Institute for Mineral and Energy Resources

THE UNIVERSITY of ADELAIDE

South Australian Centre for Geothermal Energy Research

Program 2 Summary Report

ARENA Measure: Reservoir quality in sedimentary geothermal resources

REV	Date	Objective	Author	Recipient	Status
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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 2 is described in this document.

Program 2 – Summary Report

Introduction

Achieving economic fluid flow rates from deep geothermal reservoirs is one of the most significant technical challenges confronting the Australian geothermal industry. Geothermal resources hosted within sedimentary basins, also known as Hot Sedimentary Aquifers (HSA) were targeted by developers because unlike fractured granite systems, they were thought to have high natural permeability, so these systems may not require significant reservoir enhancement to achieve economic fluid flows. However, the natural permeability of sedimentary reservoirs can be reduced by diagenesis, where the nature of sediments changes as they are buried. Diagenesis is controlled by parameters including temperature, pressure, mineralogy, and fluid-rock interactions. Drilling activities can also cause damage to the sedimentary rocks in the vicinity of the drill hole, masking the true permeability of the reservoir. Finally, the act of producing hot water from sedimentary reservoirs can also cause formation damage as fine particles migrate under production towards the well.

Two geothermal wells have been drilled into HSA plays in Australia: Panax Geothermal Ltd tested their Penola prospect with the 4025 m Salamander-1 well, targeting the Pretty Hill Formation in the Otway Basin (Figure 1), and the Origin Energy Ltd -Geodynamics Ltd JV tested their "Innamincka Shallows" prospect with the 2416 m deep Celsius-1 well, targeting the Hutton Sandstone in the Cooper-Eromanga Basin (Figure 3A).

This project entitled *Reservoir Quality in Sedimentary Geothermal Resources* is a collaborative research effort between research institutions the University of Adelaide, CSIRO, the South Australian Museum, geothermal development companies Geodynamics Ltd and Raya Group Ltd, and is co-funded to the tune of $1.25 million by the Australian Government's Australian Renewable Energy Agency (ARENA).

The Otway Basin

The Otway Basin is a northwest–southeast striking, divergent margin rift and drift basin. It covers an area of 150,000 km^2, 80% of which lies offshore (Geoscience Australia, 2011). It was formed in the Jurassic to late Cretaceous (DMITRE, 2013) as a result of rifting between Antarctica and Australia.

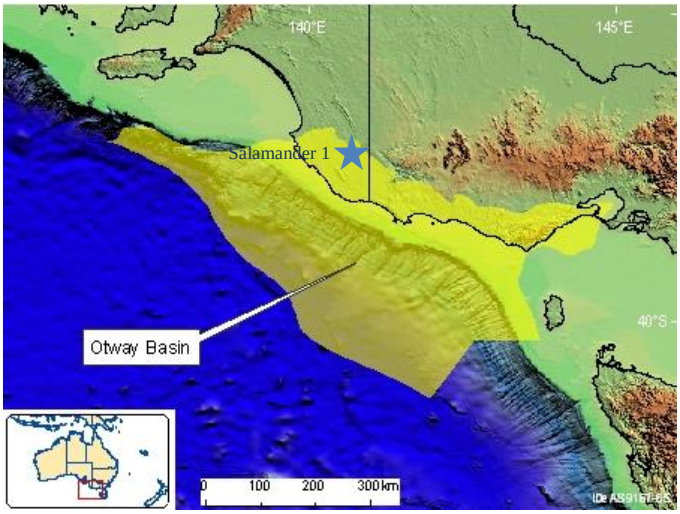


Figure 1 - Location of the Otway Basin and Salamander 1 (source: Geoscience Australia)

Key Stratigraphic units

The oldest unit in the Otway Basin is the Casterton Formation, a succession of interbedded shale, feldspathic sandstone and siltstone characterised by interbedded olivine basalt and volcaniclastics (Morton, 1995). Overlying the Casterton Formation is the Crayfish subgroup which in turn is divided into the Pretty Hill Formation, Laira Formation and Katnook Sandstone (Figure 2).

The Pretty Hill Formation, the target formation for Salamander 1 is divided into the Upper and Lower Pretty Hill Formations. The upper formation generally consists of interbedded feldspathic litharenite and carbonaceous siltstone and mudstone. The lower formation is predominantly clean sandstone (Morton, 1995). The inferred environment of deposition is a silty flood plain with crevasse-splay and sheet-flood sandstone interbeds. Localised lakes and swamps occurred on the floodplain. The uppermost limit of the Crayfish group is the Laira Formation, consisting of shale and silty sandstone, which in turn is overlain by the braided, fluvial Katnook Sandstone (DMITRE, 2013). The thick shale, siltstone, coal and sandstone of the Eumeralla Formation was deposited in fluvial to lacustrine environments. It acts as a thermal and hydraulic seal to the underlying geothermal systems present in the Crayfish Group. In the Penola Trough the Pretty Hill Formation is up to 2,000m thick. Temperature ranges from 85^{0}C to 175^{0}C. Porosity ranges from 1 to 23 %, with an average measured porosity of 10 %.

