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TITLE: THE SIZING OF A HOT DRY ROCK RESERVOIR FROM A HYDRAULIC FRACTURING EXPERIMENT

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The sizing of a hot dry rock reservoir from a hydraulic fracturing experiment

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Abstract Hot dry rock (HDR) reservoirs do not lend themselves to the standard methods of reservoir sizing developed in the petroleum industry such as the buildup/drawdown test. In a HDR reservoir the reservoir is created by the injection of fluid. This process of hydraulic fracturing of the reservoir rock usually involves injection of a large volume (5 million gallons) at high rates (40BPM). A methodology is presented for sizing the HDR reservoir created during the hydraulic fracturing process. The reservoir created during a recent fracturing experiment is sized using the techniques presented. This reservoir is then investigated for commercial potential by simulation of long term power production.

Background The creation of a geothermal reservoir by hydraulic fracturing is a major component in energy extraction by the HDR method. In its simplest form, the HDR reservoir is a flow path consisting of an injection well, a fractured rock mass (created by hydraulic fracturing) and a production wellbore intersecting the fractured rock at a sufficient distance from the injection well for a good heat transfer area to be established in the fracture system. The idealized reservoir is shown in Figure 1.

This study was motivated by a large fracturing operation (Experiment 2032) conducted December 6-9, 1983 in which 5.6 M gallons (21,200m^3) of water were injected into wellbore EE-2 at the Fenton Hill Hot Dry Rock site. A variety of data were acquired in the experiment. The data included flowrate, bottom hole pressure and seismic event mapping. During flowback of the injected fluid useful geochemical and temperature data was obtained as was an estimate of the volume of the returned fluid.

A critical parameter in analyzing the flow and pressure data is the fracture aperture size and how the fracture aperture behaves with pressure. The aperture size can be estimated using a procedure developed by Geertsma and de Klerk (1969). In their analysis the maximum aperture w is expressed as a function of flowrate, Q, fluid vicosity, μ, rock shear modulus, G, and fracture radius R:

$$w = 2(\mu QR/G)^{.25} \qquad [1]$$

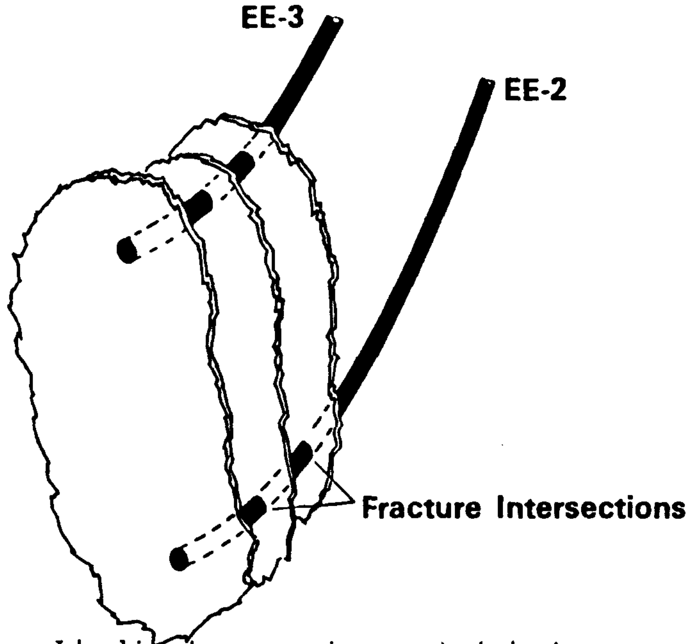

Figure 1. Idealized reservoir created during Experiment 2032

Values appropriate to Fenton Hill and Experiment 2032 (μ = 1cp, Q = .111 m^3/s, R = 500 m, G = 2.65 x 10^{10} Pa), give a maximum aperture of 0.002 m. Because of the 1/4 power in Eq. 1, the result is relatively insensitive to changes in flowrate (or the number of fractures). Geertsma and de Klerk's analysis also predicts a parabolic variation in aperture to the top of the radial fracture. This 0.002 m was used as the aperture value at the observed fracturing pressure. A finite element based geothermal reservoir simulator (Zyvoloski 1983) was used to model the pumping and flowback during the fracturing experiment. To model the experimental results, it was necessary to use a pressure dependent aperture model with the aperture being a rapidly varing function of pressure:

