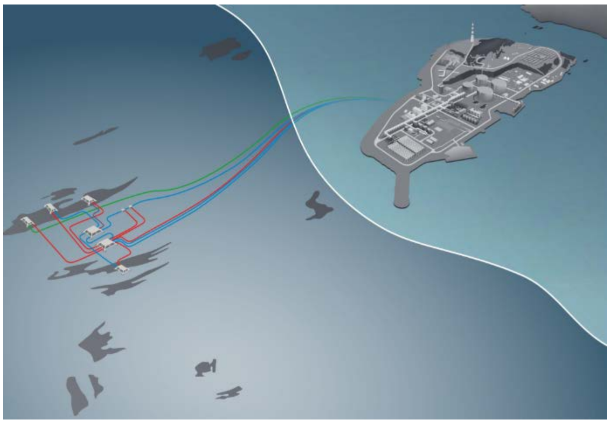
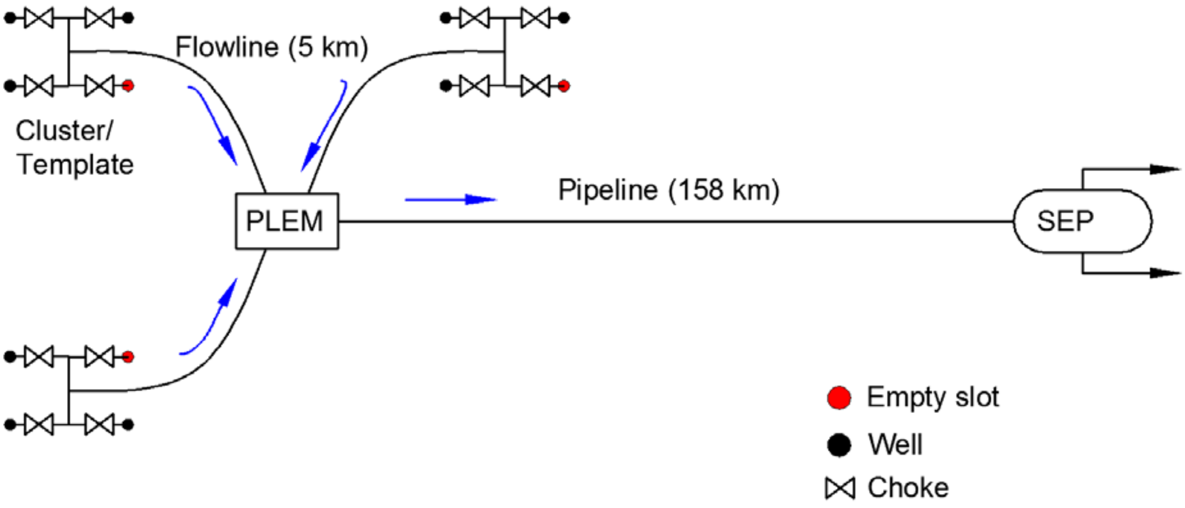
Production scheduling calculations for the Snøhvit field

Snøhvit is an offshore gas field located in the Barents Sea 158 km from Hammerfest. The field will be developed with the “subsea to beach” concept. The gas production will be processed in a LNG plant on Melkøya (a nearby island) and transported further in LNG carrier to customers in US and Spain.



According to the base case Scenario (BCS) selected for the study, the field is completed subsea with subsea templates, each with 4-well slots. Typically, only three wells are completed in each template (there is one slot is for redundancy). The templates will be 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.



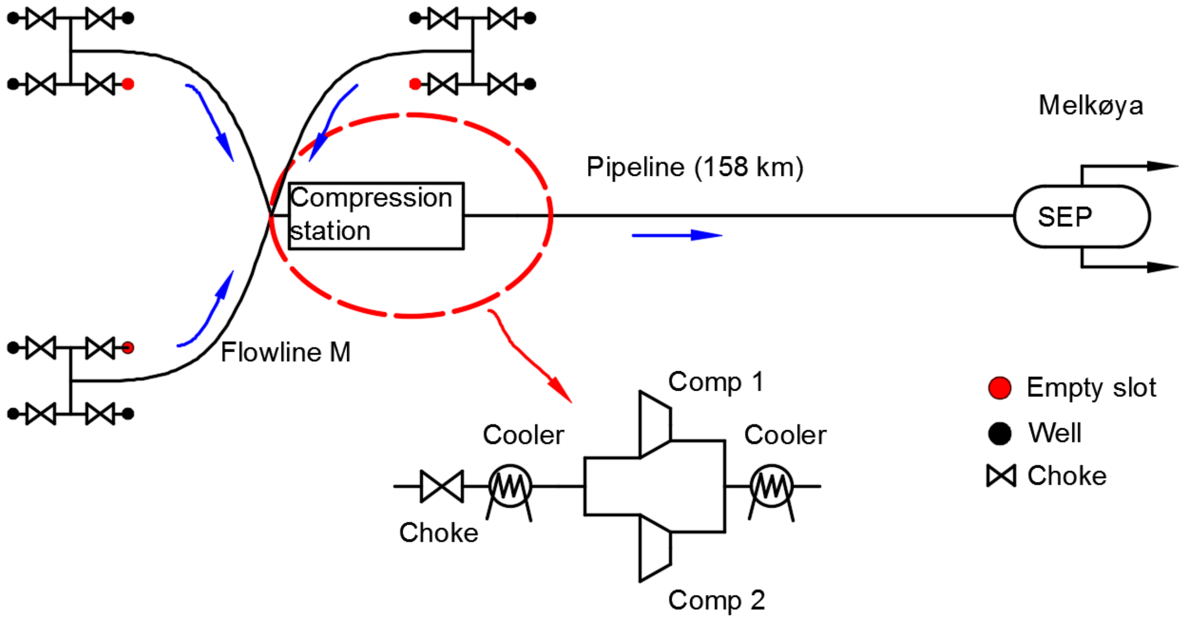
Field layout when using 9 wells.

