GRC Transactions, Vol. 43, 2019

Application of Oil and Gas Methodology to Geothermal Formation Evaluation: The Value of Data

Tom Bradley, Ingelinn Aarnes

Baker Hughes, a GE Company

Damien Outrequin, Nicolas Monneyron

Engie Reseaux

Keywords

Formation evaluation; Subsurface; Wireline; Logging whilst drilling; Geochemistry; Seismic

ABSTRACT

The energy landscape is transitioning to a low carbon future through energy efficiency and green energy sources. Within the European Union, a target of 20% has been set of energy needs to be met by renewable sources in 2020, increasing to 27% by 2030. Several countries have already set targets much in excess of these. Therefore the race is on to meet these targets whilst still meeting the countries energy needs.

As part of this transition, renewable sources of energy are becoming more prominent in the energy needs of each country. Geothermal energy is an important part of the energy mix as it can supply a wide range of energy needs, ranging from low temperature heating, through mid-temperature industrial uses, to high temperature power generation. Additionally, compared to sources such as wind and solar which are dependent on the wind blowing or sun shining, it has essentially no variability so can be relied on to provide a dependable source of energy.

To make geothermal profitable detailed knowledge of the subsurface is crucial. Many of the key formation properties for prospect evaluation are the same as those desired in hydrocarbon exploration. However, the geothermal industry in Europe is in its infancy and many projects still disappoint in their energy production.

The oil and gas industry has considerable expertise and knowledge in evaluation of the subsurface. However, traditionally geothermal and oil and gas operators work in very different spheres, hence there has been very little knowledge sharing between the two industries. As the

importance of geothermal energy grows there is considerable opportunity for expertise sharing and transfer of best practices and experience between oil and gas and geothermal.

In this paper, we discuss the key similarities and differences between oil and gas and geothermal prospects. And we describe how oil and gas formation evaluation techniques can be applied to geothermal prospects to optimally utilize geothermal resources.

1. Introduction

In many ways, the geothermal and hydrocarbon extraction industries have very similar objectives: The safe, economic extraction of a subsurface energy source with the minimum of adverse effects on the environment. To do this it is most often necessary to drill a borehole into the subsurface strata containing the energy source in question. For the hydrocarbon industries this is most commonly a subsurface reservoir of hydrocarbons, whereas with geothermal prospects this is a subsurface formation containing sufficient energy in the form of heat. For both industries, the amount of energy contained in the reservoir has to be sufficient value to make extraction viable.

The viability of hydrocarbon reservoirs are commonly controlled by the following reservoir properties:

- Reservoir thickness and areal extent
- Formation Porosity
- Formation Permeability
- Formation hydrocarbon saturation
- Formation recovery factor

For oil and gas prospects, higher values of all these properties are desirable as this results in greater economic value. However a hydrocarbon prospect will only be developed if the total value (both economic and potentially strategic) of the recoverable hydrocarbons exceeds the costs involved with the exploration, appraisal, development, production and final abandonment of the prospect. If this is not the case the prospect will not be developed.

Many of the same considerations apply for geothermal prospects - detailed knowledge of the reservoir properties are crucial for accurate assessment of the value of the potential geothermal energy in place, and if this value exceeds the costs involved with producing this energy.

2. Viability of Geothermal Prospects

For a geothermal prospect, commonly the most important formation properties to determine the viability of a prospect are as follows:

- Formation temperature, generally higher temperatures are associated with increased value through greater energy production. However, conversely too high temperatures (such as those associated with encountering magma chambers) can result in adverse conditions and greater risks and costs that are not covered by the greater potential energy production.

- Permeability, higher generally being better as this gives greater flow of injected and produced water, so producing more hot water. However too high permeability can result in too high water flow and hence insufficient energy transfer between the formation and circulating water, resulting in lower energy production.
- Effective porosity, higher being better, as this gives greater surface area to transfer heat from the formation to the injected water.
- Presence of interconnected fractures, more being better, as this has the benefits associated with high permeability and porosity, giving better flow and greater surface area to transfer energy. However extensive fracturing can result in the caveats of extreme permeability as discussed above.

However, other formation properties are also crucial to the success of a geothermal prospect: amongst these are:

- Formation lithology and geochemistry
- Formation water chemistry
- Formation and reservoir structure
- Formation geomechanical properties

To develop a prospective geothermal reservoir, there are many costs involved, the greatest of which are the drilling and completion of the wells, installation of pumps, development of surface facilities, and the provision of infrastructure to deliver the generated geothermal energy to the market. The most common markets being either electricity generation from high temperature geothermal, or local heating grids for lower temperature geothermal.

3. Subsurface Evaluation

In many countries, operators of subsurface assets are required to deposit a copy of their subsurface data with a national repository. After a certain period, many of these repositories publish the data; either freely available in the public domain, or available to interested parties for a fee. Examples of these data sources are:

- The Netherlands Log (NLOG) database, Netherlands
- The Norwegian Petroleum Directorate
- UK Oil and Gas Authority

These are valuable sources of data. However, most subsurface databases are biased towards oil and gas exploration areas as historically this was the primary objective of the majority of subsurface exploration. Therefore, it is often the case that in prospective geothermal areas no data are available, or what data are available is limited and/or older.

