The United Nations University

GEOTHERMAL TRAINING PROGRAMME
Orkustofnun, Grensásvegur 9,
IS-108 Reykjavík, Iceland

Reports 1996
Number 4

PERMEABILITY FROM PRESSURE BUILD-UP TESTS IN THE SE-KAMOJANG FIELD, WEST JAVA, INDONESIA

M. Irhas
PERTAMINA - Direktorat Eksplorasi dan Produksi,
Divisi Panasbumi,
Gd. Pramuka Kwarnas Lt.6, Jakarta,
INDONESIA

ABSTRACT

The report presents analysis procedures for the estimation of permeability in the SE-Kamojang field, West Java, Indonesia. The interpretation methods include semi-log, Horner plot, type curve matching, skin factor determination and calculation of other reservoir parameters. The calculations are based on a solution of the pressure diffusivity equation for the conditions prevailing at the Kamojang field. The results from four wells in the SE-Kamojang field indicate moderate to high transmissivities, and positive skin factor in three of them suggests flow restriction at those wells.

1. INTRODUCTION

The Kamojang geothermal field has been operated by Pertamina for 25 years with a total capacity of 140 MW_e, produced from 26 wells. Expansion in 1997-98 of the south-east sector at Kamojang is expected to add 2 x 30 MW_e to the plant. The Kamojang reservoir is vapour-dominated (Hochstein, 1975; Grant, 1979), with some liquid present in the pores of the reservoir (GENZL, 1984). Production is steam, as steam is the only mobile fluid, with liquid water immobile. However, the presence of liquid water means that two-phase conditions prevail in the reservoir.

This report presents analysis of pressure build-up tests in the SE-Kamojang field from wells KMJ-48, KMJ-49, KMJ-53, and KMJ-57 (see Figure 1). The report is the final part of the author's study at the United Nations University Geothermal Training Programme at Orkustofnun, Reykjavík, Iceland.

2. PRESSURE TRANSIENT ANALYSIS IN VAPOUR-DOMINATED SYSTEMS

Pressure transient methods have been used for decades in evaluating groundwater and petroleum reservoirs (Witherspoon et al., 1967; Matthews and Russel, 1967; Earlougher, 1977). These methods involve creating a transient condition in the reservoir by producing from (or injecting into) the formation.

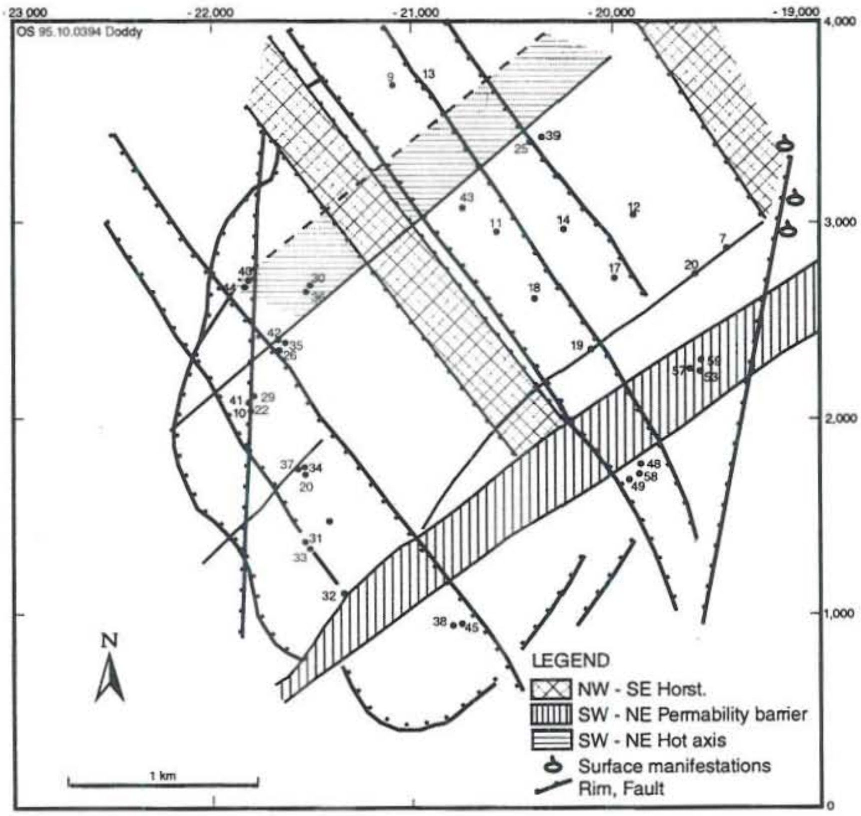

FIGURE 1: A structural map of Kamojang geothermal field with locations of wells (adapted from Robert, 1982)

The effect of the disturbance is then investigated by measuring the time dependent pressure changes that occur either at the active well (single well test) or at nearby shut-in (observation) wells (interference test). The main parameters obtained from these tests are the transmissivity (kh/μ) and storativity ($\phi c_t h$) of the reservoir region affected by the pressure transients. In the case of a single well test, one can also obtain a measure of the condition of the well from the so called "*skin factor*". If an indication of low permeability is found near the wellbore, perhaps as the result of a drilling mud invasion, the skin factor (s) will have a large positive value (10 to 30). Conversely, a negative value for the skin factor is indicative of fractures that intersect the well. Other useful information that can be obtained from pressure transient testing include preferential directions of permeability within the reservoir and the presence of discontinuities, such as faults.

Conventional pressure transient methods have been successfully applied to the analysis of field data from many geothermal wells, especially those completed in single phase reservoirs. The interpretation of data from two-phase geothermal reservoirs, especially those with highly heterogeneous fracture conditions, is much more complicated and requires specialized methods of analysis.

2.1 Theory for vapour-dominated systems with immobile water

Vapour-dominated systems are either saturated or superheated. Saturated system (wet steam system) means that the thermodynamic conditions of the fluid are in the two-phase regime and the temperature is a unique function of fluid pressure. In a superheated system (dry steam system) temperature and pressure are independent parameters.

Interpretations of temperature and pressure logs from the southeast sector of Kamojang field indicate that the main reservoir is vapour-dominated and in a saturated condition (Sasradipoera, 1995). A conceptual model of the SE-sector assumes a low permeability caprock of 500-1000 m thickness overlying a vapour-dominated reservoir of 240-246°C temperature. The essential components of the vapour dominated reservoir are an overlying condensated layer and a deep zone of boiling brine. Under exploitation the vapour-dominated reservoir can be locally depleted of water to form a dry (superheated) zone. Fluid flows in this exploited state are shown in Figure 2. The superheated zone formed in the zone of exploitation expands into the vapour-saturated region. There is a recharge of steam from the deep boiling layer and a recharge of steam and hot water from the condensate layer. There is also a possible recharge of cold groundwater, either into the condensate layer or through laterally adjacent groundwater aquifers.

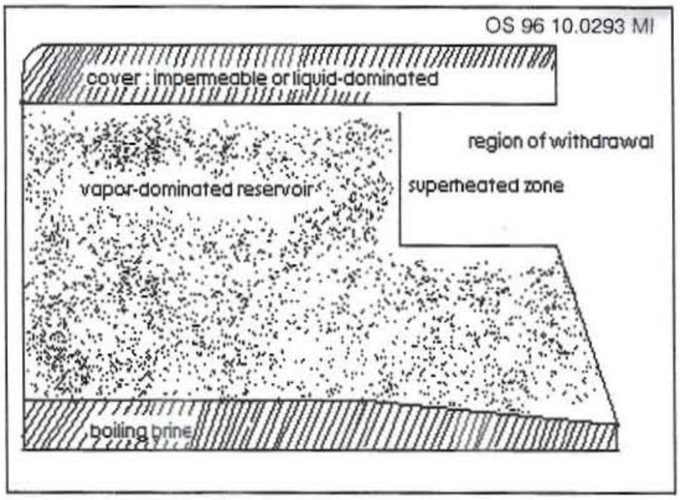

FIGURE 2: Exploited vapour-dominated reservoir (adapted from Grant, 1982)

A simplified case of a two-phase system is a porous medium containing water at or below residual (stagnant) saturation. The water is then immobile, it cannot move because its relative permeability is zero. The fluid flowing in the reservoir is steam, which is at saturation temperature due to its contact with the water. Observations would seem to indicate that the reservoir is dry, since only steam can enter the wells. The water reveals its presence in temperature and pressure logs through the saturated state of the steam.

Following are the basic equations forming the base for the analysis procedures for transient pressure testing in vapour-dominated systems. The equations involved are the balance equations for mass and energy, Darcy's law or momentum equation and an equation for two-phase apparent compressibility.

- The mass balance for a flowing fluid can be expressed as (O'Sullivan and McKibbin, 1989)

$$q_m = \frac{\partial A_m}{\partial t} + \nabla Q_m \tag{1}$$

For an explanation of parameters used in the equations, see nomenclature at the end of the report.

The mixture mass, A_m, can be expanded to

$$A_m = \phi(\rho_w S_w + \rho_s S_s) \tag{2}$$

$$A_m = \phi[\rho_w (1 - S_s) + \rho_s S_s] \tag{3}$$

since $S_w + S_s = 1$ or $S_w = 1 - S_s$

For radial flow and neglecting gravity forces, Darcy's law is written as

$$Q_m = -\frac{k}{\nu}\frac{\partial P}{\partial r} \tag{4}$$

For two-phase flow, Darcy's law for each flowing phase water, and steam is

$$Q_w = -\frac{k k_{rw}}{\nu_w}\frac{\partial P}{\partial r}$$

and

$$Q_s = -\frac{k k_{rs}}{\nu_s}\frac{\partial P}{\partial r}$$

with the total mass flux given as

$$Q_m = Q_w + Q_s$$

Substituting these relationships into the mass balance equation and writing it in radial coordinates gives for constant porosity

$$q_m = \phi\frac{\partial}{\partial t}[\rho_w(1-S_s) + \rho_s S_s] - \frac{1}{r}\frac{\partial}{\partial r}(rQ_w + rQ_s)$$

$$q_m = \phi\frac{\partial}{\partial t}[\rho_w(1-S_s) + \rho_s S_s] - \frac{1}{r}\frac{\partial}{\partial r}[(\frac{k_{rw}}{\nu_w} + \frac{k_{rs}}{\nu_s})kr\frac{\partial P}{\partial r}] \tag{5}$$

Equation 5 is the two-phase mass balance equation in radial coordinates for constant isotropic permeability.

