PERFORMANCE OF EAST OLKARIA POWER PLANT AND PLANS FOR MAINTAINING STEAM SUPPLY IN THE FUTURE

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ABSTRACT

Olkaria East geothermal power plant has been in operation since 1981. The wells that supply the plant produce two phase fluid from a 240-340^{o}C hot, low gas, liquid dominated reservoir which is related to volcanic pile and fractures. Separated steam from twenty seven (27) wells, flows to 3 X 15 MWe Mitsubishi direct contact condensing units while the brine is disposed off through infiltration ponds. The plant performance has been excellent with the plant equipment remaining in good shape after fourteen (14) years of operation as a result of favourable chemistry of discharge fluid. As predicted in the Reservoir Simulation studies for this field, there has been gradual decline in steam production from the wells supplying the plant. In order to maintain adequate supply of steam to the plant in the future, two schemes are being advanced. The first scheme is to re-inject water into the reservoir to offset the reservoir pressure drawdown and steam decline and effectively, limit the number of make-up wells to be drilled and connected to the plant. Secondly, leave out re-injection and establish a scheme for drilling and connection of the make-up wells. The cost implication of either of the alternatives has been addressed.

1.0 INTRODUCTION

Olkaria East Power Plant is located within the East Olkaria geothermal field which is one of the three sectors that when put together constitute the Greater Olkaria geothermal field, located 125 km north east of Nairobi (Fig. 1).

The geothermal power development in this sector of Olkaria continued over a span of eleven (11) years. After extensive geo-scientific surveys in the early seventies, exploration drilling started in 1974 and continued through 1977. After the initial drilling results were evaluated, a feasibility report was produced in 1977. The following year 1978, production drilling commenced and continued until 1983. Sufficient resource capacity was confirmed and this led to the commisioning of the first 15MWe turbo-generator unit in 1981. Along side the production drilling activity was the installation of a second and third 15MWe turbo-generator units which were commissioned in 1983 and 1985 respectively, bringing the total installed capacity to 45MWe. The geothermal power generation currently constitutes about 8% of the National power demand in Kenya.

Since commencement of exploitation, the steam output from the wells has been on the decline and the decline rate has been maintained at an average of about 4% per year. That steam decline rate has been in good agreement with the prediction from Reservoir Simulation studies for the field. No major equipment breakdown has occurred in the steamfield or power plant during the fourteen (14) years of plant operation. During annual plant inspections it has been noticed that most of the equipments are in sound condition. The decline in wells output is currently being compensated for by drilling and connecting make-up wells to the plant. Already five (5) make-up wells have been hooked to the existing steam system since the plant started operating at its full capacity. Advanced plans are underway to start re-injection to minimize the need to drill and connect make-up wells.

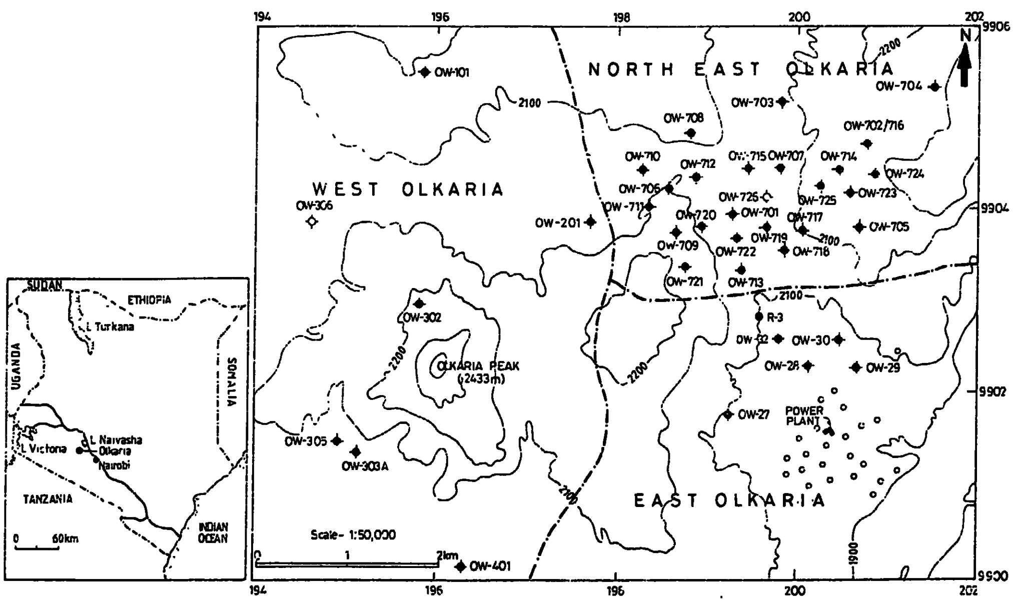

Figure 1. Location map of Olkaria East Power Plant.

