PET 200 – Prod. Olje & Gass (1)

Eksamen 18. Feb. 2016 (Kont)

LØSNINGSFORSLAG OPPG. 1

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a) Leser av $H(6000\ \ell/\text{min})$ på pumpekarakteristikken $\approx 37\ \text{m}$.

$$\Delta p = \rho g H = 768\ \text{kg/m}^3 \cdot 9.81\ \text{m/s}^2 \cdot 37\ \text{m} = 278761\ \text{Pa}$$

$$= \underline{\underline{2.79\ \text{bar}}}$$

b) $$P_{1b} - P_2 = \Delta P_f = \frac{1}{2} \rho u^2 f_D \frac{L}{D}$$

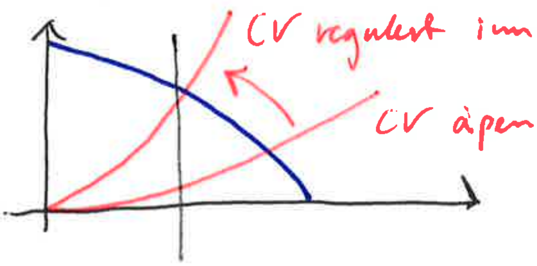
$$u = \frac{\dot{Q}}{A} = \frac{4\dot{Q}}{\pi D^2}, \qquad \dot{Q} = 6000 \frac{\ell}{\text{min}} \cdot \frac{10^{-3}\ \text{m}^3/\ell}{60\ \text{s/min}} = 0.1 \frac{\text{m}^3}{\text{s}}$$

$$\rightarrow u = \frac{4 \cdot 0.1\ \text{m}^3/\text{s}}{\pi \cdot (0.16\ \text{m})^2} = \underline{4.97\ \text{m/s}}$$

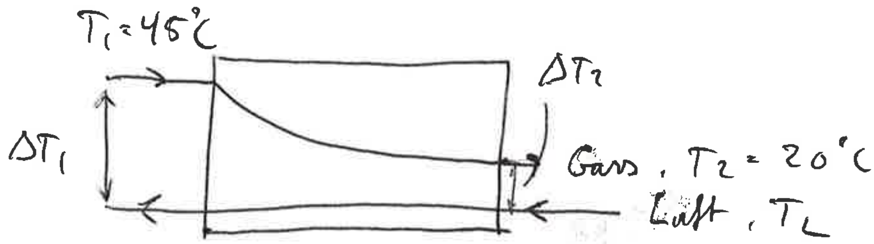
$$\Delta P_f = \frac{1}{2} \cdot 768 \cdot (4.97)^2 \cdot 0.019 \cdot \frac{100}{0.16} = 112636\ \text{Pa} = \underline{1.13\ \text{bar}}$$

$$P_{1b} = \Delta P_f + P_2 = 1.13 + 1 = \underline{\underline{2.13\ \text{bar}}}$$

c) Kontrollventilen representerer en ekstra, regulerbar friksjonsmotstand i rørsystemet, og bidrar til å gjøre systemkarakteristikken brattere.



d)



$$LMTD = \frac{\Delta T_1 - \Delta T_2}{\ln\left(\frac{\Delta T_1}{\Delta T_2}\right)} = 20\,K$$

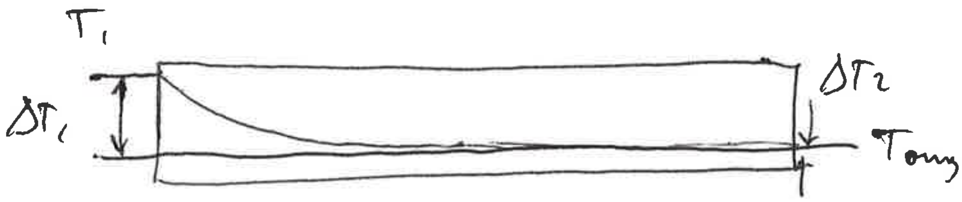
$$\Delta T_1 - \Delta T_2 = T_1 - \cancel{T_L} - T_2 + \cancel{T_L} = T_1 - T_2 = 45 - 20 = \underline{25\,K}$$

