Norwegian University of
Science and Technology (NTNU)
INSTITUTT FOR PETROLEUMSTEKNOLOGI
OG ANVENDT GEOFYSIKK

Guiding questionnaire for re-sitting examination

Course: TPG 4230
Field Development and Operations

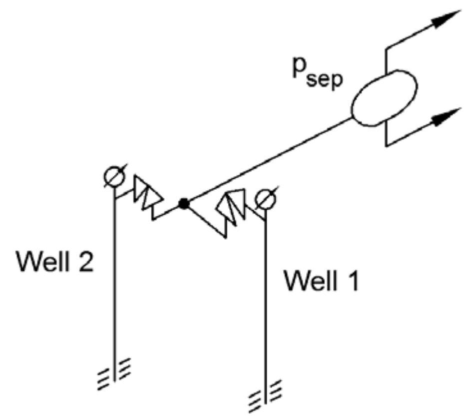
Date: Thursday, 6 august, 2015

Time: 09:00

MATERIAL ALLOWED IN THE EXAMINATION ROOM:

No written/printed material allowed
Allowed approved hand held calculators.

Problem 1 (20 points). Network solution for a gathering system in a gas field.
Consider the gas field with two wells, a manifold, a pipeline and and a separator shown in the figure below. The wellhead of the wells are very close to the junction so it can be safely assumed that the wellhead pressure and junction pressure are equal **when the choke is open**.



Given for each well:

- The available junction (wellhead) pressure curve versus well gas rate (See next page). This curve has been calculated concurrent from reservoir pressure to the wellhead (including flow in reservoir and flow in tubing).

Given for the pipeline:

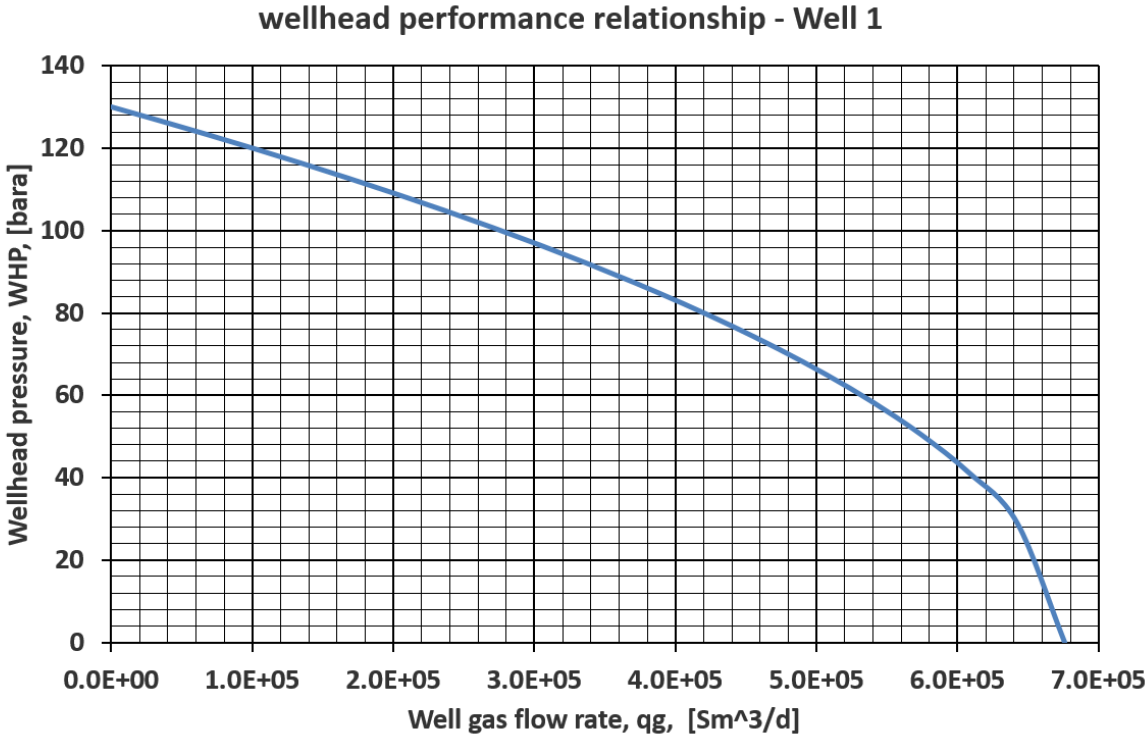
- The required junction pressure curve versus pipeline gas rate (See next page). This curve has been calculated countercurrent from separator pressure to the junction (including flow in the pipeline)