Similarly the energy balance for the rock and fluid mixture can be expressed as

$$q_e = \frac{\partial A_e}{\partial t} + \nabla Q_e \tag{6}$$

From thermodynamics the internal energy is $U = H - P/\rho$. For geothermal application it will suffice to assume for the rock that $U_r \approx H_r$ and $H_r = C_r T$. Now the energy content, A_e, may be expanded as

$$A_e = (1-\phi)\rho_r C_r T + \phi(\rho_w U_w(1-S_s) + \rho_s U_s S_s) \tag{7}$$

and the energy flux, Q_e, as

$$Q_e = H_w Q_w + H_s Q_s - K_m \nabla T \tag{8}$$

Substituting Equations 7 and 8 into Equation 6 and writing it in radial coordinates gives

$$q_e = \frac{\partial}{\partial t}[(1-\phi)\rho_r C_r T + \phi(\rho_w U_w (1-S_s) + \rho_s U_s S_s)] + \frac{1}{r}\frac{\partial}{\partial r}[r(H_w Q_w + H_s Q_s)] - \frac{1}{r}\frac{\partial}{\partial r}(K_m r \frac{\partial T}{\partial r})$$

$$q_e = \frac{\partial}{\partial t}[(1-\phi)\rho_r C_r T + \phi(\rho_w U_w (1-S_s) + \rho_s U_s S_s)] + \frac{1}{r}\frac{\partial}{\partial r}[kr(H_w \frac{k_{rw}}{\nu_w} + H_s \frac{k_{rs}}{\nu_s})\frac{\partial P}{\partial r}] - \frac{1}{r}\frac{\partial}{\partial r}(K_m r \frac{\partial T}{\partial r}) \tag{9}$$

Now the mass and energy balance equations are combined with the assumption that we have local thermal equilibrium, neglecting capillary pressures and thermal conductance. Furthermore, the following constitutive relationships are used:

$$\rho_m = (1-S_s)\rho_w + S_s \rho_s$$

$$H_m = (1-x)H_w + x H_s$$

$$x = S_s \rho_s / \rho_m$$

where x is the steam mass fraction.

Eliminating terms $\partial S/\partial t$ and $\partial H_m/\partial t$ and assuming that the saturation gradients, temperature gradient and pressure gradient are small so that products of the gradients can be neglected, one can show that the resulting equation has the form

$$\frac{1}{r}\frac{\partial}{\partial r}(r\frac{\partial P}{\partial r}) = \frac{\rho_m \phi c_t}{(k/\nu)_m}\frac{\partial P}{\partial t} \tag{10}$$

This is the pressure diffusivity equation for two-phase conditions. It has the same form as for liquid systems, but various solutions for it are available in the literature for different initial and boundary conditions. For the two-phase case the expression for the system compressibility is complex, but may be simplified for practical purposes.

It has been shown that for a two-phase system, the system compressibility is governed by the effect of phase changes (Grant and Sorey, 1979). The phase changes cause an apparent compressibility which can be several orders of magnitude larger than the corresponding compressibilities for each phase or the rock.

Writing the system volume as

$$V = (1-\phi)\,V_r + \phi V_m \tag{11}$$

and defining the system compressibility from the resulting volume change by change in pressure gives:

$$c_t = \frac{1}{V}\frac{\Delta V}{\Delta P} \tag{12}$$

The energy released from the rock and water by the evaporation of some water is given by

$$\Delta E = [(1-\phi)\,\rho_r C_r + \phi S_w C_w \rho_w]\,\Delta T\,V \tag{13}$$

In the two-phase region pressure is dependent on temperature according to the saturation/boiling curve

$$\Delta T = \left(\frac{dT}{dP}\right)_{SAT}\Delta P$$

or

$$\frac{\Delta T}{\Delta P} = \left(\frac{dT}{dP}\right)_{SAT} \tag{14}$$

The Clausius-Clapeyron equation for the saturation curve can be written as

$$\left(\frac{dP}{dT}\right)_{SAT} = \frac{\rho_s \rho_w}{\rho_w - \rho_s} \times \frac{(H_s - H_w)}{T + 273.15} \tag{15}$$

The mass of water evaporized (ΔM) from the energy released is given by

$$\Delta M = \frac{\Delta E}{H_s - H_w} \tag{16}$$

As water, this mass occupied the volume $\Delta M/\rho_w$. After the phase change, the steam occupies the volume $\Delta M/\rho_s$. The change in fluid volume due to phase changes is then

$$\Delta V = \Delta M\left(\frac{1}{\rho_s} - \frac{1}{\rho_w}\right) \tag{17}$$

Substituting these relationships into the definition for compressibility, the apparent compressibility due to phase changes is then

$$c = \frac{1}{\phi V}\frac{\Delta V}{\Delta P}$$

$$c = \frac{1}{\phi V}\frac{\Delta M(\frac{1}{\rho_s}-\frac{1}{\rho_w})}{\Delta P} = \frac{1}{\phi V}\frac{\Delta E(\frac{1}{\rho_s}-\frac{1}{\rho_w})}{(H_s-H_w)\Delta P}$$

$$c = \frac{1}{\phi V}\frac{[(1-\phi)\rho_r C_r + \phi S_w C_w \rho_w]\Delta T V(\frac{1}{\rho_s}-\frac{1}{\rho_w})}{(H_s-H_w)\Delta P}$$

$$c = \frac{1}{\phi}\frac{[(1-\phi)\rho_r C_r + \phi S_w C_w \rho_w]}{(H_s-H_w)(dP/dT)_{SAT}}(\frac{1}{\rho_s}-\frac{1}{\rho_w})$$

$$c = \frac{1}{\phi}\frac{[(1-\phi)\rho_r C_r + \phi S_w C_w \rho_w]}{(H_s-H_w)(dP/dT)_{SAT}} \times (\frac{\rho_w-\rho_s}{\rho_s\rho_w}) \qquad (18)$$

or

$$\phi c_t = \frac{<\rho C>}{(H_s-H_w)(dP/dT)_{SAT}}\frac{(\rho_w-\rho_s)}{\rho_s\rho_w} \qquad (18a)$$

where $<\rho C>$ is the volumetric heat capacity of the wetted rock. For common values of rock and water densities and heat capacities, a reasonable approximation to this term is

$$<\rho C> = (1-\phi)\rho_r C_r + \phi S_w \rho_w C_w \approx 2.5\times 10^6 \ J/m^3K$$

with ρ_r = 2650 kg/m^3;
C_r = 1000 J/kg K;
ϕ = 0.1;
C_w = 4886 J/kg K at 250°C;
ρ_w = 800 kg/m^3;
S_w = 0.25-0.70.

A convenient numerical approximation for the apparent two-phase compressibility equation is available from Grant et al. (1982):

$$\phi c_t = <\rho C> x\, 0.42\, x\, 10^{-5}(P)^{-1.66}$$

where P is now in MPa. Substituting for a common <ρC> value, this becomes

$$\phi c_t = 10.5\,(P)_{SAT}^{-1.66}$$

2.2 Pressure build-up test

Pressure build-up testing requires shutting in a production well. The most common and simplest analysis techniques require that the well produces at a constant rate, either from start-up or long enough to establish a stabilized pressure distribution before shut-in.

The effects of the pressure build-up can be looked on as if an imaginary well located at the same point as the production well started injecting with the same flowrate as the prior production rate. Mathematically the shut-in period, when $q = 0$, can be treated as the sum of the pressure change due to continued production ($q = q_p$) and that due to injection at the same rate ($q = -q_p$) starting at the time of shut-in. Writing the solution for an infinite acting case with superposition in time and assuming that the logarithmic approximation applies, gives

$$\Delta P = \frac{q\mu}{4\pi kh}\left[\ln\frac{4k(t_p+\Delta t)}{\gamma\phi\mu c_t r_w^2} - \ln\frac{4k\Delta t}{\gamma\phi\mu c_t r_w^2}\right] \tag{19}$$

$$\Delta P = \frac{q\mu}{4\pi kh}\left(\ln\frac{t_p+\Delta t}{\Delta t}\right) \tag{19a}$$

Here t_p is the duration of production and Δt is the elapsed time after shut-in. As the equation shows, the pressure build-up data can be plotted vs log $[(t_p + \Delta t)/\Delta t]$ and the resulting straight line used to determine the transmissivity (kh/μ). Also by extrapolating the pressure to infinite time, when $(t_p + \Delta t)/\Delta t \rightarrow 1$, one can obtain an estimate of the reservoir pressure. This should be the original reservoir pressure provided the system acts as if it were of infinite areal extent or has a large recharge. If the system is bounded or other wells are in production, the extrapolation of the pressure data will yield an estimate for the average reservoir pressure.

2.2.1 Storativity

Storativity of confined reservoirs define the quantity of fluid that the rock matrix will yield if fluid pressure is slightly reduced. The fluid is released from the rock matrix by two means. Firstly, the fluid in the pores is compressed and expands with reduced fluid pressure. If the pore volume remains constant, some fluid has to escape. Secondly, the pore fluid carries some fraction of the overburden weight. If pore pressure is reduced, the formation will deform a little and reduce its pore volume, hence releasing some fluid.

These two effects are often described by a lumped parameter called compressibility, c, which at constant temperature is defined by Equation 12. It relates the volume change, ΔV, to a pressure change ΔP in a unit volume of porous rock. Well testing analyses do not generally determine the compressibility of a reservoir, but instead a lumped parameter of compressibility, porosity and reservoir thickness. This parameter is called storativity and is defined by

$$S = \phi c_t h \tag{20}$$

Storativity has the unit m/Pa (in the SI unit system). Physically it means the volume of fluid stored/released per unit area of reservoir per unit pressure change.

2.2.2 Wellbore storage effect

When a shut-in well is initially opened the fluids that are discharged are those that have been standing in the wellbore. It will take some time before fluid is extracted from the formation. Therefore, some time will elapse before the flow extracted from the formation equals the discharge rate. Conversely, when a discharging well is closed, fluid continues to flow into the wellbore from the reservoir. This will continue until pressure equilibrium is reached between the well and the formation/reservoir. Both effects are caused by the storage capacity of the wellbore itself and the effect is called "*wellbore storage*". Wellbore storage alters the well's initial pressure response to discharge or closure. Wellbore storage also effects the well's response to injection.

