Asset Management Services

Dynamic Simulation Services

Germanischer Lloyd – Service/Product Description
Dynamic Simulation Services

Service Title: Asset Management Services
Lead Practice: GL Asset Management (UK)

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Service Description and Values Generated:

Flow assurance is about ensuring the safe and economical supply, transport and processing of multiphase mixtures of gas, oil and water. As hydrocarbon production now increasingly comes from ageing reservoirs, marginal or deep water fields all with long subsea pipelines and commingling of fluids under extreme conditions, the need for flow assurance is more crucial than ever.

Germanischer Lloyd (GL) offers a multi-disciplinary consultancy service, based upon dynamic pipeline simulations, to predict the behaviour of produced fluids as they travel along pipeline. These can then be used to highlight any issue that could impact on production capacity and availability. Issues typically addressed include pipe sizing, liquid handling capacity and materials selection. Operating strategies to minimise liquid hold up and solids deposition (wax, hydrates or scale) can then be evaluated to determine their cost effectiveness. The block diagram in Figure 1 illustrates the areas that could be examined during a typical flow assurance modelling exercise. Each flow assurance exercise is tailored to meet the client’s exact requirements as these will vary depending on the composition of the produced fluids and whether the exercise is part of the design for a new field, a tieback to an existing system or a change of operating conditions.

Figure 1: Simplified block diagram of GL’s flow assurance capabilities
a. Transient Pipeline Operations (Ramp Up/Ramp Down)

GL can evaluate the operability issues associated with the start up and ramp up or ramp down and shut down of pipelines using transient simulations. To do this GL would:

- Input fluid compositions into HYSYS or PVTSim to generate representative model field and pipeline fluids with the correct liquid dropout characteristics.
- Set up an OLGA model with the appropriate well, pipeline and processing configuration.
- Run a parametric series of transient simulations to determine the effects of ramp up and ramp down on:
  - The pipeline flow and operating regimes illustrated in Figures 2 and 3.
  - Liquid hold up and the variation in liquid delivery that may occur.
  - The maximum aqueous and condensate delivery rates and the resulting slugcatcher capacity and draw off rates required.
  - Possible inhibitor starvation during flow ramp down.
  - The performance of the export system in the event of a gas leak.
  - Safe operating envelope limits, shown in Figure 4.

Figure 2: Flow regime map
b. Slugcatcher Sizing

Significant savings on CAPEX can be made by reducing the size of the slugcatcher needed to prevent liquid surges from pipelines upsetting processing equipment and halting production. To select the most appropriate slugcatcher, GL would:

- Use a compositional simulator such as PVTSim to generate representative model pipeline fluids that give realistic liquid dropouts
- Set up an OLGA pipeline model with the appropriate pipeline topography, materials of construction and insulation
- Run a series of OLGA pipeline simulations to:
  - Determine variations in liquid hold up as a function of flow rate as shown in Figure 5
  - Calculate liquid arrival rates
  - Compare liquid hold up, flow regime and elevation as illustrated in Figure 6 to show if slugging is predicted in the inclined sections of pipe
  - Run OLGA simulations with slugtracking to determine the liquid surge volumes at the pipe exit for various flow rates
  - Use the predicted surge volumes and arrival times, as illustrated in Figure 7, with different flow rates to determine minimum slugcatcher size requirements
Figure 5: Variation of liquid hold up with gas flow rate.

Figure 6: Liquid hold up, flow regime and elevation approaching pipeline exit.

Figure 7: Slugcatcher sizing
c. Hydrate Remediation

Hydrates can block pipelines, restricting production and increasing pipeline pressures, or they can block valves preventing the correct functioning of safety equipment. To assess whether hydrate formation is likely to be a problem, GL uses Infochem’s Multiflash programme to generate a hydrate dissociation curve. This is then compared to the pipeline temperatures and pressures to determine if hydrate formation is likely, as illustrated in Figure 8 below. Software predictions can be validated by laboratory testing for hydrates under pipeline conditions in GL’s hydrates test facilities.

