Proceedings World Geothermal Congress 2010
Bali, Indonesia, 25-29 April 2010

Tongonan Geothermal Field: Conquering the Challenges of 25 Years of Production

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Keywords: Tongonan geothermal field, reservoir

ABSTRACT

Tongonan is one of only a few geothermal fields worldwide that has achieved a milestone of continued production for 25 years. Reservoir management has been a cornerstone in sustaining the field's generation and in conquering the challenges since the commissioning of the first power plant in 1983.

Being one of the largest water-dominated systems, the series of challenges in its 25-year history, from the early workers first experience with injection returns and pressure drawdown to present day maintenance of optimum production, have been a source of lessons and the reason for the sound production and injection protocols that are set in place in the different geographical sectors of the field.

Technological knowledge and developments in geochemistry, tracer tests, stable and radioactive isotopes and reservoir engineering were crucial in analyzing and addressing these challenges. Likewise, experience and advances in well intervention techniques ensured optimum performance of production and injection wells in transmitting the energy to the surface and recycling of fluids back to the resource. With sound resource management, Tongonan Geothermal Field is poised for another 25 years of sustainable production.

1. BACKGROUND

The Tongonan Geothermal Field (TGF), found in the island of Leyte, is currently one of the largest wet-steam field in the world. It lies along the northwest trending chain of Quaternary volcanoes associated with the Philippine fault. It is bounded to the southeast by the cold impermeable Mamban block, which separate it from the Mahanagdong geothermal field (Alvis-Isidro *et al*., 1993). It is subdivided into three production sectors of Upper Mahiao, Tongonan-1 and Malitbog-South Sambaloran (Fig. 1). Sixty-six (66) production wells supply the steam requirement of the three Main Power Plants (Upper Mahiao Power Plant, Tongonan-1 Power Plant and Malitbog Power Plant), the Tongonan-1 Topping Cycle Plant (T1TCP), and the Malitbog Bottoming Cycle Plant (MB BCP) in the three sectors. Two outfield injection sinks in Upper Mahiao (Pads 408 and 4RC) and Malitbog-South Sambaloran (Pad 5R1 and 5R7) sectors, and one infield injection sink in the Tongonan-1 (Pad 1R8) sector accommodate the separated brine.

Exploration for geothermal resources in Tongonan and the adjacent Mahanagdong field started in the 1960's to 1970's. This included the geologic study of Vasquez and Tolentino (1972) that documented the geology and the thermal features of the area. More detailed work in the late 1970's by KRTA and PNOC-EDC focused on the Bao valley sector.

Commercial operations started in 1983 with the commissioning of the 112.5 MW NPC Tongonan Geothermal Power Plant (TGPP) in Tongonan-1 sector. Further development in the whole field slowed down thereafter, but picked up again when the country experienced severe power shortages in the late 1980's to early 1990's. With the introduction of the Build-Operate-Transfer Law in 1994, private foreign companies' participation in the development of power plants paved the way for the installation of the 132 MW and the 231 MW power plants in Upper Mahiao and Malitbog-South Sambaloran sectors, respectively. Massive expansion and deep-well development drilling ensued in the whole steam field. The new power plants started operating in 1996 and 1997 to energize the Leyte-Cebu and Leyte-Luzon power grids. In 1998, the 18 MW and 15 MW Optimization Plants in Tongonan-1 (Topping Cycle) and Malitbog (Bottoming Cycle) respectively, were commissioned increasing the total installed gross capacity of Tongonan Geothermal Field to 508 MW.

These surface developments are likewise reflected in the monthly mass extraction and injection to the reservoir (Fig. 2). Mass extraction started at around 1 million tons per month in 1983 to 1996 during the commercial operation of the 112.5 MW Tongonan-1 Power Plant, with about 50% of mass injected back in the form of separated brine and power plant condensates. Extraction increased significantly starting in 1996-1997 to around 5 million tons per month during the commissioning of the additional power plants with injection rate at around 40% of the extracted mass. Increases and declines in mass extraction and injection from 1997 onwards manifest in changes observed in the geothermal reservoir.

In 2008, Tongonan joined a few other geothermal fields in the world for achieving a milestone of continued production for over 25 years. Other fields in the Philippines which have also surpassed the 25-year operation are Palinpinon, also owned by EDC, and Tiwi and Makiling-Banahaw fields operated by Chevron (Table 1). The 50-year landmark achieved by the pioneering fields of Larderello, Wairakei and the Geysers is something that the workers of Tongonan also hope to achieve. This paper consolidates all the major reservoir processes that bore down on the steam production of the field in response to the different developments in the surface, and how these challenges were managed in the past 25 years.

