As the price of oil remains depressed worldwide, pressure increases on existing pipeline systems to ensure delivery of fluids in the most cost effective and dependable means possible. Whether lines are onshore or offshore, feedstock or product, maintaining or expanding capabilities is increasingly important, with the mantra ‘more for less’ but also ‘for longer’ often cited. Existing pipelines are having their design lives extended and others are having their uses changed (e.g., oil production to water injection) to drive the economics of recovery in the proper direction. Mature systems are producing fluids with properties differing from those for which they were designed, while new lines are becoming longer, deeper, higher pressure, and more exotic in material than ever before. Added to this mix are a global drive on pipeline regulation and the need for regular inspection, which have become the norm. All of these factors — and more — have created new challenges for pipeline operators and those service companies associated with pipeline integrity and flow assurance. Maintaining or increasing flow, cleaning for inspection, and coping with ‘unpiggable’ systems are everyday issues.

Typical deposits found inside operational oil and gas pipelines include — but are not limited to — salts and scales, corrosion products (including ‘black powder’), paraffin wax, asphaltenes, hydrates, sand and well fines, naphthenates, emulsions, sludge, and water. Many of the deposits come from the transported fluids themselves while others can be caused by chemical reactions between fluids and system metallurgy or through a combination of different fluids in transport lines. Regardless of their origin, their deposition in a pipeline is not preferred and can lead to issues, such as increased back pressures, decreased flow, reduced system reliability, and the risk of full or partial blockage. As a result, product quality is negatively impacted, operational expenditures (OPEX) rise, and correspondingly, profitability decreases.

In many circumstances, deposits are managed through regular ‘maintenance pigging’; that is to say, pipeline pigs are run at regular intervals through the line to remove debris before it can become an issue. Other lines, however, are never pigged until there is a requirement to do so, such as for internal inspection or because of negative impacts on flow regime. Whatever the scenario, there is associated risk. For the former, there is a risk that pigging is too frequent and therefore not at optimum efficiency. In other words, the pigging interval can be increased without significant probability of impeding flow or running the risk of a pig becoming stuck when it is eventually run. For the latter, there is always the risk of any pig being run becoming stuck because of unknown quantities of debris within the flowline or a poor choice of pig. In the current arena, the goal is to be able to evaluate what is in the line before launching any intrusive tool to help mitigate and manage the associated risks.

Knowing which deposits are present, where those deposits are located, and the quantity of the deposits inside the line are key to devising the best strategy, not only for cleaning the pipeline but also for handling what comes out of the line at the receiving end, to help minimise the risk of clogging or damaging the process plant downstream.

Non-intrusive technologies are currently available that can be used to determine some of the ‘unknowns’ related to the pipeline internal condition. This added knowledge helps allow informed decisions to be made.

Magnetic resonance imaging (MRI) type tools can be attached to a pipeline, effectively detailing a ‘slice’ through a cross-section at a given point. These provide a good definition of deposition profile and can even yield information related to deposit density, which helps determine the type of deposit present. This information, coupled with knowledge of what is being produced, can help identify the deposit composition as well as the size and location. There are drawbacks, however, as the ‘slices’ can be very small in length, making the process of scanning an entire line time-consuming and potentially cost prohibitive. In any pipeline articles use clichés alluding to the importance of pipeline infrastructure to convey production fluids and finished products to market. Imagery related to blood flowing through arteries has been used to convey the vital role pipelines play in the global energy market. Recent world events have further re-enforced this notion, as political and economic climates are at the very forefront of shaping the infrastructure of the future, with high profile projects shelved and new partnerships forged between governments relating to developing and expanding pipeline systems.
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Time of flight (TOF) surveys have been used for years, in which a suitable tracer is introduced into the flow within a pipeline, and the time taken for that tracer to pass a fixed point is measured. The time difference between the theoretical time to traverse the distance and the actual measured time (at the pipeline fixed flow rate) is then used to calculate the actual hydraulic diameter of the pipeline. This information is, in turn, used to calculate the volume of a deposit within the line (theoretical hydraulic diameter - calculated hydraulic diameter). Drawbacks exist with this methodology, though. The calculated volumes are averaged over the distance of the monitoring. For example, if the tracer is only monitored inlet to outlet, the hydraulic diameter would be averaged over the entire length of the line; in other words, it would not be possible to differentiate between the two extremes shown in Figure 1 or anything in between.

This can be mitigated by introducing multiple monitoring points at regular intervals; however, this can lead to access issues in buried or offshore pipelines as well as increase the cost of the operation. Another potential issue is choice of tracer used. It should be possible to monitor the tracer from outside of the pipeline, such as when using a radioactive fluid or including radio frequency identification (RFID). However, if monitoring at certain points in the line (e.g., by means of a suitable offtake that is routed safely to continued production) is required, then dyed fluids or gels can be used, but downstream fluid compatibility is also a consideration. A TOF survey, while effective at quantifying, will not determine the nature of any deposit in the line, but this might be known already from production data and production history. If the deposit composition is not known, a TOF survey can be used in conjunction with obtained samples to help provide some missing information.

Another viable non-intrusive technology for debris deposition analysis is the use of a pressure pulse (PP) survey. In flowing conditions, a PP is introduced into the flowline, typically by closing a valve. The impulse travels through the fluid within the line at the speed of sound, and high-fidelity rapid sampling pressure transducers measure responses resulting from internal reflections. By tuning out background noise through the use of proprietary algorithms, the time for the reflection can be translated into a pipeline distance, and the pressure variations of the return signal are related to hydraulic diameter changes. As such, an internal ‘map’ of the line can be generated. This operation is easy to perform, with minimal personnel, a simple set up, and a minimal interruption of product flow required; however, as with the other methods listed, limitations exist.

Homogenous liquid with limited gas content is required to produce reliable data. In addition, the proper flow conditions and system geometry must be present to perform successful surveys, and the ability to create a clear pulse through a quick closing valve is key to obtaining a ‘clean’ survey. Just as with a TOF survey, PP surveys do not identify the deposit type; however, as with TOF surveys, this can be determined through either production history or sampling.

The industry is a long way from achieving a ‘one-size-fits-all’ off-the-shelf solution that definitively determines the composition, volume, and location of deposits in pipelines. Each solution has advantages and limitations. The best compromise between cost, risk, and accuracy should be considered for each line to allow informed decisions on future strategies for pigging regimes for pipeline cleaning.

Figure 1: Extreme examples of deposit formations.

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