INSIGHT INTO MODERN GEOTHERMAL RESERVOIR MANAGEMENT PRACTICE

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ABSTRACT

The non-renewability, at human time scale, of geothermal energy sources arises the critical problem of the longevity of reservoir exploitation and sustainable mining of the steam/heat in place.

The present paper reviews the key issues involved in sustainable development and management of geothermal resources, such as reservoir performance, well and reservoir life. Those address relevant methodologies among which reservoir production engineering, water injection and risk assessment take an important share. Last but not least the impact of so called externalities is also discussed

The foregoing are illustrated in a selected case study addressing the Paris Basin geothermal district heating scheme, and concluded by the simulation of future exploitation trends and reservoir pressure/temperature patterns over a 75 year life projection.

Keywords: geothermal energy, reservoir simulation, risk assessment, sustainability, Paris Basin

1. INTRODUCTION

Once a geothermal resource has been identified and the reservoir assessed leading to a conceptual model of the geothermal system, reservoir development and relevant management issues come into play.

In the broad sense, reservoir management is an extension of reservoir engineering. Whereas the latter addresses key issues such as heat in place, reservoir performance, well deliverabilities, heat recovery, water injection and reservoir life, reservoir management aims at optimised exploitation strategies in compliance with technical feasibility, economic viability and environmental safety requirements.

Reservoir management involves also resource management, a matter raising growing interest in the perspective of sustainable development of alternative, preferably renewable, energy sources as highlighted by the debate on Global Warming/Climatic Changes and recommendations of the recent World Environmental Summits (Kyoto Protocol) reducing greenhouse gas emissions.

The foregoing arise the crucial question on whether geothermal heat is a renewable energy source. It is not, at human time scale, for the simple reason that the heat is abstracted from the reservoir via convection and supplied by conduction.

Hence longevity of heat mining should be sought through properly balanced production schedules and designed water injection strategies in order to achieve sustainability. This is indeed a challenging accomplishment, in which reservoir/resource management takes an important share.

The present paper reviews: (i) the main headings involved in the sustainable development and management of geothermal reservoirs (reservoir performance, well/production system/reservoir life, market penetration), (ii) the associated investigation/assessment methodologies (reservoir/production engineering, water injection, tracer surveys, geothermochemistry, reservoir simulation, risk evaluation, and (iii) related requirements (operation/maintenance, monitoring, well design, surface processes, corrosion/scaling abatement, model forecasts). Alongside economics/financing and legal/institutional implications, the impact of non-straightforwardly quantifiable barriers and benefits (social acceptance and clean air concerns among others), the so-called externalities, are also discussed.

Those are illustrated in a selected case study borrowed to a low enthalpy carbonate reservoir of regional extent, located in the Central part of the Paris Basin, long exploited for the supply of base load geothermal heat to ca. thirty five (as of year 2002) district heating grids.

As a conclusion it will exemplify the behaviour of a, locally representative, district heating scheme over a seventy five year life span using a versatile reservoir simulation code.

2. RENEWABILITY VS. SUSTAINABILITY. A HISTORIC OVERVIEW.

Direct uses of geothermal heat from hot springs and fumaroles are as ancient as human societies if not mankind.

Industrial utilisation of geothermal fluids, under the form of power generation and (mainly district) heating, dates back to the early and mid 1900s respectively.

It enabled a better understanding of geothermal systems, leading to comprehensive generic models accepted nowadays by the geothermal community and applied accordingly in scientific and engineering practice.

Worth recalling in this respect are the most significant milestones of this conceptual evolution, brilliantly summarised by Ramey [1].

Visual manifestations of geothermal heat such as, the most spectacular, geysers and fumaroles had long raised the interest of the scientific community. A magmatic origin of geothermal fluids, among which the once popular juvenile water concept, was first advocated. This theory was defeated since geochemical measurements proved the sampled waters were meteoric. Hence, geothermal systems being subject to meteoric recharge they could be regarded as an inexhaustible and renewable source of energy, provided they were produced below the natural recharge rate. This theory became soon popular and remained such for quite some time.

Measures carried out on hot springs and shallow (100 to 200 m) wells of the Geysers fields, California, contradicted this belief. They proved that high pressure steam had no communication whatsoever with spring waters. Therefore the steam was considered as trapped. Further evidence was brought here by the pressure depletion noticed since commercial development started in the 1960s and which resulted later in a drastic drop of steam production. A similar trend had been already noticed on the Larderello field, Tuscany, where electricity production from geothermal steam was initiated in 1904.

The Larderello and Geysers fields are vapour dominated systems hosting dry superheated steam, a distinctive singularity in the world geothermal energy spectrum. As a matter of fact the most frequently encountered high enthalpy (i.e. eligible to steam production) systems belong to the liquid dominated type, either two phase (a steam cap overlying liquid water) or single phase, compressed, liquid (the steam is flashed in the wellbore) reservoirs. A major part of the power generated worldwide from liquid dominated settings comes from lithospheric subduction zones/volcanic island arc environments [2].

The first liquid dominated system was developed at Wairakei, New Zealand, in the 1940s. Here again a regular pressure decline with production could be observed. It pioneered modern geothermal reservoir engineering practice.

Low enthalpy (i.e. eligible to non-electric, direct, uses) reservoirs are of compressed liquid type. The most important developments addressed the large scale geothermal district heating schemes implemented in Rejkjavik, Iceland, in the 1950s, and the Paris Basin, France, in 1969, the latter illustrating the well doublet design of heat mining.

Pressure decline and heat depletion with continued steam and heat production arises the crucial problem of reservoir life, a main concern for geothermal reservoir engineers and managers.

The minimum lifetime assigned to the exploitation system is that required to achieve return on invested capital, according to given economic criteria (the usual Discounted Cash Flow –DCF- analysis and related ratios, Pay Back Time – PBT -, Internal Rate of Return – IROR – and Net Present Value – NPV), taking into account the uncertainties provided by a risk analysis. This is the basic entrepreneurial approach long adopted until the advent of sustainability, a concept largely inspired by the environmental consequences of global warming and climatic changes,

The maximum life should comply to the original definition of sustainability, issued in 1987, quoted by Rybach: [3] *"Meeting the needs of the present generation without compromising the needs of future generations"*.

As regards geothermal energy this means practically the ability of a geothermal heat mining system to secure production over very long times [3].

Thus far, achieving sustainable development of an exhaustible resource, meeting the requirements of economic viability, is what engineering and farsighted management of geothermal reservoirs is all about.

Worth mentioning here is that, further (prior in several instances) to reservoir depletion, geothermal operators have already devoted significant efforts, in the Geysers, Larderello, Paris Basin fields among others, toward water (re)injection, a major issue of sustainability developed later in this paper.

The general approach to sustainable reservoir management strategies is summarised in the Fig. 1 diagram.

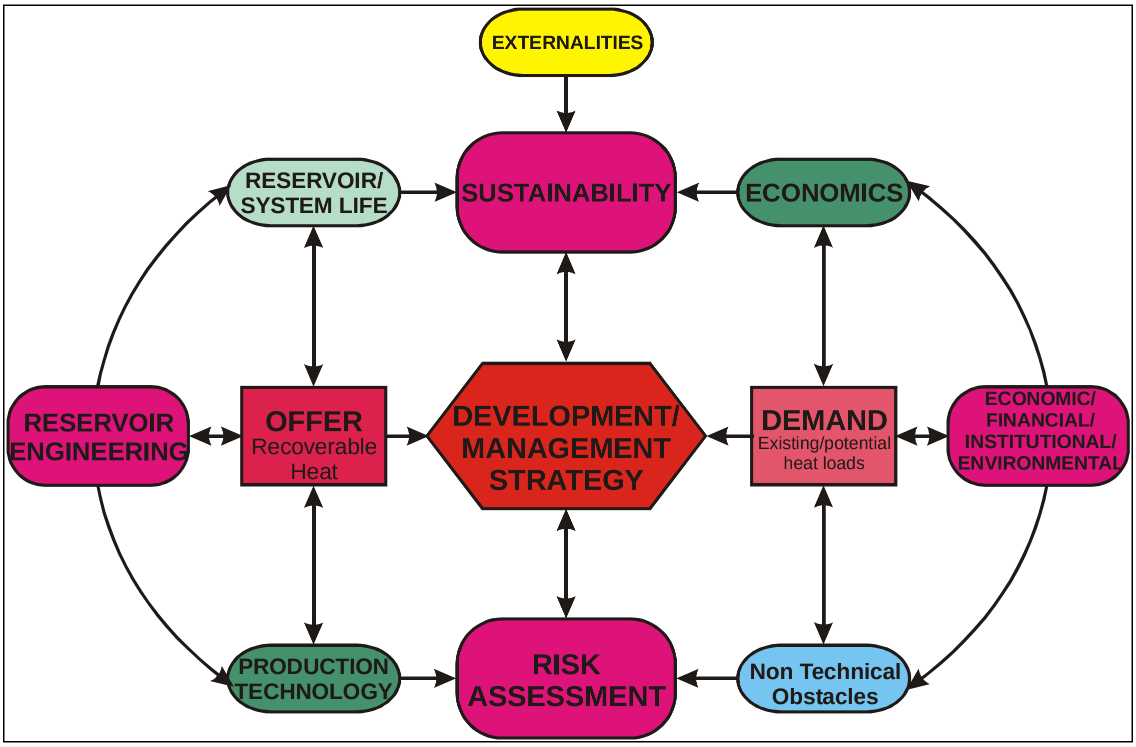


Figure 1: Reservoir management diagram

3. HEAT MINING ISSUES

The issues involved relate to heat in place, well deliverabilities, heat recovery, efficiency of the heat extraction system and reservoir life/heat resupply.

For the sake of simplification it is assumed here that the reservoir is homogeneous, of constant thickness and the fluid in compressed liquid state (low enthalpy resource).

3.1 Heat in place

The heat in place, referred to the mean annual outdoor temperature T_e, is expressed as:

$$G = \gamma_t (T_0 - T_e) Ah \qquad (1)$$

where:

$$\gamma_t = \phi \gamma_f + (1 - \phi)\gamma_r \qquad (2)$$

is the total (rock+fluid) heat capacity, γ_f and γ_r the rock and fluid heat capacities (J m^{-3} °C^{-1}), ϕ the porosity, T_0 the geothermal reservoir temperature (°C), A and h the reservoir areal extent (m^3) and thickness (m) respectively.

3.2 Well deliverability

The thermal power W(kW$_t$) available at wellhead is given by:

$$W = Q\gamma_f (T_0 - T_r) = Q\gamma_f \Delta T \qquad (3)$$

where Q is the well discharge rate (m^3s^{-1}) and T_r is the rejection temperature, achieving a temperature depletion ΔT.

Equation (3) shows that a high thermal power can be obtained through either high flowrate or high temperature depletion or both. The flowrate depends on the reservoir hydrodynamic properties and the temperature depletion on the surface heating processes. Thus, assuming a ΔT=30°C (T_0=70°C; T_r=40°C), a 7 MW_t installed capacity would require a 200 m^3/h discharge rate. The limiting factor to discharge will be the maximum allowable pressure drawdown at wellhead, a matter discussed later.

3.3 Heat recovery

The amount of heat H recovered from a reservoir volume Ah is equal to:

$$H = \eta\gamma_t\left(T_0 - T_r\right)Ah \qquad (4)$$

where η is a coefficient which measures the efficiency of the heat abstraction system over a productive time t_p.

Hence a recovery factor R can be derived from equations (1) and (4):

$$R = \frac{H}{G} = \eta\frac{T_0 - T_r}{T_0 - T_e} \qquad (5)$$

It shows quite clearly that, the higher the efficiency, η, and the lower the reinjection temperature T_r of the heat production scheme the higher the recovery of the heat in place.

3.4 Efficiency

It can be easily derived from a simple balance between the heat recovered from the reservoir and the total heat produced by the well over a period t_p.

$$\eta\gamma_t\left(T_0 - T_r\right)Ah = Wt_p = Q\gamma_f\left(T_0 - T_r\right)t_p \qquad (6)$$

Hence:

$$\eta = \frac{Q}{Ah}\frac{\gamma_f}{\gamma_t}t_p \qquad (7)$$

Numerical application:

Q=200 m^3/h	t_p=30 years	A=20 km^2	h=20 m
ϕ=0.2	γ_r=2.14 10^6 $Jm^{-3}°C^{-1}$	γ_f=4.186 10^6 $Jm^{-3}°C^{-1}$	
η=0.22	R=0.07		

If Q=300 m^3/h, A=15 km^2, all other parameters unchanged, η=0.44 , R=0.14.

These cursory calculations show that, irrespective of temperatures, upgraded efficiencies and recovery factors require higher flowrates, Q, and lower “influenced” areas, A, a matter discussed later while contemplating multiple production/(re)injection well arrays.

3.5 Heat resupply/reservoir life

The vertical conductive heat flow originating from a deep seated heat source, a cooling magma body or simply hot rocks at depth, is expressed as:

$$q = -\lambda\left(\frac{\partial T}{\partial z}\right) \qquad (8)$$

where q is the heat flow density per unit area (Wm^{-2}), λ the rock thermal conductivity ($Wm^{-1}°C^{-1}$) and $\left(\partial T / \partial z\right)$ the temperature (or geothermal) gradient ($°Cm^{-1}$). The average continental heat flow density is 0.06 Wm^{-2}.

