RESERVOIR ENGINEERING

Introductory Lectures No. 2

by

Jónas Elíasson, professor, Lic.techn.

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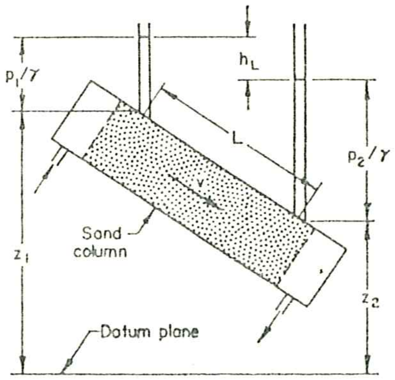
1. RESERVOIR PROPERTIES

1.1 Rock properties

Rock properties of interest to the reservoir engineer are global properties defining the flow resistance and fluid storage capacity of the rock mass. To obtain this information one has mainly to rely on geological and geophysical evidence brought about by field investigations. These properties are mainly function of the distribution of cracks and pores within the rock mass, which is very inhomogeneous in this respect, there are usually great variations from point to point (microscale variation) so information obtained by testing of small samples in the laboratory is usually of limited value.

The rock properties of greatest interest are as follows:

Permeability Coefficient K is defined according to Darcy's law (Fig. 1)



$$V = K \cdot i = K \cdot \frac{h_L}{L}$$

K has the dimension of velocity. It depends on the viscosity and density of the fluid and geometered propertrical properties of the rock. Another definition of permeability which is independent of fluid properties is the intrinsic permeability.

$$k = \frac{\mu}{\rho g} k$$

μ: dynamic viscosity of the fluid

ρ: density of the fluid

g: acceleration of gravity

k has the dimension of area, usually expressed in DARCY

$$1 \text{ DARCY} = 0.987 \cdot 10^{-12} m^2 = 1.062 \cdot 10^{-11} ft^2$$

k varies within wide limits. ENGELUND (1953) gives for homogeneous sand

$$k = c d_{10}^2 \frac{n^2}{(1-n)^3}$$

d^{10}: 10% sieve diameter in mm

n: porosity

c is a constant for individual formations, but varies with factor 5 between different formations.

In rock formations the permeability is more or less due to cracks and fissures. Local k values show great variation. The reservoir as a whole has a gross average permeability which is more than all other factors responsible for the thermodynamical characteristics of the reservoir and its energy capacity.

TABLE I.

Permeability of various reservoirs.

Field	Permeability in millidarcy Horizontal	Vertical
Broadlands, N.Z. average		1
- " -, central 1 km^2		100
Lardarello, Italy	10	10
Olkaria, Kenya	19	13
Wairakei, N.Z.	100	10
Long Valley, U.S.	30-50	
Svartsengi, Icel.	1000	100

The figures in table I are estimates of global values by various researchers. Global permeability coefficients (k-values) may be estimated by natural heat output studies, pumping test analysis or more often by avaraging local well-permeabilities. The only local permeability values of interest are well permeabilities, these are estimated from injection tests, step drawdown tests (well completion tests) or pressure build-up tests. Permeability values brought about by such tests may be affected by skin effects, which are local alterations in the flow field in the immediate vicinity of the well. These alterations may be due to disturbances of the rock during drilling, or concentrated inflow into the well where turbulence is developed and Darcy's law breaks down.

Porsity is actually the void fraction of the rock mass, i.e.

$$n = \frac{\text{Total pore volume}}{\text{Total volume}}$$

All the pores are filled with fluid (liquid or gas), but some of the pores are closed, and some fluid is electro-chemically bounded to the rock minerals, so when water is flowing within the reservoir, only a part of the water in storage is actually in motion. If we define

$$n_e = n \cdot \frac{\text{Fluid free to move}}{\text{Fluid in storage}}$$

then n_e may be referred to as the effective porosity. This is usually much smaller than the real porosity, especially when all the reservoir is liquid saturated.

Porosity is usually estimated from resistivity logging or radioactive logging (well - logging).

Estimations of effective porosity are very difficult, and cannot be obtained by standardized methods. It is obvious that it is the effective porosity rather than the total porosity that defines the volume of fluid available for harnessing..

Compressibility. The coefficient of bulk compressibility is defined as fractional changes in bulk volume per unit change in effective stress

$$\alpha_r = -\left(\frac{1}{V}\frac{dV}{dz}\right)$$

The total stress σ at any point in a confined reservoir may as a rule be treated as a constant, equal to total weight of overburden in the horizontal plane. Total stress is composed of effective stress (grid stress in the rock mass) and fluid pressure.

$$\sigma = \sigma_z + p$$

Which defines σ_z

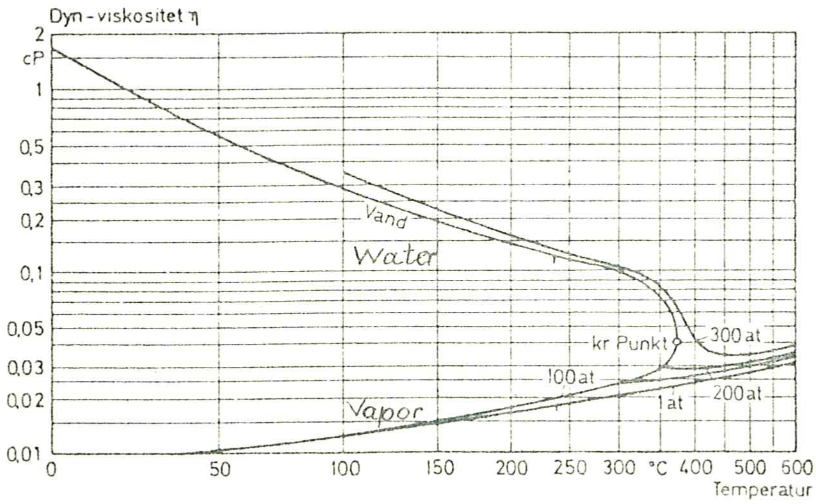
α_r is constant as long as the rock responds to changes in stresses as an elastic medium, and in that stage the comppression and stress changes are reversible. For larger changes in stress the compression becomes plastic and irreversible. Plastic deformations are much larger than elestic determations and can reduce the effective porosity irreversibly so the permeability may be permanently decreased.

1.2 Fluid properties and state

Most important of fluid properties are the density and viscosity. Distinction must be made between dynamical viscosity μ and kinematic viscosity ν

$$\nu = \frac{\mu}{\rho}$$

ρ: density (unit mass)



Den dynamiske viskositet i centipoise for vand og vanddamp ved forskellige temperaturer.
1 cP = 1,02 · 10^{-4} kpsek/m²

Fig. 2. Dyn. viscosity for water and steam in centipoise.

$$1 \text{ cP} = 100 \frac{\text{dyn sec}}{m^2}$$

Fig. 2 shows that the viscosity depends heavily on the temperature but variation with fluid pressure is unimportant.

Density varies slowly with temperature. It is usually listed in thermodynamical tables together with the thermodynamical properties. Fluid enthalpy is the thermodynamical property of greatest interest to the reservoir engineer. In a point in the reservoir where x is the mass fraction of steam of the fluid we can calculate the total enthalpy,

$$H = xH_V + (1-x)H_L$$

where H_V and H_L are the specific enthalpies of the vapour and liquid, these are functions of state, i.e. temperature and pressure of the liquid. Let T denote the temperature then we have,

$$H_V(T) = H_L(T) + \cancel{P}\ r$$

r: Heat of vaporization.

Let us note that we have at saturation

$$P = P_b(T)$$

From the reservoir engineering point of view the fluid chemistry is a fluid property. Of main interest are the dissolved solids and noncondensable gases. The solids and gases interact with the rock according to complicated laws of chemical equilibria and reactions that are functions of pressure and temperature, and time. The silica thermometer and other chemical thermometers are examples of the practical use of such laws.

When all fluid properties are known within a reservoir, then the complete state of the reservoir is defined. Above we said that the temperature and pressure define the state of the fluid. Actually, knowledge of any two of the properties define all the others so these can be calculated. To understand this, and the meaning of it for reservoir engineering we take two idealized (unrealistic) examples. Visualize two reservoirs filled with ideal fluid. The liquid ideal frictionless liquid, and the vapour ideal friction less gas. The two reservoirs are two extremes, one is static (no fluid flow) the other dynamic (fluid constantly flowing). Both are isolated.

In the static reservoir the temperature distribution will be uniform, the temperature is the same everywhere equal to T say. The pressure will be hydrostatic. The vapour phase will be seperated from the liquid phase and we get a picture of the state of the reservoir as shown on fig. 3.