This is illustrated in Figure 1. This presents the overview map from the online Netherlands NLOG database with the locations of all borehole plotted (as colored dots), and geothermal license areas shaded in green. With the exception of the South West of the map centered on the known oil and gas areas around Rotterdam, most of the potential geothermal areas are poorly characterized. A similar situation is seen when seismic coverage is compared to geothermal license areas. Where data are available it is limited to legacy 2D seismic, and vintage borehole data recorded between the 1950s (or earlier) and 1980s.

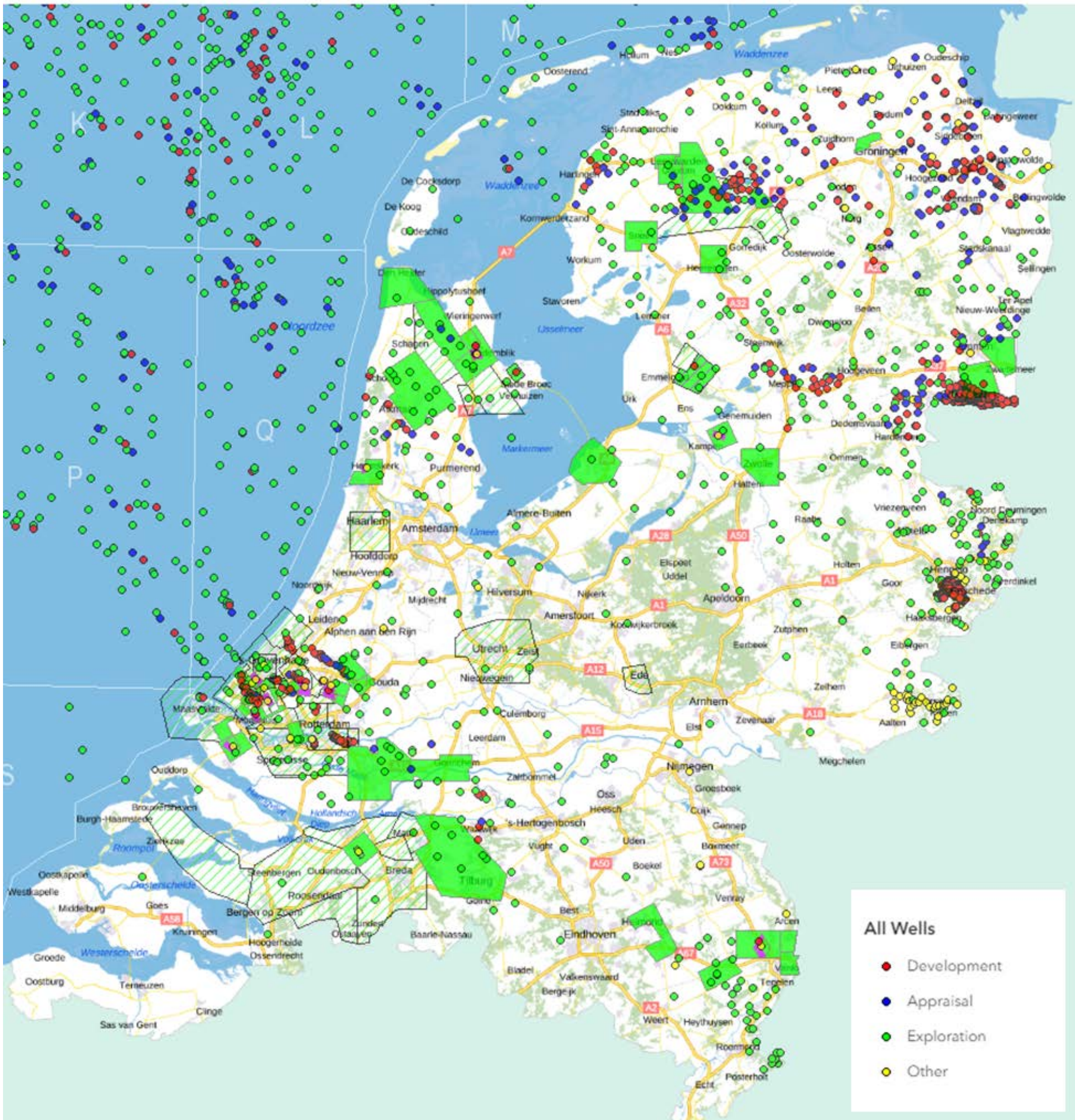

Figure 1: The overview map for the Dutch NLOG subsurface database showing existing wells (as dots) and geothermal exploration licenses (green shading) (from www.nlog.nl)

Prior to developing a project and drilling a well, in the oil and gas industry considerable rigorous pre-planning is conducted to ensure the success of the project. This includes (but is not limited to) the following:

- Evaluation all existing data to determine the initial feasibility of a project
- Cost/value analysis to determine if the total value of a resource exceeds the costs involved with developing it. And to determine the information needed for adequately assessing a prospect in terms essential information, 'nice to have', and non-essential.
- Risk mitigation to ensure that the lowest risk method of proceeding is followed.
- Prior to drilling wells, a drilling well on paper (DWOP) exercise to examine the complete process of drilling a planned well and to discuss all the risks involved to ensure success of the well.