At equilibrium conditions, i.e. before any exploitation commenced, the heat entering the reservoir is equal to the heat flowing to surface. If the reservoir temperature is depleted from T_0 to T_r then the heat balance will be modified as follows:

Heat inflow (from heat source)	—	Heat outflow (to surface)	=	Heat resupply

or:

$$\Delta q = q\frac{T^* - T_r}{T^* - T_0} - q\frac{T_r - T_e}{T_0 - T_e} \qquad (9)$$

where Δq is the unit heat resupply and T^* the heat source temperature.

Numerical application

T^*=200°C T_0=70°C T_r=50°C T_e=10°C

Δq=0.49q

This example means that the natural heat flow resupplies only one half of the abstracted heat, thus leading to a heat depleted reservoir status.

Another interesting information is the time t^{**} required for the reservoir to recover its initial temperature T_0 which can be derived from the following heat balance:

$$0.49qt^{**} = \gamma_t(T_0 - T_r)H_0 \qquad (10)$$

where H_0 is the depth of the reservoir.

Hence:

$$t^{**} = \frac{\gamma_t H_0}{0.49q}(T_0 - T_r) \qquad (11)$$

In the case of a 2,000 m deep reservoir, all other parameters remaining unchanged, the resupply time t^{**} would be nearing 110,000 years.

Heat is resupplied, by conduction, at a heat flow density q and withdrawn, via convection, at a density q' given by:

$$q' = \frac{W}{A} = \frac{Q}{A}\gamma_f(T_0 - T_r) \qquad (12)$$

Numerical application:

$Q=200\ m^3/h$ T_0-T_r=25°C A=15 km^2

q'=0.39 Wm^{-2} i.e. 6.5 times the continental average q=0.06 Wm^{-2}

3.6 Additional remarks

There are two more concepts which need to be discussed: (i) well deliverability; it depends on both the reservoir/well performance and temperature depletion, and (ii) reservoir/well performance; the well discharge – pressure relationship being governed by the following equations (pressures are expressed in bars).

$$p_{wp} = p_0 + \Delta p_d + \Delta p_{se} + \Delta p_{fl} \tag{13}$$

where:

p_w = production wellhead pressure

p_0 = static wellhead pressure

Δp_d = reservoir dynamic pressure drawdown

Δp_{se} = skin effect pressure drawdown (induced by either formation impairment – positive skin – or upgrading – negative skin – at the well-reservoir interface)

Δp_{fl} = friction induced losses in the well casings (from top reservoir to the wellhead)

with:

$$\Delta p_d = 0.51 \frac{Q\mu}{kh} \log_{10} \frac{0.81kt}{\phi \mu c_t r_w^2} \tag{14}$$

$$\Delta p_{se} = 0.44 \frac{Q\mu S}{kh} \tag{15}$$

$$\Delta p_{fl} = 1.06 \cdot 10^{-12} \frac{\mu^{0.21} Q^{1.79}}{r_c^{4.79}} l_c \tag{16}$$

Symbols:

c_t = total reservoir compressibility (bars^{-1})

kh = reservoir intrinsic transmissivity Darcy meters (Dm)

k = reservoir intrinsic permeability (D)

h = net reservoir thickness – net pay (m)

l_c = casing length (m)

Q = discharge rate (m^3/h)

r_c = casing (ID) radius (m)

r_w = well radius at reservoir (m)

S = skin factor (dimensionless)

t = time (hours)

ϕ = reservoir effective porosity

μ(T) = temperature dependant, fluid dynamic viscosity (cP)

Should a recharge (constant pressure) boundary or, more likely, an injection well pumping into the source reservoir the heat depleted brine, be placed at a distance d(m) from the production well, the reservoir dynamic pressure drawdown Δp_d would stabilise at a value given by:

$$\Delta p_d = \frac{Q\mu}{kh}\log_{10}\left(\frac{d}{r_w}\right) \tag{17}$$

Assuming:

Q=200 m^3/h	r_w=0.08 m
k=2 D	c_t=1 10^{-4} bar^{-1}
h=15 m	d=1000 m
μ(70°C)=0.44 cP	t=12 years (half life)
φ=0.16	

the dynamic pressure drawdown, with and without recharge, would stand at 12 and 19 bars respectively.

This illustrates one of the benefits expected from water injection, pressure maintenance which is achieved, in this case, via the doublet concept of heat mining, associating a production and an injection well, a design first implemented at Melun l'Almont in 1969 [4].

Similarly to equation (13) the pressure p_{wi} at injection wellhead will be derived as follows:

$$p_{wi} = p_0 + \Delta p_d + \Delta p_{se} + \Delta p_{fl} - \Delta p_{ts} \tag{18}$$

with:

Δp_{ts} = thermosiphone pressure = $9.81 \cdot 10^{-5}(\rho_i - \rho_0)Z_r$

$\rho_0 = \rho(T_0)$= volumetric mass at production temperature (kg m^{-3})

$\rho_i = \rho(T_r)$= volumetric mass at injection (rejection) temperature (kg m^{-3})

$\mu_i = \mu(T_r)$= dynamic viscosity at injection temperature (cP)

Z_r = top reservoir depth

Not only does this well pair design secures pressure maintenance it also solves, the environmentally sensitive, waste disposal problem. However these advantages are counterbalanced by: (i) the injection of the heat depleted brine which, if the wells are not properly spaced, could result in a premature cooling of the produced water reducing dramatically system life, and (ii) the additional pumping power requirements, not to mention additional capital investment and running costs.

The cooling effect can be first appraised by the thermal breakthrough time t_B which, under the, conservative, assumption of convective heat transfer alone, is written:

$$t_B = \frac{\pi}{3}\frac{\gamma_t}{\gamma_f}\frac{d^2h}{Q} \tag{19}$$

A first approach would consist of assigning t_B as the heat production system lifetime. Therefore, under this conservative assumption, would a twenty year life be sought, assuming a constant 200 m^3/h discharge/recharge rate and a 15 m net reservoir thickness, the doublet spacing should meet a ca. 1070 m requirement.

The pumping power W_p is equal to:

$$W_p\left(kW_e\right) = 2.78 \cdot 10^{-2} \frac{Q}{\eta} \Delta p \qquad (20)$$

where η is the pump efficiency and Q(m^3/h) and Δp (bars) the discharge/recharge rate and total head respectively.

From an energy point of view the efficiency of the heat mining system is often estimated from the coefficient of performance (COP), expressed as the ratio of the yearly produced heat to the pump power consumption which, in case of constant production, reduces to:

$$COP = \frac{W}{W(production) + W_p(injection)} \qquad (21)$$

A COP close to 15 is generally regarded by operators as an optimum figure on both technical and economical grounds.

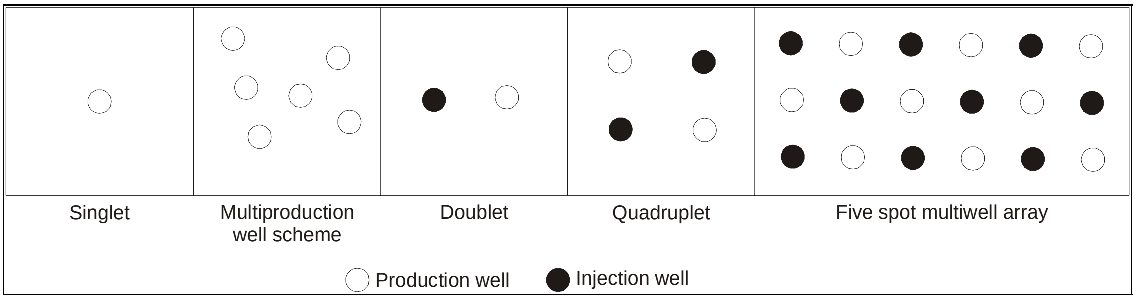


Figure 2: Typical heat mining schemes

The matters discussed previously are illustrated in Fig. 2, 3, 4 sketches. Fig. 2 displays various well configurations, ranging from the single production well to the multi-production/injection well array, known as five spot, similar to those applied by the oil industry in secondary recovery (water flooding) oil production practice. It is worth adding that heat recovery efficiencies increase accordingly, from less than 5% for the single production well up to 50% and more for the five spot array [5]. Fig. 3 evidences the pessimistic nature of convective heat transfer alone in assessing system lifetime. On the contrary, the actual diffusive conductive/convective heat transfer, known as dispersion, taking place in the reservoir leads to significantly longer system lives. The latter is exemplified in Fig. 4 which demonstrates increasing breakthrough times from the doublet to the multi-doublet heat abstraction arrays, the five spot achieving a 50% improvement (from 17.2 to 25.8 years).

Note that the temperature responses were calculated on an analytical model accounting for conductive heat recharge (sweeping) from the confining caprocks and bedrocks.

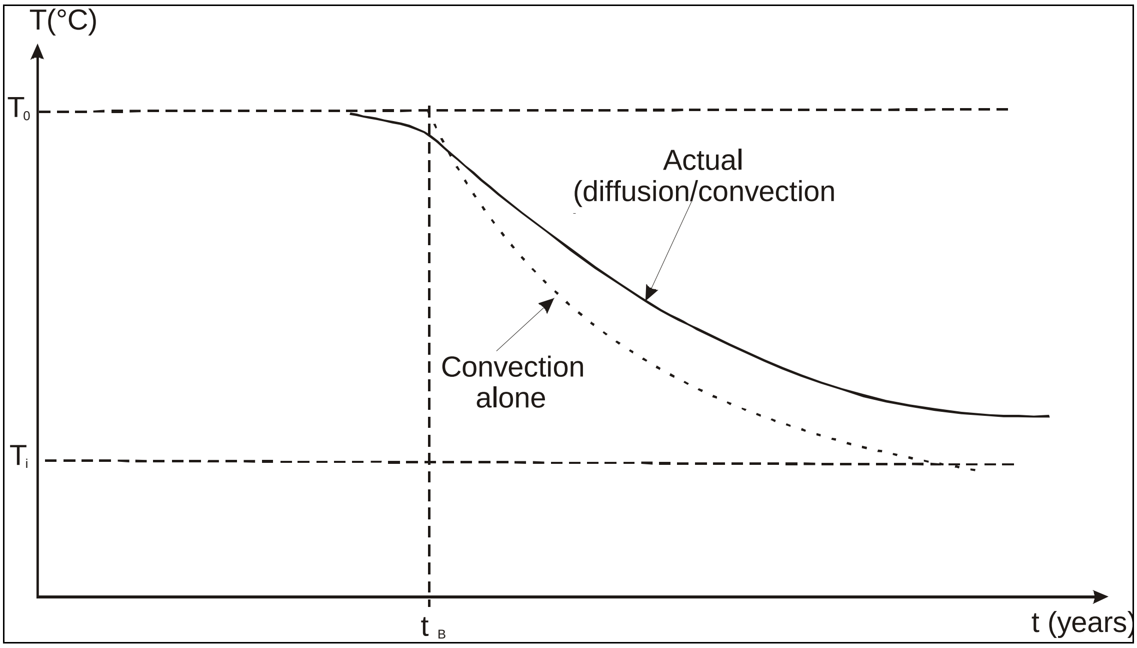


Figure 3: Production temperature transients. Doublet configuration. (t_B thermal breakthrough)

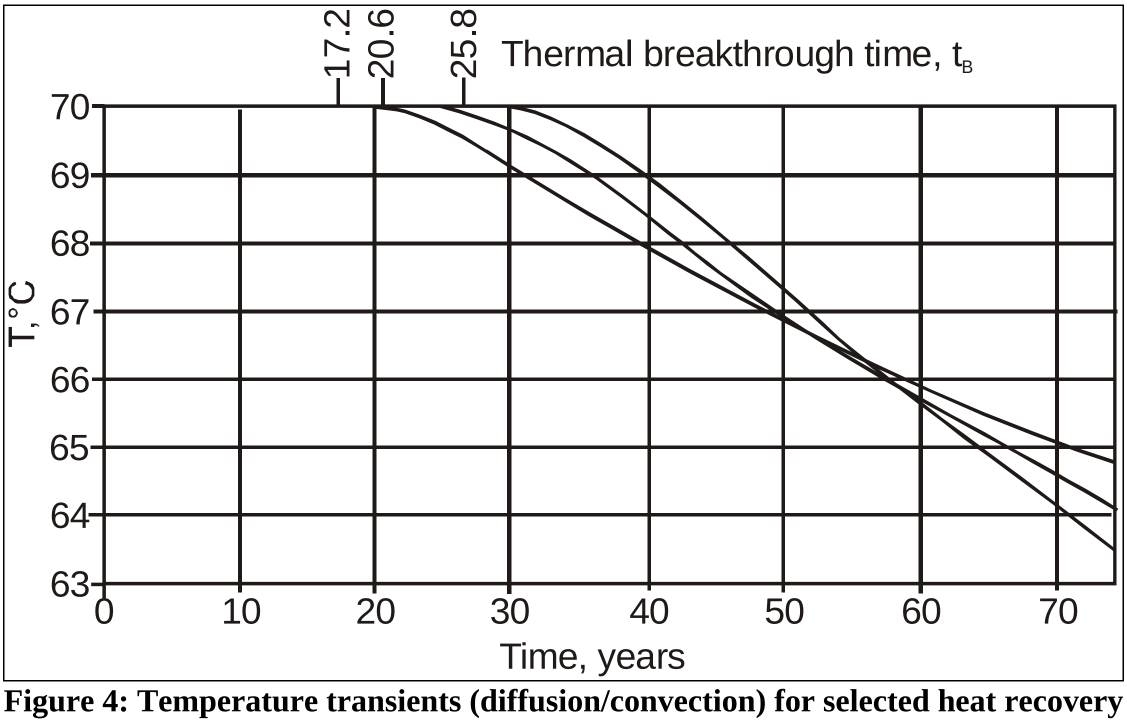


Figure 4: Temperature transients (diffusion/convection) for selected heat recovery arrays [5]

The foregoing aimed at illustrating basic heat mining concepts through an idealised picture of actual reservoir settings. When addressing the latter one has to cope with heterogeneous reservoirs, non-regularly spaced heat production systems and space/time varying production/injection schedules.

