A Snapshot of the Drilling and Completion Practices in High Temperature Geothermal Wells in the Philippines

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Abstract

Well drilling costs in the Philippines currently account for 66 % of the cost of steamfield development and 33 per cent of the total project cost. Drilling cost is directly influenced by the problems associated with unrecoverable loss of circulation and collapsing formations which hindered drilling progress. Considering its significant impact in the pricing of steam, and the need to make the geothermal electricity price more competitive, geothermal operators in the Philippines continue to search for innovations to test new technologies that would speed up drilling operations. Recent drilling results indicate an emerging and better performance that was previously subsumed to be unpredictable, based on a wide scatter in the Cartesian plot of the total depth (TD) drilled versus duration.

Considerations applied in well design, drilling practices and completion technology in the Philippines are discussed in this paper. Downhole logging, to determine static formation temperatures while drilling, aides in setting the production casing at desired temperatures. Right-sizing of casing allows wellbore output optimization and, thus, reduces total well requirements for highly permeable reservoirs. Hydro-fracturing, thermal fracturing and acidizing have been effective in improving production and injection capacities of wells. Under-balanced drilling using aerated mud and water in an under-pressured reservoir significantly improved drilling performance and led to attainment of drilling targets and successful completion of wells. The completion of >2500 meter well in less than 30 days had been achieved through the use of portable top drive equipment, high performance polycrystalline diamond bits (PCD), high temperature mud motors and implementation of improved drilling practices.

1. Introduction

The Philippines remains the second largest producer of geothermal energy in the world with an installed capacity of 2,027 MW. Drilling activities for development of high temperature fields in the country began as part of the government's exploration program in Tiwi from 1964-1971. As of end 2005, a total of 658 wells had been drilled in support of the geothermal power program (Figure 1).

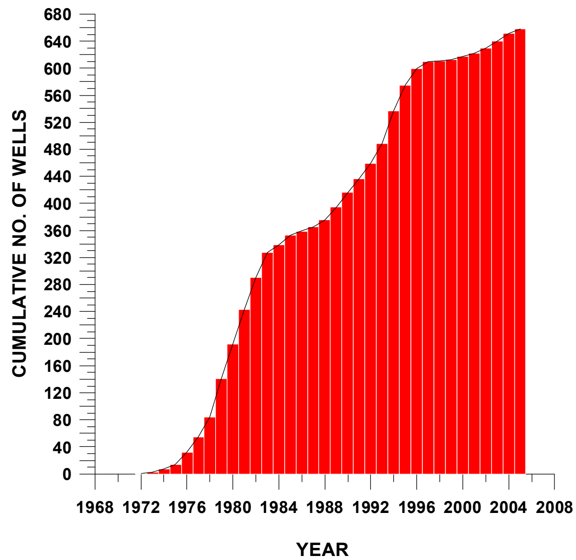

Figure 1: *Annual drilling for high temperature geothermal wells in the Philippines.*

The country's geothermal drilling program was launched by initially drilling shallow thermal gradient holes from 120-200 meters; leading to site identification and completion of a discovery well in 1972, and subsequent commitment for commercial development of the Tiwi geothermal field to 330 MW.

In 1973, series of shallow exploratory wells were also drilled in Tongonan using a Truck-Mounted Failing Rig up to depths of 268-600 meters (KRTA, 1979). These exploratory wells were later followed by deep drilling which also led to the completion of each discovery well in MakBan in 1974, Tongonan in 1976 and Palinpinon in 1978. Tiwi and MakBan were both operated by Unocal Philippines Inc. (now Chevron Geothermal). All the other fields were discovered in 1980 onwards. Deep drilling in Tiwi and MakBan were conducted utilizing rigs with a capacity of 3,050 meters.

In Tongonan, the production wells were initially drilled utilizing Ideco H-525 and Ideco H-725 to total depth of 1100-1990 meters. Geothermal drilling got a boost from the government's geothermal company (PNOC-Energy Development Corporation) when it acquired new rigs vis-à-vis: National 610, Conemsco D-3, National 370, Ideco-E2100 and Romanian F 200. These rigs had capacities ranging from 2,100 to 6,400 meters. Figure 2 shows the 288 and 370 drilled respectively for Unocal and PNOC-EDC since 1972.

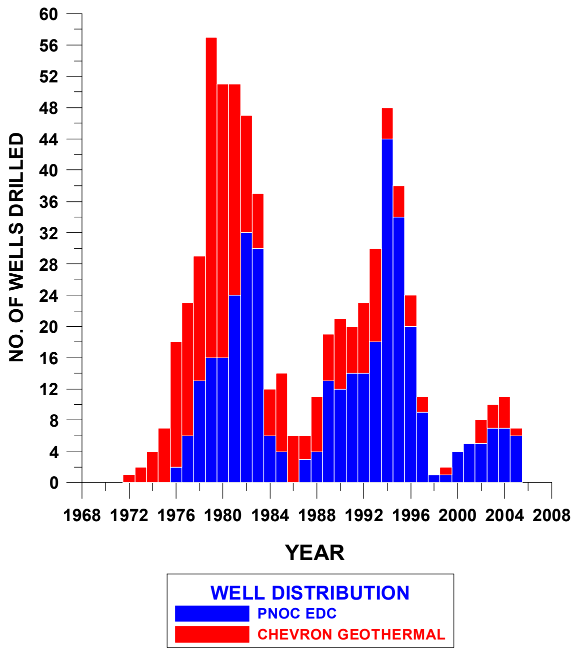

Figure 2: *Well drilling distribution by two steamfield operators in the Philippines.*

Directional drilling in the Philippines started in 1978 in Tiwi and MakBan. In view of the very steep topography and to overcome the constraints in the limited number of production and reinjection pads that could be constructed, PNOC EDC adopted this technique in 1980 in Palinpinon. The Palinpinon case serves as a model for compact field development, where environmental impact is minimized due to minimal surface excavations. However, this strategy resulted in additional drilling problems and remarkable increase in drilling cost compared with conventional vertical drilling. For Tiwi and MakBan, vertical wells with average depth of 1,525 meters were completed from 30-40 days with somewhat longer duration for directional wells (Horton et al., 1981). More recent wells drilled as make-up wells in MakBan were drilled much deeper than 2845 meters, with the deepest reaching 3,425 meters including a well with forked-completion (Golla et al, 2006; Southon, 2003). However, these wells have now been drilled in almost the same period as the earlier wells with the use of latest rig equipment including portable top drive system in rotating the drill string, in lieu of Kelly Rotary Table; downhole motors, PCD bits, aerated drilling and implementation of more improved drilling practices.

