GEOTHERMAL TRAINING PROGRAMME
Orkustofnun, Grensásvegur 9,
IS-108 Reykjavík, Iceland

Reports 2002
Number 9

TECHNICAL, ECONOMIC AND INSTITUTIONAL EVALUATION OF ADOPTING DIRECTIONAL DRILLING BY KENGEN, KENYA

Paul K. Ngugi
KenGen - Kenya Electricity Generating Company Ltd.
Olkaria Geothermal Project
P. O. Box 785, Naivasha
KENYA
pngugi@KENGEN.co.ke

ABSTRACT

KenGen envisages that adoption of directional drilling to target vertical permeability for its future production wells will bear substantial financial benefits arising from a possible increase in average well productivity and a reduction of the surface steam gathering pipe network. The fact that great disparity in productivity has been noted between adjacent wells suggests that vertical or near-vertical structural permeability may be important in this system. Efforts are underway to acquire the capacity to undertake this form of drilling. In this report a comprehensive technological overview and a study of experiences of various operators in the geothermal arena has been undertaken, in order to build a concise understanding of the technology. Directional drilling technology has successfully and widely been employed in the geothermal sector, in particular to target vertical/semi-vertical permeability and for environmental reasons. Use of downhole positive displacement motors with a bent housing / bent sub, and measurement while drilling (MWD) instruments is now the standard practice. Studies undertaken have put to question that in general directional wells are better producers than vertical ones. Multiple-leg (forked) wells and larger diameter casings, two emerging technologies, have promised significant production improvements. An increase in production of up to 200% has been reported in wells with larger diameter casings. Drilling directional wells will cost about 22-41% more and may increase a 64 MWe project cost by between 2.8 and 6% if well productivity does not improve. For an increase in average production from 3.5 MWe to 5 MWe per well as projected, a saving on project cost of between 3.4 and 6% could be realised. An increase of about 0.8 MWe per well, would make this option economically viable. Adopting larger diameter casings (13⅜" OD production casing and 9⅝" OD liner) would increase the well cost by about 16% and could increase the project cost by about 3.1% per well. Savings of about 4.6% would be realised if 5 MWe average well output is achieved and an increase of 0.5 MWe would make this option economically viable.

It is recommended that KenGen apply directional drilling technology to optimise exploitation of Longonot and Suswa prospects. A new drilling rig and on the job training for KenGen's drillers will be necessary. Hire of directional drilling services will be greatly advantageous to KenGen directional drilling operations.

1. INTRODUCTION

Serious considerations of adopting directional drilling as a strategy for future production wells on geothermal fields developed by Kenya Electricity Generating Company Ltd. (KenGen) is underway. It has been projected that savings of up to half (US$ 8 million for a 64 MWe plant) of the capital invested on a cross-country geothermal pipe-network and civil works will be realised against a modest increase in drilling costs if the strategy is adopted. It has further been projected that the number of wells required for a 64 MWe power plant will be reduced by between a half (15 wells) and a third (7 wells). Average output of 5 MWe per well was recently achieved in directional wells drilled within the Olkaria geothermal system, compared to a vertical well average output of 2.5 MWe in the Olkaria East and 3.5 MWe in the Olkaria Northeast fields. Along with reduction in the number of wells, the project implementation time could be reduced by between 1 and 2 years for a 64 MWe project. This period is significant since production drilling is the time critical activity in a typical geothermal electricity power project. This development further promises substantial reduction in capital costs for geothermal plants, making them more attractive financially and possibly doubling the profits.

The importance of geological structures to the productivity of the Olkaria geothermal system seems to be demonstrated by outputs from wells OW-32 (10.5 MWe) OW-709 (9 MWe) and OW-714 (11 MWe). Successful targeting of the important structures, which is greatly enhanced by directional drilling, can have major economic implications as noted above.

Directional drilling will furthermore reduce the capital investment cost of a wellhead generation unit by making it possible for multiple wells to be drilled on a single pad, hence reducing the temporary pipe-work required for a sizeable (10-12 MWe) unit. The economy of early generation using wellhead units is under evaluation. The concept has merit due to the long period that wells remain idle before they can be utilized and the need to recoup as early as possible part of the investment expended in drilling. Wellhead generation could also bear immediate benefits by eliminating rig diesel fuel cost on an electric drilling rig. Fuel accounts for about 10% of well costs.

Directional drilling capability will make economic exploitation of hottest up-flow fluids associated with the volcanoes Mt. Longonot and Mt. Suswa (Figure 1) possible, by its extended horizontal reach. Promising surface exploration studies have been undertaken in both of these prospects and these fields are earmarked for exploration drilling after the Olkaria Domes field.

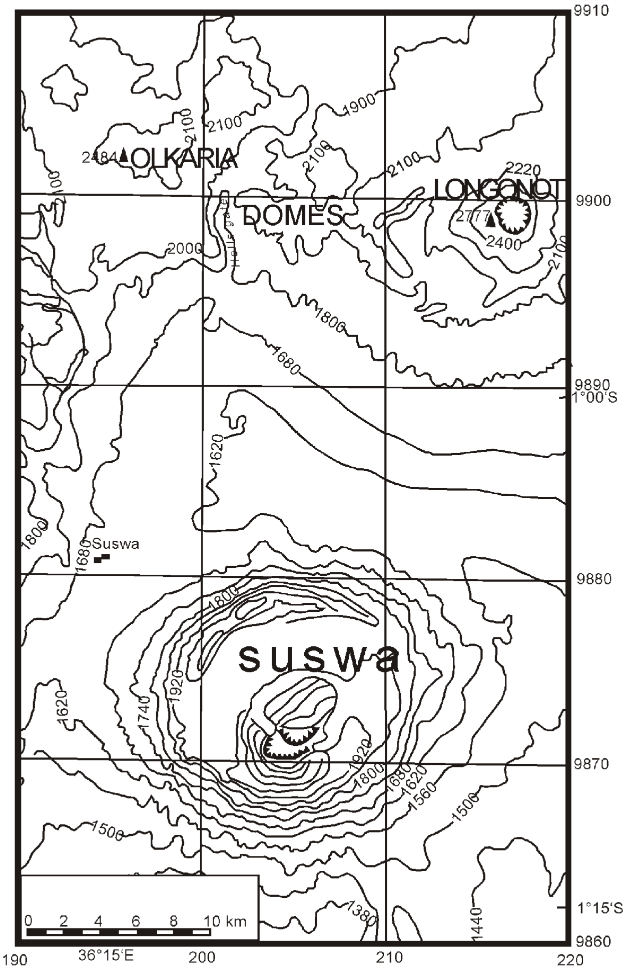

FIGURE 1: Location of Olkaria Domes, Longonot and Suswa prospects (Ng'ang'a, 1995 - redrawn by author)

KenGen embraces the norm of sustainable development and is committed to environmental conservation. Environmental concerns are now embodied in Kenyan law and are a major consideration of funding agencies that support geothermal development in the country. Directional drilling will be a tool to exploit geothermal resources in a fragile environment. Reduction of land requirements will reduce conflicts between geothermal power development and other socio-economic activities.

Geothermal power is very important to Kenya because, besides being indigenous, it is the least-cost energy source for Kenya and offers diversity to predominantly drought prone hydropower. According to the updated least cost power plan for Kenya (Kenya Power & Lighting Co. Ltd, 1997), analysis of the total capital and variable costs for several types of resources indicated that geothermal is the least-cost resource available for Kenya at about 80% capacity factor. In addition, the country has vast geothermal resources manifested in the Rift valleys in more than 20 prospective areas that are largely unexploited (Ng'ang'a, 1998). Geothermal currently contributes 57 MWe to the interconnected national electrical power grid in Kenya.

The national electrical power expansion plan requires that an additional 560 MWe generated from geothermal sources be connected to the grid over the next 20 years (Kenya Power & Lighting Co. Ltd, 2001). Two geothermal power plants currently under construction will together generate 112 MWe. The rest of the power will be provided by seven 64 MWe power plants. Up to 210 wells will have to be drilled to supply steam to these plants.

KenGen is the executing agency for the geothermal development programme (Ng'ang'a, 1995). Under the programme, sustained drilling activity has been undertaken since 1973. KenGen owns and has been operating a National N370 rig for the last 22 years. Its employees man all positions on the rig. All wells drilled by this crew are vertical. A few wells that required sidetracking necessitated the hiring of expertise from abroad. The N370 rig, though able, has not been used to drill directional wells due to its limited reach (hook load). With the aging of the N370, it has become necessary to procure a new rig in order to meet future drilling requirements. It is now agreed that the next KenGen rig to be purchased should have directional capability to the economic depths of the Olkaria geothermal system (2000-3000 m vertical depth) in order to harness the various benefits directional drilling capability avails.

Adoption of directional drilling will, however, result in increased well cost, drilling time and changes in certain operations, casing and bottom hole assembly (BHA) designs. Additional tools and instruments will be required. Certain difficult drilling problems are likely to increase, particularly doglegs, stuck casing and drill pipes and fishing operations.

This report considers the technical aspects necessary to plan and implement directional drilling. It includes a technological overview, well design and unique problems related to the actual directional drilling operations and the practice and experience in other geothermal fields in different parts of the world. Recommendation of the best strategy for development of Olkaria Domes field is made. It also explores the economic implication of the increased costs associated with directional drilling vis-à-vis the cost of vertical wells for an entire geothermal power project with Olkaria Northeast geothermal field as a case study.

2. DIRECTIONAL DRILLING TECHNOLOGY OVERVIEW

The following directional drilling technology overview is mainly a review of two books by French Oil and Gas Industry Association (1990) and Inglis (1987). Any other references are indicated. It is pertinent to note that this literatures is biassed towards petroleum drilling practices.

2.1 General application of directional drilling

Directional wells are drilled for various reasons as follows:

a) Inaccessible locations such that drilling can not be undertaken directly above the resource, e.g. under mountains, below populated or tourist areas, drilling below sea from shore, etc.

b) To optimise capital investment required for supporting the rig and all or part of the production equipment, e.g. roads, drilling water pipelines, rig shifting, steam pipeline and separation stations, etc. This is achieved by drilling many wells from a single site. In offshore drilling operations, as many as 60 wells can be drilled from a platform.
c) To minimize pollution and noise, e.g. tourist areas, urban, conservation areas (game parks).
d) To solve drilling problems, e.g. relief wells to contain blowouts, sidetracked wells to avoid junk in hole.
e) To target or avoid key geological structures, e.g. faults, salt domes for oil drilling, etc.

2.2 Terminology and definitions

Directional drilling is the art and science involved in the deflection of a well bore in a specific direction in order to reach a pre-determined objective or target below the surface of the earth. Figure 2 shows the main dimensions of a directional well.

Directional well: A well where the vertical line passing through the target (well bottom) is located at a certain horizontal distance from the vertical line passing through the wellhead. Vertical wells are wells with inclination within 5°. Wells with inclination greater than 60° are referred to as highly deviated wells. Wells with a section having an inclination greater than 90° for a significant distance are called horizontal wells.

Displacement: The horizontal distance between the vertical lines passing through the target and the wellhead.

Azimuth: The angle (°) between the north direction and the plane containing the vertical line through the wellhead and the vertical line through the target.

Inclination: Angle (°) made by the tangential section of the hole with the vertical.

Kick-off point (KOP): The depth at which the well is first deviated from the vertical.

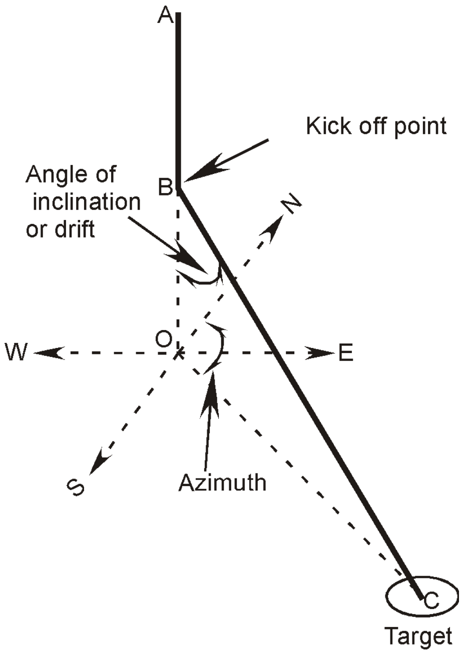

FIGURE 2: Important dimensions of a directional well (modified from Gabolde & Nguyen, 1991)
ABC: Well path followed by bit;
ABC: Measured depth;
AO: True vertical depth;
OC: Deflection or displacement;
Angle CONorth: Azimuth;
Angle OBC: Inclination or drift angle.

Build-up rate: The angle from the kick-off point is steadily built up. This is the build-up phase. The build-up rate (°/30 m) is the rate at which the angle is built.

Drop-off point: The depth where the hole angle begins to drop off (i.e. tending to vertical).

2.3 Directional drilling practice

Segments of a vertical well are classified based on the bit/casing sizes or use. A directional well can further be zoned out into four sections namely the vertical, build-up, tangential and drop-off sections based on their inclination (Figure 3).

The vertical section is drilled conventionally by rotary method. Jet bits or whipstocks were used in the past to deflect the well and special angle building bottom hole assemblies (BHA) used to increase the angle as required. A stiff assembly was used to drill the tangential section while maintaining the angle of inclination. A pendulum BHA drills the drop-off section while the angle of inclination is reduced tending to vertical.

The most commonly used method today is a downhole motor coupled to a bent-sub used to deflect the well, building angle, and drilling straight through the tangential section and to drop angle.

Surveys are carried out to orient the deflection tool to the desired direction. Additional surveys are made with logging tools to determine the actual inclination and direction (azimuth) as drilling progresses. The latter surveys are used as records and also for correction of the well path to the desired inclination and direction. Now, most of this information is transmitted from the mud tool on top of the mud motor and the wireline logs used to confirm the readings.