An example of a risk-mitigation-contingency table prepared for planning a methane hydrate well is presented in table 1. Note that not all risks have mitigations and contingencies classified as these are often only known later in the realization of the well.

At each stage of the feasibility study, a series of progress gates have to be passed. If the conditions for a gate are not fulfilled the viability of that step of the project will be reevaluated. Although similar processes are followed in geothermal exploration, this is sometimes not as rigorous as that followed in oil and gas. Hence the risks (health, safety and environmental (HSE), technical and commercial) involved in drilling a geothermal prospect can be much higher.

4. Implication of Limited Subsurface Evaluation

In a high-cost and high-risk environment, subsurface evaluation is often seen as a cost that can be minimized as much as possible. Reference is commonly made to publically available data for initial prospect evaluation (see figure 1). Dedicated data acquisition is limited to the absolute minimum needed to fill the gaps in knowledge gleaned from existing data.

When data are acquired in a new geothermal prospect it can be limited to the bare minimum - identify formation tops for stopping drilling when the target formation is reached. Commonly this is logging whilst drilling (LWD) gamma ray, resistivity and mud logs. Little detailed formation evaluation is then conducted on the acquired data.

Although this minimizes the initial costs of bringing a project on stream, this can have significant implications for costs later on in the life of the project. Some of these are discussed below.

Table 1: Example of a risk-mitigation-contingency table used for planning a methane hydrate well

ID	Risk	Mitigation	Contingency
1	Wellbore instability while drilling through unconsolidated methane hydrate formation.	Provide GeoMechanics model of project and use to control drilling parameters.	Controlled drilling practices as per recommendations. Also utilising LWD acoustic imager for verification.
2	Inability to define formation fluid contacts or the fluid itself from logs.	Ensure multiple datasets overlap to allow ability to cross reference results.	Look at using HC Vision to enhance the logging data both from LWD and wireline.
3	Unable to deploy logging tools in to the well.	Follow Baker Hughes Deployment Risk Management process.	Evaluate need for PCL kit on location.
4	Tool failures during LWD logging.	Follow cold temperature logging procedures.	Full backup tools available on location.
5	Tool failures during wireline logging.	Follow cold temperature logging procedures.	Full backup tools available on location.
6	Production front does not intersect monitor wells.	Review spacing of wells along with GeoData to ensure optimum production projection.	
7	Fibre-optic cables damaged while running in hole with completion in production well.		
8	Fibre-optic cables damaged while running in hole with completion in monitor well.		
9	P/T Gauges fail in hole in production well.		Use wireline PLT log to verify DTS/DAS data.
10	P/T Gauges fail in hole in monitor well.		Use wireline PLT log to verify DTS/DAS data.
11	Ambiguity in LWD data.		
12	Ambiguity in wireline data.		
13	Thermal changes in the upper methane hydrate or permafrost during drilling.		
14	Thermal changes in the upper methane hydrate or permafrost during cementing.	Look in to the use of alternate barriers	
15	Wellbore damage while drilling changes near wellbore characteristics.		
16	Complex stratigraphy reduces data certainty.		Look at using ACE to get real time stratigraphy etc. to enhance logging data from both LWD and wireline.
17	Methane Hydrate released either thermally or through pressure drop.		
18	Wellbore size increase and wellbore instability due to thermal/pressure changes can reduce data quality on shallow DOI measurements		Acquire more data on LWD depending on expected borehole increase with time
19	High porosity neutron (Noise)	Slow down logging speed	

4.1 Accurately understanding the reservoir aerial extent, thickness and structure

Initial estimations of the reservoir thickness, areal extent and porosity are derived from surface seismic and offset wells. As discussed previously, often only limited legacy 2D seismic lines are available in the area of a prospect. The limited resolution gives uncertainty both in the depth and thickness of potential formations of interest in the tens or even hundreds of meters, which can have significant commercial consequences. One such major uncertainty of this approach is the well location. If the optimal location for the wells is uncertain (both geographically and within the reservoir itself), optimal heat production will not be realized. If an appropriate seismic campaign is planned prior to drilling to complement and fill gaps in the existing surveys, uncertainties in the reservoir model can be minimized with the following benefits:

- Knowledge of the structure can help to plan well paths, and subsequently refine the model with real time LWD measurements to steer wells into the most productive horizons, to maximize heat production.
- When multiple wells are drilled in an area, knowledge of the reservoir structure is key to determine where injected water will flow and produce. If sub-seismic barriers or preferential flow paths are present in the reservoir this can affect flow, resulting in unexpected high flow from some wells, and no flow from other wells. This will have associated costs if surface facilities are not being utilized to their planned capacity.

