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Geochemical Assessment on the Sustainability of the Deep Geothermal Resource of Tongonan Geothermal Field (Leyte, Philippines)

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ABSTRACT

The past 6 years saw rapid changes in the Tongonan geothermal reservoir as the field underwent full commercial operations starting in 1996 from 112 MWe to 550 MWe gross generation. The most prominent among the changes is the transformation of the discharge of production wells, mostly from the center of the field, from being liquid-dominated to steam-dominated. To properly manage and sustain the reservoir, a geochemical evaluation was made of the deeper resource untapped by the production wells.

The results show that the reservoir is sustainable as the deeper part of the resource still hosts more than 90% of the hot geothermal liquid. The gas-mineral equilibria (FT-HSH2) by D'Amore gave estimates of the steam fraction and temperature in the central region of 1 - 5% steam (or 95 - 99% liquid) and 290 - 310°C, respectively. A temperature of 280 - 300°C for the same region extrapolated using the Na/K geothermometer shows the consistency of both methods.

In the outflow region of the reservoir, production wells still have a liquid fraction in their discharge. Here, a steam loss of 1% is estimated in areas having inflows of cooler peripheral waters and injected brine while a 5% steam fraction was noted in areas producing from higher-enthalpy wells.

The same gas-mineral equilibria method gave good agreements with the quartz geothermometer for the low-enthalpy wells signifying its fast re-equilibration. In dry wells, the method reflected higher temperatures indicating that the last re-equilibration of the participating species is far from the wellbore, probably at the point where water containing the reacting minerals is still present.

1. INTRODUCTION

The full commercial operations of the Tongonan geothermal field starting in 1996 brought about rapid changes in the reservoir. The initial operation, which began in 1983, involved only a 112.5 MWe power plant. By 1996-1998, the commissioning of new power plants raised the total generation to around 500 MWe. By 2000, this increased further to around 550 MWe when Tongonan started to augment the steam requirement of the neighboring Mahanagdong geothermal field (Fig. 1) through a steamline interconnection. The production history in terms of the monthly net mass extraction (i.e. total mass extraction less mass injected back to the reservoir) is presented in Figure 2. The figure shows the huge increase in the mass extracted during the full operations of the field, about 7 times the initial rate.

The most prominent among the changes in the reservoir to maximized exploitation is the transformation of the discharge of the production wells, mostly from the central part or near the upflow region, from liquid-dominated to steam-dominated. Majority of these wells are found in the Upper Mahiao and Tongonan-1 sectors (Fig. 1). Their discharge enthalpies increased sharply from 1600-1900 J/g to 2400-2700 J/g (Fig. 3) indicating two important related points: the reservoir is undergoing extensive boiling and there is limited or no natural recharge at all from the northern periphery of the field (Dacillo, 2003). Even the brine returns from the injection sinks of Tongonan-1 and Upper Mahiao did not persist because the flow of separated brine decreased appreciably when the discharge enthalpies of production wells continued to increase.

The major outflow region, the South Sambaloran and Malitbog sectors, had an opposite response. Pressure drawdown drew in cooler meteoric waters inferred to be from the eastern and western periphery of South Sambaloran. This kept the discharges of production wells at the margin of the sector at liquid enthalpies. Those located in the more central part have enthalpies closer to Upper Mahiao and Tongonan-1. In Malitbog, the production wells in the south have considerable inflow of the injected brine from the Malitbog injection sink. This artificial recharge maintained the sector's average enthalpy at less than 1600 J/g.

The concern on the sustainability of the reservoir encouraged this geochemical evaluation of the deeper aquifer. Characterization of the deeper parts of the resource has become important considering that the depth tapped by most of the existing production wells became dry. Specific parameters like the deep temperature and water fraction of the reservoir were sought using the FT-HSH2 method as the main tool in the evaluation. These and additional geochemical data were used to give a clearer picture of the deep fluids feeding the dry production wells in the north and the cold water-encroached wells in the south. The evaluation however, is limited only to the reservoir beneath the Tongonan geothermal field and does not include the reservoir of the Mahanagdong geothermal field. The resources of the two fields are separated by the cold and impermeable Mamban block (Alvis-Isidro *et al*., 1993).

