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Palombeta: A case study on Petrobras's longest and deepest subsea tie-back

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Abstract
The Palombeta ultra-deep oil well presents unique challenges in flow assurance due to its long tie-back distance, rugged seabed conditions, and the potential for flow instability over its operational lifespan. This article discusses the effective management of flow assurance concerns, primarily through the implementation of a continuous gas-lift system, ensuring adequate thermal insulation, and incorporating subsea equipment for hydrate dissociation. The insights and strategies derived from this study contribute to the optimization and success of future ultra-deep oil wells, offering valuable guidance for similar deepwater projects. The successful development of Palombeta—Petrobras's most significant flow assurance challenge since the Pre-salt era—will enhance the overall efficiency and productivity of its deepwater operations.

Keywords
Flow assurance; Long tie-back; Deepwater production

Introduction
This article discusses the main concerns and strategies employed in the development of the Palombeta area, located at a water depth of approximately 2,600 m. Scheduled to initiate production in 2030, Palombeta will be the location of one of Petrobras's most challenging wells. It will drain hydrocarbons (37°API and 340 Sm^3/Sm^3 GOR) from a sandstone formation at a depth exceeding 5,000 m. The long tie-back distance (~23 km) will pose a significant challenge for flow assurance. Palombeta's production system consists of only one oil production well with the support of a single water injection well, with provisions made for a second pair of wells (producer/injector) for future expansion in a trunkline configuration.

The produced hydrocarbons will be transported through an 8-inch pipeline connected to a Floating Production, Storage, and Offloading (FPSO) vessel. A 6-inch service line will also be deployed alongside the production line to allow for gas lift and fluid circulation **(Fig. 1)**. Injected water will flow through another 8-inch pipeline. The sizing of the subsea lines was carefully evaluated to accommodate initial flowrates from the original scope of the project, as well as its possible expansion. However, the long pipelines, which cross two large subsea canyons, introduce additional complexities in ensuring continuous operation.

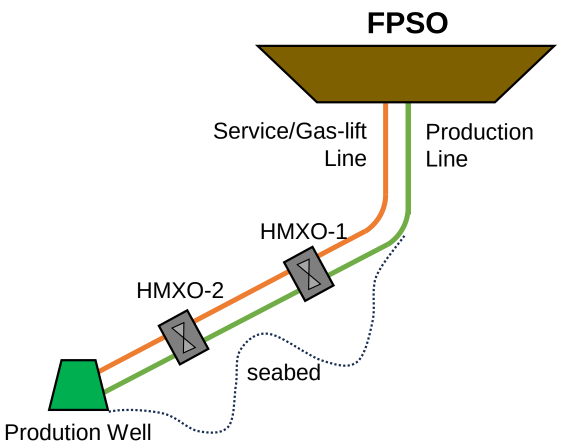

Figure 1. Subsea layout schematic for production in Palombeta.

Results and Discussion
The following sections summarize the main flow assurance-related concerns in Palombeta and how they have been addressed by the project team.

Layout Selection
The selection of the subsea layout for Palombeta involved various factors, such as the proximity to other fields sharing the same FPSO, their respective volumes of oil in place (VOIPs), and the presence of two large subsea canyons. The objective was to optimize the project's profitability while addressing flow assurance and operational risks.

Figure 2. Route selection for Palombeta's oil pipeline.

Palombeta plays a crucial role in the overall economic feasibility of the project, as its production significantly impacts the total net present value. Therefore, careful consideration was given to the design and layout of the subsea infrastructure to ensure the successful development and production of Palombeta. During the screening phase, it was decided to position the FPSO close to another oil field with larger VOIP, more wells, and higher total production rate. This decision aimed to maximize the project's total income by leveraging the higher potential of the neighboring field. As a result, the FPSO was situated far from the Palombeta field.
In the conceptual phase, different path configurations for the pipelines connecting the FPSO were evaluated. One approach involved circumventing the two large canyons by taking a longer route, resulting in a total length exceeding 30 km. The longer pipeline increased costs and posed a higher risk of wax deposition due to the cooling of the fluids along the extended flow path. Alternatively, another approach was to pass through both canyons, minimizing the total length of the pipelines. However, this led to a bathymetric profile with much larger amplitudes, reaching up to a 100-meter difference between nearby peaks and valleys. In this configuration, the remaining pressure at the bottom of a valley after a depressurization might still be higher than the hydrate formation pressure, making the dissociation of an eventual hydrate at this point nearly impossible. To mitigate this risk, additional equipment (HMXO valve) was placed as deep as possible to connect the production and gas lift lines, as discussed later in this article.
Various alternatives in between the two previous options were thoroughly examined, ultimately leading to a compromise in the final subsea layout for Palombeta. The selected layout incorporates two HMXO valves strategically positioned at the bottom of the canyons **(Fig. 2)**.

Scale
Scaling is expected in Palombeta as soon as water is produced along with the hydrocarbons, regardless of the content. Specifically, calcium carbonate deposition along the entire flow path is of concern. To mitigate this impact, the injection of scale inhibitor in the wellbore is expected to start during the early phases of production and continue until the end.

