WESTERN PACIFIC
REGIONAL BRANCH

Applications of Geology in Geothermal Development

Module 4

WESTERN PACIFIC
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Contents

1. Introduction

Geology in geothermal development can be divided in surface geology, which takes place mainly before drilling, and well-site geology in conjunction with drilling. Often these activities will take place consecutively, and by different teams. It is important though, for the wells site geologist to be aware of the surface geology, and if necessary to go back (or request others to do so) and re-examine features in the field on the basis of what has been found by drilling. Geotechnical and geohazards geology are discussed separately in this course, but once again the geothermal geologist may be asked to comment on these matters especially at the early stage of project definition when well pad and power plant site options are being considered.

2. Surface Geology

2.1 Volcano-Stratigraphic Mapping

Standard geological mapping techniques can be used to determine the surface geology and stratigraphy of a geothermal area. Regional mapping may be useful to predict the probable subsurface sequences. There may be complete volcanic cover in a prospect area, but the presence of sediments or a metamorphic basement may be predicted from the stratigraphy in the wider area and the geological structure. For example, in a certain area in Sumatra, previous regional mapping at 1:250,000 scale had lumped together all of the Tertiary and Quaternary volcanics within a major volcanic complex into a single unit. It was apparent during more detailed investigations for geothermal exploration that subdivision into several different units based on eruptive centres and lithologies was possible and would be useful. However, it was also apparent from the regional mapping that the volcanic complex was located over a structural dome in the metamorphic basement. This meant that it was likely that the permeable volcanic sequences were thin, thus down-grading the potential of the area as a geothermal resource. The geophysics and geochemistry of the area were re-examined, and supporting evidence for that hypothesis found. It would not have been possible to draw that conclusion without considering the wider regional picture.

Stratigraphic subdivision may be difficult in volcanic areas, but a general idea of stratigraphic relationships and the thickness of the sequences may be gained from a consideration of the volcanic landforms and analogy with other areas. A basic concept in erecting a volcanic stratigraphy is to distinguish the products of separate eruptive centres. If these are lithologically identical, volcanic facies models can be used to provide mappable units (Bogie and MacKenzie, 1998). At the same time it is important not to try to divide volcanic sequences into too many minor members, or to rely too heavily on radiometric dating for chronostratigraphy, particularly when the volcanics are young and subject to alteration.

Radiometric dating can however be useful if combined with rock analysis. Bulk rock and trace element analysis (most particularly rare earth elements) is now available relatively cheaply. If clear differentiation trends with time can be identified for a volcanic centre which has an age consistent with it hosting an active geothermal system it is likely that the volcanic centre has a pluton at depth to act as a heat source. This information can be used to focus geophysical surveys; particularly where there is limited surface activity.

It may be possible to gain information on subsurface formations from the geochemistry of thermal features. For example, waters that flow through marine sediments may have a high boron content. The presence of a granitic basement may be indicated by high helium concentrations in the gases.

As well as its value *per se* in predicting and interpreting subsurface sequences within the geothermal reservoir, developing a stratigraphy within a geothermal prospect will have value in assessing volcanic and hydrothermal eruption risk, and other geohazards. It is therefore important to pay close attention to the most recent, near surface formations, since these are the most relevant and accessible. For example, at one geothermal project in Indonesia, recognition of a distinctive young pyroclastic unit permitted interpretation of a certain hydrothermal eruption breccia. At another location, landslide debris was identified as being < 10,000 years old, and therefore having some relevance to hazard studies. These factors influenced the choice of power plant site. Similarly, at another project, recognition that faults did *not* disrupt a certain young pyroclastic unit permitted the interpretation that the faults had not moved recently, and therefore posed less of a hazard to surface facilities than they may have otherwise done.

For this reason it is advantageous for the upper 100 m or so of each deep drillhole to be logged on a geotechnical basis as well as from the point of view of the geothermal resource. In our experience this is rarely done. Geothermal rig geologists will often pay only scant attention to the near-surface formations, or even not start logging until the first one or two strings of casing are set. While this is understandable, it loses an opportunity to gain information that is of value to the project as whole. The cuttings should be carefully preserved for future geotechnical examination, at least.

2.2 Structural Mapping

Based on theoretical considerations and experience in productive reservoirs, it is possible to predict in general terms what the permeability in a typical geothermal reservoir will be like. There will be a general level at which temperatures are high enough for production, and fracture permeability is most likely. Within this sub-horizontal zone, at a scale of individual well production, the most productive zones will tend to be steeply-dipping structures. Other things being equal, directional wells therefore have a better chance of being highly productive than do vertical wells, but to do so they must be oriented across the tectonic grain of the area, not parallel to it.

The need for permeability to be constantly rejuvenated means that the most productive zones will be concentrated on major structural channels. This will especially apply to any lateral outflow zones, simply because the available fluid is potentially spread over a much wider area. So surface structural studies should be an important part of the exploration programme.

These should include detailed fracture and vein mapping in the field. But it is also important to consider structures on the larger scale. This may be best done using aerial photography or satellite imagery, especially in steep or jungle-covered terrain.

There is now a wide range of commercially available satellite imagery. These include Landsat, SPOT and IKONOS optical imagery and JERS, ERS and RADARSAT radar imagery. The majority of Landsat images have a low resolution of 30 m and are only useful for mapping very large scale regional structural features. However, Landsat 7 launched in April 1999 has a 15 m black and white resolution. SPOT has a resolution (at least in black and white images) of 10 m and is available in stereo pairs from which digital elevation models can be constructed. These can then be manipulated using commercially available software to identify large and medium scale structural features (although simple stereoscopic examination will also yield useful results). Unfortunately, the results are not sufficiently accurate to identify individual drilling targets, although they do show the overall structural controls on the geothermal system, which can be used to focus geophysical surveys and provide a guide to the location and orientation of permeable structures associated with the larger structures. IKONOS has the best resolution of 1 m. These images are similar to high level aerial photographs. Unfortunately stereo images are only available to approved United States government agencies and the single images provide limited structural information. All the optical imaging suffers from the presence of clouds, particularly in prospects in the tropics and in areas of high relief.

The radar imagery uses active radar that penetrates clouds but not vegetation. The resolution of individual images ranges from 18 to 100 m and stereo images are not available. Hence, whilst the radar images will provide information on some areas where optical images are less effective, only relatively large-scale features can be clearly identified. However, where there are a number of sequential images available of an area they can be analysed by interferometry to detect changes in the elevation of the ground. This is useful for monitoring subsidence, which is a problem in some geothermal fields. It has also been used to detect movements in active faults. It does take substantial specialised computer time and so is relatively expensive.

Side-scanning aerial radar imagery can also be very useful, especially in areas without good topographic maps. It is better than aerial photography for revealing the fine detail of topography in heavily vegetated areas, but has the disadvantages that thermal areas do not show up particularly clearly, and features such as roads and houses may not be as apparent making it more difficult to locate significant points. In Indonesia there is a good series of 1:50,000 radar images available as hard copy A1 sheets for some areas.

It is best to use the different types of image in combination.

Using these techniques it may be possible to identify target structural zones which can then be investigated in detail. It is important to appreciate the scale of such structures. Major faults in active systems can often be traced over several kilometres.

The process of structural interpretation aimed at identifying permeable target zones for aerial images consists of recognition of as many geological features as possible, and then looking for signs of anomalous lineations that could represent faults. Since the targeted structures are generally steeply dipping they will show up on aerial images as more or less straight lines. A vertical structure will be straight regardless of the terrain, whereas inclined structures will appear to curve to a degree depending on the angle of intersection of the structure and the surface. Where the terrain has sufficient relief it may be possible to interpret the direction of dip of the fault from the direction of curvature, even if there is no visible offset.

In the simplest case, a fault lineation will be represented as a linear feature with visible topographic offset (*Figure 1*). There are two situations were this is unequivocally recognisable: very recently active (Quaternary) faults that usually have small offset (up to a few tens of metres) and cut across recent geomorphic features such as alluvial terraces, shorelines, or pyroclastic flow surfaces; or larger, older fault zones which offset major geomorphic elements such as a range of hills by 100 m or more.

More commonly, topographic lineations due to faults will not have a clearly defined sense of offset and are recognisable only because they form zones of subdued relief or straight segments of streams due to selective erosion of soft, crushed, or hydrothermally altered material in the fault zone. Supporting evidence may be apparent in terms of aligned zones of alteration or slumping.

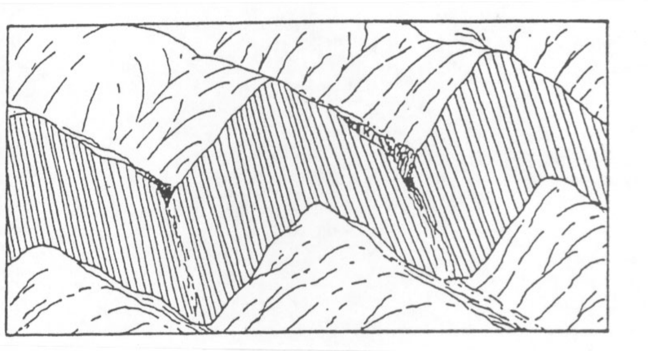

Figure 1 Ideal evidence of landscape faulting (after Cotton 1958).

A more subtle form of topographic lineation consists of distribution of the geomorphic drainage pattern, especially by faults with a strong strike-slip component. This may give rise to cut-off spurs, shutter ridges (*Figure 2*), or simply aligned spur-ridges with a consistent elevation. The latter is particularly important to identify, since on a deeply eroded stratovolcano benches on secondary ridges may constitute inviting-looking flat sites for well pads and power plants. Valuable experience in recognising such features can be gained by examining air photos of the great strike-slip faults zones of the world especially where they pass through areas of consistent, preferably non-volcanic lithologies (to avoid complicating factors), such as parts of California and the South Island of New Zealand.

