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Sustaining the Operation of the Palinpinon-1 Production Field, Philippines, for the First 15 Years

R.G. Orizonte, A.E. Amistoso, A.R. Aqui, and R.G. Jalando-on

PNOC-Energy Development Corporation, Ft. Bonifacio, Makati City, Philippines

ABSTRACT

This paper summarizes the physical response and performance of the reservoir and the Fluid Collection and Disposal System (FCDS) of the Palinpinon-1 Production Field (P1PF), and focuses on the reservoir management strategies implemented to sustain the adequate steam supply during the first 15 years of operation of the 112.5 MWe Palinpinon-1 Geothermal Power Plant (PGPP1). Other strategies, e.g., revisions in the engineering design of the FCDS to increase operation and maintenance efficiency, and newer technologies like top zone cement plugging and acid stimulation, in addition to mechanical work-overs, are also discussed.

The successful strategies formulated through the experience gained in P1PF guided the development and first few years of operation of the 4x20 MWe modular power plants in Palinpinon-2 Production Field.

Introduction

The Palinpinon-1 (P1PF) and Palinpinon-2 (P2PF) Production Fields comprise the Southern Negros Geothermal Production Field (SNGPF), also called the Palinpinon Geothermal Field located in Valencia, Negros Oriental, central Philippines (Figure 1, overleaf). Production drilling in SNGPF started as early as 1978, and to date a total of 75 wells have been drilled, of which 38 belonged to P1PF. The 112.5 MWe Palinpinon-1 Geothermal Power Plant (PGPP1) was constructed in P1PF and began commercial operation in May, 1983. When the simulation studies done by Amistoso, *et al.*, (1990) warranted further development expansion, four (4) modular power plants in P2PF, namely 1x20 MWe Balasbalas, 1x20 MWe Nasuji and 2x20 MWe Sogongon modules, were constructed and commissioned between 1993 and 1995. SNGPF supplies power to the whole island of Negros and to the neighboring islands of Panay and Cebu via submarine cables.

Reservoir Response To Exploitation

Pressure Trends

The initial response of the Palinpinon field to exploitation was the drawdown of pressure in the production area. From a baseline of ~11.0 MPag, the pressure declined by ~1.5 MPa within one year after the start of the plant operation. The rate of decrease, however, was somewhat minimized by near-field injection that provided some pressure support (Amistoso and Orizonte, 1997) as reinjected fluids rapidly returned to the production area. By 1988, the pressure drop was only 2.5 MPa.

Dramatic drawdown occurred when the bulk of injection was shifted away from Puhagan to the Ticala and Malaunay areas (Figure 2, overleaf)—a reservoir management strategy implemented in late 1989 to address the problem of reinjection (RI) returns. Coupled to this was the susbtantial increase in mass extraction by more than 200 kg/s between 1990 to 1992 after the interconnection of the Panay power grid to Negros.

By 1992, the total pressure drop in P1PF had reached ~6 MPa. Since then it has stabilized at 5-5.5 MPag. Apparently, the reduced mass extraction during the low plant loading from August 1997 to March 1999, did not significantly affect this steady trend. Meanwhile, the pressures in the adjacent Puhagan RI area stabilized at ~7 MPag, resulting to an average pressure differential of 2 MPa between the production and reinjection areas.

The decrease in pressure resulted in fluid flashing and consequent lowering of the hydrostatic levels of the production wells. In the central Puhagan area, where the mass extraction was concentrated, water levels dropped by as much as 500 m (Figure 3, overleaf). Boiling likewise enhanced the expansion of the pre-existing shallow two-phase cap. Lying between +400 m and -100 m, mean sea level elevations, this two-phase zone has a volume of approximately 2.47 cu. km. and has an estimated reserve potential of 35.5 MWe-years (Amistoso, 1993).