This paper draws on some of the tests and practices applied in achieving the drilling objectives and improving the results in high temperature geothermal fields in the Philippines. The techniques to be described include some of the methods used in setting the production casing, the drilling difficulties typically encountered in Philippine geothermal fields and the strategies and stimulation methods adopted. The drilling cost and the overall drilling performance in comparison with international drilling data are also presented. A detailed presentation on the key drivers of the drilling performance in the Philippines could be referred to another presentation by Abanes (2007).

2. Casing Design Considerations

Several papers and codes had been published dealing with various parameters in designing casing for high temperature geothermal wells: Chillingar and Rieke (1962), Dench (1970), Karlsson (1978), Nicholson (1984), New Zealand Code (1991) and the API (1989). Well casing design in the Philippines subscribes to the above references to ensure the integrity of the completed wells. Thorhallsson et al (2003) also discussed in detail the bases of their design in drilling for supercritical fluids that are in excess of 375 °C.

Figure 3 shows the typical hole-sizes and casing string configuration adopted in high temperature geothermal well drilling in the Philippines. Of particular interest is the successful drilling completion of a forked-hole in MakBan geothermal field by Unocal Philippines Inc.

More recent wells in the Philippines were drilled with 10-3/4” and 8-5/8” instead of the 9-5/8” and the 7-5/8” casing-liner combination (Southon, 2003).

2.1 Production Casing Setting Depth

Geothermal reservoirs in the Philippines are typically water-dominated, under-pressured and usually encountered at 800 meters ASL, with the highest wells collared in Mindanao from 1200-1600 meters ASL. Most of the wells drilled in this terrain stand with water level up to 1000 meters below the surface. As such, there is inherent difficulty in initiating the well’s discharge because of large pressure drops the fluids have to overcome in flowing to the surface. These reservoir features, aside from the safety of the well and its structural targets, dictate the setting depth of the production casing.

In drilling for oil and gas wells, all the casings are cemented and perforations are conducted opposite the payzones for production. In comparison, geothermal wells are completed with open-holes run with slotted or perforated liners from the production casing shoe to total depth (TD). Such difference in design requires the setting depth of production casing to isolate the top of the reservoir from overlying cold aquifers, gas-rich fluids or acid condensates so that the wells could be used commercially. For production wells, it has to be set at a minimum temperature of 220°C to successfully initiate the fluid flow of the wells. Besides, geothermal fluids with enthalpy lower than the feed zone temperature of 220°C are more suitable for direct heat utilization than for power generation.

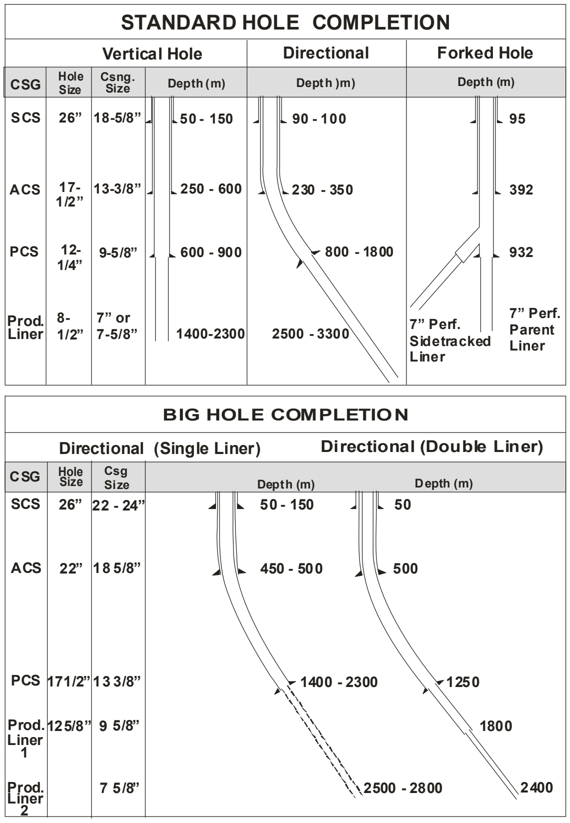

Figure 3: *Typical hole and casing design in the Philippines*

Injectors also require a minimum temperature limit of 220°C below the shoe to ascertain that the shallowest open zone in the well has temperature higher than the usual injection temperatures of 165-185°C. This injection temperature range is maintained to minimize silica deposition in the wells and thus slow down loss of injection capacity.

Based on the temperature distribution in a fully developed geothermal field, the 220°C setting depth is easily determined. However, this information does not exist in newly developed and exploration areas. The techniques, which are described below, are therefore used in approximating the setting depth in conjunction with the projected target intersection of the structural faults.

2.1.1 Boiling Point for Depth Curve

The equation of the curve for boiling point with depth (BPD) in a geothermal well satisfies a preliminary prediction of subsurface temperature in exploration areas to project the setting of the casing shoe depth. This approximation enables the drilling engineer to plan the total number of drill strings, casings, cement and other consumables prior to drilling. This technique makes use of the elevation of a boiling chloride hot springs located in the vicinity of the wells to be drilled. The elevation is used to approximate the existing water table, and serves as the datum level to extrapolate the 220°C from the BPD curve for the programmed well.

2.1.2 Static Formation Temperature Tests (SFTT)

SFTT is a temperature recovery measurement conducted while drilling is stopped at a designated depth in the hole. The test is run after maintaining full returns of circulation to the surface. The objective of the test is to establish the 220°C depth or any temperature that may be used for decision making while drilling the hole. The predicted temperature is extrapolated from the results of a single test or series of measurements.

The SFTT result is used to confirm the predicted result obtained from the use of the BPD curve. In designing the succeeding exploratory wells, data could be used without waiting for three months for the well to recover from drilling.

Several methods had been developed about this subject that began in the oil and gas industry (Edwardson et al., 1962; Raymond, 1969; Dowdle, 1975). Messer (1976) presented a paper on determining static temperatures using dimensionless Horner type curves of temperature recovery versus circulating time during drilling operations. Roux et al., (1979) solved the differential equation using the Horner type temperature build-up plot that provides a correction factor to address the non-linearity of the build-up curve. Later, Brennand (1997) developed a simple and quick method for the same basic equation without a correction factor by plotting observed temperatures against 1/ ($\Delta t + 0.785\mathbf{t_c}$) as shown in Figure 4.

