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LAST 20 YEARS OF GAS HYDRATES IN THE OIL INDUSTRY: CHALLENGES AND ACHIEVEMENTS IN PREDICTING PIPELINE BLOCKAGE

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ABSTRACT

The continuous effort to understand the complicated behavior of gas hydrates in multiphase flow has led to the evolution of a new paradigm of hydrate blockage. The hydrate community continues to debate the impact of kinetics, agglomeration, and oil chemistry effects on hydrate blockage formation in pipelines and wellbores. However, today's industry for the most part still continues to rely on thermodynamic means to develop strategies to prevent hydrates altogether in its production systems. These strategies such as thermal insulation of equipment, electric heating, dead oil displacement, and methanol injection add CAPEX, OPEX, and operational complexities to system design. In spite of high oil prices, adopting such strategies to mitigate perceived hydrate blockage risk can end up taxing economics of marginal fields.

Developing a comprehensive multiphase flow simulator capable of handling the transient aspects of production operations - shut-in, restart, blowdown and blockage prediction - continues to drive the research in Flow Assurance. New operating strategies based on risk management approach seem to be evolving from the model predictions. A shift in paradigm that allows for operations inside the hydrate region based on sound risk assessment and management principles could be a factor enabling future developments of marginal fields.

This paper discusses the challenges and opportunities that have led to the change in focus from prevention of hydrates to prevention of blockage, and describes some initial successes in the development of a first generation empirical tool for the prediction of hydrate blockages in flow lines. Also presented in this article are new experimental data that shed some light on different ways that hydrate blockages can manifest in the field.

Keywords: hydrates, plug, plugging, blockage, simulations, restart, CSMHyK-OLGA

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INTRODUCTION

During the last two decades, the design and operational challenges associated with offshore production have demonstrated the need for flow assurance in the area of gas hydrates. The need to minimize offshore systems CAPEX and OPEX, especially of those involving hydrate management operations, is catalyzing the development of implicit rules into effective technology. As a result, a fluid flow oriented hydrate paradigm has evolved in the recent years to replace the intrusive hydrate strategy, which is mainly based on chemicals and external infrastructure to mitigate hydrates.

The emerging approach is progressively growing as researchers and engineers learn from the hydrate setbacks and achievements of the last twenty years. Effective coupling of the field and laboratory observations and novel ideas favors the new paradigm. For instance, the rigid hydrate plug concept has been "demystified" by experimental evidence, which suggests that changes in rheological properties by hydrate formation might be the actual cause of system failure.

This article presents information that relates how the successes of the last twenty years have shaped the new hydrate focus and provides an insight into state of the art tools in hydrate plugging prediction, such as CSMHyK-OLGA.

HYDRATE PLUGGING & OIL CHEMISTRY

Although there are no two crude oils with identical properties, it is expected that oils with similar characteristics behave alike under a set of pressures, temperatures and flow parameters. Unfortunately, when examining hydrate plugging behavior, this is not always the case. Marked differences in plugging behavior have been promoting an important initiative to understand how chemical classes native to the oil might prevent hydrate plugging. Initial studies [3] suggested oils that emulsify readily tend to exhibit lower plugging potential than segregating oils that do not strongly disperse water. This behavior was associated with the decrease of oil-brine interfacial surface tension caused by asphaltene and surface-active components present in the oils. Later studies [7, 8] offered an explanation to this phenomenon as they hypothesized that the removal of naphthenic acids and phenols favors the asphaltene destabilization, which increases the emulsion stability and thus hydrate transportability. Similarly, it has been proposed that surface-active components (phenols & naphthenic acids) by themselves contribute to a lesser extent to the emulsion stability than asphaltenes.

Further investigation of deasphalted and pH14 modified oils through hydrate testing showed opposite behaviors. Oils without naphthenic acids and phenols performed better in terms of plugging in flow wheel hydrate experiments, while deasphalted oils showed better hydrate transportability in flow loops. Given the difference in shear field for each technique, the discrepancy observed might be apparatus specific rather than the class behavior.

Although surface-active components influence the hydrate plugging mechanism, their role is still unclear. However, given the evidence[10] that oil-wetted hydrates could transport hydrates as slurries, studies are in progress to relate wettability with oil surface-active components.

Irrespective of whether active surface components are responsible for the transportability of hydrates, researchers seem to agree on the conceptual pictures of hydrate transportation in oil dominated systems. The transportation process seems to be possible as Heterogeneous or Homogeneous transportation as can be seen in Figure 1. These transportation patterns might be modified according to the flow pattern developed, which can result in stationary or moving beds that can be described through modeling[11].