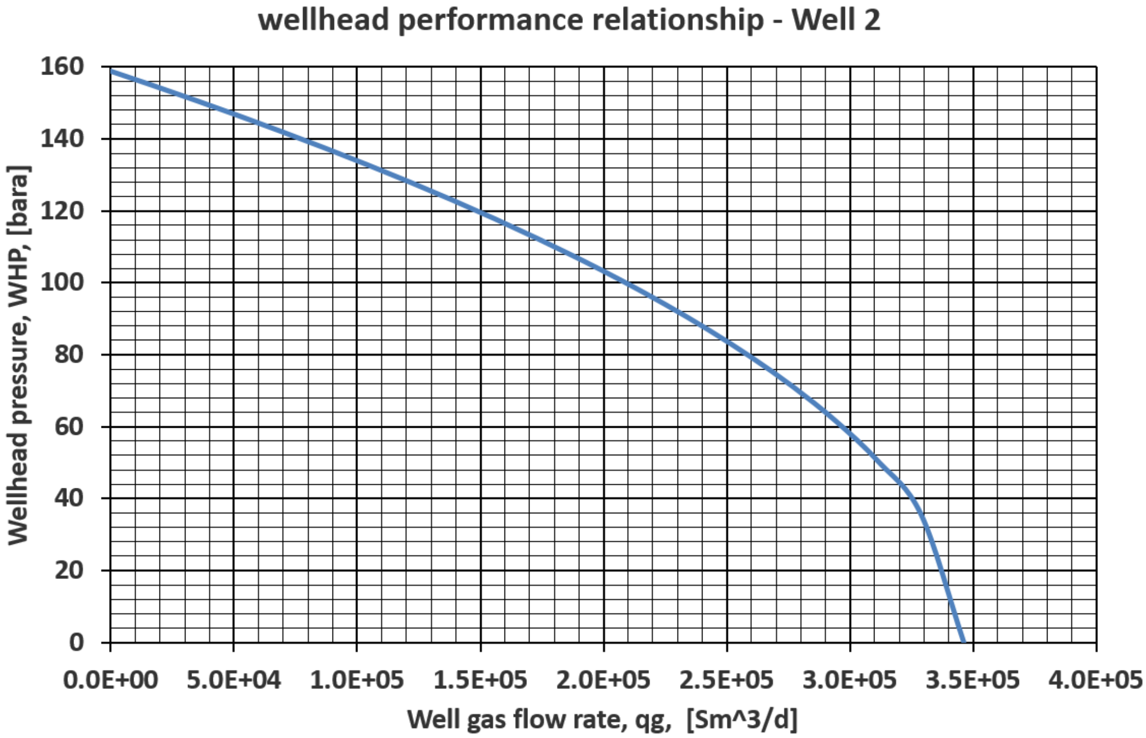
<u>Tasks.</u>

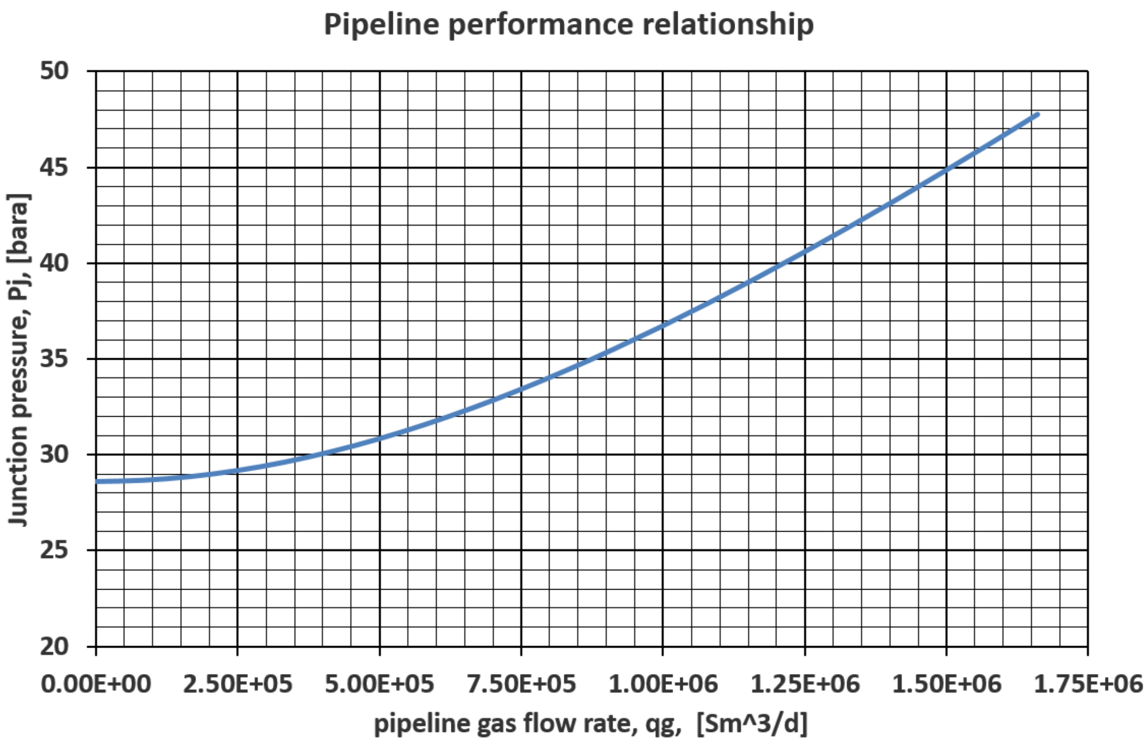
1. Estimate graphically the gas rates of the two wells if the chokes are fully open, (solve the hydraulic equilibrium of the network).
2. Estimate graphically the pressure drop of the chokes required to produce 3E5 Sm^3/d from well-1 and 1.5E5 Sm^3/d from well-2.
3. You have been asked to solve an allocation problem. The gas rate measured at the separator for the system operating with open chokes is 8.5E5 Sm^3/d. Determine how much corresponds to which company according to the following ownership table and the results of task 1 (use the reconciliation factor).

	Well 1	Well 2
BP	30 %	50 %
Marathon	70 %	50 %

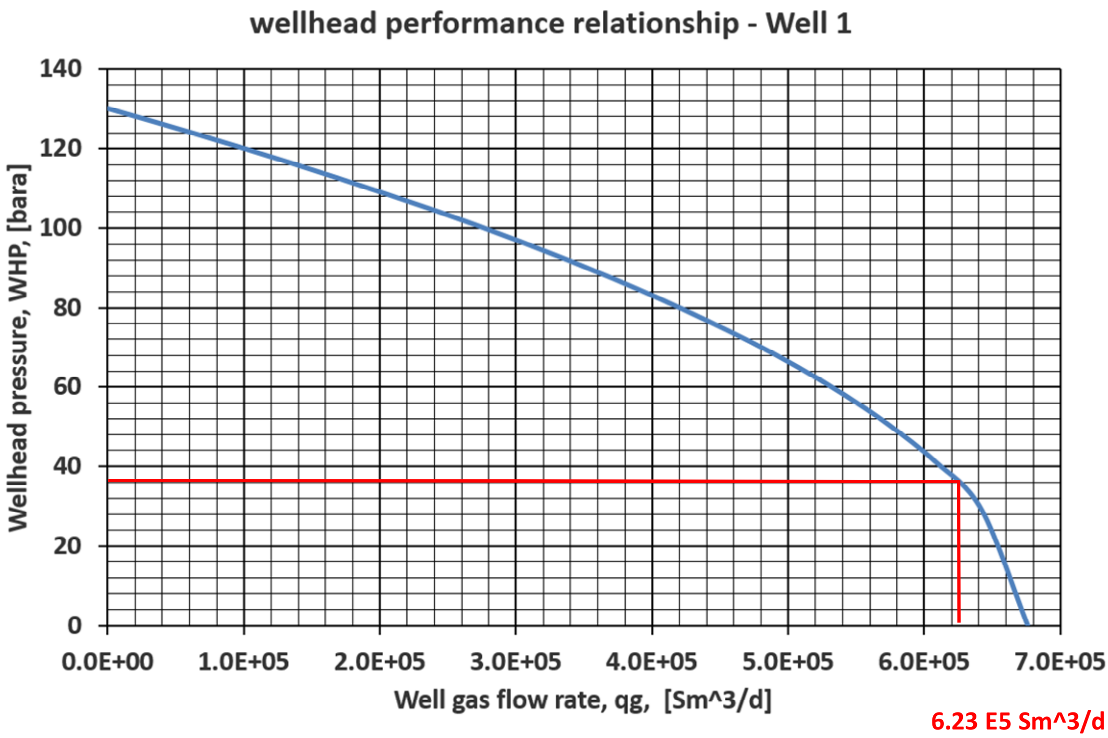
4. If a compressor is installed at the junction (at the inlet of the pipeline) and the wells have fully open chokes, estimate the pressure increase required from the compressor to deliver a total gas rate of 1.0 E6 Sm^3/d.

