STANDARDISED RESERVOIR MODEL DESIGN FOR SIMULATING PRESSURE TRANSIENTS IN GEOTHERMAL WELLS

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ABSTRACT

The need for numerical models to simulate geothermal pressure transients has been long recognised. In the last few years various studies have used the TOUGH2 reservoir simulator to model different well tests, in each case with a different model setup. Important features such as the skin effect and wellbore storage are incorporated differently or are sometimes not present. Rarely is the model setup fully described or the reasoning given. In this study all the best features of the reported models to date are incorporated into one and the model design is described and justified. The sensitivities of the model are investigated. This model design is suggested as a useful standard as the use of TOUGH2 for simulating well tests grows, hopefully beyond the academic sphere and into the wider geothermal industry.

1. INTRODUCTION

Pressure transient analysis (PTA) is currently under-utilised in the geothermal industry. The reason for this is because standard analytical models for PTA do not often fit geothermal datasets. Geothermal PTA cannot be described by these analytical models as there are many geothermal factors which violate the assumptions behind the analytical models (McLean and Zarrouk, 2015; O'Sullivan et. al., 2005).

The analytical models were mainly developed for the oil and gas industry and there they work well in a lower temperature environment and simpler reservoir structure. However even in the oil and gas industry there is a requirement for numerical models in order to describe injection tests as there are two different fluids present, the reservoir fluid and the injectate (Verga et. al., 2011).

The TOUGH2 numerical simulator is available to model pressure transients in geothermal reservoirs. A number of recent student studies at the University of Auckland have used TOUGH2 for exactly this purpose. However there are no standard model setup guidelines and all published models are slightly different from each other. The reasoning behind the model setup is rarely given in detail and the sensitivities of these models are not known.

The field-based reservoir engineer is unlikely to be an expert in TOUGH2, including this author. In order to make TOUGH2 more accessible and increase its use in geothermal PTA, this study proposes a standard model setup utilising the PyTOUGH scripting code. All aspects of the model are described and the reasoning for the design given. A reference model is then created for a particular well test and subjected to sensitivity analysis.

2. BACKGROUND

2.1 Numerical vs analytical models

Numerical modelling is a powerful tool available to obtain solutions where systems of equations are non-linear and therefore so complicated that simple linear analytical solutions are not possible. Numerical modelling involves the design of a grid of interconnected elements to represent the real-world system. The system behaviour can then be described by calculating the interactions and exchanges between each element and its neighbours.

2.2 TOUGH2 and PyTOUGH

There are a wide variety of numerical modelling codes which calculate various properties depending on the application for which they are designed. The TOUGH2 numerical code is used for modelling underground geothermal reservoirs. TOUGH2 calculates exchanges of mass and heat between elements in order to describe fluid flow through porous media (Pruess, 1991). It is commonly used to model the medium to long-term behaviour of entire geothermal reservoirs (see Figure 1 for example). The version used in this study is AUTOUGH2 which was developed at the University of Auckland to have some features particularly useful for geothermal simulations (Yeh et. al., 2012).

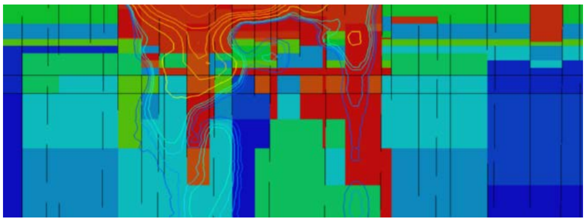

Figure 1: Cross-section through the Ohaaki reservoir model. Coloured blocks showing the vertical permeability of different rock types and contours showing the vapour saturation (Newson et. al., 2012).

PyTOUGH (Croucher, 2011) is a library for the Python scripting code, built in order to automate TOUGH2 simulations. PyTOUGH allows easy and automated modification/running of TOUGH2 input files and extraction of results from TOUGH2 output files, a previously more onerous task. The flexibility of PyTOUGH allows for the setup of an unlimited range of model types.

As the inverse modelling code iTOUGH2 (Finsterle, 2000) does not currently run with PyTOUGH each parameter will be tested individually in a manual model sensitivity analysis.

2.3 Relevant recent studies

Various relevant numerical modelling studies are detailed here from between 1987 and 2014. None of the studies present sufficient information to allow reproduction of the model or provide much justification for the model setup.

2.3.1 O'Sullivan (1987)

MULKOM, the predecessor of TOUGH2, was used to simulate drawdown/buildup and injection tests as a pure modelling study not based on field data. The results for a uniform porous reservoir were compared to a fractured reservoir. The scenarios considered were: 1) drawdown/buildup test in an initially two-phase reservoir, 2) drawdown/buildup test in an initially hot water reservoir which flashes during drawdown, and 3) injection into a two-phase reservoir. It was concluded that fracturing complicates the results of geothermal well tests.

A radial grid was used, with a central well block and 59 blocks of increasing radius. No skin zone is included.

2.3.2 Nakao and Ishido (1998)

Nakao and Ishido (1998) published one of the first studies using a numerical simulator to model a geothermal well test. Field data was used from an injection test in well YT-2 in Yutsubo geothermal field, Japan. The study modelled permeability change during injection. Permeability and porosity were calculated as a function of the local instantaneous temperature and pressure. The numerical simulator used was STAR (Pritchett, 1995).

The model geometry was a 10m thick radial model with a central well block and a skin zone radius of 7.1m. The reservoir is a dual porosity (MINC) type. Beyond 97.2m the reservoir is treated as a porous medium (without fractures). The reasoning behind the combination of porous media and fractured media is not described. The lack of wellbore storage in this model was considered to be an obstacle in improving the match further (Nakao and Ishido, 1998).