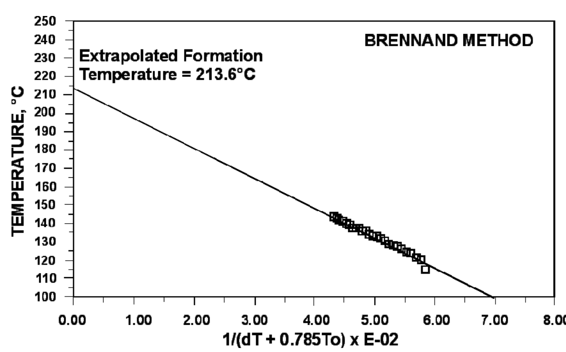

Figure 4: *Plot of the downhole temperature used in predicting stable formation temperatures while drilling (After Sarmiento, 1993).*

The constant (.785) was empirically derived from various tests conducted in the Philippines while the $\mathbf{t_c}$

represents the total circulation time. The total duration of the test, including the pull-out and run-in of the drill strings for circulation is about 12 hours. When an e-line temperature tool is used, the tests could be shortened by 3 hours because data analysis could be done in parallel with the measurements

The SFTT results in the Philippines using the Brennand method have been found to be within ±5°C, enough to be used as a basis to accurately set the casing shoe for exploratory wells. The results further suggest that only 15% of the predictions deviated by >15°C from measured data (Sarmiento, 1993).

More SFTTs are conducted when confronted with decisions to pre-terminate drilling if (i) sufficient production temperatures (at least 270°C) in the well has been achieved and (ii) the well is at risk and lower temperatures or reversals are inferred for the remaining portion of the hole.

2.1.3 Circulating Temperature Projection

Some of the main functions of drilling fluids are associated with balancing formation pressures and maintaining formation stability. Other functions of drilling fluid are for cooling of the hole and deployment of downhole tools like mud motors, drilling jars, logging tools and MWD at possibly longer period. A good mud also keeps the cuttings in suspension until it is brought to the surface. It prevents the cuttings from sticking to the bits or collars which are the main causes of stuck-pipes. These functions could be adversely affected by high temperatures encountered in geothermal wells, and requires monitoring of the flowline and bottomhole circulation temperatures (b_{hct}) so that mud conditioning could be done while drilling.

Drilling practices in the Philippines make use of a simple correlation that exists between the *bottomhole circulating temperature* ($\boldsymbol{b_{hct}}$) and *flowline outlet temperature* (f_{out}), where b_{hct} is 1.3 times the value of f_{out}. The temperature differential between the inlet (f_{in}) and f_{out} temperatures is usually maintained at 5-10°C. $\boldsymbol{F_{out}}$ temperature reaches as high as 90°C for high temperature areas, requiring introduction of newly prepared mud mixtures. The results of these flowline temperatures are further checked by using temperature stickers attached to downhole motors and other tools.

2.1.4 Thermal Simulators

The application of monitoring the flowline temperatures could be extended in predicting downhole static or equilibrium temperatures through the use of thermal simulators. This method was also originally applied in the oil and gas industry, and found applications with some modifications in geothermal well evaluation. Hefu (2000) showed the results of two wells in Krafla with close agreement between the calculated and measured formation temperatures using STAR, developed in Orkustofnun, Iceland and GEOTEMP2 by Mitchell (1982). Stable formation temperature predictions from Espinosa et al. (2000) also demonstrated a good agreement to the measured downhole temperatures by using TEMPLOP1V.2 - thermal simulator for drilling mud, and GEOMIST - for air-water mixtures. If the same accurate results from the thermal simulators could be obtained, a considerable savings equivalent to a minimum of 27 hours in drilling time per well could be gained by not running the SFTT.

2.2 Casing Sizes

2.2.1 Output Optimization

The results of a study dealing with the feasibility of drilling big holes were discussed by Sta Ana et al. (1989). The study was conducted to evaluate the increase in well output and reduction in the total number of wells to be drilled in a development project. The result of the study indicated that a significant increase in well output could be achieved for wells with very high permeability.

Later, big-hole completion was also used to justify the construction of production pads at higher elevations to minimize pressure drops, instead of reaching inaccessible flat and low lying areas.

Large hole-completion is adopted for wells where the output are found to be *wellbore* controlled, i.e., the total mass flow rates are controlled by the size of the well, and is increasing with declining WHP.

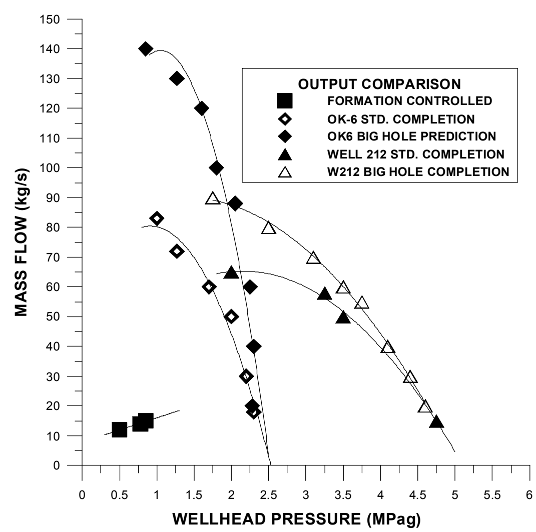

Figure 5: *Output comparison for high and medium enthalpy wells in the Philippines with standard and big hole- completion (After Sarmiento. 1993)*

This discharge characteristic is illustrated in Figure 5. A well is run with regular casing combination, when the mass flow rate has little change or would remain constant with change in WHP, also described as *formation controlled*.

By simulating the effects of size variation on the casing of high temperature wells, a 30-60 % increase in wells' output was derived by shifting to big-hole completion. Only 38% increase in output is needed to justify design change. Moreover, as much as 250% improvement in output has been achieved in the actual drilling results (Sta Ana et al., 1997). Figure 6 shows the relative comparison in cost of drilling big and standard holes.

A total reduction of 19 wells, out of the total 49 wells initially programmed to supply field requirement, was achieved in Leyte for its 600 MWe expansion program. This reduction in total number of wells translated into a savings of USD 38 million, based on a USD 2.1 million per well cost.

