Institute for Mineral and Energy Resources

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South Australian Centre for Geothermal Energy Research

Program 3 Summary Report

ARENA Measure: Reservoir quality in sedimentary geothermal resources

REV	Date	Objective	Author	Recipient	Status
01	14th December 2014	Program 3 summary report	Cameron Huddlestone-Holmes	Melissa Pang ARENA Project Manager	

Introduction

The Government-Industry-Academia research collaboration entitled *Reservoir Quality in Sedimentary Geothermal Resources* is comprised of three programs relating to the "failure analysis" of Hot Sedimentary Aquifer (HSA) geothermal exploration wells Salamander 1, drilled in the Otway Basin, and Celsius 1, drilled in the Cooper-Eromanga Basin. The project aims were to conduct a scientific research-driven analysis of the two geothermal wells – the only ones drilled in HSA reservoirs in Australia, and to evaluate why the achieved fluid flow rates were significantly lower than expected.

Two failure analysis Programs were undertaken. The first Program involved evaluating the primary reservoir quality of the two target formations – the Pretty Hill Formation in the Otway Basin, and the Hutton Sandstone in the Cooper-Eromanga Basin. The second Program involved evaluating formation damage that may have been caused during the drilling of the two wells and subsequent production tests.

Researchers from the University of Adelaide, CSIRO and the South Australian Museum collaborated to conduct petrology, SEM, TEM, QEMSCAN, cathodoluminescence and seismic attribute analysis. Laboratory experiments simulating secondary mineral growth and fines production under different conditions were conducted. Analysis of results to allow reservoir behaviour to be modelled also occurred.

The conclusions reached from Program 1 were that diagenetic factors have made the deep, hot water reservoirs less permeable than hoped, but that the effects are not uniform basin-wide, and that it may be possible to identify more permeable zones using seismic and petrology. Program 2 concluded that formation damage is more likely in hot water settings than hydrocarbon reservoirs under production, but there are ways that this can be mitigated. A summary of Program 3 is described in this document.

Program 3 – Summary Report

Program 3 – A recommended workflow for HSA geothermal in Australia

This report will take the lessons learnt throughout the rest of this study to develop a workflow for assessing geothermal reservoir quality ahead of drilling and protocols for HSA geothermal well drilling. These recommendations for future development of sedimentary geothermal resources in Australia will help to reduce the risks that have been highlighted by the two exploration projects that were the subject of this study.

Sedimentary Geothermal Resources

This project has focused on sedimentary geothermal resources, which are within the Deep, Natural Reservoir category described above. These resources are targeting permeable formations within sedimentary basins. The conceptual model is that these high permeability formations will allow geothermal fluids to be produced at high flow rates without any significant engineering of the reservoir. Fracture permeability may contribute but is not the primary target. The generally sub-horizontal nature of the layering of formations in sedimentary basins means that if a highly permeable formation can be identified, there is a good chance that the resource would have good lateral extent. Intersecting a horizontal formation with a vertical drill hole would be straightforward and lower risk than targeting the sub vertical fractures typically found in convective geothermal resources.

The thermal regime in sedimentary basins is dominated by conduction. Regions with anomalously high geothermal gradients are desirable, but not required may. Higher than average geothermal gradients may be present due to elevated heat flow from the basement or due to heat being trapped by sediments with low thermal conductivities. Anomalously high thermal gradients in these conductive settings are likely to be more than 50°C/km (compared with the crustal average of about 30°C/km).

A key challenge in developing sedimentary geothermal resources is in finding areas where the permeability is preserved at the depths required to reach the necessary temperatures for a geothermal resource. The effects of diagenesis, both through compaction and chemical changes, act to reduce the permeability and porosity as sediments are buried.

Exploration Workflow

The characteristics of a geothermal resource must be quantified to a high enough level of certainty that would this investment decision to be made with an acceptable level of risk. Throughout the exploration process, the costs of gathering new information are balanced against the probability of a successful outcome. A successful outcome could be considered to be a reduction in the uncertainty around resource as well as a confirmation that the resource has the desired characteristics. Different activities in the exploration process have different costs. For example, drilling a deep well costs several orders of magnitude more than a desktop study of existing geophysical data, however, drilling deep well is the only way of directly sampling or testing a resource. There are a range of technical resource characteristics that need to be determined during the exploration process. The main parameters are listed in table 1.