2. LOOKING BACK

In the 25 year history of Tongonan Geothermal Field, major processes developed from the deep geothermal resource in response to the field utilization. These challenges have been conquered by a resource management team from the reservoir geochemistry and reservoir engineering

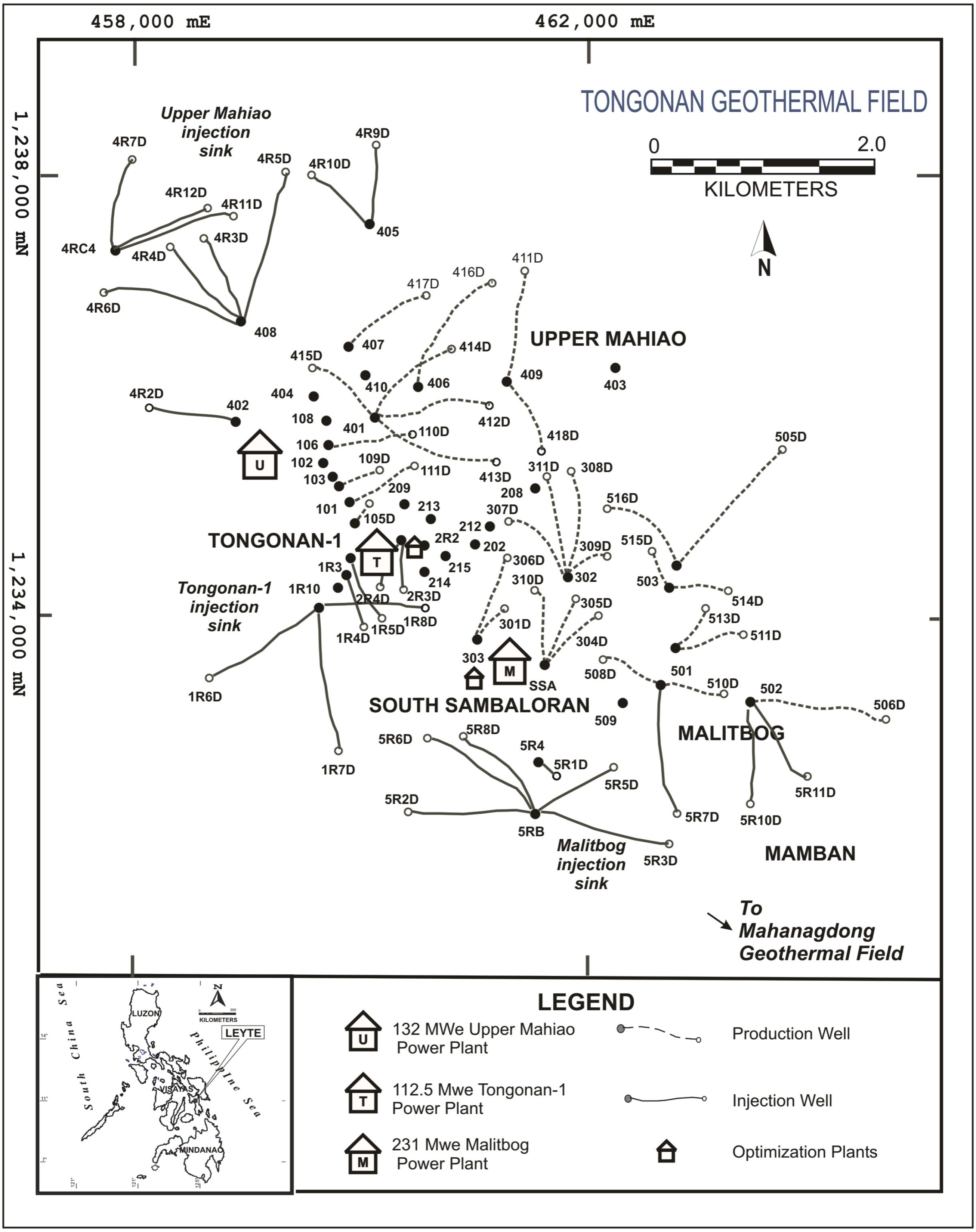

Figure 1: Welltrack map of Tongonan geothermal field subdivided into Upper Mahiao (w/ 400-series name wells), Tongonan-1 (100&200-series wells) and Malitbog-South Sambaloran sectors (500 & 300-series wells, respectively). Inset map: the Philippines

