Exercise 01 – Gas production plateau studies of a Subsea Gas Field (Atila East field)

PART 1

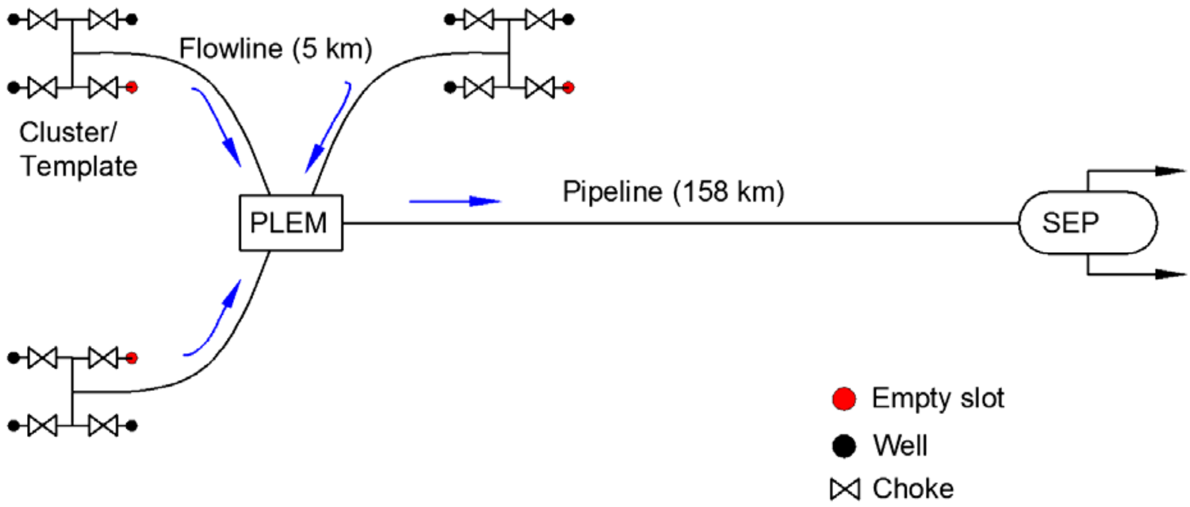
Background

You have to conduct a study on the length of the production plateau of the Atila East, a sub-sea gas field that is producing directly to shore. The objective is to export from the field a daily production rate of 20 million Sm^3 (q_F = 20·10E06 Sm^3, equivalent to a plateau rate of 700 million SCF/D). The objective is a plateau length of 20 years.

According to the base case Scenario (BCS) selected for the study, the field is completed subsea with three subsea templates, each with 4-slots (well bay). In the base case, only three wells are completed in each template.

According to the BSC, the templates are symmetrically positioned at 5 km away from the subsea Pipeline Entry Module (PLEM). Each template is connected by flow line to the PLEM where the production streams of all the templates are commingled (combined and mixed). The PLEM is on the seabed approximately 158 km from shore and is connected by the main field export pipeline to the slug catcher (separator) on shore.

All the wells are identical (in structure and productivity and all other design and operation parameters) and produce from the same reservoir (tank model).



These are your tasks:

1. Develop a spreadsheet (Excel) to calculate the plateau length of the field for the base case (you may use one year or half a year as a time step).
2. Plot (in Excel) the results of your calculations and the change of pressure in the important nodes of the system versus time. Indicate on the plot the end of the plateu. (Important pressure nodes are reservoir, bottom-hole, wellhead, across the choke, At the Template downstream the choke, at the PLEM and at the slug catcher)
3. List and explain (in a table) the practical measures that can be considered to prolong the production plateau.
4. Forecast the gas production profile for the period after the plateau. Perform your calculations until the field gas rate reaches a minimum economical rate of 5 E06 Sm^3/d. Plot the field gas production profile for the complete life of the asset.

Assumptions in the solution approach:

- Assume dry gas flow equations, dry gas tank model material balance, and no condensation in the entire system
- All wells, templates, and infield flow lines are symmetric in configuration and capacity
- You may use the uploaded VBA calculators (Flow, Mbal, Zfact)

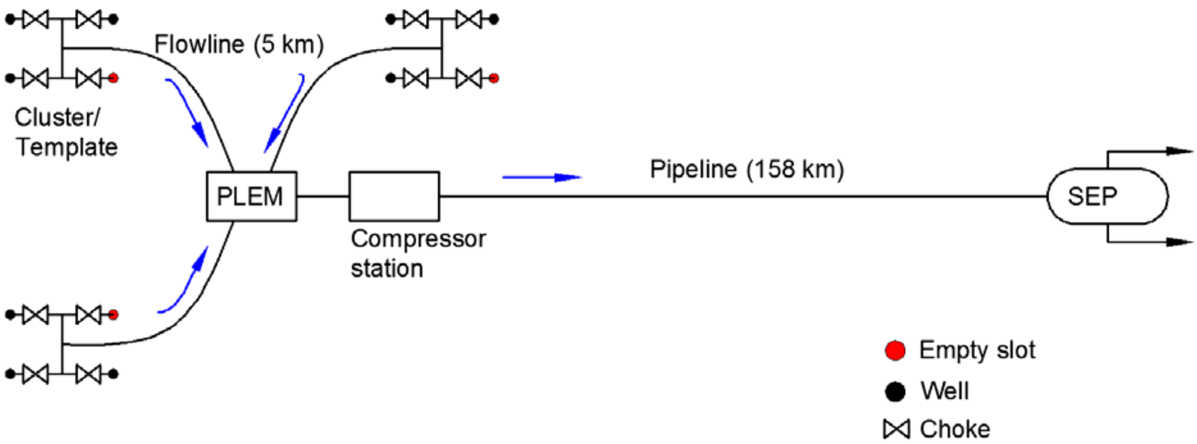
Atila gas Field (Base Case Data)			
G=IGIP	270.00E+09	Sm3	
Production days per year	365	day	
T_R	92	oC	
Pi, initial Res pressure	276	bara	
C, inflow Back pressure coefficient	1000	Sm3/bar^2n	
n, backpressure, exponent	1		
Ct, Tubing coefficient (2100 MDx0.15 ID m)	4.03E+04	Sm3/bar	
Elevation coeff, S	0.155		
$C_{FL\ Flowline}$ Template-PLEM (5000x0.355 ID m)	2.83E+05	Sm3/bar	
$C_{PL\ Pipeline}$ PLEM-Shore (158600x0.68 ID m)	2.75E+05	Sm3/bar	
Separator (slug catcher) pressure	30	bara	
Gas molecular weight (Methane)	22	kg/kmole	
Gas specific gravity	0.76	Gas specific gravity	
Number of template	3		
Number of wells	6		
Desired plateau	20	years	
qfield	20.0E+6	[Sm^3/d]	

Material balance: $p_R = p_i\left(\frac{z_R}{z_i}\right)\left(1-\frac{Gp}{G}\right)$	Horizontal Pipeline and flowline equation Horizontal $q_{sc} = C_{FL}(p_{in}^2 - p_{out}^2)^{0.5}$
Inflow equation: $q_{gsc} = C_R\left(p_R^2 - p_{wf}^2\right)^n$	User define function for calculating Z factor: *Z factor:* $Z=f(P_R, T_R, \gamma_g)$
Tubing equation $q_{gsc} = C_T\left(\frac{p_{in}^2}{e^s} - p_{out}^2\right)^{0.5}$	

PART 2

As part of preparing a PDO (Plan for Development and Operations) for the subsea field,***Atila East,*** it is required to establish the feasibility of extending the natural flow plateau of the field by 5 additional years using offshore compression. The Atila-East field was introduced in PART 1.

This study investigates the feasibility of extending the rate plateau by 5 years using offshore pipeline compressors. At the PDO stage it has not decided yet if the compressor station will be installed subsea (like in Ormen Lange of Shell or Asgard of Statoil), or on top of a dedicated compression/power generation platform.