$$\Rightarrow \ln\left(\frac{\Delta T_1}{\Delta T_2}\right) = \frac{25}{20} = 1.25 \Rightarrow \frac{\Delta T_1}{\Delta T_2} = e^{1.25}$$

$$T_1 - T_L = e^{1.25} \cdot T_2 - e^{1.25} \cdot T_L$$

$$T_L = \frac{e^{1.25} \cdot T_2 - T_1}{(e^{1.25} - 1)} = \frac{3.49 \cdot 20 - 45}{(3.49 - 1)} = \underline{\underline{9.96°C}}$$

e) Pga. lengden vil temperaturen være omtrent det omgivelsen er størstedelen av strekningen



$$\lim_{\Delta T_2 \to 0} \ln\left(\frac{\Delta T_1}{\Delta T_2}\right) \to \infty \Rightarrow LMTD = \frac{\Delta T_1 - \Delta T_2}{\ln\left(\frac{\Delta T_1}{\Delta T_2}\right)} \to 0$$

$$\Rightarrow T_m \to T_{omg}.$$

f) $$\dot{q}_{sc} = 1.185 \cdot 10^{7} \cdot \frac{T_{sc}}{p_{sc}} \cdot \sqrt{\frac{(p_1^2 - p_2^2)\, D^{5.333}}{\gamma L T z}}$$

$$\Rightarrow \quad \frac{(p_1^2 - p_2^2)\, D^{5.333}}{\gamma L T z} = \left(\frac{\dot{q}_{sc} \cdot p_{sc}}{1.185 \cdot 10^{7} \cdot T_{sc}} \right)^2$$

$$\Rightarrow \quad p_2 = \sqrt{p_1^2 - \frac{\gamma L T z}{D^{5.333}} \left(\frac{\dot{q}_{sc}\, p_{sc}}{1.185 \cdot 10^{7} \cdot T_{sc}} \right)^2}$$

~~E~~Enheter (!)

$\gamma = 0.75$, $L = 100\,000$ m, $p_1 = 25\,000$ kPa, $D = 0.3$ m,

$\dot{q}_{sc} = 5 \cdot 10^{6}$ Sm³/d, $T_{omg} = 6 + 273.15 \Rightarrow T = 279.15$ K,

$z = 0.89$, $T_{sc} = 288.15$ K, $p_{sc} = 101.325$ kPa

$$\Rightarrow p_2 = \sqrt{25\,000^2 - \underbrace{\frac{0.75 \cdot 100\,000 \cdot 279.15 \cdot 0.89}{0.3^{5.333}}}_{1.14499 \cdot 10^{10}} \cdot \underbrace{\left(\frac{5 \cdot 10^{6} \cdot 101.325}{1.185 \cdot 10^{7} \cdot 288.15} \right)}_{0.14837}{}^{2}}$$

$= 19312$ kPa $= \underline{\underline{193.12 \text{ bar}}}$

Solution POG Exam H2015 (Part – 2)

Question 2:

a. i)Vigtigste komponentene inkludert:
   i. Reservoir and reservoir fluid
   ii. Well, wellhead and production line
   iii. Separators
   iv. Pumps
   v. Compressors for gas
   vi. Transportation pipelines
   vii. Safety system

