Abstract
Parque das Conchas (BC-10) is a deepwater development offshore Brazil. A novel Caisson / Electrical Submersible Pump (ESP) subsea separator (gas/liquid) and pumping system to enhance production and maximize recovery has been utilized as part of the development of two of the fields (Ostra and Abalone). A third field, Argonauta B-West utilizes multiphase boosting with a modified Caisson/ESP (C-ESP) system to operate with a single, non-separated multiphase outlet. These novel designs have significantly impacted system and flow assurance engineering such as separator level control, hydrate mitigation, system operability, and chemical injection. The fields have been successfully started up with production through the subsea processing system since late 2009.

This paper outlines the performance of the subsea processing and production system from the perspective of flow assurance, and presents comparisons of the actual operating performance to design expectations. Learnings from key factors that strongly impact the production system operability and operational strategies are discussed, including the achieved separation efficiency of the caisson, the impact of defoamer performance on caisson operation and the importance of the hot oil circulation system.

Introduction
Parque das Conchas (BC-10) is a deepwater (~ 6000 ft) development located at Campos Basin, approximately 75 miles southeast off the coast of the city of Vitoria in Brazil. Shell is the operator with a 50% interest, in a joint venture with Petrobras (35%) and ONGC (15%). Since its startup in July 2009, BC-10 has been in successful production.

The properties of the fluids in the BC-10 reservoirs vary considerably with depth from heavy, low GOR fluids to light, high GOR fluids. These properties, and the fact that BC-10 requires subsea artificial lift to achieve economic production rates posed severe challenges for the design and operation of the subsea system [1].

Figure 1 provides an overview of the development. The Ostra and Abalone fields are produced in a commingled mode. The Ostra field has 6 producers and 2 production manifolds (PM1 and PM2). An artificial lift manifold (ALM1) equipped with four separated C-ESP systems connects to PM1 via flowline jumpers. The produced fluids from the wells flow into three caissons while the fourth caisson stands by as a spare. The well streams entering the caissons (currently at over 1200 psig) are separated into gas and liquid phases. While the separated gas flows into the Ostra gas line, the liquid flows down the length of the caisson and is boosted by the ESP and enters the Ostra oil line.

The B-West field has a stand-alone subsea production system. The two producers are connected to two non-separated C-ESP systems located at artificial lift manifold 2 (ALM2). Each producer is designed to flow to its own caisson and flow to topsides via its own subsea flowline. In addition, the producers can be directed into one caisson and flow via one flowline to the FPSO while the other flowline works as the service flowline if needed.

Both Ostra and B-West require subsea artificial lift to achieve economic rates, due to their low reservoir energy. The novel subsea hardware and design provides robustness and flexibility to ensure sustainable production performance, and to safeguard the subsea production system after shut down.
This paper presents some of the major subsea learnings from the first year of field life, including:

- The viability of subsea separation in high aspect ratio vertical caissons resulting in:
  - Low liquid carryover in to the gas line;
  - Low gas carry under in the separated caisson that impacts the ESP boosting system, separator level control system, hydrate inhibition strategy, and chemical injection strategy of the oil flowline.
- The non-separated caisson’s tolerance of high gas volume fraction (GVF) fluids.
- The need for highly reliable auxiliary systems / services as part of a subsea processing system, such as:
  - Flawless defoamer injection into the caisson to allow effective separation.
  - High availability hot oil circulation, for subsea system safeguarding and subsea processing system startup.

Learnings from the Separated Caisson ESP System Operation

The caisson separator (Figure 2) is a two phase separator situated at the seafloor. Separation of the gas and liquid takes place in both the angled and tangential inlet, as well as within the caisson itself. Heavier liquid is directed to the wall of the separator and flows down to the ESP. The lighter gas is allowed to migrate to the top of the caisson and onward through the gas outlet [1]. An ESP is installed in the liquid leg of the separator to transport the liquid production to the surface facilities. Incomplete (but not necessarily suboptimal) separation leads to gas carryunder in the liquid leg and liquid carryover in the gas leg. The common phenomenon behind both of these is foaming at the liquid-gas interface.