This is best achieved by solving the following simultaneous set of equations governing mass and heat transfers:

- mass transfer:

$$\nabla\left[\frac{k}{\mu}\nabla\left(p+\rho g z\right)\right]=\phi c_t\frac{\partial p}{\partial t}+Q \tag{22}$$

- heat transfer:

$$\nabla\left(\lambda\nabla T\right)-\gamma_f\left(\phi U\nabla T\right)=\gamma_t\frac{\partial T}{\partial t} \tag{23}$$

- equations of state:

$$\begin{aligned}\rho &= \rho(T,p)\\ \mu &= \mu(T,p)\\ \gamma_f &= \gamma_f(T)\end{aligned} \tag{24}$$

where:
g = gravity (mt^{-2})
U = flow velocity (ms^{-1})
to which are added relevant boundary and initial conditions.

The set of partial differential equations (22) and (23), coupled with the equations of state (24), is non linear as a result of a temperature dependant velocity field subject to temperature dependant densities and viscosities. It is solved by means of complex reservoir simulation computer codes, discussed in a later section.

4. WATER INJECTION

It has been shown in the previous section that injection of the heat depleted brine in a compressed liquid, low enthalpy, reservoir could increase by one order of magnitude the heat recovery factor. This could be achieved by sweeping the heat stored in the rock which, in that peculiar setting, was three times higher than that stored in the soaking fluid. For a vapour dominated field this ratio is reported by Economides [6] to stand ten times higher.

Water injection exhibits several other advantages, namely:

- disposal of the waste, cooled, brine a major concern owing to, increasingly stringent, environmental regulations;
- pressure maintenance as exemplified by the, mass conservative, doublet concept of heat mining;

- release, via triggering of microseisms and fault lubricating, of stresses accumulated in seismically active zones thus preventing the advent of, most likely, devastating earthquakes;
- land subsidence control.

Waste water disposal has obviously been, and still remains, the primary objective of geothermal operators.

However, water injection had been a prioritary specification in commissioning, in the mid 1970s, geothermal power plants in the Imperial Valley of Southern California to prevent subsidence shortcomings in an intensely irrigated farmland.

The fast depletion noticed in the Geysers and Larderello vapour dominated fields portrayed water injection as an attractive means for sustaining steam production. However, the waste water is limited here to steam condensates so that an additional water source is required.

In the Geysers field, injection of steam condensates began in 1969 on marginally productive wells and the process still continues nowadays, resulting in the replacement of ca. one quarter of the produced steam [7].

It was followed in 1998, by the injection of 1300 m^3/h of surface diverted, treated, water were piped over 40 km and pumped into 7 to 10 injection wells located in the Southeastern part of the reservoir. It reduced well pressure decline thus boosting steam production which had been depleted by almost one half since the peak 2,000 MW_e recorded in 1989.

A huge water injection scheme, due to start in late 2003, has been commissioned. It aims at piping 1800 m^3/h of treated sewage water from the, 65 km distant, city of Santa Rosa to the Northern part of the field, a larger, thicker and hotter area hosting thermochemically sensitive solution gases (H_2S). Hence, significant enhancement of reservoir performance on both steam production and quality grounds is expected.

In Larderello, where similar depletion trends had long been observed, injection of steam condensates started in 1979. It was followed, in 1994, by the injection of 350 m^3/h of combined condensate/ground water recharge which proved rewarding in supplying low pressure steam to a 60 MW_e rated power plant [7].

Vapour dominated fields such as the Geysers and Larderello are of large areal extent and water/steam condensates injection often implemented on peripheral zones.

Liquid dominated, high enthalpy, reservoirs are often more limited in size and fluid circulation is governed by prevailing fractured porosity/permeability patterns. Therefore water injection is subject to channelling along preferential flow paths and subsequent short circuiting of production wells. These distinctive features of fractured geothermal reservoirs led Bodvasson [8] to recommend that injection wells be drilled at least one kilometre apart and the water injected several hundred meters below the exploited reservoir. This obviously poses the problem of the injectivity of this deeper horizon which is not known beforehand.

The large majority of low enthalpy reservoirs, eligible to direct uses, belong to sedimentary environments as opposed to high enthalpy, liquid dominated, volcano-tectonic settings.

The critical problem areas deal with the injection of cooled waste water into clastic sedimentary reservoir combining clay, sand and sandstone sequences. If not carefully designed, injection practice may turn into a disaster caused by non-compatible, formation vs. injected, waters, external/internal particle entrainment, capture and release leading ultimately to well and formation, often irreparable, damage.

As stressed by the author [9], suspended particles of either (or both) external (carrier fluid) or (and) internal (matrix) origins represent the main permeability impairment risk to well and formation integrities. As a result, in designing water injection systems in such environments, emphasis is to be placed on low velocities, particle characterisation, filtering criteria and facilities, fluid processing and, last but not least, sound well completion (screen and gravel pack) achieving slow flow injection of, particle free, waters thus securing long well life.

5. TRACER TESTS

Tracer testing is a vast domain whose scope will be restricted here to the main issues relating to geothermal reservoir characterisation, flow mechanisms and water injection.

An early application of tracers was designed in 1954 by Ramey and Nabor [10] to estimate the swept reservoir volume between one injection and several producing wells. They derived the following equation relating the tracer detection to the swept volume:

$$c_{\min} = \frac{V_{inj}}{1.076\phi D^2 h} \qquad (25)$$

where:
c_{min} = tracer detection limit (t/m^3)
V_{inj} = injected tracer mass
D = well spacing (m)
h = net reservoir thickness (m)
ϕ = effective porosity

In so doing the tracer is assumed stable (no decay or long decay period) and non-adsorbed by the swept rock.

Another popular application of tracers aims at tracking the migration of (re)injected reservoir fluids. A series of tests were conducted in the Dixie Valley, Nevada, high temperature field as reported by Rose et al [11], [12]. They used fluorescein and naphthalene sulfonate and disulfonate which proved to be reliable due to their environmentally benign and stable properties at high temperatures and easy detection (fluorescence spectroscopy) at low concentrations (0.1 ppb). In addition, field responses in terms of flow paths, elution curves and breakthrough times were model calibrated via two reservoir simulation codes thus providing the reservoir engineer with optimum design features of future tests. Similar conclusions were reached on several Philippines and Indonesian fields.

Another attractive application addresses the estimation of the thermal breakthrough time on a geothermal district heating doublet, of the type discussed in a previous section, in order to check whether model predictions match the actual field behaviour. The idea consists of adding a given volume of tracer to the (re)injected water and measure the arrival time of the **hydraulic** front on the production well. This would allow to predict the thermal breakthrough time, bearing in mind that the arrival of the **thermal** front is significantly delayed, owing to rock/fluid heat transfer, by the following ratio:

$$\frac{\phi\gamma_f}{\phi\gamma_f + (1-\phi)\gamma_r} \qquad (26)$$

In such circumstances a stable, long period (≥12 years), isotope such as Tritium seems an appropriate candidate. Unfortunately such an experiment could not be carried out on Paris Basin wells.

More sophisticated applications, discussed by Vetter [13], use chemically reactive tracers which, absorbed by the rock, might give an estimate of the rock to fluid heat exchange area provided reaction rates do not get affected by pH effects.

There are other, more or less exotic, uses of tracers among which should be mentioned the injection/repumping of either radioactive or chemical tracers in order to detect and localise well casing leaks discussed by Ungemach et al. [14], a cost effective substitute to conventional packer leak-off tests.

Tracer flow conforms to a solute transport process, mathematically expressed by the following partial differential (dispersion) equation [15]:

$$\left(\overline{\overline{D}}\nabla c - Uc\right) = \phi\frac{\partial c}{\partial t} \qquad (27)$$

where D is the dispersion coefficient (m), which can be added to the heat and mass transfer reservoir simulation codes.

6. RESERVOIR SIMULATION

During early geothermal exploration and development, in the first half of the past century, reservoir engineering was primarily involved with the documenting of well inputs and their physical characteristics such as temperature and pressure.

Nowadays reservoir engineers are required to construct a realistic conceptual model of the field including sub surface temperature and pressure distributions in both vertical and horizontal planes, the distribution of chemicals and gases, field boundaries, reservoir storage and transmissivity, and the flow of fluids both within the reservoir and across the boundaries. The sources of information from which the model is deduced are well test results and downhole measurements. The reliable interpretation of field measurements is therefore a major consideration for the reservoir engineer. The conceptual model of the field often provides sufficient understanding of the reservoir to enable informed and logical decisions on the field development and reservoir management.

Perhaps the most important, and most challenging part of the modelling process is the integration of information gathered by all the geoscientific disciplines leading to the development of the conceptual model. The success of any reservoir modelling exercise is dependent upon the flow of high quality information from the basic data collection phase, through the conceptual modelling phase, to the simulation process. This flow of information must go both ways, as the modelling process is an iterative one, often requiring numerous reconstruction and reinterpretation.

The procedure discussed here is employed by many general purpose geothermal reservoir simulators and is based on the integrated finite difference technique developed at Lawrence Berkeley Laboratory. These simulators proved to work well in case of simulation of low temperature geothermal systems.

It is assumed that the region of interest is divided up into blocks or elements (Fig. 5). The i-th block has a volume V_i and is connected by an area of $a_{i,j}$ to the j-th block. This formulation allows for an irregular block structure but includes more regular block structures such as rectangular blocks or polar coordinate systems as special cases. Here p_j^n and T_i^n are used to represent pressures and temperatures in the i-th block at the end of the n-th time step. The n-th time step is of duration Δt_n.

All successful geothermal simulation techniques are based on two common ideas:

1. Difference equations are fully implicit with all mass and energy fluxes evaluated at the new time level.
2. Upstream weighting is used to calculate interface quantities.

The procedure discussed here is block-centred for pressures and temperatures while fluxes are calculated at block boundaries. The discrete mass balance equation can be written:

$$V_i\left(A_{mi}^{n+1} - A_{mi}^{n}\right) = -\sum_j a_{ij} Q_{mij}^{n+1} \Delta t_{n+1} + q_{mi}^{n+1} \Delta t_{n+1} \qquad (28)$$

Here Q_{mij}^{n+1} is the mass flux from block i to block j evaluated at the end of the (n+1)th time step. Similarly q_{mi}^{n+1} is the mass production from block i evaluated at the end of the (n+1)th time step (positive for injection). The production rate q_{mi}^{n+1} use in equation (28) is a total flow rate (kg/s). Similarly the discrete energy equation is:

$$V_i\left(A_{ei}^{n+1} - A_{ei}^{n}\right) = -\sum_j a_{ij} Q_{eij}^{n+1} \Delta t_{n+1} + q_{ei}^{n+1} \Delta t_{n+1} \qquad (29)$$

Here Q_{eij}^{n+1} and q_{ei}^{n+1} are defined as for the mass equation above.

For discretisation of Darcy's Law the equations below are used:

$$Q_{m\ell ij}^{n+1} = -\left(\frac{kk_{r\ell}}{\nu_\ell}\right)_{ij}^{n+1}\left[\frac{p_j^{n+1} - p_i^{n+1}}{d_{ij}} - \rho_{\ell ij}^{n+1} g_{ij}\right] \qquad (30)$$

$$Q_{mvij}^{n+1} = -\left(\frac{kk_{rv}}{\nu_v}\right)_{ij}^{n+1}\left[\frac{p_j^{n+1} - p_i^{n+1}}{d_{ij}} - \rho_{vij}^{n+1} g_{ij}\right] \qquad (31)$$

The total mass flow becomes

$$Q_{mij}^{n+1} = Q_{m\ell ij}^{n+1} + Q_{mvij}^{n+1} \qquad (32)$$

$$Q_{eij}^{n+1} = h_{\ell ij}^{n+1} Q_{mij}^{n+1} + h_{vij}^{n+1} Q_{mvij}^{n+1} - K_{ij}^{n+1}\frac{T_j^{n+1} - T_i^{n+1}}{d_{ij}} \qquad (33)$$

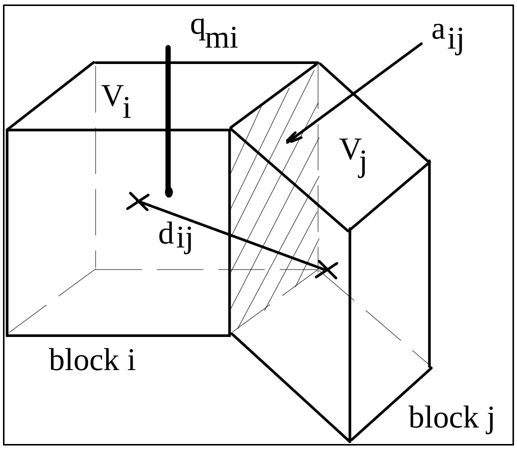


Figure 5: Block discretisation

There are several terms in equation (30) whose calculation requires further explanation. The gravity term g_{ij} is the component of gravity acting through the interface. For example, $g_{ij}=0$ for two blocks horizontally adjacent, and $g_{ij}=g$ for two blocks with block i vertically above block j the interface densities in the "weight" terms are evaluated using:

$$\rho_{\ell ij}^{n+1} = \frac{1}{2}\left(\rho_{\ell i}^{n+1} + \rho_{\ell j}^{n+1}\right) \qquad (34)$$

$$\rho_{vij}^{n+1} = \frac{1}{2}\left(\rho_{vi}^{n+1} + \rho_{vj}^{n+1}\right) \qquad (35)$$