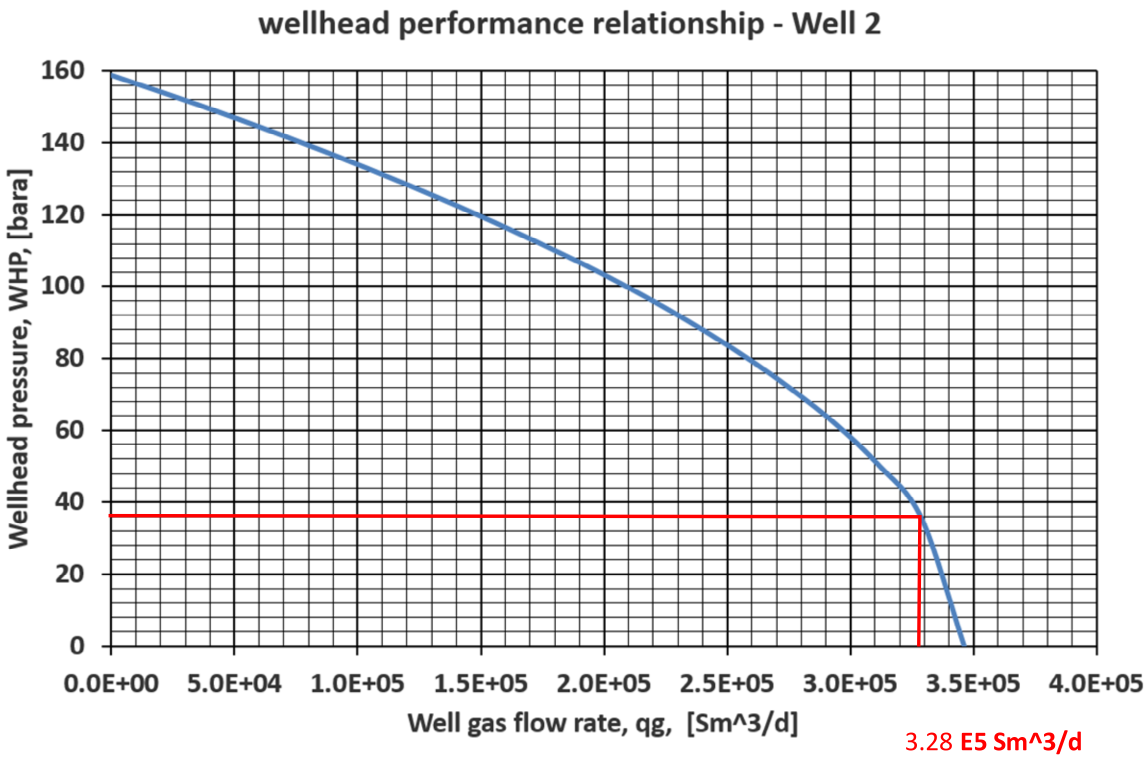

wellhead performance relationship - Well 1
Wellhead pressure, WHP, [bara]
140
120
100
80
60
40
20
0
0.0E+00
1.0E+05
2.0E+05
3.0E+05
4.0E+05
5.0E+05
6.0E+05
7.0E+05
Well gas flow rate, qg, [Sm^3/d]


wellhead performance relationship - Well 2
Wellhead pressure, WHP, [bara]
160
140
120
100
80
60
40
20
0
0.0E+00
5.0E+04
1.0E+05
1.5E+05
2.0E+05
2.5E+05
3.0E+05
3.5E+05
4.0E+05
Well gas flow rate, qg, [Sm^3/d]

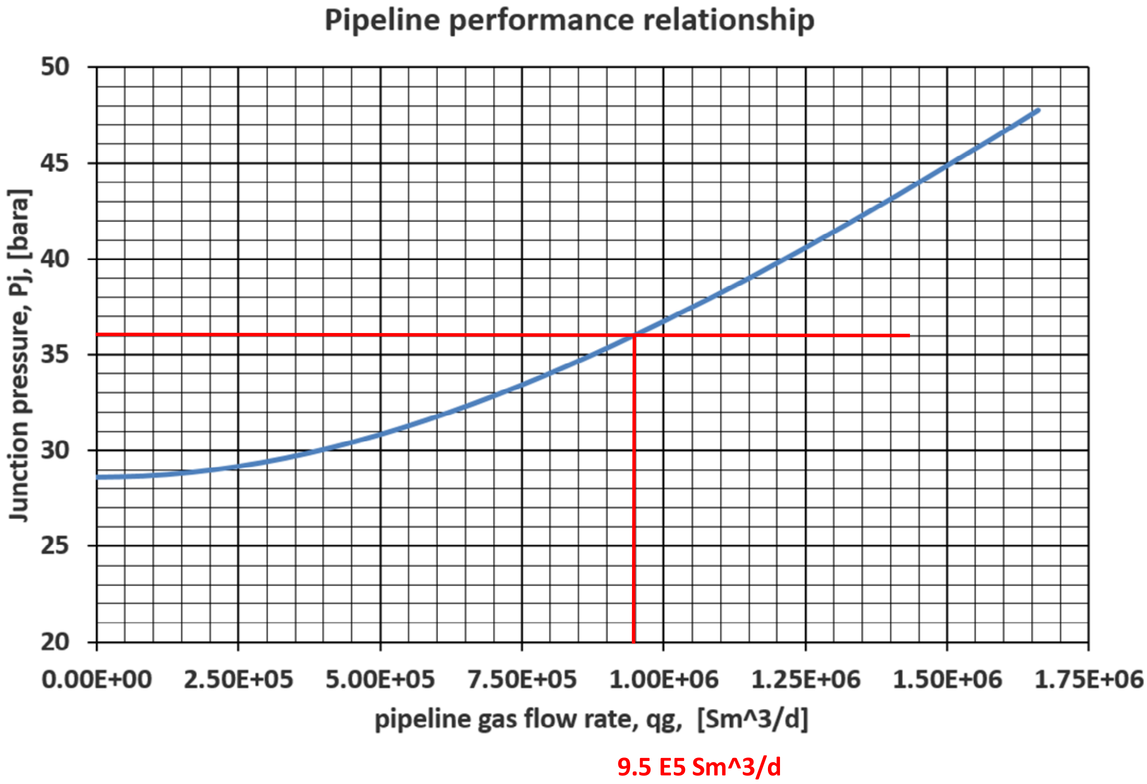


1.1. In this case, the junction pressure seen from W1 (concurrent), W2 (Concurrent) and Pipeline (countercurrent) has to be the same. As explained in class, the most convenient way is to guess pj, read rate of well 1, well 2, and pipeline, and then verify that $q_1+q_2 = q_p$. If not, repeat again. The final solution is $p_j \approx 36\ bara$