2. METHOD

The use of geochemical tools based on water chemistry has been very effective in monitoring the Tongonan reservoir since the start of production in 1983. This is because the Tongonan reservoir is water-dominated. By 1996-1998 however, water chemistry became obsolete for most of the production wells in the northern half of Tongonan that eventually produced dry steam. Thus, different techniques developed using gas chemistry has been very useful.

Two methods of calculating the reservoir steam fraction are known by this author, one from the group of D'Amore (D'Amore and Celati, 1983; D'Amore and Truesdell, 1995), the other from Arnorsson (1995). D'Amore's work

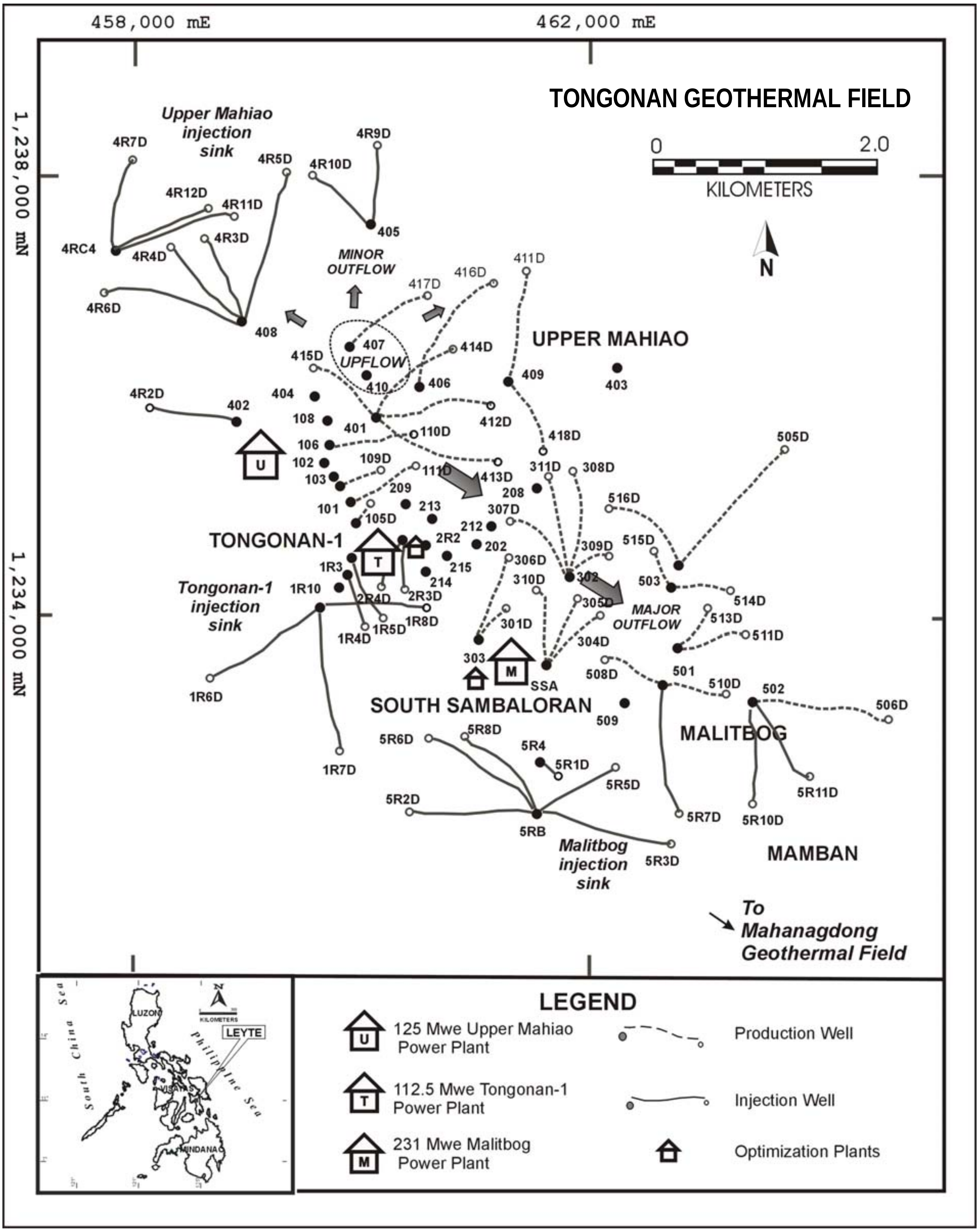


Figure 1. Map of Tongonan Geothermal Field subdivided into the sectors of Upper Mahiao (w/ 400-series name wells), Tongonan-1 (100&200-series wells), South Sambaloran (300-series wells) and Malitbog (500-Series wells). Inset map: the Philippines

