ANALYSING INDUCED SEISMICITY IN GEOTHERMAL RESERVOIRS: A MODIFICATION OF THE HALL PLOT

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ABSTRACT

The Habanero-1 well in the Cooper Basin, Australia and RRG-9 well in the Raft River geothermal field in the United State are two examples of an enhanced geothermal system. Both underwent hydraulic stimulations and experienced notable amounts of injection induced seismicity. Hall's method plots the time integrated wellhead pressure versus the cumulative injection volume, with changes in the slope of the plot indicating changes in injectivity. In this paper, we analyse the induced seismicity using a modified version that plots cumulative earthquake count versus cumulative injection volume. This test provides a simple graphical interpretation of spatiotemporal features of the seismicity and any changes that occur during injection. The modified method is applied to datasets from the Cooper Basin and Raft River to analyse the seismicity and correlate this with changes in reservoir properties. In the case of Habanero-1, a linear trend is obtained indicating that the number of induced seismic events is directly proportional to the cumulative volume of water injected, however the high level of induced seismicity appears to be decoupled from any change in permeability. In contrast, at RRG-9, a piecewise linear slope was obtained indicating that, unlike Habanero-1, the productivity of seismic events with injected volume changed during the stimulation.

1. INTRODUCTION

During research, exploration and development of geothermal systems, it is common to experiment with fluid injection. The main operational variables of these experiments are injection rate, injection pressure and the duration of injection. The injection phases designed to create an enhanced geothermal system (EGS) can last from several weeks to several years and are generally associated with microseismic activity. During stimulation, wellhead observations and seismic monitoring of the subsurface can reveal quantitative features of the changing reservoir.

To create an EGS, cold water is injected into a volume of hot, dry rock at variable rates with the intention of reproducing the water in a superheated form at a different production well. Fluid injection increases the pore pressure in the rock, which consequently reduces the effective normal stress. This can trigger sliding along pre-existing, favourably orientated cracks in the formation as the frictional strength preventing slip is overcome. In EGS projects, injection induced seismicity (IIS) is anticipated and a probably unavoidable consequence of creating high surface area fracture volumes that make geothermal production economic and sustainable. Evolution of the microseismicity can be explained by a model of linear pressure diffusion as proposed by Shapiro et. al. (2009), which assumes the hydraulic properties of the medium are constant. However, sometimes the reservoir permeability is not constant, e.g., when fluid pressure is high enough to induce tensile failure of the rock (a hydraulic fracture), or when direction pressure, or thermoporoelastic processes trigger shear slip (Dempsey et al., 2015). The magnitude and location of these episodes of slip are detected as microearthquakes by seismic arrays installed at the surface. The availability of accurate seismic data, and records of wellhead pressure and injection rate provides reservoir engineers with the potential to observe change in reservoir parameters.

A simple tool used to evaluate a reservoir is Hall's method. Halls method assumes a steady-state, radial flow regime with a homogenous and incompressible fluid. In a traditional Hall plot (Earlougher, 1977), the time integral of injection pressure is plotted against the cumulative injection volume. The slope of the plot is then an indication of the injectivity, or the ability for the reservoir to accept fluid – changes in slope indicate a change in injectivity, which may reflect permeability changes in the reservoir. The advantage of Hall's method is that the only inputs required are the injection rate and the wellhead pressure, which are regularly recorded during injection.

In this work, Hall's method is modified to analyse the induced seismicity. The modified hall plot is applied to datasets from two EGS projects: the 2003 stimulation of the Habanero-1 well in the Cooper Basin, South Australia and the Raft River Geothermal-9 Stimulation-1 (RRG-9) well in Idaho, United States, which has been ongoing since 2013.