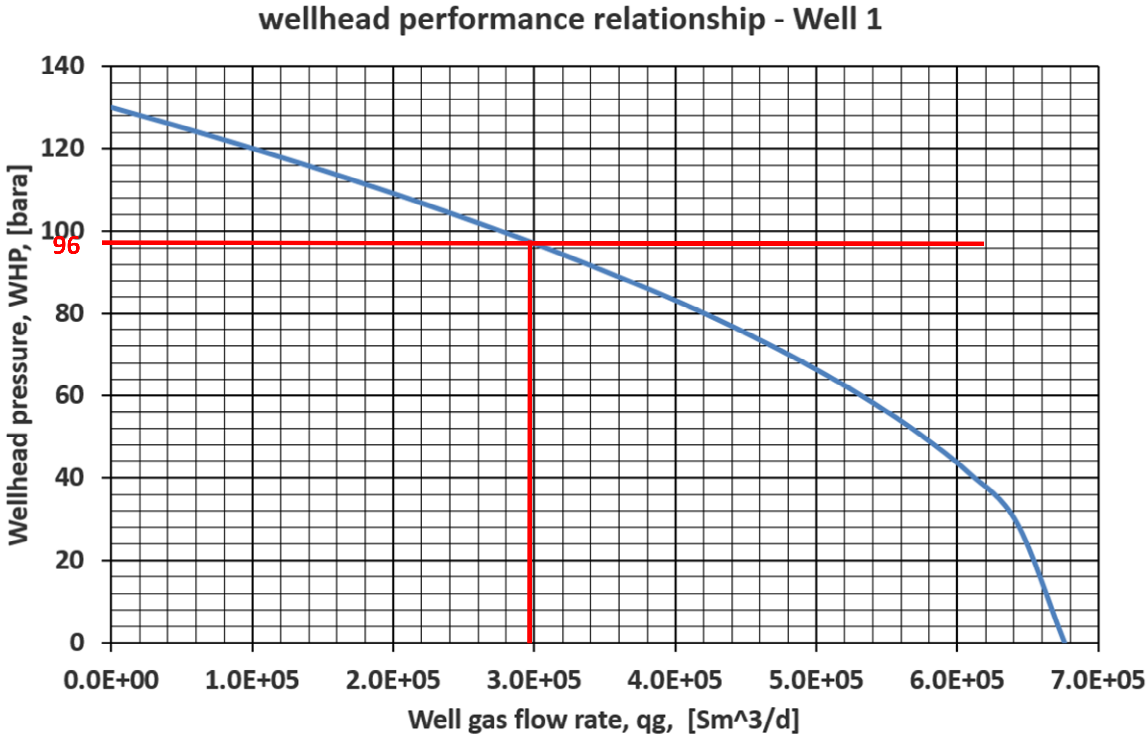


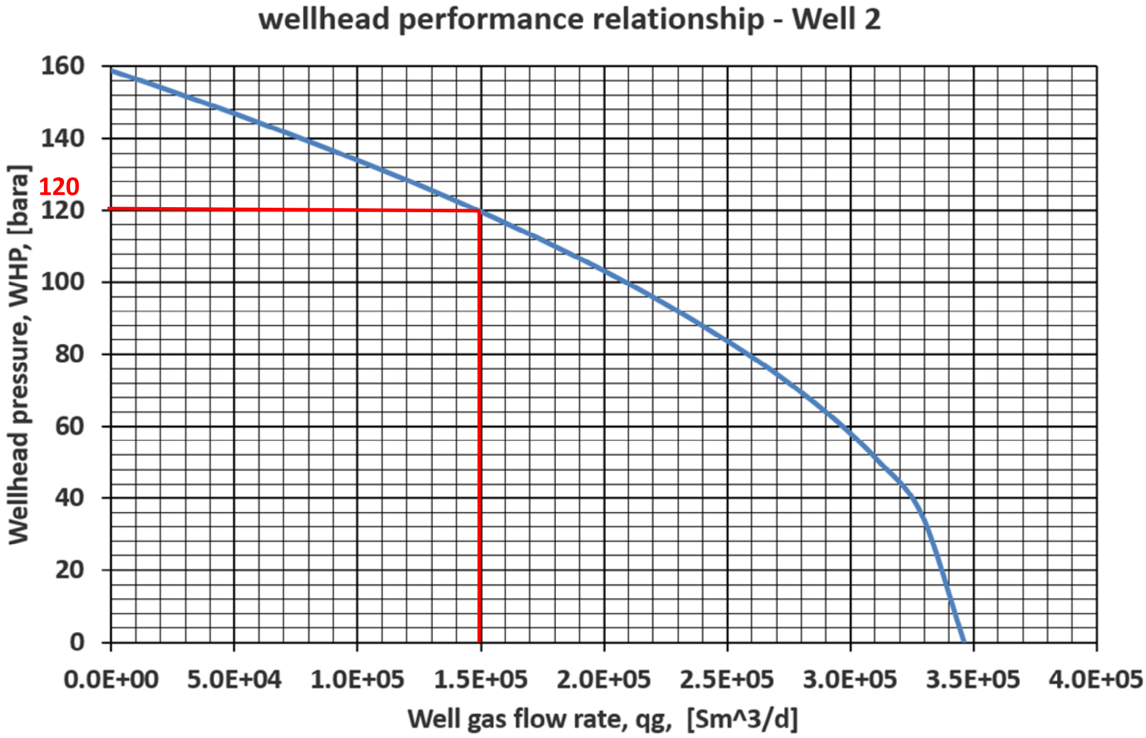
$q_1 + q_2 \approx 9.51\ E5\ Sm^{\wedge}3/d$

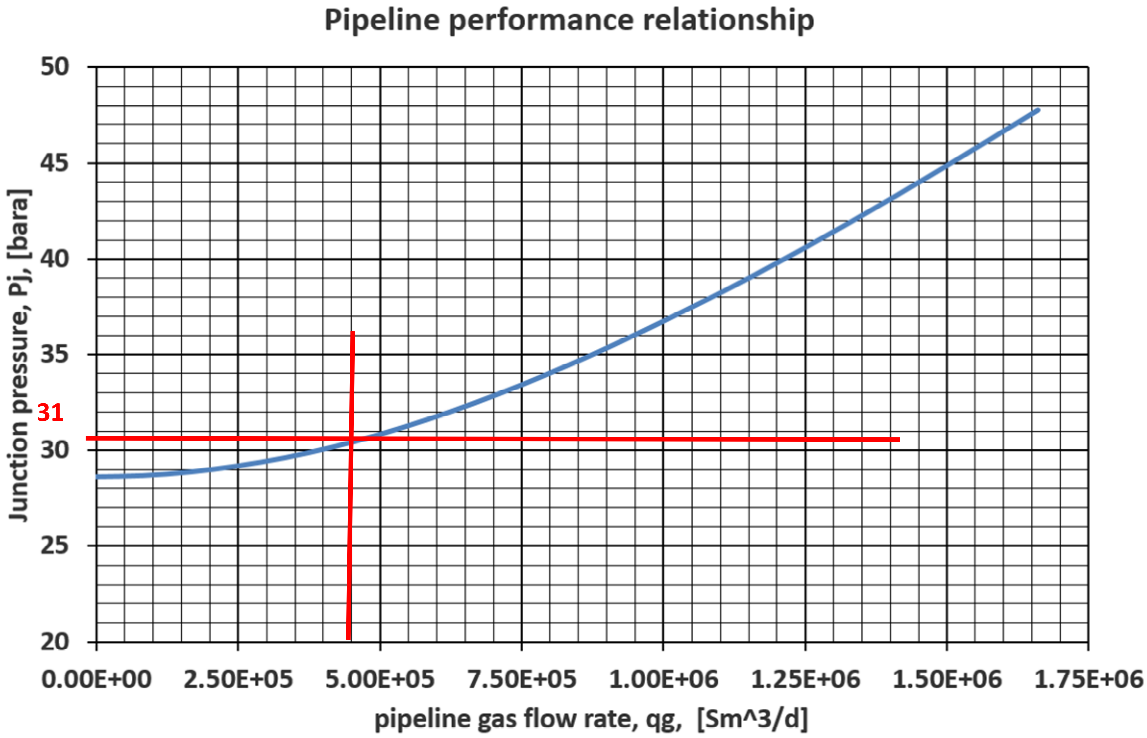


$q_1 + q_2 \approx 9.51\ E5\ Sm^{\wedge}3/d \approx 9.5\ E5\ Sm^{\wedge}3/d$

1.2. In this case, I fix the rates of W1, W2 and pipeline and read the required junction pressure


wellhead performance relationship - Well 1
Wellhead pressure, WHP, [bara]
140
120
100
96
80
60
40
20
0
0.0E+00
1.0E+05
2.0E+05
3.0E+05
4.0E+05
5.0E+05
6.0E+05
7.0E+05
Well gas flow rate, qg, [Sm^3/d]