2.3.3 AWTAS O'Sullivan et al. (2005)

In 2005 an automated numerical well test system was created called AWTAS (Automated Well Test Analysis System) (O'Sullivan et al., 2005). It is the first and only geothermal well test analysis software to be developed which calculates the model response numerically rather than analytically. The objective of AWTAS was to create something accessible, by means of a graphical interface with a range of models already set up and with non-linear regression capability. These models include homogeneous porous layer, fractional dimension, skin, wellbore storage, leaky aquifer and various other models to represent different reservoir types.

AWTAS was never widely utilised as it was developed for a private client and the user interface was written in a programming code which is now obsolete. It is also widely considered to have been superceded by PyTOUGH. While PyTOUGH is indeed a powerful tool, the advances toward user-friendliness made by AWTAS are lost, notably built-in non-linear regression and having models already set up. AWTAS has been used for a small number of academic studies (Villacorte and O'Sullivan, 2011; Zarrouk et. al., 2007).

2.3.4 Zarrouk et. al. (2007)

As part of a larger study, radial models have been developed for four dry steam production wells at the Poihipi power station, Wairakei geothermal field, New Zealand. Cyclic operation of the wells has inadvertently created a dataset with a wealth of pressure transient behaviour.

Radial models are single-layer with a thickness of 150m. The model outer radius is described only as being of sufficient extent to be considered infinite. AWTAS (Section 2.3.3) is used but no reference is made to whether the wellbore storage or skin capability of AWTAS was utilised.

2.3.5 Villacorte and O'Sullivan (2011)

The manner in which formation permeability varies during injection/falloff tests was investigated by Villacorte and O'Sullivan (2011). Field data from injection tests on two unidentified wells were simulated/matched using various methods. These included three numerical methods TOUGH2, FEHM™ (Zyvoloski et al., 1988) and AWTAS, with non-linear regression by iTOUGH2 or PEST (Doherty, 2005). Analytical models were applied using SAPHIR™ (http://www.kappaeng.com/software/saphir).

The field data was considered in various stages, corresponding to the different injection rates. A different permeability (and other model parameters) could then be calculated for each stage. The permeability was found to increase with increasing injection rate and then decrease for the fall-off stage. These stage-wise simulations fit very well to the field pressure data during the increasing injection steps, but not well to the pressure during fall-off.

No mention of wellbore storage being considered in the model other than a "well" block appearing in the schematic. It was found that without a skin region included in the model, most of the initial simulations did not match the field data. The skin region was then included as a region of fixed radius while the permeability within the skin region was allowed to vary. Various values were used for the skin zone radius but no conclusions were drawn on the best value to use. However the presence of a skin zone was found to improve the match (Villacorte and O'Sullivan, 2011).

2.3.6 Aqui (2012)

As part of a larger study into permeability enhancement, a single-well radial model was set up for the well TC5RD in Southern Negros geothermal field, Philippines. The simulator used was TOUGH2 in combination with PyTOUGH. Inverse modelling was achieved using a built-in optimization code.

The radial model grid has a thickness of 100m and 86 blocks of increasing radius. Various scenarios are considered, some without a skin zone, and some with a skin zone with a fixed radius of 11m. This number comes from some preliminary analytical-model based PTA.

2.3.7 Saldana (2012)

Analytical and numerical methods of PTA were applied to field data from an interference test involving the wells 501, 508D and 510D in Tongonan geothermal field, Philippines. No conclusions are drawn on the efficacy of numerical methods.

The grid has large blocks covering a wide area encompassing the wells of interest. Based on a Voronoi gridding system blocks are hexagonal or irregularly spaced. No other details of the grid setup or model parameters are given. The simulator used was not specified.

2.3.8 Kusumah (2014)

This objective of this study is to obtain estimates of reservoir permeability and porosity using both pressure and temperature field data from the well THM15 in Tauhara geothermal field, New Zealand. This is a deviation from other studies, which typically use pressure data only. A numerical model is set up in order to match pressure and temperature data from both an injection test at well completion, and also during subsequent heat-up runs.

The simulator was TOUGH2 and iTOUGH2 was used to obtain matches to the field data. Kusumah (2014) concluded that manual model matching is superior to iTOUGH2 in obtaining matches to the pressure data. Good matches were not obtained with the temperature data, which is tentatively attributed to a skin effect which is not included in the modelling.

A complex grid was used with 40 different layers with 17 different rock types, corresponding to the geology of the reservoir near the well. The casing, liner and well are also represented with different ‘rock types’. The grid is radial, 200m thick, with 99 blocks of increasing radius out to 15,000m. No details were given on the parameters of the well block and no skin zone is included.

2.3.9 Malibiran and Zarrouk (2014)

A number of pressure transients are studied from the well T4, Mt Apo geothermal field, Philippines: 1) at the time of drilling completion, 2) after cement-damage, 3) after mechanical clearing and 4) after acidizing. Analytical model-based analysis was carried out using SAPHIR^{TM} and also numerical models were set up using TOUGH2. Although results consistent with the four stages of the well history were obtained by both analytical and numerical methods, it was not established which method was the best.

The radial model grid has layer thickness 100m, 99 blocks of increasing radius with expansion factor 10% and a central well block of radius 0.15m. No other properties of this well block are described. It is stated that a skin zone is included by allowing the permeability to be different near the wellbore, though no more details are given.

2.3.10 Phan (2014)

This study builds on the previous work of O’Sullivan (1987). In this case TOUGH2 is used in a pure modelling study with no field data, to simulate drawdown and buildup tests for a variety of reservoir conditions. The results of the study are inconclusive.

A radial grid was used with a central well block and 99 blocks of increasing radius, with an expansion factor of 20%. The single layer thickness is 100m. Other than the presence of a well block no other information is given on this block, and it is stated that significant wellbore storage effects are not considered (Phan, 2014). No skin zone is included.

