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Transient Simulations of Well Shut-in and Startup in Offshore Production Facilities at Characteristic Brazilian Pre-salt Conditions

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Abstract
Temporary well shut-in and startup operations require risk-management protocols due to flow assurance and structural integrity issues of the well and production pipeline, for example, arising from the formation of hydrates during downtime and the high-pressure oscillations characteristic of transient multiphase flows. Here, two commercial multiphase flow simulators, ALFAsim and Olga are explored in the context of shut-in and subsequent startup operations. Cool-down and pipeline depressurization times during shut-in were evaluated at the sea-bed pipeline as 1.5 and 3 hours, respectively. Following that, the time needed for a return to a quasi-steady operation was also assessed, being 2 hours from the reopening of the valve system. In the full paper, these timescales, as well as no-touch time for hydrate formation will be assessed for a range of conditions characteristic of the Brazilian pre-salt production scenario.

Keywords
Offshore production; Transient multiphase simulation; Commercial software comparison

Introduction
Transient simulations of Offshore Production Facilities (OPFs) are an important step in the design of such systems and a key tool to ensure their safe operation. In deepwater developments, for instance, a major concern is the potential impact of unscheduled shutdowns in production, which can lead to hydrates or wax blocking the production pipeline. Assessing the flow behavior during well shut-in and startup through simulations allows engineers to identify potential risks ahead of time and design equipment (e.g. thermal insulations) and mitigation measures accordingly, therefore reducing production losses and operational costs due to excessive downtime. In this work, we assess the performance of the commercial software packages when dealing with complex transient operations.
Comparisons between commercial software and field data are rare in the literature, particularly for transient conditions. Nemoto *et al.* [1] utilized the commercial software OLGA to determine pipeline-riser geometry dimensions and insulation requirements under specific pressure and temperature conditions. Transient modeling was employed to evaluate production shutdown scenarios, considering hydrate formation. Trujillo *et al.* [2] utilized the commercial software ALFAsim to investigate severe slugging in a subsea tieback and the impact of CO_2 content on flow dynamics. Góes *et al.* [3] assessed the predictive capabilities of OLGA, ALFAsim, and a proprietary Drift-Flux Model for hypothetical and actual offshore gas and oil pipeline flow data. Almeida *et al.* [4] conducted a comprehensive comparison of OLGA, ALFAsim, and an in-house 1-D model using steady-state production data from OPFs in the Campos Basin.
The objectives of this work are threefold: first, to explore the flow behavior in the tubing, flowline and riser of different OPFs during two operations: well shut-in and startup. Second, to compare the different predictions by two commercial software packages used as flow assurance tools in the oil & gas industry, namely ALFAsim and OLGA. Third, to evaluate key operation parameters such as cool-down time, depressurization time and no-touch time for a range of OPFs representative of the Brazilian pre-salt production scenario, that is, comprising a specific hydrocarbon composition and water content, high flow rates, high pressures, large pipe diameters, and significant quantities of dissolved gases.

Methods
A number of Offshore Production Facilities (OPFs) situated in two offshore pre-salt fields within the Campos Basin were modeled in the commercial multiphase flow simulators ALFAsim (ESSS O&G) and OLGA (SLB). The geometries included the well and the production pipeline, described in detail next. The fluid's properties and phase equilibrium have been evaluated previously, validated against

data obtained from flash and differential liberation tests with samples from pre-salt fluids [5]. The simulations performed consisted of achieving a quasi-steady state condition of the flow in the OPFs, after which a number of valve operations were performed to investigate the flow behavior.

Geometry and Boundary Conditions

Each OPF comprises a well – through which flows the hydrocarbon mixture from the reservoir to the seabed via the production tubing – served by a dedicated production pipeline. The production pipeline consists of a flowline, which rests on the seabed, and a riser, which is suspended. Both well and production systems are connected by the Wet Christmas Tree (WCT), with remotely-controlled valves. The OPF geometries were identically implemented in both softwares and were based on two subdomains: (i) well, from the Permanent Downhole Gauge (PDG) to the WCT; (ii) production pipeline, from the WCT to the Stationary Production Unit (SPU). Their key parameters are given in Table 1.