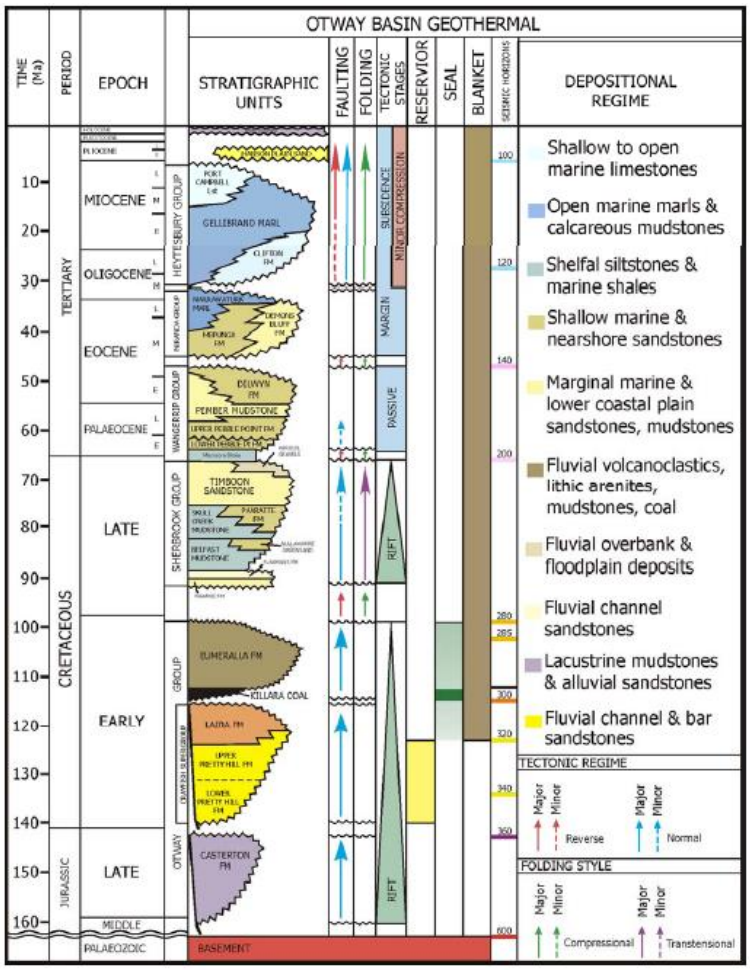


Figure 2 - Stratigraphy of the Otway Basin

The Cooper-Eromanga Basin

The Cooper-Eromanga Basin has had 40 years of petroleum, mining and geothermal exploration and development, including drilling 1200 wells, leading to the discovery of 121 gas and 25 oil fields. The wells drilled to date in the Eromanga basin have been on structural plays and approximately 70 % of the oil discovered is in the Hutton Sandstone and sealed by the Birkhead Formation.

The Cooper Basin consists of a broad downwarp with two main depocentres – the Poolowanna Trough in the north-west which contains a thick sand-dominated sequence, and the Cooper region where intercalated shale and siltstone units occur. Three major troughs in the Cooper region (Patchawarra, Nappamerri and Tenappera) are separated by structurally high ridges commonly associated with oil and gas fields (Figure 3A). These troughs contain up to 2500 m of Permo-Carboniferous to Triassic sedimentary fill overlain by as much as 1300 m of Jurassic to Tertiary cover. The Nappamerri Trough contains the deepest and thickest Cooper Basin sediments. The giant Moomba gas field lies at the southern end of the Nappamerri Trough (Roberts et al. 1990).