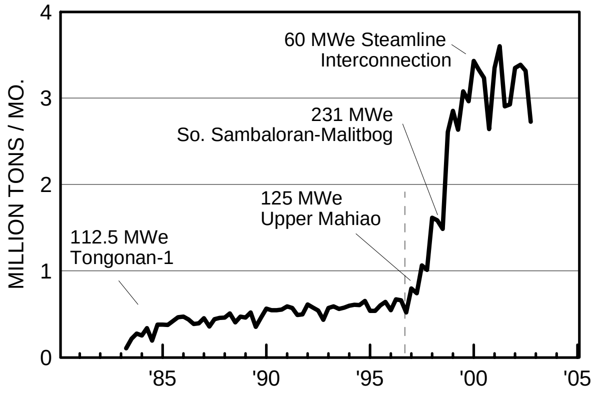


Figure 2. Historical trending of net mass extraction rate (i.e. total mass extracted less mass injected back to the reservoir).

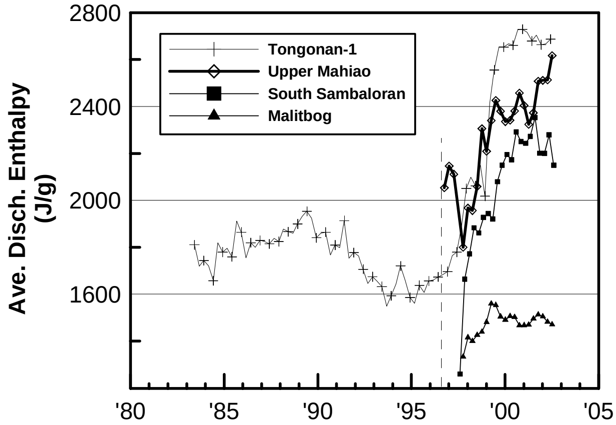


Figure 3. Plot of average enthalpy per sector with time.

revolves on various gas-mineral reactions that are assumed to have attained full equilibrium in the reservoir. The end parameters that are calculated from his method are the temperature and the steam fraction in the reservoir where thermodynamic and chemical equilibrium of the reactions are attained.

Siega *et al.* (1999) used D'Amore's method which are based on the different gas-mineral equilibria and evaluated their applicability of each in the different geothermal fields in the Philippines. The equilibria considered were the following:

$$FT \quad : \quad CH_4 + 2H_2O = CO_2 + 4H_2 \qquad (1)$$

$$HSH1 \quad : \quad H_2 + 2H_2O + 3/2\ FeS_2 = 3H_2S + 1/2\ Fe_3O_4 \qquad (2)$$

$$HSH2 \quad : \quad 5/4\ H_2 + 3/2\ FeS_2 + 3/4\ Fe_2O_3 + 7/4\ H_2O = 3H_2S + Fe_3O_4 \qquad (3)$$

$$HSH3 \quad : \quad FeS_2 + H_2 = FeS + H_2S \qquad (4)$$

where FT, HSH1, HSH2 and HSH3 are the symbols used to denote each reaction. However, only the combination of FT and HSH2 will be used in this paper since it is the most applicable and consistent for the mature hydrothermal system in Tongonan (Siega *et al.*, 1999). Expressing the above reactions in terms of the equilibrium constant equation and applying the law of mass action, equations 1 and 3 yield:

$$FT = 4\log(H_2/H_2O) + \log(CO_2/H_2O) - \log(CH_4/H_2O) \qquad (5)$$

$$FT = \log K_{FT} + 4\log A_{H2} + \log A_{CO2} - \log A_{CH4} - 2\log P_{H2O} \qquad (6)$$

