SHELL FLAGS INSPECTION CASE STUDY

J. Nonemaker, Solution Engineer, ROSEN
T. Steinvoorte, Business Development, ROSEN
R. Subramanian, Pipelines & Subsea Technical Support Engineer, Shell U.K. Limited

Introduction

In-line inspection of offshore pipelines is a challenging task for several reasons, including:

- Many pipelines that were not designed to be piggable, now require inspection
- Change in operating conditions resulting in ultra-low flows and pipelines with bore restrictions
- Presence of in-line components including non-return valves, hot tap tees, etc.
- Demand for reduced operational impact as a result of pigging operations

Offshore pipelines distinguish themselves from onshore lines because external reference measurements and local repairs are often complex and challenging. Furthermore, inspecting offshore pipelines is often more demanding because of logistics, accessibility, and cost.

Consequently, tool performance, first run success, risk mitigation and operational impact are key factors to be considered when selecting an inspection solution. Additionally, in order to successfully execute these inspections, expertise from both the operator and inspection contractor, need to be combined in a multidisciplinary team that operates as 'one team' and establishes the confidence and trust in each other to make the correct decisions.

This paper will discuss a recent example of such a challenge: the successful inspection of a key Shell U.K. Limited (Shell) pipeline in the North Sea, which required a bespoke solution to overcome the pigging challenges associated with this pipeline.

The Challenge

The Far North Liquids and Associated Gas System (FLAGS) is an offshore 36" x 450 km pipeline which runs from the Brent B platform to the St. Fergus gas terminal in Scotland. It was commissioned in 1983 and had been in-line inspected on two previous occasions. It was due for the next ILI inspection in 2026. However, due to the decommissioning of the Brent platforms, Shell required an in-line inspection whilst still having topsides launch capability and no subsea pigging operations. This resulted in a step change increase in risk, cost and complexity. The pipeline layout is shown in Figure 1.

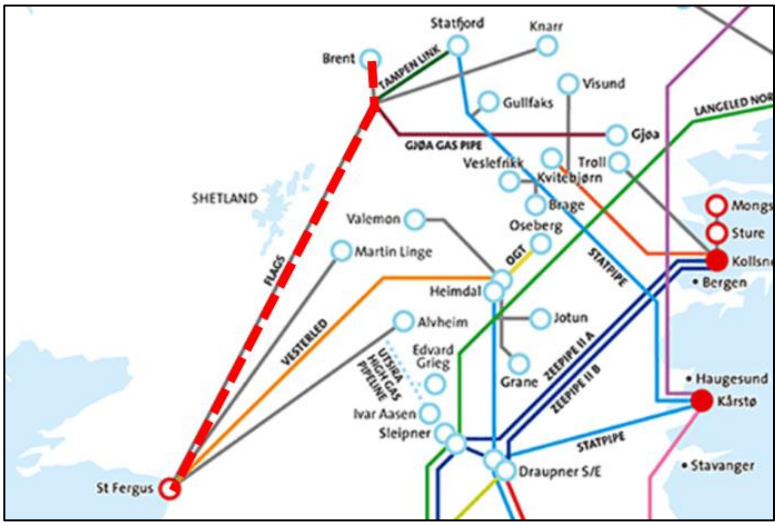

Figure 1: FLAGS pipeline layout (red dotted line)

Although the FLAGS pipeline had been in-line inspected before, changes in operating conditions and the addition of a hot tap tee in the system made the inspection task a unique, industry-first challenge. The inspection solution had to overcome:

- Ultra-low flow of gas at inlet ~ 0.05 m/s
- Presence of a non-return clapper valve which could not be locked open. Clapper has a weight of 750 kg.
- High side flow where the gas enters the pipeline with a speed of approximately 15 m/s through the hot tap tee (HTT)
- High speed and heavy wall thickness downstream of the HTT

The pipeline configuration can be found in Figure 2.