wellhead performance relationship - Well 2
Wellhead pressure, WHP, [bara]
160
140
120
120
100
80
60
40
20
0
0.0E+00
5.0E+04
1.0E+05
1.5E+05
2.0E+05
2.5E+05
3.0E+05
3.5E+05
4.0E+05
Well gas flow rate, qg, [Sm^3/d]



Deltap Choke 1 = 96 – 31 = 65 bar
Deltap Choke 2 = 120 – 31 = 89 bar

1.3. The Open flow rate measured in the field (8.5 E5 Sm^3/d) is a bit different than the open flow rate calculated with our model (9.5 E5 Sm^3/d). We can do our allocation calculations in two ways:

a) Calculate reconciliation factor f = 8.5/9.5 = 0.89

Multiply the well rates found in section 1.1. by the reconciliation factor:

qw1 = 6.23*0.89 = 5.57 E5 Sm^3/d

qw2 = 3.28*0.89 = 2.93 E5 Sm^3/d

Determine how much corresponds to each Company:

q_{BP} = qw1*0.3 + qw2*0.5 = 1.67 E5 + 1.47 E5 = 3.14 E5

q_{MAR} = qw1*0.7 + qw2*0.5 = 3.9 E5 + 1.47 E5 = 5.37 E5

b) Calculate Split factor per Well:

f1 = 6.23/9.5 = 0.66
f2 = 3.28 / 9.5 = 0.34

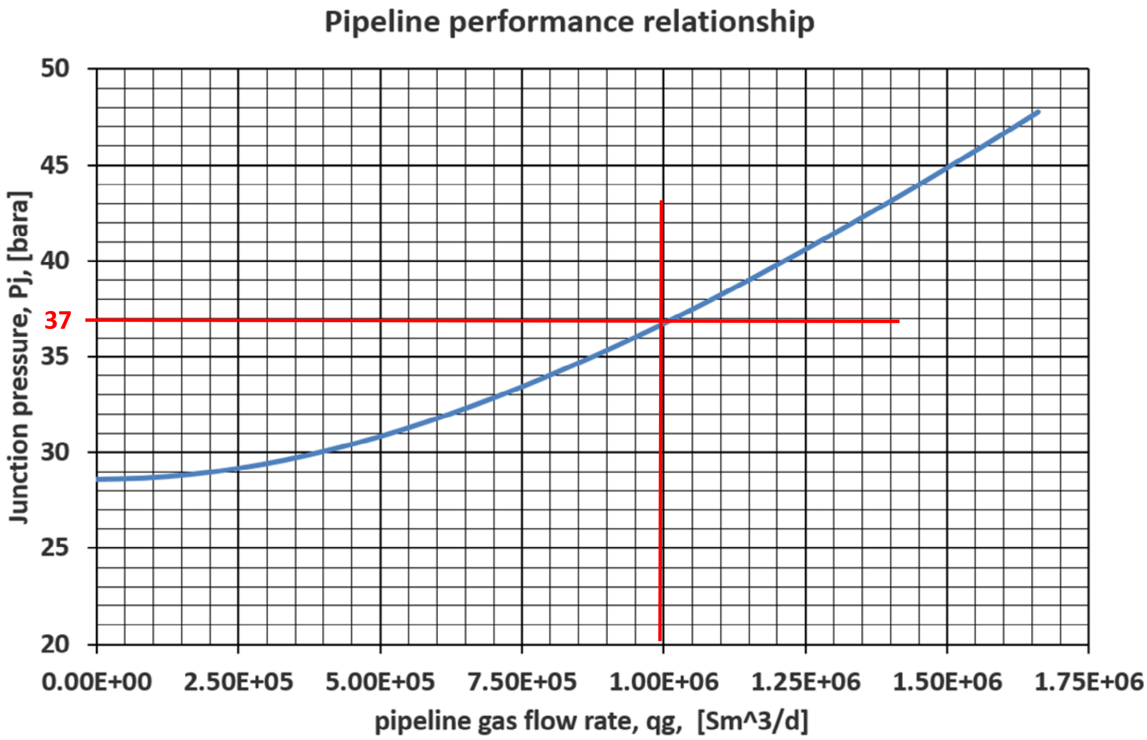
determine well rates

qw1 = 8.5 E5 * f1 = 5.6 E5 Sm^3/d
qw2 = 8.5 E5 *f2 = 2.9 E5 Sm^3/d

and repeat as in section a)

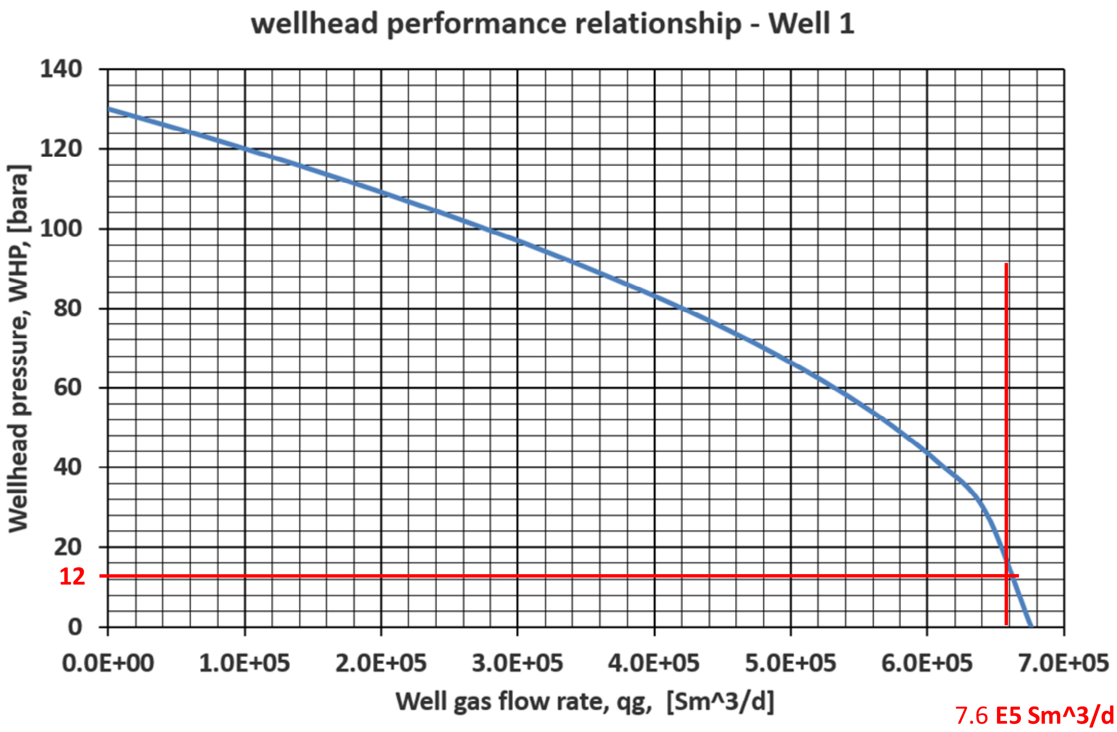
1.4. The system is, in theory, able to deliver a rate of 1E6 Sm^3/d, because the sum of maximum rates (at junction pressure of 0 bara) in the available well curves are greater than 1E6 Sm^3/d .