2.0 STEAMFIELD

2.1. The lay-out

The plant steam supply comes from a total of twenty-seven (27) wells which tap a two-phase water dominated reservoir extending from 500m down to 2500m and may be deeper. Initially the steamfield lay-out consisted of very short two-phase pipelines from the wellheads to wellhead separators beyond which long steamlines transmitted the separated steam to the turbines at the plant. The effluent from the separators and cooling tower blowdown was directed to the infiltration ponds for disposal. Later steamfield design for connection of replacement/make-up wells OW-27, -28, -29 and OW-30 has applied a different lay-out strategy where some wells have been grouped together to share the same separation equipment, a move towards centralized separation system. In that later design, OW-28 was connected to the wellhead separator for OW-24 from where the steam is transmitted through the same steam pipeline formerly utilized by OW-24 alone. Likewise OW-29 and OW-30 have been put to share the same separation equipment located at OW-30 wellpad and OW-27 is scheduled to share the same separation equipment with OW-31.and OW-33 (Fig. 2).

2.2 Field Performance

From the time the third turbo-generating unit was commissioned in 1985, the field has experienced pressure drawdown and hence decline in output from the wells resulting into decline in steam supply to the plant. The decline in pressure has also introduced severe cyclicity in some of the wells (Ouma, 1992, Ambusso and Karingithi, 1993) and throttling orifice plates have been applied to throttle them back in order to stabilize their discharge and in the process they have been turned to even smaller producers. The steam decline rate was higher in the first year after commissioning of the last unit but it levelled out to an average of 4% per year (Fig. 3). The steam decline has been in good agreement with the predictions from the Reservoir Simulation model for this field (Bodvarsson et al.,1990, Ouma, 1992). To compensate for the pressure drawdown and decline in steam supply, nine (9) make-up wells (OW-26, -27, -28, -29, -30, -31, -32, -33 and OW-34) have been drilled since the plant was commissioned and five (5) of them (OW-26, -27, -28, -29 and OW-30) have been connected to the existing steam system in order to sustain the plant output at full capacity of 45MWe. In addition to that a contract has just been awarded for connection of another two (2) make-up wells (OW-31 and OW-33) and the remaining two (2) make-up wells (OW-32 and OW-34) are scheduled for connection as soon as funds are available.

Numerical Simulation studies of reservoir performance at Olkaria (Bodvarsson and Pruess, 1984) indicated that injection of water into the geothermal reservoir would significantly increase the economic life time of production wells and thus save on the drilling of replacement wells to sustain 45MWe power production, particularly if 100% re-injection could be achieved. However, the re-injection programme has not been effected as was recommended by Numerical Simulation studies because some critical field tests had to be carried out before moving into a long term programme. Therefore a short- term injection test coupled with tracer test was carried out by KPC from April to September 1993 using lake Naivasha water and Sodium Fluorescein. Following the favourable results obtained from that test (Ambusso, 1993 and Karingithi,1994) long term re-injection into the East Olkaria geothermal reservoir is scheduled soon.

Because re-injection programme was deferred until after injection and tracer tests had been carried out (Ouma, 1991), the alternative of drilling and connecting replacement wells became inevitable in order to sustain 45MWe power production. The programme of drilling and connecting of make-up wells took a very slow pace, thus, OW-26 was drilled in 1984 and connected to the plant in 1986. From 1984 to 1988, the exploration programme in other sectors of Olkaria geothermal field was given priority against the drilling of replacement wells in the East Production field. In 1988 four (4) make-up wells (OW-27,-28,-29 and OW-30) were drilled but were not connected to the plant until April, 1995. Since 1986 through 1995 the plant power production dropped from 43MWe down to 30 MWe. The connection of make-up wells OW-27,-28,-29 and OW-30 brought into the plant additional 16.7MWe worth of steam. Four (4) other make-up wells (OW-31,-32,-33 and OW-34) which were drilled in 1992 are yet to be connected to the plant. The plant can currently operate at its full capacity but in order to sustain its production at 45MWe for another year, two (2) more make-up wells (OW-31 and OW-33) are being connected by 1996.

