdown. Predicting the response of Reykjanes reservoir in 2012-2027, for a production to maintain 150 MW_e power generation with 77.8 kg/s injection, caused the mass being removed at a higher rate than physically possible. Increasing the injection to 220 kg/s resulted in a steady decline in pressure and after 15 years of simulation a total of 18 bar drawdown in pressure was detected in the reservoir and 12 bar at the boundaries.

NOMENCLATURE

A cross sectional area [m^2]
d diameter [m]
f friction factor
Fr Froude number
g acceleration due to gravity [m/s^2]
G mass velocity [kg/m^{2}s]
h enthalpy [J/kg]
$\dot{m}$ mass flow [kg/s]
k permeability [mD]
p pressure [Pa]
$\dot{Q}$ heat loss [W/m]
PI productivity index
Re Reynolds number
S slip ratio
u velocity [m/s]
We Weber number
x steam quality
z axial coordinate
Φ friction correction factor
σ surface tension [N/m]
α void fraction
ρ density [kg/m^3]
μ dynamic viscosity [Pa/s]
ε roughness [m]

Subscripts
l liquid phase
g gas or vapor phase

INTRODUCTION

With growing world population and increasing environmental concerns, the demand for renewable energy and sustainable use of resources is steadily rising. Excessive exploitation of geothermal resources is often pursued, resulting in cooling of rocks, reduced production capacity and finally depletion of geothermal reservoirs. Mathematical models are therefore one of the most fundamental tools in geothermal resource management for they can be used to extract information on conditions of geothermal systems, predict reservoir's behavior and estimate production potential (Axelsson, 2003).

Most reservoirs are monitored by descending equipment to measure pressures and temperatures in wells. From these measurements the drawdown in pressure in a reservoir can be estimated. This is a time consuming and expensive process which usually involves a production stop in producing geothermal wells. On the other hand, well conditions are observed constantly by measuring instruments accessible at the top of wells. From the information gathered at the wellheads much can be learned about the behavior of wells and consequently the reservoir behavior. Therefore, a method for simulating the response of geothermal systems to exploitation, such as the drawdown in pressure, by easily obtained wellhead parameters is very desirable.

The main objective in this study is to create a practical tool to evaluate the state of geothermal reservoirs and well performances using measured wellhead conditions and inverse analysis. This is to be done by coupling a wellbore simulator to a reservoir simulator with the measured conditions as main inputs. For this purpose the program TOUGH2 is used to simulate the multi phase flow in a reservoir while a new wellbore simulator, FloWell, is designed to simulate the behavior of wells. The inverse analysis, performed with the program iTOUGH2, enables continuous evaluation of chosen parameters in both FloWell and TOUGH2 and the measured wellhead conditions provide up to date data to model the current situation in the geothermal system.

In addition to coupling FloWell to TOUGH2 the wellbore simulator FloWell is validated with pressure logs from the Reykjanes and Svartsengi geothermal fields in Iceland. Finally, a detailed numerical model of the Reykjanes geothermal field including the coupled FloWell-TOUGH2 model is constructed and used in several forecasting scenarios where different reservoir management options are examined.

THE PHYSICAL MODEL FLOWELL

Following sections describe the mathematical approaches behind the wellbore simulator FloWell. The expressions of the governing equations for single and two phase flow proposed by Pálsson (2011) are used in this study.

Single phase flow

The continuity equation derives from conservation of mass and can be written as

$$u\left(\frac{\partial\rho}{\partial p}\frac{dp}{dz}+\frac{\partial\rho}{\partial h}\frac{dh}{dz}\right)+\rho\frac{du}{dz}=0 \tag{1}$$

The energy equation contains a kinetic energy part, gravitational potential energy part and thermal energy part. The equation can be written as

$$\dot{m}u\frac{du}{dz}+\dot{m}\frac{dh}{dz}+\dot{m}g+\dot{Q}=0 \tag{2}$$

The momentum equation contains inertia, pressure changes, hydrostatic pressure and head loss part. The relation is written as follows

$$\rho u\frac{du}{dz}+\frac{dp}{dz}+\rho g+\frac{\rho f}{2d}u^2=0 \tag{3}$$

where f is the friction factor and d is the pipe diameter. Possible relations for the friction factor are the Blasius equation for smooth pipes

$$f=\frac{0.316}{Re^{1/4}} \tag{4}$$

and the Swamee-Jain relation, where the effect of pipe roughness is included;

$$f=\frac{0.25}{\left(\log\left(\frac{\epsilon}{3.7d}+\frac{5.74}{Re^{0.9}}\right)\right)^2} \tag{5}$$

The Reynolds number used for the evaluation of the friction factor is defined as

$$Re=\frac{\rho ud}{\mu} \tag{6}$$

Two phase flow

In two phase flow the flow consist of liquid and vapor states. Assuming constant pipe diameter, using the void fraction definition and introducing the uniform velocity u instead of the actual velocities, the continuity equation becomes

$$u\frac{\partial\rho_l}{\partial p}\frac{dp}{dz}+\rho_l\frac{du}{dz}=0 \tag{7}$$

Similar to single phase flow, the energy equation can be written as

$$\frac{d}{dz}\left(\dot{m}_l\left(\frac{{u_l}^2}{2}+gz+h_l\right)+\dot{m}_l\left(\frac{{u_l}^2}{2}+gz+h_l\right)\right)+\dot{Q}=0 \tag{1}$$

By using the mass fraction x, the uniform velocity u and the partial derivatives the energy equation can be expressed on the form

$$\gamma u\frac{du}{dz}+\frac{u^2}{2}\frac{\partial\gamma}{\partial p}\frac{dp}{dz}+\left(1+\frac{u^2}{2}\frac{\partial\gamma}{\partial h}\right)\frac{dh}{dz}+g+\frac{\dot{Q}}{\dot{m}}=0 \tag{2}$$

where γ is defined as

$$\gamma=\frac{(1-x)^3}{(1-\alpha)^2}+\frac{\rho_l^2x^3}{\rho_g^2\alpha^2} \tag{3}$$