The basic definition for the wellbore storage coefficient is (Earlougher, 1977)

$$C = \frac{\Delta V}{\Delta P} \tag{21}$$

For a wellbore with a changing liquid level, the following definition for the wellbore storage coefficient is used with V_u as the wellbore volume per unit length.

$$C = \frac{V_u}{\rho g}$$

If the wellbore were completely filled with single phase fluid, then the wellbore storage coefficient takes the form

$$C = V_B c$$

Since the wellbore fluid compressibility is pressure dependent, the wellbore storage coefficient may vary with pressure. Fortunately, such variation in wellbore storage coefficient is generally only important in wells containing gas or steam and in wells that change to a falling or rising liquid level during the test.

The wellbore storage causes the sandface flowrate or the flowrate at the interface between the well and the formation to change more slowly than the surface flowrate. The sandface flowrate may be calculated from (Sigurdsson, 1993)

$$q_{sf} = q + C\frac{dP}{dt} \tag{22}$$

$$q_{sf} = q[1 - C_D \frac{\partial}{\partial t_D} P_D(T_D, r_D, C_D, ...)] \tag{22a}$$

where C_D is the dimensionless wellbore storage coefficient defined as

$$C_D = \frac{C}{2\pi \phi c_t h r_w^2} \tag{23}$$

2.2.3 Skin factor

The diffusivity equation used here assumes uniform permeability and horizontal radial flow throughout the reservoir. Often drilling or well completion practices produces a small zone of altered permeability in the vicinity of the well. This region has a significant effect on the performance of the well as all fluid must flow through it to reach the well. This altered zone around a discharging or injecting well is treated as a skin and the effects called *"skin effect"*. The skin effect is quantified as a skin factor, *s*. Positive values of the skin factor relate to reduced permeability near the well and negative values relate to improved permeability near the well.

In Equation 19 the superposition caused the skin factor terms to cancel out. The pressure difference in Equation 19 has a reference to the initial pressure in the reservoir which is often unknown and is often one of the objectives for build-up tests. However, the flowing pressure immediately before the well is shut-in is usually known. One can make use of the flowing pressure at the end of the production period and therefore bypass the need for knowing the initial pressure in the system. Still assuming that the logarithmic approximation applies to the pressure solution, the pressure for the flowing period can be written as

$$\Delta P = \frac{q\mu}{4\pi kh}[\ln t_p + \ln(\frac{4k}{\gamma \phi \mu c_t r_w^2}) + 2s] \tag{24}$$

Subtracting Equation 19 from Equation 24 and noting that $P_{ws}(\Delta t = 0) = P_{wf}(t_p)$ we get

$$P_{ws} - P_{wf} = \frac{q\mu}{4\pi kh}[\ln t_p + \ln(\frac{4k}{\gamma \phi \mu c_t r_w^2}) + 2s - \ln(\frac{t_p + \Delta t}{\Delta t})] \tag{25}$$

or

$$P_{ws} - P_{wf} = m[\log t_p + \log(\frac{k}{\phi \mu c r_w^2}) + 0.351 + 0.869s - \log(\frac{t_p + \Delta t}{\Delta t})] \tag{25a}$$

where

$$m = \frac{2.303\,q\,\mu}{4\,\pi k h} \tag{26}$$

Choosing Δt = 1 hour so $P_{ws} = P_{1\,hour}$ or the pressure read of the semi-log straight line at Δt = 1 hr and assuming that the production time t_p is much greater than Δt, Equation 25 reduces to

$$P_{1hr} - P_{wf} = m\,[\log(\frac{k}{\phi \mu c_t r_w^2}) + 3.908 + 0.869\,s] \tag{27}$$

The well skin factor, s, is then calculated after rearranging Equation 27 to give

$$s = 1.151\,[\frac{P_{1hr} - P_{wf}}{m} - \log(\frac{k}{\phi \mu c_t r_w^2}) - 3.908] \tag{28}$$

3. ANALYSIS OF PRESSURE BUILD-UP TESTS

3.1 Well KMJ-48

Well KMJ-18 was drilled in 1989 to a measured depth (MD) of 1375 m or 1314 m total vertical depth (TVD) with 32° inclination directed to N65° E and completed with a slotted 7" liner, open in the range 930-1369 m. The well is not connected to the Kamojang steam gathering system. It was opened and closed several times before the actual build-up test. The test was carried out after a discharge period, for nearly 72 days (71 days, 18 hours, 48 minutes) or 103,368 minutes . The flowrate at the time of shut-in was approximately 88.15 ton/hr (= 24.49 kg/s). This well responded very quickly to the flowrate change so that at the instant of complete closure of the master valve, the well was already nearly under full wellhead pressure. Cumulative production during discharge amounts to 117,094 tons. Horner production time, t_p is then

$$t_p = \frac{117{,}094.07\ ton}{88.15\ ton} \times 60\ minute = 79{,}701\ minutes$$

For pressure build-up data, refer to Appendix I. Figures 3-5 show the log-log, semi-log and Horner plots. The slopes for the semi-log straight lines are essentially the same on both the Horner plot and the regular semi-log plot (MDH plot). The resulting values for transmissivity, storativity and skin are presented in Table 1. The storativity is evaluated from Equation 20, with approximations to Equation 18.

The interpretation indicates that the well is "damaged" with a skin factor of approximately $s = +25$. At 246°C the steam viscosity, μ, is 17.45 x 10^{-6} Pa s which gives the permeability 0.208 Darcy.

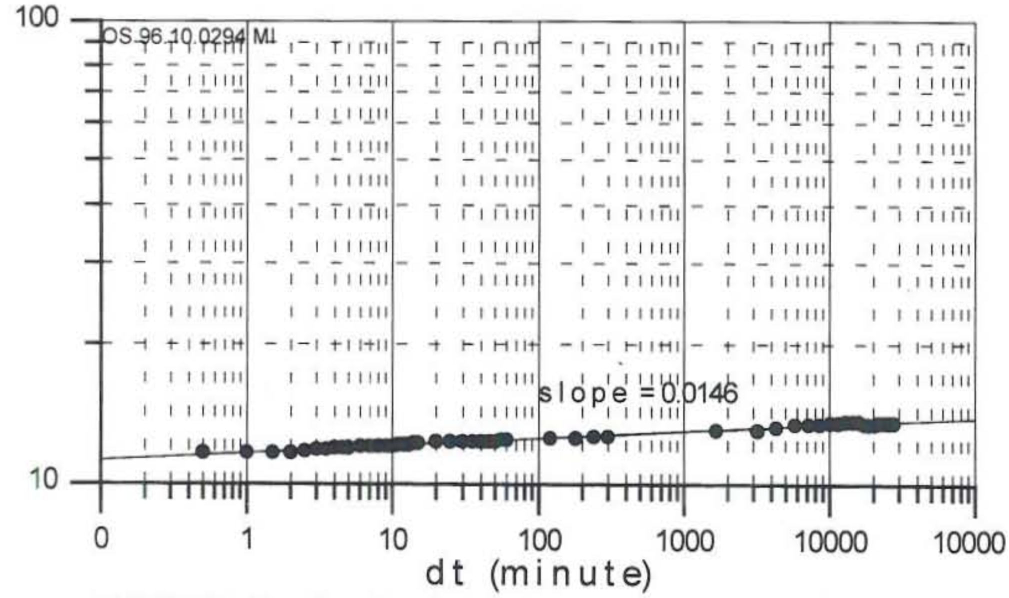

FIGURE 3: Log-log plot of pressure build-up in well KMJ-48

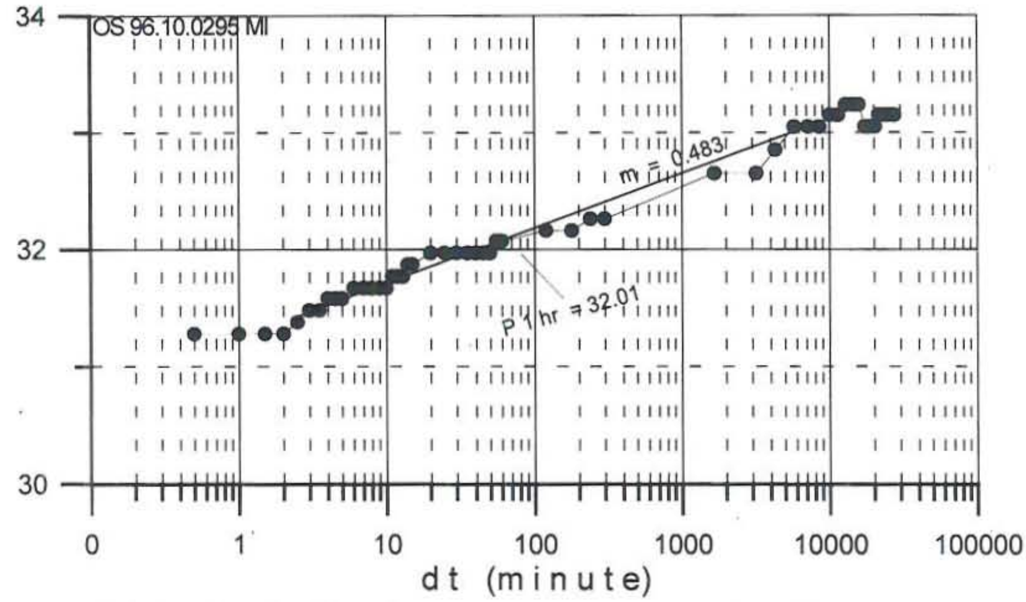

FIGURE 4: Semi-log plot of pressure build-up in well KMJ-48

TABLE 1: Transmissivity, storativity and skin in Kamojang wells

Well	Analysis method	P_{wf} (bar)	$P_{1\,hr}$ (bar)	q (m^3/s)	h (m)	kh/μ (m^3/bar s)	$\phi c_t h$ (m/bar)	Skin
KMJ-48	Semi-log	19.61	32.01	1.40	445	0.531	41.1	+24.979
KMJ-49	Semi-log	19.61	29.09	0.61	513	7.78×10^{-2}	62.7	+ 4.211
KMJ-53	Semi-log	1.96	24.20	1.56	567	12.53×10^{-2}	69.34	+ 7.64
KMJ-57	Curve-matching	3.92	-	0.81	380	2.53×10^{-2}	51	- 1.274

