Chapter 4

Case Studies on Sustainable Use of Geothermal Energy

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Chapter 4

Case Studies on Sustainable Use of Geothermal Energy

4. Introduction of Chapters 4 and 5

The topics of interest for sustainability of geothermal power generation and direct heat use pointed out in Section 2.5 are summarised below in order of priority (based on input from China, Indonesia, the Philippines, and Japan):

1. Monitoring and reservoir engineering,
2. Reinjection,
3. Anti-scaling, and
4. Anti-corrosion and anti-erosion.

For ground source heat pump (GSHP) systems, no common interests were found, but basic hydrogeological data collection and system monitoring were pointed out to be important for the sustainable use of GSHP. On the other hand, in Section 4.1, the importance of international cooperation was pointed out.

Therefore, we decided to collect case studies from each member country concerning these topics to find possible solutions for sustainable use of geothermal energy. Thus case studies are presented in the next section. These case studies are compiled and used as a base of the guidelines shown in the following chapters.

Although the solutions shown in the following sections and chapters may contribute to the sustainability of geothermal use to some extent, continuous studies are needed for future use. As listed in ‘Recommendations to Policymakers’, these topics are a matter of importance to be studied continuously and cannot be solved by our current project only.

Note that ‘sustainability’ in this report is mainly for ‘resource sustainability’ and environmental sustainability is only partially discussed (on subsidence and brine disposal to rivers). Separate investigations are necessary to discuss environmental, economic and/or social sustainability.

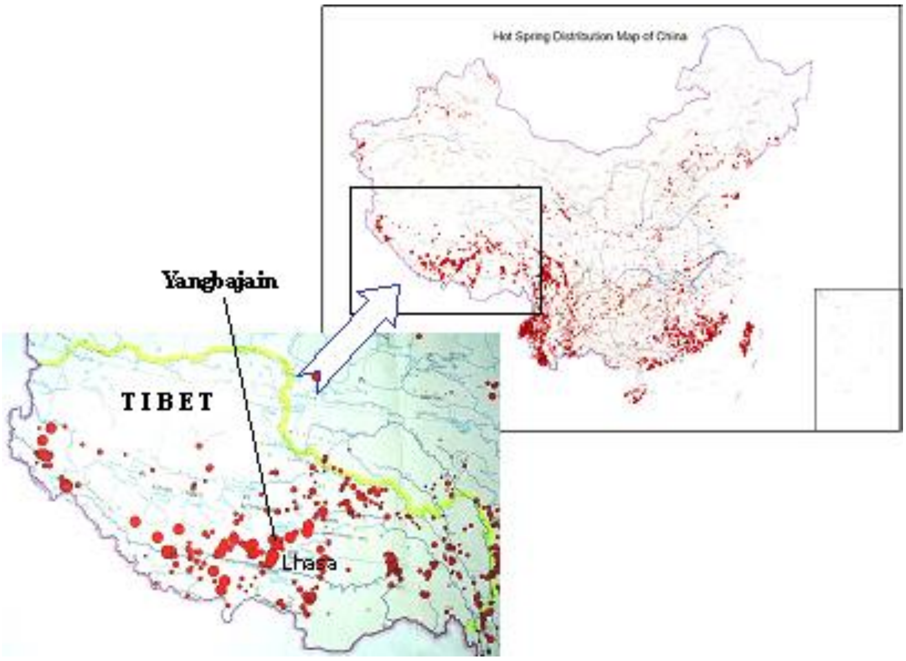
4.1 China: Comparison of Yangbajain and Xiaotangshan Geothermal Fields

A. Case Study on Yangbajain Geothermal Power Station

4.1.A1. Introduction: Yangbajain Geothermal Power Station

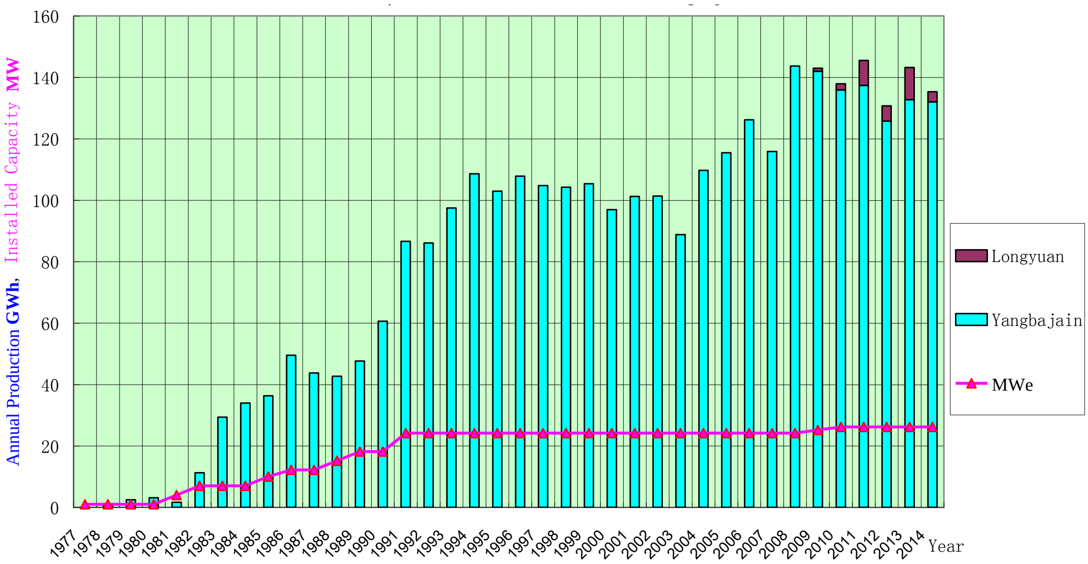
The Yangbajain Geothermal Power Station is located 90 kilometres (km) northwest of Lhasa, the capital of Tibet Autonomous Region, China (**Figure 4.1-A1**). Its elevation is 4,300 metres (m) above sea level, the highest geothermal power station in the world. It started power generation of 1 MW_e in 1977. At that time its fluid was 153°C in temperature with wellhead pressure of 0.33 MPa (mega Pascal). The total flow of steam and water was 72 m^3/h. It generated 600 kWh per hour. During 1981–1991, 8 units of 3 MW_e each (including one unit of 3.18 MW_e) were installed progressively. These completed a total installed capacity of 24.18 MW_e (1MW_e unit retired). Its annual power generation was 87 million kWh in 1992. Then it exceeded 100 million kWh in 1984. It reached a highest record of 140 million kWh in 2008. It is about 130 million kWh in recent years (**Figure 4.1-A1**). Up to 2014, the station has generated 3,100 million kWh in total.

Figure 4.1-A1. Yangbajain Location Map



Source: Edited by authors based on Shangyao Huang: Hot Spring Distribution Map of China (1993) and K. Zheng et al. (2012), Geothermal resources development in Tibet, China.

Figure 4.1-A2. Annual Production and Installed Capacity of Yangbajain Geothermal Power Station



Source: Edited by authors based on the statistics data of Yangbajain Geothermal Power Station.

The station uses two stages of flash technique. The geothermal fluid came from the Yangbajain shallow reservoir. After exploitation for dozens of years the capacity of the shallow reservoir has declined. But the variation of annual production shown in **Figure 4.1-A2** was caused not by resources or technical reason. It is restricted by the deployment of the power grid. When power supply decreased demand, geothermal power generation was required to reduce production.

The rated speed of 3 MW_e unit is 3,000 r/min, and main steam pressure is 0.42 MPa with a temperature of 145°C. The primary entering steam pressure is 0.17 MPa with a temperature of 118°C at a flow rate of 22.5t/h. The second entering steam pressure is 0.05 MPa with temperature of 102°C and the same flow rate. The exhaust steam pressure is 0.008 MPa. Per tonne of thermal fluid produces electricity of 7 kWh in average. The transfer efficiency of heat-electricity is 9 percent. Its capacity factor is 69 percent in winter, but lower in summer.

The Yangbajain geothermal power station supplied Lhasa's electricity demand for 50 percent in general situations and 60 percent in winter in the 1990s. At present, the Central Tibet grid has enlarged its total installed capacity. Geothermal power has reduced its proportion. There is a lack of energy resource (rare coal and oil) in Tibet. In order to protect the local fragile ecology environment, it is not permitted to transfer coal into

Tibet. The Tibet power grid is independent without connection to the national grid. The Central Tibet grid is formed by hydropower mainly. There is small electrical power from light oil, solar photovoltaic, and wind power, amongst others, except geothermal power generation.

Figure 4.1-A3. Yangbajain Geothermal Power Station,

Outdoor View (left) and Indoor View (right)

Source: Photo by Keyan Zheng.

4.1.A2. Geothermal reservoir and its exploitation in Yangbajain

The Yangbajain geothermal field covers an area of 35.6 km^2. But the high temperature area, which is suitable for power generation, is 5.6 km^2. The shallow reservoir is sand and gravel deposits of the Quaternary period at a depth of 120–300 m. It is covered by a silty soil layer and local hydrothermal alteration (silica sinter). This shallow reservoir yields wet steam for power generation. The average wellhead working pressure of steam is 0.3 MPa with 150°C in temperature at flow rate of 95 t/h for single well. The proven reserves are 34 MW_e. Besides, deep reservoir is fractured granite. It was completed exploration in 1990s. Its proven reserves are 30 MW_e. Well ZK4001 drilled a depth 1,459 m had wellhead working pressure of 1.5 MPa with a temperature of 200°C and a flow rate of 360 t/h, in which the steam flow rate is 37 t/h.

The developer was concerned that exploiting the deep reservoir would reduce recharge at the shallow reservoir. Therefore they didn't use the deep reservoir until 2008. In 2009 a full flow unit (screw expander) of 1 MW_e started to use the flow partially from well ZK4001. In 2010 another 1 MW_e unit started operation using the same flow. The power station has a total installed capacity of 26.18 MW_e. Its annual power production is about 140 million kWh.

Reinjection tests have been carried out in the Yangbajain geothermal field several times using tail water from the power station. But the injection rate was so small that it was not in a production scale. It was not due to technical difficulties, but due to low-level management and personnel quality. The discharge from the power station was used partly for space heating, greenhouses, and swimming, amongst others, whilst the bigger part was discharged into the surface river of Zangbu. The higher contents of Arsenic (As), (Hydrogen sulphide (H_2S), and Florine (F) have contaminated downstream river.

4.1.A3. Sustainability problem in Yangbajain

The Yangbajain geothermal power station is a contrary example for sustainable development. This is the first practice of high temperature geothermal exploration and development by China. Due to lack of geothermal technicians, no experience, and poor management, a lot of imperfections existed.

Geological reconnaissance and integrated scientific investigation discovered strong surface geothermal manifestations in the Yangbajain area in early 1970s. The first exploration hole was drilled in 1975. But it erupted by high temperature fluid when at 38.89 m depth. The Tibet Geothermal Geological Team was established in 1976, with hydrogeologists but no professional geothermal geologists. They carried out 'seeking heat from heat' tests. Exploration well drilling and power station building were conducted only in the vicinity of natural high temperature manifestations. Well ZK316 was buried after eruption and subsiding. Wells ZK322 and ZK312 were damaged after hydrothermal eruption. Especially, about a decade later, all manifestations including the boiling fountain and hot lake disappeared.

The reinjection of thermal tail water from the power station wasn't carried out properly mainly due to poor skills of the crew team. Reinjection wells weren't disposed in time when partially jammed. Finally the well wasn't able to reinject. Although the surface subsidence was monitored especially for shallow reservoir area, no counter-measures were considered for prevention. (In comparison, the Wairakei geothermal power station in New Zealand was built 2 km away from the geothermal well site. The well site is also far away from the geothermal manifestation area. So their surface manifestations, well site and power station building avoided disadvantageous effects on each other.)

The shallow reservoir has encountered declining pressure and decreasing temperature, which reduced the yield. There was an incomplete daily record, but no reservoir engineering study, no countermeasure and remedy were conducted. In fact, the shallow reservoir exploitation should be shut down in advance, and then transferred into deep reservoir development. However the enterprise did not change, and did not intend to change.

Lessons learned: Causes of failure in sustainability

- Lack of systematic survey: 'Seeking heat from heat' type of exploration.
- Failure in implementing reinjection: The importance of injection was recognised at the start of production but problems related to: 1) poor skills of drilling and operating crew, and 2) scaling in initial injection cools, prevented the successful full implementation of reinjection.
- No prevention of subsidence: Caused abolished well and dry-out of natural manifestation.
- Delay of change in strategy in reservoir management: Although the shallow reservoir encountered pressure and temperature drop, they did not change the production zone into deep reservoir, causing a drastic decline in production.