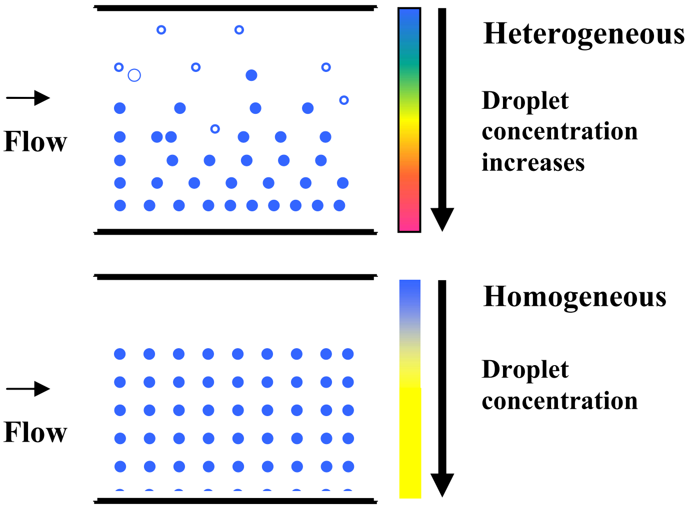

Figure 1 Conceptual Depiction of Viscous Plugs

Classifying hydrate slurry as viscous plug does not completely depend on the characteristics of the slurry formed but also the system characteristics. Viscosification effects observed in flow loop studies during viscous plugging studies revealed pressure drops as high as 3,300 psi/mi. Such a significant pressure drop would certainly choke off flow from any naturally flowing reservoir across an extended (>20-mile) pipeline.

The overall concept of hydrate blockage formation is still under debate. The complexity of the blockage mechanism increases significantly as a combination of fluid flow, phase distribution and solid particle forces dictates the interaction between phases and thus blockage development. For instance, common flow patterns in oil dominated systems: stratified and intermittent flow might induce different hydrate plugging processes. Chevron and our industry alliances conduct significant efforts to continue hydrate plugging research along this path.

HYDRATE PLUGGING AND RHEOLOGY

Before identifying the effect of chemical classes on hydrate formation, scientists [4] had already observed a phase distribution effect on the hydrate plugging outcome. However, their observations showed that emulsified conditions (before hydrate formation) resulted in a “slush” like mixture and segregated fluids resulted in hard hydrate spheres, the observations were attributed to velocity effects rather than to shear stress conditions that might have promoted the phenomenon. Later investigations[6] approached these observations from a rheological point of view rather than fluid flow aspect. It was proposed that chemical classes such as asphaltenes were adsorbed on the hydrate surface, promoting a reversible aggregation process. This hypothesis helps to understand the shear thinning behavior observed in laboratory and flow loop experiments.

As rheology theory continues to give insight into the hydrate plugging concept, other studies about droplet size distribution, particle-particle micro-mechanical forces and phase inversion point allow the application of pre-existing flow concepts. These concepts are already being used to quantify the force required to overcome the yield stress generated by viscous plugs during restart operations, as seen in Figure 2.

The information presented in Figure 2 reports ongoing flow loop experimental work that will be detailed in future articles. Preliminary results of this study confirmed that the preexistence of an emulsified phase before hydrate formation improves the hydrate transportability as a slurry flow. However, the enhancement of hydrate slurry flow seems to be limited by the initial physico-chemical properties of the fluids. Experiments conducted by DeepStart[7], further corroborate this observation. Oils with high emulsifying characteristics and high viscosity exhibited poor hydrate transportability when compared to less viscous oils with similar asphaltene content. From this observation, it could be inferred that failures resulting from increasing water cuts in oil continuous systems are pre-set by the increase of mixture density and viscosity. Field application of this concept might result in mature wells with readily emulsifying fluid properties having lower viscous hydrate plugging probabilities than fluids from new low water cut wells without emulsifying characteristics.

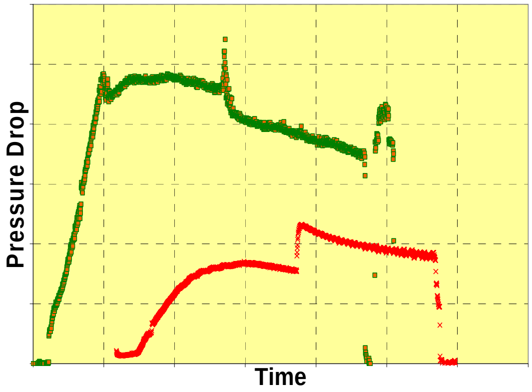

Figure 2 Pressure Drop Behavior during a Viscous Plug at Restart

Although preliminary results from hydrate slurry rheology testing are promising, an extension of fluid flow theory incorporating the gleaned information is required. This would allow verifying that processes corresponding to fluid flow are consistent with the current rheological findings.