Foaming Control in Subsea System

Operation of the Ostra field has demonstrated that foaming control is a critical factor for successful operation of the separation C-ESP systems. Foaming is a fluid lift enhancement phenomenon in which the gas and liquid is converted into foam. During the design phase, the risk of foaming in the caisson was identified in laboratory and prototype tests (at the Shell Gasmer facility). Foaming of Ostra and Abalone fluids were tested and studied [2]. Two types of foaming were observed in the lab tests. “Lacy” foaming of gas bubbles was seen in the gas phase and sustained by a stable liquid film, and the “froth” foaming induced by the gas bubbles entrained in liquid phase, which increases gas-carry-under (GCU).

Foaming characteristics are affected by multiple factors including fluid viscosity, surface tension, flow agitation, pressure and temperature. Foaming results in a vertical density gradient in the caisson. The outcome is an un-distinguishable gas/liquid interface and reduced gas/liquid separation efficiency.

Continuous defoamer injection at the caisson inlet has been used to control foaming. BC-10 was the first application of chemical defoamers subsea and required the development and testing of a unique product [2]. The need for stable low-rate delivery of defoamer to the sub-hydrostatic caisson necessitated the development of new subsea components which continue to be refined in the pursuit of increased reliability. Operational experience has shown that once defoamer is under delivered, the foaming in the caisson increases very fast. If defoamer injection stops, the caissons have to be shut down. Figure 3 demonstrates the immediate GVF response in the caisson observed in the field as the defoamer injection is started.
Gas Carryunder
The separation performance required for the liquid leg of the caisson separator is dominated by the performance degradation on the introduction of 2 phase flow to the ESP. Performance requirements include

- Gas to the ESP (gas locking of pump)
- ESP operating window (current draw, motor speed, upthrust/downthrust, etc)
- Topsides production separator capacity

Each of these performance requirements are interdependent, for instance increased gas carried under to the ESP reduces power draw but requires higher motor speed. Therefore under different operating scenarios, the system could be limited by any single performance requirement. The two distinct oils processed with ALM1 manifold created unique processing challenges.

For the low GOR Ostra fluids, the C-ESP combination achieved 115% of the design capacity. After optimization of chemical defoamer injection upstream of the caisson, the gas fraction in the liquid leg of the separator (gas carryunder) was calculated to be less than 10%. This is shown in Figure 4. This carryunder amount was consistent with small scale and full scale testing on synthetic fluids.
Operation of the caisson separator with the high GOR Abalone fluids proved a different story. Gas carryunder performance was significantly different than what was experienced with only Ostra fluids. When Abalone was comingled with Ostra and dead oil, this combination limited caisson separator capacity to approximately 65% of design capacity.

At this rate, the gas volume fraction (GVF) in the liquid leg of the separator was calculated to be around 45%. It is interesting to note that the amount of gas actually reaching the pump was less. One possible explanation of the deviation of GVF compared to the actual gas carryunder (GCU) reaching the pump is a stationary bubble front in the liquid leg. For gas bubbles of a certain size, the bubbles buoyancy will equal the drag of the liquid down into the inner shroud. This is obviously a very dynamic situation with many factors affecting this stationary bubble front, but a quasi steady state can exist where more gas is being held up and not migrating up or down than is actually making it to the ESP.

This increased GVF had several subsequent effects on the operation of the caisson/ESP system. The level is calculated based upon the differential pressure across gauges at a known location in the caisson. If the density in the liquid leg is constant, the level estimation is straightforward. When flowing Abalone/Ostra, the density was not constant. This gradient introduces uncertainty in the level calculation, and when coupled with the accuracy of the pressure gauges used to estimate level, this uncertainty can exceed 10% of the caisson length. The risk in overestimating the liquid level can starve the ESP of fluids if the actual liquid level drops below the pump inlet. If the liquid level is underestimated the liquid level cause flooding of liquids out the gas outlet if the liquid level approaches or exceeds the multiphase inlet to the caisson. Considerable upfront design effort was undertaken to understand this impact. During actual operation, this phenomenon did not hinder production. The limiting performance requirement was liquid carryover uncertainty.

**Liquid Carryover**

The separation performance required for the gas leg of the caisson separator is dominated by the increased pressure drop, potential slugging and hydrate considerations associated with liquids accumulation in the gas flowline back to the host. These risks play an important role in the operational envelope of the caisson system.