2.3.11 Riffault (2014)

This study revisits the dataset from the injection test of well YT-2 of Yutsubo geothermal field, Japan. This dataset was originally used in a modelling study by Nakao and Ishido (1998) using STAR numerical simulator. In this study the simulator used was TOUGH2, using PyTOUGH for automation. A number of relationships for the dependence of porosity and permeability on pressure and temperature were investigated beyond the one from the original study by Nakao and Ishido (1998).

This model is exciting as it is the only one currently published which models changing permeability by allowing it to vary with each time step. This advance is made possible by the automation provided by PyTOUGH. The previous similar study by Villacorte and O’Sullivan (2011) dealt with changing permeability by breaking up the dataset into stages, based on injection rate and then analysing them separately.

The model geometry set up by Riffault (2014) was a complex three-dimensional radial model with 47 layers and a thickness of 1750m to represent the entire well from the surface down. There are blocks to represent the well, casing, liner, reservoir rocks, other non-reservoir rocks and a thin fracture. No skin zone is included.

2.3.12 Seto (2014)

The objective of this study is to obtain quantitative reservoir data by modelling field data from the well THM15, Tauhara geothermal field, New Zealand. Pressure and temperature profiles during the injection test at well completion and the subsequent heat up runs are used, similar to the study of Kusumah (2014). The best results were obtained from an inverse modelling approach using iTOUGH2. Matching pressure and temperature data from the heatup runs proved to be problematic near the feed zones, which are areas of localised rapid change.

A complex two-dimensional radial grid was set up with 40 layers and five rock types, and then an even more complex grid with 14 rock types. There are also ‘rock types’ for the casing, liner and well. The grid is 200m thick. The well block is described as being highly permeable but no other details are given. No reference is made to the skin effect.

3. MODEL SETUP

3.1 General setup

The general setup is for a single-layer radial grid with three main components, to be described in the following sections (Figure 2):

- Well block
- Skin zone
- Reservoir Zone

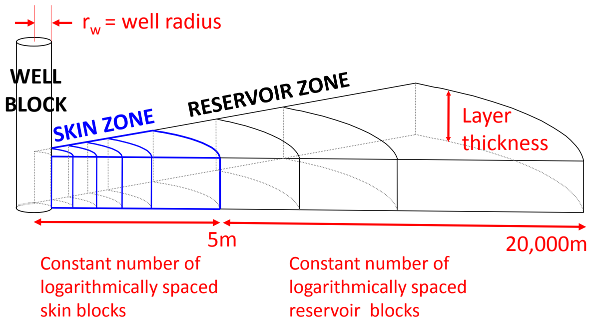

Figure 2: Schematic of radial model grid

A radial grid should be used as a normal square grid cannot reproduce the behaviour seen during well testing. This is due to the square blocks being connected only to the neighbours with which they share a side, and not to the diagonal neighbours, this is referred to as the five-point differencing. This can be improved by creating a special grid with diagonal connections and it becomes a nine-point setup, though still does not reproduce the required behaviour.

3.2 Radial blocks: spacing and number

The radial limits of the well block and skin zone are set as described in Section 3.4.1 and 3.5. The radial extent of the model is constant at 20km which is many times beyond the likely radial extent of the changes induced by injection or production during testing.

The grid needs to be much finer close to the well and can be coarser further out. This is achieved using a logarithmic radial block spacing. Within the skin zone 50 blocks are logarithmically spaced, with the 50^{th} block having an outer radius of 5m. In the reservoir zone there are 100 blocks, with the 150^{th} block having a radius of 20km. In the past it was considered that 99 blocks was enough. However for the sake of redundancy, more blocks are included here, especially in the skin zone which is the most critical area.

3.3 Layer thickness

The thickness of the model is the thickness of the permeable zone, which includes all the feed zones in the well. Identification of feed zones can be subjective. It is suggested that the entire open-hole depth of the well is included, unless there are very good reasons to exclude part of it. An example of a good reason would be if there was a clear and significant dead leg at the bottom of the well. In many cases no information is available on the location of the feed zones in the well and so the entire open hole should be used.

For deviated wells the true vertical depth should be used to obtain this parameter, not the measured depth. Due to the large reservoir thicknesses involved it does not seem likely the deviation will have any fundamental effect on the model results.

3.4 Well block: wellbore storage

Inclusion of the wellbore storage effect is very important as it affects all geothermal pressure transients. TOUGH2 is a code to simulate flow through porous media, and so the well must by necessity be represented as a porous medium, which does not describe the true nature of the well. To more accurately model the well block behaviour requires the use of a wellbore simulator, coupled to the reservoir simulator. This is not readily available or well developed and adds a great deal of complexity to the problem. For these reasons the well block in this standard model is represented using TOUGH2 alone, with porous media characteristics modified to represent a real well to the greatest extent possible, as described in the subsequent sections. As research into this subject continues, coupled wellbore and reservoir simulation is a natural progression.

3.4.1 Well radius

The radius of the well block is to be the real radius to the wellface underground. In reality this is variable over the length of the open hole, so should be taken to be the size of the drill bit used to drill the open-hole section.

3.4.2 Well volume

Generation of the model grid using PyTOUGH as suggested will produce a central well block with volume specified by its radius and the layer thickness of the model. The volume of this block must be overwritten so that the real volume of fluid present in the well is represented. The real volume of fluid is divided by the porosity of this block, so that the volume of fluid in the pore space of the block is equal to the real volume of fluid. The area of the connection of the well block to the first skin zone block is not changed, in order to reflect the geometry in reality.

3.4.3 Well porosity

The 'rocktype' properties of the well block are set to default values with the exception of porosity, permeability and compressibility. The porosity is set to 0.9. A real well effectively has a porosity of 1, however TOUGH2 is not designed to deal with blocks of 100% pore space. A porosity of 0.9 is suggested as an appropriate value which will allow TOUGH2 to run in a stable manner.