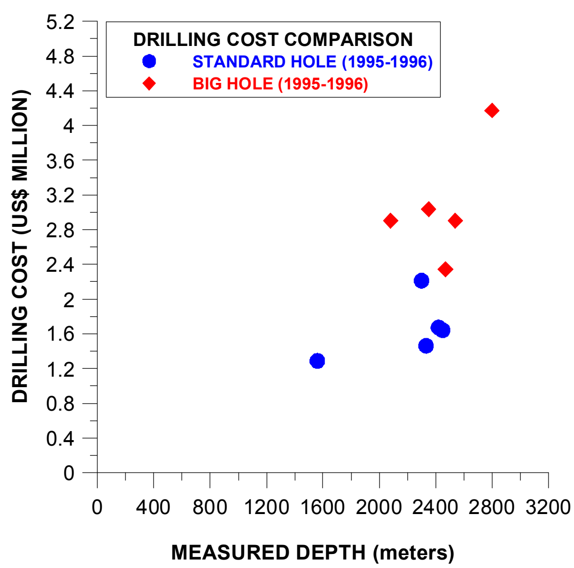

Figure 6: *Comparison* of d*rilling cost between big hole and standard completion in Leyte wells adjusted at 2006 level (From Sta Ana et al., 1997.)*

Additional savings are also achieved with the reduction in well numbers associated with the material and space requirements for the construction of production and reinjection pads, fluid collection and disposal system and impact to environment. Furthermore, early commissioning date is also attained and thus early return on investment.

3. Drilling Problems

3.1 Big-hole design

Aside from optimizing well output, big-hole completion was also adopted as a drilling strategy to drill up to 3000 meters in areas that are saddled with unstable or collapsing formation. Talens et al., (1997) discussed the challenges faced in completing the drilling campaign for the development of the 180 MWe Mahanagdong Field in Tongonan, Leyte. Using the standard-hole completion, persistent drilling problems were encountered in 14 wells leading to failures in attaining target depths and missing intersection on 56 % of the targeted geologic structures; and thus lesser output per well.

The problems consist of the inability to penetrate more than one permeable zone after encountering a total loss circulation (TLC) from the first loss zone. Total loss circulation (TLC) is a common phenomenon in geothermal drilling that occurs when massive fractures and faults are intersected. To avoid damaging the payzone and prevent an enormous volume of mud to be lost, drilling shifts to water in what is known as *blind drilling*. Drilling mud fluids are nevertheless regularly slugged to keep the cuttings from settling to the downhole assembly and bits. While blind drilling, wellbore instability is frequently encountered because "weighting-up" to stabilize collapsing formation is not possible. Similarly, the risk of backflow of cuttings into the hole increases during blind drilling, upon intersection of another loss zone at the bottom, and when the first loss zone has a very low cuttings acceptance capacity. These features increase the risk for occurrence of stuck-up pipes.

To overcome these problems, a big-hole completion (Figure 3) with two liner system using 13-3/8" casing and 9-5/8"blank liner on top of the 7-5/8" liners was implemented in drilling for the balance of Mahanagdong wells.

By casing off the upper loss zone through big-hole completion, full circulation was regained and potential collapsing formation was isolated while drilling down to the second loss zone. Moreover, the backflow of cuttings was arrested at least until the last targeted loss zone is intersected.

Table 1 summarizes the drilling performance of wells that were classified in four categories.

On type C wells, 5 were drilled with big-hole completions using the double-liner system of 9-5/8" and 7-5/8" diameters enabling the attainment of all drilling and geological objectives. These wells were drilled at a faster rate and deeper than those with standard completion (D). Drilling with this design was faster by 11-21 days than the standard completion. Moreover, perforation of the 9-5/8" casing could be conducted to tap the brine and steam from the cased-off permeable section if production from the 8-1/2" hole is insufficient.

The same technique was adopted in some wells previously drilled with similar problems, but smaller 4" slotted liners were used at the bottom (Southon, 1994).

This configuration was, however, not pursued because results from subsequent productions from this type of completion did not yield significant contribution from the slim-hole portion of many holes.

Table 1: *Drilling performance summary from the Mahanagdong Sector in the Philippines (After Talens et al., 1997)*

Well Type	S/B Hole	T/I Struc-tures	Prog. Depth	Total Depth	Days Drilled	Drift Angle
A	2/2	2/2	2300	2400	69.5	-
B	8/1	3.3/3	2396	2482	75.2	40
C	6/5	2.5/2.5	2495	2414	64.4	29
D	13/1	3.6/2	2595	2155	85	35

A: Vertical, B: Minimal Losses, C: Attained Geo. Obj., D: Failed to Attain Geo. Obj., S: Standard Hole, B: Big Hole, T: Target, I: Intersected

3.2 Polymer as Drilling Fluid

Another drilling problem common in the Philippines is the swelling of clays frequently encountered at the top zone of the reservoir. This happens when the clayey formation is exposed to the water-laden drilling fluids in 5-7 days. As the clay swells, the formation collapses. A high temperature liquid polymer (.08 liter/gallon of water, funnel viscosity=28 spq), was tried in drilling one well to 2900 meters to avoid this problem, as well as to maintain good hole cleaning during TLC and to avoid mud damage to permeability caused by regular slugs of mud. The dosage rate was increased to .46 liter/gallon water, (funnel viscosity of 40-42 spq), when a massive circulation was encountered in the open-hole section of the well just above the TD. The use of this liquid polymer had been satisfactory because the well was drilled without obstruction down to TD of 2900 meters. The high consumption and cost of the polymer constrained further trials on additional wells.

3.3 Under Balanced Air Drilling

Reservoir depletion due to continuous production has resulted in significant pressure drawdown and expansion of the two-phase zone in maturing fields in the Philippines. During drilling of infill wells, the mud hydrostatic pressure exceeds the reservoir pressure, especially at the top zone where steam easily condense and collapse. This transition in the fluid properties of the reservoir causes drilling fluids to be lost to the formation, especially when penetrating the highly fractured andesitic lavas and pyroclastics in the reservoir, and has added complexities to the inherently problematic drilling operations in the Philippines. Jumawan et al (2006) and Herras and Jara (2006) described the performance of conventional drilling mud and aerated fluids while drilling infill wells at the center of the under-pressured reservoir of Tongonan.

3.3.1 Circulation Losses while Air Drilling

Two wells were drilled with the same target in the same sector where there is significant pressure drawdown; one with conventional drilling mud fluids and the second well with aerated mud/water at under-balanced drilling condition. The objectives of the two wells were to drill up to 2,900 meters to tap the high temperature fluids at depth. The casing shoe had to be set from 1,600-1,900 meters to avoid producing from the depleted top zone. All losses were required to be plugged.