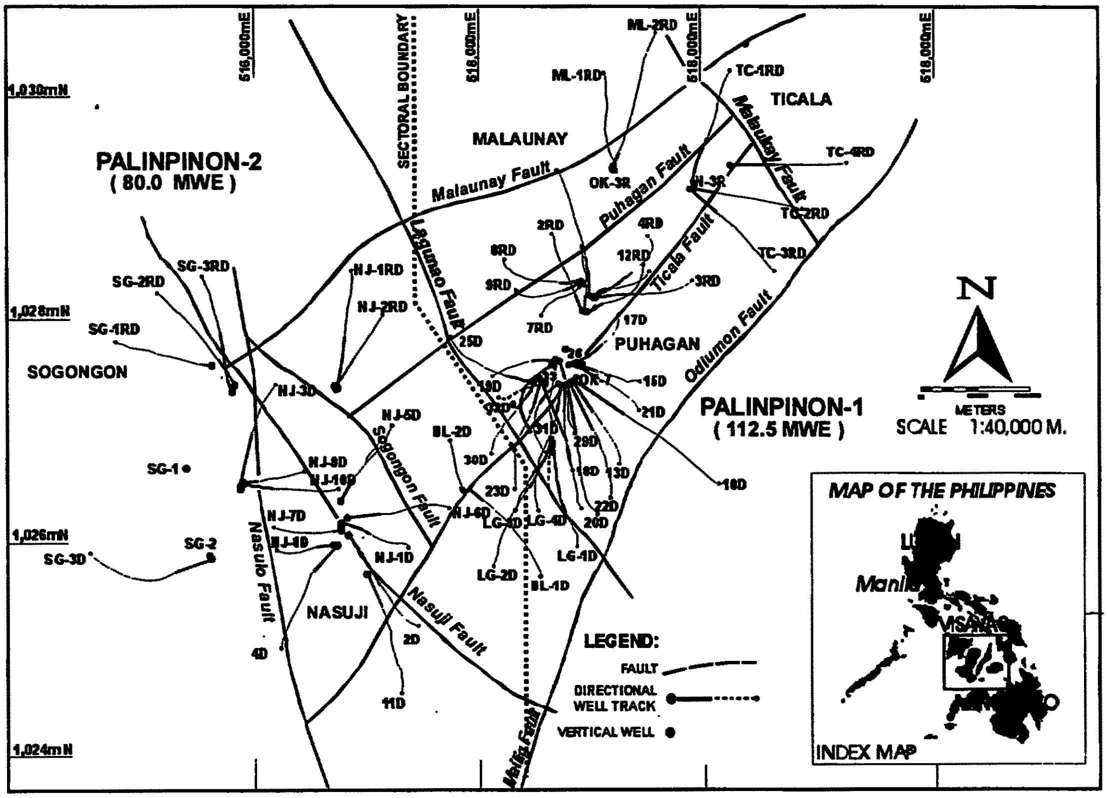

Figure 1. Location and structural map of the So. Negros Geothermal Production Field.

Reservoir Temperature Trends

Generally, the saturation temperature of a fluid decreases with pressure. However, the thermal decline in P1PF was not solely attributed to the decline in pressure. Rapid returns of pre-maturely reheated injected brine to the production sector caused cooling of feed zones in wells. Driven by pressure differential, these fluids were channelled to the production area through the Ticala, Puhagan and Odlumon faults and their splays. Also, the compact development of the field, somehow enhanced this fluid flow pattern in the reservoir.