Figure 4.1-A4. Hot Lake (left) and Boiling Spring (right) before Disappearance in Yangbajain

Source: Photo by Keyan Zheng.

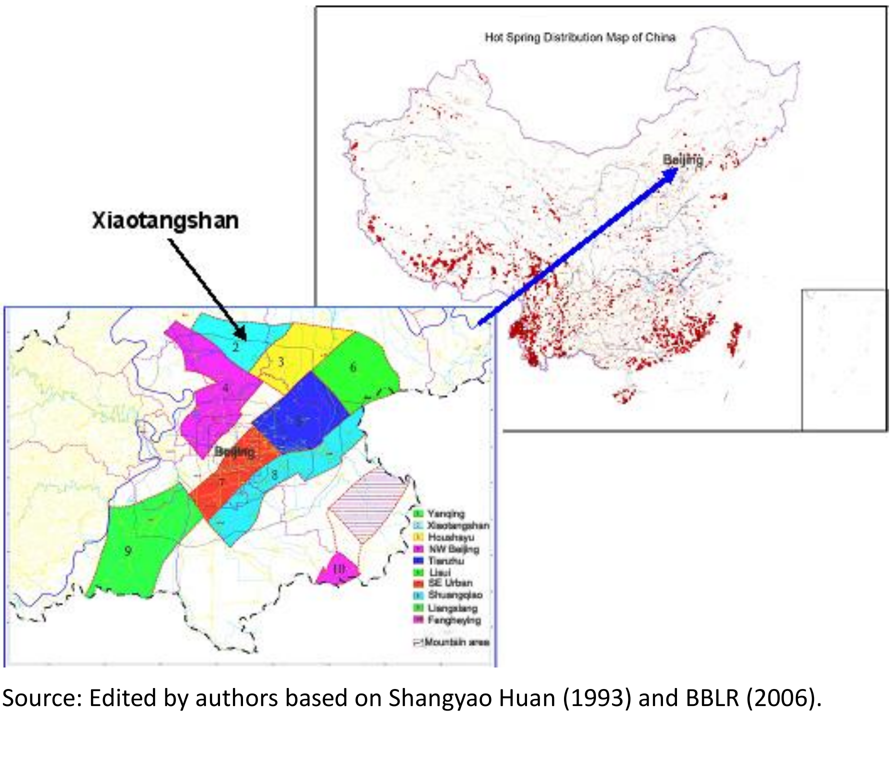
B. Case study on Xiaotangshan Geothermal Field

4.1.B1. History

The Xiaotangshan hot spring had its highest temperature of 53°C. Its earliest historic record is found to be 700 years old in the Yuan dynasty. A later warlord occupied it as a private villa. After liberation in 1948, the Xiaotangshan Hot Spring Sanatorium was built to serve the people. In order to ensure the thermal water supply for physiotherapy, exploration of hot mineral water was carried out in 20 km^2 area from 1956 to 1958 (**Figure 4.1-B1**). The total drilling depth reached 4,281.33 m with deepest depth of 433 m. Finally, 0.6 km^2 of distribution area of 37°C thermal mineral water was delineated. The exploration holes didn't transfer into production wells. The hot springs kept their artesian situation.

More than ten hot springs had existed in Xiaotangshan area, but in the early 1970s the hot springs petered out. In order to maintain a hot water supply, well drilling was started at that time. Thereafter well drilling and exploration enlarged the range, and well depth became deeper and deeper. The deepest well has reached 2,935 m. The highest temperature has been 83°C. There are now 70 or more wells in the field: 34 production wells, ten reinjection wells, two monitoring wells, and other reserved or retired wells.

Figure 4.1-B1. Xiaotangshan Location Map



Source: Edited by authors based on Shangyao Huan (1993) and BBLR (2006).

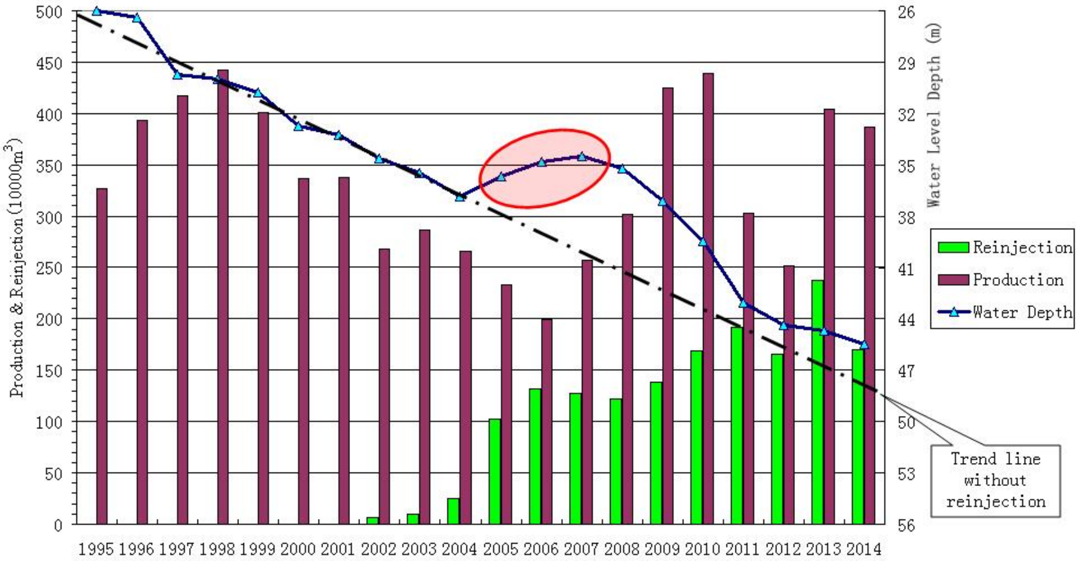
Geothermal resources management has been implemented in the Beijing area. New well drilling needs to be approved in advance. A production well needs injection well(s) which capacity match the production capacity. Geothermal tail water reinjection was started in 2002 in the field when 70,000 m^3 was reinjected that year. It had increased so rapidly that the annual reinjection was 248,000 m^3 in 2004 and was 1,027,000 m^3 in 2005. The reinjection rate reached the scale of production.

Figure 4.1-B2. Lower Water Level of the Eastern Spring (right) and the Western Spring (left) in Xiaotangshan Hot Spring Sanatorium

Note: Water level in the early 1970s.
Source: Photo by Keyan Zheng.

Such reinjection brought enormous positive effects. The thermal water level in the year ensuing is higher than the previous year in the corresponding month. The annual average water level rose three years continuously (**Figure 4.1-B3**). The first year it rose 1.20 m, the second year it rose 0.84 m, and in the third year it rose 0.35 m. The total rise is 2.39 m.

Figure 4.1-B3. Production and Reinjection with Water Level Behaviour in Xiaotangshan

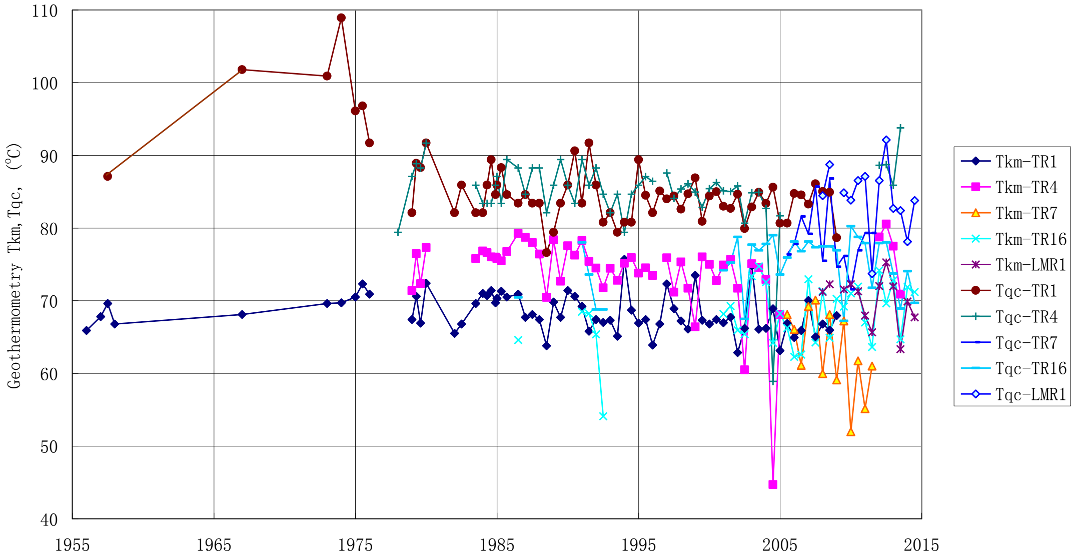


Source: Edited by authors based on the monitoring data from Beijing Geothermal Engineering Institute.

Figure 4.1-B3 shows the relationship among water level behaviour, annual production, and reinjection in the Xiaotangshan geothermal field in the last 20 years. During the first half of the period when there was rare reinjection, the water level showed a continuous declining. While in the latter half of the period, the large scale reinjection caused the water level to rise. (Note that it has not 'reduced the slope of declining' as usually be seen.) The rising trend can be seen as the red circle in **Figure 4.1-B3**. Later years, annual reinjection rate was kept around 1.3-1.9 million m^3, among which the maximum number of 2.38 million m^3 was recorded in 2013. However enlarged production made the water level decline again.

In addition, integrated geothermal monitoring including water chemistry, water level, and water quantity, has been carried out since 1956 in the geothermal field. It is the longest history of geothermal monitoring in China. **Fig 4.1-B4** shows the monitoring of geothermometry during the past 58 years as an example.

Figure 4.1-B4. Behaviour of K-Mg (Tkm) and Quartz (Tqc) Geothermometry in Xiaotangshan



K = potassium, Mg = magnesium.

Source: Edited by authors based on the monitoring data from Beijing Geothermal Engineering Institute.

4.1.B2. Sustainability of the Xiaotangshan Geothermal Field

Xiaotangshan geothermal field could be a typical model for sustainable geothermal development. The area of the geothermal field was 0.6 km^2 trapped in 1958 but it is 168 km^2 now. It has increased 280 times. The total artesian flow of the hot spring was 1.30 million m^3 in 1958. Now the field is exploited about 4.00 million m^3, three times more than before. Geothermal resources management has been carried out in the field. It controlled the water level, even raising the level sometimes.

Sustainable development in Xiaotangshan geothermal field could be kept in the future. Under certain conditions of production and reinjection, the geothermal water level could be controlled within a gentler slope of decline.

Figure 4.1-B5. Installation of Geothermal Reinjection Well in Xiaotangshan Field

Source: Photo by Keyan Zheng.

Lessons learned

- Successful reinjection in production scale may recover water level.
- Monitoring of water chemistry including geothermometry, water level, and water quantity is important.
- Resources management was achieved by water level control.

References

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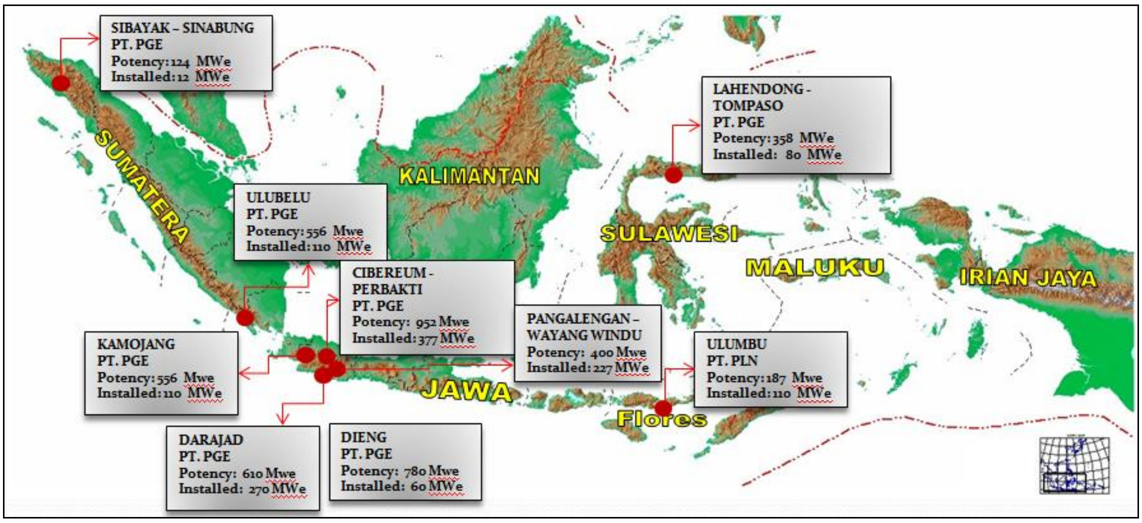
4.2. Indonesia: Summary of Six Geothermal Fields

The purpose of using geothermal energy in Indonesia is to generate electricity. Indonesia generates geothermal electricity from 10 geothermal fields. To do this in Indonesia, continuous supplies of geothermal fluids to power plants are always technical matters of concern. In the Indonesian case study in six geothermal fields, namely Kamojang, Salak, Wayang Windu, Lahendong, Dieng, and Darajat, common technical problems are identified in all components of the production system – in the reservoirs, in the well (production and reinjection), in the pipelines, and in the turbines. The reservoir problems are mainly induced by physical characteristic changes such as temperature and pressure changes. Common well, pipeline, and turbine problems are mineral deposition (scaling) and corrosion. To discuss the sustainable use of geothermal energy from Indonesia's geothermal fields, we divide the topics into energy efficiency, fluid production, fluid reinjection, monitoring activity, and problems encountered. The case study is summarised as follows, and as listed in **Table 4.2-1**.