3.4.4 Well permeability

In reality the wellbore is like a vertical pipeline and the 'permeability' is almost infinite. In the model the well permeability is set to three orders of magnitude greater than the reservoir permeability. Increasing the permeability beyond this makes little difference to the results and can lead to convergence problems.

3.4.5 Well compressibility

For most geothermal well tests the water level is somewhere in the casing below the wellhead. As the injection rate changes the water level moves up or down and the volume of fluid changes. To attempt to replicate this behaviour while retaining simplicity, a large pore compressibility is specified for the well block. This compressibility is estimated from the actual change in fluid volume and change in pressure at two different injection rates:

$$C = \left(\frac{\Delta V}{\Delta P}\right)\frac{1}{V} \tag{1}$$

where:

C = compressibility (1/Pa),

ΔV = change in volume (m^3) calculated from change in water level

ΔP = change in pressure (Pa) measured at the transient depth

V = total volume of fluid (m^3) under static conditions.

3.5 Skin zone: skin effect

The skin zone can be represented easily in the grid as it requires only that the blocks near the wellbore have a different permeability to the reservoir. It is considered reasonable to assume that the alteration to the reservoir by drilling through the rocks there extends 5m from wellbore. Therefore the skin effect is represented by a zone of fixed radius of 5m and the permeability within this zone is variable.

It is also possible to define the radius as a variable parameter. There will then be too many combinations of skin zone radius and permeability that could produce the same result. This is proved by a model sensitivity analysis completed with iTOUGH2 (Stefan Finsterle, pers. comm., 2014) using a model in which the skin zone radius is variable. It was found that the correlation between the skin zone radius and skin zone permeability was almost 1, too high to determine these parameters independently.

The skin factor *s* is a variable parameter of the model, the value of which is used to calculate the permeability of the skin zone using the following equation:

$$k_s = \frac{k_r}{\left(1 + \left(\frac{s}{ln\left(\frac{r_s}{r_w}\right)}\right)\right)} \tag{2}$$

Which is rearranged from (Horne, 1995):

$$s = \left(\frac{k_r}{k_s} - 1\right) ln\frac{r_s}{r_w} \tag{3}$$

where:

k_s = skin zone permeability (m^2)

k_r = reservoir zone permeability (m^2)

s = skin factor (dimensionless)

r_s = skin zone radius (m)

r_w = well radius (m)

3.6 Time stepping

The method of time stepping is complicated when modelling transient tests. Many closely-spaced time steps are required when there are changes in flow rate, and much longer time steps are required at other times. The closely-spaced time steps are required in order to reproduce early-time transient behaviour when pressure is changing rapidly. Longer time steps are required when modelling late-time behaviour, when pressure is changing slowly. Longer time steps in late time prevent the model running time from becoming too large and keep the size of datasets manageable.

The rigid input format of TOUGH2 does allow for non-constant time steps to be specified. However only the first 104 time steps can be specified, in a table, and the last specified time step is then retained for the remainder of the simulation. This is a problem because the transient will occur in the middle of the simulation, not at the start. The reason for this is that the simulation must include the period of injection into the well prior to the transient period. Therefore the closely spaced time steps will appear at the start of injection, and by the time the transient period is reached the time step will be some large constant value. One method to get the closely spaced time steps to appear at the time of the pressure transient is to end the simulation at this time and start a second simulation, linked to the first. Therefore these simulations are run in two stages (Figure 3):

Stage 1: Start of injection to the start of the transient of interest.

Stage 2: Start of the transient to the end of the data.

This can be achieved easily using PYTOUGH as the conditions at the end of Stage 1 are saved and used as initial conditions for Stage 2.

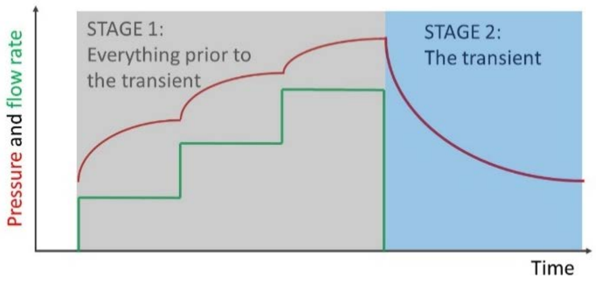

Figure 3. Schematic of the two-stage simulation process

Although usually there is only one transient period in a dataset of sufficient length to be analysed, some injection tests have more than one. In theory it is possible to set up a model using PYTOUGH with any number of linked simulations. At this stage it does not seem necessary to go this far as each transient can still be modelled separately using this standard model.

3.7 Setup of reference model

A reference model has been created to simulate the results of an injection test on well BR66 using the standard method described above. The parameters of this model are given in Table 1. This reference model will then be subjected to sensitivity analysis. Inverse modelling to fit the field data is beyond the scope of this paper.

Table 1

PARAMETER	VALUE	REASONING
Number of blocks in skin zone	50	Standard constant
Number of blocks in reservoir zone	100	Standard constant
Skin zone width (m)	5	Standard constant
Model radial extent (km)	20	Standard constant
Layer thickness (m)	600	Permeable interval containing all identified feed zones
Well radius (m)	0.1	8.5” bit used to drill the open hole section
Well porosity	0.9	Standard constant
Well volume (m^3)	81.4	Actual volume of fluid in wellbore from static water

		level to base of permeable zone ÷ porosity
Well compressibility (Pa^{-1})	6×10^{-8}	$(\Delta V/\Delta P)/V$ between two injection rates
Well permeability	*	*3 orders of magnitude greater than reservoir permeability

The reference model is then assigned a reservoir permeability guess of 10mD and skin factor of 0. These are guesses only, made for the purpose of testing the model. Once justified, the model can be used in an inverse process to fit the field data, and determine the true (matched) values.