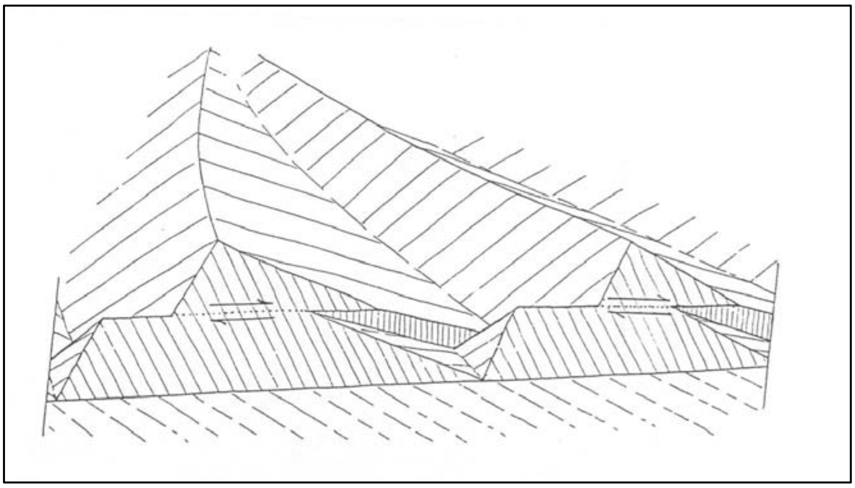

Figure 2 Shutter ridges partly block ravines, producing Z-shaped (or "dog-leg") offsets in stream courses, as on the northeast end of the Tararua Range, New Zealand (after Cotton 1958).

It is equally important to avoid mapping spurious "faults". Particularly where there is little exposure and the geologist finds it difficult to explain the observed distribution of permeability in drillholes, there can be a tendency to assign all observable surface lineations to faults. Without direct evidence such as sheared or slickensided outcrops, inconsistent juxtaposition of lithologies, or strong lineation of thermal activity and alteration, a fault should only be inferred if other explanations can be discounted. Lineations that can be mistaken for faults include:

- Bedding planes or foliation.
- Radial or other linear drainage off conical volcanoes (*Figures 3, 4*).
- Raised coastal or alluvial terraces.
- Junctions between lava flows or lahar surfaces.

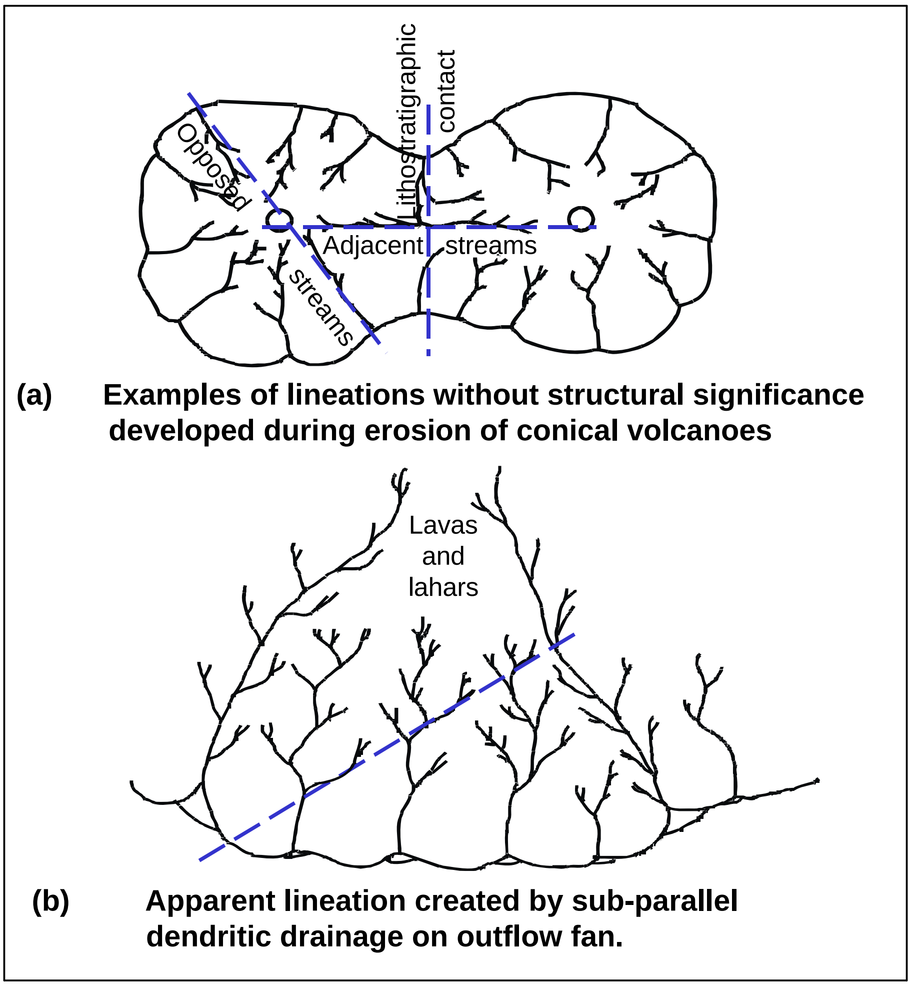

Figure 3 Development of lineations during geomorphic development

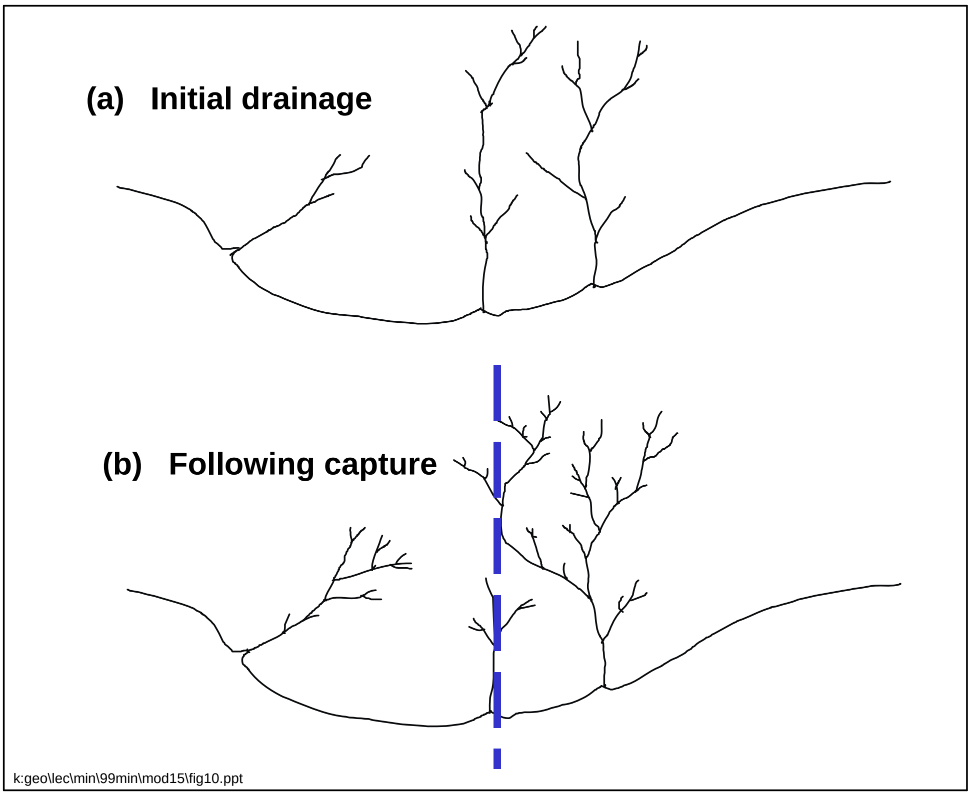

Figure 4 Stream piracy producing lineation

Similar comments apply to the interpretation of ring-faults and calderas. Such structures do occur in volcanic areas, although it has not been clearly demonstrated that they constitute good permeable targets for geothermal exploration. Not all sub-circular structures are of this origin. Other explanations include slump or sector collapse amphitheatres, lithological contacts at the margins of a volcanic ring-plain (*Figure 5*), eroded structural domes and large-scale karst features.