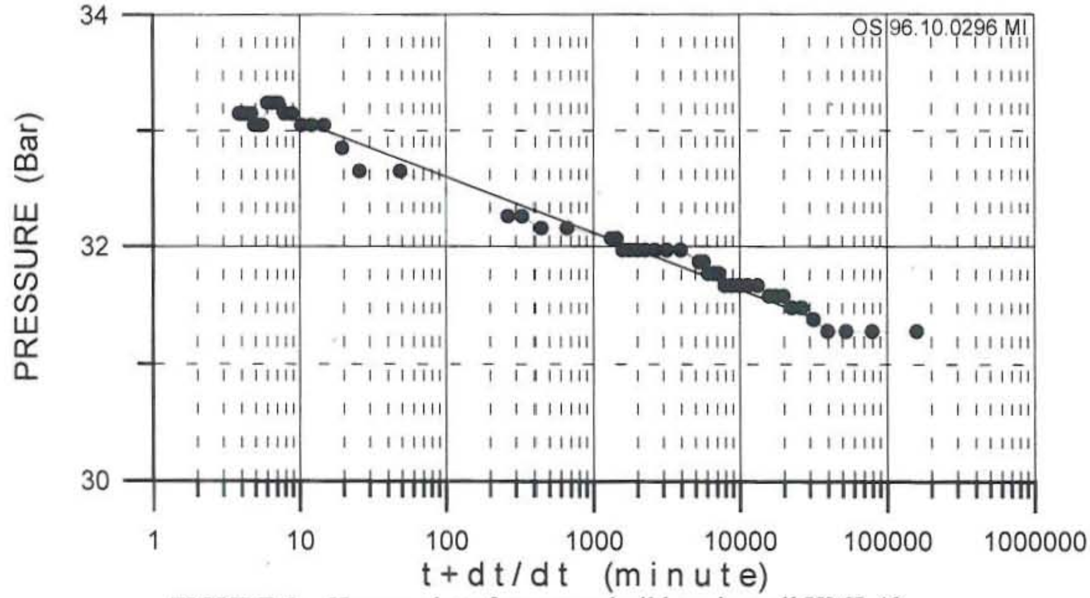

FIGURE 5: Horner plot of pressure build-up in well KMJ-48

3.2 Well KMJ-49

The well was drilled in 1991 to a depth of 1483 mMD (or 1401 mTVD) with 34° inclination directed to S6°E and completed with a slotted 7" liner, open in the interval 999-1510 m. The well KMJ-49 has the same drilling pad as well KMJ-48 and is not connected to the Kamojang steam gathering system. The well was discharged for nearly 71 days (70 days, 20 hours, 40 minutes) before the build-up test was done, which amounts to a flowing period of 102,040 minutes. The flowrate at the time of shut-in was approximately 39.76 ton/hour (= 11.04 kg/s). Cumulative production during discharge was 81,073 tons. Horner production time, t_p, is then

$$t_p = \frac{81{,}073.35\ ton}{39.76\ ton} \times 60\ minute = 122{,}344\ minutes$$

Pressure build-up data are given in Appendix II. Figures 6-8 show the log-log, semi-log and Horner plot. The interpretation results are presented in Table 1.

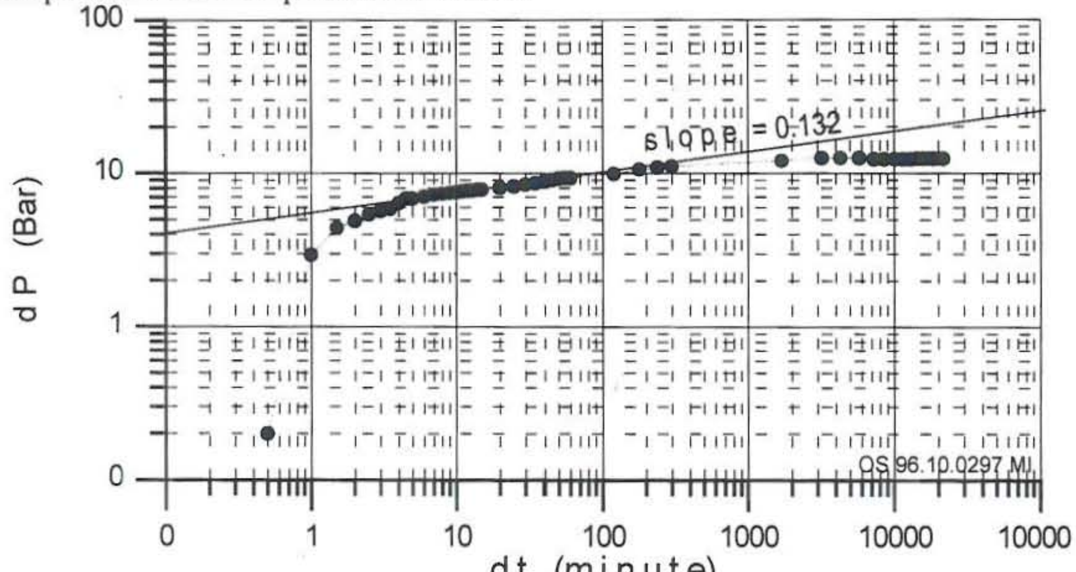

FIGURE 6: Log-log of pressure build-up in well KMJ-49

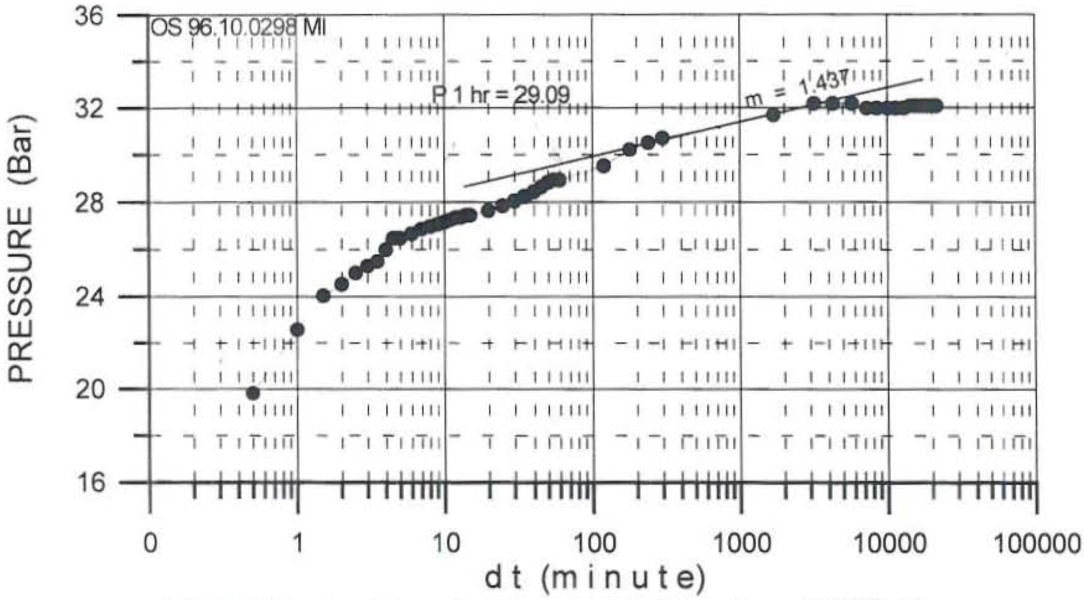

FIGURE 7: Semi-log plot of pressure build-up in well KMJ-49

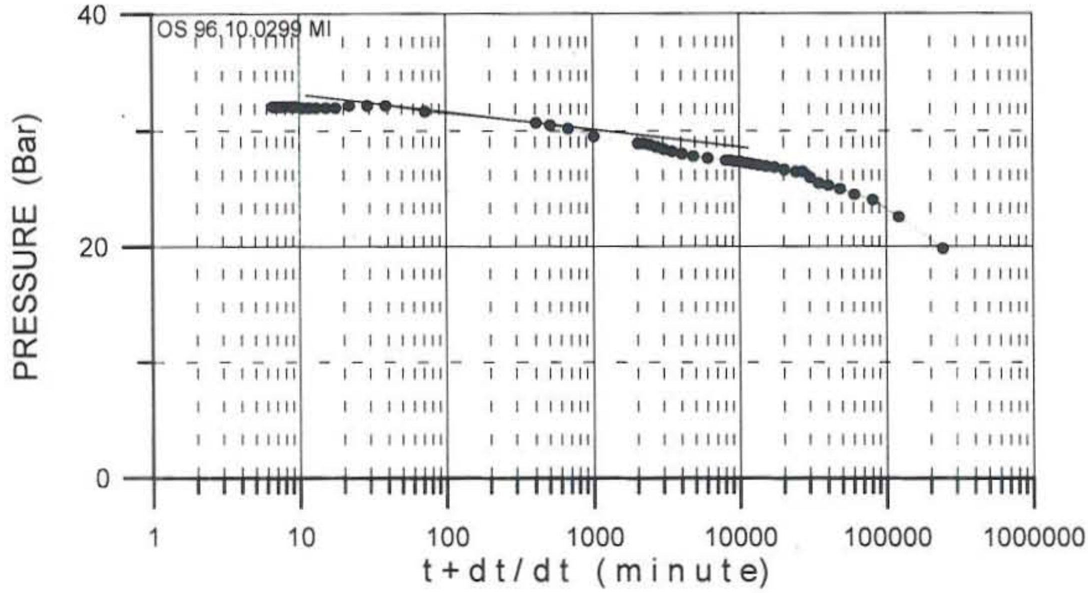

FIGURE 8: Horner plot of pressure build-up in well KMJ-49

The skin factor for well KMJ-49 indicates that it is "less damaged" than well KMJ-48. At 245°C the steam viscosity, μ, is 17.41×10^{-6} Pa s which gives the permeability 0.0264 D.

3.3 Well KMJ-53

Well KMJ-53 is a production well, and was completed in December 1992 to a depth of 1300 mMD (or 1239 mTVD) with 33.5° inclination directed to N65°E. The well was cased with a 9 5/8" production casing to 697 m and with a slotted 7" liner, which is open in the interval 703-1270 m. Well KMJ-53 is drilled from the same drill pad as well KMJ-57 and therefore close to it. The well was discharged for nearly 82 days (81 days, 17 hours, 32 minutes) or 117,692 minutes. The flowrate at the time of shut-in was approximately 91 ton/hr (= 25.28 kg/s). Cumulative production during discharge was 105,023 tons. Horner production time t_p is then

$$t_p = \frac{105{,}023.32\ ton}{91\ ton}\ x\ 60\ minute\ =\ 69{,}246.15\ minute$$

The pressure build-up data is in Appendix III but the results from the interpretation are presented in Table 1. Figures 9-11 show the log-log, semi-log and Horner plots.

At 245°C the steam viscosity μ is 17.46 x 10^{-6} Pa s which gives a permeability of 0.0386 D.