The momentum equation for two phase flow can be written as

$$\eta\rho_l u\frac{du}{dz}+\left(1+\rho_l u^2\frac{\partial\eta}{\partial p}+\eta u^2\frac{\partial\rho_l}{\partial p}\right)\frac{dp}{dz}+\rho_l u^2\frac{\partial\eta}{\partial h}\frac{dh}{dz}+\left((1-\alpha)\rho_l+\alpha\rho_g\right)g+\frac{\Phi^2\rho_l f_l}{2d}u^2=0 \tag{4}$$

where Φ^2 is the frictional correction factor for pressure loss in two phase flow and η is defined as

$$\eta=\frac{(1-x)^2}{1-\alpha}+\frac{\rho_l}{\rho_g}\frac{x^2}{\alpha} \tag{5}$$

Since u is based on a fluid with liquid properties, the friction factor is evaluated based on

$$Re_l=\frac{\rho_l ud}{\mu_l} \tag{6}$$

Friction correction factor

Various relations exist for the friction correction factor Φ^2. Here, two relations will be presented, the Friedel and Beattie approximations. The Friedel correction factor is defined as

$$\Phi^2=E+\frac{3.24FH}{Fr^{0.045}We^{0.035}} \tag{7}$$

where

$$E=(1-x^2)+x^2\frac{\rho_l}{\rho_g}\frac{f_g}{f_l} \tag{8}$$

$$F = x^{0.78}(1 - x^2)^{0.24} \tag{9}$$

$$H = \left(\frac{\rho_l}{\rho_g}\right)^{0.91} \left(\frac{\mu_g}{\mu_l}\right)^{0.19} \left(1 - \frac{\rho_g}{\rho_l}\right)^{0.7} \tag{10}$$

$$Fr = \frac{{\rho_l}^2 u^2}{g \rho_m^2 d} \tag{11}$$

$$We = \frac{{\rho_l}^2 u^2 d}{\sigma \rho_x^2} \tag{12}$$

$$\frac{1}{\rho_x} = \frac{x}{\rho_g} + \frac{1 - x}{\rho_l} \tag{13}$$

The ρ_x is the homogenous density based on steam quality. The Bettie correction factor is much simpler, and can be calculated by a single equation (García-Valladares et al., 2006)

$$\Phi^2 = \left(1 + x\left(\frac{\rho_l}{\rho_g} - 1\right)\right)^{0.8} \left(1 + x\left(\frac{3.5\mu_g + 2\mu_l}{(\mu_g + \mu_l)\rho_g} - 1\right)\right)^{0.2} \tag{14}$$

Void fraction definition

One of the critical unknown parameter in predicting pressure behavior in a wellbore is the void fraction, which is the space occupied by gas or vapor. Countless void fraction correlations have been created and it can often turn out to be a difficult task choosing the appropriate correlation.

The homogeneous model is the most simplified. The two phases, liquid and vapor, are considered as homogeneous mixture, thereby traveling at the same velocity. Another approach is to assume that the phases are separated into two streams that flow with different velocities. The modified homogeneous model introduces the slip ratio, S, which is the ratio between the flow velocities at given cross section. The model can be written as

$$\alpha = \frac{\frac{x}{\rho_g}}{\frac{x}{\rho_g} + \frac{1 - x}{\rho_l} S} \tag{15}$$

In the homogenous model it is assumed that the slip ratio is equal to one. Other models extend the simple homogenous flow model by using other derived relations as the slip ratio. Zivi (1964) proposed that the slip ratio was only dependent on the density ratio of the phases;

$$S = \left(\frac{\rho_l}{\rho_g}\right)^{1/3} \tag{16}$$

Chisholm (1973) arrived at the following correlation for the slip ratio

$$S = \left(\frac{\rho_l}{\rho_x}\right)^{1/2} \tag{17}$$

One of the more complex void fraction based on slip ratio is the one introduced by Premoli et al. (1970). Their slip ratio is defined as

$$S = 1 + F_1 \left(\frac{y}{1 + yF_2} - yF_2\right) \tag{18}$$

where

$$F_1 = 1.578 Re_l^{-0.19} \left(\frac{\rho_l}{\rho_g}\right)^{0.22} \tag{19}$$

$$F_2 = 0.0273 We_l Re_l^{-0.51} \left(\frac{\rho_l}{\rho_g}\right)^{-0.08} \tag{20}$$

$$y = \frac{1}{\left(\frac{1 - x}{x}\right)\left(\frac{\rho_g}{\rho_l}\right)} \tag{21}$$

$$We_l = \frac{G^2 d}{\sigma \rho_l} \tag{22}$$

$$Re_l = \frac{Gd}{\mu_l} \tag{23}$$

The Lockhart-Martinelli correlation (1949) is often chosen due to its simplicity. In this model, the relationship between void fraction, steam quality, density and viscosity is derived as

$$\alpha = \left(1 + 0.28\left(\frac{1-x}{x}\right)^{0.64} \left(\frac{\rho_g}{\rho_l}\right)^{0.36} \left(\frac{\mu_l}{\mu_g}\right)^{0.07}\right)^{-1} \tag{24}$$

Rouhani and Axelsson (1970) proposed a void fraction computed by a semi-empirical equation given as

$$\alpha = \left(\frac{x}{\rho_g}\right)\left(\left(1 + 0.12(1 - x)\right)\left(\frac{x}{\rho_g} + \frac{1-x}{\rho_l}\right) + \right. \tag{25}$$

1.181−xgσρl−ρg0.25Gρl0.5−1

This model is more extensive than previous model, where it takes into account the effects of cross sectional are of the pipe, mass flow rate of the mixture, surface tension and gravitation.