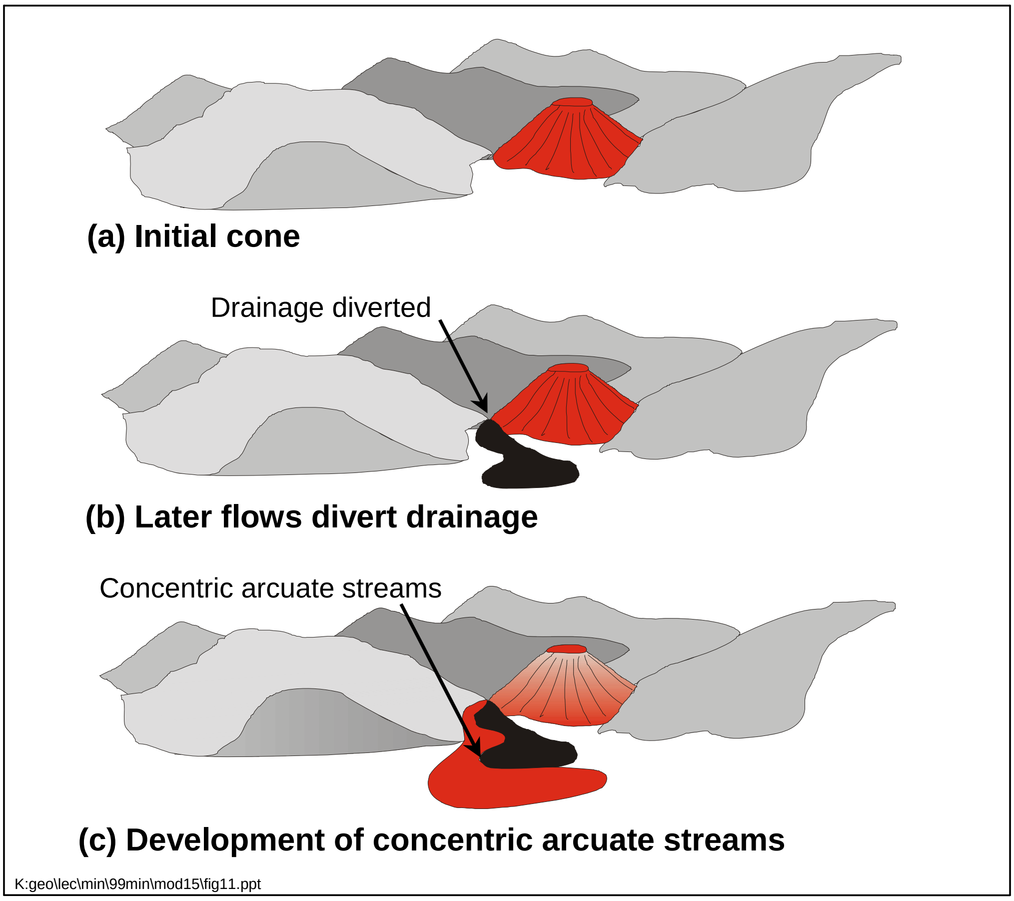

Figure 5 Development of non-structural arcuate drainage

Structural interpretation from aerial images is therefore not as simple as just identifying lineations. *All* geological features that can be recognised, such as eruptive centres, slump scars, alluvial terraces, beach lines and so on should be noted. Much useful experience in interpreting aerial images in volcanic terrain can be gained by examining images of currently active volcanoes, so that "primary" volcanic geomorphic features can then be recognised in dormant, eroded areas. It is only by recognising which features are *anomalous within the overall geomorphic framework* that faults can successfully be identified (*Figure 6*). The process is then iterative. Features (including items other than postulated faults) are tentatively identified, a field check made, and the aerial images re-visited in the light of the field information obtained.

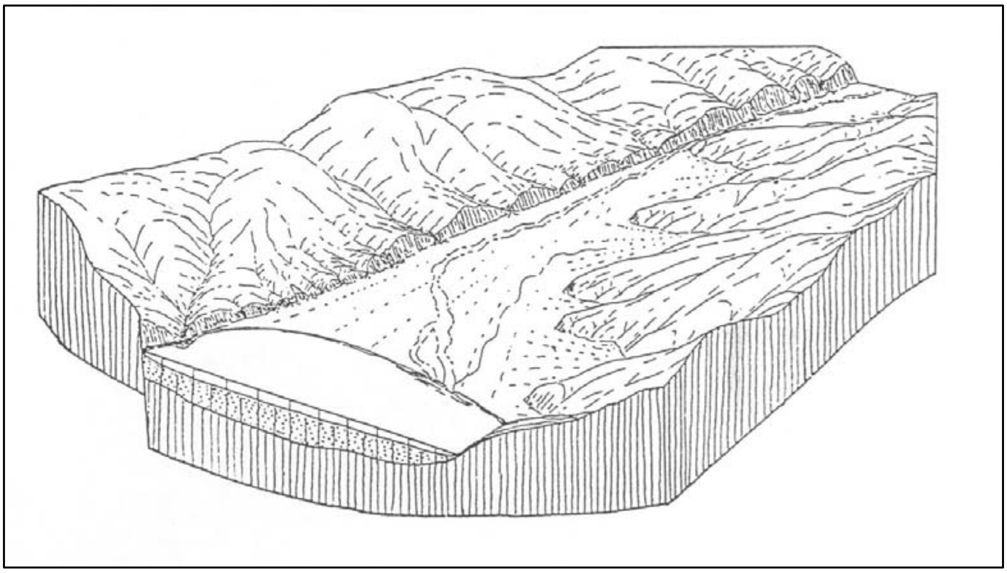

Figure 6 Straight baseline of the valley-side slope formed by Wellington fault scarp, Hutt Valley, New Zealand. Contrast the valley-side spurs, half buried by alluvium, on the opposite side of the valley (after Cotton 1958).

It is vital to remove discredited "faults" from geological maps. While there is some point in preserving older version of maps for historical reasons, at some stage an "official" version must be produced which contains only the structures where there is some good evidence for supposing they exist. If this is not done, there is a danger of ending up with maps with so many "faults" shown that it is impossible to target wells with any reliability, or conversely to site surface facilities to avoid supposedly hazardous structures. One can end up "not seeing the wood for the trees", and there is a risk of the geologist losing credibility with the other disciplines involved if incorrect prognoses are made based on discredited structural interpretations.

Stratigraphic mapping should not be neglected, as significant stratigraphic dislocation may imply the presence of a major fault. But in volcanic areas, erection of a sufficiently detailed and meaningful stratigraphy may be impossible. Fluid inclusion and alteration studies can also reveal faulting on a smaller scale.

Once a structural map of the area is completed, a structural analysis should be conducted in order to predict which of the structures have the most potential for permeability. When sufficient wells have been drilled into an area, this can be done by correlating production zones to particular faults. For targeting exploration wells, however, regional tectonics must be considered.

In geothermal fields on convergent plate margins three main structural regimes can be identified (Bogie, 2000). The first is where the combined vector of movement of the two plates is at right angles to the subduction zone. This produces reverse faulting parallel to the subduction zone with some normal faulting normal to it, with only limited opportunities for fault related permeability to develop. The second structural regime occurs where the combined vector of movement of the plates is at an angle to the subduction and subduction is taking place at a shallow angle. In this case strike strip faults will run parallel to the vector and cut the volcanic arc at an angle. The strike slip faults may not be particularly permeable themselves but they can have associated structures at predictable orientations that are. The third structural regime arises when the combined vector of movement of the plates is oblique and subduction is steep. Strike slip faults develop parallel to the subduction zone and can run down the volcanic arc; these have associated permeable structures at predictable orientations.

Once a structural map of a prospect on a convergent plate margin has been completed the results can be interpreted in light of these regional tectonic regimes. Combined vectors of plate movement and subduction zone angles can be obtained from the literature for an area and used to establish which structural regime applies. Major strike slip fault orientations can then be obtained and compared to those found during the structural mapping. Senses of movement can also be obtained from the regional data and compared to those established in the field or from remote sensing. Once the existence of strike slip faults and their sense of movement have been established the orientation of permeable structures, such as normal faults and tensional gashes, associated with the strike slip faults can be predicted. They will be at approximately 40° to the strike slip fault, with different orientations on sinistral and dextral faults.

A simpler structural pattern is found in geothermal fields related to divergent plate margins where geothermal fields are found in rifts. Structural permeability will be found associated with normal faults parallel to the rift, although for hydrological reasons faults cross cutting the rift, particularly reactivated basement structures may be more important (Bogie, 2001).

Geothermal fields associated with hot spot volcanism on oceanic islands fields will also be found in rifts. However, these are not major global tectonic features. They are localised collapse features where the reinforcing effect of the intrusion and solidification of dykes up possible failure planes have restricted the collapse. Permeable normal faults (at least those not occupied by dykes) will therefore be found at right angles to the slope of the collapse with dips oriented down slope.

3. Well Site Geology

3.1 Role of the Well Site Geologist

A good well site geologist can play an invaluable role in monitoring the performance and procedures of a drilling contractor, thus protecting the interests of the owner/operator.

The role of the well site geologist is to:

- Clearly enunciate the objectives of the well. These may be a balance between exploration, delineation and production/reinjection capacity. Choice between these will often involve a trade-off in well targeting. Even in a mature field every well will yield some new geological information.
- To design the well track in such a way that most if not all of the objectives of the well are met while still maintaining a bottom hole target which is realistic with respect to the capacity of the drill rig and associated equipment to be used during drilling. This can require considerable work to optimise well-track azimuth, drift angle, kick off point and throw. Simple hand-held calculator or spreadsheet routines can be helpful in this process.
- Draw up a geologic prognosis that synthesises all available stratigraphic and structural data from surface and subsurface studies in the vicinity of the well, in terms of:
    - Geological stratigraphy and structures to be encountered at various depths in the well.
    - Depths at which permeable zones may be experienced and the nature of such permeability.
    - Likely temperature and pressure distribution with depth.
- Make recommendations for a production casing shoe set depth based on temperature, fluid chemistry criteria, MT survey interpretations and the elevation of neutral-Cl springs.
- Establish coring depths before drilling commences and be prepared to modify these as changing drilling conditions might dictate.
- Provide regular (at least daily) reports to the drilling engineer and drilling staff on:
    - The nature of the formation.
    - Expected hardness or softness - *i.e*. drillability.
    - The presence of any hydrating/swelling clays or collapsing zones.
    - Nature of any circulation losses and association with geologic structures.
    - Any mineralogical evidence for acid fluids.
    - Mineralogical or other evidence for subsurface temperatures and fluid state.
    - The engineering properties of the formations encountered and correlation of geology with any drilling problems.
- Confirm that the country rock at proposed casing shoe set depths is competent and make recommendations for the setting depth.

- Maintain a detailed geologic log from examination of cores and cuttings at the rig site.
- Correlate physical drilling parameters, *e.g.* changes in rate of penetration and bit pressures, with geological findings.
- Verify and maintain a log of directional survey data generated by the directional drilling engineer, and co-ordinate with the directional drilling engineer in the event of problems in maintaining hole direction or if there is a need to change the hole orientation.
- Co-ordinate, communicate, support, and generally nurse and encourage all parties involved in the drilling a well to provide their best efforts to meeting the objectives set for the well.