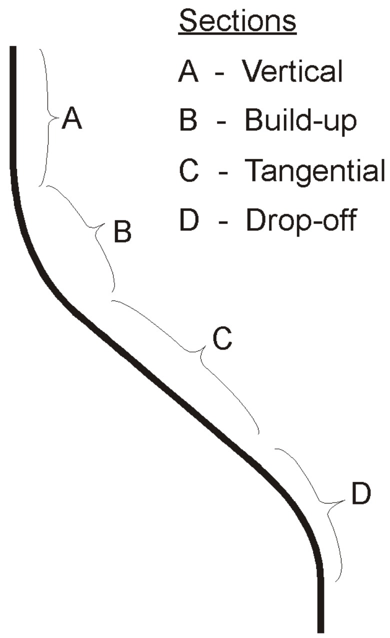

FIGURE 3: Section of a directional well

2.4 Factors involved in directional well planning

Target shape, size and selection of optimum surface location for a drilling rig: The reservoir needs to be defined. The target or area to be penetrated by the well should be specified at a stated depth. Consideration is made for any geological structures and well spacing. The target would normally be defined as a radius (30 m) because it is difficult to steer the bit with absolute precision. The rig location should take advantage of formation deviation tendencies and existing infrastructure, e.g. access roads, waterlines, etc.

Selection of basic hole pattern (trajectory profile): Figure 4 shows examples of directional well profiles.

Type I profile is most common and least complicated to achieve. At the selected kick off point, the well is deviated to the desired angle, and that angle is maintained constant to total depth. It is commonly employed in moderate depth drilling, in areas where the production formation is located in a single zone or in deeper wells requiring large lateral displacement. The typical range of angle of inclination is 15-55°.

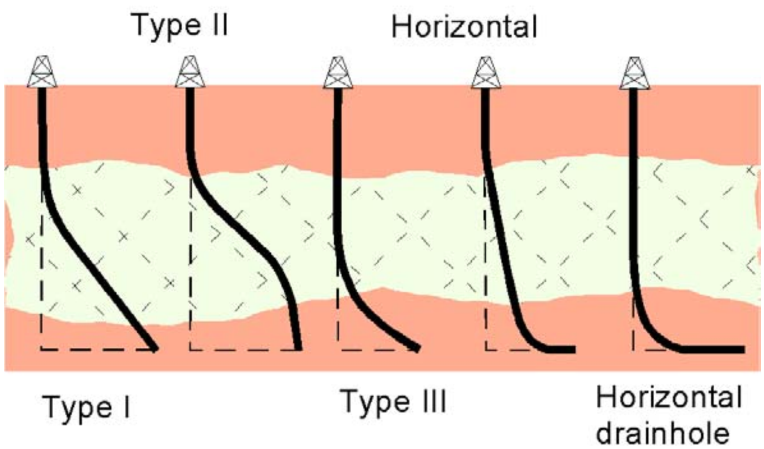

FIGURE 4: Main types of horizontal well profiles

Type II profile wells are normally demanded to facilitate the performance of complex operations e.g. multiple pay zones, lease or target limitation. The well is deviated to the desired angle and lateral displacement and then returned to vertical before entering the potential reservoir. Type II profile requires careful consideration before implementation. Since the angle change will occur deeper in the well where the formations are harder, directional control may be more difficult. In addition, since angle dropping requires fewer stabilizers in the bottom-hole assembly (BHA), azimuth control problems may occur. If a hole with a high-angle is returned to the vertical position, key-seating may develop if a long section of vertical hole is drilled. Type II profile will usually require 10-20% more drilling time than a Type I profile.

Type III profile is only used in particular situations such as sidetracking.

Horizontal wells have important applications in improving production from certain reservoirs that otherwise would be uneconomic. They have more than one build-up section. Horizontal drainhole is used in oil reservoirs to produce from tight formations and reduce gas or water coning problems. A special BHA is required with articulated collars and knuckle joints. The angle is built up very rapidly, e.g. 20 °/m (2° per foot).

Selection of kick-off point (KOP): A determining factor for the success of the directional drilling operations is to select the best kick-off point or depth at which the directionally drilled section is to be started. The KOP must be selected with due consideration of the drillability of the formations, and the ease of kick-off. The KOP is usually selected in soft-medium, shallow formations where directional drilling is easier. Formations in the deeper part of the well are harder, making it more difficult to achieve directional control. Very soft formations will result in washouts. In addition, the KOP is often selected so that the final angle built up can be achieved prior to setting intermediate or anchor casing. This approach minimizes key-seat problems in holes. Build-up should not be started in a loss or difficult zone.

Selection of inclination or drift angle: A minimum drift angle of approximately 15° is desirable. A common upper limit is 45-48°. Drift angles greater than this range encounter problems such as increased torque and drag in addition to the requirement to pump down some logging equipment. To remain within the framework of normal operations, the limit of running in wireline tools under their own weight is used to determine the maximum hole inclination. Many operators establish 35° as their upper limit. The target depth must be put into consideration. Deeper wells are more difficult to drill than shallow wells. Drift angles with an upper limit of 45-55° are recommended for deep wells (4000-5000 m), and 55-60° for shallow wells (2000-2500 m).

Selection of build-up rate: The build-up rates are measured as °/30 m (°/100 ft) of wellbore path. Typical ranges for build-up and drop-off angle rates are 1-3°/30 m, with 3°/30 m being the most common. Angles that are greater can create dogleg and key-seat problems. However, it is recommended that the drop-off rate be less than 1.5°/30 m.

Casing programme: Figure 5 shows the typical casing profile of a directional well. The conductor pipe and surface casing are normally vertical and cover the formations above the KOP. The 13⅜" O.D. intermediate casing string covers the build-up and part of the straight section. The production casing is usually set at the top of the reservoir.

It is recommended that the build-up zone be cased immediately after drilling that section. This is because unforeseeable difficulties, e.g. losses, water inflows, or fishing, may considerably increase the drilling time of the tangential section after the build-up.

Typically, the KOP is at least 50 m below the shoe of the surface casing (20" OD) and the build-up section cased with a 13⅜" O.D. casing. The casing at the build-up

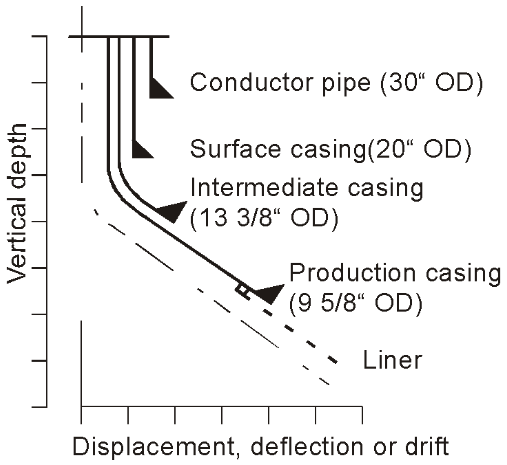

FIGURE 5: Typical casing programme

zone and subsequent casing strings must pass through the deflected part of the well. The casings sustain stresses due to the imposed curvature. In addition, the casings are subject in the same zone to increased wear due to friction of the rotating drill string. It is therefore important to use new and sufficiently thick casings with buttress or VAM joints and to avoid using API round eight-thread joints, which tend to disconnect in the case of bending. The casing must be fitted with enough centralizers to make them easier to run in and to prevent sticking. The number and the position of the centralizers should be calculated according to their restoring force and the position of the lateral component of the casing weight, which depends on the well geometry. Computer programs that solve this problem are available from certain suppliers.

2.5 Deflection tools

2.5.1 Jet bits

The jet bit is a fast and economic deflection tool that was used to deviate well bores in soft, highly drillable and homogeneous formations. It is a two or three cone bit, with three jet nozzles – two small and one large. This method is, however, not suitable for the volcanic rocks in geothermal systems.

The BHA consists of the bit, an extension sub, full gauge near bit stabilizer with a non-return valve recess, non-magnetic drill collar, two standard drill collars, another stabilizer and the normal string. The assembly is lowered and oriented with the large bit nozzle in the desired azimuth. Maximum mud circulation is then established and the washing action begins. While pumping, the drill string is reciprocated up and down washing out a large jet eye (Figure 6). After making 1.5-2 m (5-7 ft), the hole is conventionally drilled about 6 m (20 ft) using the same assembly. The procedure is repeated until the desired angle and direction are obtained. Frequent surveys help maintain control. The economics of the process, which depend on the time spent in actual jetting, generally limits its use to depths less than 1200 m.

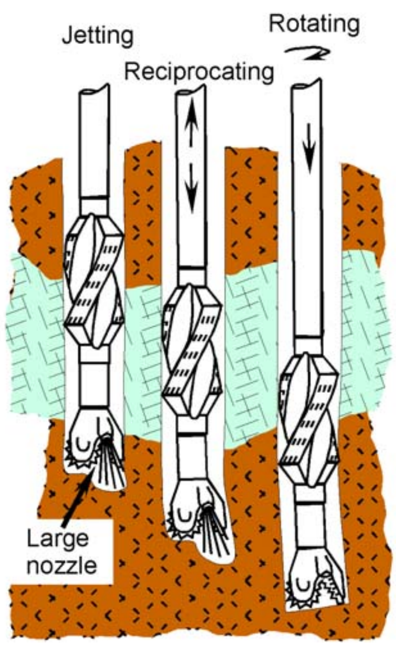

FIGURE 6: Schematic drawing of kick-off procedure with a jet bit

2.5.2 Whipstock

Using a whipstock is another method from the past. It is not used for drilling geothermal wells, but has at times been used to drill past an obstruction or deflect the bit out of the main hole where the casing has been milled. The whipstock is a wedge shaped casting, generally of steel, with a slightly tapered concave groove on one side that holds and guides a whipstock drilling assembly. The bottom is chiseled-shaped to press into the formation at the bottom to prevent it from turning. It has a heavy collar at the top with a shear pin, which ensures a fixed position with respect to the string when going into the hole and withdrawal of the tool from the hole. The whipstock is run with a BHA consisting of a properly sized whipstock drill bit, a spiral stabilizer and an orienting sub rigidly attached to the whipstock by means of a shear pin.

The whipstock is run in the hole; at the bottom, the tool is oriented in the desired direction. Weight is applied to the tool to force the chisel point into formation to prevent rotation, additional weight is applied to shear off the shear pin, and the bit is rotated at low speed (Figure 7). After drilling about 6 m (20 ft), the assembly is retrieved from the hole, and the hole is enlarged using hole openers. If the formation is relatively soft, or if the kick-off point must be some distance from the bottom, it is necessary to install a cement plug. The tool only helps to create a kick-off and is complemented by a build-up BHA. If the first 10 m of the kick-off are off course by about 20 to 30° azimuth, a cement plug will be set and the procedure repeated about 9 m above. Regular surveying is necessary.

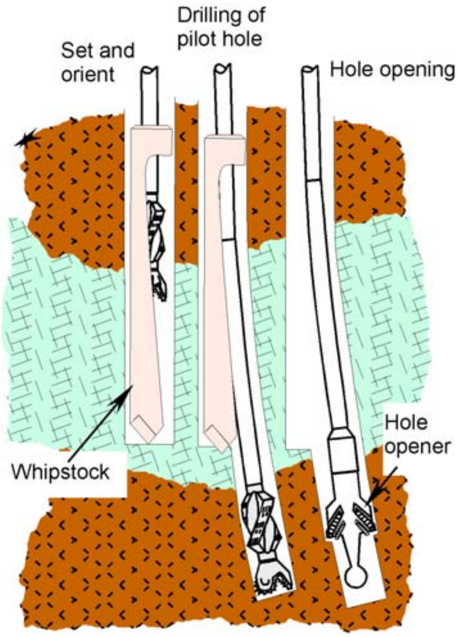

FIGURE 7: Schematic drawing of kick-off procedure with a whipstock

The technique is especially suitable in the situation where there is insufficient pumping capacity, the rig is small, there is low power due to altitude, and very high downhole temperature.

2.5.3 Bent sub and downhole mud motors

The downhole motor is today's most widely used deflection tool and is, in many cases, used to drill the well to total depth. It is driven by drilling fluid flowing down the drill string to produce rotary power downhole that is transmitted to the bit, thus eliminating the need for rotating the drill string. A possible BHA includes a full-gauge ordinary rock bit, the downhole motor with a stabilizer, a bent sub, stabilizer, a non-magnetic drill collar, measurement while drilling (MWD), ordinary drill collars, a jar and the normal drill string. The bent sub is used to impart a constant deflection to the tool. Its upper thread is cut concentric to the axis of the sub body, and its lower thread with an axis inclined 1-3° in relation to the axis of the upper thread. A bent housing (Figure 8) is progressively replacing the bent sub. Surveys are carried out after drilling about 6-9 m (20-30 ft), and any changes in orientation are made as necessary.

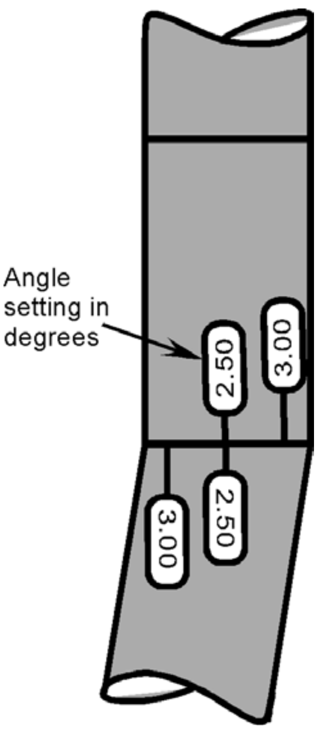

FIGURE 8: Sketch of an adjustable bent housing; some are adjustable at the rig site

The downhole motor presents many advantages over the whipstock and jetting assemblies. It permits the drilling of a full gauge hole at the kick-off point, thus eliminating costly follow-up trips to ream the hole to full gauge. Orientation is also more accurate since the motor penetrates along a smooth gradual curve in build-up and drop-off portions. The motor eliminates the need for clean up trips due to bridges, doglegs etc., since the tool can be circulated and drilled to the total depth.

There are two different types of motors the positive displacement and turbodrill motors. The positive displacement motors have superior features over the turbine motors.

The positive displacement motor consists of a steel shaft rotor that is shaped in the form of a spiral or helix and a stator (Figure 9). The cross-section of the rotor shaft is dependent on the number of lobes. For a single lobe, the shaft is circular while motors with more than one lobe have a complex configuration. The shaft is free at the top but attached to a drive train at the bottom. The stator is a moulded rubber sleeve that forms a spiral passageway to accommodate the rotor. The rubber sleeve is fixed to the steel body of the motor. The axis shaft is assembled with an eccentricity to the axis of the stator.

The rotor and the stator form a series of sealed cavities so that when drilling fluid is pumped into the tool, the rotor will be driven in eccentric rotary motion relative to the stator, allowing the fluid to pass through while transmitting rotational power to the drive train and bit (Baker Hughes, 1998). The drive train consists of a universal joint that converts the eccentric motion to concentric motion and transmits the motion to the bit via a drive shaft and bearing assembly. The speed of the motor is dependent on the number of lobes and the pumping rate. The more numerous the lobes, the lower the speed and the greater the torque developed.