The inter-block distance d_{ij} is the sum of the distances d_i and d_j from the centres of the ith and jth block to their connecting interface respectively. The interface permeabilities and conductivities are calculated using harmonic weighting and usually they are assumed to be independent of pressure and temperature and therefore need to be evaluated only once at the beginning of the simulation using:

$$\frac{1}{k_{ij}}=\frac{\left(\frac{d_i}{k_i}+\frac{d_j}{k_j}\right)}{d_{ij}} \tag{36}$$

The most important aspect of the interface calculations is the upstream weighting of the mobilities and enthalpies. For example the mobilities are expressed as:

$$\left(\frac{k}{\nu_\ell}\right)_{ij}^{n+1}=\begin{cases}\left(\frac{k}{\nu_\ell}\right)_i^{n+1}, \text{ for } \quad G_\ell^{n+1}<0\\ \left(\frac{k}{\nu_\ell}\right)_j^{n+1}, \text{ for } \quad G_\ell^{n+1}>0\end{cases} \tag{37}$$

where:

$$G_\ell^{n+1}=\frac{p_j^{n+1}-p_i^{n+1}}{d_{ij}}-\rho_{\ell ij}^{n+1}g_{ij} \tag{38}$$

$$\left(\frac{k_{rv}}{\nu_v}\right)_{ij}^{n+1}=\begin{cases}\left(\frac{k_{rv}}{\nu_\ell}\right)_i^{n+1}, \text{ for } G_v^{n+1}<0\\ \left(\frac{k_{rv}}{\nu_v}\right)_j^{n+1}, \text{ for } G_v^{n+1}>0\end{cases} \tag{39}$$

where:

$$\mathrm{G}_{\mathrm{v}}^{\mathrm{n+1}}=\frac{\mathrm{p}_{\mathrm{j}}^{\mathrm{n+1}}-\mathrm{p}_{\mathrm{i}}^{\mathrm{n+1}}}{\mathrm{d}_{\mathrm{ij}}}-\rho_{\mathrm{vij}}^{\mathrm{n+1}}\mathrm{g}_{\mathrm{ij}} \tag{40}$$

Similarly the enthalpies can be evaluated using the following equations

$$(h_\ell)_{ij}^{n+1}=\begin{cases}(h_\ell)_i^{n+1}, \text{ for } \quad G_\ell^{n+1}<0\\ (h_\ell)_j^{n+1}, \text{ for } \quad G_\ell^{n+1}>0\end{cases} \tag{41}$$

$$(h_v)_{ij}^{n+1}=\begin{cases}(h_v)_i^{n+1}, \text{ for } \quad G_v^{n+1}<0\\ (h_v)_j^{n+1}, \text{ for } \quad G_v^{n+1}>0\end{cases} \tag{42}$$

The quantities $\mathrm{A}_{\mathrm{mi}}^{\mathrm{n+1}}$ and $\mathrm{A}_{\mathrm{ei}}^{\mathrm{n+1}}$ are evaluated as follows:

$$\mathrm{A}_{\mathrm{mi}}^{\mathrm{n+1}}=\phi_{\mathrm{i}}\left(\mathrm{S}_\ell\rho_\ell+\mathrm{S}_{\mathrm{v}}\rho_{\mathrm{v}}\right)_{\mathrm{i}}^{\mathrm{n+1}} \tag{43}$$

$$\mathrm{A}_{\mathrm{ei}}^{\mathrm{n+1}}=\left(1-\phi_{\mathrm{i}}\right)\rho_{\mathrm{ri}}\mathrm{C}_{\mathrm{ri}}\mathrm{T}_{\mathrm{i}}^{\mathrm{n+1}}+\phi_{\mathrm{i}}\left(\rho_\ell\mathrm{S}_\ell\mathrm{u}_\ell+\rho_{\mathrm{v}}\mathrm{S}_{\mathrm{v}}\mathrm{u}_{\mathrm{v}}\right)_{\mathrm{i}}^{\mathrm{n+1}} \tag{44}$$

In these formulae variations of porosity with pressure and temperature could be included by adding the n+1 superscript to ϕ_i. The difference equations (28) and (29) together with equations (30) to (44) above are then solved for each time step.

The main aim of reservoir modelling is to set up a computer model which represents the permeability structure, heat inputs of the real reservoir with sufficient accuracy so that the simulated behaviour of the model for twenty or thirty years can be used confidently as a prediction of the real reservoir. There are a number of minor reservoir simulation tasks that often accompany the development of a complete reservoir model. For example the results of pressure tests and interference tests can be simulated in order to help to establish the correct permeability and porosity values for different parts of the reservoir.

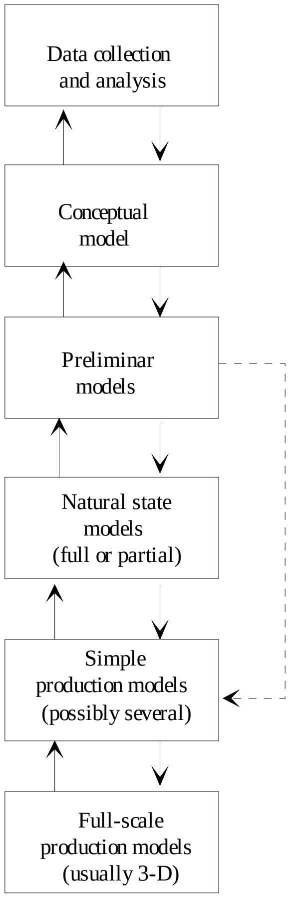


Figure 6: Modelling steps

All modellers agree that a computer model of a geothermal reservoir must be preceded by a conceptual model; that is, a good understanding of the physical behaviour of the reservoir.

In summary a successful reservoir modelling program has three fundamental components:

1. The collection of meaningful and reliable geoscientific, production, and reinjection data, and the interpretation and analysis of this data.
2. The construction of a conceptual reservoir model.
3. The development of a computer model of the reservoir, to allow the simulation of behaviour patterns and response to exploitation.

The reservoir modelling studies published have helped to establish some general simulation procedures:

1. Selection of block structure and layout that best suits the conceptual model size and shape.
2. Initial selection of reservoir and fluid parameters that best match the observed conceptual model.
3. Iterative refinement of model parameters in order to provide the best match to observed reservoir behaviour under exploitation.
4. Further refinement of the model in order to reproduce the observed pre-exploitation state of the reservoir. These models are run over extremely long simulation times in order to confirm that the model approaches stability under observed reservoir conditions.
5. The best model is used to predict the reservoir behaviour throughout the expected project life under a variety of exploitation conditions.

The basic steps required in setting up a computer model of a geothermal field are summarised in Fig. 6. The two-way arrows indicate that the process is an iterative one. For example, investigations of preliminary models may lead to further field studies and data collection followed by some modification of the original conceptual model and preliminary models.

7. RISK ASSESSMENT

Risk assessment addresses both financial issues and reservoir management strategies.

As regards financial risks incurred at exploration level, the World Bank [16] has produced a comprehensive overview summarised in Fig. 7 risk vs. expenditure chart. It shows quite clearly that, in the compiled project areas located chiefly in East Africa and Pacific Rim countries, the exploratory drilling risk could be minimised thanks to the filtering out of the less attractive, most risky, prospects identified in the preliminary reconnaissance stages, thus leading to a 80% drilling success ratio.

After project commissioning and start-up the first years of exploitation provide the reservoir/production engineers and management with additional clues on future development alternatives.

The latter are usually investigated by integrating all pertinent data – reservoir characteristics, surface heat/power loads, well productivities, plant performance, make up well drilling and plant production schedules, economic parameters – into reservoir and economic models to assess ultimately well/field productivities and project economic value.

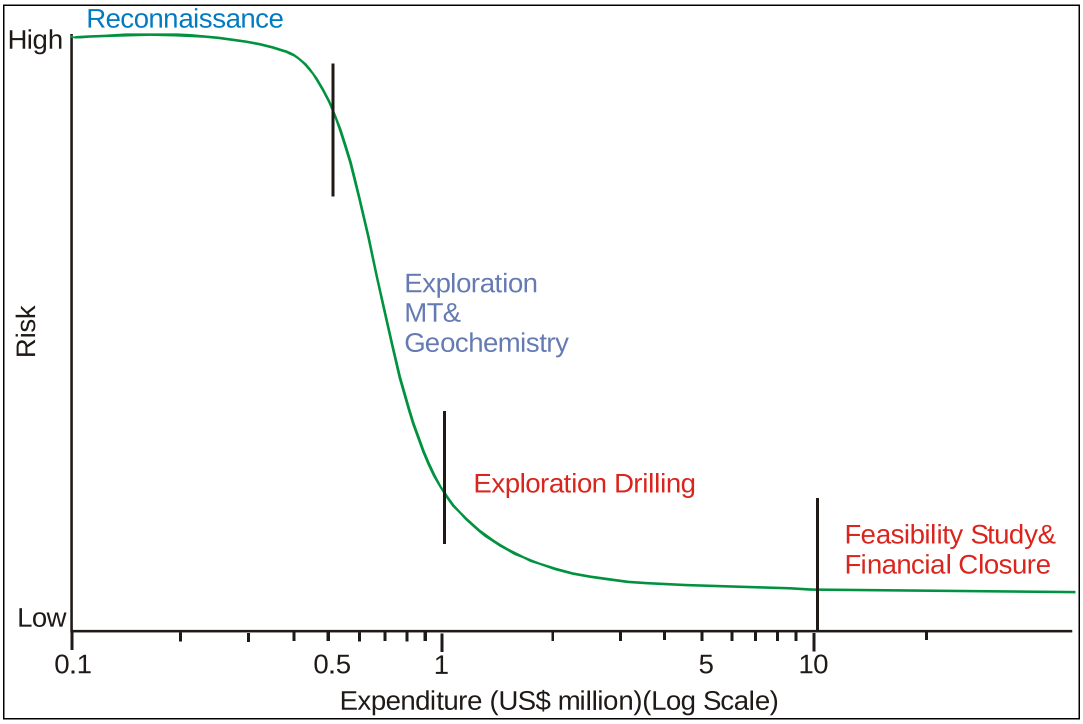


Figure 7: Expenditure and risk prior to geothermal development (source Worldbank [16])

However, the decision making process is clouded by the many uncertainties affecting model inputs. A purely deterministic or probabilistic approach could be misleading. A thorough coupled deterministic-probabilistic approach could prove more relevant but by all means irrealistic considering the huge numbers of model runs involved, indeed a tedious and costly exercise if manageable ever, unless kept into reasonable limits by adequate constraints.

Acuna et al [17] review the case of a liquid dominated field in the Philippines where a strategic decision is to be taken as to whether a deep, poorly produced, reservoir underlying the presently exploited shallow seated reservoir, should be developed or not.

In order to overcome the aforementioned limitations the authors suggest an interesting methodology outlined hereunder.

- up to ten different exploitation strategies were selected;
- the economic model calculates the project NPV (net present value) probability distribution. The uncertainty for each relevant parameter is described by the most likely (50% probability – P50); pessimistic (10% probability – P10) and optimistic (90% probability – P90) values, defining the parameter cumulative probability function;
- in order to reduce the number of reservoir simulation runs for the P10, P50, P90 uncertainties allocated to the parameters for each exploitation strategy, the model results were synthesised, after preliminary model tests, by using a polynomial approximation to key output data, and four cases reflecting changes in steam extraction rates and make up well drilling schedules constrained by existing well deliverabilities.

The polynomial approximation of reservoir performance (as well deliverability vs. cumulative produced steam) proved rewarding in that it enabled to integrate this key uncertainty into the probabilistic economic model to assess the risk impact on project NPV.

In the Paris Basin geothermal district heating scheme, the risk assessment exercise dealt with the evaluation of future exploitation hazards and their implications on heavy duty well workover and doublet operation-maintenance (OM) costs [16], whose results are commented in the case study section of this paper.

8. CASE STUDY

It concerns the development and management of large geothermal district heating systems exploiting, since 1970, a dependable reservoir located in the Central part of the Paris Basin, France. It led to the completion of 54 geothermal doublets, of which 34 remain in operation to date, and enabled to accumulate a considerable experience with respect to reservoir engineering and maintenance/surveillance of production facilities [18]. Future exploitation trends will be analysed in the perspective of sustainable heat mining, a key issue in securing reservoir longevity.

8.1 Resource setting

The Paris Basin area belongs to a large intracratonic sedimentary basin, stable and poorly tectonised, whose present shape dates back to late Jurassic age [19] (see areal extent in Fig. 8a)

Among the four main litostratigraphic units exhibiting aquifer properties, depicted in the Fig. 8b cross section, the Mid-Jurassic (Dogger) carbonate rocks were identified as the most promising development target.