3.2 Well Design and Targeting

Well targeting and design is an iterative process involving communication and compromise between the geologist, the drilling engineer and management. The geologist would usually want to drill as deep as possible and often has a desire to drill the least-tested parts of the field to maximise new information, while the drilling engineer will be concerned with the limits of rig capacity and risk. Management ideally wants all wells to be highly productive, as cheap as possible and with minimum risk.

3.2.1 Depth and Diameter

The main rig limitations to consider are usually dependent on the power of the rig. There will be a maximum depth that it can drill to with an adequate safety margin for a certain diameter hole. As well as the horsepower limits of the rig in terms of rotary and draw-works, pump power capacity can be a limitation on keeping the hole clear of cuttings. Maximum hook load is also important as this may limit the length of casing string which can be run, as will the mechanical strength of the string itself.

There are also more intangible considerations of time and risk. As a general principle geothermal wells should be drilled as rapidly as possible, especially if swelling or sloughing formations are anticipated. The longer the formation is exposed to drilling fluids, the more likely that it will collapse and the more difficulties will be experienced with tight hole or stuck pipe. This provides another reason to limit the lengths of open hole interval between casing strings in some instances.

One possible solution if drilling difficulties are experienced and to maximise the open-hole interval while still giving some measure of protection is to use a stepped casing design. That is to say either running a larger-diameter slotted liner with a drillable shoe part way down the production interval, then drilling on and set a smaller diameter slotted liner below, or to run large diameter blank (but uncemented) liner in the upper part and then perforate afterward. There can still be problems: the formation can still squeeze in through slots, the annulus may become clogged with cuttings, or there may be hydraulic difficulties if permeable zones with a large vertical separation are encountered.

3.2.2 Casing

The casing programme should be designed from the bottom up. The total depth of the well is used to determine a minimum production casing depth to permit safe drilling to the TD. However, it is often the case that the production casing is set to considerably greater depth than this minimum, to exclude cool or acid inflows (*Figure 7*). To permit the well to discharge, if single phase liquid is anticipated the production casing should be set to a depth at which temperatures are anticipated to be at least 240°C. If a steam zone is known to exist, a cooler target may be adopted. At the same time the open-hole interval should be maximised, to give maximum information and potential for production. A compromise is called for.

Having determined the production casing depth, the main criteria for shallow casings are safety, to prevent blow-outs during drilling, and to avoid problems with difficult formation during drilling (*Table 1*). The number of casings should be selected on the basis of the hydrology and degree of knowledge of the field. In an area with a deep water level and little sign of thermal activity, a two-string casing (plus a surface-driven conductor pipe at the top and a slotted liner at the bottom) would be adequate and is probably the norm. In a previously-undrilled thermally active area with a high water level, three or four casings would be better. For the first few wells in a field, casing designs have to be more conservative and are based on theoretical considerations of maximum pressures which can be expected in a well during drilling. At a later stage Formation Leak Off Tests (FLOT) should be carried out in a number of wells after drilling out the casing shoes, and a specific fracture gradient with depth established on which casing depths can be based.

Table 1 Casing programme for well XX

MINIMUM CASING PROGRAM			
Inputs		Outputs	
Density of formation, g/cm^3	2.5	Conductor casing	26.6
Target total measured depth, m	2457	Surface casing	82.8
Minimum casing depth, m	470.6	Anchor casing	321.9
Chosen prodn casing depth, m	1524	Production casing	1524.0
		Total measured depth	2457.0

External casing corrosion by acid fluids can be a problem in some fields, and the geologist may be called on to give advice. A production well may be required to last for 30 years, or more in areas such as New Zealand where there have been 30 years delay in some cases between drilling and bringing wells into production. External casing corrosion in the upper part of the hole has been known to occur, but it is uncommon, so unless special circumstances prevailed, such as drilling close to a magmatic solfatara, it would normally be regarded as adequate to rely on the fact that there are several concentric strings of casing in the hole as far down as the anchor casing, and use conventional carbon steel materials

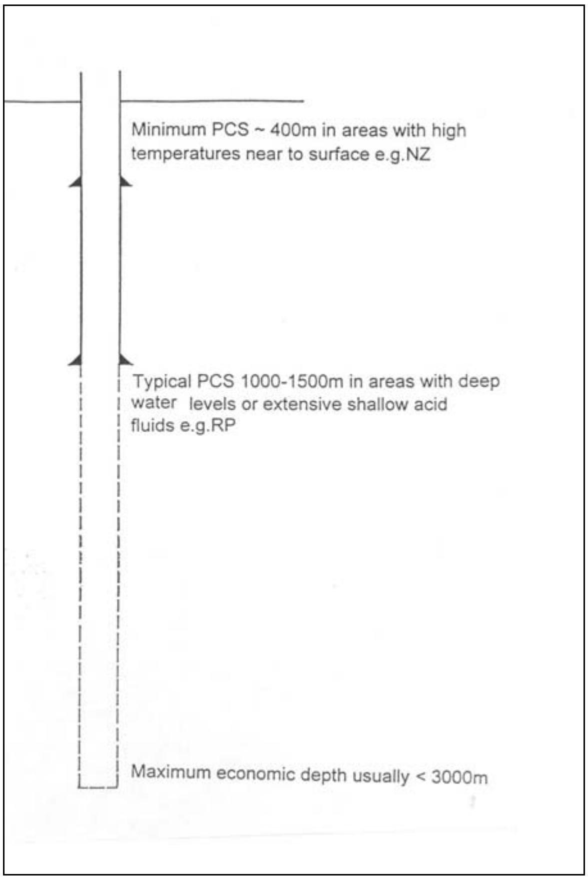

Figure 7 Typical range of geothermal well depths

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For the section of the production casing between the anchor casing and the production casing shoe, internal as well as external corrosion may be an issue. In some fields sections of corrosion resistant casing are used in this interval where acid fluids are suspected. The correct identification of active acid zones by the rig geologist during drilling is therefore vital. Similarly, it may be the case that a suspected acid zone is encountered within the production section of the hole, after setting the production casing. The safest option would be to set another cemented string of solid casing and go down one size for the remainder of the hole, but unless the hole is being drilled at larger than standard diameter and the zone is close to the PCS this may not be practical. A compromise is to include a corrosion resistant section of liner in the slotted string adjacent to the anticipated acid zone. This could be a blank section. This does not give a guarantee of protection, since the acid fluid can still percolate down the annulus into the slotted liner, but it can be effective especially if the main concern is to prevent anhydrite deposition by fluid mixing rather than preventing corrosion. If all of these measures fail to prevent the production of fluids with a pH of less than 4, there is no alternative but to plug the well with cement from the production casing shoe to the surface. This should be done as soon as acid conditions are confirmed. Delay can have drastic consequences.

3.2.3 Target Selection

The process of well target selection will be different at the exploration stage and the development stage, as discussed below. If vertical wells are to be used the only target aspect to be selected is the depth, which will be dependant on the predicted temperature, gas content, occurrence of acid fluids, and any known difficult drilling formations.

The objectives of the well need to be carefully thought out in advance. Attempting to achieve too much with a single well can be counter-productive. For example, once a highly permeable zone has been encountered shallow within the production interval of the hole, drilling on without risking the well may be difficult.

The targeting geometry of a well is dependent upon the degree of confidence in the location and orientation of permeable targets. This is because there is a trade off between maximising the probability of intersecting a permeable feature and maximising the well's intersection with that feature.

Generally the well target will be a fault and as discussed earlier permeable faults are likely to be steeply dipping if not vertical. Thus drilling a long throw directional well at right angles to a fault will increase the chances of intersecting such a fault. However, the longer the throw the higher the angle of deviation, the smaller the intersection with the fault, and the lower the probability of obtaining high permeability. Alternatively, hitting the fault at less than right angles can increase the length of intersection of the well with the fault but since the effective throw is less will have less chance of hitting the fault.

The greater the length of intersection, the greater the probability of obtaining high permeability. This is illustrated in *Figure 9* where three 2500 m measured depth wells are compared.

One of the wells is vertical; the other two are deviated. The two deviated wells have the same kick off points, build up and drift angle but one is drilled from the fault's hanging wall and the other is drilled from the fault's footwall. An envelope of uncertainty in the faults location is shown that combines the uncertainty in the location of the surface trace of a fault (in this case plus or minus 60 m) and the faults dip (in this case plus or minus 4°). There is an area 260 m wide where the vertical well can be located on the surface to intersect the envelope of uncertainty in the reservoir (where the top of the reservoir is at a depth of 800 m) with a maximum length of intersection of 1700 m. A well drilled from the footwall can be drilled from an area 810 m wide but can achieve only a maximum 680 m intersection with the zone of uncertainty in the reservoir. The well drilled from the hanging well can be drilled from an area 1000 m wide and still intersect the envelope in the reservoir but with only a maximum intersection of 460 m. Therefore, because a vertical well has the most limited area that it can be drilled from, it has the least chance of intersecting the fault, but because the intersection could be the longest has the greatest chance of encountering high permeability. Note that permeable faults tend to be a zone of brecciation rather than a simple planar feature, so the longer the intersection the better.

The chance of hitting the fault *increases* with a footwall well but the chances of encountering high permeability *decreases*, although it must be noted that with less steeply dipping faults, foot wall wells become less favoured because their chance of hitting the fault also decreases. A hanging wall well has the most chance of intersecting the fault but the least chance of intersecting high permeability.

