Performance analysis of associated gas transport in a multiphase pipeline

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Abstract

The aim of this paper is to evaluate the fraction of gas that can be safely transported in a multiphase pipeline instead of flaring it at the production site. The Olga software was used to estimate the pressure increase in the pipeline due to the injection of the gas. Furthermore, potential flow assurance problems were checked using the same software. It was found that all the produced gas can be safely injected in the pipeline as the resulting pressure increase did not reach its maximum allowable operating pressure (MAOP). Hydrate formation and slug problems were predicted by Olga. It was shown that they can be readily handled using a slug catcher for the first and Mono-ethylene Glycol (MEG) injection for the second.

Keywords
Flaring, multiphase flow, flow assurance, hydrate, OLGA software.

1. Introduction

Flaring the associated gas leads to inherent gas emissions which is a major environmental concern. According to the recent data by the National Oceanic and Atmospheric Administration (NOAA) [1], approximately 140 billion cubic meters (bcm) of gas are flared annually. Substantial reduction in those emissions is required to control their negative impact of on the environment.

In this context, researchers continue to work toward finding solutions to reduce the flaring activities and mitigate their adverse effects. Several alternatives have been investigated such as the reinjection of gas for enhanced oil recovery [2, 3], its injection into the natural gas distribution network [4, 5] and its use for on-site electricity production [5-8]. The latter is the most used strategy in practice.

To produce electricity, the associated gas is then considered as a primary source of fuel for gas turbines. Therefore, it has to be transported via pipeline which imposes additional charges. Thus, the transportation of the associated gas with oil and water is found to be the appropriate solution. Although, it may lead to serious flow assurance problems caused by multiphase flow.

According to the American Petroleum Institute (API), the term flow assurance can be used to cover a wide range of flow-related issues like hydrate, slug and wax formation. It refers to the successful and economical flow of hydrocarbon streams from the reservoir to the point of sale [9].

The hydrate formation is one of the most flow assurance challenges which can occur when light hydrocarbons and water are present at thermodynamically favorable temperature and pressure [10]. Various methods are investigated to mitigate their negative effect. According to Reyna and Stewart [11], the simplest technique is to reduce pressure below the hydrate formation point at ambient temperature. Bai and Bai [12] investigated the effect of using Mono-ethylene Glycol (MEG) injection for hydrate dissociation. For the oil and gas industry, prevention methods are the most favorable and desired option that avoid operating within the hydrate formation region [13].

Further, the slug flow is a major challenge of flow assurance as it generates high pressure fluctuations which can affect production rate. Choking, gas lift and slug catcher installation are the most important solutions to this problem [14]. In practice, a slug catcher is the most used tool [15].

In this study, the technical potential of flare mitigation technology has been highlighted as a means to generate electricity in an oil and gas producing company. The effect of associated gas transport in the existing pipeline network is studied. The analysis is carried out by studying the flow assurance issues in the pipeline, especially slug and hydrate occurrence where the effect of MEG injection for hydrate alleviation is analyzed.

2. Methodology

This section summarizes the main tools used to assess the potential impact of the associated gas transportation in the existing pipeline network. Its objectives are (i) to evaluate the process transportation and under which conditions the project is technically viable, and (ii) to determine the flow assurance issues and their mitigation methods.

2.1 Process description and Feasibility study

The oil production field is composed of onshore and offshore producing wells. The associated gas of the offshore wells was considered as a by-product which is flared. To recover the energy and overcome the environmental effect caused by flaring, the proposed solution is to generate electricity from the associated gas of offshore wells using six micro-turbines.

For economic reasons, transporting the gas in the existing offshore pipeline was studied. Therefore, case studies were considered, where the fraction of gas injected with oil and water varied from 10% to 100%, to check the viability of this solution.

A numerical simulation model for the studied process was developed using OLGA software. The pipeline network, which is made of carbon steel, is presented in figure 1. The input data is shown in table I. The geometry of the offshore pipeline, which is composed of 44 pipes and 328 sections, is depicted in figure 2.