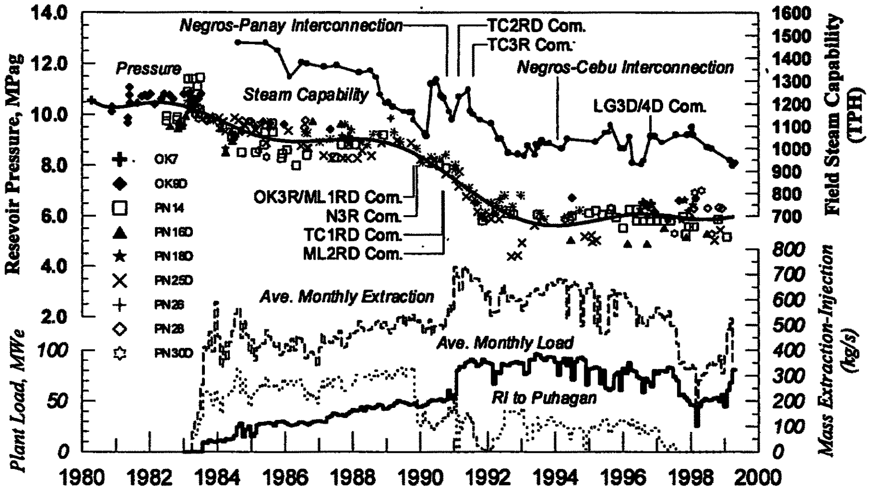

Figure 2. PIPF pressure, mass extraction, injection, steam capability and plant load.

Entering the wells at the shallow feed zones (600 m - 1000 m below sea level), RI returns could decrease the reservoir temperatures by 60°C. Figure 4 shows the deterioration of feed temperatures in severely affected wells OK-7, PN-26 and PN-29D.

Bore Output Trends

Wells affected by pressure drawdown are characterized by increased enthalpy with accompanying decline in mass flow, as seen in the output trend of PN-15D (Figure 5). Favorably, the steam flow increased by ~20 TPH or ~2.0 MWe in spite of the declining mass flow. In some cases, however, the improvement in steam flow due to enthalpy increase can be offset by the decrease in mass flow resulting to a net decline in output when drawdown is severe.

Production wells experiencing massive reinjection fluid returns exhibit decrease in enthalpy and increase in mass flow. The enthalpy of PN-26 decreased significantly from 1350 kJ/kg to 900 kJ/kg within 5 years of utilization. Despite the reduction of RI into Puhagan, its output further deteriorated until it ceased to produce commercially in mid-1990. On the other hand, OK-7 initially showed a positive response to the strategy of reducing injection at Puhagan. Its enthalpy

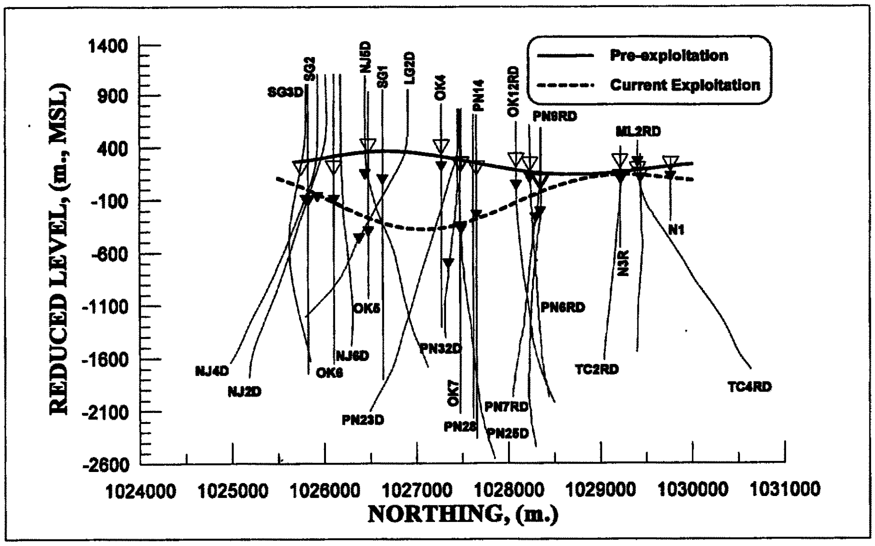

Figure 3. Contours of hydrostatic levels in the Palinpinon Geothermal Field.