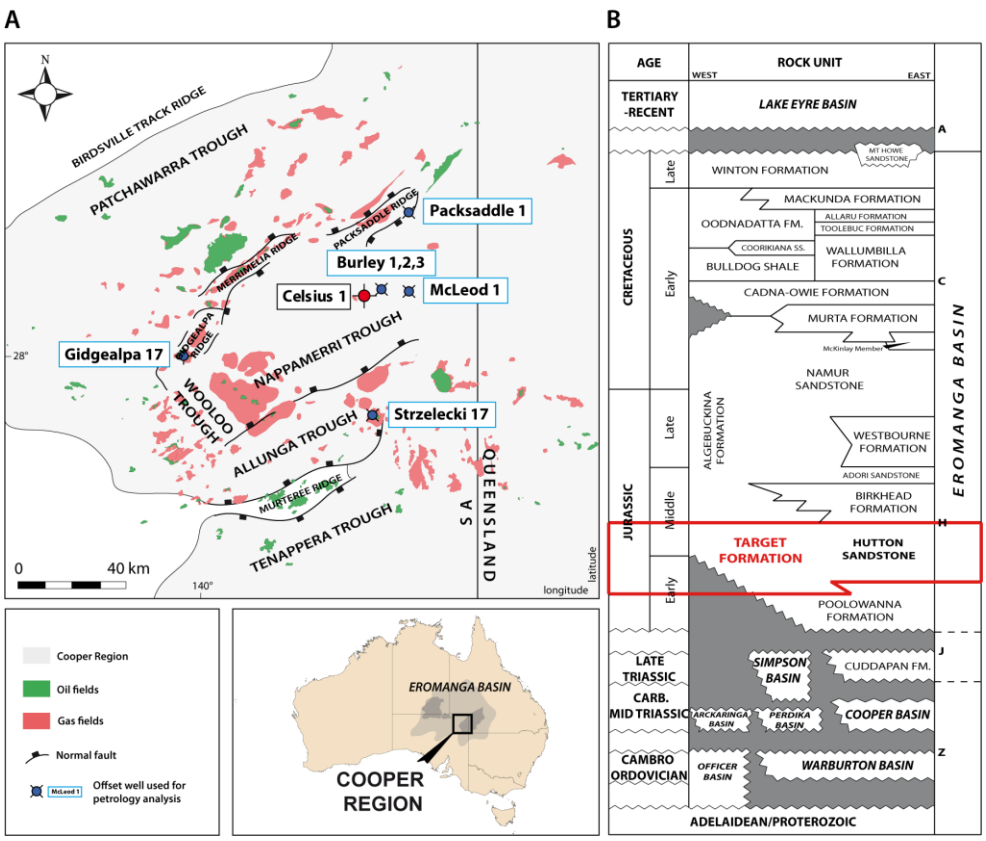


Figure 3: Overview of the Cooper region. A. Location of Celsius-1 and offset wells used in this study. B. Geological summary of the Eromanga Basin and older basins (modified from Watts (1987)). A, C, H, J, and Z represent seismic horizons (from Dillinger et al 2014).

The region is part of a broad area of anomalously high heat flow – the Central Australian Heat Flow Province - which is attributed to basement enriched in radiogenic elements. High heat-producing granites form a significant geothermal play that was targeted for Australia's first Enhanced Geothermal System (EGS) development at Habanero. The thick sedimentary sequences of the overlying Cooper-Eromanga Basin provide a thermal blanketing effect resulting in temperatures as high as 250 °C at 4.2km depth.

The target formation: the Hutton Sandstone

The Hutton Sandstone is Lower to Middle Jurassic in age (Figure 3B), and consists of mineralogically mature, fine to coarse grained quartzose with minor siltstone interbeds. Sands are at least second or third cycle and were originally sourced from a cratonic provenance. The Hutton Sandstone contains clasts reworked from Triassic, Permian and older sediments and was deposited in braided stream to high energy, low sinuosity fluvial environments with influence from aoelian and lacustrine processes (Watts 1987).

A significant amount of core analysis is publicly available from existing stratigraphic or petroleum exploration wells drilled in the Cooper Basin and intersecting the Hutton Sandstone. Figure 4 shows a porosity-permeability cross-plot of core analysis (Helium porosity and air permeability) performed by drillers on 449 samples under ambient conditions and 140 samples under overburden conditions on 22 wells. It reveals that formation porosities range mainly between 12 and 25 % while the permeability span is from 100 mD to 5000 mD with a low stress sensitivity (ambient~ overburden). Core analysis thus demonstrate the good reservoir quality of the Hutton Sandstone, and justify its potential as a geothermal resource, even though the continuity of its petrophysical properties over a wide area is sometimes not obvious, especially when considering local variations. Moreover, high permeabilities combined with low stress sensitivities suggest a stiff formation behaviour that is usually related to tightly cemented sandstones (Dillinger et al. 2014).

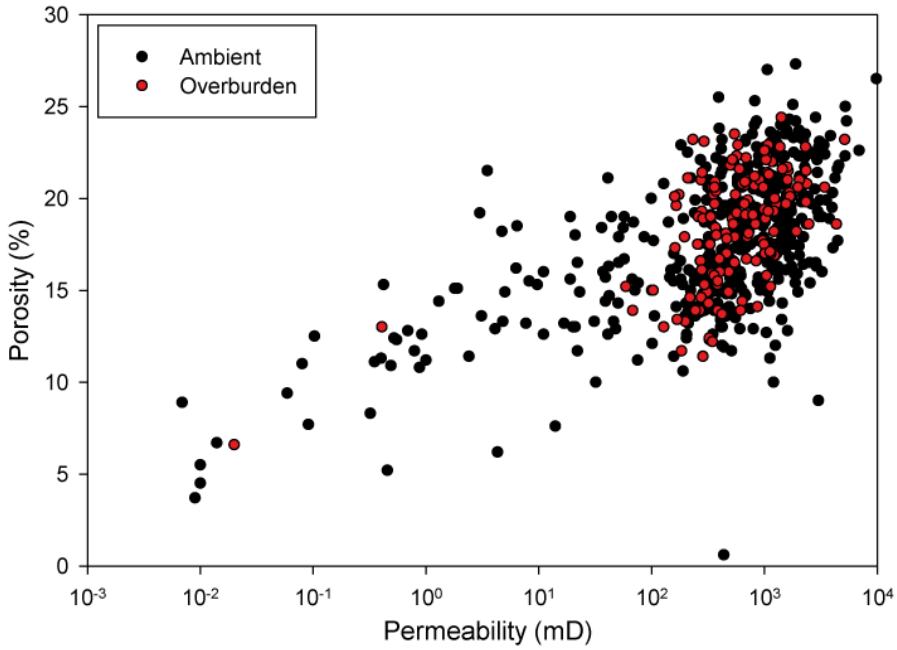


Figure 4 – Porosity-permeability cross plot of core analysis from wells in the Cooper region

Program 2 – HSA reservoir formation damage from drilling and production

Neither Salamander-1 nor Celsius-1 produced the anticipated flow rates, raising the question of whether the sedimentary formations were damaged by either the drilling of the wells or from production of hot water from the reservoirs.

