NTNU – Trondheim
Norwegian University of
Science and Technology

Department of Petroleum Engineering and Applied Geophysics

Resitting examination paper for TPG4230 – Field Development and Operations

Academic contact during examination: Prof. Milan Stanko

Phone: +47 954 40 756

Examination date: August 09, 2016

Examination time (from-to): 09:00-13:00

Permitted examination support material: No Written or handwritten aids permitted.

Approved calculator permitted

Other information:

Language: English

Number of pages (front page excluded): 6

Number of pages enclosed:

Informasjon om trykking av eksamensoppgave

Originalen er:

1-sidig ☐ **2-sidig** ☐

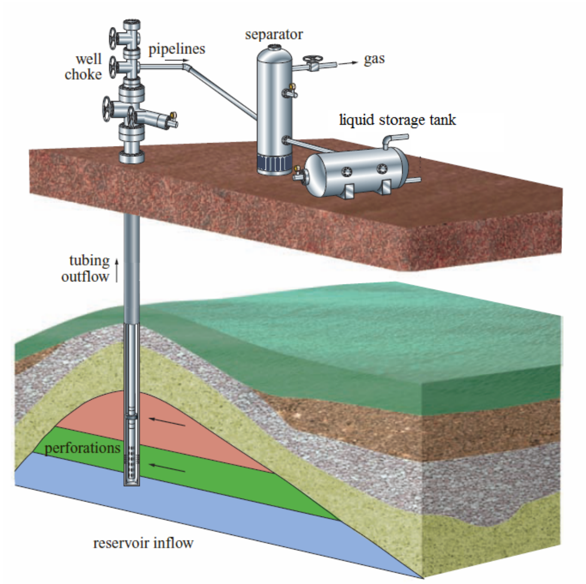
sort/hvit ☐ **farger** ☐

Checked by:

Date Signature

PROBLEM 1. (30 POINTS) Gas field planning

Atoka is a small sandstone reservoir bearing dry gas located in Pittsburg County, Oklahoma. The field is planned to be developed by the company Paleo Inc. **with 3 standalone vertical wells** (each one with its own pipeline and separator as shown in the figure below). The wells will have a depth of 3200 m and completed with a 4 inch production casing and 2 3/8 inch production tubing, and gas is produced through the tubing. The wells will be equipped with an adjustable wellhead choke. The separator operates with a constant pressure of 4 bar.



In order to perform a simplified production scheduling, a production engineer has estimated the following analytical expression for **single gas well production potential** (in **Sm^3/d)** as a function of **cumulative gas production of the field** (G_p in **Sm^3)**:

$$q_{pp} = q_{pp0} - m \cdot G_p = 6.86 \cdot 10^4 - \left(2.20 \cdot 10^{-4} \cdot G_p\right)$$

Assume that all wells are identical, are drilled from year "0", and that their production potential depends on the field cumulative production. This yields that the field production potential can be expressed as:

$$q_{ppfield} = N \cdot \left(q_{pp0} - m \cdot G_p\right)$$

Where N is the number of wells.

The company hasn't decided yet about how to operate the field, but it wishes to operate it in plateau mode for about 5-7 years and, after that, in decline mode.

1. **1.** Generally speaking, what are the two types of production modes that could be employed to produce an oil and gas field? and when should each one of them be used? Explain your answer.

2. **2.** Make a sketch (schematically, not using the actual values) of the pressure profile along the production system (single well) from the reservoir boundaries to the separator in three different times: start of production, end of plateau and in the decline phase. Make sure to mark the important points in the system: bottomhole, wellhead (upstream of choke), downstream of choke and separator.

3. **3.** Calculate what field plateau rate one must produce to achieve a plateau length of 5, 6 and 7 years. Sketch a plot of plateau rate vs plateau duration and provide an explanation for the trend. Assume that there are 360 operational days in a year.

4. **4.** Propose/derive an analytical expression for the field rate vs time after the plateau period.