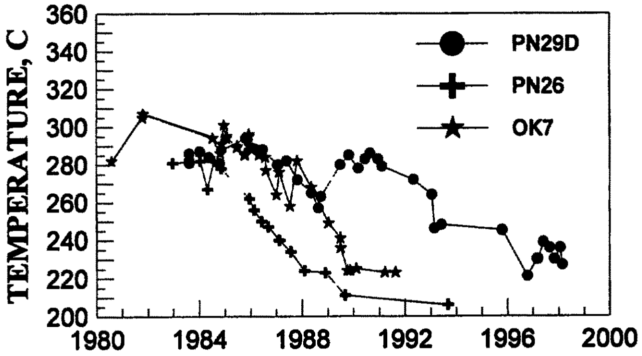

Figure 4. Temperature trends in P1PF wells.

increased from 1250 kJ/kg in 1990 to 1500 kJ/kg in 1991 when the upper zone temperatures recovered (Figure 4). But the continued utilization of PN-2RD and TC-3R further cooled the well to 220°C in 1992. An attempt to recover the well by plugging the top zones with cement failed. At present, it cannot attain a commercial wellhead pressure when discharged.

Another well, PN-29D, has an initial output of 90 TPH or 9.0 MWe. Rapid RI returns started to affect its performance as early as 1985 when load was picking up. Injectors used then were those near the production area e.g., OK-12RD, PN-7RD and PN-9RD. By 1988, PN-29D's enthalpy had declined from 1600 kJ/kg to 1200 kJ/kg and correspondingly, the output to only 30 TPH or 3.0 MWe. When the Malaunay and Ticala RI wells were commissioned in late 1989, the well responded positively. Its enthalpy and output improved to 1500 kJ/kg and 80 TPH (8.0 MWe), respectively. However, the recovery was only temporary as increased demand, which entailed increased mass extraction and separated brine, necessitated the use of PN-2RD, PN-3RD and PN-4RD in addition to TC-3R, also a known communicator. Between 1995 and 1996, the well's output again dropped to 1.5 MWe and has remained until the present.

Chemistry Related Developments

Cool, acidic inflows and mineral depositions are two processes that developed as the field was continuously exploited. The intrusions of cool, acid-sulfate-bearing waters in some wells was closely related to pressure drawdown. The genesis of these fluids is discussed by Seastres, *et al.* (1995) in detail. Discharged fluids in the affected wells display increases in SO_4 and Mg and a decrease in pH.

Minerals commonly deposited in the wellbore and formation are calcite ($CaCO_3$), anhydrite ($CaSO_4$) and silica (SiO_2). The first two usually form in production wells as bore blockages, while the third forms in RI wells. In some cases, like in OK-3R, silica deposition extends to the surrounding formations. These mineral deposits effectively reduce the capacity of wells.

Operational Constraints in the Operation of the FCDS

De-scaling of the long reinjection lines (<2 km.) has been a maintenance problem. This was addressed by spooling the lines, and by constructing a redundant pipeline to ensure year-round line availability. Long reinjection pipelines are maintained at full-flow condition in order to eliminate fluid slugging flow and hammering during low plant loads. The P1PF Fluid Collection

