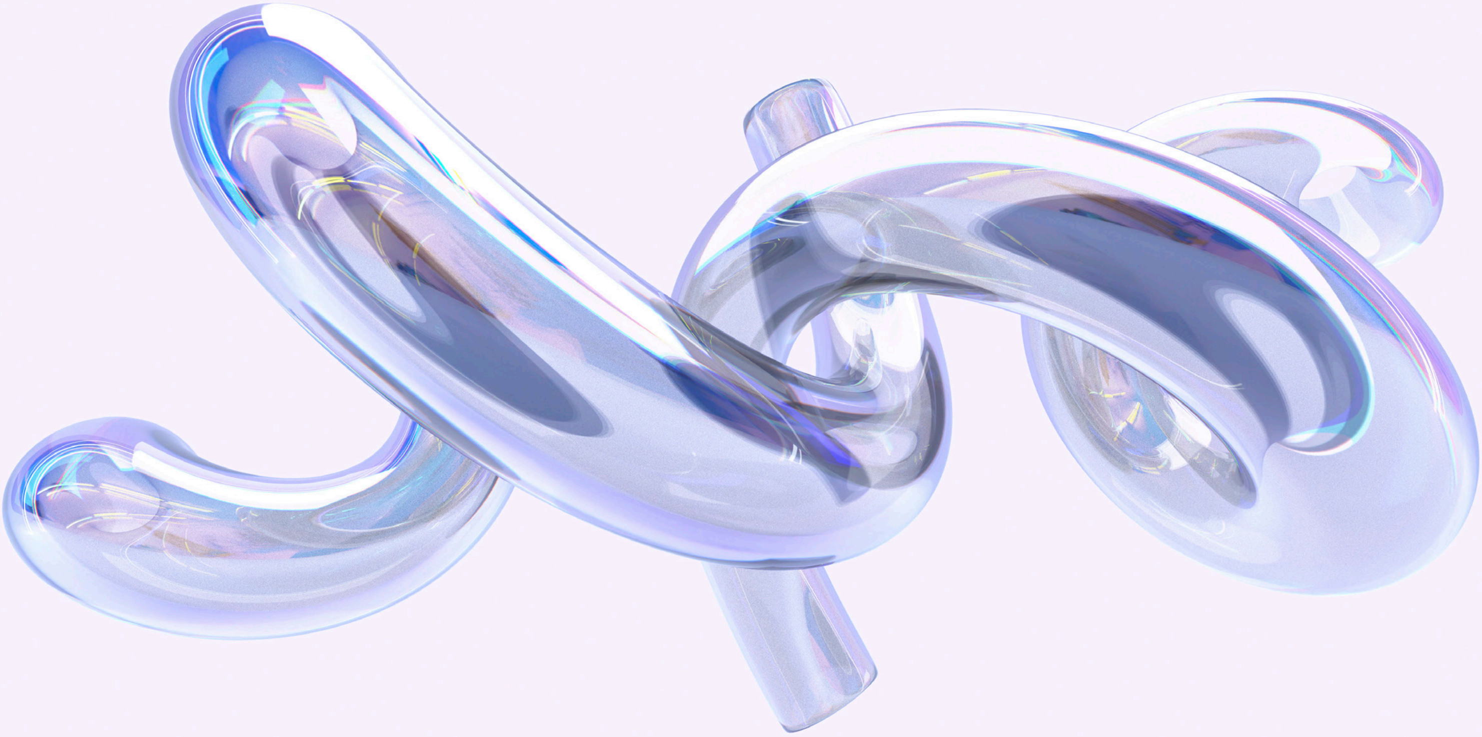
Flexible or rigid: the big debate

Roberta Pires, Flexible Pipe Systems Early Engagement Director, Baker Hughes, discusses features to be considered in a comparison between rigid and flexible pipes.



Flexible pipes have been a revolutionary force in the oil and gas industry for more than 75 years, beginning in World War II when they were used to supply fuel to troops in northern France. The pipe used readily available materials arranged in a way that made it flexible and easy to install subsea at record speeds, mitigating the risk of bombing raids and casualties. Today, flexible pipes are used in offshore fields across the globe to transport oil, gas, water, and even dense CO_2. Despite their versatility, flexible pipes make up only 15% of the worldwide pipeline market share.