Assume all the wells are identical (in completion, depth and productivity and all other design and operation parameters) and produce from the same reservoir (tank model).

Your main task is to determine the number of wells and field plateau rate that give maximum economic value. To decide, you have to compute the net present value of the project at abandonment.
For the best case, you should make a sensitivity analysis on the gas price (+-20%), the CAPEX of the LNG plant (+-20%). Present your results in a tornado chart or using a spider plot.
The multiphase/flow assurance expert working on this project has said that the prediction of the pressure drop in the main transportation pipeline using commercial tools (e.g. Olga®) could be extremely unreliable. This is because of the hilly profile of the pipeline and the presence of some liquid flowing together with the gas. He says that the error associated with the pressure drop estimation might be of ±50%. He therefore suggested to perform an experimental campaign in the large scale multiphase loop of SINTEF (http://sintefloops.com/?page_id=962) in Trondheim to verify and reduce the inaccuracy of the pressure drop models. The experimental campaign costs 5 E06 USD.
Before taking the decision, your manager has asked you to determine what would be the influence of an inaccuracy of 50% in the prediction of the pressure drop in the production profile of the Block 2 field. Specifically on the duration of the plateau. **Your task is then to add 50% to the original pressure drop in the pipeline and calculate the production profile again. Discuss your results.**

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 minimum temperature possible to achieve in the inlet cooler is 20 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.

Guidelines, requirements and useful information

- To calculate revenue, you should compute the production profile until abandonment (field rate of 5 E06 Sm^3/d). To compute the production profile you have to use flow equilibrium calculations. Due to the fact that wells are identical, and if the system is symmetric, it is possible to perform flow equilibrium by looking at the path: well (formation), well (tubing), flowline and pipeline, but using different rates (i.e., well rate, template rate, and field rate, correspondingly). The recommended equilibrium point is the wellhead. (upstream and downstream the choke).
- Use the pre-programmed VBA functions to calculate flow in tubing, pipeline and flowline (VBA function linep1 or line p2), for the dry gas material balance, for the Z factor and for the IPR.
- It is recommended for you to test at least 9 cases, for example number of wells between 6-15 and plateau rates 20-35 E06 Sm^3/d. When presenting your results be crystal clear about what cases were tested.
- To avoid sand production, wells shouldn't produce more than 3 E06 Sm^3/d.

- When varying the number of wells, there should be always the same number of wells in each template (to take advantage of symmetry when doing flow equilibrium). Add and remove templates as needed.
- All wells must be drilled before production startup. The average time required to drill a well is 3 months (4 wells per year). The average cost per well (including perforating, completing, tree and well equipment) is 100 E6 USD. **Note that the number of wells affects the production startup.**
- The cost of a single subsea manifold is 20 E06 USD (to be paid during the first year of the project).
- The cost of the main transportation pipeline and umbilicals is 500 E06 USD (to be paid evenly during the first two years of the project).
- The cost of the LNG plant is a linear function of the field gas rate, expressed by $CAPEX_{LNG} = 160 \cdot q_{g,field}$ where $CAPEX_{LNG}$ is in USD and $q_{g,field}$ is the maximum rate of the field in Sm^3/d. (to be paid evenly during the first two years of the project).
- LNG carriers are needed to take the LNG production from Hammerfest to customers in Spain. Each LNG carrier has a capacity of 145,000 m^3 of LNG (equivalent to 86 E06 Sm^3 of produced gas) and can make 22 trips per year. The cost of each LNG carrier is 200 E06 USD. (to be paid evenly during the first two years of the project). Estimate the number of carriers needed depending on annual production during the plateau period.
- Neglect tax and depreciation, OPEX (operational expenditures) and ABEX (abandonment expenditures).
- It is recommended you plot project NPV versus field plateau rate, for a fixed number of wells.
- It is recommended you plot project NPV versus number of wells, for a fixed field plateau.
- It is estimated you compute and report plateau duration and ultimate recovery factor for all alternatives.
- Production starts in year 6