The motors can be operated by air, foam, water and some mud based drilling fluids. The use of rubber parts limit the use of the positive displacement motors to a temperature of up to 175°C and limit oil based drilling fluids. The life of the motors are also limited by the bearing that is the most critical component. The motors can be run continuously for a period of between 100 and 200 hours before a major overhaul is required.

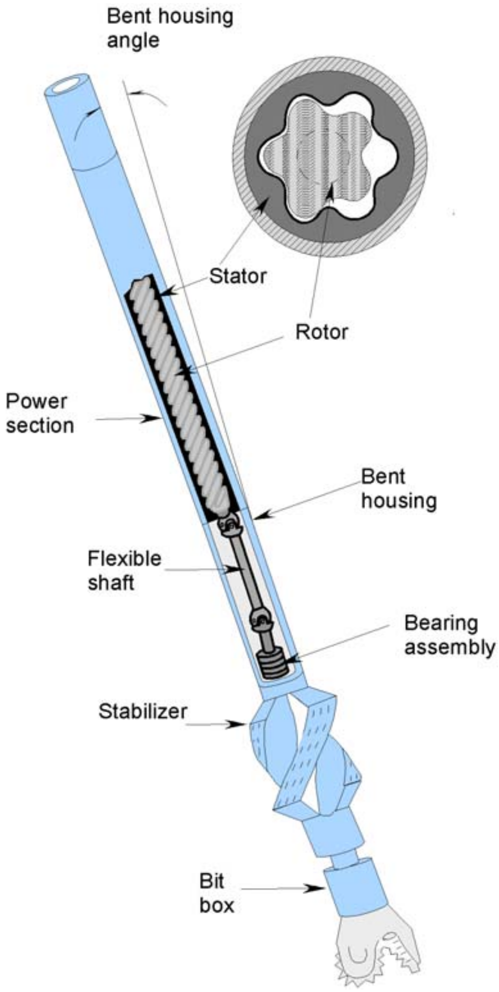

FIGURE 9: Positive displacement mud motor

Turbodrill or *a turbine type motor* is a rugged multistage axial tool that has proven to be highly efficient and reliable, especially in areas of medium to hard formations. The fluid flow rates required are high, and very often demand large on-site pumping capacity. The major application of turbodrills is to drill the long tangential section of the deviated well. Shorter turbodrills may be used for kick-offs with a bent sub, but positive displacement motors are usually preferred.

The turbine consists of a series of rotors and stators. The rotors have carbon steel alloy blades that are mounted on a vertical shaft while the stator stages are fixed to the body of the turbodrill. The turbodrill can have between 25 and 250 stages (pairs of rotor and stator). As the drilling fluid is pumped through the turbine, the stators deflect the flow of fluid against the rotors, forcing them to turn the vertical shaft in a clockwise direction.

The turbodrills are sensitive to the drilling fluid conditions. Any solid particles or debris in the mud could easily cause clogging of the motor. A sand content of 2% or more could also cause excessive wear of the turbine blades. Loss of circulation material (LCM) cannot be allowed through the turbine and are diverted through a circulating sub installed above the turbine for this purpose. A straining device must be fitted to protect the turbine from any debris in the mud. The turbodrills operate at speeds of 720-1100 rpm (Gabolde and Nguyen, 1991). For this reason, they cannot be used with conventional bits whose speeds range between 30 and 175 rpm (Gabolde and Nguyen, 1991). The turbodrills are most commonly run with natural diamond and polycrystalline diamond compact (PDC) bits. The optimal operation conditions for turbodrills are sufficient pump capacity at discharge pressure over 276 bars (4000 psi) and larger diameter drill pipe for better pump performance with an appropriate bottom hole assembly.

2.6 Directional surveying

Logging is an integral part of all drilling operations. The data sought can be categorised as directional, temperature and pressure, formation characteristics and drilling parameters. In directional surveying, the hole inclination, azimuth and the toolface are obtained. The toolface is the direction in which a bit is oriented in the hole. Directional surveys are carried out to:

i) Monitor the actual well path as drilling continues to ensure that the target will be reached;
ii) Orient deflection tools in the required direction when making corrections to the well path;
iii) Ensure that the well being drilled is in no danger of intersecting an existing well nearby;
iv) Determine the true vertical depths of the various formations that are encountered to allow accurate geological mapping;
v) Determine the exact bottom hole location of the well for the purpose of monitoring reservoir performance and also for relief well drilling;
vi) Evaluate the dog-leg severity along the course of the wellbore.

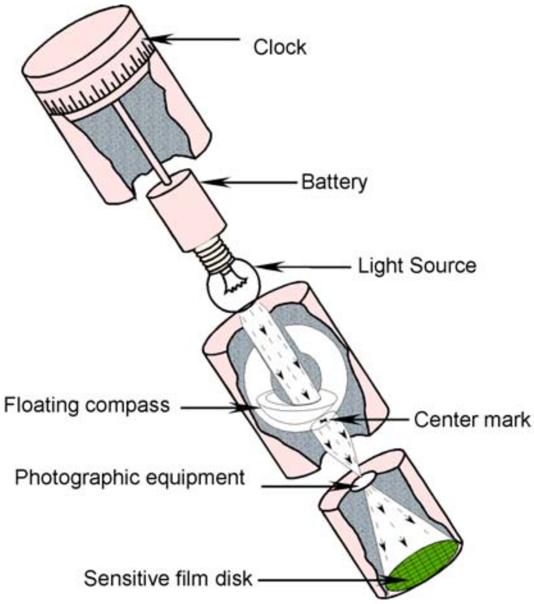

FIGURE 10: Single shot magnetic directional survey instrument

Magnetic single shot and multishot instruments are photomechanical devices that use a plumb bob to measure inclination and a compass direction (Figure 10). A camera with a light assembly is incorporated into the instrument to photograph the angles downhole onto a photographic disk. A timer or motion-sensing device activates the unit. The results for magnetic single and multishot must be corrected for magnetic declination (difference between magnetic and true north). The multishot instrument in place of a photographic disk has a photographic film reel and is capable of taking a series of pictures at pre-set intervals. The magnetic instruments cannot give accurate results in a cased hole or near other wells that have been cased. Its other disadvantage is that it takes ½ to 1½ hours to carry out a single survey. The instrument is very reliable but rarely used today.

Gyro single shot and multishot are instruments very similar in working principle to the magnetic single shot and multishot except that the magnetic compass is replaced by a gyroscopic compass that is not affected by the magnetic fields. The instruments are therefore suitable for use in the cased hole or near other wells. The gyroscope consists of a spinning wheel mounted on a horizontal axis driven by an electric motor. The direction in which the gyro is spinning is maintained by its own inertia and can be used as a reference for measuring azimuth and inclination. The gyro is aligned to true north before running it in the hole. The instrument's major problem is that allowance for gyro drift from the set direction as the instrument is run in the hole is required. Correction is applied to the results to allow for the drift.

The above tools are run on wireline. However, the magnetic instruments can drop into the drill string before tripping out. They require that drilling be stopped in order to carry out surveys. Frequent surveying and re-orientation can be time consuming and expensive.

Steering tool is run in the bottom hole assembly to survey the well continuously while it is being drilled with downhole motors. The tool consists of electronic probes that are run in the hole on a conductor cable and provide the directional driller with the necessary information to steer the bit in the correct direction. The instrument conveys data via the conductor cable to the surface where the data is analysed in real time. The advantage with this instrument is that it eliminates the large number of wireline trips required to take surveys and check orientation, thus saving rig time. Continuous monitoring will reduce the risk of the well straying off course and therefore reduce the number of correction runs. Owing to better control, the well path should be smoother with fewer doglegs.

The most common method to obtain hole trajectory information is called *Measurement while drilling (MWD)*. MWD, like steering tools, provides information while drilling is in progress (Figure 11). In addition, it is not limited to a non-rotating string as in the case of steering tools. The main difference is that unlike the steering tool that transmits data on a cable, the MWD transmits pressure pulses through the drilling fluid generated by the tool. The transmitter creates a series of pulses that are detected on the surface by a transducer and decoded by a surface computer. The pressure pulses are generated typically every 10–60 s.

Both steering tools and MWD use robust downhole electronic sensors called *magnetometers* and *accelerometers.* The magnetometers and accelerometers respond to the earth's magnetic and gravitational fields respectively. Like all magnetic tools mentioned above, magnetometers are run inside non-magnetic drill collars to isolate them from magnetic fields in the steel drill pipe and collars. They also suffer inaccuracy when run in a cased hole or near other cased wells.

Rate gyro instruments are north seeking gyroscopic tools that eliminate the need to align them on the surface. This eliminates errors introduced by conventional gyroscopic tool drift.

Continuous guidance tools (GCT - Schlumberger) are tools designed to survey cased boreholes without stopping at each survey point. This allows an accurate survey of the complete trajectory of the well in a much shorter time. The tool works on the principle of an inertial platform consisting of a dual-axis gyroscope that is north-seeking and a dual-axis accelerometer.

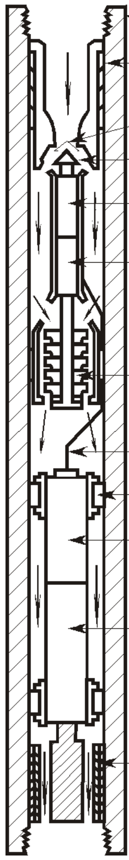

FIGURE 11: Measurement while drilling (MWD) instrument

The well course is reconstructed by computation of inclination and azimuth measurements with respect to a reference direction at different depths or survey stations distributed along the well path. In addition, course correction while drilling requires knowledge of the orientation of the drilling string in the hole, sometimes called the tool face.

The survey tools are categorized based on the following:

- Operation principle e.g. magnetic, inertia (gyroscope) etc.;
- Number of measurements they allow per run;
- Immediate or delayed reading;
- Possible use during drilling;
- Need for wireline;
- Tool diameter and length;
- Operating procedure, e.g. need to stop rotation etc.;
- Survey cost.

Table 1 shows the various instruments and their characteristics.

The general trend is to use the MWD tools as drilling progresses. The MWD tools are designed to provide real-time, or instantaneous, recording and transmission to surface of the downhole data. This is their main advantage. In addition, some bottom hole assemblies are capable of altering the bit direction and drift easily by an appropriate drilling procedure. They also cut rig time for surveying, which is substantial in directional drilling.

TABLE 1: Directional survey instruments

Instrument	Op. princ.	No. of Surveys	Type	Readout	Diameter	Line	Procedure	Time
Single-shot	M	1	Optical or mechanical	Delayed	1 ¼”	Wireline	Drilling stopped	Depends on depth
Multishot	M	≈ 300	Optical	Delayed	1 ¼”	Wireline		Depends on depth
Steering tool	M	Unlimited	Electrical	Immediate	1 ¾”	Single conductor	While drilling	
Teleco (MWD)	M	Unlimited	Electrical	< 3min	8” drill collar	None	While drilling	
Schlumberger (MWD)	M	Unlimited	Electrical	< 1 min	8” drill collar	None	While drilling	
Free gyr	G	≈ 300	Optical	Delayed	3”	Wireline	Drilling stopped	Depends on depth
Cable gyr	G	Unlimited	Electrical	Immediate	3”	Single conductor	Drilling stopped	Depends on depth
Ferranti	G	Limited by battery size	Electrical	Delayed	10 5/8”	Wireline	Drilling stopped	
Schlumberger sonde	G	Unlimited	Electrical	Immediate	3 5/8”	Logging	Drilling stopped	Very fast

The MWD measurements are normally complimented with magnetic multishot surveys before setting casing in directional wells.

2.7 Drilling problems unique to directional drilling

Delivering weight to the bit: In vertical well drilling, practically all available drill collar weight is transmittable to the bit. In directional drilling, only a fraction of the available drill collar weight is transmitted to the bit. Drill string drag due to gravity and also the tendency of the tool joints to plough the wellbore further decrease the fraction of drill collar weight transmitted to the bit. In horizontal drilling (inclination of 90°) the fraction approaches zero. In this scenario, downhole motors are used or drill collars are run in the vertical section of the hole. However, running drill collars on the vertical section of the hole subjects the string to compressive forces that increase the tendency of the string to fail.

Increased torque and drag: Drag on the drill pipe increases with the angle of inclination. As the angle approaches 90°, the string weight is transferred from the hook load to drag weight. As the pipes in directional wells lie on the lower side of the wellbore, friction increases resulting in increased torque. For a 3000 m well deflected at 40°, it is common to have between 10 and 30 tons of friction while tripping. Mud control is extremely important in decreasing the drag in a directional well. Friction reducing additives e.g. oil, torque trim or glass beads can be added to the drilling fluid, with mud weight and viscosity kept under control at all times.

Drill string and casing abnormal wear: Drill pipe wear is inevitable in a deviated well. As the pipes rotate against the casing, the casing also sustains wear. Hard facing on drill pipes must be avoided to spare casings. Uses of high-temperature rubber protectors are recommended to spare both casing and drill pipe in high-inclination wells. The protectors should have oversized spirals. Note that drill pipe wear in deviated holes is significant and has, at times, been a problem in contractual relations between well owners and the drilling contractors.

Increased hole cleaning problems: In holes that exceed 45° inclination, there is a tendency for cuttings to form beds on the lower side of the bore, which increase drag, increase risks of the pipe sticking, and pipe failure. In addition, hole angle affects hole cleaning because cuttings removal depends on the vertical component of fluid velocity rather than normally calculated annular velocity. Drill pipe movement regrinds cuttings to very fine powder subjecting the solid control equipment to great strain. Note that the use of MWD tools will normally demand the maintenance of very low (1% or less) sand content in the drilling fluid.

Dogleg severity: A dogleg may be defined as an abrupt, large change of angle over a short distance and can subject high bending stresses on the string. This often results in drill string failure due to fatigue, excessive wear on string (most serious problem) and key-seating problems. Although doglegs are not unique to directional drilling, they are given great attention.

Effects of drill string magnetism and adjacent wellbores on survey instruments: Experience has shown that a drill string worked in a borehole usually becomes magnetized. Also some surveys taken in adjacent holes may be affected by residual magnetism in the casing of previous holes. These effects affect magnetic instruments, e.g. the single and multi-short magnetic survey instruments. Using non-magnetic drill collars that prevent inconsistencies in survey readings can compensate for these effects.

