Proceedings World Geothermal Congress 2015
Melbourne, Australia, 19-25 April 2015

Discrete Fracture Embedding to Match Injection Returns in a Single Porosity Model

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Keywords: TOUGH2, numerical simulation, injection returns, single porosity, dual porosity, fracture flow, discrete fracture embedding

ABSTRACT

The single porosity numerical reservoir model of the San Jacinto geothermal system, Nicaragua has been created and developed over the past 3-4 years. Recent reservoir tracer tests have shown a connection between an injection well and the main production area. In order to assess the significance of this link in terms of reservoir management, a quick and effective numerical reservoir model update was required. When considering the impact of injection returns in a reservoir, the associated thermal effects of injection returns is of critical importance. The matching of temperature declines caused by injection returns in a single porosity reservoir can be inadequate due to the relatively large volumes of the model blocks and heat diffusion from reservoir block surfaces. Travel times and return volumes are often very difficult to match. Dual porosity modelling introduces the ability to model fracture flows, and as such provides a mechanism to achieve closer matching of injection returns. It is widely accepted that the conversion of single porosity numerical models to dual porosity models is a difficult and highly time consuming process due to the increased computational requirements, the introduction of additional matching parameters such as fracture volume, porosity, permeability and spacing, and the inherent difficulty in acquiring field measurements for these parameters. Discrete fracture network (DFN) models can be implemented as an alternative approach; however these also require significant re-gridding and calibration if applied to existing models.

In order to achieve the desired level of calibration in an appropriate timeframe, we considered an alternative approach to matching the reservoir tracer injection returns while still using the single porosity model. Given that the connection between the injection well and production area had been interpreted to be structurally controlled with linked feed zones, a distinct fractured zone or channel between the injection well and production area was selected to represent the fault structure. Within this fault structure, the volume of each block was reduced and assigned a high porosity. Anisotropic permeability calibration was also performed to attain a good match to injection returns. This approach has been termed 'discrete fracture embedding'.

This alternative approach allowed an accurate match of injection returns in multiple wells and a close match for the overall travel times. Production well enthalpy and pressure responses were also matched during the tracer calibration. A number of injection scenarios were investigated to assess the impact of the injection returns. The results highlighted that there was sufficient heating of the injection returns between injection and production areas at the current production and injection rates, and that the injection returns should not be a concern at present. Long term limits for the main injection well linked to the reservoir were suggested in order to minimise impact, but there was significant flexibility for short term increases in injection load if necessary. The quick numerical reservoir model calibration, high level of accuracy in the matching of field data and sensitivity of the reservoir to injection have provided valuable information for the management of the San Jacinto reservoir in a highly cost effective manner. While field data initially suggested a potential issue to production, it has provided confidence that the current reservoir production and injection strategy remains appropriate and sustainable.

1. INTRODUCTION

1.1 Numerical Modeling

The use of numerical reservoir modeling in the planning and management of the development of geothermal fields has been standard practice for the past 25-30 years. Significant advances in computing power and the range of physical phenomena which can be matched have facilitated the creation of sophisticated 3D models capable of matching complex multiphase flow systems.

In the past, the vast majority of numerical models of geothermal reservoirs have been based on an equivalent porous medium or single porosity approach (Austria and O'Sullivan, 2012). More recently there has been a trend to use the dual porosity or MINC (multiple interacting continua) approach.

Single porosity models are usually adequate in matching natural state temperatures, pressure data and long term production histories in reservoirs with permeability related to complex and pervasive fracturing or high permeability and porosity lithologies. In reservoirs where fracture flow is the dominant mechanism for the transfer of heat and mass, with only minor contribution from the matrix blocks, there is a need to represent the fractures more explicitly. This is particularly the case when attempting to model the impact of injection returns on production, as fracture flow can transmit the cool fluid back to the reservoir over much shorter time periods than if the fluid were required to pass through the matrix rock only. This has implications on thermal decline in production wells. Reservoir tracer tests are commonly used to assess links between the wells. The simulation of tracer transport in fractured reservoirs has been noted to be a particularly challenging problem (Juliusson and Horne, 2010b).

In order to calibrate both matrix and fractures components, a dual porosity approach is required for the simulation. It requires the modeler to provide information relating to the fracture volume, porosity, permeability and spacing. These additional model parameters increase the calibration time and place additional importance on obtaining good reservoir data. In reality, obtaining field data for many of these model parameters is challenging.

Discrete Fracture Network (DFN) models have also been prepared to simulate fracture dominated flow paths in geothermal reservoirs (Juliusson and Horne, 2010) and EGS (enhanced geothermal system) type reservoir simulations (DOE et al., 2014). These require specific non regular grids to be set up with fracture and non-fracture blocks which share connections. This approach would require a significant amount of information to be already known at the time of model start-up or require re-gridding of the numerical model if chosen to be implemented further down the line.

In the early stages of reservoir development, the data and understanding of the subsurface conditions is limited. Therefore, at this stage, single porosity models are often created. As more information is obtained when the reservoir is progressively explored and developed, there can be a need to adopt a dual porosity approach to ensure that the model is appropriate and reservoir management decisions are well founded. This will depend heavily on well logging data, structural geology observations and reservoir injection strategies. There is ongoing research to determine when dual porosity models should be preferred ahead of single porosity models (Austria and O'Sullivan, 2012).

