Permeability Enhancement of Conventional Geothermal Wells

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ABSTRACT

All geothermal systems require some degree of permeability to create heat convection and allow transport of this heat from below the earth to the surface. Production and injection capacities depend largely on this permeability hence, a poor or low permeability is a perennial concern of geothermal operators even in highly convective systems.

A review of the existing permeability stimulation techniques, i.e. hydraulic fracturing, thermal fracturing and acidizing have been made including published reports of field and laboratory experiments to understand the mechanism of each technique in improving wellbore permeability. The learning derived from this review will be used as the fundamental basis for the ongoing case study of actual field data where production or injection capacity of wells had been substantially increased (>>100%) with continuous injection of fresh water, cooling tower condensates or waste brine. Effects of pressure and temperature will be investigated using a pressure cell on an actual field core sample while a fluid-rock interaction in a flow-through simulator will be set-up to characterize the specific chemical reactions. Ultimately, the result of this study hopes to generate site specific stimulation program, and produce practicable correlations to predict results.

Presently, this paper summarizes the results of the review, and outlines the works to be done necessary to accomplish the objectives of the ongoing research.

1.0 Introduction

Worldwide geothermal energy development has increased significantly since the first geothermal plant was commissioned in Larderello, Italy almost a century ago. From a few countries that followed including New Zealand and Mexico in the late 1950s, the number dramatically increased to 78 countries in 2010 which reported to have some degree of utilization both for electricity and direct use applications (Armstead 1977; Lund, Freeston et al. 2010). Despite the increase in the installed capacity from 250kW in 1913 to almost 9GW in 2005, the average annual growth of geothermal power has not gone beyond 15.0%, recorded during the second oil crisis in 1979 to 1985, averaging a little less than 5% annually until 2005 (Administration 2008; DiPippo 2008). Vigorous geothermal energy development in the last 5 years, driven by the increasing worldwide demand for power and interest in renewable, green sources of energy has accelerated the growth by at least 20% per year to a total installed capacity of 10.7GW in 2010. Notably, the 21 countries reported in 2000 with installed geothermal plants increased only by 14% to a total of 24 in 2005 and had remained the same until the present (Fridleifsson 2001; Bertani and Lund 2010).

One reason for this relatively sluggish growth is the limited access to geothermal heat around the world. Mostly, places located in regions associated with tectonic plates boundaries and recent volcanism are likely to have hydrothermal resources with temperatures >150°C that can support power generation. Yet, geothermal developments in these areas are still met with difficulties despite availability of new technologies as exemplified by countries such as China, Costa Rica, Mexico, Ethiopia, France, Russia, Portugal, Nicaragua and the Philippines who have been unable to meet the additional plant capacity projections in the past decade (Huttrer 2001; Bertani 2010).

Finding new geothermal prospects has become more complex after the impressive development in the late 1970s to the 1980s, sending exploration farther away to remote areas and triggered renewed interests on previously assessed areas for developmental re-consideration. Subsequently, more geothermal operators have turned to low and medium temperature reservoirs (85°C to 150°C) which are pervasive to generate power with the availability of relatively recent technology of binary power plant systems, i.e. the Organic Rankine Cycle (ORC) and the Kalina Thermodynamic Cycle (Gupta and Roy 2007).

Geothermal development efforts are generally geared towards finding resources where the heat underground can be harnessed for power generation. DiPippo, R., et.al. (DiPippo 2008) cited a number of elements i.e., heat source, presence of fluids, recharge mechanism, a permeable reservoir and overlying cap rock, must be present to make a geothermal resource commercially viable. For new geothermal prospects, most of these elements can be assessed based on surface geology and chemistry of thermal manifestations. Drilling of a well is necessary to access the geothermal resource to validate these surface data. It is usually at this stage where the difficulties are encountered. Because of limited data, exploration wells are prone to miss permeability targets causing their failure to flow. Permeability of geothermal reservoirs is supplied by networks of fractures, fault structures and lithologic contacts. If these are not intersected by the wellbore, transport of heat-bearing fluids to the surface is impeded.

Even in well-developed geothermal fields in highly convective systems, drilling of make-up and replacement wells, especially in the outer boundaries of the resource, often fail to intersect sufficient fracture networks necessary for steam extraction or brine re-injection. In such cases, the open section of the wellbore lies at some distance from the major fault structures resulting in a low permeability well or there is significant damage to permeability. This has become a perennial concern and a costly one, as geothermal operators almost always tend to rely on drilling of new wells or to re-drills as a remedy (Brown 1983).

2.0 Well Stimulation Techniques

Permeability stimulation techniques from the petroleum industry have been adopted for geothermal application as cheaper alternatives to drilling and re-drill. It provides a means to remedy and/or improve connection of the wellbore with the natural fractures or faults in the reservoir to improve permeability. Stimulation techniques, in the petroleum industry, have been in use for more than a century with the primary objective of improving the economic viability of the resource by increasing the formation delivery rate of hydrocarbons.