THE MODEL TOUGH2

TOUGH2 is a general numerical simulator for non-isothermal multi phase flow in porous and fractured media. TOUGH2 calculates the thermodynamic conditions present in a predefined geothermal reservoir by integrating basic mass and energy balance equations for a given domain. The mass and energy equations are discretized in space based on an integral finite difference method. To obtain numerical stability required for multi phase flow calculations the time is discretized as a first order finite difference in a fully implicit manner. This results in a set of coupled nonlinear equations which are solved by employing Newton-Raphson iteration. TOUGH2 accounts for sinks and sources in calculations and the generation rates can be time dependent or independent. Furthermore, it can be assumed that wells operate on deliverability against fixed bottomhole pressures and productivity indices (Pruess, 1999).

THE MODEL ITOUGH2

Inverse problems often lead to difficult optimization routines with no straightforward solution. Therefore, no general method is at hand to solve all inverse problems. The most common formulation is based on system identification techniques and least-squares fitting of parameterized models to measured data. In brief, inverse modeling consists of estimating model parameters from measurements of system response at discrete points in time and space.

A number of mathematical models and data processing techniques can be used in solution of an inverse problem. A basic simulation package called iTOUGH2 is frequently used. iTOUGH2 is a computer program for parameter estimation and sensitivity and uncertainty analysis. The program contains various minimization algorithms to find the minimum of the objective function which is the difference between model results and measured data. The basic procedure in iTOUGH2 is to continuously compare the calculated output from TOUGH2 to measure data while changing the value of selected input parameters. If a change in an input parameter results in reduction of the objective function, the program has found a better estimation for the parameter. In this study the Levenberg-Marquardt minimization algorithm is used to evaluate the objective function.

iTOUGH2 is usually run in combination with TOUGH2, a forward simulator for non-isothermal multiphase flow in porous and fractured media, but can also be linked to non-TOUGH2 models. In that way the iTOUGH2 can be used as an inverse analyzing tool for models such as the wellbore simulator FloWell (Finsterle, 2007).

To be able to link non-TOUGH2 models with iTOUGH2, a protocol called PEST has been implemented in iTOUGH2. The protocol enables interaction between the non-TOUGH2 model and iTOUGH2 through a clear and simple communication format (Finsterle, 2010).

THE BASIC ARCHITECTURE OF FLOWELL

For this study, a numerical wellbore simulator has been developed and named FloWell. The simulator is built around eq. (1)-(32) defined in the chapter The *Physical Model of FloWell* and MATLAB is used as a programming language.

To perform a simulation with FloWell the following input parameters are needed:

- Inner diameter and depth of a well
- Roughness of the pipe walls in a well
- Total mass flow rate at the wellhead
- Enthalpy of the working fluid
- Bottomhole pressure or wellhead pressure

Features and assumptions

The wellbore simulator is capable of:

- Modeling liquid, two phase and superheated steam flows
- Allowing users to choose between various friction, friction correction factor and void fraction correlations
- Performing wellbore simulations from the bottomhole to wellhead section, or from the wellhead to the bottom of the well
- Providing simulated results, such as pressure and temperature distribution as well as steam quality, friction, velocity, enthalpy and void fraction at each dept increment
- Providing graphical plots of simulated pressure and temperature profiles

Some general assumptions have been made in the development of the simulator. It is assumed that:

- The flow is steady and one dimensional
- Multiple changes of the wellbore geometry, such as diameters and roughness, do not occur
- Simulations will be restricted to wells with single feedzones
- The fluid is pure water
- Phases are in thermodynamic equilibrium
- Fluid properties remain constant within a step
- The presence of non-condensable gases and dissolved solids is ignored

The simulator solves the continuity, energy and momentum equations up or down the well using numerical integration. The *ode23* function built in MATLAB is used to evaluate the differential equations. The depth interval is adjusted by the integration function and at each depth node the function produces velocity, pressure and enthalpy values.

VALIDATION OF FLOWELL

Validation is usually achieved through model calibration, that is comparing results from the simulation to actual system behavior. To validate FloWell, data, provided by the Icelandic company HS Orka, from wells at two geothermal fields, Reykjanes and Svartsengi, in the Reykjanes peninsula is used.

FloWell offers a considerably wide selection of empirical correlations for two phase calculations. Which correlation performs best is a question many scientists and researches struggle to answer. More often than not, there is no one right answer to this question as it can prove to be difficult to find one correlation to simulate the diverse characteristics found in geothermal wells.

Utilizing the features iTOUGH2 has to offer, a measure of how each void fraction correlation performs in simulating the pressure and temperature profiles in a well can be found. Since FloWell is a non-TOUGH2 model, an inverse run with iTOUGH2-PEST is initialized to calculate an objective function. The function describes how a simulation with FloWell fits measured data, in this case data points from pressure logs. If, for example, the objective function calculated using the void fraction correlation by Rouhani-Axelsson is lower than the one found with the Homogenous correlation, the Rouhani-Axelsson correlation is more likely to simulate the expected behavior of the well.

The objective function is calculated for each well and for all void fraction correlations. The calculated objective functions are compared within each well and the correlation which yields the lowest objective function is identified. With that, a ranking of the correlations can be established for each well. These individual rankings can be summarized to find an overall ranking for the wells. Several feedzones are present in a well but since FloWell is a single feedzone simulator the most reliable simulations would be the ones that only reach the bottom of the production casing. Simulating further down the well is also an option but it may invite unreliable predictions

The results from the void fraction comparison show that the model by Chisholm most often yields results closest to measured data. The model by Premoli et al. is the one that is most often in second place, the model by Rouhani-Axelsson is most often in third place and the model by Lockhart-Martinelli is most often in fourth place. The model by Zivi is the one that produces the worst predictions, placing most often in the last two places. To further summarize the results the correlation by Rouhani-Axelsson ranks most often in the top three while the model by Zivi ranks most often the lower three as before.

To better understand how FloWell performs, visual results are of great help. Wells RN-11, RN-12, RN-21, RN-24 and SV-21 have similar characteristics. They are vertical wells with low enthalpy fluid and steam fraction between 9-13% at the wellhead. Simulations for wells RN-12 and SV-21 can be seen in Fig. 2 and 3. For these simulations the Blasius equation and the model by Friedel are used to calculate the friction factor and friction correction factor.