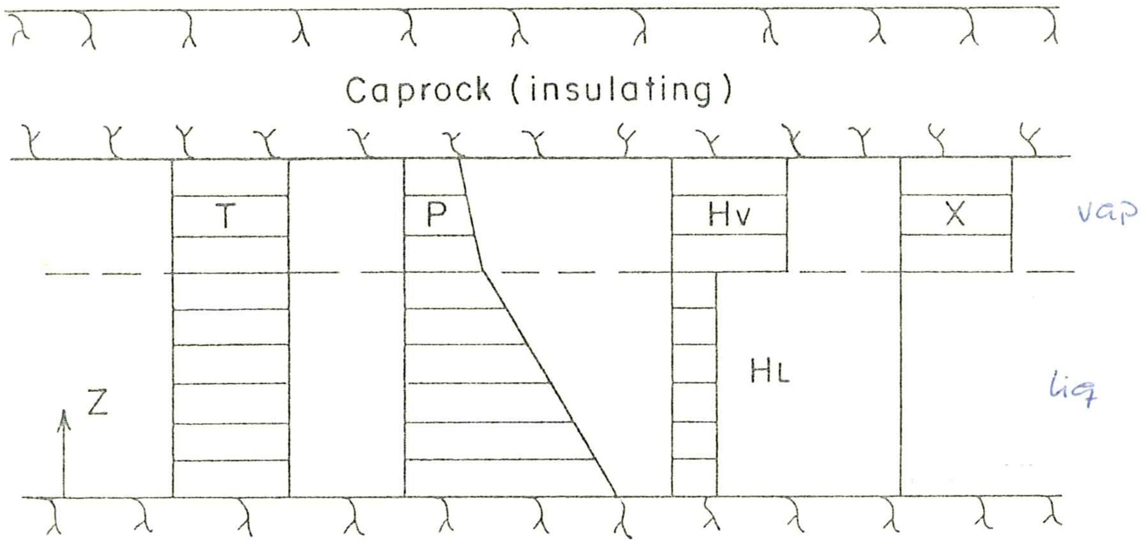


Fig. 3. State of an ideal static reservoir.

We measure the temperature and pressure at the top of the reservoir just beneath the caprock. We find that $T > T_b(p)$ (boiling point at the measured pressure). From thermaodynamical tables we find the density, calculate the pressure downwards by the hydrostatic pressure relation.

$$\frac{dp}{dz} = - \rho g$$

At a certain depth we find

$$T = T_b(p)$$

from there and down we have liquid and steeper rise in pressure. The enthalpy is easily calculated. For ideal fluids it is function of temperature alone.

In the dynamic reservoir the fluid is flowing. Ideal fluids flow with constant enthalpy so the enthalpy is constant everywhere. The flow is frictionless, so the pressure distribution is still hydrostatic Let us assume that the temperature and enthalpy is known just beneath the caprock. From thermodynamical tables we get the specific enthalpies corresponding to the measured temperature and the saturation pressure, (boiling point pressure). We can now calculate the vapor mass fraction x and the density and use the hydrostatic relation to find the pressure gradient. Use this to calculate the pressure a little bit further down, find new temperature, repeat the whole thing and in this way we integrate the pressure profile numerically down until we come to the depth where x = 0. Below it there is only liquid and constant temperature

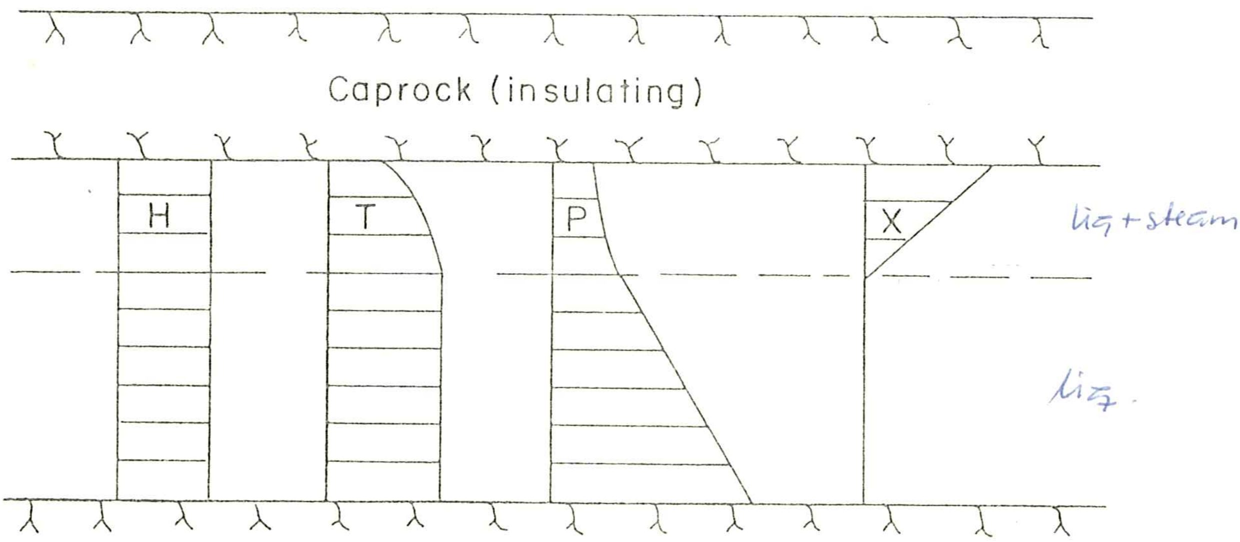


Fig. 4 State of an ideal dynamic reservoir.

In both cases we have seen that one measurement of two properties defines the complete state of the reservoir. This is because the static reservoir is isothermal and the dynamic reservoir is isenthalpic in the thermodynamical sense of definition. Real reservoirs are neither isothermal nor isenthalpic, but the isothermal and isenthalpic approximations may be used to calculate the state of certain regions within them. These small examples also demonstrates the main purpose of reservoir engineering: To calculate the state of the reservoir from minimum of information, in order to find the most feasible method to exploit energy.

1.3 Aquifer properties.

Aquifer properties are of course defined when rock and fluid properties are separately defined. But in the literature one comes across several parameters that are combined quantties. We will name a few.

Storage coefficient: is defined as the volume of water released by unit volume of reservoir for unit drop in pressure head. It depends on the compressibilities of the rock and the water as follows

$$S' = \rho g(\alpha_r + n\alpha_f) \text{ (lenght}^{-1}\text{)}$$

$Q = \Delta h \cdot S' \cdot V$

$Q = \Delta h \cdot S \cdot A$

Volume

Area

α_f = fluid compressibility m^2/N

In horizontal flow studies, a storage coefficient that depends on the aquifer thichness is used for aquifers with hydrostatic pressure.

$$S = \rho g D\ (\alpha_p + n\alpha_f) \text{ (dimensionless)}$$

representing the water released from storage per unit area.

Transmissivity: is usually denoted by T and is simply

$$T = KD\ m^2/s$$

Barometric efficiency: Fluctuation in atmospheric pressure causes fluctuations in the water level of wells. We have

$$\text{B.E.} = \frac{\text{waterlevel changes}}{\text{Atm. pressure head changes}} < 1$$

B.E. is related to S'

$$\text{B.E.} = \frac{n\rho g\alpha_f}{S'} = \frac{1}{1 + \dfrac{\alpha_r}{n\alpha_f}}$$

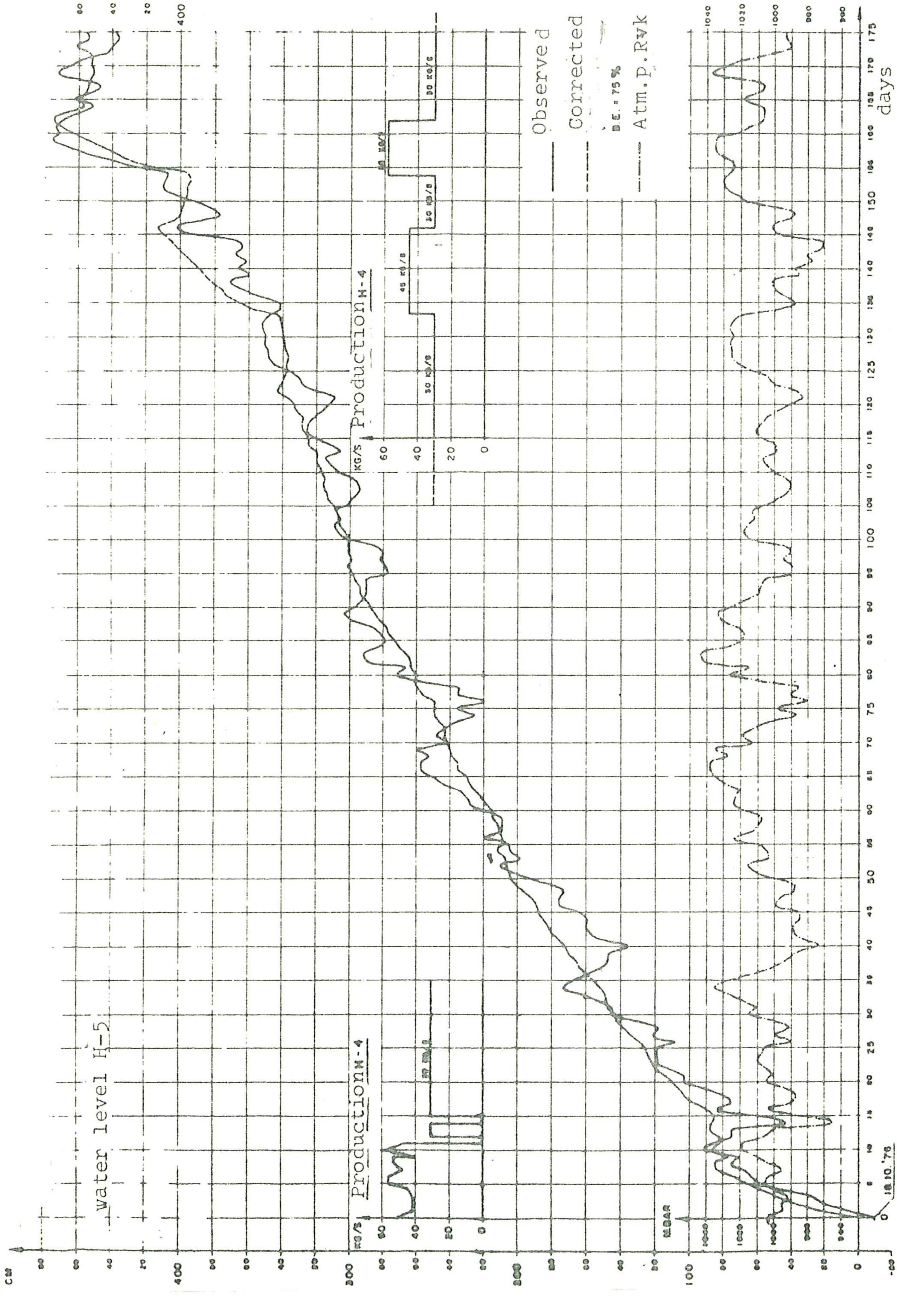


Fig. 5. Water level changes, well H-5, Svartsengi.