These are your tasks

1. Uses a simplified dry gas approach (dry gas equations) to indentify the approximate compression requirements and the compression conditions for a compressor station at, or near, the PLEM (Pipeline Entry Module). The compression plateau rate should last at least 5 years starting when the natural flow plateau ends. The first part of this activity requires a reproduction of the results of PART 1 for a specific template and wells spread configuration. Note that the field data of PART 2 including the symmetric assumption of all wells and templates are identical to the field data in PART 1. Determining compression requirements at this activity imply calculating the available suction pressure and the required discharge pressure and the derived required compression ratio (Discharge pressure divided by suction pressure) at each compression year (you may use one year or half a year as a time step). Also this activity should produce a figure for the actual local gas volumetric rate at the inlet of the compressor m^3/d.

Present the results in tables and plots:

- Suction pressure available at the compression station at each compression year
- Compression ratio at each compression year
- Local (actual) volumetric gas flow rate at the compressor inlet at each compression year assuming that suction temperature is 67°C
- Assume that the minimum operating pressure at the suction of the compressor is 5 bara.

In order to calculate the local volumetric flow of gas at the inlet of the compressor (p_{suc}, T_{suc}) employ the following expression:

$$q_{g(p_{suc},T_{suc})} = B_{gd(p_{suc},T_{suc})} \cdot q_{\bar{g}field(p_{sc},T_{sc})}$$

Where the dry gas formation volume factor B_{gd} is defined by:

$$B_{gd(p_{suc},T_{suc})} = \frac{p_{sc} \cdot Z_{suc} \cdot T_{suc}}{T_{sc} \cdot p_{suc}}$$

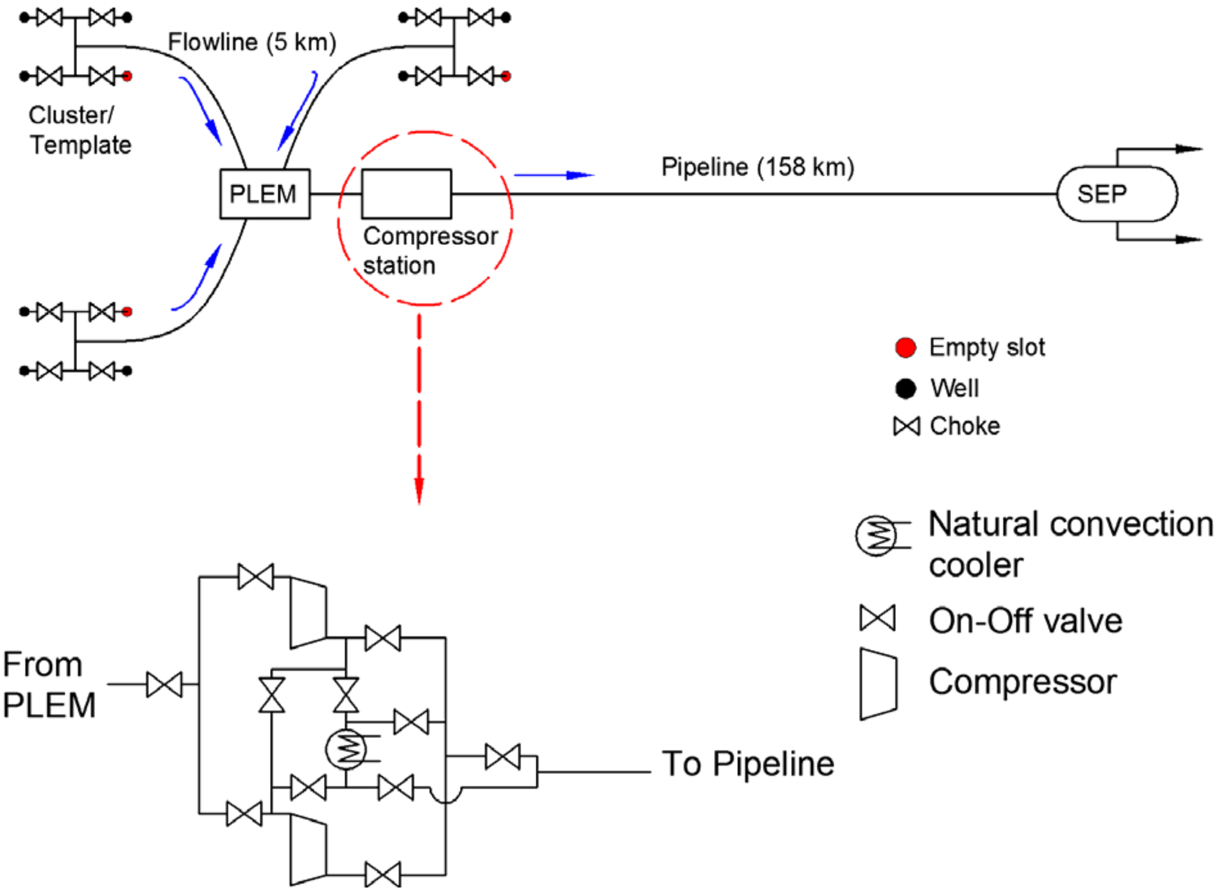
Exercise 02 –Atila East field – Subsea Compression detailed design and realistic modeling of Pipeline gas flow and condensation

PART 1

Background

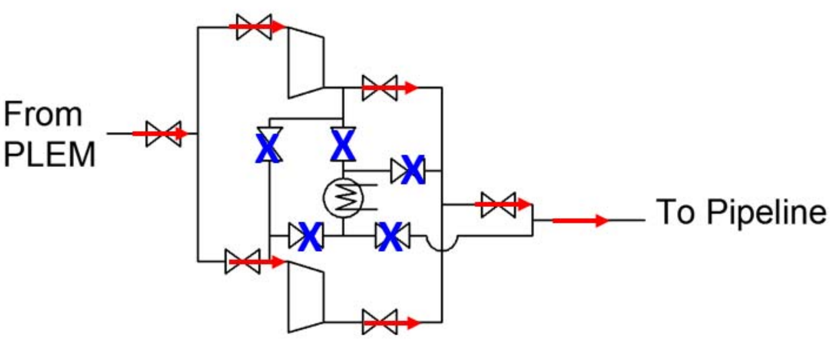
Based on the preliminary studies performed by you in exercise 1, the management of your company has decided to explore more in depth the concept of subsea compression. The objective is to use it to prolong the plateau length 5 years after the natural flow plateau ends.

A compressor manufacturing company: FRAMTIDA A/S, has approached your company and has proposed the following subsea compression solution:

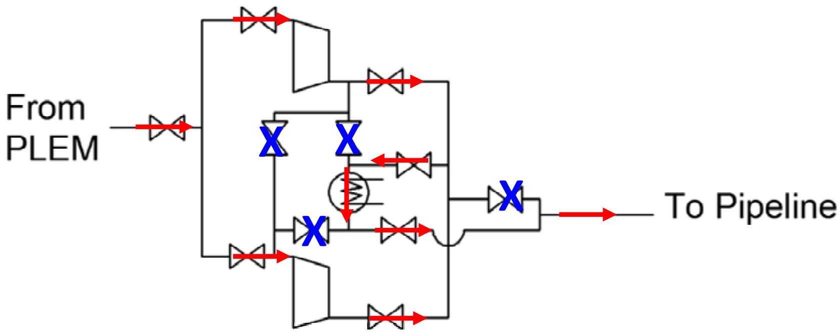


With the following operating modes:

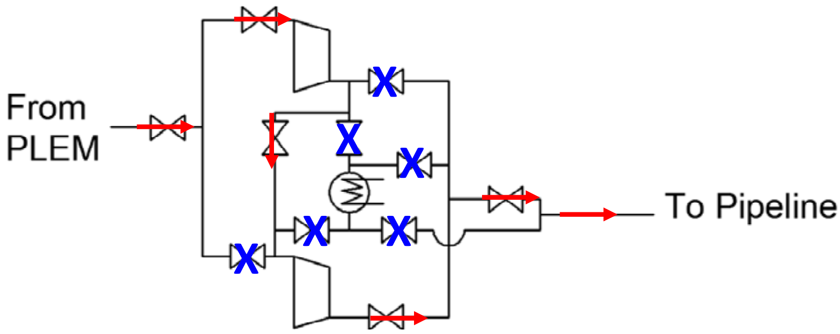
- Parallel compressors with no cooling



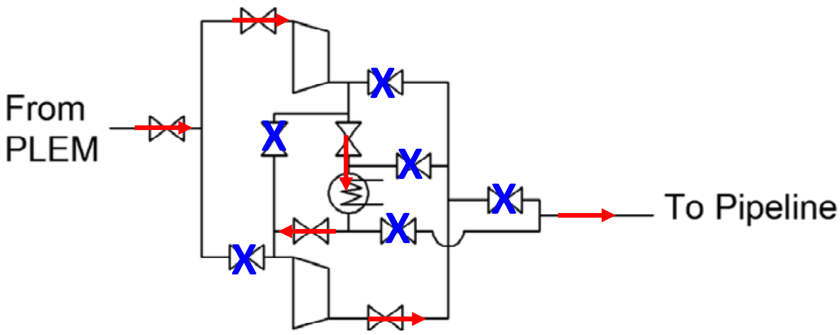
- Parallel Compressors with discharge cooling