The information generated can then be used to determine the amount of insulation or chemical inhibitor required (as illustrated in the Figure 8) to prevent hydrate formation.

d. Wax Prediction

Wax deposition can seriously reduce production rates, increase line or pumping pressures and prevent correct functioning of safety valves and other equipment. To prevent this from happening, the first step is to identify whether or not wax precipitation is likely to occur.

To do this our approach is to input fluid composition data into either industry standard or state of the art modelling software such as PVTsim or TUWAX to generate a wax phase line for that particular fluid. Ideally this wax phase line is then tuned to measure fluid wax appearance temperatures. The potential for wax to form in lines throughout field life is then assessed by comparing the actual or simulated pipeline temperature and pressure profiles, as illustrated in the Figures 9 and 10 below.

Figure 8: Hydrate Curves for a North Atlantic pipeline

Figure 9: Likelihood of wax formation in production lines in early life

Figure 10: Probability of wax formation in production lines in late life
Once the waxing tendency of the pipeline fluid is established, GL can then run pipeline simulators such as OLGA Wax or TU WAXPRO to calculate the location and thickness of wax build up as a function of time. The effect of wax build up on pressure during normal operations and following shut in can also be determined as shown in the Figure 11 below. The requirement for pipeline insulation, heating or chemical injection to prevent wax deposition can then be systematically investigated to determine the best most cost effective means of controlling wax deposition.

Figure 11: Wax deposition in pipeline simulations

e. HIPPS

Traditionally all subsea facilities were designed to withstand pressure equal to the maximum wellhead shut in pressure. For high pressure, deep water applications this meant using thicker walled more expensive pipe. By protecting process trains from overpressure in the event of restrictions in the export flowlines, High Integrity Pressure Protection Systems (HIPPS) allow flowlines and risers to be rated to lower pressures, enabling high pressure, deeper water fields to be developed more cost effectively.

To protect the system the HIPPS trigger pressures need to be set below the relief pressure but high enough above the normal operating pressure to avoid spurious shut downs and loss of production.

GL uses dynamic modelling to simulate the effects of shutting down gas flows from wells into the process chain when high pressure is detected. Trigger pressures can then be optimised for maximum productivity with least risk to the integrity of the system. The results in Figure 12 show that the HIPPS set point needs to be 1330 psig to protect the vent system from pressure relief at 1300 psig. If, however the header operating pressure is reduced to 1280 psig, then the HIPPS would no longer protect the system.

Figure 12: HIPPS trigger pressure calculations
f. Flare/Vent Modelling

Increasing hydrocarbon production is a way of increasing revenues but this may only be safely achieved if the vent and flare systems in place are able to cope with the additional throughput in the event of a blocked outlet.

GL uses transient modelling to determine the response within flare systems resulting from the action of the pressure safety valves (PSV) on production separators opening and closing. To do this we would set up an OLGA model, illustrated in Figure 13, of:

- Flowing wells, associated pipework, chokes and Subsea Safety Valves (SSV)
- Separator and PSV
- Gas lines linking wells to vessels and on to the export line
- HP flare system

The model is then benchmarked by comparing the calculated pressure drops across the flare tip against pressure data as in Figure 14. Pressures in Figure 15 (and temperatures) in the flare system in response to opening and closing of safety valves for various increased production scenarios can then be calculated. This information can then be used to determine the safe operating limits for the maximum production rate for a given PSV configuration.

![Figure 13: Complete OLGA model](image1)

![Figure 14: Comparison of pressures across vent tip](image2)

![Figure 15: Pressure variation in the flare system](image3)
g. Surge Analysis

**Surge Control**
GL offers advice on normal operating procedures such as start up, shut down, manifold switch and valve operation to minimise the pressure surge magnitude. MASP violations (and possible ruptures) can be avoided by having the correct operational procedure.