Acid injection, known also as "acidizing", and hydraulic fracturing are the two stimulation techniques predominantly in use. Thermal fracturing, a relatively new technique used in stimulating geothermal wells shows promising potential of success notwithstanding the inadequate understanding of the mechanism of how it works. These stimulation techniques will be discussed extensively in this paper partly for their cost effectiveness relative to well drilling and re-drill, and partly because these are of interest to the current study. Other well stimulation techniques, with application proclivity towards geothermal operation, will also be presented briefly including "novel and advanced" technologies which are still at the infancy stage of development.

2.1 Acidizing

The history of well stimulation in the petroleum industry in general, and acidizing in particular are well documented. Acid injection is the oldest well stimulation yet still in use in modern times that predates hydraulic fracturing by about half a century. Herman Frasch, the chief chemist of the Solar Refinery of the Standard Oil Company was credited for the development of the acidizing technique when he proposed the use of hydrochloric acid (HCl) to treat oil wells as far back as 1895 (Kalfayan 2008). Despite significant success, acidizing did not gain popularity due to the intrinsic corrosion problem affecting the wellbore casings. It was only in 1932 that the use of acid was again attempted when Grebe and Stoesser of Dow Chemical Co. discovered arsenic as a corrosion inhibitor. Since then commercial acidizing in the petroleum industry has begun resulting to an average increase in production by 412% in the US (Economides, Nolte et al. 2000). The acidizing technology had advanced through the years with the development of additives, methods, and systems to address varied problems relating to acid injection, and to improve zone coverage during the acidizing process (Economides et al. 2000).

The use of acidizing as a well stimulation in the geothermal industry has come much later. The earliest documented and perhaps the first application of chemical stimulation was in 1977 when sodium carbonate solution (Na_2CO_3) was used to dissolve quartz in the Fenton Hill Hot Dry Rock project in New Mexico, USA in attempts to reduce flow impedance (Mortensen 1978). This was succeeded by acid etching treatment of conventional geothermal well Ottoboni State No. 22 in early 1981 at the Geysers Geothermal field in California designed to create new conductive flow paths to the main reservoir. An acid stimulation on the Batz well of the Beowawe Geothermal field followed in November 1982 and later in 1984 on another well which resulted to a 2.2 fold increase in the injectivity (Campbell, Morris et al. 1981; Portier, André et al. 2007). Since then, acid stimulation has gradually gained popularity with recent successful treatments on wells in Ahuachapan, Berlin and Momotombo geothermal fields in Central America (Gomez, Pachon et al. 2009), in Bacman, Leyte and Tiwi geothermal fields in the Philippines (Malate 2003), in Salak geothermal field in Indonesia, in Los Azufres, Mexico and Larderello, Italy (Portier, Vuataz et al. 2009). Reported improvement in the wells' injectivity varied from 40% to >300% increase from the original values.

There are two popular acidizing treatment techniques being used in the petroleum industry namely,1) matrix acidizing and 2) acid fracturing, also known as "fracture acidizing". The major difference between the two is the pressure at which acid is pumped into the formation relative to the "fracturing pressure" of the reservoir formation.

2.1.1 Matrix Acidizing

In matrix acidizing, acid treatment is injected at pressures below the formation fracturing pressure designed to remove skin damage caused by mud cake and cement during drilling operations, and other formation damage that may occur during well operation (Portier et al. 2007; Kalfayan 2008). From Darcy's equation of a steady-state liquid flow in a radial reservoir, shown below, the production rate is directly proportional to the permeability term *k*, and inversely proportional to the skin, *s*. These two variables, i.e. permeability and skin can be measured from pressure-transient tests

$$q = \frac{2\pi kh}{s\mu B}(p_r - p_w) \qquad (1)$$

where q = production rate
k = permeability
h = thickness
p_r = reservoir pressure
p_w = well flowing pressure
B = formation volume factor (reservoir vol/production vol)
μ = fluid viscosity
s = skin (dimensionless)

Equation (1) demonstrates the effect of skin damage to the permeability of the well and hence, to its productivity. It is therefore important to assess the formation damage before any acid treatment is conducted. Aside from skin damage, the presence of mineral deposits within the production liner and around near-wellbore formation is of interest in the stimulation of geothermal wells particularly in the acid treatment of re-injection wells. In such cases, the mud acid dissolves the mineral deposits, i.e. silica scales, plugging the natural fractures that impede the flow of brine into the reservoir.

Matrix acidizing in geothermal wells is usually conducted in three stages (Malate 2003):

1. Pre-flush – usually 5 – 15% concentration hydrochloric acid (HCl) is injected designed to dissolve carbonate minerals in the formation which would react with the hydrofluoric acid (HF) present in the main flush to form insoluble calcium and magnesium fluorides.
2. Main-flush – is a mixture of HCl and HF known as "mud acid". A 10% HCl and 5% HF is the usual concentration used in geothermal well stimulation. HCl is effective in dissolving limestone and dolomites while HF is effective

in dissolving siliceous minerals such as clays, feldspar and silica sands.