The Dogger limestone and dolomite are typical of a warm sea sedimentary context associated with thick oolithic layers (barrier reef facies). The oolithic limestone displays by far the most reliable reservoir properties as shown by the present geothermal development status. Reservoir depths and formation temperatures range from 1,200 to 1,700 m and 60 to 78°C respectively.

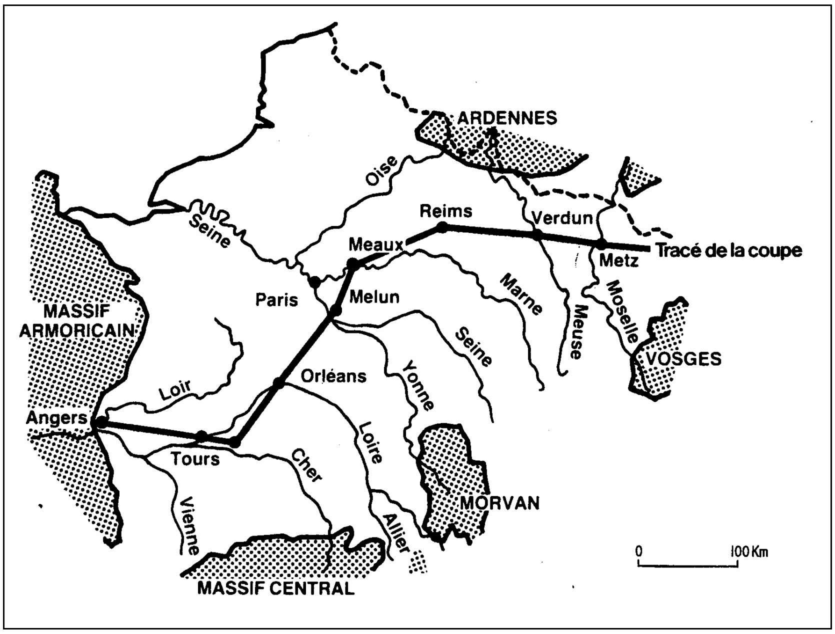


Figure 8a: Paris Basin areal extent [19]

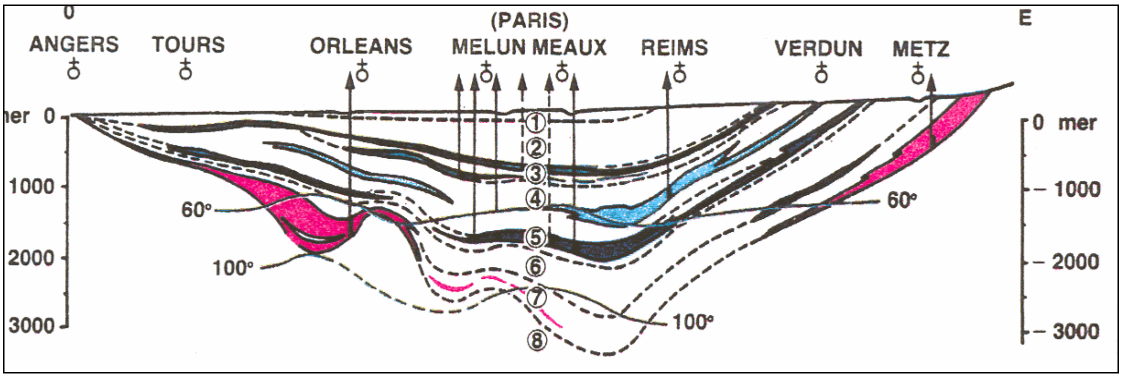


Figure 8b: Cross sectional view of the main deep aquifer horizons [19]

8.2 Development status and milestones

The location of the geothermal district heating sites is shown in Fig. 9. They consist of thirty four (as of year 2003) well doublets supplying heat (as heating proper and sanitary hot water, SHW) via heat exchangers and a distribution grid to end users.

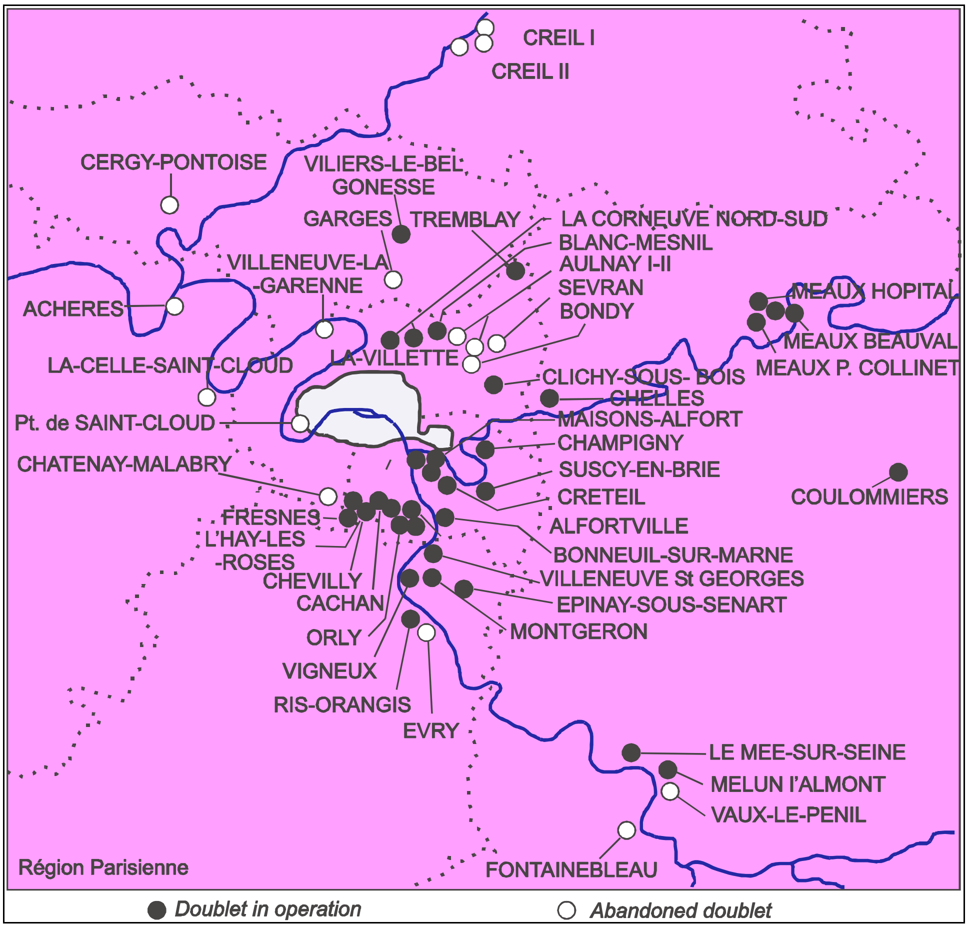


Figure 9: Location of the geothermal district heating sites in the Paris Basin

The methodology adopted in assessing the reservoir, developing heat extraction, operating and maintaining the production systems, processing the exploitation data and managing the reservoir in relation to the timescale and milestones is summarised in the Fig. 10 diagram.

This diagram highlights the following:

- the reservoir could be early assessed, prior to the first oil shock, thanks to previous hydrocarbon exploration-production (expro) which evidenced the attractive geothermal potential hosted by the Dogger reservoir;
- feasibility studies made it possible to locate the candidate development sites in terms of eligible surface heat loads and local reservoir performance/well deliverabilities;

- simultaneously a risk diagram was defined, for each site, in order to match the critical Q (discharge rate)-T(wellhead temperature) success/failure criteria required to meet economic viability. This set the bases of a, State supported, insurance fund aimed at, in case of a total failure, covering up to 80% of the costs incurred by drilling of a first exploratory well;
- field development (1969-1985) resulted in the drilling/completion of 54 well doublets of which 52 addressed the Dogger geothermal reservoir proper. An almost 100% drilling success ratio was recorded after deduction of the mitigated success/failure (50%) ventures recorded on two sites;
- the Mining Law, applicable to low grade geothermal heat (sources below 150°C) was enforced in 1975 together with a package of accompanying incentives (coverage of the exploration risks, creation of a mutual insurance fund compensating exploitation, heat mining induced, shortcomings/damage, financial support to prefeasibility/feasibility studies and energy savings/fossil fuel replacement);
- these voluntarist measures, decided in the aftermath of the first and second oil shocks, created a legal/institutional/regulatory framework lubricated by various financial (fiscal)/ insurance incentives, which boosted the reclamation of geothermal energy sources in this area. Exploration/exploitation concessions were awarded, subject to approval and control by the ad-hoc competent mining authority and subsidies allocated accordingly.
- the early exploration stages were subject to the inevitable learning curve hazards, odd equipment design, corrosion/scaling damage, poor maintenance protocols, loose management and financial losses aggravated by high debt/equity ratios negotiated by, mostly public, operators. They could be overcome thanks to improved monitoring, maintenance and managerial policies.
- After infantile disease and teenage geothermal exploitation turned adult, the technologies becoming mature and the management entrepreneurial, setting the premises of sustainable development for the future.

Several events are worth mentioning in this perspective:

- the first industrial application in 1969, at Melun l'Almont, South of Paris, of the well doublet system of heat mining, irrespective of any energy price crisis whatsoever. Despite its innovative and premonitory character it was regarded at that time as a technical, somewhat exotic, curiosity;
- the drilling/completion in 1995 at the, henceforth emblematic, Melun l'Almont site of the new anticorrosion well design, combining steel propping casings and removable fiberglass production lining and of the operation of a well triplet array which, as later discussed, are likely to meet the requirements of increased well longevity and reservoir life;
- the advent, since 1998, of gas fired cogeneration systems equipping nowadays one half of the existing geothermal district heating plants which should secure both economic and sustainable reservoir exploitation issues.

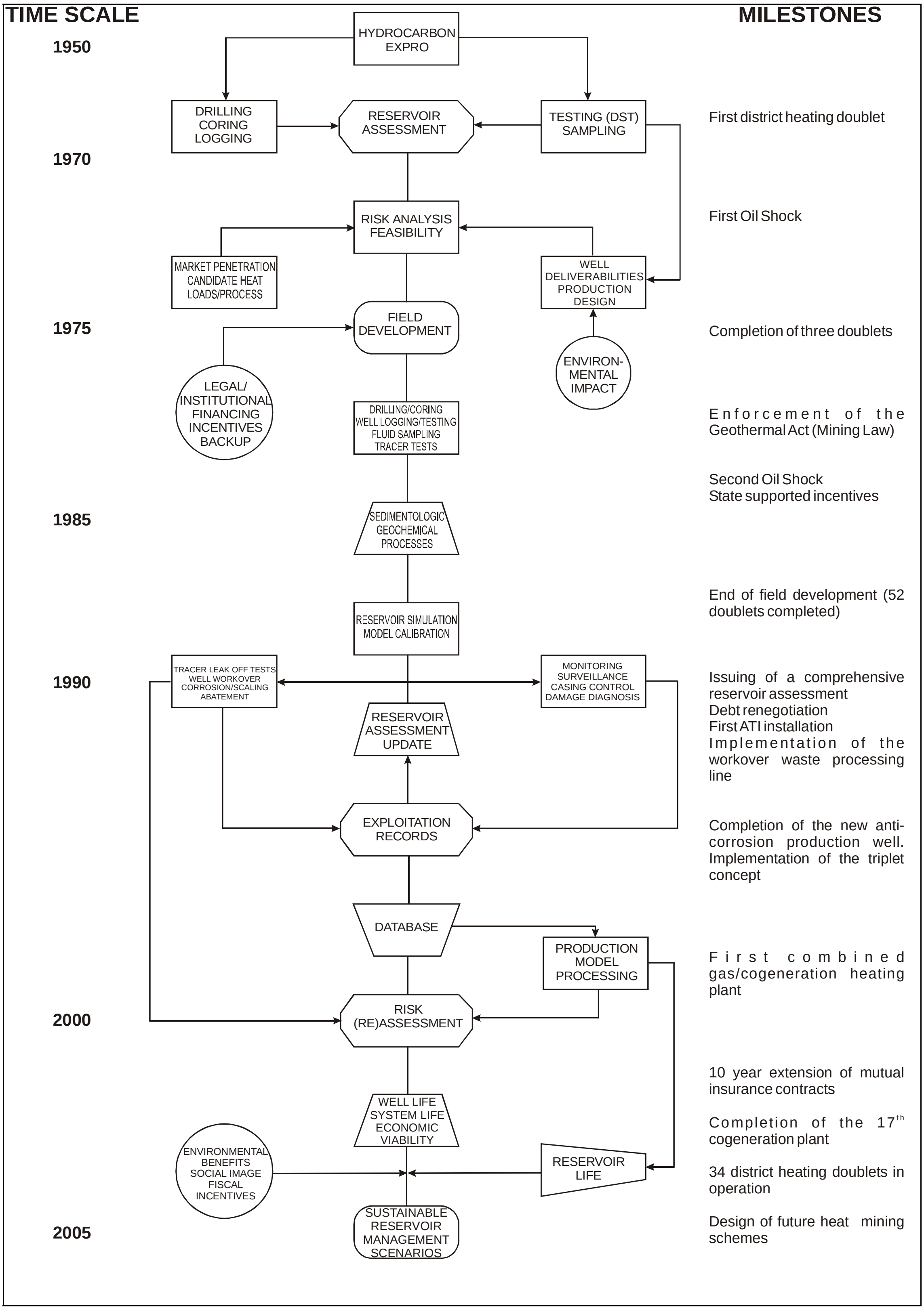


Figure 10: From oil exploration to geothermal sustainable development

8.3 Technology outlook

The standard geothermal district heating system components and governing parameters are schematised in fig (11). It should be noticed that:

(i) most well (production/injection) trajectories are deviated from a single drilling pad with wellhead and top reservoir spacing of 10 and ca. 1,000 m respectively. They are produced via, variable speed drive, electric submersible pump (ESP) sets;

(ii) the heat is recovered from the geothermal brine by, corrosion resistant, titanium plate heat exchangers;

(iii) geothermal heat is used as base load and therefore combined with backup/relief, fossil fuel fired, boilers, unless otherwise dictated by combined gas cogeneration/geothermal systems;

(iv) district heating complies to retrofitting which means that geothermal heat supply has to adjust to existing conventional heating devices most often not designed for low temperature service. This has obvious implications on rejection (injection) temperatures and well deliverabilities.

