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RESERVOIR ENGINEERING ASPECTS OF THE PHILIPPINES GEOTHERMAL DEVELOPMENTS IN LEYTE AND SOUTHERN NEGROS

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ABSTRACT

The current state of development of the Tongonan and Puhagan geothermal fields in the Philippines is presented and the nature of the reservoirs is described. In the latter part of the paper, reservoir engineering techniques which have been found to be particularly valuable are discussed and some aspects which give rise to problems are identified.

INTRODUCTION

The Tongonan and Puhagan geothermal fields are water dominated fields on the islands of Leyte and Negros respectively - (Fig. 1). The Tongonan field currently supports the Tongonan I, 112 MW(e) power station which was commissioned earlier this year and the Puhagan field supports the Palinpinon I, 112 MW (e) station which is still in commissioning. In contrast to the Tiwi and Mak-Ban fields on the island of Luzon, which were developed by non-Philippine companies and the steam sold to Philippine National Power Corporation (NPC) power stations, Tongonan and Puhagan have been developed by the Energy Development Corporation of the Philippine National Oil Company (EDC-PNOC). Exploration began with the help of a New Zealand - Philippines Economic Co-operation programme in which KRTA were New Zealand Government representatives. The field development phases were carried out by EDC-PNOC, with the aid of a joint venture company formed by EDC-PNOC and KRTA: the scope of work covered geoscience, drilling management and reservoir engineering as well as the design, construction and commissioning of all field surface works.

So far as the power stations are concerned, both are owned and operated by NPC. Tongonan I design, construction management and commissioning was carried out by KRTA over the period 1979 to 1983. Palinpinon I was started later and, of largely prefabricated construction, was designed, constructed and commissioned by 1983 under a turnkey contract by a Japanese manufacturer.

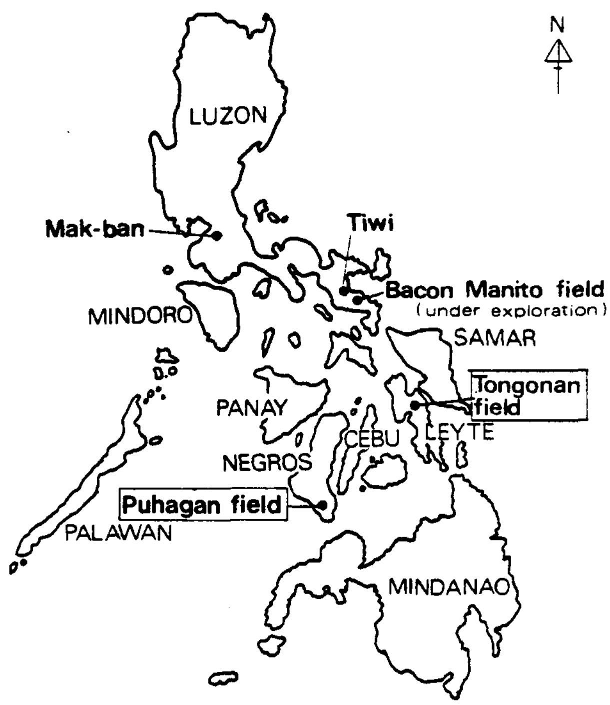

Fig. 1. Field locations in the Philippines.

CURRENT STATE OF DEVELOPMENT OF THE FIELDS

The two developments are rather similar in terms of operating parameters and general type. Each field provides single flash dry saturated steam to its 112 MW(e) power station at 0.6 MPa abs from production wells supplying a two-phase mixture to cyclone separators. The separators operate at about 0.7 MPa abs and the waste water is fed to reinjection wells without any further cooling. In plan view, however, the developments have distinct differences - Figs 2(a) and (b). The Tongonan two-phase pipelines are long and follow the main river valleys to separator stations situated about 400m from the power station. In the Mahiao sector of the field there are 6 vertical production wells spaced at 200-300m in almost a straight line; in the

Sambaloran sector there are 6 vertical production wells in a random cluster with rather wider spacings. The Puhagan development on the other hand, is one in which deviated wells have been drilled from four multi-well pads situated within 500m of the power station. The longest two-phase line is about 300m and a single separator station is situated about 200m from the power station. Both field developments have been constrained by topography, being located in very steep and easily eroded terrain. In both, the reinjection wells have been sited so as to be downhill from the separator stations.

