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Retrofit Installation of In-riser Composite Tubing as an Artificial Lift Solution

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Abstract
A growing trend in subsea field development is the simplification of subsea production system design. The primary driver of this trend is operating companies' increased focus on capital allocation in response to market uncertainty about the energy mix of the future and, thus, the requirement to reduce the payback period. Increasingly common design features such as over-sized risers & flowlines and single-flowline tiebacks exacerbate the flow assurance challenges that arise during mid & late life production and necessitate the requirement for novel techniques to deliver artificial lift in order to maximize economic oil recovery. One such field-proven technique that lends itself particularly well to mid & late life production from subsea wells is the installation of steel coiled tubing inside the production riser to deliver gas lift. This comparatively low-cost solution has been successfully applied on several deepwater SPARs in the US Gulf of Mexico , however, it is far more challenging and costly to apply this method on other production facility types (e.g. FPSOs, semi-submersible TLPs) due to the lack of direct vertical access (DVA) to the riser. Composite coiled tubing does not require DVA and is therefore proposed as an enabling technology for wider-spread adoption of this solution.

Keywords
Artificial Lift; Composite Coiled Tubing; Slugging

Introduction
The upstream oil and gas industry has experienced significant internal and external shocks and change during the past decade. Ranging from the advent of the US shale industry and its de-stabilizing effect on supply to the more recent policy uncertainties surrounding the pace of the transition to clean energy, changing market dynamics have forced many operating companies to re-evaluate their approach to growth to manage these risks and preserve shareholder value.

Increased capital discipline has emerged with a shift in focus from the pursuit of growth to reducing debt levels and returning cash to shareholders, which has undoubtedly affected how new fields are developed and how existing fields are optimized. This can be particularly well exemplified in the deepwater sector, where higher upfront capital expenditures and longer payback periods in comparison to more conventional oilfield developments are the norm and where the potential for stranded assets is therefore higher.

Two development strategies that have become more prevalent are the oversizing of production risers & flowlines and installation of single-flowline tiebacks. Increasing pipe internal diameter (ID) reduces pressure loss and therefore increases production rates in a well's early-life phase, normally resulting in a shorter payback period. However, as the well enters its mid-life phase and rates decline, the larger ID of the riser-flowline system can exacerbate the effects of increased water production and reservoir pressure depletion. An example of this is the increased frequency & severity of liquid slugging, which can cause topsides process upsets that lead to reduced productivity.

Similarly, single versus dual-flowline developments deliver a significant reduction in CAPEX and can make production from smaller satellite fields economic. However, this approach usually increases the likelihood of a future intervention requirement due to reduced operational flexibility (e.g. from the inability to perform certain maintenance & prevention activities such as pigging & circulation, or the inability for flowline re-purposing to enable gas lift, etc.).

Composite Coiled Tubing (CCT) technology is uniquely capable of addressing many of these challenges. The CCT system can be described as a miniaturized and flexible coiled tubing technology that has been developed specifically for riser and flowline interventions. Its principal application and the majority of its usage history to date has been high-pressure liquid jetting for the remediation of solids deposits - including hydrates, paraffin wax, sand and asphaltene - that form inside the production flowline & riser and which lead to reduced or fully occluded system throughput, however, it can also be used for the installation of tubing permanently inside the production riser (PR).

These 'in-riser' installations enable either increased fluid velocity via a reduction in the cross-sectional area (i.e. an in-riser velocity string) or reduced system back-pressure via gas lift at or near the riser touchdown point (i.e. in-riser gas lift). Numerous production and flow assurance challenges often associated with mid & late-life wells, such as slugging and pressure depletion, can be alleviated with these artificial lift techniques.

This solution has been applied extensively as a low-cost, retrofit artificial lift solution on several platforms in the US Gulf of Mexico (GoM), primarily on SPAR facilities which have the direct vertical access (DVA) into the PR. DVA is required for in-riser steel tubing installation using conventional coiled tubing (CT) systems, where the high minimum bend radius (MBR) of the steel tubing prevents it from being run through the short radius pipe bends that can often be encountered on topsides prior to entry into the PR. Unlike SPAR platforms, which represent only 13% of the deepwater production facility asset base globally and are concentrated in the US GoM, the majority of deepwater production facilities (i.e. FPSOs and semi-submersible production platforms) do not have DVA to the PR, thus, preventing or greatly complicating the application of the in-riser solution.

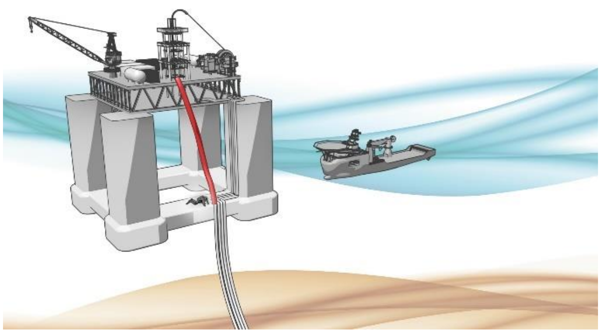

Figure 1. Temporary Riser System for Installation of In-riser Steel Tubing on a Semi-Submersible TLP.