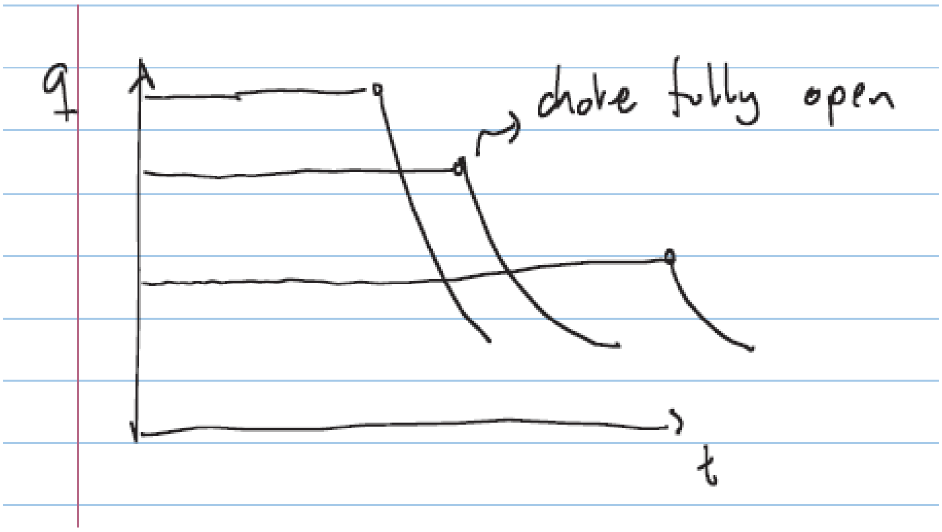
5. **5.** If the plateau rate chosen is 80 000 Sm^3/d, estimate the plateau duration.

6. **6.** If the plateau rate chosen is 80 000 Sm^3/d, Estimate when the field will reach the abandonment rate of 10 000 Sm^3/d of gas (you can use the expression derived in question 4).

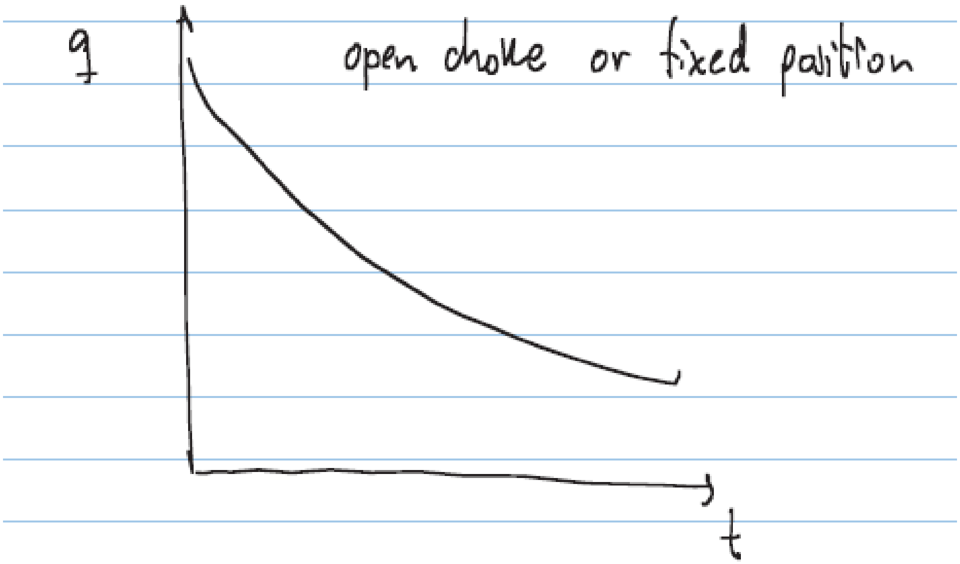
7. **7.** One of your colleagues has the theory that by drilling the wells gradually, i.e. two during year "0" and the third well the first year (entering in production the second year), will prolong the duration of the plateau and increase the total NPV. Please provide your engineering assessment of this idea and justify why **will** or **will not** work.

P.1.