The principles governing geothermal district heating are summarised in table 1. It should be stressed here, that in no way is the heat supply constant but highly variable instead, as it varies daily and seasonally (in summer only sanitary hot water is produced) with outdoor temperatures. This entails variable discharge/recharge rates and injection temperatures, well deliverabilities and production schedules.

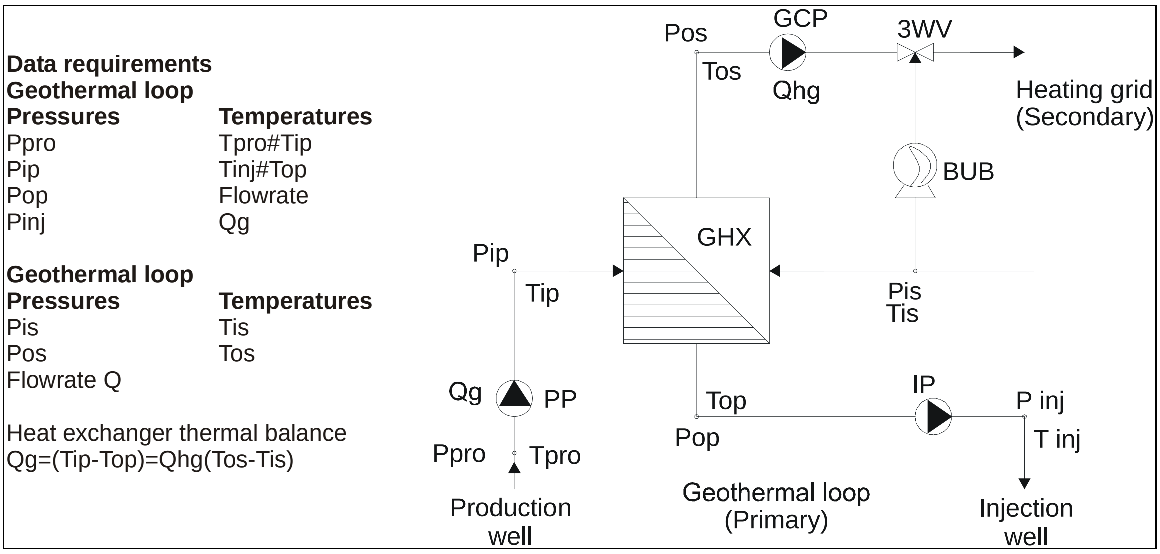


Figure 11: Geothermal district heating parameters

Table 1: Geothermal district heating analysis. System components and parameters(after Harrison et al)

GEOTHERMAL POWER	NETWORK/HEATERS	HEAT DEMAND
$P_g = M_g (\theta_g - \theta_r)$ $M_g = \rho_w \gamma_w q_g / 3.6$	$P_n = M_n (\theta_a - \theta_{ref})$ $M_n = NED \times V \times G / (m_{hi} / m_{ho})$ $m_{hi} = (\theta_{hi} - \theta_{nh}) / (\theta_a - \theta_{ref})$ $m_{ho} = (\theta_{ho} - \theta_{nh}) / (\theta_a - \theta_{ref})$	$P_d = M_d (\theta_a - \theta)$ $M_d = NED \times V \times G /1{,}000$ $W_d = 24 \times NDD \times M_d / 1{,}000$ $NDD = \int_0^{NHD} (\theta a - \theta) dt$

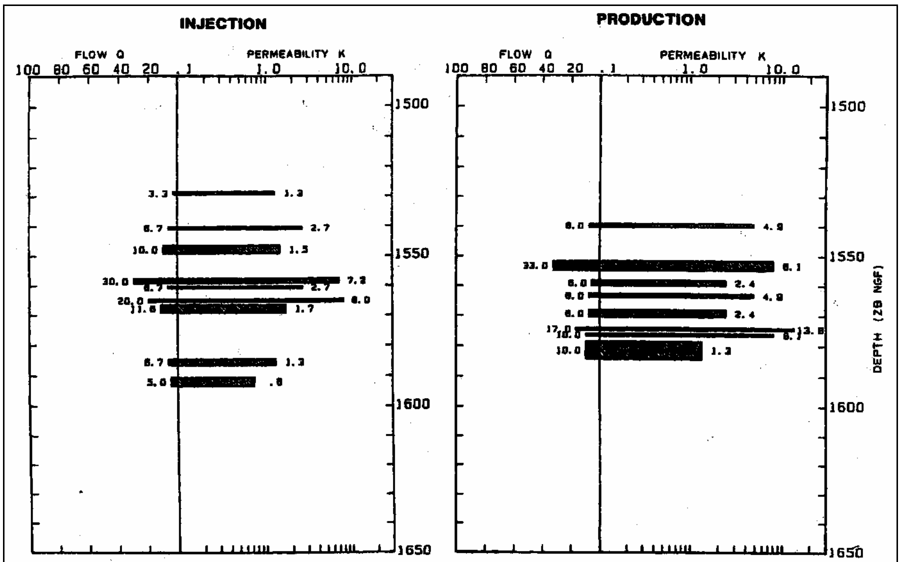
HEAT EXCHANGE	GEOTHERMAL SUPPLY
$P_{hx} = \eta_{hx} P_g = \eta_{hx} M_g [(\theta_g - \theta_{nh}) - M_{ho} (\theta - \theta_{ref})]$ $\eta_{hx} = \{1 - \exp [- N (1 - R)]\} / \{1 - R \exp [- N (1 - R)]\}$ $N = UA / M_g$ $R = M_g / M_n$	$W_{hx} = \eta_{hx} M_g \{(\theta_g - \theta_{nh}) - m_{ho} \times 24 \int_0^{NHD} [\theta(t) - \theta_{ref}] dt\}$ $GCR = W_{hx} / W_d$
REGULATION CRITERIA	
$\theta_{no} = \theta_{ref} + m_{no} (\theta_a - \theta)$ $\theta < \theta*$: maximum geothermal flowrate, back up boilers $\theta* < \theta < \theta_{ref}$: total geothermal supply	

NOMENCLATURE	
P = power (kW_t)	U = heat exchanger heat transfer coef. ($W/m^2°C$)
W = energy (MWh_t /Yr)	A = heat exchanger area (m^2)
M = thermal capacity (kW_t/°C)	R = flow ratio
NED = number of equivalent dwellings	GCR = geothermal coverage ratio
NDD = number of degree days	m = heater characteristic (slope)
NHD = number of heating days	q = flowrate (m^3/h)
V = equivalent dwelling volume (m^3)	γ = specific heat (J/kg°C)
G = average dwelling heat loss ($W/m^3°C$)	ρ = volumetric mass (kg/m^3)
N = number of heat transfer units	θ = temperature (outdoor) (°C)
Subscripts	
g = geothermal	o = outlet
w = fluid (geothermal)	hi = heater inlet
d = demand	ho = heater outlet
n = network	nh = non heating (lowest heater temperature)
h = heater	a = ambient (room)
hx = heat exchanger	ref = minimum reference outdoor
i = inlet	r = rejection (return)

Typical values (Paris area)		
NED = 2,000/4,500	V = 185 m3	θ_{hi}/θ_{ho} =
NDD = 2,500	θ_{ref} = - 7°C	90/70°C cast iron radiators
NHD = 240	θ_r = 40/50°C	70/50°C convectors
N = 5	θ_g = 55/75°C	50/40°C floor slabs
qg = 200/350 m3/h	θ_a = 17/18°C	
g = 1.05 W/m3°C	θ_{nh} = 20°C	

8.4 Reservoir characterisation

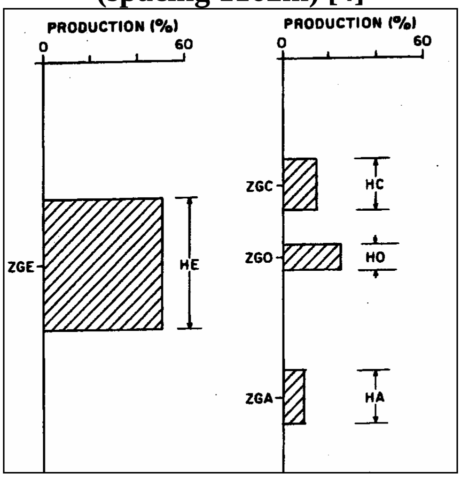
Up to ten productive layers may be individualised on flowmeter logs as shown in Fig. 12a. However sedimentologic (lithofacies) analyses on cores and cuttings allowed to group them in three main aquifer units and permeability and thickness allocated accordingly which confirm the dominant share of the oolithic limestone. It leads to the equivalent, either single layer or three layer, reservoir representation depicted in Fig. 12b used later for reservoir simulation purposes.



PARAMETER	COMBL.	OOLIT.	ALTER.	TOTAL PAY
H m	2.1	9.6	5.0	16.7
KH Dm	4.2	33.2	5.0	42.4
K D	2.0	3.5	1.0	2.5
Q %	10.0	78.3	11.7	100.0
ZB NGF	1536.6	1560.2	1588.2	1561.1

PARAMETER	COMBL.	OOLIT.	ALTER.	TOTAL PAY
H m	1.3	11.2	5.9	18.4
KH Dm	6.3	65.9	8.0	80.2
K D	4.9	5.9	1.3	4.4
Q %	8.0	82.0	10.0	100.0
ZB NGF	1539.8	1563.4	1581.4	1563.3

Figure 12a: Flow permeability spectra on injection and production wells (spacing 1162m) [4]



equivalent single layer reservoir

equivalent three layer reservoir

Figure 12b: Equivalent reservoir model from flowmeter log

8.5 Reservoir simulation

Three modelling strategies are contemplated:

- local modelling restricted to a single doublet neighbourhood, assuming homogeneous reservoir properties, and an equivalent monolayer geometry with either constant pressure (recharge) or impervious (no flow) boundary conditions. Two simulators are currently used, either the analytical model described in [5] or TOUGH2, discretised field, computer code. An application of the latter to a 75 year, doublet/triplet projected life under changing well locations and production/injection schedules, is illustrated in fine;
- multidoublet areal modelling by means of both analytical and numerical simulators. In the first case the reservoir is assumed homogeneous and multilayered. This exercise may exaggeratedly oversimplify the actual field setting in which case a numerical simulator such as TOUGH2, taking into account reservoir heterogeneities and a multilayered structure, would be preferred instead;
- regional or subregional modelling, encompassing the whole exploited domain or a significant fraction of it which, by all means, requires a numerical simulator to meet actual reservoir conditions. This poses the problem of the interpolation of the, space distributed, field input data, which is currently achieved by geostatistical methods. In the Dogger reservoir, however, the process can be biased for permeabilities and net thicknesses by the locally strong variations, evidenced by well testing at doublet scale between the production and injection wells, introduced in a regional context;
- a solute transport partition can be added to handle the tracer case and track a chemical element (iron, as a corrosion product for instance) continuously pumped into the injection wells.

Summing up, the general modelling philosophy consists of using a calibrated regional model as a thorough reservoir management tool, online with the Dogger database, and to extract multistage subregional/local models whenever required by the operators.

8.6 Operation and maintenance requirements

This vital segment of reservoir exploitation includes three main headings:

(i) monitoring and surveillance of heat production facilities;
(ii) well workover, and
(iii) corrosion/scaling abatement.

Monitoring and surveillance of production facilities

According to the mining and environmental regulatory framework in force and to site specific agreements, geothermal loop monitoring and surveillance comply to the following protocol :

- geothermal fluid :
    - hydrochemistry (main anions/cations) and corrosion/scaling indicators : iron and sulphide/mercaptane

- thermochemistry : bubble point, gas/liquid ratio, dissolved gas phase,
- microbiology (sulphate reducing bacteria),
- suspended particle concentrations,
- coupon monitoring,

- loop parameters :
  - well head pressures and temperatures,
  - production well head dynamic water level,
  - heat exchanger inlet/outlet temperatures,
  - geothermal and heating grid flowrates,
  - heat exchanger balance check,
- well deliverabilities :
  - well head pressure/discharge (recharge) curves (step drawdown/rise tests),
- pump and frequency converter characteristics
  - voltage, amperage, frequencies,
  - powers,
  - efficiencies,
  - ESP insulation,
- inhibitor efficiencies :
  - corrosion/scaling indicators control,
  - inhibitor concentrations,
  - filming (sorption/desorption) tests,
- inhibition equipment integrity :
  - metering pump,
  - regulation,
  - downhole chemical injection line,
- wellhead, valves, spool, filter integrities,
- surface piping (ultrasonic) control,
- casing status : periodical wireline logging (multifinger calliper tool) inspection of production and injection well casings.