4.2 Why understanding reservoir porosity, permeability and heterogeneity is important

Porosity and permeability are often derived from seismic, local knowledge, and assessment of offset wellbore data. Seismic-derived porosity is a bulk measurement, and offset wellbore measurements can be influenced by reservoir lateral variability. More accurate porosity can be determined by indirect measurements such as acoustic, density and neutron logs. All of these measurements have inherent uncertainties and the combination of these measurements provides a more confident basis for decision making.

Permeability is commonly not directly measured, and is often inferred from commonly used published porosity-permeability relationships (of which there are many). Today a well test is often conducted to determine bulk flow of the formations of interest with the assumption being the complete interval contributes to flow. This does still leave uncertainties about which intervals are flowing, which may have implications for well completion and performance. More direct log-derived measurements such as nuclear magnetic resonance (NMR), acoustic and formation testing derived permeability are recommended to reduce these uncertainties.

4.3 The value of evaluating the presence of fractures

Fractures can significantly contribute to fluid flow pathways in the formation, and hence effectively increase both the effective formation permeability and surface area to transfer heat from the formation to the working fluid.

However, the majority of fractures that contribute to flow are on the sub-seismic scale, and visualizing the majority of fractures on basic logs is challenging if not impossible. The primary sources of information for fracture determination are measurements such as borehole images and full waveform acoustics (in particularly the information derived from cross dipole measurements). Without detailed knowledge of presence of flow contributing fractures, optimal completion design cannot be determined. This has a significant cost impact to the project.

4.4 Subsurface geochemistry

For geothermal energy production, many prospects require the injection of water into the geothermal reservoir via an injection well and production of this from a nearby well after it has flowed through the reservoir. The chemistry of the formation and injected water, and the formation mineralogy can influence the behavior of the flowing water.

Reactions between the various fluids (native and injected) and minerals are possible, especially in the presence of high temperatures. This can have several consequences, such as:

- Reaction between formation and injected water, or the formation itself, potentially resulting in plugging in the formation pores and pore throats so restricting or preventing water flow and heat production
- Deposition of scale in tubing, pumps, and surface facilities, either formed by deposition of salts present in the native formation water as it cools, or by precipitation of salts formed by the reactions between the injected water and the formation itself. Scale will reduce flow and affect the life of both pumps, tubing and surface facilities. Many forms of scale are high in concentration of radioactive materials such as certain lead isotopes and uranium salts, hence requiring special handling and disposal with associated costs and HSE risks.
- Produced salt water can be corrosive, especially at temperature, which can have significant implications for wellbore and casing integrity.

Knowledge of geochemical properties can help manage these concerns. There are several sources of geochemistry information such as cuttings, core, and measurements from geochemical logging tools such as pulsed neutron elemental spectroscopy. Formation water information is commonly from samples during well testing or from downhole formation testing tools. Appropriate geochemical analysis can help to manage these concerns.

4.5 Formation geomechanical properties

To flow injected water round a geothermal system, a pressure difference between wells is needed. This pressure difference will by its nature change the pore pressure within the formation in the vicinity of the wells. This can have multiple consequences:

- Seismicity – as pore pressure changes, this changes the stresses in the formation. If faults are present in the formation at the limits of their stability, even a small change in pore pressure can be sufficient to reactivate these faults. This will potentially result in seismicity. Any seismicity noticeable on the surface will have significant negative impacts. An extreme example of this being the seismicity experienced in the Groningen gas field in the Netherlands associated with gas production.
- Well planning – knowledge of the formation geomechanical properties is critical for optimal well construction. For example, selection of mud properties to ensure hole stability whilst minimizing formation damage. Determination of optimal wellbore trajectory to ensure well stability. Planning of casing schemes for maximum casing

diameter in the productive zones, and maximizing hole section lengths to eliminate unnecessary casing runs.

- Wellbore integrity and stability – when the well is on production, changes in pore pressure will affect the stresses round the wellbore. Over the life of the well this could result in casing deformation, and under extreme circumstances even wellbore collapse if casing insufficient to support the stress changes is selected. Knowledge of the local stress régime ensures that a casing and completion scheme that is fit for purpose is chosen.

Detailed geomechanical information can be derived be combining measurements such formation lithology, density, acoustics and borehole images. Sometimes geomechanical information is considered, but commonly a 'rule of thumb' is applied to limit the circulating pressure based on local conditions. But it should be questioned if this is always appropriate. Circulating at a too low pressure can limit flow and hence energy production, whereas too high a pressure could result in the issues previously described. By understanding the geomehanical setting it is possible to maximize the well performance and life-of-well.

4.6 The cost of initial savings can be large

In addition to the properties discussed above, many other formation properties may influence the performance of a geothermal project, many of which may only become apparent later in the life of the project.

Although initial data acquisition is seen as expensive, the value may only become apparent later in the life of the project. Once the well is completed and pumps and surface facilities are installed, it may be impractical, even impossible, and highly costly to acquire information needed to identify and rectify these issues.