Bit walk (lateral drift): The tendency for the bit to drill a hole curved in the right hand direction is known as bit walk. The right hand rotation and increase in bit offset cause it. It may also contribute to the increase in the hole inclination. Evidence exists that increase in bit offset in a specific bit increases the tendency for the bit to walk towards the right and may also contribute to the increase in the hole inclination. Bits with zero drift are said to check these deviation tendencies. A packed hole assembly is the best method of controlling inclination and direction caused by bit walk. Bit walk is, however, not unique to directional drilling but is also experienced in vertical drilling.

Rebel tools are specially designed to counteract bit walk. The primary purpose of the tool is to cause the bit to walk to the left or the right as desired and consequently correct azimuth. The tool exploits the fact that a BHA in a deflected hole lies on the lower side of the hole. It is only effective if the inclination is at least 8-10°, and the speed of rotation is not more than 80 revolutions per minute (rpm). Changing rpm or weight on the bit operates the tool. As such, the tool can be regulated while drilling.

Fishing: Fishing in directional drilling is about five times more common than in vertical drilling.

Running casing and survey tools: Substantial friction (drag) is encountered in directional drilling when running casing, e.g. 60 tons drag is normal for a 3000 m hole deviated at 30°. Consequently, it is recommended that rig capability be for about 30-50% deeper hole than the total depth of the planned directional well. Special logging procedures and pumping of wireline tools become necessary at elevated angles (50-60°) of inclination.

Cementing: Deviated wells pose a unique problem during cementing that compromises the integrity of the cement anchorage. This is because the cement slurry moves faster than the mud on the lower side of the casing, and is polluted at the upper side. Use of scratchers, reciprocating the casing before cementing and proper reconditioning of mud before cementing are methods suggested to alleviate this problem.

2.8 Drilling performance and cost indicators

The following can be said about drilling performances:

- Directional wells are more difficult to drill. Specialized skills are required to deviate the hole, to steer the bit in the desired course without trouble. Great effort is made to plan directional wells.
- There is an increase in the number of trips to survey and change or adjust bottom hole assemblies.
- Fishing increases and accounts for about 10% of the drilling time. Fishing is about five times more common in directional drilling than in vertical drilling.

The following gives indications about costs:

- Directional drilling requires a larger rig for a particular depth, additional tools for deflection and a higher grade of drill pipe.
- It is recommended that a thicker casing be used at the build-up zone due to abnormal wear and use of a greater number of centralizers in the deflected part of the hole.

- Additional surveying tools/services become necessary.
- Specialized drilling services, e.g. a directional drilling specialist may become necessary.
- It normally takes about 30-50% longer to drill an average deviated hole than to drill a vertical hole due to increased surveying, tripping and fishing.

2.9 Geometrical planning for Type I profile

Gabolde and Nguyen (1991) have given the procedure for the calculation of the various measurements relating to directional well profile, as shown below. The following dimensions would be decided in advance (Figure 12):

Vertical section (KOP)	-	Z_K
True target vertical depth	-	Z
Build-up angle	-	α
Horizontal displacement	-	D
Inclination angle	-	i

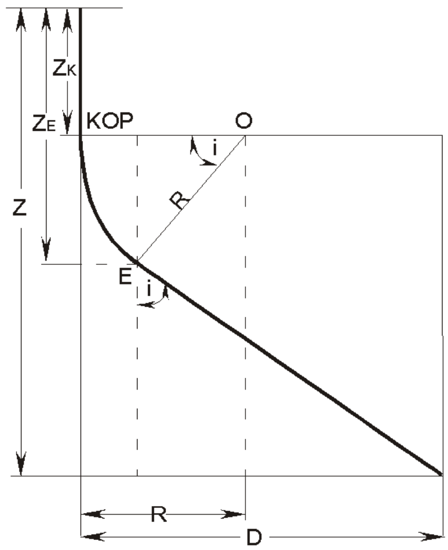

FIGURE 12: Type I profile

The radius R is given by

$$R = \frac{360}{2\pi}\frac{1}{\alpha} \tag{1}$$

The length of build-up section L_E from surface,

$$L_E = Z_K + \frac{\pi iR}{180} \tag{2}$$

The true vertical depth at end of build-up Z_E,

$$Z_E = Z_K + R\sin i \tag{3}$$

The total measured well depth TD,

$$TD = Z_K + \frac{\pi iR}{180} + \frac{Z - Z_K - R\sin i}{\cos i} \tag{4}$$

3. EXPERIENCE OF DIRECTIONAL DRILLING IN OTHER COUNTRIES

3.1 Philippines

The country of Philippines is ranked the second electrical geothermal power producer in the world with an installed generation capacity of 1909 MWe (Huttrer, 2000). Directional drilling was employed in Tongonan, and Palinpinon (South Negros) (Sanyal et al., 1982; Tracey and Vasquez, 1982; Jordan, 1982; Stefánsson 1987) and Mahanagdong sector of Leyte geothermal field (Talens et al., 1997).

Directional drilling was adopted in Palinpinon because of the limited number of available flat drilling-pad sites. The strategy adopted was to drill several wells from a single pad. The area of drilling was extremely rugged and forested terrain in a tropical climate. Building of access roads was difficult while both drilling sites and roads were subject to flooding and mud slides during the rainy season. Difficult access increased drilling costs (Sanyal et al., 1982). Tracey and Vasquez (1982) have added that the economics of drilling vertical wells with the associated roads, well site and pipelines as opposed to directional wells to the same targets but from accessible sites near the power plant was also a consideration. Stefánsson (1987) reports further that a scenario had become evident as well completion tests progressed, that a network of high angle faults with a NE-SW strike controlled the reservoir fluid flow. As a consequence, directional drilling was systematically used to target as many production fractures as possible. Table 2 is a summary of the directional drilling practice and experience while drilling the two fields reported by Tracey and Vasquez (1982).

TABLE 2: Summary of directional drilling practice in Philippines

Trajectory profile	Type I (build and hold)
Kick off point	350 m approximately, the KOP is at least 30m from the anchor casing depth
Angle of inclination	15-45°
Casing design (typical)	20” surface casing to 85 m depth - vertical section 13⅜” anchor casing to 320 m depth– vertical section 9⅝” production casing to 1400 m minimum depth– deviated section 7⅝” liner to hole bottom about 3000 m – tangential section
Build-up angle	2°/30 m
Deflection tool	7¾” diameter Dynadrill (positive displacement motor) with 12¼” bit (limited to a temperature of 120°C). The motor was used to kick off and after 30 m, a build-up conventional rotary assembly was used to increase the angle on inclination to the desired value
Tangential section	Drilled using a stiff assembly
Directional control	6½” diameter Dynadrill used to correct well path deviation in the tangential section. It was planned that azimuth be maintained after kick-off.
Drilling fluid	Primarily mud, changed to water if persistent total loss of circulation was encountered
Survey tool	Single shot (Sperry Sun type B) fitted with heat shield. The tool resisted temperature of up to 425°C. Surveys were taken every 12, 50 and 75 m while drilling with the motor, build–up bottom hole assembly, and the stiff assembly respectively. Survey duration ranged between 15 and 90 minutes depending on depth. Gyro multishot instrument was run when concerns of external magnetic interference existed.

Several problems unique to directional drilling were encountered. The bit life was drastically reduced by up to 80-83% while drilling with the motors. This was attributed to the very high motor rpm (310 rpm) compared to the design bit rpm of 60-80 rpm. However, length of hole drilled per bit was doubled. Weight on bit was limited to 5-10 tons when using the motor on an 8 ½” bit, unlike 17-20 tons that was allowable using conventional assemblies. High temperatures that were encountered resulted in a slow tripping-in rate of the motor in order to cool the well fluids. The motor life was drastically reduced from about 50 hours to 5 hours in temperatures around 240°C.

Stefánsson (1987) has argued that the result of 40 wells drilled in the Palinpinon geothermal field does not show a clear production advantage of directional wells over the vertical wells, despite the fact that this had been inferred during much of the well testing period. He showed that production from the two types of wells is comparable. The drilling time for vertical and directional wells was comparable. However, it is important to note that the direction wells were drilled much later (Sanyal et al., 1982) when drilling knowledge had been improved and hence higher drilling rates were achieved. Sanyal et al. (1982) concede that directional wells significantly increased costs of the wells. On the other hand, Tracey and Vasquez (1982) conclude that environmental benefits were achieved.

Besides using directional drilling in the above wells, larger completion casings (13⅜” OD and 9⅝” OD production and liner, respectively) were employed in all the above fields (Sta et al., 1997). Sta et al. have reported an increase of up to 200% in production due to this well completion change. As a result, substantial savings were realised arising from a reduction of the number of wells required for the various projects. The larger casing diameter of 13⅜" was also employed in Svartsengi - Iceland (Karlsson, 1982) and yielded double the output of wells with the conventional casing programme (9⅝" OD and 7" OD production casing and liner, respectively).

3.2 Iceland

Geothermal provides about 50% of the total energy supply of Iceland (Ragnarsson, 2000). In Krafla high-temperature geothermal field both directional and vertical wells have been drilled. By 1999, a total of 35 wells had been drilled there, nine of which are directional (Muluneh, 1999). Table 3 gives a summary of drilling of three wells KJ–20 (Ng'ang'a, 1982), KJ-22 (Abera, 1983) and KJ-32 (Muluneh, 1999) representing the directional drilling practice at Iceland.

TABLE 3: Summary of directional drilling practice in Iceland

Descriptions	KJ-20	KJ-22	KJ-32
Reason for employing directional drilling	To cut a fracture at 1000-2000 m depth believed to be vertical or inclined at 15° to the vertical. Permeability fracture controlled and hence greater permeability expected with directional well. First directional well in Iceland.	Aimed at increasing output and was planned to traverse near-vertical faults.	Aimed at traversing faults.
Trajectory profile	Type I	Type I	Type I
Kick – off depth	250 m	350 m	450 m
Angle of inclination	30°	30°	30°
Build-up angle	1-3° / 30 m	1.5° / 30 m	1.5° / 30 m
Casing program	18⅝" OD surf. casing (≤100 m), 13⅜" anchor casing to 250 m, 9⅝" production casing to 650 m, 7" liner to 2150 m,	18⅝" OD surface casing to 43 m, 13⅜" anchor casing to 200 m, 9⅝" product. casing to 550 m, 7" liner to 2150 m	18⅝" OD surf.casing to 62 m, 13⅜" anchor casing to 300 m, 9⅝" production casing to 1070 m (true depth), 7" liner to 1875 m (true dep.)
Deflection tools	Dynadrill with 12¼" bit to kick off; a flexible assembly to build angle to a max. of 20°. Increase angle with 8½" bit to 30; decrease with flexible build-up string and hold to hole bottom	Dynadrill with 12¼" bit to kick off; a flexible assembly to build angle to a max. angle of 11°. Increase angle with 8½" bit to 30 decrease with flexible build-up string and hold to hole bottom	9⅝" OD Halliburton F2000s positive displacement motor with 12¼" bit to kick off and build angle to 30°
Tangential section	Drilled with a stiff assembly	Drilled with stiff assembly	Drilled with 6¾" OD Halliburton F2000S (5/6) positive displacement motor with a 1° bent sub (housing)
Directional control	A fixed azimuth; directional control taken every 30 m	A fixed azimuth.	A fixed azimuth
Drilling fluids	Mud when using the Dynadrill	Mud when using the Dynadrill	Primarily mud to produc. hole and water in reservoir zone
Surveying tools and procedure	Gyro single shot instrument with mule-shoe assembly	Gyro single and multishot instruments. An inclinometer used after the desired inclination was achieved. A gyro multishot used to survey hole after drilling to bottom	MWD used in the inclined hole to bottom.
Total true vertical depth	2000 m	2000 m	1875 m
Horizontal displacement	Approximately 750 m	700 m	170
Number of drilling days*	55 days including 17 days fishing	About 45 days	43 days

* Number of days excludes drilling of the surface casing that is conducted by a different rig

Ng'ang'a (1982) has noted that bit walk was a concern and that directional drilling had complicated the fishing procedure encountered due to twist-off. He has further noted that the cost of directional drilling is about 25% greater than that of the vertical well. Armstead (1983) has reported a 28% cost increase in France. The drilling duration for vertical wells KJ-18 and KJ-19 in the same field were 55 and 53 days, respectively (Abera, 1983). These drilling times are comparable with those for directional drilling.

Muluneh (1999) has detailed the current drilling practice that has graduated from the early practices as reported by both Ng'ang'a and Abera. The kick-off is normally about 50 m below the anchor casing shoe. The kick-off is carried out with a measurement while drilling (MWD) instrument and a positive displacement motor with a bent sub (housing) of appropriate build-up angle. This assembly is used for drilling the 12¼" production hole to the desired angle of inclination with mud as a drilling fluid. Angles of inclinations of up to 35° have been drilled. The tangential section of the well is drilled with a similar assembly holding the angle of inclination constant. The string would normally be rotated making a slightly over gauge hole due to the presence of a bent sub. The bent sub is used for steering the tool face when the bore tends to drill away from the planned well path. The MWD gives instantaneous readings of angles at all times on surface. Well path correction is effected by orienting the tool using the rotary table to rotate the string. At the corrected orientation, the table is locked and drilling progresses with the motor without string rotation for a while referred to as sliding mode. To supplement the MWD, a cable gyro is used.

Production data for both vertical and directional wells for this field is not available to the author. However, considering that the Krafla field is located in a highly fractured area, it would be very interesting to compare productivity of the vertical wells against directionally drilled wells in this field. Karlsson (1982) from his work on optimisation of geothermal well diameter has concluded that larger casing than conventional would have been more economic for the Krafla field in Iceland.