Fig. 5 shows barometric water level fluctuations in a 1500 m deep well, 240°C hot.

Relative steam and water permeabilities: When steam and water are flowing in mixture through rock, studies of wellfluid entnalpy have indicated different permeabilities of the steam flow and water flow. The ratio between these permeabilities and the true (intrinsic) permeability are called relative permeabilities, and are usually listed as functions of water saturation.

It is possible to find physical arguments for the relative permeabilities. The numerical values of relative permeabilities are very uncertain, and the use of them in flow equations is disputable. Considerable research is being done on this subject throughout the world (KRUGER and RAMEY 1978).

1.4 Reservoir Characteristics.

No system exists to classify geothermal reservoirs according to their characteristics. A certain terminalogy and certain phrases are in use in the literature and it is useful to know what exactly there is ment by them.

Vapor dominated and water dominated reservoirs. Most reservoirs contain either water or mixture of water and steam. Reservoirs where the wells flow dry (or almost dry) steam are called vapor dominated. This means that the reservoir fluid is dry steam at wellhead pressure, but not at reservoir pressure. Boiling water that flows through a rock mass towards a well, is cool off due to the boiling and thereby the water can draw head from the rock. The wells can thus discharge dry steam, (or high entalphy fluid) although the reservoir is not vapor dominated in the undisturbal state. Important to note is, that steam will seek upwards in the reservoir driven by a strong buoyancy force due to its large specific volume. Vapor dominated reservoirs must therefore be solidly confined, i.d. closed in under a nearly impervious layer (caprock).

Low temperature and high temperature reservoirs: This is a classification according to base temperature, originally proposed by G. BÖDVARSSON:

Base tempteratures lower than 150°C are called low, higher than 180°C high temperature, but there does not seem to be any general agreement about the temperatures inbetween these limits. This classification has special significance in Iceland because most low temperature geothermal resources in the country yield water of good quality (low content of dissolved solids). This is not the case elsewhere. E.g. are low temperature geothermal brines exploited in France.

Boiling curve. This feature is often seen in the literature, in most cases it is a pre-calculated curve (Fig. 6a) but as shown in Fig. 6b, the boiling curve is the boiling point for actual reservoir pressure at the corresponding height so in fact it is a real reservoir characteristic.

In this respect it must be mentioned that well pressure and temperature logs do not neccessarily show actual reservoir pressures or temperatures at all depths because of internal flow in the well, either of convective nature or between aquifers.

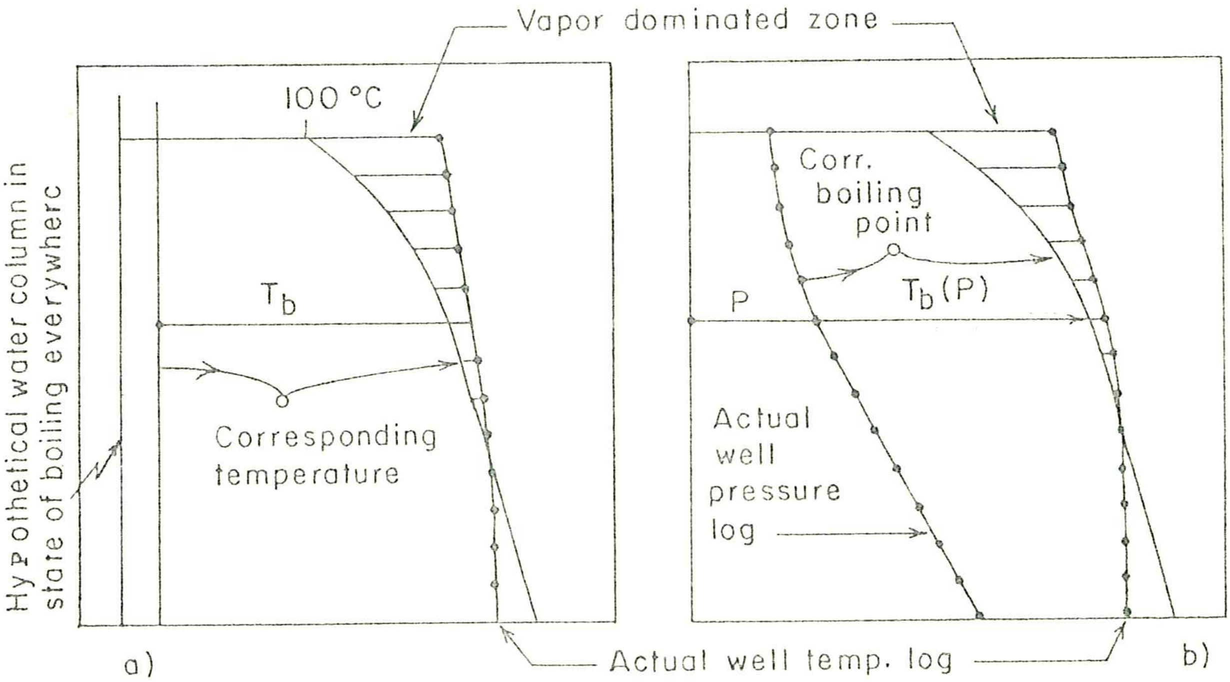


Fig. 6 wrong a) and right b) boiling curve

Fig. 6 a) wrong, and b) correct, boiling curve.

1.5 Conceptual reservoir models.

To build a conceptual model of a geothermal reservoir, is basically to gather all available hydrogeological information into one picture where all the elements are compatible with each other. A conceptual model should show:

A hydrogeological section with aquifers and aquicludes separately designated.

Natural discharge and recharge areas.

Direction of flow in aquifers.

Impervious boundaries.

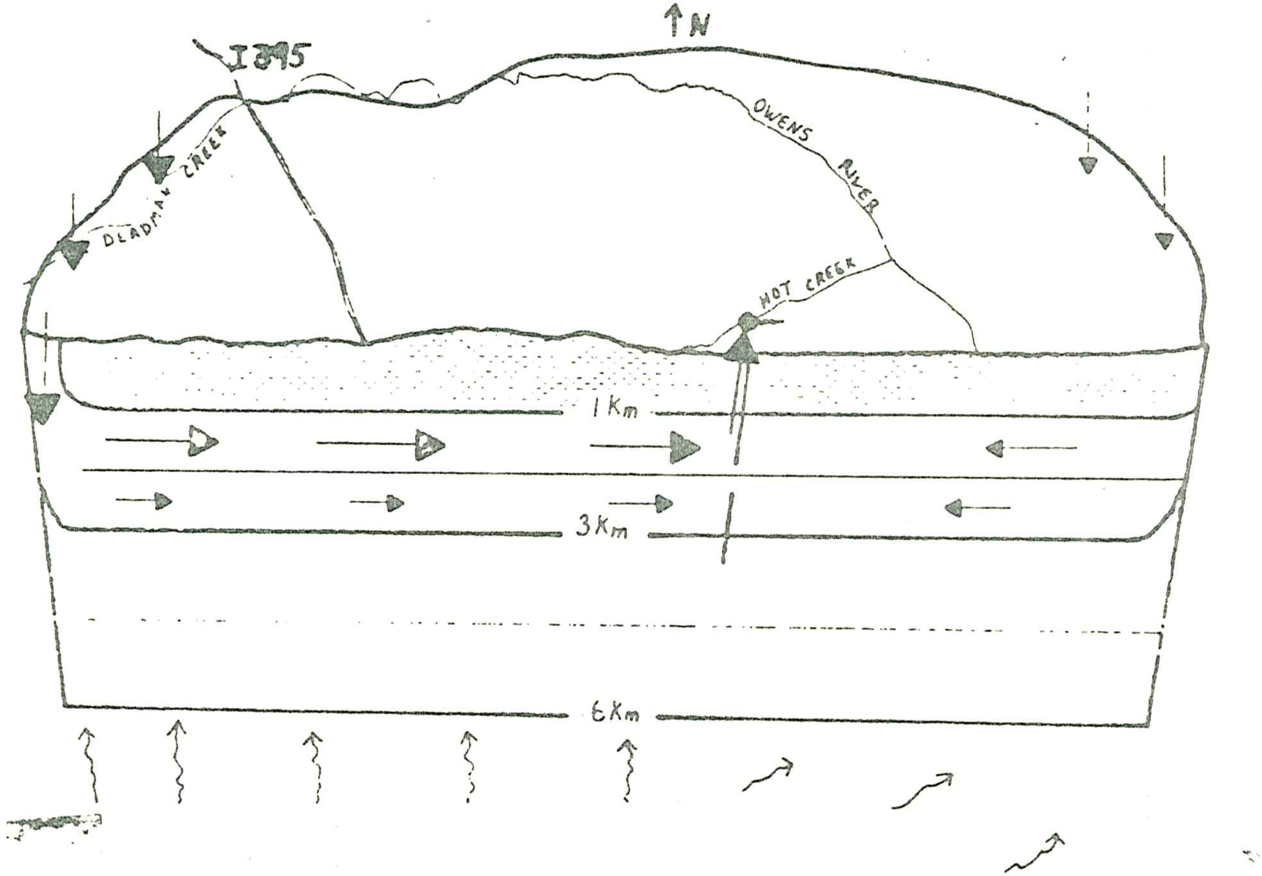
Such a model is a great help in planning further investigations, and it is a neccessary basis for all reservoir calculations.