$$HSH2 = 3\log(H_2S/H_2O) - 5/4\log(H_2/H_2O) \qquad (7)$$

$$HSH2 = \log K_{HSH2} + 3\log A_{H2S} - 5/4\log A_{H2} \qquad (8)$$

The derivation of final equations 5 to 8 is detailed in Siega *et al.* (1999) and the guiding assumptions and limitations are found in D'Amore and Truesdell (1995) and D'Amore and Celati (1983). Equations 6 and 8 generate a "grid" while equations 5 and 7 are computed based on total gas compositions in the discharge of production wells. The values of the reservoir temperature and steam fraction become known by plotting the calculated values from equations 5 and 7 inside the "grid".

Arnorsson (1995) proposed a different approach to the estimation of the reservoir steam fraction. His method takes into account the possible segregation of the flowing water and steam in the aquifer. Such segregation will cause the discharge composition of gases to differ from that of the parent reservoir fluid. This is the main difference in the two methods since one of the basic assumptions of D'Amore and Celati (1983) is that no mass is gained or lost as the reservoir fluid is transferred to the wellhead. The reservoir steam fraction calculated from Arnorsson's method is always lower than that of D'Amore and Truesdell. Examples given in Arnorsson's paper (1995) showed a range of 1-25% from D'Amore's method for Cerro Prieto in Mexico and Hveragerdi, Nesjavellir and Namafjall in Iceland whereas Arnorsson obtained -0.01 to 0.35% for the same fields.

For the purposes of this paper, the method of D'Amore (FT-HSH2) will be used considering that the author is looking for the widely-used method that would give the lowest reservoir water fraction (~the highest steam fraction), the worst picture that could be painted for the Tongonan reservoir. It is also already outside the scope of this paper to compare and validate, in the Tongonan setting, the two methods that have been discussed above.

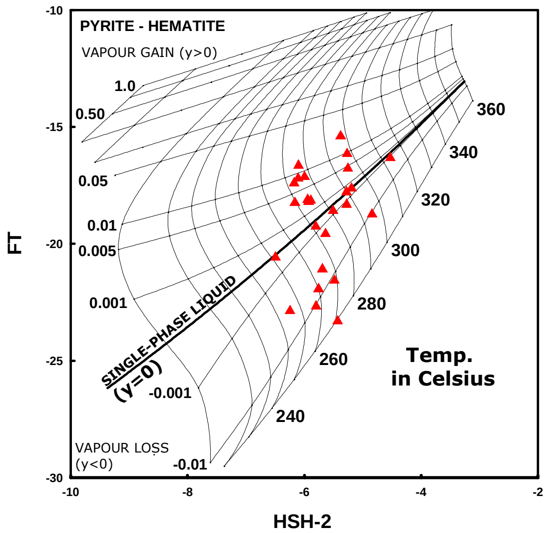
3. RESULTS AND DISCUSSION

3.1 FT-HSH2 Data

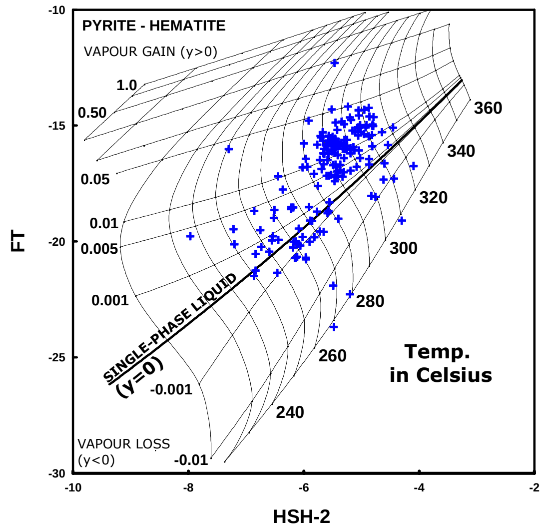
Figures 4a to 4e are plots of the gas data of all the production wells before (pre-1997) and during (1998-2004) the maximized exploitation of the field.