2. MODIFIED HALL PLOT

In a traditional Hall plot, cumulative bottom hole flowing pressure is plotted against the cumulative injection volume. Eq. [1] below (Earlougher,1977) is the basis for this plot:

$$\int_0^t p_{WH}\,dt - (p_e - \Delta p_{tw})t = \frac{\mu(\ln\frac{r_e}{r_w} + s)}{2\pi k h} Q_c(t) = \frac{1}{II} Q_c(t) \qquad [1]$$

where the lefthand side is composed of the wellhead pressure p_{WH}, the external reservoir pressure p_e, and the hydrostatic pressure of the fluid column Δp_{tw}. It is assumed that pressure drop due to wellbore friction can be neglected as well as any fluid density changes resulting from temperature effects downhole. Other terms in Eq. [1] are the viscosity, μ, dimensionless pressure defined as the natural log of the external wellbore radius divided by the wellbore radius, $\ln\frac{r_e}{r_w}$, skin factor, s, permeability, k, formation thickness, h and the cumulative injection volume, $Q_c(t)$. For simplicity, we combine a number of the righthand side terms into a single parameter, , the injectivity index of the well. Under constant reservoir properties, the plot will produce a straight line. A change in slope indicates a change in the reservoir properties such as permeability, skin factor or dimensionless pressure, all of which affect the injectivity.

In the modified method, we replace time integrated pressure behaviour with a term describing the cumulative number of detected seismic events. $N_{t_i<t}$ denotes the number of events whose occurrence time, t_i, is less than t. In addition to computing $N_{t_i<t}$ for the entire dataset, we also apply the modified method for subsets of events within a threshold distance, r, from the well, i.e., $N_{t_i<t,r_i<r}$ where r_i is the distance between the event and the well.

Shapiro et al., (2013) developed an analytical model relating the number of induced earthquakes to the injection volume

$$N_{ev}(t) = \frac{Nm_c(t)}{C_{max}\rho_0 S_p} \approx \frac{NQ_c(t)}{C_{max}S_p} = PI_S\, Q_c(t), \quad [2]$$

where $m_c(t)$ and $Q_c(t)$ are the cumulative injected mass and volume at time, t, N is the density of fractures, S_p is a uniaxial storage coefficient, and and C_{max} is the max critical value of the pore pressure necessary to induce a seismic event in accordance with the Coulomb failure criterion. $PI_S = N/C_{max}S_p$ is a productivity index for the induced seismicity.

In this formulation, the number of events larger than a given magnitude cutoff, $N_{ev}(t)$, is predicted to be proportional to the volume of fluid injected. Thus we motivate a graphical approach to understanding injection and seismicity, similar to Hall's method for Eq. [1]. Note, Eq. [2] does not hold for $N_{t_i<t,r_i<r}$ when $r < \infty$, i.e., strictly speaking, the modified Hall plot consider all seismic events.

To facilitate comparison between sites, we have only included events larger than a common magnitude cut-off of -1. The magnitude cut-off depends on the sensitivity of the seismic network. The number of events that are induced depends on multiple factors, including the tectonic and geologic environment, the abundance of fractures, the poroelastic response of the rock and the pre-injection stress state of the reservoir (Cladouhos et al 2010).