3. Post-flush (also known as Over-flush) – serves to push the main-flush acid mixture further away into the formation and minimize inevitable precipitation reactions from taking place near the wellbore. In oil well stimulation, weak hydrochloric acid (HCl), ammonium chloride, diesel oil (for oil wells and only following a water or weak acid overflush) and nitrogen gas (for gas wells and only following a water or weak acid overflush) are usually used (Economides et al. 2000). In geothermal well stimulation however, it is a common practice to use fresh water as over-flush.

2.1.2 Acid Fracturing

Acid fracturing or "fracture acidizing" is designed to stimulate undamaged formation conducted above the formation fracturing pressure. Acid is injected to create fractures or injected into a fracture created by a viscous fluid, e.g. gel known as a "pad". Conductivity of the fracture is retained by the asperities of the fracture surfaces resulting from the dissolution etching of the passing acid (Kalfayan 2008).

Acidizing of geothermal wells is related to sandstone acidizing as most geothermal reservoirs are associated with andesitic or silica-based formation. However, actual field practice does not follow strictly the matrix acidizing concept as acid injection is usually conducted at high pumping pressures regardless of the formation fracturing pressure, and at relatively high rates because of the need to extend the reaction process beyond the wellbore. One advantage of acidizing geothermal wells over oil and gas wells is the high production flow rates that makes it unnecessary to dissolve all mineral deposits during stimulation. Un-dissolved precipitates loosened or softened by the acid reaction are usually cleared out during flow back.

Fracture acidizing, as a means of extending or creating new fractures, has been very seldom if tried at all in geothermal reservoirs. The high temperatures and the highly consolidated nature of the geothermal formation limits the penetration of the live acid deeper into the formation resulting to relatively shorter conductive flow paths or channels as maybe in the case of the unsuccessful acid etching stimulation of the Ottoboni State No. 22 well at the Geysers geothermal field (Campbell et al. 1981).

2.2 Hydraulic Fracturing

Hydraulic fracturing evolved from the acidizing technology when Grebe and Stoesser (1935) observed that the formation "lifting pressure" was sometimes obtained during acid injection, indicating that the formation was also being fractured. It is closely related to acid fracturing having the same fracturing objectives of creating long, open, conductive channels beyond the wellbore extending deeper into the formation, and basic principles of fracture propagation. The difference lies on how the fracture is created and maintained. Acid fracturing depends on the dissolution etching to create fractures and rely largely on the resulting asperities on the fracture surfaces to maintain conductivity.

The fracturing process involves exerting hydraulic pressure on the rock formation until the formation fracturing pressure or "breakdown pressure" is overcome (Adachi, Siebrits et al. 2007; Guo, Lyons et al. 2007). It is usually conducted in two stages:

1. Pad Stage – only the hydraulic fracturing fluid, mainly water is injected into the well to breakdown the formation and initially create a fracture and to sufficiently reduce fluid loss into the immediate wellbore formation in preparation for the succeeding injection stage.
2. Slurry Stage – once pad stage is completed, the slurry, a mixture of the fracturing fluid and propping solid material called "proppant" is injected into the wellbore and into the fractures.

Upon the creation of hydraulic fractures, leak-off of the fracturing fluids into the formation increases, and when the pumping rate is maintained higher than this fluid-loss rate, fracture propagation continues to open new formation area. The new fractures are kept open by the fracturing fluid pressure until pumping is stopped causing the fractures to close and render the newly fractured formation unavailable for production (Economides et al. 2000). Closure is prevented by the proppant usually sand, bauxite or ceramics spheres that is mixed into the fracturing fluid injected during the slurry stage.

Three hydraulic fracturing concepts exist in stimulating tight oil and gas wells which depend on rock, formation and fluid properties (Reinicke, Rybacki et al. 2010), namely:

1. Hydraulic Proppant Fracturing (HPF) – this is the conventional method which uses highly viscous gel as fracturing fluid with high proppant concentration to create conductive yet relatively short fractures in porous matrix formation suitable in reducing permeability impairments (i.e."skin") in the direct vicinity of the wellbore. The well is shut after the fracturing process to allow the fractures to close on the proppants in place.
2. Water Fracturing (WF), "Self-propped Fracs" or "Water Fracs" – use of water containing friction-reducing chemicals partially added with low proppant concentration as frac fluid to create long and narrow fractures to connect the wellbore, which is at some distance from the main reservoir. The "upropped fracture conductivity" induced by the water fracturing stimulation is maintained by the self-propping ability of the reservoir rock.
3. Hybrid Fracturing or "Hybrid Fracs" – is a combination of fracture stimulations using different gels and slick water fluids as the fracturing fluid. This concept utilizes the advantages of the HPF and WF in creating the fracture geometry and in the effective placement of the proppant into the far-end of the induced fracture.

It has been proven that water fracturing performs as much as the conventional hydraulic proppant fracturing albeit at a lower cost, in improving well performance in a comparative evaluation of the two fracturing stimulations in wells in the East Texas Cotton Valley (Britt, Hager et al. 1994; Mayerhofer and Meehan 1998). Although proven successful in improving well production, these hydraulic fracturing methods are not without problems.