Results

Analysis of well testing data in Salamander-1 and comparing it to nearby well Ladbroke Grove-1

To analyse the well productivity performance, the well impedance index is calculated as the normalised ratio between the pressure drop and the flow rate:

$$J(t) = \frac{\Delta p(t)}{\Delta p_0} \cdot \frac{q_0}{q(t)} \qquad (1)$$

In the Salamander field case, the production well was discharged for five hours with the volumetric flow rate 15.5 L/s. The impedance history obtained from field data is shown in Figure 1. The results show that the well impedance increases with time at early stages during production, and then tends to constant at later times. This is a typical phenomenon for the case of productivity decline due to straining of the mobilised fines near the well.

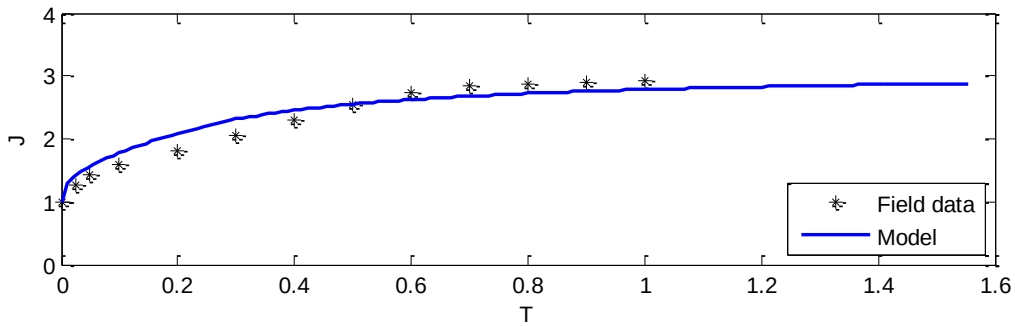


Figure 1 - Well impedance growth during well exploitation from the modeled results and field data.

It is necessary to investigate the effect of reservoir temperature on geothermal well performance. Let us start from the analysis of temperature effect on the maximum retention function. Besides the field temperature T_2=129 ºC, three other typical values of temperature are chosen for the calculation of the maximum retention function versus flow velocity: T_1=100ºC, T_3=200ºC, T_4=300ºC. Results shown in Figure 2 indicate that the higher temperature leads to the lower value of maximum retained particle concentration at a fixed flow velocity. Thus, the larger amount of fines are lifted and released to the carrier water at the higher temperature. It causes the larger particle straining rate subsequently and results in worse impairment of well. The well impedance as a function of time at different temperature values is presented in Figure 3.

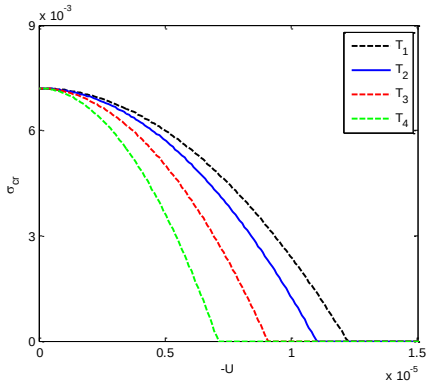


Figure 2 - Critical retained particle concentration as a function of flow velocity at different temperatures (T_1=100 ºC, T_2=129 ºC, T_3=200 ºC, T_4=300 ºC).

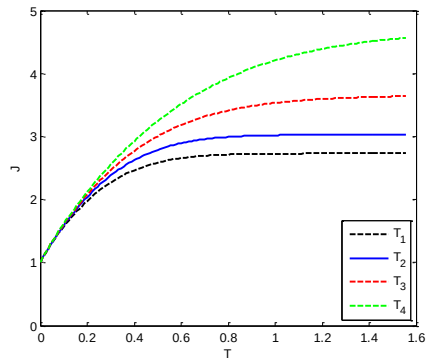


Figure 3 - Effect of temperature on the well impedance index profile (T_1=100 ºC, T_2=129 ºC, T_3=200 ºC, T_4=300 ºC).

Another important parameter affecting geothermal well performance is the production rate. The impedance curves in Figure 4 are generated from modelling results with three flow rate values: q=15.5 L/s is the well rate in the field case; 1.5q and 0.5q are chosen for sensitivity study. It is found that the higher is the rate, the larger is the well impedance (Figure 4). This is because a high rate causes decrease of the maximum retained particle concentration, which leads to more fines detached from rock surface and larger permeability decline due to particle straining afterwards.

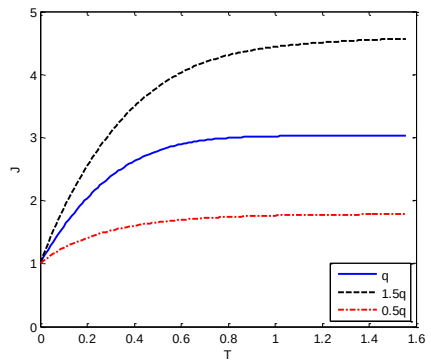


Figure 4 - Timely increase of well impedance for different production rates (q=15.5 L/s)

Scanning Electron Microscopy (SEM) and X-ray Diffraction (XRD) analysis of mobilised fines and comparison with data from adjacent wells

Effluent suspensions after concentration measurements were filtered through a 0.45 µm filter and dried. SEM and Energy Dispersed Analysis of X-rays detector (EDAX) were used for imaging of samples surfaces. An example of these analyses for fines released from studied samples is presented in Figure 5. Kaolinite and chlorite are major clays presented in all studied rock cores and fragments.

