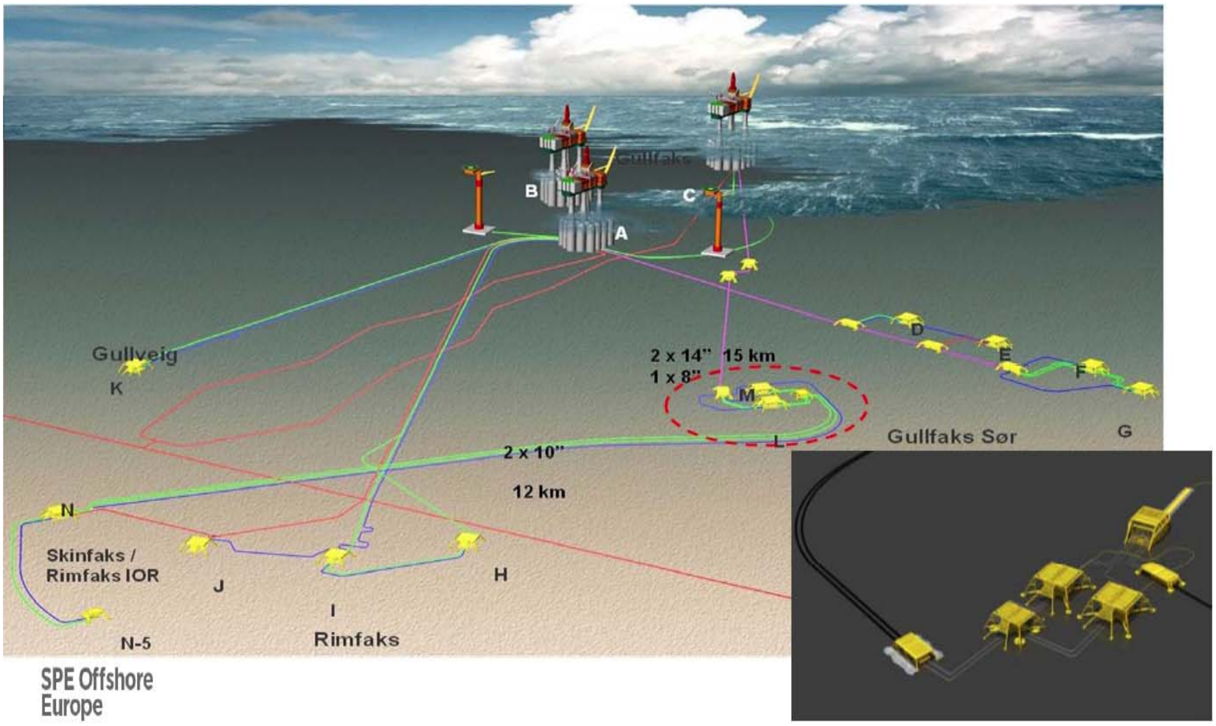
Exercise set 05

Problem 1: Determining operating conditions of the separator train of Gullfaks South.

Gullfaks South (GFS) is a group of subsea wells that are tied-back to the Gravity-Based platform Gullfaks C (GFC). Wells were initially completed in the oil layer, but due to depletion and high GOR, they have been recompleted in the gas layer. The production will be boosted with a subsea Wet Gas compressor (WGC). The field is expected to produce around 7 E06 Sm^3/d of gas for 10 years.



The separator train in GFC has three stages, and its operating conditions are presented in the table below.

Separator stage	Pressure, p	Temperature
[-]	[bara]	[C]
1	65	70
2	20	65
3	2	60

Task 1: You have been asked to create a simple model of the processing facilities in Hysys (Use the Peng-Robinson EoS). You have to use just three separators. Place coolers between the stages to take the fluid to the specified pressure and temperature conditions. Take the separated oil and gas streams to standard conditions (with a cooler) to report the GOR (gas oil ratio). Plot the phase envelope of the fluid stream from the field and the phase envelopes of the oil and gas leaving the high pressure separator.