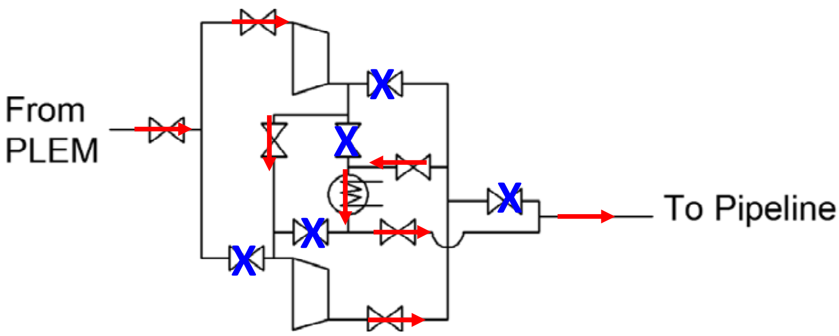
- Compressor in series



- Compressor in series with intercooling



- Compressor in series with discharge cooling



The compressor model proposed is the FRAM-2000, and its operating curves, for test conditions, are given in the excel sheet attached.

Tasks

Your main task is to conduct a verification study to confirm if the proposed solution can operate satisfactorily during the 5 years operation period. This means:

- Determine when (in which compressor year) only one compressor is required and when two compressors are required (and if they have to operate in series or in parallel)
- Determine when (in which compressor year) the cooler is required. Determine the required heat removal rate in W.
- Estimate the rotational speed of the compressor and the required compressor power for each compressor year.

Considerations:

- The compressor discharge temperature has to be below 157 °C (to avoid MEG evaporation and to avoid problems with the compressor and the pipeline)
- The cooler is a free convection heat exchanger using seawater, so the temperature at the outlet cannot go below 6 C.
- The temperature at the PLEM (suction of the compressor station) is 67 C.

Solving suggestions

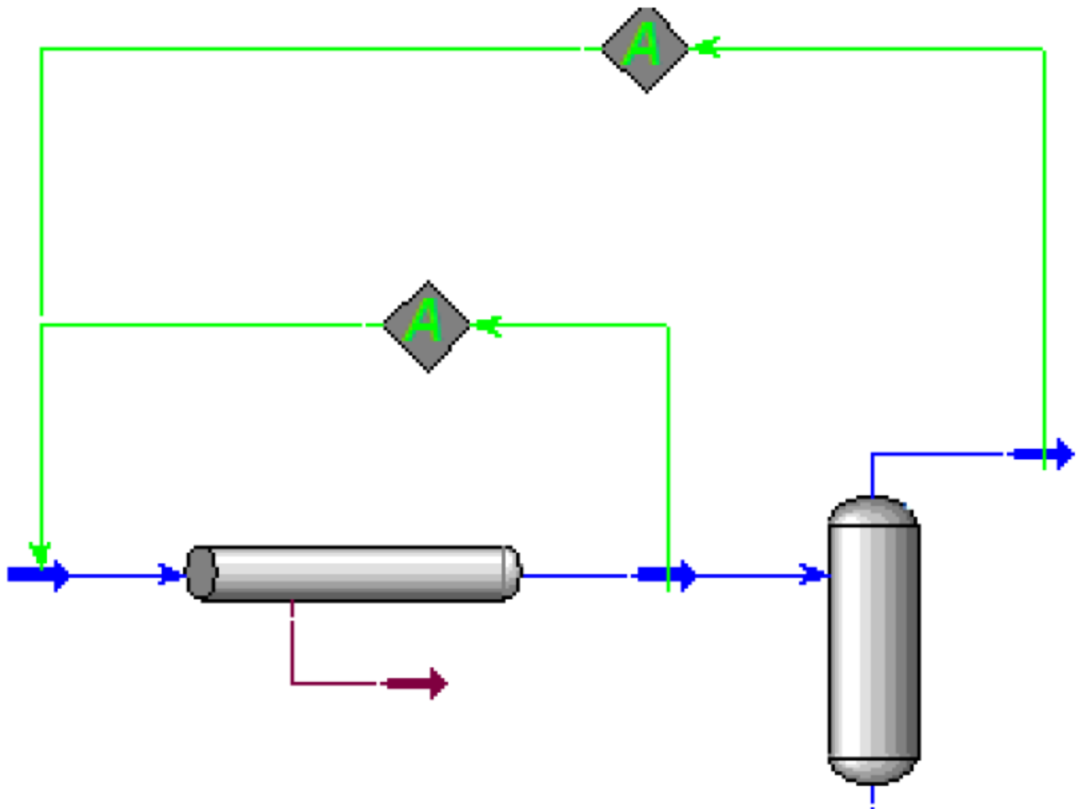
- Use the following data calculated in Exercise 01: deltaP compressor, compression ratio, suction pressure and the actual gas flow rate at compressor inlet for each compression year. If you haven't delivered exercise 1, please ask a friend to give you the data.
- For each year:
  - As a starting point, assume that you can perform the required compression using only one compressor with no cooling.
  - Convert the operating condition to test conditions of the compressor map. Locate the point in the test map of the compressor. If it is inside, calculate the discharge temperature, rpm, power requirements, etc. Use the cooler as needed if Tout>157 C.
  - If it falls outside 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 (as discussed in page 12 of class from 20.01.2015).
    - Two compressors in parallel (with the same pressure ratio)
    - Two compressors in series (with the same pressure ratio = r_p ^ 0.5)
  - Use the cooler as needed if Tout>157 C.

PART 2

For exercise 1, you have done your calculations assuming that the gas consists of pure methane, that there is no fluid condensation therefore the dry gas equations are applicable. In reality, the gas has the following composition:

Component	**Mole %**
Nitrogen	2.525
Carbondioxide	5.262
Methane	81.006
Ethane	5.027
Propane	2.534
i-Butane	0.4
n-Butane	0.83
i-Pentane	0.281
n-Pentane	0.308
Hexanes	0.352
Heptanes	0.469
Octanes	0.407
Nonanes	0.203
Decanes	0.397

You are asked to perform a more realistic simulation of the flow condition along the 158 km pipeline extending from the PLEM to the slug catcher using the software HYSYS. This is the recommended HYSYS layout:



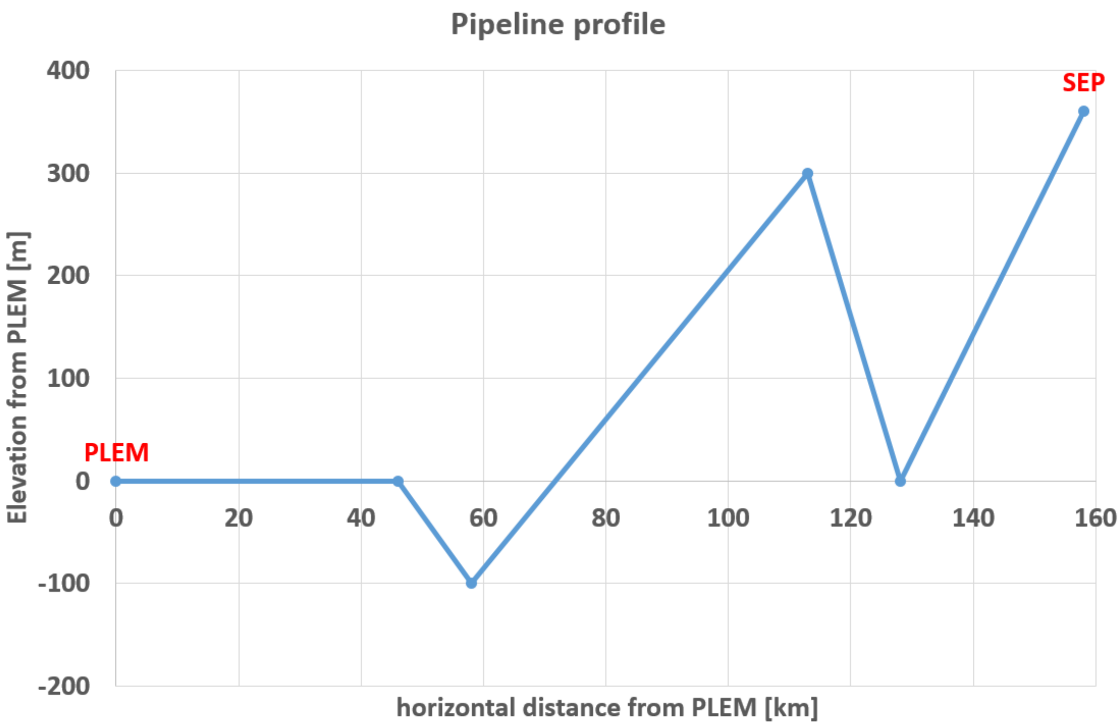
Using the following data:

Pout (Slug catcher pressure)	**[bara]**	30		
Tin pipeline	**[C]**	67		
Flowrate	**[Sm^3/D]**	2.00E+07		
Tsea	**[C]**	6		
Pipe ID	**[in]**	26.7		
Pipe OD (Including insulation)	**[in]**	30		
Length of pipeline	**[km]**	158		
Pipeline elevation [inclination]	**[Deg]**	0		
Overall pipeline heat transfer coefficient	**[W/m^2 K]**	0.5	1.5	5

Conduct the simulations considering three values of overall pipeline heat transfer coefficient (HTC) as listed in the pipeline data set.

Tasks:

- Calculate the pressure drop in the pipeline Pplem-Psep using HYSYS and compare it with the value obtained during the natural plateau period in exercise 1. How different are they? Was the dry gas assumption a good approximation? Discuss on what might be causing the differences in the pressure drop estimation.
- Tabulate and plot pressure, temperature and liquid holdup along the pipeline for each of the 3 cases of thermal insulation specifications.
- Plot the phase envelope (P-T diagram) of the gas mixture illustrating the saturation lines (bubble and dew point lines) and the quality lines inside the two-phase region (0.01, 0.02, 0.03, 0.04, 0.05, 0.1, 0.2). Indicate in your plot the following:
  - Cricondenbar and Cricondentherm points
  - The region with retrograde condensate behavior (if any)
  - Plot the p-T along the pipeline on top of the P-T diagram for the three different thermal insulations. Detect if there is any condensate retrograde behavior.
- Include now the real elevation profile of the pipeline in the Hysys simulations and repeat your calculations (see the graph below). Are there any differences between the simplistic and real approach?



Real pipeline elevation profile (referenced relative to PLEM position)						
	X	Y				
	[km]	[m]				
	0	0	PLEM			
	46	0				
	58	-100				
	113	300				
	128	0				
	158	360	SEP			

Solving suggestions

- Remember that Hysys performs its calculations co-current. This means that you provide a Pplem pressure, Tplem temperature, and a mass rate at the inlet of the pipe, and Hysys calculates the gas flow rates at the exit of the separator and the separator pressure. However, we now that separator pressure has to be 30 bara, and the gas flow rate has to be 20E6 Sm^3/d. In order to force Hysys to reach these values, it is necessary to use 2 simultaneous ADJUSTS. The ADJUSTS will modify, using an iterative solver, the inlet pressure and inlet mass rate, until the appropriate separator pressure and separator standard gas flow rate have been reached.
- As a starting point for the mass rate at the inlet of the pipe, convert the standard condition flow rate to mass rate using the following equations (12.01.2015 class, page 3):
  Relationship between surface volume and number of moles (from the Ideal gas law)

$$V_{sc} = \frac{R \cdot T_{sc}}{p_{sc}} \cdot n$$

Based on this expression, It is also possible to write the relationship between surface gas rate and molar flow:

$$q_{\bar{g}} = \frac{R \cdot T_{sc}}{p_{sc}} \cdot \dot{n}_g$$

And, finally, the relationship between molar flow and mass flow:

$$\dot{n}_g = \frac{\dot{m}_g}{MW}$$

EXERCISE DELIVERABLES:

- **Excel sheets and Hysys Models with calculations, simulations and plots (legible and well presented).**
- **Word document containing: summary of the main results, relevant plots and tables, discussion of the results and analysis, conclusions. Well presented and up to a level of potential delivery to an Oil company.**

Exercise 03 – Simplified expenditure, revenue and NPV calculations of petroleum assets

PART 1: Visund field

Background

Visund is an oil and gas field in blocks 34/8 and 34/7, 22 kilometers north-east of the Gullfaks field in the Tampen area of the Norwegian North Sea. On stream in the spring of 1999, this development embraces a floating production, drilling and quarters platform.
The subsea-completed wells on the field are tied back to the floater with flexible risers. Oil is piped to Gullfaks for storage and export. The Visund field began producing gas and exporting it to continental Europe on 7 October 2005.

Tasks

- Calculate the NPV cost of the exploration and development wells in the field. Present your results in a tabulated form, and plot:
  - Net cash flow distribution (drilling costs in USD vs time)
  - NPV distribution
  - Cummulative NPV (assume a discount rate of 8%)
- Calculate the annual net cash recovery (NCR and the NPV of the Visund field based on well costs and hydrocarbon revenue only (ignore the production facilities CAPEX and OPEX in this analysis). Perform the analysis for the period from 1997 to 2012. Present your results using plots.

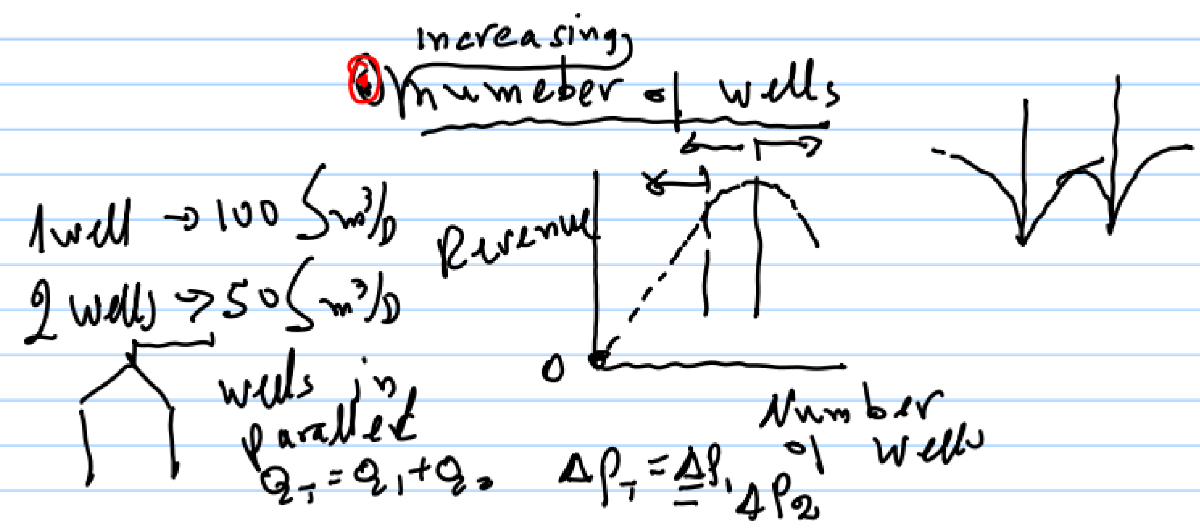
Assumptions:

- All the data you need for your calculations is included in the attached excel file. However, if you prefer to use your own data or use your own sources (internet search, etc.), feel free to do it.
- Assume that the 1997 daily rig rate (semisubmersible at a water depth of less than 350 m) has been USD 120 000 and there is a constant 5% annual increase in the rig daily rate until today.
- Note: The daily cost to the operator of renting the drilling rig and the associated costs of personnel and routine supplies. This cost may or may not include fuel, and usually does not include capital goods, such as casing and wellheads, or special services such as logging or cementing. In most of the world the day rate represents roughly half of the cost of the well. Similarly, the total daily cost to drill, test and complete a well (spread rate is roughly double what the rig day-rate amount is).