Characteristic	Parameters	Use
Thermal Regime	Resource Temperature	Essential for determining the amount of energy within the reservoir and design of the power plant

	Thermal Gradient	Determining the depth to the required temperature, Input for modelling resource temperatures
	Heat Flow	Input for modelling and predicting resource temperatures and thermal drawdown during production from the reservoir
Reservoir Quality	Stress State	Well design and potential and potential response of reservoir formation to production (e.g. compaction)
	Depth	Well field design
	Mechanical Properties	Well design and potential and potential response of reservoir formation to production (e.g. compaction)
	Lateral Extent	Essential for determining the amount of energy within the reservoir. Identification of compartments due to faulting also critical determining well placement and spacing
	Thickness	Essential for determining the amount of energy within the reservoir. Essential for determining the performance of the reservoir
	Porosity	Determining the rock to fluid ratio which is essential for determining the amount of energy within the reservoir
	Permeability	Essential for determining the performance of production wells
	Heat Capacity of Formation(s)	Input for modelling and predicting resource temperatures and thermal drawdown during production from the reservoir
Geothermal Fluids	Pore Pressure	Determining the performance of production wells and otential response of reservoir formation to production
	Chemistry	Determine corrosion and scaling issues in wells and the power plant
	Heat Capacity	Essential for determining the amount of energy within the reservoir and the design of the power plant

Table 1: Technical resource characteristics required to design a geothermal power system.

These characteristics allow the size of a resource to be quantified and the design of the well field, brine field and power plant to be completed. This design is a necessary input into the Project Review and Planning stage of a geothermal project's development at which a decision to proceed to field development, the most capital intensive stage of project, is made. It is very important to characterise the geology of the resource to allow these technical characteristics to be determined. The rocks that make up the resource and their history will determine many of these characteristics. The geological information that needs to be collected summarised in
Table 2.

Parameter	Use
Stratigraphy	Identification of target formations and the surrounding horizons. Input for modelling and predicting resource temperatures and reservoir performance
Depositional Environment	Determines the likely complexity of the reservoir (permeability- thickness distribution) which is essential for determining the size and performance of the reservoir. May also influence diagenetic processes
Lithology	Determine the likely effects of diagenesis on the preservation of permeability. Determine potential for fines migration, reactivity (with re-injected and cooled geothermal fluids)

Diagenetic History	Determine the likelihood of permeability being preserved due to diagenetic processes such as compaction, cementation and dissolution
Basin Structure	Determines the lateral extent of the reservoir, variations in depth of the target formation, and compartmentalisation due to faulting
Burial History	Determine that pressure, temperature, time path that the rocks have travelled through that influences diagenesis and the preservation of permeability
Heat Capacity of Formation(s)	Input for modelling and predicting resource temperatures and thermal drawdown during production from the reservoir
Stress State	Well design and potential and potential response of reservoir formation to production (e.g. compaction)
Mechanical Properties	Well design and potential and potential response of reservoir formation to production (e.g. compaction)
Heat Production	Input for modelling and predicting resource temperatures and thermal drawdown during production from the reservoir
Thermal Conductivity	Input for modelling and predicting resource temperatures and thermal drawdown during production from the reservoir
Fluid Chemistry	Determine the likely effects of diagenesis on the preservation of permeability due to fluid rock interactions

Table 2: Geological parameters that need to be determined to allow the reservoir engineering parameters to be adequately characterised.

Two peculiar aspect of exploration for geothermal resources in Australia is the lack of working examples of deep sedimentary geothermal resources and the marginal economics of geothermal energy. The lack of working examples is a significant issue for potential investors who need to see evidence that geothermal projects can work in Australia. The effect of this is that geothermal developers struggle to raise the requisite funding to conduct a thorough exploration program. The marginal economics of geothermal energy in Australia also makes it difficult for explorers to adopt a portfolio approach to exploration where overall risk is reduced by exploring in several different areas. This approach increases the chances of success but also increases the costs of exploration if only some projects in the portfolio prove to be successful.

Reservoir Quality

The experience with the Celsius-1 and Salamander-1 wells reinforces the importance of reservoir quality to sedimentary geothermal resources. However, the characteristics of a resource that define its reservoir quality are also a very difficult to explore for. As for the temperature of the resource, reservoir quality can only be directly measured through drilling. Predicting reservoir quality ahead of drilling is a challenging task that has been well studied in the petroleum sector. Geophysical methods, primarily involving techniques based on 3-D seismic data (e.g. Bosch, Mukerji, & Gonzalez, 2010; Gunning & Glinsky, 2007; Johansen, Jensen, Mavko, & Dvorkin, 2013 and work by Khair reported in Milestone Report 4 of this project) are being actively developed although their use is generally limited to qualitative assessments at this stage (Hart, 2013). Another approach has been to predict reservoir quality based on models for diagenesis (Ajdukiewicz & Lander, 2010). These models have also been applied with varying degrees of success in petroleum exploration with the best results achieved where the models are well calibrated and linked to basin burial history models (Taylor et al., 2010). Until reservoir quality can reliably measured using remote sensing methods (such as combined inversion of multiple geophysical data sets), reducing uncertainty in predictions of reservoir quality before drilling will most likely benefit from a combination of approaches.

Perhaps the most important parameter of reservoir quality is the permeability. Permeability tends to decrease with depth. Predictions of reservoir petrophysical properties, such as porosity, based on models for diagenesis will provide the most information for the minimum expenditure when compared with the costs of the acquisition of seismic (millions of dollars) and other geophysical data or drilling to reservoir depths (tens of millions of dollars). Such models will require as much detail as possible about the targeted formations and the burial history of the basin to be reliable. The interrelationship between these processes are complex, but are ultimately controlled by the geology and geological history of the basin.