$$w = 1E\text{-}4 \exp(0.209\,\Delta P) \qquad [2]$$

where ΔP is the difference between the current pressure and the initial pressure, with Eq. 2, w = 2.E-7m at ΔP = 0 and w = 0.002 m at ΔP = 44 MPa, the observed fracturing pressure. Other, more rapidly opening aperture laws could be used, and this is indicated by the experimental data. However, a more rapidly varying law would produce numerical instability. The permeability was related to the fracture aperture using the usual parallel plate model

$$k = fw^2/12 \qquad [3]$$

where k is the permeability and f is a friction factor. In the usual flow between plates theory,f is taken to be 1; however, Barton et al (1984) have observed that for flow in rock joints f may be as low as 0.01. In this work f=0.01 was used, this corresponds to a very rough joint. Figure 2 shows the variation of w with P as well as the variations of k with P. The computational grid for the simulator runs is shown in Figure 3. A less complex mesh could have been used to model the fracturing experiment, but this mesh was also used for the long term drawdown simulations. Other parameters used in the computer model are shown in Table I.

Table I Experiment 2032 Simulation

Parameter	Symbol	Value
Permeability	k	$10^{-18}m^2$ matrix $10^{-8}m^2$ fracture (maximum)
Thermal conductivity		2.7 W/m°C
Porosity	ϕ	0.001 matrix 1.0 fracture
Rock density	ρ	2700 kg/m^3
Rock specific heat	C_r	1000 J/kg°C
Fracture radius	-	500 m
Fracture width	-	0.002 m (maximum)
Initial pressure	P^o	36.5 MPa
Initial temperature	T^o	216°C
Injection rate	-	111kg/sec (average)

Model Results To model the results of Experiment 2032 several preliminary calculations were made. The seismic surveillance put bounds on the dimensions of the computational grid. Since there were no events recorded 500 m or farther from the injection point the limit on the flow extent was placed at 600 m (Figure 3). In other words, if a significant ΔP were observed in the model at 600m ($\Delta P \geq 5$MPa), then the model was considered invalid. The minimum distance of the seismic event cloud was 200 m (taken orthogonal to the fractures). This was used to bound the spacing between fractures. A unit fracture concept was used whereby the flow was divided into n parallel fractures each carrying 1/n of the total flow. Each fracture was bounded by a permeable matrix. This concept leads to optimistic values of the water loss in a HDR system due to the inability to represent the permeation from the end fractures; however, for the small times involved in the fracturing process little error would result. A material balance on the injected fluid would yield about 13 fractures of .002 m aperture and 500 m radius. However there are probably less than this number of "large aperture" fractures due to permeation along orthogonal joints and the fact that the seismic results indicated a preponderance of shear events which would yield apertures along the sheared surfaces many times smaller. The final picture is something like this; several large aperture (tensile) fractures and surrounded by many small aperture (shear) fractures. In this work it is assumed that the larger tensile fractures carry the bulk of the fluid and that the small shear fractures can be accounted for by permeation. The permeability in the direction orthogonal to the large fractures was set to a value of several darcies (the in situ permeability) but allowed to increase to a value determined by parallel plate theory for an aperture of 0.0002 m (Dey 1985). This value was then averaged over the mean joint spacing orthogonal to the main fractures. The joint frequency was taken as 1 meter based on surface outcrop observations. This gave an effective maximum permeability in the direction orthogonal to the fracture of about $10^{-14}m^2$. The porosity of the matrix material using similar arguments is 0.0002.