The shallow wells (OW-5,-12,-13,-14 and OW-17) which are tapping the steam reservoir have declined in production so much that they may soon have to be retired if they cannot be deepened as is the case of OW-12 which is being turned to a re-injection well.

2.3 Field Equipment Performance

The cyclone separators, hot water collecting tanks (HWCT), ball check valves (BCV), isolating valves, bursting diaphragms, wellhead silencers, control orifices, level switches and indicators and the piping have performed

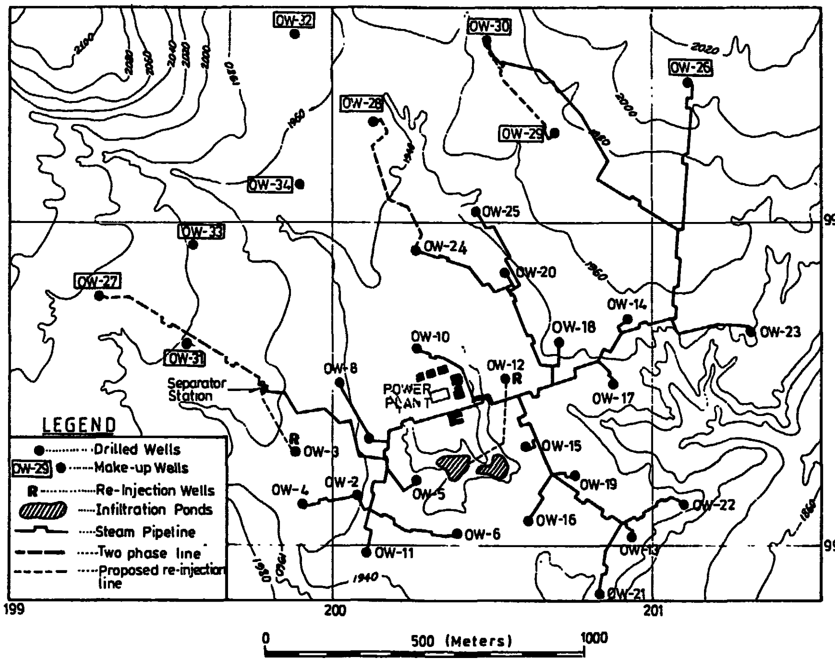

Figure 2. Olkaria East Steamfield lay-out.

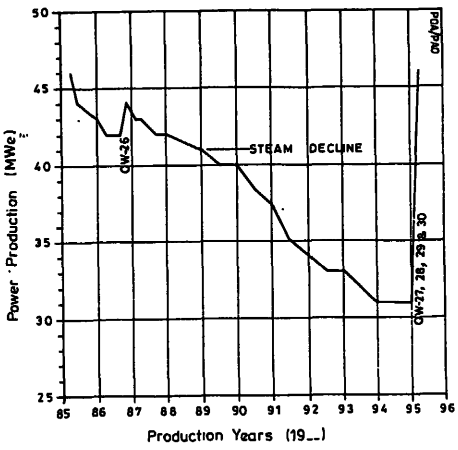

Figure 3. Steam decline trend at Olkaria East Field.

remarkably well. Routine maintenance on the equipment have been carried out with no major breakdowns experienced. However, bursting diaphragms are occasionally replaced when the BCV operates and the line pressure builds up above the allowable design value.

The control orifices are serviced regularly to unblock them of any silica build-up while the level switches and indicators are routinely calibrated. The control valves are mainly maintained on such areas as valve seats, valve stem and gland packings.

Certain sections of the pipelines especially around the wellhead equipment do get blocked with silica or corroded and are maintained. Inspections on the main steam pipelines of 250, 350, 500 and 700NB have revealed no silica deposition, a situation which could be attributed to lack of scrabbing of silica from the steam which could be superheated. This situation could be corrected by introduction of moisture into the steamlines to stop the steam from getting superheated and at the same time create scrabbing of silica and chlorides from the steam.