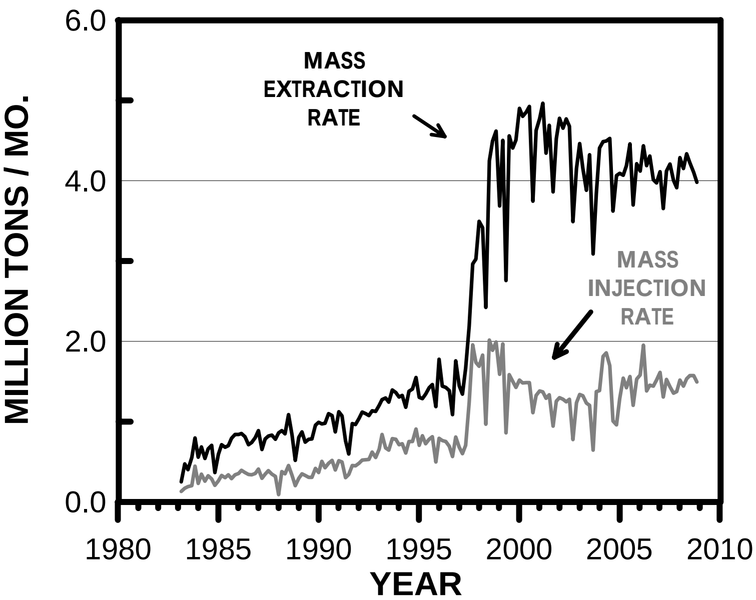

Figure 2: Monthly total mass extraction and injection in millions tons per month

Table 1. Some of the Geothermal Fields in the World which are already over 25 years in Operation as of Y2009 and the Respective Installed Capacities (Bertani 2007).

Field	Country	Start / Years in Operation	Installed Capacity, MWe
Tongonan	Philippines	1983 / 26	512*
Palinpinon	Philippines	1983 / 26	192
Tiwi	Philippines	1979 / 30	275
Makiling-Banahaw	Philippines	1979 / 30	458
Geysers	USA	1960 / 49	1,360
Wairakei	New Zealand	1958 / 51	176
Larderello-Travale / Radicondoli	Italy	1913 / 96	703

**Excluding the 198MW installed capacities in the adjacent but separate Mahanagdong geothermal system.*

disciplines, gathering and evaluating valuable data on production well geochemistry and stable isotopes, downhole surveys and output measurements among others. Special studies, such as tracer tests, multiple-well discharge interference and geochemistry tests, and special downhole surveys, are sometimes needed to validate the results of evaluation. This section enumerates the major reservoir processes, some of the evaluation tools and the resource management strategies that have been applied to mitigate the detrimental effects of these reservoir processes to ensure sustainable operation in the past 25 years.

2.1 Pressure Drawdown

Since the commissioning of the first power plant in 1983 up to 1996, when the operation of the additional power plants in Leyte commenced, the total pressure drawdown in the Tongonan reservoir ranged from 0.5 to 1.5 MPa. However, the pressure trend with time (Fig. 3) indicates periods of pressure increase brought about by injection returns (Sta. Ana et al., 1999). Increased pressure decline ensued when the field went into maximized utilization with the commissioning of the Upper Mahiao and Malitbog-South Sambaloran Power Plants in 1996-1997. The immediate effect was increased steam availability in the greater northern part of the field from Upper Mahiao, Tongonan-1 and South Sambaloran sectors due to field-wide reservoir boiling as evidenced by significant increases in discharge enthalpy (Fig. 4) and concentration of gases in the discharge fluids of production wells. This was not observed in Malitbog due to brine injection returns that maintained the discharge enthalpy of production wells at less than 1600 J/g.

Increase in discharge enthalpies of production wells and data from flowing surveys indicate expanded two-phase at the shallow region overlying a liquid reservoir (Sta. Ana et al., 1999). Shift in data points in the gas equilibria diagram show increase in steam fraction from less than 0.5% (y=0.005) before 1997 to as high as 5% (y=0.05) in year 2002. This implies that despite the extensive boiling, the reservoir still hosts more than 90% of geothermal liquid (Dacillo, 2004).

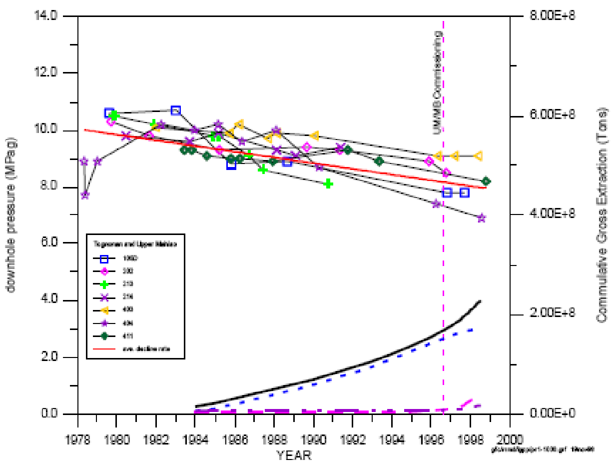

Figure 3: Pressure through time of Upper Mahiao and Tongonan-1 production wells at -1000mRSL (Sta. Ana et al., 1999)