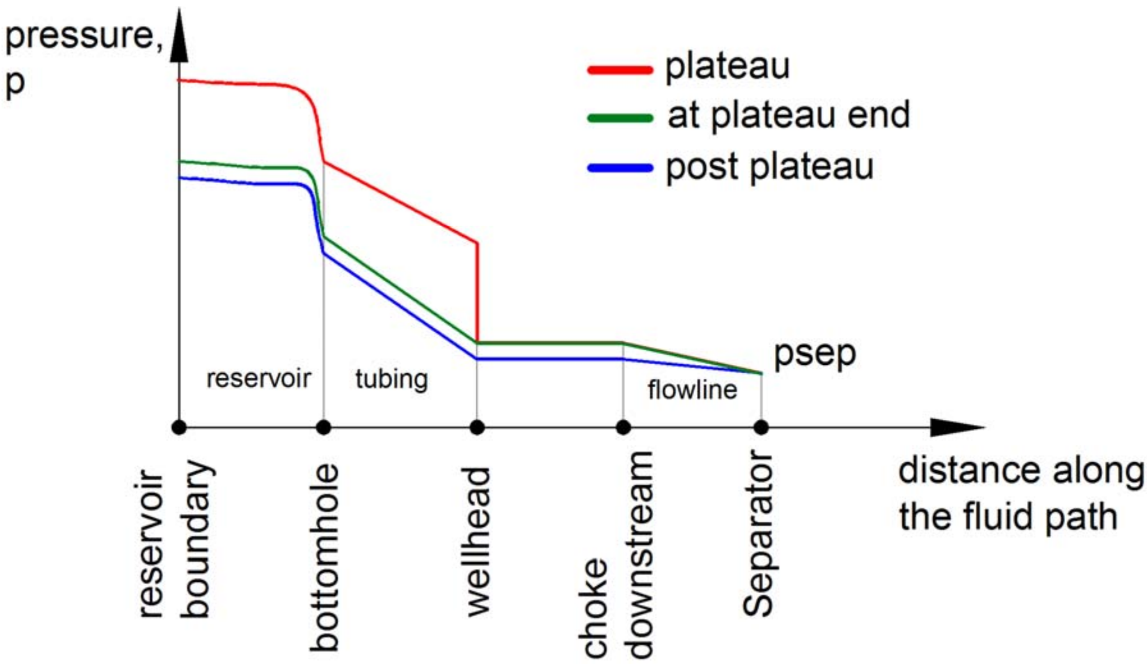
Plateau mode: operating with a constant rate. In this approach chokes are employed to control production at a fixed value when the reservoir is depleting. This mode is suitable for standalone fields that will have its own processing facilities or for situations when there is a sales contract.



Constant pressure mode (rate decline) operating against constant separator pressure. In this approach the reservoir is producing the maximum allowed, therefore the rate will reduce with time with depletion. This operating mode is appropriate for satellite fields that will use existing facilities of neighbouring field that has spare capacity.



P.2.



P.3.

The Gp at plateau time is unknown, but can be expressed by the following equation:

$$G_{p\_plateau} = q_{plateau} \cdot N_{days\_in\_year} \cdot N_{years} \qquad \text{Eq. 1}$$

Using the expression of the fied potential, at $G_{p\_plateau}$, the field potential should be equal to the plateau rate:

$$q_{plateau} = N \cdot \left(q_{pp0} - m \cdot G_{p\_plateau}\right) \qquad \text{Eq. 2}$$

Substituting eq. 1 in Eq. 2:

$$q_{plateau} = N \cdot \left(q_{pp0} - m \cdot q_{plateau} \cdot N_{days\_in\_year} \cdot N_{years}\right) \qquad \text{Eq. 3}$$