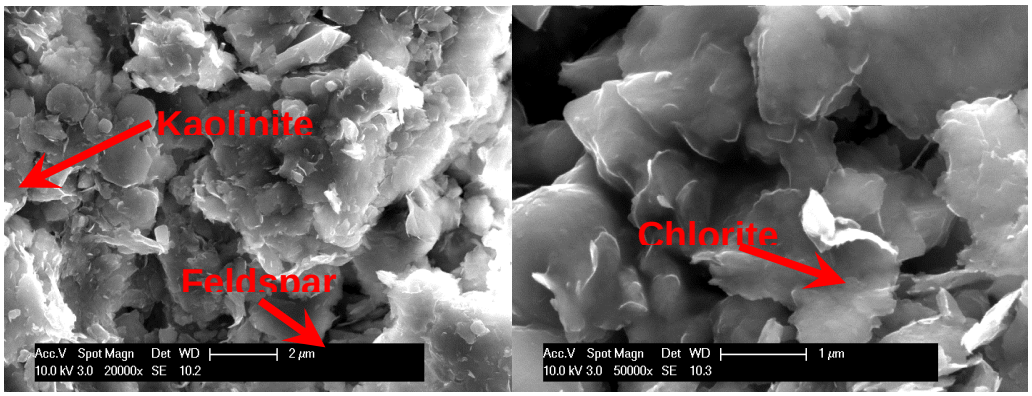


Figure 5 - SEM-EDAX for Sal-1/1.

Laboratory studies into the factors that affect fines migration events

An experimental apparatus for liquid permeability measurements was assembled (Figure 6). The following aspects of experimental procedure were tested: variation of permeability with effective stress relevant to the formation, thus, variation of permeability with depth was established; variation of permeability and release of fines with various salinities of water (0.6 M and MilliQ deionised water) and at two values of pH – 7.5 and 10; measurement of size distribution of released particles using a particle counter (this information together with appropriate salinity and pH of flushing solution will be used later for the evaluation of experimental conditions for fines mobilisation from porous media).

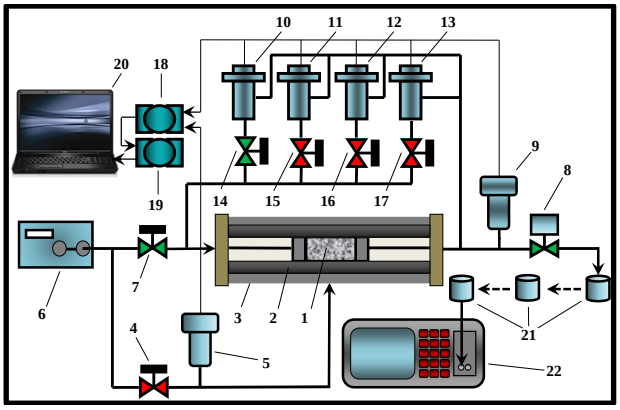
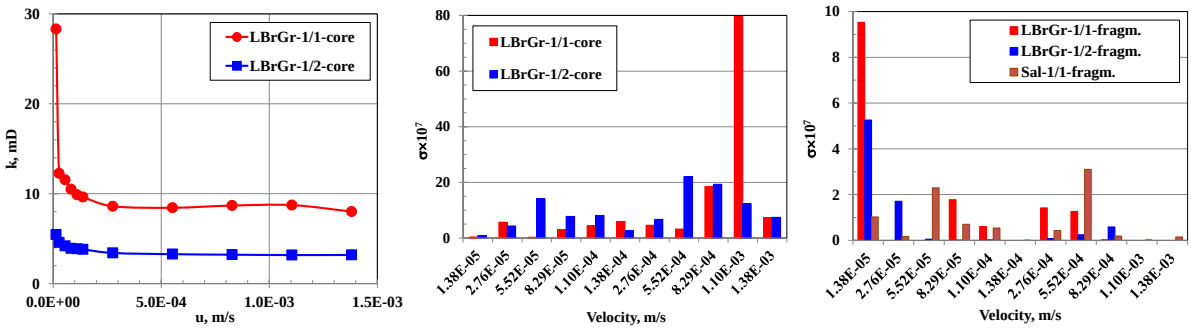


Figure 6 - Setup for liquid permeability and fines migration measurements: 1 – sandstone core; 2 - rubber sleeve; 3 - high-pressure core holder; 4, 7, 14-17 - manual valves; 5, 9 – high-accuracy pressure transducer; 6 - HPLC pump; 8 - back-pressure regulator; 10-13 - Validyne differential pressure transducers; 18 - ADAM-4019+ data acquisition module; 19 - ADAM-5060 RS-232/RS-485/RS-422 signal converter; 20 - personal computer; 21 -beakers; 22 - PAMAS S4031 GO portable particle counter.

Three representative core plugs from the Pretty Hill Formation Penola Trough sandstone were taken. The first two samples come from a productive interval, while the last one from a tight non-productive interval.