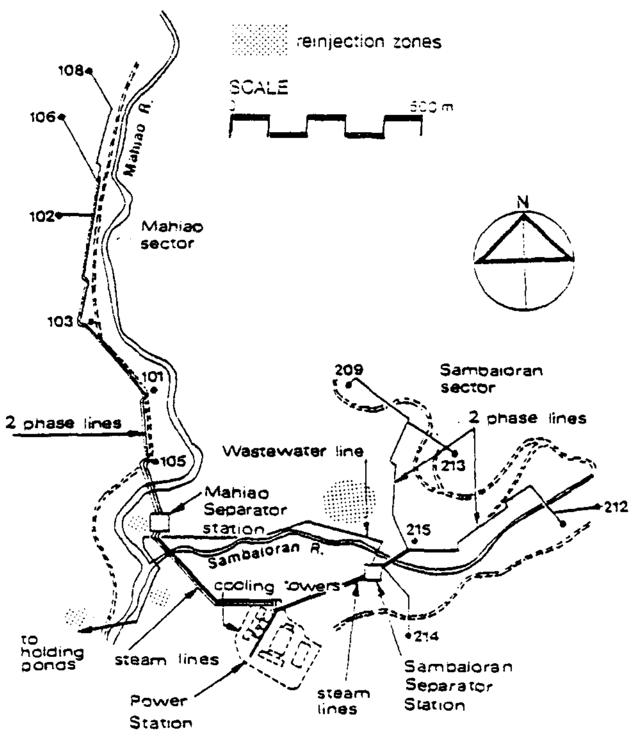

Fig. 2(a). The Tongonan field.

As indicated briefly in the introduction, major production from the Tongonan field started in April 1983 and from Puhagan more recently. Leyte has no major electrical grid; the load for Tongonan I is made up mainly by a nearby copper smelter which has several items of equipment that present large electrical loads and can be switched on and off almost instantaneously. The fluctuating load which results is not ideal for a geothermal power plant, however, the steam gathering system was designed with such conditions in mind and so far has performed well.

Southern Negros has a more developed electrical grid system and Palinpinon I should not have to operate with major load variations. In both fields the main power station was preceded by the installation of small non-condensing units, 3 MW(e) at Tongonan and four 1.5 MW(e) units at

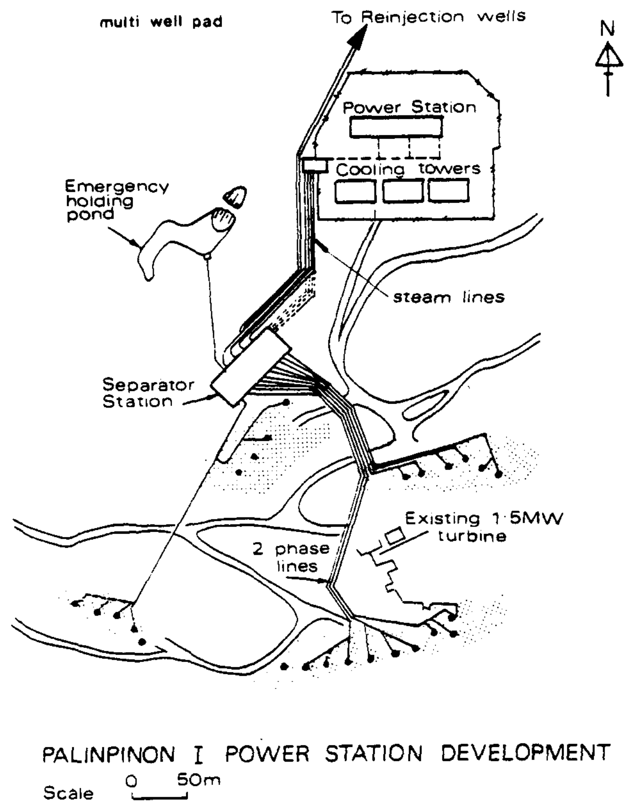

Fig. 2(b). The Puhagan field.

Puhagan. These have provided useful electricity generation as well as field operations experience.

A major feature of both fields is that full reinjection is designed for. Silica concentrations in the waste water are such that supersaturation and deposition can only be avoided by using waste water temperatures of 165-180°C, which is the temperature level after the first flash stage. Fortunately an economic assessment showed that a second stage flash was not clearly cost beneficial and the single flash cycle was adopted. From the surface engineering point of view, reinjection at either field presented no major problems. The cold standing water level in the wells is sufficiently low that injection pumps are not required, particularly at Puhagan where it was so low (in excess of 600m in some wells) as to cause difficulties in promoting discharge. In addition the layout of pipelines and separator stations was done with reinjection areas in mind, to take advantage of local topography. The choice of areas in which to reinject was not easy and to some extent is rather subjective. Reinjection tests lasting several months have been carried out at Tongonan in order to provide experience on which to base the selection of waste water temperatures etc.