The drain pots that are situated along the steam pipelines have control orifices fitted on them to discharge any condensate. However, it has been estimated that about 5% of the available steam is lost through these drain pot orifices whenever the condensate is discharged. Even though to maintain these orifices is an easy exercise, it has been decided that they be replaced with steam traps to minimize steam wastage.

3.0 POWER PLANT

3.1 The Set-up

Two-phase mixture in general proportions of 85% steam and 15% water from individual wells is led into the cyclone separators where the steam and water are separated. The dry steam (approx. 99.9% dry) is inturn led into the turbines via network of pipelines. The separated water is discharged into the infiltration ponds. Dry saturated steam is maintained at inlet pressure of 5.0 bara and temperature of 151.9 degrees C. The turbines are of single cylinder, single flow four-stage condensing type. Exhaust steam from the turbine is condensed in the jet condensers at a pressure of 0.127 bara. The steam gas ejectors are used to remove non-condensable gases from the condenser and therefore help maintain condenser vacuum. The condensed steam is recirculated with the help of centrifugal vertical pumps from the hot wells to the cooling towers where the condensate is cooled from 45 to about 20 degrees C. The cooling towers are of the mechanical draft cross-flow type. The cooling tower blowdown is also led to the infiltration ponds for disposal (Fig. 4).

3.2 Plant Performance

3.2.1 The Turbines

Since the start of commercial operation, the station has achieved an overall load factor of 81.9% and availability factor of 92.5%. Continuous operation of upto ten months in one year has been realised.

During annual plant inspection/maintenance (KPC, 1995), no significant silica scaling common in many geothermal plants has been found on the turbine blades of the fixed or moving types. However, during the recently carried out overhaul on unit one turbo-generator (commissioned in 1981) it was noticed that the 3rd and 4th stage diaphragms fillet welds on the leading side were separated. The second stage diaphragms were also eroded on the shroud. The stellite strips affixed on the last stage blades have not been

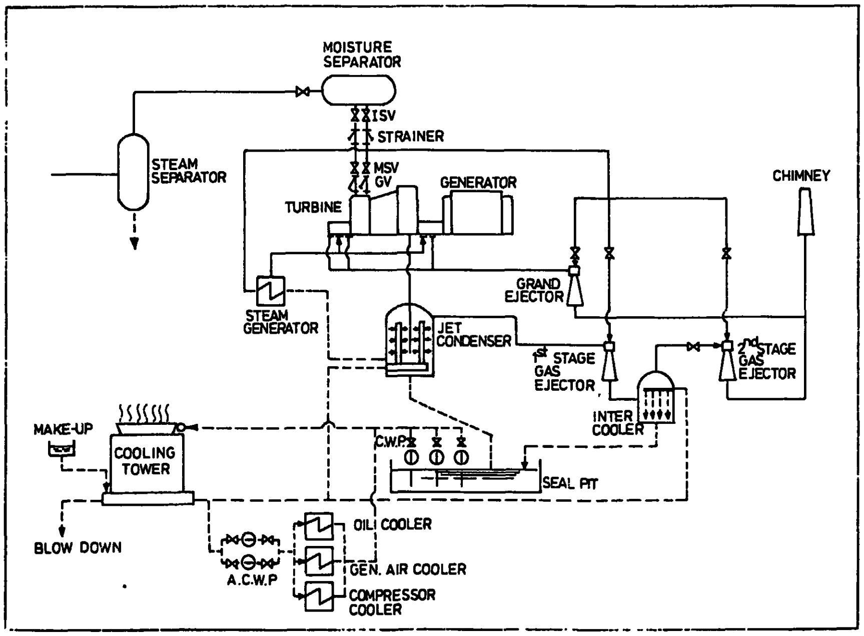

Figure 4. Olkaria East Power Plant set-up (schematic).

affected by erosion/ corrosion. The nozzles at the last stage are equiped with moisture removal groove and drain catchers to remove the drain from the cascade of blades as wetness of around 14% is expected. These have proved effective.

Heavy deposits of silica and sludge have been found on both the LP and HP gland packings and the packing boxes. These deposits are attributed to either using poorly treated water or prolonged use of geothermal steam as gland steam.