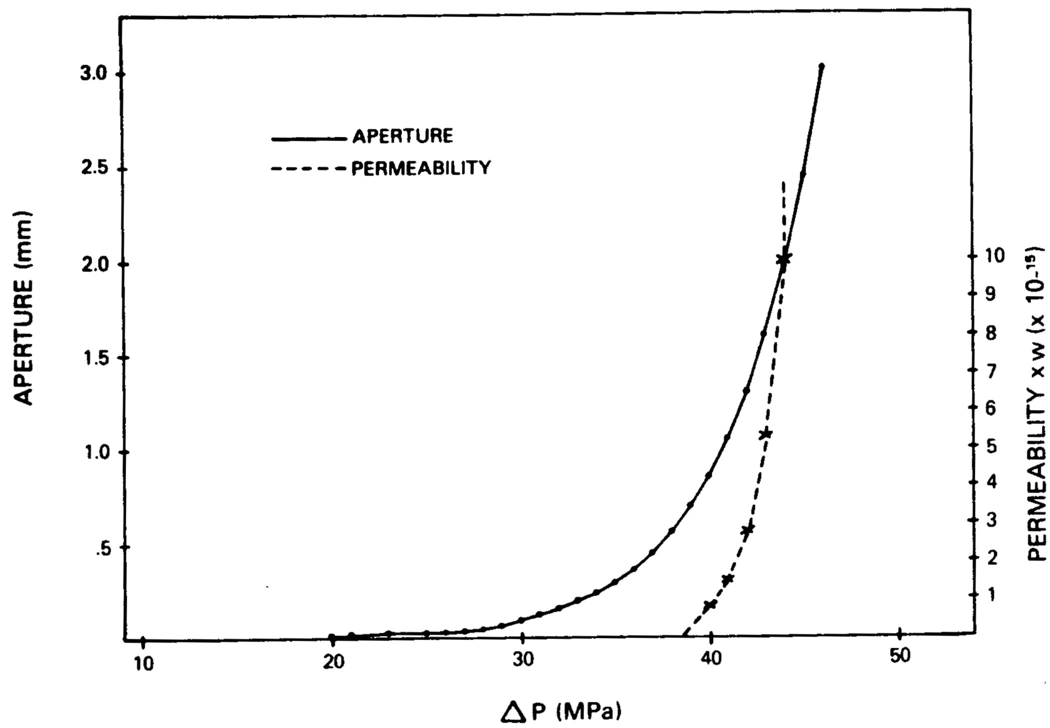

Figure 2. Aperture and permeability variation with ΔP

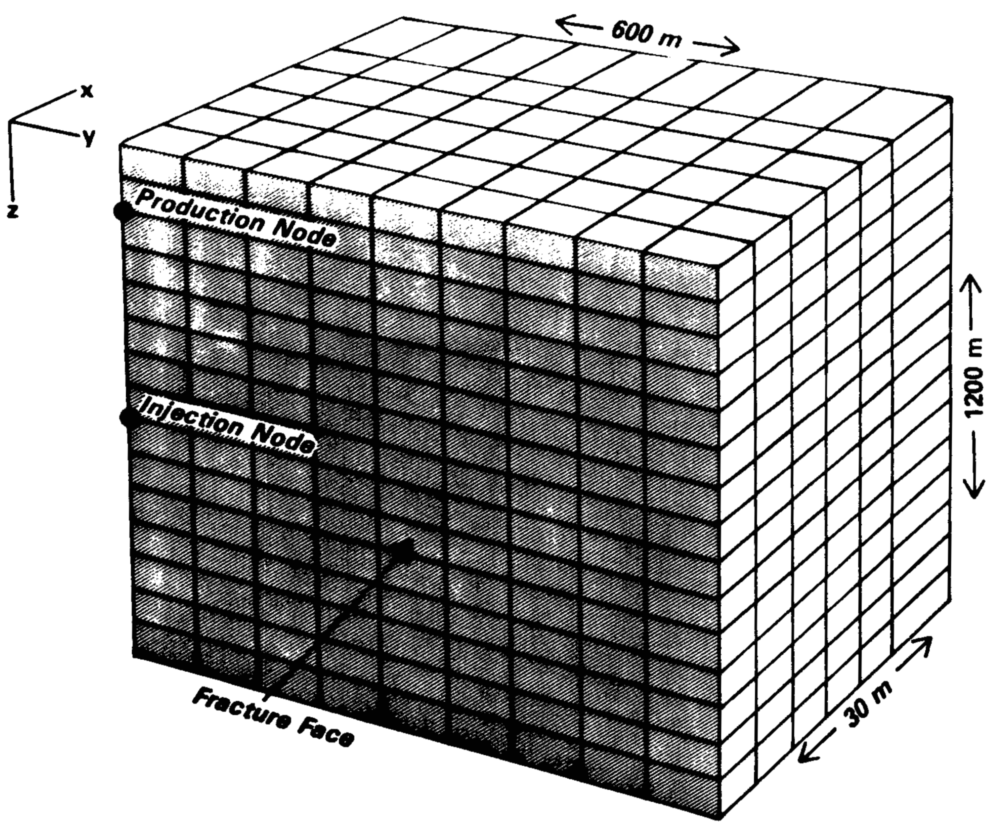

Figure 3. Computational guide for fracture model

Figure 4 shows the Experiment 2032 pressure responses, while Figure 5 shows the computer generated response. Figure 5 also shows the effect of the number of fractures on the pressure at the injection point and at 600 m. It is instructive to notice in the figure the pressure at the point 600 m away from the injection point. The pressure there must be small ($\leq$5MPa) for results to match the seismic data, even the 10 fracture case would be on the "high side of pressure", though it fits the data better than the other cases. The seven fracture case was used as a conservative estimate. It was necessary to make the porosity in the matrix material 0.0075 to obtain the results. Since this is overestimating the response of the joints, the results will be conservative with respect to the number of fractures. So far no heat transfer data were used in the modelling process, this information is very qualitative. The computer generated temperature near the injection point showed a quick rise to the initial temperatore of 216°C. This may be compared to a value of the return temperature inferred by geochemical analysis of the return fluid which also indicated a rapid temperature rise to the temperature of the fluid at the injection point.