Data prior to 1997 (Fig. 4a) generally lie close to the zero steam fraction or a range from -0.01 to 0.01. Those that are on the positive side are the wells in Tongonan-1 and Upper Mahiao that already has a natural two-phase cap. Those with lower temperatures and have negative steam fractions or steam losses are the wells in the periphery of Malitbog which relatively have higher mixing with degassed meteoric water than the wells in the central part of the field.

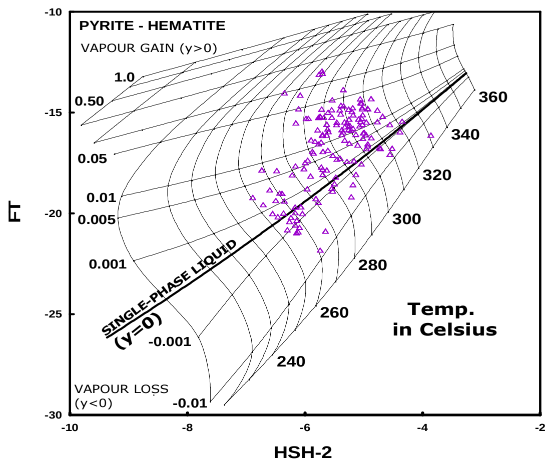
As the field underwent full production, data points of 1998 (Fig. 4b) shifted to higher steam fraction relative to the pre-1997 data. This is consistent with the boiling process indicated by the significant increases in the discharge enthalpy of Upper Mahiao, Tongonan-1 and majority of South Sambaloran production wells. However, one would notice that all through the maximized exploitation stage, from 1998 to 2004 (Figs. 4b-4e), the maximum steam fraction has been steady at around 0.05 (or 5% steam). This probably suggests that at the current rate of extraction, the reservoir is able to sustain the 5% steam cap that is being tapped by the ‘dry’ production wells. The value of the steam fraction likewise implies that the reservoir is still 95% liquid.



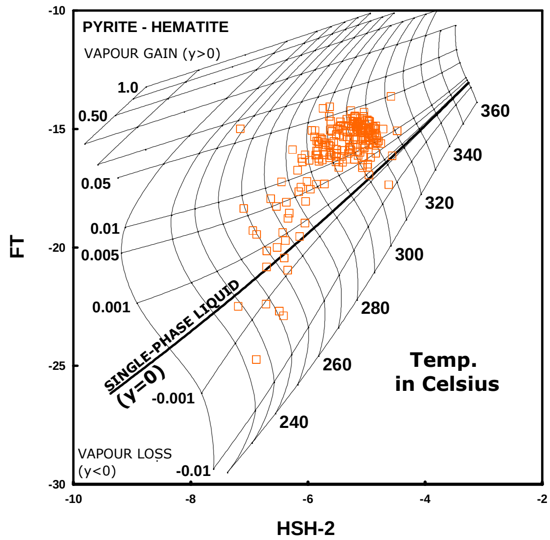
a.) Pre-1997



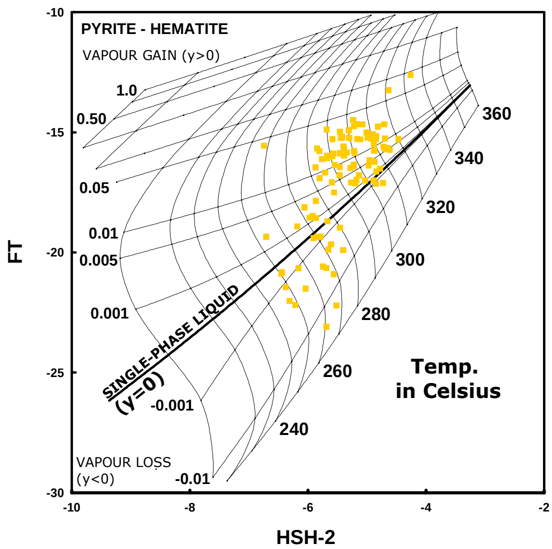
b.) 1998



c.) 2000



d.) 2002



e.) 2004

Figure 4. FT-HSH2 data of all production wells before [a] and during [b - e] maximized exploitation.