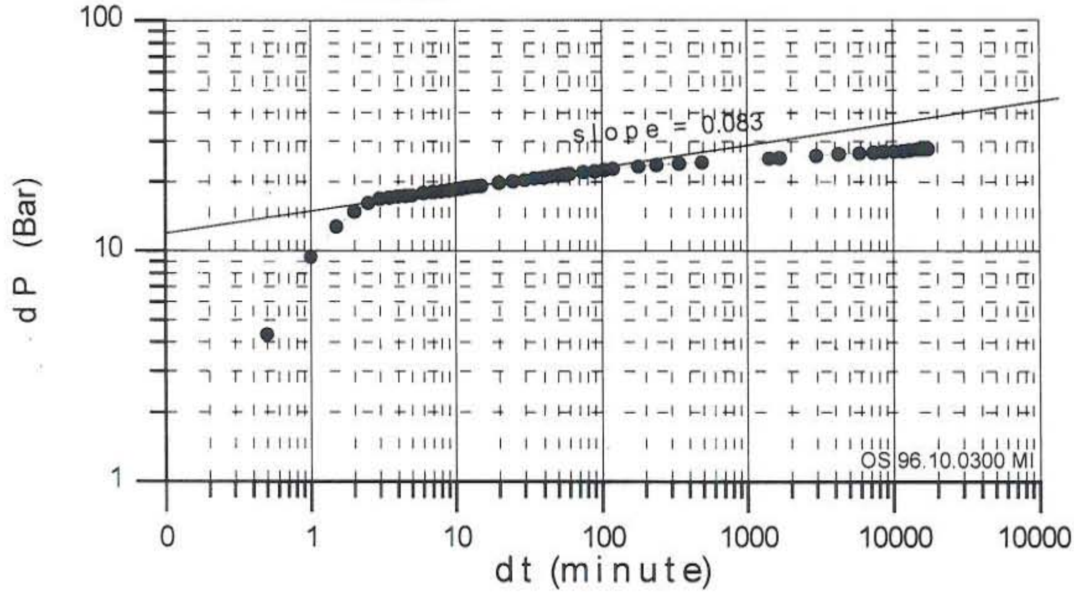

FIGURE 9: Log-log plot of pressure build-up in well KMJ-53

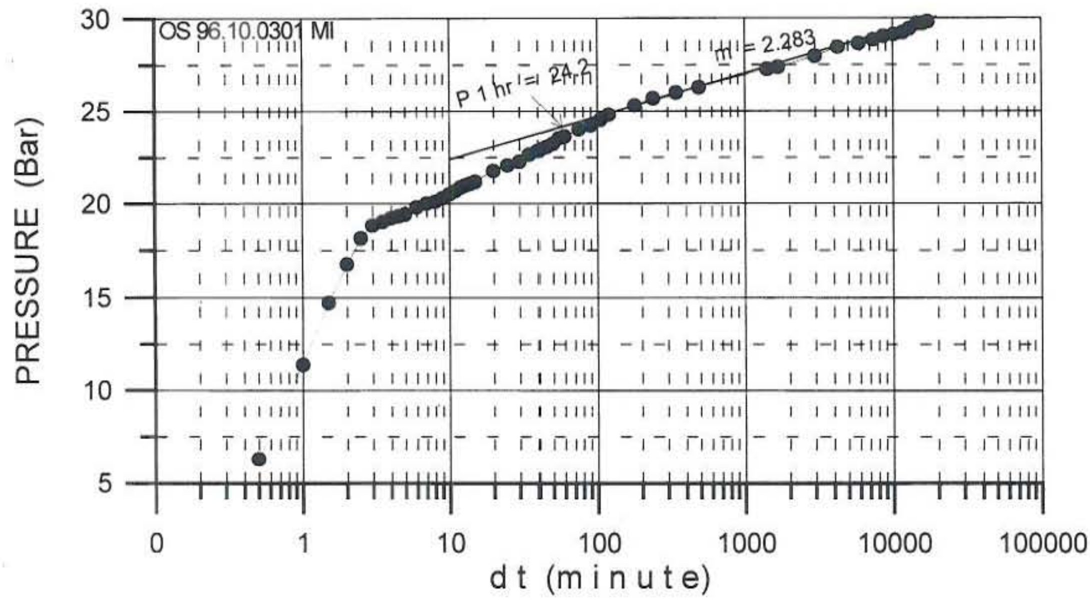

FIGURE 10: Semi-log of pressure build-up in well KMJ-53

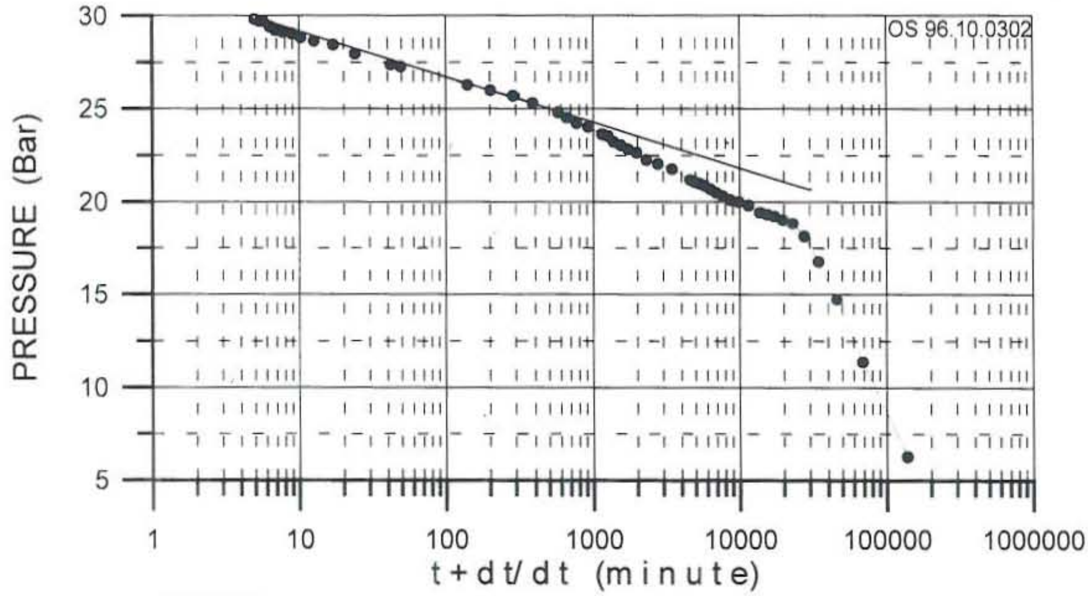

FIGURE 11: Horner plot of pressure build-up in well KMJ-53

3.4 Well KMJ-57

The well was drilled in 1994 to a depth of 1210 mMD (or 1145 mTVD) with 25.25° inclination directed to S31°E and completed with a slotted 7" liner, open in the interval 830-1200 m. The well was discharged for nearly 86 days (85 days, 21 hours, 27 minutes) which amounts to 123,687 minutes. The flowrate at the time of shut-in was approximately 49.60 ton/hr (= 13.78 kg/s). Cumulative production during discharge was 63,496.34 tons. Horner production time t_p then becomes

$$t_p = \frac{63{,}496.34\ ton}{49.6\ ton} \times 60\ minute = 76{,}810.10\ minute$$

The pressure build-up data is given in Appendix IV. Figures 12-13 show the log-log plot and a curve matching plot. The data was matched with a type curve for bilinear flow as a line with a slope of