Chemical injection, liquid carryover from the caisson, and condensed liquids from the gas all contribute to liquids management of the gas flowline. All of these sources of liquids contribute to the liquid hold up for the gas line. Once the gas line reaches its liquid hold up capacity, then the liquids will start to reach topsides. Due to the low condensation and chemical injection rates, the time required to reach the calculated liquid hold up of the flowline is significant if there is not any appreciable liquid carryover. The combination of sources of liquids, the liquid hold up, and the instrumentation to monitor liquid carryover makes determining the carryover challenging.
Monitoring includes the differential pressure in the gas section of the caisson, the differential pressure across the flowline, and the liquids being produced to the gas separator on topsides. Calculations indicate that reaching the steady state liquid hold up of the flowline with just chemical injection and condensation could take many months. The impact of this means the system does not actually reach steady state, but rather a quasi-steady state of increasing differential pressure. Coupled with the indirect methods of actually monitoring carryover and the challenges this presents become apparent.

Onset of carryover as determined by the differential pressure in the gas section of the caisson is estimated at best. The basis for the estimation was the result of testing at our full scale test facility with synthetic fluids. With that information, a value was set below where the onset of flooding of the gas riser would result. This led to a very conservative number to be used due to the uncertainty around determining the flooding point. If a better method to understand this flooding point in relation to the pressure differential in the gas phase was available, it is possible the capacity of the caisson could be significantly increased. Perhaps more design effort to quantify this flooding phenomenon in context of the available monitoring methods would have allowed a less conservative setpoint, thus increasing caisson capacity.

The differential pressure monitoring to determine liquid carryover is impacted by the liquid holdup, condensation rate, chemical injection, gas flowrate, etc. The system experienced a slow increase in differential pressure over a significant operating period, which indicated no appreciable liquid carryover.

Liquids arrival topsides from the gas line is another parameter that gives indication of liquid carryover from the caisson. Liquids production in the topsides gas separator has been minimal to non-existent. This is another indication that the gas flowline has not reached the steady state liquid hold up, thus liquid carryover from the caisson is negligible. All of these indicators combined gives confidence that the unit is not experiencing any liquid carryover greater than had been experienced during full scale testing with synthetic fluids.

**Impacts on Gas line Operability**

The primary factors affecting the stability, deliverability and performance of Ostra gas flowline operation include the caisson pressure, the topsides separator pressure, and the LCO from the caissons [3]. The separated caissons were originally designed to operate at 900 psia during initial production [3]. In general, a higher caisson pressure provides a broader operational window for the gas flowline, but it imposes additional back-pressure on the Ostra wells thereby reducing production from the wells. This is applicable if the well choke is fully open. Because of the strong performance of the wells and reservoir the caissons have been operating at 1200 psia with no impact of production by reducing the differential across the well choke. Figure 5 presents the Ostra gas flow line arrival pressure upstream of the topside choke, with the caisson operating at 1200 psia and the gas flow operates at topside choking mode for steady state operation. The figure displays how the operation window varies with gas rate, pressure, and liquid carryover from the separation caissons. Figure 6 presents the pressure drop...
across the Ostra gas line. In both figures the increased pressure drop at lower gas rate is mainly due to the hydrostatic head, and at the higher gas rate side it is due to friction loss.

The impact of separation efficiency was identified as a high consequence risk during the design phase. Strong efforts were committed to investigate the caisson separation efficiency, associated LCO impact on the gas line operation, and the mitigation strategies. Because the LCO from the caissons increases the liquid hold up in the gas flowline, the pressure loss increases substantially as LCO increases. Thus the deliverability of the gas flowline is significantly dependent upon the LCO. Substantial LCO can curtail the Ostra production.
The field operation data are presented in Figure 5 and 6 for comparison, showing very low LCO into the gas line. The topside has not received any liquid except during the transient process of start up and ramp up. Though the gas line has been operated at low gas rates relative to design, the pressure drop across the gas line has increased very slowly during a long production period, almost "quasi" steady state. This indicates that the liquid build up in the gas line is very slow, mostly due to condensation. All of the observations have indicated that the caisson actually operates at very high efficiency at the higher caisson pressure. The high separation performance the caisson was achieved by proper engineering of the separator, the control scheme, and the successful foaming control strategy.