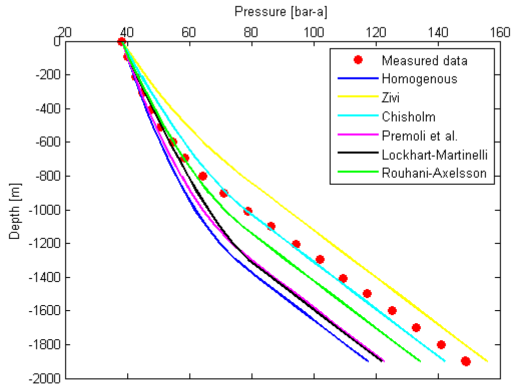

Figure 1: Simulations for well RN-12 with FloWell.

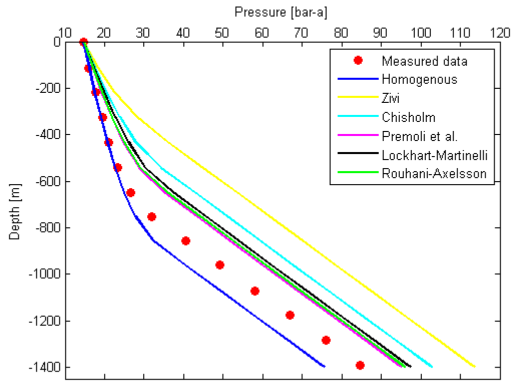

Figure 2: Simulations for well SV-21 with FloWell.

For well RN-12 the Rouhani-Axelsson and the Chisholm void fraction correlations perform the best. For well SV-21 the Homogenous correlation shows simulations closest to the measured data. The Homogenous correlation usually yields adequate simulations for wells with a low steam fraction, for it assumes that the phases travel at the same velocity. This is the case in well SV-21, the steam fraction in the well is between 9-10%, while the steam fraction in well RN-12 is little over 13%.

Since FloWell is also capable of starting at the bottom of a well and calculating up, it is interesting to see a simulation up the well versus down the well. Simulations up well SV-21 are presented in Fig. 4. Comparing Fig. 3 and 4 it can be seen that considerable difference is between simulating up the well and down the well. Despite this difference, the homogenous correlation still performs best and the model by Zivi the worst. From this discussion the question which option is more accurate arises. As it is easier to measure wellhead parameters than downhole ones, wellhead conditions are constantly being monitored and noted. From that alone it may be concluded that simulating down the well is more accurate but if carefully measured parameters exist at the top and at the bottom it may prove difficult to favor one over the other

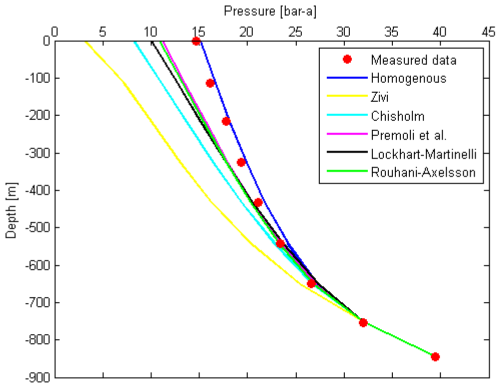

Figure 4: Simulations for well SV-21 starting at the bottom and simulating up.

FloWell manages to simulate the behavior of geothermal wells to some extent but no correlation simulates the exact pressure profile in a well. It is intriguing to use inverse analysis with iTOUGH2-PEST to improve parameters in the void fraction correlations so simulations with FloWell better fit measured data. Using the Homogenous model in Eq. (22) to calculate the void fraction in well RN-11, FloWell yields a simulation that is not very close to the known pressure profile. It is assumed that the slip ratio is equal to one in the Homogenous correlation. If inverse analysis is applied to well RN-11 and the slip ratio evaluated, several iterations with iTOUGH2-PEST result in a new value for the slip ratio, $S=1.68$. Using this value instead of one in the Homogenous correlation, almost a perfect match to the measured data is obtained with FloWell as seen in Fig. 5.

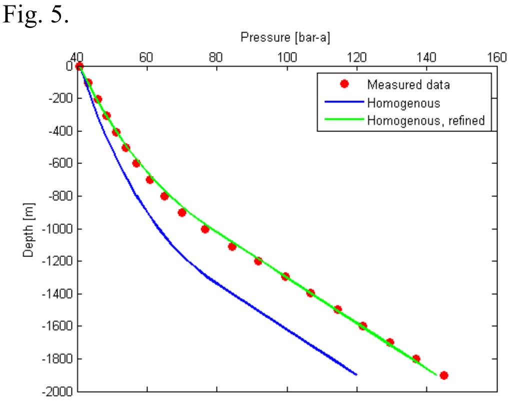

Figure 5: Simulations for well RN-11 with the original Homogenous model (blue) and with improved slip ratio (green).

THE COUPLED FLOWELL-TOUGH2 MODEL

In addition to designing a coupled wellbore-reservoir model, an inverse analysis with continually measured wellhead parameters as observations is applied to the coupled model to improve the model design and keep it up to date. For the model calibration the inverse analysis program iTOUGH2 is used. Usually, the emphasis is on calibrating the reservoir model TOUGH2, but the method suggested here is to apply an inverse analysis on the wellbore simulator as well. This is to be done in an iterative manner where measured wellhead conditions are used to calibrate the reservoir model to find estimates for the bottomhole pressures in wells. These bottomhole pressures are then used to calibrate the wellbore simulator. This iteration process is explained in detail in following paragraphs.

One of the main focuses in this study is to utilize the measured wellhead parameters to a greater extent than has been done so far, by using them as an input to the coupled model and to calibrate the model with an inverse analysis. As new wellhead parameters are measured they are imported into the coupled model and an iterative inverse analysis process is initiated. This results in continuous improvements being made to the model design in the reservoir simulator and in the wellbore simulator.