There are many geological factors that control diagenesis and its effects on porosity and permeability in particular including:

- initial composition of the sediments at deposition;
- depositional environment of the sediments;
- burial history (depth and rates);
- temperature history (closely related to burial history);
- pore fluid migration; and
- effective stress (related to burial depth and pore pressure).

Collecting data on each of these aspects and conducting a thorough analysis of the diagenetic history of sediments in the basin will be a critical aspect of the exploration phase of sedimentary geothermal resources. The data required and analytical techniques that would be employed are no different to those that would be used in exploration for oil and gas resources. Perhaps the main difference is that the risk posed to a geothermal project from underestimating the permeability is significantly greater than to a petroleum project due to the value of the fluid to be extracted. The exact approach to studying the diagenetic and burial history will be dependent on the available data and the geology of the resource being studied. Ajdukiewicz & Lander (2010) discuss the state of the art in predicting reservoir quality in sandstones, and the large variety of approaches are too numerous to discuss here. The critical nature of permeability to the success of a geothermal project does mean that all avenues for assessing the diagenetic and burial history of the target formations in the basin and the prediction of reservoir quality based on these analyses should be exhausted before exploration proceeds to more costly activities such as drilling or the acquisition of 3d seismic data.

Summary

The development path of every geothermal project will be unique, controlled by a range of factors including the geology of the resource, the availability of precompetitive data as well as the risk profile of the developer. However common to all projects will be the continuing trade-off between the costs of gathering data and the reduction in uncertainty in the key resource parameters that results from that data.

Figure represents a workflow that might be followed during exploration for sedimentary geothermal resources. This highlights the common aspects of exploration, which are the collection of data, the interpretation of that data and then decisions based on the remaining risk and potential rewards on whether to continue. There is also a continual assessment of where additional data is required to reduce uncertainties around key parameters for a successful resource development. This workflow reinforces the need for the development of resource models (both static models of the geology of the resource and diabetic models of expected reservoir performance) to allow a proper assessment of the viability of the project.

The key technical parameters for sedimentary geothermal resources are resource temperature and reservoir quality. Clearly understanding the controls on reservoir quality such as burial and diagenetic history will be critical in assessing the permeability risk and should a priority throughout the exploration.

If deep drilling is contemplated, then data collection from the first well(s) should be of sufficient quality to allow an analysis of the controls on the key reservoir parameters. Insufficient data may lead to decisions being made based on incorrect interpretations that are made in the absence of appropriate information. Simply conducting a flow test is not enough to allow good understanding of the reservoir, particularly if it has performed below expectations.

The aim of exploration is to demonstrate the existence of a resource with the technical parameters that are required to be commercially feasible with a low level of uncertainty in these parameters. This knowledge will allow a business case to be made to attract funding for the project to proceed through the high cost phase of field development and construction. The exploration stage of project development must result in a sufficient understanding on the controls of the key parameters to provide this certainty.