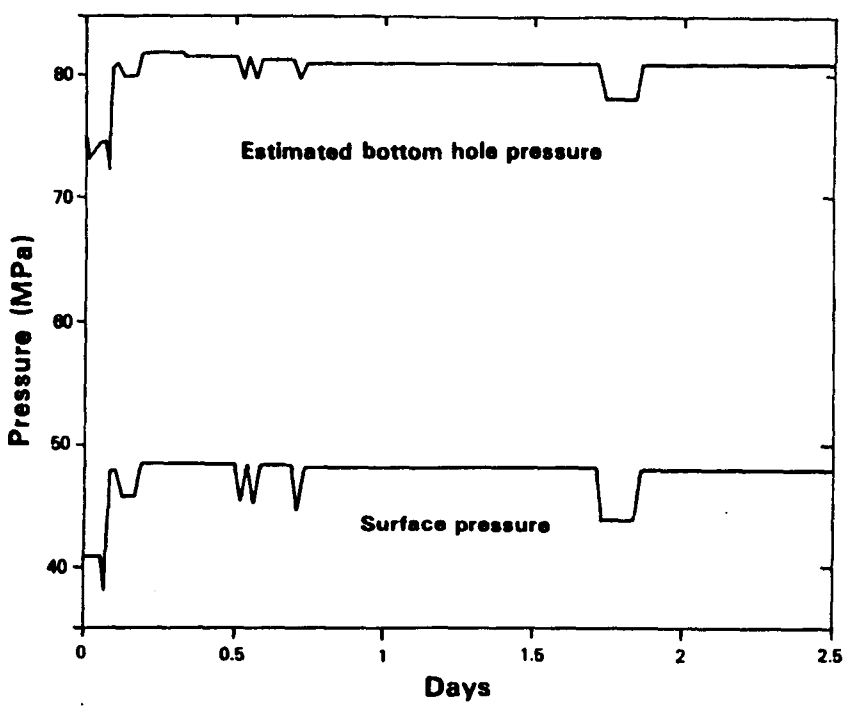

Figure 4. Pressure history during Experiment 2032

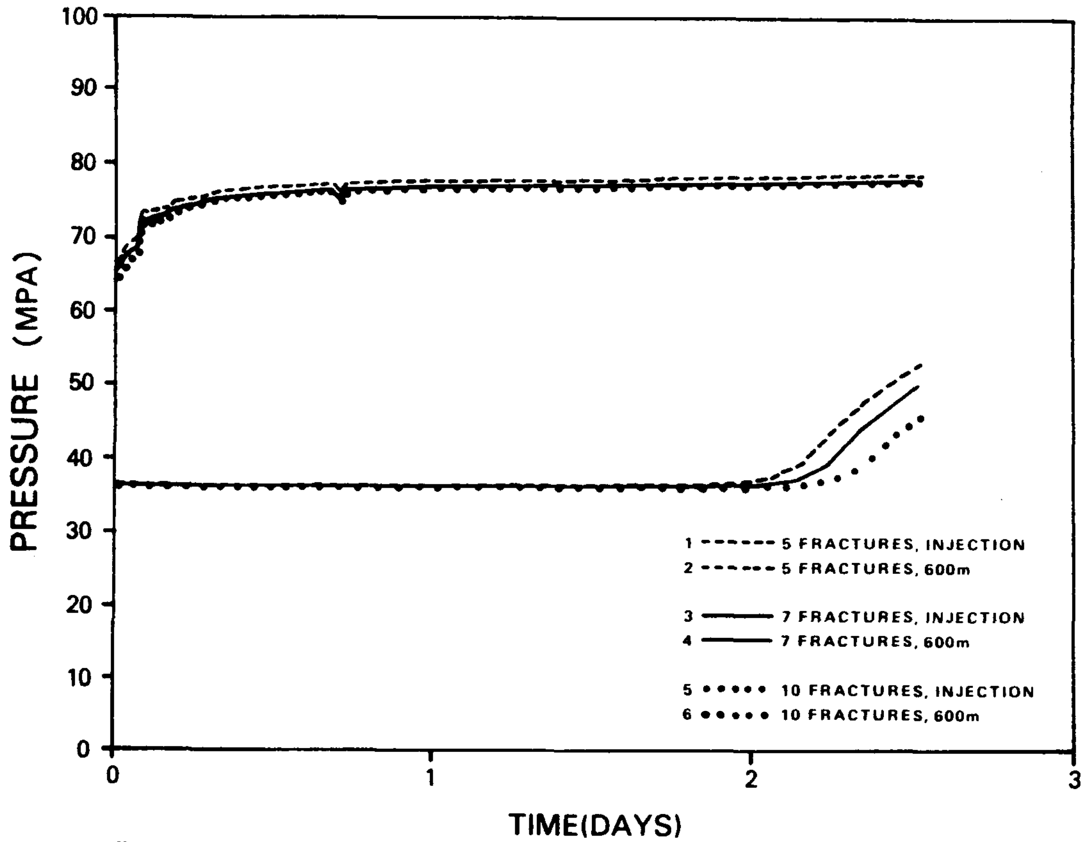

Figure 5. Model pressure history during Experiment 2032

The last piece of information used to verify the model is the amount of fluid vented after pumping, and it is speculative. It was estimated (Potter, 1984) that about 50% of the injected fluid returned in 3 days following the end of pumping. Figure 6 shows the flowrate calculated by the computer model. Using the area under the curve as an indicator, it is evident that the model returns the required amount of fluid after the end of pumping.