Unrecoverable losses and blind drilling led to the premature completion of the first well while drilling with conventional mud fluids. Mud fluids and cuttings migrated swiftly to adjacent wells causing surges to water levels in separators, and subsequent increase in total suspended solids in steam. The turbines required temporary shutdown until remedial action to reduce the TSS was put in place. Some wells collapsed due to substantial cooling, and drilling could not progress until well was prematurely TDed.

The major impact of these problems was the reduction in total output of the field and forced-acidizing of production wells that had communicated and had been damaged by mud while drilling.

Learning from this experience, subsequent drilling in the same sector was conducted with aerated drilling, and full circulation returns were recovered by adjusting the air-water and air mud ratios. Steam influx and well kicks from the top zones were allowed but at conditions where temperatures would not go beyond the limitation of the rubber O-rings of the BOP stack (Jumawan et al., 2006). Good hole cleaning due to maintenance of full circulation led to completion of these wells at much deeper levels than when they were drilled with conventional mud systems. One well was completed to 2,900 meters with air drilling applied at the production casing interval only, and mud as the drilling fluids from the 9-5/8” shoe to bottom hole.

4. Stimulation Methods

Stimulation procedures to enhance reservoir permeability are conducted immediately after well drilling completion or subsequently after the well recovery. It may consists of hydro-fracturing, thermal fracturing and acidizing. Hydro-fracturing and thermal fracturing create or enlarge fractures that connect with pre-existing fractures within or farther away from the wellbore. Acidizing dissolves the mud that blocks the sandface fractures. Wells also require some stimulation to initiate flow to the surface. These methods involve air compression, gas lift, and two-phase stimulation by boiler or by hook-up from production wells. The availability of the coil tubing unit (CTU) and rig allows the use of nitrogen gas or air to stimulate even the most reluctant wells through lifting of the cold fluid column to the surface, until the well is emptied and the well kicks by itself. This method is also used to clear the well with mud that settled at the bottom including those that are blocking the permeable zones.

4.1 Hydro-fracturing

Hydro-fracturing usually involves injecting water at high wellhead pumping pressures, and in some cases entail the use of proppants to wedge the fractures propagated during the operation.

Figure 7 shows the results of a hydro-fracturing job for the first well (LB-1D) drilled in the Mt. Labo geothermal prospect in Southern Luzon, Philippines (Sarmiento, 1993). Hydro-fracturing was conducted during the completion test after high WHP was measured while pumping at minimal flow; a condition suggesting the tightness or the lack of permeability of the well. The operation consisted of injecting water at maximum pump rate of 30 l/s for 24 hours until the WHP turned into vacuum condition.

A well is at vacuum condition when it is sucking more fluids than what the pump could deliver. The final injectivity index of the well after the *hydrofrac* was 25 l/s- MPag at vacuum condition against 45 l/s-MPag with a positive WHP before the *hydrofrac*. Moreover, a pressure difference of >5 MPa was measured before and during the *hydrofrac* operation, suggesting the opening and enlargement of fractures. The well sustained a commercial output by using the CTU for gas-lift operation.

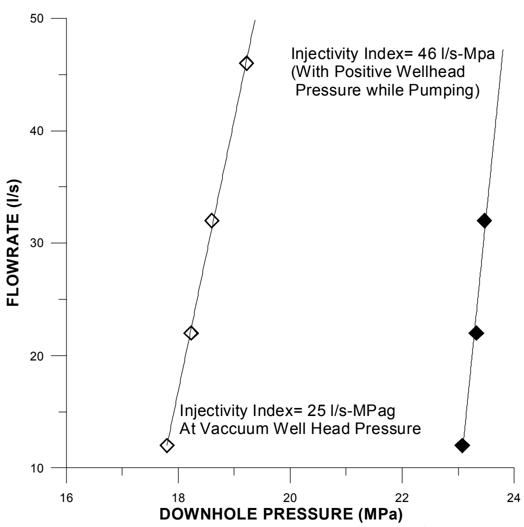

Figure 7: *Injectivity Index comparison of LB-1D before and after a hydro-fracturing job (After Sarmiento, 1993).*

The above result is typical of many wells successfully stimulated by hydro-fracturing in the Philippines. Other injectors that were earlier diagnosed to be tight during drilling because of the lack of total or partial loss of circulation (PLC) had been highly stimulated after hydro-fracturing, thereby eliminating drilling of additional wells for replacement.

4.1.1. Proppants

One reinjection well displayed a positive result with hydro-fracturing using proppants until it was put on line as an injector. The proppants used were normal graded silica sand which is liable for dissolution in hot water. Clotworthy (1997) suggested that the apparent gain in injectivity might have been caused by the opening of the zone below the shoe. However, it was also possible that the loss in capacity after a short period of time was due to silica scale build-up in the proppant-initiated fractures. The case may have been different if this was tried in a production well, especially in a dry steam well where the chance of scaling due to silica is small.

Two other wells had been subjected to hydro-fracturing with proppants but no improvements were gained. These wells were drilled along the western boundary of the Tongonan field where the formations are found to be mineralized with clay.

4.2 Thermal Fracturing

Thermal fracturing is done by alternately pumping water and allowing the well to recover by heat-up, and creating thermal shocks that are capable of producing cracks into the formation. It can also be demonstrated by injecting cold fluids in a relatively hotter formation to create or enlarge fractures during the contraction of the rock matrix contracted. Example of this method in the Philippines is the low temperature condensate injection being implemented to comply with the prescribed zero-waste disposal in the Environmental Compliance Certificate of the project. A condensate injection well in Mindanao I after being used for more than 3 years was tested to have increased its injectivity from 10 to 12.3 liters/s-MPag with a corresponding drop in downhole pressures. The calculated kh also increased from .2dm to 4.88 md.

4.3 Acidizing

Acidizing consists of pumping HCl and HF mixtures to treat the formation of mud damage resulting from drilling operations. Because of the expense involved, this method is usually delayed during the well recovery as an ultimate solution to enhance well output. However, in some cases where the urgency for steam supply requires immediate acid treatment, then it becomes part of the drilling program (Yglopaz et al., 2000).

4.3.1 Output Change

Since 1993, acid treatment has been widely used in the

Philippines to enhance production and injection capacities of geothermal wells. Sarmiento (1993) first showed that mechanical workover or clearing of scales in reinjection wells should not be confined only within the wellbore, and must extend beyond the sandface to recover lost injection capacity. This finding led to the trial and successful acidizing jobs in Palinpinon involving one production well (PN-32D) that was damaged by mud during drilling, and one reinjection well (PN-2RD) that had suffered a declining injection capacity.