Learnings from Argonauta B-West Non-Separated Caisson Operation

Performance of the Non-Separated System
The B-West Field has a low GOR, heavy oil, and with high viscosity. It is critical for the gas to remain in solution in order to maintain a manageable viscosity for production, and for restarting the system. Ref.1 has indicated the non-separated caisson operating mode is an adaptation of the separated caisson to allow standardization of equipment. The significance of this standardization in the caisson inlet utilizes the same pre-separation piping in the separated caisson. This pre-separation piping is designed to stratify the flow of the fluids entering the caisson, working against the overall goal of getting a homogenous fluid mixture to the inlet of the ESP.

With some pre-separation of fluids entering the caisson, a gas cap will form at the top of the caisson, with the remaining two phase fluids falling along the caisson wall to enter the inner shroud at the bottom of the caisson. To prevent gas from accumulating at the top of the caisson, a gas flow path was created to allow this accumulated gas to migrate from outside the shroud to inside. In addition to this gas flow path, the shroud height itself was increased higher up into the caisson as opposed to the short shroud closer to the pump inlet on the separated caisson. This is shown in Figure 2.

Once the system was started up however, this phase separation never consistently materialized. A defined gas/liquid interface was not detected as it was in the Ostra caisson. Instead a constant density across the entire Argonauta caisson was observed. The Ostra caisson operates with a density gradient, with the lighter fluid (predominately gas) at the top, and the heavier liquids at the bottom. Fluid densities for a separated caisson and a non-separated caisson are shown in Figure 7.
The data for the non-separated caisson shows the difference in fluid density between the top and the bottom is not significant. Based upon the density profile of the non-separated caisson, it is concluded that all the gas is being entrained in the liquids outside the shroud and carried down to the pump.

The fluid density across the Argonauta-BW caisson indicates a fluid with approximately 30-35% GVF as expected from the operating conditions. The lack of fluid separation does not have any material impact on the processing capability of the caisson/ESP. The long term reliability is still being assessed.

**Rapid Gas Decompression Learning**

Rapid gas decompression and its impact on the equipment has been discussed previously [Ref 1,3]. As part of anticipated start up scenarios, rapid pressure reduction in the Ostra caisson was anticipated. During the initial start up of the Ostra caissons, rapid pressure reduction was not experienced. The lack of a gas line on the Argonauta non-separated caisson causes unique issues, particularly during hot oiling of the system. If the caisson is allowed to equalize with the flow loop at full hydrostatic head pressure during hot oiling, start up of the unit could cause rapid gas decompression.

In this operating scenario, the non separated caisson exceeded the anticipated decompression rates. Figure 8 shows a pump start up after the caisson pressure has been equalized to the loop pressure during hot oiling. The pressure reduction was anticipated at two levels, from high pressure to an intermediate pressure, then intermediate pressure and then low pressure. The decompression rate exceeds the high pressure to intermediate pressure by 3.2 times higher than anticipated. The decompression rate exceeds the intermediate pressure to low pressure by 2.2 times higher than anticipated.

Subsequently, the start up procedures were modified to allow for this operating condition as a start up. For future projects, this issue could be mitigated in a number of ways, either procedurally or through the installation of additional equipment, such as a discharge choke. An example of a procedure modification is shown in Figure 9. Allowing the caisson to cooldown before restarting allows the pressure to drop in the caisson. Cooldown as a mitigation for rapid gas decompression was not originally considered as an operational mitigation due to potential deferment if the caisson was available for immediate restart. Given the potential damage from rapid gas decompression this procedural change was implemented.

![Figure 8. Rapid gas decompression during high pressure start](image-url)
Validation of Hot Oiling Circulation System Hydraulic Performance

For BC-10, the production system operability and hydrate management strategy strongly relies on hot oil circulation. The Ostra dry and dead oil is used as the hot oil circulation medium, because its viscosity does not cause restart issues, i.e., the dead oil is pumpable at seabed conditions. The dead oil is needed for the commissioning of the subsea production systems, start up of the ESP system, dead oil displacement (DOD) of the subsea system after shut down, and hot oil circulation (HOC) for restarting the subsea system and providing the required cool down time to hydrate, before bringing the wells on-line. The reliability and sustainable performance of the hot oil circulation system is essential for field production. Hence the simulation of DOD and HOC are important for both design and operation. Proper prediction of HOC and DOD hydrodynamics can avoid overly conservative system design that causes significant increase in CAPEX or under design of the system that may impair the production due to insufficient hot oil capacity.