THE NATURE OF THE RESERVOIRS

Tongonan

Many more wells have been drilled in Tongonan than are needed for Tongonan I as a deliberate policy for additional power plant and these give a good spread of data points to help understand the field. As mentioned previously the wells are mainly vertical and of depth less than 3000m. Usually at least two production zones occur in a well; there does not seem to be major disequilibrium between the zones, as judged by the tendency for internal flows in wells. Internal flows do occur however, for example, a two-phase upflow in well 209. This leads us to the most significant geological feature - the principle production zone is a contact zone between the upper surface of a quartz diorite plutonic intrusion and the overlying volcanics. The upper surface contours of the pluton are shown in Fig. 3 from which it can be seen that the Sambaloran wells are grouped around a local high point whilst the Mahiao valley wells follow a steeply dipping edge. How much production can be gained by drilling into the pluton is still a point of conjecture; certainly well 209 penetrates 600m into the pluton and seems to produce from well below the pluton surface. It has the highest output of any Philippines well at about 25 MW(e) equivalent, but it is blocked to instruments at depth and the nature of the deep production cannot be examined. The contact zone contains propylitised andesites and andesite/microdiorite breccias and is of varying thickness across the field, up to a maximum of about 500m. It is heavily fractured.

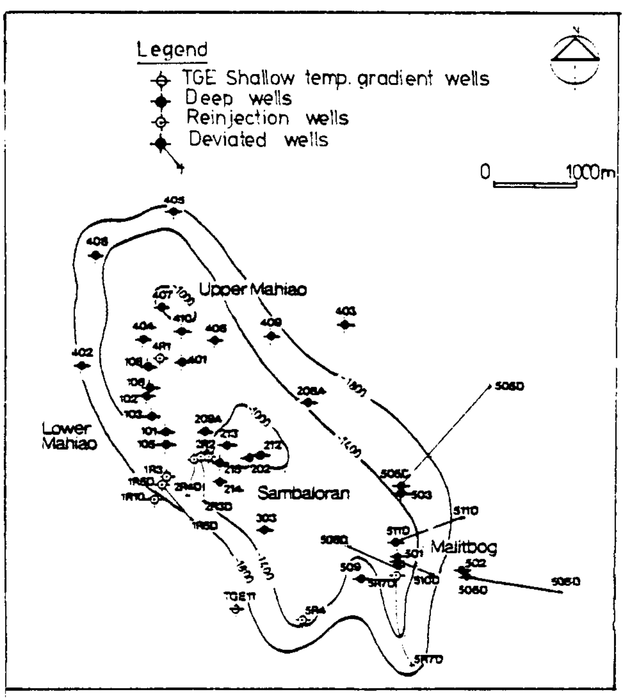

Fig. 3. Pluton surface contours at Tongonan.

The overlying layers are mainly volcanic andesites, breccias and tuffs, and although certain well defined sequences such as thin beds of sandstones and siltstones and some dykes are evident, they have no major effect on reservoir performance. Gross transmissivity of the wells is between 1 and 8 darcy-m as measured by pressure buildup and pressure falloff tests. It is KRTA/EDC practice to measure injectivity by injecting water on well completion, and values between 20 and 60 ℓ/s MPa are typical. Temperature contours on a plane at 900m below MSL show a similar general shape to the pluton surface contours, suggesting that the contact zone which 'cloaks' the pluton itself contains the highest temperature fluid. Maximum temperatures are about 320°C, and production from the contact zone is single-phase saturated liquid. Production from within the pluton in the case of well 209 is two-phase and there are two-phase zones at shallow levels in the reservoir. These appear to be naturally occurring, and their presence leads to discharge enthalpies which are quite strong functions of wellhead pressure. The extent to which discharge tests could be carried out was limited by environmental restrictions on allowable discharge to the rivers in the 'dry' seasons and by pipeline construction in the case of Tongonan I wells, but as shown by Lovelock, Cope and Baltasar (1982) correlation of discharge enthalpy with chloride concentration in discharge has proved to be very instructive as regards natural fluid movements in the field. Under full bore discharge the output enthalpy is higher than that of liquid from the contact zone because of steam production from the upper zones. With the discharge restricted so that wellhead pressure is high, steam production is suppressed and the discharge enthalpy is that of liquid at depth. Fig. 4 shows the chloride concentration in the total discharge plotted as a function of discharge enthalpy for one particular well. The linear plot is an indication that the discharge consists of a mixture of two fluids with different chloride concentrations and enthalpies. The points with numbers attached refer to restricted output - the restriction and hence the wellhead pressure is greatest for