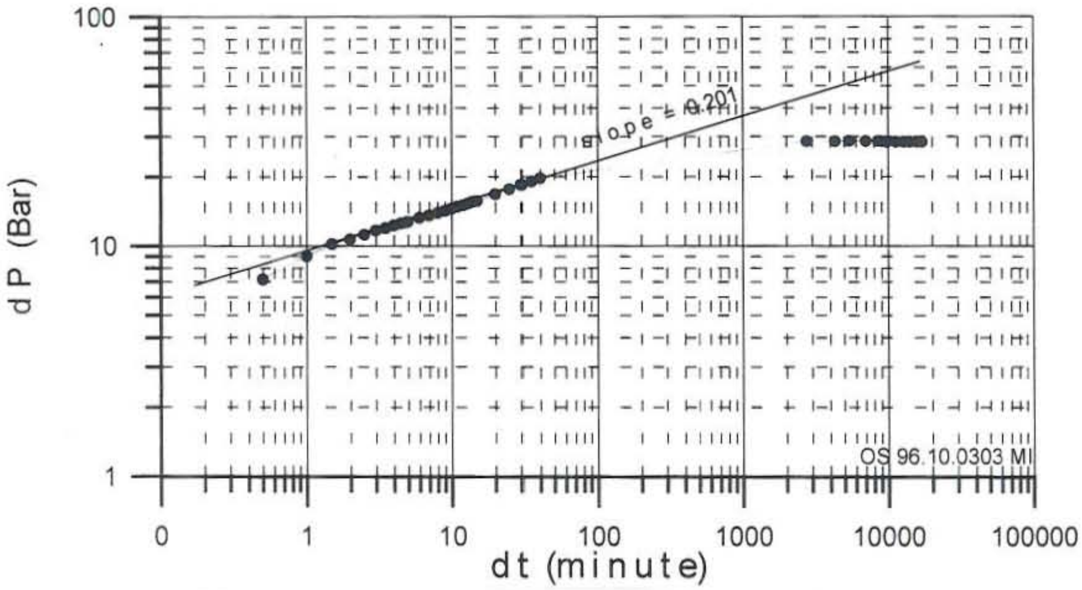

FIGURE 12: Log-log plot of pressure build-up in well KMJ-57

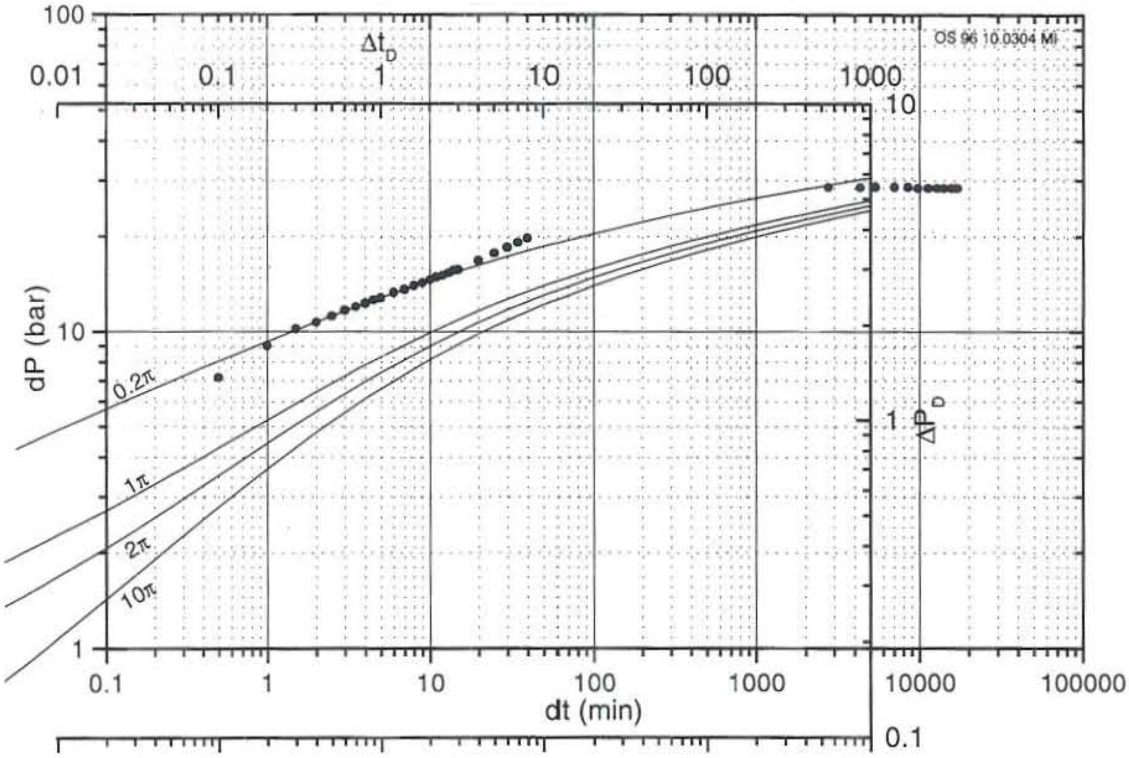

FIGURE 13: Curve matching plot of pressure build-up in well KMJ-57

approximately 1/4 (one-fourth-slope straight line) was found as seen on the log-log graph. The match points selected, $P_D = 1$ and $t_D = 1$, correspond on the log-log graph to dt = 5 minutes and $dP = 5.1$ bar. This type of curve matching also shows that pressure data matched the curve for $(k_f b_f)_D = 0.2\pi$. For calculation of skin, the wellbore radius must be known. By using a log-log graph from Cinco-Ley and Samaniego (1981), one sees a dimensionless effective wellbore radius r_w'/x_f versus dimensionless fracture conductivity $(k_f b_f)_D$. The fracture half length $x_f = 2.797$ m can be obtained which can be used to calculate the fracture conductivity $k_f b_f = 0.02$ Darcy meter. Others results are presented in Table 1.

Skin factor can not be calculated with a Horner plot due to missing data 40 minutes from the beginning of the test. The skin factor was calculated using type curve matching yielding $s = -1.274$ which means that the well is slightly stimulated. At 242°C the steam viscosity, μ is 17.30 x 10^{-6} Pas which gives the permeability 0.0116 D (11.6 mD).

4. DESIGN OF AN INTERFERENCE TEST

The author has made some effort to estimate possible pressure response between the feedzones for wells in each cluster and to note likely pressure changes with time. In the Kamojang field one cluster consists of 3-5 wells with different directions, located about 5-10 m apart from each other at the wellheads. The KMJ-48 and KMJ-49 wells are included in one cluster (Figure 14), while wells KMJ-53 and KMJ-57 are in another cluster (Figure 15). The calculations are carried-out for each cluster assuming that an interference test could be performed by discharging.

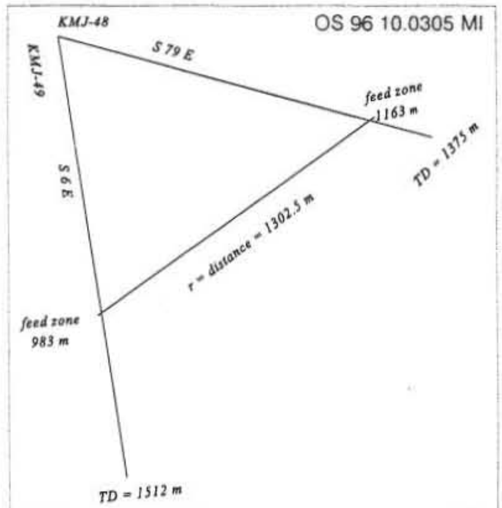

FIGURE 14: Schematic location of well profiles for cluster KMJ-48 and KMJ-49

4.1 Cluster KMJ-48 and KMJ-49

S_{av} = (41.1 + 62.7) / 2 = 51.9 m/bar
T_{av} = (0.531 + 0.0778) / 2 = 0.3044 m^3/bar s
t = $S\,r^2/T$

Hence

$$t = \frac{51.9\ m/bar \times (1302.5)^2\ m^2}{0.3044\ m^3/bar\ s}$$

or t = 289253201 s = 3347.84 days = 9.3 years

The above calculation indicates that if the reservoir at Kamojang is considered to behave as a two-phase system, the interferences between wells KMJ-48 and KMJ-49 will be felt after 9 years. On the other hand, if the reservoir is assumed single-phase vapour, it will interfere in less than 3 months. This means that when the wells will be needed for production it could be worthwhile to start the production from only one well. If no interference is observed after more than 3 months of production, the above calculation indicates that it could take a lot longer time so other wells could be put on line. However, if an interference is observed it will give valuable information about the reservoir.

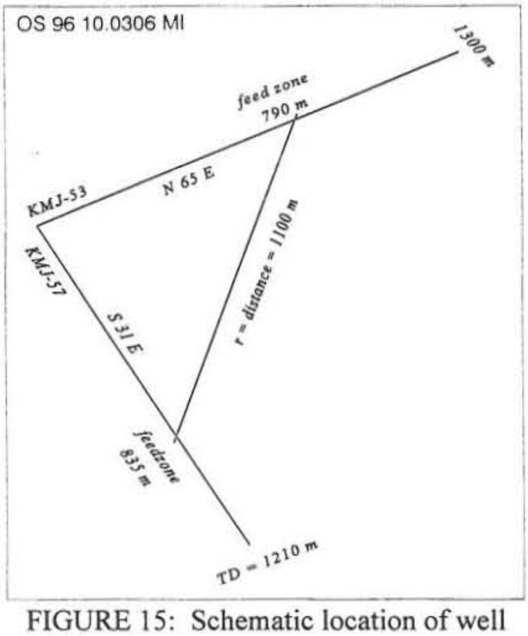

FIGURE 15: Schematic location of well profiles for cluster KMJ-53 and KMJ-57

4.2 Cluster KMJ-53 and KMJ-57

S_{av} = (69.34 + 51) / 2
= 60.17 m/bar
T_{av} = (0.1253 + 0.0253) / 2
= 7.53 x 10^{-2} m^3/bar s
t = $S\,r^2/T$

Hence

$$t = \frac{60.17 m/bar \times (1100)^2\ m^2}{7.53 \times 10^{-2}\ m^3/bar\ s}$$

or t = 975391766.3 s = 11289.26 days = 31.36 years
Similarly if KMJ-53 and KMJ-57 wells are assumed to be in a two-phase reservoir system, interference will take more than 31 years. If the reservoir is considered to contain single-phase vapour, the interference will take only 6 months, due to its lower compressibility value.

5. DISCUSSION AND CONCLUSIONS

The calculations in this report have been done based on a vapour-dominated two-phase system existing in Kamojang field. Usually the pressure build-up is plotted versus $\log_{10}[(t_p + \Delta t)/\Delta t]$ where t_p is the equivalent Horner production time and Δt is the running time during the shut-in period. The best straight line is drawn through these points and is extended to intersect the line for which $[(t_p + \Delta t)/\Delta t] = 1$. The pressure at this point of intersection is supposedly equal to the aquifer pressure. From calculations it is shown that the SE-sector of the Kamojang field has high transmissivity and high storativity, whereas interpretation of the skin factor data for three wells indicates high positive values, especially for well KMJ-48. Nonetheless, well KMJ-48 exhibits good flowrate. Also from the interpretation, a negative skin factor value is indicated for well KMJ-57, but the results are probably not accurate due to a lack of data during the transient period.

For calculating interference response it is important to know the feedzone depth for each well and which feedzone at SE sector of Kamojang field lies between 800-1200 m. The results from the calculations show that wells KMJ-48 and KMJ-49 will be interfering after 9 years. This could influence the support for steam supply to the power plant from these wells since the calculated economic lifetime is approximately 25 years. The other cluster with wells KMJ-53 and KMJ-57 will interfere after 31 years (note the calculations are based on the assumption for two-phase conditions). If the reservoir behaves more like a dry steam system, this interference time will only be a few months.

The main conclusions from the analysis of the pressure build-up data are:

1. To be able to obtain accurate results, it is necessary to monitor carefully and regularly the changes in the wellhead pressure.

2. The finite time required to shut the master valve, like in well KMJ-48, has to be minimized since the wellhead pressure rises as the master valve is closed reaching about > 90% of full pressure when the valve closure is completed. The early pressure data is, therefore, lost making interpretation of the test more difficult.

3. Based on the calculated skin factors, the results indicate positive values, meaning that formations around the wells are damaged. By looking at the drilling practice for these wells, it may be possible to reduce the risk of damage by changing the circulation fluid during drilling operations.

ACKNOWLEDGEMENTS

The author of this paper is indebted to PERTAMINA (National State Oil, Gas and Geothermal Company, Indonesia) for permission to attend this training programme of the United Nations University at Orkustofnun National Energy Authority in Iceland. Special thanks go to Dr. Ingvar B. Fridleifsson, the director of the United Nations University Geothermal Training Programme and, in addition, I wish to thank Mr. Lúdvík S. Georgsson, Gudrún Bjarnadóttir and the staff of Orkustofnun. Also thanks to my supervisor Mr. Ómar Sigurdsson, Mr. Benedikt Steingrímsson and the staff in the reservoir department for guidance during this special project report.