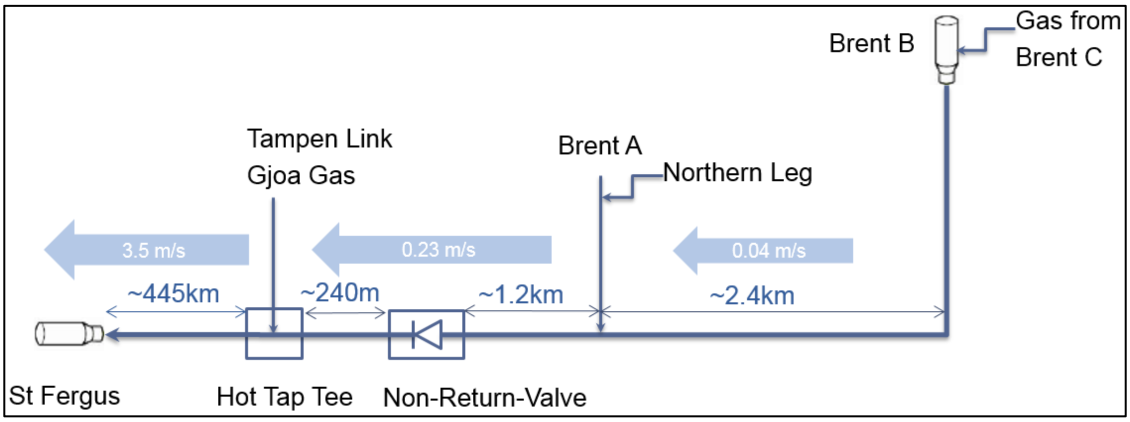

Figure 2: Pipeline configuration

The Solution

ROSEN's overall approach to the inspection solution was to provide a ruggedized MFL tool that could perform in the low and high-flow pipeline sections, as well as traverse the check valve and hot tap tee side flow without any damage to any of the elements that would results in sub-optimal tool performance.

The main risk associated with low-flow inspections is a stationary tool due to insufficient sealing capacity. Because of the low flow, a small amount of gas bypass over the tool could cause the tool to stop. The engineers therefore designed customized pulling units for the MFL tool and the cleaning/gauging pig that decreased gas bypass to an absolute minimum.

The dual-body MFL tool design included protective frames and bumpers to allow the tool to push open the check valve and traverse without becoming damaged or getting caught by the valve clapper. The engineers developed a similar cleaning and gauging pig that would prevent the gauge plate from being damaged by the clapper. The magnetization of the MFL tool was increased to ensure full measurement specifications for the nominal pipe thickness at speeds of up to 3.5 m/s.

Because of the challenging nature of the inspection, the tool designs had sufficient contingency. A safety factor of 8 was used to ensure the MFL tool could provide enough drive force to push open the check valve. The tools could perform to speeds as low as 0.01 m/s, lower than the expected minimum in the pipeline (0.05 m/s). Furthermore, the modules of the MFL tool and the cleaning/gauging pig were designed to ensure they would still be functional if the modules separated, i.e. resulting from a joint break at the HTT due to exposure to high side flow. The electronics were placed inside the MFL measurement module so that a joint break between the pull unit and measurement module would still allow the module to record data. For further contingency, in the unlikely event that a tool became lodged, a rescue pig was available on standby.

A comprehensive testing program was performed to confirm ROSEN's tool design:

- Differential pressure evaluation tests to determine the friction characteristics and confirm the sealing performance.
- Pump tests with a large side flow in the test loop simulating the high speed inflow at the hot tap tee (Figure 3).
- Pull tests through a mock check valve in order to determine the gauge/cleaning and MFL tools could open it without becoming damaged (Figure 4).
- Tensile test program on the newly developed ultra-strong flexible joint (Figure 5). It was expected that the side flow would cause a force of 60 KN (60 ton) on the joint. During the test it failed at 111 tons.
- High-speed pull tests as part of the final tool acceptance checks as well as to validate and calibrate the magnet setup.

The initial risk assessment revealed a theoretical risk of a reversed flow resulting in the tool moving backwards in the pipeline. This situation would occur in case of a platform shutdown, after which gas would be removed from the pipeline to restart the platform. During the first MFL tool design, solid brushes on the MFL tool were included because they improve the tool's bi-directional capability. However, during testing, excessive wear was observed on these brushes, which forced the engineers to reconsider the design and adjust the inspection schedule. After an in-depth assessment of the issue, a change to lamella brushes was proven suitable and was selected for the final tool design. The risk of tools running backwards was mitigated by establishing operational procedures that prevented removing gas from the pipeline that would result in a reversed flow.

Figure 3: Side-flow test setup

Figure 4: MFL tool during check valve testing

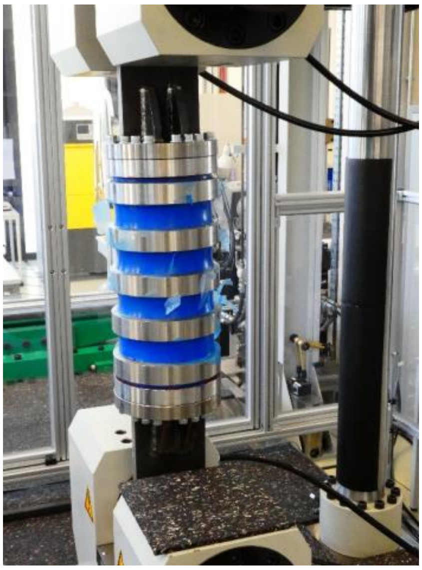

Figure 5: Stiff joint tensile test

The Field Work

After all testing was completed the inspection team mobilized to the platform in November 2016 and launched the cleaning and gauging pig. It was received after 59 hours and 53 minutes. The pig brought out little debris from the pipeline and there was no significant damage to the gauge plate or the tool body. These results led to the conclusion that there were no major risks associated with launching the intelligent tool. The MFL tool was mobilized to site in January 2017 and launched. It arrived at the receiver 60 hours and 6 minutes after launch.