During the early exploration phase the degree of confidence in the location and orientation of faults is generally low. This is because it is only after a well has intersected a fault at a predicted point that there can be a degree of confidence in the fault's location. This arises because if a well is targeted at a fault and a permeable zone is encountered anywhere in that well, unless there is corroborating evidence for the intersection being that fault, interpreting the permeable zone to be the fault is circular reasoning. If however the zone of permeability is found where it has been predicted there can be greater confidence the intersection is actually with the particular fault. As more wells are drilled and intersections are found, as predicted, confidence in fault locations steadily increases.

However, at early stages of exploration where there is a low degree of confidence the wells must be orientated so as to maximise intersections rather than maximising the lengths of intersections. Therefore long throw directional wells should be drilled early in an exploration program. In some programs there can be pressure from management to drill early wells vertically as a cost cutting measure. In this circumstance all parties need to acknowledge the concept that a hot well is a successful well otherwise what could have been a productive field, if drilled directionally or with a greater knowledge of fault locations, could be dismissed as impermeable.

When the fault pattern becomes better known, production wells can be targeted vertically into near vertical faults giving very long intersections and very productive wells. Alternatively wells can be targeted from the footwall in to a fault to give long intersections and productive wells. This can be combined with drilling the well at an angle to faults. This will be necessary anyway to infill drill a drill pad. The angle of intersection should however not become too oblique otherwise there is a risk that the well will start travelling along the outer zone of silicification that can surround permeable features without actually penetrating it. This risk becomes greater the deeper the intersection is.

Another factor to consider at the production stage is that the full cost of the well does not stop at the well head. There is also a cost to connect the well to the steam gathering system. A deviated well close to the steam gathering system will overall be cheaper than a vertical well at a distance from the steam gathering system aimed at the same target.

Some fields can have significant stratigraphic permeability that since such fields are usually hosted by young volcanics is generally horizontal. The simplest option in this case is to drill a vertical well. However, a directional well can still be advantageous, as there will be an increase in the length of intersection with a horizontal permeable feature and whilst overall the zone's distribution may be horizontal, the actual permeable features within it may be vertical. An example is columnar jointing in the welded centre of an ignimbrite. In this situation a well's permeability may be enhanced by a deviated intersection.

In targeting intersections, be they with faults or permeable stratigraphic horizons, they must be within the reservoir. Once a number of wells have been drilled and the top of the reservoir determined by contouring alteration mineralogy occurrences or stable downhole temperature data if available, the depth necessary to set production casing will be well established. However, for an early exploration well there is far less certainty and geophysics and geochemistry must be relied upon. The geophysics to be used is either a 1D layered model of the nearest MT station or better yet a 2D or 3D layered model with the section running through the well site.

Other things being equal, an exploration well should be located in the up domed part of the low resistivity cap. In rhyolitic or andesitic volcanic piles this depth corresponds to a change from where smectite is the dominant clay to where illite predominates, although smectite will persist as interlayered illite smectite to greater depth. The transition takes place at approximately 180°C. As the boiling point with depth relationship is the highest temperature gradient that can be expected, the top of the reservoir at 240°C will be at a minimum of 300 m below the low resistivity cap. Targeted intersections should be below this depth. In basaltic volcanic piles smectite persists in interlayered chlorite smectite to higher temperatures and the base of the low resistivity cap will be found at temperatures of between 230 and 250°C and hence will effectively mark the minimum production casing setting depth.

If the resistivity data is not available (although it would be doubtful an exploration well would be drilled without it and this second method is better used as a cross check on the resistivity) the elevation of neutral Cl springs needs to be taken into account. This can then be assumed to be the reservoir water level and by applying boiling point with depth relationships a temperature of 240°C should occur at a minimum depth of 400 m below it. If there are no neutral-Cl springs either the system is vapour dominated or it is well capped. If the system is vapour dominated (which should be known from fumarole chemistry) the depth to the top of the reservoir can be estimated (with significant uncertainty) if temperature gradient data showing a conductive profile is available. In this case the conductive profile can be extrapolated down to where a depth where a temperature of 245°C (the general temperature of vapour dominated systems) is found. In the absence of conductive temperature gradient data, a minimum depth of 400 m can be assumed (taking the boiling point with depth curve to be the highest possible gradient from the surface), while noting that locally high level exploitable steam zones have been found shallower than this in otherwise liquid dominated systems. If the system is a well-capped liquid dominated one, and it is not at extremely high elevation, it should be assumed that sea level approximates the water level in the reservoir and the top of the reservoir estimated to be at 400 m below sea level.

Establishing the depth of the top of the reservoir is not only important in estimating where the production casing should be set: it is important information required to site well pads. This is because whilst it is vital that a permeable feature be intersected in the production section of the hole they should be avoided in the section of the hole to be cased off. This is because they can provide drilling difficulties in the form of circulation losses, directional problems and the failure to obtain a good cement job. Therefore well pads should be sited away from the traces of shallow faults unless a vertical well is to be drilled.

Geothermal directional wells are routinely drilled by experienced contractors with measured depths of 3000 m and horizontal deviations of 1500 m, with a bottom hole diameter of 8 1/2" or so. Large diameter wells (12 1/4") have been drilled to 2800 m measured depth with the same directional parameters. Any greater combination of depth, angle and diameter would require an unusually large capacity rig and as yet undeveloped high temperature downhole steerable systems.

There is a trade-off in directional wells between angle of inclination (drift angle) and depth. As the angle goes up, the depth capability of the rig must be reduced. In practical terms, drift angles up to 45° are routinely used in geothermal wells and greater angles have been successfully used in some cases. Drift angles less than 15° are not selected as little horizontal deviation can be achieved within a reasonable depth, and there is difficulty in maintaining constant azimuth.

For a given horizontal target there are a range of possible kick-off points (KOP) and drift angles to achieve the same point (*Table 2*). Unless there are other considerations, the best solution is to chose a KOP is as soon after the anchor casing shoe as possible (while maintaining at least 50 m clearance), as this will minimise the drift angle and avoid having to run the downhole mud-motor in very hot formations. In the example shown in *Tables 1* and *2*, the preferred KOP would therefore be 372 m with a drift angle of 26°.

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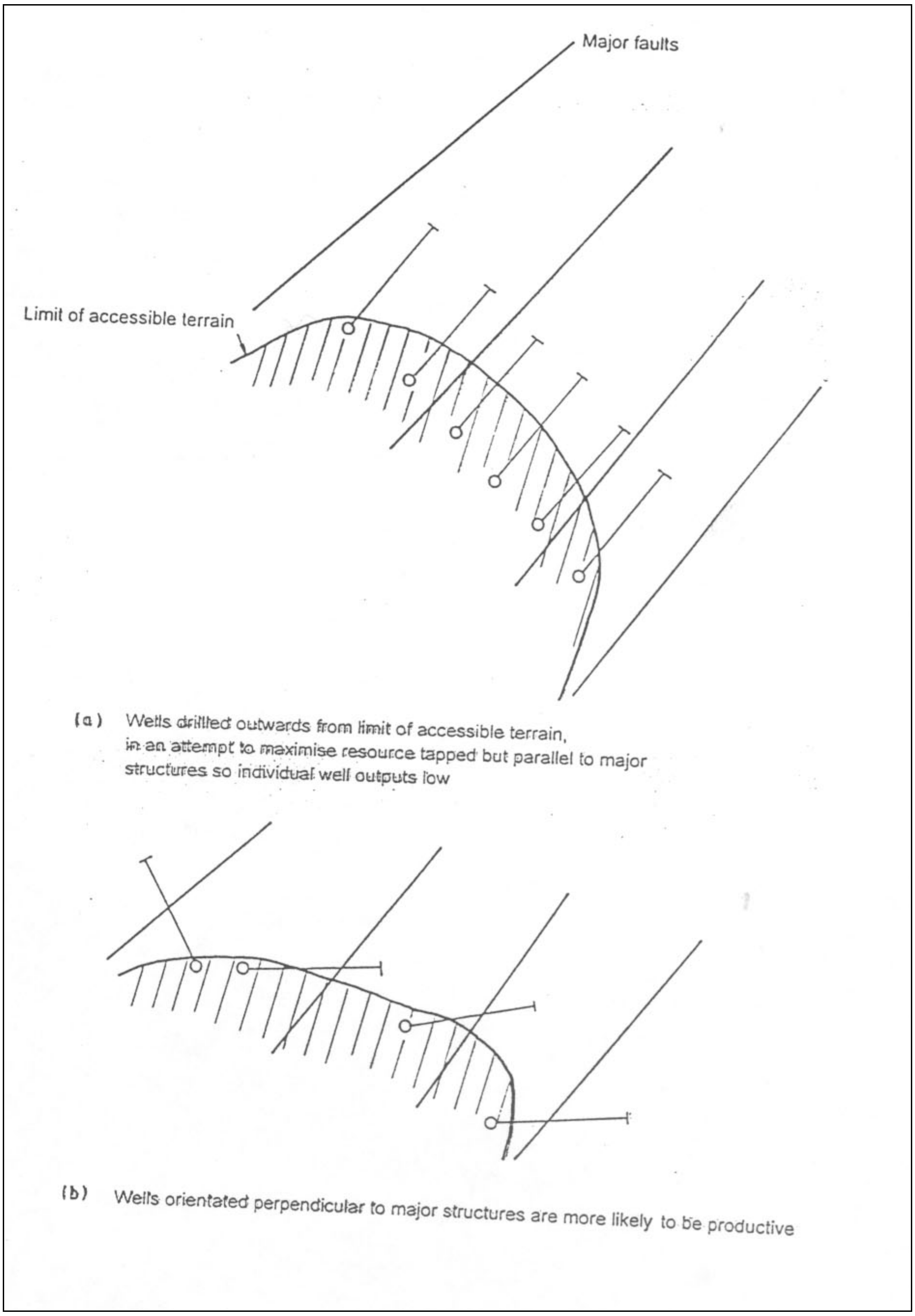

