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Low-Dose Hydrate Inhibitors Save Flow-Assurance Costs

Axel Bokiba, Published May 2016

This option replaces traditional topside practices, freeing space and increasing efficiency.

Flow-assurance chemicals are typically fed from supply tanks on FPSOs and are metered via surface-dedicated chemical injection pumps. (Images courtesy of IDEX Corporation)

As oil and gas prices remain low and long-range forecasts continue to dip, offshore producers seek every opportunity to bolster efficiency and lower the break-even point (BEP) for production. The best practices associated with flow assurance in offshore environments are evolving. Costs and limitations that affect topside operations can be overcome by metering chemicals directly from the sea floor. These efficiencies, however, can only be realized through technology that can withstand harsh subsea environments.

Low-dose hydrate inhibitors (LDHIs) metered directly from the sea floor could perform just as well as traditional topside flow assurance practices—with substantial cost savings and efficiency benefits. But pumps used to deliver chemicals must adhere to certain criteria to withstand the unique challenges of the sea floor environment.

A Quick Primer on Flow Assurance

The goals of flow assurance are to prevent oil from cooling and to ensure its fluidity from the reservoir to the surface. One of the biggest issues for offshore production is the formation of hydrates. Hydrates form when light hydrocarbons and water mix under high pressures and low temperatures. Hydrates restrict flow and can form solid plugs that block production and damage equipment.

Because remediation can be time-consuming, expensive and dangerous (to people, equipment and the environment), a sound strategy for managing hydrates and providing uninterrupted production is critical. Hydrate formation is best mitigated with the help of chemical inhibitors. There are two primary methods of chemical inhibition.

Thermodynamic Inhibitors

Thermodynamic inhibitors (TIs) such as methanol are used for most offshore operations. They work by shifting the hydrate equilibrium curve and lowering hydrate equilibrium temperatures to a point where hydrates cannot form. TIs require high injection rates and high volume—in some cases, more than 60 percent (or 4 barrels [bbls] of methanol injection for every 6 bbls of produced water) to prevent hydrate formation. Large quantities of methanol must be stored topside, consuming valuable space on the floating production, storage and offloading (FPSO) vessel or platform, and they need to be replenished regularly.

Despite the high quantities required, flow-assurance chemicals like methanol remain effective under most conditions. In an industry where the adage "if it's not broken, don't fix it" has always applied, few offshore producers have considered the topside storage (and regular replenishment) of methanol stocks a major concern. Until recently, the price of oil remained above the BEP for offshore production, so few operators viewed flow-assurance chemicals as a possible opportunity for cost cutting.

But today, and in the foreseeable future, oil prices may remain below the current BEPs for offshore production. More important, production activities in deeper waters must address harsher conditions, and they require longer subsea tiebacks (especially for FPSOs with lines that stretch horizontally, in some cases over a dozen miles on the seabed, under hydrate-forming conditions). These conditions exacerbate the challenges that come with using TIs for flow assurance. All of this has led producers to examine the role of LDHIs as a better alternative for flow assurance in deepwater operations.

Low-Dose Hydrate Inhibitors

Unlike TIs, LDHIs do not significantly change the hydrate equilibrium curve. They operate on completely different mechanisms. Although LDHIs are used sporadically, they are gaining popularity. LDHIs require far lower injection rates (of 0.5 to 2.0 percent by volume) and are much more cost-effective and practical when used properly. There are two types of LDHIs: kinetic hydrate inhibitors (KHIs) and anti-agglomerates (AAs).

KHIs are typically water soluble, low molecular weight polymers whose active groups interfere with the nucleation and growth of hydrate crystals. KHIs delay hydrate formation for a length of time, known as the hold time or induction time. The length of the hold time (which can vary from a few hours to several days) depends on the composition of hydrocarbons and water and is primarily determined by the sub-cooling of the system, with higher sub-cooling resulting in shorter hold times. Because KHIs operate on a time-dependent mechanism, they are not always practical in systems that experience long shut-in conditions. KHIs are independent of water cut and provide excellent temperature compatibility.

AA hydrate inhibitors are surface active molecules that attach to fine hydrate particles to prevent them from sticking together and growing into masses that could become a plug. When small hydrate crystals begin to form, AA molecules attach their hydrophilic ends to the hydrate, which changes the hydrophobic structure and disperses fine particles into the oil layer (and out of contact with water). This creates a transportable slurry with tiny hydrate particles that can flow all the way to the processing facilities. Although AAs have limitations, such as water cut and topside emulsion formation, they are generally considered to be more effective in higher-salinity brines. AAs work independently of sub-cooling, and they do not require any hold/induction time.

Today, engineers are dedicating extensive research to formulating newer and better LDHIs. Because they require less product volume than traditional TIs for flow assurance (2 percent versus 60 percent per volume), they are less expensive to transport. They require a smaller platform footprint, and their use results in easier separation and less product contamination downstream.

As a result, many of the latest offshore production systems are being designed with LDHIs as the primary hydrate control system. In the years ahead, more and more subsea delivery systems that leverage LDHIs will be built, provided that the following criteria can be met.