Wax
To mitigate wax deposition on the pipe walls, the production lines were selected with adequate thermal insulation (TEC 2 W/m°C). Simulations show that this insulation is effective in preventing most wax from precipitating and depositing along the flow. Based on reservoir predictions, wax formation is limited to the top riser section in the rare cases when it appears along the flow path. In this region, where shear stress is at a maximum and ambient temperatures are relatively high, the impact of wax deposition is significantly reduced. However, measures will be taken on the FPSO design to address any potential impact of wax. Special features have been incorporated to the FPSO specification to deal with wax-related challenges, including circulation of heated dead oil (or diesel) in reverse flow (from production to service lines) to help dissolve deposits.

Hydrate
Hydrate formation is a significant concern, especially in ultra deep wells. The thermal insulation of the pipes provides considerable protection against hydrate formation, as it takes at least 10 hours for fluids to enter the hydrate envelope after a shutdown, according to simulations at different periods of the well's lifespan **(Fig. 3)**. In these situations, large capacity service pumps (360 m^3/h) should help displace produced fluids as quickly as possible from the subsea lines with diesel (or dead oil). In adverse situations where hydrates are allowed to form, a total blockage is likely, as lab experiments have shown that any produced water should be in a continuous phase—**not** as an emulsion with oil. To address hydrate events, two subsea hydrate-mitigating cross-over (HMXO) valves are planned at the seabed near the deepest points of each canyon (Fig. 1). This equipment will provide a connection between the production and the service/gas-lift lines, facilitating the dissociation of eventual hydrates.

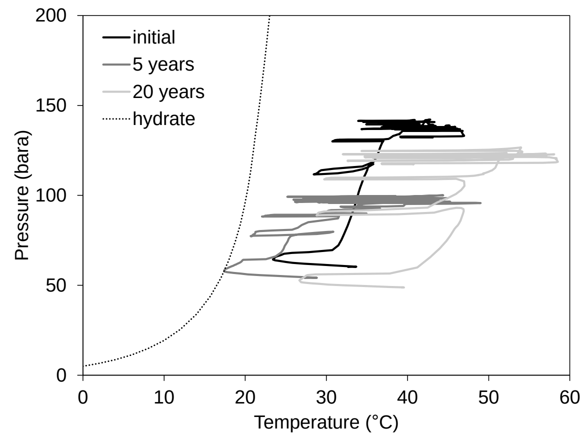

Figure 3. Subsea line conditions 10 hours after a "no-touch" shutdown.

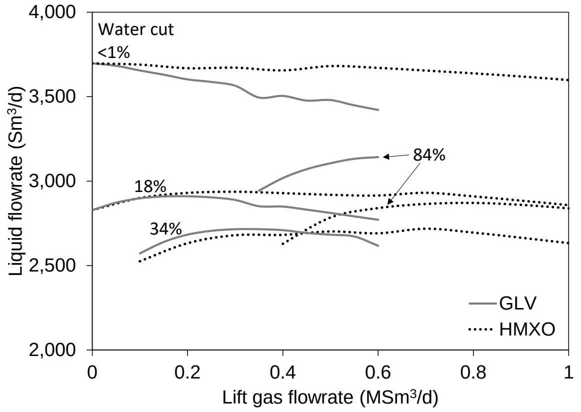

Figure 4. Gas-lift performance curves for varying water cuts (at two different gas injection points—GLV or HMXO).

Gas Lift

A continuous gas-lift system will be implemented. Initially, gas lift will not be required. As the water cut increases with time, continuous gas lift will play a crucial role in improving production and stabilizing the multiphase flow. **Figure 4** shows the gas-lift performance curves for two different injection points: *(i)* the gas-lift valve (GLV) located at the wellbore (solid lines), and *(ii)* the HMXO-1 valve at the seabed (dashed lines).

As depicted in Fig. 4, gas lift is detrimental to hydrocarbon production at low water contents. However, for water cuts higher than 30%, it becomes not only beneficial but also necessary to maintain a steady flow. The dependency on gas lift is even more pronounced for very high water cuts (e.g., 84% shown in Fig. 4). After modeling the thermally-coupled wellbore and annulus flows **(Fig. 5)**, an unusually large (3/8") Venturi valve is selected to be installed at the deepest possible location, providing stable lift gas flowrates in the range of 0.3-0.6 MSm³/d.

Given the importance of gas lift in Palombeta, an alternative to injection at the wellbore is available via the HMXO-1 at the seabed. To assess the effectiveness of this operation, several lift gas flowrates were simulated, as exemplified in **Fig. 6** for mid-life conditions. Even though a steady gas flowrate is maintained at the FPSO for 20 hours at each step (red solid line), the rate at which gas is injected through a 5 1/8" valve at the HMXO-1 (dashed red line) is dependent on the flow dynamics arising from the production and service lines modeled through OLGA [1]. Figure 6 then shows that, starting at 0.8 MSm³/d, the lift gas flowrate can be continuously reduced up to 0.5 MSm³/d and still provide somewhat stable liquid flowrates at the FPSO (blue line). Lower gas flowrates then cause liquid to enter the service line and seriously disrupt the operation. Although less efficient, continuous gas lift via HMXO-1 can be regarded as an important backup system in the event of the primary valve at the wellbore failing.