The conversion of a single porosity model to dual porosity (or indeed a DFN model) is a significant challenge and can take a significant amount of time to achieve improved to natural state and production histories.

2.1 San Jacinto Geothermal Reservoir

The San Jacinto Tizate geothermal project is located in northwestern Nicaragua approximately 20 km northeast of the city of Leon and centrally located among a series of active volcanoes (Figure 1-1). The first major exploration of the resource began in 1993 with a Russian company, Intergeoterm. The initial phase of exploration drilling concluded in 1995 with the completion of 6 wells and the partial drilling of a 7^{th} well. Exploration drilling also confirmed the presence of a relatively low gas (<0.4 wt %) liquid-dominated neutral chloride resource, with a temperature range of 260°C – 300°C in the central upflow area (Mackenzie et al., 2012).

Following the acquisition of Polaris by Ram Power in 2009, a drilling program was initiated by Ram Power in 2010 to increase the project generation capacity. Phase 1 was successfully commissioned in December 2011, with Phase 2 coming on line in late 2012. Following some unsuccessful drilling results in 2010, Ram Power have successfully completed a number of new wells and forked wells (multi-legged wells as opposed to side tracks) between 2011-2012, using improved drilling approaches and more robust targeting strategies followed by a well intervention campaign in 2013. The latest campaign was completed in early 2014 targeting 60MWe of generation.

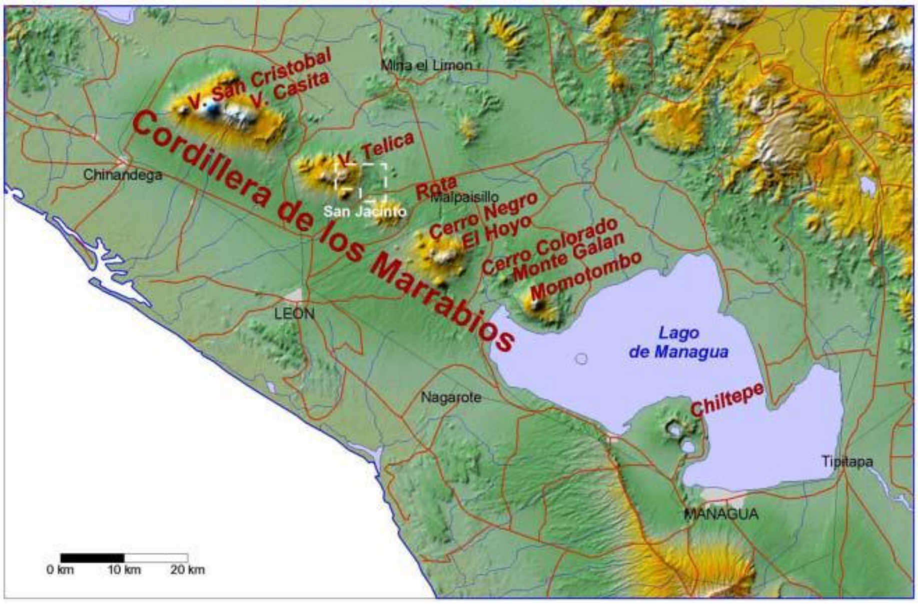

Figure 1-1: San Jacinto Project Location

The San Jacinto geothermal project currently consists of 15 active wells including forked wells (4 injectors, 11 producers). The borefield configuration comprises a central production area covering approximately 1.75km^2, with injection areas to the north and south (Figure 1-2). The upflow within the field has been interpreted to be in the eastern and southeastern part of the central production area (near Pad X on Figure 1-2). The fluid flows up and to the west towards western limits of the production area. There is an outflow from the system interpreted to the southern well SJ10-1 and SJ1-1. There are surface geothermal features (primarily steaming/heated ground) in the central production area and near the southern injection area. A conceptual W-E section diagram is shown in Figure 1-3 using the downhole measured temperature based 3D model.

