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Stimulation of Geothermal Wells, Can We Afford It?

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ABSTRACT

Unexpected, low production rates in a geothermal well can occur due to several causes: e.g. formation damage, completion effects or lack of connectivity to main fluid conduits. Stimulation treatments have been successfully applied in many cases to increase the well production rate to commercial levels. These stimulation techniques were originally developed to address similar problems in oil and gas production wells. The applicability of these stimulation techniques to a high temperature, naturally-fractured reservoir is less well known. This is particularly relevant since oil and gas field experience has shown that fractured formations have often proven to be one of the most difficult well types to treat.

This paper addresses the twin questions of whether stimulation technology can be successfully applied:

1. Technically, to the high temperature environment of naturally fractured geothermal wells.

2. Commercially, to the different financial environment of the geothermal industry compared to that of the oilfield.

This paper provides a comparative, techno-economic study of three well stimulation techniques (matrix acidising, hydraulic fracturing and thermal fracturing) within the technical and economic environments of two Power Companies: Comisión Federal de Electricidad in México and Landsvirkjun in Iceland.

Thermal fracturing is shown to be potentially the most attractive, but least understood, stimulation technique. There is currently no well-founded methodology to design such well treatments. Initial work, on a novel approach to develop a methodology to be able to efficiently design and execute such treatments, will be discussed.

1. INTRODUCTION

A geothermal resource is quite different from an oil or gas reservoir or even a ground water reservoir. In an oil reservoir, once the oil has been extracted, the reservoir is exhausted. By contrast, in a geothermal reservoir the water or steam originally present in the reservoir can be replaced by surrounding cooler water that is heated by the reservoir rock, becoming available for additional production (O`Sullivan and McKibbin, 1993). Despite all the differences between hydrocarbon and geothermal reservoirs, the techniques used for extraction of fluids are very similar; as are the exploration techniques and reservoir management approaches.

Like in an oil prospect, the key issue in a geothermal development is the ability to reach rock with sufficient flow and storage capacity that can produce fluids with sufficient energy that they drive a surface turbine to generate electricity for a long enough time period that the project is economically viable. Techniques similar to those used in the oil industry are employed to drill and complete well in the productive reservoir. In both cases formation damage should be minimized in order to optimize well performance and, in our case, maximize power generation at the surface.

The economic climate, and the reduced levels of investment in geothermal wells necessary to maintain project profitability, are very different between the two cases. This is due to the large differences in specific energy content and price of a given volume of oil and a similar quantity of steam. This, together with the highly consolidated nature of the rock, is one of the reasons why geothermal wells are frequently completed using slotted liners or open holes. Drilling is normally performed using cheap, bentonitic mud, sometimes even in the reservoir zone, for the same reason. Geothermal reservoirs are characterized by a large degree of fracturing even when they occur in sedimentary rocks with intergranular porosity (Aguilera, 1995). The presence of such fractures is often first recognized by the sudden occurrence of large volume mud loss during drilling. Such losses to the natural fracture network have the potential to inflict large-scale formation damage with a consequent significant reduction in steam production. A well may encounter multiple, widely spaced, fracture zones, resulting in flow rates that are too low Depending on the geological environment, the well may only contact a matrix formation of insufficient permeability. Stimulation techniques have the potential to remediate such causes for low flow-rate wells. In the first case, the damage due to mud invasion into open fractures, and the pores or minor flow channels present in the host rock, can be reduced with an acid job. Low productivity due to lack of communication with the naturally occurring, main conduits for fluid flow can be improved by thermal and /or hydraulic propped fracturing of the wells. These types of stimulation can make the difference between a productive or an abandoned well.

2. WELL STIMULATION TECHNIQUES

Matrix Acidising, Hydraulic Fracturing and Thermal Fracturing have been analysed for their applicability to geothermal environments (**Table 1)**.

2.1 Matrix Acidising

Matrix acidising is used to remove near wellbore permeability damage with the objective of restoring the well to its natural undamaged inflow performance. This (chemical) treatment involves injection of a reactive fluid, normally an acid, into the porous medium at a pressure below the fracturing pressure (Economides and Nolte, 1987). The acid works through a process of dissolution of (foreign) materials deposited within the porous formation, such as carbonates, metallic oxides, sulfates, sulfides or chlorides, amorphous silica, drilling mud and cement filtrates from invasion (Davies, 2003). A second type of acid stimulation and perhaps the most common one for geothermal environments, is the cleaning of (pre-existing) fractures. The intention is for the acid to dissolve (or

mobilize sufficiently that they can be removed by later flow processes) either foreign or original fracture-blocking material. Treatment volumes, injection rates, acid placement techniques, acid system selection and evaluation of the results when stimulating geothermal wells all follow the same criteria as for oil wells. The important difference is the formation temperature. High temperatures reduce the efficiency of corrosion inhibitors (and increase their cost) as well as increasing the acid/rock reaction rate. The high acid rock reaction rate requires the use of a retarded acid system to ensure acid will not all be spent immediately next to the wellbore, but will penetrate deeper into the formation. Cooling the target formation by injecting a water preflush will reduce the temperature and the acid reaction rate.