4. SENSITIVITY ANALYSIS RESULTS

4.1 Number of blocks in skin zone

The reference model has 50 blocks in the skin zone. This parameter was assigned the following values: 20, 30, 40, 50, 100 and 500 blocks in the skin zone. A derivative plot comparing the results (Figure 4) shows the model is insensitive to this parameter when skin factor is zero. The same insensitivity was observed in equivalent plots for which skin factor was -2 and 5.

This information could be used to justify a value below 50, however some redundancy is a useful safeguard. Also there is no imperative to reduce block numbers as the total number of blocks is so low compared to most reservoir models with thousands of blocks.

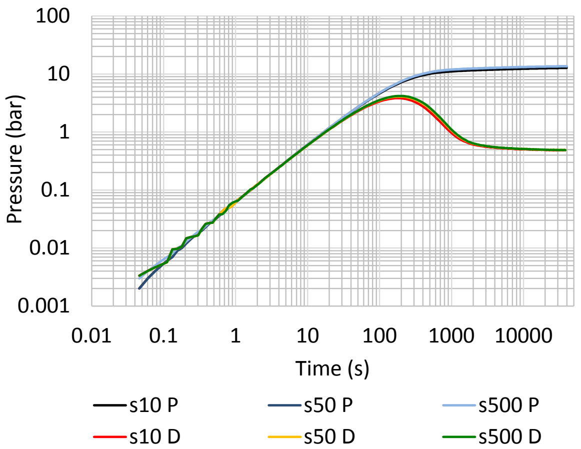

Figure 4: Log-log plot: Effect of changing number of blocks in skin zone (P = pressure difference, D = pressure derivative).

It can also be seen in Figure 4 that despite some noise the model results have a unit-slope in early time, as is expected when wellbore storage dominates the response (Horne, 1995). This unit slope is present in all the model results discussed in this paper, however the first two log cycles of very early-time response are removed in all subsequent figures to allow focus on the changes happening in intermediate- and late-time.

4.2 Number of blocks in reservoir zone

The reference model has 100 blocks in the reservoir zone. This parameter was assigned the following values: 50, 100 and 150 (±50%). A derivative plot comparing the results (Figure 5) shows the model is completely insensitive to the number of reservoir blocks.

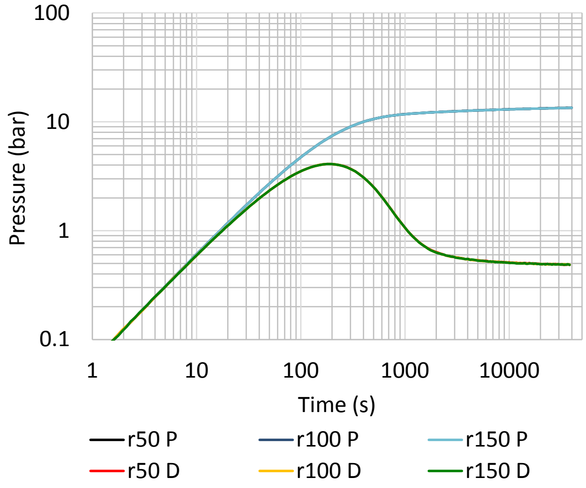

Figure 5: Log-log plot: Effect of changing number of blocks in reservoir zone.

As above (Section 4.1), these results could be used to justify a reduction in the number of blocks from 100. However for the same reasons of redundancy and lack of imperative, the value of 100 is retained.

4.3 Layer thickness

The reference model has a layer thickness of 600m based on the location of feed zones. This parameter was assigned the following values: 300, 400, 500, 600, 700, 800, 900 and 1200m (-50% to +100%). A derivative plot comparing the results (Figure 6) shows that the results are sensitive to the reservoir thickness.

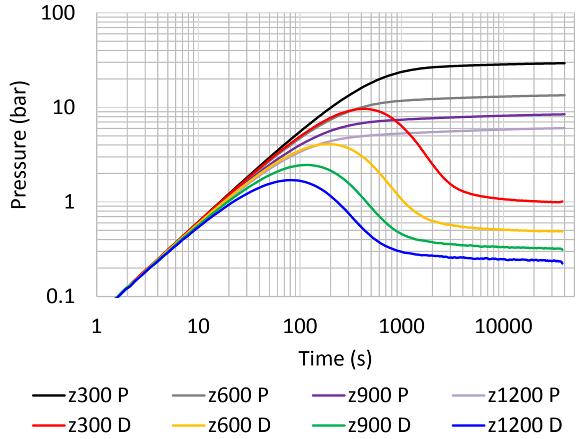

Figure 6: Log-log plot: Effect of changing layer thickness.

A change to the reservoir thickness results in a large change in the volume of all the skin and reservoir blocks. The process for estimating the reservoir thickness comes up against the very nature of geothermal reservoirs. It is subjective and can only be estimated. For many wells there is no information on the location of feed zones and so the entire vertical thickness of the open-hole section must be used. It can be seen for this reference model that if the entire open hole is used (e.g. a thickness of approximately 1200m) then the results will differ markedly from the results from using the thickness of the permeable zone (approximately 600m). It is therefore very important to obtain good information on the location of feed zones and make this estimation with great care. It is critical that the model thickness remains the same for subsequent models.

4.4 Skin zone width

The width of the skin zone in the reference model is 5m. This parameter was assigned the following values: 1, 2, 5, 10, 15 and 20m. If the skin factor is zero then the width of the skin zone is not important. Therefore for this investigation two scenarios were considered, one with a moderately negative skin factor of -2 and one with a moderately positive skin factor of 5.