Conceptual models are often speculative in the details, and for that reason difficult to work with. So much is it neccessary to use <u>all</u> available information to construct them.

Fig. 7 shows a conceptual model of the Long Valley hydrothermal system, California U.S.A. (SOREY, 1976). It shows a 450 km^2 caldera with a two-layered aquifer. Recharge is along the caldera boundary discharge is all in the Hot Creek Gorge. The model is used for numerical calculation of the temperature and pressure pattern. From such calculations one can e.g. estimate if reservoir pressure drop from exploitation causes increased recharge.

Fig. 8 shows a conceptual model of the Olkaria Geothermal field, Kenya (SWECO & VIRKIR). It shows a vapor dominated reservoir overlying a water-dominated zone. Heating is from an unidentified heat source below, steam escapes through a fault zone. Note the complicated steam-waterflow picture.

Fig. 9 shows a conceptual flow model (not published) from REYKJANES, Iceland. Water percolates through a deep tectonic fault and feeds many reservois on its way.



Block diagram showing conceptual model of Long Valley hydrothermal system.

System consists of five horizontal layers having properties listed in text. Patternless layers between depths of 1 and 3 km represent hydrothermal reservoir in fractured, densely welded Bishop Tuff. Recharge to the reservoir is by way of the caldera rim fracture in the west and northeast. Discharge is by way of faults and fractures to springs in Hot Creek gorge.

Fig. 7. Long Valley Model.

Nr 28

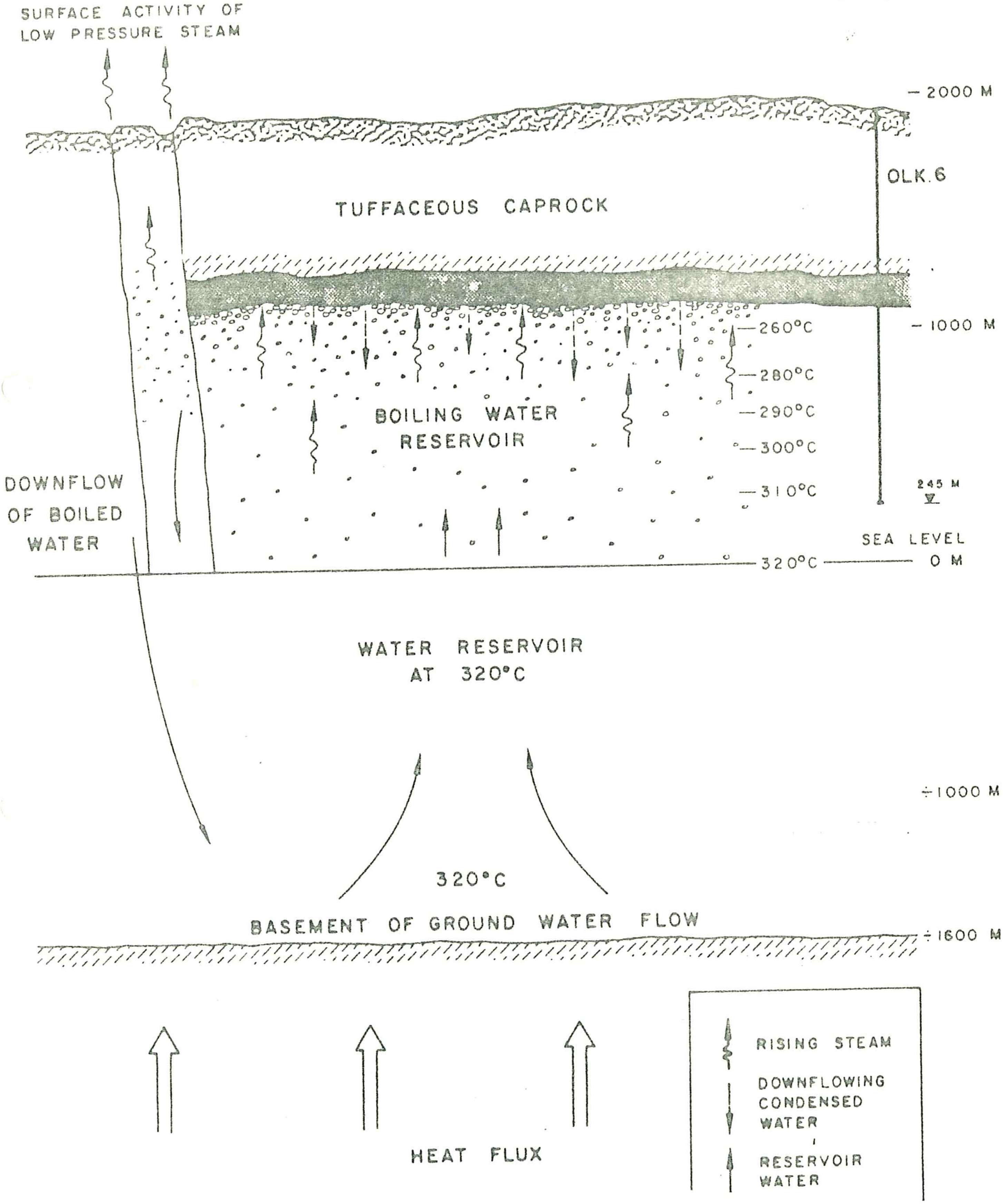


Fig. 8. OLKARIA Model.

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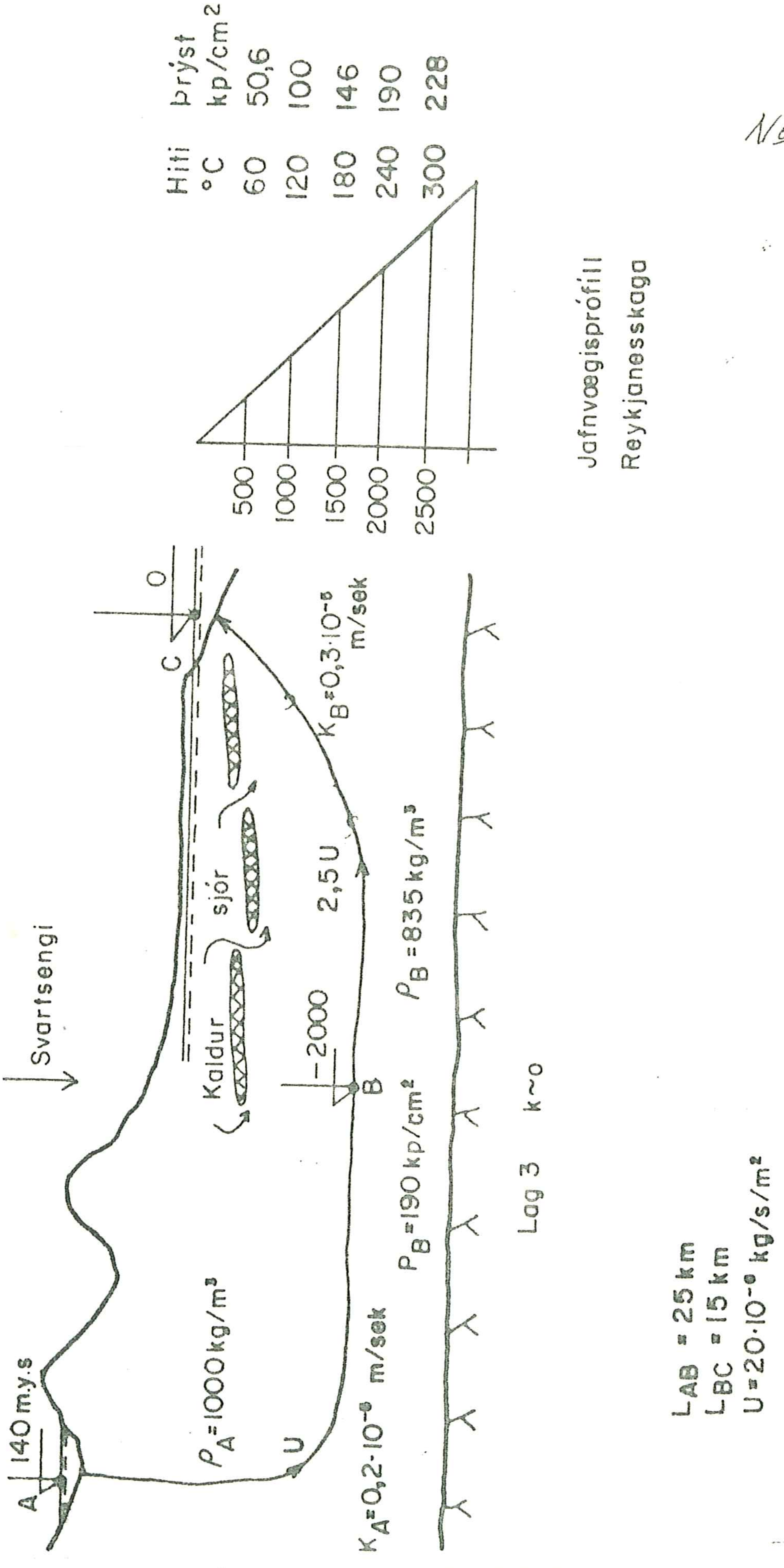


Fig. 9. REYKJANES Model.