Table 1: Applicability of Stimulation Techniques to geothermal environments

Stimulation Technique	Description	Applicability to Geothermal Wells
Matrix Acidising*	Injection of acids below fracture propagation pressure to remove permeability damage within the fracture or the near wellbore area	Reduced Acid Reaction required? Avoid corrosion of Well Construction materials Treatment of selected, smaller intervals requires use of diverters
Hydraulic Fracturing*	Fluids pumped at high pressure and rate so that formation fracture propagation pressure exceeded. . Placeproppant to maintain created fracture flow capacity	High quality, small proppant grain size may be required Resin Coated materials Treat Short fracture interval (economics) Standard liner completion not preferred
Thermal Fracturing*	Injection of cool water into a hot formation to reduce the thermal stresses sufficiently to create new fracture flow channels	"Rule-of-thumb" experience based techniques only. No soundly based, treatment design methodology available.

*Use scale inhibitors to prevent scale precipitation in the newly formed flow channels is an issue common to all methods if large volumes of water injected

Protecting the tubulars against corrosion is another serious challenge. This requires careful selection of acid fluids and inhibitors (Buijse et al, 2000), while cooling the well by injecting a large volume water preflush may reduce the severity of the problem.

2.2 Hydraulic Fracturing

A propped, hydraulic fracturing treatment is performed by pumping specially engineered fluids at sufficiently high pressure into the interval to be treated so that an (often vertical) fracture is opened. Connection of many, pre-existing fractures and flow pathways within the reservoir rock with a larger fracture may be achieved. The final stage of the treatment is the injection of a proppant (usually sand) slurry. This proppant maintains the created fracture flow capacity after relaxation of the hydraulic pressure. The published literature contains only a limited number of successful cases when fracturing high temperature formations. That is probably because hydraulic fracturing of high temperature, naturally-fractured formations places severe demands on the fluid and proppant selection. These include (Entingh, 2000):

- Thermal degradation of fluid viscosifying polymers and cross-linkers preventing effective growth and propping of the hydraulic fractures,
- Excessive fluid leak-off leading to early screen-out and creation of a fracture of inadequate length
- Degradation of proppant by the highly saline produced fluid.

Limited research, specifically for geothermal wells, has been reported, although work targeted at fracturing high-temperature oil and gas reservoirs has suggested the following guidelines :

- Small proppant grain size (20/40 or 30/50 mesh Bauxite) show better performance
- Maximise pump rate and reduce treatment time by using large tubing sizes and higher wellhead pressures
- Increase fluid viscosity by using higher gel loadings

It is conventional geothermal practice to complete wells using slotted liners over intervals as long as 1000 m. Hydraulic fracturing treatments in such environments become very difficult due to the impossibility of controlling the point of fracture initiation. The technical and economic implications of a change of the well completion design to a cemented and perforated casing should be analysed in detail.

2.3 Thermal Fracturing

Thermal fracturing is a stimulation phenomenon that occurs when a fluid (e.g. produced water, seawater, aquifer water or surface water), considerably colder than the receiving hot formation, is injected. Injection of the cooler water leads to thermal contraction of the reservoir rock in the region near the injection well, reducing the stresses. The reservoir can be fractured at a significantly lower pressure than the original, *in situ* stress would indicate, when there is a large temperature contrast between injected water and the formation (Slevinsky, 2002). The occurrence of thermal fracturing during cold-water injection into porous and permeable classic formations is well documented. Suitable rock-mechanical process models have been developed for treatment control and optimization.

The process is less well documented in geothermal production wells. Tulinius et al (2000) report thermal fracturing of such a geothermal well in Guadeloupe in France. A 253°C reservoir was stimulated using seawater mixed with an inhibitor to prevent anhydrite scaling. Production results showed an output increase of 50% compared with original production flow rate. The enhanced production rate made the well sufficiently economically

successful that it was still flowing to an existing power plant one year after the treatment.

Thermal fracturing will not always be a technically suitable solution – for example, if it is required to dissolve material that is blocking the flow of steam e.g. a scale. However, thermal fracturing is very attractive compared to the other options for cases when flow can be restored by the generation of a (relatively) near wellbore fracture network that will (hopefully) reconnect to a main reservoir flow system. The fluids used during Thermal Fracturing are characterised by:

- Benign compared to aggressive acids
- Easy-to-prepare fluid with simple chemistry, especially when compared to a fully-formulated, high temperature, cross-linked fracturing fluid
- Requires mobilization of a minimum of equipment
- High pump pressures not normally required
- Treatment fluids present minimal Health, Safety & Environmental Issues
- Low Cost

Fracture closure is frequently cited as a cause of concern when designing a thermal fracturing treatment, though the productive flow channel had clearly remained open in the case above. Producing the treated well will increase the temperature of the cooled zone, with a consequent restoration of the previous rock stress. This would be expected to reduce the gain in flow capacity, since proppant is not present to keep the fracture open after the treatment. Although strain changes in the rock appear to be controlling the remaining increased permeability, there are no accepted models that describe the fundamentals of this process. The first stages in the development of such a model will be discussed next.