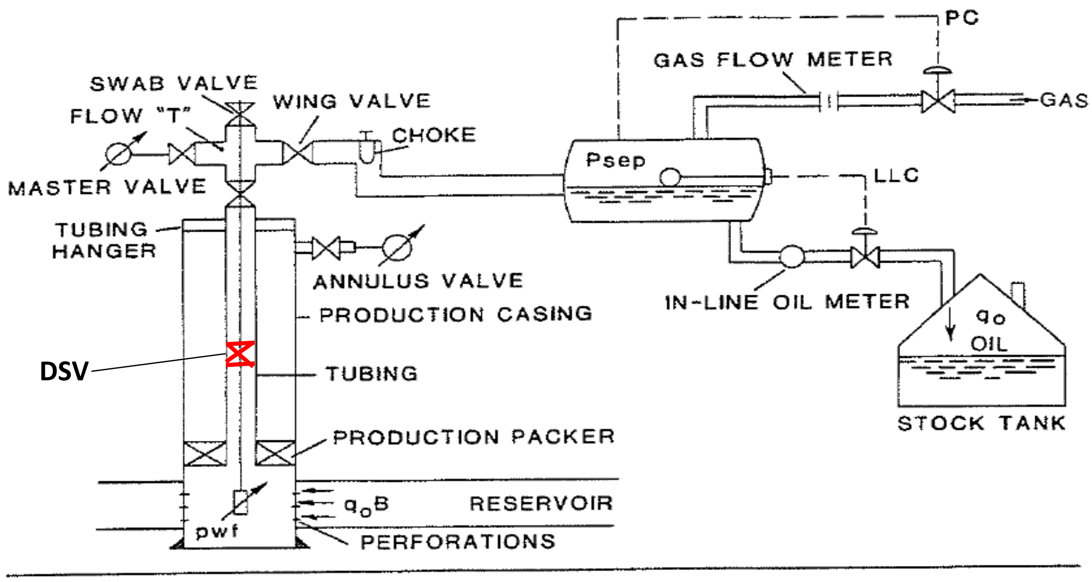


Figure 1.2 Simple single-well production system.

b. DSV
   i. A **downhole safety valve** refers to a component on an oil and gas well, which acts as a **FailSafe (FS)** to prevent the uncontrolled release of reservoir fluids in the event of a **worst case scenario** surface disaster. It is almost always **installed as a vital component** on the completion.

      A downhole device that isolates wellbore pressure and fluids in the event of an **emergency or catastrophic failure** of surface equipment. The control systems associated with safety valves are generally **set in a fail-safe mode**, such that any interruption or malfunction of the system **will result in the safety valve closing** to render the well safe. Downhole safety valves are fitted in almost all wells and are typically subject to rigorous **local or regional legislative requirements**.

   ii. The downhole safety valve (DSV) operates on hydraulic pressure from the surface. DSVs are opened using a hydraulic panel linked directly to a well control panel. When Hydraulic pressure is applied down a control line, the hydraulic pressure forces the sleeve within the valve to slide down. This compresses a large spring and pushes the flapper downwards to open the valve. When the hydraulic pressure is removed, the spring pushes the flapper back up and causes the flapper to shut.

c.

i. With transient flow the reservoir pressure has not equilibrated at the drainage radius r_e at a ”constant” / ”final” value. Under transient flow the pressure wave propagation from the wellbore has not reached the boundaries of the reservior. The developing pressure funnel is small relative to the reservoir size.

$$q_o = \frac{k \cdot h \cdot (p_i - p_{wf})}{162.6 \cdot B_o \mu_o \left(\log(t) + \log \frac{k}{\phi \mu_o c_t r_w^2} - 3.23 + 0.87 \cdot S \right)}$$

ii. ”Steady-state flow” is defined as a flow regime where the pressure within the reservoir zone remains constant with time. This is achieved when the pressure waves from the well into the reservior is in contact with an interface that gives constant pressure such as an aquifer or an injection well.

$$q_o = \frac{k \cdot h \cdot (p_e - p_{wf})}{141.2 \cdot B_o \mu_o \left(\ln \frac{r_e}{r_w} + S \right)}$$

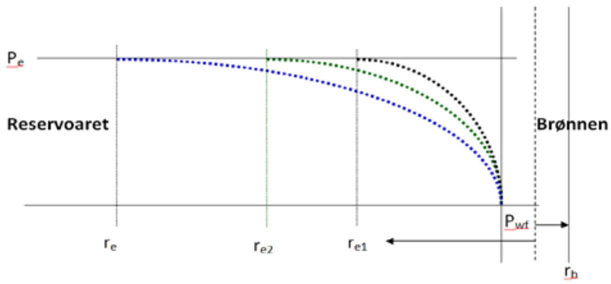
iii. ”Pseudosteady – state flow” is a flow regime where the pressure at any point in the well decreases at a constant rate as a function of time. Pseudo steady state occurs when there is **insurficient pressure** in the reservoir (either naturally or from gas- / water- injection) so that the pressure decreases over time.