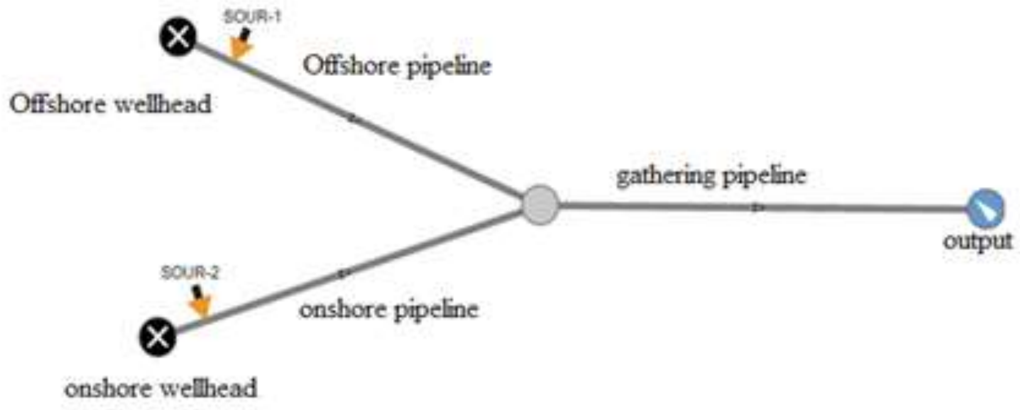

Figure 1.Schematic pipeline network diagram.

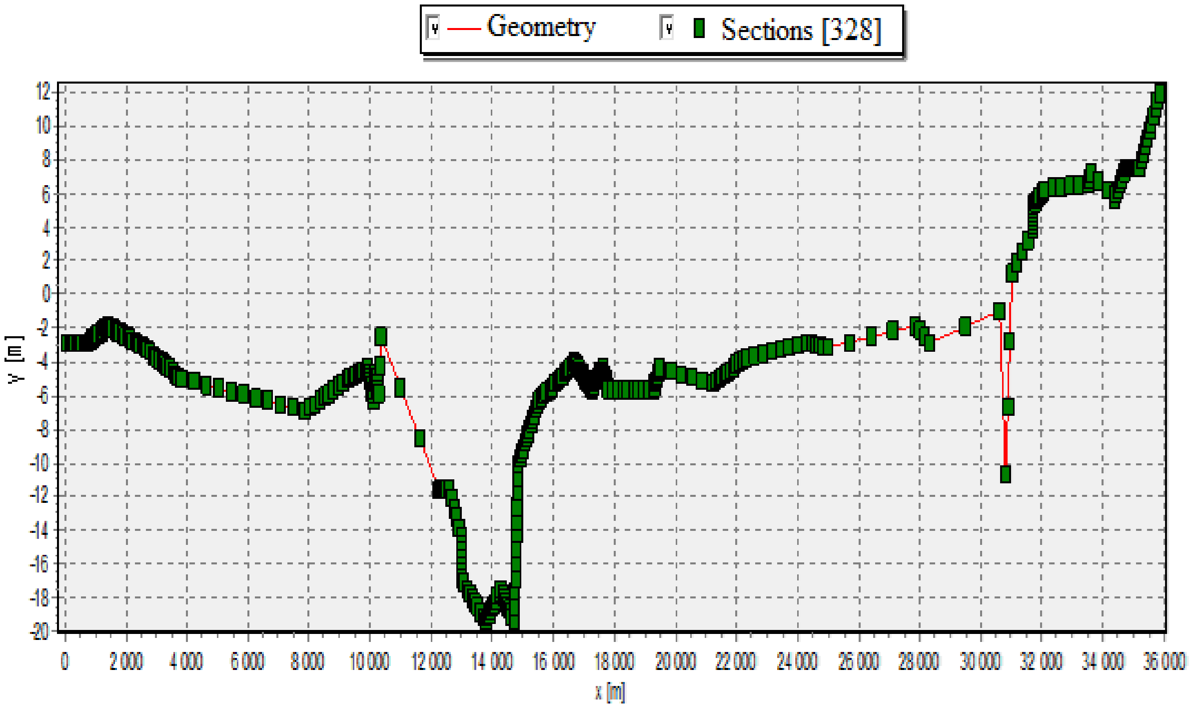

Figure 2.Geometry of the offshore pipeline generated by OLGA software.

Table I. Inlet parameters of the studied process.