Figure 4.2-1. Geothermal Power Plants in Indonesia



Source: Compiled by Geological Agency of Indonesia.

Kamojang Geothermal Field

The Kamojang field is a steam dominated system, having been exploited since the 1980s marked by generation of power plant units 1-2-3. Since then, the reservoir temperature decrease due to reservoir fluid mixing with recharged cooler water, is one of the common technical problems. The temperature problem induced a drop in pressure in the reservoir. Physical characteristic changes in the reservoir and other problems such as scaling in production wells caused a decline of geothermal fluid production to about 3–4 percent in average per year. To solve the decline of production fluid, some reserve and 'make-up' wells are provided. In addition, new production zones were identified to ensure the expansion of production.

Ever since the temperature decrease was identified, the reinjection strategy has been always reformulated to avoid mixing problem. Another problem is scaling, occurring in production wells, pipelines, gathering pipes, and also in the turbine. Scaling removal in production wells is done by adding chemical inhibitors.

To maintain steam production, monitoring activity has been applied. The surveillance activity includes quantity of steam produced, the geochemistry of reservoir fluid, microgravity, seismicity, temperature (including logging pressure and temperature (PT) or pressure, temperature and spinner (PTS)), and tracer tests (radioactive tracers, fluorescent dyes, chemical tracers). After 30 years of production, in terms of power plant perspective, concerns have risen related to the improvement of power plant efficiency.

Salak Geothermal Field

The Salak field is a water dominated system with the reservoir temperature reaching more than 300^{o}C. Technical problems encountered are reservoir temperature decrease due to mixing of cooler recharge fluids and boiling, well production decline rate, low permeability of production wells, a large non condensable gas (NCG) percentage (east block), and decrease of turbine output caused by scaling in the turbine (ferrous iron particles and silica).

Exploring new productive zones of the reservoir by using geophysical and drilling works has been done to determine targets for some additional production wells to be drilled as make-up wells in order to maintain steam supply. To increase the production of lower production wells, the stimulation works of low permeable wells have been attempted by using massive water injection, thermally induced cracking, slow-acidizing, and coiled-tubing acidizing.

Since the Salak field is water dominated, it produces big amounts of waste water, and therefore more reinjection wells are needed; 21 reinjection wells existed in 2009. To reduce the reservoir temperature decrease due to mixing problems, a reformulating reinjection strategy was applied.

Scaling in the turbine is removed by the application of a non-oxygenated steam wash system and also a material improvement for the demister element holder and online steam. In terms of the sustainability of the field, especially from a power plant perspective, turbine output was increased from 330 MW_e in 1998 to 337 MW_e in 2012.

To maintain the steam supply, surveillance activities have been done since 1994, that is, quantity of steam produced, geochemistry of reservoir fluid, microgravity, seismicity, and temperature (by using PT, PTS, and geochemistry).

Lahendong Geothermal Field

The Lahendong field is a water dominated system, with temperatures reaching 320^{o}C, and is the first geothermal power plant on Sulawesi Island. The main technical problems in the field are acid geothermal fluid, high chloride content, and high sulphate content in a big productive well. Surveillance activities include quantity of steam produced and short-term micro seismic monitoring.

Dieng Geothermal Field

The Dieng field is located in Central Java, a water dominated system, with capacity of 60 MW_e, and beginning production in 1998. After that production had been unstable, declining rapidly, and the unit was shut down until 2002, but production then dropped below 30 MW_e in 2010–2011. Technical problems observed were unstable power generation and declining rapidly due to problems in the steam production process, power plant performance, silica scaling in the reinjection well and pipeline, sulphide scale in the production well, and the presence of pitting corrosion, dent, erosion, and a crack in the turbine. An increase in the steam production process, plant performance, and reliability, removal of scale by mechanical cleaning, reformulating the reinjection scheme were conducted to increase power production. After several attempts to overcome the problems, the maximum plant load reached approximately 52.56 MW_e in February 2014.

Darajat Geothermal Field

The Darajat field is a dry steam system, located close to Kamojang, with reservoir pressure of 28 bar on average, temperature around 240^oC, and 49 active production wells. The technical problems of the Darajat field are similar to those of the Kamojang field and other systems: well production decline rate, pressure drop, and scaling (silica, and ammonium carbonate). Mechanical cleaning of the well to clean the obstruction in the wellbore and improve the deliverability of the well is common practice. An enhanced geothermal system is now attempted in this field to increase the permeability of the low permeable wells. Another attempt to reduce the flow rate decline was done by optimising the pressure drop around the interface area, a surface facility engineering work. This work was dedicated to increase pressure, hence reduce number of make-up wells. Surveillance activities are of integrated control system, quantity of steam produced, geochemistry of reservoir fluid, microgravity, seismicity, and temperature logging measurement (PT, PTS) using 6 monitoring wells.

Wayang Windu Geothermal Field

The Wayang Windu field is a two-phase system, now producing 227 MW_e from two units, where Unit 1 has been operating since 2000. The main technical problems are reservoir pressure decline and erosion of the turbine. New production wells were needed since the pressure declined. To provide new productive zones, new zones were explored by applying geophysics and well drilling works. Another attempt to provide a greater steam rate was done by applying hydraulic fracturing using cold water (condensate) injection to stimulate more permeability. Output optimisation was also conducted by increasing turbine output from 110 MW_e to 117 MW_e. Monitoring or surveillance activity in the Wayang Windu field consists of an integrated control system, quantity of steam produced, the geochemistry of the reservoir fluid, microgravity, seismicity, and temperature measurement (logging PT, PTS).

Lessons learned

- The most common problems in geothermal power plants are scaling (in production wells, piping, reinjection, and turbines), corrosion (in particular in production wells), and water mixing.
- Chemical inhibitors and mechanical cleaning (workover) are the most common methods to overcome the mineral scaling problems.
- Make-up well is a common practice to maintain steam supply.
- Major surveillance activities are to monitor the quantity of steam produced, the geochemistry of the reservoir fluid, microgravity, induced seismicity, temperature, and chemical tracers.
- Silica sinter problem was reduced by new a production design (by pressure and temperature control).

Table 4.2-1. Summary of Case Study of Six Geothermal Power Plants in Indonesia

Field Name	Energy Efficiency	Fluid Production	Reinjection	Monitoring	Problem
Kamojang: Vapour dominated ~ 245°C	- Life time turbine analysis of Unit 1 (after 30 years production)	- Removing silica scale by using chemical inhibitor - Reserve well and make-up wells to maintain steam supply - Exploring new productive zones (geophysics and well drilling) for expansion of production	- Reinjection well - Reformulating reinjection strategy due to mixing problem	Surveillance activities - Quantity of steam produced - Geochemistry of reservoir fluid - Microgravity - Seismicity - Temperature: PT, PTS - Tracer test: Radioactive tracers, fluorescent dyes, chemical tracers	- Well production decline rate 3–4% per year; - Reservoir temperature decrease: mixing of cooler recharge fluids - Scaling (silica) steam pipeline, gathering pipe and production wells, and turbine - Pressure drop
Salak: Water dominated 240–310°C ;	- Increase turbine output from 330 MW_e in 1998 to 337 MW_e in 2012. - Resolve decrease of turbine output caused by scaling problems: application of a non-oxygenated steam wash system, material improvement for the demister element holder and online steam	- Number of wells: 69 wells used for production in 2009, now some additional well - make-up wells to maintain steam supply - Exploring new productive zones (geophysics and well drilling) for expansion of production - Stimulation of low permeable wells: massive water injection, thermally-	- 21 wells in 2009 - Reformulating reinjection strategy due to mixing problem	Surveillance activities since 1994: - Quantity of steam produced Geochemistry of reservoir fluid - microgravity - seismicity - Temperature: PT, PTS, geochemistry	- Reservoir temperature decrease: mixing of cooler recharge fluids; boiling. - Well production decline rate - A number of wells (10 add wells added 2004–2009) have low permeability; - A large NCG percentage (east block) - Decrease of turbine output scaling in

		induced, slow-acidizing, and coiled-tubing acidizing; - Scale removal: application of a non-oxygenated steam wash system, material improvement			turbine (ferrous iron particles, silica)
Lahendong: Two phase 280–320°C			- Reinjection well	Surveillance activities: - Quantity of steam produced - Short-term micro-seismic	- Acid fluid, high chloride, high sulphate in a big productive well.
Wayang Windu: Two-phase system 227 MW_e, unit 1 operating since 2000	- Increase turbine output	- Exploring new productive zones (geophysics and well drilling) for expansion of production - Permeability stimulation: hydraulic fracturing by using cold water (condensate) injection	- Reinjection well	Surveillance activities: - Integrated control system - Quantity of steam produced - Geochemistry of reservoir fluid - Microgravity - Seismicity - Temperature: PT, PTS	- Reservoir pressure decline - erosion of turbine problem
Dieng: water dominated installed capacity of 60 MW_e	- Steam production process, - Plant performance and reliability	- Production wells productivity - Well workovers were performed using mechanical cleaning combined with a jet pulsation	- Reinjection well - Brine injection scheme - Well workovers were performed using mechanical cleaning combined with a jet pulsation	Surveillance activities - Quantity of steam produced - Scaling rate	- Power generation not stable and has declined relatively rapidly - Performance of steam production process, power plant - Silica scaling in well

					and pipeline as a major problem - sulphide scale in production well, silica scale in reinjection well - Presence of pitting corrosion, dent, erosion, and crack in turbine
Darajat: Dry steam; 28 bar in average; around 240°C 49 active production wells	- Optimisation of the pressure drop around the interface area	- Clean obstructions in the wellbore and improve the deliverability of the well - Enhanced Geothermal System to increase permeability	- One active injection well	Surveillance activities: - Integrated control system - Quantity of steam produced - Geochemistry of reservoir fluid - Microgravity - Seismicity - Temperature: PT, PTS - 6 monitoring wells	- Well production decline rate of ~12.1% per year - Pressure drop - Silica scale in the wellbore - Stopped producing completely due to ammonium carbonate (NH4CO3) scale build up near its wellhead - 20 years of continuous operation, the decline rate is about 9.3%

Source: Compiled by authors.

4.3 Japan: Cold Injection to Superheated Steam Zones

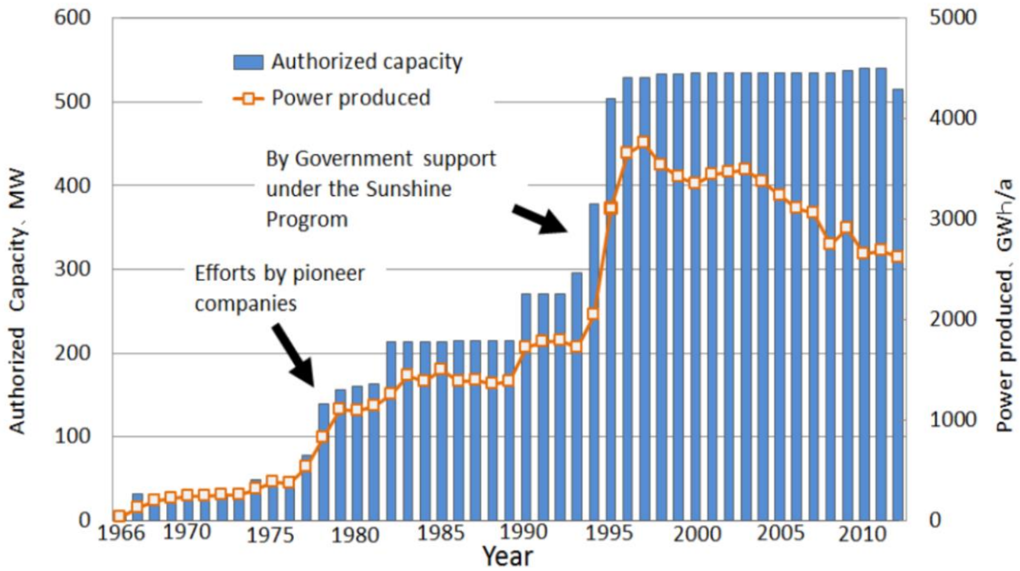
4.3.1. Status of Japan's geothermal power plants

The authorised capacity of geothermal power plants in Japan is about 520MW$_e$ and has been almost the same since 1996. However, the annual power production is gradually decreasing.