HYDRATE PLUGGING PREDICTION TOOL

Given the current operational perception that hydrate formation is synonymous with blockage, hydrate thermodynamic predictions are considered the standard while defining the hydrate operability envelope. Although "safe" for operations, such a conservative approach can be a significant burden on economics of field development concepts. As such, the project economics in these cases may preclude the development of marginally economic resources.

Efforts to minimize the overly conservative use of the "hydrate plugging" envelope have resulted in promising tools. That is the case for CSMHyK-OLGA, where coupling of transient multiphase flow calculations with a first order hydrate kinetic model was effectively achieved. Moreover, the modification of the relative viscosity concept by Mills[2] in order to account for solid sphere interactions, makes CSMHyK-OLGA a useful tool to investigate the hydrate viscous plugs described in previous sections.

A hypothetical case study relevant to an offshore oil producing system is described in the next section to demonstrate the utility of this tool.

System Setup

The case consists of a manifold connected to a 24 mi. production flowline. The flowline profile can be seen in Figure 3.

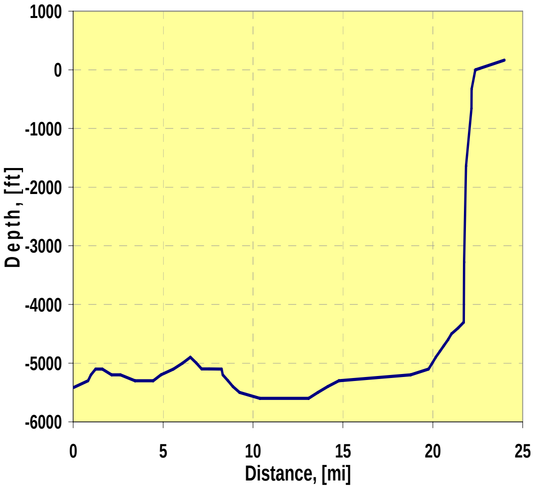

Figure 3 Simulation Flowline Profile

The system will be studied under two conditions: steady state and restart conditions. The following parameters were assumed:

T_{in} = 150 °F

P_{res} = 6,000 psia

P_{out} = 200 psia

$$U = 5 \ \frac{W}{m^2 \cdot {}^\circ C}$$

Oil flow rate = 32,000 STBO/d

Flow line ID = 10 in.

Fluids

The hydrocarbon phase was tailored to resemble a Gulf of Mexico crude oil with a compositional representation from methane to C_{30}+. The resulting hydrocarbon and brine mixture exhibited the following characteristics:

Density = 26 °API

GOR = 500 SCF/STB

Water cut = 30 %

NaCl concentration in brine = 35,000 ppmW

Steady State Results

The temperature and liquid hold up results can be seen in Figure 4. The study of these parameters allows verification of the insulating characteristics of the system and anticipation of possible challenges arising during restart and shut-in conditions. For instance, Figure 4 indicates that the system insulation as defined will not be sufficient to achieve a cool down time of 8 hours as the riser temperature (last 2 miles of profile) is close to the hydrate temperature curve during steady state. This cool down time is desired as a buffer time needed to allow operations some time to determine whether to execute procedures to make the system hydrate safe during shut-in or to allow a few hours to restart the system prior to executing these procedures. Typical flow interruptions are 3 hours or less.

Restart Results

As anticipated, restart simulations showed significant hydrate formation. Subcoolings of about 20 °F were observed throughout the system within 5 hours of shut-in. Restarting the system under such conditions inherently presents a high risk of plugging. Figure 5 further demonstrates this point as viscosity ratio (μ/μ_o) grew to greater than 4,200 and hydrate fraction in the oil phase reaches unity at the bottom of the riser.

The combination of transient fluid flow behavior and hydrate kinetics coded in CSMHyK-OLGA not only allows the quantification of hydrate formation as shown previously, but also becomes a handy tool to investigate the interrelation of these parameters. For instance, gas dominated system simulations[12] have shown that heat transfer limitations and the exothermic hydrate formation during restart might induce a localized temperature increase equal to or greater than the hydrate equilibrium temperature, as seen in Figure 6. Taking advantage of this phenomenon might avoid excessive pretreatment of gas dominated systems with methanol or MEG during restart.

