FLOW ASSURANCE

What is Flow Assurance?

Flow assurance is a term originally coined by Petrobras in the early 1990's. The term in Portuguese was "Garantia de Fluxo", which translates literally to "Guarantee the Flow".

Flow assurance refers to ensuring the flow of produced hydrocarbons from the reservoir to the point of sale. It covers all aspects of the production system and incorporates topics such as:

- THERMO-HYDRAULIC ANALYSIS
  encompasses all pressure and temperature related aspects of single and multiphase flow behaviour. This will include pressure loss (or gain) calculations for applications such as deliverability optimization and pipeline sizing. It will also include heat loss (or gain) calculations that consider the pipeline surroundings, thermal insulation, and active heating of pipelines.

- OPERABILITY
  refers to how the system reacts to changes in operating conditions. For example, an operability study might address concerns associated with terrain slugging or slugs generated by pigging operations and the sizing of slug catchers required by such operations. Other examples might include thermal effects of start-up and shut-down operations or limiting flow rates associated with a variety of operating conditions.

- BLOCKAGES
  can result from the deposition of hydrates, wax, asphaltenes, elemental sulphur, sand, or other produced solids. The formation of such deposits is a function of the operating conditions in the production system.

- PVT & RHEOLOGY
  define the properties of the fluids flowing in the system. The phase behaviour and physical properties of the fluids will significantly impact all aspects of the production operations. For example, the viscosity of produced fluids, from more conventional hydrocarbon-water mixtures to less common fluids such as stable emulsions and foam, will have a significant impact on the frictional pressure losses in the system.

- MECHANICAL INTEGRITY
  includes the impact of corrosion and erosion on the physical materials (e.g. steel) that make up the system. Both the corrosion and erosion affecting the inside of the pipes (whether surface pipes or well tubulars) can be significantly influenced by the nature of both the fluids in the system and the manner in which they flow.

- MITIGATION
  efforts such as chemical inhibition, operational procedures, or choking that may be used to address various concerns will be influenced by the nature of the flow in the pipe.

Why is PIPEFLO the tool of choice for flow assurance studies?

According to the Norwegian Institute for Energy Technology (IFE), “The term ‘Flow Assurance’ covers broadly the same meaning as the term ‘multiphase transport technology.” Based on this assessment, Neotec was involved in delivering “Flow Assurance” software and services to the oil and gas industry for approximately 20 years before the term was coined.

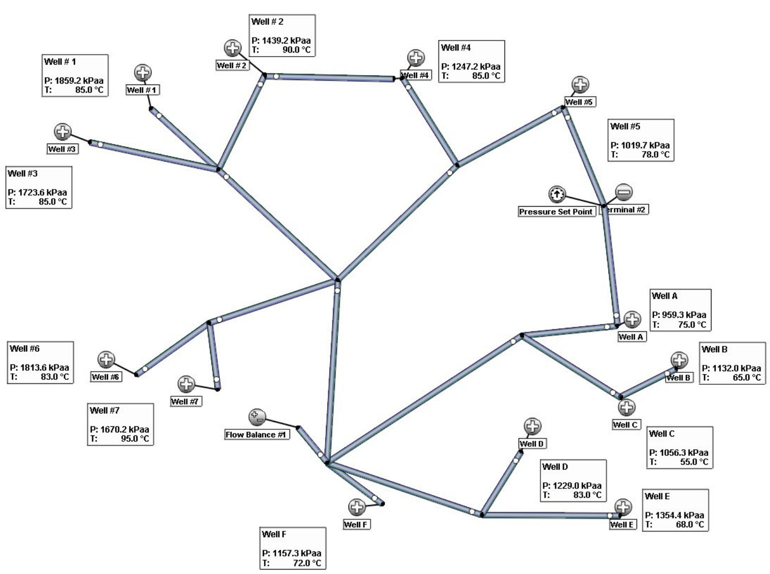
PIPEFLO combines superior multiphase flow and heat transfer technologies with best-in-class thermodynamics models to provide solutions for all aspects of a flow assurance study. **PIPEFLO** can be used to model anything from single lines to complex networks, and includes tools which facilitate powerful sensitivity studies.