The rate of production decrease depends on the site. Several geothermal power plants have rapidly decreased, while others have not. The reasons for decreasing production are mainly as follows:

1) Decreasing pressure or volume of reservoir due to over production rather than suitable production rate.
2) Scaling in production wells or injection wells and decreasing flow rate. In this case, the solution has been to remove scale from wells or drill new wells.

Figure 4.3-1. Geothermal Power Production and Authorised Capacity in Japan

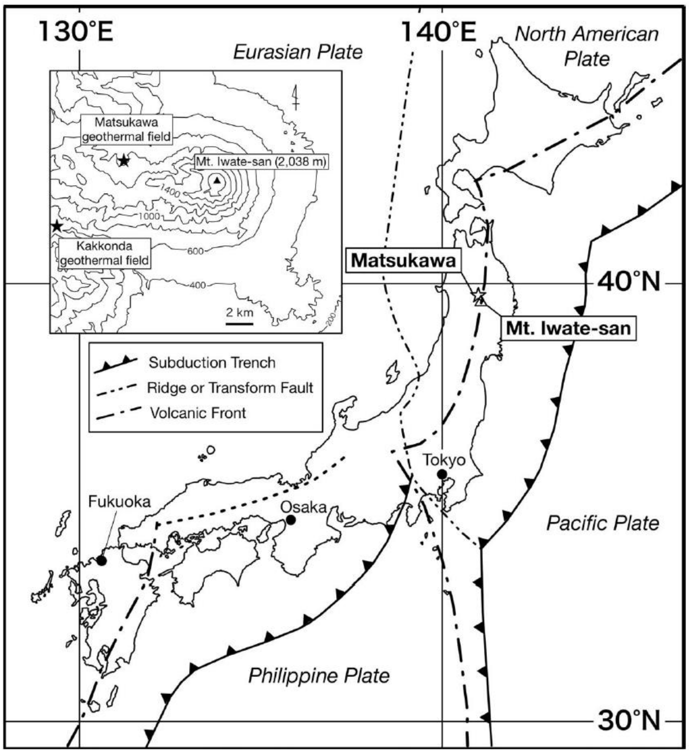


Source: Edited by authors based on TENPES (2014).

4.3.2. Review of injection test at Matsukawa Geothermal Field

The Matsukawa Geothermal Power Station is located near an active volcano Mt. Iwatesan in the Hachimantai volcanic area, northeast Japan (**Figure 4.3-2**). Its operation began in October 1966 with an installed capacity of 9.5 MW$_e$ as the first commercial geothermal power station in Japan. Its capacity was increased gradually up to 23.5 MW_e by June 1993. Matsukawa is known as the only vapour dominated reservoir in Japan.

Figure 4.3-2. Site of Matsukawa Geothermal Power Station

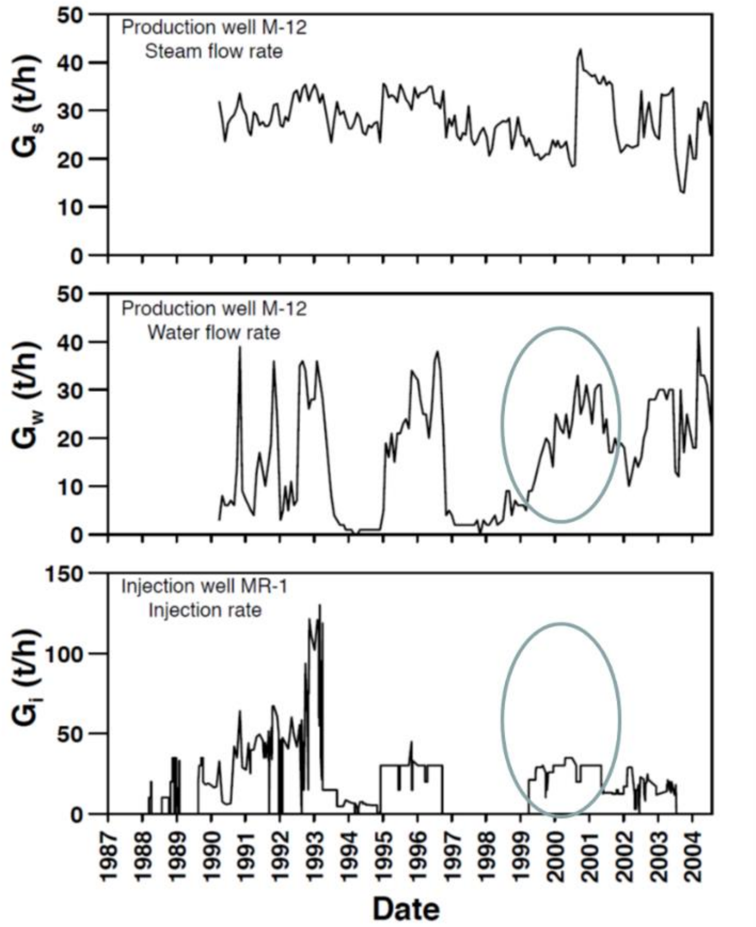


Source: Fukuda et al. (2006).

This geothermal field is situated in a valley and the production wells are distributed along a stream (**Figure 4.3-3**). Since it is a vapour dominated reservoir, no reinjection has been conducted. However, injection of river water was experimentally conducted from 1988 to 2003, aiming at recovery of the reservoir pressure (**Figure 4.3-3**). Although most of the production wells had been producing superheated steam, two of them started producing saturated steam following water injection.

In the Matsukawa geothermal field, the effect of injection to production rate and connectivity between injection well and production well were analysed (Fukuda, et al., 2013). **Figure 4.3-3** shows the relationship between the injection at MR-1 and production at M-12 from 1987 to 2004. In **Figure 4.3-4**, G_s and G_w represent the steam and water production rate of Well M-12, respectively, while G_i represents the injection rate of well MR-1.

Figure 4.3-3. Production History of Well M-12 and Injection History of Well MR-1

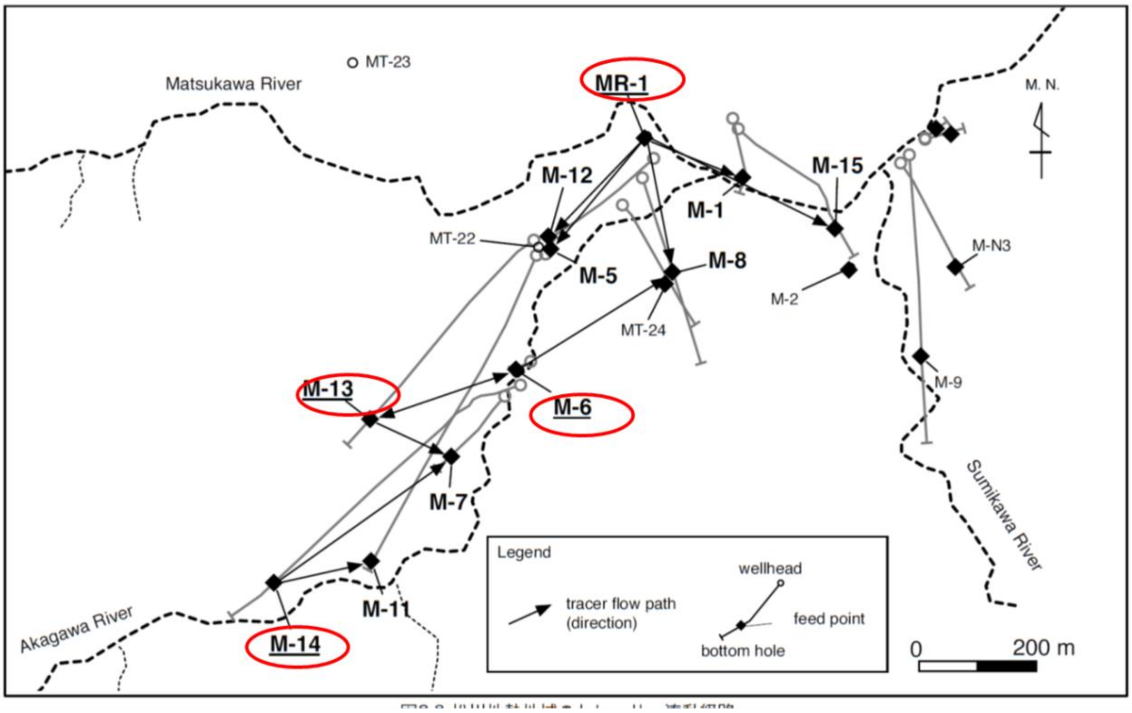


Source: Fukuda et al. (2013).

The increase of production rate at M-12 seems to be synchronising with injection rate of MR-1. The increasing rate of water production is higher than that of steam production. Since tracer return from MR-1 to M-12 is identified (**Figure 4.3-4**) with a return ratio of about 25 percent, the increasing production is recognized as the response of injection.

As for other wells, **Figure 4.3-5** show the relationship between injection well M-6 and production wells M-8 and M-13. In the Matsukawa geothermal field, the steam tends to be overheated steam. In the case of M-8 and M-13, the saturation temperature is around 145^{o}C for the wellhead pressures around 0.45 MPa. The steam temperature of M-8 and M-13 was about 180^{o}C before injection to M-6 and this means that M-8 and M-13 produced over-heated steam.

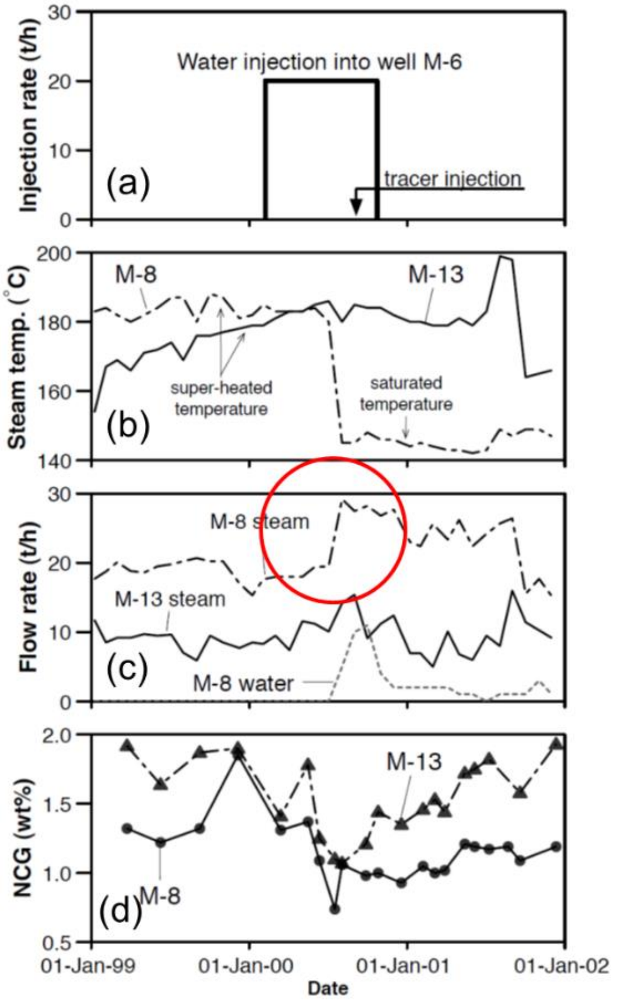
Figure 4.3-4. Tracer Flow Paths in the Matsukawa Geothermal Field



Notes: The arrows, connecting main outflow points of injection wells, and feed points of production wells, express tracer flow paths and directions.
Source: Fukuda, et al. (2013).

In this case, water injection from M-6 started in early 2000 and the injection rate is about 20 tonnes/hour. Six months after beginning of injection, the steam temperature rapidly decreased and the over-heated steam changed to saturated steam. With this change, the steam production increased about 10 tonne/hour with water production. The concentration of non-condensable gas (NCG) decreased 0.7 percent. The return ratio of tracer at M-8 is about 72 percent from M-6. These production rates and chemical components are the result of strong response of water injection. Therefore, after stopping water injection, the production status did not change to that of before injection. On the other hand, the status of production at M-13 did not change as that of M-8. The difference of the response is due to hydrological connection (water paths) between the wells identified by tracer return ratio.