The basic methodology behind the coupled model is illustrated in Fig. 6. The parameters that are measured or estimated at the wellhead, the mass flow rate, enthalpy and pressure, are the input to the wellbore simulator FloWell. FloWell calculates the bottomhole pressures in the wells using available empirical correlations. To couple FloWell to TOUGH2 the bottomhole pressures are inserted into the input file for TOUGH2. An inverse analysis by iTOUGH2 on the reservoir model returns new values for the bottomhole pressures in the wells. Lastly, these new values are used in a second inverse analysis performed on the wellbore simulator by iTOUGH2-PEST to obtain a new estimate on parameters in void fraction correlations. From this point, the whole process is repeated where FloWell calculates new bottomhole pressures with the improved void fraction correlation. This iteration is continued until a stopping criteria has been met.

Although the basic ideology seems simple enough, the total coupling and calibration process is considerably more complicated as illustrated in Fig. 7. The model design is best explained by taking a regular power plant with several producing wells that has been operated for i+1 years as an example. Historical data about the rate of production and the pressure drawdown in the reservoir is available, as well as continually measured data at the top of the wells

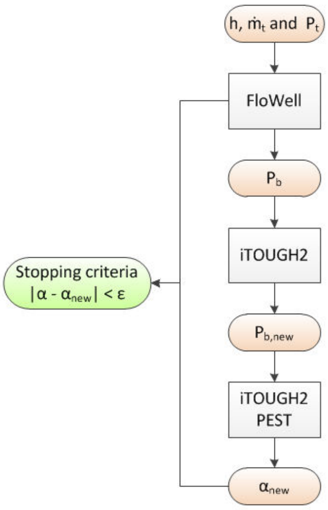

Figure 6: The basic ideology for the coupled FloWell-TOUGH2 model.

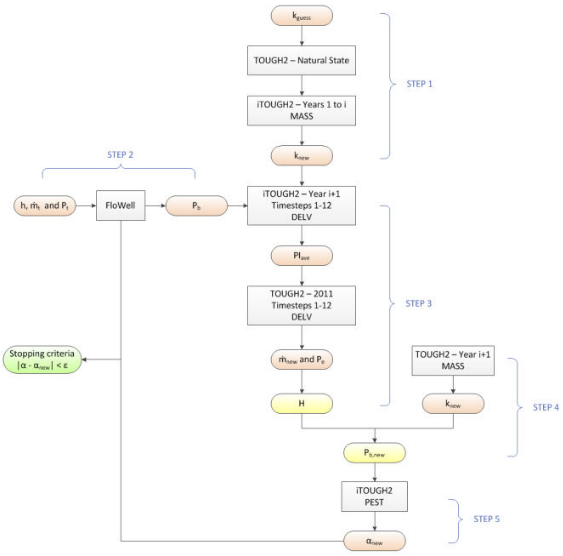

Figure 7: The detailed model design for the coupled FloWell-TOUGH2 model.

In the first step a conceptual model is constructed for the reservoir in question. Before simulating the response of the reservoir to production the natural state of the reservoir is obtained by using a reasonable value for the permeability (k_{guess}) until a steady state has been reached. Supposing that historical data describing the pressure drawdown in the reservoir exists for year 1 to year i the data can be used to calibrate the model in order to obtain a fairly good estimate for permeability (k_{new}) of the rock structure in the reservoir.

In step 2 it is assumed that measured wellhead conditions, mass flow rates ($\dot{m}_t$), enthalpies (h) and pressures (P_t), are available for every month of the year i+1. These parameters are used as inputs into FloWell, which calculates the bottomhole pressures (P_b) in producing wells in the reservoir.

Desirably, the next move would be to insert the calculated bottomhole pressures and the measured mass flow rates at the wellheads directly into the TOUGH2 model. However, TOUGH2 does not offer an option in which a mass flow rate and a bottomhole pressure for a well can both be used as inputs.

In the model design presented here, the DELV type is used to couple FloWell with TOUGH2. In step 3, the calculated bottomhole pressures from FloWell are entered to the reservoir model that has been arranged for year i+1 and guess values assigned to the productivity indices (PI) of the wells. By using mass flow rates as observations to calibrate the TOUGH2 model and to find new estimates for the productivity indices that suite the bottomhole pressure and mass flow rate for each well, the flow rates have now been linked to the coupled model. This calibration has to be performed in twelve timesteps where each timestep represents one month. In total the timesteps add up to one year, year i+1 in production. The reason for this is that TOUGH2 does not allow the user to define time-dependant bottomhole pressures, the pressures have to be fixed throughout the simulation.

As it is custom to denote only one productivity index for a well an average is taken of the twelve values obtained above (PI_{ave}). The average values of the productivity indices, one average value for each well, are now inserted into the TOUGH2 model instead of the guess values and a forward run in twelve timesteps executed as before. After each run, pressures in the elements where wells are defined (P_e) are extracted from the output report from TOUGH2, along with mass flow rates ($\dot{m}_{new}$).

At this stage, the variable K (which is dependent on the density and viscosity of the fluid and the relative permeability) can be calculated with following equation as described by Pruess (1999);

$$\dot{m}_{new} = K \cdot PI_{ave} \cdot (P_e - P_b) \qquad (26)$$

In step 4 a new estimate for the permeability that describes year i+1 is found with iTOUGH2. Similarly to step 1, the MASS option in TOUGH2 is used and values for mass flow rates observed at the wellheads inserted into time-dependent tables. Since forward runs with MASS should not differ much from runs with DELV, the element pressures found in step 3 are used as observations for the inverse analysis in step 4. The inverse analysis results in permeability that yields element pressures that are close to the ones used as observations. These new element pressures can then be used along with correct mass flow rates ($\dot{m}_t$), the productivity indices and the variable K found in step 3 to achieve new bottomhole pressures ($P_{b,new}$) with Eq. (33).

The final step involves the calibration of FloWell with iTOUGH2-PEST. The new bottomhole pressures calculated in step 4 are used as observations in the inverse analysis and the parameters chosen for evaluation are variables in void fraction correlations. When the void fraction has been manipulated so bottomhole pressures match the ones from step 4 the first iteration has been completed. This new void fraction is inserted into FloWell and the procedure repeated until a stopping criteria has been reached.