$$q_o = \frac{k \cdot h \cdot (\bar{p} - p_{wf})}{141.2 \cdot B_o \mu_o \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + S \right)}$$ (3.8) where $\bar{p}$ is the average pressure

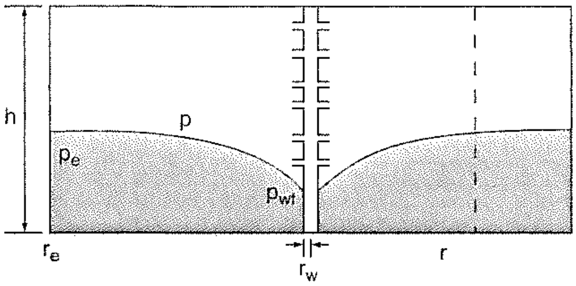
d.

i.

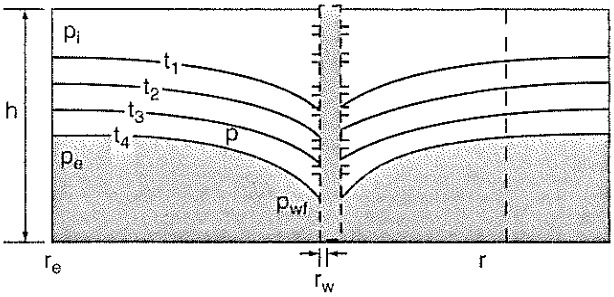
1.Transient flow pressure distribution in reservoir



2. Steady state flow pressure distribution in reservoir



3. Pseudo-steady state floe pressure distribution in reservoir



ii. Transient flow occur initially after startup and then continue until ”equilibrium” (r_e = konstant) is established between the well and the nearest ”control limit” in the reservoir (this may take hours – days – weeks – months)

e.

i. Reservoir A, pe > pb, undersaturated reservoir; Reservoir B, pe = pb, saturated reservoir

ii. IPR for reservoir A: $q_o = \dfrac{k \cdot h \cdot \left(\overline{p} - p_{wf}\right)}{141.2 \cdot B_o \mu_o \left(\ln \dfrac{r_e}{r_w} - \frac{3}{4} + S \right)}$

IPR for Reservoir B: $q_o = \mathrm{q}_{\max} \cdot \left(1 - 0.2\left(p_{wf}/p_e\right) - 0.8\left(p_{wf}/p_e\right)^2\right)$

iii. Reservoir A will give the highest productivity, because we have a significant amount of single phase oil flow before we reach the bubble point at which two-phase oil and gas will begin. With two phase oil and gas flow from the reservoir, as the pressure drops below the bubble point pressure, the productivity of the reservoir drops due to increase in frictional pressure drop and liquid entrainment in the well as the gas flow speed increases.

Question 3:

a.

i. Simplest forms of the TPR equation for wells:

A (oil); TPR = $P_{wh} + \Delta P_{P.E.} = P_{wh} + \frac{g}{g_c} \cdot \rho \cdot \Delta z$

B (gas); TPR = $P_{wh} + \Delta P_{P.E.} + \Delta P_F = P_{wh} + \frac{g}{g_c} \cdot \rho \cdot \Delta z + \frac{2 \cdot f_f \cdot \rho \cdot u^2 \cdot L}{g_c \cdot D}$

ii. Total pressure drop

$$\Delta P = \frac{g}{g_c} \cdot \rho \cdot \Delta z + \frac{\rho}{2 \cdot g_c} \cdot \Delta u^2 + \frac{2 \cdot \mathrm{f_f} \cdot \rho \cdot u^2 \cdot L}{g_c \cdot D} \qquad (4\text{-}1)$$