The composition of the fluid stream for 3 different years is given below (Estimated using a compositional reservoir simulator):

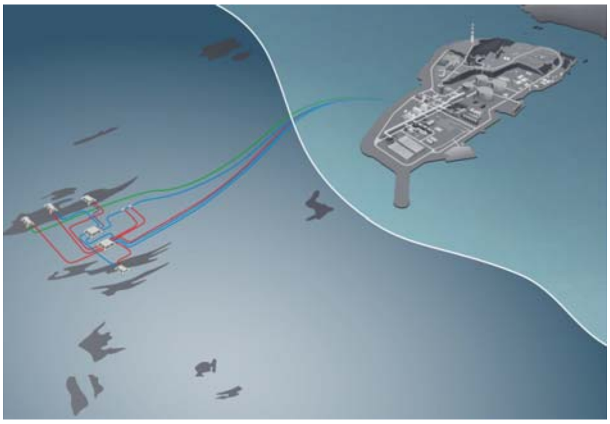
Time [year]	**0**	**5**	**12**
Name	**Zi**	**Zi**	**Zi**
Nitrogen	0.002421	0.002427	0.002437
CO2	0.015738	0.015872	0.015933
Methane	0.868644	0.878342	0.881809
Ethane	0.055993	0.056563	0.056763
Propane	0.021186	0.021270	0.021291
i-Butane	0.002926	0.002865	0.002850
n-Butane	0.006457	0.006360	0.006305
i-pentane	0.002018	0.001879	0.001832
n-pentane	0.002623	0.002402	0.002326
n-hexane	0.003228	0.002672	0.002470
n-heptane	0.002320	0.001659	0.001418
n-octane	0.002421	0.001445	0.001092
n-nonane	0.001816	0.000906	0.000583
n-decane	0.012207	0.005337	0.002892

Task 2: Your colleagues have been arguing that if the second stage separator is changed, this will increase significantly the condensate recovery from the field (This, however, entails a heavy investment and modifications to the topside facilities). To assess these claims, use the Hysys model and vary the pressure of the 2nd stage separator from 64-3 bar. Plot the GOR of the field vs the pressure of the second stage.

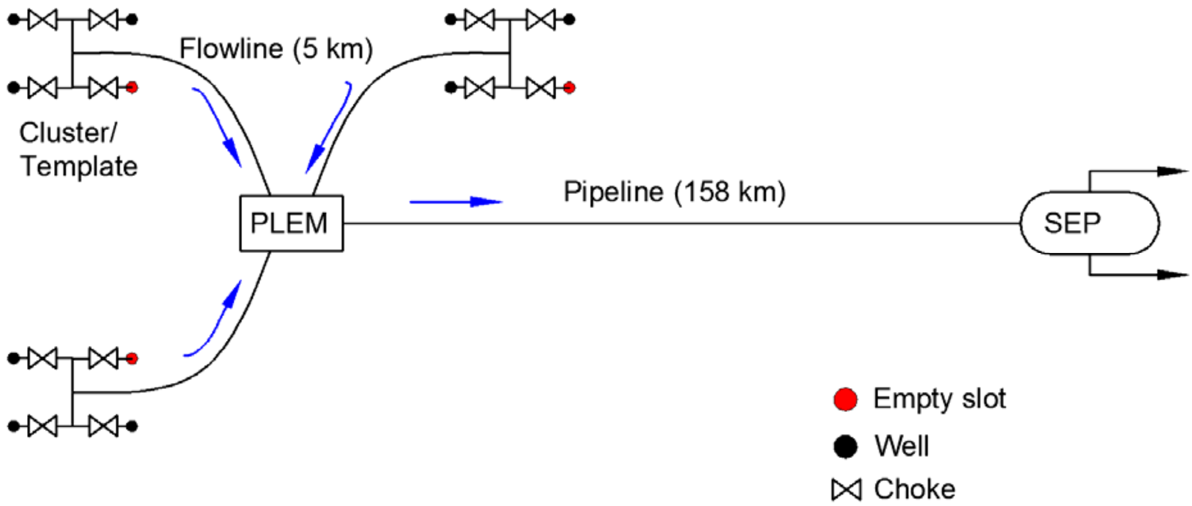
Task 3: How are your results affected by the pressure of the 1rst stage separator? Repeat your analysis for 75 bara and 55 bara.