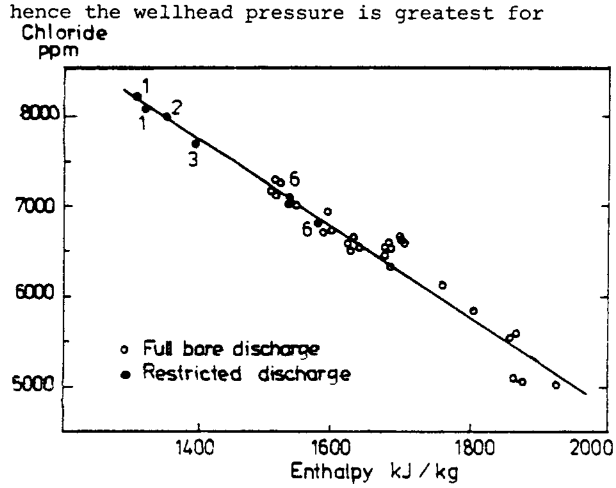

Fig. 4. Chloride-enthalpy plot for a Tongonan well.

points marked 1 and number 6 is almost an unrestricted full bore discharge. The high enthalpy full bore discharge points in Fig. 4 represent different mixes of steam and water produced probably because of drawdown whilst the low enthalpy points suggest that the 'primary' reservoir fluid for this well has an enthalpy of about 1300 kJ/kg and hence a temperature of about 290°C. This is supported by the Na-K-Ca geothermometer and SiO_2 geothermometer results.

Applying the same technique over the rest of the field gives an indication of the chloride concentration of the local geothermal fluid. Assuming that the chloride concentrations vary due to mixing with meteoric water, then the shape of the contours of this variable over the field gives some indication of the natural flow of geothermal fluid. The suggestion is that the fluid is at maximum concentration and possibly rises in the Upper Mahiao Valley region and that a major percolation of this primary fluid into the Bao Valley region has taken place, which fits with the interpretation of the early exploration drilling results. Lovelock, Cope and Baltasar go into more detail about the interpretation of natural flows. It is of interest to note that the Malitbog area wells display temperature inversions, which are consistent with the natural flow interpretation.

Puhagan

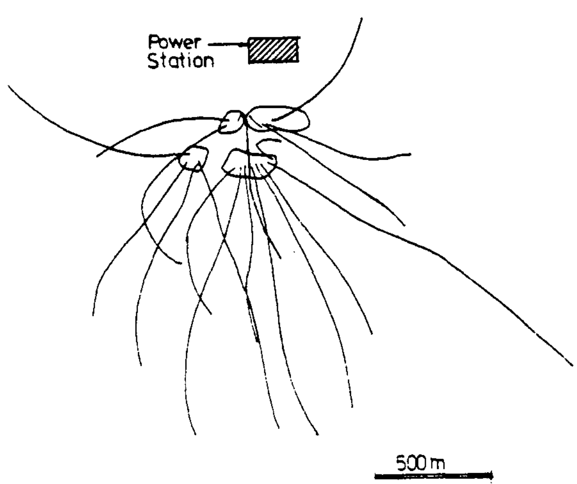

Fig. 5. Well tracks at Puhagan.

A plan view of the well tracks is shown in Fig. 5 and it will be immediately clear that the spread of data points for establishing temperature contours etc. is not so good as at Tongonan. An additional complicating factor in establishing undisturbed reservoir temperatures from the wells is the frequent occurrence of downflows. This feature is consistent with the idea of the permeability being fracture dominated with the reservoir composed of low permeability material. Detailed descriptions of the stratigraphy have been given by Leach and Bogie (1982) and Maunder, Brodie and Tolentino (1982). A further indication of the localised nature of the permeability is that the variation of chemical constituents in a well output in response to variations in wellhead pressure is rather random, in contrast to Tongonan wells, which suggests that different fluids can occur in isolation throughout the reservoir. Fig. 6 represents a cross section of the reservoir showing the main geological components. The near-horizontal sill is fairly influential in channelling ground water into the reservoir, giving rise to calciting problems in some wells. As in Tongonan, it has been established that production occurs from within the pluton; well SG1 is cased into the pluton and has a power output of about 5 MW(e) and maximum temperatures of 277°C, however its ability to provide for long term production still needs to be established.