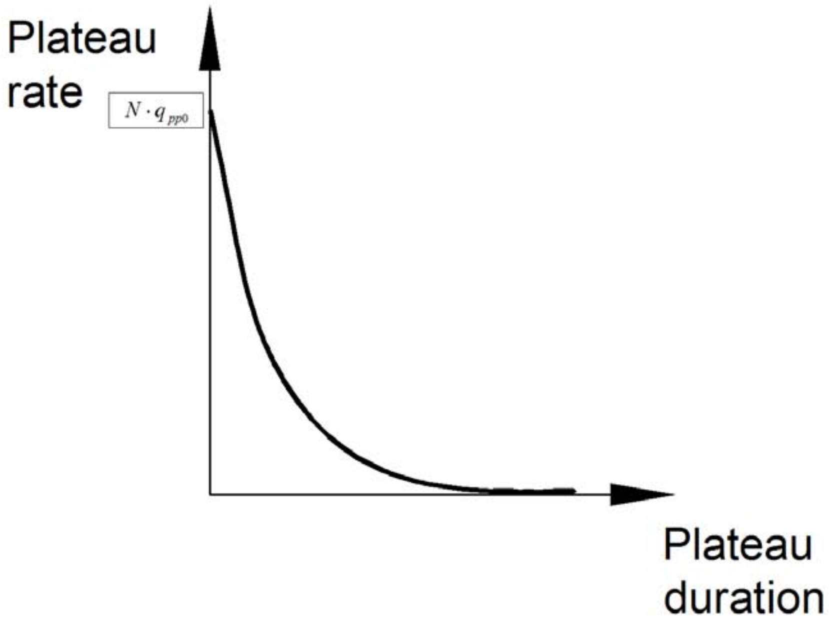
And clear from eq. 3 the plateau rate

$$q_{plateau} = \frac{\left(N \cdot q_{pp0}\right)}{\left(1 + N \cdot m \cdot N_{days\_in\_year} \cdot N_{years}\right)} \qquad \text{Eq. 4}$$

For all plateau durations specified, the plateau rate yields

Plateau length	$q_{plateau}$
[years]	[Sm^3/d]
5	9.41E+04
6	8.48E+04
7	7.73E+04

The function is an asymptote (q=a/(1+b*t))



When we increase the plateau rate, the plateau becomes shorter and shorter. This makes sense because, as we increase the plateau rate, the Gp for the same time is bigger, thus the potential is smaller, yielding a shorter plateau.

P.4.:

As seen in class, if the production potential of the field is linear with cumulative gas production, and the field is producing always at its production potential, the rate is described by an exponential equation. Using the expression given:

$$q_{pp} = N \cdot \left(-m \cdot G_P + q_{ppo}\right)$$

The gas cumulative production (G_P) is then cleared from it and substituted in Eq. below:

$$G_P = \int_0^t q(t) \cdot dt$$

$$\frac{q_{pp} - N \cdot q_{ppo}}{-N \cdot m} = \int_0^t q_{pp} \cdot dt$$

Rearranging:

$$q_{pp} - N \cdot q_{ppo} = \int_0^t -N \cdot m \cdot q_{pp} \cdot dt$$

Deriving with respect to time to get rid of the integral:

$$\frac{dq_{pp}}{dt} = -N \cdot m \cdot q_{pp}$$

The differential Eq. is solved using separation of variables and evaluated between time end of plateau (potential rate: $q_{plateau}$) and time "t", with a production of $q(t)$:

$$\ln(q_{pp})\Big|_{q_{plateau}}^{q(t)} = -N \cdot m \cdot (t - t_{plateau})$$

And lastly, by rearranging, the exponential expression is obtained:

$$q(t) = q_{plateau} \cdot e^{-N \cdot m \cdot (t - t_{plateau})}$$

P.5.

The plateau duration:

Using the field potential expression, calculate the cumulative production when the field production potential is equal to the plateau rate

$$G_P^* = \frac{1}{m} \cdot \left(q_{pp0} - \frac{q_{ppf}}{N} \right) = \frac{1}{2.2 \cdot 10^{-4}} \cdot \left(6.86 \cdot 10^4 - \frac{8.0E4}{3} \right) = 1.91E8\ Sm^3$$

Obtain the plateau duration by dividing G_P^* by the plateau rate and the number of operational days in a year:

$$Plateau\ years = \frac{G_P^*}{q_{plateau} \cdot 360} = 6.62\ years$$

P.6.

Time when the abandonment rate is reached:

$$q(t) = q_{plateau} \cdot e^{-N \cdot m \cdot (t - t_{plateau})}$$

$$10E4 = 80E4 \cdot e^{-3 \cdot 2.2E-4 \cdot (t - t_{plateau})}$$

$$\ln\left(\frac{10E4}{80E4}\right) \cdot \frac{1}{-3 \cdot 2.2E-4} + t_{plateau} = t$$

$$t = 15.37\, years$$

P.7.

During the first year, there will be two wells producing (40 000 Sm^3/d each, to meet the plateau rate). Then, from the second year, the splitting will change and each well will produce 26 666 Sm^3/d.