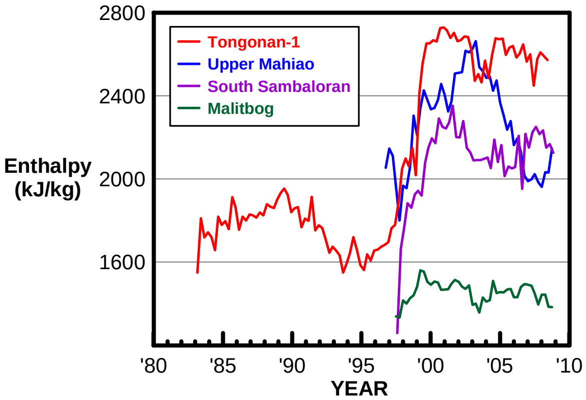

Figure 4: Average enthalpy of the different sectors of Tongonan geothermal field

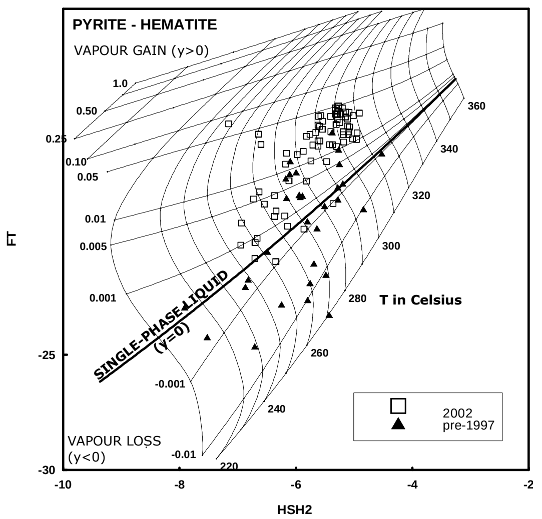

Figure 5: Steam fraction, y, and equilibration temperature, T, of all Tongonan production wells based on mineral-gas equilibria

2.2 Injection Returns

2.2.1 Tongonan-1 Sector

From 1983 to 1996, injection returns was the only major reservoir process in Tongonan-1. Increasing mineralization and decline in gas concentration in wells surrounding infield injection wells indicated the influx of highly saline, degassed injected brine. Enrichment in both chloride and ^{18}O isotope provided an estimate of 20-40% mixing of injected brine with in-situ fluids of affected production wells (Fig. 6). The total injection load of wells in the Sambaloran sector of Tongonan-1 were reduced in September 1995. The rest of the load was transferred to Mahiao injection wells. Starting October 1995, the increasing Cl and decreasing gas concentration of affected wells stopped and began to recover (Siega et al., 1998).

The second episode of brine injection returns in Tongonan-1 occurred after the diversion of the South Sambaloran brine to Tongonan-1 in 2001 to provide pressure support in the area. Wells affected immediately showed increases in Cl coupled with decreases in enthalpy and output. Infield injection well was shut and its brine load was transferred to a more peripheral injection well 1R8D within the infield Tongonan-1 injection sink to lessen the effect of brine injection returns. The enthalpies of some of these affected wells reverted back to 2700 kJ/kg thereafter.

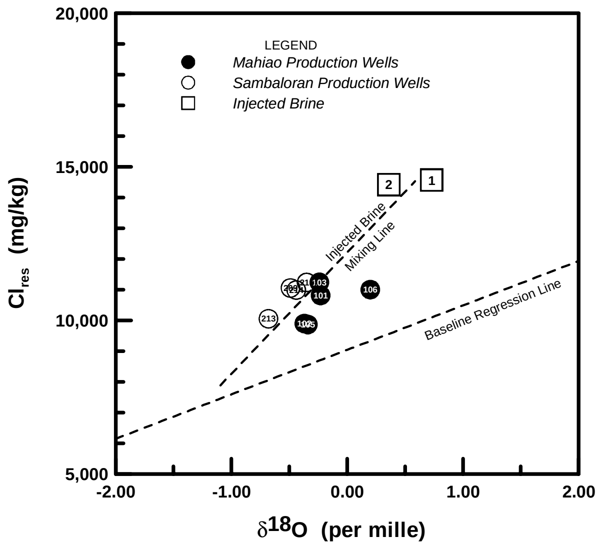

Figure 6: ^{18}O and Cl enrichment in production wells due to incursion of injected brine from Tongonan-1 injection sink. The regression line represents the baseline distribution of ^{18}O and Cl among the Tongonan-1 production wells prior entry of the injected brine

After the brine load was transferred, a tracer test was conducted in June 2006 with Naphthalene Disulfonate (NDS) tracers injected in well 1R8D. The NDS results confirmed the flow of brine injected in 1R8D to the "watery" production wells in Sambaloran sector. Based on the results, the brine injection management strategy in Tongonan-1 was modified and the impact of brine injection returns was reduced with the cut-out of well 2R4D and its conversion to a producer. Also, the bulk brine load (230 kg/s) injected into well 1R8D, with a depth of -1511 mRSL was transferred to a new adjacent well 1R9D drilled deep (-2391 mRSL) into the resource. Injection in well 1R9D would sufficiently reheat the injected brine in the deeper part of the reservoir before it returns to the production sector and still provide mass recharge and pressure support through the in-field injection.