Table 1. Geometric and operational parameters of the Off-shore Production Facilities

Parameter	Average (Min/Max)
Water depth m	1380 (1310/1450)
Riser length, m	2100 (2000/2200)
Riser internal diameter, mm	152.4 (-/-)
Flowline length, m	3600 (2000/5800)
Flowline internal diam., mm	203.2 (152.4/203.2)
PDG depth, m	3750 (3500/3900)
Tubing internal diam., mm	118.6 (76.2/150.4)
SPU pressure, barg	55 (10/140)
Liquid flow rate, m3std/d	2700 (1100/3900)
Water vol. fraction (BSW), %	4% (0/22)

In the simulations, a mass flow boundary condition was implemented as zero flow at the reservoir, and a reservoir model was used with an Inflow Performance Relationship (IPR) table and set values for oil flow rate, temperature, and water cut. A pressure boundary condition was set as the pressure of the reservoir. Additionally, the SPU pressure and temperature of the Temperature and Pressure Transducer (TPT) were also set as input parameters.

Implementation in Olga

In OLGA, a three-fluid model was used, in which continuity and momentum equations are applied to each of the continuous and dispersed phases, while the fluids are coupled by interfacial mass transfer. A transient solver was used to solve a set of one energy equation and seven conservation equations, as well as a state equation for pressure. PVT tables containing fluid properties of each OPF were used in Olga as well as ALFASim.

The pressure drop calculation used OLGA's classic formulation with surface roughness values of 50 μm for well tubings and 210 μm for production pipelines). The thermal modeling of each OPF considered the contribution of metal alloys and polymers layers to the thermal insulation of the production pipeline, as well as a forced convection condition on the internal and external surfaces, concerning the hydrocarbon flow and the sea currents, respectively. As for the wells, external convection gives rise to 1D transient heat conduction in the rock formation, and there is also the effect of natural convection in the annulus, which was also represented.

Implementation in ALFAsim

ALFAsim's three-phase three-layer model was used for all simulations, solving for the global energy equation and mass and momentum conservation equations for each layer consisting of a continuous plus a dispersed phase. The unit cell model approach was selected to capture flow-regime effects with a minimum and maximum segment size of 1 m and 8 km, approximately.

The friction factor was evaluated explicitly, updated at each timestep. Heat transfer to pipe walls was modelled identical to the simulations performed in OLGA, and the same tabulated fluid properties in a PVT tab file were used. The OPF was modelled using a mass flow node connected to a blank node and, finally, to a pressure node -- following the scheme described previously.

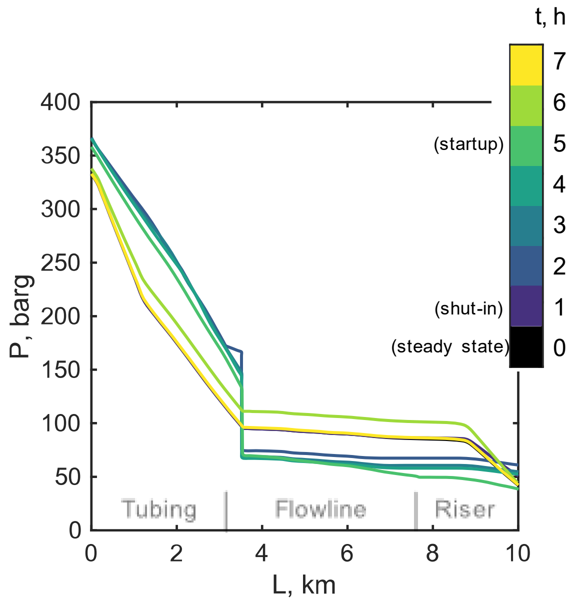
Validation at Quasi-Steady State Conditions

In the authors' previous work [4], both numerical schemes have been compared to field data gathered during production tests conducted in seven OPFs. The pressure drop from quasi-steady state conditions obtained in the simulations were compared to 350 data points from seven OPFs. Overall, the resulting predictions fell within ±20% of the field measurements, with a similar hit performance of 94% for both simulators.