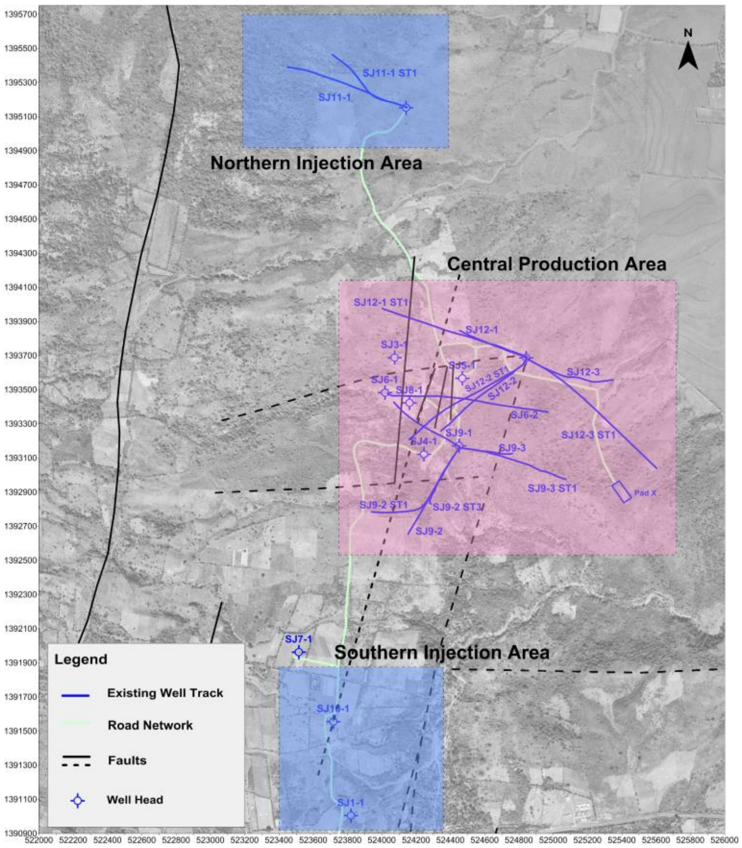

Figure 1-2 San Jacinto Project Borefield Layout

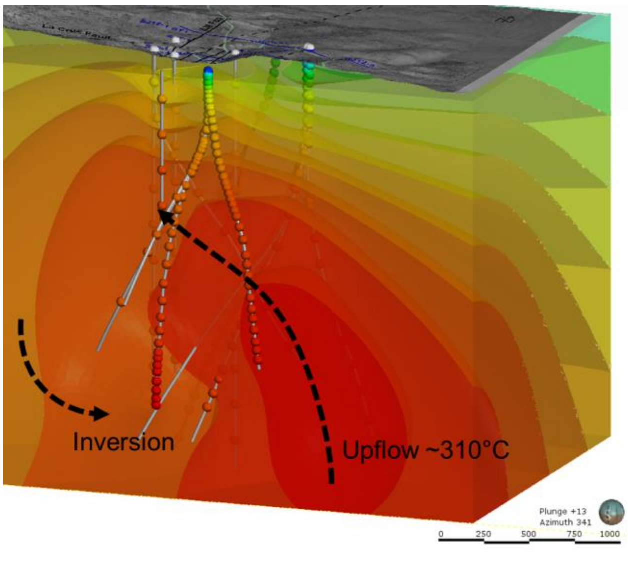

Figure 1-3 W-E Model Cross Section (temperature contours shown)

A number of structures have been mapped at the field, with significant permeability noted on the NE/SW faults. While there are also E-W faults interpreted, these are considered to be less important in terms of production targets. Figure 1-3 shows the interpreted trace of the SJ-8 fault which was interpreted through well drilling and surface fault expression (in 3D looking W). From this figure a number of interpretations were made relating to wells with linked feedzones. In this paper the connections between of SJ-4, SJ9-1 and SJ6-2 in the shallow part of the reservoir are in focus.

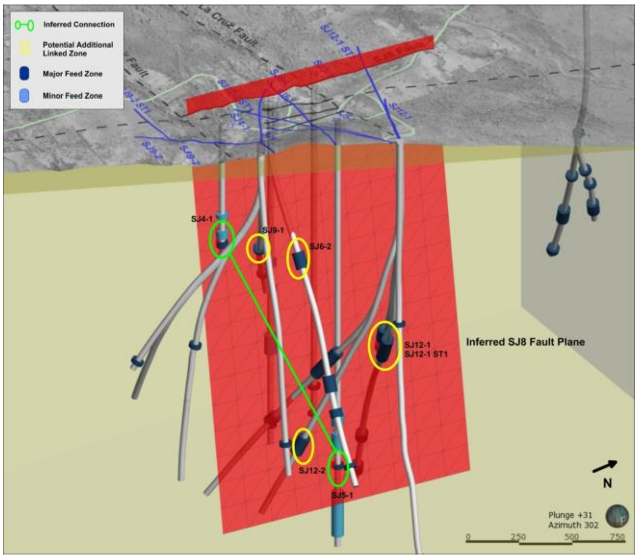

Figure 1-4 SJ-8 Fault Trace with linked feedzones (SKM 2012)

A soil gas survey carried out in 2011 indicated elevated CO_2 fluxes in a linear orientation between the production area and injection well SJ10-1 approximately 1.5km to the south. This, alongside well temperature profiles which suggested a shallow outflow from the production area to the south, provided further evidence that a permeable connection (potential SJ10 fault structure) between the two areas existed. The link and potential crossing of the SJ8 fault was also identified.