3. APPLICATION TO EGS STIMULATIONS

3.1 Habanero-1, Cooper Basin

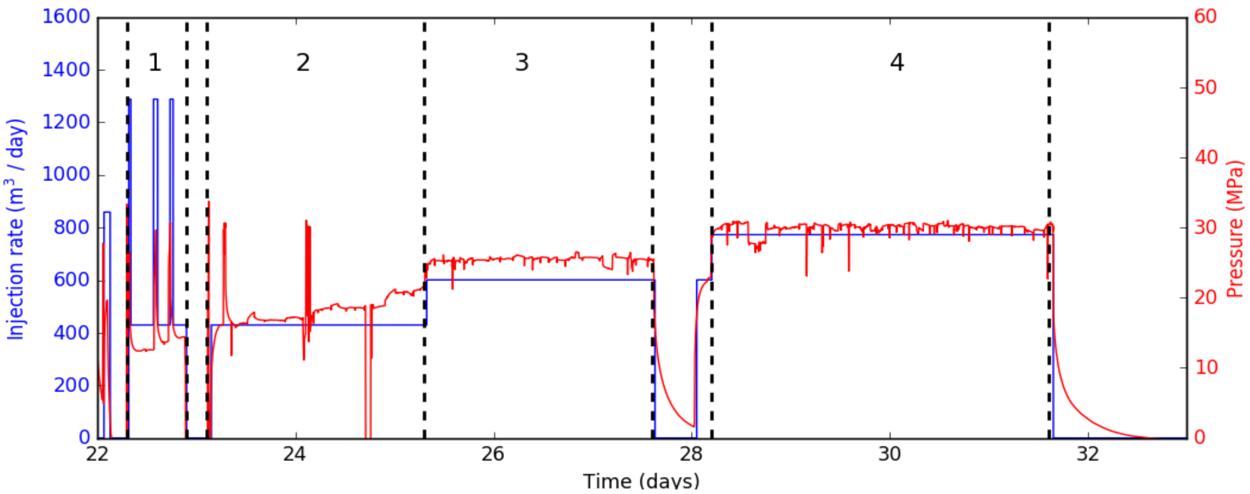

Figure 1: Wellhead pressure (MPa) and injection rate (m3/day) plotted against time for stimulation of the Habanero-1 well, Cooper Basin, South Australia. Time, in this case, is the period in which the step-rate injection was performed in the span of the overall 40-day injection. Dashed lines and numbers indicate four periods of constant flow rate injection and are these are replicated, for reference, in later figures.

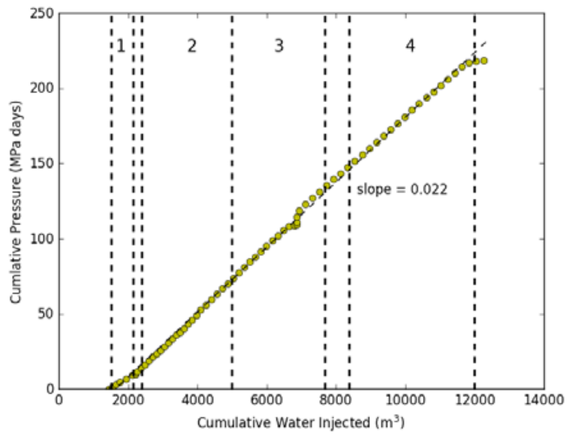

Figure 2: Standard Hall plot (Eq. [1]) of the Habanero-1 stimulation summarized in Fig. 2. Dashed lines

The Cooper Basin in South Australia has been identified as an EGS site with an approximate reservoir size of 1,000 km^2 of high-temperature granite via geophysical surveys and wildcat drilling tests (Baisch et al. 2006). In 2003, over a 40 day period, a series of stimulations were performed at the Habanero-1 well in the Cooper Basin. Over 15,000 m^3 of water were injected into the water-saturated and naturally fractured basement granite inducing a microseismic cloud with approximate thickness 150-200 m at a depth of 4,250 m. The temperature at the bottom of the well was measured to be 250°C. The basement is covered by approximately 3.6 km of sedimentary fill and has a long history of nearby hydrocarbon production resulting in a high resolution of data pertaining to the regional subsurface stratigraphy. Prior to injection, an artesian pressure of approximately 35 MPa above hydrostatic was identified in the granite basement. From a previous study (Baisch et al., 2006), the stimulated part of the reservoir was shown to be dominated by a single sub-horizontal fracture zone.

During (and immediately following) injection, over 27,000 seismic events were detected by a local eight-station seismic monitoring array deployed in boreholes between 70-1,700 m depth. Magnitudes for the measured events range from -2.1 to 3.7. It is assumed that the seismicity was accompanied by self-propping of shear fractures in the granite. The injection program was designed to have several steps in which the injection rate was held constant as shown in Fig. 1. Approximately 66% of the total number of seismic events that occurred were recorded in this time period. To aid in analysis, the steps are identified and denoted 1 through 4. Fig. 2 presents a traditional application of Hall's Method (Eq. [1]) to the Habanero-1 dataset with the injection steps superimposed for reference. The slope is reasonably constant during the stimulation indicating no significant change of injectivity. This is notable given the quite significant amount of seismicity induced during the experiment.