For the Ostra field, DOD mainly serves as a hydrate prevention strategy after shut down. During steady state flow, the insulation on Ostra intra-field and oil flowlines allow them to operate outside hydrate region though the field life. After shut downs, there is a 3-hours ‘No Touch Time’ period which a re-start can be initiated if the shut down can be resolved and cleared. After 3-hours, the intra-field, oil flowlines are displaced by dead oil provided from the FPSO via the insulated service flowline. DOD is performed using one of the topsides hot oil pumps with a discharge pressure of 2,000 psia. All dead legs within Ostra production system are left full with Ostra dead oil after completion of dead oil displacement. Alternatively, the intratfield lines can also be depressurized to sub-hydrostatic through the caisson separators and the Ostra gas line, in case of constrained HOC capacity during a full field shut down. For start up of the Ostra field, hot oil is circulated from topsides to the Ostra service riser to PM1 and returns from the Ostra oil riser to pre-heat the flowline system before starting up the caissons and wells. HOC is continued until a minimum of 12-hours cool down time becomes available.

For B-West, DOD has two functions for shut down: to displace the high viscosity fluids from the loop to prevent re-start difficulty, and to prevent hydrate formation. Hot oil is pumped down from one of the B-West flowlines (as the service line), and returns up the other flowline. The heavy oil’s viscosity increases dramatically as the pressure and temperature decreases. The heavy oil is also prone to stable emulsions as the watercut increases, which substantially increases the emulsion viscosity until passing the emulsion inversion point as shown in Figure 10. If the live B-West oil would be left in the subsea system due to the failure of dead oil displacement, restarting the system would be very difficult.

Due to the non-Newtonian behavior of the heavy oil and its emulation, simulations of DOD and HOC are very challenging, and beyond the capability of commercial engineering tools. The simulation requires tuning of fluid viscosity based on the experimental data under various pressure, temperature, and watercut assumptions. The required displacement times and dead
oil volumes are calculated. Efforts have been made to validate the DOD prediction and verify the hot oil systems’ performance. The results are shown in Figure 11. The required DOD time depends on

- The time to start DOD after shut down - The longer the waiting time, the longer the DOD time.
- The DOD rate available for the loop - The higher the rate, the shorter the DOD time.
- The production mode prior to system shut down - Two lines or only one line in production.

Figure 12 describes a shut down event in B-West and following DOD operation, of which the DOD started 1 hr after shut down. The DOD rate is 10000 bpd, and only one flowline is in production prior to shut down (the other leg is filled with cold Ostra dead oil). Figure 12 presents the simulation results of the event shown in Figure 11, using tuned viscosity data. The comparison of calculated DOD time and field operation data is displayed in Figure 13. The hydraulic performance of the DOD process and the hot oil circulation has been confirmed and the methodology of numerical simulation has been validated.

Figure 10. BC-10 heavy oil viscosity variation with temperature, pressure, and water cut.

Figure 11. B-West flow loop dead oil displacement – required time versus shut down time; production mode prior to shut down.
Figure 12. Field surveillance data of B-West field shut down and dead oil displacement operation.

Figure 13. Simulation of dead oil displacement operation in Figure 11.

Conclusion

Since start up, Parque das Conchas has been in successful operation. This paper summarizes how it has been possible to build a highly effective subsea processing and production system around vertical caisson separators and ESPs. The reliance of such a system on high reliability auxiliary / service system has been clearly shown.

Taken as a whole, it’s interesting to note that the portions of the system that have provided the most consistent challenge and variation in terms of noted performance throughout the first year of operation have not necessarily been those that are most
novel (uniquely-applied pressure and level control systems interfacing with medium voltage drives to operate high horsepower ESPs on a reasonably long offset) but rather the ancillary equipment (like continuous chemical injection and distribution) that have been regularly included in conventional subsea systems. It was (and continues to be) through a multi-disciplinary systems approach, carried through design into operation and surveillance, that the challenges that have arisen have been successfully addressed.

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