2. RESERVOIR MECHANICS.

2.1 Groundwater Convection.

A hydrothermal system (recharge - reservoir - discharge all put together) may be looked upon as a thermodynamical engine that pumps energy from the interior of the earth by means of free or forced convection. In free convection the flow is driven by the density gradients and there is a close non-linear relationship between the temperature distribution and the flow field. In forced convection the flow is driven by external pressure gradients and more or less independent of the temperature. Flow within geothermal reservoir is often of a mixed type where both external pressure gradients and internal temperature distribution play there role. Often we have the situation that internal flow in the reservoir is free-convection type, but flow towards wells is almost entirely forced-convection type.

Free convection by single-phase fluids through homogeneous thin layers takes place in regular hexagonal flow-cells (Benard-cells).

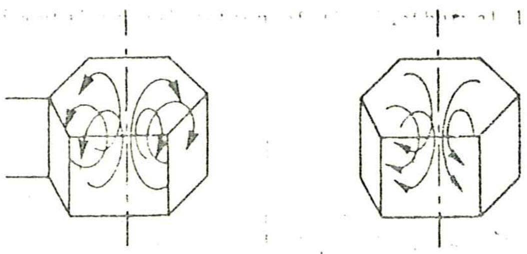


Fig. 10. Flow in Benard-cells.

The flow is upwards in the middle when the fluid is liquid, down when it is gas (PALM 1960). The flow characteristics are functions of the Rayleigh number

$$Ra = \frac{\Delta\rho c D K}{\lambda}$$

$\Delta\rho$: Maximum density differnce.

c : Heat capacity of rock (0.3 kcal/kg°C)

λ : Heat conduction coefficient (0.4 - 0.5 average for the earth's crust cal/(m s °C))

D : Thickness of layer m

When there is no convection (low temperature differences) the heat flux is constant everywhere and the temperature distribution is linear everywhere (constant temperature gradient) for Ra $> 4\pi^2$ ($\simeq 40$) convection starts and the temperature gradient is disturbed (ELIASSON 1973).

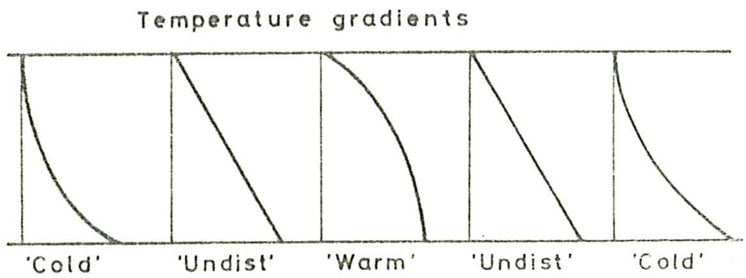
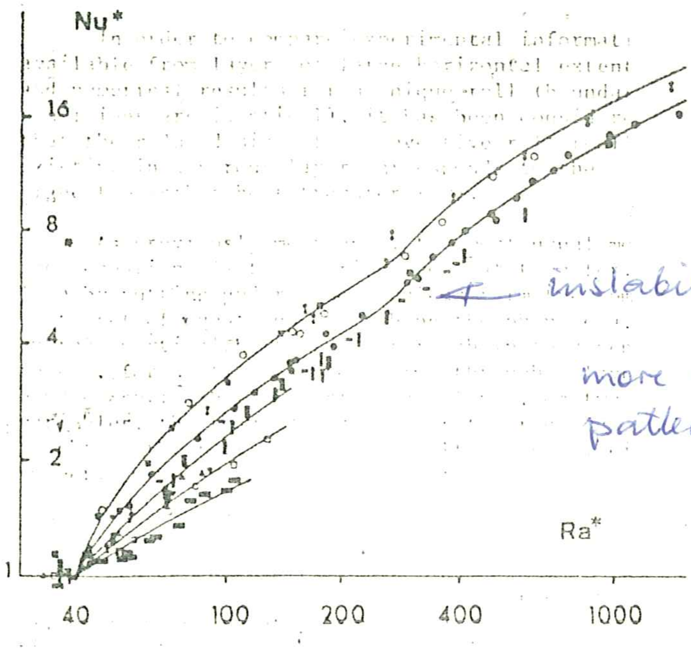


Fig. 11. Temperatur gradient disturbed by convection.

We see immediately that the "hot area" gradient has a great resemblance to what we find in geothermal areas. The heat flux caused by such convection is measured by the Nusselt's number.

$$Nu = \frac{\text{Heat flux with conv.}}{\text{Heat flux without conv.}} \qquad \text{same temperature gradient.}$$



instability of regular inflow sets in more complicated flow pattern above ~250

Fig. 12. Nu - Ra experimental results (Combarnous 1978).

By using Fig. 12 it is possible to estimate the natural heat output of geothermal convective reservoirs. On the other hand it is possible to estimate Ra and thereby the gross permeability K if the natural heat output is known. Care must be taken that all the cell area must be included when area of the geothermal field is estimated and NU calculated, i.e. the downflow area must be included, when the heat flow <u>without</u> convection is estimated.

For low Rayleigh numbers, convection may be calculated, but above Ra = 250 the stability of the cells breakes down and secondary convection starts in smaller cells inside the big cells, (note the irregularity on the Nu - Ra graph). Fig. 12 shows a cross section through a stable cell (ELIASSON 1973).

Ra ~ 100

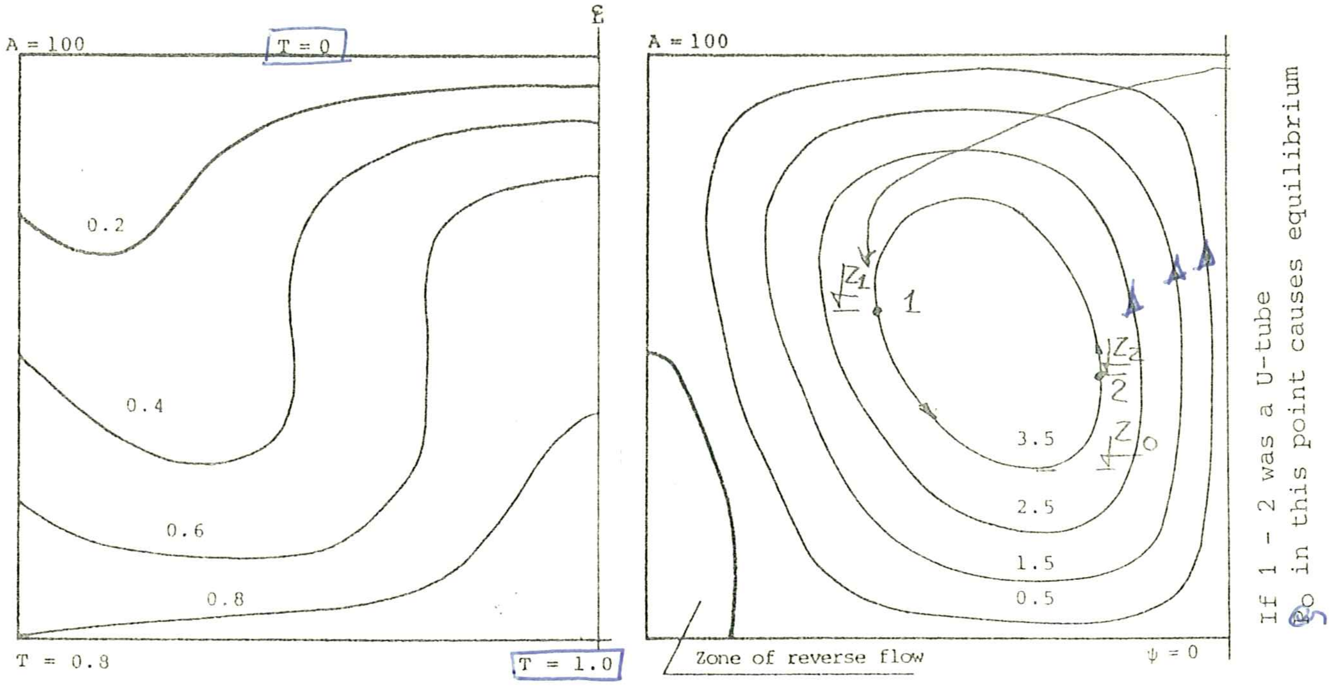


Fig. 13. Convection cell.

It may be shown, that between any two points on the same streamline the follwing relation is valid.

$$\bar{V} = K \frac{P_o + P_1 - P_2}{l\ \rho_o\ g}$$

P_o : Mean density of fluid.

$\bar{V}$: Mean velocity along streamline.

P_1, P_2 : Fluid pressures in 1, 2.

$\wp_o$: Buoyancy pressure explained in Fig 13.

l : Length of streamline 1-2.