PART 2: Determining optimum number of wells for the Atila field

Tasks

You are asked to perform a sensitivity analysis of the revenue of the development of the Atila field with respect to number of wells. This in order to obtain the optimum number of wells that gives maximum revenue (As discussed by Prof. Michael Golan in page 2 of class of 02.02.2015).



- Use the excel sheet created in Part 1 of exercise 1. Change the number of wells and the number of templates. A suggested number of cases is presented below:

Case N	Nwells	Ntemplates
1	3	1
2	4	1
3	4	2
4	6	2
5	8	2
6	9	3
7	12	3
8	12	4
9	15	5
10	16	4

- Calculate, for each case, the duration of the plateau. Neglect the gas production after the plateau ends.
- Consider the same drilling costs as in part 1 and assume that all wells are drilled from year 0. Assume that it takes an average of 115 days to drill a well.
- Assume that the startup of the project is in 1997
- Calculate, for each case, the annual net cash recovery (NCR and the NPV of the Atila field based on well costs and hydrocarbon revenue only (ignore the production facilities CAPEX and OPEX in this analysis). Perform the analysis from field production startup until the end of the plateau.
- Make a plot depicting the number of wells in the x axis and the total revenue of the asset in the y axis. Locate the optimum number of wells in the plot.
- If there are some years for which there is no gas price data (e.g. if the field production stretches after 2013) assume that the gas price remains constant.
- For the case with highest revenue, consider that the Atila field is producing with a gas condensate ratio (GCR) of 5808 Sm^3/Sm^3. What impact does including the revenue coming from condensate production have on the revenue?

EXERCISE DELIVERABLES:

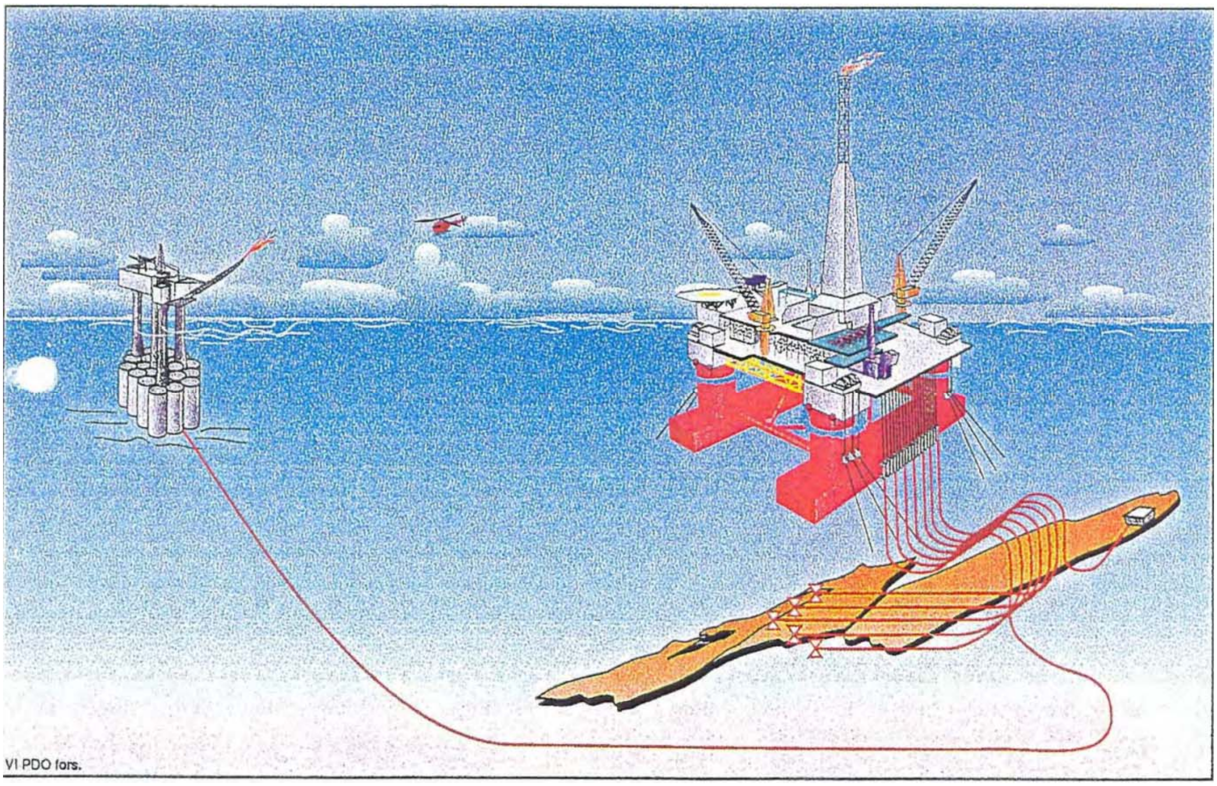
- **Excel sheets with calculations and plots (legible and well presented).**

- **Word document containing: summary of the main results, relevant plots and tables, discussion of the results and analysis, conclusions. Well presented and up to a level of potential delivery to an Oil company.**

Additional info:

Visund field (from www.npd.no):

Development	Visund is an oil field east of the Snorre field in the northern part of the North Sea. The development includes a semi-submersible integrated accommodation, drilling and processing steel facility (Visund A). The water depth is about 335 metres at Visund A. The PDO for gas export was approved in 2002. The northern part of the Visund field is developed with a subsea template, about 10 kilometres north of Visund A.
Reservoir	The Visund field contains oil and gas in several tilted fault blocks with varying pressure and liquid systems. The reservoirs are in Middle Jurassic sandstones in the Brent Group and Lower Jurassic and Upper Triassic sandstones in the Statfjord and Lunde Formations. The reservoirs lie at a depth of 2 900 - 3 000 metres.
Recovery strategy	Oil production is driven by gas injection and water alternating gas injection (WAG). Produced water is also re-injected into one of the reservoirs. Limited gas export started in 2005.
Transport	The oil is sent by pipeline to Gullfaks A for storage and export via tankers. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes in Norway, where the NGL is separated and the dry gas is further exported to the market.
Status	A challenge for Visund is to optimise oil recovery before gas export increases. The northern part of the Visund field is redeveloped with a new template. Production from Visund Nord started in late 2013. The 34/8-13 A (Titan) oil discovery is included in Visund and is planned to be developed by wells drilled from the Visund A platform. The 34/8-15 S (Rhea) gas discovery, drilled from the Visund Nord template in 2013, is also included in the Visund field. Exploration well 34/8-17 S, drilled from the Visund Nord template in 2014, proved a new gas discovery at the east flank of Visund.



Standard Cubic Foot of Gas (SCF)

A standard cubic foot (SCF) is a standard measure of natural gas, equal to the amount of natural gas contained at standard temperature and pressure (60 degrees Fahrenheit and 14.73 Pounds standard per square inch) in a cube whose edges are one foot long.
There are 1,031 Btu in a cubic foot of natural gas. BCF (billion cubic feet) and TCF (trillion cubic feet) are common abbreviations used in the natural gas industry.

British Thermal Unit (Btu)

A British Thermal Unit (Btu) is the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit. This is the most common unit used for buying and selling natural gas. A typical home in the U.S. Midwest using natural gas for heating will use approximately 14 MMBtu during a typical month in the heating season.