Pipe sizing

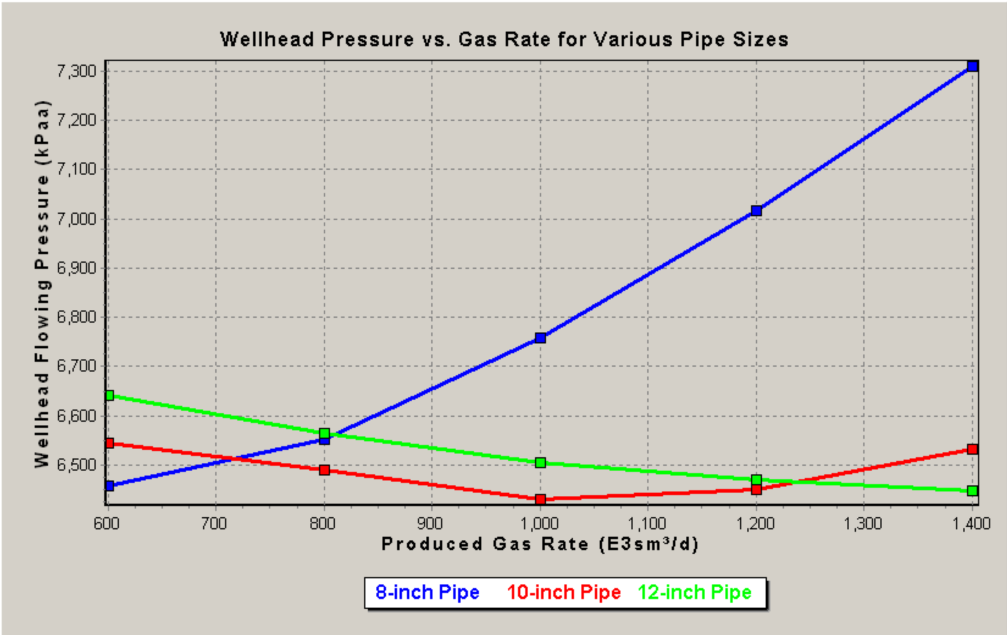
Selecting an appropriate size for a new multiphase pipeline is a common problem. These are just some of the questions that must be considered in such an application:

- How does the terrain affect the pressure loss profile?
- What happens to the performance of the system as production rates decline?
- Can the pipeline accommodate increased rates as the field grows?
- Are special measures required to prevent hydrate formation, wax deposition, or other pipe blockages?
- What happens to the temperatures if the pipeline is shut in?

When a multiphase pipeline is built in an area with significant terrain effects, hydrostatic head losses may be significant. When this is the case, although it may seem counter-intuitive, a smaller diameter pipe may lead to lower total pressure losses. Unlike single phase pipelines, the combination of frictional and hydrostatic pressure losses that occurs in multiphase flow means that a bigger pipeline does not always lead to reduced pressure losses.



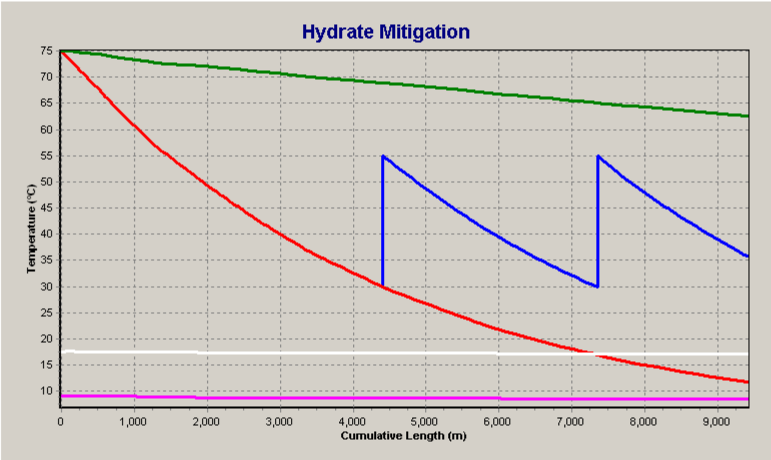
The example plot below shows the wellhead pressure at various flowrates for three different pipe sizes. The blue line represents an 8-inch pipe, where the wellhead pressure increases with the flow rate. This is the behaviour expected in most pipelines; it indicates that the predominant pressure losses result from friction.



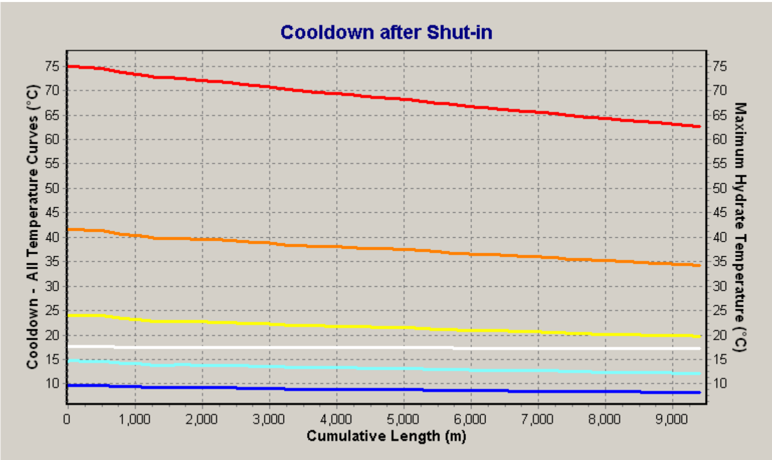
The green curve represents a 12-inch pipe. In this case, the wellhead pressure *decreases* with increasing flow rate, indicating that the pressure losses in the line result mostly from hydrostatic effects (i.e. liquid loading). Other results from **PIPEFLO** might indicate that the risk of corrosion is increased due to high liquid holdup and the resulting flow patterns. If the large line is selected because more gas production is expected in future, results from **PIPEFLO** could be used to size the slug catcher required for pigging operations and to design operational procedures for the start-up of additional production to avoid flooding downstream separation equipment.