Figure 1 shows a temporary riser system (shown in red) connecting a CT system to a vertical tubing hanger that has been installed beneath the waterline at the PR hang-off on the pontoon. The steel tubing is then run from surface through the temporary riser on a temporary work-string and landed-off in the hanger which holds it permanently in place. If gas lift is required then piping running from the tubing hanger assembly up the column and to the gas compression system must also be installed, further increasing the subsea construction required in and around the facility's splash zone.

The CCT technology uses more flexible composite tubing that can navigate all the short radius pipe bends at surface and on the column & pontoon of the semi-submersible TLP prior to entering the PR (see Figure 2). Consequently, hang-off at surface versus at the waterline is possible, thus, eliminating the significant cost and operational risk of the subsea construction activity required when using standard steel tubing and conventional CT systems.

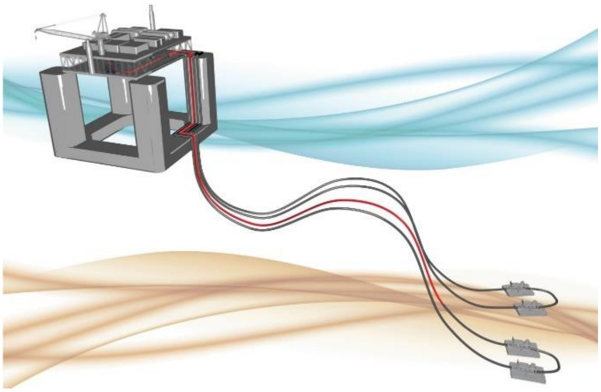

Figure 2. Composite Coiled Tubing Hung-off at Surface

Field Application

A recent application of this solution was applied in the US GoM in a 32km tieback to a semi-submersible TLP in 1,370m water depth. Declining well rates and increased water production led to a severe slugging issue that was causing significant upset and outages of the facility's process system. Boarding pressure was increased to manage the slugging, however, this also reduced production rates from the wells.

The tieback operator initially considered either installation of a gas lift riser (externally connecting to the production riser-base as planned in the original system design for future integration) or a subsea multi-phase pump, however, these would have increased platform load to above the maximum allowable limit and were rejected by the facility operator. In addition, the lead time of each of these solutions was multi-year, compounding the cost of deferred production.

The optimal solution was therefore deemed to be installation of a 2.375" outer-diameter composite in-riser velocity string (IRVS) inside the 5.23" inner-diameter PR using the CCT technology (Figure 3), with the aim being to increase superficial fluid velocities by reducing the cross-sectional area of the riser by approximately 20%.

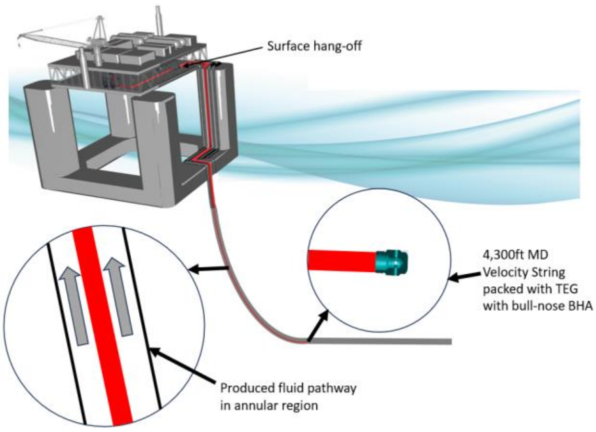

Figure 3. IRVS Simplified Schematic.

In preparation for the installation of the composite IRVS the flow-loop was first pigged and then flushed with seawater to allow for removal of the hard pipe spool connecting into the boarding valve (BV) as shown in Figure 4.

Figure 4. Old Production Piping Connecting to BV.

This spool was then replaced with a wye-piece type assembly with one leg connecting to the BV and the other a dead-leg that contains the IRVS tubing hanger (see Figure 5).

Figure 5. Post-Installation Piping Assembly.

Available deck space on the congested platform was extremely limited, however, the CCT system's components could be deployed across multiple decks and locations (see Figure 6), in contrast to conventional CT packages.

Figure 6. Example of Multi-Deck Layout of CCT System.

The composite IRVS was then successfully installed via a cumulative total of 523° of pipe bends using the CCT package within a 24-hour period. During steady-state operations boarding pressure has been reduced from approximately 1,000psi to 600psi with greatly reduced slugging frequency & severity, while increasing production by approximately 30%.

This application was delivered at a cost of approximately 60% less than the estimated cost of deploying steel tubing using conventional CT (as shown in Figure 1) and without any recordable weight gain to the facility due to the inherently buoyant nature of the composite IRVS.

Conclusion

The successful execution of this industry-first project within a 7-month period demonstrates that a low cost, field proven and rapidly deployable artificial lift solution can be applied on the majority of deepwater production facilities to address the technical and economic challenges that face mature assets.