HEAT ENERGY PER UNIT OF MEASURE FOR NATURAL GAS

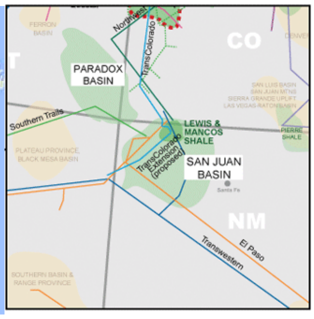
UNIT OF MEASURE	APPROX. HEAT ENERGY
1 Std cubic foot	1,000 BTU's
100 Std cubic feet (1 therm)	100,000 BTU's
1,000 Std cubic feet (1 mscf)	1,000,000 BTU's

Exercise 04 – Gas production allocation and production optimization

<u>PART 1: Model-based production allocation on a multi-layer gas well</u>

Background

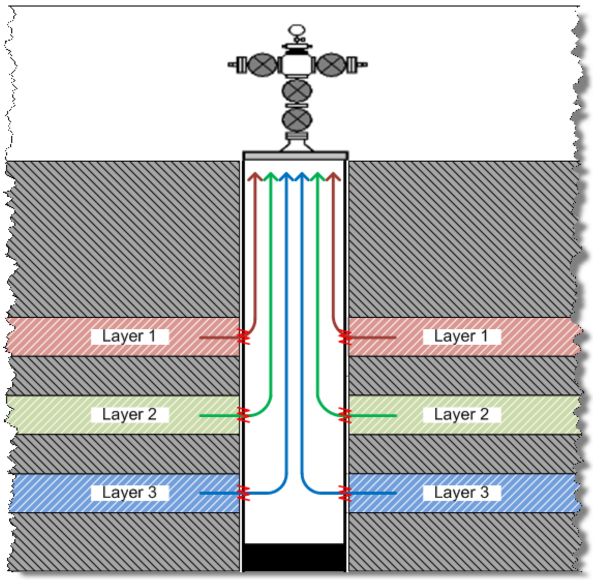
You have been asked for your expert advice to solve a problem on production allocation on a dry gas well from the San Juan area, New Mexico, US.



The well is the Dunavant 1-15 U 4 from the "Ignacio Blanco" Field. The well is producing **at a constant gas flow rate of 180 E3 Sm^3/d** from three formations (3 layers) that have different ownerships:

Layer Name Company	FRUITLAND COAL	WATERISLAND COAL	SAN JUAN
BP	30 %	70 %	10 %
Chesapeake energy corp.	40 %	10 %	40 %
Marathon	30 %	20 %	50 %

Each layer has its own properties, permeability, porosity, reservoir pressure, deliverability, etc. The vertical separation between the layers is pertinent and has to be considered. The well architecture is as follows:



Tasks:

You are asked to determine: 1). what fraction of the total gas flow rate is coming from each layer and 2). what fraction of the total gas flow rate corresponds to each company.

You are also asked to analyze if the allocations fractions that you estimated will change in a year from now. If they change, please advice the company what would be the best way to calculate in an accurate way the new fractions.

Solving Suggestions

- Transform the three layer well in an equivalent downhole network (consider from reservoirs until wellhead). Solve the network several times for different wellhead pressures until the total gas flow rate of the well is 180 Sm^3/d.
- Assume that there are no other wells producing from layers 1, 2 and 3.

Information provided

Inflow performance of the layer (backpressure equation)

$$q_{gsc} = C_R\left(p_R^2 - p_{wf}^2\right)^n$$

Tubing equation (for each vertical segment)

$$q_{gsc} = C_T\left(\frac{p_{in}^2}{e^s} - p_{out}^2\right)^{0.5}$$

The material balance for each layer has been approximated by the reservoir specialist by the following equation:

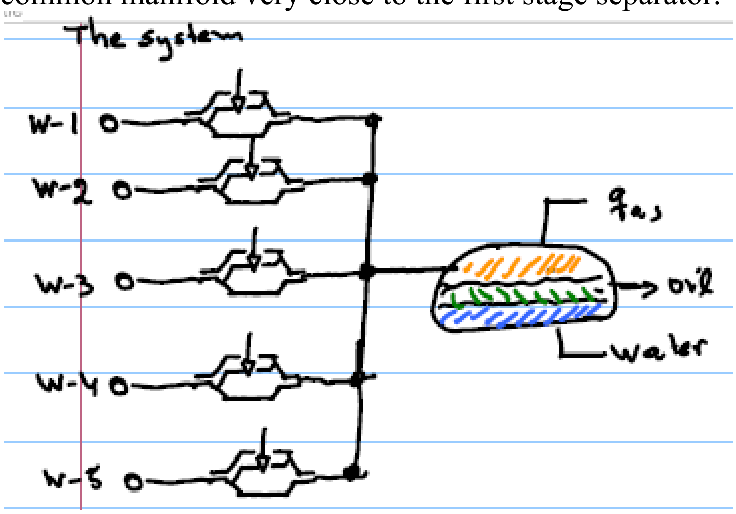
$$p_R = p_i - m \cdot G_p$$

All relevant data is given in the attached excel sheet.

<u>PART 2: Production optimization on choke opening</u>

Tasks:

You are asked to perform production optimization on 5 wells from the Troll oil field. The goal is to maximize oil production by changing choke opening on each well and honoring maximum total processing capacities of water and gas. Each well is producing independently and comingle in a common manifold very close to the first stage separator.



Information provided:

The production engineer in charge has provided you with a very simple (but accurate) set of equations to predict oil, gas and water production with respect to choke position (z ranging from 0, fully closed -1 fully open):

$$q_o = q_{o\max} \cdot z$$

$$q_g = q_o \cdot GOR$$

$$q_w = q_o \cdot \left(\frac{WC}{1-WC} \right)$$

Where GOR is gas-oil ratio and WC is water cut.

It is not allowed to shut-in wells. The minimum choke opening is 0.15.

EXERCISE DELIVERABLES:

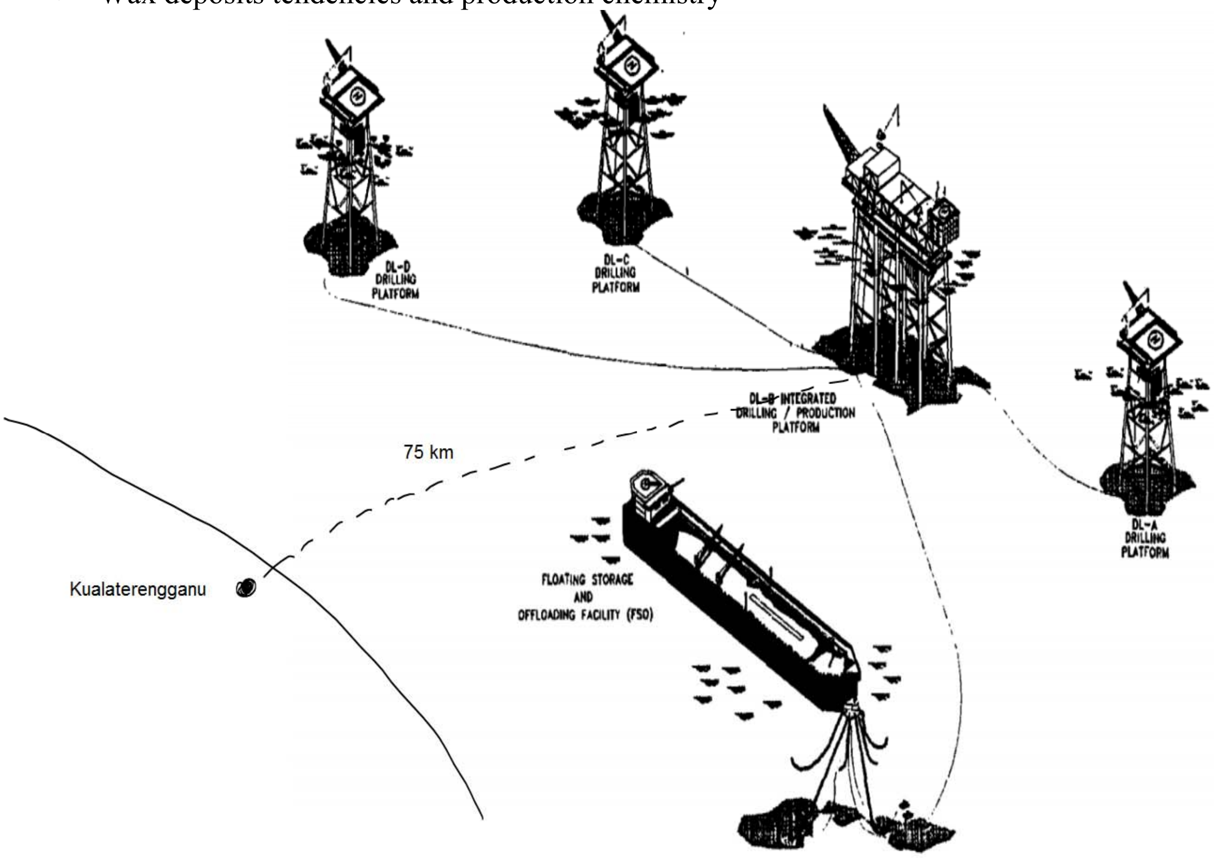
- **Excel sheets with calculations and plots (legible and well presented).**
- **Word document containing: summary of the main results, relevant plots and tables, discussion of the results and analysis, conclusions. Well-presented and up to a level of potential delivery to an Oil company.**