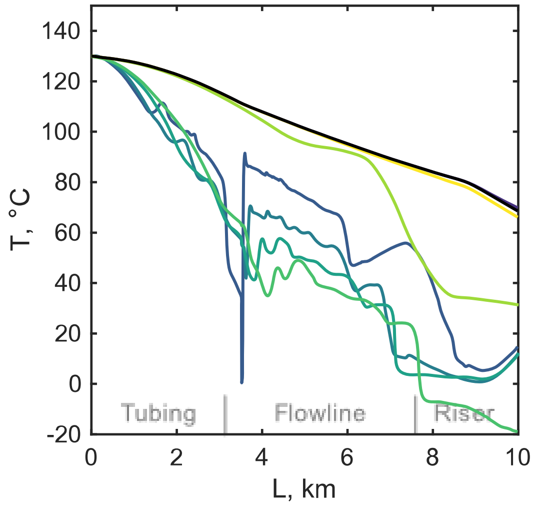
Results and Discussion

A well shut-in/startup is performed for one of the OPFs with 20.2% of basic sediments and water (BSW) and a liquid flow rate of 2133.3 m_{std}^3/day. The operation was implemented numerically by setting the two Perkins valves located at the WCT and SPU positions to close after 1 hour from a steady-state condition (t=0). The valve orifice is gradually closed over 30 seconds until fully closed, with a 1.5-min phase difference (first SPU valve). Then, both are reopened after 4 hours (t=5 h).

The effects of shut-in can be observed across the whole pipeline system in Figure 1 through three important parameters of hydrocarbon production: (a) pressure, (b) temperature and (c) liquid holdup. After the well shut-in, an increase in pressure was observed in the tubing region (Fig. 1a), which is replicated in the following hours with a sharp transition due to the position of the closure valve in the WCT. This occurs due to the accumulation of production hydrocarbons in that region, contrasting with the flowline and riser region, which over the well shut-in period exhibited an almost steady



(a)



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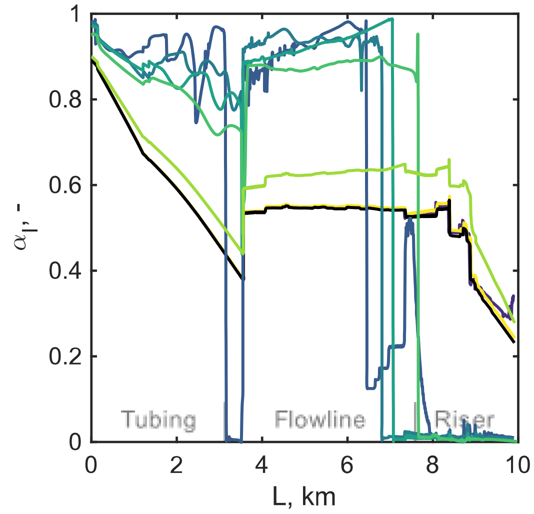


(c)

Figure 1. Evolution of (a) pressure, (b) temperature, and (c) liquid holdup profiles across the well and production pipeline.

pressure profile. From Figure 1b, it is evident that the well shut-in procedure primarily caused a generalized cooling of the pipeline in the period between t=2 and 5h, expected due to the resting of the flowline at the seabed, with a surrounding temperature of approximately 4°C.

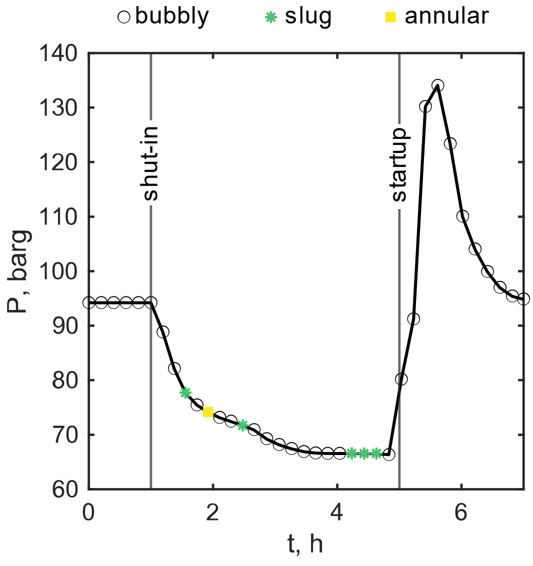
Fluid remained stationary in the pipeline after the valve closure, resulting in continued thermal exchange with the sea-bed currents and, in turn, significant cooling of the system (Fig 1b). As flow was reestablished, the fluid recovered most of the same temperature profile at t=6h (light green line), reaching its initial csteady-state condition in terms of temperature at t=7h (yellow and black lines overlaping in the plot). One can also notice that flow fluctuations stem from the well shut-in process, as large variations of the liquid holdup (Fig. 8c) seem to propagate across the pipeline, representing a range of different phenomena such as flow reversal and accumulation.