With diameters ranging from 2 - 22 in., the most commonly used internal diameter is 6 or 8 in. These pipes were initially designed for shallow waters, but have gradually been developed for use in deep and ultradeep waters, with the deepest on record being 3000 m in the Gulf of Mexico. In the coming years, there is significant demand for flexible risers and flowlines at 2900 m. Today, design pressure capacities reach as high as 750 bar (10 in.) and 900 bar (8 in.) with design temperatures reaching as high as 170°C. The future looks bright for flexible pipes, and they continue to be a critical tool for the oil and gas industry.

Rigid or flexible pipes?

There are several reasons why both flexible and rigid pipes can be technical enablers, and consequently the only choice for a given application. A vast amount of infield pipes, however, could go either flexible or rigid, often triggering a passionate debate: Is there a significant cost difference? Which is installed the fastest? Which one is the most reliable? How does the type of field layout impact pipe type choice and should different types be considered? What is the most economic considering the complete service life?

Answering these questions is a task for talented concept and front end engineering design teams. However, certain variables come into play as well: lack of experience with either option, out of date information, or an incorrect perception of the technical or commercial pros and cons could default to leaning to the familiar, rather than the best, option.

Development drivers

The most common indicators to drive field architecture and pipe selection are:

- Total cost of ownership (TOTEX), which groups capital expenditures of the subsea umbilicals risers and flowlines (SURF), the subsea production systems (SPS) and the costs related to pipes transportation, installation and vessel mobilisation.
- Net present value (NPV), setting to present value the revenue and operational expenses forecast combined with the TOTEX.
- Faster access to first oil, due to shorter supply time, increased vessel availability and faster installation speeds.
- Early on the level of return on investment (ROI).
- Breakeven oil price.
- Lowest CO_2 emission; a factor becoming increasingly important for decision-making.
- Pipeline re-use or re-purpose and field decommissioning.

Comparing TOTEX, as opposed to pipe price per meter is critical when comparing rigid and flexible pipe scenarios. Let's break down the cost layers.

Flexibles cost per metre is often more expensive than rigid when it is solely carbon steel, without internal coating. When rigid pipe must be clad or full CRA, the cost of flexibles becomes cheaper per metre. This is more evident now due to geopolitical instabilities, post-pandemic supply chains being severely impacted, and inflation hitting several commodities, including the alloy elements used for these materials.

However, it's best not to compare rigid pipe price per metre directly with flexibles because the former is not the cost of a finished product, while the latter is. A rigid pipe is not a finished product until it is installed, and all 12 m rigid joints (or pre-welded bi, quad and even hexa-joints) are welded offshore using a J-Lay or S-Lay installation vessel. Moreover, often flexible pipe installation is cheaper than that of rigid pipes since it takes fewer installation days and daily rates tend to be lower. Thus, installation cost must be accounted for.

For the reel lay method, rigid pipe is welded and almost fully prepared at onshore spoolbases in 1 - 2 km lengths. After preparing and welding the 12 m joints, performing non-destructive testing (NDT) and protecting welds, the now continuous 1 - 2 km long pipe (stalk) is spooled onto massive reels (inner dia. ~20 m, whereas flexibles are typically 4 - 7 m). After reeling a stalk, the next one is prepared and the two are welded together until the full length is on the reel and

