os testes de formação, mostrando com isso que a injeção na AST vem obtendo resultados satisfatórios. Podem existir casos isolados em que haja necessidade de injeção abaixo do *mudline*, esses casos têm de ser avaliados para cada teste; as maiores dificuldades na injeção abaixo do *mudline* residem na adaptação do sub de injeção com passagem pela AST;

- considerações acerca dos volumes calculados e os recomendados para o caso do Poço Alfa do Campo Beta, foram mostradas no quadro 1, que, pelo fato de o fluido ser de solução salina saturada em sal com 260.000mg/L (26% de NaCl), considerou-se que 50% da água concentrada no gás será inibida pelo sal. Assim sendo, o quadro resumo comparativo, faz essas considerações e comparações entre os volumes injetados durante o teste e os volumes calculados pelo *software* HYD-III;

- por tratar-se de um estudo de caso do Poço Alfa do Campo Beta, o trabalho ficou restrito à análise dos dados do TFR-3 do Poço Alfa e, a partir desses dados, foram feitas comparações com os obtidos na simulação pelo *software* Pipesim, para o poço no 2° fluxo. A abertura para 1° e 2° fluxos, não foram simuladas em virtude das dificuldades encontradas em medir os teores de água no gás.

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expanded abstract

The formation of hydrates in drilling and production operations, as well as the completion and evaluation of oil and gas wells, in offshore, deep water areas, is a concern for the operation technicians. Hydrates are crystalline compounds with the appearance of ice, which is formed when gas molecules are trapped by the hydrogen molecules contained in water, under high pressure and low temperature conditions. When this happens, there is a usually blockage in the production systems (lines, manifolds, valves etc.). Offshore operations at depths below 800m, in the presence of water and gas, are conducive to hydrate formation due to the normally low temperatures at the mudline, around 4^0C associated with high pressures of the well operations. Therefore the prevention of hydrate formation in deep water operations has become a challenge. Many articles have already been published in national and international literature dealing with the subject. By and large, there is a wide diversity of petroleum operations that must be performed with hydrate formation preventive actions. Once the hydrate is formed, its removal can be time-consuming, with significant cost implications for the companies. Among the main hydrate formation prevention methods, chemical kinetic and thermodynamic inhibitors can be highlighted. The latter is most commonly used by Petrobras in the form of ethanol and monoethylene glycol (MEG), while other overseas operators use methanol. Despite its high performance efficiency in hydrate prevention, the inhibitor methanol, for health related reasons, is not used by Petrobras.

This study seeks to detect possible situations favorable to hydrate formation during the phases of a Repeat Formation Test (TFR), in a deep water natural gas well at a depth of 1,608m. The study was developed for the (Alpha) gas well in the Beta Field, with the reservoir and the composition characteristics as defined in scenario 1.

It was of paramount importance to identify pairs of points [P Pressure versus T Temperature] that favored hydrate formation, using the Sealink test column near to the mudline. Sealink is equipment which facilitates a faster disconnection of the Landing String test column above the mudline, in emergency situations. In addition it records the temperature and pressure parameters at the mudline during testing, thus identifying conditions favorable to hydrate formation.

During the work, each step of the TFR is shown with pressure and temperature profiles, as well as the thermodynamic inhibitor dosages used to prevent the hydrate formation during the test. The dosages of hydrate formation inhibitors were calculated using the Petrobras/Cenpes software HYD-III.

From the reservoir condition data and the mechanics of the formation test column scheme used in Alpha Well, simulations were made of well flow conditions for three choke openings [16/64"; 24/64"and 32/64"] and their respective flow rates, for the second run of the TFR. The values obtained for the pressure and temperature simulations at the mudline were compared with the Sealink measured values. The comparison of those figures, after a few test flow rate adjustments, showed that it is possible, through simulation, to find pairs of points [*P* Pressure versus *T* Temperature], which permit the thermodynamic inhibitor dosage calculation to be used during this phase of testing. The Pipesim software also enables the multiphase flow curves and the hydrate envelope to be traced with the thermodynamic equilibrium curves.

Salt is an important hydrate formation inhibitor and as the test fluid used was a saturated saline solution with 260,000mg/L salinity, it allowed the saline solution inhibition influence to be considered in the recommended dosage calculation in each test phase. The fluid salinity variation used in the first run, during the well cleaning, was recorded and taken into account in the final evaluation of the inhibitor dosages. For the purposes of thermodynamic inhibitor calculations, the completion fluid was considered to inhibit only 50% of the contained water.

The well cleaning phase during the first run is highlighted as causing a major hindrance to estimate the amount of hydrate inhibitor, due to the difficulty to

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obtain a reliable value for the concentration of water in the gas [lb/MM ft^3]. This is caused by the difficulty to accurately register the gas flow rates and respective BSW's in the Page Type 1 (FT-1). This particular case requires a laboratory research study to resolve some doubts left regarding the concentration of water in the gas, taking into consideration the change in salt concentration observed during the test.

The increasing difficulty to locate storage for large ethanol and MEG volumes on drilling rigs, points to consider the use of kinetic inhibitors, which require smaller concentrations compared to thermodynamic inhibitors. From this case study analysis, it was concluded that it would be possible to use kinetic inhibitors during the second run, because the lowest cooling values found in this test phase were $12^{0}C$, these values being smaller than those recommended for the use of kinetic inhibitors. In view of their limited application time, kinetic inhibitors are not recommended in the well cleaning stage nor following the well reopening after the static. For these cases thermodynamic inhibitors are recommended, as already mentioned, due to their infinite application time. The use of one or another inhibitor must be taken into account in addition to the ease of use, the technical characteristics of the products and the costs involved. The use of kinetic inhibitors in test operations is still a paradigm to be broken. To date there is no awareness of the use of these inhibitors during stabilized flow periods in formation tests.