3.1.1 Upper Mahiao and Tongonan-1 Sectors

It is worth noting that plotting the data by sector yields interesting results. Figure 5 shows the data points of Upper Mahiao and Tongonan-1 before and during maximized exploitation.

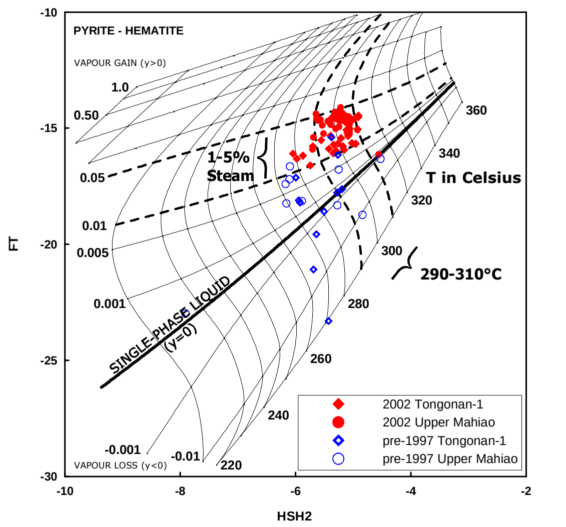


Figure 5. FT-HSH2 of all Upper Mahiao and Tongonan-1 wells before (pre-1997) and during full exploitation (2002).

In the pre-1997 data, these two sectors have scattered data points. Those production wells with injection returns from the Tongonan-1 and Upper Mahiao injection sink plotted in the vapour loss region while those in the center of the sector plotted slightly above the single-phase liquid line reflecting the presence of the natural, shallow steam-cap in the reservoir.

In the 2002 data wherein injection returns have declined, it appears that pressure drawdown forced the data points of the two sectors to cluster inside the 290-310°C isotherms and 1-5% steam fraction. This is about the same as the baseline temperature that has been measured in two Upper Mahiao wells, wells 407 and 410, considered to have hit the upflow region of the reservoir because both have the highest temperature (>300°C) among all production wells. Geochemical and isotopic data support the location of the upflow within this area (Salonga *et al.*, 1996).

The year 2002 temperature is 10-20°C higher than the average temperature in the pre-1997 data suggesting that the gaseous and aqueous mineral species considered in the FT-HSH2 reactions have equilibrated deeper into the hotter regions of the reservoir and farther away from the lower temperature boreholes. This is likely due to pressure drawdown which caused the level of the waters bearing the dissolved mineral species to recede deeper into the hotter regions.

3.1.2 Malitbog and South Sambaloran Sectors

Unlike Upper Mahiao and Tongonan-1, the data points of Malitbog and South Sambaloran sectors are dispersed over a wider range of temperature from 245 to 310°C (Fig. 6).

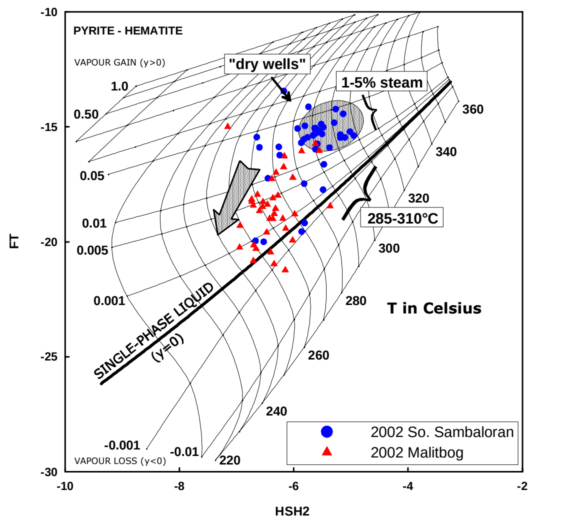


Figure 6. FT-HSH2 of South Sambaloran and Malitbog wells during full exploitation (2002).

It is interesting to note that the dry wells of South Sambaloran have plotted between the 285-310°C isotherms and 1-5% steam fraction, which is similar to the dry wells of Tongonan-1 and Upper Mahiao. What this means is that the dry South Sambaloran wells are drawing steam from the same area as that of Tongonan-1 and Upper Mahiao even though this sector is already far from the upflow. The other South Sambaloran data points with 1-5% steam fraction but with lower temperature at 260-280°C, may have fluid contribution from deeper source at the area with lower temperature near or beneath South Sambaloran.