3. COUPLED GEO-MECHANICAL AND FLUID FLOW SIMULATIONS TO DERIVE EFFECTIVE PERMEABILITY

Design of a fracture stimulation treatment tacitly assumes that an un-fractured and continuous rock is being treated. However, in the geothermal case, the rock mass is largely discontinuous, anisotropic and not elastic (Jing, 2003). A rock mass is also a porous medium containing fluids under complex *in situ* conditions of stress, temperature and pressure. Such conditions make the representation of rock behavior by simple analytical relationships unreliable.

This paper briefly describes a novel approach to estimate how pre-fractured rocks might behave during a cooling/warming cycle. This emulates the process that occurs when thermal fracturing is applied to a discontinuous material such as fractured rock. The simulator HYDRO-DDA, which couples flow and geo-mechanical phenomena for a discontinuous material, was used. This simulator was jointly developed by Heriot-Watt University and the University of Glasgow (Couples et al, 2003). The term DDA stands for "Discontinuous Deformation Analysis", which is a type of discrete element approach. HYDRO-DDA allows a calculation of effective flow properties (permeabilities) in a 2D region that result from the combined fluid gradient and mechanical loading of a fractured rock mass.

Unfortunately, HYDRO-DDA does not (presently) explicitly calculate thermal effects. (It was originally developed for civil engineering applications where these are less important.) This limitation was overcome by calculating the thermal strains separately, assuming linear thermal expansion and thermo-elastic behaviour. The mechanical loads were then adjusted to equal the calculated thermal stresses, a process which may approximate what might happen during cooling or warming the rocks. The model provides new effective permeabilities based on the thermal deformation of the rocks and the associated movements of the fracture-bounded blocks. Finally, the resulting effective permeabilities were compared with the original values to determine if there was any improvement in this rock property as a consequence of the thermal cycle and the non-linear motions of the fractured rock mass

Figure 1 shows the initial block configurations studied. These represent a range of natural fracture patterns that might exist prior to thermal deformation. This system was then loaded by imposing a range of stresses, from 0.7 to 56 Mpa, in either the X or Y directions. Fluid pressures across the model were estimated based on a matrix permeability of 10 mD, constant flow rate of 60 l/s, similar to flow rate use during thermal fracturing in geothermal wells in Iceland (Palsson, 2003), and initial downhole pressure of 125 bar (Hydrostatic head of 1200 m TVD=117 bar, WHP = 25 bar, friction loss in tubing = 17 bar). The 1 m by 2 m model was used to represent locations at varying distances from the well by adjusting the loading parameters. **Figure 2** shows the rock deformation before and after applying thermal loading in combination with mechanical loading.

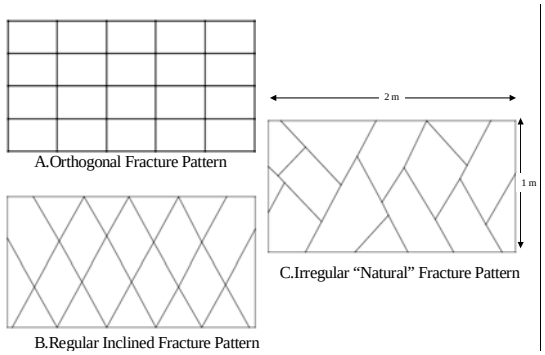

Figure 1: Fracture patterns used for the geo-mechanical modeling in HYDRO-DDA

Table 2 shows the changes in effective permeability at a distance of 28 m away from the wellbore after cold water injection times of up to 10 hours followed by an equivalent warming-up period. The results show a general increase in effective permeability compared to the pre-treatment permeabilities, even after the formation surrounding the well has warmed up again. This suggests that rock movements related to pre-existing natural fracture patterns and the anisotropic stresses, can lead to rock deformations that increase the effective permeability of the system to a surprising extent.

Figure 3 depicts a similar increase in effective permeability at different distances from the wellbore for different cooling/warming times. The regular inclined fracture pattern (Figure 1B), with an initial stress condition of σ_x=32, σ_y=38 Mpa, was used for these calculations. No results are shown for fluid flow in the "x" direction, which might give different effective permeabilities than those discussed here.

In summary, the limited results available to date indicate that the degree of permeability enhancement is a function of injection time, fracture pattern and distance away from wellbore. The available results should be considered qualitatively rather than quantitatively, since the modelling tools used were not overly robust and only fluid flow in the y-direction was considered. However, these results and the scale of the increase in permeability reported here fully support using thermal stimulation as a technically effective treatment technique. Its cost effectiveness will be examined in the next section.