As part of the UNU fellowship, the author witnessed well HE-6 kick off operations and the drilling of the build-up section, at Hellisheidi geothermal field (Hengill geothermal area) in Iceland. Figure 13 shows the planned wellbore trajectory details and the

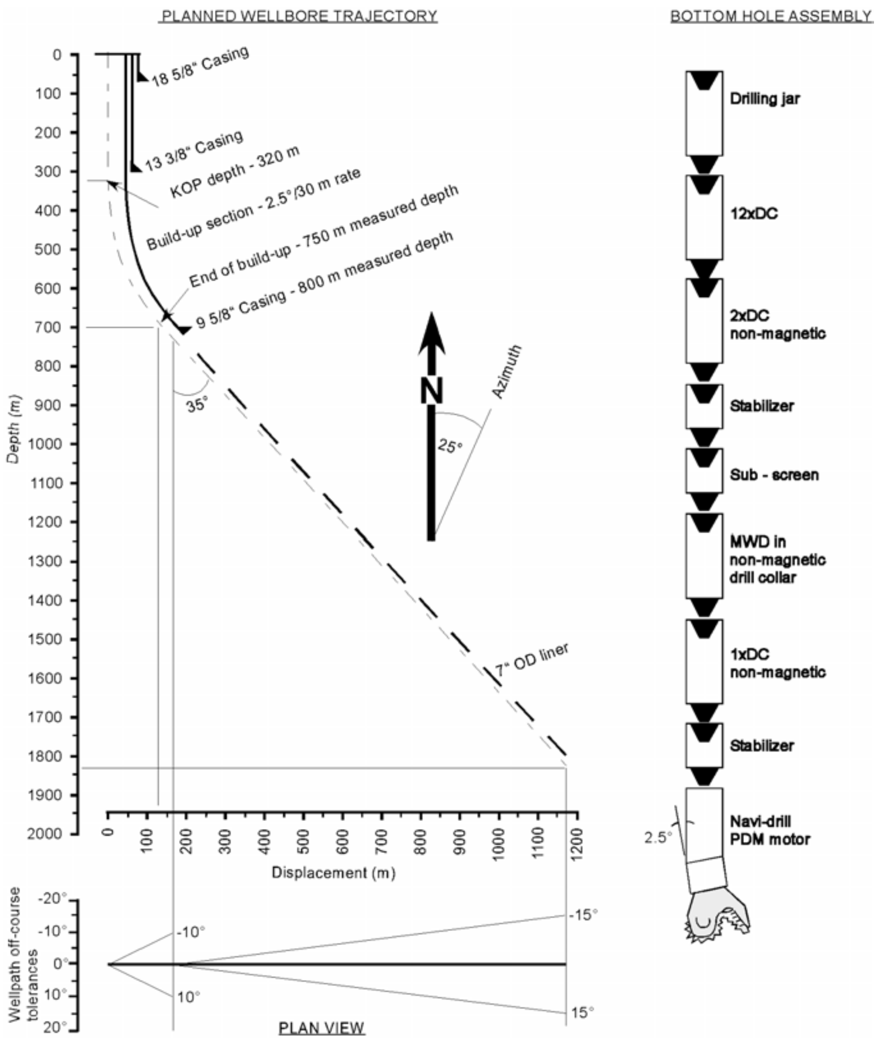

FIGURE 13: Trajectory details of well HE-6 at Hellisheidi geothermal field and the bottom hole assembly used to drill the build-up section

bottom hole assembly (BHA) used to drill the build-up section. A gyro instrument was used to set the BHA in the desired azimuth. Thereafter, a MWD instrument was used to survey the well path as drilling progressed. The section was drilled with mud with the bit rotating at about 120 revolutions per minute.

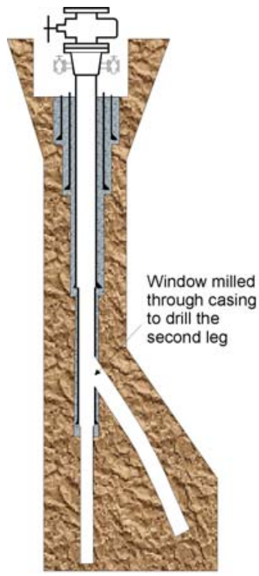

FIGURE 14: Multiple-leg well

3.3 Italy

Bianchi et al. (1995) have detailed a 10-year Italian experience in drilling directional geothermal wells beginning in 1983. They have taken the technology further by drilling the first horizontal well in high temperature fields in addition to a multi-leg (forked) well (Figure 14). By 1995, Bianchi reported that over 70% of wells drilling by ENEL were directional. The first directional well (PC 35 A) was drilled at Mt. Amiata development project employing a Type II profile (kick-off, hold angle and drop to vertical). It was planned that the wellbore drop back to vertical and progress vertically for a distance of about 2000 m from the drop-off section. Drilling of this well was terminated in advance because directional control could not be achieved. A summary of the standard directional drilling practice in Italy is given in Table 4.

TABLE 4: Summary of directional drilling practice in Italy

Item descriptions	Profile and drilling parameters
Reason for employing directional drilling	Target to traverse faults for increased productivity
Trajectory profile	Type I (kick-off, build inclination angle and hold)
Kick – off depth	About 1000 m
Angle of inclination	Maximum 25°
Surveying tools and procedure	Shielded single shot tools
Drilling fluid	Aerated water and foam plus frictional reducer
Directional control	A changing azimuth angle with depth
Total true vertical depth	3500 m
Horizontal displacement	About 1000 m

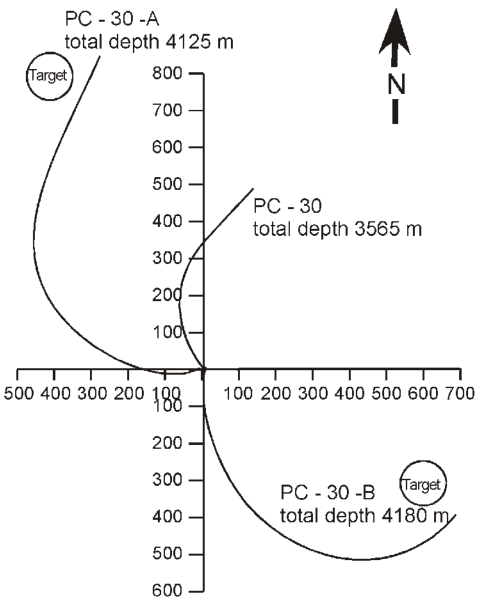

FIGURE 15: Plan view of directional wells with changing azimuth as a result of formation deviation tendencies

Typically three wells are sited on each pad, two of which are directional. Bianchi has reported one case of five wells on a site, four of which were directional.

Two major problems experienced by ENEL are temperature limitation of the downhole motor and MWD equipment (150°C) and formation deviation tendencies that lead to difficult azimuth control (Figure 15). Bit life reduction as a result of the high speed of turbine motors was noted and high drag forces, especially in the sliding mode. Casing wear was also reported as a problem. Metal protectors installed on the drill pipes at the casing wear zone reduced wear.

3.4 Japan

Japan was by 2000 generating electricity from 11 high-temperature fields (Fuchino, 2000). Three fields Kakkonda, Kirishima and Takigami have employed directional drilling (Saito, 1995, Soda, 2000; Jotaki, 2000). Jotaki has reported the directional practice at Takigami as summarised in Table 5 and, in particular, drilling of highly deviated wells.

TABLE 5: Summary of directional drilling practice in Takigami, Japan

Descriptions	Drilling and profile parameters
Reason for employing directional drilling	Target permeability zone (faults) and as a tool to exploit resources under protected nature parks
Trajectory profile	Type I
Kick – off depth	147 - 1133 m
Build-up angle	2.5 - 3.5° / 30 m
Angle of inclination	Max. 34 - 66°
Surveying tools and procedure	MWD
Drilling fluid	Mud
Directional control	Changing azimuth angle with depth (2 - 4°/30 m)
Total true vertical depth	1461 - 2161 m
Horizontal displacement	393 - 944 m

The directional problems associated with highly deviated wells as experienced in Takigami were cleaning of the hole and inability to run conventional survey equipment under their own weight with a hole whose inclination angle is 50-60°.

3.5 United States

The United State leads the world in geothermal electricity generation (Huttrer, 2000; Sifford, 2000). The Geysers (1,137 MWe), Imperial Valley (45 MWe) and Coso (260 MWe) are the major producing, fields, accounting for over 90% of the country's generation (Sifford, 2000). Directional drilling was adopted in the development of The Geysers prospect to combat environmental impacts that had resulted from earlier development (Reed, 1975; Glass, 1977; Maurer, 1978). Glass (1977) adds that it was considered more feasible to drill multiple wells per drill pad due to difficult terrain, high costs of the site (up to 10% of well cost) and permit restrictions. Stockton (1982) noted that by 1982 all wells drilled at The Geysers were directional.

A multiple legged or forked well is an emerging technology aimed at increasing productivity at minimum cost that is gaining application in The Geysers (Henneberger and Gardner, 1995; Maurer, 1978). The former have reported an improved productivity of 58% in three wells that were drilled with 2 and 3 legs. They have noted that productivity of the forked wells can approach that of two wells at a cost substantially lower than that of two wells. However, they have cautioned that the techniques for completing multiple-legged wells is under developed and can be complex and risky. Other fields that have employed multiple-legged directional wells are the Raft River, Idaho geothermal project (Miller et al., 1978), and ENEL of Italy has also successfully drilled the first European forked well (Bianchi at el., 1995).

3.6 Other countries

Kenya, with side tracking in the Olkaria geothermal fields, and El Salvador with the Berlín geothermal field (Guerra, 1998) are other countries that have employed directional drilling. New Zealand had directional wells as early as 1970 (Stilwell, 1970), and has recently drilled some re-injection wells with a horizontal displacement of 2000 m (King and Robson, 1998).

4. PROPOSED DIRECTIONAL WELL DRILLING STRATEGY FOR THE OLKARIA DOMES

4.1 Introduction to the Olkaria Domes geothermal field

It is planned that production wells in Olkaria Domes will be directionally drilled (Ngure and Ngugi, 2002). This is after completion of the current appraisal programme in which six appraisal wells are to be drilled. Olkaria Domes is a proven field with three exploration wells, two of which have encountered temperatures of about 340°C at economic depth. Geophysical data indicates that the field is within the same geothermal system as the Olkaria East and Northeast geothermal fields. The area of the field is estimated to be about 6 km^2 with temperatures greater than 260°C. The potential of the field is estimated at over 102 MWe. The field is earmarked for development of a 64 MWe Olkaria IV power plant.

Figure 16 is a cross-section through the three Olkaria Domes wells and some Olkaria East production field wells. Mungania (1999) has concluded that the litho-stratigraphy between Olkaria Domes and the adjacent Olkaria East production field is similar.

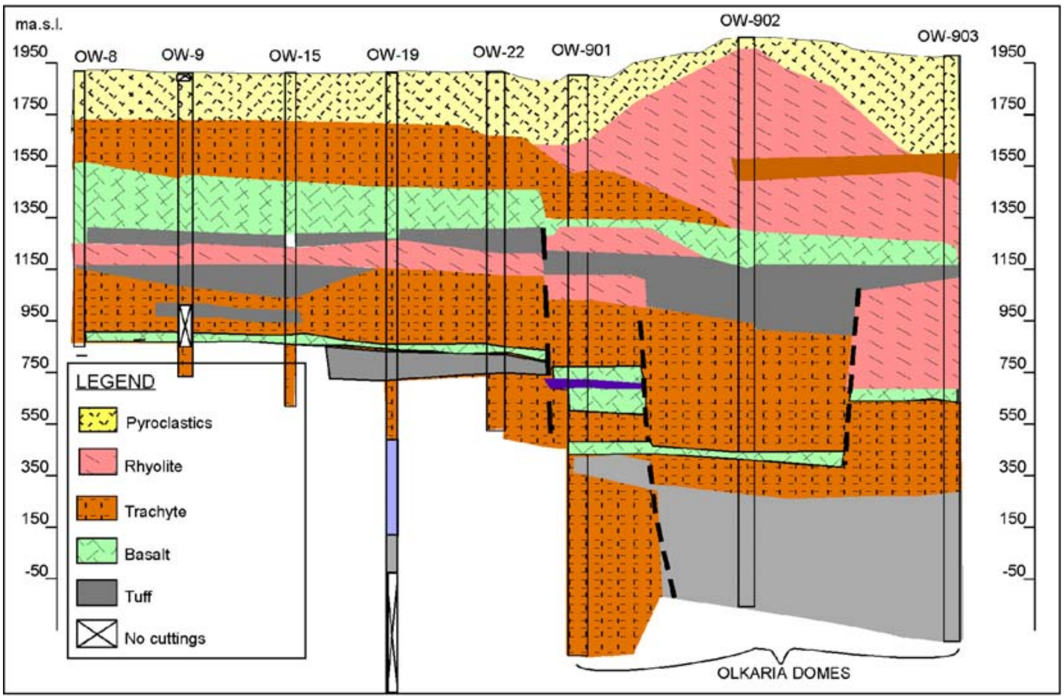

FIGURE 16: Stratigraphy of the Olkaria Domes and a part of Olkaria East production field (Mungania, 1999, redrawn by author)

Figure 17 shows a simplified surface geological map for the greater Olkaria Area. The structural pattern of the Olkaria geothermal area is characterised by N-S, NW-SE, NNW-SSE and the ENE-WSW fault trends. The N-S faults and fractures represent the latest tectonic activities. The vertical permeability along some fault/fractures is indicated by the occurrence of strong fumarolic activity. Most of the fault structures are buried by younger volcanics. They are inferred based upon alignment of eruptive centres, hydrothermal fluid seepages and lineament based on remote sensing imageries. The ENE-WSW trending Olkaria fault, visible from the surface, is the most important permeable structure. The fault transects the Northeast and West fields, where it forms the most productive part of the system. Since surface volcanic products conceal these subsurface structures, predicting the permeability distribution in the field without drilling a well is difficult. This fact is shown by the contrasting productivity of wells drilled as close as 300 m apart. Wells drilled within known faults zones have higher productivity due to fracture permeability, but in areas outside the faults fluid migration is mainly horizontal and is along lithologic

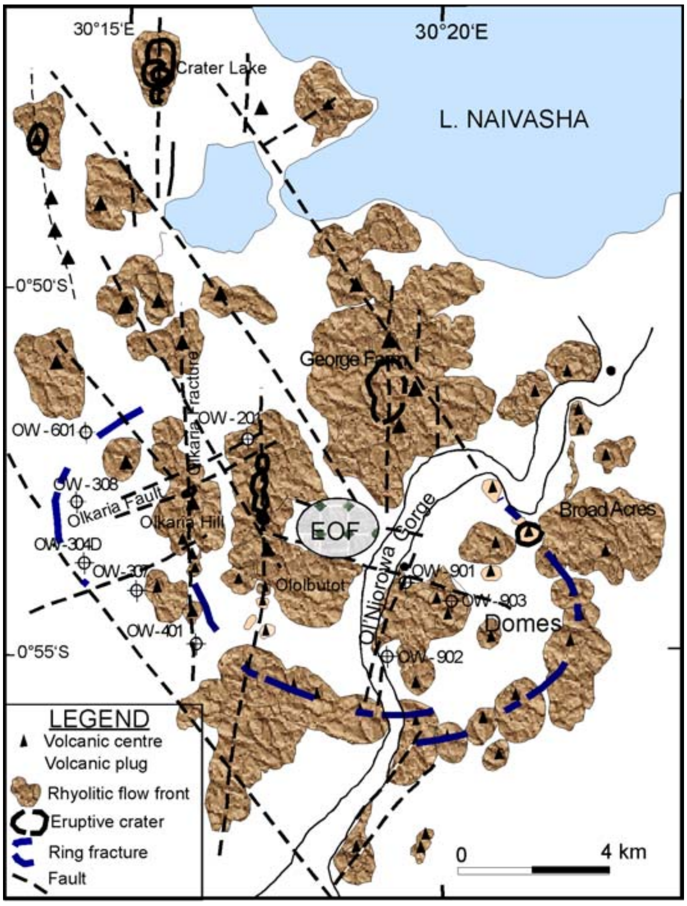

FIGURE 17: Tecto-volcanic map of the greater Olkaria geothermal area (Mungania, 1999, redrawn by author)

contacts. The important structures for Olkaria Domes are the ring structure marked by the alignment of the eruption centres, the NNW-SSE fault, extrapolated from regional remote sensing imageries and the N-S fault, defined by the exposed dykes (Omenda, 1998; Mungania, 1999).