Hydraulic proppant fracturing stimulations are prone to leave gel residues or may result to precipitation of minerals that may affect the performance of the stimulated well (Reinicke et al. 2010). Since water fracturing stimulations are dependent on the self-propping ability of the reservoir formation, fracture closure is likely to occur rapidly as a result of pressure solution processes at the asperities that are essential in keeping the hydraulic fractures from closing. Also, the low viscosity of water makes it difficult to effectively transport proppants into the newly created hydraulic fractures. Hybrid fracs usually inherit the same problems as the parent frac methods where they are developed.

Experiments studying the mechanism of water frac and that of the conventional hydraulic proppant frac (Fredd, McConnell et al. 2001) confirmed that fracture displacement is necessary for surface asperities to provide residual fracture width and sufficient conductivity. The presence of proppants increases fracture conductivity, i.e. proppant-dominated, and reduce the effects of formation properties. The success of water frac is largely controlled by formation properties to provide the necessary conductivity, which are difficult to predict.

In naturally fractured reservoirs such as tight, fissured oil and gas formation, problems of excessive leak-off resulting to low propagation of hydraulic fractures has to be resolved before any fracturing stimulation can be done (Warpinski 1991; Britt et al. 1994). Excessive leak-off usually results to poor propagation of hydraulic fractures. Geothermal reservoirs are generally associated with natural fractures and faults to provide the necessary permeability. Hot geothermal fluids are accessed from the reservoir by intersecting the wellbores into these natural fracture networks and structural faults to generate production. Hydraulic fracturing treatments in geothermal reservoirs is generally performed to connect these natural flow paths to the wellbore hence leak-off is not a problem but a good indication that significant connection has been attained. Geothermal well completion using slotted liner over long interval of open hole section however makes it difficult to control the point of fracture initiation (Flores, Davies et al. 2005).

Grant and Bixley, (2011) proposed that fracture initiation during hydraulic fracturing treatments in geothermal wells occurs most likely just below the production casing shoe (PCS) where the fracturing pumping pressure will overcome the formation fracturing gradient. The exact location nonetheless depends on formation geology or on the presence of existing natural fractures (Grant and Bixley 2011). Hydraulic fractures tend to orient vertically (Fink 2011) upward owing to the excess fracturing pressure above the point where fracture initiation occurs. The successful fracturing treatment done in wells at the Nigorikawa Geothermal fields in Hokkaido, Japan closely demonstrates this concept (Niitsuma, Nakatsuka et al. 1985).

Published reports of hydraulic fracturing treatments of geothermal wells have been very limited. Fracturing experiments conducted at the Raft River in Idaho in 1979, at the Imperial Valley, East Mesa, California in 1980, and at Baca, New Mexico in 1981 are the earliest records of this stimulation method (Entingh 2000) where remarkable post – frac treatment improvement were achieved, particularly in the case of the East Mesa wells.

By about the same period, wide-ranging experimental works were also conducted to evaluate the effectiveness of hydraulic fracturing in stimulating hot dry rock systems (HDR) or engineered geothermal systems (EGS) to create artificial fractures that will provide the necessary permeability to mine the heat from the rocks. Considerable amount of literatures can be found describing the results of previous and recent experiments in the HDR and EGS systems in the US at the Fenton Hill, New Mexico (Mortensen 1978; Duchane and Brown 1995; Murphy, Brown et al. 1999), and Coso, California (Rose, Sheridan et al. 2005), and at Soultz-sous-Forets, France (Baria, Baumgärtner et al. ; Durst and Vuataz 2000; Dezayes, Genter et al. 2005; Schindler, Nami et al. 2008).

Similar studies have been pursued in Japan (Matsunaga, Niitsuma et al. 2005), Germany (Rummel and Kappelmeyer 1982), and Australia (Wyborn, de Graaf et al. 2005). Growing interest in HDR and EGS have triggered recent efforts to assess potential prospects in India (Chandrasekharam and Chandrasekhar 2010), Korea (Lee, Park et al. 2010), United Kingdom (Law, Batchelor et al. 2010), Lithuania (Sliaupa, Motuza et al. 2010) and the Philippines (Bayrante, Caranto et al. 2010).

The limited research on hydraulic fracturing stimulation for geothermal application consequently resort to the use of fracturing techniques designed for the oil and gas reservoirs notwithstanding the high-temperature environment of the latter (Flores et al. 2005). This technical drawback was exemplified in the 3-well hydraulic proppant fracturing stimulation conducted at the Leyte Geothermal Production field in the Philippines using viscous gel which resulted to only average improvement of the injection capacities of two of the wells. The third well showed no improvement (Malate, 2003). Despite the lack of an industry-specific procedure, brute-force fracturing treatments in geothermal wells have been undertaken usually after completion of tight wells as practiced in Iceland, in the Philippines and elsewhere in attempts to enhance permeability.

