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1 INTRODUCTION

The optimal design of a Subsea Pipeline system is always an uphill task. Subsea operations pose such challenges as Pressure drop, temperature drop, etc. which lead to chemistry related flow challenges like formations/precipitations of; waxes, scales, Asphaltene, Hydrates, etc. Hence the essence of Flow Assurance which involves the thermal-hydraulic designs of production and offtake systems as well as the predictions and remediation of these flow challenges [1].

Normally to avoid the problem of temperature drop or heat loss, flow rate should be increased. To increase the flow rate, a smaller inner pipeline diameter has to be used but this leads to the problem of pressure drop and slugging [2,3]. To avoid excessive pressure drop a larger pipeline inner diameter can be used but also with draw backs on cost [4], reduced flow rate and then heat loss due to large distance between the wellhead and the platform. To curb excessive heat loss, a good insulation material is used for the pipeline but this also comes at a great cost especially for long distance pipelines [5].

With all these, it can be seen that the solution of one problem leads to another problem. Hence in the course of this work, an optimum design of a pipeline system which would address and curb all these challenges mentioned above would be reached. The system will be able to discharge the produced fluid to the host platform at a pressure above 10.3 bar and the arrival fluids have to be at a temperature above 25^{o}C to avoid wax and hydrate formations over a distance of 10,000m through a riser of 200*m* elevation. Having been provided with ranges of inner pipeline diameter and flow rates, an Optimum pipeline diameter to use which will give an outlet pressure above 10.3bar and a good Insulation configuration would be suggested in order to avoid temperature dropping to below Wax and Hydrate appearance temperatures.

The Pipeline diameter which would be recommended should be able to deliver fluids at a pressure above 10.3 bar towards the end of the field life when the produced fluids will be 90% water, otherwise there would be need for artificial gas lift [6].

The scope of this work also covers looking into the suitability of the slug handling capacity in the system when the flow rate is at 3280m^3/day which is the worst case scenario.

To come up with these optimal and appropriate design parameters, a steady state simulator "**PIPESIM**" which is Production System analysis software that models multi-phase flow from the reservoir to the wellhead would be used [7,8] .

The methodology section of this report would detail how the simulations and design were carried out based on the given set of data, the results of the simulation and the analysis of the results would as well be detailed out under results and discussion sections respectively.