A CASE STUDY OF REYKJANES GEOTHERMAL FIELD

Reykjanes Conceptual Model

The Reykjanes peninsula, situated at the south-western end of Iceland, is an onshore continuation of the Mid-Atlantic Ridge. The general topography of the Reykjanes peninsula has been shaped by sub- and postglacial fissure eruptions that created the northeast trending hyaloclastite ridges and crater rows. No central geothermal volcanoes have been developed in Reykjanes so the heat sources for the high temperature fields in the peninsula are a dyke swarms (Friðleifsson et al., 2009).

From resistivity measurements reaching down to 1000 km it is believed that the geothermal system at Reykjanes covers about 10 km^2 in area. Interpretations of satellite pictures indicate however that the geothermal system becomes considerably more extensive with depth, where large parts of the system may lie beneath the ocean floor far south of the Reykjanes Peninsula (Friðleifsson et al., 2009).

The Reykjanes power plant began producing 100 MW_e in May 2006 with two 50 MW_e twin steam turbines with sea cooled condensers. HS Orka plans to expand the power production by 50 MW_e in coming years as well as increase injection to support the pressure in the reservoir (HS Orka, 2009).

Little is known about the pressure change in the Reykjanes reservoir before power production started in the area but the data available indicates that the drawdown in pressure was hardly more than 2 to 3 bar prior to production (Hjartarson and Júlíusson, 2007). During the first months of production, steep decline in pressure was detected which continued until spring 2007. In total, from beginning of year 2006, the pressure drawdown in the center of the reservoir (RN-12) had reached the maximum of 36 bar while at the boundaries (RN-16) the drawdown is much less or 21 bar. This goes hand in hand with the magnitude of mass being extracted from the reservoir (HS Orka, 2011).

Numerical Model

The numerical model can be broken down into four main parts:

i. A natural state model defining the Reykjanes geothermal reservoir prior to any production from the area.
ii. A reservoir model to simulate the production history ranging from the year 1977 to the year 2010 in Reykjanes along with calibration of the model against measured pressure drawdown in the reservoir over the production period.
iii. A coupled wellbore-reservoir model where wellhead measurements in 2011 are used to calibrate both the wellbore and the reservoir model.
iv. A forecasting model using the results from parts i-iii where different scenarios are simulated to predict the reservoir's response the next 15 years.

The mesh design is based on the conceptual model of Reykjanes geothermal field. Fig. 8 shows the overall mesh used. The mesh covers 10x10 km area and consists of 2064 elements where 344 elements are defined inactive. The numerical model of Reykjanes geothermal field consists of 12 layers, each with 172 elements and a thickness of 300 m. The horizontal mesh remains the same for each layer. Fig. 9 displays the innermost core of the mesh along with placements of wells at Reykjanes geothermal field. The rock types for the Reykjanes geothermal field can be seen in Fig 10. Layers A and L have the rock type names CAPR1 and BASE1 for the cap and base rock and the boundary of the Reykjanes geothermal field SIDE1. For the surroundings and the center of the reservoir rock type names ROCK1-5 have been assigned.

The initial conditions of the reservoir are set by a temperature gradient of 100°C/km with a corresponding hydrostatic pressure gradient. For simplicity and to facilitate calculations in the inverse program iTOUGH2 by reducing number of unknowns, the permeability in x and y direction in this model is assumed to be the same.

Table 1: Physical properties of Reykjanes numerical model.

Physical properties	*Values*
Rock density	2650 kg/m^3
Thermal conductivity	2 W/m°C
Heat capacity	1000 kJ/kg
Porosity	10%

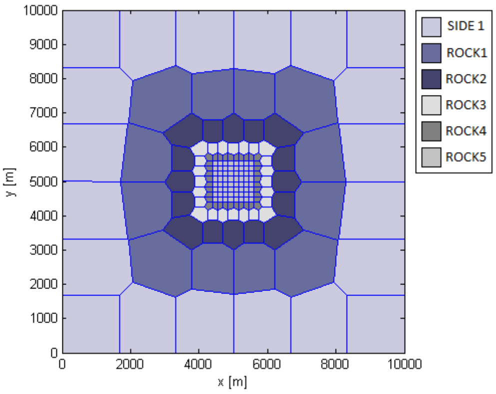

Figure 8: Horizontal mesh of Reykjanes numerical model.

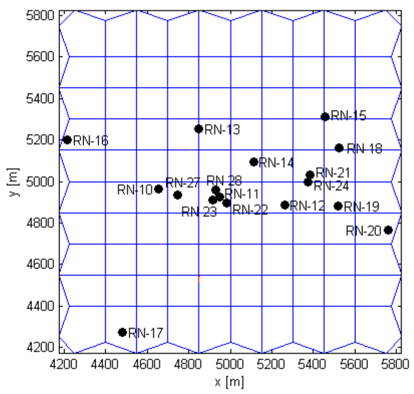

Figure 9: The innermost core of the numerical model and placements of wells at Reykjanes geothermal field.

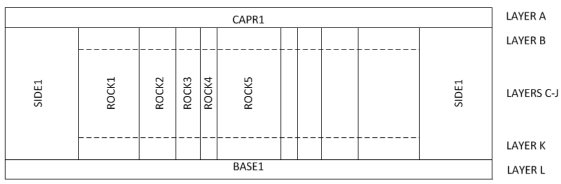

Figure 30: Vertical cross section of Reykjanes numerical model.

Numerical Results

For the natural state the change in thermodynamic variables becomes negligible after approximately 100.000 years and therefore it may be expected that a steady state has been reached in the reservoir. Heat entering the reservoir is equal to the one being discharged and the model is believed to describe the state of the Reykjanes reservoir in 1977, before exploitation started. The natural state model simulates the formation temperature and pressure reasonably well in some wells but inadequately in others.

The historical model describes the response of Reykjanes reservoir to exploitation from the year 1977 to 2010. This part mainly involves calibration of the historical model in order to use it in forecasting scenarios in the following section. The parameter estimation with iTOUGH2 is performed on the permeability distribution of the rock structure in Reykjanes reservoir with measured pressure drawdown in wells RN-12 and RN-16 as observations.