Well workover. Corrosion and scaling abatement

During a Paris Basin geothermal well life (20 years minimum), a number of heavy duty workovers are likely to occur, addressing well clean-up (casing jetting), reconditioning (lining/cementing of damaged casings) and stimulation (reservoir acidising and casing roughness treatment). The probability level of such events is analysed in the risk assessment section.

Corrosion and scaling abatement

The geothermal fluid, a slightly acid (pH≈6), saline brine including toxic and corrosive solution gases (H_2S and CO_2), creates a thermochemically hostile environment endangering well casing and surface equipment integrities.

The corrosion and scaling mechanisms in the aqueous CO_2-H_2S system cause these gases to interact with the exposed steel casings, pipes and equipment, forming iron sulphide and carbonate crystal species as a result of corrosion. These aspects had been merely overlooked and impaired dramatically well performances in the early exploitation stage before appropriate downhole chemical injection strategies [20] be successfully implemented to defeat, or at least slowdown, the corrosion process.

Well workover and corrosion/scaling abatement caused the operators to prove technically innovative in the design and implementation of well cleanup jetting tools, continuous downhole chemical injection lines and inhibitor formulations, soft acidising techniques, tracer leak off testing and waste processing lines.

8.7 Risk assessment

Paris Basin geothermal district heating projects and accomplishments faced five levels of risks, exploration (mining, geological), exploitation (technical, managerial), economic/financial (market, institutional, managerial), environmental (regulatory, institutional) and social acceptance (image) respectively. Only the assessment of exploitation risks will be discussed here.

Exploitation risks

Those could not be estimated from scratch. A (long term) fund initially financed by the State was created in the 1980s to cope with the hazards induced by the exploitation of the geothermal fluid. Later this could be supplied by operators’ subscriptions.

It soon became obvious that the, initially overlooked, hostile thermochemistry of the geothermal fluid provoked severe corrosion and scaling damage to casing and equipment integrities resulting in significant production losses. A prospective survey commissioned in 1995 aimed at assessing the exploitation risks and related restoration costs projected over a fifteen year well life. This exercise was applied to thirty three doublets. The governing rationale, developed in [18], consisted of (i) listing potential and actual, technical and non technical, risks ranked and weighted as shown in table 2, and (ii) classifying risks according to three levels (1 : low, 2 : medium, 3 : high), each subdivided in three scenario colourings (A : pink, B : grey, C : dark) regarding projected workovers deadlines and expenditure. This analysis led to a symmetric distribution, i.e. eleven sampled sites per risk level, each split into three (A), five (B) and three (C) scenario colourings.

Table 2 - Summary of risk factors

Risk description	*Nature weight*	*Ranking*	*Status*	*Remarks*
Last known casing status	Technical 1	1	Fine	Residual steel thickness >75% nominal WT before treatment
		2	Fair	Residual steel thickness >50% nominal WT before treatment
		3	Bad	Residual steel thickness <50% nominal WT before treatment
Damaging kinetics	Technical 1	1	Low	Corrosion rate <150µm/an before treatment
		2	Medium	Corrosion rate >150µm/an before treatment
		3	High	Corrosion rate >300µm/an before treatment
Chemical inhibition efficiency	Technical 1	1	High	Provisional statement
		2	Low	Provisional statement
Casing lining opportunities	Technical 1	1	Full	No diameter restrictions
		2	Partial	Some diameter restrictions
		3	None	Total diameter restrictions
New well drilling expectation	Technical 1	1	Long term	> 20 yrs
		2	Medium term	> 10 yrs
		3	Short term	< 10 yrs
Other	Non technical 3	1	favorable	
		2	hostile	

The next step applied the workover/repair unit costs to the concerned wells, required to forecast the workover types and relevant schedules, thus leading to the synthetic expenditure breakdown summarized in table 3. This evaluation illustrates the paradox between competing (if not conflicting) well heavy duty maintenance strategies, i.e. repeated repair of damaged infrastructures vs. re-drilling/re-completion of new wells reflected by scenarios 2 (A, B, C) and 3 (A, B, C). Here, the optimum, in terms of investments but not necessarily cash flows, is represented by scenarios 2B and 3B, case 2C displaying definitely the worst profile.

Table 3: Recapitulation of provisions (sinking funds) required by heavy-duty well workover/repair/ redrilling over 15 years (cost per well/year, 10^3 EUR)

SCENARIO	A	B	C
Risk level		1	
Yearly provision	74	99	125
Risk level		2	
Yearly provision	203 (229)	193 (221)	255 (277)
Risk level		3	
Yearly provision	222 (241)	201 (213)	206 (277)
TOTAL (Weighted average)		173 (186)	

In conclusion, an average provision (fiscally deductible) of 0.19 million EUR (ca 186,000 €/yr) has been recommended to cope with future exploitation hazards resulting in a 12 % increase of initially anticipated OM costs. Loose management remaining the exception, managerial risks could be reliably regarded as minimized in year 2000. Surprisingly, the risk model matched expectations as of late 2002.

8.8 Dogger database

In noway has the Dogger reservoir and exploitation database be designed as archives dedicated to a geothermal saga but instead as a dynamic monitoring and management tool.

The whole database, whose structure is organised according to the Fig. 13 diagram, is currently developed, operated and hosted on the Oracle platform and data instructed locally via a Microsoft Access interface.

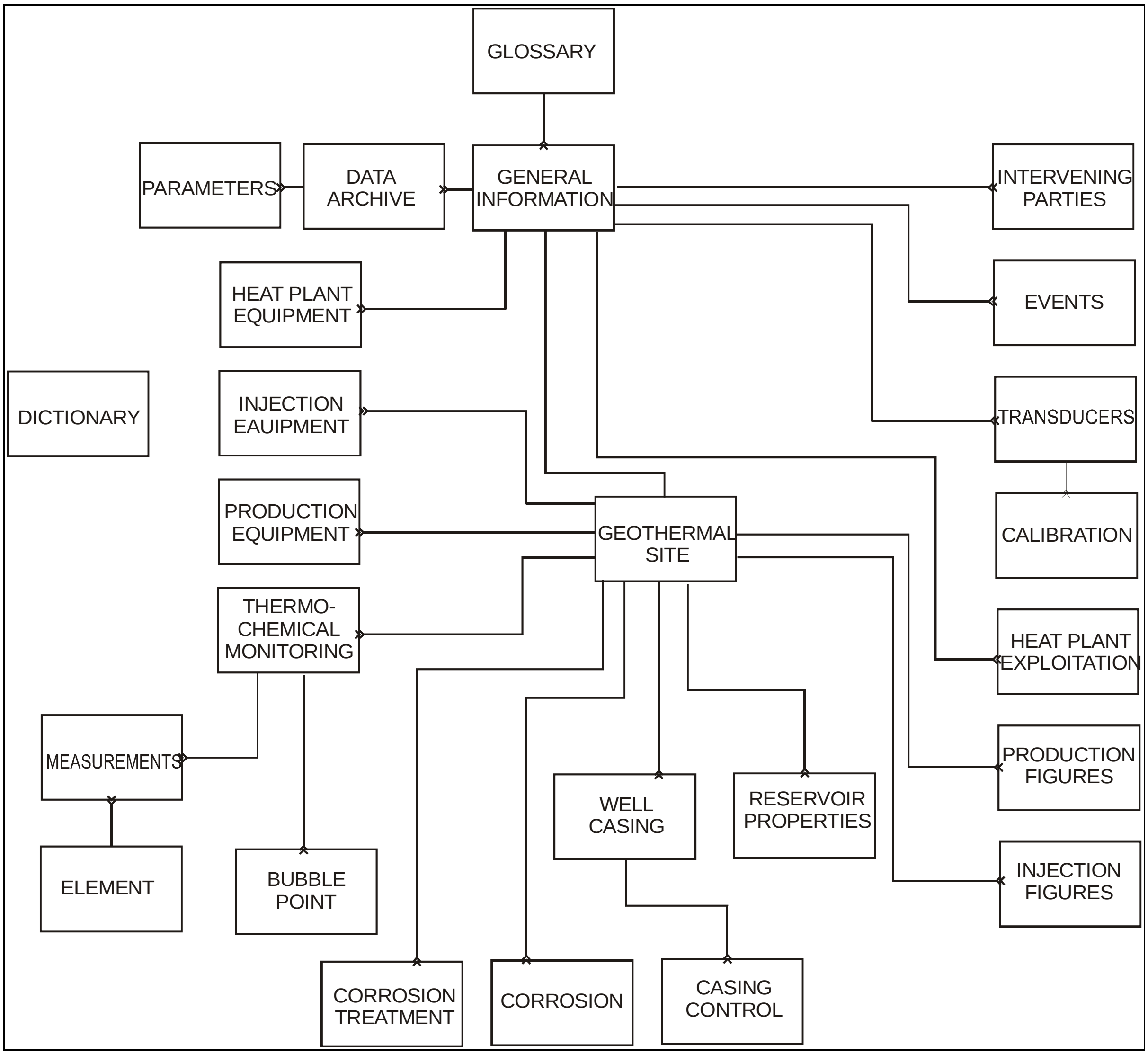


Figure 13: Dogger database structure (source: BRGM/GPC/CFG)

8.9 A tentative sustainable development scenario

The theme of sustainability deserves a few introductory comments.

Apart from projects abandoned at exploratory stage or aborted after early production trials, almost none of the fields developed in the past decades has yet ceased commercial exploitation.

Larderello, the eldest geothermal field, is approaching the one century exploitation mark and the Geysers the half century line.

Clearly, water injection, whatever the fears (and early failures) related to well spacing problematics and short-circuiting hazards particuraly acute in the sensitive liquid dominated fractured environments, is a key issue in sustaining reservoir performance and exploitation longevity.

So everything considered a hundred year life for a steam producing reservoir can no longer be regarded as utopia. This, irrespective of the field ownership/concession statute, of either aggressive (cash flow oriented) or moderate (resource conservative) exploitation strategies. This, in spite of the non-renewability of the resource.

Projecting an exploitation scenario over seventy five years, from 1985 to 2060, proved a challenging, thought provoking, exercise, for the following reasons:

- based on available exploitation records well life is deemed to seldom exceed twenty five years;
- reservoir life is assessed from the system thermal breakthrough time, to which can be added a few more years at the expense of a 10% loss in well deliverability, i.e. a total twenty five to thirty year life;
- which production schedules and injection temperatures should be allocated for the future fifty years, bearing in mind that new building/insulation/heating standards and novel designs in heating devices be substituted to the existing ones.

The projected scenario, displayed in table 4, is based on the following considerations:

- the base case doublet is produced during the first twenty five years according to the existing seasonal production rate /injection temperature schedule;
- starting on year 26, the existing wells are converted, after due reconditioning (lining), into injector wells, and a new, long lasting, steel casing fiberglass lining well drilled to the North and the system operated according to the triplet design earlier implemented at Melun l'Almont. Flowrates and injection temperatures are estimated from a combined geothermal/ gas cogeneration plant performance;
- On year 50 the two injector wells are abandoned and a new injection well drilled to the South. The doublet revisited system is exploited with the cogeneration plant at lower rates and injection temperatures in compliance with upgraded heating processes.

Table 4: Main reservoir and system features. Projected development schedule (1985-2060)

- **Reservoir characteristics**

- intrinsic transmissivity (kh) = 30 Dm
- net reservoir thickcness (h) = 20 m
- intrinsic permeability (k) = 1.5 D
- effective porosity (ϕ) = 0.16
- initial reservoir temperature (T_0) = 72°C
- rock grain density = 2700 kg/m^3
- formation heat conductivity = 2.1 W m^{-1}°C^{-1}
- rock grain specific heat = 1000 J kg^{-1}°C^{-1}
- initial doublet spacing (d) = 1250 m
- area contemplated =20 km^2

- **yearly production/injection schedule**

Period	1985-2010					2011-2035					2036-2060				
Mining scheme	doublet (1)					triplet (2)					doublet (3)				
Annual prod./inj. schedule	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
Time (months)	3	4.5	8.5	10	12	3	4.5	8.5	10	12	3	4.5	8.5	10	12
Flowrate (m^3/h)	250	160	80	160	250	150	150	80	150	150	125	150	80	150	125
Inj. Temp. (°C)	50	40	62	40	50	40	40	62	40	40	30	30	62	30	30

(1) initial doublet: 2 deviated wells (steel cased 9"5/8)
(2) intermediate triplet: 2 injection wells (initial reconditioned doublet, 7" steel lining), 1 new anticorrosion (steel/fibreglass lined), large diameter deviated well
(3) final doublet: 3 anticorrosion (steel/fibreglass lined), large diameter deviated (existing producer and newly completed injector) wells.

The results of the simulation runs with the TOUGH2 code are shown in Fig. 14-15 output maps. They indicate no thermal breakthrough thus confirming that the contemplated scenario achieves sustainability.