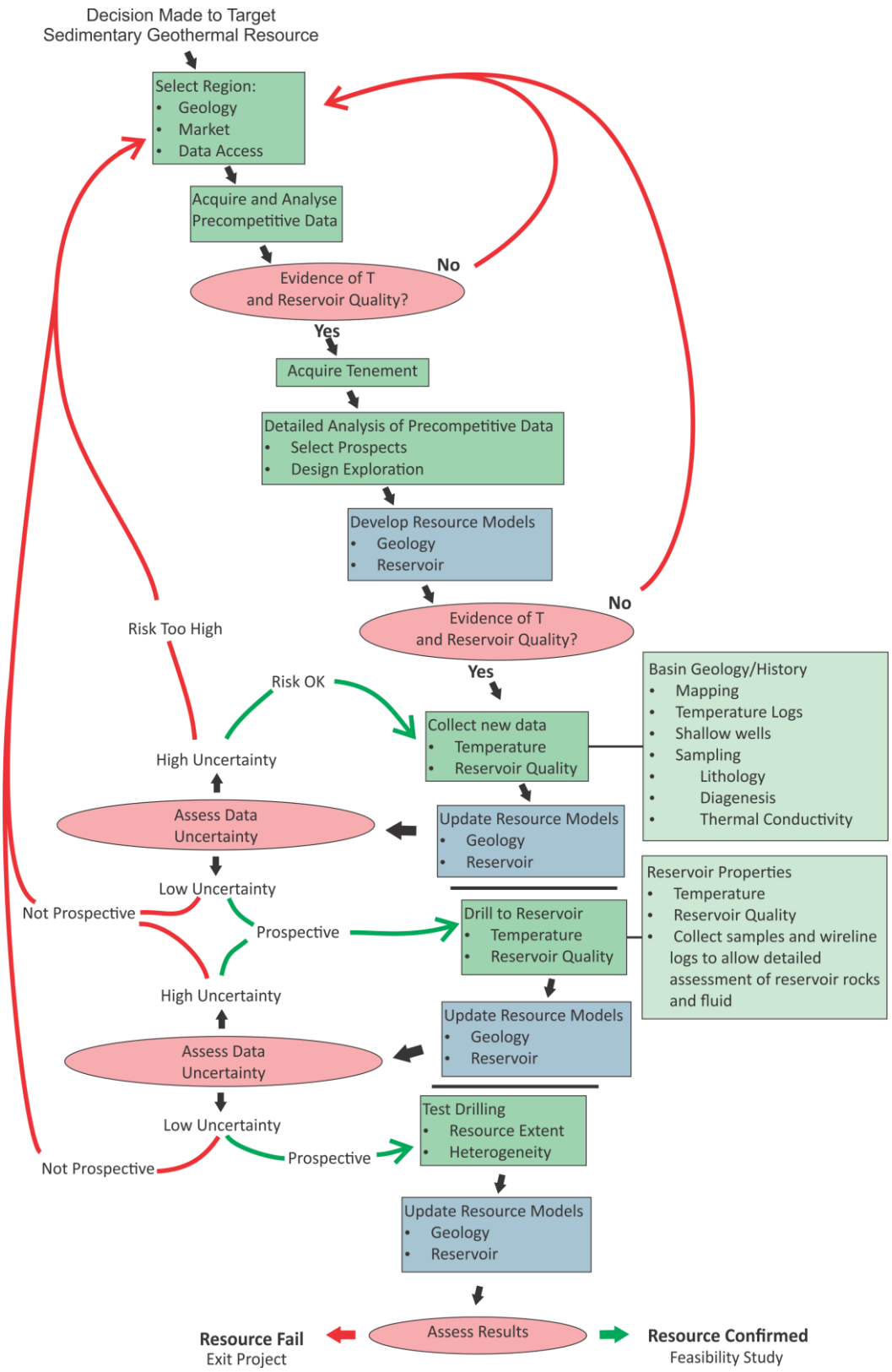

Figure 1: A workflow for exploration, highlighting the many decision points and the often iterative nature of data collection, interpretation, modelling of the results and decisions.

Reservoir Engineering

Mitigating against fines migration during well testing

The proper way to assess fines migration and consequent formation damage with further prediction of well behaviour from well testing would be through measurements of wellbore pressure, rate and fines concentration in produced fluid during the well test. The results should be matched by a mathematical model yielding the tuning of the maximum retention function, initial concentration of movable fines in the reservoir and the filtration and formation damage coefficients.

The analytical solutions for flows associated with fall-off, build-up and injection tests accounting for fines migration are readily available in the literature (Bedrikovetsky et al., 2012a,b; Zeinijahromi et al., 2012a,b; Marquez et al., 2014, Bedrikovetsky and Caruso, 2014). The amount of produced fines during fall-off can be measured from particle concentration in produced oil/water. The data allows determining model functions and constants for the mathematical model from the well test data. It would allow for long-term prediction of production/injection well behaviour accounting for fines migration.

However, the above hasn't been applied in well testing to identify whether fines contribute to skin or to predict further well behaviour. Well testing methods for fines migration are not available in the literature. The above corresponds not only to geothermal well testing, but to overall well testing in oil and gas reservoirs and aquifers.

Several papers detect fines and determine skin from well tests, showing how it was removed by acidizing [Hardin et al., 2003]. However, none of the numerous papers that detect fines-migration-induced skin during well testing determine model coefficients for fines migration from well test data.

Recommendations for fines migration assessment during geothermal well tests

Fall-off and build-up tests, including the multi-rate options, along with measurements of fines concentration in produced fluid, allow for reliable prediction of timely well impairment due to fines mobilisation, migration and straining with consequent permeability decline. The procedure includes matching of well test data by the analytical/numerical model, tuning the fines-migration model coefficients and prediction using the analytical model for inflow performance with fines migration.

In the scenario where produced fluid sampling is not feasible with single-rate build-up and injectivity tests, they should be combined with fall-off or build-up multi-rate tests. Another option for reliable well behaviour prediction is using coreflood data along with the single-rate build-up and injectivity test results.
Since geothermal wells are more susceptible for fines migration, the above methods would have higher resolution if compared with conventional oil reservoirs and aquifers.

Explicit formulae for steady state skin as established during long-term production can be taken from Bedrikovetsky et al., 2012a and Zeinijahromi et al., 2012a. Explicit formulae for steady state skin at high velocities, where the inertia effect is significant, are obtained in Zeinijahromi et al., 2012b. The transient solution for inflow well performance with fines mobilisation, migration, straining and clogging is presented in Marques et al., 2014. The solution for injectivity test is given in Bedrikovetsky and Caruso, 2014.