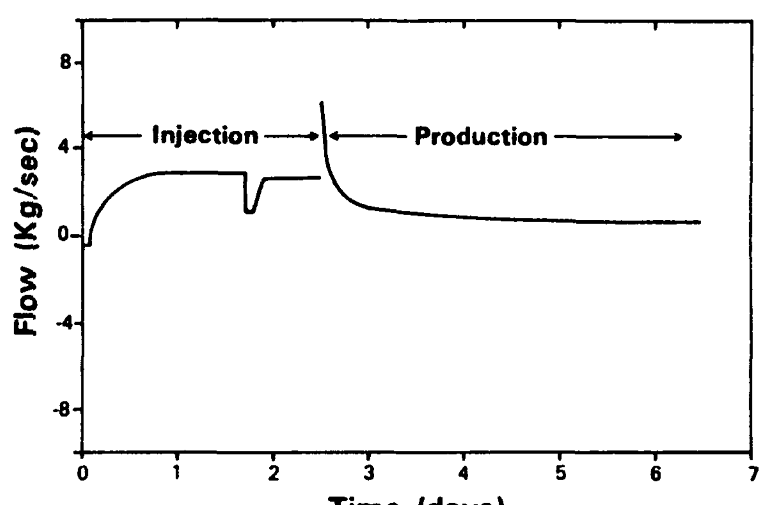

Figure 6. Flowrate during Experiment 2032

The fractured model of the reservoir is not the only model possible. A block model may be appropriate if earth stresses are not aligned with the path between the injection and production wells. In this case several joint sets may open up equally making a block volumetric model a better choice. The analysis, however, would be similar. Using a pressure dependent aperture law, an effective block size would be obtained.