2.2.2 Upper Mahiao Sector

In December 2002, EDC started deep injection of the 40°C Upper Mahiao Power Plant condensates to the northwestern outfield Pad 4RC injection sink, in compliance with the Zero Effluent Disposal policy of the Philippine government. A tracer test was conducted in June 2003 by injecting NDS tracer in a well at Pad 4RC to establish flow paths, rate and magnitude of influx of the cooler power plant condensates into the production sector. Results of the tracer test confirmed the hydrological connection between Pad 4RC injection sink and Upper Mahiao production sector, primarily into Pad 405 production wells, then to other nearby Upper Mahiao production wells (Fig. 7). The other monitored production wells southeast of Pad 4RC showed neither positive tracer breakthrough nor geochemical signatures of the power plant condensate throughout the monitoring period. This is due to the stored brine in the adjacent Pad 408 injection sink that acted as pressure and thermal barrier to the direct influx of the condensate from Pad 4RC to the main production area of Upper Mahiao (Dacillo, 2007).

Another process that is closely interrelated with condensate injection returns is brine injection returns from Pad 408. When the power plant condensates were injected in Pad 4RC starting December 2002, it pressurized the injection sink of Upper Mahiao and pushed the stored brine in Pad 408 towards the production sector. In August 2003, the reappearance of water fraction in the reservoir of wells with condensate and brine injection returns resulted to the increase in separated brine flow in Upper Mahiao sector from 30 kg/s to 180 kg/s. This also necessitated the resumption of separated brine injection in Pad 408 that further pressurized the injection sink; the injected brine eventually made its way to the depressurized production sector.

In a way, the brine and condensate injection returns is welcome and important as pressure support and mass recharge for sustaining the Upper Mahiao reservoir that has become highly two-phase due to extensive boiling. It also mitigates the problem on solids discharge associated with a reservoir that is becoming steam-dominated. To balance the benefits of mass recharge to the highly two-phase reservoir and the cooling effects of injection breakthrough to the producing wells, the injection wells' load distribution were modified and optimized. In Pad 4RC condensate injection, the injection load in wells nearest to the production sector were reduced and transferred to well 4R7D directed away from the production sector. In Pad 408 brine injection, well 408 was shut, well closest to the production sector was throttled while loads in wells much farther were maximized to accommodate the brine load and maintain pressure barrier for the condensate from Pad 4RC. At this configuration, the effects of condensate inflow to Pad 405 production wells and of the brine returns to the production sector were minimized as indicated by leveling off of the enthalpy and in the significant reduction of steam decline rate in the affected production wells.

2.2.3 Malitbog Sector

In Malitbog sector, brine injection returns from in-field injection was observed in producers closest to the injection wells. The increasing mineralization, declining gas content and deep liquid enthalpy of these production wells manifest the incursion of injected brine into the production sector. Evidences of this incursion is reflected in Figure 8, which presents the crossplots of the reservoir chloride, CO_{2TD} and deep liquid enthalpy (based on quartz geothermometer) of the affected production wells. Production well data shift towards the cooler, highly saline and highly degassed brine from the Malitbog injection sink.

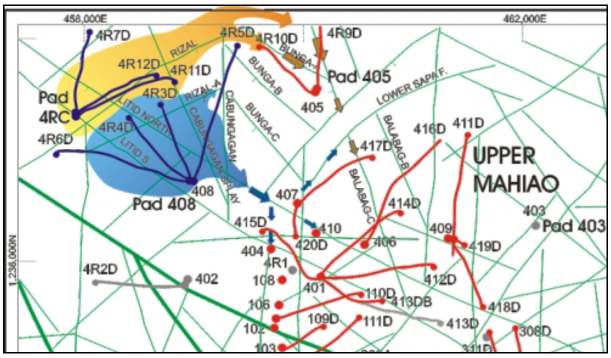

Figure 7: Flow model of condensate from Pad 4RC (yellow area, yellow arrows) and of the injected brine from Pad 408 (blue area, blue arrows) based on tracer studies and geochemical data