Figure 4.3-5. Relationship Between Injection Well M-6 and Production Wells M-8 and M-13



Notes: (a) Injection History of Well M-6, (b) Steam Temperature, (c) Steam and Water Production Rates, and (d) Non-condensable Gas (NCG) Concentration of Wells M-8 and M-13.
Source: Fukuda, et al. (2013).

Lessons learned

- An over-heated vapour dominant reservoir, such as Matsukawa, showed increasing steam production with water injection.
- Tracer test is one important method for evaluating the production recovery.
- Other over-heated reservoirs and water dominant reservoirs should be checked, and the possibility of the EGS and water injection to maintain geothermal power generation should be discussed.

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4.4. Philippines: Reservoir Management Case Studies of Two Philippine Geothermal Steam Fields for Sustainable Production and Reinjection

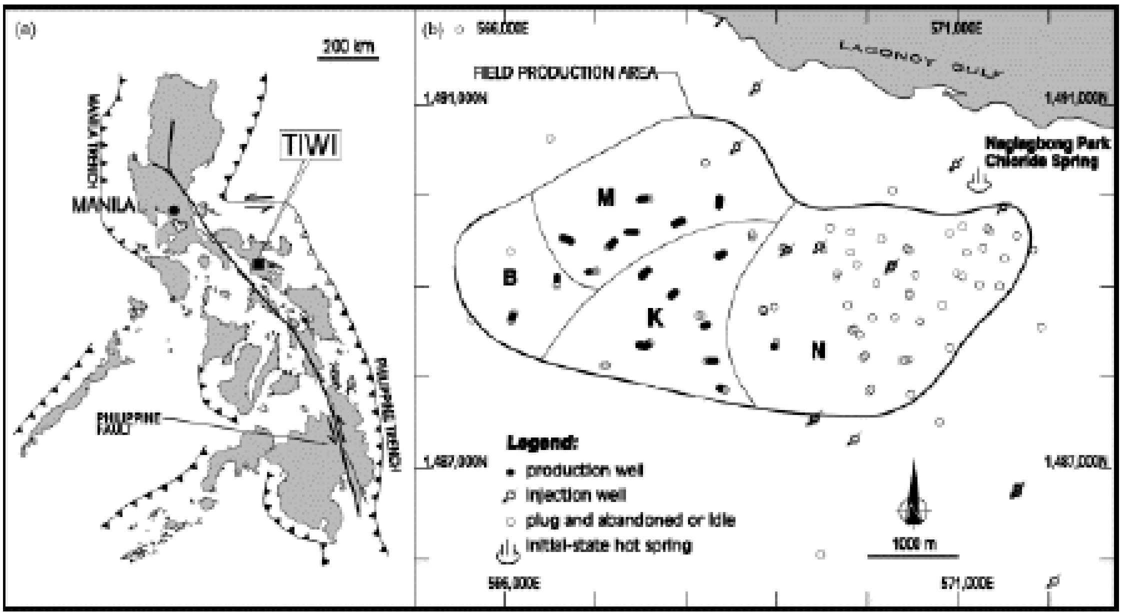
A. <u>Case study on Tiwi Geothermal Field, Albay</u>

(Condensed from Menzies et al. (2010)

4.4.A1. Background

The Tiwi geothermal field is located on the northeast flank of Mt. Malinao in Albay Province, the Philippines, approximately 350 km southeast of Manila (**Figure 4.4-A1**). Commercial operation began on 15 May 1979 with the start-up of the first National Power Corporation (NPC) 55 MW_e unit and over the next three years, the installed capacity was increased to 330 MW_e (Alcaraz, et al., 1989). After 30 years of operation, the total gross generation already reached 49.5 TWh, at an average of 157 MW_e per year. The turnover of NPC power plants to Aboitiz Power Renewables, Incorporated took place on 25 May 2009.

Figure 4.4-A1. Location of the Tiwi Geothermal Field



Notes: N = Naglagbong, K = Kapipihan, B = Barlis, M = Matalibong.
Source: Menzies et al. (2010).

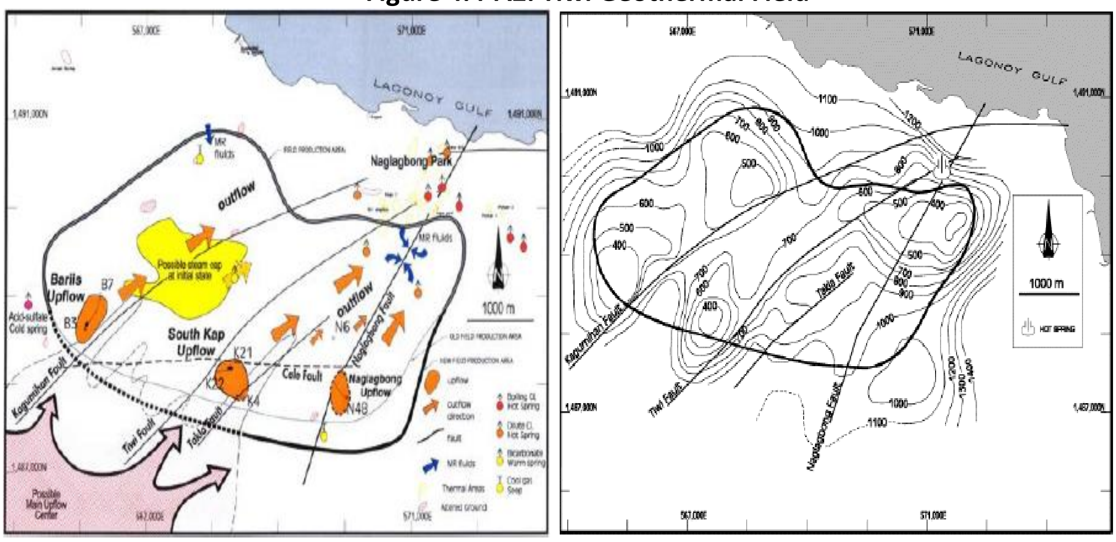
4.4.A2. The Tiwi Geothermal Field: From exploration to development

The commercial potential of the Tiwi field was established in the 1960s. Drilling of the first deep exploratory well, Naglagbong-1, in early 1972 proved the existence of a high temperature resource viable for commercial development, whilst drilling of the succeeding wells was successful in delineating a large reservoir.

4.4.A2.1. Conceptual model

The Tiwi field is divided into four distinct geographic sectors: Naglagbong (Nag), Kapipihan (Kap), Matalibong (Mat), and Barlis (Bar). Results of geochemical, geophysical, and early delineation drilling identified three different upflow zones in the Bar, South Kap, and Nag sectors (**Figure 4.4-A2**). The heat sources are believed to be related to intrusions underlying small dacitic to andesitic domes located south of the Kap and Bar sectors, as well as a broader heat source beneath Mt. Malinao. The Kagumihan and Tiwi faults (**Figure 4.4-A2**) and possibly the Naglagbong fault are main structural controls of fluid distribution. The cap rock overlying the productive reservoir is dominated by smectite clay. It is thinnest in the northeast of the Nag sector, where the reservoir top is shallowest (**Figure 4.4-A2**).

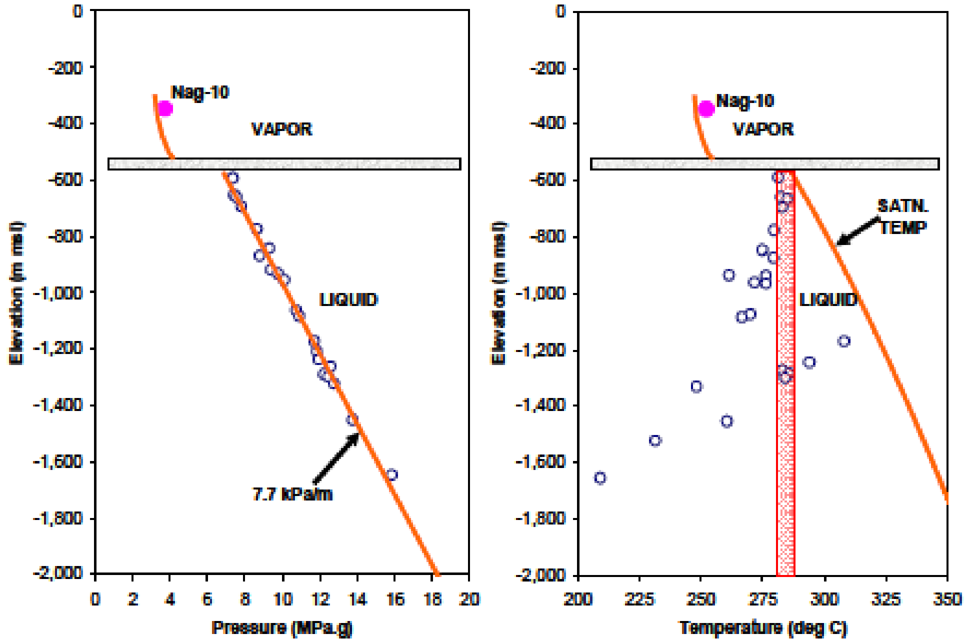
Figure 4.4-A2. Tiwi Geothermal Field



Notes: Initial state conceptual model of Tiwi (left); Reservoir top and major structures in Tiwi Geothermal Field (contours in metres below sea level) (right).
Source: Menzies et al. (2010).

The reservoir was initially an over-pressured (Strobel, 1982) and liquid dominated system (**Figure 4.4-A3**), with an average resource temperature of ~290°C (Sunio, et al., 2004). A shallow steam zone was present in the vicinity of Nag Park (**Figure 4.4-A3**) that was formed by leakage through the cap rock and subsequently expanded due to boiling associated with pressure decline. An extensive steam zone was also encountered in the west (**Figure 4.4-A2**) that was probably formed or expanded by pressure drawdown.

Figure 4.4-A3. Initial Pressures and Temperatures in Naglagbong Sector Wells



Source: Strobel (1982).

4.4.A2.2. Operational highlights

Figure 4.4-A4 shows generation performance from start-up in 1979 to the end of 2008 and steam production from the eastern (Nag) and western (Kap-Mat-Bar) areas of the field. Currently, the field has a baseload capacity of 234 MW_e, with Unit 3 designated as a stand-by plant. Out of the 156 wells drilled in the Tiwi area, 37 wells are presently used for production, whilst 20 wells are used for injection (12 hot and 8 cold). The operational highlights are summarised below:

1979–1984: Initial start-up of the power plants, with production mainly from the Nag area, reaching peak generation of 290 MW_e.

1985–1987: Decline in generation to 170 MW_e due to the impact of meteoric recharge

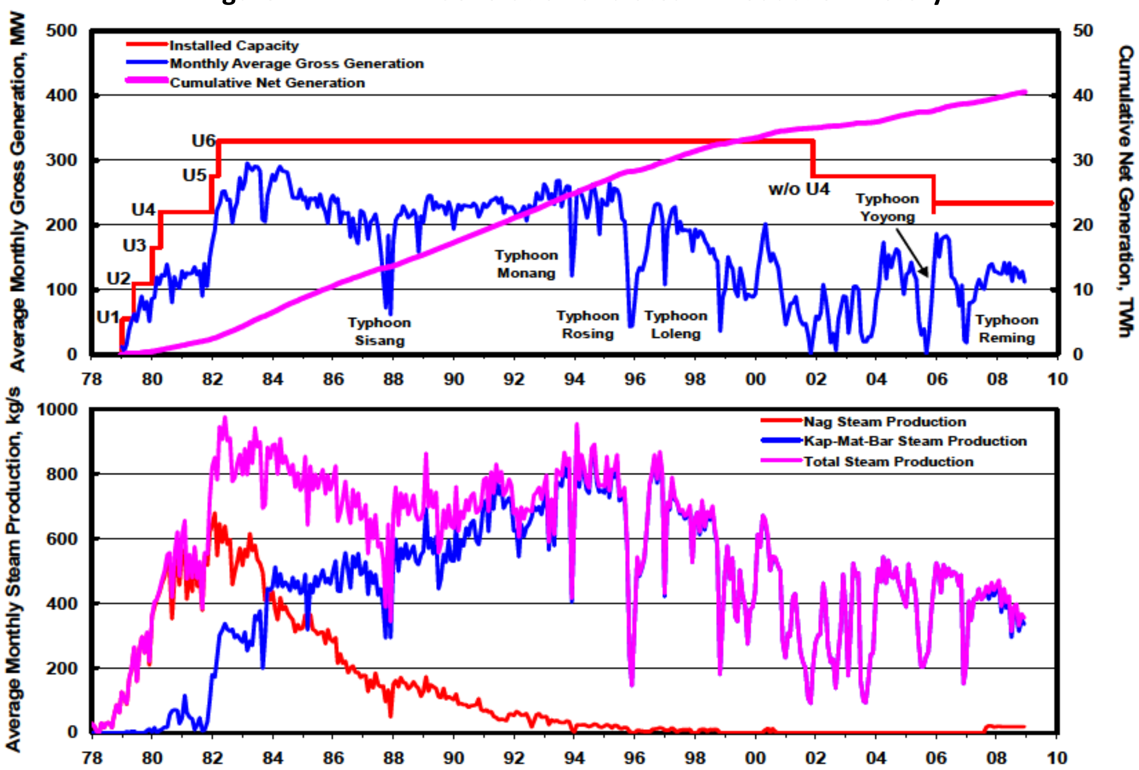
(MR) in the Nag area.