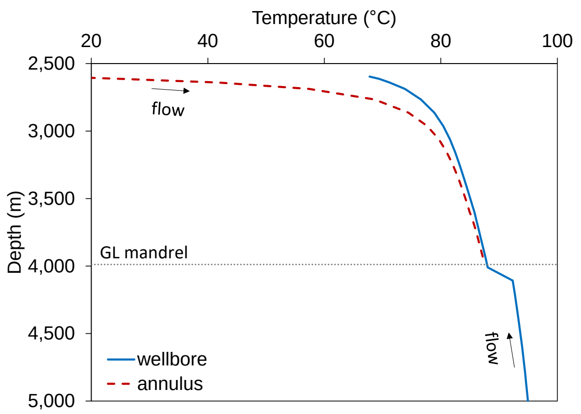

Figure 5. Flow temperatures in the wellbore (produced hydrocarbons) and the annulus (injected gas).

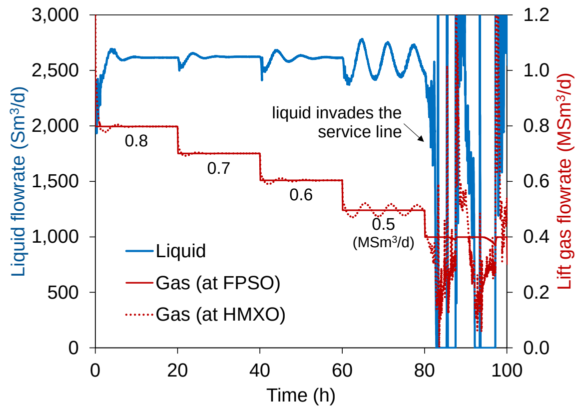

Figure 6. Liquid flowrates (blue) for different lift gas flowrates (red) at the seabed injected through the HMXO-1 valve.

Restarts

The long tie-back on a rugged seabed can pose a challenge to maintaining a stable multiphase flow in Palombeta. Especially during restarts at later stages of the well's lifetime—with high water cuts and depleted reservoir pressures. **Figure 7** simulates this condition when the well is reopened after an 8-hour "no-touch" shutdown. As gas lift is essential in these conditions, two methods are tested. First, gas lift is performed via the wellbore with the gas flowrate limited by the choked flow through the 3/8" Venturi valve (~0.6 MSm³/d). For this case, the liquid flowrate at the FPSO (blue solid line) requires a whole day to stabilize. Meanwhile, if the HMXO-1 is used as the gas injection point instead, a steady liquid flowrate can be reached within only a couple of hours. The latter takes advantage of a much higher gas flowrate—**not** constrained by choked flow—at around 1.5 MSm³/d.

Chemical Injection

The long tie-back can also be challenging for the chemical injection system. The use of, at least, hydrate and scale inhibitors is highly probable in the field, with available injection points at the wellbore, X-mas tree, and HMXO's. For hydrates,

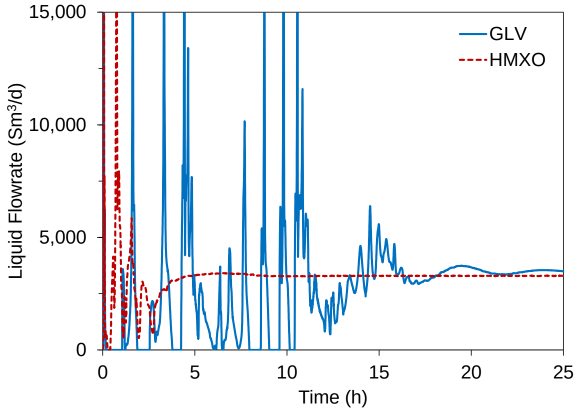

Figure 7. Liquid flowrate during a restart for when gas is injected at the wellbore (GLV) or at the seabed (HMXO).

glycol (MEG) is regarded as the main inhibitor for the field. LDHI alternatives are currently undergoing qualification efforts by Petrobras's Research Center. **Table 1** shows typical MEG flowrates for different tubing diameters, considering the maximum pump discharge pressure and hydrostatic pressure from diesel at the X-mas tree. If conventional umbilical structures (with ½" hoses) were used in Palombeta, the resulting flowrate would be too low, requiring almost 16 hours to inject a typical batch (~2 m^3) of MEG. Nevertheless, newer umbilical structures with 1" tubing can allow for a much quicker operation, taking less than an hour for the same batch volume. The selected umbilical configuration for Palombeta, a mix of ½" and 1" diameter structures, offers an acceptable compromise at ~1 m^3/h of MEG.

Table 1. Glycol (MEG) Injection at the X-mas tree.

Inner diameter	MEG flowrate *(L/h)*	Time for 2 m^3 *(h)*
½"	127	15.7
Hybrid (*current*)	1,088	1.8
1"	2,645	0.8

Responsibility Notice

The authors are the only responsible for the paper content.

References

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