NOMENCLATURE

A_m = Mass of fluid mixture per unit volume of reservoir (kg/m^3);
A_e = Energy content per unit volume of reservoir (J/m^3);
$C_{(D)}$ = Wellbore storage coefficient (dimensionless);
C_r = Specific heat capacity of the rock at constant pressure (J/kg K);
c = Compressibility (Pa^{-1});
g = Gravity (m/s^2);
H = Enthalpy (J/kg);

h	= Reservoir thickness (m);
K_m	= Heat conductance (m/s or m/day);
k	= Permeability (m^2) (1 Darcy ≈ 10^{-12} m^2);
k_{rs}, k_{rw}	= Steam and water relative permeabilities;
M	= Mass (of steam) (kg);
m	= Slope of semilog plot;
P	= Pressure (Pa);
Q_m	= Fluid mass flow per unit area, mass flux (kg/m^2 s);
Q_e	= Energy flow per unit area, energy flux (J/m^2s);
q_m	= Mass flowrate of fluid per unit volume reservoir (kg/m^3 s);
q_e	= Energy flowrate per unit volume reservoir (J/m^3 s);
r	= Radial distance (m);
r_w	= Radius of well (m);
S	= Storativity (m/Pa);
S	= Volumetric saturation water/steam;
s	= Skin factor;
T	= kh/μ = Transmissivity (m^2/s);
T	= Temperature (°C or °K);
t	= Time (s);
t_p	= Production time (s);
Δt	= Time increment during shut-in (s);
U	= Specific internal energy (J/kg);
V	= Volume (m^3);
V_u	= Wellbore volume per unit length (m^3/m);
V_B	= Total volume of the wellbore (m^3);
$\langle\rho C\rangle$	= Volumetric heat capacity of the wetted rock (J/m^3 K).
ϕ	= Porosity;
ρ	= Density water/steam (kg/m^3);
ν	= Kinematic viscosity (=μ/ρ) (m^2/s);
μ	= Dynamic viscosity (Pa s = N s/m^2);
∇	= Gradient operator (m^{-1});
$\nabla.$	= Divergence operator;
γ	= Euler constant = 1.78.

Subscripts

av	= Average;
D	= Dimensionless;
e	= Energy;
I	= Initial;
m	= Mixture;
p	= Production;
r	= Rock;
SAT	= Saturation;
s	= Steam;
sf	= Sandface;
t	= Total;
w	= Water;
wf	= Well flowing;
ws	= Well shut-in.

REFERENCES

Cinco, H., and Samaniego, F., 1981: Transient pressure analysis for fractured wells. *Journal Petroleum Technology, Sept. 1981,* 1749-1766.

Earlougher, R.C., 1977: *Advances in well test analysis.* Soc. Petr. Eng., monograph 5, 264 pp.

GENZL, 1984: *Reservoir science seminar pressure transient analysis.* GENZL report presented at a seminar for Indonesian eng. and scientists, 52 pp.

Grant, M.A., 1979a: Mapping Kamojang reservoir. *Geothermal Res. Council, Transactions, 3,* 271-274.

Grant, M.A., Donaldson, I.G., and Bixley, P.F., 1982: *Geothermal reservoir engineering.* Academic Press, New York, 369 pp.

Grant, M.A., and Sorey, M.L., 1979: The compressibility and hydraulic diffusivity of water-steam flow. *Water Resour. Res. 15-3,* 684-686.

Hochstein, M.P., 1976: Geophysical exploration of the Kawah Kamojang geothermal field, West Java. *Proceeding of the 2nd United Nations Conference on the Development and Use of Geothermal Energy, San Francisco, 2,* 1049-1058.

Matthews, C.S., and Russell, D.G., 1967: *Pressure build up and flow test in wells.* Soc. Petr. Eng. Monograph 1, 167 pp.

O´Sullivan, M.J., and McKibbin, R., 1989: *Geothermal reservoir engineering.* Report (Draft edition 1), University of Auckland, 162 pp.

Robert, D., 1982: *The geothermal field in Kamojang.* Pertamina/Beicip, report.

Sasradipoera, D.S., 1995: Reservoir assessment of the SE-sector of the Kamojang geothermal field, Indonesia. Report 12 in *Geothermal Training in Iceland 1995.* UNU, G.T.P., Iceland, 303-320.

Sigurdsson, Ó., 1993: *Basic well test theory.* Unpublished Lecture notes, UNU, G.T.P., Iceland.

Witherspoon, P.A., Javandel, I., Neuman, S.P. and Freeze, R.A., 1967: *Interpretation of aquifer gas storage conditions from water pumping tests.* Amer. Gas Assoc., monograph.

APPENDIX I: Pressure build-up data for well KMJ-48

Status	: Build-up test
Opened	: 23-01-1995 (time : 03.05 pm)
Closed	: 05-04-1995 (time : 09.17 am)
Flowing Period	: 103,368 minutes
Flowrate Before Shut in	: 88.15 ton/hr = 24.49 kg/sec
Cum. Production	: 117,094.07 tons
Production Times (t_p)	: 79,701 minutes

dt (minute)	*P* (Ksc)	*P* (Bar)	*dP* (Bar)	P^2 (Bar)	dP^2 (Bar)	$\frac{t+dt}{dt}$
0.0	20.0	19.61		384.55		
0.5	31.9	31.28	11.67	978.64	594.09	159,403.00
1.0	31.9	31.28	11.67	978.64	594.09	79,702.00
1.5	31.9	31.28	11.67	978.64	594.09	53,135.00
2.0	31.9	31.28	11.67	978.64	594.09	39,851.50
2.5	32.0	31.38	11.77	984.70	600.15	31.881.40
3.0	32.1	31.48	11.87	990.99	606.44	26,568.00
3.5	32.1	31.48	11.87	990.99	606.44	22,772.71
4.0	32.2	31.58	11.97	997.30	612.75	19,926.25
4.5	32.2	31.58	11.97	997.30	612.75	17,712.33
5.0	32.2	31.58	11.97	997.30	612.75	15,941.20
6.0	32.3	31.67	12.06	1002.99	618.44	13,284.50
7.0	32.3	31.67	12.06	1002.99	618.44	11,386.86
8.0	32.3	31.67	12.06	1002.99	618.44	9,963.63
9.0	32.3	31.67	12.06	1002.99	618.44	8,856.67
10.0	32.3	31.67	12.06	1002.99	618.44	7,971.10
11.0	32.4	31.77	12.16	1009.33	624.78	7,246.55
12.0	32.4	31.77	12.16	1009.33	624.78	6,642.75
13.0	32.4	31.77	12.16	1009.33	624.78	6,131.85
14.0	32.5	31.87	12.26	1015.70	631.15	5,693.93
15.0	32.5	31.87	12.26	1015.70	631.15	5,314.40
20.0	32.6	31.97	12.36	1022.08	637.53	3,986.05
25.0	32.6	31.97	12.36	1022.08	637.53	3,189.04
30.0	32.6	31.97	12.36	1022.08	637.53	2,657.70
35.0	32.6	31.97	12.36	1022.08	637.53	2,278.17
40.0	32.6	31.97	12.36	1022.08	637.53	1,993.53
45.0	32.6	31.97	12.36	1022.08	637.53	1,772.13
50.0	32.6	31.97	12.36	1022.08	637.53	1,595.02
55.0	32.7	32.07	12.46	1028.48	643.93	1,450.11
60.0	32.7	32.07	12.46	1028.48	643.93	1,329.35
120.0	32.8	32.16	12.55	1034.26	649.71	665.18
180.0	32.8	32.16	12.55	1034.26	649.71	443.78
240.0	32.9	32.26	12.65	1040.70	656.15	333.09
300.0	32.9	32.26	12.65	1040.70	656.15	266.67
1668.0	33.3	32.65	13.04	1066.02	681.47	48.78
3213.0	33.3	32.65	13.04	1066.02	681.47	25.81
4309.0	33.5	32.85	13.24	1079.12	694.57	19.50
5805.0	33.7	33.05	13.44	1092.30	707.75	14.73
7200.0	33.7	33.05	13.44	1092.30	707.75	12.07
8575.0	33.7	33.05	13.44	1092.30	707.75	10.29
10125.0	33.8	33.15	13.54	1098.92	714.37	8.87
11491.0	33.8	33.15	13.54	1098.92	714.37	7.94
12953.0	33.9	33.24	13.63	1104.90	720.35	7.15
14394.0	33.9	33.24	13.63	1104.90	720.35	6.54
15795.0	33.9	33.24	13.63	1104.90	720.35	6.05
17446.0	33.7	33.05	13.44	1092.30	707.75	5.57
18634.0	33.7	33.05	13.44	1092.30	707.75	5.28

dt (minute)	*P* (Ksc)	*P* (Bar)	*dP* (Bar)	P^2 (Bar)	dP^2 (Bar)	*t+dt* / *dt*
20357.0	33.7	33.05	13.44	1092.30	707.75	4.92
21601.0	33.8	33.15	13.54	1098.92	714.37	4.69
22998.0	33.8	33.15	13.54	1098.92	714.37	4.47
24528.0	33.8	33.15	13.54	1098.92	714.37	4.25
26023.0	33.8	33.15	13.54	1098.92	714.37	4.06
27534.0	33.8	33.15	13.54	1098.92	714.37	3.89

APPENDIX II: Pressure build-up data for well KMJ-49

Status	: Build-up test
Opened	: 24-01-1995 (time : 01.00 pm)
Closed	: 05-04-1995 (time : 09.20 am)
Flowing Period	: 102,040 minutes
Flowrate Before Shut-in	: 39.76 ton/hr = 11.04 kg/sec
Cum. Production	: 81,073.35 tons
Production Times (t_p)	: 122,344 minutes

dt (minute)	*P* (Ksc)	*P* (Bar)	*dP* (Bar)	P^2 (Bar)	dP^2 (Bar)	*t+dt* / *dt*
0.0	20.0	19.61		384.55		
0.5	20.2	19.81	0.20	392.44	7.89	244,689.00
1.0	23.0	22.56	2.95	508.74	124.19	122,345.00
1.5	24.5	24.03	4.42	577.44	192.89	81,563.67
2.0	25.0	24.52	4.91	601.23	216.68	61,173.00
2.5	25.5	25.00	5.39	625.00	240.45	48,938.60
3.0	25.8	25.30	5.69	640.09	255.54	40,782.33
3.5	26.0	25.50	5.89	650.25	265.70	34,956.43
4.0	26.5	25.99	6.38	675.48	290.93	30,587.00
4.5	27.0	26.48	6.87	701.19	316.64	27,188.56
5.0	27.0	26.48	6.87	701.19	316.64	24,469.80
6.0	27.2	26.67	7.06	711.29	326.74	20,391.67
7.0	27.4	26.87	7.26	722.00	337.45	17,478.71
8.0	27.5	26.97	7.36	727.38	342.83	15,294.00
9.0	27.6	27.07	7.46	732.78	348.23	13,594.78
10.0	27.7	27.16	7.55	737.67	353.12	12,235.40
11.0	27.8	27.26	7.65	743.11	358.56	11,123.18
12.0	27.9	27.36	7.75	748.57	364.02	10,196.33
13.0	27.9	27.36	7.75	748.57	364.02	9,412.08
14.0	28.0	27.46	7.85	754.05	369.50	8,739.86
15.0	28.0	27.46	7.85	754.05	369.50	8,157.27
20.0	28.2	27.65	8.04	764.52	379.97	6,118.20
25.0	28.4	27.85	8.24	775.62	391.07	4,894.76
30.0	28.6	28.05	8.44	786.80	402.25	4,079.13
35.0	28.8	28.24	8.63	797.50	412.95	3,496.54
40.0	29.0	28.44	8.83	808.83	424.28	3,059.60