For all wells, with constant diameter (D), Δu = 0, thus $\Delta P_F = 0$. For well A (oil) the contribution from frictional pressure drop is usually very small, less than 2% of the total pressure drop and thus may can be neglected, but for well B (gas) the frictional pressure drop is usually significant enough not to be neglected.

iii. In well A (oil) the hydrostatic pressure drop ($\Delta P_{P.E.}$) contributes most to the total pressure drop. For well B (gas) the highest contributor may be either the hydrostatic pressure drop, or the frictional pressure drop. If the density of the gas is high enough and significantly high well depths, ($\Delta P_{P.E.}$). Otherwise ΔP_F would contribute most if the gas density is very low and at low well depths.

iv. If we take the vertical well to be a horizontal pipe, the well depth becomes Δz = 0, giving a hydrostatic contribution ($\Delta P_{P.E.}$) = 0.

b.

i. IPR-curve = $P_{wf,test}$ vs. $q_{o,test}$, we must plot all corresponding column values of $p_{wf,test}$ against $q_{o,test}$, from $p_{wf,test} = p_e$ against $q_{o,test} = 0$, to absolute open flow when $p_{wf,test} = 0$ against $q_{o,test} = q_{o,max}$.
TPR-curve = [$P_{wh,min}$ + ΔP] vs. $q_{o,test}$ = [Pwh,min + ($P_{wf,test}$ - $P_{wh,test}$)] vs. $q_{o,test}$. We must create an additional column with the values of [Pwh,min + ($P_{wf,test}$ - $P_{wh,test}$)], and plot all corresponding values of the TPR vs. $q_{o,test}$ from $q_{o,1}$ to abosolute open flow at $q_{o,max}$.

ii.

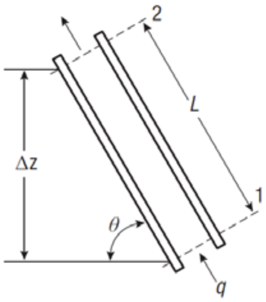
c. A = p_e = 6500 psi,
B = p_b =4500 psi,
C = $q_{o,b}$ = J*(p_e – p_b); J = $q_{o,test}$ / (p_e – $p_{wf,test}$) = 600/(6500 – 5000) = 0.4; thus C = 0.4*(6500 – 4500) = 800 stb/d,
D = $q_{o,max,add}$ = J*p_b/1.8 = 0.4*4500/1.8 = 1000 stb/d,
E = $q_{o,max,total}$ = $q_{o,b}$ + $q_{o,max,add}$ = 800 +1000 = 1800 stb/d.

d.

$$\Delta P = \frac{g}{g_c} \cdot \rho \cdot \Delta z + \frac{\rho}{2 \cdot g_c} \cdot \Delta u^2 + \frac{2 \cdot f_f \cdot \rho \cdot u^2 \cdot L}{g_c \cdot D} \qquad (4\text{-}1) \left\{ \text{Note}: f_f = \frac{1}{4} f_M \right\}$$

D = constant, i.e $\Delta P_{K.E.} = 0$. Thus

$$\Delta P = \Delta P_{PE} + \Delta P_F = \frac{g}{g_c} \cdot \rho \cdot \Delta z + \frac{f_M \cdot \rho \cdot u^2 \cdot L}{2 \cdot g_c \cdot D}$$



For single phase gas flow $\rho_g = f(p, V, T) \neq$ const. We must find the

average value of ρ_g as: $\rho_g = \rho_{mean} = {28.97 \cdot \gamma_g \cdot p_{mean}}/{Z_{mean} \cdot R \cdot T_{mean}}$

where $X_{mean} = (X_1 + X_2) / 2$

For inclination θ, Δz = L*sinθ = fluid column height. Thus the hydrostatic pressure

drop $\Delta P_{PE} = {g}/{g_c} \cdot \rho_{mean} \cdot L \cdot sin\theta$

$u = {4 \cdot q}/{\pi \cdot D^2}$, meanwhile $q = f(p, V, T) \neq$ const;

But $q = \partial V/\partial t$. From the real gas equation ${PV}/{ZnRT} = const.$