The topographical setting for most of the fields in Olkaria is flat to gentle slopes. Vegetation is pre dominantly shrubs and savannah grasslands. The topsoil is mainly volcanic ash and tephra. Occasional rhyolitic domes and sharp erosion valleys dot the fields. Availability of locations to site wells is, in general, not a problem. An environmental programme is in place to mitigate effects of human activities to the environment. In comparison, Olkaria Domes exhibits a greater surface gradient than the general Olkaria area with much more prominent erosion features and rhyolitic domes. Availability of locations for siting wells is not critical. However, the service roads and possible pipeline routes may economically justify adoption of directional drilling. It is worth noting that the field is not fully delineated.

4.2 Preferred well pad distribution and spacing

Wells at Olkaria are spaced at about 200 – 300 m. Siting multiple directional wells on a single drill pad is economically advantageous, cashing-in on savings arising from reduced cross-country steam pipelines, road networks and other infrastructure. This also has environmental benefits arising from less surface disturbance. The exploration strategy affects the siting of wells. Until recently, Olkaria employed a strategy where exploration and appraisal drilling sought to prove and delineate a field, i.e. prove an area. The discovery well was targeted at the most likely location of the prospect while subsequent wells were drilled at the likely margins of the field. This strategy resulted in wells of great distances apart and the delineating wells were not expected to be producers. To seize the opportunity for early production, a new strategy has been recommended whereby subsequent wells from the discovery well are stepped-out at twice the normal well separation distance, i.e. 600 m for vertical wells. This strategy progressively proves an area and potentially yields a greater number of producing wells at the end of the appraisal program. The earlier method would be suitable for siting most of the wells on one pad, which has been shown to have greater savings than multiple pads. This is because the shape of the reservoir will be fairly well known during production drilling. This also assumes good permeability in the field. Where structural permeability is believed to be important, the sites will depend on the well trajectory and the depth at which the structures are to be traversed. The later strategy is more suited to siting multiple pads in a field. While vertical wells prove for this case an area of between 900 and 1200 m width, use of moderate horizontally drifted directional wells will prove an area of 2400-3600 m. Note that up to about seven wells can be sited on a single pad and for 64 MWe, only about three drill sites may thus be necessary. The distance between wellheads on the same pad will depend on the space required for work-over rigs and surface fluid processing structures.

4.3 Anticipated drilling problems in Olkaria Domes

The build-up section will be between 300 and 1200 m depth. The formation in this section is predominantly medium to medium-hard with intercalation of soft to medium-soft and hard. Some sections are rough, i.e. they generate exceptionally high vibrations to the drill string. This zone is also prone to major drilling fluid losses if drilled with either water or mud. Where losses are encountered, poor hole-cleaning conditions are experienced. Experience shows that drilling with aerated water and foam results in good drilling fluid circulation and adequate hole-cleaning. Drilling, however, with aerated water and fluid results in under-balanced hole conditions. Occasionally, the well kicks between 500 and 700 m and cooling must be undertaken. While drilling, downhole temperatures are maintained below 100°C. The static formation temperature at 1200 m is about 235°C.

The section between 1200 and 2200 m is predominantly medium soft and medium hard and soft sections are often encountered. The zone is drilled with aerated fluids and water where circulation can be sustained. The section is normally smooth to drilling. Higher flow rates of water are normally required while drilling with aerated fluids due to the high circulation velocity in order to effect adequate cooling. Water flow rates as high as 42 l/s are sometimes used.

Several problems will arise from the above. A great variety of motors are designed to operate with mud and water based drilling fluids. A few motors do exist that can operate with aerated fluids and foam. In addition, a flow rate of about 42 l/s is on the higher limit for most motors, many of which operate with lower flow rates. These factors will require consideration when selecting a motor for the Olkaria operations. In addition, the pulse transmission system for MWD equipment is normally based on mud and water. Introduction of air, especially at shallow depth where the drilling fluid operating pressure is low, may introduce errors. This factor needs to be investigated further. The rough drilling sections will subject the MWD (electronic) equipment to severe vibrations. This may render them inappropriate. Vibrations may also render it difficult to maintain a smooth well path and closer monitoring may be required in the rough sections. Most of the directional tools and instruments are limited in operating temperature. In general, operating fluid temperatures in aerated fluid drilling are higher than for water due to the fact that aerated fluids result in a under-balanced hole condition and the formation fluids entering the wellbore. In general, it will be more difficult to drill the production hole than the tangential section.

4.4 Recommended directional well plan

It is recommended, as has been the experience of many operators, that KenGen adopt the most obvious and simplest directional plan and modify the plan as greater confidence is gained and the formation influence on the directional process becomes well known. The formation influence cannot be underrated as experience in Italy (Bianchi et al., 1995) indicates. The parameters for a simple plan are given in Table 6.

TABLE 6: Summary of proposed directional drilling profile parameters for Olkaria Domes

Description	Profile Parameters
Well profile	Type I
Kick-off depth	As shallow as possible but deeper than 300 m
Inclination angle	15 - 40°
Build-up rate(s)	½ - 3 °/30 m
Drilling fluid	Mainly aerated water and foam
Casing programme	20” OD casing 0-60 m depth - vertical 13⅜” OD casing 0-300 m depth - vertical 9⅝” OD casing 0-1200 m depth - deviated 7” OD liner from 1200 to 2200 m depth - deviated

4.5 Drilling process strategy and surveying

The use of positive displacement motors with a bent housing or coupled to a bent sub has become the standard deflection method. The advantages of using downhole motors over the other methods are that they permit full gauge holes to be drilled from the at kick-off point, eliminating pilot holes necessary in both the whipstocks and the jet bits. It further saves tripping time since the same assembly used to kick-off is used to build or drop angle to the desired inclination and even drilling the well to total depth. In addition, the continuous side force produced at the bit by the bent sub gives a smooth curvature with less risk of a severe dogleg, and gives more accurate orientation. The assembly is also steerable. Depending on the orientation of the bent sub, the technique can be used to build or drop inclination and steer the bit to the left or right.

The mud motor assembly is normally run with a measurement while drilling instrument (MWD) above it which has the following advantages over the conventional tools; rig time is saved by eliminating the large number of wireline trips required to take surveys and check orientation, continuous monitoring will reduce the risk of wells straying off course and therefore reduce the number of correction runs; owing to better control, the well path should be smoother with fewer doglegs and the toolface can be monitored during drilling to account for reactive torque. The motor and the MWD assemblies are also used to drill the tangential section of the well. This reduces the need to rotate the drill string hence reducing excessive wear on the string and casing. However, it is desirable to maintain low string rotation because it reduces the risk of differential sticking, allows a smoother application of weight to the bit and improves drilling fluid circulation in the annulus, which helps to prevent cutting settling on the lower side of the hole. It is a common practice to use Gyro instruments to supplement the MWD especially at kick-off and to reconfirm the MWD measurements at specific depths.

It is recommended that KenGen adopt this standard practice for its directional drilling, especially initially.

5. INSTITUTIONAL EVALUATIONS AND RECOMMENDATIONS

5.1 Rig equipment requirement

Directional well drilling subjects certain rig members to higher loading than that in vertical wells. The hoisting equipment and mast has to bear additional loads due to drag and fishing requirements for difficult directional drilling. The additional pressure drop in the bottom hole assembly, due to directional drilling tools (downhole motors) and instruments, is substantial. In order to deliver hydraulic power to the bit, pumps with higher-pressure ratings are necessary. It must be noted that using turbines requires extremely high pressures. KenGen plans to procure a rig with the capability to drill directional wells to a measured depth of at least 3000 m. Quotations have been obtained for a new drill rig having 1000 horsepower drawworks, 454 tons (1,000,000 pounds) static hook load mast, 12 line travelling block, two 9-P-100 triplex single acting slush pumps and a 5” drilling string (National-Oilwell). The projected loads on the hoisting system based on the Olkaria Domes directional drilling and casing programme are tabulated in Table 7. The maximum projected total hook load allowing for 60 tons drag force and 50 tons margin of over-pull (safety margin) is therefore 242 tons. The hoisting system is therefore adequately rated. Table 8 tabulates pressure losses as would be expected for a circulation rate of 2500 l/min of water. The method and figures used have been taken from Gabolde and Nguyen (1991) and the IADC drilling manual (1992).

The maximum operating pressure is limited by the air compressor package’s maximum pressure rating of 1500 psi. Aerated drilling is an integral part of Olkaria drilling operations due to major fluid circulation losses. The above results imply that selection of downhole motors with very low differential pressure losses will be essential for Olkaria drilling operations. In addition, bit nozzles are limited to those with low pressure losses (large flow area). However, the latter case may not be critical as it is not a common practice to have nozzles in the bits at Olkaria.

TABLE 7: Projected hook loads (Gabolde and Nguyen, 1991)

Description		Size (“)	Nominal weight (lb/ft)	Total measured length (m)	Total weight (ton)
Normal casing programme	Surface casing	20	83	60	7
	Interm. casing (anchor)	13⅜	54.5	600	49
	Production casing	9⅝	40	1301	77
	Liner	75	26	1335	52
	+ landing string		19.5	1306	+ 38
	Max. weight				**90**
Larger casing programme	Intermediate casing	18⅝	87.5	600	49
	Production casing	13⅜	68	1301	132
	Liner	9⅝	47	1335	93
	+ landing string	5	19.5	1306	+ 38
	Max. weight				**132**
Production hole drill string	Pipes	5	19.5	1212.5	35
	Drill collars	8	68.4	85	9
	Motors	8	118.7	8.5	2
	Max. weight				**46**
Main hole drill string	Pipes	5	19.5	2473	66
	Drill collars	6½	41.6	132	8
	Motors	6½	76.7	7	1
	Max. weight				**75**

TABLE 8: Pressure losses in the fluid circulation system while drilling

Description	For production casing (bar)	Main hole (bar)
Surface equipment	1.86	1.87
Drill pipe bore	16.41	16.41
Drill pipe annulus	0.28	0.00
Drill collar bore	10.21	10.21
Drill collar annulus	0.14	0.14
MWD	8.28	8.28
Downhole motor sizes 8–9⅝” and 6½-6 ¾” OD for production and main hole, respectively	24.97 - 82.00	24.97 - 70.00
Total system pressure loss less bit losses	**62.14 - 119.24**	**68.55 - 113.59**
Maximum operating pressure allowable	**103.45**	**103.45**
Pressure loss limitation on bit for hydraulic horsepower delivery	-15.57 to 41.38	-10.14 to 34.90

5.2 Personnel training and hiring of directional services

Directional drilling is not a different technology entirely removed from the common drilling practice, but it is a highly specialised technique within drilling that offers solutions for certain drilling and prospect development problems. For successful adoption of any new technology, adequate knowledge is required on the technology, equipment involved, equipment operation techniques and care, servicing and maintenance requirements of the equipment. In addition, the equipment must be acquired and commissioned. The worldwide practice has been to hire directional drilling services. The service providers’ supply the following equipment required for the directional drilling on a rental basis:

- Various sizes of motors, non-magnetic (monel) collars, stabilizers and appropriate rock bits including spare ones;
- The required downhole surveying instruments, e.g. MWD, magnetic and gyro instruments, and also logging equipment;
- Surface equipment, i.e. transducers, digital displays and or computers and the necessary software for data interpretation.

The benefits of hiring directional drilling services are considerable especially for rig operators employing directional drilling for the first time. These benefits are

a) Interaction of the KenGen's planning engineers and the directional drillers from the service provider will avail experience for the engineers, a requirement for effective planning.
b) The responsibility for commissioning, care, servicing and maintaining the tools and instruments lies with the service provider, thus eliminating costly learning curves, investment in service and maintenance facilities and tools. It becomes therefore possible for the rig operator staff to learn on the job without affecting the drilling program.
c) The responsibility for conducting directional drilling is normally shared with the directional service provider. As such, a worldwide experience is made available to the rig operator especially in bottom hole assembly design and deployment of the tool, which may be critical for a successful directional drilling operation. Solutions to different drilling problems associated with directional drilling may become easily available.
d) The hired service providers make available backup and fallback options. The providers maintain a wide inventory of different tools and instruments that could be available at quick notice. The alternative is for the rig operator to commit large sums of money in establishing such an inventory or incur delays as such equipment is acquired at the time of need.

It is recommended that KenGen integrate hired directional drilling services in the beginning as directional drilling is adopted. This eliminates mandatory rigorous directional drilling training on the part of KenGen staff and hence directional drilling can commence at will. However, the KenGen drillers will require training on the operation of the downhole motors. The directional service provider on the job can conduct this training.