2.3 Thermal Fracturing

Thermal fracturing stimulation is a variation of the conventional hydraulic fracturing concept but differs in the way of initiating hydraulic fractures. Instead of the hydraulic pressure “breaking the rock formation” by overcoming the formation fracturing pressure, thermal fracturing relies on the thermal contraction induced by significant temperature difference between the cold fracturing fluid against the hot rock formation to create new fractures. Thermal cracking is attained by alternately injecting cold fluid, i.e. cooling tower condensate, fresh water, seawater or cold waste brine and then shutting the well to generate contraction of the formation as the well thermally recovers. The pumping pressure is relatively low so as not to cause hydraulic fracturing. Yet productivity improvements have been achieved even if the warming stage has been excluded as experienced by the continuous river water injection in wells at Rotokawa, New Zealand (Siega, Grant et al. 2009).

Although the mechanism of cold water stimulation is still poorly understood (Grant and Bixley 2011), a number of injection tests have already been reported recently in Borinquen, Costa Rica (Zúñiga 2010), in Los Humeros, Mexico (Flores-Armenta and Tovar-Aguado 2008), in Sumikawa, Japan (Kitao, Ariki et al. 1990), in Salak, Indonesia (Yoshioka, Pasikki et al. 2009). In all these reports, the injectivity index and hence the productivity of the well had improved.

Similar occurrence had been experienced in a number of geothermal fields operated by EDC in the Philippines while injecting cold waste brine or cooling tower condensates into injection wells as part of the company's environmental policy. A newly completed low permeability injection well was stimulated by pumping large volume of fresh water >25 BPM at high pressures for a few days with little or no improvement in the well's injectivity. However, subsequent prolonged injection of cooling tower condensates in a span of at least 3 months albeit at lower flow rates of <10BPM, resulted in a remarkable increase in the injection capacities much greater than 100% of the original value.

2.4 Other Geothermal Stimulation Techniques

Other well stimulation techniques to improve well permeability have been cited by a number of literatures including casing perforation (Malate 2003), explosive propellant stimulation, acoustic stimulation, electric stimulation (Chu, Jacobson et al. 1987; Tambini 2003).

1. Casing perforation – a stimulation technique designed to access cased-off permeable horizons by perforating the well casing. These horizons are typically found at the shallow depths of the reservoir and usually indicated by a characteristically high temperature. Further evaluation is performed based on drilling circulation losses, geology and petrology of the formation prior to the conduct of the perforation job.
2. High Energy Gas Fracturing (HEGF) or Explosive Stimulation - creates the breakdown of the formation at the same time improves clean up of the perforations. High gas wave generated from the vaporizing propellant called as the deflagration crushes the formation damage creating small fractures near the perforation channel. When pressure dissipates, the gas surges back carrying back the fine particles from the formation.
3. Acoustic Stimulation (Active Cavitation and Ultrasonic) – use of the simple ultrasonic wave source has been proven in everyday life in the removal of scale of potable water filters or dentist's apparatus. In geothermal application, the interaction between the acoustic field and the saturated porous rock made it possible to cause changes in the permeability or removal of plugging materials.
4. Electric Stimulation – uses electric current to stimulate the well. The effect could either be electrothermal or electrodynamic type. The electrothermal effect is evident in the near wellbore zone during heating with infrared or high frequency or microwaves. The electrodynamic effects create a cleaning of the bottom hole formation zone from clay particles restoring or improving the well permeability (Baterbaev, Bulavin et al. 2002).

Most of these novel stimulation techniques however are still on the infancy stage of development and requires more research before they can be tested in a wider scale.

3.0 Discussion

Several fluid-rock interaction and pressure cell experiments have already been conducted in the past to investigate the effects of conventional hydraulic fracturing on well and formation permeability under hydrothermal conditions.

Water-Rock interaction (WRI) analysis have shown the effect of temperature on the fluid and mineral reactions, i.e. dissolution-precipitation (Mountain 2011) and its effect on fracture aperture growth (Yasuhara, Polak et al. 2006). Tri-axial Pressure cell experiments have established that confining pressure and fracture displacements have significant effect on formation permeability (Watanabe, Hirano et al. 2004). This was corroborated by an earlier tri-axial cell experiment on shear displacement-induced dilations which lead to enhanced fracture permeability even at high normal stresses (Chen, Narayan et al. 2000).

Below are some of the information taken from the literature review particularly on hydraulic and thermal fracturing stimulation methods, viz:

1. Hydraulic fractures tend to orient itself such that the fracture plane is perpendicular to the minimum compressive stress and that the minimum stress state deep underground is horizontal, hence the fracture will in general be vertically oriented (Lam and Cleary 1987).
2. Formation Fracturing Pressure or the Breakdown Pressure or Fracture Gradient is the pressure at which the rock will fracture (Guo, Morgenstern et al. 1993; Grant and Bixley 2011); the fracture gradient can be determined from a "leak-off test" during drilling.
3. Hydraulic fractures tend to cross pre-existing fractures only under high differential stresses and high angles of approach; to be most effective these should cross and connect the natural fracture system, but it is possible that arrest, diversion, or offset could occur thus inhibiting fracture growth (Blanton 1982).
4. The permeability of a fracture to the flow of fluids is a product of two factors namely, aperture or fracture opening and tortuosity resulting from the number of points of contacts between asperities (Walsh 1981).
5. The effect of fluid-rock interaction on fracture permeability is dependent on the type of rock formation and the fluid used as permeant, and other factors as temperature and stresses. The separate experiments on the injection of cold brine in the Soul-sous-Forets EGS (André, Rabemanana et al. 2006), and distilled water on an Arkansas Novacolite (Polak, Elsworth et al. 2003; Yasuhara et al. 2006) demonstrate the distinct effects of any particular fluid-rock interaction.
6. The rate of fracture aperture reduction increases as temperature and applied stress increase. The dependency of aperture reduction rate on stress is roughly linear: doubling the effective stress roughly doubles the closure rate (Yasuhara, Elsworth et al. 2004).
7. The success of a water-fracturing treatment will be highly dependent on formation properties such as the degree of fracture displacement, the size and distribution of asperities, and rock mechanical properties. Fracture displacement is required for surface asperities to provide residual fracture width and sufficient conductivity in the absence of proppants (Fredd et al. 2001).
8. Effect of Thermal Stress – cooling gives rise to tensile stress components which will decrease the internal fluid pressure required for hydraulic fracture. In extreme cases, the sum of thermal and regional stresses can become tensile to the point of exceeding the tensile strength of the rock, even without internal pressurization of the hole. In contrast, heating induces compressive stresses near the borehole wall, and the internal pressurization needed to overcome the sum of regional and thermal stresses is correspondingly higher. In extreme cases, these compressive stresses could match the uniaxial (or

biaxial) compressive strength of the rock (Stephens and Voight 1982).

9. Permeability of a fracture decreases with increasing confining pressure. Fractures with lateral displacement as small as 1mm can significantly increase the permeability however at high confining pressures fracture permeability decreases abruptly. For larger lateral displacement, i.e. 3mm, permeability does not decrease, and remains large even under high confining pressure (Watanabe et al. 2004).
10. Shear dilation angle is litholigy and stress dependent, and decrease almost linearly with increasing confining pressure. Shear displacement, repeated loading and unloading processes, and high normal stresses could cause damage to fracture surface, i.e. crushed fracture asperities causing considerable reduction in fluid flow channels and hence, fracture permeability (Chen et al. 2000).

Actual thermal fracturing stimulations conducted in Salak, Indonesia, Los Humeros, Mexico, Sumikawa, Japan and Bouillante, Guadalupes, and the cold injection tests in Rotokawa, Kawerau, New Zealand, Borinquen, Costa Rica as well as unpublished reports from similar tests in a number of geothermal fields in the Philippines have confirmed remarkable increases in the injectivity or productivity of the stimulated wells. Notably, the effectiveness of this stimulation technique has been prolific despite the diverse geological settings of the fields tested and chemistry of the injected fluid, not to mention the apparent dissimilarity in the injection methodology.

Experimental studies on thermal fracturing in a laboratory scale have been very scarce. Basic questions like, "Which injection fluid is most effective?" or "How long a heat-up or warming of the well formation should be undertaken for an effective fracturing?" need to be addressed. Obviously, a lot more questions than those stated above must well be understood for an effective and scientific approach to this fracturing technique. The proposed laboratory experiments hopes to gain some insights into the mechanism of thermal fracturing particularly the initiation of fractures and the role of the chemical reactions during the stimulation process.

4.0 Permeability Enhancement – A Case Study of Cold Cooling Tower Condensate Injection in the Southern Negros Geothermal Production Field, Philippines

Normally, a geothermal power plant generates steam condensates that mixed with fresh water at the cooling tower. The amount varies with the generating capacity of the turbine and the power plant operating conditions. Cooling tower condensates may contain minerals that are hazardous to the environment hence the need for proper disposal usually through an injection well.

This is exemplified by an injection well in the Southern Negros Geothermal Production field drilled purposely to dispose 60 kg/s of cooling tower condensates from the 112.5MW Palinpinon 1 Geothermal Plant. The well was drilled deep north-northeast of the Ticala RI sector towards the edge of the reservoir boundaries to intersect inferred permeability of three structural faults (Figure 1). Another good reason for choosing this particular target is to inject the cold condensates farther away from the production sector to keep the reservoir equilibrium between effects of pressure support, drawdown and injection returns (Malate and Aqui 2010).

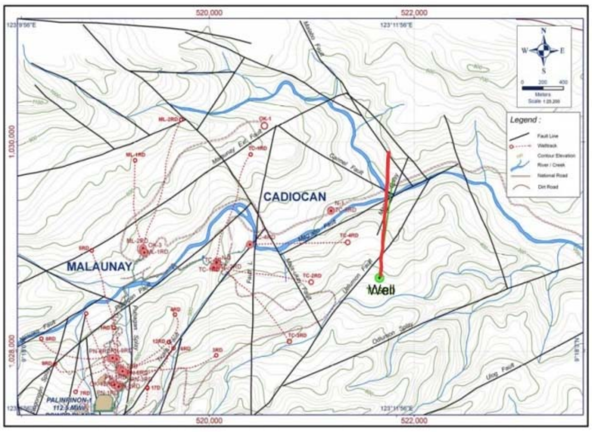

Figure 1: Palinpinon-1 Structural Map Showing the Condensate Injection Well Target

4.1 Hydraulic Fracturing and Well Completion Results

The well was completed to a total depth of 3033mMD after drilling was extended to bottom out all three target faults. The absence of total circulation losses (TLCs) based on drilling records suggested poor well permeability. A hydraulic fracturing stimulation using fresh water preceded the completion test. Increasing injection rates from rig pump rate of about 8BPM to a maximum of 25BPM in a span of two days induced little or no improvement in the well's permeability as reflected by the increasing WHP with increasing pump rate (Figure 2).