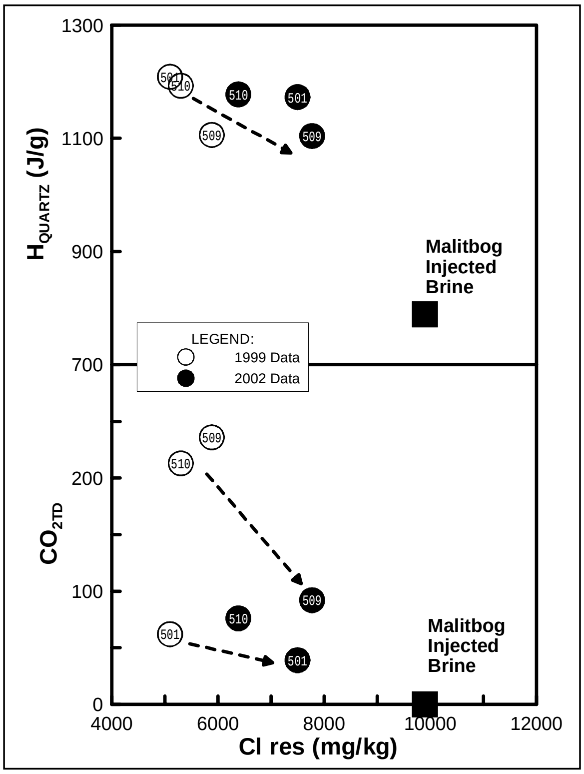

Figure 8: Crossplots of CO2TD and deep liquid enthalpy (based on quartz geothermometer) against reservoir chloride reflect incursion of injected brine into the affected production wells

A multiple-NDS tracer test was conducted last June 2007 and monitoring is currently on-going. The results of the test will further refine and optimize the loading of the injection wells. Also, with the utilization of well 5R13D as an injector, well 5R1D was cut-out from the system and made as a reserve or back-up well to reduce brine injection returns to the affected production wells.

2.3 Cooler Fluid Inflow

Cooler, dilute waters are flowing from the northeastern area to the production sector of Malitbog-South Sambaloran.

The area east of the Malitbog sector hosts cooler, sulfate-rich waters that are also slightly acidic compared to the waters in the main reservoir. With the maximized production in the field starting in 1996-1997, these peripheral waters were drawn-in towards production wells at the eastern periphery of Malitbog-South Sambaloran. Its influence on the chemistry of the affected production wells is seen in Figure 9. The in-situ waters of the production wells became cooler, less saline, as shown by lower chloride levels, and have lower Cl/SO_4 ratio.

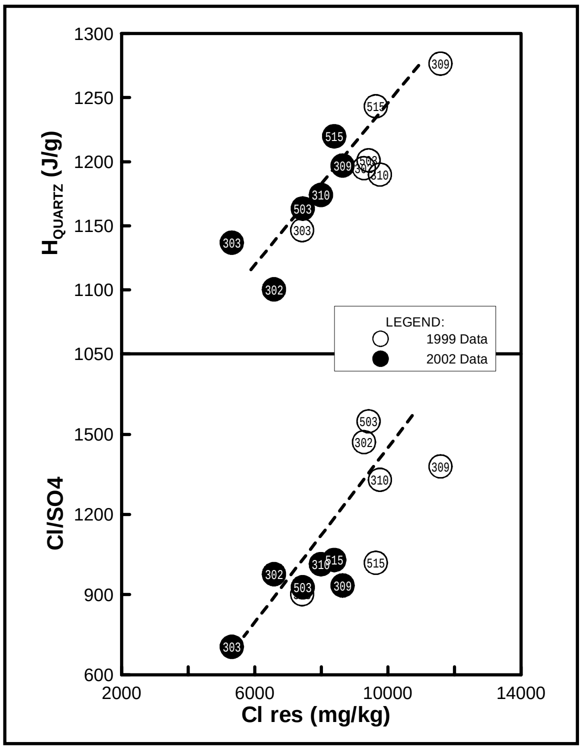

Figure 9: Plots showing the dilution and cooling of peripheral production wells caused by inflow of cooler, sulfate-rich waters

The same type of water is also encroaching on the western flank of South Sambaloran. Production wells here also exhibit the same declining trends in Cl, Cl/SO_4 and deep liquid enthalpy. However, their source of cooler waters appears to be coming from the southwestern side, which is more dilute than that in the northeastern area. The incursion of cooler waters in the southwestern side started only in year 2001 and caused well 303 to have the present chloride level of 5000 mg/kg. The inflow in the northeastern side started earlier in year 2000 and at present, the chloride level of well 309D in that area, leveled off at 8000 mg/kg.

To mitigate the effect of the cooler waters from the southwestern side, sacrificial wells are continuously being discharged to portable silencers as these wells preferentially drew-in the cooler, peripheral waters. This has resulted to significant enthalpy and output recoveries in central production wells that are affected by the peripheral cooler waters.