<u>Problem 2: Subsea gas compression design for the Snøhvit field</u>

Snøhvit is an offshore gas field located in the Barents Sea 158 km from Hammerfest currently in operation. The field was developed with the "subsea to beach" concept. The gas production is taken by a LNG plant and transported further in LNG carrier to customers in US and Spain. The plateau rate of the field has been set to 20E6 Sm^3/d.

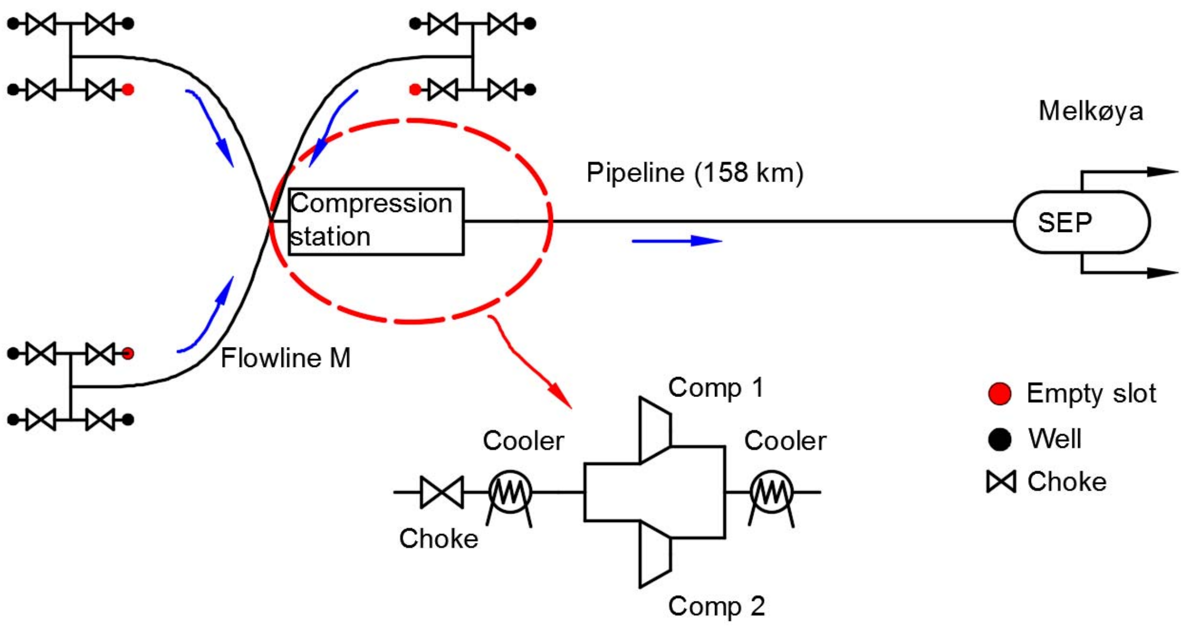


According to the base case Scenario (BCS) selected for the study, the field is completed subsea with three subsea templates, each with 4-slots.



Your task is to conduct an analysis to evaluate the impact of using subsea compression to maintain plateau production after the natural plateau end is reached. Expand the excel sheet provided to calculate the length of the production plateau in the compression period and compute post plateau production profile (when operationally, due to compressor constraints, it is not possible to maintain plateau production any longer). **Perform your calculations on a yearly basis until the end of year 28.**

The proposed layout for the installation of the compressor (suggested by Aker solutions) is shown in the figure below:



The compression station has a choke valve, a cooler and two identical compressors in parallel. In normal operating conditions, the choke is fully open. Some operational constraints are the following:

- The discharge temperature of the compressor has to be below 140 C to avoid problems in the seals of the compressor, avoid structural integrity issues in the pipeline and avoid vaporization of the hydrate inhibitor.
- The maximum power per compressor is 11 MW.
- The maximum temperature drop in the coolers is 30 C.
- The minimum suction pressure to the compressor is 15 bara.
- Assume that the compressors operate with a polytropic efficiency of 70%.
- The gas temperature at the inlet of the compressor station is 67 C.