The parameter estimation results are shown in Table 2 along with initial values for the permeability distribution. After only four iteration with iTOUGH2 the objective function had decreased to 94% of the initial value. The simulated pressure drawdown for wells RN-12 and RN-16 with the new estimates for the permeability distribution is shown in Fig. 11 and 12. In both wells the historical model simulates the 3 bar pressure drawdown quite accurately. The model also produces acceptable simulations of the steep decline in pressure of 36 bar in the center of the reservoir and considerable lesser decline of 21 bar at the boundaries of the reservoir.

Table 2: Parameter estimation results and initial values for the permeability distribution in xy- and z-direction [mD].

	SIDE 1	*ROCK 1+2*	*ROCK 3+4*	*ROCK 5*
xy (guess)	2.00	20.00	20.00	100.00
z (guess)	0.010	1.00	1.00	200.00
xy (estimate)	0.41	4.48	6.04	97.48
z (estimate)	0.0097	1.66	0.97	117.77

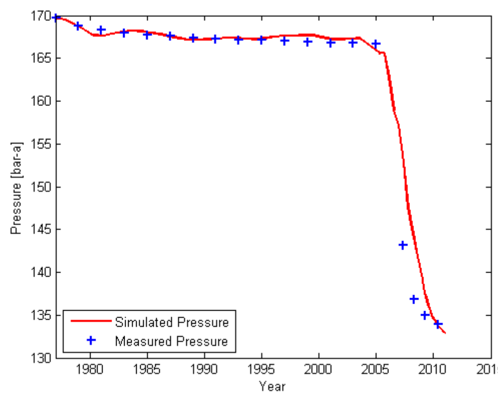

Figure 11: Simulated pressure drawdown vs. measured drawdown in well RN-12.

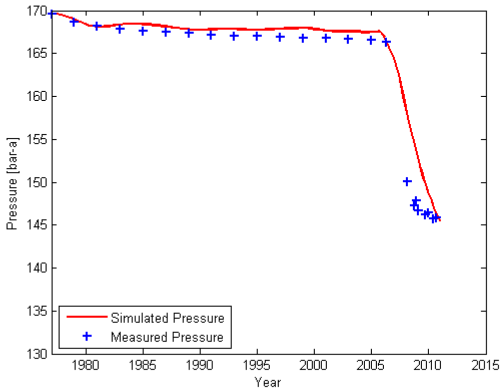

Figure 12: Simulated pressure drawdown vs. measured drawdown in well RN-16.

For the coupled model calculated bottomhole pressures are inserted to the reservoir model along with guess values ($3.0\cdot10^{-12}$ m^3) for the productivity indices of the wells. The reservoir model is then calibrated using observed mass flow rates and enthalpies at the wellheads, yielding new estimates of the productivity indices in all wells for the year 2011. Along with the productivity indices, the permeability of ROCK5 in xy- and z-direction is calibrated. Only the permeability of the center of the reservoir is considered in order to minimize the number of unknowns since the total process is very computational expensive. The parameter, shown in red in Eq. (32) in the Rouhani-Axelsson void fraction correlation is chosen for the inverse estimation with iTOUGH2-PEST to improve the model design in FloWell.

It takes approximately five iterations for the average of the productivity indices in the reservoir model and the void fraction in the wellbore model to reach equilibrium. The iteration process yields productivity indices in the range of $0.300\text{-}2.267\cdot10^{-12}$ m^3 for wells in consideration and an estimation of 0.111-0.122 for the parameter in the Rouhani-Axelsson void fraction correlation. For the permeability it takes around eight iterations to reach steady state. Minor changes are observed for the permeability of ROCK5, especially for the permeability in xy-direction. This is not unexpected since the simulation time only spans one year.

The purpose of designing a reservoir model is to use it to predict the future response of the reservoir to different production scenarios. In this study, four different production scenarios were modeled for the Reykjanes geothermal field. All scenarios involved simulations up to the year 2027.

- **Scenario 1**: Maintaining the same total production and injection rates as in the year 2011.
- **Scenario 2**: Maintaining the same total production rate as in the year 2011 and increasing the injection rate to 30% of the total extracted mass.
- **Scenario** 3: Increasing the production capacity of the power plant by 50 MW_e and maintaining the injection rate as in the year 2011.
- **Scenario 4**: Increasing the production capacity of the power plant by 50 MW_e and the injection rate to 30% of the total extracted mass.

In the forecasting model the forward simulator TOUGH2 is used. FloWell is excluded in this part but the permeability distribution found in the historical and the coupled FloWell-TOUGH2 models is used for the predictions.

Predictions of pressure drawdown in the center of the Reykjanes reservoir (well RN-12) and at the boundaries (well RN-16) are illustrated in Fig. 13 and 14. Scenarios are distinguished by colors where dotted lines represent cases with increased injection.

The figures show that in scenario 1 the pressure drawdown decelerates and the pressure in the reservoir is close to achieving equilibrium with just a total of 3-4 bar decline in pressure for the prediction period. By increasing the injection, the pressure in the reservoir starts to rise again as displayed for scenario 2. In scenario 3 the power generation is boosted up to 150 MW_e with almost no injection taking place. Approaching five years of simulation a decline of 18 bar in the reservoir and 12 bar at the boundaries is observed. After five years of simulation a convergence failure is encountered in TOUGH2 indicating that mass is being removed at a higher rate than physically possible. When adding considerably to the injection in scenario 3 less decline is detected and after 15 years of simulation the total drawdown in pressure is equal to the total drawdown after 5 years in scenario 3.

Fig. 15 shows the development of the average enthalpy for the years 1977 to 2027. From the figure it can be concluded that the greater the production is from the reservoir, the greater the average enthalpy of the geothermal fluid becomes. Increasing the production causes the pressure to drop to a greater extent. As the pressure drops, boiling starts in shallow feedzones in the wellbores and the enthalpy increases. However, the injection in scenarios 2 and 4 supports the pressure in the reservoir and hinders boiling to occur, which yields lower enthalpy.