For 1 mole of gas, we have ${PV}/{ZRT} = const.$

The flow rate in a gas well in real time is related to measurements taken from a well

Taken at standard conditions (sc). i.e: $PV\ /\ ZRT = P_{sc}\, V_{sc}\ /\ Z_{sc}\, RT_{sc}, V = P_{sc}\, V_{sc}\, Z\, T\ /\ PZ_{sc}\, T_{sc}$

But Zsc = 1, thus $V = P_{sc}\, V_{sc}\, Z\, T\ /\ P\, T_{sc}$

Then, $q = {\partial V}/{\partial t} = \partial V_{sc}/\partial t \cdot (Z \cdot {P_{sc} \cdot T}/{P \cdot T_{sc}}) = q_{sc} \cdot (Z \cdot {P_{sc} \cdot T}/{P \cdot T_{sc}})$

For real time flow in the well, $Z = Z_{mean}$, $P = P_{mean}$, and $T = T_{mean}$. Inserting q for u, and

ρ_{mean} for ρ in the ΔP_F equation we get:

$$\Delta P_F = \frac{8 \cdot f_M \cdot \rho_{mean}}{\pi^2 \cdot g_c \cdot D^5} \cdot \left(q_{sc} \cdot Z_{mean} \cdot \left(\frac{T_{mean}}{T_{sc}} \right) \left(\frac{p_{sc}}{p_{mean}} \right) \right)^2 \cdot L$$

Thus the total pressured drop:

$$\Delta P = \Delta P_{PE} + \Delta P_F = \frac{\rho_{mean} \cdot g}{g_c} \cdot L \cdot \sin\theta + \frac{8 \cdot f_M \cdot \rho_{mean}}{\pi^2 \cdot g_c \cdot D^5} \cdot \left(q_{sc} \cdot Z_{mean} \cdot \left(\frac{T_{mean}}{T_{sc}} \right) \left(\frac{p_{sc}}{p_{mean}} \right) \right)^2 \cdot L$$

e. $\Delta P_{PE} = {}^{g}/_{g_c} \cdot \rho \cdot L \cdot sin\theta$

= 17.32/17.32*(51.48* 1000* sin(75)) = 49725.86 lbf/ft^2 = 345.319 psi

$$\Delta P_{KE} = \tfrac{1}{2} \cdot \rho \cdot \left(\left(\frac{4Q}{\pi \cdot D_2^2} \right)^2 - \left(\frac{4Q}{\pi \cdot D_1^2} \right)^2 \right) = \frac{8 \cdot \rho \cdot Q^2}{\pi^2} \cdot \left(\frac{1}{D_2^4} - \frac{1}{D_1^4} \right)$$

= 8*51.48lbm/ft^3* (1000*6.493*10^{-5}ft^3/s)^2*(1/(2.875/12)^4 - 1/(2.259/12)^4)*1/ft^4/(32.17 lbm ft/lbf s^2*3.142^2) = -0.86 lbf/ft^2 = 0.006 psi

Question 4:

a. Well perforation
   i. Definition: Perforation of an oil and gas well is the establishment of contact between the well and the reservoir by creating hole or channels through the well's casing and cement, with the use of shaped charges to produce perforating jets which perforate (pierces) through the casing and the cement. The shaped charges are assembled and run into the well in an assembly referred to as a perforating gun.
   ii. Important factors in perforating
      1. **Penetration depth:** The deeper the penetration canal extends into the reservoir the better the more effective. Increased length provides increased contact with the the reservoir and thereby increased effect in terms of production.
      2. **Diameter of perforation canal**: Larger diameter of the perforation canal increases inflow effect but Penetration seems to be a more important factor.
      3. **Shot density**: The more shots per foot (per meter) the better effect, but with shot density over 4 charges per foot this effect seems to decline, while the chances of damage to the casing due to weakened strength seems to increase.
      4. **The phase shift between charges**: The phase angle between the charges around the well periphery has an effect on the production capacity achieved by perforation. The worst choice is 0 ° phase shift (all shots on the same side and along the same line), but with good positioning of the gun all around the casing wall one can achieve a good penetration depth in all the canals.
      5. **Distance between perforation canals**: Optimal distance between perforation canals is achieved through an optimal density per unit length and an optimal phase angle. Conditions that give the least interference between canals and dense placement provides the best overall effect