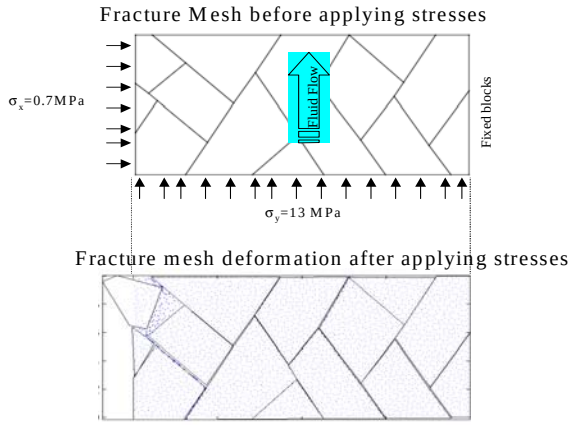

Figure 1: Example deformation before and after thermal cycling as modeled by HYDRO-DDA plus adjustments due to thermal effects.

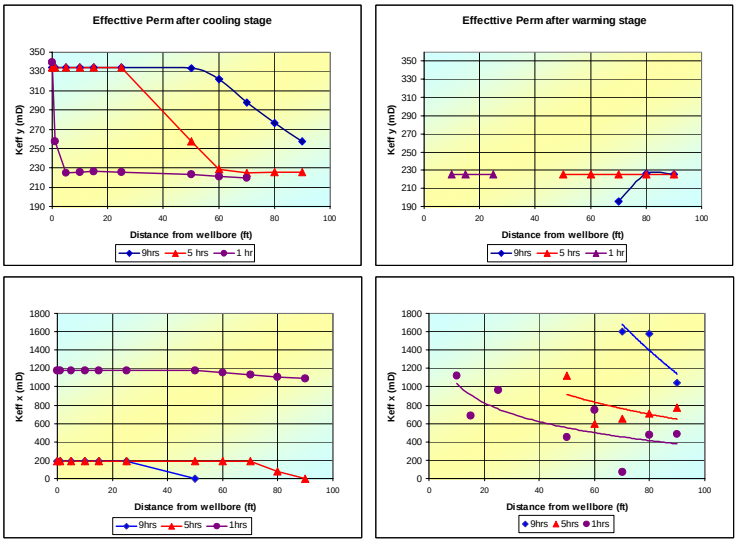

Figure 2: Effective permeability vs. distance from wellbore after different cooling/warming cycles

4. ECONOMIC ANALYSIS

A simple comparative economic study of the three well stimulation techniques was performed within the economic environment of two Power Companies: Comisión Federal de Electricidad (CFE) in México, and Landsvirkjun in Iceland. The analysis concept was to rank the various stimulation techniques in terms of the level of production enhancement necessary to make them profitable in two geothermal areas where operations are carried out under different geological and economic constraints.

Table 2: Summary of Effective Permeability results at 28 m distance from the wellbore after cool fluid injection followed by formation warm-up (OOR stands for Out Of Range)

	Orthogonal Fracture Pattern			Regular Inclinal Fracture Pattern			Irregular Natural Fracture Pattern		
	σx=σy	σx<σy	σx<<σy	σx=σy	σx<σy	σx<<σy	σx=σy	σx<σy	σx<<σy
Mpa	38=38	32<38	20<38	38=38	32<38	20<38	38=38	32<38	20<38
Original K mD	10	10	10	10	10	10	10	10	10
Keff x (cool) mD	375	59	767	0	0	0	749	701	543
Keff x (warm) mD	0	422	OOR	2369	2035	0	OOR	OOR	OOR
%change	*nd*	*4122*	*nd*	*23588*	*20251*	*-100*	*nd*	*nd*	*nd*
Keff y (cool) mD	178	155	165	225	241	280	617	956	1447
Keff y (warm) mD	466	228	OOR	201	216	0	OOR	OOR	OOR
%change	*4564*	*2176*	*nd*	*1912*	*2058*	*-100*	nd	nd	nd

4.1. Economic Parameters in México

CFE typically use (COPAR, 2003) the following parameters for the economic evaluation of technical proposals:

- Discount Rate > 10%
- Median Well life ~ 5 years
- Electricity cost ~ 0.065 US$/ kwh
- Operation & Maintenance Cost ~ 0.015 US$/KWh

This economic analysis will assume that all the stimulation techniques can be applied to CFE operated geothermal resources. It has also been assumed that CAPEX only includes the cost of the stimulation treatment, without taking into account the price of drilling the well, surface equipment and power plant. This implies the well has produced sufficient steam to pay these previous expenses, or they are regarded as a sunk cost which is not considered when evaluating future expenditure. The example chosen is for a problematic field in which the well life is limited to about 5 years due to casing and formation scale. Excessive scaling reduces the production rate (or wellhead pressure) below the minimum values to allow connection to the power station. Different scenarios exist for fields, such as Los Azufres, Los Humeros or Cerro Prieto, where the median lifetime of the wells is 20 years.

A base case (**Table 3**) was developed using the following data from well LV-11 located in Las Tres Virgenes Geothermal Field located in the Baja California Peninsula in Mexico. This well was connected to a 5 MW-condensing power station, supplying 12 t/h of steam at a wellhead pressure of 4.6 bar, coming from a liquid reservoir. Studies of the available data of the well have shown that the well was damaged during drilling due to mud losses (Jaimes and Flores, 2002). The well has contacted a fracture system of 200 m thickness in total. This is separated into three zones, based on FMI and production log spinner surveys. The estimated zero skin or undamaged flow rate is approximately 20 t/h of steam.