<u>Summary of Modeling Results</u> The model needed to fit the data consisted of:

1. An aperture law of the form $w = 2E\text{-}8\,\exp(.209\,\Delta P)$
2. A permeability law of the form $k = fw^2/12$ $(f=0.01)$
3. Ten fractures (7 used in long term simulation)
4. Fracture Spacing of 20 m

<u>Application of the Modeling Results of Experiment 2032 to Long Term Heat Extraction</u>

With an estimate of the reservoir created during the fracture operation, an investigation of the commercial potential can be made. The reservoir parameters given in Table I and a flowrate of $0.05 m^3/s$ (20BPM) were used. Several different wellbore spacings were investigated because despite the large fractures created, it is likely that the final connection distance may be less than 500 m. Shown in Figure 7 are the outlet temperatures for several wellbore spacings. From the figure it is evident that the most probable fracture case (7) and most probable spacing (340m) will supply 45 MWt for 10 yrs. It also shows that if only 5 fractures were available then the reservoir could not support 45MWt of power production.

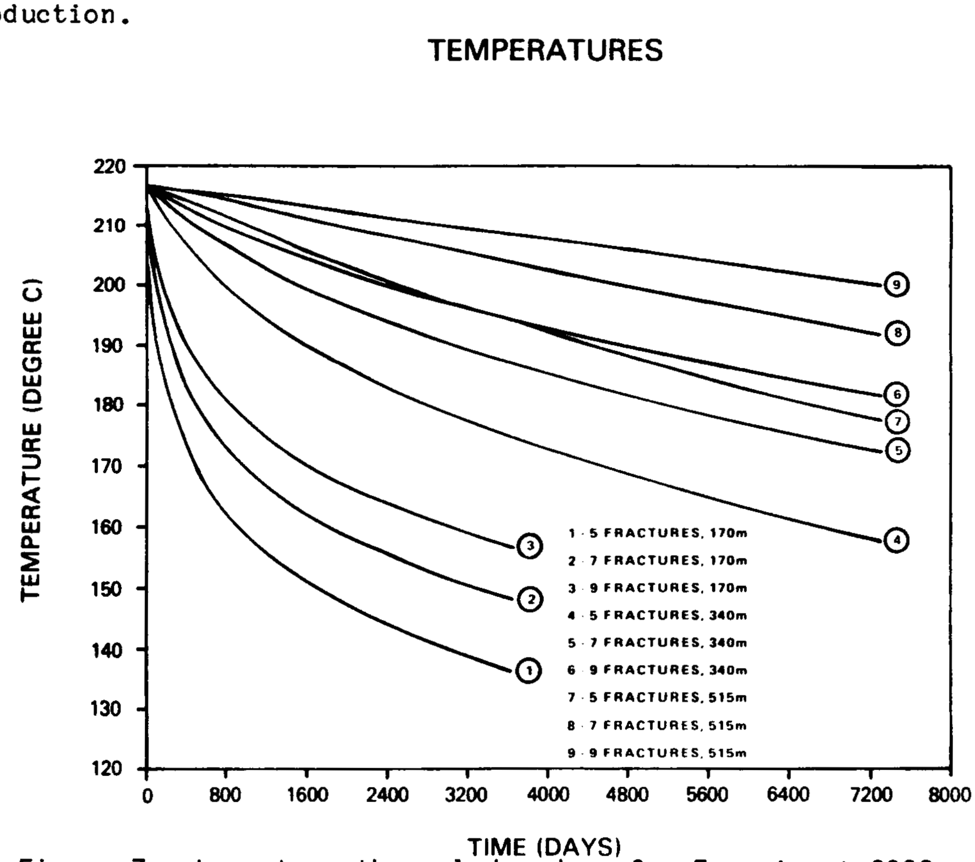

Figure 7. Long term thermal drawdown for Experiment 2032 reservoir

The results presented do not include the beneficial effects of thermal stress cracking which would tend to enlarge the reservoir as it cooled down.

Conclusions

1. The Experiment 2032 (5.6 M gallon pump) can be described with a multiple fracture pressure-dependent aperture law based computer code.

2. Long term thermal drawdown calculations reveal a reservoir capable of producing 45 MWt for 10 years with 7 fractures, 340m wellbore separation and an extraction rate of $0.05m^3/s$.

Acknowledgements

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