Parameter		Offshore	Onshore
Ambient temperature (°C)	Summer case	20	25
	Winter case	6	25
Output pressure (bar)		-	5
Material Density (kg m^{-3})		7850	7850
Material heat capacity (J kg^{-1} K^{-1})		470	470
Material thermal conductivity(W m^{-1} K^{-1})		45	45
Thickness (in)		0.43	0.5
Inner diameter(in)		6	4
			7.6
Roughness (in)		1.110^{-3}	1.1 10^{-3}
Water flow rate (kg/d)		492.4510^{3}	265.31 10^{3}
Oil flow rate (kg/d)		308.210^{3}	69.42 10^{3}
Gas flow rate (kg/d)		119.510^{3}	46.2 10^{3}

2.2 Flow assurance study

The hydrate curves were first determined using PVTsim, then dynamic simulation was carried out by OLGA. To check the occurrence of slug and hydrate, the slug tracking and hydrate check models were used, respectively. The positive value of the difference between the hydrate and the fluid temperature is the predicting parameter of hydrate formation.

3. Results and discussions

3.1 Feasibility study of transporting associated gas in the existing pipeline network

The results showing the effect of gas injection on pressure in the offshore pipeline are presented in table II. This table indicates that the pressure increases with the amount of gas injected in the pipeline. A maximum value of 43.3 bar is reached when all the gas is injected for the winter case. This value is well below the maximum allowable operating pressure (MAOP) of the pipeline which is equal to 60 bar. Hence, all the produced gas can be injected safely in the pipeline.

Table II. Pressure value for summer and winter cases.

Case study	**Pressure (bar)**	
	Winter	**Summer**
Case 1	20.7	21.03
Case 2	24.3	24.6
Case 3	27.7	27.9
Case 4	29.7	29.9
Case 5	34.5	34.8
Case 6	36.5	36.7
Case 7	38.7	38.6
Case 8	40	39.9
Case 9	41.8	41.6
Case 10	43.3	42.8

3.2 Flow assurance study

This study is carried out for the case of total gas injection and focuses on slug tracking and hydrate formation. According to figure 3, the flow regime fluctuates between slug and stratified with the slug regime prevailing almost along the entire pipeline. A maximum slug volume of 1,5 m^3 is predicted by Olga which can already be handled by the slug catcher installed at the outlet of the pipeline.

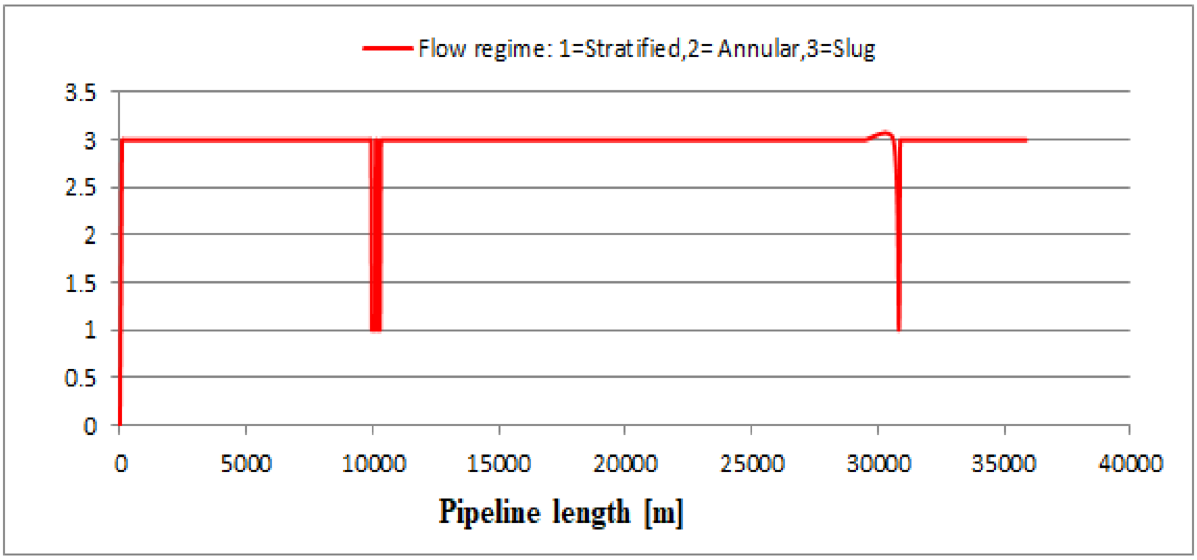

Figure 3. Flow regime variation.