**Surge Protection**
Surge protection is required to protect the system integrity against failure under events beyond the operator’s control (power failure, emergency valve operation, accidents, operator error). GL’s Hydraulic Consulting team can simulate these events and the relief devices that are required to avoid MASP violations using SPS. We can recommend the device that best suits your needs (relief valve, rupture disk, rupture pin, surge tank) and the set pressures needed to protect your pipeline.

GL can help you save money by preventing MASP violations (which are reportable incidents) and possible pipe failure. We can also help you determine the most cost-effective solution for your pipeline.

Figure 16: Inspecting a surge relief valve

**Batch Tracking**
GL can run different batches (gasoline, jet fuel, crude, etc.) in the same pipeline simulator. This feature allows surge studies to take place for different equilibrium conditions. It can also be used for timing the batches in the pipeline so that the flying switches are correctly calibrated and product loss is kept to a minimum.

h. Sphereing Operations

One way to potentially reduce the liquid surge volumes that a slugcatcher would need to handle is by regular sphereing or pigging of the line. To determine if sphereing could be used, GL would first of all run a series of OLGA pipeline simulations to see if the amount of liquid holdup in the line is significant.

The results of the simulations in Figure 17 show that steady state production at 80 MMscfd of a gas condensate in this pipeline would ultimately result in a sizeable liquid hold up of 30,000 barrels. Further OLGA transient simulations would be used to show that increasing the flow rate in the pipeline from 80 to 150 MMscfd results in large liquid surge volumes at the processing facility that could potentially halt production.

Figure 17: Liquid hold up in pipelines
Then, to determine if regular pigging of the line could effectively reduce the liquid surge volume and therefore the slugcatcher size requirements, GL would carry out a parametric study using the OLGA transient pipeline simulator to determine:

- Slug size
- Optimum sphere size for bypass pigging
- Sphereing interval required to keep slug size below the slugcatcher volume
- Maximum flow rate at which sphereing can be effectively used to maintain liquid surge volumes within the minimum slugcatcher limits

The results of such a parametric study, illustrated in Figure 18 below, suggest that for spheres of less than 22.1 inches in diameter, the liquid discharge will not exceed the minimum slugcatcher volume of 1500 barrels when flowing at up to 150 MMscfd.

GL can also use WAXPRO or OLGA wax to estimate pigging frequencies for sphereing to remove wax deposits. As Figure 19 below illustrates, wax build up is likely to cause the pipeline pressure to fall below the minimal arrival pressure after 6 months so regular removal of wax at intervals of less than 6 months is needed.

Figure 18: Sphere sizing

Figure 19: Estimating pigging frequencies based on arrival pressures
CASE STUDIES

a. FEED Case Study

Date: 2004-06
Customer: North Sea Operator
Savings: Fully operational pipeline system

Issue:

A North Sea operator requested a flow assurance FEED study for their gas condensate field to identify optimum pipeline sizes and to investigate aspects of flow assurance within the infield and export pipelines.

GL were required to benchmark the current models against those used in previous studies and optimise the pipeline sizes given the latest reservoir models and hydrate control philosophy.

Methodology & Results:

The OLGA models previously created by the operator were reviewed and modifications made now that the design phase had progressed. The study demonstrated that the optimum pipeline sizes were a 16” export line and a 12” infield flowline. This was a change from the previous study undertaken where an 18” export line and 10” infield line had been recommended.

Having identified the optimum pipeline sizes steady state and transient simulations were performed to determine:

- The pipeline flow regimes and the variation in liquid delivery that may occur during slug flow
- The maximum aqueous and condensate delivery rates onshore and the resulting slugcatcher capacity and draw-off rates required
- The possibility for MEG starvation during flow ramp down cases
- The performance of the export system in the event of a gas leak

Slugging was predicted in the offshore section of the pipeline and although these slugs do not completely dissipate, the slug volume is well within the capacity of the slugcatcher.

A condensate processing rate of 38.4 m³/h was predicted to be adequate to limit the surge volume in the slugcatcher during flow ramp-ups and to process hydrocarbon liquids delivered at the maximum flow of 230 MMscfd.
OLGA predictions showed that Joule-Thompson cooling in the pipeline would lead to low gas temperatures (lower than 4°C ambient sea temperature). The hydrate curve predicted by Multiflash and the temperature/pressure profile through the export line were plotted to identify the potential for hydrate formation.