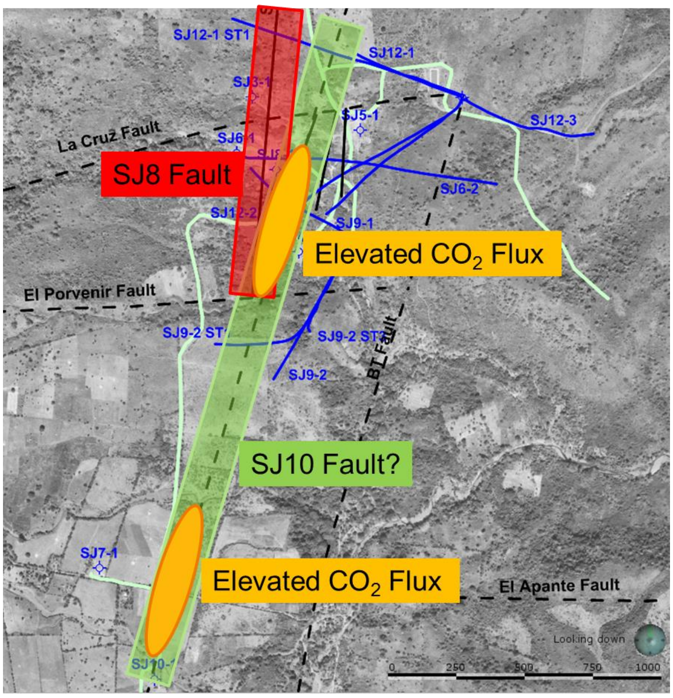

Figure 1-5 CO_2 Flux Survey Results

2. SAN JACINTO NUMERICAL MODEL

The San Jacinto numerical reservoir model was created to understand the response of the field to expanded production and the relationship between production and injection areas. Originally it was a full single porosity, air/water model created using the TOUGH2 numerical simulator. The summarized model details are provided in Table 2-1. A cross section through the model showing the vertical structure and model surface is shown in Figure 2-1. The shallow groundwater table was used as the top of the model. This surface was based on measured water levels combined with subdued topographic elevations.

Table 2-1 San Jacinto Model Details

Model Area	340km^2
Model Blocks	~26,000
Block Areas	125m x 125m - 2000m x 2000m
Model Depth	-3,200masl
Top of Model	Open boundary, fitted surface to interpreted water table (subdued topographic surface)
Atmosphere	Single block, 1bar, 25°C
Side Boundaries	Closed
Base of Model	Closed with heat (100mW/m^2-400mW/m^2) and mass fluxes (~ 65kg/sec hot fluid)

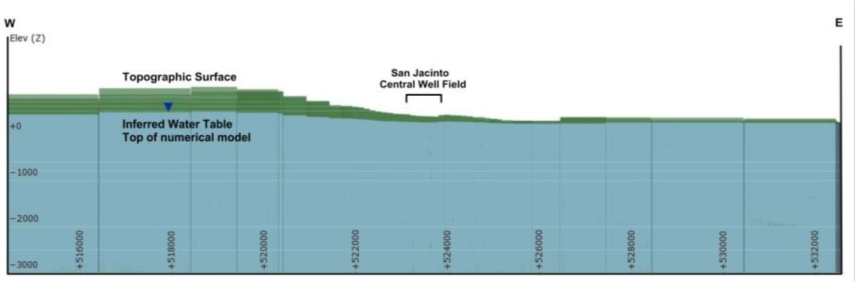

Figure 2-1 Model Vertical Slice and Topography

2.1 Model Calibration

Calibration of the numerical model has been ongoing since 2011, with permeability adjustments made to refine matching and reflect additional data for new and existing wells. During this time a number of wells have been drilled in the central production area as well as a new forked injection well SJ11-1 to the north. Periodically the new data provided by these drilling campaigns as well as updated monitoring of reservoir pressures in response to production has been incorporated into the model calibration to aid development decisions.

Both natural state and production history matching was achieved through to mid-2012. The details of the matching are beyond the scope of this paper.

Overall the model was considered to be a good match to the conceptual model, well parameters and production history.

3. RESERVOIR TRACER TESTING

A reservoir tracer test was undertaken in July 2012 to establish injection returns to the production area of the field. The results confirmed a northward movement of SJ10-1 injected brine towards the production sector, but also confirmed that the other injection wells did not connect with the central reservoir. The results showed that approximately 30% of the brine injected at SJ10-1 was being produced by three wells; SJ4-1, SJ9-1 and SJ6-2. The tracer return velocities were considered to be moderate, with heating of the injected brine anticipated along the 1.5 km path from SJ10-1. A N-S cross section is shown in Figure 3-1 highlighting the connected feedzones along the interpreted SJ10 fault (green plane).

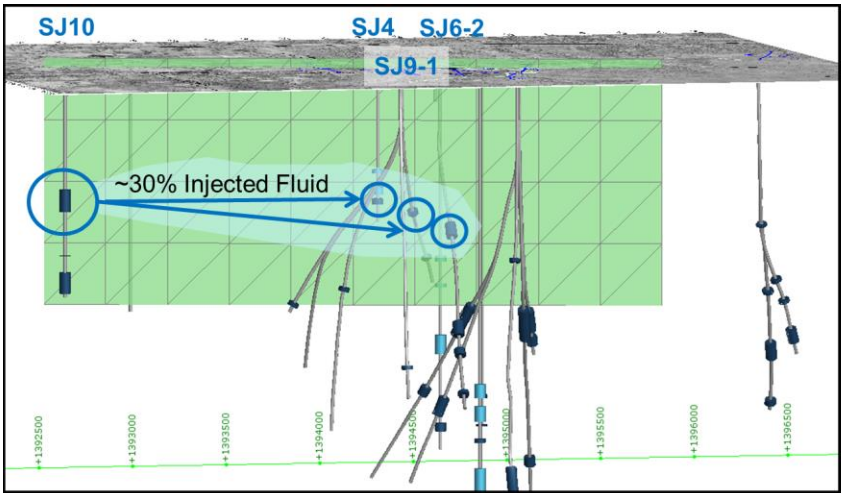

Figure 3-1 Cross section showing connection between SJ10-1 and the production area (~4km along section line)

There were no returns from the other injection wells (SJ1-1, SJ11-1 and SJ12-1).