4.4.1 Skin factor -2

A derivative plot comparing the results for this scenario (Figure 7) shows the model is not very sensitive to increases in this parameter. There is negligible difference in results as the skin zone radius increases from 5m to 10m or 20m. There is a significant difference in results if the skin zone radius decreases to 2m or 1m.

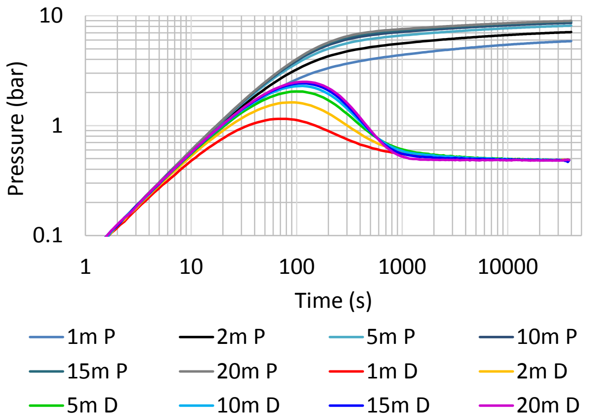

Figure 7: Log-log plot: Effect of changing skin zone width when skin factor is -2.

4.4.2 Skin factor 5

A derivative plot comparing the results for this scenario (Figure 8) shows the model is not very sensitive to this parameter. There is negligible difference in results as the skin zone radius increases from 5m to 10m, 15m or 20m. There is a small difference in results if the skin zone radius decreases to 2m or 1m.

Once the skin zone radius reaches 5m there is little difference in the model results with values >5m. This conclusion is the same whether the skin is positive or negative.

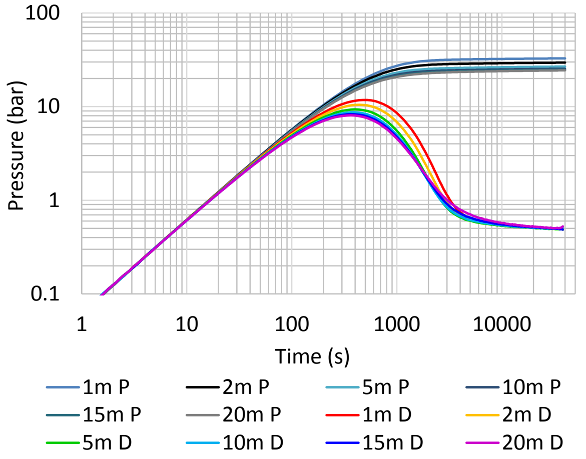

Figure 8: Log-log plot: Effect of changing skin zone width when skin factor is 5.

4.5 Well radius

The well radius in the reference model is 0.1m. This parameter was assigned the following values: 0.05, 0.1 and 0.15m (± 50%). A derivative plot comparing the results (Figure 9) shows that the model is marginally sensitive to the well radius.

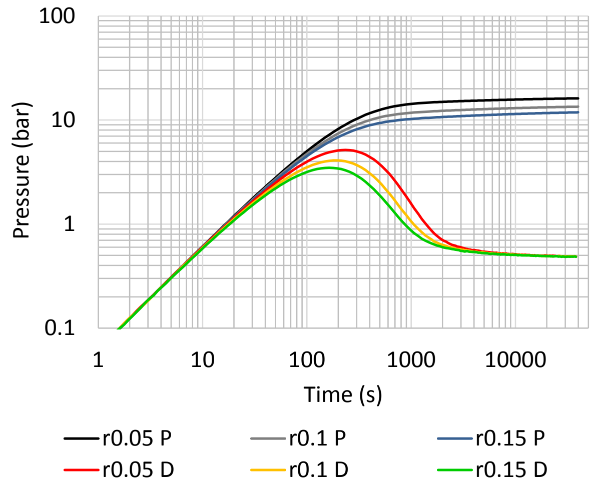

Figure 9: Log-log plot: Effect of changing well radius.

The radius is chosen based on the size of the drill bit. Due to the marginal sensitivity this should therefore be estimated as carefully as possible, and the same radius used for any subsequent models. Note that in practice there might be some hole-collapse and washout in some parts of the open section that deviates the analysis from the assumption of constant well bore radius.

4.6 Well volume

The well volume in the reference model is 81.4m^3 (actual volume of fluid in static well in real life). This parameter was assigned the following values: 40, 60, 81.4, 100 and 120 m^3 (±50%). A derivative plot comparing the results (Figure 10) shows the model is marginally sensitive to the well volume.

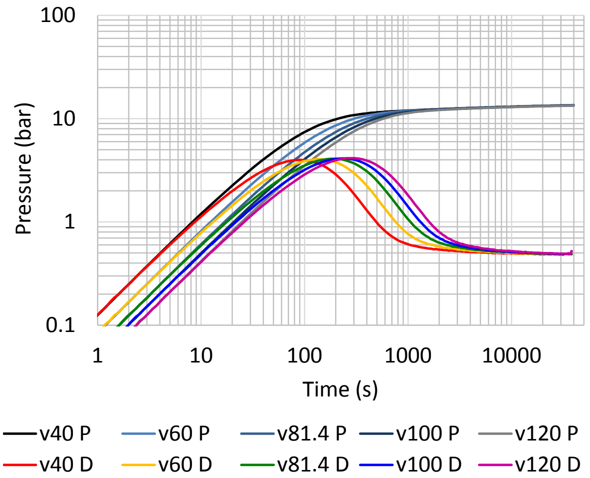

Figure 10: Log-log plot: Effect of changing well volume.

The shape of the derivative curve does not change but simply shifts to the right at the volume increases. The sensitivity is greater as the volume decreases and less as the volume increases.