A production decline rate in this field averages 5% per year, increasing to 6% per year after stimulation (CFE, 2003).

Dowell Schlumberger did two acid jobs in November 2002 (CFE, contract 9400007822) in this geothermal field. The estimated cost of of acid placed into the reservoir is 2033 US$/m3 . The estimated cost included all mobilisations, chemicals and additives, labour, equipment and personnel needed to perform the acid job.

Table 3: Summary of properties for well LV-11.

PROPERTY	VALUE	UNITS
Reservoir Permeability	7.5	MD
Skin Factor	20	
Initial Total Production Rate	37	T/h
Steam Quality	30	%
Reservoir Pressure	100	Bara
Reservoir Temperature	225	°C
Reservoir Thickness	200	M
Well Radius	0.1078	M
Specific Consumption to power station	0.0095	T/h-kw

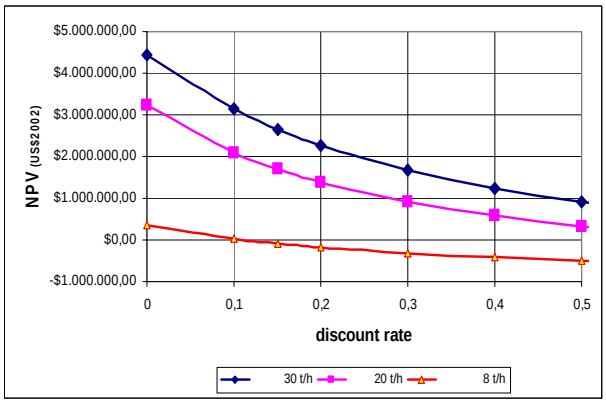

Figure 4. Net Present Value vs. discount rate for different initial increases in steam production

The basic design was to inject 75 gal/ft of mud acid at 10%HCl-5% HF, 50 gal/ft of 10%HCl for preflush and 10 gal/ft in the post flush, followed for the injection of two times the volume of the wellbore with geothermal water to rinse the tubulars and displace the reaction products further away into the formation. A coiled tubing unit of 2 7/8" of diameter was used and two diversion stages were included (foam) to maximise the effectiveness of the treatment.

The procedure to analyse the economics of the treatment is as follow:

Total cost for the stimulation job is the sum of the cost of injected volume of acid plus the production losses during the treatment:

$$cost\ of\ treatment = 2033\frac{US\$}{m^3}V_{acids} + \frac{Q_{lost}}{SC}\frac{0.065\,US\$}{kwh}t_{treatment}$$

Annual Operation and maintenance costs are calculated using the following formula:

$$OPEX = 8760\frac{\Delta Q_{steam}}{SC}\frac{0.015\,US\$}{kwh}$$

Annual revenues due to the increase in steam production is calculated as follows:

$$Revenues = 8760\frac{\Delta Q_{steam}}{SC}\frac{0.065\,US\$}{kwh}$$

Using the economic parameters mentioned before for CFE in Mexico, a cash flow balance was performed for different cases.

Sensitivity analysis to treatment cost, achieved additional production and length of treated interval were also done to see their effect on the economics of the proposal.

A minimum initial increase of ~8 ***t/h of steam*** (~842 kw or 20,210kw-h) is needed to make an acid treatment profitable in Mexico **(**Figure 4**)**. Hydraulic fracturing treatments are more expensive, economic analysis indicates that a minimum initial increase in steam production of ***~18 t/h*** (1897 kw or 45,473 kw-h) is needed to achieve profitability **(**Figure 5**)**. For such economic analysis, prices were taken from statistical costs of hydraulic fracturing treatment jobs in gas and oil wells in Mexico, performed between 2002-2003. It has been estimated a total cost between $12.8 USD/lb and $14.5 US$/lb (PEMEX, contracts TOUSPI-024/02-P and 4140438172)' of proppant placed in the formation. The reference proppant is resin-coated bauxite of 10,000psi of strength and gelled water was used as carrier fluid. The estimated cost includes materials, equipment, power, personnel and design of the treatment job.The procedure to analyse the economics of the treatment is as follow:

Assuming a design fracture conductivity of 1500 mD-ft and a proppant loading of 4 lb/ft2 and a small grain size (20/40 mesh), different quantities of proppant were selected. Their corresponding fracture half-length, dimensionless fracture conductivity and the effective wellbore radius were estimated from Cinco-Ley and Samaniego correlation.

Folds of increase after the treatment were calculated using the following equation. Additional production was computed using the original one and FOI.:

$$FOI = \frac{\ln\frac{r_e}{r_w}}{\ln\frac{r_e}{r_w'}}.$$

Total cost of the stimulation is the sum of the injected proppant plus the production lost during the treatment.

$$cost\ of\ treatment = 14.5\frac{US\$}{lb\ proppant}Proppant Weight + \frac{Q_{lost}}{SC}\frac{0.065\,US\$}{kwh}t_{treatment}$$

Annual Operation and maintenance costs and annual revenues were calculated in the same way as in matrix acidising.