Velocity Assisted Fines Migration

Velocity-assisted fines migration (0.6 M NaCl as flowing fluid) was performed using setup for permeability measurements at velocities varied from 1.38×10^{-5} to 1.38×10^{-3} m/s. Results for samples Ladbroke Grove-1/1 (2553.25 m), Ladbroke Grove 1/2 (2557.12 m) and Salamander-1 (2903-2906 m) are shown in Figure 7.



(a) (b) (c)

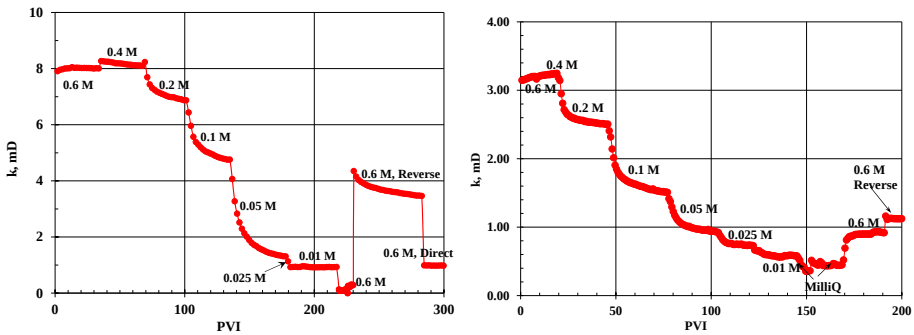
Figure 7 - Permeability variation (a) and normalised incremental particle volume (b, c) during fluid velocity alterations.

Results

- LBrGr-1/1 and LBrGr-1/2 rocks showed permeability decline from 28.3 to 8.01 mD and 5.46 to 3.19 mD, respectively;
- The amount of particles mobilized in cores show increasing trend with solution velocities;
- The observed reduction in permeability is caused by particles loosely associated with pore matrix;
- Sal-1/1 fragments show increase for normalised effluent particle concentration with increased fluid velocity.

Low salinity-assisted particle mobilisation

Low-salinity-assisted particle mobilisation was carried out at flowrate of 10 mL/min (velocity ⍰ 1.38⍰10^{-4} m/s) using setup for permeability measurements. Results are shown in Figure 8.



(a) (b)

Figure 8 - Low-salinity-assisted fines mobilisation for Pretty Hill sandstone core and cuttings: (a) LBrGr-1/1 and (b) LBrGr-1/2.

Results

- LBrGr-1/1 and LBrGr-1/2 show similar step-like trend in permeability reduction with decrease of salinity of flowing solution;
- For both samples, permeability dropped approximately 8 times when fluid salinity decreased from 0.6 to 1.25⊠10^{-4} M of NaCl in MilliQ water;
- A slight reduction in permeability (0.4 M NaCl) was accompanied by fines mobilisation of up to 0.238 ppm;
- Maximum reduction in core permeability was associated with flushing of 0.05 M NaCl solution with concentration of collected particles ≈ 2.48 ppm;
- Highest concentrations of collected particles of 10.88 and 8.91 ppm were associated with 0.025 and 0.01 M NaCl solution flushed through cores.

Experimental apparatus for fines mobilisation on cuttings

An experimental apparatus fines mobilisation from cuttings was assembled (see Figure 9).

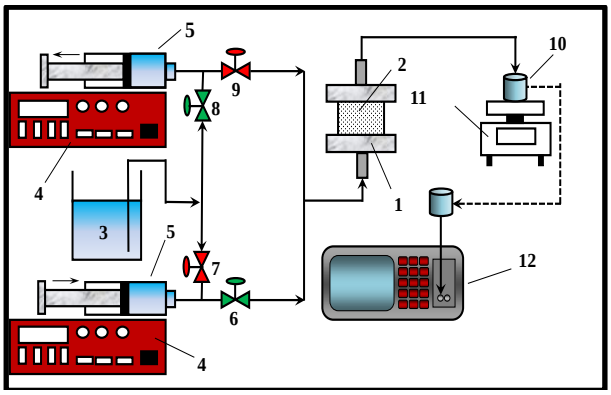


Figure 9 - Setup for fines mobilisation from cuttings: 1 - column; 2 - glass beads; 3 - colloidal suspension vessel; 4 - syringe pumps; 5 – syringes; 6-9 - one-way valves; 10 - effluent suspension collection beaker; 11 - analytical balance; 12 - PAMAS S4031 GO portable particle counter.

A procedure for fines mobilisation from sandstone cuttings was developed as follows. Cuttings were placed in a PVC flow-through column. The spaces between cuttings were filled by clean spherical glass beads thus forming a so-called "composite" porous medium. The size of glass beads was chosen so that the mean pore-throat size formed by glass beads is *NOT larger* than that formed by grains of the sandstone sample.

The size distribution of particles collected from analogous core and cuttings are similar (Figure 10), suggesting that the method developed for fines mobilisation from cuttings is adequate as an analogy of that for removal of fines from cores;

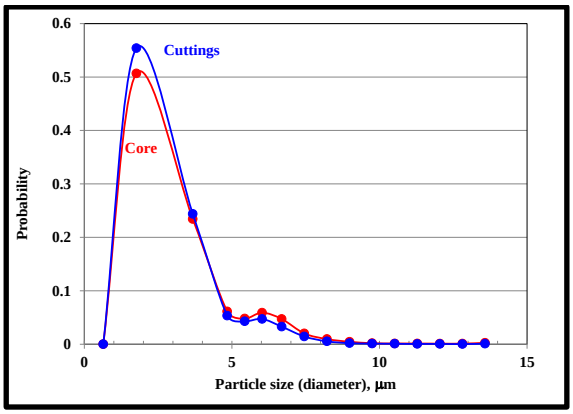


Figure 10 - Particle size distribution for lifted fines from Ladbroke Grove 1 core and cuttings.