Following the testing and interpretation of the tracer test results, an update of the numerical reservoir model was required to incorporate the new information in the model calibration in order to assess the implications of this observed connection and improve the accuracy of future reservoir performance predictions.

4. MODEL CALIBRATION UPDATE

4.1 Model Calibration

Given the interpretation that a high permeability pathway, likely to be fracture or fault related, existed between SJ10 and the production area, there was a need to incorporate this into the numerical model.

In reservoirs where fracture flow is an important fluid flow pathway with relatively small matrix flow, there is merit in utilizing a dual (double) porosity modelling approach to capture both types of flow (Figure 4-1). This allows more accurate representation of fluid travel times and any thermal attenuation. However, this also introduces additional variables (compared to a single porosity model) which need to be calibrated; fracture spacing, fracture permeability and fracture porosity. The full conversion of a single porosity model to a dual porosity model represents a significant undertaking and should be performed if there is sufficient data available to calibrate appropriately.

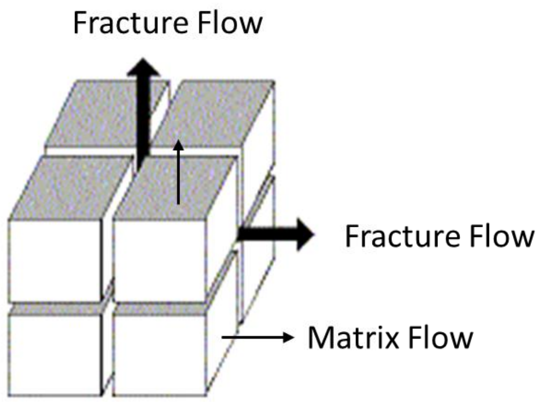

Figure 4-1 Dual Porosity Modelling Schematic

In the case of San Jacinto, single porosity modelling would not have been able to achieve the required accuracy to match the reservoir tracer results. This is due to flows within a single porosity model being entirely from matrix block to matrix block, therefore representing too slow a travel time, and too much heat attenuation and dilution of the fluid. In order to match the injection returns, the incorporation of dual porosity modelling was required. As this was required between one injection well and the production area, the possibility to use an alternative approach to full conversion of the model to dual porosity was assessed. This also had the advantage of maximizing the benefit against the effort and modeling time requirement.

As opposed to full conversion to dual porosity, an area of the model was chosen to represent the permeable connection/channel (representing the fault or fracture network) between SJ10-1 and the production reservoir. This area is shown in yellow in Figure 4-2. Two layers were chosen in the numerical model corresponding to the feedzone elevations. Simply raising the permeability of the chosen blocks would not have represented the flow appropriately. In order to represent fracture flow, the volume of each of the blocks in the channel was reduced to 0.05 – 0.1% of the original block volume. This is a relatively straightforward change within the TOUGH2 input file. The porosity of each block was increased to 99%. In doing this, each block then behaved more like a fracture within the model. As such a discrete fracture or fault was embedded into the model (Figure 4-3). Figure 4-3 is a diagram representing the concept that while the volumes of the blocks are significantly reduced they still share the same boundaries with adjacent cells. The permeability was also calibrated, with anisotropy included to encourage flow in the appropriate direction and limit mixing with the surrounding reservoir. These changes allowed calibration of the transit time and mass returns with the measured data.

In TOUGH2 there is an option to assign injection fluid with a different identifier. Therefore the produced fluid from the production wells could be split into ‘reservoir’ fluid and ‘injection’ fluid components allowing calibration based on the tracer results. This required the tracer data to be used to calculate the percent of injection fluid being produced by the production wells at the time of the tracer test. It was this data that was used to calibrate the model.

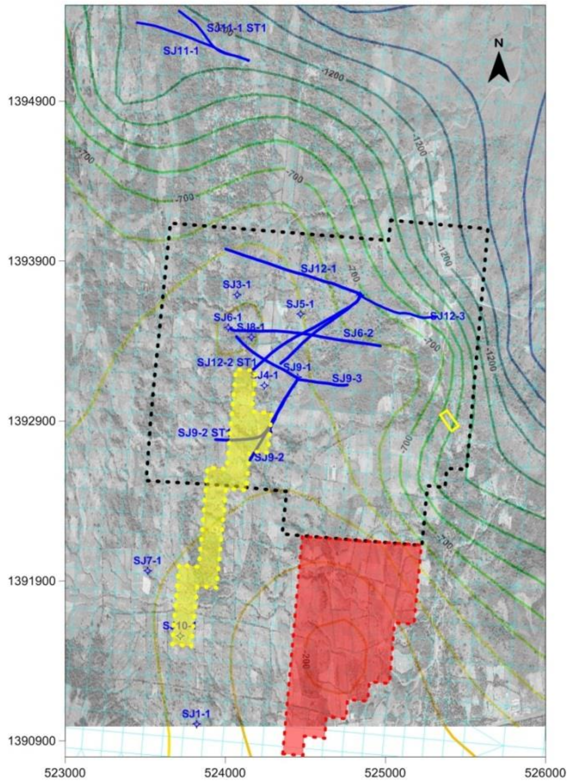

Figure 4-2 SJ10 Connection to Production area (yellow area).