Using the economic parameters mentioned before for CFE in Mexico, a cash flow balance was performed for different achieved fracture half-length. Fixed cost of the treatment were estimated using prices for 2 different jobs and extrapolating to zero proppant plus engineering judgment. It has been found that this fixed cost is on the order of US$845,000

The optimum technical increase in steam production should be that able to achieve a fracture dimensionless conductivities higher than 15, therefore the minimum initial increase of steam production of 18 t/h is required at the optimum fracture half-length of 30 m, being the shorter height fracture of 6 m the most profitable. This steam production is equivalent to 57,600 kwh. For wider height

fractures (60 m), the treatment is economically optimum if the initial increase in steam production is up to 18 t/h and 25 m half fracture length. Initial increases in steam production above that value are possible but requires a much higher investment that might end up in a negative NPV. For the case of 20 m fracture height, the optimum economic initial increase in steam production is 25 t/h and 75m half-fracture lengths.Production rates between 10 and 18 t/h are still economic, but the achieved fracture dimensionless conductivities do not guarantee optimum well inflow performance and therefore this kind of treatment design is not recommended **(**Figure 6**).**

Thermal fracturing will probably always be the low cost treatment option, since only cold water needs to be injected to fracture the formation. In addition, the expenditure for mobilization, equipment, power and personnel will be minimised. A specific procedure to apply this treatment is not available. Field experience suggests that the injection of cold water for 2-4 hours (with the rig pumps, if appropriate) at wellhead pressures of 10-20 bars followed by a warm-up period of 4-8 hours once injection has ceased. This process is repeated for 2-3 days, the well injectivity being closely monitored at all times (Palsson, 2003). The all-in cost of injecting fresh water into the formation is around 25 US$/m^3. Injection of water for 3 days at a flow rate of 150 m^3/h during stimulation treatment will result in a cost of pumped water of US$ 95,000. This type of treatment could, but need not necessarily, be done using the rig immediately after completing the well. The daily cost for renting such equipment has also been included in the analysis. Figure 7 shows the economic analysis for thermal fracturing - an initial increase in steam production of 5 t/h is enough to pay for the project. This technology thus has a considerably lower treatment cost, and hence economic risk associated with it, compared to the alternative stimulation treatment costs.

4.2. Economic Parameters in Iceland

The Krafla geothermal field is currently operated by Landsvirkjun, the national power company of Iceland. The history of the problematic field development is widely known and has been published numerous papers [Paper by A. Gudmundsson]. The Krafla field is located in an active central volcano in Northeast Iceland. After a relatively limited exploration period, development of the 2x30 MW power station started in 1974. However, the project was affected by various difficulties, most importantly being complicated geology and a sequence of nine volcanic eruptions from December 1975 to September 1984. The eruptions and the subsequent seismic activities caused corrosive magma gas to enter the hottest wells, damaging the well tubings and even the turbines. The first 30 MW turbine was commenced in 1978 but it did not reach full capacity until the main drill site had been moved to a lower enthalpy section of the field, in 1980-1985. In the 1990's, the fluid chemistry had re-stabilised and in 1999 sufficient stream had been gathered to eventually start the second 30 MW turbine at a full load.

In total 35 production wells have been drilled in the Krafla drill site, but only 21 are currently connected to the power station and further two serve as injection wells. Many of the production wells are very sensitive and can be killed by minor pressure fluctuations. A summary of the production well performance is presented in table 4. As can be seen, the average well output is near to the known "global average" of 5 MW per well, although the well output of individual wells range from practically 0 MW to 18 MW. Although the annual well production decline is 2,6%, it is only 1,3% if the three worst cases are excluded, all relatively new wells. Still, sufficient power to operate a new 30 MW turbine has been "lost".