Recommendations for restoration of well index after productivity decline

Acidizing

Our conclusion is that the main reason for well impairment is migration of clay fines, like kaolinite and chlorite. The choice of the chemical composition of acidizing fluid and design of well acidizing is a separate work outside of the scope of this project. Nevertheless, the acidizing fluid must contain the organic acids dissolving clays, like acetic or hydrofluoric acids. Hypothetically speaking, one can use organic clay acid (OCA) which fuses migratory clays. Presently, the well is not completed for acidizing. The large portion of the open hole section increases chance that acid will go into small interval (which is likely already connected) leaving rest of the zone without contact with acid. So, some measures for homogenization of the treatment profile must be taken.

Hydraulic fracturing

Presently the well is not completed for fracturing. Well completion with pre-perforated liner precludes performing hydraulic fracturing. Recompletion - removing the liner (if no formation collapse or solids build up around it; else have to pull it piece by piece or drill a sidetrack), cementing new one, perforating and installing upper completion capable to withstand frac pressures, would be required to prepare well for the frac.

Reservoir simulation and well productivity forecast based on numerical and analytical methods

For reservoir simulation purposes, new mathematical models were developed accounting for both the Damaged Zone and the Undamaged Zone in the reservoir domain. Basic equations were developed for the flow of water with fines. Initial and boundary conditions were derived for non-steady state flow towards a well, an analytical model for flow with fines was created, and well index calculations were performed.

Study of external cake formation on sandstones from a geothermal well

6Materials

Sandstone samples from the Pretty Hill Formation of the Otway Basin in South Australia were obtained. Drilling fluid a KCl-polymer based mud was used in the present study.

A new experimental apparatus for real-time permeability measurements was designed. The schematic view of this setup is shown in Figure 11.

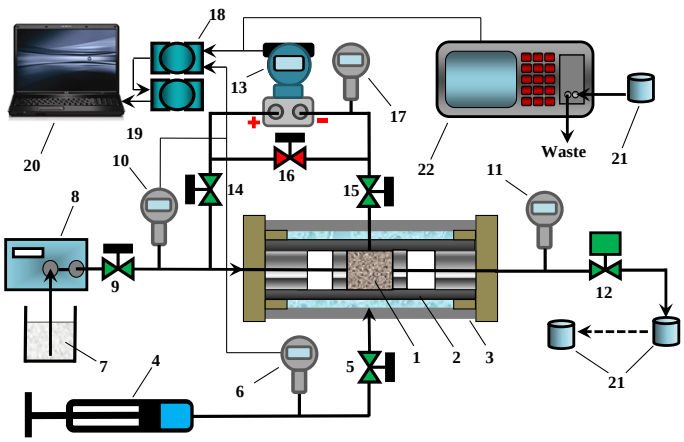


Figure 11 - Schematic view of a real-time liquid permeability apparatus.

Sandstone core plug *1* located inside a Viton sleeve *2* was placed inside a high-pressure stainless steel TEMCO coreholder *3*. Overburden pressure was generated by a manual HiP pressure generator *4* via a manual valve *5*. This pressure was measured by a PA-33X absolute pressure transmitter *6*. Drilling fluid *7* from a vessel with a magnetic stirrer was pumped though the core plug sing HPLC pump *8* via a shut-off manual valve *9*. Inlet and outlet pressures were measured by PA-33X absolute pressure transmitters *10* and *11*. Smooth operation of HPLC pump was ensured by a back-pressure regulator *12*.

The present experimental arrangement allows measurement of two differential pressures: between inlet and the middle point of the core plug, and across the whole core plug. The first differential pressure is measured by EJX-110 differential pressure transmitter 13 via shut-off manual valves *14* and *15*. Maximum differential pressure measured by this transmitter is 140 kPa. Prior differential pressure measurements this differential pressure transmitter was re-zeroed using equilibration manual valve *16*. In series with this differential pressure transmitter is located PA-33X absolute pressure transmitter *17*, which is used to measure differential pressure across a half of the core plug with similar device *10* at pressures above 140 kPa. Differential pressure across the whole core plug was measured by pressure transmitters *10* and *11*. All information from pressure and differential pressure transmitters were fed into a real-time data acquisition system consisted of ADAM-4019+ data acquisition module *18* (Taipei, TAIWAN), ADAM-5060 RS-232/RS-485/RS-422 signal converter *19* (ADVANTECH^{TM}) and a standalone personal computer *20*. Suspended particle concentrations (in *ppm*) in effluent fluid samples *21* were measured by a portable particle counter *22*.