3.2.2 The Control Valves

The main stop valves and the governor valves are regularly given stem free test to ensure that no sticking occurs. When any sticking is detected the affected valve is removed for service while a better one is put in its place. No significant level of corrosion/ erosion has been detected on the valve discs or seats. However, the valve spindles have been repaired following corrosion damage from leaking condensate through the gland packing and seals.

3.2.3 The Gland Steam Generators

These are of shell and tube types. Geothermal steam passed through a bank of tubes helps heat up fresh water inside the shell in order to generate the required gland steam. Annual inspection of the steam generators always reveal deposits of sludge on the tubes and at the bottom of the shell. The sludge is formed from suspended solids in the water or corrosion products. The sludge reduces the efficiency of the steam generator and is normally removed by cleaning with water and steam blasting of the tubes.

3.2.4 The Barometric jet condensers

The condensers are of the spray type and uses 50mm diameter swirl nozzles in the main condenser part and the gas cooling zone. The condensers are of low level type located beneath the turbine and has barometric legs running approximately 25 metres into the hot wells installed outside the turbine building. The barometric leg is made of clad steel and recent inspections revealed that the entrance to the hot well at the elbow is heavily corroded and will be replaced in the near future.

The turbine exhaust hood and the condenser inlet are joined through an expansion joint which is protected by metal plates. The protection plates suffer constant corrosion attacks and are regularly replaced. The condenser shells are occasionally punctured due to corrosion attack and prompt repairs have been done.

3.2.5 The Gas Extraction System

The system uses steam gas ejectors. Each condenser is connected to 3x50% capacity units. The system consists of a first stage ejector, an inter-cooler and a second stage ejector. During normal operations, only two units run while the third one is on stand-by. The ejectors are quite reliable and efficient in removing the non-condensable gases (NCGs) from the condenser. The ejectors are normally stripped down and the inter-condenser baffle plates cleaned-up to remove clogging from sludge build-up.

The ejectors exhaust above the turbine building and since hydrogen sulphide gas is heavier than air, this has resulted in sensitive control equipment located in the control room and adjacent sub-station being attacked by the gas. A better ejectors exhaust arrangement probably to the cooling tower fan stack is recommended.

3.2.6 The Cooling Towers

The cooling towers support structures are wooden including the distribution basins. Inside the cooling towers are the splash bars which are also wooden and these help break-up the water into tiny droplets for better heat transfer. The drift eliminators are positioned in the central part of the cooling tower to help eliminate drift carry over with the effluent stream. The splash bars are arranged on grid packings made of reinforced fibre plastics.

The cold basin is made of concrete. Although this concrete basin is coated with acid-resistant cement, this has been broken-up in some portions by the splash water exposing the anchor bolts holding the vertical structure members. The damaged portions are usually rescreeded during the scheduled annual maintenance.

The wooden structures of the tower especially the fan deck floors, distribution basins and the support members are becoming increasingly weak after more than ten years in use and plans are underway to overhaul unit one cooling tower (commissioned in 1981). Currently local timber is being experimented on for the members that do not carry heavy loads like the cross-members and the distribution basins. If proven successful, then, this would immensely reduce the maintenance costs as at present cooling tower timber has to be imported from overseas suppliers.

3.2.7 The Electrical and Instrumentation Equipment

The sub-station houses the 132kV transformers for all the three units. Since this is an out door set-up, various parts such as main contacts of isolators and earthing wires have visibly turned black due to hydrogen sulphide gas attack. Local control boxes accommodating the operating mechanisms of the circuit breakers and isolators require replacement of the sealing gasket material which have hardened and no longer seal properly.

The 11kV, 3.3kV and 415V switch gears are installed in the first floor of the turbine house in air conditioned electrical switch gear rooms. Equipment here are in good condition as the rooms are pressurised and no outside atmosphere is expected to contaminate the clean environment in the switch gear rooms.

The copper conductors and nickel plated parts maintain their gloss, however, silver plated parts have turned blue due to small amounts of hydrogen sulphide gas that enter the switch gear rooms whenever the air conditioning plant breaks down.

Despite the fact that hydrogen sulphide gas control appear good, equipment such as vacuum switches, primary junctions, capacitor tripping devices, surge absorbers of circuit breakers as well as protective relays are regularly inspected/serviced to avoid any failure as a result of corrossion or sticking.