To better understand the impact of the shut-in and restart operation at important region prone to hydrate formation, the same parameters are evaluated at the WCT position (Fig. 2). Once the valve closure procedure was initiated, pressure and temperature continously drop at the WCT for 1.5 h, and a momentary transition from bubbly to annular flow was observed at this position due to the large depressurization of the pipeline at a high-enough temperature, enhancing phase change. Cooling of the pipeline down to a temperature of roughly 15°C occurs within approximately 1.5 hour, and progressive depressurization down to 60 bar occurs during 3 hours after closure of the valves. After both valves are reopened, a peak pressure is reached at nearly 140 bar with the influx of hydrocarbons, reducing to 100 bar and recovering its initial steady-state conditions 2 hours after the reopening operation. During the 4-hour intermission between shut-in and restart, no conditions prone to hydrate formation were detected in the pipeline. In the full paper, the no-touch time for hydrate formation will be assessed for each OPF condition.

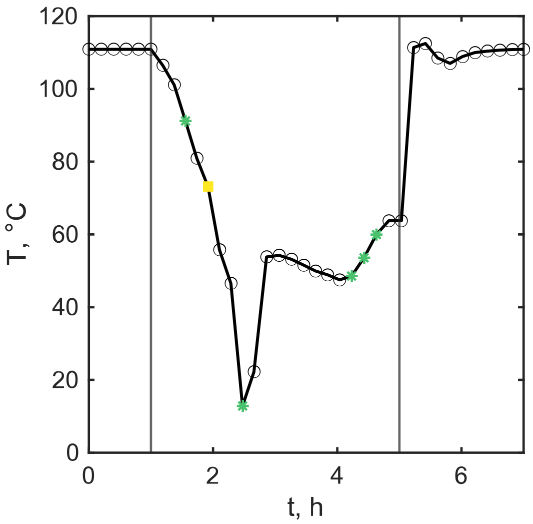
Conclusions

The flow behavior in the well and the production pipeline was explored at conditions representative of Brazilian Offshore Production Facility in pre-salt wells, as predicted by the commercial software ALFAsim in light of a shut-in/startup operation. After a programmed shut-in, cool down of the sea-bed pipeline occurred within 1.5 hours, while complete depressurization took roughly 3 hours. The operation was resumed and recovering of the initial steady-state condition was achieved after 2 hours from the reopening of the valve system.

In the full paper, results from simulations using both ALFAsim and Olga will be compared against each other. The time scales of cooling, depressurization, and no-touch time for hydrate formation will be assessed in terms of geometric, environmental and



(a)



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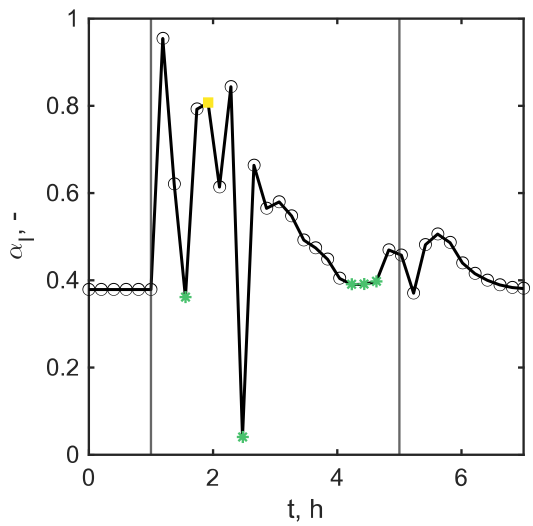

(c)

Figure 2. Evolution of (a) pressure, (b) temperature, and (c) liquid holdup at the Wet Christmas Tree.

operational parameters of a number of Offshore Production Facilities.

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Responsibility Notice

The authors are the only responsible for the paper content.

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