Modified Hall profiles for all events, i.e. $r = \infty$, and for $r =$ 100, 200, 300 and 600 m are shown in Fig. 3. The profile for all seismicity ($r = \infty$) is almost linear. From Eq. [2], this indicates a constant value PI_S and likely little change of its constituent parameters (fracture density, rock compliance, threshold stress) as the stimulation accesses rock at greater and greater distance from the borehole. As expected, profiles with larger values of r necessarily encompass more events and therefore plot above profiles with smaller r.

The slope of each profile is interpreted as the number of seismic events induced in a particular part of the reservoir ($r_i < r$) per unit volume of fluid injected. In general, the radial profiles are concave down, i.e., assuming a constant injection rate, then for a given radial distance from the wellbore, seismicity rate decreases with time. As the slope approaches zero this indicates a cessation of seismicity in that part of the reservoir, which we assume corresponds to pressure equilibrium. This equilibrium occurs at later time for larger radial distances as expected for a diffusive process.

Profiles on the modified Hall plot appear linear for all r when Q_c is plotted on a log axis, i.e., we can approximate a simple model

$$N_{t_i<t, r_i<r} = m \log(Q_c - Q_0), \qquad [3]$$

where the slope m has some dependence on the radius, r.

3.2 Raft River

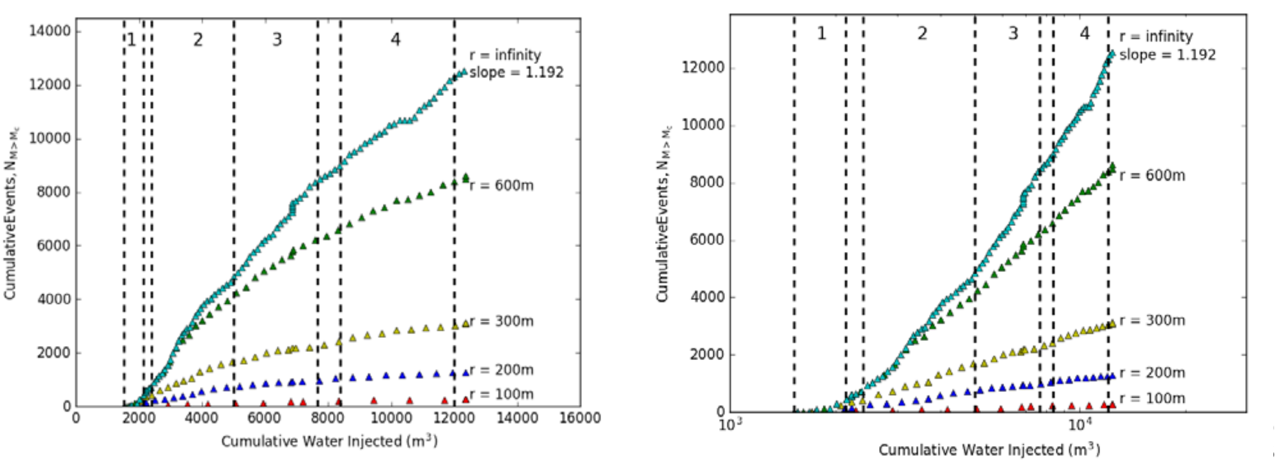

Figure 3: Modified hall plot (Eq. [2]) applied to Habanero-1 for seismicity within different radial distances, r, from the wellbore plotted on linear (left) and logarithmic axes (right). Dashed lines delineate the different injection rate steps.