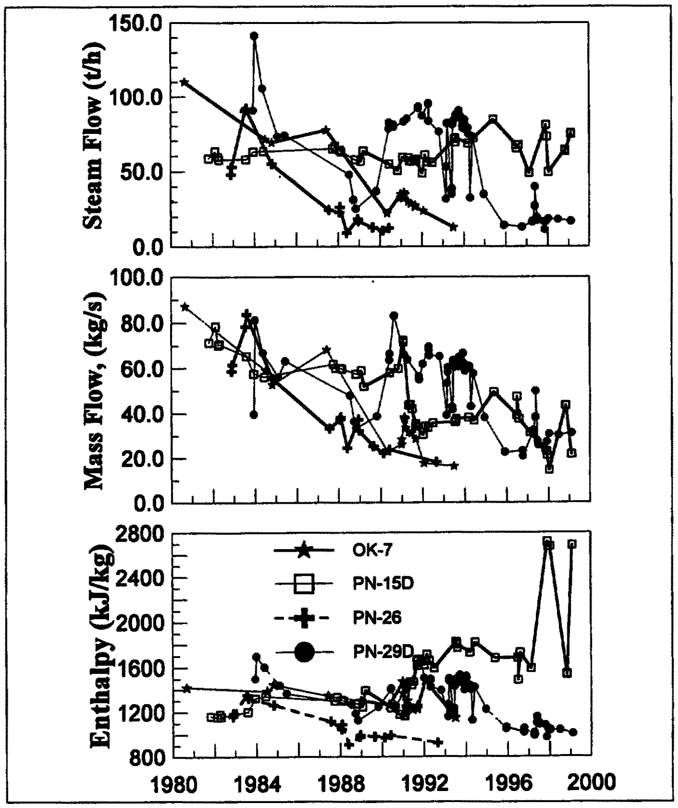

Figure 5. Bore output trends in P1PF wells.

and Disposal System (FCDS) design is such that three or more production wells feed a dedicated pair of vessels. Poor flexibility for maintenance and testing of the FCDS has been experienced during full loads. In effect some vessels are either over- or under-loaded. This has become an operational constraint, particularly during vessel maintenance, consequently putting wells off line. To ensure stable steam supply, the two-phase interconnection piping was installed in 1990.

However, interconnection on the FCDS brought some operational constraints, such as: the back pressure effect on wells with low output due to a common high interface pressure (reducing full load production capacity by 5 MW); high two-phase pipeline pressure drop (aggravating the back pressure effect); and preferential flow to separators. These were usually encountered during full loads and when all wells have been interconnected. No physical solution has been implemented to address this occasional problem. However, operation was improved by closing some interconnection valves, using selective control blow-off, and prioritizing high enthalpy wells.

Wells with low wellhead pressures during full load occasionally ceased production and even experienced back flows, accepting steam from nearby wells. Production was optimized when the separator pressure was reduced from 6 kscg to 5.8 kscg in the early 90's. To cope with full load demand, these wells were shut and stimulated during low loads, and put online during peak loads, thereby allowing these wells a short-term output recovery.

Reservoir Management Strategies

Shift of Reinjection Load Farther Away From the Production Sector

The initial RI wells in P1PF were drilled close to the production area (e.g., the nearest well, OK-12RD, is only ~300 m away from the production well PN-17D at the permeable zone). Also, the geologic structures provide connection between specific RI and production well. These permeability connectors provide a channel for RI returns that affect the steam production of the wells. Utilization of these RI wells further risk other production wells. Thus in 1986, it was recognized that the RI load should be shifted farther away from Puhagan especially when the load increases. However, the implementation of such strategy was realized only in October 1989 after the completion of the RI lines to the Malaunay and Ticala areas. OK-3R in Malaunay and N-3R in Ticala were the wells initially utilized and additional wells ML-1RD and ML-2RD in Malaunay and TC-1RD, TC-2RD, TC-3R/3RD and TC-4RD in Ticala were drilled later and utilized since then. The shift in RI load had temporarily relieved the production wells from RI fluid returns, thus improving the total field steam capability in 1991 (Fig. 2). However, with the increase in production due to the increase in load after the Panay-Negros power grid interconnection, reinjection of waste brine also increased. Reinjection fluid continued to intrude back to the production sector since some wells, like TC-3R, had a strong permeability connection with some production wells through the Ticala Fault.

Drilling and Prioritized Utilization of High Enthalpy Wells

The problem of reinjection fluid returns was partly addressed by reducing the waste brine through the utilization of high enthalpy production wells, especially those drilled near the upflow area southwest of Puhagan. This strategy improved the total steam supply for the power station but was not enough for a sustained production at full-load operation. Thus, additional production wells PN-32D and PN-33 were drilled to tap the shallow two-phase zone. This strategy improved the steam supply only slightly since the wells were relatively tight and were poor producers. Additional wells LG-3D and LG-4D at the Lagunao area were then drilled towards the postulated upflow to improve the steam supply and at the same time reduce the waste brine flow. These two wells were able to produce from a highly two-phase zone.