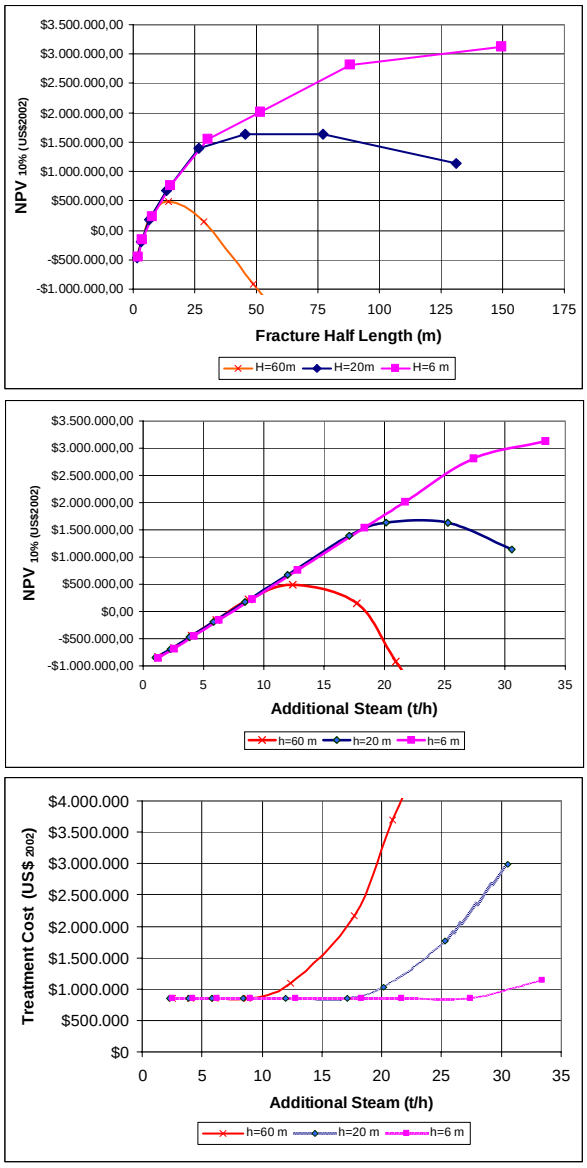

Figure 3 Net Present Value for different fracture half-lengths and initial increase in steam production

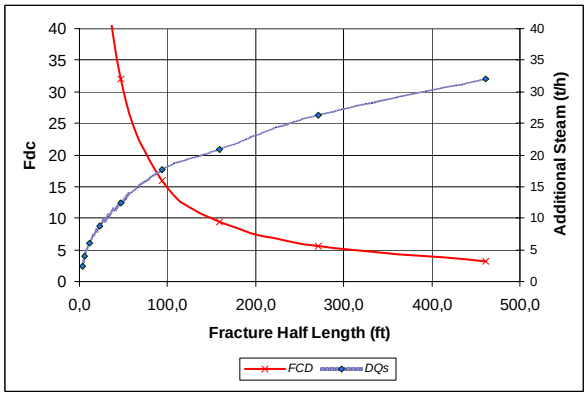

Figure 4. Increases in steam production for different values of the dimensionless fracture conductivity

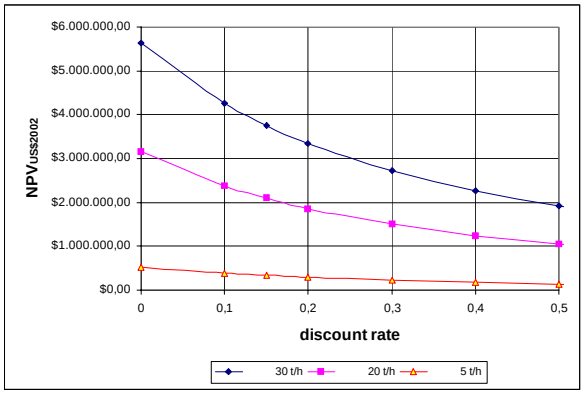

Figure 5. Net Present Value vs. discount rate for different initial increases in steam production due to Thermal Fracturing

Table 4. Performance of the 21 production wells connected to the Krafla Power Station.

	Total	Average
Initial well power	106,1 MW	5,1 MW/well
Present well power	73,6 MW	3,5 MW/well
Years in production	#	16
Decline/well	#	1,5 MW/well
Decline/year	3,2 MW	0,2 MW/well/year
Relative annual decline	#	2,6%/well/year

Landsvirkjun is now looking into methods to secure stream to maintain current production rate and even increase the production capacity to 100 mw by installing the third turbine. The well damage is generally of two sources, iron sulphate and carbonate scaling in tubing and near-wellbore and depletion in excess of the reservoir pressure decline and the options to recover well productivity that have been per reviewed in this paper Until now, recovery attempts have mainly focused on wells suffering from scaling buildup in the production liner. Four to five wells are acid washed every two to five years and occasionally wells plug completely up and the scale has to be drilled out. Neither of these methods can be considered a good long term solution as they can greatly affect the tubing conditions. Acidising is the most commonly applied stimulation treatment in Krafla and the treatments are normally performed by the steam supply operation crew. Acidising typically cost around $20k whereas a scaling drill-out could cost around $150k-$250k, depending on how many wells are bearing the rig transport cost, and therefore acidising is always a preferred option. The type of acid used in Krafla includes HCl, HFl, and mud acid depending on each condition. The main disadvantages are that acids are nasty to handle and if it comes back to surface, it has to be led to the injection flowline. In the long term it may affect the reliability of the well tubings.

Hydraulic fracturing is an option to improve wells with poor reservoir connectivity. , There is limited tradition for "sophisticated" hydraulic fracturing treatments involving proppants, acids etc. in Iceland, but a thermal cycling/fracturing has in recent years become a standard practice when stimulating new wells. Then, cold water is injected in cycles through the drill string to a selected depth in an attempt to break up to formation and open up a fracture that might extend to a natural fracture network. In a recent exploration well drilled for Landsvirkjun, the well injectivity was improved from 2 l/sec to 60 l/s by a four day "thermal cycle" injection, using 2°C cold water.