Mitigating against fines migration during full production

Fines are mobilised mainly near to wellbores, where pressure gradients are high enough to detach the fines from the reservoir grains. High flow velocity results in large detaching drag and lifting forces. During fall-off after switching the well on, pressure wave propagates into the reservoir from the well. The pressure gradients near to wellbore are particularly high during the short time period after switching the well on, where the pressure drop between the wellbore and the reservoir occurs across short distance. Therefore, the majority of fines are lifted near to well and at the beginning of the pressure depletion. The fines are lifted by high velocity flow in a limited area around the well, where flow velocity exceeds critical fines migration velocity. The flow time between the boundary of the fines mobilisation area and the well is the moment when the last lifted fine particle is produced. No particle is mobilised afterwards, unless the production rate would be increased. At this moment, skin factor stabilises. **Error! Reference source not found.** shows typical time dependency of well impedance.

Another cause for fines mobilisation in oilfields is the arrival of strange water. Water wet rocks can be consolidated at connate water saturation, where the menisci radii are small and capillary forces are high. The arrival of water results in water saturation increase and in the increase of menisci radii and decrease in the adhesion capillary force, causing the rock dis-consolidation. Another reason for intensive fines production after water arrival can be the reduced salinity or enhanced pH of the breakthrough water if compared with the reservoir formation water. Attaching electrostatic force decreases with salinity decrease or with pH increase, yielding particle mobilisation by drag and lifting forces.

FINES FIXING BY POLYMERIC FILMS

Well established temporary stabilisers for fines are strong solutions of potassium chloride and sodium chloride. Adding high concentration KCl and NaCl into drilling fluids, completion fluids, fracturing fluids or squeezing fluids promotes the attractive electrostatic fine-grain interaction. These solutions are the most commonly used in the petroleum industry. Their effectiveness in petroleum practice was been well established (Himes et al., 1990). However, because of the high bulk volumes and potential environmental hazards associated with the salts, many operators use different alternatives. Numerous clay-control agents have been developed to minimise fines migration. It includes *organic polymeric clay-control* agents, *inorganic clay-control* agents and *nano* particles, however, the problem remains. Presently it is impossible to propose an agent that is readily available to stabilise fines in geothermal reservoirs.

Most of the agents for the fines fixing concentrate on clay water sensitivity and ignore fines mobilisation by high flow rates. The majority of *fines* described in literature are *clays* (kaolinite, illite, chlorite and mixed-layer clays). However, *silts* comprising of feldspar, mica, amorphous silica, zeolite, carbonates, salts and quartz can be the predominant migratory species. Commonly used clay stabilisation *polymers contain quaternary ammonium salts, hydrolysable metal cations such as zirconium oxychloride and hydroxyl aluminium*. The above described chemicals are very effective as clay stabilisers, but they do not prevent lifting, mobilisation and migration of non-clay particles (Sharma and Sharma, 1994).

Kalfayan and Watkins, 1990, Stanley et al., 1995 propose using organosilane to stabilise siliceous and clay fine particles attached to the rock grains. Several field cases demonstrate the effectiveness of the organosilane treatments for fixing fines and decreasing the formation damage.

Ezaukwu et al., 1998 compared organic polymeric clay-control agents with inorganic clay-control agents based on treatment of numerous oilwells. It was found that organic polymeric clay-control agents do not

prevent post-treatment productivity decline due to plugging in the matrix and gravel packs. They do not prevent mechanical dislodgement. On the contrary, the *inorganic systems, based on fluoboric acid* prevent both mechanical and chemical dislodgement. The inorganic systems result in significant improvement in accumulative production because of minimizing fines migration. The improved well productivity sustained for several years.

A sophisticated well treatment technology using acids and solvents has been developed in this paper. The sequence of injections includes cleaning up solvent, pre-flush by 10% of HCl to dissolve calcareous materials, injection of regular mud acid medium (RMA) (6% HCl and 1.5% of HF) that dissolves aluminium silicates and removes drilling fluid and fine clay particles, Ammonium chloride injection to remove RMA and injection of fluoboric acid, which is the main treatment fluid. The resulting film is supposed to stay on the grain surface during oil production, preventing fines mobilisation. The paper reports several well case histories, where rate reduction has been significantly decreased after the treatment.

Other chemical clay stabilisers include *simple inorganic salts, cationic inorganic polymers, cationic organic polymers and anionic organic polymers*. Zhou et al., 1995 present a comprehensive discussion on advantages and disadvantages of those clay stabilisers.

It is necessary to emphasize that excess acidizing by hydrochloric acid may create wormholes caused by the non-uniform dissolution of limestone or dolomite. The wormholes are large, empty channels that can penetrate several feet into the formation. Without wormholes, the micron-size fines produced from remote areas of the reservoir are captured mainly near to wellbore, where the velocity is particularly high. The fines pass via the wormholes, decreasing the formation damage but yielding massive fines production. The produced fines must be separated from produced water; they yield erosion of well column and destroy equipment (pumps, wellbore devices, etc).

Another clay stabiliser that could be used is potassium chloride KCl or sodium chloride. Several other environmentally friendly clay stabilisers are investigated by El-Monier and Nasr-El-Din, 2011. Feasibility of the above procedure should be learned for high temperature conditions of geothermal wells.