In the northeastern side, the influx of cooler waters has been manageable. Although affected wells have shown decreases in enthalpies and outputs, these have stabilized, attributed to the pressure support into the reservoir from the injection returns in Upper Mahiao, Tongonan-1 and Malitbog sectors. If the influx of cooler waters would advance further into the field, this may be mitigated by continuously discharging idle peripheral wells in Malitbog, similar to the set-up of wells in western flank of South Sambaloran. The two peripheral wells in Malitbog are currently being tested for sustained discharge.

2.4 Mineral Deposition

Silica deposition in the wellbore is observed in production wells located at boundaries between areas with brine injection returns and areas with extensive boiling. Evidences include ejecta samples that contain mainly silica scales with circular shapes and corrosion products on the smooth sides of the scales indicating encrustation of these scales on the inside surface of the well casing or liner. The scales are postulated to be coming from silica-rich brine injection returns that gradually supersaturates due to continuous flashing as the injected brine flows towards the center of the field. Output decline rates of wells affected solely by injection returns are low while that of production wells closer infield affected by silica deposition are high; decline rates significantly taper off again in wells closer infield affected by extensive boiling only. Outputs of wells affected by silica scaling are substantially recovered by conducting only mechanical clearing of wellbores (Fig. 10). There are also instances that significant output recoveries of up to 4 MW are achieved by simply vertically discharging the wells to dislodge silica scales from shut, highly-pressurized condition. To mitigate further the effect of silica deposition, deep injection well 1R9D in Tongonan-1 injection sink is maximized to allow injection returns to mix with the hotter, deep geothermal liquid instead of the shallower two-phase of the reservoir where the returns are subjected to continuous flashing.

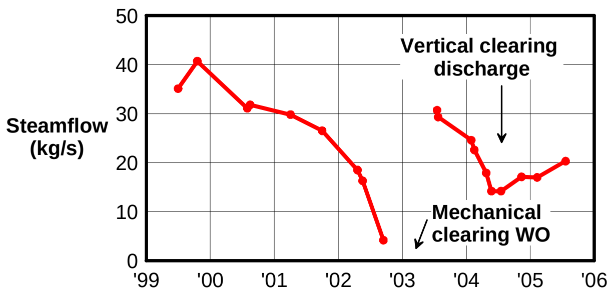

Figure 10: Steamflow vs. time of well 110D affected by silica deposition

3. IMPACT TO STEAM GENERATION AND SUMMARY OF RESOURCE MANAGEMENT STRATEGIES

The reservoir processes discussed in Section 2 have influenced the availability of steam supply in the Tongonan field through time. Reservoir-wide boiling increased the field's steam supply to 1500 kg/s in year 1999-2000 (Figure 11). However, subsequent pressure drawdown, injection returns, inflow of peripheral waters and silica deposition caused a gradual decline in steam supply from 2000-2005. The measures and resource management strategies implemented since then arrested this decline to a stable level since 2006 to present.

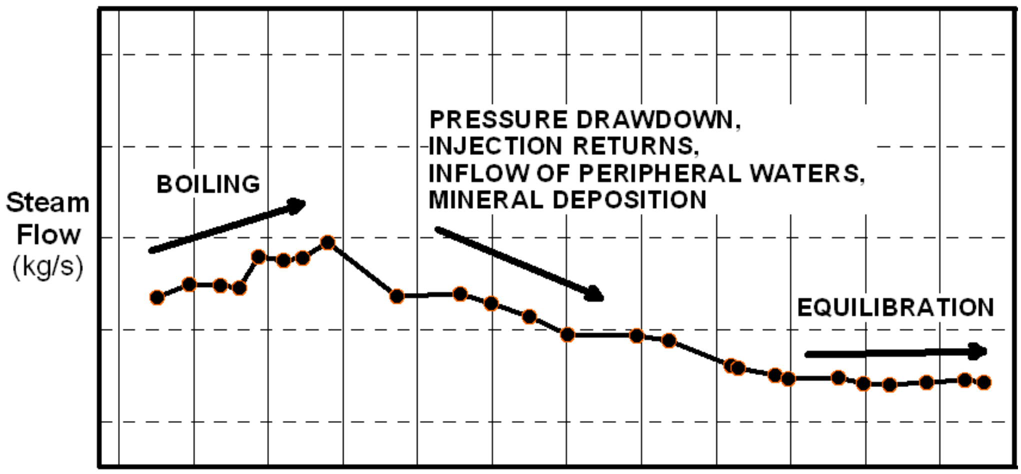

Figure 11: Trend of the total steamflow from the 3 sectors of Tongonan geothermal field as influenced by the major reservoir/wellbore processes