4.0 STEAM SUPPLY IN THE FUTURE

Olkaria East geothermal reservoir is a liquid dominated two-phase (boiling) with vapour zone at the top but the earlier wells drilled here were completed to shallow depths. Two of those wells, OW-5 and OW-12, are less than 1000m deep and majority of the other wells were completed to depths ranging between 1000 and 1400m. Most of these wells are therefore bound to be tapping the steam/vapour zone. The steam/vapour forms because the hot liquid rising from depth through the reservoir with low permeability experiences pressure drop but heat is abundant enough in the rocks to cause boiling. Because of the low permeability in the reservoir, even recharge from depth into these shallower steam/vapour dominated zones is expected to be poor and consequently rapid decline in output has been observed for the shallowly completed wells. The best examples are wells OW-12 and OW-5 which started as some of the best producers and mostly producing steam but have had very rapid decline rates. OW-12 was retired in 1994 and is earmarked for re-injection because it could not be deepened due to its unconventional completion following problems encountered during drilling. Some of the shallowly completed wells are scheduled for deepening to 2200m to enable them to tap the deep higher pressure liquid reservoir and hence have prolonged production life.

Drilling of replacement/make-up wells has already been undertaken but connecting them to the plant has not been prompt. At the moment four (4) replacement/make-up wells (OW-31,-32,-33 and OW-34) have been drilled and production tests concluded but they still await connection to the plant. Design has already been done and contract awarded for connection of wells OW-31 and OW-33 to the plant by the end of 1995 but funds are still being sourced to finance the design and connection of wells OW-32 and OW-34 by the end of 1997. Connection of OW-31 and OW-33 will add another 4.5 MWe worth of steam supply to the plant and when OW-32 and OW-34 are eventually connected additional 10 MWe worth of steam will be available to the plant. After connection of OW-32 and OW-34 further drilling of replacement wells will depend on results of re-injection trials which are being started in the Olkaria East field.

Both hot and cold re-injection will take place in the Olkaria East field. Hot re-injection into OW-03 using hot water coming from OW-27 separator station will start by the end of May, 1995. Initially 20 t/hr of hot water will be available from that separator station when OW-27 alone is connected to the plant and will be channelled under pressure through 200NB piping to

OW-03 which is located about 250m away. As soon as OW-31 and OW-33 are connected to the same separator station currently being utilized by OW-27 alone, a total of 30 t/hr hot water will be available to be re-injected into OW-03 because additional 10 t/hr of hot water is expected to come from separation of discharge from OW-31 and OW-33. Cold re-injection into OW-12 is scheduled to start in June,1995 using water from the other separators/separator stations around the field and the cooling tower blowdown. This water estimated to be about 200 t/hr is currently being directed to the infiltration ponds for disposal through seepage and evaporation. A pumping station is to be installed at an appropriate location within the infiltration ponds area from where cold effluent will be pumped to OW-12. The re-injection programme will inco-orperate tracer tests in order to carefully monitor the movement of the re-injected fluid in the reservoir.

The re-injection programme is expected to reduce pressure decline in the reservoir and prolong the production life of the wells. If the results are positive then the number of replacement wells to be drilled and connected to the plant in the future may be substantially reduced. According to the Reservoir Simulation studies for this field (Bodvarsson and Pruess, 1984), it was suggested that if a well density of 11 wells/km^2 or well spacing of 300m was chosen for the replacement wells, 24 make-up wells would be required to be drilled and connected to the plant through the 30 year period in order to maintain its Power Production at 45 MWe with no re-injection. But as long as thermal interference is not too severe with 100% re-injection, large increases in total steam flow from wells might be realised and the number of replacement wells could be reduced from 24 to only 9. Thus drilling and connection of the 15 make-up/replacement wells could be avoided if 100% re-injection programme is in place.

The cost figures appearing on the above table will support re-injection programme for only 230 t/hr of water but double that amount of water will have to be re-injected into the ground to achieve 100% re-injection strategy. That may double or even triple the cost of re-injection but still it will be much cheaper when compared with the cost of drilling and connecting fifteen (15) replacement wells. On average, the cost of drilling a 2200m deep production well at Olkaria ranges between 1 to 1.2 million US$ whereas the cost of connection of that same well to the plant ranges between 0.5 to 1 million US$. Therefore the cost of 100% re-injection may be considered not to exceed that of drilling and connecting only two (2) replacement/make-up wells, suggesting a saving in expenditure of drilling and connecting of thirteen (13) additional wells.