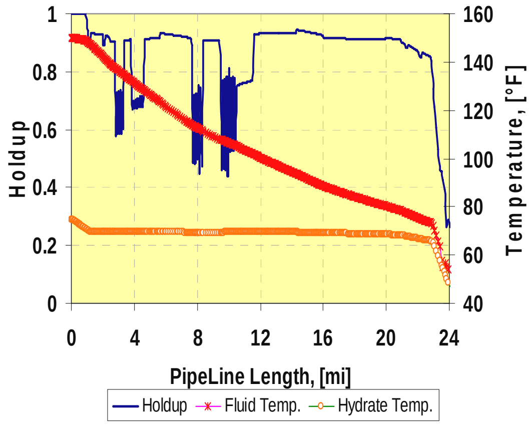

Figure 4 CSMHyK-OLGA Steady State Results

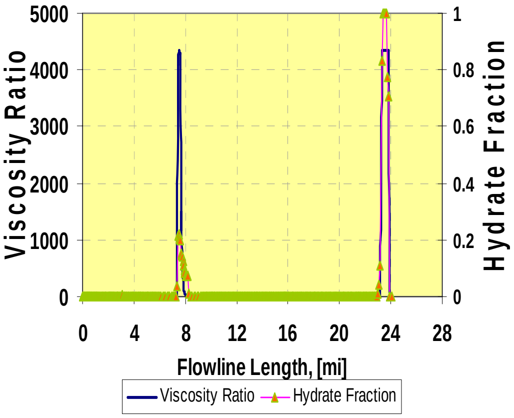

Figure 5 Hydrate Occurrence Profile after one hour into Restart

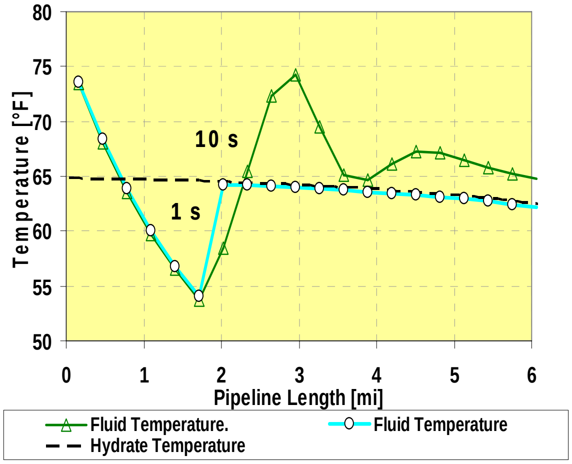

Figure 6 Localize Temperature Increase due to Hydrates Formation during Restart

Coupling CSM hydrate prediction tool and the OLGA^{TM} transient multiphase flow simulator, surely offers valuable advantages However, further development of this tool is needed, as empirical knowledge is still required to interpret the results. For instance, the current modeling does not account for high levels of gas entrapment in the oil phase observed during flow loop experiments. This fact leads to erroneous pressure drop prediction; unless, an induced swelling of the oil from dispersed gas is applied to the fluid mixture. Plugging mechanism, such as jamming and wall deposition, play an important role in the improvement of this tool. Consequently, studies have been initiated with the goal of incorporating these mechanisms into this useful tool in the future.

CONCLUSIONS

The result of compiling the last twenty years of achievements and failures in the hydrate plugging area shows significant improvement. Although the hydrate plugging mechanisms have not been unveiled, better understanding of the factors that affect hydrate blockage formations were achieved. Integrated forecasting tools, which allow not only hydrate studies but also transient multiphase studies, have been developed. Phase distribution effects prior to hydrate formation have shown a significant influence on determining the hydrate slurry transportability. Evidence suggests that crude oil with emulsifying characteristics could be excellent candidates for hydrate slurries, provided that pre-hydrate physico-chemical properties are not severely modified (i.e. high viscosity.)

A significant amount of innovation was obtained through collaboration between chemical engineering with other scientific disciplines such as chemistry and rheology. For instance, without them it would have been more difficult to hypothesize how the chemical classes present in crude oils stabilize emulsions and actually support the creation of dispersed phases in the presence of hydrates in the total fluid system. Further collaboration with other areas such as fluid flow is required to unravel the hydrate plugging mechanistic mystery.

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