Figure 6 shows the MFL tool velocity profile along the full pipeline. The tool was initially in the low-flow pipeline section, as indicated in Figure 7. For the first two kilometers, the tool had an average speed of ~0.1 m/s, but then the velocity rose sharply at the HTT. After passing the tee, the velocity steadily increased as the pressure along the pipeline decreased.

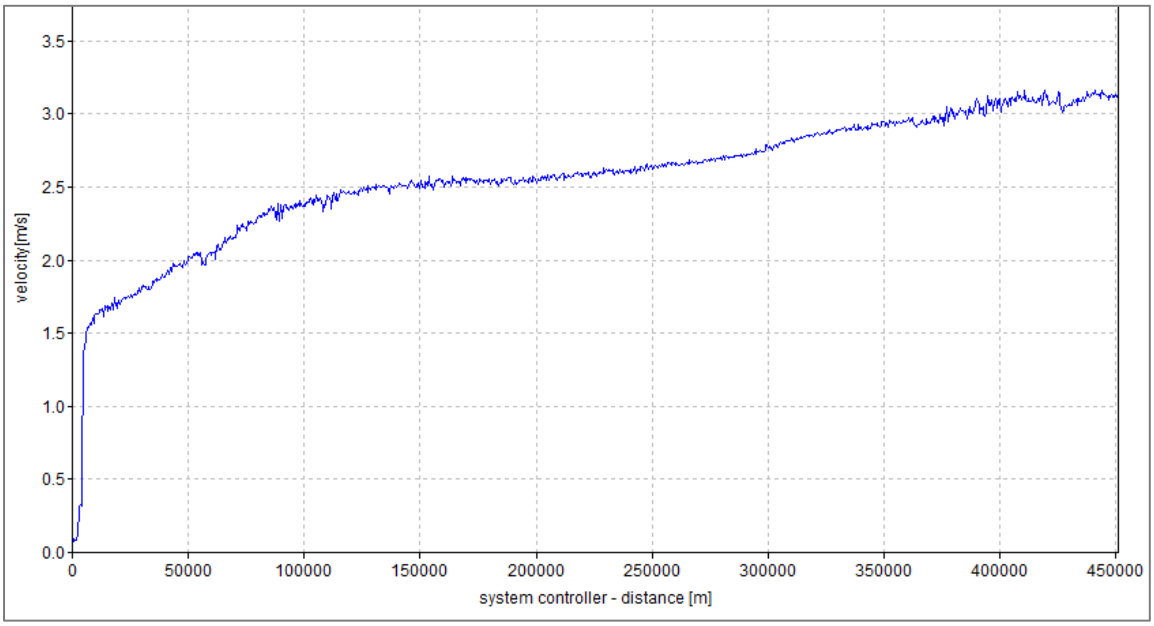

Figure 6: Tool velocity across pipeline

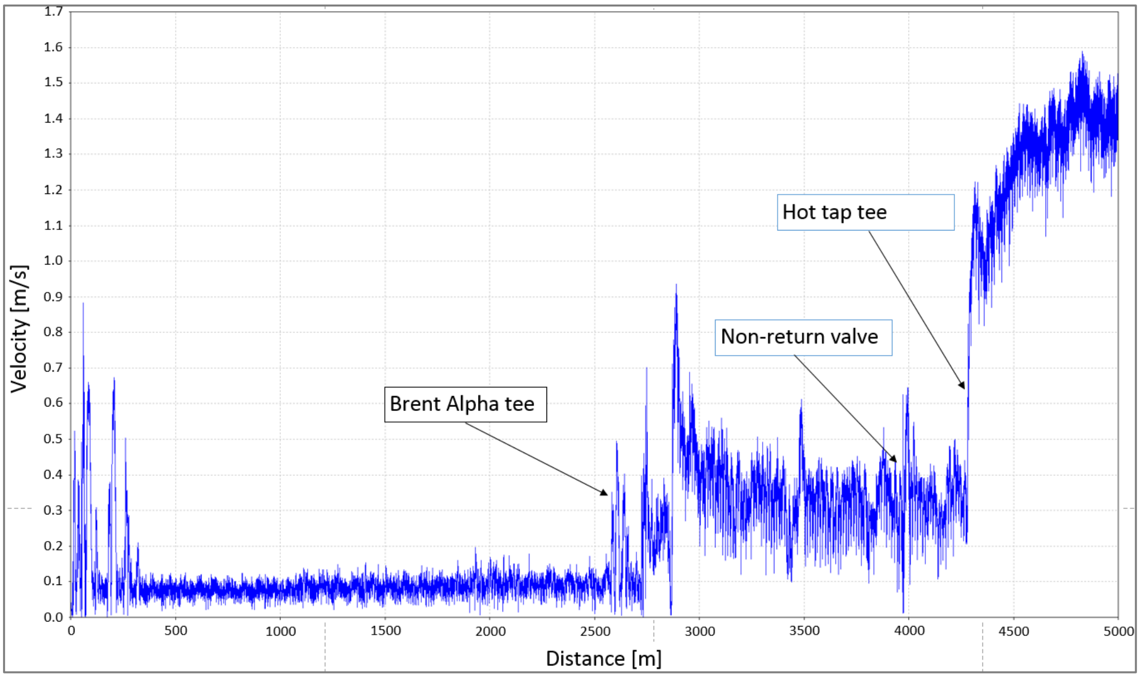

Figure 7: Tool velocity in low-flow section

To support the FLAGS activities, Shell built a Compas/USD model. The scope of the model included the main FLAGS pipeline and the Gjoa-Vega and Tampen Link pipelines, and all the associated export flows. The model schematic is shown in Figure 8.

During the actual runs, the model was used in the PI connected mode to track the tools from launch at Brent B to receipt at St. Fergus. Filtered real-time PI data was brought into the model by means of a PI Read spreadsheet. Export flows and the pressure at St. Fergus were used directly as inputs at the model boundaries, and the export pressures and St. Fergus flows were plotted against model calculated values to monitor the model performance.

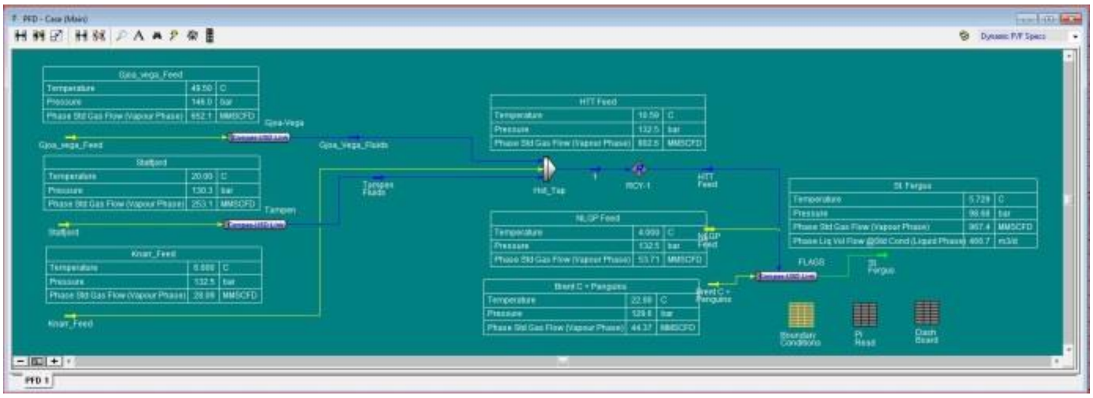

Figure 8: Compas/USD model schematic

Although it would have been possible to infer the progress of the pig(s) through the system from the flow and pressure conditions, the model provided this information in a simple format. A dashboard was developed to show the pig progress and the estimated arrival times at key points in the system (valve assembly spool piece, HTT, and St. Fergus).

Another advantage of the model was the ability to manage unexpected deviations from the operating plans during the pigging runs. Although it was not required, the model could have been used to provide advice to the operations control center to recover from such an event in an efficient way.

The performance of the model was excellent and the predicted pig arrival times at St Fergus were very much in line with the run in the field (1 hour over prediction for the cleaning pig and 20 minutes under prediction for MFL tool).

Result

Thanks to the diligent efforts of the project team, the project was executed safely, with a first-time success, on budget, and with minimal impact to normal operations.

The engineers were able to qualify the MFL tool for speeds as low as 0.01 m/s and that the chosen polyurethane setup is suitable for the pipeline conditions. Low wear on the discs was observed, meaning that the MFL tool could theoretically have been rerun without exchanging polyurethane. In addition, the engineers demonstrated that reliable testing programs can be developed for low-flow gas conditions and an array of mechanical and operational challenges.

The Shell and Rosen personnel operated as one team to identify, embrace, and overcome inspection challenges in a systematic manner. This was achieved by applying success factors such as value driver identification, rigorous planning, onshore testing, risk identification and mitigation, and proactive stakeholder engagement.