Figure 8 Orientation of wells and structures

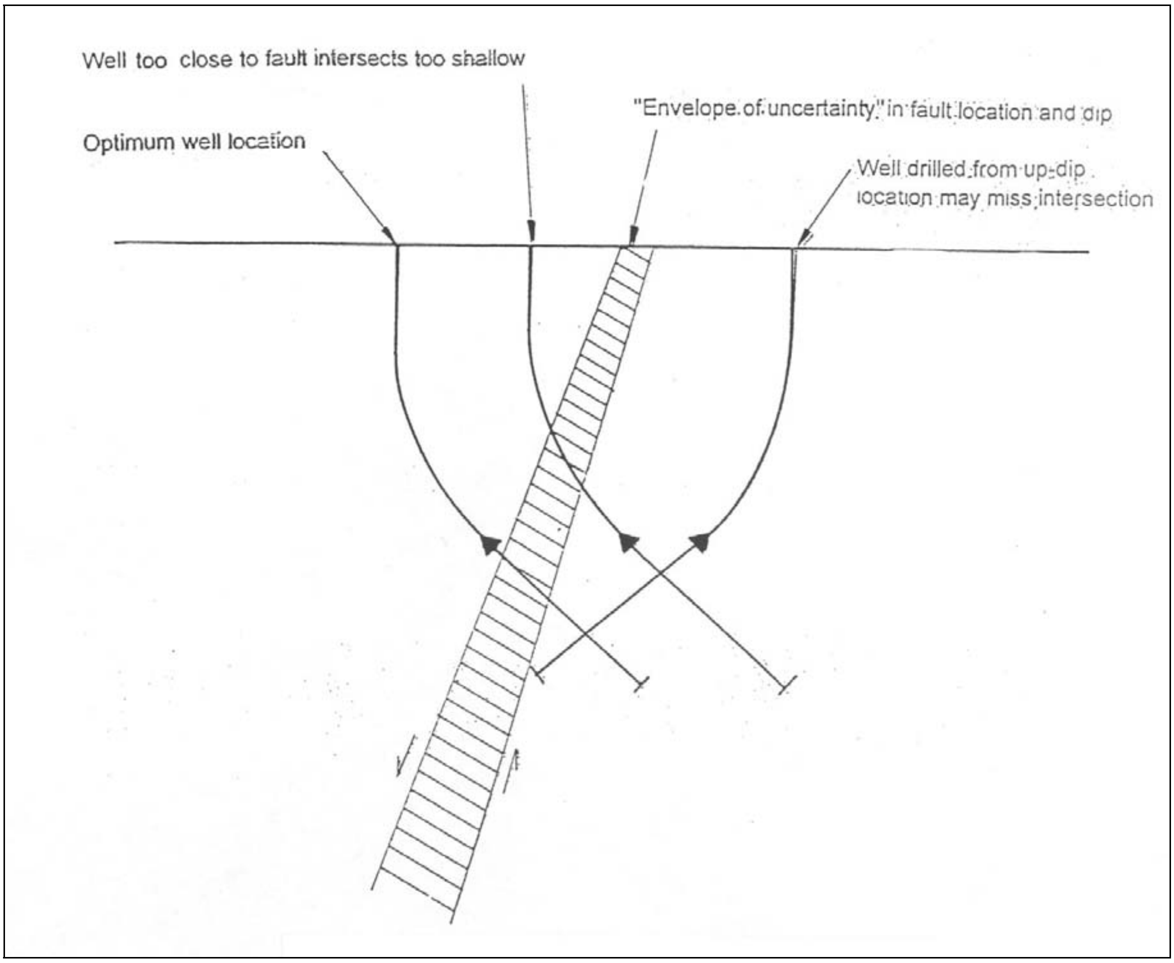

Figure 9 Siting directional wells in optimum locations to intersect faults

Table 2 Range of possible KOP's and drift angles to reach target

Target Location:		2220 804	m VD m Throw	**Well Name:**	XX
Rate build up		2	Degrees/30m	Date	26/07/97
Drift angle	KOP m	Target MD, m	End build up m VD	m MD	m Throw
20		No Solution			
21		No Solution			
22	61	2373	322	391	63
23	150	2379	336	495	68
24	230	2386	350	590	74
25	304	2393	363	679	81
26	**372**	**2399**	**377**	**762**	**87**
27	435	2406	390	840	94
28	492	2412	403	912	101
29	546	2419	417	981	108
30	596	2425	430	1046	115
31	643	2432	443	1108	123
32	686	2438	455	1166	131
33	726	2444	468	1221	139
34	764	2451	481	1274	147
35	800	2457	493	1325	155
36	833	2463	505	1373	164
37	865	2469	517	1420	173
38	894	2475	529	1464	182
39	922	2482	541	1507	192
40	948	2487	552	1548	201
41	973	2493	564	1588	211
42	997	2499	575	1627	221
43	1019	2505	586	1664	231
44	1040	2511	597	1700	241
45	1060	2517	608	1735	252

Predicting the depth of a fault intersection can be done by simple geometrical methods, or use of a spreadsheet (*Table 3*). It is advisable to allow for some uncertainty both in the fault location and its dip (*Figure 10*). Other things being equal, the production casing depth can then be selected to be just above the minimum possible fault intersection. If the fault is inadvertently encountered before the production casing is set, it may be possible to set a gel/gravel pack and a cement plug to get the production casing in and cemented. In this way hopefully the permeability can be preserved when the hole is re-drilled.

Table 3 Program fault intersection

Input		**Output**	**Deviated Well**	
Kick off point: m	475.00	Vertical Depth: m	1649.00	
Rate of build-up: deg/30m	2.00	Measured Depth: m	1803.00	
Drift Angle: Deg	32.00	Throw: m	580.00	
Fault strike: Deg	180			
Well Azimuth: Deg	90.00			
Well Elevation: m	1720.00	Range	Max	Min
Fault elevation: m	1900.00	Vertical Depth: m	1871.00	1457.00
Fault dip: Deg	85.00	Measured Depth: m	2064.00	1576.00
Well/fault distance: m	740.00	Throw: m	718.00	460.00
Uncertainty: ± m	50.00			
Dip uncertainty: ± Deg	3.00			

3.3 Sampling

Recommended practice is sampling at 3-5 m depth intervals for cuttings or from cores collected at 300 m depth intervals in the event a well is being drilled blind and hole conditions are sufficiently stable to allow running a coring barrel into the hole without undue risk. Additional cores should be cut at intervals of particular interest, even if there is full recovery of cuttings, since there is always some question as to where cuttings have come from, and macroscopic features of the formation such as coarse breccias may not be revealed in cuttings alone.

Recovery of cuttings can be done by a relatively untrained technician or contract mud-loggers if such are employed. If cuttings are collected by non-professional staff, though, it is important to make checks as to their reliability. If changes in lithology appear to correlate with changes of shift, for example, check to make sure the technician is not taking all of the samples at the start of the shift and then sleeping for the remainder!

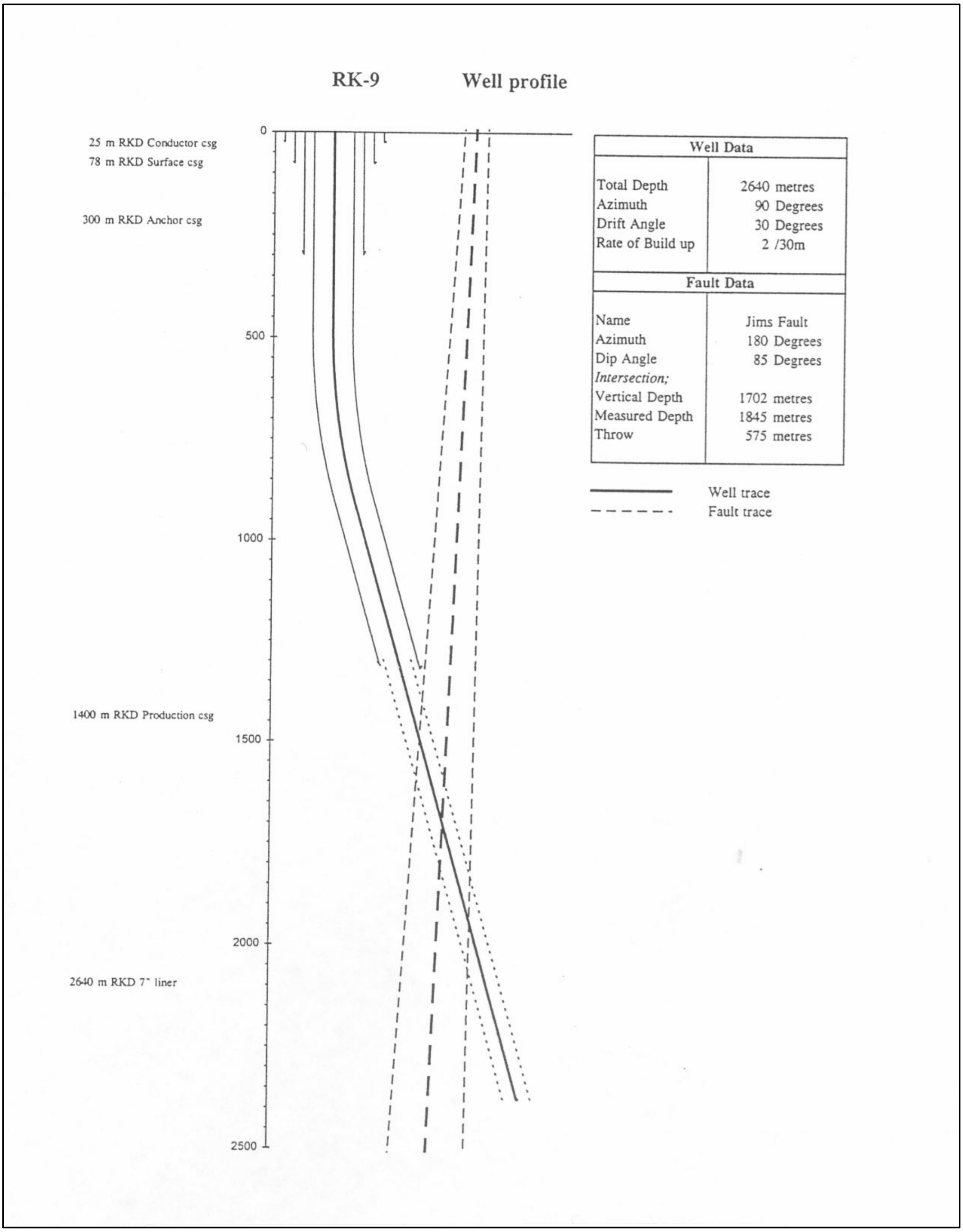

Figure 10 Well and fault profile for well XX

The rig geologist should always be on the rig floor to recover core, so that he can make an immediate recommendation to drilling staff should this be needed. The rig geologist should prepare an immediate report describing the core and commenting on any significant features, before selecting samples for petrology.