Exercise 05 – Temperature and pressure profiles in offshore export line - Single phase, incompressible oil flow

Background

The Dulang field is located 75 km offshore Kuala Terengganu in the South China Sea. The reservoir oil has tendencies to form wax crystals and to increase apparent viscosity with reduction of temperature. Two development options are considered for oil export; (1) offshore loading terminal and (2) marine pipeline to shore. To assess the feasibility of marine pipeline it is necessary to calculate the temperature in the export line. The temperature calculations will allow to conduct rheological studies to establish flow properties needed to calculate:

- Steady state pressure loss at nominal flow rate
- Steady state pressure loss at reduced or minimum rate
- Restart pressure after a pipeline shut-down
- Wax deposits tendencies and production chemistry



Following the thermal calculations, the engineering design team will determine:

- Pipe diameter
- Thermal insulation and needs to bury the line
- Minimum allowable flow rate and minimum allowable inlet temperature
- Maximum allowable shutdown time
- Effect of chemical flow improvers (pour point suppressor)
- Effect of mixing field production with the production of adjacent fields.
- Needs for frequent pigging

Tasks:

1. Calculate and plot the steady state temperature profile of the pipe after 100 days for the following cases:
   a) Concrete coated (unburied)
   b) PVC insulated (unburied)
   c) Buried (concrete coated)

2. For the case of buried pipe, plot the temperature profile during the transient period for the following time stages: 20, 40, 60, 80, 100 days

3. Digitize the viscosity versus temperature plot reported by a laboratory which tested the Dulang Waxy crude (see attached plot) and list the average temperature and viscosity for each computation segment of the pipe (assume linear average for each increment). Present the information on the viscosity in a table and in a new plot.

4. Calculate and plot the pressure profile along the pipe starting from the platform to the land terminal. The pipeline exit pressure at the land terminal (slug catcher pressure) is 50 bara. For calculation purposes, assume that the pipeline is horizontal (elevation changes are negligible) and that the pipeline roughness is 0.045 mm.

Data and information

Design information:

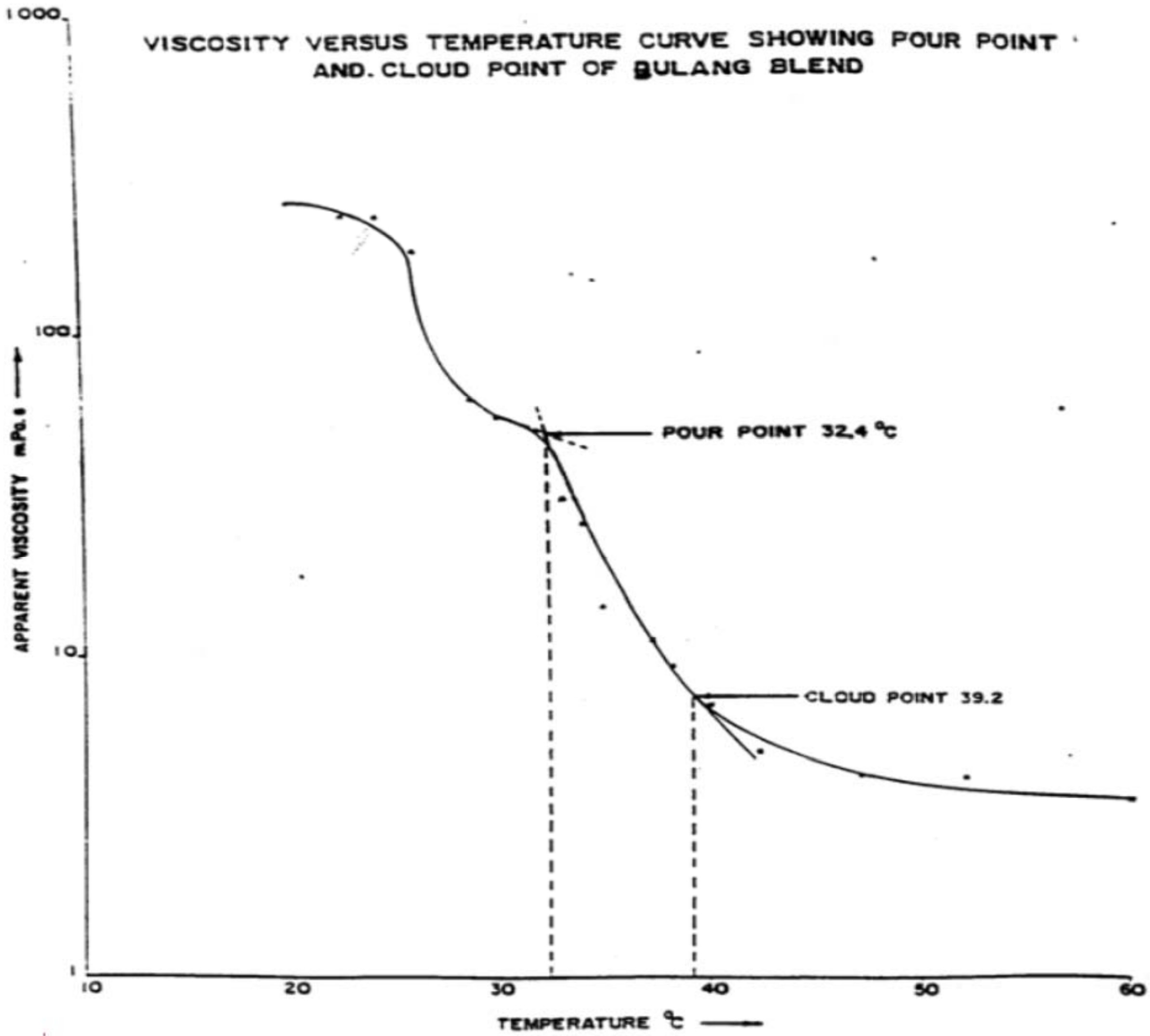
Pipe diameter=16 in (ID)
Pipe roughness=0.045 mm
Pipe and insulation external diameter:

- Concrete coated = 18 in
- PVC foam coated = 20 in

Oil flow rate=100 000 STB/D
Inlet oil temperature: 60°C
Oil density = 750 kg/m3
Minimum sea-bottom water temperature = 14°C
Specific Heat capacity of oil= 2300 J/kg-K
Overall heat transfer coefficient of the insulated pipe (calculated)

- Concrete coated =4 J/s-m^2-K
- PVC foam coated =0.5 J/s-m^2-K

Thermal diffusivity of earth = 0.857 ft^2/day
Thermal conductivity of earth = 0.24 W/m K



Equations for pressure gradient in single phase flowing pipelines

The dimensionless- pressure- loss (Moody friction factor, f,) versus the dimensionless-flow velocity (Reynolds number, Re), for engineering calculations is as follows:

Reynolds Number	$N_{RE} = \frac{\rho \cdot D \cdot V}{\mu}$	Moody friction factor	$f_M = \frac{2 \cdot D \cdot \Delta p}{\Delta L \cdot \rho \cdot V^2}$

Haaland Friction factor:

$$\frac{1}{\sqrt{f}} = -1.8 \cdot \log\left[\frac{6.9}{N_{RE}} + \left(\frac{\varepsilon}{3.7 \cdot D}\right)^{1.11}\right]$$

Unburied pipeline-incompressible fluid - steady state temperature distribution

$$(T_i)_L = T_w + \left[(T_i)_0 - T_w\right] \cdot e^{-L/B}$$

Where

$$B = \frac{(\dot{m} \cdot c_p)}{2 \cdot \pi \cdot r_a \cdot U}$$

Buried Pipeline-incompressible flow - transient temperature distribution

$$\left(T_i\right)_{L,t} = T_w + \left[\left(T_i\right)_0 - T_w\right] \cdot e^{-L/A}$$