The German company MAN has already proposed a specific compresor model to use in the system. The compressor map, measured for test conditions is also included in the excel sheet.

Being a preliminary study, considerable simplification assumptions will be used:

- The gas is dry, its depletion and recovery characteristics can be modeled by reservoir tank model
- The flow in the wells and the pipeline can be represented by isothermal flow equations.
- Wells are operating with fully open choke during the compression period.
- All wells, templates, and infield flow lines are symmetric in configuration and capacity.

If, during your analysis, the operating point falls outside the operational map of the compressor, consider the following options:

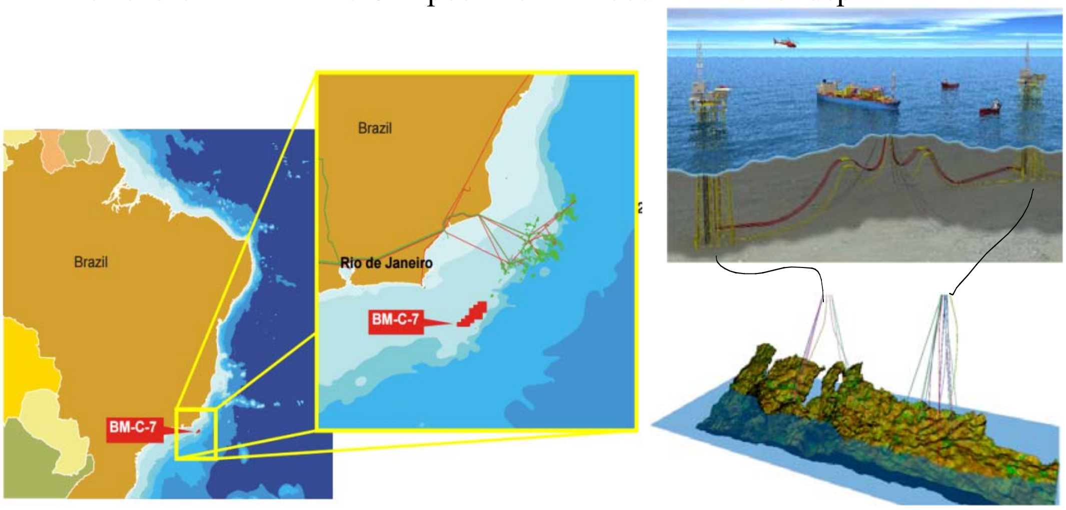
- Use the valve at the inlet of the compressor station as a choke valve to drop the inlet pressure and increase the compression ratio
- Use the coolers
- Use single compressor, two compressor in parallel or two compressors in series.
- Reduce field rate.

Some specific tasks are:

- Compute and plot the field gas production profile, deltaP compressor, compression ratio, suction pressure for the complete life of the asset.
- Determine when the cooler is required.
- Estimate the rotational speed of the compressor and the required compressor power for each compressor year.
- Plot the operational points on top of the compressor map (for test conditions).
- Your company is evaluating eliminating the suction and discharge coolers to reduce costs. Compute the production profile considering that there is no cooler and issue a recommendation on the matter.

Problem 3: ESP design and verification with output from reservoir simulator for the Peregrino field

Peregrino is the largest oil field operated by Statoil outside of Norway. The field is located 85 km offshore Brazil in the Campos Basin at about 100 water depth.



The field is developed with two fixed platforms from which wells are drilled and completed. There are 40 producing wells in total. The production is taken to an FPSO where the processing takes place. The separated water is transported back to the platforms and injected in the lower part of the formation.