To calculate the buoyancy pressure the density distribution along the streamline must be known. If it is linear then we have:

$$- p_o = \left(\rho_2 - \frac{\rho_2 - \rho_1}{2} \; \frac{Z_2 - Z_o}{Z_1 + Z_2 - 2Z_o} \right) g \left(Z_2 - Z_o \right)$$

$$- \left(\rho_1 + \frac{\rho_2 - \rho_1}{2} \; \frac{Z_1 - Z_o}{Z_1 + Z_2 - 2Z_o} \right) g \left(Z_1 - Z_2 \right)$$

This formula is a quick and easy check on flow velocities and permeabilities when temperature and pressure distribution is known. But strictly it is valid for stable convection only.

2.2 Hybrid convection models.

Fig. 12 shows that the heat flux to the surface is many times its normal value when there is convection in the reservoir. This heat flux has to escape through the confining layers (caprock) and it may be shown that this is almost impossible if the heat transport through the caprock is by conduction alone. There has to be some heat escape by hot water and steam discharge to keep the convection going.

When there is such outflow from an resevoir one has to expect that it is balanced by equal amount of inflow. We dont have to bother whether the inflowing heat comes with the recharge or by means of conduction from a deeplying source, we can calculate the heat that comes with the inflow this gives rise to the hybrid convection model Fig 14.

From Fig. 14 we can detuct the following continuity relations.

Point A continuity of:

Mass : $\dot{m}_{KU} = \dot{m}_{KN} + \dot{m}_{U} + \dot{m}_{g}$

Enthalpy : $H_{KU} \cdot \dot{m}_{KU} = H_{g} \cdot \dot{m}_{g} + H_{KN} \cdot \dot{m}_{U} + H_{KN} \cdot \dot{m}_{KN}$

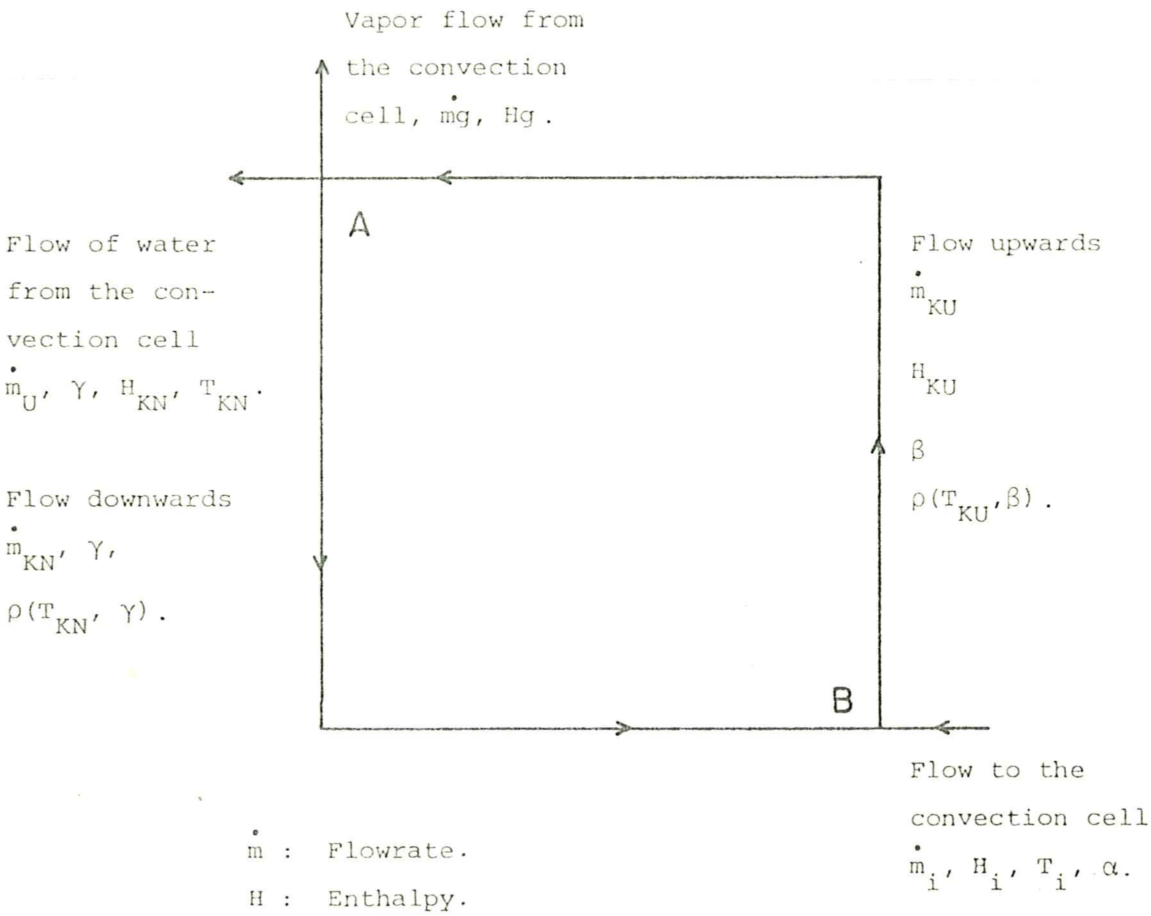
Concentration : $\beta \cdot \dot{m}_{KU} = \gamma \cdot \dot{m}_{KN} + \gamma \cdot \dot{m}_{U}$

Point B continuity of:

Mass: $\dot{m}_{KU} = \dot{m}_{KN} + \dot{m}_{i}$

Enthalpy: $H_{ku} \cdot \dot{m}_{KU} = H_{i} \cdot \dot{m}_{i} + H_{KN} \cdot \dot{m}_{KN}$

Concentration: $\beta \cdot \dot{m}_{KU} = \alpha \cdot \dot{m}_{i} + \gamma \cdot \dot{m}_{KN}$



$\dot{m}$: Flowrate.

H : Enthalpy.

T : Temperature.

$\alpha\beta\gamma$: Cloride relation to sea.

$\rho(T_{KU}, \beta)$: Liquid ensity of water with temperature T_{KU}, and consentration β.

Fig. 14. Hybrid convection model.

There are 12 unknowns and 6 equations. If we know the total natural heat output is makes the 7. equation but 5-6 quantities have to be known.

2.3 Reservoir response.

When fluid is discharged from the reservoir, it responds to the exploitation, and the first measurable effect is a drop in the reservoir pressure. When this pressure drop is investigated, horizontal flow is usually assumed. This is a rather crude assumption but usually good enough for operational purposes.

When the horizontal flow assumption is used, pressure drop from the discharge of individual wells can be superimposed. Taking the simplest case, one discharging well, the pressure drop at a given point in the reservoir can be written as

$$H = \int_0^\infty f(\tau)Q(t-\tau)\, d\tau$$

Q : discharge from the well.

h : drop in pressure head.

$f(t)$ is the response function. To learn a little bit about its properties let us take as example a constant pumping that starts at a moment $t = 0$. Then we have

$$h = Q \int_0^t f(\tau)d\tau = Q \cdot F(t)$$

We are interested to know what happens when $t \to \infty$, that is when we proced the exploration.

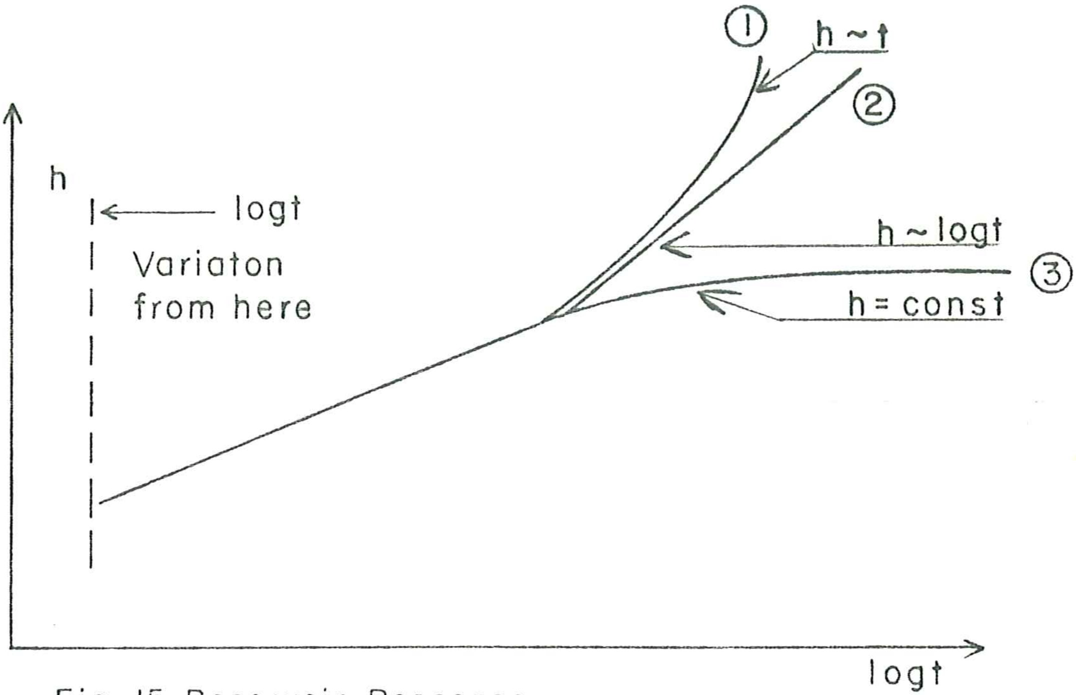


Fig. 15 Reservoir Response

Fig. 15. Reservoir Response.

The pressure drops fast in the vicinity of the well, then slower and slower still farther a way from the well, and builds the <u>draw-dawn cone</u>, well known in well hydraulics. This means that after some time has elapsed, will the draw-down (pressure drop) vary logarithmically with time, and plot as a straight line on semilog paper. Later on it will do one of three things.