When ramping down the flow from 230 to 100 MMscfd, more water becomes condensed at the chokes, rather than along the pipeline as at the higher flow. Although this would cause dilution of the MEG at the start of the export pipe, this drop in MEG concentration would not be sufficient to lead to hydrate formation.

A leak of 24 MMscfd from a 21.6 mm hole should be reliably detected by the difference in gas flow readings at the wellhead wet gas meters and onshore fiscal metering.

A smaller leak of 5.3 MMscfd from a 10 mm hole is unlikely to be detected by either the offshore/onshore flow difference or pressure based systems.

In addition, further simulations were conducted to evaluate the MEG injection pipelines and to determine the size and capacity of the MEG storage and regeneration facility onshore.

Benefits:

The reduction in the 80km export pipeline diameter to 16” decreased the initial CAPEX of the development.

The transient simulations showed that the existing slugcatcher at shore was sufficient to handle the expected ramp-up rates without any modifications required.

GL were able to provide a continued support to the project and also worked on examining HAZOP actions, operating guidelines, hydrate inhibition strategy, new development options and ramp-up rates for reduced flow from one well only.
b. Life Studies

Date: 2008
Customer: North Sea Operator
Savings: Prolonged operation at lower flow rates

**Issue:**
An aging field was coming to the end of its productive life so the operator wished to optimise the extraction of the remaining gas and condensate. Different operational changes were simulated that could either allow higher levels of production from the declining wells or continued production at lower flow rates and pressures.

**Methodology & Results:**
Several possible changes to the current operation were investigated using OLGA multiphase simulator.

*Lowering the Onshore Arrival Pressure*
The required onshore arrival pressure had been limited so that the discharge pressure of the compressor was great enough to enter the NTS. However, due to the reduction in gas flow rate the required suction pressure for the compressor could also be reduced while still achieving the required discharge pressure. Reducing the onshore pressure provides a large pressure differential from the declining reservoir.

The simulations showed that there should not be any operational problems, such as liquid hold-up, slugging, excessive velocities, etc. associated with reducing the onshore pressure.

*Reducing the Low Flow Limits*
The original operating envelope had limited the total flow rate of the system due to liquid handling issues during ramp-ups from reduced flow rates back to the normal flow rate. However, this restriction no longer applied because the higher flow rates were not achievable. Hence, it was possible to decrease the flow rate to below this low flow limit.

The new low flow limits imposed were slug sizes of greater than 40 m³ (slugcatcher size) at the arrival terminal and a MEG hold-up of greater than 1000 m³ in the pipeline. OLGA predicted that flow rates down to 15 MMscf/d could be achieved before the MEG hold-up limit was exceeded. Although slugging increased throughout the pipeline as the flow rate was decreased, the slug sizes at the arrival terminal did not exceed 40 m³.
Periodic Gas Pigging
To achieve manageable surge volumes at the slugcatcher and lower FWHPs at reduced production rates, “gas pigging” can be employed to control the pipeline inventory. The pipeline can be operated at a lower flow rate then ramped-up at short notice if the pipeline liquid hold-up is not allowed to reach steady-state at the lower flow rate. A “gas pigging” cycle of 2 days would be required to prevent the surge volume from becoming too great during ramp-up.

Pressure Recovery
Shutting in production from a reservoir allows the pressure in that reservoir to partially recover. Upon restart of flow from the reservoir, higher production rates can be achieved before the pressure begins to decline further.

The simulations performed investigated the effect on the pipeline operation of shutting in one or both reservoirs for one week and then restarting production. When all the wells are shut-in or when only the richer wells are shut-in no problems were predicted with an instantaneous restart. However, when the leaner wells were shut-in for pressure recovery a 2 day restart was required to prevent the slugcatcher from slugging.