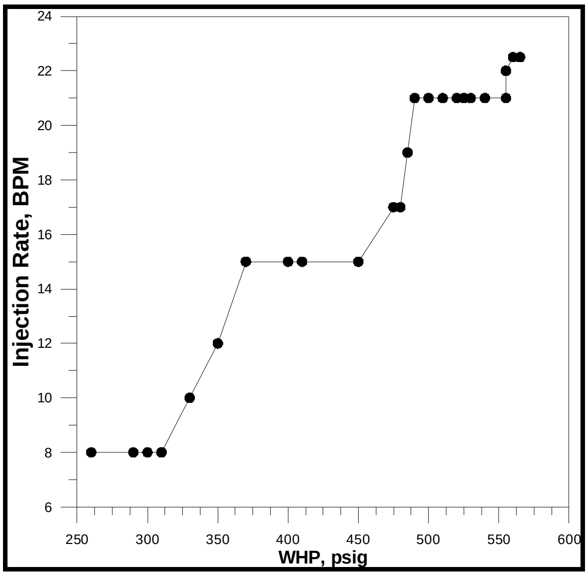

Figure 2: WHP vs Injection Rate During HydroFrac

Higher injection rate was not attained due to fresh water availability and rig pump capacity limitations. The subsequent completion tests indicated three distinguishable permeable yet relatively tight zones confirmed by a relatively low injectivity index of 13.0 l/s/MPa (Figure 3). The injection capacity estimate of about 16kg/s based on an operating pressure of 1.2MPag closely matched the actual acceptance of the well of ~19kg/s.

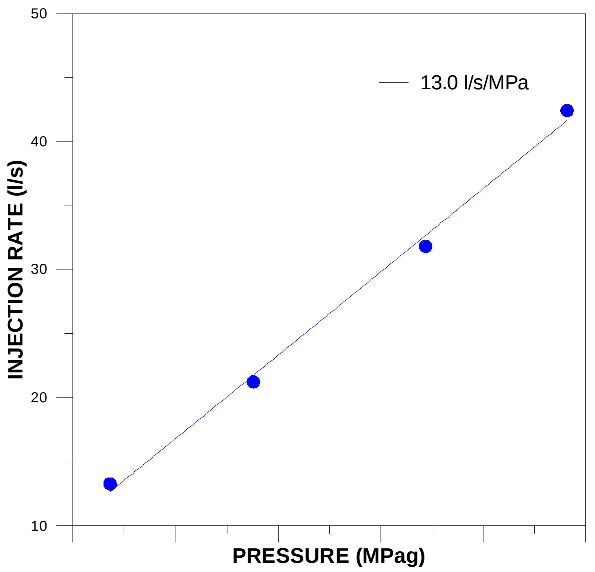

Figure 3: Post-Fracturing Injectivity Index

4.2 Injection Capacity Trend

The well was put on-line to partially dispose cooling tower condensates as part of the company's Zero Condensate Disposal system. Condensate fluid from the cooling tower is conveyed by gravity through a combination of high density polyethylene (HDPE) pipe and 13 – 3/8" pipe to the well about 160m below the elevation of the power plant. To prevent bursting of the HDPE pipe, the well head injection pressure was kept no more than 1.2 MPag.

The initial flow rate of 19.0kg/s gradually increased with continuous injection of the condensates at a daily average of 0.3 kg/s based on the acceptance of the well with time (Figure 4). The wells acceptance has increased significantly from its initial value of 19.0kg/s to 57.0kg/s after almost 5 months of condensate injection, attaining almost the 60.0kg/s target capacity. From the plot, it is evident that the well can still accept more fluid however the preventive maintenance shutdown of one of the turbo-generators reduced the volume of condensates at the cooling tower hence the well could not be tested further at higher injection rates.