b. Sand control
   i. Sand production would normally occur in sandstone reservoir with poorly consolidated sand. Due to drag forces between the oil flowing through the reservoir and "poorly glued" sand grains (unconsolidated sand) in sandstone formations, some sand grains tear away and are transported to the well along with the oil. This is especially severe at high well production rates.
   ii. Problems associated with sand production include:
      1. Reduced production due to sand penetration in well.
      2. Production problems due to sand that comes with oil flow and which is deposited in a pipeline between the well and the process unit.
      3. Packing of sand in separator system.
      4. Erosion in pipelines and equipment (abraded / "sandblasted").

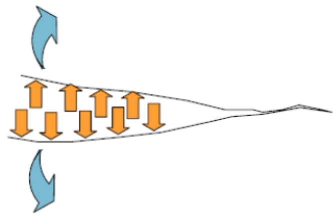
iii. Sand control measures include:
   1. Artificial consolidation / glueing by injecting chemicals that glue the sand grains in the reservoir
   2. Setting of gravel/sand filters (Gravel packing, sand screen, screened liner).

iv. The $d_{50\text{-sand}}$ is the average size distribution of the sand grains obtained from reservoir sand analysis. $d_{50\text{-sand}}$ is used for gravel pack mesh and screen design.

c. Fracturing

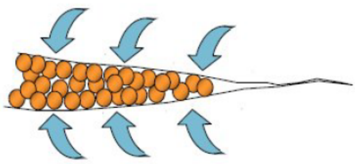
i. The 3 steps in a fracturing process:

   a) Actual fracturing by pumping of fracturing liquid at high rate and high pressure around the well.



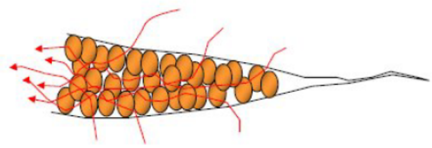
(a): Illustration of the fluid creating a fracture in the formation

   b) After fracturing proppant solution is pumped into the fractures formed during point a).



(b): Illustration showing the proppant keeping the fracture open

   c) The proppant has a firmness which keeps the crack open at a size conducive to good conductivity through the established fracture channels.



(c): Illustration of fluids entering the highly conductive fracture

ii. The rock must also have a certain mechanical strength. if too soft, it will move in between the sand when the fracture closes, and more or less destroy the permeability of the proppant layer. Especially limestone reservoirs are susceptible to this.
If the proppant is too soft compared with the reservoir rock, the proppant gets crushed ones the fracturing pressure is removed and the permeability of the proppant layer is destroyed as well.
Thus the rock and proppant hardness most be must be weighted proportionately such that the proppant permeability is maintained at a reasonable level, and thus give good fracture conductivity after the fracturing pressure is removed.

iii. Fracture length for:

Rectangular fracture $r = {}^{k_f \cdot w}/_{k_R} = 254.64\ m$

Elliptical fracture $r_e = ({}^{\pi}/_{4}) \cdot {}^{k_f \cdot w}/_{k_R}$

Thus $r_e = (\pi/4)*r = 0.785*254.64$ m $= 199.99$ m ≈ 200 m

d. Formation damage

i. For a flow of q_o from the reservoir across the skin zone to the well,

With ideal flow,

$$q_o = \frac{k \cdot h \cdot (p_s - p_{wf,ideal})}{141.2 \cdot B_o \cdot \mu_o \cdot \left(ln \frac{r_s}{r_w}\right)};$$

$$i.e.\, p_{wf,ideal} = p_s - \frac{141.2 \cdot B_o \cdot \mu_o}{k \cdot h} \cdot \left(ln \frac{r_s}{r_w}\right)$$