5. Value of Subsurface Data Acquisition - A Case Study

Here we present a case study that demonstrates the value of subsurface evaluation for geothermal exploration. The well is in a fractured carbonate prospect with a potential 110m productive interval. It was initially assumed that the total interval would equally contribute to the water (and hence heat) production.

Carefully planned fit-for-purpose wireline logging was conducted over the interval of interest, including gamma ray, nuclear magnetic resonance (NMR) and cross dipole acoustic. Subsequent production logging was conducted whilst the well was tested. Even minimal logging such as this is uncommon in many geothermal wells.

Figure 2 presents a summary of the open hole wireline log data acquired over the potential geothermal reservoir.

The tracks on the plot and key presented curves are as follows

- Track 1 – gamma ray, caliper. Shading to indicate gamma ray value (yellow – low, green – high)
- Track 2 – depth

- Track 3 – NMR apparent T2 spectrum
- Track 4 – NMR permeability derived from Coates equation
- Track 5 – NMR derived clay bound, irreducible and moveable porosity, acoustic derived porosity

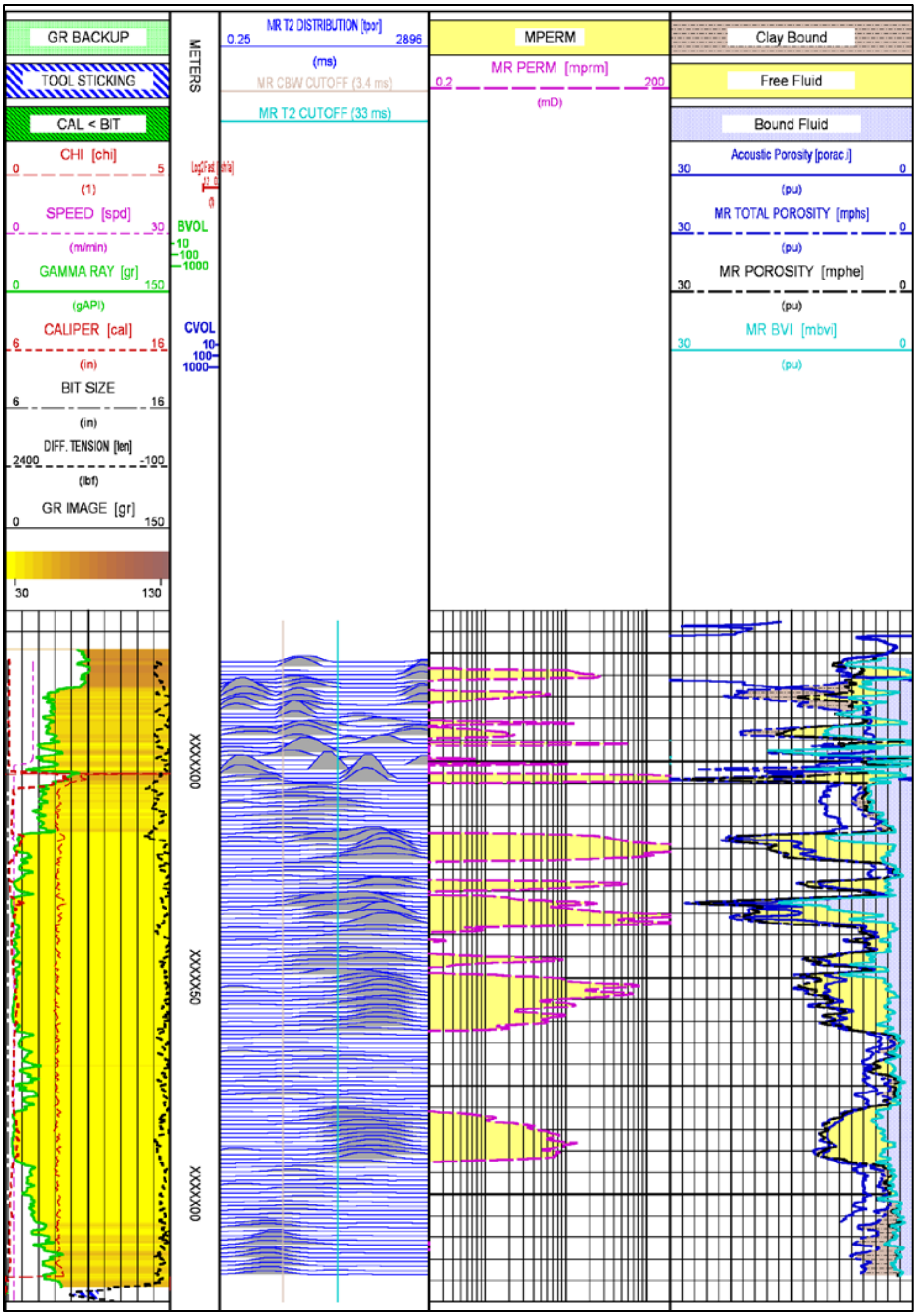

Figure 2: Summary plot presenting log data acquired over the interval of interest. Refer to text below for a detailed description of the presented data.