1988–1995: Recovery in generation to 270 MW_e due to continued drilling in the Kap, Mat, and Bar areas and improvements to surface facilities to optimise steam usage.

1996–2004: Low generation and steam production due to decline in base steam supply, lack of make-up well drilling, low steam efficiency due to deterioration of the power plants and plant shut-downs due to typhoon damage and rehabilitation activities.

2005–present: Improvement in steam efficiency as the rehabilitated plants came back on-line.

Figure 4.4-A4. Tiwi Generation and Steam Production History

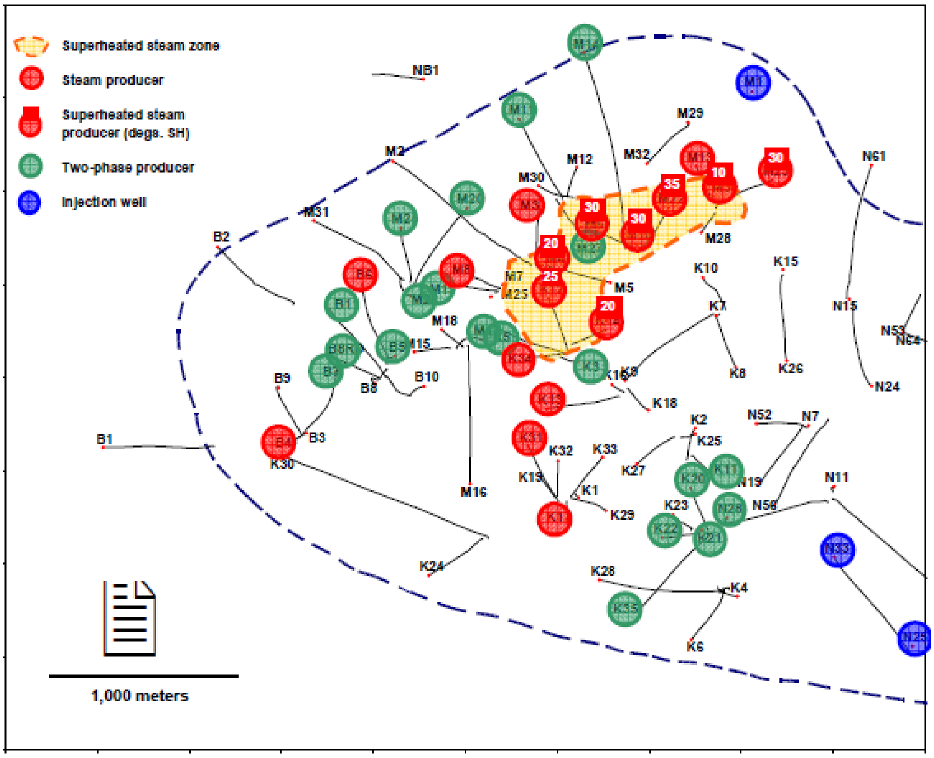


Source: Menzies et al. (2010).

In the initial development of the Tiwi field, the disposal of brine via a canal to Lagonoy Gulf (**Figure 4.4-A1**) caused high initial pressure drawdown. Injection in the Nag sector using existing acidic wells started in 1983 (Santos and Carandang-Racela, 1993) but this resulted in the cooling of nearby production wells. Shifting of injection location then took place, and by 1993 all brine and condensate were being injected at different parts of the field.

The present steam availability is estimated to be 450 kg/s from the 37 production wells (**Figure 4.4-A5**). This is equivalent to ~200 MWe, based on the design steam requirement of 2.25 kg/s-MWe for the rehabilitated power plants with their mechanical gas extraction systems operating. The discharge characteristics of the wells vary widely (**Figure 4.4-A5**) from liquid dominated producers, with enthalpies as low as 1,050 kJ/kg, to superheated steam wells with up to 35 °C of superheat.

Figure 4.4-A5. Tiwi Production Well Locations and Production Characteristics, December 2008



Source: Menzies et al. (2010).

4.4.A3. Current resource challenges

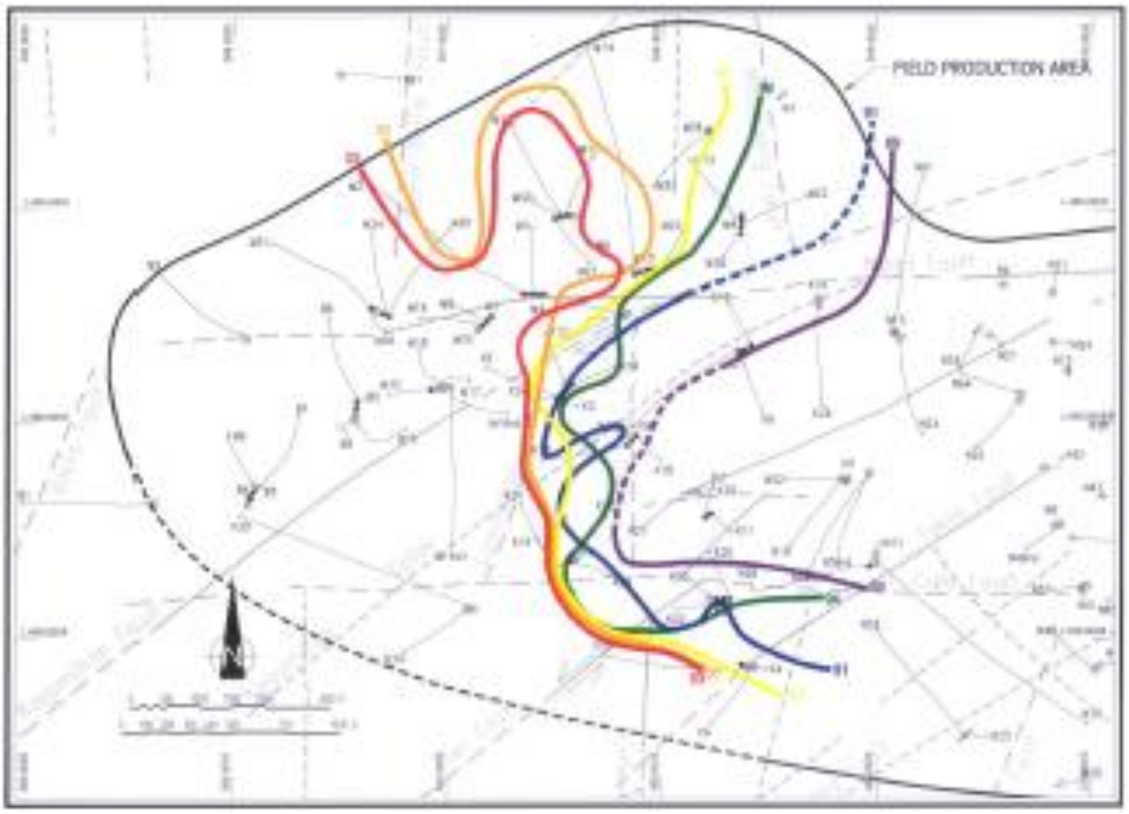
4.4.A3.1. Meteoric recharge

Intrusion of cooler, dilute groundwater in the Nag sector was inferred based on the decreasing Chloride (Cl) content of produced brine (Gambill and Beraquit, 1993) and results of tracer tests using tritium (**Figure 4.4-A6**). Induced by pressure drawdown, this rapid meteoric recharge encroachment caused calcite scaling both in wellbore and formation and resulted in significant reduction in steam supply. Later on, development shifted from Nag to Kap, Mat, and Bar sectors due to flooding with meteoric recharge of the shallow Nag reservoir.

Although a number of wells stopped producing due to the influx of cold meteoric recharge, it is believed that the increasing mass flow at constant enthalpy of some South Kap wells (Kap-20, 21, and 22) is associated with the pressure support coming from meteoric recharge (MR).

Repeat precision gravity surveys are becoming more helpful in tracking MR movement. The natural decline of tritium tracer concentration makes it impractical to use in studying the flow of fluids.

Figure 4.4-A6. Tritium Contours Showing Movement of MR 'Front' with Time



MR = meteoric recharge.
Source: Menzies et al. (2010)

4.4.A3.2. Production of acid-sulphate fluids

Wells drilled in the Bar and Kap sectors, situated in the southwest, and North Mat area were found to produce acid-sulphate fluids. These acidic wells are allowed to flow to the system as long as the discharge fluid pH is ≥ 4.0. The fluid's iron ion (Fe) concentration and potential hydrogen (pH) are carefully monitored as per set guidelines (Villaseñor et al., 1999) to ensure that corrosion is not occurring both within the well and in surface facilities.

Although the attempt to increase the discharge pH by injecting sodium hydroxide through capillary tubing was successful for 3 months (Bar-08), there was no other downhole mitigation system implemented due to the observed scaling in the wellbore and recovered corroded liner during workover.

The recent success of implementing a deep cemented liner strategy in two Bar wells proved that the shallow acid-sulphate zones can be isolated and that the south and southwest acidic areas can now be commercially exploited.

4.4.A3.3. Injection breakthrough

When injection started in 1983, cooling was quickly observed and injection was relocated to the southeast 'edgefield' and 'outfield' wells. Since then, there have not been any significant thermal breakthrough issues. But as a preventive measure, limits have been placed on the allowable injection rates in specific wells and production wells 'at risk' are carefully monitored.

In the Mat area of the field, some of the dry and superheated steam wells have turned two-phase over the past 5 years and there is a possibility this might be associated with injection.

In 2005, the volume of separated brine has increased significantly resulting to a lower overall flash fraction. Hence, there will be a continuing need to review the injection strategy and chemical monitoring, flow testing and tracer testing programmes and look for new injection sites in case of injection capacity shortfall.

4.4.A3.4. Matalibong 'superheated' steam zone

The increased extraction from the Mat area in the early 1990s caused extensive boiling to occur as the pressures declined, forming a reservoir zone that produces 'superheated' steam (Lim, 1997). Along with superheated steam, the wells produced volatile Cl (Sugiaman, et al., 2004), which formed very high, localised, concentrations of HCl that may promote accelerated corrosion in pipelines when condensation takes place. Scaling also occurred where the superheated steam mixed with two-phase fluids in the wellbores and pipelines.

To mitigate corrosion, the Mat-Ridge production system was redesigned to inject sufficient separated brine into the steam pipelines to prevent the high, localised HCl concentrations. This has been effective and with the increasing brine production in recent years, there is no longer a significant risk to the surface facilities.

Since 2001, the Mat superheated steam zone has lost 76kg/s of flow due to the water rising and ‘flooding’ zones that used to produce steam or superheated steam. The rise in water level is due to the combined effect of increasing deep reservoir pressure and declining steam zone pressure.

Both deep reservoir and shallow steam zone pressures are now being monitored to help develop a strategy to maintain production from the steam zone. If the effect of the increasing water level can be reduced, previously affected wells may be able to produce again. However, there will be a risk of MR influx from the field margins if the reservoir pressure becomes too low.

Summary and lessons learned

- The Tiwi Geothermal Field has been affected by a number of resource management challenges including meteoric-water influx, injection breakthrough, acid fluids utilisation, scaling and corrosion.
- The biggest challenge was the influx of MR in the Nag area, which necessitated the relocation of the entire production system. Repeat precision gravity survey is becoming useful for monitoring.
- To prevent detrimental effects of injection breakthrough, relocation of infield to edgefield and outfield injection was an effective strategy in the Nag area. Production wells at risk are carefully monitored and allowable injection rates are limited for specific injection wells to avoid cooling.
- As for mitigating corrosion attack from acidic fluids, the new well design with a cemented blank liner run to below –1,000 m msl was proven effective to case-off potential acid zones.
- For controlling superheated steam zones, pressure balance of shallow steam zone and deep reservoir is essential and pressure monitoring in these zones are important.
- The key to overcoming these challenges is to have a strong multi-disciplinary resource team in-place that understands the problems and can provide feasible solutions.