With real flow (skin),

$$q_o = \frac{k_s \cdot h \cdot (p_s - p_{wf,real})}{141.2 \cdot B_o \cdot \mu_o \cdot \left(ln \frac{r_s}{r_w}\right)}$$

$$i.e.\, p_{wf,real} = p_s - \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{k_s \cdot h} \cdot \left(ln \frac{r_s}{r_w}\right)$$

$$\Delta p_s = p_{wf,ideal} - p_{wf,real}$$

$$= [p_s - \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{k \cdot h} \cdot \left(ln \frac{r_s}{r_w}\right)] - [p_s - \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{k_s \cdot h} \cdot \left(ln \frac{r_s}{r_w}\right)]$$

$$= \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{h} \cdot \left(\frac{1}{k_s} - \frac{1}{k}\right) \cdot \left(ln \frac{r_s}{r_w}\right) = \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{k \cdot h} \cdot \left(\frac{k}{k_s} - 1\right) \cdot \left(ln \frac{r_s}{r_w}\right)$$

$$= \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{k \cdot h} \cdot s$$

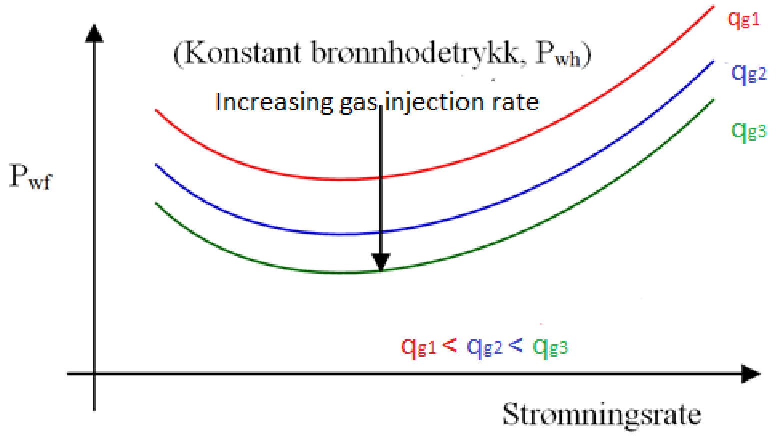
ii. Skin factor $s = \left(\frac{k}{k_s} - 1\right) \cdot \left(ln \frac{r_s}{r_w}\right)$.

Given, k = 75 mD, k_s = 15 mD, r_s = r_w + damage radius = 4.5/12 ft + 3 ft = 3.375 ft. Thus skin factor, s = (75/15 -1)*(ln(3.375/0.375)) = 8.79

$$\Delta p_s = \frac{141.2 \cdot B_o \cdot \mu_o \cdot q_o}{k \cdot h} \cdot s = \frac{141.2 \cdot 1.7 \cdot 1.5 \cdot 600}{75 \cdot 100} \cdot 8.79 = 253.16\, psi$$

e. Gaslift

i. Effect of gaslift on the TPR of a well: Injection of gas into the production tubing decreases the density of the fluid and thus the hydrostatic pressure drop. This in turn decreases the TPR, pushing the TPR-curve downwards and injection rate increases.



ii. As the gas injection rate increases, this reduces the hydrostatic pressure drop, but at the same time increases the frictional pressure drop. But since the hydrostatic pressure drop contributes most to the total pressure drop, the overall effect will be a decrease in the total pressure drop. But there is a limit at which any further increase in the gas injection rate increases the frictional pressure drop such that any reduction in hydrostatic pressure drop is cancelled out. And at this point it would be unrealistic to further increase the gas injection rate.

iii. Pressure drop across the well $\Delta P = P_{wf} - P_{wh}$. Pwh = 1500 psi. During gas lift we have a new GLR due to gaslift = 2000 scf / stb. Using the gradient curve diagram, this gives a flowing well pressure P_{wf} = 2500 psi during gas lift. Thus the pressure drop in the well during gaslift = 2500 – 1500 = 1000 psi.

Gas injection rate qg = ql*(GLR2 – GLR1)
= 600*(2000 – 1000) = 6×10^5 scf/d.