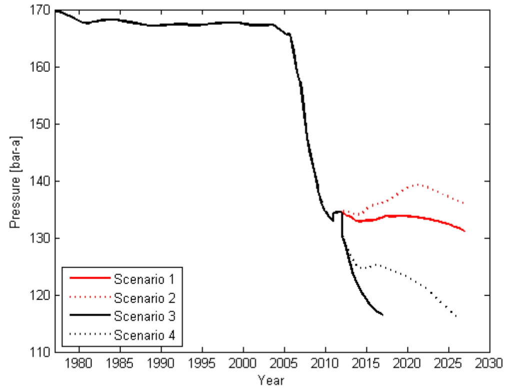

Figure 13: Pressure drawdown in well RN-12 in the forecasting scenarios.

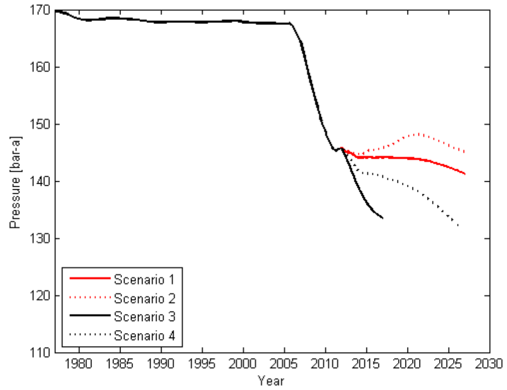

Figure 14: Pressure drawdown in well RN-16 in the forecasting scenarios.

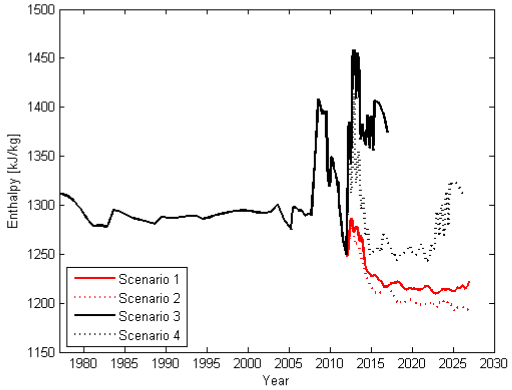

Figure 15: The average enthalpy development in wells in Reykjanes in the forecasting scenarios.

As noted above, scenario 3 causes convergence failure in TOUGH2. Increasing the production rates of the wells and keeping them constant throughout the simulation displays that the recharge to the reservoir cannot keep up with the rate of extraction. This also indicates that existing wells at Reykjanes may not support increased production from the reservoir and new wells covering larger area must be drilled. It should be mentioned that calculations of production rates needed for power generation of 150 MW_e are based on the state of the geothermal fluid observed in 2011. However, increased production causes the pressure to drop and boiling to start in the reservoir, yielding geothermal fluids with higher enthalpy. More steam can be obtained from fluids with higher enthalpy than the ones with lower enthalpy so the total mass of geothermal fluid needed for power production diminishes. Therefore, the pressure drop due to increased production will eventually result in less mass extraction from the reservoir. From this discussion it can be assumed that scenarios 3 and 4 display the worst-case scenario of increased production from the reservoir and that this increased production may even sustain greater power generation than 150 MW_e.

CONCLUSIONS AND FUTURE WORK

The focus of this work was to develop a model that can simulate the flow in a geothermal reservoir as well as the flow in a production well in a coupled manner using measured wellhead conditions as main inputs. The program TOUGH2 was used to simulate the behavior of a reservoir while a new model was designed to simulate two phase flow in a wellbore.

The validation of FloWell displayed that in most wells the simulations were in good agreement with pressure logs from wells at Reykjanes and Svartsengi geothermal fields. Furthermore, a comparison was made between available void fraction correlations in FloWell, resulting in the Rouhani-Axelsson correlation fitting the data best in most cases while the Zivi correlation produced the worst fit. Despite these results it is difficult to favor one correlation over the others, to reach conclusive results more extensive data must be examined.

A detailed numerical model of the Reykjanes geothermal field in Iceland including the coupled wellbore-reservoir model was constructed. An acceptable pressure distribution for the natural state was obtained in most wells. The exploitation and pressure drawdown history of the Reykjanes reservoir was used to find new estimates for the permeability in xy-direction and z-direction in the rock types SIDE1 and ROCK1-5. The new estimates yielded an excellent fit to the pressure data, but since the rock structure of Reykjanes was only roughly divided into sections it cannot be stated that these estimates reflect the actual permeability distribution.

Measured wellhead conditions for each month of the year 2011 were used to couple the numerical model to FloWell. The coupling procedure was carried out in an iterative manner where the model design in FloWell and in the numerical model was improved by calibration with iTOUGH2. The parameters improved were the productivity indices of the wells, a variable in the Rouhani-Axelsson void fraction correlation and the permeability in the center of the reservoir.

The calibrated numerical model was used in forecasting scenarios to predict the reservoir's response to future exploitation. Four scenarios were considered where the production rates of the wells were either kept constant as observed in 2011 or increased to maintain a 150 MW_e power production, with an increase in injection or not. Increasing the production the pressure dropped in the reservoir and the average enthalpy of the geothermal fluid in the reservoir increased. Seeing as the production rates were fixed throughout the simulations in the scenarios it can be assumed that they can sustain even greater power generation than 150 MW_e.

In the future, several improvements could be made to the wellbore simulator FloWell, the coupled FloWell-TOUGH2 model and the numerical model of Reykjanes. The option of multiple feedzones in a well as well as diverse changes of a wellbore geometry could be incorporated into FloWell. For the coupled FloWell-TOUGH2 model and the numerical model of Reykjanes it would be advisable to increase the simulation time when more measured wellhead data becomes available. Lastly, the modeling approach introduced in this study should be applied to other geothermal systems with as accurate data as possible to improve its performance and hopefully extend its application field.

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