FINES FIXING BY NANOPARTICLES

Coating the rock surface by nano particles (NPs) can alternate the surface charge/zeta-potential and completely change the electrostatic force between the rock grains and fines. Therefore, use of *NPs to fix reservoir fines in-place* is considered to be an attractive method for prevention or at least minimisation of fines mobilisation at high flow rates, reduced salinity or increased pH. It may also prevent fines migration at high temperatures, which makes it an attractive option for geothermal wells. Habibi et al., 2013 t al., performed several laboratory experiments by soaking natural rocks in different nano fluids and then carrying out the fines migration tests. The results show that *MgO* fixes silica fines better than Al_2O_3 *or* SiO_2.

The delivery is an important problem regarding NP applications for rock treatment. Therefore, determination and possible prediction of the NPs free run in porous media is essential. Caldelas et al., 2011 lists several mechanisms of NPs retention in rocks and investigates the effects of salinity, pH, velocity, surface area and length. Application of a mathematical model allows predicting the depth of the fines fixing NP treatment in the rock. Similar proposal to use NPs for fixing the produced reservoir fines to proppant particles has been presented by Belcher et al., 2010. Productivity decline has been observed in the field before the treatment. It was attributed to plugging of the pack by the invaded fines. The productivity stabilises after the treatment.

ACIDIZING TO REMOVE ALREADY STRAINED FINES

Often an acidizing treatment is performed to remove the permeability damage by dissolution of the trapped fines that clog the well. However, there are numerous challenges with applications of acidizing to dissolve fines. One of the most important investigations when selecting the proper fluid for acidizing is the fluids compatibility with the formation mineralogy. *Hydrofloric acid HF* is known for its ability to dissolve strained and plugged reservoir fines. The compatibility issues include precipitation of fluosilicates, ion-exchange transformation of rock minerals and brines, decomposition of clays in HCl, removal of carbonates in order to prevent the precipitation of complex solid aluminium fluorides, silica-gel filming and various others.

The successful treatment to dissolve fines has been developed by Hardin et al., 2003. Fines migration has been identified as a major cause for formation damage. XRD and SEM analysis identify the rock minerals in order to propose the acid composition and the treatment sequence. Pre-flush and post-flush XRD and SEM data show how the proposed composition releases pores from fines plugging. The corefloods by the proposed acidizing fluid show no damage or incompatibilities with application of the developed fluid recipe.

The proposed procedure includes: acid pre-flush by 10% acetic acid, 5% HCl and corrosion inhibitor; HF treatment with 9% HCl, clay stabiliser, iron control, corrosion inhibitor and surfactant; after-flush by 5% NH4Cl and surfactant.

The efficiency of the acidizing treatment with the goal to *remove fines-migration damage* has been checked by a comprehensive production logging program both before and after stimulation treatment. The production logs were essential in evaluating horizontal well performance and high treatment efficiency. The main conclusion was: “the results of the treatment were outstanding”.

ULTRASONIC REMOVAL OF RETAINED FINES

Ultrasonic treatment is a very promising method for formation damage induced by fines migration during production as well as caused by invasion of drilling or completion fluid. Venkitaraman et al., 1995 from M Sharma’s Research group (Uni of Texas at Austin) claims an increase in permeability from 3 up to 7 times after ultrasonic treatment of the cores. The results can be improved by variation of *frequencies and acoustic intensities*, and also by *back-flushing*. The method is claimed to be effective in sandstones as wells as in limestones, in water and oil environments.

MULTIPURPOSE ACIDIZING, INCLUDING FINES MIGRATION CONTROL

A multipurpose treatment was been applied in 15 *geothermal wells* in Mexico (Exler et al., 2014). A hybrid design methodology that encompasses acidizing technique in sandstone and dolomite reservoirs was applied. Mainly, HCl was applied in conjunction with HF, in different proportions during pre-flush and main fluid squeezing. One of the purposes was dissolution of fines strained in rock after drilling and production. Another goal was clay stabilisation to avoid fines migration and permeability damage. The field data presented exhibit more than 50% increase in well productivity.

Recommendations for fines migration control by lock-in-place techniques and fines dissolution in geothermal fields

The optimum treatment would integrate techniques to dissolve already plugged natural reservoir fines strained during the production, enlarge pore-throat size to diminish particle bridging and arching, and finally

immobilise the reservoir fines that have not been removed by treatment but could be lifted by high velocities or salinity change. The mobilisation decrease treatment should be meters in depth, providing a long-term, integrated solution.

The important fines are not clays only. Mobilisation of silts like silica, quartz and carbonates also causes well index reduction and equipment erosion. The inhibitors and stabilisers must prevent the fines migration caused by salinity and pH alterations as well as by mechanical dislodgement.

Presently, the above treatment technique is not readily available for geothermal wells.

The fines stabilisers can be added into drilling, fracturing and completion fluids in order to remain during the production; the stabilisers can be also squeezed in during well stimulation. The above mentioned methods are applicable to geothermal reservoirs.