To date, the success of this stimulation method is repeated in the Philippines and around the world on many wells that are suffering from mud damage and mineral deposition. Buning et al., (1995) updated the acidizing results from 1993-1995 and reported significant improvement in the capacities of 9 out of ten wells initially acidized in the Philippines. Other results are reported in Malate et al., (1997), Yglopaz et al., (2000) and Sarmiento (2000). Table 2 summarizes the results of acidizing jobs in the Philippines since the trials in the first two wells. A minimum 29 % with a maximum 911 % increase in output/injection capacities had been obtained from various acid treatment operations.

Table 2: *Summary of acid treatment operations in the Philippines (After Sarmiento, 2000)*

Well Name	Injection Capacity/Output (kg/s) or (MWe)			Improvement (%)
PRODUCTION WELLS	(MWe) **(1)**	**(2)**	**(3)**	
PN-32D	2.2	2.2	4.1	86
110D	4.1	4.1	12.4	202
MG-29D	ND	ND	7.3	
MG-27D	NC	NC	8.9	
MG-30D	4.3	4.3	14.7	242
MG-31D	ND	ND	19.6	
MG-28D	5.9	5.9	8.2	39
MG-24D	3.8	3.8	5.6	47
MG-26D	untested	untested	2.4	
OP-5DA	1.5	1.5	4.1	173
OP-3D	2.6	2.6	5.5	110
REINJECTION WELLS	(kg/s)			
PN-2RD	60	40	187	367
2R4D	90	*18	*182	911
TC-2RD	146	57	97	70
1R10	35	*30	*48	60
4R-7D	70	36	91	153
4R12D	149	149	264	77
KL-2RD		56	134	139
KL-1RD		103	133	29
OP-1RD	30		70	133
OP-2RD	70		137	96
TIGHT WELLS	kg/s			
MG8D		10	22	120
MN-1		20	39	95

Notes: 1: Before Drill Out, 2: Pre-Acidizing 3: Post Acidizing
* Calculated Max. Results

4.3.2 Thermal Recovery

Of significant results shown by acid treatment was the relative rapid recovery of temperatures on heavily mud-damaged wells (2,700-42,000 barrels of mud lost) compared with the period after drilling completion. Wells damaged by mud takes up to more than 5 weeks to thermally recover. On the other hand, wells could be ready for discharge within 5 days to 3 weeks after acid treatment. Post acid treatment of wells in Mahanagdong Production Field in Leyte resulted in significant output improvement and immediate availability of capacity from 14-64 MW for the scheduled plant commissioning; and thus averting a penalty situation for PNOC Energy Development Corporation due to insufficient steam (Yglopaz et al., 2000).

Acid treatment of geothermal wells has been proven to be effective also in dissolving calcite deposits opposite the flash point in production wells. The same treatment is found to be effective for wells that have been cased-off and later perforated for production.

4.3.3 Quantifying Improvements by Acidizing

One of the most significant advances in the application of acidizing for well stimulation in the Philippines is the development of a method that predicts the most likely improvement of a well if it undergoes acid treatment. Aleman and Clothworthy (1996) described it in detail.

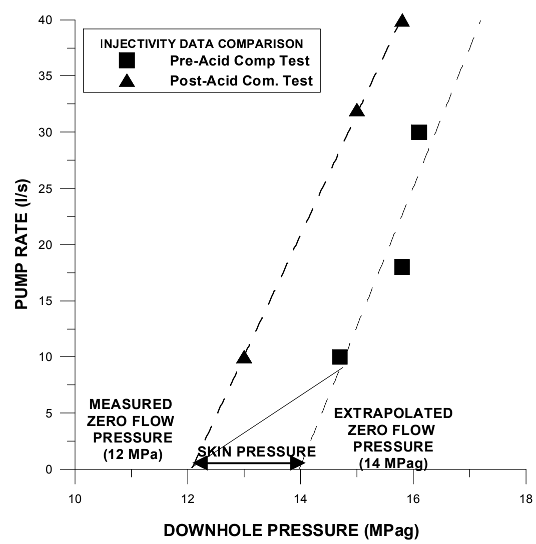

Figure 9: *Typical injectivity plot for comparison on an acidizing job for damaged wells*

In general, the skin pressure caused by the mud cake or mud damage in the well's sandface refers to the difference between the extrapolated measured pressure at zero flow rate during pumping and the stable pressure measured during the recovery period at the same depth where the test was conducted. This technique is illustrated in Figure 9 by plotting the pump rates versus the measured pressures obtained during the well completion test.

The minimum amount of additional flow that could be induced by acidizing can be estimated by multiplying the injectivity index of the well and the skin pressure as shown in the following correlation:

Capacity Gain (l/s) = ($\Delta P_{skin,}$ MPag) X (Injectivity Index, l/s-MPag)

This correlation could be directly applied with injectors. For production wells, an equivalent increase in well output is determined by using the discharge enthalpy and the steam fraction.

In addition to the evaluation of skin factor using transient pressure analysis, this prediction method provides a numerical basis in reinforcing the economic viability of a proposed acid treatment. The result serves as a better criterion for well candidate selection. Wells that would not pass this criterion are acidized only as ultimate resort on wells that are drilled in an entirely different environment but with abundant minerals that could be dissolved by mixtures of HCl and HF. This had been proven effective in the treatment of reinjection wells in one geothermal field which are drilled in volcanic and carbonate-rich sedimentary formations. Hydro-fracturing was first conducted in 3-4 wells in the area but no improvements were gained. Acid treatment was then conducted as a last resort because the alternative was to relocate the injection pad further away from the steamfield facilities. The success of the chemical treatment avoided drilling additional wells and the use of the existing pads for permanent reinjection.

5. Drilling Performance

Figure 10 shows the drilling performance in the Philippines during the last 15 years based on the various reports by Talens et al., (1997), Southon (2003), Herras and Jara (2006). These wells were selected to show the marked difference on the drilling performance for the various wells. The red and the blue squares shows that as much as 20 days were involved in non-rotating hours (downtime) from the performance of a conventional rotary drilling rig using mud as the main drilling fluids. The graph of the total depth vs. drilling duration indicates that there is a significant potential for improvement in achieving faster drilling by mainly reducing the downtime incurred during the actual drilling, which by experience makes up 15-25 %. Furthermore, 10-17 % of this downtime could be controlled with better planning and logistics. The black circles represent what could be considered as drilling record for completing geothermal wells in a span of 26 days for 2800 meters, and less than 60 days for 3400 meter wells, by using conventional rig equipped with a portable top drive system and steerable MWD tools (Southon, 2003). Other improved drilling practices that involved reducing the non-rotating hours were also implemented which had significantly contributed to the new record. This emerging performance record deviates significantly from the unpredictable performance of past drilling results clearly shown in Figure 10.