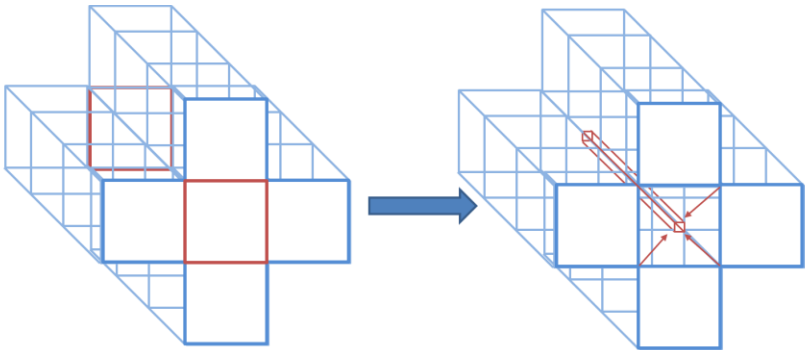

Figure 4-3 Discrete Fracture Embedding Conceptual Model showing block volume reduction.

4.2 Reservoir Tracer Calibration Results

Table 4-1 shows the results summary with the interpreted injection mass contributions for each well. The percentage of tracer recovered by each well was used to calculate the proportion of injection mass flow return from SJ10-1. Alongside the total production well mass flows, each well's proportion sourced from SJ10-1 was calculated. This mass flow was used as the calibration reference data within the TOUGH2 model.

Table 4-1 Injection Returns Summary

Well	Tracer Recovered %	First Arrival Time (days)	Production Well Mass Flow (tph, July 2012)	SJ10-1 Mass Return (SJ10-1 Mass Flow - 261 tph, July 2012)	Mass Flow Injection Fluid % (July 2012)
SJ4-1	17%	28	390	44	44/390 = 11%
SJ9-1	8%	37	466	21	21/466 = 4.5%
SJ6-2	3%	35	234	8	8/234 = 3%

A relatively quick process of model calibration (2-3 weeks), by varying permeability and block volumes, led to the successful matching of the injection returns to SJ4-1 and SJ9-1. The model calibration did not achieve a good match for SJ6-2 which was the well showing the least injection returns. This well has also been identified in the past as having complex and variable flow mechanisms between deep and shallow feedzones, which are not completely represented in the numerical model.

Figure 4-4 shows the matching results for SJ4-1 and SJ9-1 production between 2008 and 2013. The left axis shows the percentage of fluid from SJ10-1 contributing to the total mass flow of SJ4-1 and SJ9-1. The right axis shows the injection mass flow into SJ10-1. Both well plots show an accurate match to the measured contributions of 11% and 4.5% respectively in July 2012 (the time of the tracer test). The trends of the tracer returns closely match the trend of injection mass flow (right axis) at SJ10-1.

The first arrival travel time for returns to SJ4-1 in the model also showed a good match – 28 days for the tracer study compared to approximately 1 month within the model following the start of injection at SJ10-1. SJ9-1 shows a slightly slower tracer arrival time of ~2 months. The tracer testing indicated a faster tracer travel time for SJ9-1 of a little over 1 month. However an error of 1 month is considered to be acceptable and shows that the relatively quick response is matched in the model.

Simulation runs tracking injection returns for SJ12-1, SJ1-1 and SJ11-1 were also conducted. For the duration of the production history simulation, the model showed no returns from these wells, thereby matching the tracer test results.

By matching both the travel times and mass contribution from the injection well SJ10-1 we can be confident that thermal impact has also been captured. Additional tracer testing as part of ongoing reservoir management will be assessed within the model to ensure that the calibration is accurate.