The red curve represents a 10-inch pipe and includes a minimum flowing wellhead pressure at 1000 e^3sm^3/d; this marks the transition, beyond which the increase in frictional pressure loss due to an increase in the flow rate is greater than the corresponding decrease in pressure loss due to hydrostatic head (i.e. the rate at which the pressure losses become friction dominated). The 10-inch line appears to give the lowest and most stable pressure losses, but it is important to review other possible complications.

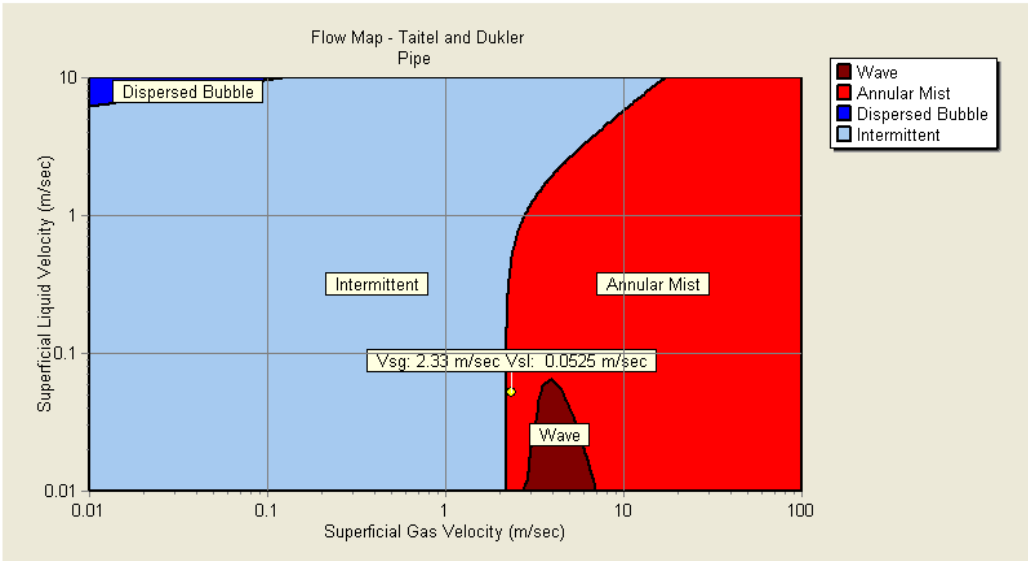
Thermal issues are also very important, as hydrate formation or wax deposition can reduce efficiency or even stop flow entirely. The plot below shows the unmitigated fluid temperature in red and the hydrate formation temperature in white, indicating a hydrate problem starting around 7200 m along the pipeline. The blue line shows the effect of adding two line heaters to keep the fluid temperature above 30°C. (A unique feature of **PIPEFLO** automatically locates facilities, in this case heaters, based on user-defined criteria.) The green line shows the effect of adding insulation to the pipe. The pink line shows the hydrate formation temperature when methanol is injected at the wellhead. Thus, **PIPEFLO** allows all of these scenarios (heating, insulation, and mitigation) to be analyzed with ease.



Operational issues may also be analyzed and dealt with using **PIPEFLO**. In the plot below, an insulated pipeline is shut in, and the operators want to know how long they have before hydrates start to form in the line. The white curve again represents the hydrate formation temperature, and the other curves represent the temperature profile at shut-in and every six hours thereafter. With this plot we can see that the pipeline must start flowing again or be purged within about twelve hours (the yellow line) to avoid hydrate formation. This result is based on a pseudo-transient calculation and is intended to give only a qualitative estimate of the timelines involved. Full transient simulations are required for a more accurate assessment.



PIPEFLO also has a variety of options to deal with slugging issues. Flow pattern maps can be generated, indicating the current operating conditions and the boundaries between flow patterns. In the example below, a pipe is currently experiencing annular mist flow but a small drop in the gas rate will shift the pipeline into intermittent (i.e. slug) flow. With this information, the engineer can take appropriate action to either prevent or accommodate slug flow. For example, it is likely that different corrosion mitigation techniques would be required if the pipeline were operating in slug flow rather than in annular mist flow.



A pigging slug calculation can be performed to estimate the size of the liquid slugs generated when pigging the line. **PIPEFLO** can also estimate the likelihood of severe slugs (which can damage equipment) forming in risers.

Using routines developed by BP, **PIPEFLO** can estimate the slug frequency, slug length, and bubble length under steady-state slugging conditions. For design purposes, both the mean and the more extreme 1 in 1000 values, the values most commonly used in industry, are provided for each.