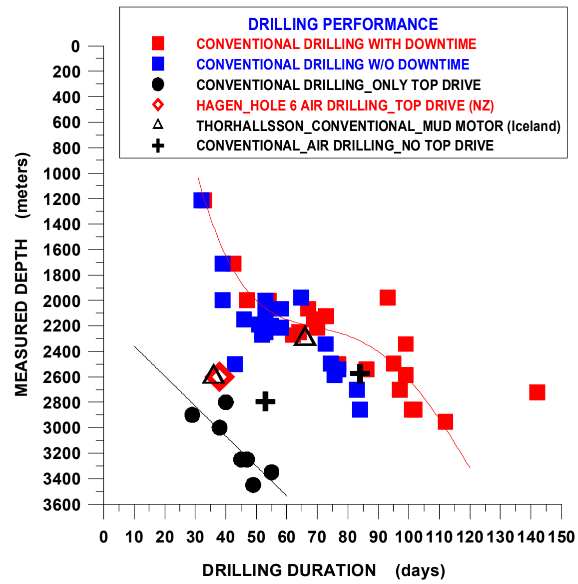

Figure 10: *Drilling performance results of selected wells from the Philippines, New Zealand and Iceland.*

The open diamond is a well completed in NZ using air drilling and a top drive to supplement the conventional rig (Hole, 2006). The black crosses represent the

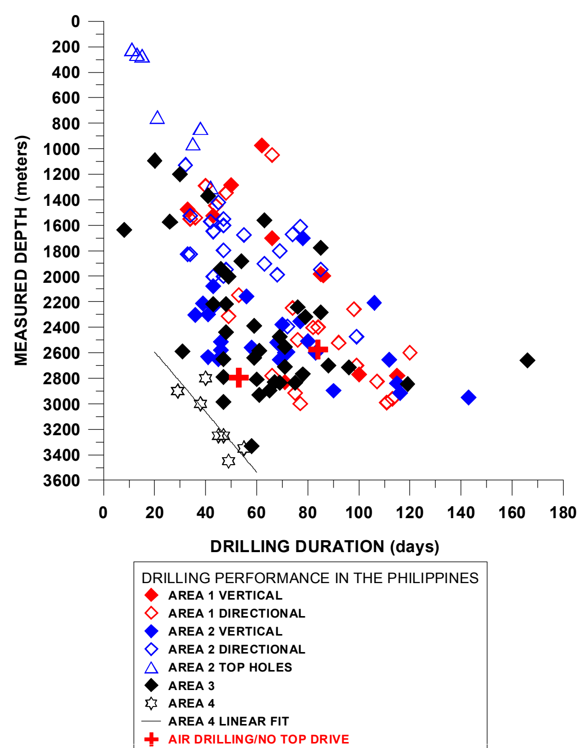

Figure 11: *Comparative drilling performance in four geothermal areas in the Philippines.*

performance of conventional rig in the Philippines without a top drive but with aerated drilling. One of the two wells fits linearly with this Hole (2006) in NZ. The two triangles represent two wells drilled in Iceland; one using the conventional drilling and the other with mud motor drilling down to TD (Thorhallsson, 2007). The first well that was drilled conventionally falls within the performance of many wells (red and blue squares); while the one drilled with mud motor all the way matches well with that drilled with air drilling. It is clearly shown in the plot that the combination of aerated drilling and top drive units adopted from Hole (2006) hole was not enough to match the drilling rate demonstrated in the Philippines. The objective of using aerated drilling in the Philippines for drilling and completing infill wells has been achieved with a better drilling rate than conventional drilling.

To further demonstrate the unpredictable drilling performance in Philippines, many wells with available information were plotted in Figure 11.

6. Drilling Cost

Table 3 shows that the costs of drilling geothermal wells make up 29 % of the total investment in a geothermal project in the Philippines. These costs exclude stimulation costs. Table 3 also illustrates the significant increase in the recent drilling cost of wells in the country, which had been almost unchanged from 1985 to 2005 - from USD 1.91 million to USD 2.1 million per well (Tolentino, 1986; Dolor, 2005; Dolor, 2006). These costs are considered average; therefore, costs could be significantly lower or higher in some cases as shown in Figures 6 and 12.

Table 3: *Typical Drilling Cost for a 100 MW geothermal field in the Philippines. (See text for reference)*

Item	Cost/Well MM US$			Total Cost MM US$			% Proj. Cost
Year	'85	'05	'06	'85	'05	'06	'06
Explo. Wells	1.91	2.1	2.9	5.73	6.3	8.7	3.1
Prod/Reinj. Wells	1.91	2.1	2.9	53.5	58.8	81.2	29.3
Steamfield (With Drilling)				88.4	115.7	136	49.1
Power Plant Cost				88	140	140	50.5
Total Project Cost				176.4	255.7	276.9	100

Explo Wells: 3 Production Wells: 21 Reinjection wells: 7

Southon (1994) indicated that drilling cost per well in 1994 may not exceed USD 1.5 million while Tolentino (1986) might have indicated the upper range of the drilling cost at USD 1.9 million. The most recent account in drilling cost jumped by 38% from USD 2.1 million to USD 2.9 million from 2005 to 2006 (Dolor, 2005; Dolor, 2006). Twenty five percent of this cost is incurred with the adoption of air drilling technique (Jumawan et al., 2006). The second major reason for the increase is due largely to high cost of rig rental caused by the huge demand for rigs all over the world, which should also be reflected by field operators owning a rig. The costs of casings and valves, which account for 9-13 % of the total well costs, had recently experienced dramatic increases in prices because of strong demand for metals as shown by Cooney (2006).

Figure 12 shows the drilling cost as a function of depth in 2006 US $. The data were extracted from KRTA (1979), Sta Ana (1997), Dolor (2005, 2006), Hole (2006) and Thorhallsson (2007).