Design of fines stabiliser must include DLVO calculations of electrostatic “fine-rock” interaction. The salinity, pH and composition of the brine must promote the “fine-rock” attraction. Laboratory tests with reservoir cores must be used for the design of fines stabilisers.

If compared with using the high concentration inorganic salts during oil production, where the injected salts remain in the connate water and prevent fines mobilisation, the injected salts are displaced by the produced water during the geothermal production. The ionic exchange is usually very fast, the salts would not act as inhibitors due to the gradual delay in the dissolution in produced water. However, the effects of diffusion from low permeable pockets and inclusions into produced water should be studied. High rate short time injection would place the injected brine into the low permeable zones, causing gradual supply of produced water by the inhibiting agent. The high-rate injection of the condensation inhibitors with the following production of gas-condensates and gradual diffusive inhibitor release was successful in several field cases and may be tested for geothermal production.

Regarding the chemical compositions of tested fines stabilisers and inhibitors, the organosilanes along with several other cationic and anionic polymers has been proven to prevent mobilisation of clay and also non-clay based particles. The polymer film coats the rock surface with attached clay- and silt fines.

The organic cationic and anionic polymers prevent from fines migration triggered by the composition alterations. However, it does not prevent from the fines mechanical dislodgement by viscous forces. The inorganic fluoboric-based clay stabilisers prevent the attached fines from mechanical mobilisation also. The above techniques have been successfully incorporated into comprehensive rock treatments like acidizing.

The metal oxide nano-particles (NP) can be used to fix fines by creation the attractive grain-NP and NP-fine bonds, which remain intact during the production. The same NPs can be used in fracturing fluids in order to coat the proppant and attach the produced fines; it results in uniform fines distribution along the frac-pack and prevents the fines accumulation near the wellbore.

The low production rate is the important controlling factor in the fines management. The maximum rate, preventing fines migration can be calculated from the traditional critical velocity as determined from the fines migration test. Usually the obtained critical rate values are unfeasible, so the higher rates with fines migration are applied. The rate dependence of the induced formation damage can be predicted using the analytical model for inflow performance with fines migration.

Numerous acidizing studies regard removal of trapped fines as an important component of successful well stimulation. Despite good dissolution of retained fines and clay stabilisation was proven, deep dissatisfaction with traditional HF and HCl mixture is a common place. The fast reaction prevents deep penetration; the wormholes open the paths for fines production; the secondary reaction products plug the filtration paths. Several modifications of the injected acid composition with successful field applications have been reported. However, the details of the applied mixtures remain confidential.

Numerous successful tests of the multi-purpose acidizing have also been reported. The fines-related aims include removal of fines, mobilised and trapped during drilling, completion and production, and also clay- and non-clay particle stabilisation. The details of chemical compositions besides known HCl and HF have not been reported.

The ultrasonic removal of retained / strained fine particles has been reported as being successful for both corefloods and some well tests. However, the result contradicts to inefficient ultrasonic removal of injectivity damage during PWRI, which has been studied in details in Shell. If the mobilised fine particles are significantly smaller than pores, they can be mobilised by the ultrasonic vibration and produced by the back-flush. However, the small particles do not damage the permeability. On the contrary, the large particles can be easily mobilised, but they are strained along a few pore lengths distance, which does not release the permeability. Usually the inertia forces are significantly lower than the attaching electro-static forces; so it could be a very specific case where the vibration destroys the dendrite bridge structure. We think that the ultrasonic removal could be more applicable for external filter cake removal rather than to in-depth damage.

Summary and recommendations

Fines migration is significant formation damaging factor particularly for geothermal reservoirs. Particle detachment factor of weakening the electrostatic DLVO forces under high temperature dominates over the viscosity decrease that restricts the fines mobilisation. Therefore, geothermal fields are more susceptible for the fines migration formation damage if compared with the conventional aquifers.

Presence of residual oil decreases the fines-migration-induced formation damage by factor of 10, i.e. the expected productivity decrease 50-500 times for aquifers turns to be 5-50 times for similar formations with residual oil. Commingled oil and water production corresponds to oil saturations higher than Sor, so the formation damage is expected to be even lower. However, fines migration usually causes very high skin factor in production and injected wells. It shows that the fines-migration-induced formation damage in single-phase-flow geothermal fields is significantly higher than in conventional oilfields.

The above two reasons show that it is necessary to take a special care of fines migration in the geothermal energy developments.
Fines migration usually causes the formation damage under alteration of flow velocity (rate), salinity, pH and temperature during drilling fluid invasion into the formation, production at elevated rates, injection of incompatible water, breakthrough of “foreign” water in the producer, etc. The prediction of induced skin for the above situations can be predicted by the mathematical model that uses the maximum retention function. The maximum retention function is calculated from torque balance and DLVO theory for electrostatic fines-rock grains interaction. The above approach has been published in 2012-2014, so the bulk of the works do not use the mathematical modelling for prediction of induced skin during drilling fluid invasion into the formation, production at elevated rates, injection of incompatible water and breakthrough of strange water in production wells.