MEG Reduction
The current MEG requirement of 4 m3/h was defined to protect the main export pipeline from hydrates under a water breakthrough case of 400 bpd and worst case shut-in conditions. During current operation, the onshore terminal was experiencing a water arrival rate of ~100 bpd. Whilst it was still a valid strategy to protect against 400 bpd, at the late stage of field life protecting against a smaller margin above the current water production rate could have been more appropriate.

Hydrate calculations were performed in Multiflash and predicted that a MEG injection rate of 1.3 m3/h was required to protect against 100 bpd of produced water. This lower injection rate results in the liquid inventory of the system increasing slower during flow rate reduction and hence would result in a longer “gas pigging” frequency.

Benefits:
After completing the study the operator decided that the lowering of the arrival pressure and reduction in the low flow limits would provide them with the continued production for another 3-6 months.
c. Hydrate Control

Date: 2004-06  
Customer: North Sea Operator  
Savings: Reduced MEG requirement

Issue:

The gas-condensate fields are produced by a subsea development comprising three wellheads, a subsea manifold, and an 80km multiphase pipeline to shore. MEG is injected at the wellheads to prevent the formation of hydrates.

The conceptual design included venturi meters on each wellhead for gas production monitoring and wet gas meters on the subsea manifold for water breakthrough detection. A requirement for accurate measurement from the wet gas meter was a minimum liquid level: this was provided by excess MEG injection into each of the wellheads.

By the time the detailed design was under way, wet gas metering technology had progressed and there was the opportunity of simplifying the metering philosophy. Also, there was the opportunity of reducing the MEG injection rate to that required for hydrate prevention and reducing the size of the onshore MEG regeneration process accordingly.

Methodology & Results:

A study was undertaken by GL to review the MEG injection, water detection and metering requirements for gas condensate field.

The MEG injection rates required for hydrate prevention were calculated for a range of operating conditions using Multiflash. Subsea wet gas metering and water breakthrough technologies were reviewed. Meter operating envelopes, measurement sensitivity and measurement uncertainty were evaluated for the conceptual and revised arrangements. The functional specification for the wet gas flowmeter was reviewed and updated.

Benefits:

The study provided the operator with the information and confidence to change the metering philosophy. The conceptual arrangement of five meters of two different types at four locations has been replaced by a new arrangement of three meters of a single type at three locations. Wet gas meters will perform both production monitoring and water detection functions on individual wellheads. Uncertainty in breakthrough detection is improved as water breakthrough will now be attributed to individual wells rather than individual fields.

Improvements to the wet gas meter since the conceptual design means that MEG is no longer required for accurate meter operation: the MEG requirements therefore reduced to those required for hydrate inhibition and the onshore facilities have been reduced in size for the lower MEG flowrate.

The field has experienced no hydrate problems since it started producing.
d. Riser Slugging

Date: 2004
Customer: North Sea Operator
Savings: Reduced topside shutdowns

Issue:

A North Sea operator was experiencing problems with slugging in their risers coming up to an FPSO. The slugging was leading to 5-10 bar pressure oscillations at the top of the risers and 2-3 bar in the first stage separator. The accompanying swings in gas and liquid flow rates caused process trips and lost production.

Methodology & Results:

There are three types of slugging problems:

- Transient slugs generated by a rapid increase in gas flowrate and the liquid surge
- Hydrodynamic slugging arises from the flow regime in the pipeline
- Terrain/Severe Slugging due to the topography of the pipeline and flow conditions

GL created an OLGA model simulating the system. The model was run to match process data for the periods of slugging seen in the risers and the pressure drops throughout the system. Initial simulations failed to predict slugging – this suggested that the slugging was hydrodynamic rather than riser slugging and the OLGA slug tracking model was used in subsequent simulations.

This successfully reproduced process conditions and the model was then used to perform a parametric study which varied:

- Total liquid rate
- Water rate
- Gas lift rate
- Friction rate (to simulate effect of a drag reducing agent)

A further series of simulations looked at use of chokes at the top of the risers as a means of reducing the slugging severity.