B. Case study on Tongonan Geothermal Field, Leyte

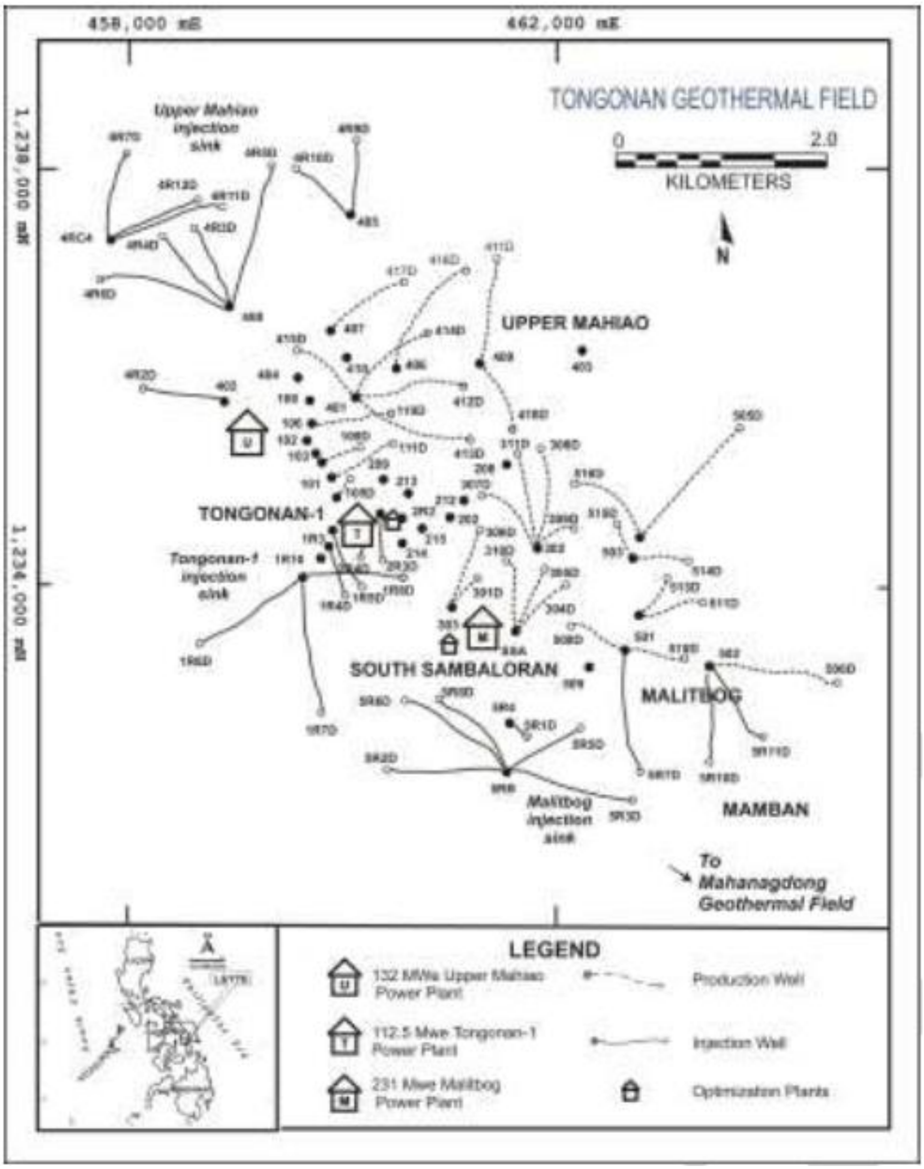
(Condensed from Dacillo et al., 2010)

4.4.B1. Background

The Tongonan Geothermal Field (TGF) in Leyte, Philippines has achieved 30 years of continued sustainable production. The TGF is one of the hydrothermal systems encompassed by the Leyte Geothermal Production Field (LGPF), one of the largest wet steam fields in the world. The LGPF is located along the northwest trending chain of Quaternary volcanoes that runs parallel to the Philippine trench and lies on a bifurcation of the Philippine Fault.

The developed production area of the LGPF draws from two distinct hydrothermal systems—the TGF and Mahanagdong, which are separated by the low permeability Mamban block. The TGF itself is divided into four production sectors—Upper Mahiao, Tongonan-1, Malitbog, and South Sambaloran—supplying steam to three power plants (**Figure 4.4-B1**). The oldest of the plants is the 112.5 MW_e Tongonan-1 Power Plant, which came online in 1983. From 1995 to 1996, the Upper Mahiao and Malitbog plants came online with installed capacities of 132 and 231 MW_e, respectively. By 1998, optimisation plants in the form of an 18 MW_e topping cycle plant in Tongonan-1 and a 15 MW_e bottoming cycle plant Malitbog were installed, bringing the total installed capacity of TGF up to over 508 MW_e.

Figure 4.4-B1. Well-track Map of the Tongonan Geothermal Field

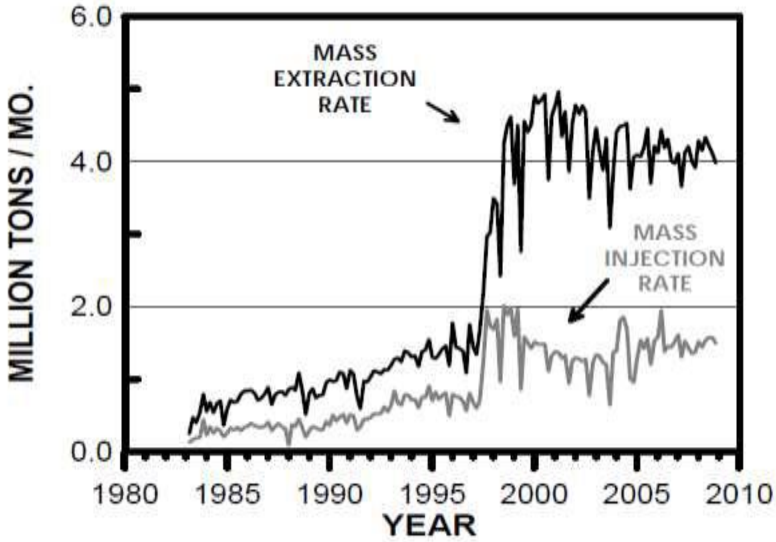


Source: Dacillo, et al. (2010).

4.4.B2. Effect of extraction and reservoir management strategies

From the commissioning of Tongonan-1 in 1983 until right before production was expanded in 1996, the TGF experienced a total pressure drawdown of 0.5 to 1.5 MPa. The increase in production caused a subsequent increase in the rate of pressure drawdown. Being a wet steam field and with the zero effluent disposal policy of the Philippine government, the increase in mass extraction also meant an increase in the rate of brine and condensate reinjection (**Figure 4.4-B2**). The combination of these led to reservoir processes that had a direct impact on steam production.

Figure 4.4-B2. Monthly Total Mass Extraction and Injection (in million tonnes per month)

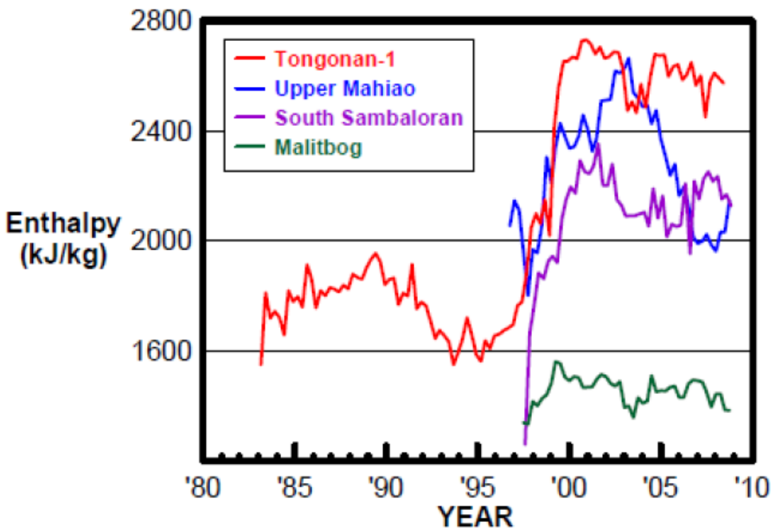


Source: Dacillo, et al. (2010).

4.4.B2.1. Pressure drawdown and boiling

With pressure drawdown came boiling and expansion of the two-phase zone in the reservoir, which brought about an increase in the enthalpy of most wells (**Figure 4.4-B3**). The phenomenon was also observed during flowing surveys and as shifts in the gas equilibria. While boiling led to an increase in overall steam available, it also brought about the problem of increased solids discharge that contributed to erosion of the casings.

Figure 4.4-B3. Average Enthalpy of the Different Sectors of the Tongonan Geothermal Field



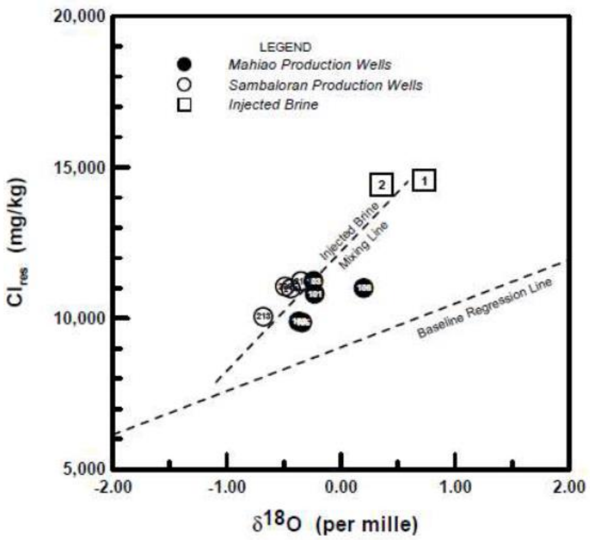
Source: Dacillo, et al. (2010).

Despite the increase in enthalpy in most of the production wells, a number of other wells did not show evidences of boiling or manifested declining enthalpy. As the depressurisation of the main production area and its surroundings resulted in boiling, it also created a pressure sink that draws fluids from the relatively higher pressure peripheral areas and injection sectors. Effects of injection returns and cooler fluid inflow were observed in a number of wells in the field.

4.4.B2.2. Injection returns

A decrease in the gas concentration and an increase in salinity of the discharge of wells are evidence of the production fluids mixing with the degassed and highly saline injected brine returns. Enrichment of the fluids in both chloride and ^{18}O isotope provided an estimate of how much injected brine mixed with in-situ fluids. Naphthalene disulfonate (NDS) tracer tests confirmed the connection of these wells with the brine injection sectors (**Figure 4.4-B4**).

Figure 4.4-B4. ^{18}O and Cl Enrichment in Production Wells due to Incursion of Injected Brine from Tongonan-1 Injection Sink

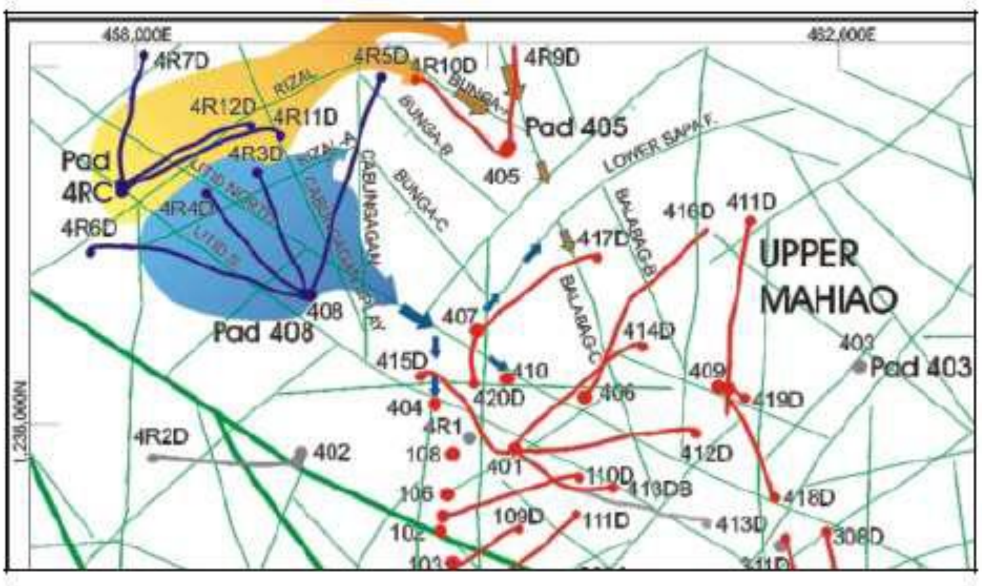


Note: The regression line represents the baseline distribution of oxygen eighteen (^{18}O) and Chloride (Cl) among the Tongonan-1 production wells prior to entry of the injected brine.
Source: Dacillo, et al. (2010).