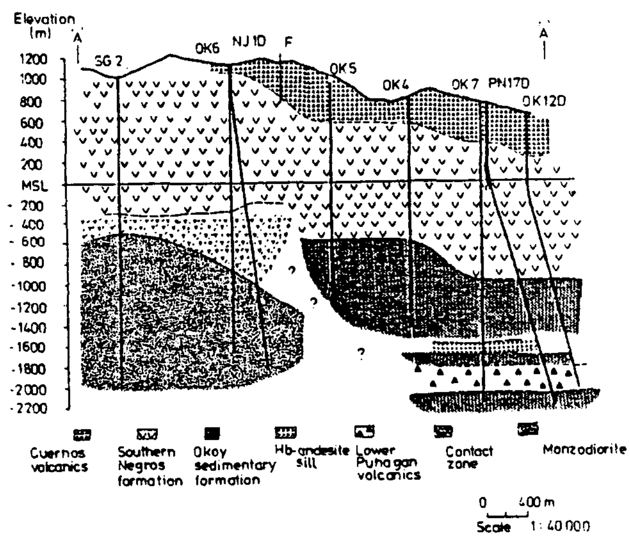

Fig. 6. Cross section of Puhagan.

RESERVOIR ENGINEERING TECHNIQUES

Well Discharge Stimulation

The wells in the Puhagan field were drilled from a high elevation and it is mainly these which caused us to examine the problem of how to discharge reluctant wells. Water levels 600m below the wellhead were encountered. A column of liquid standing in the well exerts a hydrostatic pressure at the production zone which is just sufficient to balance the reservoir pressure. The problem of how to get the well to discharge continuously may be considered to be that of reducing the density of the column to such an extent that the length needed to balance off the reservoir pressure will not fit in the available length of wellbore. This becomes more difficult as the empty part of the wellbore occupies a greater proportion of the well, however if it can be achieved then the well will flow. If the reservoir fluid entering the well is hot enough it will flash and provide the expansion needed to keep the well discharging. An obvious method to try is pumping, to remove some of the cold water, cause the formation to flow and hence fill the wellbore with flashing water. Airlifting has been used on occasions in the Philippines, but is inappropriate for Puhagan wells because of the very large compressor which would be needed. At the other extreme of sophistication, liquid nitrogen injection via a continuous tubing unit is prohibitively expensive in this instance. The two methods which are used are air compression and steam heating.

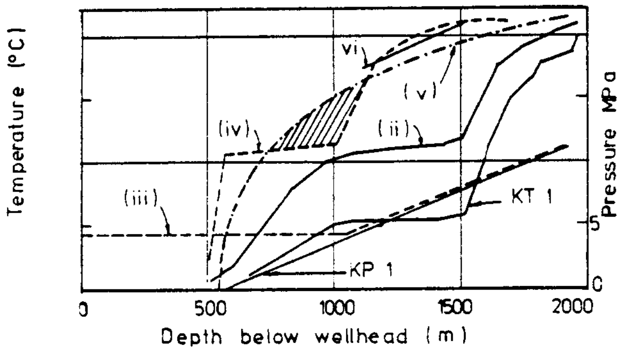

Fig. 7. Temperature and pressure profiles in a well with compression.

Fig. 7 shows the interpretation of events in a well which was compressed. The example chosen is one in which air compression was tried but appeared at the outset to be marginal and in fact did not work. Curve (i) shows early temperature and pressure, and curve (ii) a 25 day shut temperature profile. The well was then compressed to a wellhead pressure of about 4.5 MPa, curve (iii), and the well allowed to stand for the fluid to reach thermal equilibrium with its new surroundings.

Curve (iv) shows the temperature distribution which would have existed in the water after the air release, superimposed on the temperature distribution which would be expected of a column of boiling water with its surface at 550m, curve (v). The hatched area shows the length of the well which clearly would have contained liquid water. The water above this, from 750m upwards, would have expanded into the cool upper portion of the well. It appears as if liquid below 1150m would have found itself above local saturation temperature, however it must be remembered that the liquid filled length exerts a greater hydrostatic pressure than the equivalent length of boiling liquid so the local saturation temperature is raised from curve (v) to curve (vi) in this region. The degree of superheat in the lower section of the well is now only marginal. In addition, the fluid entering the well from the reservoir is likely to come from the region between 1100m and 1500m deep, so no superheat at all may occur below 1100m. In the event, the well did not discharge by compression.