Any "accidental" pieces of formation recovered should always be sampled and described. These might include fragments lodged in drilling assemblies, especially if these have been recovered from stuck points, samples from junk baskets, or ejecta from well discharge tests.

3.4 Well Site Geological Operations

Geological support should be continuously deployed at the rig site while drilling is in progress (approx. 30 to 40% of the time as indicated in *Figure 11*).

It requires substantial commitment to manning, since it means having at least three geologists assigned per rig (two on 12-hour shifts and one on break). A site with more than one rig drilling would have at least one Senior Geologist also, plus a number of trained technicians. However, the costs of providing this level of service are small compared to the potential increased drilling cost or foregone production through making poor drilling decisions through a lack of immediate knowledge of the geology.

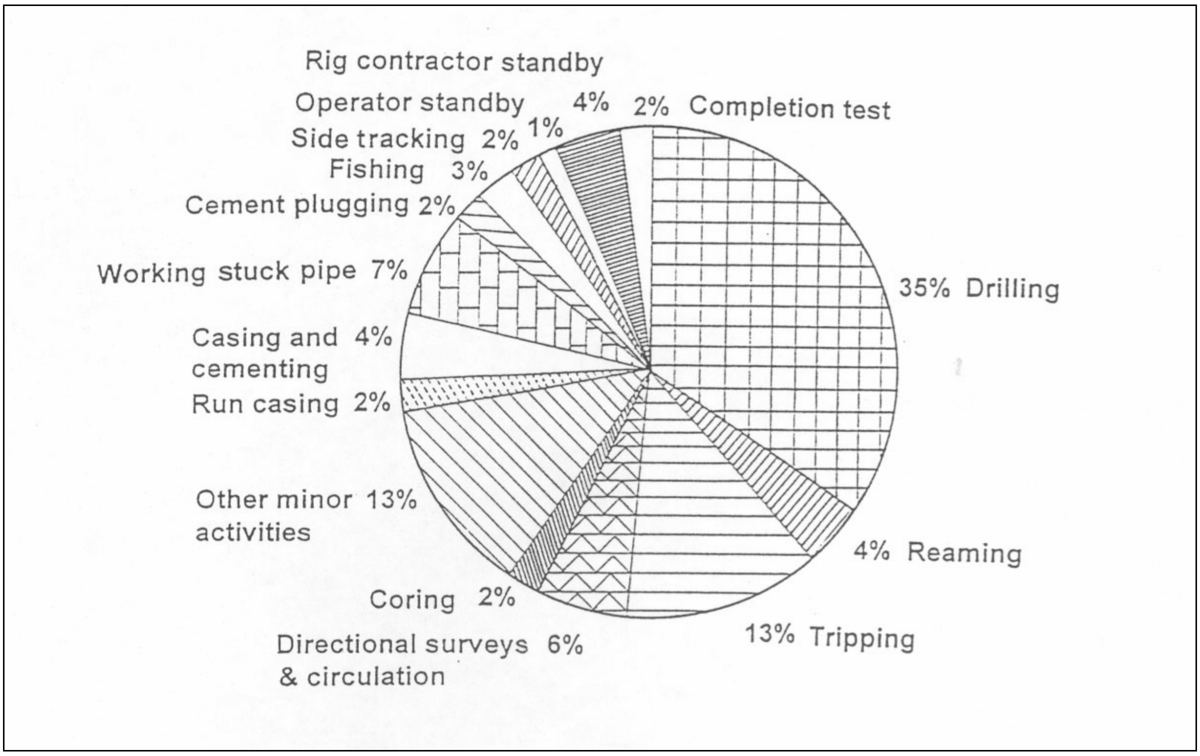

Figure 11 Typical time distribution for drilling a 2500 m directional well

The geologist should have available at the project site at least the following equipment:

- A binocular microscope with 10 to 50 X magnification (at the rig site).
- Chemical stain methods for distinguishing swelling from non-swelling clays (base office).
- Chemical methods for determining acid minerals in cuttings and cores (base office).

and preferably:

- Rock thin sectioning equipment.
- A basic polarising petrographic microscope.

The following equipment should also be available in a centralised laboratory which can ideally receive samples of cores and cuttings within 24 hours from dispatch from the project site:

- An X-ray diffractometer.
- Microscope heating and cooling stages for analysis of fluid inclusions.
- Rock thin sectioning equipment.
- Polarising petrographic microscopes.
- Triaxial testing (compression testing) or other equipment to provide data on the engineering properties of cores, such as strength and erodibility.

3.5 Downhole Geophysics

One of the major differences between geothermal and petroleum rig geology is in the use made of downhole geophysical tools. Many of the downhole tools which are routinely used in petroleum operations cannot be used in geothermal wells because of the temperature or because the conventions of interpretation which are used in petroleum work have not been calibrated in the geothermal environment.

The only downhole tools which are used routinely on all geothermal sites around the world are mechanical (Kuster-type) temperature and pressure gauges. In many locations these are now being superseded by surface-read-out electronic tools, which have the advantage of giving much more detailed logs and permitting real-time read out over zones of interest. In some locations a "PTS" (pressure-temperature-spinner) tool is used instead. This incorporates a flowmeter. These will cope with internal flows when a well is shut, and yield much valuable data in that respect, but cannot usually cope with a discharging well. Indeed, one of the reasons why mechanical PT tools are still used is they can more confidently be used in flowing wells, because their smaller tool and cable diameter creates less drag.

There are a variety of tools which can be run within casing, such as callipers or CBL's (casing bond log), which have more specific drilling engineering applications but which the geologist may sometimes need to be aware of. Open-hole callipers are not used much in geothermal wells because the nature of the formations tends to lead to irregular and oversized holes, though note that they are always run along with FMS logs. Neutron logs have been used successfully for porosity measurements at some projects.

Micro-resistivity tools have recently become available from Schlumberger (FMS and FMI) and other service companies which are capable of operating in geothermal wells. These are run in open hole. By measuring resistivity at a large number of points around the well bore, and being run up the hole, they in effect reproduce a picture of the inside of the wellbore.

The resistivity response comes mainly from the presence of clays. Where there is variation in the clay content between clasts and matrix in a breccia the image has almost photographic clarity. Where there are no clays or a uniform distribution of clays in the formation, only the fractures filled with drilling mud show up, but different lithologies can still be recognised from their joint patterns. Secondary fractures also show up when they are filled with drilling mud. Hence this technique works best in the sections of hole drilled with mud rather than water.

The orientation (strike and dip) of features such as fractures and bedding can be automatically calculated during computer post-processing. Some very impressive results have been achieved (*e.g.* Huntoro *et al.* 1996). In one drillhole in Indonesia the FMI permitted discrimination of 40 separate geological units within an interval which conventional logging of cuttings had lumped together as one unit. There are however limitations: because of the extensive computer enhancement which is needed, runs are expensive (about US $ 50,000 per survey plus mobilisation), and the tools need to be kept cool by injecting cold water into the well during the survey. If a well has a shallow permeable zone, it may not be possible to get adequate quenching at the bottom.

Usually a total gamma ray counter is run with the FMS/FMI tool. Where it is cross logged with overall resistivity, areas of illite rich alteration around permeable features can be identified by their low resistivity/high gamma signature, and areas of silicification are revealed by high resistivity/low gamma count.

3.6 Data Handling and Reporting

Considerable thought should be given as to how the initial data should be stored. They must be accessible and understandable throughout the life of the project, while at the same time allowing for revisions as new geological information becomes available. For example, a certain stratigraphy may be erected during initial surface exploration and drilling, and this then has to be revised in the light of later data. Because of the subjectivity involved in geology re-interpretation must be allowed for. Similarly, individual well logs will usually largely be completed during drilling of each well. If more data subsequently becomes available from detailed petrological analysis, there must be scope to go back and revise the logs.

In addition to the daily report discussed above, the well site geologist should at the conclusion of each well prepare a consolidated geological report which provides at least the following information:

- A megascopic log of cuttings encountered throughout all depths in the well that were drilled with circulation returns.

- Percent recovery of all cores that were cut and detailed description of lithology, alteration and structure apparent in the cores.
- Hydrothermal alteration with depth (including data from XRD, MeB and petrographic studies) and evidence for fluid chemistry and state.
- Evidence from fluid inclusions for subsurface temperature and fluid chemistry.
- Assessment of permeable zones in a well from drilling, geologic and completion test data.
- Correlation of permeable zones in the well with geological features giving primary (porosity) and secondary (structural) permeability.
- Correlation of surface structural geology with downhole structural permeability.
- Correlation of the well geology with other wells drilled in the area.