6. ECONOMIC EVALUATION WITH OLKARIA II AS CASE STUDY

6.1 Significance of drilling costs to project cost

Geothermal power economically competes well with other forms of power sources in addition to being environmentally friendly. This is true for Kenya where geothermal has been for many years the least-cost power option for the country. However, geothermal offers several project implementation hurdles, namely:

a) *Large initial capital requirements.* Geothermal prospects are usually in remote undeveloped locations. Besides the actual power plant requirements, infrastructure such as access roads, telephones, staff housing and drilling water must be in place ahead of the actual project. In addition, the lifetime power plant fuel (steam) supply cost must be paid for in advance through drilling (Bronicki, 2000).
b) *Long project maturation period.* The risk factor in geothermal prospects is higher than for competing sources of power, primarily because its evaluation is based on indeterminate earth science. Systematic and carefully designed studies are carried out before a prospect can be committed for development. These studies can take from 1 to 3 years at the least. A project implementation period of about 7 years is normal, due to a conservative development approach characterizing many geothermal prospects.

c) *Availability of capital.* Kenya, a developing country, greatly depends on bi-lateral and multi-lateral donor capital for its major power projects. Such funds are subject to terms and conditions beyond the project. This fact has made the availability of capital increasingly scarce, unreliable and expensive.

The relatively low capital cost and short project implementation period has led to thermal plants being developed alongside geothermal in Kenya to supplement the power shortfall. Gowka (1997) has estimated that 30–50% cost of a typical geothermal power project is the cost of drilling and completing the wells. Kamiirisa and Kondo (2000) estimate that the cost may generally be greater than 50%. KenGen has estimated a ratio of 31% in its future development.

Hiriart and Andaluz (2000) have reported that the cost of installed kW for various Mexican geothermal projects ranges between USD 797 and 1,434. Estimated KenGen cost for future developments is USD 1837. Liguori (1995) has estimated that the installation cost for the power plant alone is about USD 1,250 per kW.

6.2 Cost sensitivity analysis

Adoption of directional drilling will result in significantly increased drilling costs. Depending on how the wells are sited, savings could be realised on the surface casing and cost of civil works related to a well. It is also hoped that average well output will increase.

A simple cost model taking Olkaria Northeast as a case study was carried out in an attempt to explore a quantitative cost comparison of vertical wells against directional. It must be noted that the author did not undertake a detailed optimisation exercise but sought to attain reasonable figures. Economic analysis of drilling costs eludes many because the cost of vertical wells is so varied from one well to another depending on the difficulty each well poses. In order to carry out a comparison the following conditions were assumed characteristic of the general observation at Olkaria Northeast field. These are 14% drilled wells failure rate for all scenarios, 1661 kJ/kg average enthalpy for all wells, 5 bar (abs) separation pressure, 0.484 average dryness fraction, 2 kg/s steam consumption per MWe, steam separation at the wellhead (this is the very basic design), plant size of 64 MWe, 3.5 MWe average well output and ignores re-injection. The following scenarios were considered:

A1 Directional wells with drilling duration equal to that of vertical wells (50 days) - optimistic drilling time.
- i) Directional wells drilled at locations of vertical wells;
- ii) Directional wells drilled on one pad near station ;
- iii) Directional wells drilled at three pads.

A2 Vertical and directional wells drilled simultaneously but with larger diameter casings (13⅜” production casing and 9⅝” liner).
- i) Vertical wells with larger casings;
- ii) Directional wells at current location of vertical wells;
- iii) Directional wells drilled on one pad but with larger casings;
- iv) Directional wells at three pads.

B1 Same as A1 except that duration of directional drilling increase by 24% to 62 days (additional hole 3 days, surveying 3 days, reaming 2 days and fishing 4 days) - conservative drilling time.

B2 Same as A2 except that the duration of directional well is increased by 24%.

All the above cases were compared with the average cost of vertical wells utilizing regular casings. The variable costs were time dependent drilling costs, steam pipeline costs, increased well consumables and output, 20% decrease in string lifespan for directional wells and increased fishing cost (time element only). The procedure involved was:

a) Calculation of the number of wells required for a 64 MWe plant for various average well outputs.
b) Determination of the appropriate pipeline diameters and measurement of lengths for all segments of steam pipeline and calculation of the pipeline costs. The pipeline cost includes cost of service roads. The pipeline length was measured based on the surveyed pipeline route. The steam velocity was limited to below 40 m/s. A pipe thickness of about 6 mm was assumed. This was done for each scenario above (A1, A2, B1 and B2).
c) Estimating the cost of wells for the each of the above scenarios (A1, A2, B1 and B2).

Tables 9, 10, 11 and 12 summarize the results obtained for a 64 MWe geothermal power project. The costs for vertical wells included in this Table10 are to be compared with all the scenarios (A1, A2, B1 and B2).

TABLE 9: Summary of drilling and steam pipeline costs for directional wells assuming **optimistic drilling time** (50 days); costs are in million US dollars

Average well output (MWe)	**No. of wells req.**	**Vertical wells**			**Directional wells on individual pad**			**Directional wells on single pad**			**Directional wells on three pads**		
		Drilling cost	**Pipe cost**	**Total**	**Drilling cost**	**Pipe cost**	**Total**	**Drilling cost**	**Pipe cost**	**Total**	**Drilling cost**	**Pipe cost**	**Total**
3	22	29.6	4.8	**34.4**	36.1	4.8	**40.9**	36	2.5	**38.5**	35.1	4.4	**39.5**
4	16	21.5	5.2	**26.7**	26.3	5.2	**31.5**	26.1	1.8	**27.9**	25.3	3.6	**28.9**
5	13	17.5	4.4	**21.8**	21.3	4.4	**25.7**	21.1	1.3	**22.4**	20.7	2.6	**23.3**
6	11	14.8	3.8	**18.6**	18.1	3.8	**21.9**	17.8	1.0	**18.8**	17.4	2.5	**19.9**
7	10	13.5	3.4	**16.8**	16.4	3.4	**19.8**	16.1	1.1	**17.2**	15.8	2.6	**18.4**
8	8	10.8	2.9	**13.7**	13.1	2.9	**16**	12.8	1.0	**13.8**	12.8	1.0	**13.8**
9	8	10.8	3.2	**14.0**	13.1	3.2	**16.3**	12.8	1.1	**13.9**	12.8	1.1	**13.9**
10	7	9.4	2.3	**11.7**	11.5	2.3	**13.8**	11.2	1.0	**12.2**	11.2	1.0	**12.2**

TABLE 10: Summary of drilling and pipeline cost for directional wells assuming **conservative drilling time** (62 days); costs are in million US dollars

Average well output (MWe)	**No. of wells**	**Directional wells on individual pad**			**Directional wells on single pad**			**Directional wells on three pads**		
		Drilling cost	**Pipe cost**	**Total**	**Drilling cost**	**Pipe cost**	**Total**	**Drilling cost**	**Pipe cost**	**Total**
3	22	41.6	4.8	**46.4**	41.4	2.5	**43.9**	40	4	**44.4**
4	16	30.3	5.2	**35.5**	29.9	1.8	**31.7**	28.6	3.6	**32.2**
5	13	24.6	4.4	**29**	24.2	1.3	**25.4**	23.5	2.6	**26.1**
6	11	20.8	3.8	**24.6**	20.3	1	**21.4**	19.7	2.5	**22.3**
7	10	18.9	3.4	**22.3**	18.4	1.1	**19.5**	17.8	2.6	**20.5**
8	8	15.1	2.9	**18**	14.6	1	**15.6**	14.6	1	**15.6**
9	8	15.1	3.2	**18.3**	14.6	1.1	**15.7**	14.6	1.1	**15.7**
10	7	13.2	2.3	**15.6**	12.7	1	**13.7**	12.7	1	**13.7**

TABLE 11: Summary of drilling and pipeline cost for directional wells utilising **larger diameter casing** (13 3/8” production casing and 9 5/8” liner) assuming **optimistic drilling time** (50 days); costs are in million US dollars

Average well output (MWe)	No. of wells	Vertical wells			Directional wells on individual pad			Directional wells on single pad			Directional wells on three pads		
		Drilling cost	Pipe cost	Total	Drilling cost	Pipe cost	Total	Drilling cost	Pipe cost	Total	Drilling cost	Pipe cost	Total
3	22	34.2	4.8	**38.9**	40.6	4.8	**45.4**	41.0	2.5	**43.5**	39.8	4.4	**44**
4	16	24.9	5.2	**30.1**	29.5	5.2	**34.7**	29.6	1.8	**31.4**	28.7	3.6	**32.2**
5	13	20.2	4.4	**24.5**	24	4.4	**28.4**	24.0	1.3	**25.2**	23.4	2.6	**26.0**
6	11	17.1	3.8	**20.9**	20.3	3.8	**24.1**	20.2	1.0	**21.2**	19.7	2.5	**22.3**
7	10	15.5	3.4	**18.9**	18.5	3.4	**21.8**	18.3	1.1	**19.4**	17.9	2.6	**20.5**
8	8	12.4	2.9	**15.3**	14.8	2.9	**17.7**	14.5	1.0	**15.5**	14.5	1.0	**15.5**
9	8	12.4	3.2	**15.6**	14.8	3.2	**18.0**	14.5	1.1	**15.6**	14.5	1.1	**15.6**
10	7	10.9	2.3	**13.2**	12.9	2.3	**15.2**	12.6	1	**13.6**	12.6	1.0	**13.6**

TABLE 12: Summary of drilling and pipeline cost for directional wells utilising **larger diameter casing** assuming **conservative drilling time** (62 days); costs are in million US dollars

Average well output (MWe)	No. of wells	Vertical wells			Directional wells on individual pad			Directional wells on single pad			Directional wells on three pads		
		Drilling cost	Pipe cost	Total	Drilling cost	Pipe cost	Total	Drilling cost	Pipe cost	Total	Drilling cost	Pipe cost	Total
3	22	34.2	4.8	**38.9**	44.8	4.8	**49.6**	44.9	2.5	**47.5**	43.3	4.4	**47.7**
4	16	24.9	5.2	**30.1**	32.6	5.2	**37.8**	32.5	1.8	**34.3**	31.1	3.6	**34.7**
5	13	20.2	4.4	**24.5**	26.5	4.4	**30.8**	26.2	1.3	**27.5**	25.5	2.6	**28.1**
6	11	17.1	3.8	**20.9**	22.4	3.8	**26.2**	22.1	1.0	**23.1**	21.4	2.5	**24**
7	10	15.5	3.4	**18.9**	20.4	3.4	**23.7**	20.0	1.1	**21.1**	19.4	2.6	**22**
8	8	12.4	2.9	**15.3**	16.3	2.9	**19.2**	15.8	1.0	**16.8**	15.8	1.0	**16.8**
9	8	12.4	3.2	**15.6**	16.3	3.2	**19.5**	15.8	1.1	**16.9**	15.8	1.1	**16.9**
10	7	10.9	2.3	**13.2**	14.3	2.3	**16.6**	13.8	1.0	**14.8**	13.8	1.0	**14.8**

Figures 18- 21 represent the saving/loss as a percentage of the project cost against average well output for the above scenarios, worked out from Tables 9 - 12. The project cost for future KenGen of 64 MWe projects has been estimated as US$ 128.6 million. The sum of drilling and pipeline costs are pegged to the Olkaria Northeast average well output of 3.5

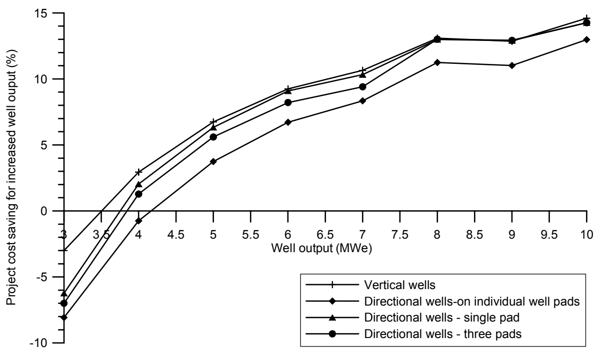

FIGURE 18: Project cost saving with increase in well output for directional wells - optimistic drilling time

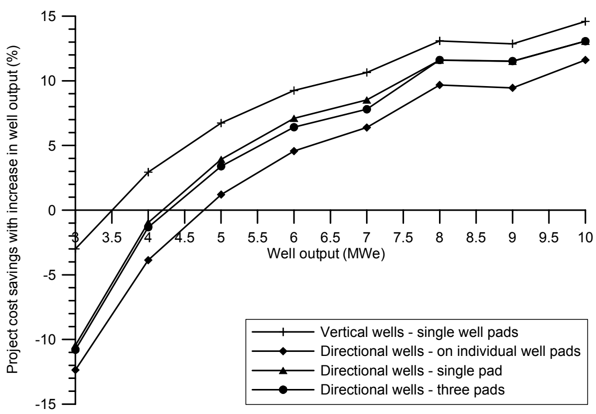

FIGURE 19: Project cost saving with increase in well output for directional wells - conservative drilling time

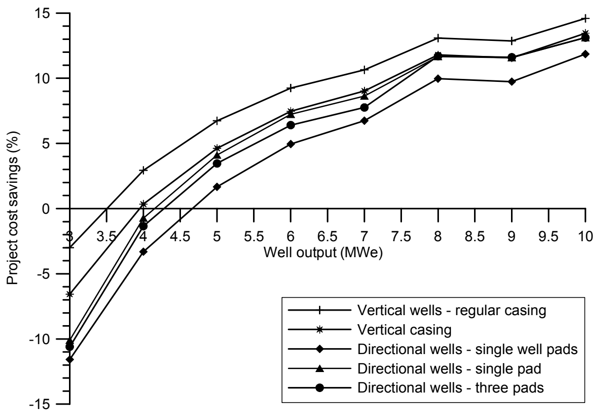

FIGURE 20: Project cost saving with increase in well output for vertical and directional wells - larger casing and optimistic drilling time

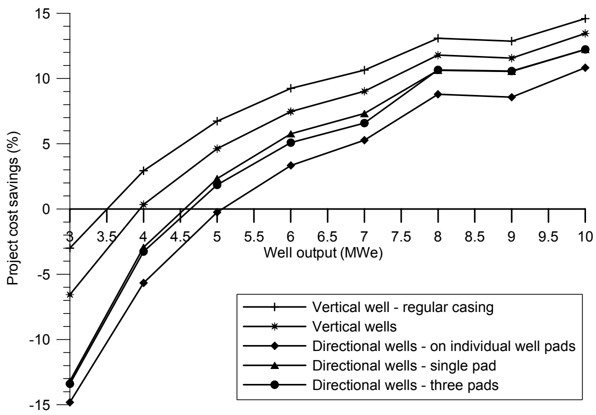

FIGURE 21: Project cost saving with increase in well output for vertical and directional wells - larger casing and conservative drilling time

MWe. At this output, the sum of drilling and pipeline cost is estimated at USD 30.5 Million. It is interesting to note that the graphs generally show two trends; a sharper gradient to 6 MWe and relatively lower gradient from 6 to 10 MWe. In addition, about 50% of the potential for savings is realised at about 6 MWe which corresponds to an increase in well output of about 2.5 MWe. This implies that considerable benefits would be attained by a relatively small increase in well output. Table 13 presents the increase in project costs if directional wells were drilled without increase in well output.