The availability of fresh water is limited in the Krafla area and the drilling water is normally gathered by damming a nearby stream, which includes both natural water and the condense water from the power station. Therefore, the water is both 30-40°C warm and rich in chemistry. Water from the separation station has been injected to stimulate wells in Krafla resulting in initially good but short lasted production improvements. Well KJ-26, for example, had started as an excellent producer but declined sharply and was eventually disconnected from the steam supply system. However, it serves now as an injection well, accepting 60 l/sec or half of the water from the separation station.

The economic conditions in Iceland are quite different than in Mexico. The Krafla power station employees 17 people and the operating cost, without infill drilling, is estimated around $0.004/kWhr, mostly due to employment cost. Landsvirkjun only sells electricity in wholesale and the electricity price that it considers calculations is therefore of that sort of magnitude, or around $0.02-0.03/kWhr. Landsvirkjun has access to low interest funds and the operation in Krafla is now considered a low risk operation. Therefore, the economic evaluation would consider discount rate of the order of 6-8%.

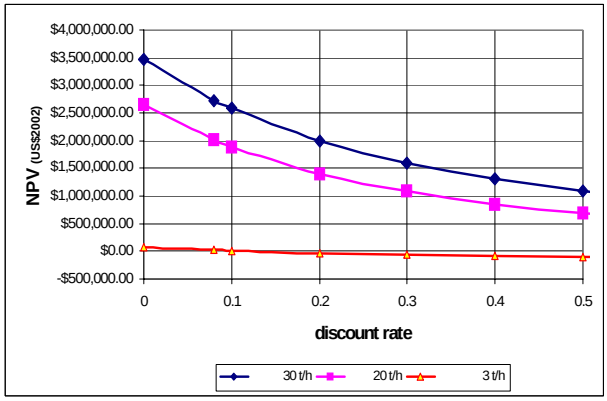

Figure 6. Net Present Value vs. discount rate for different initial increases in steam production due to Acidising in Iceland

Figure 6 shows the Net Present Value for acidising in Iceland. As it can be seen, due to the differences in economic parameters, an acid job can be profitable with increases on production as low as 3 t/h, assuming a pre acid steam production of 11 t/h, similarly to the Mexican case. Of course that when designing such a treatment, 3 t/h of increase should not be taken as the target of the treatment, but larger production should be achieved. Analysis for thermal fracturing and hydraulic fracturing show similar results: smaller steam gain in Iceland wells is enough to pay stimulation treatments if they area completed successfully.

5. CONCLUSIONS

Matrix acidising to clean up existing fractures was found to be fully applicable to geothermal environments, but specific technologies suitable for high temperatures and long

intervals, such as reduced in reaction rate and diversion, needs to be considered to maximise the efficiency of the treatment.

Very limited successful cases were found in fracture and high temperature formations when stimulating the formation with a ***Hydraulic Fracturing*** treatment. This technology has to be tested at geothermal reservoir conditions so that confidence can be gained if its application is essential for the delivery of economic development wells. Specific technical issues such as thermal degradation of fracturing fluids and excessive leak-off leading to an early screen-out, need to be considered.

Thermal fracturing was also found to be fully applicable to geothermal environments. This technique shows great promise as a cost effective treatment for geothermal wells. This is based on the reported field results and the significant changes in effective permeability calculated during preliminary modeling work. Economic analysis showed it to be highly cost effective. The preliminary results indicated that the degree of permeability enhancement is a function of injection time, fracture pattern and distance away from wellbore. However, the available results should be considered qualitatively rather than quantitatively, since the modelling tools used were not overly robust and only fluid flow in the y-direction was considered.

From the economic point of view, it was found that in liquid dominant reservoirs a minimum initial increase of ~8 ***t/h of steam*** is needed to make ***matrix acidising*** a profitable prospect in Mexico, having a payback in less than 3 years. This steam production rate is equivalent to 842 kw or 20,210 kw. Similar economic analysis for the economic parameters in Iceland show that smaller gain in steam production is enough to pay this type of stimulation treatments. Even though the electricity price for sales is lower than in Mexico, the results are basically due to lowest operation and stimulation treatment cost compare with those costs in Mexico.

On the other hand, in Mexico´s projects, the technically minimum initial increase in steam production of ***18 t/h is*** needed for a ***hydraulic fracturing*** treatment, equivalent to 1985kw or 45,473 kw-h. The payback time depends on the designed fracture length since that is related to the cost of the treatment, but for the recommended fracture half-length of 6m and the mentioned additional production, the payback is in one year. Productions between 10 and 18 t/h are still economic, but the achieved fracture dimensionless conductivities do not guarantee optimum well inflow performance and therefore this kind of treatment design is not recommended.

Thermal fracturing so far appears as a very inexpensive and effective treatment, according to the economic analysis and to the coupled flow and geomechanical modelling, however it is still subject of additional research to understand the mechanism that control the permeability improvement.

The most significant results of this work, is related to the changes in effective permeability resulted from the coupled flow + geo-mechanical modeling of cooling/warming cycles in pre existing natural fracture systems. These results are quite intriguing and they demand further and deep analysis to get a better understanding of the physical process involves in thermal treatments.

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