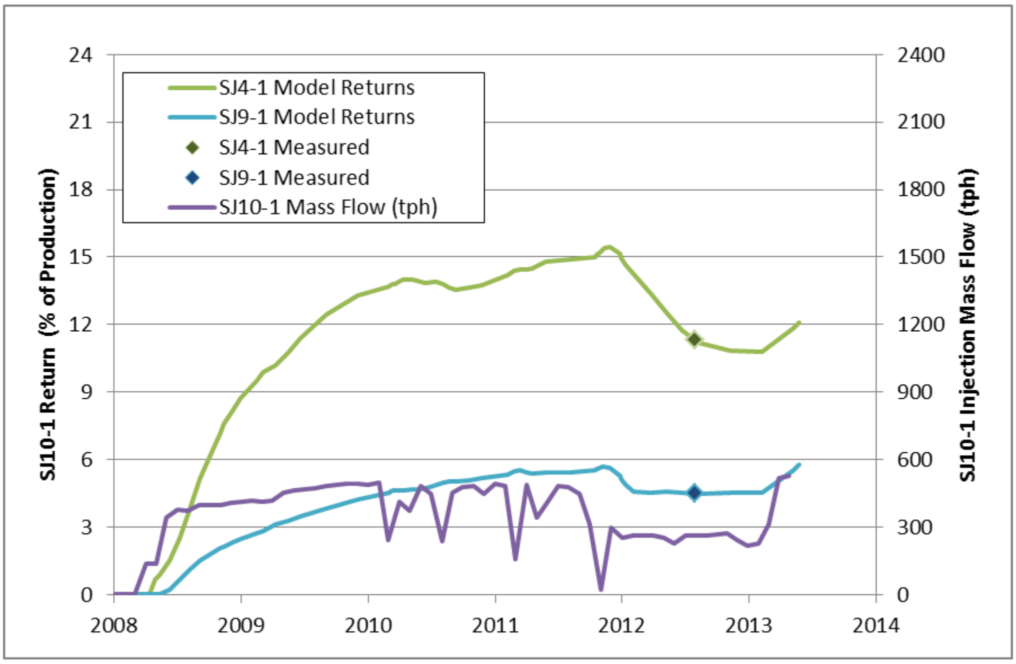

Figure 4-4 Injection Return Calibration Result

4.3 Model Calibration Implications

The calibration of the injection returns has allowed greater confidence in the matching of the model to the reservoir behaviour. The pressure and enthalpy responses of the production wells receiving injection returns showed slightly better fitted pressure and enthalpy matching. Figure 4-5 shows the pressure and enthalpy matching improvement at SJ4-1 between the earlier 2012 model and the latest version as well as the pressure trend comparisons at SJ10-1. At SJ10-1 there was an increase in the pressure at the feedzone in the latest numerical model. The measured data is limited to discrete shut well conditions and is not replicated in the model as average monthly flows were used. Therefore the model shows higher pressures overall. The disparity here is not considered significant as the improved pressure response and stabilized pressure trend indicates that updated calibration approach (and reduction in block volume) is appropriate and provides a better match compared to the 2012 numerical model.