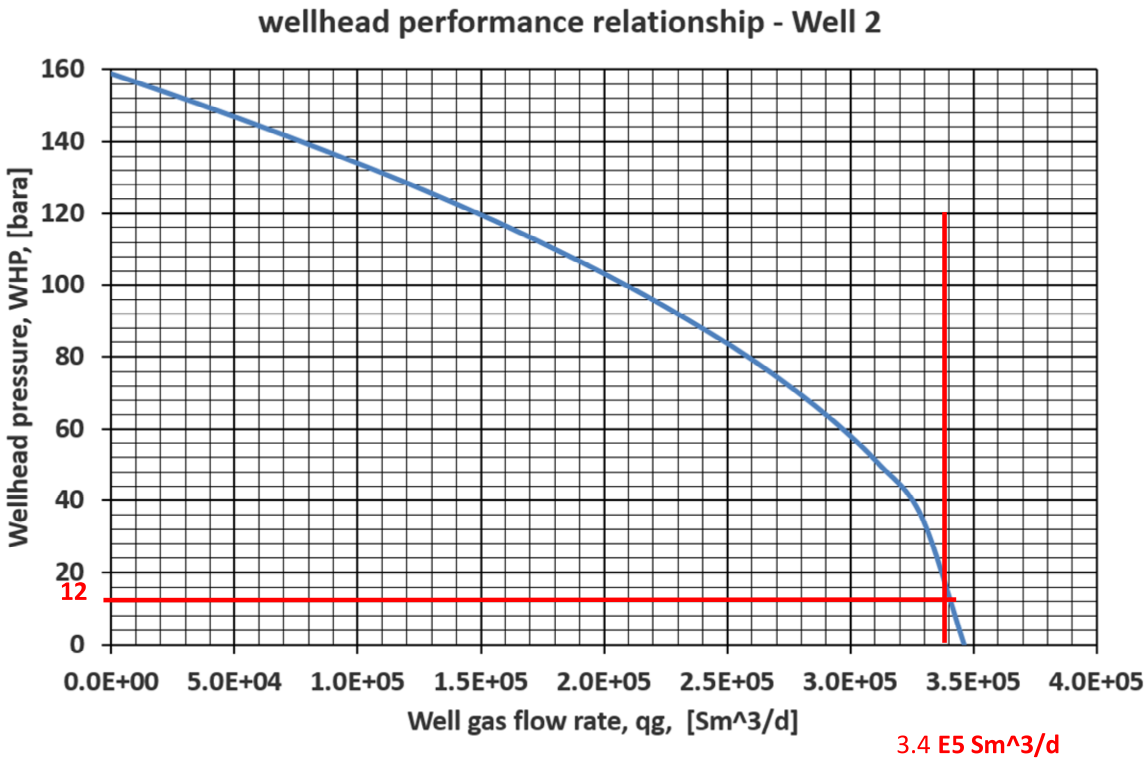
In the pipeline curve, find pdis compressor such as q = 1 E 6 Sm^3/d



The required discharge pressure is 37 bara.

At the suction of the compressor, both wells will be operating against a common suction pressure. The suction pressure has to be such as $q_1 + q_2$ = 1E6 Sm^3/d. At natural flow equilibrium, the junction pressure was 36 bara, so I know the pressure has to be lower than that. I guess wellhead pressure for W1 and W2 until $q_1 + q_2$ = 1E6 Sm^3/d. The final solution is p_{suc} = 12 bara:





Deltap compressor: 37-12 = 25 bara

Problem 2. (20 points) Production Scheduling planning of an offshore gas field

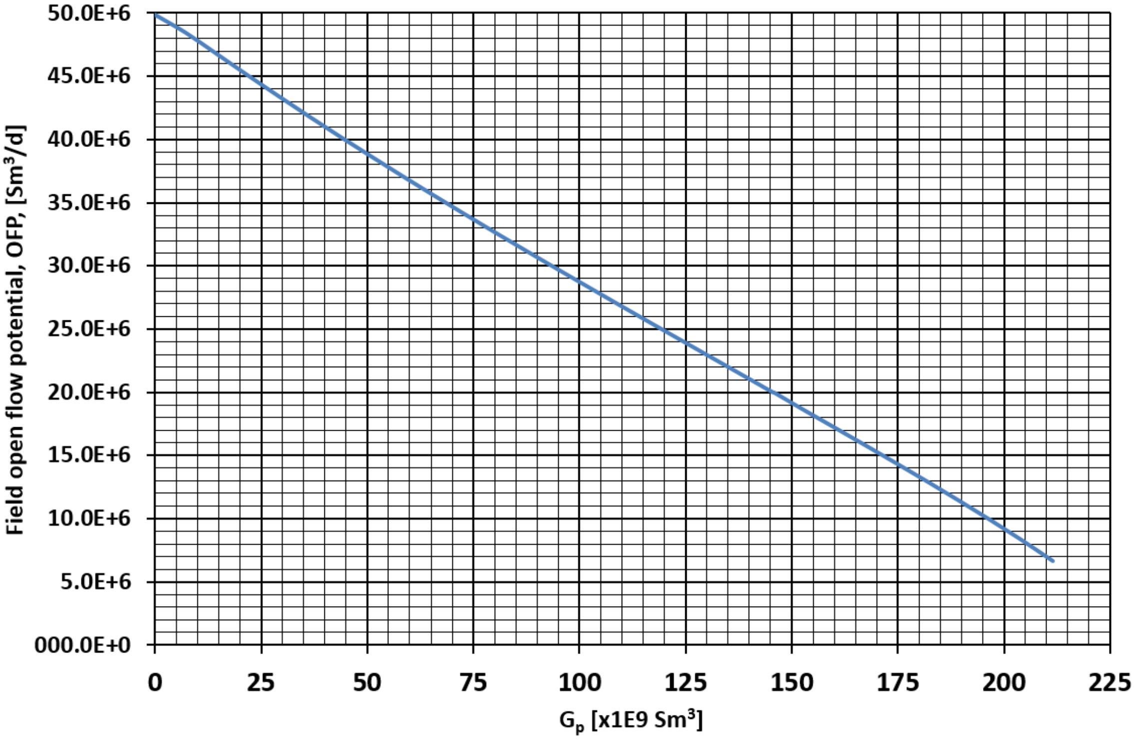
The Mnazi bay gas field has been discovered recently offshore Tanzania. The IGIP is 2.7 E11 Sm^3. You are part of the team that has to execute field development studies.