Figures 4 and 5 show the results of hydrate formation. The first one indicates that this phenomenon is widely expected for the offshore pipeline. According to figure 5, however, the difference between hydrate and fluid temperature is negative for both onshore and gathering pipeline thereby excluding the occurrence of hydrate formation in those pipelines.

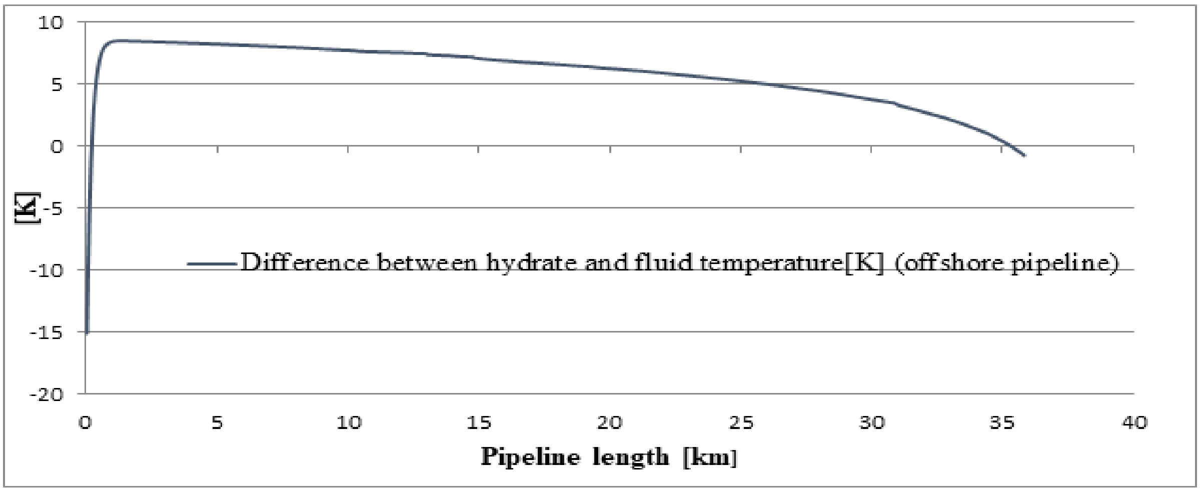

Figure 4. Difference between hydrate and fluid temperature in the offshore pipeline.

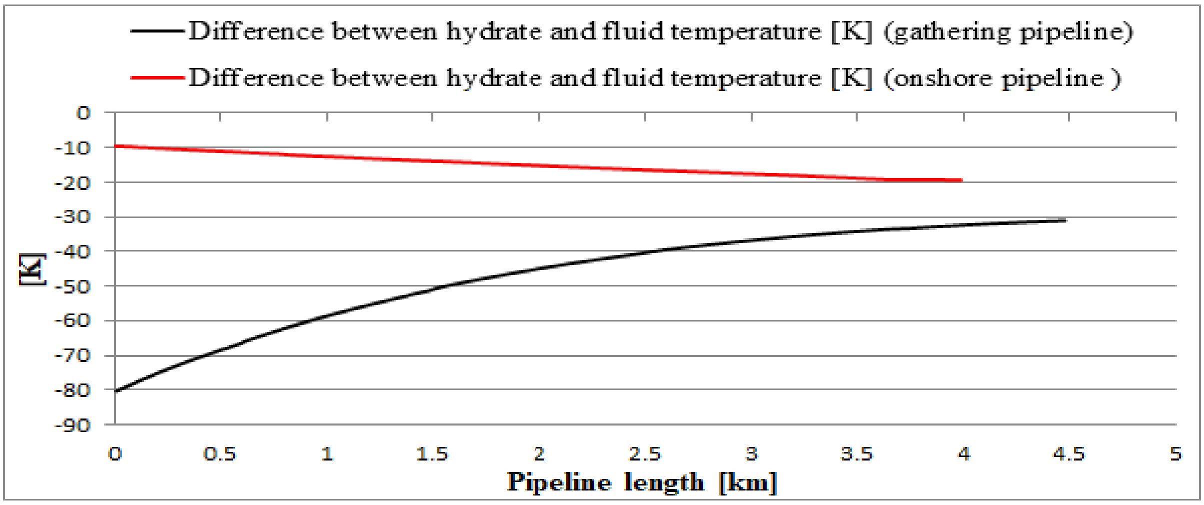

Figure 5. Difference between hydrate and fluid temperature in the onshore and gathering pipeline.