The acquired open hole log data are sufficient to determine some important basic reservoir properties, including shale volume, total and effective porosity, permeability, indication of fractures, and some basic geomechanical properties.

It can be seen from the log data that although the gamma ray log reads consistently low indicating a consistently low shale content, both the NMR and acoustic porosities show considerable variation. Furthermore, the NMR partial porosities shows a considerable variation in moveable porosity. This is reflected in the Coates derived permeability, with only approximately 50% of the interval (indicated by the yellow shading in track 4) being potentially productive.

The production log results are presented in figure 3:

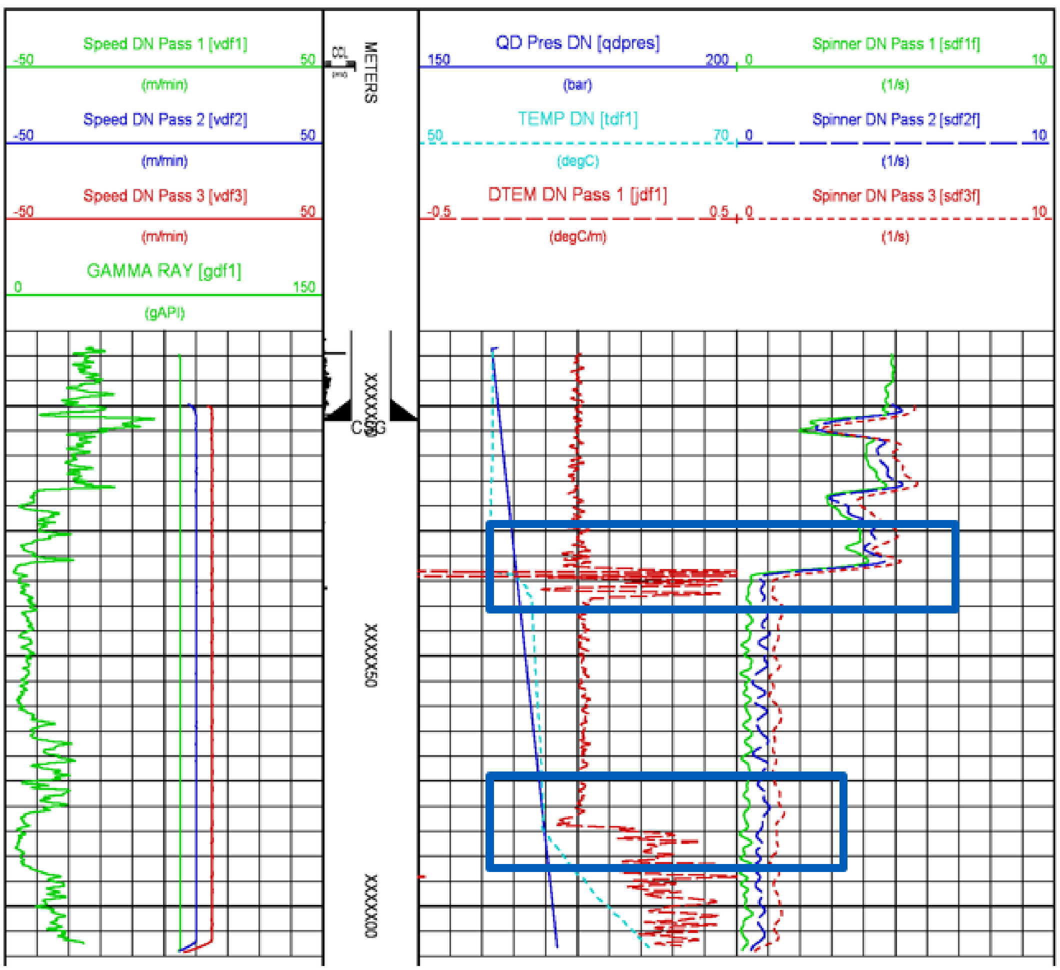

Figure 3: Production log data acquired over the interval of interest. Refer to text for a detailed description of the presented data.

The tracks on the plot and key presented curves are as follows:

- Track 1 – Gamma ray, logging speed for each pass
- Track 2 – Depth, casing collar locator

- Track 3 – Pressure, temperature and differential temperature for log pass 1, Spinner readings for three down passes at different logging speeds.

The production log data can be used to indicate the locations of flow from the formation to the borehole, and the flow rate.

It can be seen from the temperature and spinner curves that only one short interval centered on xx34m is contributing to flow (indicated by the upper blue box), as indicated by the significant changes in both spinner velocities and temperature.

A temperature gradient change is also seen xx85m (indicated by the lower blue box): Temperature changes are often associated with inflows into the wellbore, however no corresponding changes in spinner velocity are observed, so it is assumed that this interval is either not flowing, or the change in flow velocity is so low that it is insufficient to be recorded by the spinners, and therefore a minor contribution to the overall well production.

Further investigations were conducted to determine the reason why only one interval contributes to the total flow. Although only limited open hole data was acquired, much useful information could be extracted from the cross dipole acoustic data. In particular, azimuthal anisotropy analysis for determination of local near-wellbore stresses (in the meter scale), and near wellbore shear reflection imaging for visualizing fractures in the near wellbore environment (to tens of meters from the wellbore).