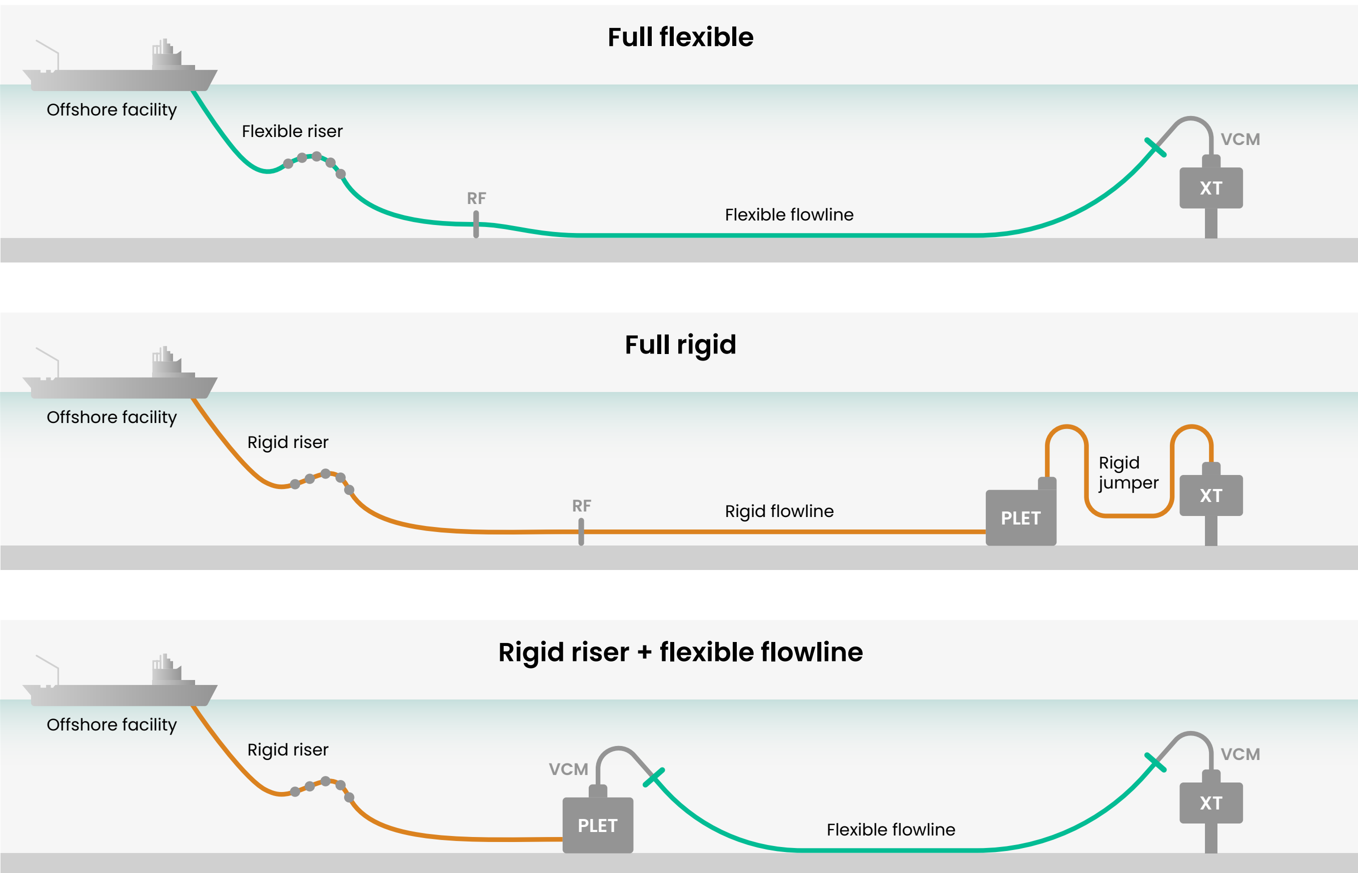


Figure 1. Elimination of rigid jumper and PLET with flexible flowlines. More compact horizontal distances with flexible risers.

the product is at a finished state. For reel lay, it's important to correctly account for installation cost as duration and daily rates can be different. It may also be necessary to add the cost of trips to the spoolbase to re-load, depending on pipe volume, pipe weight and reel capacity when using the reel lay method. Whereas re-loading of reels of flexible pipe onto the installation vessel may, if needed, occur in sheltered waters near the field location, with the help of a supporting lift-vessel. All of these durations and costs must be factored in.

A reduced installation campaign has benefits on overall execution certainty and allows the installer to take advantage of shorter weather windows. Faster installation and fewer vessels means less fuel consumption and lower CO_2 emissions; flexible installation vessels CO_2 emissions are, on average, 30 - 60 % lower.

The amount of associated subsea hardware may also differ. Flexible flowlines can be directly connected without pipe line end terminations (PLET) and rigid jumpers. If there is extra length when approaching the subsea hub, it can simply be laid on the seabed, creating a side curve. Some of the subsea structures will contain sensors, controls, and valves and are not there only to allow a precise subsea installation but to manage production and the life of the pipe. The SPS equipment eliminated, therefore, must be assessed for each field carefully.