Resource management and well intervention procedures that are being implemented to prevent further decline in steam availability include: (a) on steam production – (1) utilization of peripheral marginal output wells that draw-in cooler waters and reduces the flow further infield into the higher output production wells; (2) priority drilling of M&R wells in sectors with ample excess steam and diversion of the same to other sectors through steamline interconnection; and (3) conversion of idle injection wells to production wells; (b) on separated brine and power plant condensate injection – (1) cut-out or optimize loading of injection wells with direct communication with production wells based on results of tracer tests; (2) injection wells which have deep permeable zones and with the least direct hydrological connection to the production sector are maximized to maintain pressure support but minimized thermal effect; and (c) on well intervention – (1) workover and/or acidizing of wells with mineral deposition; (2) mechanical repair of wells with casing and/or liner breaks; and (3) vertical clearing discharge on wells with mineral deposition.

4. LOOKING BEYOND: GROWTH FOR THE FUTURE

The future direction for Tongonan Geothermal Field is to sustain its power generation capacity through development of three peripheral pads to tap fresh resource to connect to the system. The estimated replacement capacity is 80 MW that is expected to be more sustainable for future steam requirements or even field capacity expansion (Alcober, 2007).

4.1 Pad 403 Development

In Upper Mahiao sector, the north-easternmost pad where wells 403 and 424D are located (Fig. 1) will also be developed for M&R drilling and become a step-out drill pad location to further explore the northeastern margin of exploitable resource in Upper Mahiao. This expansion development is expected to be completed in November 2009 with two more wells to be drilled. It is targeted to provide an additional 20 MW. Also, Pad 405 to the north of Upper Mahiao, currently having three wells can still be expanded to accommodate one well to tap the northern margin of the resource. All these expansion areas will ensure the sustained steam availability from the Upper Mahiao sector, to supply the main power plant as well as provide additional steam to the other sectors if needed.

4.2 Pad 4RD Development

Also in Upper Mahiao, the area to the northwest of Pad 4RC will be developed as Pad 4RD with wells programmed for drilling, to serve as an outfield injection sink for the cold power plant condensate. Pad 4RD wells will be drilled deeper into the reservoir because of its lower elevation compared to existing production wells in Upper Mahiao. This would allow injection of 40°C condensate into the deeper, hotter regions of the reservoir. This development is expected to be completed in September 2010.

Once condensate injection has been transferred to Pad 4RD, brine injection in Pad 408 will also be transferred farther north to the current condensate injection Pad 4RC. Pad 4RC injection wells are also relatively deep at -1836 to -2050 mRSL compared to the Upper Mahiao production wells with depths of -536 to -1948 mRSL. The maximized depth and distance for both the brine and condensate injection will mean that the injection fluids, which will provide mass recharge and pressure support to the production sector, will be much more reheated before returning to the production wells. Moreover, maximized depth would mean that silica-saturated brine will be injected into the liquid region of the reservoir instead at the two-phase region where it will deposit silica because of continuous flashing.

After the condensate and brine injection have been transferred to Pads 4RD and 4RC, respectively, Pad 408 brine injection wells will then be converted into production wells. Based on field temperature contours, the Pad 408 injection sink has been evaluated to still have exploitable hot fluids of ~240^{o}C. Also, discharge tests in these injection wells after drilling proved that they can attain commercial wellhead pressures.

4.3 Pad 208 Development

In Tongonan-1 sector, Pad 208 to the east of the current production sector already has one drilled well (W208). Additional M&R drilling of two more wells are programmed for the 20 MW development scheduled for cut-in in January 2010. This will augment the requirement of the Tongonan-1 power plant, with the flexibility of also supplying the other power plants in Tongonan Geothermal Field or to the nearby field of Mahanagdong through the steamline interconnections.

CONCLUDING REMARKS

The Tongonan Geothermal Field has sustained production through the past 25 years dotted with challenges that affected the field steam generation. These challenges have developed from the reservoir as a response to the field utilization. Resource management strategies on production and fluid injection, well intervention involving well repair, mechanical clearing, acidizing, and others have been effective in sustaining the field generation and in attaining the optimum performance of individual production sectors. The utilization of valuable geochemical and reservoir engineering data and evaluation tools, the integrated evaluation and interpretation have been vital in formulating the strategies that have been implemented, refined over the years and added or replaced with more effective ones with the future direction of outfield peripheral development. With sound resource management, Tongonan Geothermal Field is poised for another 25 years of sustainable production.

ACKNOWLEDGMENT

Our congratulations to all the EDC personnel who have contributed in sustaining the geothermal resource in this occasion of Tongonan Geothermal Field's 25th year anniversary of commercial operation. Those efforts did not fall in vain and will again be mustered to propel the resource 25 years more into the future. We also wish to thank the EDC management for the support in publishing this paper.

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