5.0 CONCLUSION

The steam gathering system has performed remarkably well, but in view of the changing well characteristics, closer monitoring of the wellhead equipment is necessary to avoid dry or slightly superheated steam causing plugging of the equipment and possibly the turbine nozzles.

An optimisation exercise should be undertaken both in the steamfield and power plant to determine which equipment needs to be derated or replaced so that high plant reliability can be maintained for the next two decades.

The decline rate of steam supply from the Olkaria East field has been in good agreement with the predictions of the simulation studies. Therefore to maintain the plant at full generation capacity, either re-injection programme has to effective or replacement wells have to be drilled and connected promptly.

Table 1. Re-injection system costs

Cost of installation and operation of the re-injection system	Kshs	US $
Installation of hot re-injection line from OW-27 separator station to OW-03	3,809,556.25	69,264.66
Installation of cold re-injection line from infiltration ponds area to OW-12	4,712,940.00	85,689.82
Operation cost for the re-injection system upto the year 2015 (20 yrs)	83,421,434.28	1,516,753.351
Total Cost	91,943,930.53	1,671,707.831

In order to achieve 100% re-injection it will be necessary to bring more water from an outside source to supplement the 200 t/hr from the infiltration ponds area and 30 t/hr from OW-27 separator station. This additional water will be taken from Lake Naivasha. More injector wells will have to be identified to add to OW-03 and OW-12. Wells OW-09, -13, -22, -23 and OW-25 were treated as injectors during the simulation studies and it was assumed that about 25% of the water was to be injected into the steam zone, 30% into the upper liquid zone and 45% into the lower liquid zone. That implies some of the injectors will have be shallow and others deep. Wells OW-09 and OW-12 are planned to serve as shallow injectors, OW-23 and OW-03 as injectors into the upper liquid zone and OW-25 as an injector into the lower liquid zone. When the North East Power Plant becomes operational, re-injection into the lower liquid zone will also start in OW-R3 located in the buffer zone separating Olkaria East and North East geothermal fields.

4.1 Cost implications of a successful re-injection programme

The re-injection programme will soon start with the hot re-injection into OW-03 and cold re-injection into OW-12. The cost to be incurred in installing and operating this first phase of the programme is summarised in Table 1.

Pumping requirement determines the cost of effecting a re-injection programme and wherever it can be avoided that option should be favoured.

A lot of economic benefits may be realised with a successful re-injection programme in Olkaraia East geothermal field management.

6.0 RECOMMENDATIONS

Routine maintenance of equipment both at the steamfield and the power plant have been carried out thereby ensuring high plant availability. However, detailed metallurgical inspection of the turbo-generators is necessary so as to ascertain their integrity.

The current gas ejectors exhaust above the turbine house should be redirected to discharge at the cooling towers' fan stacks as this would help disperse the hydrogen sulphide gas and hence reduce contamination being done to the electrical installations in the adjacent control and switchgear rooms.

Where sealing material and gaskets of the control panels in the outdoor substation and the switchgear rooms have hardened and no longer seal, effectively, activated charcoal bags should be placed inside the panel boxes to absorb the hydrogen sulphide gas while arrangements are made to replace them.

Application of micro-carbon grease, which has good electrical conductivity and wide operation temperature range, onto the contact points of the conductors is necessary to keep hydrogen sulphide gas out of reach of these points. Also painting of the equipment exposed to the hydrogen sulphide environment will help eliminate corrosion attack.

Ageing wooden structures of the cooling towers support, fan decks and the distribution basins need replacement with properly treated timber.

If positive results are obtained with the first phase of the re-injection programme, every effort should be made to effect further phases so that 100% re-injection can be achieved.

Hot re-injection is prefered to cold re-injection, provided there is no pumping requirement and hence arrangements should be made as soon as practicable to start re-injecting hot water being generated at the seperator station on OW-30 wellpad to OW-25.

7.0 ACKNOWLEDGEMENT

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