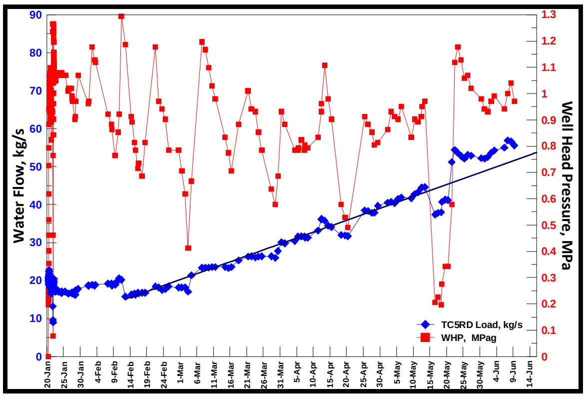

Figure 4: Condensate Injection With Time

4.2.1 Experimental Methodology

The slow yet continuous injection of cold cooling tower condensates that gradually increased the capacity of the well implies a different mechanism in creating artificial fractures than the effect of brute force hydraulic fracturing stimulation usually employed to stimulate tight wells. Evidently, the combined effects of temperature, hydraulic pressure and chemical reactions that occur during the injection could have been the reason for the observed improvement in the permeability of the injection well. The study will therefore focus on these three parameters that are involved in the stimulation process. In-situ conditions at the reservoir formation, i.e. pressure, temperature and chemical reaction will be investigated in a laboratory setting in an attempt to understand the mechanism of how injection of cold fluid, and formation warming cycle can improve well permeability in general and in creating artificial fractures in particular.

A core sample representative of the geology of the local formation where the well was drilled, and an equivalent cooling tower condensate was used. Due to the unavailability of a pressure cell that can incorporate all three parameters, separate experiments are conducted for the chemical reaction and for the physical effects. Crushed rock sample has been tested in a hydrothermal apparatus (flow-through simulator) at the Geological and Nuclear Sciences (GNS) Wairakei laboratory in Taupo, New Zealand to characterize the fluid-rock interaction while permeability measurements will be conducted in a tri-axial pressure cell at different pressure and flow conditions.

4.2.2 Fluid – Rock Interaction

The hydrothermal apparatus (Figure 5) simulates fluid-rock interaction under geothermal conditions up to a maximum operating pressure and temperature of 500 bars (50MPag) and 400°C, respectively. A double-piston metering pump ensures a continuous, one pass flow through a 15 cm^3 sample holder inside an externally heated pressure vessel which can hold a rock core or crushed rock sample at flow rates between 0.001 ml/hr to 15ml/min. A Ti-separator contains the pore fluid which is forced through the rock sample by a second medium, in this case, distilled water separated by a diaphragm and under pressure by the metering pump. The reaction effluent is collected by an airtight syringe inserted into the back pressure regulator (Mountain 2011).

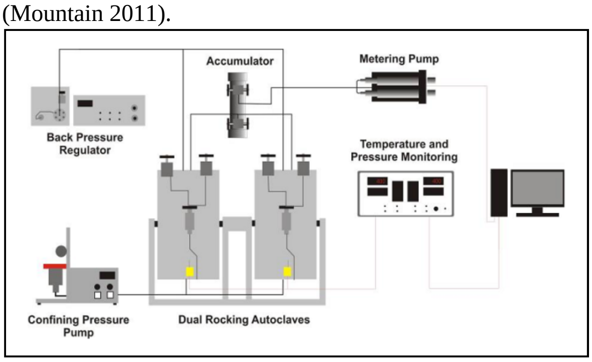

Figure 5: GNS Hydrothermal Apparatus (after B. Mountain, 2011)

For this experiment, the andesitic rock sample was crushed using the ring mill and sieved. A 27.7 gram crushed rock sample was washed with distilled water using an ultrasonic bath and oven-dried before it was placed inside the 15 cm^3 core holder of the autoclave. An X-Ray Diffraction (XRD) analysis was also run to define the mineralogy of the rock core sample. Also, the chemistry of the cooling tower condensate was analyzed. To prevent oxygen from the fluid-rock interaction, the condensate was de-oxygenized prior to injection by bubbling it with nitrogen gas. The pre-WRI data are shown in Table 1 below.

Table 1: Pre-WRI Chemistry and Experimental Parameters

Crushed Rock Sample (Andesitic rock)	
Size	0.5 – 1.0 mm
Sample Weight	27.7 grams
Mineralogy *(based on XRD analysis)*	Albite ($NaAlSiO_2$) Quartz (SiO_2) Clinochlor ($MgAlFeSiO_2$) Calcite ($CaCO_3$) Pyroxene
Cooling Tower Condensate (pore fluid)	
Injection rate	1 ml/min
pH	7.8
H_2S	blank
Experimental Parameters	
Pressure	200 bars
Temperature	230 °C
Test duration	30 days

As of this writing, the WRI experiment is still ongoing.

4.2.3 Permeability Measurements

A standard 61mm diameter tri-axial pressure cell will be used. The apparatus was designed for loading rock samples under confining and axial pressures, and measures permeability and fracture volume.

The proposed experiment will test a 61mm diameter sample, re-cored from the original 100mm diameter rock core taken from the actual geothermal well, and load it under a steady confining pressure representing the in-situ conditions. The flow rate will be scaled down to simulate the actual condensate injection rate while keeping the inlet temperature at atmospheric or about 25°C. The experiment will investigate the thermal effects of cold injection – warming cycle on the permeability of the rock sample and compare it with the effect of cold injection.

The experimental set-up is work in progress. At present, re-coring of the original rock core is put on hold pending the availability of the 61mm diameter diamond coring bit.

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