When exposed to temperature and pressure cycles, flexible flowlines expansion and contraction are mild thanks to flexible pipe natural construction, eliminating the need for sliding structures to absorb axial movement. They do not require mitigation against free spans or vortex induced vibrations (VIV), and no need for buckle initiation sleepers as flexibles are made to bend and buckle, within limits. Generally, the amount of engineering for flowlines is much smaller for flexibles.

Flexibles may also eliminate rigid jumpers. This means eliminating long baseline metrology (LBL), jumper drawing elaboration, jumper cutting, welding, weld NDT, jumper factory acceptance testing, jumper subsea integration testing, and jumper rigging and transportation to quayside using mobile cranes. This process takes 14 - 35 days per jumper, depending on remoteness and teams' efficiency.

The number of rigid jumpers depends on field layout and can vary significantly. For instance, it is common to have 10, 20 or even 35 jumpers. The elimination of jumper quantity and all associated design, transport, manufacture, test, and installation removes risk while creating an optimised installation schedule. There are some jumpers that will never be eliminated, like the ones that connect Xmas trees to manifolds or to a gathering flowline. If these are selected to be flexible, they will come as a finished product ready to be rigged, installed, subsea connected, and system tested; a process that will take one to two days per jumper.

Comparatively, rigid jumpers can be up to 45 m long, whereas flexibles can have any length and are adaptable to seabed bathymetry – providing flexibility for manifold and wells' location late changes if needed.

Flexibles inner carcass material makeup is qualified to resist corrosion throughout its entire service life (316L, duplex, super duplex or super-austenitic stainless steels, or even nickel alloy carcass may be employed, depending on fluids corrosivity) so regular inspection through pigging is not required. This is relevant when topsides space is scarce or non-existent.

Taking into account all the light construction vessels that can be easily adapted with rented laying equipment, there are twice as many installation vessels for flexible than for rigid. This may minimise risk of delays or enable cheaper and earlier installations.

Flexible components are highly standardised, which allows an optimised supply chain, often leading to shorter engineering and supply times. One of the most common critical path items for rigid pipes is the equipment that smooths riser top bending at connection to its offshore facility (flexjoints or tappered stress joints). For rigid, it typically takes two years to supply during regular demand periods, while flexibles equivalent takes 12 months.

Different types of field layouts and their financial impact

The main types of field architectures are satellite, manifold, loop and a combination of all three. While we review the technical differences between them, a key driver for the field layout definition is flow assurance, which ultimately aims to maximise the field production.

Satellite type, the most common field layout type offshore Brazil, is characterised by each Xmas tree being individually connected to the platform. Oil flows up directly, without being grouped with that from other wells. Satellite pipes ID are typically 8 or 6 in., diameters known today to have produced 45 000 boe/d and 6 000 000 gas m^3/d (at 620 bar), respectively. Each well is typically serviced by a service and/or gas lift pipe. Umbilicals can be individually connected from the platform or from a system distributing unit, that is linked to the platform through a dynamic umbilical and allows control of up to five wells each.

Manifold type is characterised by using a manifold to group the production of neighbouring wells and then flowing oil up using two flowlines and two risers per manifold. The wells are typically all directional and located close to the manifold in so-called drill centres. Depending on the quantity of wells and manifolds, these risers must accommodate oil coming from 2 - 20 wells needing larger diameters, typically 10 - 14 in. The flowlines and risers come in pairs for redundancy and to allow for intermittent cleaning with hot oil, diesel or chemicals circulation (in case a pipe experiences constriction due to wax or hydrates buildup, for example) using one pipe system to provide the cleaning fluid to the other. In such a situation or even in preventive regular pigging, all wells must be shut. Manifolding reduces the number of risers and flowlines compared to satellite. On the other hand, there is increased SPS (manifold and connectors) and bigger pipes. Manifolds can be long lead items and critical equipment, which increases installation and operational risk for the field.