4.7 Well porosity

The reference model has a porosity of 0.9. This parameter was assigned the following values: 0.5, 0.7, 0.9 and 1.0 (-45% to +11%). A derivative plot comparing the results for this scenario (Figure 11) shows the model is completely insensitive to this parameter.

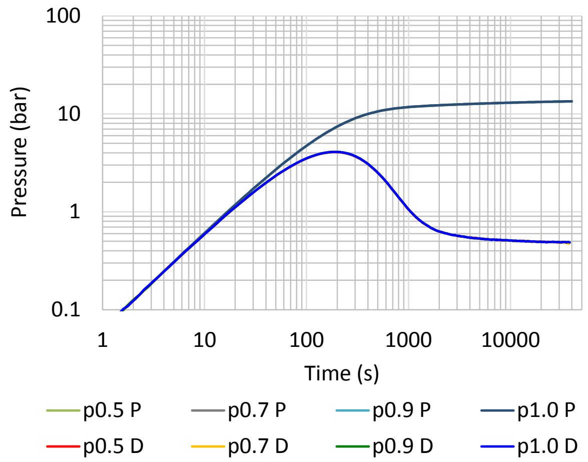

Figure 11: Log-log plot: Effect of changing well porosity.

As the well block porosity changes the volume of the well block is automatically changed so that the true volume of fluid in the well is represented by the volume of fluid in the pore space of the well block in the model.

It seems that is does not matter which porosity is used, as long as the true fluid volume is represented. The value of 0.9 is considered justified. The model ran with no trouble with a porosity of 1.0, contrary to expectations. It may be the case that a value of 1.0 works only for certain circumstances and may cause issues for other circumstances. This could be the subject of much further investigation, which would not add value to this particular study.

4.8 Well compressibility

The reference model has a well compressibility of 6×10^{-8} Pa^{-1}. This parameter was assigned the following values: 3×10^{-8}, 4.5×10^{-8}, 6×10^{-8}, 7.5×10^{-8}, 9×10^{-8} Pa^{-1} (±50%). A derivative plot comparing the results (Figure 12) shows the model is sensitive to the well compressibility.

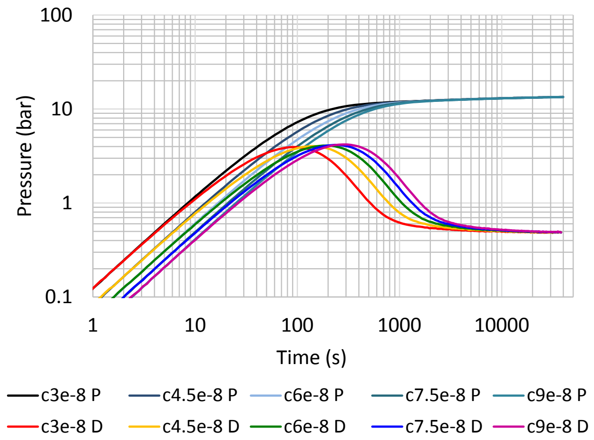

Figure 12: Log-log plot: Effect of changing well compressibility.

As the value of compressibility increases the shape of the derivative plot does not change but instead moves to the right, in a similar manner to a change in volume of the well block.

As the model results are a bit sensitive to this parameter it is recommended that the value is carefully calculated from available data and then used for all subsequent models.

4.9 Well permeability

The reference model is set up so the permeability of the well block is 3 orders of magnitude greater than the reservoir permeability. This parameter has been given the range: 1, 2, 3, 4 and 5 orders of magnitude. A derivative plot of the results (Figure 13) shows that the results have no sensitivity to this parameter.

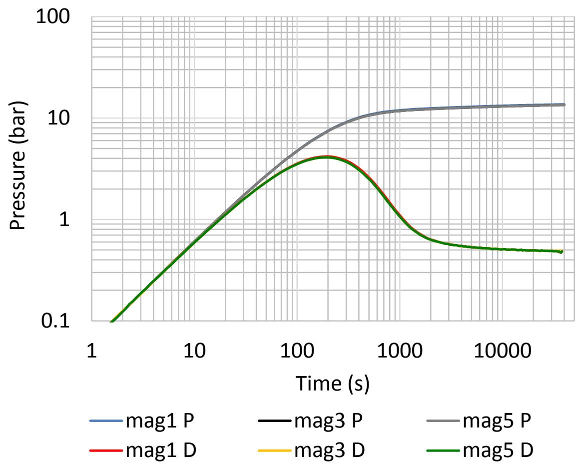

Figure 13: Log-log plot: Effect of changing well permeability.

While there is no sensitivity to this parameter it is still a good idea to choose one value and always use it. An order of magnitude of 3 is still the obvious choice as it is high enough to be representative of the reality of extremely high ‘permeability’ in a vertical pipeline. While no convergence problems were experienced with values of 4 and 5, it does not make sense to push this limit when there is no benefit.

4.10 Time stepping

The minimum time step used in the reference model was 0.01 seconds and then there are 104 logarithmically spaced time steps up to the maximum time step size, which is then retained for the rest of the simulation. The maximum time step is given a range of values: 1, 10, 100 and 1000 seconds. A derivative plot of the results (Figure 14) shows that there is negligible difference between the results across this range of time steps.

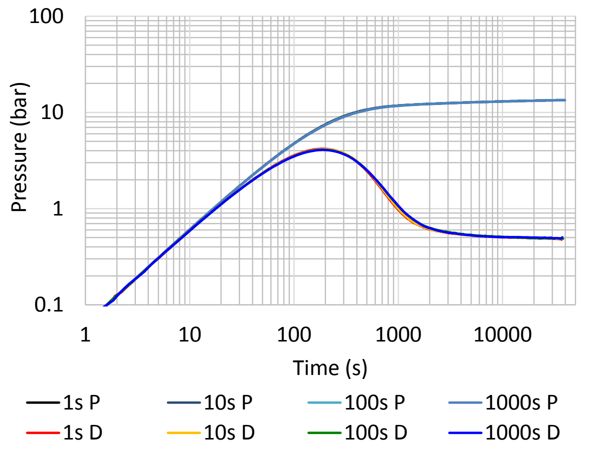

Figure 14: Log-log plot: Effect of changing maximum time step.