For the rest of the South Sambaloran and Malitbog data points, there is a gradual decline in temperature as well as in the steam fraction. This reflects the gradual cooling of geothermal fluids as they flow from the upflow towards Malitbog-South Sambaloran outflow and mix with the cooler meteoric waters and injection brine. Also, the FT-HSH2 geothermometer has good agreement with the quartz geothermometer for the watery production wells of Malitbog (Fig. 7). This means that the participating species in the FT-HSH2 method seem to re-equilibrate as fast as quartz as long as all these species are present. In the case of the low enthalpy wells of Malitbog, the dissolved minerals and the gases are there so that the temperatures reflected are those near the wellbore.

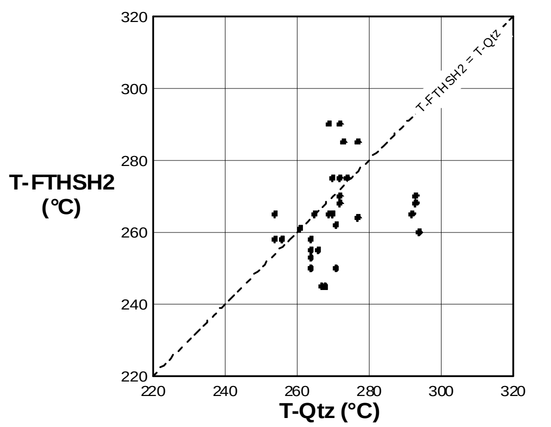


Figure 7: T-FTHSH2 vs. T-Qtz (2002) of the watery wells of Malitbog.

In the case of dry wells of Upper Mahiao, Tongonan-1 and South Sambaloran, the participating species have equilibrated deeper or far from the wellbore, probably at the point where the water bearing the minerals is still present. Only the gases, which retained the thermal impression of the area of the last equilibration, have reached the wellbores.

3.2 Water Chemistry Data

In addition to the FT-HSH2 method, water chemistry data from the remaining few watery wells in the south were also used to further characterize the deeper fluids feeding the production wells. The problem with these wells is that most of them are affected either by the inflow of cooler and dilute peripheral waters from the eastern and western sections of South Sambaloran, or by the inflow of cooler brine returns from the injection sink of Malitbog in the soouth. These waters mask the chemistry of the deeper geothermal water. However, one well in Malitbog, well 514D, remained unaffected by inflow of the cooler peripheral waters.

Figure 8 presents the geochemical and physical trends with time of well 514D.

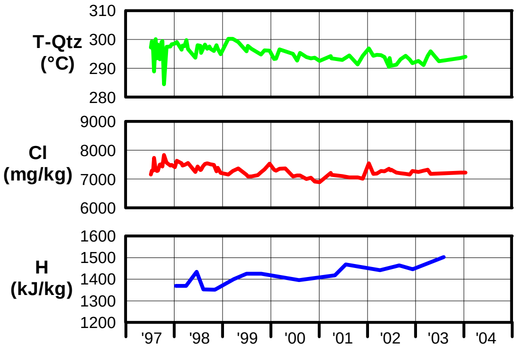


Figure 8. Geochemical trend of Well 514D.

The well's discharge enthalpy is slightly increasing from 1350 J/g in 1998 to 1500 J/g in 2003, while the reservoir temperature, based on quartz geothermometry, is decreasing from 300 to 294°C. The trend of the reservoir chloride is stable to slightly decreasing from 7500 to 7200 mg/kg. These trends suggest higher contribution from the less mineralized, lower-temperature, upper-two phase zone. Nevertheless, this implies that the local reservoir of well 514D is not yet affected by inflow of cooler peripheral waters. More importantly, this suggests that the deeper waters moving from the upflow region of Upper Mahiao to the outflow in Malitbog presently has a temperature greater than 294°C and salinity greater than 7200 mg/kg in terms of Cl. This liquid component of the reservoir is not seen in Upper Mahiao, Tongonan-1 and in the dry areas of South Sambaloran probably because of the thick dry steam cap that is present at the depths of the production wells. It only manifested itself in Malitbog where the steam cap is thin (y<1%).