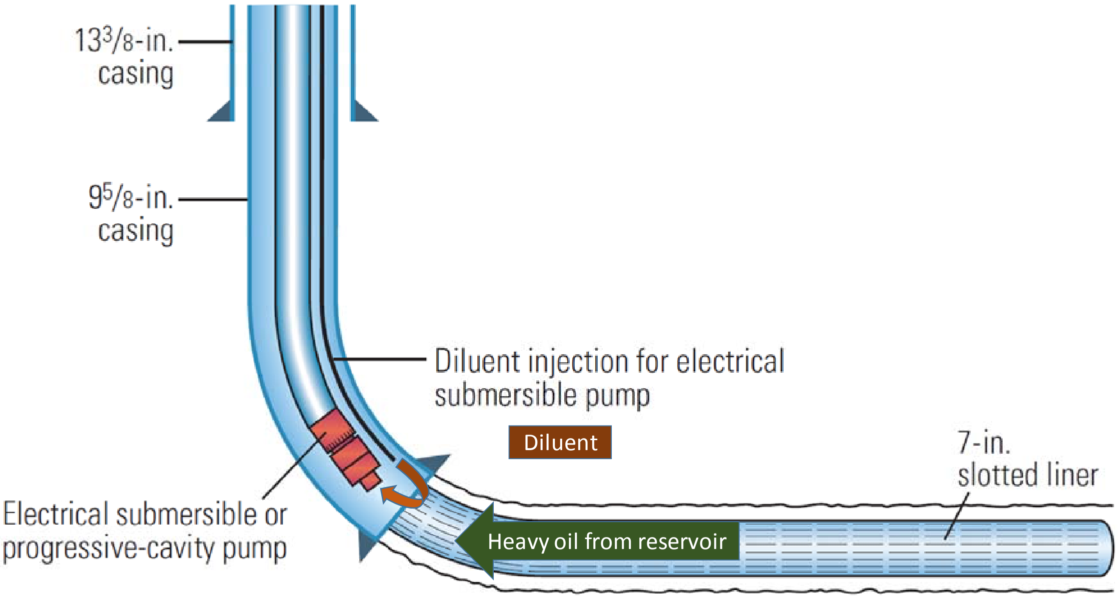
The field production potential will increase at the beginning of year 2, when the extra well enters in operation. After this point, the field production potential curve will be exactly the same as for the case where all wells start from the beginning.

Please note that, during the plateau period, we are producing at all times below the potential, so it doesn't really matters what the production potential is, as long as it is greater than the plateau rate.

Due to this, the plateau length will be the same. The field cumulative production Gp doesn't change (the plateau rate is still being produced) and the potential will be reached at the same time. This indicates that the revenue profile coming from gas sales will remain constant.
If the well is drilled during year 1, the value is discounted when calculating the NPV (increasing the NPV). However, there will likely be some increase on the drillex due to inflation, thus the two changes might cancel out.
From this discussion, it seems that the idea will not give an important change in the NPV of the project. The drilling schedule should be then given by the rig availability.

PROBLEM 2. (20 points) Optimization of a diluent-lifted well and verification of ESP design

For wells producing from heavy oil reservoirs (low API high viscosity crudes), an artificial lift technique often used is to combine ESP (electric submersible pump) lifting and diluent injection at the pump suction. The diluent is usually a high API crude bought from another field. The diluent is mixed with the heavy oil and reduces its viscosity, which makes it easier to pump and transport in the well.



1. **Statoil has asked your expert advice to determine the optimal amount of diluent to inject in the Mariner field (50 wells) to maximize revenue at a given point in time.** Use the following simplified equation for revenue:

$$Revenue = q_{oR} \cdot (oil\ \ price) - q_{dil\_inj} \cdot (diluent\ \text{cost})$$

Take into account the following considerations:

- Assume an oil price of 252 USD/m3 and a diluent cost of 315 USD/m^3.

- All wells can be considered identical and display the following diluent performance behavior (oil produced from reservoir (q_{oR}) vs amount of diluent injected (q_{dil_inj}), keeping ESP frequency and well-head pressure constant):

q_{dil_inj}	q_{oR}	Viscosity of oil mixture at ESP inlet
[Sm³/d]	[Sm³/d]	[cp]
0.0	2435	1943
200.0	3225	908
400.0	3459	513
600.0	3347	329

- All wells are operated at constant ESP frequency and well-head pressure, with the same values used to generate the table presented before.

- The total amount of diluent available is 15 000 **[Sm³/d]**

P.1.

As no other information is given in the text, we will assume that to find values for intermediate quantities of diluent a linear interpolation in the table is accurate.