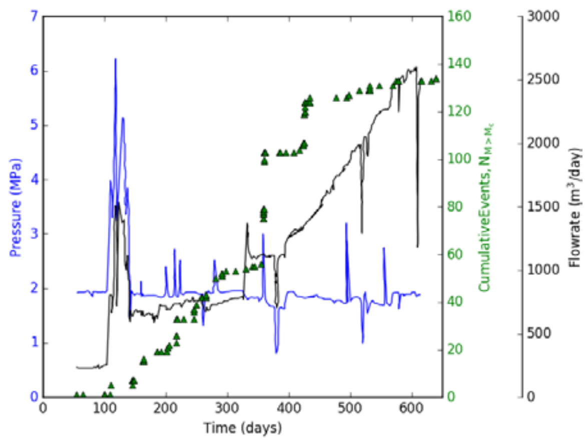

Figure 4: Wellhead pressure (MPa), Injection Rate (m^3/day) and detected seismic events of RRG-9.

Located in the United States near the Utah-Idaho border, the Raft River geothermal field has been a subject to numerous injection tests. The injection well to which our dataset correspond, RRG-9, was drilled to a measured depth of 1,615 meters where it encountered the geothermal formation consisting of schist, quartzite and monzonite, (Bradford et al. 2015). Temperatures at depth are approximately 150°C. Between 2013 and 2015, nearly 700,000 m^3 of water have been injected into the formation resulting in 156 detected seismic events. These events were detected by a locally installed, 8-station seismic array and range in magnitude from -1.27 to .63, however only events with a magnitude greater than -1 are considered (136 events).

Fig. 4 shows that from about day 130, a relatively constant wellhead pressure was maintained while, at the same time, injection rate was steadily increasing. This indicates that well injectivity is increasing, a feature also reflected in the Hall plot (Fig. 5) which shows a slope that decreases over time. This indicates an increase in permeability around the wellbore and/or a decrease in skin factor. Injectivity increases do not appear to correspond with ongoing seismicity, which was more sporadic (Fig. 6).

There were relatively few seismic events detected during the RRG-9 stimulation and this prevents our constructing multiple modified Hall profiles at different cutoff radii, as in Fig. 3. However, the modified Hall profile for all events at RRG-9 was computed and is shown in Fig. 7. The results appear to be approximately piecewise linear, with slope decreasing by a factor of 5 from after about 200,000 m^3 of water had been injected. Given the ongoing increases in injectivity, which were initially conceptualized as a consequence of shear stimulation (and thus correlated to seismicity), this finding was somewhat unexpected. However, a possible conclusion is that since the injection period of RRG-9 was over the course of approximately 650 days, significantly longer than that of Habanero-1, the increase in reservoir permeability at Raft River is unrelated to the induced seismicity. Thermoelastic properties of the reservoir rock, when in contact with the low temperature injection fluid, may allow for contraction of the rock matrix and widening of fracture apertures. A study conducted by Bradford et al. (2016) concluded that permeability and injectivity had been successfully increased at RRG-9 as a result of the stimulation. However, the non-linear slope observed in Fig. 7 may also indicate a change in one or more of the parameters defining PI_S in Eq. [2].

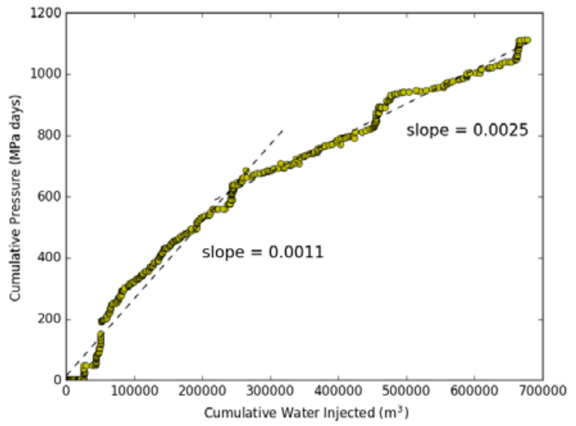

Figure 5: Standard Hall plot (Eq. [1]) of RRG-9.