3.3 Na/K Geothermometer

The results of the FT-HSH2 for the Malitbog sector and the few watery areas of South Sambaloran have been somehow validated by the water chemistry data. As for Tongonan-1, Upper Mahiao and the dry wells of South Sambaloran, the Na/K geothermometer is utilized.

Due to the slow response of the Na/K geothermometer to the prevailing temperature in the different section of the reservoir, the Tongonan experience is that the values obtained from this geothermometer remains relatively constant from the upflow to the outflow. This is shown in Figure 9 where the Na/K temperatures are plotted with the fast-equilibrating quartz temperature using the pre-1997 data when the production wells of the whole field still have considerable water fraction at the wellhead. The Na/K geothermometer retained the 300-320°C temperature of the parent fluids from the upflow region all the way to the outflow whereas quartz temperature declined from 300 to 260°C. The Na/K geothermometer was virtually unaffected by cooling due to conduction and gradual mixing of cooler meteoric waters and returns of the injected brine.

Using this understanding, the 2002 water chemistry data of the only remaining watery wells in outflow region of South Sambaloran and Malitbog sectors were used to extrapolate the temperature of the parent fluids under the Upper Mahiao sector. In Figure 9, results show that the Na/K geothermometer of 280-310°C is comparable to the 290-310°C temperature of FT-HSH2. This independently validated the temperature estimated by the FT-HSH2 method. Also, the 2002 data is lower by about 20°C than the pre-1997 data which is probably due to pressure drawdown.

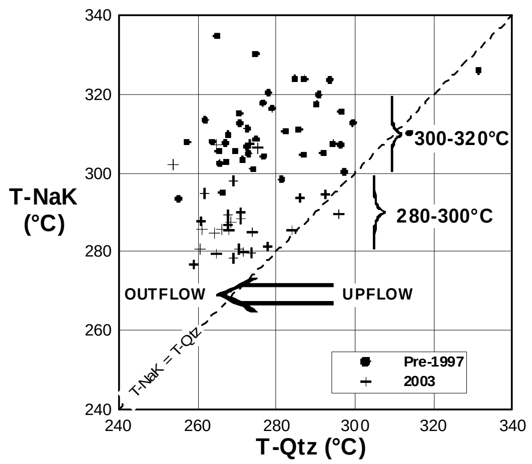


Figure 9. Na/K geotemperature before (pre-1997 data of all wells in Tongonan Goethermal Field) and during (2002-2003 data of Malitbog and the remaining watery wells in South Sambaloran) full exploitation of the field.

4. SUMMARY AND CONCLUSIONS

Pressure drawdown and limited recharge in the northern half of the field transformed the discharge of production wells in Upper Mahiao, Tongonan-1 and the central part of South Sambaloran from liquid-dominated to steam-dominated during the full exploitation of the field. The reservoir though is still sustainable as the FT-HSH2 method estimated 95-99% geothermal liquid with a temperature of 290-310°C present beneath the expanded steam cap that is feeding the dry production wells. The extrapolated Na/K geothermometer independently validated the presence of 280-300°C parent fluids.

Most of the dry wells of South Sambaloran is likely drawing the more mobile steam boiled off from the upflow zone with less contribution from the liquid that is flowing from the upflow to the outflow under the steam cap. The outflowing geothermal liquid is not seen in the production wells of Upper Mahiao, Tongonan-1 and the central part of South Sambaloran because of the expanded steam cap present at the depths of the production wells. It manifests only in the margins of South Sambaloran and the whole Malitbog sector where steam cap is thin (y<1%). The remaining watery wells in South Sambaloran and Malitbog showed that the outflowing geothermal liquid has high temperature (>290°C) and salinity (>7000 mg/kg) before mixing with the cooler peripheral waters (meteoric and injection returns) in these sectors.

The same gas-mineral equilibria method gave good agreements with the quartz geothermometer for the low-enthalpy wells signifying its fast re-equilibration. In dry wells, the method reflected higher temperatures indicating that the last re-equilibration of the participating species is far from the wellbore, probably at the point where water containing the reacting minerals is still present.

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