Pipes are also grouped in the loop type production. The main flowline is set to pass reasonably close to the wells and to be fitted with tee connectors called 'In Line Ts', which connect to the well's Xmas trees. The main flowline is typically 8, 10 or 12 in., and the well jumpers or flowlines typically 6 or 8 in. As the main flowline and associated riser need to be cleanable, they are connected to an adjacent main flowline – another pipe grouping production for other wells. The two are connected with a flowline, all forming a loop. When there is a need to clean or pig one of the pipes all wells must be shut. The number of risers and flowlines is smaller than in satellite and potentially bigger than in manifold, depending on oil production volume from each well and field layout. The SPS hardware here is light and small, and most importantly, installed in line with the pipe in a continuous operation, saving time and mitigating risk.

One of the fundamental differences between those options is the profit lost due to production interruption for cleaning and well tax metering. The lost revenue can be estimated and should, whenever possible, be factored into the NPV as numbers can be significant.

Pipe ID is another fundamental difference. The greater the ID, the greater:

- The pipe cost, with a variance in a non-linear way and that differs between flexibles and rigid.
- The likelihood a higher capacity installation vessel is required. What the satellite option allows is ID minimisation; it is usually possible to remain below 8 in., which is cost beneficial, especially for flexibles and particularly in deep waters.

Expenditures with SURF and SURF installation account for 50 - 90% of SURF and SPS total expenditures, so is a key piece to optimise. Assessing different field layout arrangements, each with its internal diameter and covering the two types of pipes, all while maintaining total production per day, is what may unlock optimisation.

Technical enabling

Pipes with ID greater than 22 in. must be rigid as no flexible supplier can produce larger flexibles. There are combinations of pipe ID and design pressure, or pipe ID and water depth, where rigid has a track record and flexibles don't. Flexible qualification and track record varies for each supplier, and manufacturers should be consulted for their qualification limits. Fluid corrosiveness may also lead to rigid selection. This has been the case in the past five years for part of the Brazilian pipes that transport the world's highest levels of CO_2: part of the infield pipes are clad or mechanically lined rigid pipes. Stringent thermal requirements may require rigid pipe in pipe with passive insulation inbetween or actively heated pipes, of which there are qualified suppliers for both flexible and rigid options.

A classic case of enablement through flexible pipes is the North Sea. All oil produced with floating host facilities passes through a flexible pipe as it is hard to design a working rigid pipe configuration in its shallow water depths (average 90 m, deepest 700 m). A floating facility's offset and movements are transmitted down along pipe leading to small bending radii at touch-down on the seabed, resulting in compression and fatigue that can be too strict for rigid but suitable for flexibles. Other technical benefits for flexibles are as follows.

Rough seabed topography and straighter flowline routings

- Flexibles accommodate to the seabed passing through free spans with no mitigation equipment, allowing optimised routes.
- Flexibles allow for sudden route turns at much smaller radius (for example ~3 m for an 8 in. pipe).

Reusability

- Reconnecting an existing flexible to a new well that produces more oil is an efficient way to revamp an asset's production and is regularly done offshore Brazil.
- Flexibles offer versatility for field life extension, for example, a dynamic flexible can be re-purposed to be static and the fatigued top section of flexible risers can be replaced or just re-terminated.

Congested fields

- Flexibles touch down zone horizontal distance is smaller, making efficient use of limited space.
- During installation, flexibles don't require an installation pile to be initiated, thus reducing risks of initiation wire touching already installed subsea structures. Also, it is simpler to solve crossings non-destructively.

Reliability

- Despite the general perception, flexible and rigid pipes failure rate are of the same order of magnitude.
- This is the conclusion reached by a joint industry programme that included key industry stakeholders.
- The most frequent flexible incident is seawater ingress into the annulus, an event that does not usually lead to pipe failure as long as it is accounted for in design.

Integrity and monitoring (I&M):

Today, the I&M portfolio includes tools that allow understanding:

- Is annulus flooded?
- Are tensile wires intact?
- What is annulus fluid composition along time?
- Is it safe to extend pipe service life?
- A pipe health dashboard can be accessible on your smart phone.

Conclusion

From World War II to the present day, the inventiveness and passion of thousands of people have brought flexibles to constantly push past technology limitations, enabling deeper, hotter and higher-pressure field development, and bringing execution certainty to oil and gas developments. The need to transition towards greener technology and resources is a new challenge in product and business development; one to ignite the passion for innovation guided by the vision of safe, secure and affordable energy to all corners of the world.