4. Drilling and Development Strategy

4.1 Exploration Stage

Well design and site selection during exploration inevitably involve a trade-off between many factors. The first point to determine is whether this is to be a one or several well programme. Economics might force this decision, but if at all possible a minimum of three wells should be drilled before making a decision as to whether to proceed with development of any particular area. The only exception to this might be in a system where the hydrology is so clear-cut that it can be adequately tested with a single well. The history of exploration at other projects shows that considerable persistence may be needed before commercial production is achieved. For example, it was not until the tenth well that commercial production was obtained at Tongonan (including slimholes), or the fourth well at Bacon-Manito in the Philippines. Both of these fields are now in successful large-scale commercial production.

Exploration well targets need to fulfil several objectives, namely:

- They should test the hydrological model of the area.
- They should confirm temperatures and permeability at depth.
- They should be capable of being discharged to give information on fluid chemistry.
- They should be accessible at reasonable cost.
- Ideally they should be commercially productive.
- Ideally they should become part of a feasible development scheme.

In practice, one usually selects a general area for exploration drilling on the basis of the hydrological model of the area, and the geophysics, and then within that area identifies a specific geological target such as a fault. Next locate a feasible site for drilling from, and which is part of a sufficiently large area of accessible terrain to be part of a feasible steamfield.

The next aspects to consider are well depth and diameter. These two are intimately linked: Other things being equal (such as casing weights and whether there are circulation returns) any given rig can drill deeper at smaller diameter for the same cost. Drilling costs during exploration can be reduced by either drilling slimholes (small diameter but deep holes using a smaller rig than for conventional wells) or drilling shallow ("temperature gradient") holes using a lightweight mineral-investigation-type rig, or some type of rig capable of combined operations with, for example, rotary drilling in the upper part of the hole and continuous coring below.

In our experience slimholes are useful in certain circumstances but will eventually have to be replaced with full-diameter wells, though the slimholes will in that case have provided useful information about potential problem zones while drilling. Slimholes do have their useful applications but it should be acknowledged that the objectives of drilling slimholes need to be clearly established and are not the same as for full-diameter wells. Their main advantage may be in an accelerated investigation programme such as at Wayang Windu, Indonesia where two slimhole rigs have been used as well as two full-sized rigs to permit the investigation of a wide area in a short time. We generally do not favour routinely drilling temperature gradient holes in convective magmatic systems as we consider that the results are rarely sufficiently unambiguous to justify the cost.

The target depth should be chosen on the basis of the hydrology. In an area with subdued relief and a high piezometric level and high solute geothermometer temperatures, it would be reasonable to assume conditions close to boiling point for depth. Hence relatively shallow wells, say 1000 m, would be adequate for exploration. In contrast, in an area of elevated terrain without liquid outflows, 2500 m might be more appropriate for exploration

The casing programme should be designed as above. The hydrological model should be invoked to predict a production casing setting depth at which temperatures are thought to be adequate, with a suitable safety margin.

Each exploration well should test a specific aspect of the hydrological model. If possible they should have both exploration value and potentially be connectable to a feasible development scheme. For example, it may be easy to access a certain prospect from a site at low elevation, but there is a strong risk this area may overlie an outflow and hence possibly sub-economic temperatures. It may also be at too low an elevation to easily connect to the later development scheme. Hence, it would be advisable to spend an extra $ 150,000 or so to extend the access road by another kilometre, rather than risk wasting a well costing perhaps $ 3.5 M.

At the same time, the exploration drilling programme should be designed to test the extent of the resource (up to the maximum envisaged for the first stage development), so exploration wells should be reasonably widely spaced. Because of the level of costs involved, it is at this stage when the need for a clear strategy becomes important. Before the first well is drilled, the possible outcomes of drilling should have been discussed and an unambiguous decision tree drawn up. If the first well is productive, then the decision to move on to the second well is clear-cut. If however the first well is not productive, then the decision could be to persist with the second well as planned, persist with the second well but change its target depth or location, postpone a decision while the first well undergoes an extended test programme, or abandon the prospect. Making this decision is complicated by the fact that unless a vapour dominated resource is tapped; the first well may take several months to heat up completely. Placing the rig on stand-by is usually an expensive option, but so is drilling a second un-productive well. One way to ensure that the programme retains flexibility is to always have at least two alternative sites ready for the rig to occupy at the end of drilling each well. This requires some pre-investment in civil works, but minimises the chance of unproductive down-time. The well testing programme, including means of waste disposal, must also be thoroughly thought-out in advance.

These matters must be carefully discussed with the management of the development company and often the funding agency before drilling starts.

4.2 Delineation Drilling

The initial exploration programme may have consisted of drilling perhaps three wells. The presence of a productive resource will have been confirmed, if not fully quantified. The objective is now to drill out the extent of the resource that can be connected to the initial development. In a large geothermal system in difficult terrain such as Tongonan or Bacon-Manito in the Philippines, further exploration drilling may proceed simultaneously in other parts of the prospect, but it should be recognised that the objective of this is not the same as delineation drilling for the first-stage development.

There are three aspects to the delineation drilling programme: resource quantification, resource proving, and providing data for design. By the end of the delineation drilling and well-testing programme the resource capacity will be known with some confidence and sufficient data will be available to undertake some preliminary numerical simulation modelling. A reasonable proportion of the wells which will ultimately be required for the first-stage power plant will have been drilled- perhaps 40 - 60 % - and this will provide confidence for obtaining project finance. Information from well testing and geochemistry will affect the preliminary design of the fluid collection and disposal system (FCDS) and selection of power plant size and system operating pressures. Preliminary reservoir management studies will identify the most favourable production and reinjection areas.

It is common practice to mobilise more than one drilling rig during the delineation stage, which could occupy anything from nine months to two years.

It should not be thought that delineation drilling will achieve a 100 % success rate. Since the objective is to determine the extent of the productive resource, sooner or later one or more unproductive wells may be drilled. Nor should it be assumed that the initial estimate of resource capacity will remain fixed. It may be determined that the resource is capable of supporting a larger or smaller power plant than was initially considered.

A decision to abandon or significantly modify a proposed development at the end of the delineation stage would not be made lightly, but it may be necessary. One example is the Bacon-Manito Stage One plant in the Philippines, where a decision was made to shift the focus of development to a new area after drilling six deep wells, despite the fact this meant not including the two most productive wells drilled so far, one of which produced > 10 MWe. The decision was based on a combination of factors including environmental impact and terrain. The strategy was successful: a 110 MWe plant has been commissioned in the “new” area and some of the early exploration wells have since been connected to two separate 20 MWe plants.

4.3 Production/In-fill Drilling Stage

The objectives of drilling at the production stage are to maximise production or reinjection capacity, while avoiding excessive interference between production wells or rapid return of reinjected fluids to production zones. What makes the geologist's task easier is that by this time there should be a coherent picture building up of the stratigraphy and permeability controls on the field. Nevertheless, careful geological monitoring while drilling is still required to avoid unpleasant surprises if conditions are different to those anticipated!

This is the stage when the largest part of the project cost is invested, but the opportunities for risk mitigation at this stage are progressively reduced as more aspects of the project design become fixed. The geologists, reservoir engineers and drilling engineers will be gaining an ever-increasing understanding of the permeability controls and hydrology of the reservoir, so the drilling success rate should be increased.

At this stage the reservoir engineers should be able to provide some advice on how closely wells can be spaced without causing undue interference. If no unequivocal advice is available, a spacing of 300 m between production zones can be adopted as a conservative first-estimate, and this can then be refined based on well-test data and more closely-spaced wells drilled if this seems appropriate. Note that in highly permeable reservoirs, especially where production comes from large fault zones, much closer spacing than this may be acceptable. For example, recent drilling at Wairakei has shown less than 5 % interference between shallow vertical wells in a steam zone drilled only 50 m apart. If such close-spaced drilling is to be adopted, though, consideration should be given to the possibility of causing formation damage in existing wells while cementing new adjacent wells and if possible cementing close to known production zones avoided.

Siting reinjection wells should likewise be pragmatic. If no other information is available, at least 500 m separation from production zones should be adopted and preferably twice this much. Siting reinjection wells to intersect known or suspect permeable structures that could lead back to the production zones should be avoided. Once some reinjection wells are available, the use of underground tracers may give an early warning of unacceptably rapid communication, or at least significant reservoir anisotropy.

Production casing depths for infill production wells will be based on a trade off between maximising production, obtaining sufficient separation in production zones, and avoiding cool or acid fluids. Some thought should be given to possible reservoir changes with time. For example, if there is a suspected gas-rich cap to a steam zone, it may be preferable to run production casing a little deeper than the anticipated top of the steam zone so that gas is allowed more time to dissipate and become diluted with steam, rather than being sucked into wells as soon as pressure draw down.

Reinjection casing depths will similarly be dictated by reservoir engineering considerations. Provided that reinjected fluids do not track back to near-surface groundwater aquifers, or to production zones, there is no need to run reinjection casing particularly deep. If possible reinjection should be sited to zones of temperature no less than the fluid separation temperature, to avoid rapid silica deposition, but not so as to sterilise potential productive hotter zones. However consideration should be given to reinjecting into any wells which produce acid fluids as these may not be well hydrologically connected to the reservoir and there can be greater dispersion of silica where the acidity slows down its rate of polymerisation and deposition. Reinjection to cooler, peripheral parts of the reservoir increases the potential that there will be problems with swelling smectitic clays during drilling and these should be monitored for by the rig geologist.