dt (minute)	P (Ksc)	P (Bar)	dP (Bar)	P^2 (Bar)	dP^2 (Bar)	$\frac{t+dt}{dt}$
45.0	29.2	28.64	9.03	820.25	435.70	2,719.75
50.0	29.4	28.83	9.22	831.17	446.62	2,447.88
55.0	29.5	28.93	9.32	836.94	452.39	2,225.44
60.0	29.5	28.93	9.32	836.94	452.39	2,040.06
120.0	30.1	29.52	9.91	871.43	486.88	1,020.53
180.0	30.8	30.20	10.59	912.04	527.49	680.69
240.0	31.1	30.50	10.89	930.25	545.70	510.76
300.0	31.3	30.69	11.08	941.88	557.33	408.81
1707.0	32.3	31.68	12.07	1003.64	619.09	72.67
3212.0	32.8	32.17	12.56	1034.91	650.36	39.09
4307.0	32.8	32.17	12.56	1034.91	650.36	29.40
5804.0	32.8	32.17	12.56	1034.91	650.36	22.08
7302.0	32.6	31.97	12.36	1022.08	637.53	17.75
8570.0	32.6	31.97	12.36	1022.08	637.53	15.27
10124.0	32.6	31.97	12.36	1022.08	637.53	13.08
11490.0	32.6	31.97	12.36	1022.08	637.53	11.65
12948.0	32.6	31.97	12.36	1022.08	637.53	10.45
14393.0	32.7	32.07	12.46	1028.48	643.93	9.50
15791.0	32.7	32.07	12.46	1028.48	643.93	8.75
17444.0	32.6	32.07	12.46	1028.48	643.93	8.01
18635.0	32.6	32.07	12.46	1028.48	643.93	7.56
20355.0	32.6	32.07	12.46	1028.48	643.93	7.01
21611.0	32.6	32.07	12.46	1028.48	643.93	6.66

APPENDIX III: Pressure build-up data for well KMJ-53

Status	: Build-up test
Opened	: 23-01-1995 (time : 02.40 pm)
Closed	: 15-04-1995 (time : 08.12 am)
Flowing Period	: 117,692 minutes
Flowrate Before Shut-in	: 91.00 ton/hr = 25.28 kg/sec
Cum. Production	: 105,023.32 tons
Production Times (t_p)	: 69,246.15 minutes

dt (minute)	P (Ksc)	P (Bar)	dP (Bar)	P^2 (Bar)	dP^2 (Bar)	$\frac{t+dt}{dt}$
0.0	2.0	1.96		3.84		
0.5	6.4	6.28	4.32	39.44	35.60	138,493.28
1.0	11.6	11.38	9.42	129.50	125.66	69,247.14
1.5	15.0	14.71	12.75	216.38	212.54	46,165.10
2.0	17.1	16.77	14.81	281.38	277.39	34,624.07
2.5	18.5	18.14	16.18	329.06	325.22	27,699.46
3.0	19.2	18.83	16.87	354.58	350.73	23,083.05
3.5	19.4	19.02	17.06	361.76	357.92	19,785.61
4.0	19.6	19.22	17.26	369.41	365.57	17,312.54
4.5	19.7	19.32	17.36	373.26	369.42	15,389.03

dt (minute)	*P* (Ksc)	*P* (Bar)	*dP* (Bar)	P^2 (Bar)	dP^2 (Bar)	$\frac{t+dt}{dt}$
5.0	19.8	19.42	17.46	377.14	373.30	13,850.23
6.0	20.2	19.81	17.85	392.44	388.60	11,542.02
7.0	20.4	20.00	18.04	400.00	396.16	9,893.31
8.0	20.5	20.10	18.14	404.01	400.17	8,656.77
9.0	20.7	20.30	18.34	412.09	408.25	7,695.02
10.0	20.9	20.50	18.54	420.25	416.41	6,925.61
11.0	21.1	20.69	18.73	428.08	424.24	6,296.10
12.0	21.3	20.89	18.93	436.39	432.55	5,771.51
13.0	21.4	20.99	19.03	440.58	436.74	5,327.63
14.0	21.5	21.08	19.12	444.37	440.53	4,947.15
15.0	21.6	21.18	19.22	448.59	444.75	4,617.41
20.0	22.2	21.77	19.81	473.93	470.09	3,463.31
25.0	22.5	22.06	20.10	486.64	482.80	2,770.85
30.0	22.7	22.26	20.30	495.51	491.67	2,309.20
35.0	23.1	22.65	20.69	513.02	509.18	1,979.46
40.0	23.3	22.85	20.89	522.12	518.28	1,732.15
45.0	23.5	23.05	21.09	531.30	527.46	1,539.80
50.0	23.7	23.24	21.28	540.10	536.26	1,385.92
55.0	24.0	23.54	21.58	554.13	550.29	1,260.02
60.0	24.1	23.63	21.67	558.38	554.54	1,155.10
75.0	24.5	24.03	22.07	577.44	573.60	924.28
90.0	24.7	24.22	22.26	586.61	582.77	770.40
105.0	25.0	24.52	22.56	601.23	597.39	660.49
120.0	25.3	24.81	22.85	615.54	611.70	578.05
180.0	25.8	25.30	23.34	640.09	636.25	385.70
240.0	26.2	25.69	23.73	659.98	656.14	289.53
343.0	26.5	25.99	24.03	675.48	671.64	202.88
493.0	26.8	26.28	24.32	690.64	686.80	141.46
1428.0	27.8	27.26	25.30	743.11	739.27	49.49
1688.0	27.9	27.36	25.40	748.57	744.73	42.02
2993.0	28.5	27.95	25.99	781.20	777.36	24.14
4285.0	29.0	28.44	26.48	808.83	804.99	17.16
5924.0	29.2	28.64	26.68	820.25	816.41	12.69
7426.0	29.4	28.83	26.87	831.17	827.33	10.32
8679.0	29.6	29.03	27.07	842.74	838.90	8.98
10205.0	29.7	29.13	27.17	848.56	844.72	7.79
11700.0	29.8	29.22	27.26	853.81	849.97	6.92
12999.0	30.0	29.42	27.46	865.54	861.70	6.33
14714.0	30.3	29.71	27.75	882.68	878.84	5.71
15912.0	30.3	29.71	27.75	882.68	878.84	5.35
17329.0	30.4	29.81	27.85	888.64	884.80	5.00

APPENDIX IV: Pressure build-up data for well KMJ-57

Status : Build-up test
Opened : 18-01-1995 (time : 10.45 am)

Closed	: 14-04-1995 (time : 08.12 am)
Flowing Period	: 123,687 minutes
Flowrate Before Shut-in	: 49.60 ton/hr = 13.78 kg/sec
Cum. Production	: 63,496.34 tons
Production Times (t_p)	: 76,810.10 minutes

dt (minute)	*P* (Ksc)	*P* (Bar)	*dP* (Bar)	P^2 (Bar)	dP^2 (Bar)	$\frac{t+dt}{dt}$
0.0	4.0	3.92		15.37		
0.5	11.3	11.08	7.16	122.77	107.40	153,621.20
1.0	13.2	12.94	9.02	167.44	152.07	76,811.10
1.5	14.4	14.12	10.20	199.37	184.00	51,207.73
2.0	14.9	14.61	10.69	213.45	198.08	38,406.05
2.5	15.4	15.10	11.18	228.01	212.64	30,725.04
3.0	15.9	15.59	11.67	243.05	227.68	25,604.36
3.5	16.2	15.89	11.97	252.49	237.12	21,946.74
4.0	16.5	16.18	12.26	261.79	246.42	19,203.52
4.5	16.8	16.48	12.56	271.59	256.22	17,069.91
5.0	17.0	16.67	12.75	277.89	262.52	15,363.02
6.0	17.5	17.16	13.24	294.46	279.09	12,802.68
7.0	17.8	17.46	13.54	304.85	289.48	10,973.87
8.0	18.2	17.85	13.93	318.62	303.25	9,602.26
9.0	18.5	18.14	14.22	329.06	313.69	8,535.45
10.0	18.8	18.44	14.52	340.03	324.66	7,682.01
11.0	19.1	18.73	14.81	350.81	335.44	6,983.74
12.0	19.3	18.93	15.01	358.34	342.97	6,401.84
13.0	19.6	19.22	15.30	369.41	354.04	5,909.47
14.0	19.9	19.52	15.60	381.03	365.66	5,487.43
15.0	20.0	19.61	15.69	384.55	369.18	5,121.67
20.0	21.1	20.69	16.77	428.08	412.71	3,841.50
25.0	22.0	21.57	17.65	465.26	449.89	3,073.40
30.0	22.8	22.36	18.44	499.97	484.60	2,561.34
35.0	23.5	23.05	19.13	531.30	515.93	2,195.57
40.0	24.1	23.63	19.71	558.38	543.01	1,921.25
2767.0	33.1	32.46	28.54	1053.65	1038.28	28.76
4331.0	33.1	32.46	28.54	1053.65	1038.28	18.73
5387.0	33.2	32.56	28.64	1060.15	1044.78	15.26
7026.0	33.1	32.56	28.64	1060.15	1044.78	11.93
8526.0	33.1	32.56	28.64	1060.15	1044.78	10.01
9787.0	33.0	32.36	28.44	1047.17	1031.80	8.85
11306.0	33.0	32.36	28.44	1047.17	1031.80	7.79
12812.0	33.0	32.36	28.44	1047.17	1031.80	7.00
14097.0	33.0	32.36	28.44	1047.17	1031.80	6.45
15814.0	33.0	32.36	28.44	1047.17	1031.80	5.86
17014.0	33.0	32.36	28.44	1047.17	1031.80	5.51
17015.0	33.0	32.36	28.44	1047.17	1031.80	5.51