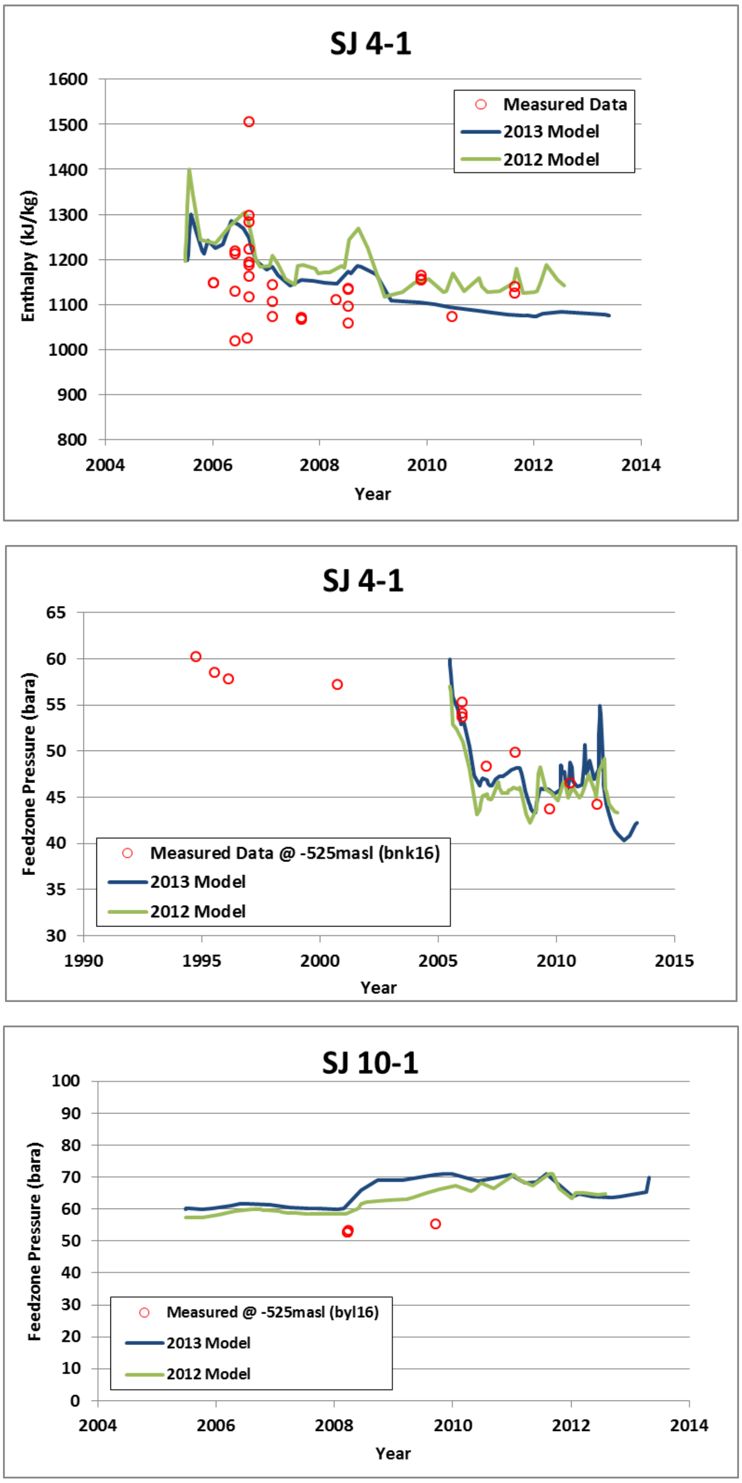

Figure 4-5 Improved Pressure and Enthalpy Matching in Wells

Sensitivity studies with varying rates of injection at SJ10-1 were performed following the initial calibration indicated minor impact on enthalpy of wells SJ4-1 and SJ9-1 in the model (note: the details are not included in this paper). It was therefore interpreted that there is considerable heating of the injected brine before it returns to the production area. This would imply that any temperature drops in wells under the current extraction and injection regime, is more affected by relatively cool recharge from the surrounding reservoir as opposed to injection returns. This matches the interpretations made prior to the modeling through geochemical analysis.

The addition of the injection calibration has enabled the model to reinforce the interpretation that the injection returns, at current rates do not represent a significant threat to production.

4.4 Application of Discrete Fracture Embedding

The incorporation/embedding of discrete fractures using the method outlined in this paper is recommended as an effective tool to achieve calibration of single porosity models where direct fracture or fault connections have been indicated between wells or production/injection areas. The incorporation of a number of discrete fractures could be considered to improve model accuracy in a relatively short amount of time for model calibration.

This method does not replace the need for or suitability of dual porosity modeling nor does it cast aside the suitability of DFN models. The approach is most useful to aid single porosity model matching to fault or fracture controlled field characteristics without requiring time consuming conversion of the model to full dual porosity. In the event that a model requires excessive use of this method to get the required matching accuracy, the consideration to convert to full dual porosity should be addressed once more based on cost-benefit principles.

5. CONCLUSIONS

A single porosity numerical reservoir model of the high temperature San Jacinto geothermal reservoir has been prepared for use in reservoir management decisions since 2011. The reservoir consists of a central production area with injection areas to the north and south. The main observed outflow from the system was to the south, towards the southern injection area.

A number of geoscientific data led to the interpretation that there may be a strong connection between the southern injection area (SJ10-1 in particular) and the main production area. Downhole temperature data and a CO_2 flux survey provided evidence of a potential structural link; a fault or fracture zone identified as the SJ10 Fault.

By 2012 the numerical model was well calibrated to the conceptual model and production data so that forward predictions of development scenarios could be run to aid management decisions. Although at this stage there was little data to fully calibrate the outflow area.

Reservoir tracer tests were undertaken in all injection wells in July 2012 to assess the connections with the reservoir more directly. The results of these tests showed that only SJ10-1 in the south had a connection with the production area. Up to 30% of the injected fluid at SJ10-1 was found to be making its way back to the production area, in wells SJ4-1, SJ6-2 and SJ9-1. An update of the numerical model calibration was required given this new information. Of particular interest, was the degree of heating of the injected fluid prior to entering the production zone (i.e. the impact of injection on production enthalpy).

Matching of injection returns is most accurately achieved using dual porosity models which allow matrix and fracture flows to be fully represented. The full conversion of the San Jacinto model to dual porosity would have required a significant amount of time and was not considered to reflect the best use of effort and finances. As a result, a quicker, but still suitable approach to matching the data was provided to allow rapid assessment of development strategies for management.

A method of embedding discrete fracture flows was utilized. An area of the single porosity model was identified linking well feedzones which could be altered to behave like a channel or fault/fracture network to achieve the required level of accuracy in data matching. The volume of the blocks in the channel were reduced significantly, the porosity increased and the permeability altered to achieve a close match to both mass contribution and travel time.

This was achieved in a very short time frame (2-3 weeks) from a modelling perspective, with good injection return matches in two of the wells, as well as an improved calibration to enthalpy and pressure matching. The non-returns from the northern injection area were also matched in the model. Sensitivity studies performed following the model calibration indicated that the injected fluid is interpreted as being heated considerably as it made its way back to the reservoir, reinforcing earlier geochemical studies. Additional tracer test data in the future will be important to increase confidence in the accuracy of the model.

The project has been shown to have significant flexibility in terms of reservoir management, with injection areas connected to the production area to the south and separated from the production area to the north. Development strategies for altering injection regimes can now be simulated in the model with much greater confidence. This includes the potential to change the boundary between northern and southern injection as well as the temperature of the injection fluid (in the event that a Binary power plant is added to optimize electricity production from the resource).

The updated numerical model calibration and analyses reinforced the geochemical interpretations and provided significantly more confidence that the management strategy for the reservoir was appropriate. The operator has been supplied with a tool which could test future development strategies and allow ongoing optimization of the reservoir for electricity production. The updated model with discrete fracture embedding will be maintained and updated alongside the resource development.

ACKNOWLEDGEMENTS

The author would like to acknowledge the permission from Ram Power to prepare and submit this paper, without which none of this interesting project would have been possible. Thanks also go to the Jacobs staff involved in the exploration and reservoir data interpretations as well as their support and peer review of the modelling work. A final thanks to Professor Michael O’Sullivan at the University of Auckland for some key guidance on dual porosity modelling and the support to document this attempt at an alternative approach.

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