MEG injection was considered as a mitigation solution for hydrate formation because it is easy to recover [16]. Figure 6 shows the effect of its injection, with different percentages, on the hydrate equilibrium curves as predicted by PVTsim. It shows the strong effect of MEG as it significantly lowers the hydrate formation temperature.

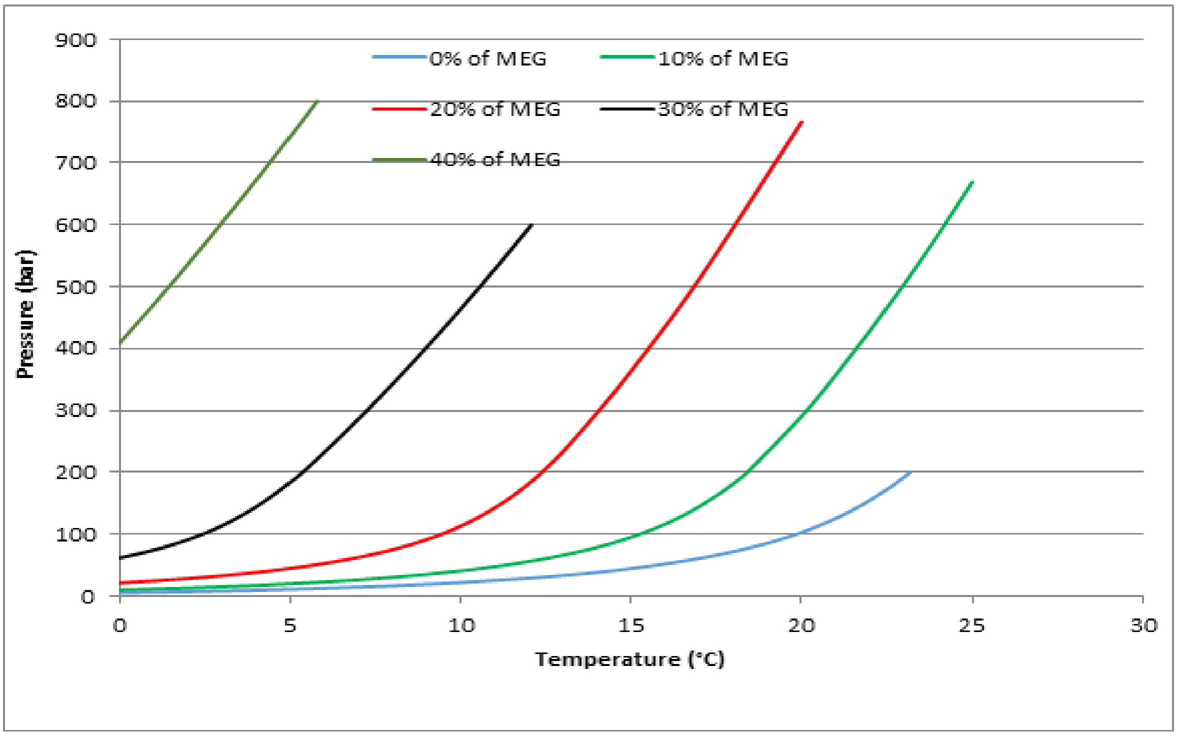

Figure 6. Hydrate equilibrium boundaries curves with 0%, 10% to 40% MEG.

Figure 7shows its effect on the difference between hydrate and fluid temperature as predicted by Olga. It shows that the percentages of 20 (figure 7(c)) and 40(figure 7(d)) shift the hydrate equilibrium curve to safe conditions. This allows the offshore pipeline to operate outside the hydrate stability region. Hence, 20% of MEG concentration is necessary to completely inhibit hydrate formation for the studied case.