Calculate a new columns with the revenue for the oil prices and water cost given:

q_{dil_inj}	q_{oR}	Revenue
[Sm³/d]	[Sm³/d]	[USD/d]
0	2435	613525
200	3225	749669
400	3459	745640
600	3347	654480

The best diluent injection rate, is, 200 Sm^3/d. (maximum revenue) I.e. 10000 Sm^3/d for all wells. This is below the available amount of diluent of 15000 Sm^3/d. The ESP will operate with a fluid which viscosity is 908 cp.

2. **Using the diluent and reservoir oil rates calculated earlier, determine (approximately, using the ESP performance map) the frequency of the ESP required to deliver the desired rate. Use the following assumptions:**

- The well inflow can be represented with a linear PI equation:

$q = J \cdot (p_R - p_{wf})$

Where:

q……total liquid rate in Sm^3/d

J……productivity index for total liquid flow **[30 Sm^3/d/bar]**,

p_R…...reservoir pressure [**200 bara**]

p_{wf}…..bottom-hole flowing pressure [bara]

Note!: The reservoir is producing only oil.

- Assume that the pressure losses between the bottom-hole and the ESP suction are negligible such as $p_{wf} = p_{suc}$.

- The diluent is injected at the suction of the ESP

- Assume that there is no gas liberation in the well and that the liquid compressibility can be neglected. In consequence, standard liquid rate is equal to local flow rate.

- Even though there is a surface network, assume for your study that the wellhead pressure remains constant at a value of 60 bara. Using this assumption, and assuming a constant viscosity of the fluid, the following expression is provided that gives pressure drop from pump discharge to wellhead vs liquid rate:

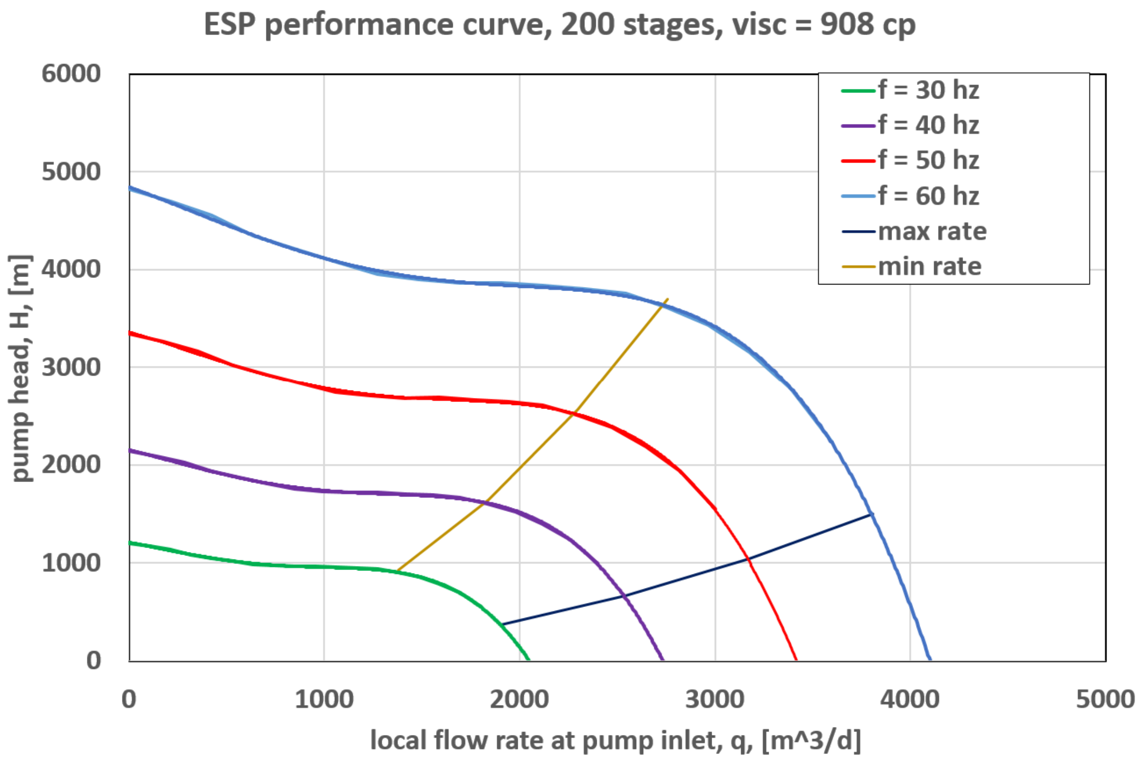
$\Delta p = 2.7307E-6 \cdot q^2 + 9.8103E-3 \cdot q + 211.5$

Where:

Δp …tubing pressure drop in bar

q……total liquid rate in Sm^3/d

- The ESP operational map is given in the figure below.