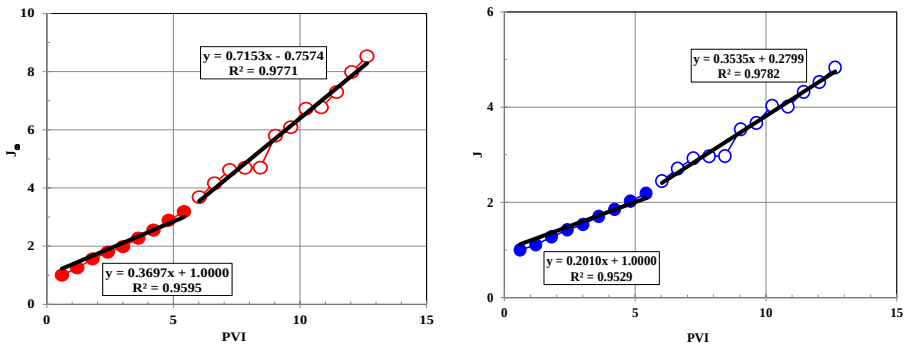
The following experimental procedure was carried out on each sandstone sample:

a) take a photo of the inlet surface of a core plug;
b) place the core plug in the coreholder and develop 500 psi overburden pressure;
c) forward flush with the background solution (0.5 M NaCl) to determine forward permeability;
d) backwards flush with the background solution to determine reverse permeability;
e) mud deposition at forward flow with high particle concentration;
f) backward flush with background solution to remove external cake and determine reverse permeability;

g) forward flush with the background solution to determine forward permeability;
h) remove the core plug from the coreholder;
i) take photo of inlet (with the external cake) and outlet surfaces of the core plug
j) mud removal by ultrasound;
k) repeat steps from (a) to (j) for low drilling mud concentration.

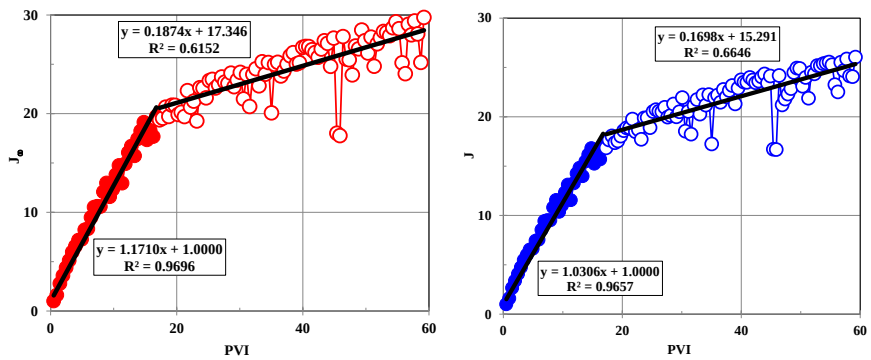
Results and discussion

Using experimental $\Delta P_{c,\omega}$ and $\Delta P_{c,tot}$ data, impedance variation $J_\omega = \frac{\Delta P_{c,\omega,i}}{\Delta P_{\omega,0}} = f(PVI)$ and $J = \frac{\Delta P_{c,tot,i}}{\Delta P_{tot,0}} = f(PVI)$ for the two studied core plugs and for the two processes of external cake deposition are shown in Figures 12 and 13.



(a) (b)

Figure 12 - Impedance as a function of PVI (pore volume injection) for external cake deposition for LG-1 core: (a, b).



(a) (b)

Figure 13 - Impedance as a function of PVI for external cake deposition for LG-2 core: (a, b).

Observable different slopes of graphs, according to Figures 12 and 13indicate that mud particles penetrated into the core and caused irreversible formation damage.

Although LG-1/1 core was almost completely regenerated after the external cake removal by an ultrasound (initial permeability of 5.602 mD compared with 5.537 mD after treatment with an ultrasound), external cake formation by injecting the drilling fluid with lower particle concentration leads to a greater formation damage. Greater formation damage is also observed for LG-2/1 core plug during the 1st external cake formation with the maximum particle concentration: this is due to the fact that this core plug has significantly higher initial permeability and therefore, larger pore-throats allowing particles to deeper penetrate into the core and cause greater formation damage.

Conclusions

- Fines-induced formation damage in geothermal wells is more probable than that for conventional oil and gas wells.
- Velocity-induced fines migration is responsible for significant formation damage in all studied rocks.
- Low-salinity water leads to an increase in particle mobilisation and resultant formation damage in the Penola Trough.
- Kaolinite and chlorite are the major clay minerals presented in fines released from formations in the Otway and Cooper-Eromanga Basins.
- high drilling fluid concentrations result in a shorter transition time and a formation of an external cake which can be removed, restoring initial core permeability;
- reduction of drilling fluid concentration results in higher values of transition time and greater formation damage;
- reduction jamming ratio while keeping high drilling fluid concentration results in almost double transition time, higher filtration coefficient, deeper particle invasion and greater formation damage;
- reduction of jamming ratio results in irreversible formation damage;
- external cake formation during drilling can't be regarded as the reason causing the irreversible formation damage in Salamander-1 well; and
- the most probable reason for the irreversible formation damage in Salamander-1 geothermal well is low-salinity fines (clays) migration as concluded in the Report for the Milestone 3

Recommendations

The following measures should be applied (separately or in combination) to prevent fines migration:

- use low rates to minimise fines mobilisation and consequent formation damage;
- use chemical stabilisers to prevent fines migration;
- use nano-particles to stabilise fines;
- inject water with controlled composition before production;
- determine maximum acidizing volume that do not filtrate fines; and
- use graded proppant particle injection to stimulate natural fracture system.