1. What are the two types of production modes that could be employed to produce the field and when should each one of them be used? Explain your answer.

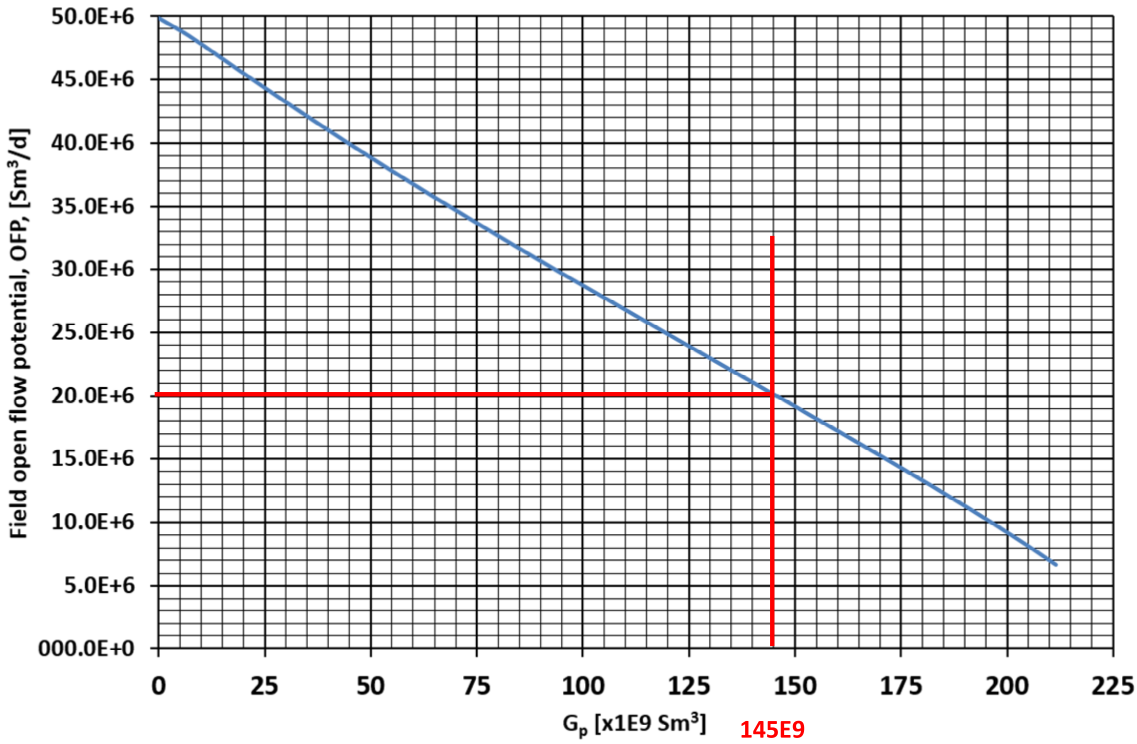
There are two possible modes to operate the field:
Plateau mode: operating with a constant rate. In this approach chokes are employed to control production at a fixed value when the reservoir is depleting. This mode is suitable for standalone fields that will have its own processing facilities or for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

As part of your study, you are evaluating the possibility to enter into a contract with a power generation company that requires 20 E6 Sm^3/d of gas for a period of 20 years. In order to determine if this is feasible:

2. Estimate the plateau length using the field open Flow Potential vs. cumulative gas production curve shown below.

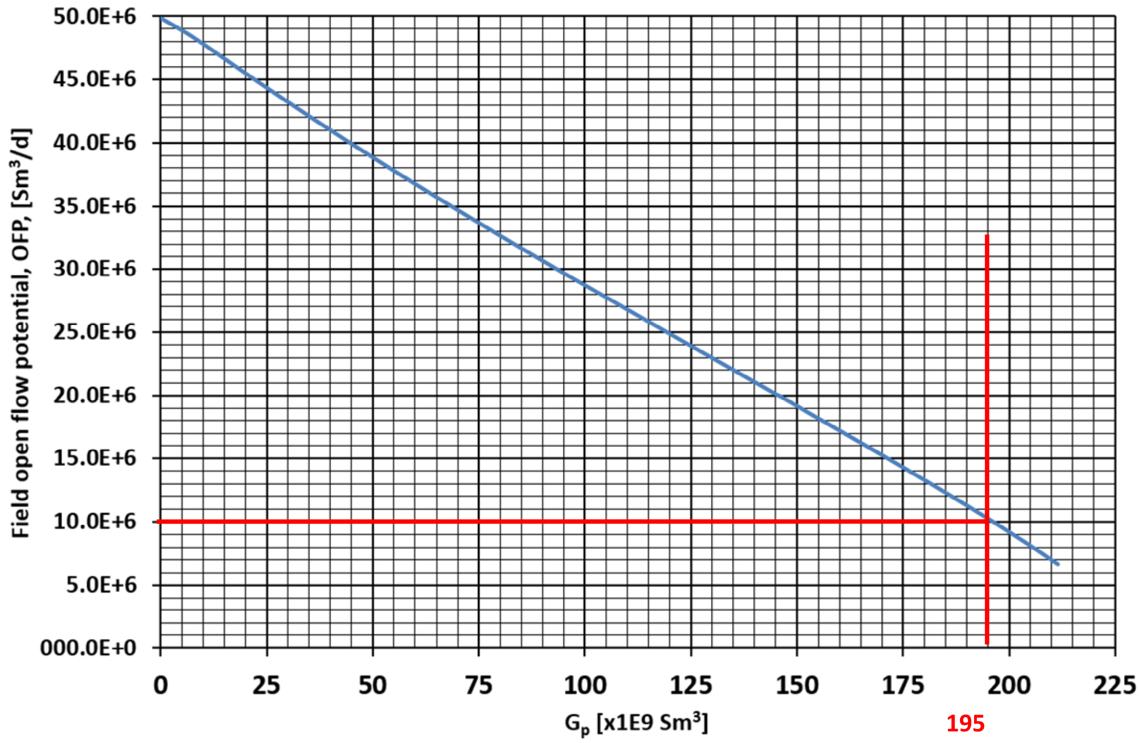


When the potential is equal to the plateau rate, It won't be possible to sustain the plateau any more.