- The pump head [m] is

$$\Delta h = \frac{\Delta p \cdot 10^5}{\rho \cdot g}$$

Where Δp [bara], ρ [kg/m^3] and g = 9.81 [m/s^2]

Assume a fluid density of 963 .5 kg/m^3

P.2.

The reservoir is producing an oil rate of 3225 **Sm³/d.** Calculate p_{wf} from IPR equation:

$$p_{wf} = \cdot\left(p_R - \frac{q_{liq}}{J}\right)$$

$$p_{wf} = 92.5\ bara$$

At the bottomhole (i.e., pump suction) the stream from the reservoir and the diluent are comingled. This indicates that the oil flowrate through the ESP and through the tubing is 3225 **Sm³/d (reservoir oil) +** 200 **Sm³/d (diluent) = 3425 Sm³/d.**

Using this rate and p_{wh} = 60 bara, calculate p_{disc} from the expression:

$$p_{dis} = p_{wh} + \Delta p(q_{liq})$$

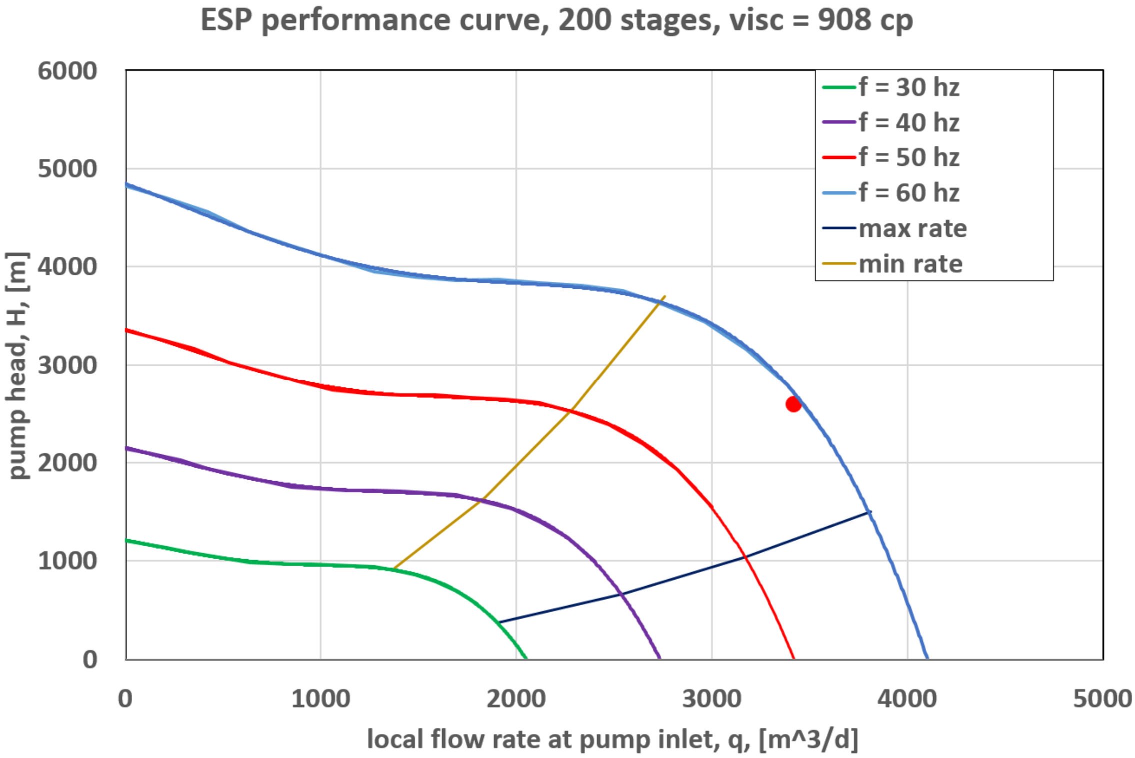
$$p_{dis} = 337.13\ bara$$

Then the pump deltap is calculated from the expression:

$$\Delta p_{ESP} = p_{dis} - p_{wf} = 244.6\ bara$$

Compute head with the provided expression:
$h_{ESP} = 2588.2\ m$

By coincidence, the ESP performance map given is for the fluid viscosity (908 cp) at a diluent injection of 200 Sm^3/d. Assuming that the fluid is incompressible, q =3425 Sm^3/d. Plotting the point in the map:



The operating frequency is around 60 hz.