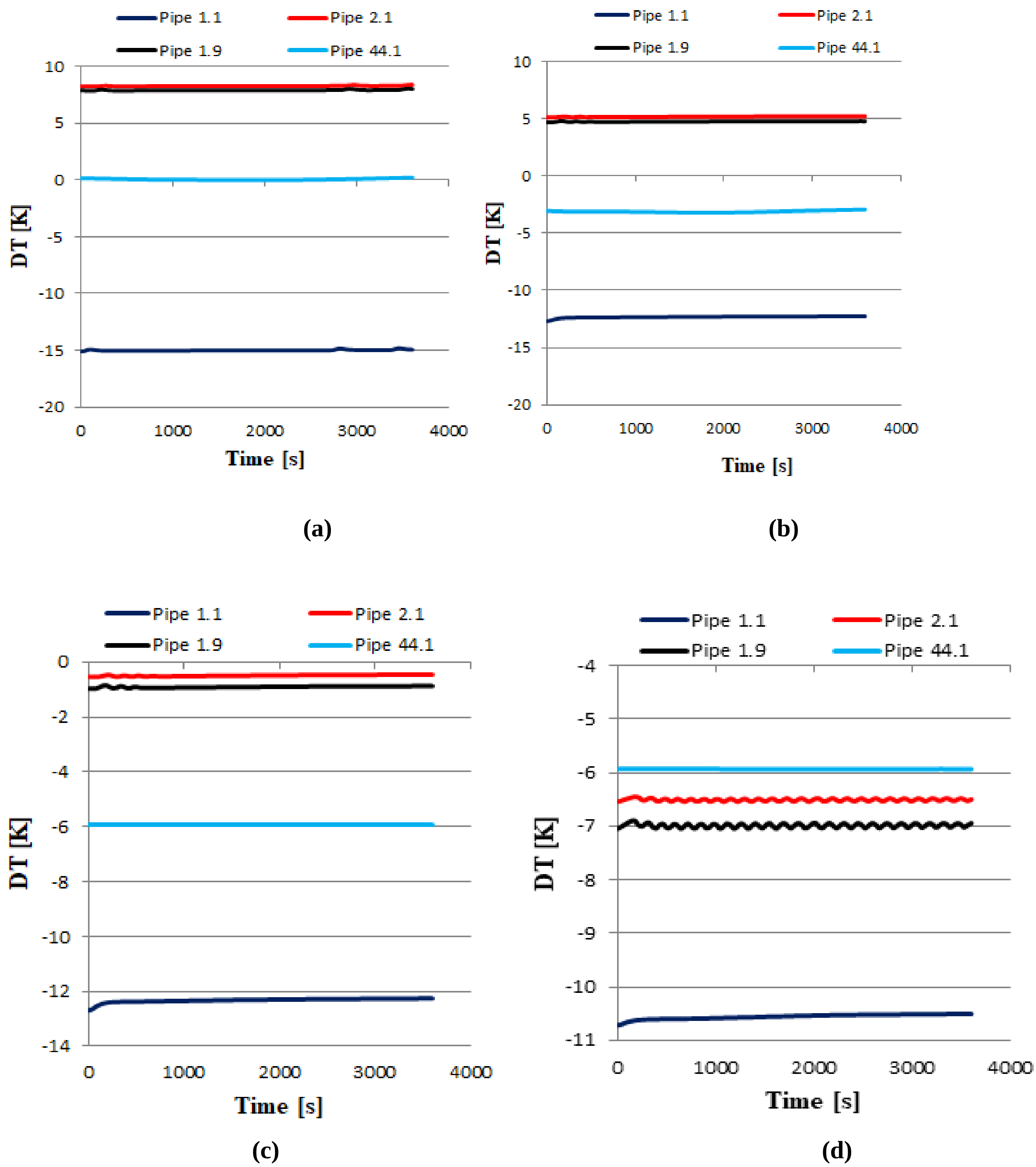

Figure 7. Difference between hydrate and fluid temperature (DT) in the different pipe section of the offshore pipeline with: (a) 0% MEG, (b) 10% MEG, (c) 20% MEG (d) 40% MEG.

4. Conclusion

In this work, the feasibility of transporting an associated gas in an existing pipeline network was studied. The obtained results showed that the overpressure generated by the injection of the gas can be safely handled by the pipeline. However, the occurrence of hydrate formation and slug flow was predicted. To mitigate the hydrate formation problem, the injection of MEG was considered. Olga simulations showed that adding 10% of this thermodynamic inhibitor cannot prevent hydrate formation and that a minimum of 20% is needed. Thus, it is concluded that the transporting of the associated gas is technically viable but a 20 % of MEG is required to allow the pipeline to operate without hydrate formation.

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