The steam heating technique is simply to inject into the well to be discharged either steam from a boiler or the two-phase discharge from a neighbouring well. Quite long temporary (welded steel) pipelines have been used to transport well outputs and have been found to be reliable and economic. The boiler used was a once-through packaged type which could be transported with fuel and water treatment plant, to where it was required. Brodie, Dobbie and Watson (1981) provide a simple analysis to show that heat loss to the upper levels of the casing of the well significantly reduces the degree of expansion of fluid achieved by the testing process. Steam heating of this section of the well counteracts this problem.

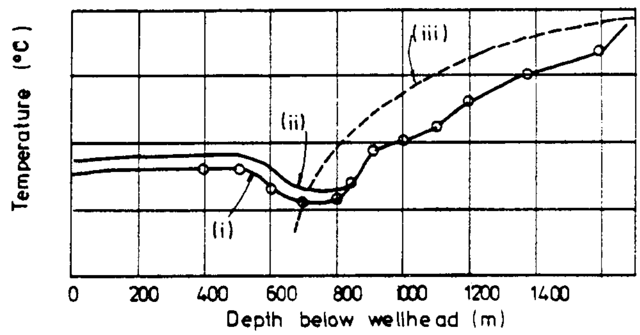

Fig. 8. Temperature profiles in a well with steam heating.

Fig. 8 shows the temperature distributions in the well to which Fig. 7 refers, after 1 day of heating (curve (i)) and 7 days of heating (curve (ii)), at which time the wellhead pressure was 1.5 MPa. abs. Curve (iii) shows the temperature distribution in the well required to make all of the column boil; it would only boil at the top, but this would (and did) unload the well and lead to discharge. The current position is that we have an empirical correlation to guide us in judging whether steam heating or merely air compression is necessary for any particular well.

Reinjection Studies

In order of priority, concerns about reinjection performance relate to reinjection capacity of the chosen part of the reservoir, life expectancy of wells because of the risk of silica deposition, the possibility of rapid returns of reinjection fluid reducing the output of production wells, and the risk of induced seismicity. Various trials have been carried out over the last few years, for example in Tongonan wells 401 and 404 supplied a 3 MW(e) turbine for several years and the waste water was reinjected to well 4R1. Reinjection at low temperatures (less than 140^{0}C) was examined using Tongonan wells 103 and 101 as producers and 105 as the reinjection well. This was a difficult trial to interpret as it was interrupted by pipeline construction which took higher priority, but it led conclusively to the idea that reinjection at less than 160°C was not possible at Tongonan, and that the waste water should not be allowed to dissolve oxygen from the atmosphere. The interpretation of more recent tests at Tongonan is currently under way. In these, the waste has been kept free of oxygen and has been reinjected at about 165°C. If there has been any reduction in 'injectivity' of the well it is very small and has caused us to examine our interpretation of injectivity tests. These are normally carried out after well completion and the results used for field design, for which they are adequate. For the more precise evaluation of reinjection damage more detailed analysis methods are needed, such as those used by Mangold, Tsang, Lippman and Witherspoon (1981) and Benson and Bodvarrson (1982), in which the effects of radial temperature variations are modelled using a simulator.

The risk of induced seismicity appears at first sight to be higher at Puhagan than at Tongonan since the terrain is generally steeper and more fracture dominated, and the wellheads are high above the standing water level in wells. Estimates of tectonic stress have been made from well measurements and appear to be higher at Tongonan than Puhagan, however, which could redress the balance. Seismic monitoring is being carried out in both fields.

Other Reservoir Engineering Aspects

KRTA/PNOC-EDC carry out a full range of reservoir engineering measurements and geochemical sampling of well fluids. We consider that these two topics taken together give the best possibility of understanding field behaviour during production. KRTA use the Shaft 79 numerical simulator and having carried out studies of the behaviour of individual Philippines wells and a full reservoir study for Hatchobaru in Japan, are convinced of the value of numerical simulation. There remains, however, a gap in predictive ability at the power station planning stage in the development of a field. At this time too little production has taken place to tune a simulator for performance predictions, and the assessment of field production capacity rests on the ideas of field hydrology gained during exploration. Our view is that it is unreasonable to expect reservoir engineering to bridge this gap and that a recourse to economic risk analysis is necessary.

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