Wells are deviated with ESPs installed in them. The wells are classified in low, medium and high producers.

A particular ESP model has already been suggested by a manufacturer (Baker Hughes) based on the well layout and production rates desired.

On the 04th of april, 2017 your company sent you to NTNU to attend a training session about ESP design analysis and verification session using Excel.

Back in the company, your task is to verify if the ESP proposed by the manufacturer will be able to produce the rate predicted by the reservoir simulator for four times provided in the excel sheet (In sheet “Data”, dates 1.0, 3.3, 6.8 and 12.5 years). If it is not possible to deliver the rate, try to reduce or increase the rate so it will fall inside the operational envelope of the pump. Identify limiting factors. If you are using the excel solver to adjust automatically the rate, please specify clearly the objective, constraints and variables.

Determine ESP operational frequency, suction pressure, required power and emulsion viscosity for each year listed above.

If you are given budget to change something in the well, is there something in particular that you will prioritize to meet the reservoir production goals?.

Plot the operational points (both original rates from the reservoir simulator and corrected rates) overlapped in the ESP operational map for each year.

Provide your final recommendations if the ESP is adequate to deliver the desired rate or not.

Assumptions:

- Use the excel sheet provided.
- Assume maximum pump power = 950 Hp
- Assume that the total liquid productivity index (J) of the formation remains constant with time.

<u>Exercise 4: Production optimization on diluent injection</u>

The management of the Peregrino field has decided to implement diluent injection at the suction of the ESP. The diluent is a very light (and expensive) crude of 50 API, 780 kg/m^3 and a viscosity of 5E-4 at reservoir temperature. The diluent will reduce the viscosity and density of reservoir oil, will reduce the water cut, thus reducing overall the viscosity of the oil-water mixture. This will reduce the viscous losses in the ESP and in the tubing, thus potentially increasing production.

However, the management doesn't know how much diluent is necessary to achieve a significant increase in production.

Task. Generate a diluent performance curve (reservoir oil rate vs diluent injection rate) for a constant ESP frequency of 50 Hz, reservoir pressure 231 bara and reservoir water cut of 0.1). Use at least 7 points to generate the curve and cover diluent fractions (qdil/(qdil+qoil)) between 0-40%. According to your results, what is the optimum diluent injection rate?

Assumptions:

- Use the excel sheet from exercise 3.
- Density of the reservoir oil-diluent blend can be calculated using a rate weighted average.
- Neglect any violation of the ESP operational constraints.
- The viscosity of the reservoir oil-diluent blend can be predicted using the procedure described in the ASTM standard D7152-11, for constant temperature. The procedure has been programmed for you in the VBA function: viscosity_blend. Please copy all the functions below in your VBA module.

```
'FUNCTIONS RELATED WITH BLENDING
Function Wi(vij)
Zij = vij + 0.7 + Exp(-1.47 - 1.84 * vij - 0.51 * vij ^ 2)
Wi = Log10(Log10(Zij))
End Function

Function Log10(x)
Log10 = Log(x) / Log(10)
End Function

Function visc_blend(WBlend)
   visc_blend = (10 ^ (10 ^ WBlend)) - 0.7
End Function
```

```
Function viscosity_blend(visc_a, den_a, visc_b, den_b, Xa)
'Function to calculate the viscosity of a blend of crudes a and b using the ASTM standard D7152-11, for constant temperature
'viscosities should be provided in Pa s
'Densities should be provided in kg/m^3
'volume fraction of Xa, Va/(Va+Vb)
nu_a = visc_a * 1000000 / den_a
nu_b = visc_b * 1000000 / den_b
Wa = Wi(nu_a)
WB = Wi(nu_b)
Wab = Wa * Xa + WB * (1 - Xa)
denab = den_a * Xa + den_b * (1 - Xa)
viscosity_blend = denab * visc_blend(Wab) / 1000000

End Function
```