Figure 4 presents the acoustic dipole waveform, azimuthal anisotropy and near wellbore shear reflection imaging results, compared to the production log data over the intervals in the well where flow is observed:

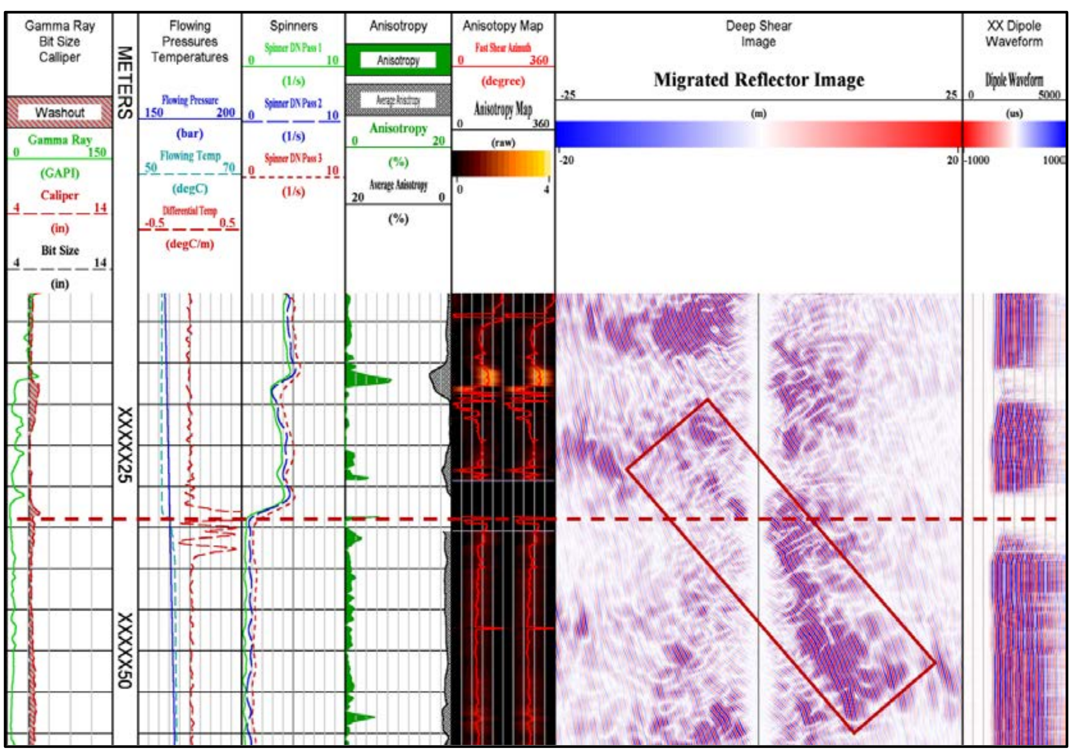

Figure 4: Analysis results for flowing intervals. Refer to text for a detailed description of presented data

The tracks on the plot and presented curves are as follows:

- Track 1 – Gamma ray, caliper, bit size. Shading to indicate borehole enlargement.
- Track 2 – Measured Depth.
- Track 3 – Flowing Pressure, temperature and differential temperature for production log pass 1.
- Track 4 – Spinner readings for three downlog passes at different logging speeds.
- Track 5 – Acoustic azimuthal anisotropy magnitudes, indicating difference between 'fast' and 'slow' shear slowness magnitudes: anisotropy (3.5ft vertical resolution) and average anisotropy (10.5ft vertical resolution).
- Track 6 – Acoustic azimuthal anisotropy map, showing anisotropy magnitude radially around wellbore. Light shading indicates higher anisotropy magnitude, and red curves indicate fast shear orientations. Edges of image are aligned to geographic north.
- Track 7 – Near wellbore shear reflection image presenting image of reflecting planar features in the near wellbore environment. Borehole is represented by the black line in the center of the image, and the edges of the image represent a radial distance of 25m either side of the borehole. Image is presented with an imaging plane strike oriented 68 degrees/248 degrees.
- Track 8 – XX dipole acoustic waveform amplitude, scaled from zero to 5000 microsecond arrival time, and arbitrary -1000/+1000 amplitude.

Of particular interest is the azimuthal anisotropy information displayed in tracks 5 and 6. This illustrates the variation of shear magnitude around the wellbore. The formation anisotropy is computed by utilizing a full waveform cross dipole acoustic logging tool that records dipole waveforms with two orthogonal dipole transmitter-receiver array pairs. By performing an inversion on the recorded data (as described by Tang and Chunduru in 1999) the shear slowness variation around the borehole can be determined. On the presentation, brighter spots indicate a greater difference in fast versus slow shear, which can commonly be related to a greater difference in maximum versus minimum stress, or the presence of fractures crossing the wellbore. This can be further compared to the dipole waveform data displayed in track 8: Over the interval xx16 to xx18m the increase in azimuthal anisotropy can be correlated to a reduction in waveform amplitude. A much greater reduction in waveform amplitude is seen over the interval xx31 to xx36m which also corresponds with the azimuthal anisotropy inversion being unable to resolve an anisotropy magnitude nor direction.

