Case study

Clearing an unexpected hurdle during pipeline decommissioning

Systems expertise, combined with pinpoint project planning, coordination, and execution, were key to safely and efficiently incinerating all evacuated gas during an offshore platform decommissioning project in the UK North Sea.

Challenge

Baker Hughes, Process & Pipeline Services (PPS) was contracted to enable displacement of several offshore pipelines in the UK North Sea as part of the decommissioning campaign for an offshore gas platform.

The original plan was for natural gas, condensate and contaminated water to be displaced with seawater and routed into the onshore gas terminal's slug catchers, where the pipeline terminated.

Phase I displaced the 7 km infield lines (16" and 3") into the 66 km export line (24"). Phase II required all liquids from the export line and the methanol line to be reinjected into offshore wells at pressure. These considerable distances meant that a high pressure pump would be required onshore, using the gas terminal's existing receiving facilities to separate liquids for reinjection to the offshore wells.

But Phase II hit a major challenge when the gas terminal's receiving facilities (slug catcher and flare system) were decommissioned before the land-terminating lines could be pigged—leaving the project with no gas separation or flaring facilities.

Solution

We designed a unique temporary receiving facility — including a high capacity filtration unit, separator, flare column, and tank farm — to provide flaring and separation services for the project. The facility included:

- High pressure, high flow filtration
- Temporary gas-liquid separation
- High flow temporary flare column
- Onshore liquid storage tank farm
- A complete suite of actuated control and safety instruments

Use of the separator and flare column, in particular, in conjunction with the pigging operation was highly unusual, requiring specific safety considerations and automatic trip systems to be specified and procured.

Typically, a decommissioning project would utilize the customer's permanent facilities, which would be more than adequately sized. However, when they become unavailable, as on this project, major hazards must be managed — such as very large flammable gas volumes and risk of liquid surges entering the flare.

There were a range of pressure ratings across the setup, for instance, there could be no pressure at the tanks, moderate pressure at the separator, minimal pressure at the flare, etc. So, we designed a control system to ensure no component could be overpressurized, and that the separator could not overflow. Individually these were standard arrangements but were a unique combination as part of an autonomously functioning temporary receiving facility.

38,000 L separator complete with emergency shutdown valve (70% liquid level and 5.2 barg high-pressure ceiling) and large-diameter, pressure-regulating valves. Approximately 20,000 sm^3 of gas passed through this unit, removing over 400 m^3 of condensate and contaminated liquids

10 temporary storage tanks (70 m^3 each) contained discharged liquids before well reinjection

We worked closely with all suppliers to ensure precise equipment specification and reliability so the temporary receiving facility would be virtually autonomous and able to respond to undesirable events faster than a human operator.

Accelerated operation
The customer had another scope of work taking place offshore before this project and wanted that particular crew to remain on site and immediately transfer to our project. We mobilized a PPS engineer offshore to work with the customer's operational team, to harmonize procedures, and provide a thorough pre-job crew briefing to ensure a seamless transition.

Flaring window
Regulators had approved a very strict four day window for flaring, and close coordination with specialized equipment suppliers ensured this could be achieved.

Intermittent flaring
To optimize safety, the flare column had to remain live throughout the operation. To mitigate the risk of low gas-flow leading to a flame-out scenario, we mandated a permanent propane pilot flame as well as automatic trip systems, thereby preventing the release of flammable or toxic gases should the flame go out.

Multi-phase pigging
We expected high gas flow at the start of operation, and high liquid flow at the end. We therefore placed additional automatic shutdowns to prevent separator overflow and procedural steps to manage the change in displaced fluid phase over the course of the operation.

Temporary flare column operating with permanent pilot flame, flame-out emergency shutdown, and LP pressure-regulating valve to allow pigging to continue at higher pressure

Benefits

Before we proposed our solution, the customer was seriously considering the worst case scenario of venting the gas to atmosphere, which would have been a major safety hazard and released a significant quantity of greenhouse gas (methane). Our solution safely incinerated all evacuated gas.

We planned for all offshore work to be completed in daylight hours only, and specified equipment to facilitate the flowrates needed to enable this. Oil-in-water acceptance criteria were met at all locations.

Baker Hughes