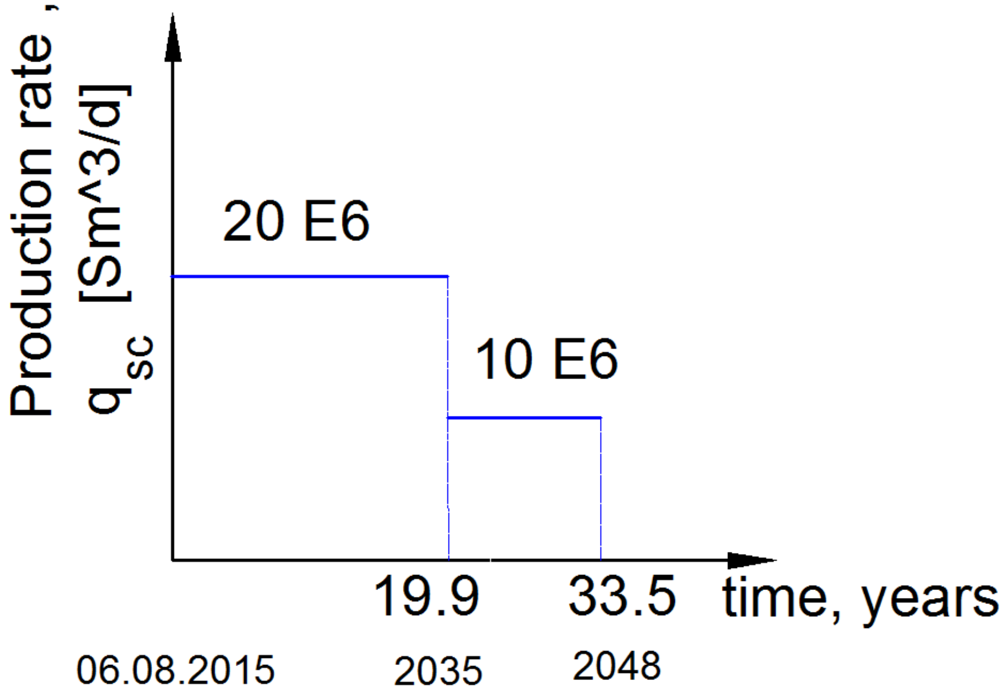
145E9/20E6= 7250 d =19.86 years (assuming 365 operational days per year). Taking into account downtime it might be feasible to produce for 20 years.

3. After the first plateau ends, the company wants to operate the field with a constant rate of 10E6 Sm^3/d. Estimate for how long it will be able to maintain this rate (duration of the second plateau). Draw the production profile of the field from the current date (06.08.2015)



The end of the 2nd plateau occurs when Gp = 195 E9 Sm^3. To calculate the duration of the second plateau:

(195 E9 – 145 E9) /(10E6 * 365) =13.69 years . Remember that up to 145 E9 Sm^3 has been already been produced with a plateau rate of 20 E6 Sm^3/d

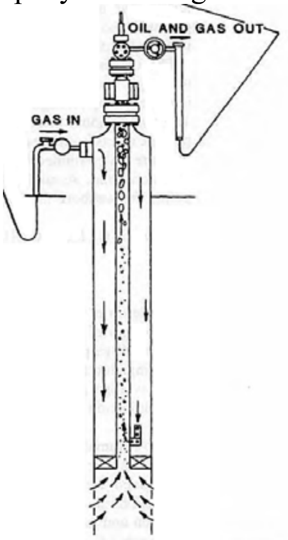


4. What is the Open flow potential?. List the possible alternatives to generate the curve. What do you think will happen if more wells are added to the system?

The open flow potential is the maximum flow rate that a well, production network, or field is able to produce for a given depletion state (i.e. reservoir pressure).
It can be estimated by: reservoir simulation, using a fixed bottomhole pressure for the well, solving the network assuming no chokes.
By increasing the number of wells in the field the open flow potential curve will probably increase, i.e. it will be possible to produce more rate at a given depletion state.

Problem 3. (10 points) Mathematical optimization of a gas-lifted well

Well VO1 is currently operating with continuous gas lift with a gas injection rate controlled at 20E3 Sm^3/d and a constant wellhead pressure of 50 bara. The gas used for lifting is currently bought from another company that charges 100 USD per 1000 Sm^3.



Given your background in production optimization, your boss: **1. wants you to estimate the gas injection rate to maximize revenue**. You are asked to do your analysis using two scenarios of prices for the barrel of oil: 40 USD/bbl and 60 USD/bbl. Use the following simplified equation for revenue:

$$\mathrm{Re}venue = q_o \cdot (oil\ \ price) - q_{ginj} \cdot (gas\ \ price)$$

The gas lift performance curve is available for your analysis as a collection of points in the table for a fixed wellhead pressure of 50 bara. Assume that interpolating on the table is a good approximation.

q_{ginj} [1E3 Sm^3/d]	q_{oR} [Sm^3/d]
3.0	68
9.0	101
20.0	119
35.0	123
55.0	122

Calculate two new columns with the revenue for the two oil prices given (remember to change units from bbl to Sm^3)

$$\boxed{\mathrm{Re}\,venue = q_o \cdot (oil\ \ price) - q_{ginj} \cdot (gas\ \ price)}$$

		40 USD/bbl	60 USD/bbl
qginj	qo	**Revenue**	**Revenue**
[1E3 Sm^3/d]	**[Sm^3/d]**	**[USD]**	**[USD]**
3	68	16768	25336
9	101	24451	37177
20	119	27869	42863
35	123	27373	42871
55	122	25122	40494

The best gas injection rate, for 40 usd/bbl, 20 E3 Sm^3/d. For 60 USD/bbl, 35 Sm^3/d.

2. **Explain the physical reason for the trend displayed by the gas lift performance curve.**

When gas is injected, the fluid column is made lighter and the pressuredrop due to gravitational acceleration is reduced, this causes that the bottomhole pressure is reduced, hence more production is achieved. When the gas rate is increased further, the friction pressure losses begin to be relevant and the bottomhole pressure increases, reducing the production rate from thewell

Problem 4 (10 points) Subsea satellite field; Manifold sketch

Volund is an oil field located about 10 kilometers south of the Alvheim field in the central part of the North Sea. The field is developed as a subsea tie-back to the nearby production vessel "Alvheim FPSO" with three horizontal subsea oil production wells. The water depth in the area is about 120-130 metres. Reservoir depth is about 2000 m.
The operator is Marathon Oil Norge AS (65%) in partnership with Lundin Norway AS (35%).

The well-stream is routed by pipeline to the Alvheim for separation and buoy-loading for shuttle tanker. The associated rich gas is stripped from NGL and condensate liquid which are recombined with the exported oil. The dry/lean gas is transported via Alvheim FPSO to the SAGE Pipeline (Scottish Area Gas Evacuation pipeline) to St. Fergus in the United Kingdom.

The original estimated recoverable reserves are 7.8 Million Sm3 oil and 1.0 Billion Sm3 gas. The planned plateau daily production of is 24 000 STB/D (3183 Sm3/D) with field GOR of 120 Sm3/Sm3

Initial production scheduling analysis suggests 3 years of half the plateau production rate due to constraint on the FPSO. There after, the field will produce 5 year at a plateau rate before the start of the decline.

As part of preparing a development, you need to perform the following task:

1. Propose a simple P&I diagram of the subsea production manifold of Volund with the production/testing lines to the separation on Alvheim FPSO. Include suggestions for pigging facilities. The production wells are satellite of the manifold template (Wellhead are not on the template)