Benefits:

The study demonstrated that the pressure swings seen at the top of the risers was being cause by hydrodynamic rather than severe/terrain slugging and that the separator could handle liquid surges provided it was left in automatic control (it was currently being operated in manual).

High gas and liquid flowrates would be released from the separator for short periods which could cause operational problems downstream of the separator.

Mean slug sizes could be reduced by setting the topside chokes to 20%, but this would need to be offset against production losses.

It was demonstrated that the use of drag reducing agents had minimal effect on the slug sizes at the top of the risers.
e. Subsea Tieback Feasibility Study

Date: 2007
Customer: North Sea Operator
Savings: Optimum pipeline design

Issue:
A North Sea operator commissioned GL to evaluate a range of development options for the production of a Gas-Condensate discovery. The field was located in an area where there is both existing infrastructure and a number of undeveloped discoveries.

The study examined the flow assurance issues associated with a tie-back into existing facilities. The pressure drop, liquid hold-up, hydrate potential, corrosion inhibition and fluid compatibilities were all examined.

Methodology & Results:
Information was selected from the Facilities Study Scope of Work Document and the well test reports. This was then combined with other data and assumptions to form the basis of the cases which were simulated.

The following scenarios were analysed:
- Straight to shore through an 80km pipeline
- Via an 8km tie-back to an FPSO
- Via a 20km tie-back to a different FPSO
- Via a 40km tie-back to an existing flowline

Start-of-life, mid-life and end-of-life flow rates were also considered for each development option.

Steady state simulations were performed (using the OLGAS calculation in HYSYS/PIPESYS) to examine the pressure profile; liquid hold-up; and temperature profile. This data was then analysed to produce an optimum pipe size for each development taking into account the available pressure drop; hydrate issues; flow regime; and erosion and corrosion analysis.

Benefits:
The most attractive route for the production of the fluids was through the 8km tieback to the FPSO. This option presented no concerns with ramp-up rates or slugging and hydrates would be manageable using inhibitors such as MEG, Methanol or an anti-agglomerant.
f. Wax and Asphaltene Deposition Assessment

Date: 2008  
Customer: Caspian Region Field Operator  
Savings: Recommendation of mitigation strategy for pipeline operations

Issue:

GL was commissioned to assess the potential for wax and asphaltene deposition to occur in support of the Front-End Engineering Design (FEED) of a new phase in the development of the existing gas-oil-condensate field.

The Phase development required the installation of a new gathering system, which consists of 65 wells connected to 13 remote manifold stations (RMS) each with a dedicated trunkline back to reception facilities. The existing export pipeline was also modified to cope with the increased production from the new development.

The study concentrated on the formation potential of waxes and asphaltenes on the pipelines and process equipments and subsequent recommendation of mitigation strategies and pipeline operating philosophy.

Methodology & Results:

Well fluid compositional data and pipeline operating conditions were supplied by the client, and were combined with other data and assumptions to get the input data required for the modelling.

The modelling was conducted for start-of-life, mid-life and end-of-life compositions under summer and winter conditions. The analysis entailed:

- Wax Appearance Temperature (WAT) calculations for the representative field fluid streams using Tulsa Wax (TUWAX)
- Generating wax phase lines (WAT as a function of pressure)
- Determination of pressure and temperature profiles using PIPEFLO for the flowlines, trunklines, infield lines and export line
- Identification of pipelines at risk of wax deposition.
- Wax deposition calculations for pipelines identified to be at risk using MSI WaxPro
- Wax deposition mitigation sensitivity modelling looking at the effect of wax deposition inhibitors
- Asphaltene precipitation prediction using Multiflash

Comparison of pipeline pressure and temperature profile versus WAT

Benefits:

Optimising the pigging frequency to keep the wax deposition in the pipelines at minimal amounts means that minimal disruption and production losses are experienced.

The study also showed that the pigging was as effective as either inhibition or pipeline insulation saving the client in both CAPEX and OPEX.
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