TABLE 13: Increase in project cost if directional drilling was adopted without corresponding increase in average well output

Item description	**Regular casing programme**		**Larger casing programme**	
	Optimistic	**Conservative**	**Optimistic**	**Conservative**
Vertical well - well cost only			16%	
Directional – well cost only	22%	41%	37%	51%
Vertical wells			3.1%	3.1%
Directional wells - single well pads	4.4%	8.1%	7.4%	10.2%
Directional wells - single pad	2.1%	5.7%	5.4%	8.1%
Directional wells - three pads	2.8%	6%	6%	8.3%

Adoption of directional wells will result in an increase in well cost by optimistic and conservative margins of about 22% and 41%, consecutively. Savings arising from a reduced cross-country steam gathering network by locating multiple wells on a single pad does significantly reduce these additional costs. However, it is important to note that it does not completely cancel out the additional costs. It is also apparent that it is slightly more cost effective to place all the wells on one drill pad. As argued earlier, this may not be practical. The best economic option from this Table is therefore directional wells utilizing regular casing if drilling time is comparable to that of vertical wells. If drilling time does substantially increase, vertical wells utilizing the larger casing program will be the optimal option. Table 14 presents the required increase in average well output for the various scenarios to become economically viable.

TABLE 14: Breakeven additional increase in well output (Mwe)

Item description	**Regular casing programme**		**Larger casing programme**	
	Optimistic	**Conservative**	**Optimistic**	**Conservative**
Vertical wells			0.46	0.46
Directional wells - single wells pads	0.68	1.29	1.2	1.61
Directional wells – single pad	0.26	0.71	0.68	1.09
Directional wells - three pads	0.35	0.80	0.8	1.18

Again, as argued above, the better option is directional wells where drilling time does not substantially change. On the other hand, vertical wells utilizing the larger casings will be the better option if directional drilling time will substantially increase. The most important factor to note from Table 14 is that very small increase (tune of 0.8 MWe) in average well output will render any of these options economically viable. An increase of 1 MWe will actually realise project savings.

Table 15 presents the project cost saving for the various options if an average of 5 MWe per well is achieved. As argued above, directional drilling on multiple well pads will give better savings followed by vertical wells with larger casing sizes.

The above analysis and comparison between directional wells and larger casing wells holds that both have an equal chance of increasing well output by the same margin. However, the probability that vertical wells utilizing a larger casing programme will yield higher output than directionally drilled wells is very high.

TABLE 15: Project cost savings if well output of 5 MWe is achieved

Item description	**Regular casing programme**		**Larger casing programme**	
	Optimistic	Conservative	Optimistic	Conservative
Vertical wells			4.6%	4.6%
Directional wells - single wells pads	3.8%	1.2%	1.6%	-0.2%
Directional wells - single pad	6.3%	3.8%	4.0%	2.2%
Directional wells – three pads	5.7%	3.4%	3.5%	1.8%

7. CONCLUSIONS AND RECOMMENDATIONS

The objectives sought by KenGen in directional drilling are shared by many worldwide, in particular cutting down on investment costs and environmental impacts. Directional drilling technology has successfully and widely been employed in the geothermal sector. Drilling using a Type I well profile with varying build-up angles at 1-3 °/30 m and inclinations of 15-45° in a fixed direction (fixed azimuth) appears to be the standard practice. Use of downhole positive displacement motors with a bent housing or coupled to a bent sub from kick-off to well bottom while monitoring the well path angles with measuring while drilling (MWD) instruments is the most advanced practice. This assembly enables real time monitoring of the well path while corrections are carried out without necessitating stopping drilling or changing the bottom hole assembly. Magnetic or gyroscopic single or multishot surveys are used to countercheck the MWD measurements. It is recommended that KenGen adopt this standard practice. Temperature limitation of the motors, MWD and single and multishot survey instruments comprise the greatest weakness of the technology in geothermal application with most of these equipment limited to not more than 160°C.

Most field operators have employed directional drilling to target secondary permeability (faults and fractures), to mitigate environmental impacts and to access resources not accessible vertically. It is worth noting that though many operators have adopted directional drilling as a means to increase productivity, information in the public domain does not indicate significant achievement if any. On the other hand, most operators have reported a significant increase in well cost. In comparison, emerging technology, namely multiple-leg wells and larger casing, has promised significant production improvements. A production increase of about 58% has been reported for multiple-leg wells at a reasonable cost increase. The disadvantage of this technology is that it is risky and under developed. A 200% production increase has been reported in the Philippines and Iceland with the use of larger diameter casing.

Adopting directional wells with a regular casing programme will increase the well cost by about 22-41%. On the other hand, savings arising from reduced surface steam pipelines will be realised if several wells are placed on a single pad. However, it is important to note that these savings do not completely cancel out the additional cost of wells. This option could increase the project cost by 2.8-6% if average well production does not improve. On the other hand, if the average well output of 5 MWe is achieved, savings on project cost of 3.4-6% could be realised. It requires an increase of only about 0.8 MWe for this option to be economically viable.

Adopting larger casing programme for vertical wells will increase the well cost by about 16%. This option has the potential of increasing the project cost by about 3.1% if production is not increased. It has the potential of realising savings on project cost of about 4.6% if the average well output of 5 MWe is achieved. An increase of about 0.5 MWe will make this option economically viable. This option has higher probability to significantly increase well output.

It is interesting to note that up to 50% of the potential for savings would be realised by an increase of 2.5 MWe. This implies that substantial benefits would be attained by a relatively small increase in well output.

KenGen will require directional drilling technology to optimise exploitation of Longonot and Suswa prospects that may not be easily accessed by vertical wells. It is easy for KenGen to adopt directional drilling with the integration of hired directional drilling services in the drilling operations. This will enable KenGen to implement the technology at any time without interrupting the drilling programme. Training in this case will be limited to KenGen drillers on the operations of the mud motors that can be conducted on the job.

Directional drilling is not the only optimal drilling strategy in the situation where an increase of productivity is the primary objective. A study of the flow characteristic of wells in Olkaria needs to be undertaken to establish whether larger casing will result in increased productivity.

ACKNOWLEDGEMENTS

All glory be to the Most High God, creator of all things inclusive of geothermal and His Son Jesus Christ my Saviour and Saviour of the world.

I am profoundly grateful to the Icelandic Government, United Nations University and Kenya Electricity Generating Company Limited who funded the fellowship directly and indirectly. My special gratitude goes to the UNU Geothermal program staff: Dr. Ingvar B. Fridleifsson Director, Mr. Lúdvík S. Georgsson Deputy Director and Mrs. Gudrún Bjarnadóttir Administrative Assistant; you were effective, efficient and gave warmth to us that enabled us to acquire the knowledge and skill and bear the stay in a foreign country; to the lecturers and Orkustofnun staff, in you we found friends and professional mentors and to my supervisor, Sverrir Thórhallsson, thank you for everything.

REFERENCES

Abera T., 1983: *Planning and drilling of a geothermal well*. UNU G.T.P., Iceland, report 7, 92 pp.

Armstead, H.C., 1983: *Geothermal Energy*. J.W. Arrowsmith Ltd., Bristol (2nd edition), 404 pp.

Baker Hughes, 1998: *Navi-Drill motor handbook*. Baker Hughes INTEG Incorporated.

Bianchi, F., Quintavalle, C. and Rossi, M., 1995: ENEL's experience with directional geothermal wells. *Proceedings of the World Geothermal Congress 1995, Florence, Italy, 2*, 1409-1413.

Bronicki, L.Y., 2000: Financing private geothermal power plant projects, hurdles and opportunities. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan,* 785-788.

French Oil and Gas Industry Association, 1990: *Directional drilling and deviation control technology*. Editions technic, Paris, France, 137 pp.

Fuchino, H., 2000: Status of geothermal power generation in Japan. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 193-198.

Gabolde G., and Nguyen, J.P., 1991: *Drilling Data Handbook*. Gulf Publ. Co., Houston, TX, 542 pp.

Glass, W.A., 1977: 1977 drilling methods and costs at the Geysers. *Geothermal Resources Council, Trans., 1,* 103-105.

Gowka, D.A., 1997: The role of R&D in geothermal drilling cost reduction. *Geothermal Resources Council, Trans., 21*. 405-410.

Guerra G., C.E., 1998: Cementing of geothermal wells. Report 6 in: *Geothermal Training in Iceland 1998.* UNU G.T.P., Iceland, 157-188.

Henneberger, R.C., and Gardner, M.C., 1995: Advances in multiple-legged well completion methodology at the Geysers geothermal field, California. *Proceedings of the World Geothermal Congress 1995, Florence, Italy, 2,* 1403-1408.

Hiriart, G., and Anduluz, J.I., 2000: Strategies and economics of geothermal power development in Mexico. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 799-802.

Huttrer, G.W., 2000: The status of world geothermal power generation 1995-2000. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 23-37.

IADC, 1992: *Drilling manual* (11th ed.). International Association of Drilling Contractors, USA.

Inglis T.A., 1987: *Directional drilling, vol. 2.* Graham & Totman Ltd., London, 260 pp.

Jordan, O.T., 1982: *Implications of solution-mineral equilibria on the exploitation of the S-Negros geothermal field, Philippines*. UNU G.T.P., Iceland, report 7, 67 pp.

Jotaki, H., 2000: High-angled directional drilling at Takigami geothermal field. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 2347-2352.

Kamiirisa, H., and Kondo, T., 2000: Development of high-temperature MWD system for geothermal well drilling. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 2359-2364.

Karlsson, Th., 1982: Optimisation of geothermal well diameter. *International Conference on geothermal energy, Florence, Italy, 1,* 317- 328.

Kenya Power & Lighting Co. Ltd, 1997: *The least cost power development plan – year 1997 update*. KPLC, unpubl. report.

Kenya Power & Lighting Co. Ltd, 2001: *The least cost power development plan – year 2001 update.* KPLC, unpubl. report.

King, T.R. and Robson, Q.J., 1998: Drilling history at Wairakei. *Proceedings of the 20th New Zealand Geothermal Workshop, University of Auckland Geothermal Institute, New Zeala*nd. 45-50.

Liguori, P.E., 1995: Economics of geothermal energy. *Proceedings of the World Geothermal Congress 1995, Florence, Italy, 4,* 2837-2841.

Maurer, W.C., 1978: Advanced turbodrills for geothermal wells. *Geothermal Resources Council, Trans., 2,* 411-414.

Miller, L.G., Prestwich., S.M., and Gould R.W., 1978: Drilling and Directional drilling a moderate-temperature geothermal resources. *Geothermal Resources Council, Trans., 2,* 455-456.

Muluneh, A., 1999: Comparison of drilling in geothermal fields in Krafla, Iceland and Tendaho, Ethiopia. Report 9 in: *Geothermal Training in Iceland 1999*. UNU G.T.P., Iceland, 221-246.

Mungania, J., 1999: *Summary of updates of the geology of the Olkaria Domes geothermal field.* Kenya Electricity Generating Company, Ltd., unpubl. report.

Ng'ang'a, J.N., 1982: *Comparison of drilling in high-temperature fields in Olkaria, Kenya and Krafla, Iceland.* UNU G.T.P., Iceland, report 10, 59 pp.

Ng'ang'a, J.N., 1995: Country update report for Kenya 1991-1994. *Proceedings of the World Geothermal Congress 1995, Florence, Italy, 1,* 233-237.

Ng'ang'a, J.N., 1998: Status of geothermal development in Kenya, June 1998. In: Georgsson, L.S. (ed.), *Geothermal Training in Iceland, 20th Anniversary Workshop 1998*. UNU G.T.P., Iceland, 29-37.

Ngure, S.N. and Ngugi P.K., 2002: *Least cost study – data update January 2002.* Kenya Electricity Generating Company, Ltd., unpubl. report.

Omenda, P.A., 1998: The geology and structural controls of the Olkaria geothermal system, Kenya. *Geothermics, 27-1,* 55-74.

Ragnarsson, Á., 2000: Geothermal development in Iceland 1995-1999. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 363-375.

Reed, M.J., 1975: Environmental Impact of Development in the Geysers Geothermal field, USA. *Proceedings of the 2nd United Nations Symposium on the Development and Use of Geothermal Resources, San Francisco, Ca, USA,* 1399-1410.

Saito, S., 1995: MWD and downhole motor performance in very high temperature geothermal wells in Kakkonda, Japan. *Proceedings of the World Geothermal Congress 1995, Florence, Italy, 2,*1451-1456.

Sanyal, S.K., Che, M., McNitt, J.R., and Vasquez, N., 1982: Drilling problems and learning curve - an example from Palimpinon geothermal field, the Philippines. *Geothermal Resources Council, Trans., 6,* 227-230.

Sifford, A., 2000: Geothermal electricity power production in the United States of America: A survey and update for 1995-1999. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 441-453.

Soda. K., 2000: History of drilling operations in Kirishima geothermal field. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 2425-2430.

Sta. A., F.X.M., Sarmiento, Z.F., Saw, V.S., Salera, J.R.M., and Retuya, R.E., 1997: Results of big-hole drilling in PNOC-EDC geothermal fields. *Proceedings of the 18th PNOC-EDC Geothermal Conference, Manila, Philippines,* 310-317.

Stefánsson, V., 1987: *First mission report 12-27 March 1987.* Project PHI/86/006, Management of geothermal reservoirs, report for the Government of Philippines, United Nations, New York.

Stilwell, W.B., 1970: Drilling Practices and equipment in use at Wairakei. *Geothermics, Spec.Issue 2, 2-1,* 714-724.

Stockton, A.D., 1982: Drilling technology in the Geysers geothermal field. *Proceedings of the International Conference on Geothermal Energy, Florence, Italy, 1,* 329-337.

Talens, M.A., Herras, E.B., and Ogena, M.S., 1997: Keys to successful drilling in Manahagdong. *Proceedings of the 18th PNOC-EDC Geothermal Conference, Manila, Philippines,* 325-338.

Tracey, W.J., and Vasquez, N.C., 1982: Philippines geothermal directional drilling. *Proceedings of the Pacific Geothermal Conference 1982, incorporating the 4th New Zealand Geothermal Workshop, University of Auckland, Geothermal Institute, New Zealand*, 199-202.