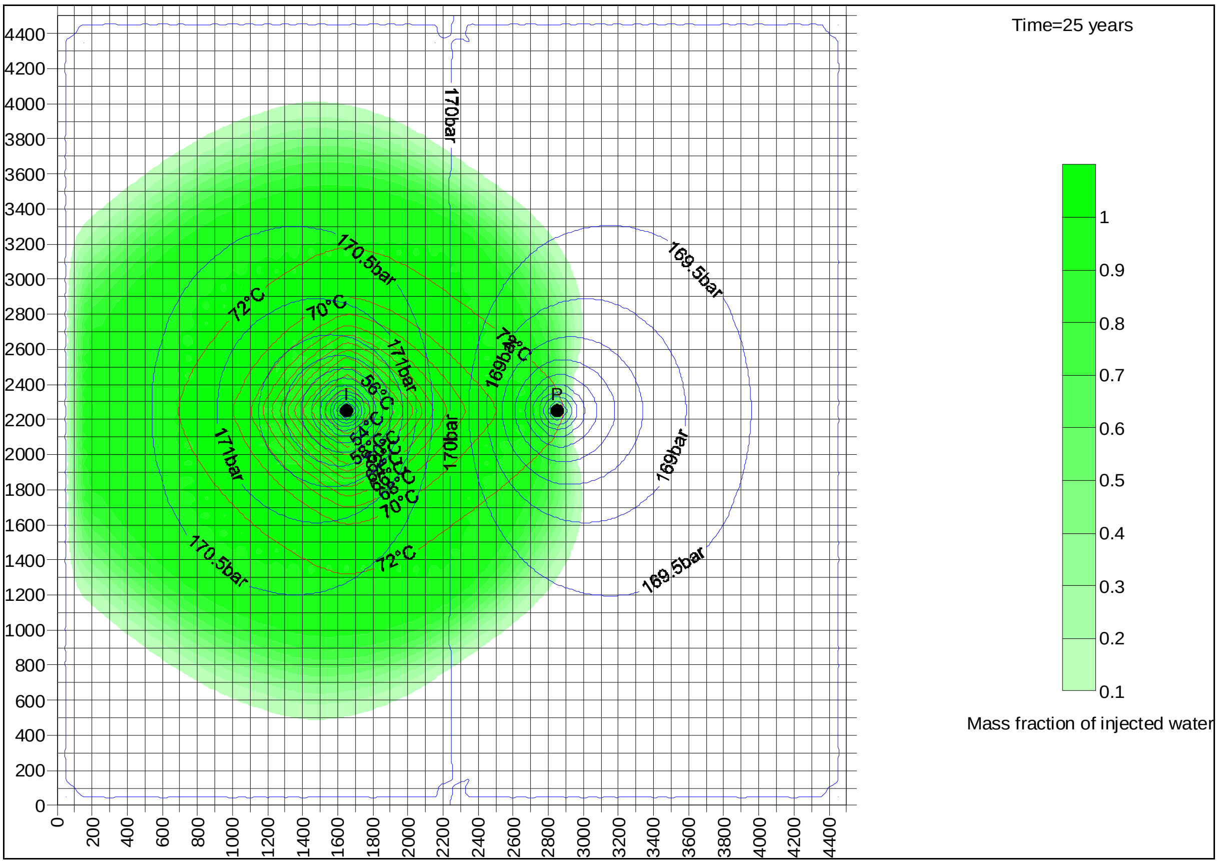


Figure 14a: Scheme 1. Simulated pressure/temperature/mass fraction of injected water

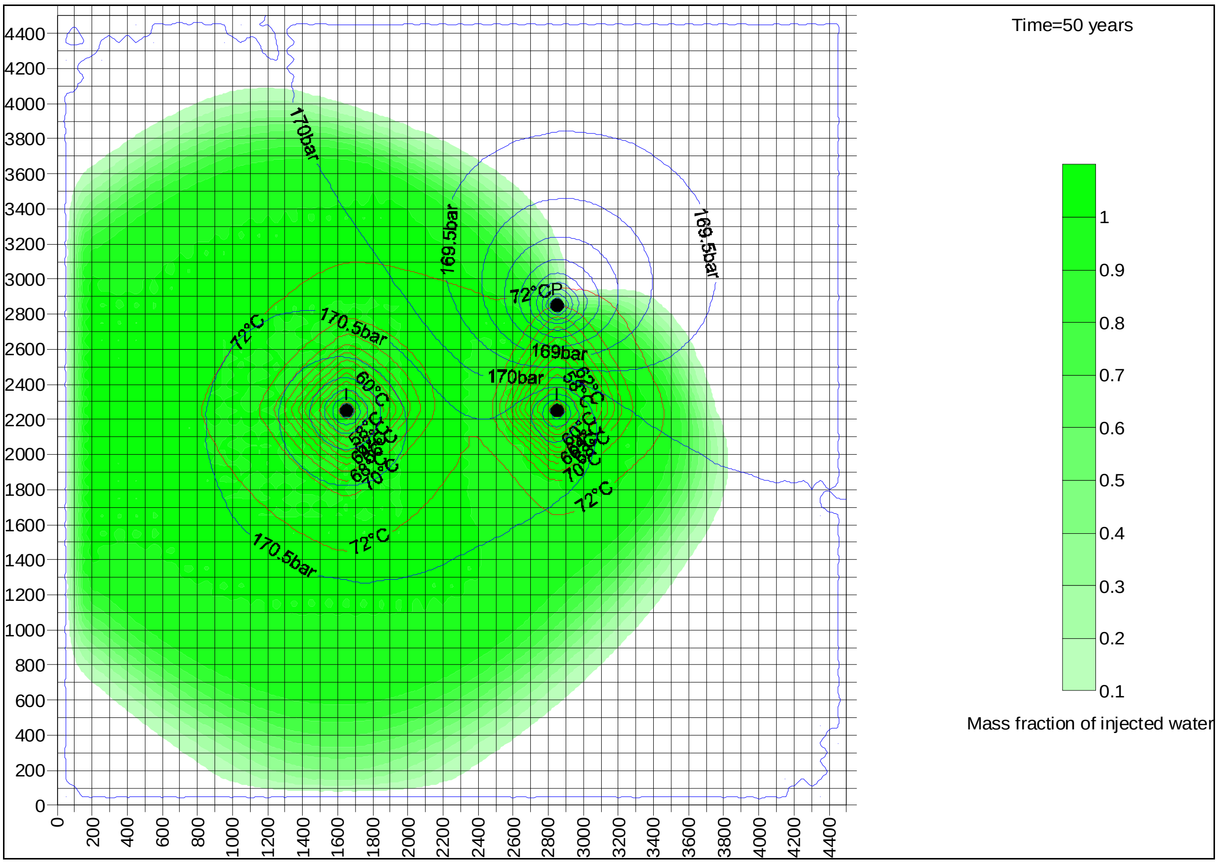


Figure 14b: Scheme 2. Simulated pressure/temperature/mass fraction of injected water

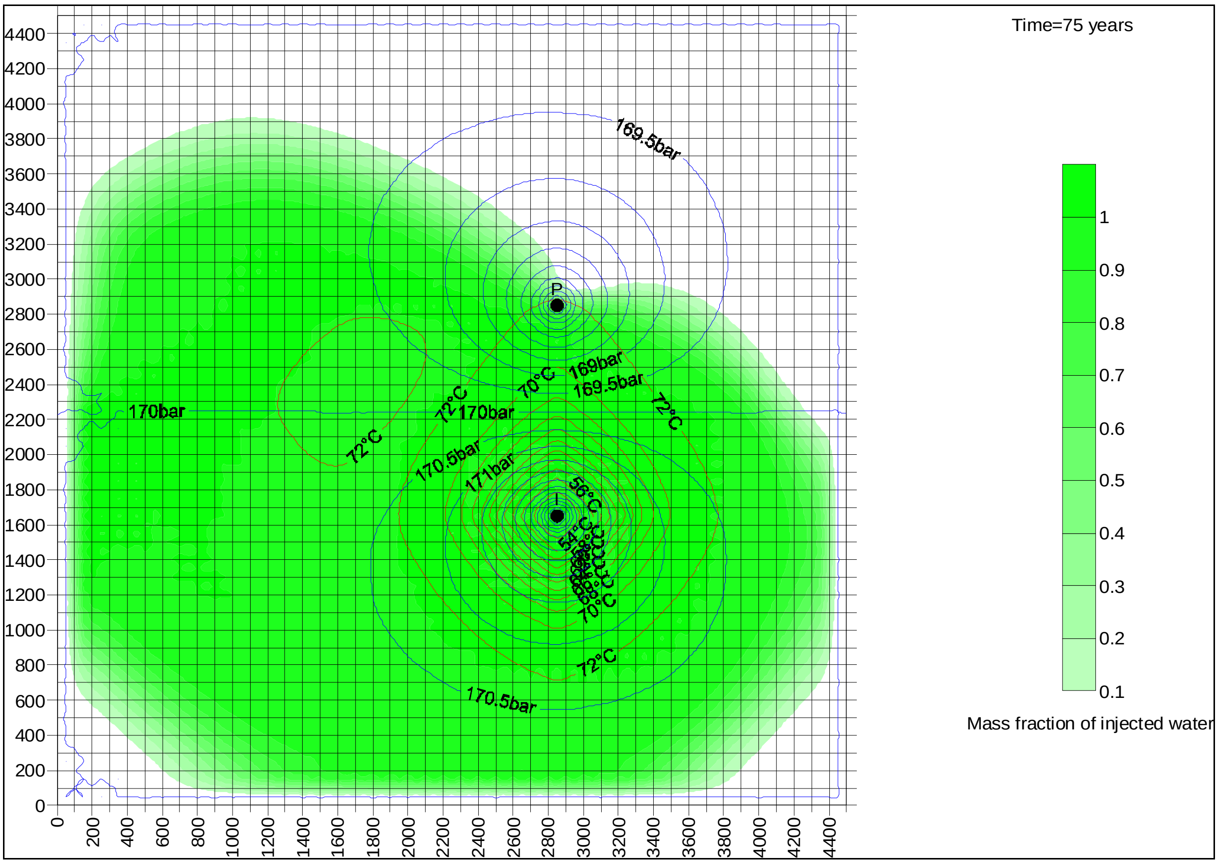


Figure 14c: Scheme 3. Simulated pressure/temperature/mass fraction of injected water

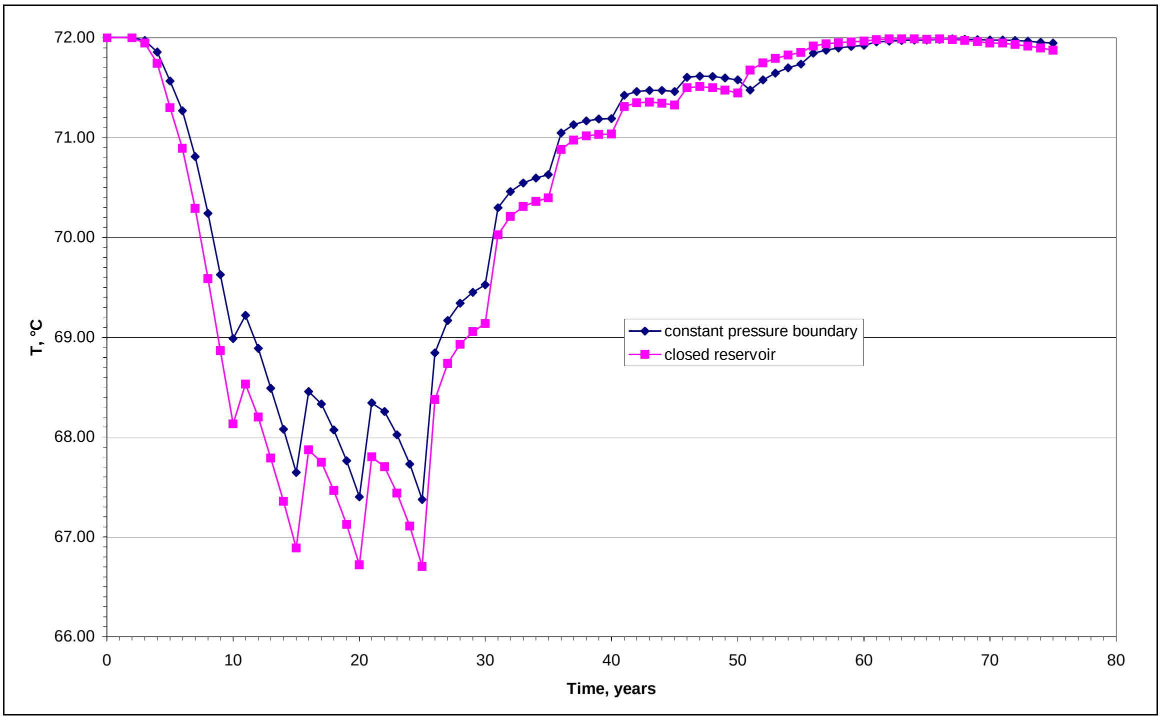


Figure 15: Model calculated temperatures at half well spacing

CONCLUSIONS

Owing to the non-renewable character, at human time scale, of geothermal resources, sustainable heat mining is a key reservoir management issue in designing and implementing relevant exploitation strategies.

This paper reviewed the basic heat mining concepts and selected reservoir engineering methodologies. Those addressed water injection, tracer tests, reservoir simulation and risk assessment among which the first quoted plays obviously a dominant role in upgrading reservoir performance and well deliverabilities thus securing exploitation longevity.

These issues were illustrated on a case study, borrowed to the well documented Paris Basin geothermal district heating scheme, and concluded by the simulation on a representative well doublet scheme of a tentative sustainable development scenario over a seventy five year life. Final results proved consistent with initially contemplated expectations as no thermal breakthrough whatsoever was noticed.

As strengthened by the geothermal exploitation record worldwide, lifetimes nearing one hundred years cannot be longer regarded as utopia, whatever the scepticism once contemplated by conventional energy planners.

Summing up, everything considered sustainable reclamation of geothermal heat has a good chance.

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