The identification of brine returns affected wells and results of tracer tests led to changes in reinjection strategies. Transferring RI load away from the main production area to more peripheral areas allowed for the recovery of the affected wells. For example, when most of the injection load of Sambaloran wells was transferred to the Mahiao injection wells in September 1995, the increasing salinity and decreasing gas concentration of affected wells began to revert to in-situ levels by October 1995. Another method is to reinject deeper so as to sufficiently reheat the injected brine in the deeper part of the reservoir. A case of this is the transfer of brine injection from 1R8D to the nearby deeper 1R9D.

It should be noted that the impact of injection returns is not all detrimental to production. Injection provides mass recharge to the highly two-phase reservoir and the additional liquid component helps mitigate the erosive effects of solids discharge in steam-dominated flow. The mass recharge from injection returns can also prevent the influx of cooler fluids such as condensate injection by creating a thermal and pressure barrier. This principle was used to manage the effects of condensate returns on Pad 405 wells through controlled injection in Pad 408 (**Figure 4.4-B5**).

Figure 4.4-B5. Flow Model of Condensate from Pad 4RC and of Injected Brine from Pad 408 based on Tracer Studies and Geochemical Data



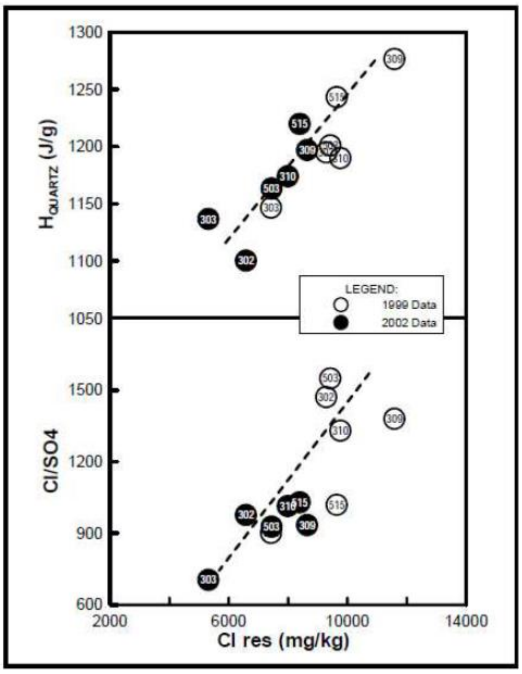
Notes: Pad 4RC = yellow area, yellow arrows; Injected Brine from Pad 408 = blue area, blue arrows
Source: Dacillo, et al. (2010).

4.4.B2.3. Cooler fluid inflow from peripheral areas

The cooler fluids from the peripheries of the field are dilute, sulphate-rich, and slightly more acidic than the in-situ fluid of the production wells. The wells affected by cooler fluid inflow therefore discharge lower enthalpy, less saline, and lower Cl/SO_4 ratio fluids (**Figure 4.4-B6**).

The effects of cold inflow were mitigated with the use of sacrificial wells. Sacrificial wells are strategically located wells that can preferentially draw in these cooler fluids when discharged. Sacrificial wells are continuously discharged to silencers. The discharge of sacrificial wells brought about significant enthalpy and steam flow recovery in cold inflow affected production wells. Though the enthalpies of affected wells were not fully recovered, they have stabilised.

Figure 4.4-B6. Plots Showing Dilution and Cooling of Production Wells due to Inflow of Cooler Peripheral Fluids



Source: Dacillo, et al. (2010).

4.4.B2.4. Mineral deposits

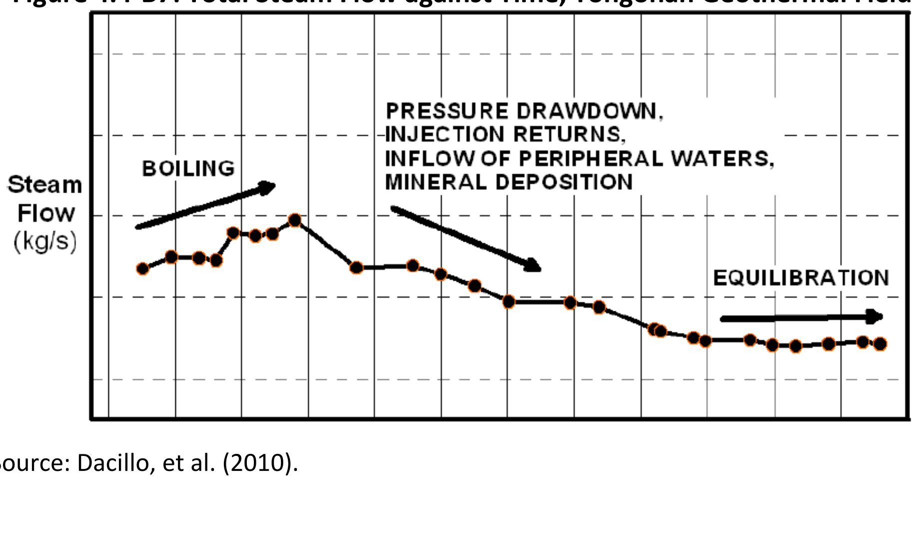
A phenomenon that derives from the encroachment of injection returns is mineral deposits in production wells affected by brine injection returns that are close to the areas with massive boiling. Since the chemistry of the injected brine has higher silica than the in situ geothermal fluid, it more easily becomes supersaturated in silica when boiled. It is postulated that as the silica-rich brine moves to the centre of the production field, it mixes with the two-phase fluids and begins to flash, increasing the silica saturation index. Production wells that are affected by mineral deposits have high output decline rates due to the constriction of the wellbore with silica scales. Silica scale ejecta recovered from the wells are evidence of this phenomenon.

Mechanical clearing workovers with rigs are usually performed to recover the output of wells with significant scaling. There are instances when a recovery of up to 4 MW_e can also be achieved by vertical clearing discharge from a high initial pressure. In this case, the force of the discharge is sufficient to dislodge the built-up scales. In the long term, deep injection ensures that injected brine mixes with the hotter, deep geothermal liquids. Mixing in the liquid state reduces the rate of further deposition.

4.4.B3. Results of resource management strategies

Negative effects on the production of reservoir processes due to massive extraction were eliminated or controlled through monitoring and good resource management strategies. The increase in steam supply due to massive boiling that was observed from 1999–2000 was soon offset by the effects of pressure drawdown, injection returns, inflow of peripheral waters, and mineral deposits. The combined effects of these reservoir processes resulted in the gradual decline in steam availability from 2000–2005. The mitigation measures implemented in the field have arrested this decline since 2006 (**Figure 4.4-B7**).

Figure 4.4-B7: Total Steam Flow against Time, Tongonan Geothermal Field



Source: Dacillo, et al. (2010).

Concluding remarks and lessons learned

- The experiences in TGF have shown that proper resource management and well intervention are effective in sustaining field generation.

- Though the effects of pressure drawdown due to extraction are inevitable, the negative impacts on steam flow production can be controlled.
- Some of the strategies used in TGF and described in this work are:
    - Optimisation of injection loading so that the benefits of mass recharge and pressure support are balanced against the drawbacks of cooling and mineral deposition;
    - Use of sacrificial wells to redirect cold natural recharge away from the depressurised production area; and
    - Well intervention techniques to address decline in production due to mineral deposition within wellbores.
- Careful monitoring of reservoir conditions through geochemical and reservoir engineering data were found to be useful in developing sound resource management strategies.
- As production continues, integration of the different data available will lead to continuous refinement of these strategies or even replacement with better methods.
- With sound resource management, TGF may be able to sustain production for another 25 years.

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4.5. Thailand: Fang Binary Power Plant and Multi-purpose Use

Many geothermal hot springs in Thailand are located along the Thai-Malay plate, western part from North to South, and almost always associated with granitic rocks. It has been reported that hot springs can be used either directly or through electricity generation, depending on factors including characteristics of the springs, temperature, flow rate, reservoir size, and structure (Lund et al., 1999). Many sites of hot springs in Thailand are currently used for various purposes including recreation and tourism. The development of geothermal energy in the future will emphasise joint investment between the community and the private sector to promote sustainable development and participation of local residents. The total of 112 hot springs have been found in most regions of Thailand except the northeast. Water temperatures on the surface level range between 40–100^oC and most of the hot springs originate from granite, especially along the fault line, in the northern provinces such at Mae Jan in Chiang Rai and Fang in Chiang Mai.

Geothermal development in Thailand was formulated in 1981–1984 by a joint technical cooperation project between the Bureau de Recherches Geologiques et Minieres (BRGM) of France and the Electricity Generating Authority of Thailand (EGAT). The purposes were to model a geothermal reservoir and to appraise geothermal enthalpy targeting electricity generation. The first geothermal power plant in Thailand, using binary cycle, was installed and completed on December 1989 in Fang, Chiang Mai province. The inlet vaporiser temperature, after passing through an air released tank, varies between 115^oC to 120^oC and the temperature of the hot water released from the vaporiser outlet is approximately 80^oC. The thermal waters released from the power plant, since these are clean, are planned to be exploited downstream for non-electrical utilisation. This is a single-module 300 kW_e plant that has a water cooled condenser. Although the capacity of the plant is 300 kW_e, the net power output varies with the seasons from 150 to 250 kW_e (175 kW_e average). This is multipurpose, which in addition to electricity production, the geothermal fluid also provides hot water for refrigeration (cold storage), crop drying, and spa. The refrigeration and crop drying systems were running for 20 years (1989–2009) but have now stopped running due to operating and maintenance costs. The artesian well provides approximately 8.3 litter per second (L/s) of 116°C water. The wells require mechanical cleaning to remove scale every six months. The estimated power cost is from 6.3 to 8.6 cents/kWh, which is competitive with 22 to 25 cents/ kWh diesel generate electricity engine. The operation and maintenance costs of the project was cheap and also has a longer durability. Electricity output from the plant is connected to the local distribution grid system of the Provincial Electricity Authority and provided 1.2 million kWh annually. The binary system was support by ORMAT International, Inc.

Lessons learned

- Mineral scaling problem is solved by chemical or mechanical cleaning to sustain system's operations.
- The operating cost of the geothermal project was three times cheaper than production from fossil fuel, with several times cheaper maintenance cost and longer durability, which may be an important factor for sustainable use in commercial sense.

Reference

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4.6. Subsidence in New Zealand Fields

Extensive study has been done in New Zealand for the sustainable use of geothermal resources. Here a paper on subsidence is introduced. Although the environmental aspect is not a scope of our project, a study on subsidence is shown here because it is strongly related to reservoir management and is not included in case studies in former sections.

Subsidence anomalies in Wairakei and other geothermal fields in New Zealand are summarised in **Table 3.2.6-1**. It shows that the subsidence in these fields are gradually stabilising with time. According to Bromley, et al. (2015), the key factors of subsidence are shallow geology distribution, injection depth, and time. Note that injection into the steam cap caused more serious subsidence than that caused by shallow production.

Lessons learned

- Region of subsidence is strongly related to geology: clay in shallow subsurface.
- The initial subsidence was caused by mass production, but the major (ten times larger) subsidence was due to pressure drop by injection into steam zone.
- Subsidence rate was stabilised by deep injection (stop shallow injection), but slow subsidence is continuing due to creep phenomenon triggered by early injection.

Table 4.6-1. Summary of Subsidence Anomalies in New Zealand Geothermal Fields

Field and Bowl	Total (m)	Max rate (mm/yr)	Year max	Current rate (mm/yr)
Wairakei Valley	15	500	1974	50
Ohaaki West	6	400	1994	170
Tauhara – Spa Valley	3	110	2005	110
Tauhara – Crown Rd	1	60	2004	20
Kawerau	0.75	50	2012	50
Mokai (injection)	0.2	30	2009	10
Rotokawa (injection)	0.2	50	2007	10
Ngawha	0.03	3	2012	3

m = metre, mm/yr = millimetre per year.
Source: Bromley, et al. (2015).

References

Bromley, C.J., S. Currie, S. Jolly, and W. Mannington (2015), 'Subsidence : An Update on New Zealand Geothermal Deformation Observations and Mechanisms', *Proceedings of the World Geothermal Congress 2015.*