PROBLEM 3. (10 POINTS) Multiphase flow pressure drop calculations in a tubing segment

1. Please explain with a scheme or a checklist the general numerical integration procedure to perform multiphase pressure drop calculations in wells and in flowlines if the rate is fixed and a pressure in a boundary is known.

P.1.

The workflow, for the case of a single conduit transporting a standard flow rate of oil, gas and water and where the temperature of the fluid is known in advance, is the following:

- Discretize the conduit into segments.
- Define a starting point where P_0 and T_0 is known.
- Calculate local volume rates:

   - If using a compositional approach: 1. calculate total mass flow rate, 2. Calculate using a PVT model fluid properties at P and T, including gas mass rate, oil mass rate and water mass rate.
   - If using a Black Oil approach: 1. Convert from standard to local conditions using BO properties at P and T.; 2. Use BO correlations or tables to determine other properties required (densities, viscosities, etc.).
- Compute superficial velocities using the local volume rates
- Estimate pressure gradient (dP/dL=c) at the starting point using a multiphase flow model.
- Calculate the pressure in the next point in the conduit by solving numerically the differential equation:

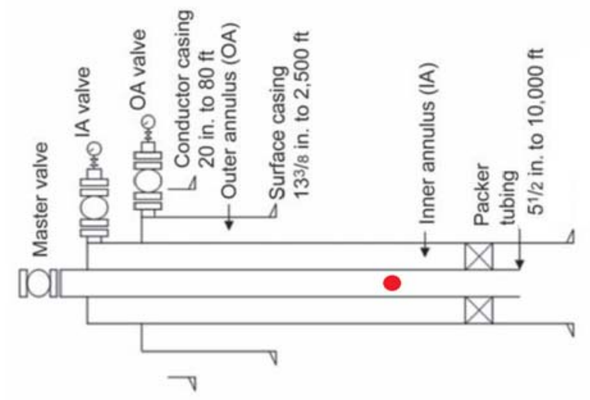
$$\frac{dp}{dL} = c, \text{ with initial conditions } p_0 \text{ at } L_0.$$

The numerical solution might be performed using an explicit or implicit method.

- If the temperature is not given and rather a temperature drop model is available, the numerical algorithm has to solve two functions simultaneously, one for pressure and one for temperature.

2. The data presented in the table below is available for a point in the tubing at a depth of 2500 m (shown with a red dot in the schematic below). Estimate the pressure in the next point (200 m below) in the tubing using Euler's integration method.

TVD	p	T	Liquid Mass fraction	mo	mg	deno	deng	qo	qg	vso	vsg	dp/dx	flow pattern
[m]	[bara]	[C]	[-]	[kg/s]	[kg/s]	[kg/m^3]	[kg/m^3]	[m^3/s]	[m^3/s]	[m/s]	[m/s]	[bara/m]	
2500	147	70	0.9978	11.92027	0.026282	569	116	0.0209	0.000227	1.851	0.020	0.056596	Bubble



P.2.

consider the problem:

$$y'(t) = f(t, y(t)), \qquad\qquad y(t_0) = y_0.$$

Euler's method for numerical integration is the following:

$$y_{n+1} = y_n + hf(t_n, y_n).$$

Using a step h.

In our case, $y = p(x)$, $y' = \dfrac{dp}{dx}$, point "0" is at a depth of 2500 m,

Using a step of h= 200 m (we don't have the generator of fluid properties or the multiphase calculator at hand) the pressure at a depth of 2700 m is:

$$p(2700\ m) = p(2500\ m) + 200\ m \cdot \left(0.056596\ \frac{bar}{m}\right) = 147\ bara + 11.31\ \ bara = 158.3\ bara$$