Therefore, we recommend starting any study of fines-migration-induced formation damage prevention, mitigation and removal by assessing the skin factor using the above mentioned analytical models. The results of the modelling are the skin factor decrease and well index increase caused by the decrease in production/injection rates, increase in injected water salinity and decrease in pH along with the temperature decrease. If compared with the traditional notions of the critical velocity and salinity that deliver only the critical regimes fully preventing fines migration, the maximum retention function allows for skin prediction causes by fines migration for any values of the rate and water compositions.

The shortcomings of the traditional fines migration models prevent using well testing for characterisation of fines migration system with the final goal of reliable prediction of well behaviour. All available in the literature studies determine only skin factor from different type well tests. Using the above analytical model allows determining the fines-migration constants from well tests and predicting well productivity decrease during fines migration.

Different clay stabilisers and inhibitors are currently used in drilling fluids and are available in the market; they can be used in geothermal drilling. Fines-migration induced damage during drilling can be prevented by using high concentration inorganic salts in the drilling mud composition. In any case, the salinity of drilling fluid must be higher than that of formation water, and the drilling mud pH must be lower than pH of the formation water. KCl, NaCl and $CaCl_2$ are presently the most popular stabilisers. Another option for clay stabilisation is using the organic soluble silicates.

Using polymers like organosilanes yields coating of the reservoir grains with the consequent fines immobilisation. Besides, the polymers coat proppant and attach the produced fines, preventing fines migration in frac-packs.

Sealing of formations by adding small solid particles or nano-particles in the drilling fluid is another way of preventing the fines migration.

The same ideas are used for fines migration prevention during production. However, if compared with oil production, where the pre-flush of well vicinity by high concentration brines changes connate water composition that is maintained during the production period before water breakthrough, the injected high salinity water would be swept by produced geothermal water. It is expected that fast ionic exchange would highly decrease the efficiency of inorganic clay stabilisers in geothermal developments. Besides the large amounts of KCl and NaCl consumed by the treatment and the environmentally un-friendly impact, the above forces industry looking for other stabilisers and inhibitors of the reservoir fines.

Organosilanes along with some other cationic and anionic polymers were proven to be effective in stabilising clay and silt fines. The polymeric film created on the rock/grain surfaces is stable and remains during long production periods. However, the organosilanes fix fines during altering salinity and pH of produced water; it does not prevent fines mobilisation with consequent damage in low consolidation rocks or under high production rates. The problem can be solved by the inorganic fluoboric-acid-based fluids that prevent from mechanical particle dislodging as well as from water composition variations.
Nano particles based on oxides of Al, Mg and Si can fix both clay and silt fines on sandstone and carbonate rock surfaces. However, the industrial applications of NPs for fines fixing is very limited.

NPs can be also applied during well fracturing for rock treatment during the leak-off as well as for proppant coating to attach the produced fines and prevent accumulation of retained fines near to the wellbore.

The critical flow rate is determined from the traditional fines migration and prevents fines migration during water production. However, usually the production rate exceeds the critical value. The rate must be controlled during the production to minimise the fines-induced damage. The rate dependency of the curve "skin *vs* time" for a specific geothermal well can be calculated from the analytical flow model.

The issue of removal of plugging fines, mobilised and strained during well drilling, is an important topic of well acidizing studies. The removal of clay ads silt particles is discussed. Shortcomings of using the traditional HF and HCl mixtures are summarised. The above text (Section 5) presents several published chemical compositions that modify the HF and HCl mixtures. The above procedures are incorporated into multi-purpose treatment sequences including different flushes by various chemicals, back-flushes, etc. However, the details of the injected compositions are not reported in the literature.

The ultrasonic removal of retained fines seems to be effective only for the shallow damage, for fairly small fines and for medium salinity with weak electrostatic attraction, where the inertia vibration forces break the bridges down with the following fines migration. However, the feasibility could be studies for specific cases of geothermal wells.

To conclude, the ideal treatment of geothermal wells would include stabilisation of both clay- and silt fine particles under the alternation of water composition and high flow rates, removal of fines mobilised during drilling, completion and production. This technique would include several stages with treatment by different chemicals. Numerous suggestions about different chemical compositions, acids, anionic and cationic organic polymers, inorganic salts and polymers and NPs are presented above. Development of this procedure for a specific geothermal well using corefloods, DLVO theory and analytical model for well inflow performance under fines migration is a feasible task.

The above text (Section 6) contains several recommended compositions of the drilling fluid for geothermal reservoirs. The compositions contain the components responsible for non-Newtonian viscosity, stable rheology and fluid loss control. For a given rock pore size distribution, there does exist an optimal particle size distribution for the drilling fluid. The mathematical models for deep bed filtration, external filter cake formation and cake stabilisation along with coreflooding allows for design of the optimal drilling fluid for specific conditions of geothermal wells.