Low Flow/High Pressure

Because deepwater reservoir pressures can exceed 25,000 pounds per square inch, overcoming high pressures will always be important for pumping equipment. Traditionally, a point-to-point chemical injection architecture has been used for subsea chemical injection systems where accuracy and reliability are required. In other cases, a ring main architecture is used.

With point-to-point injection architectures, chemicals are fed from a chemical supply tank on the FPSO vessel and are metered

Space and weight are critical concerns topside. Moving flow-assurance operations off of the platform creates significant savings.

using a surface-dedicated chemical injection metering pump. They are transported subsea via a dedicated umbilical to the specific injection point on the production system.

With a ring main injection architecture, the chemical injection system is distributed. The chemicals are fed from a surface chemical injection tank through an injection pump/large umbilical that can supply all of the chemical needs subsea. From there, they are split into various subsea branches, and the chemicals are metered using an injection rate control device (IRCD) or chemical injection metering valves to the specific subsea injection points. The injection points serviced by these systems can be downhole on the production well, at the subsea tree or on the manifold, depending on the chemical requirements and well risks. But in any case, the chemical tank on the topside platform would be much smaller, lighter and far less costly, thanks to the LDHI low-flow injection requirements.

Footprint

Space and weight are critical concerns. When platforms are built, the amount of steel required to support the platform and everything on it (both above and below the waterline) is carefully calculated. Each ton of equipment requires a ton of support steel topside and one below the waterline. Removing a single ton of pumping equipment enables engineering, procurement and construction (EPC) providers to reduce the weight of the entire platform by up to 4 tons. If an offshore platform costs $30,000 per ton to build, then removing a metering pump from the deck surface can save up to $120,000 for each pump. The same equation holds true for the weight of the tanks required to store the vast quantities of methanol or other TI flow-assurance chemicals, illustrating a further savings that can be extracted by switching to LDHIs.

Accuracy

Accuracy is critical regardless of where the chemicals are metered, and pumps at the seabed must be American Petroleum Institute (API) 675 compliant. However, the use of LDHIs on the sea floor helps to simplify matters. Traditional metering of methanol topside requires more adjustments, and the pumps used must offer greater turndown ratios. It is easier to provide steady-state accuracy using LDHIs, which are dispersed at only 2 percent per volume (compared with 60 percent per volume for TIs), and it is also easier to make adjustments over time that address the evolving needs of the well as it becomes depleted.

Reliability & Maintainability

Reliability is critical for all equipment deployed offshore because platforms are difficult to reach, and maintenance is always expensive. Of all the criteria evaluated, reliability most clearly separates subsea equipment from what is used topside. The pumping equipment used subsea must be designed to last 20 years without maintenance intervention in a heavy-duty operation mode because the average age of producing subsea wells may be greater than 10 years (in South America and the North Sea, for example).

The conditions these pumps operate in could not be more demanding. All of the materials used must be of the highest quality, and the engineering expertise used to design and build the pumps must be to the highest standards. As an example, the current API 675 requirement for double diaphragm with leak detection would no longer be sufficient. Wear parts to be replaced on a regular basis are simply not admissible with deepwater subsea equipment.

Even though it is difficult and expensive to repair broken equipment on a platform or FPSO vessel, it is still possible for trained workers to wield the right tools to keep equipment functioning. Underneath the water, however, only a few companies can service equipment at the temperatures, pressure and total darkness of 10,000 feet below the sea. People, regardless of their level of expertise, cannot operate on equipment without the help of submersibles and robots.

This—perhaps more than any other point—illustrates the need for reliability when it comes to subsea pumping equipment. To achieve the required level of system availability in terms of mean time before failure and mean time to repair, both the pump reliability and maintainability should be allocated to as many resources as are economically practical.

Looking Ahead

Today, and in the foreseeable future, the global energy mix remains largely in favor of oil and gas. Fossil fuel share is still expected to be about 80 percent by 2035, with an oil and gas share of 50 percent. By most accounts, more than 200 billion barrels—or 5 years' worth of today's global consumption—are sitting in known offshore reserves. In places like the Gulf of Mexico, offshore Brazil and West Africa (the Golden Triangle), deepwater reservoirs account for more than two-thirds of the producible volumes discovered in recent years.

Deepwater exploration and development presents some of the industry's biggest challenges and some of its greatest potential rewards. However, the BEP for offshore production in shallow environments is $40-$50 per barrel. In deepwater environments, that BEP jumps to almost $80 per barrel. In ultra-deep plays, the BEP can approach $100. Many analysts predict that prices may never reach that point again, and if they do, it may be a long time coming.

So perhaps 10 years from now, the entire industry will look back at this time and view it as the moment when companies were forced to innovate and make the offshore play more viable. Perhaps now is the time when the industry takes the first steps to eventually reduce the need for large offshore platforms and the massive costs that accompany them. These steps include the migration of more topside operations toward the seabed, including subsea injection systems and subsea separation or gas compression.

The world cannot afford to ignore the vast offshore reservoirs that have been recently discovered. But the industry must find a way to lower the BEP for offshore production. Innovation across all aspects of the upstream spectrum is the key, and making flow assurance more cost-effective is one important piece of the collective solution.

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