Where

$$A = \frac{\left(\dot{m} \cdot c_p\right)}{2 \cdot \pi \cdot r_a \cdot U} \cdot \left[\frac{k + r_a \cdot U \cdot f(t)}{k}\right] \textbf{ and } f(t) = -\ln\left(\frac{r_a}{2 \cdot \sqrt{\alpha \cdot t}}\right) - 0.29$$

Nomenclature for temperature calculations:

T_i = Temperature of flowing fluid [°C]

$\left(T_i\right)_0$ = Fluid temperature at pipe inlet [°C]

$\left(T_i\right)_L$ =Fluid temperature at pipe distance L [°C]

$\left(T_i\right)_{L,t}$ =Fluid temperature at pipe distance L and time t [°C]

T_w = Ocean bottom water temperature [°C]

L = distance along the pipe [m]

t = Time from initial flow, [s]

c_p = heat capacity of flowing fluid, [kJ/kg °C]

k = thermal conductivity of soil (kJ/ s m °C]

$\dot{m}$ = mass flow rate, [kg/s]

α =heat diffusivity of soil, $k_e/(\rho_e \cdot c_{pe})$, [$m^2$/s]

ρ_e =soil density [kg/m^3]

r_a =External radius of the conduit (with insulation) [m]

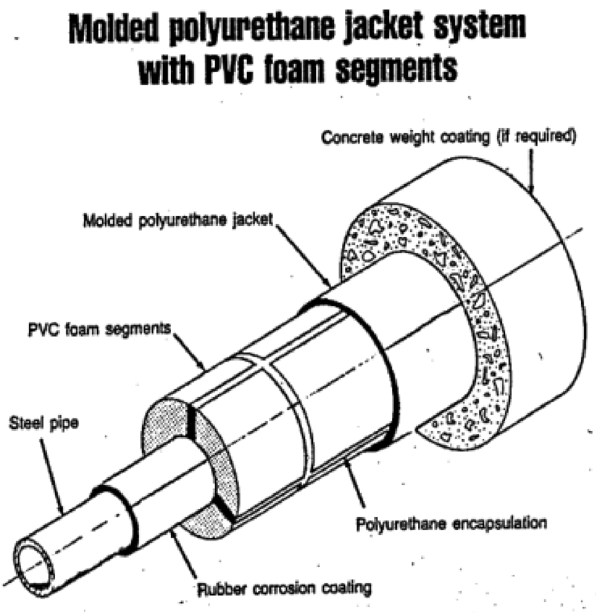
U = Overall heat transfer coefficient [W / m^2 °C]

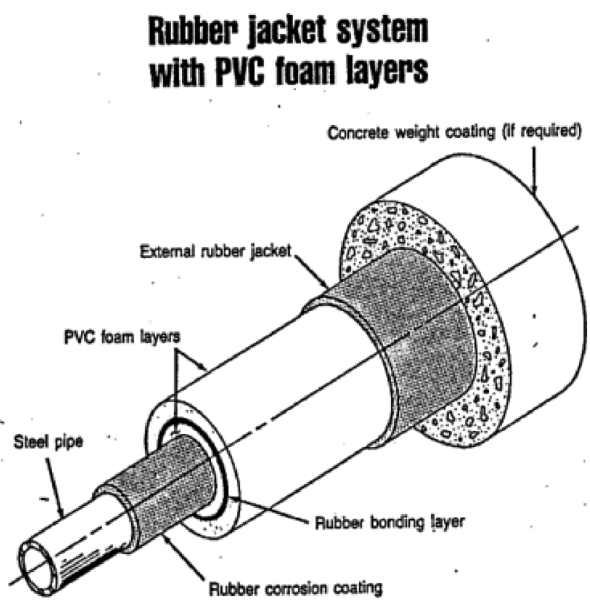
EXERCISE DELIVERABLES:

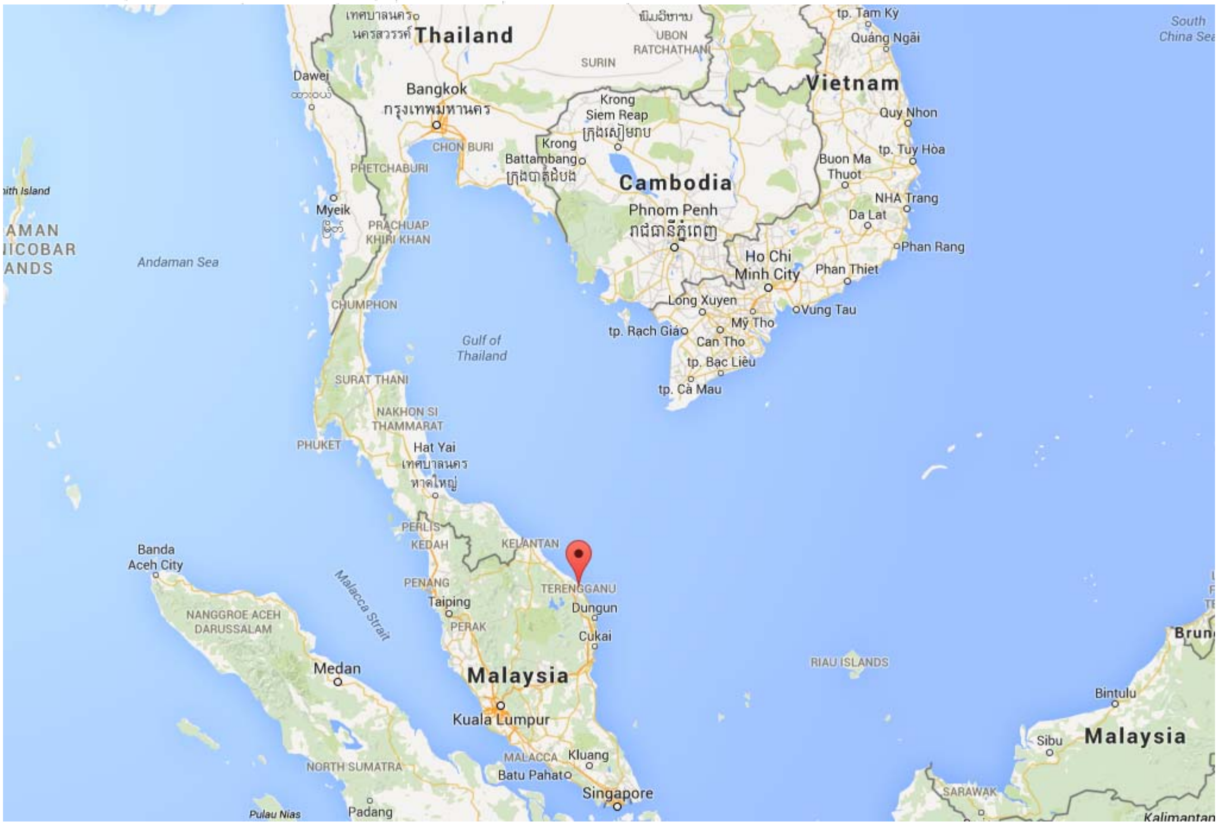
- **Excel sheets with calculations and plots (legible and well presented).**
- **Word document containing: summary of the main results, relevant plots and tables, discussion of the results and analysis, conclusions. Well presented and up to a level of potential delivery to an Oil company.**

Additional info:

To digitize the plot, you can use http://arohatgi.info/WebPlotDigitizer/ . use Google Chrome browser.


Molded polyurethane jacket system
with PVC foam segments
Concrete weight coating (if required)
Molded polyurethane jacket
PVC foam segments
Steel pipe
Polyurethane encapsulation
Rubber corrosion coating


Rubber jacket system
with PVC foam layers
Concrete weight coating (if required)
External rubber jacket
PVC foam layers
Steel pipe
Rubber bonding layer
Rubber corrosion coating


Thailand
Bangkok
Vietnam
Cambodia
Phnom Penh
Ho Chi Minh City
Andaman Sea
Gulf of Thailand
Malaysia
Kuala Lumpur
Singapore
Medan
Banda Aceh City
Malacca Strait
Terengganu
Dungun
Cukai
Kelantan
Hat Yai
Phuket
Surat Thani
Chumphon
Vung Tau
Can Tho
Da Lat
Phan Rang
Phan Thiet
Riau Islands
Bintulu
Sibu
Padang