As this model has so few blocks and runs so fast there is no imperative to reduce the running time by increasing the time step. The only consideration is the amount of data generated in the output file, as there is a data point generated for every time step. The base model value for maximum time step of 100 seconds produces a manageable data file, 100 times smaller than for a maximum time step of 1 second.

4.11 TOUGH2 version and settings

It is important to note that the model output will depend on which version of the TOUGH2 code is being used and exactly what the settings are within TOUGH2, particularly the linear solvers. In some preliminary work on the time step, it was observed that the same model run with the same time steps using two different versions of TOUGH2 produced slightly different results in early and intermediate time, though not in late time (Figure 15).

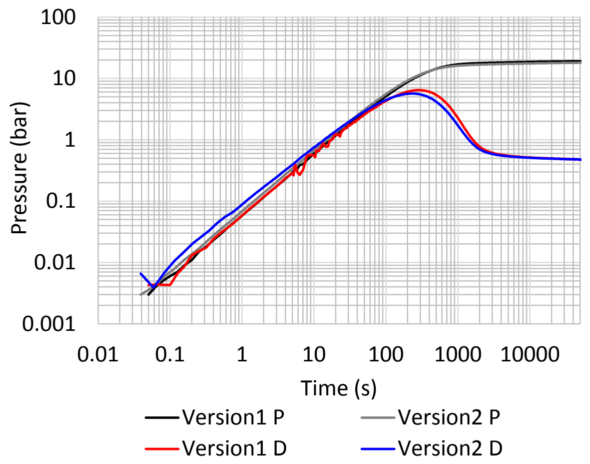

Figure 15: Log-log plot: Effect of changing version of TOUGH2.

It becomes quite a technical TOUGH2 question to explore the exact reason behind the slight differences. A slight difference is not only common but is expected when using different simulators.

A difference like this could have been the result of different steam tables as some versions of TOUGH2 use the original steam tables (IFC, 1967) and some use an updated version from 1997. The difference can be attributed to the level of detail of the equations describing the thermodynamic properties. Faster thermodynamics means simpler equations that take less time to calculate the properties, which can save computational time and vice versa. However it was found in this case that both versions of TOUGH2 use the same original IFC (1967) steam tables.

There are a wide variety of linear solvers available in the TOUGH2 code, which have their own variable settings, which will change the model output slightly. It is not a trivial task to explore exactly which solvers are used and their settings. It is beyond the scope of this study which aims to make TOUGH2 a practical choice for reservoir engineers wanting to simulate transient tests, without a requirement for expert knowledge of TOUGH2.

Results from different simulators cannot be directly compared. If for some reason a new simulator is required for subsequent modelling, then the earlier models should be re-run on the new simulator. This is not an onerous task due to the small size and brief running-time of the models as previously discussed.

5. CONCLUSION

5.1 No sensitivity

The standard model setup has been used to create a reference model and then tested by varying the model parameters within a reasonable range above and below the standard value. The models results show no sensitivity to the following parameters:

- Number of blocks in skin zone. Standard value 50. Range tested: 20 – 500 (-60% to +900%). Very marginal sensitivity only at very low values near 20.

- Number of blocks in reservoir zone. Standard value 100. Range tested: 50 – 150 (±50%).
- Well block porosity. Standard value 0.9. Range tested: 0.5-1.0 (-45% to +11%).
- Well permeability. Standard value 3 orders of magnitude greater than in situ reservoir permeability. Range tested: 1-5 orders of magnitude.
- Time stepping. Maximum time step standard value 100 seconds. Range tested: 1-1000 seconds.

It therefore does not matter the exact value used for these parameters in the model. However there is no reason to change these parameters from the standard values. This lack of sensitivity is only demonstrated within a range close to the standard values and so it is prudent to stick to the standard.

5.2 Low sensitivity

The model results show marginal to low sensitivity to the following parameters:

- Width of skin zone. Standard value 5m. Range tested 1-20m (-80% to +300%). Sensitivity only at very low values <5m.
- Well radius. Standard value 0.1m (based on size of drill bit). Range tested 0.05 – 0.15m (±50%). Marginal sensitivity to both increases and decreases.
- Well volume. Standard value $81.4m^3$ (based on volume of fluid really present in the well). Range tested $40\text{-}120m^3$ (±50%). Some sensitivity to both increases and decreases, more so to decreases. Shape of derivative plot does not change but shifts left and right.
- Well compressibility. Standard value 6×10^{-8} Pa^{-1} (based on change in fluid height at different injection rates). Range tested: 3×10^{-8} to 9×10^{-8} Pa^{-1} (±50%). Some sensitivity to both increases and decreases, more so to decreases. Shape of derivative plot does not change but shifts left and right.

These parameters warrant a little more consideration by the reservoir engineer. Using the standard skin zone width will ensure results are comparable between various tests and models. There is no way known to accurately determine the true width of the skin zone so using a standard is the only option. The well parameters of radius, volume and compressibility are estimated based on facts regarding the well size and behaviour. They should be estimated carefully, and can be estimated with far greater accuracy than the ±50% range tested. Once these parameter values are chosen they should be used for all subsequent models to ensure comparability of results.

5.2 High sensitivity

The model results show high sensitivity to the reservoir thickness. The standard value is 600m based on location of feed zones and range tested is 300 – 1200m. The unavoidable reality is that the method of estimating the reservoir thickness is subjective. It is critical that this is done with great care and the value remains the same for subsequent models.

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