Deep Reinjection and Top Zone Plugging

Downhole testing and monitoring of the RI wells showed that shallow permeable zones in some wells (e.g., PN2-RD and PN-3RD) were responsible for the rapid RI returns, while reinjection into the deeper zones showed minimal returns. Consequently, the Ticala RI wells were targeted to intersect the deeper permeable zones provided by the geological structure of the Odlumon fault. Also, in conjunction with deep injection, an attempt to plug the shallow communicative zone in PN-3RD was made in 1995, which initially showed an indication of reduced acceptance at the shallow zone. However, with continuous utilization, PN-3RD again showed increased injection into the shallow zone, as the cement plug likely deteriorated, resulting to failure in isolating the shallow zone. Another attempt to cement-plug the shallow permeable zone in PN-2RD was made in 1996, but was unsuccessful, since the shallow zone was exceedingly permeable, and the cement plug was probably drained into this zone. One aspect of cement plugging which made it unsuccessful was the high uncertainty in isolating the annular space between the slotted liner and the formation prior to cement plugging.

Mechanical Work-over and Acidizing

Work-over is accomplished by drilling out mineral blockage in wells in order to regain lost output. Whenever deposition extends to the surrounding formation, acidizing becomes necessary to dissolve the formation deposits. This relatively recent technology was proven successful in RI wells, and to a lesser degree in production wells. RI well PN-2RD increased its capacity by as much as 100 kg/s, and production well PN-33 improved its output from nil to 2.7 MWe, after acidizing.

P2PF Development and Reservoir Management Strategy

The experience of continuous exploitation in P1PF, particularly in the area of near-field injection, greatly influenced the siting of RI wells in P2PF. RI wells in Nasuji and Sogongon sectors were, therefore, drilled to the north as far away as possible to minimize RI fluid returns to the production sector. Pressure drawdown and RI breakthrough were the major reservoir processes affecting steam production during the first 5 years of P2PF geothermal field exploitation. The pre-exploitation reservoir pressure of about 10 MPag was already drawn down to ~8 MPag as a result of P1PF exploitation (Amistoso and Orizonte, 1997), evident in OK-6 drilled at the inferred upflow region. With increased mass extraction in P2PF, this was drawn down sharply further towards the stabilized P1PF level of 6 MPag at the end of 1998. Pressure drawdown was experienced mostly by the southernmost wells and those far from the RI sectors. However, only OK-6 and SG-2 slightly declined in wellbore temperatures (~10°C).

The reinjection mass front was observed in the wells that intersect the communicative fault structures, namely the Nasuji, Nasulo, and Sogongon faults. These faults channel the RI fluids coming mostly from the wells in Sogongon (SG-1RD, SG-2RD, and SG-3RD) and, to a lesser extent, from Nasuji (NJ-1RD) back to the production sectors. No thermal decline was observed based on the relatively stable silica temperatures. Drilling and utilization of NJ-2RD since March 1997 has enabled the reduction of load in the Sogongon RI sector particularly in SG-3RD which was shut since August 1997.

Similar strategies of high enthalpy well utilization were adopted to address pressure drawdown and reduce brine loading (i.e. RI returns) to the Nasuji and Sogongon RI sectors, e.g., use of NJ-2RD in lieu of SG-3RD.

Summary and Conclusions

The intensive monitoring of the P1PF reservoir response to the first 15 years of exploitation, was able identify four major processes, namely, presssure drawdown, rapid reinjection fluid returns, cool, acidic fluid intrusions and mineral depositions. These reservoir processes which have adverse impact to the aim of sustaining adequate supply of steam to the power plant, were addressed by shifting injection away from the production area, deep injection and drilling/prioritizing utilization of high enthalpy wells. Other mitigating measures such as, mechanical work-over, acid stimulation of carefully selected RI and production wells and controlling the operating conditions of wells with intrusions, have greatly improved the and sustained steam production from the field. Undoubtedly, these have demonstrated PNOC-EDC's success in formulating and implementing management strategies for the sustainable use of geothermal resouce.

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