1) The h-logt graph will gradually leave the straight line and become proportional to time. This means that the draw-down cone has struck impermeable boundaries all around the well and we are now emtying the reservoir at a constant rate.

2) The draw-down will leave the original line and settle on a new straight line with steeper slope. This means that the cone has struck impermeable boundaries at some distance from the well, but is still spreading to other sides.

3) The draw-down has produced new inflow (or diminished outflow) and the cone has stopped spreading.

All intermediate variations are of course possible. We have to note, that the resrvoir pressure has to be measured in the vaterdominated zone in the reservoir all the time or the steam zone all the time if we are to get meaningful readings from the reservoir response curve.

For all-water (low temperature) reservoirs a study of response functions is ideal to investigate the behavior of the reservoir and make projections into the future. The simplest of reservoir response functions is the one for a homogeneous confined aquifer of constant thikness and infinite horizontal extent in all directions from the well, in that case we have

$$h = \frac{Q}{4\pi T} \int_{u}^{\infty} \frac{e^{-u}}{u} \, du$$

T: Aquifer transmissivity m^2/s

u: $\frac{r^2 s}{4Tt}$

r: Distance from well m.

The use of this function is shown in almost every book on well hydraulics. It is formidable to analyse short-time response of low-temperature reservoirs and may even give accurate predictious some years ahead (THORSTEINSSON, ELIASSON 1970).

In here we have used the word "reservoir pressure". Pressure level is varying within the reservoir and we need time to find the correct response. It is therefore neccessary during testing and production to keep a complete output history for all wells tested or used.

2.4 Reservoir Capacity.

That we have exceeded reservoir capacity limits in our exploitation simply means that we don´t get the sufficient discharge from our wells. We can at any time stop the draw-down and run our reservoir at constant pressure, but then our discharge will fall off logarithmically, suppose our discharge falls off according to the relation

$$Q \doteq Q_1 \cdot e^{-t/t_k}$$

where t_k is a time constant we somehow happen to know. Suppose furthermore, that we have to stop due to economical reasons the exploitation when the discharge has fallen off to Q_o. Then is the total quantity of fluid we can produce while the discharge declines from Q_1 to Q_o

$$M \doteq t_k \; (Q_1 - Q_o)$$

which then is the present state capacity.

Suppose our reservoir contains RM total rock mass volume of known temperature and porosity. The total fluid content is

$$M' = nRM$$

This was originally believed to be the reservoir capacity, or "resource energy" (e.g. when M'was multiplied with the average entalphy). Later it was found out that only a small portion of the fluid could be economically brought to the surface and the formula took the form

$$M \doteq rnRM$$

wher r is a "recovery factor", usually of order 0.1 or smaller. Since then many formulas to preestimate reservoir capacity have been published, they are very different but do all have one thing in common: According to them every known geothermal field in the world has sufficient reservoir capacity for 50 years of technically feasible production. Now a very sensible man builds up his geothermal station in steps and uses the time to learn about the reservoir, so the question of total resource energy is nearly of academic interest.

Furthermore, we can only exploit what we can get into our wells, so well performance cannot be left out of the picture when we discuss reservoir capacity.

3. WELL PERFORMANCE

3.1 Pressure discharge relation.

To understand what happens in and around a discharging well lets look at Fig. 16. At first we look at:

a) Water dominated reservoir (low temperature reservoir).

Far away from the well the draw-down cone (NB: the curve where actual water pressure is equal to undisturbed reservoir pressure) declines logarithmically towards the well. If this trend is extended we end in a pressure level h_w' in the well.

The actual pressure level h_w in the well is much lower. This is because the fluid does not enter the well as evenly distributed flow, but rushes into the well in few concentrated feeder horizonts or water veins. We must therefore expect considerable turbulence in the flow just around the well and some inflow head loss. In accordance here with, we may write:

$$aQ^2 + bQ = h_w' - h_w$$

Q: well discharge.

The coefficients a and b are found by step-draw down tests. They are descriped in most books on well hydraulics. When they are known, and the reservoir residual draw-down is estimated by means of the response function, the total draw-down $h_o - h_w$ is known and a suitible pump arrangement can be designed. (Not shown on Fig 16). The whole procedure is in no way different from what we use on ordinary cold water wells.

b) Vapor dominated reservoirs (high temperature)

High temperature reservoirs that are water dominated at undisturbed reservoir pressure, must be expected to become vapor-dominated as exploitation proceeds as the water starts boiling when the reservoir pressure is lowered. In such reservoir the flow situation is very complicated.

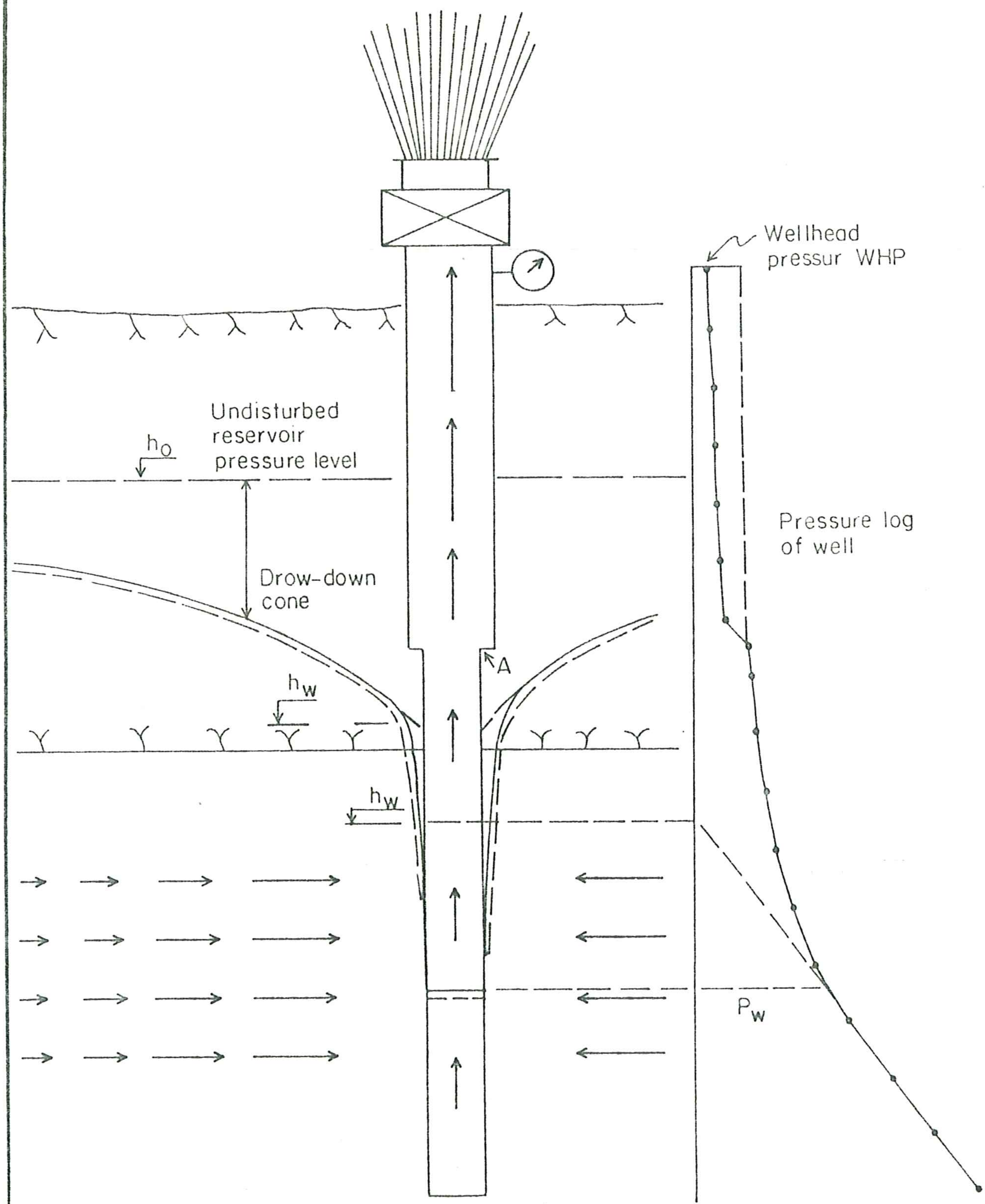


Fig. 16 Characteriestice of a flowing well

It is possible to find physical argument for, that in vapor dominated systems should the following relation hold:

$$aW^2 + bW = h'^2_w - h^2_w$$

W: Total well discharge (water + steam)

For $aW^2 >> bW^2$ we should have $W = \frac{1}{\sqrt{a}} \sqrt{h'^2_w - h^2_w}$

For $aW^2 << bW^2$ we should have $W = \frac{1}{b} (h'^2_w - h^2_w)$

Both equations are included in the following approximation:

$$W = c(h'^2_w - h^2_w)^n, \; 0.5 \leq n \leq 1$$

In vapor - dominated reservoir it is sifficult to define <u>a pressure head level</u> but we can also find physical arguments for the relation

$$h'_w \quad P'_w$$

wher P'_w is the reservoir pressure at a fixed reference level in the vapor-dominate zone. This should be the well bottom if the well is boiling (or with steam) all the way down. We have now finally arrived to:

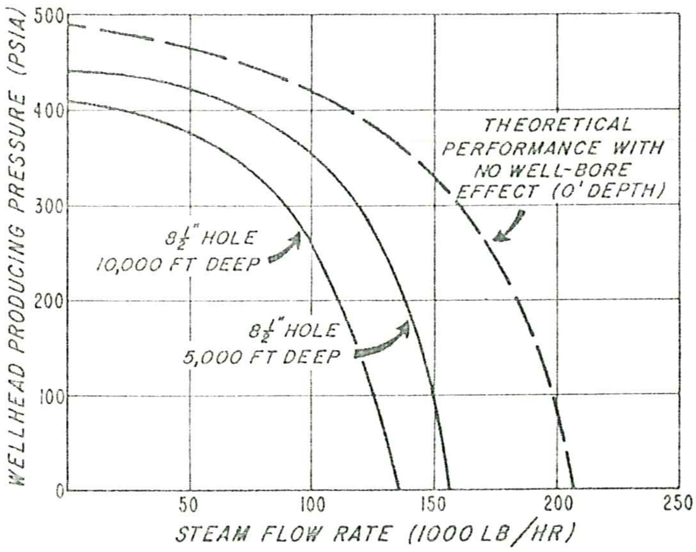
$$W = c(P'^2_w - P^2_w)^n$$

P_w: Pressure at reference level in the well.