The other key information is presented in track 7, which displays the near wellbore shear reflection image. This visualizes planar reflective features in the formation up to 25m from the wellbore. This uses the same orthogonal dipole data from a wireline full waveform acoustic tool as used for the azimuthal anisotropy analysis. By applying specialist filtering to extract reflections from the recorded waveform data, and then by applying mathematical rotation and standard seismic processing techniques to these rotated waveforms, the features causing these reflections can be imaged and their orientations estimated (as described by Tang, Zheng and Patterson in 2007).

In tracks 3 and 4 where the production log show an increase in flow and change in temperature, this can be associated with the significant waveform amplitude reduction and inability to invert an anisotropy computation. The acoustic reflection image exhibits a significant reflective feature (enclosed by the red box in track 7). By considering the data together this suggests that the source of the majority of the inflow to the wellbore is a significant open fracture or fault that intersects the wellbore at xx34m (as indicated by the horizontal red dashed line).

Over the remainder of the interval, no significant changes in either the temperature logs or spinners are seen. Therefore the indications are that over the complete interval matrix permeability is low and hence contributes very little to flow.

It can be observed that there is a reduction in spinner velocity over the interval xx17 to xx23m, however this velocity reduction corresponds to an increase in hole size (as indicated by the caliper), therefore as hole size increases, flow velocity will decrease. This is confirmed when the spinner velocities and hole size above xx17m are examined: The hole size returns to a similar diameter as seen below xx23m, and the spinner velocities return to similar baseline values as observed below xx24m, so indicating that velocities above and below this enlarged intervals are similar and the change in spinner velocity is not as a result of a thief zone.

To confirm these observations on the causes of the flow contributions, additional data acquisition such as borehole images (to image the fractures at the borehole wall) would commonly be advised.

There are several implications of not having the information that this data and interpretation has provided:

1. The entire interval may be completed with the assumptions that the complete interval will flow. Hence resulting in unnecessary expenditure on completion hardware.
2. If the best producing intervals are known, the well can be steered in the most productive intervals for little additional expenditure, thereby increasing heat production and the economic return of the well.
3. Only one short interval is producing. If this interval plugs or scales, for example as a result of deposition of native formation salts or reaction of chemically or biologically incompatible injected and formation water, there are significant implications for the well
4. If a pump is required to produce the well, and this is selected based on the assumption that the complete interval is producing. If only a small interval produces this could result in excessive pressure drawdown over this short interval, with implications for the well such as excessive sand production (if this was a clastic formation) and associated pump wear, casing erosion. In the case of fractures and faults, excessive pressure changes could result in potential reactivation with associated geomechanical consequences (such as associated seismicity).

Even with this limited information, this enables much more detailed evaluation of the prospect and from this information decisions can be made that will improve the economics of the project.

6. Conclusions

Commonly, even minimal basic data acquisition in geothermal wells is seen as an expense that can be avoided. However, the value of the data may not be realized until later in the life of the project.

In this paper we have discussed the value of data acquisition in geothermal wells and why consideration should be given to recording standard formation evaluation measurements. Formation evaluation measurements are as standard acquired and interpreted in oil and gas wells. These measurements are then subsequently interpreted using many techniques, including those presented in this paper, to determine if a prospect can be safely and economically realized.

The case study demonstrates that even when limited data are acquired in a geothermal well, with careful fit-for-purpose interpretation many important formation properties can be determined. This will subsequently aid in characterization of several key formation parameters that will aid in completion design, production decisions, and mitigation of potential issues later in the life of the project. Although up-front expenditure will be increased, the resulting future benefits of reduction of unnecessary costs in both the realization of the well (e.g. unnecessary completions) optimization of future operations, and avoidance and mitigation of potential future issues over the life of the project should more than offset these initial costs. By investing in fit-for-purpose data acquisition and interpretation, the success rate and profitability of geothermal projects should increase.

Acknowledgements

The authors would like to thank Baker Hughes, a GE Company for their support in publishing this paper. The parties who generously released data for use in the paper. And our friends and colleagues in the industry who provided inspiration and ideas for this paper.

REFERENCES

Hornby B. E., 1989: Imaging of near borehole structure using full-waveform sonic data: Geophysics, volume 54 number 6, 747–757.

Tang, X., Chunduru R., 1999: Simultaneous inversion of formation shear-wave anisotropy parameters from cross-dipole acoustic-array waveform data: Geophysics, volume 64 number 5, 1502–1511.

Tang, X., Zheng, Y., Patterson, D., 2007: Processing array acoustic-logging data to image near-borehole geologic structures: Geophysics, volume 72 number 2, E87–E97.

TNO and Ministerie van Economische Zaken, “Dutch subsurface interactive overview map”, retrieved from www.nlog.nl, 14th March 2019