At Habanero-1, the injected volume was approximately 40 times smaller than that at RRG-9 and, yet, Habanero-1 experienced about 95 times as many seismic events after the magnitude cut-off is applied. There are several possible reasons for the substantial difference:

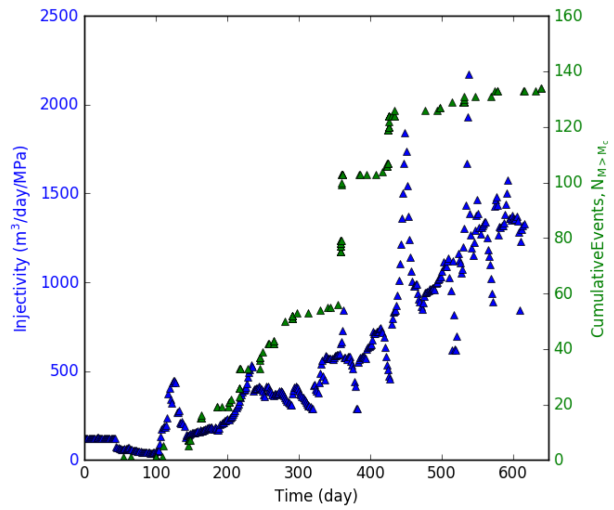

Figure 6: Injectivity and cumulative events plotted against time of RRG-9.

1. Wellhead pressure during injection at Habanero-1 was approximately 15 times higher than at RRG-9. Therefore, fractures at Habanero-1 could have been resheared multiple times, as concluded by Dempsey et al., (2016).
2. The parameters comprising PI_S in Eq. [2] might be different at RRG-9 in a way that makes induced seismicity less productive, e.g., if the rock were more

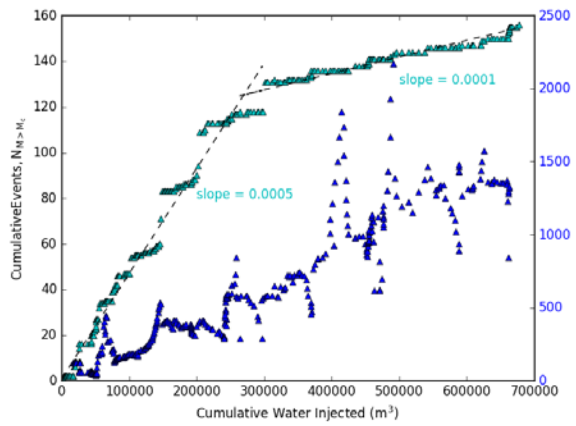

Figure 7: Modified hall plot (Eq. [2]) of seismicity and cumulative water injected (m^3) for all seismicity at RRG-9.

compliant at RRG-9, subsurface pressure build-up would be buffered to a greater extent by the rock, reducing overpressure at distance from the well.

3. Features of the geometric distribution of the stimulations may play a role. At Habanero-1, fluid flow (as indicated by location of seismic events) is approximately radial (Barton et al., 2013; Dempsey et al., 2016). In contrast, Bradford et al. (2016) showed that fluid flow at RRG-9 was linear along a “Narrows” structure. Thus, a smaller volume at RRG-9 was exposed to elevated fluid pressure, possibly resulting in fewer seismic events.

4. CONCLUSION

Seismic and wellhead data from the respective stimulations of the Habanero-1 well in the Cooper Basin, Australia and the Raft River RRG-9 well in the United States were used to test a modified version of Hall’s method. At Habanero-1, the modified Hall plots were able to distinguish the decrease in seismicity rate at an increasing radial distance from the wellbore as fluid pressure equilibrated. There appears to be a logarithmic relationship between seismicity and injection volume with parameters dependent on the cutoff radius. A physical justification for this relationship is a priority for future work.

At infinite radial distances, the seismic profiles of each site exhibited different trends. Habanero-1 produced a relatively linear slope suggesting the number of seismic events that occurred during stimulation was proportional to the volume of water injected. At the same time, it would appear that the large amount of induced seismicity did not have a significant impact on the permeability of the well. RRG-9 produced a piecewise linear slope indicating a major change in reservoir parameters at a distinct time period in the injection program. Further interpretation and extraction of information from these modified Hall plots is a subject of continuing study.

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