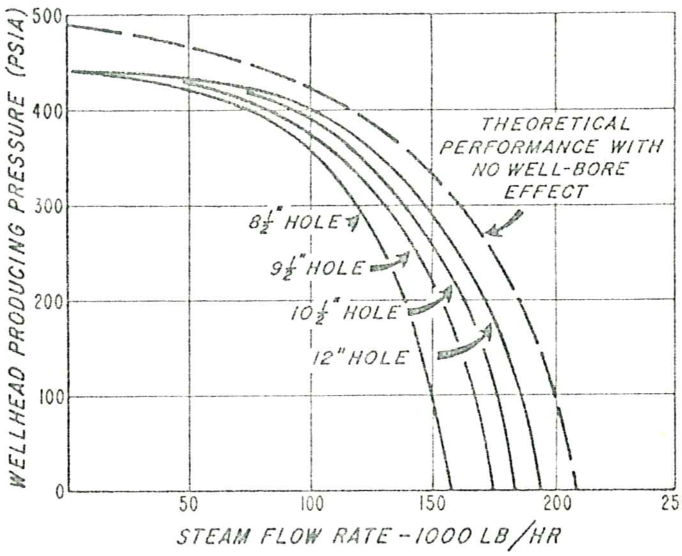
Fig. 18 shows typical pressure-discharge curves from the Geysers Field in California. We note that the curves do not follow the theoritical curve. The difference is called the well bore effect. To understand this look again on Fig. 16 and now study the pressure log.

Deep down there is linear pressure variation with depth. This is the water zone and the pressure is hydrostatic. At the water surface steam is formed the steam-water mixture is less dense than water and the pressure falls off less rapidly. Longer up there is a sudden pressure drop, at point A. There we have <u>choking</u>. It does not have to be there so we study it a little later, but imagine now that the pressure follows the dotted curve up to well-head pressure.

C. F. BUDD, JR.



Steam-flow rate vs. wellhead pressure for two well depths for a typical steam well at The Geysers.



Steam-flow rate vs. wellhead pressure for various equivalent pipe diameters for a typical 5,000-ft steam well at The Geysers.

Fig. 17. Typical W-WHP relations.

The difference

$$p_w - \text{WHP}$$

is the wellbore effect. We see on Fig. 17 that the wellbore effect is greater for narrow holes than for wide holes, it is also greater for deep wells than for shallow wells as was to be expected as the wellbore effect is essentially flow-resistance.

The last thing we have to examine is the pressure drop in A due to choking. This is a place where the flow velocity becomes sonic. Such <u>critical flow</u> has special tendency to happen in videning flow sections, as where we have a change in hole diameter, but scale deposits will do the same. At suitibly low flow velocities such critical flow does not occur, but when it occures, we can go on lowering the WHP (opening up the well) and the flow will <u>not increase</u>. When this happens at a pressure p_c, say, the pressure discharge graph will be a straight line with constant flow rate all the way down to zero WHP (take any constant flow-rate line on Fig. 17 as an example of what pressure-discharge relation we would get with choking).

The great wellbore effect in deep wells is depending on the distance from the feeder horizonts to the wellhead, so wells may be deepened without increasing the wellbore effect. On the other hand the wellbore effect will increase as shown in Fig. 17 if the water in the well sinks, or the pressure level in the well drops because of other reasons. Increased wellbore effect may occure from one of the following reasons:

1. Declining h_w and/or P_w due to depletion of reservoir pressure/ temperature.

2. Increased flow resistance in well due to scale deposits in liner or casing and/or damage of liner and casing that cause local flow contractions in the well.

3. Increased skin effect due to scale deposits in water veins or liner. ports.

3.2 Depletion of well output.

All three reasons for increased wellbore effect will have the same effect on the well output, i.e. the well will discharge the same fluid quantity as before the wellbore effect increased, but at lower WHP.

Fig. 18 shows calculatd W-WHP relations for a 1500 m deep well. The wells must discharge their fluid into pipeline systems at constant pressure, but it is evident that a well with characteristics as Fig 18, blowing at constant WHP, will yield smaller and smaller flow quantities, as reservoir pressure (aquifer pressure PA) declines.

Earlier we have stated how reservoir pressure drops with time. This will mean a drop in h_w value in Fig. 16, and the aquifer pressure will drop proportionally herewith. As a result we will have a depletion of the well output with time. In reality it is necessary to calculate reservoir capacity by this method, i.e. both reservoir haracteristics and well performance have to be taken into the picture.

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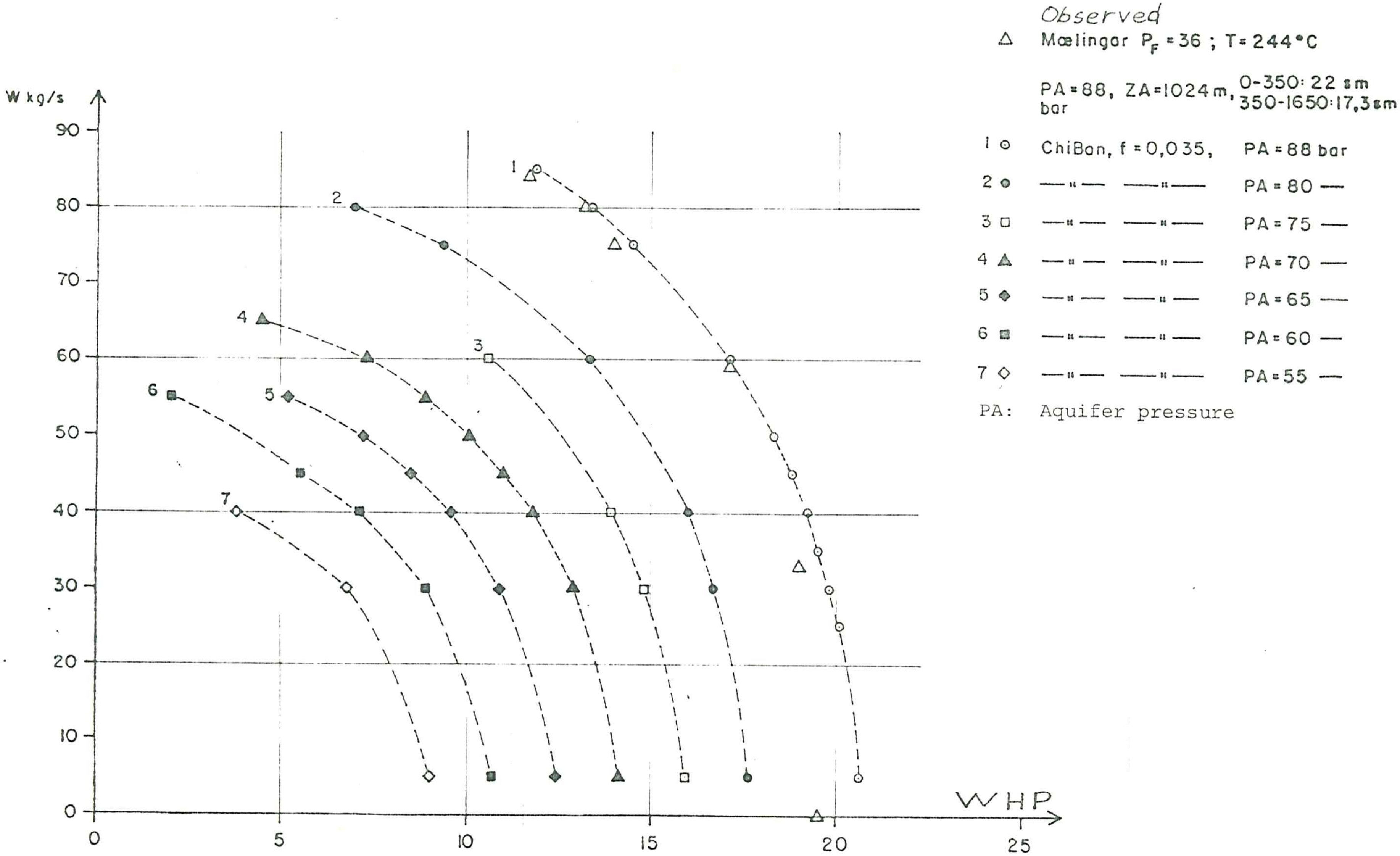

Fig. 18. Holutoppþrýstingur P_o bar absolut

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