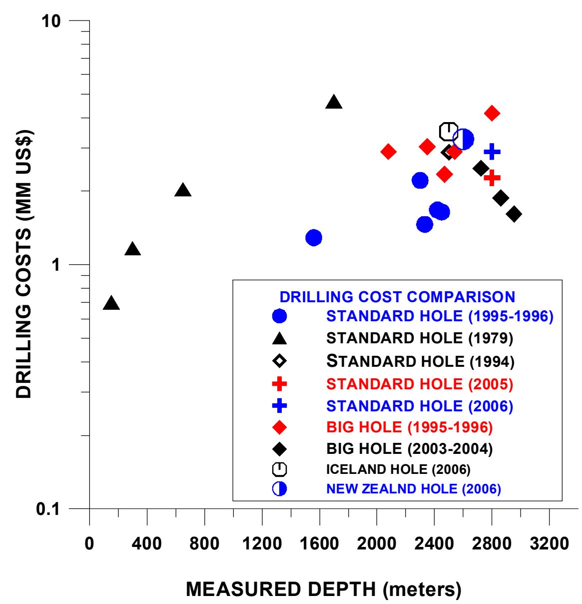

Figure 12: *Drilling costs in the Philippines in year 2006 US $ as a function of depth. (See text for reference)*

The drilling costs in the Philippines were inflated using the formula cited by DOE (2007) that took into account the Consumer Price Indices (CPI) in the Philippines and the USA (NSO, 2007; US Department of Labor, 2007) the Philippine peso vis-à-vis US Dollar exchange rates, general wholesale price index of manufactured goods and machinery, and transport equipment in the National Capital Region. The plot shows that the cost of drilling up to 1600 meters in 1979 (KRTA 1979) would exceed the 2006 cost level of drilling deeper wells. Figure 12 also illustrates that the costs of drilling standard holes in New Zealand and Iceland are slightly higher than in the Philippines.

Figure 13 shows the same data points plotted with those of the drilling costs reported by Augustine et al. (2006). The plot shows that the costs of drilling geothermal wells in the Philippines are also higher than in oil and gas drilling, albeit within the line formed by the Coso and Sandia wells

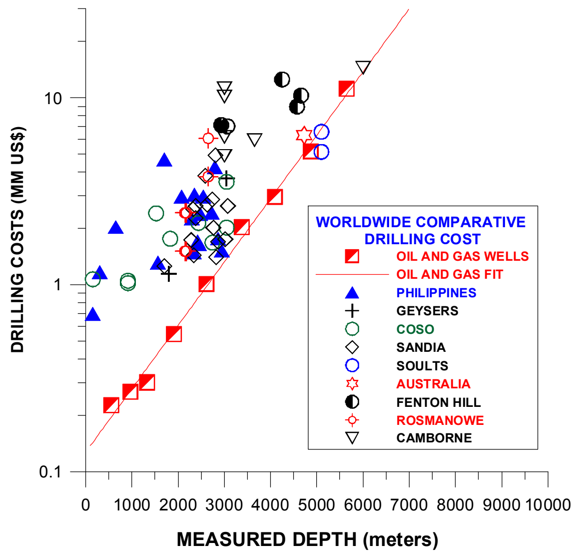

Figure 13: *Completed well costs in year 2003 US $ as a function of depth (Data from other countries are extracted from Agustine et al., 2006)*

The foreseen unabated increase in costs of drilling consumables, materials, and third party services put a lot of pressure on geothermal operators to improve existing drilling practices to reduce total drilling time completion, and minimize the number of wells to be drilled. It has been shown in the Philippines that such targets could be achieved by adopting improved drilling practices, aerated drilling and use of top drive equipment.

7. Future Areas of Research

While the foregoing results already indicate significant improvement in drilling performance, continuous innovation in drilling technology and enhancement in drilling practices should be sustained. Failure to discharge completed wells because of crossflow and downflow of cold fluids results in drilling of additional wells. Handling this zone also delays significantly the drilling operation. It should be treated immediately during drilling with high temperature packers to prevent the occurrence of a temperature reversal and allow the true wellbore fluids at depth and its true temperature to be measured in the well.

The use of high temperature acid diverters to isolate targeted zones during acidizing treatment operations would prevent opening up of unwanted fractures or injection zones that communicates directly with production wells.

During the releasing of stuck pipes while drilling, a high temperature mechanical cutter would be an advantage over the chemical or explosives cutter.

With maturing and continuing depletion of geothermal reservoirs in the Philippines, the direction in the future is to sustain production from existing fields by drilling at >3000 meters to tap the high temperature and high pressure geothermal fluids. It is crucial that well throw would have to exceed currently achievable 1,300 meters to further reduce site clearing and excavations, and be able to comply with environmental rules. Very few downhole tools are currently available that could withstand what is usually the working temperature limit of 150°C during drilling. There would be frequent trips to the surface as high temperatures wear down on downhole motors and bit. These challenges require technology innovations and superior equipment that would entail additional costs.

8. Conclusions

Significant improvement in drilling and completion technology in the Philippines has evolved over the last 3 and half decades. Downhole logging and measurements while drilling provide the necessary information where to set the casing at desired temperatures thereby increasing the success rate of drilling. The adoption of big-hole completion enables maximum production from productive reservoirs resulting in lesser number of wells to be drilled.

Problems associated with multi-loss zones and TLC are overcome by the use of two-liner big hole completion, HT polymer viscosifier, and aerated drilling fluids in an under-balanced drilling operation. The use of top drive system had demonstrated that drilling holes deeper than 3000 meters could be completed in less than 30 days, with the aid of steerable mud motors, polycrystalline diamond bits (PCD) and improvement of major drilling practices. Drilling costs have increased significantly due to additional equipment required in aerated drilling, top drives, and HT mud motors and bits. However, their applications have been instrumental in obtaining high percentage of success in achieving drilling targets and completing wells. Further improvement in reducing non-rotating hours in drilling would ensure that currently achieved drilling completion of less than 30 days could be maintained even at more complicated drilling environment.

Solutions in isolating temperature reversals and cross-flow of cold fluids should be evaluated to further increase the success rate of drilling.

Completion technology used in enhancing the permeability of the reservoir plays a significant role in maximizing production and injection capacity of wells. As high as 900 % improvement in well output has been achieved in acidizing wells, and normally noncommercial wells have been converted as production wells. Hydro-fracturing at high pressure conditions has also proven to be effective in creating and establishing fracture network. These stimulation methods will continue to contribute significantly in reducing the number of wells to be drilled, especially when mud is used as the drilling fluid and in geothermal areas with sedimentary and carbonate formations.

9. Acknowledgment

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