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Prediction and prevention requirements for natural gas hydrate formation in subsea oil and gas pipelines

海底油气管道中天然气水合物生成预测与防控要求

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Foreword

GB/T 47444-2026 | Prediction and prevention requirements of natural gas hydrate formation in subsea pipelines transporting oil and gas

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01 State Administration for Market Regulation The State Administration for Standardization issued a statement.

1.Scope This document specifies the general requirements for the prediction and prevention of natural gas hydrate formation in subsea oil and gas pipelines, and provides guidelines for the prediction and prevention of natural gas hydrate formation in subsea oil and gas pipelines. A natural gas hydrate formation prediction model was developed, specifying the requirements for natural gas hydrate prevention and control. This document applies to the prediction and prevention of natural gas hydrate formation in subsea oil and gas pipelines (including crossovers and underwater manifolds).

4 General Requirements

4.1 Risk analysis of natural gas hydrate formation should be conducted during the commissioning, stable production, production adjustment, shutdown and restart of subsea oil and gas pipelines.

4.2 When predicting and controlling the formation of natural gas hydrates in subsea oil and gas pipelines, the hydrate formation under different pressures should be determined in accordance with the provisions of Chapter 5. The temperature is determined, and a hydrate control plan is developed based on the transportation conditions.

4.3 The hydrate formation temperature should preferably be obtained experimentally; however, model calculations can be used if experimental conditions are not available. Model calculations should be employed. When calculating the hydrate formation temperature, the flow composition data should be obtained, including gas composition and water salinity.

4.4 The control plan for natural gas hydrates in subsea oil and gas pipelines should be dynamically adjusted and its effectiveness evaluated in a timely manner according to the fluid being transported and the operating conditions.

5.1 Experimental determination of hydrate formation temperature

5.1.1 Natural gas and water samples should be taken during the determination of hydrate formation temperature. Natural gas sampling should be performed in accordance with GB/T 13609; Water sampling shall be carried out in accordance with GB/T 4756.

5.1.2 The experimental method for determining the hydrate formation temperature shall be performed in accordance with SY/T 7676.

5.1.3 There should be no fewer than 5 hydrate formation temperature measurement points for each sample, and the distribution of pressure measurement points should cover the operating conditions of subsea oil and gas pipelines. scope.

5.2 Calculation of Hydrate Formation Temperature Model

5.2.1 Fluid composition data When calculating the hydrate formation temperature, the fluid composition should include the following data.

a) Content of components C1, C2, C3, C4, C5, and C6;

b) Content of non-hydrocarbon components such as CO2, N2, and H2S;

c) Water production rate and concentrations of thermodynamic inhibitors such as methanol and ethylene glycol in the water;

d) Content of salt ions such as Na, Ca2+, K+, Cl-, and Br- in the aqueous phase of the pipeline.

5.2.2 Pure Water System For pure water systems, the calculation of hydrate formation temperature in subsea oil and gas pipelines should preferably use the van der Waals-Platform method. teeuw (see A.1 in Appendix A) or Chen-Guo (see A.2) theoretical models.

5.2.3 Systems containing thermodynamic inhibitors or salts For systems containing thermodynamic inhibitors or salts, hydration can be directly calculated using the van der Waals-Platau and Chen-Guo theoretical models. The hydrate formation temperature; alternatively, it can be calculated based on the hydrate formation temperature in a pure water system, combined with the Hammerschmidt method. (Hammerschmidt, see A.3), Nielsen, see A.4, Yousif, see A.5, Muhammadi Empirical models such as (Mohammadi, see A.6) are used to calculate hydrate formation temperatures, but empirical models should be selected and used according to their applicable range. The empirical model is applicable to the following areas.

a) When methanol is used as a hydrate inhibitor in the system, the empirical model for calculating the hydrate formation temperature should preferably be the Hammerschmidt model. Model;

b) When ethylene glycol is used as a hydrate inhibitor in the system, the Nelson model should be used as the empirical model for calculating the hydrate formation temperature;

c) The cations and anions in a salt-containing system usually inhibit hydrate formation. Water mainly contains five ions. Na^+, Ca^2+, K^+, Cl^-, and Br^-. For the calculation of the hydrate formation temperature of ions, the Yussiff model is recommended as an empirical model; other salt ions in water can be calculated based on ionic equivalence and relative... Based on the principle of approximate molecular weight, the mole fractions of Na, Ca2+, K+, Cl-, or Br- are used for approximate calculation.

d) When methanol or ethylene glycol and salt components are present in the system, the hydrate formation temperature should be calculated using the Muhammad model.

5.2.4 Other Systems The hydrate formation temperature of other systems besides those mentioned above should not be calculated by model but should be determined experimentally.

Note. Other systems include, but are not limited to, alcohol systems other than methanol and ethylene glycol, and systems containing mixtures of various thermodynamic inhibitors.

6 Hydrate Control

6.1 General Requirements Common methods for controlling hydrates in subsea oil and gas pipelines include chemical control, pressure control, temperature control, and dehydration control. Each method shall be used in accordance with the provisions of

Note. Other methods for controlling hydrates include fluid displacement and pipeline cleaning.

6.2 Chemical control methods

6.2.1 Selection of Chemical Reagents Chemical agents that can be used to control natural gas hydrates in subsea oil and gas pipelines include thermodynamic inhibitors, kinetic inhibitors, and polymerization inhibitors. Chemical agents. When using chemical agents for the control of natural gas hydrates in subsea oil and gas pipelines, the following rules apply, including but not limited to.

a) The freezing point of chemical reagents should be at least 5°C lower than the operating temperature at any point along the subsea oil and gas pipeline;

b) Thermodynamic inhibitors should be given priority in the control of hydrates;

c) When a subsea oil and gas pipeline is scheduled to be shut down, thermodynamic inhibitors should be used for hydrate control;

d) When the storage space for thermodynamic inhibitors on offshore platforms is limited and the gas-oil ratio in the pipelines is greater than 550, kinetic inhibitors may be selected. Implement hydrate control measures;

e) When the storage space for thermodynamic inhibitors on offshore platforms is limited and the liquid phase water content in the fluid in the pipeline is less than 30%, polymerization inhibitors can be selected. Implement hydrate control measures.

6.2.2 Thermodynamic Inhibitors When using thermodynamic inhibitors for hydrate control, the following rules apply, including but not limited to.

a) The principle for determining the amount of thermodynamic inhibitor injected is that after adding the thermodynamic inhibitor, the operating temperature at any point along the pipeline should be higher than that of the pipeline. The hydrate formation temperature is more than 5°C higher;

b) The calculation method for the dosage of hydrate thermodynamic inhibitors is given in Appendix B;

c) If methanol is selected for hydrate control, it should be used in accordance with GB/T 338.

6.2.3 Kinetic Inhibitors When using kinetic inhibitors for hydrate control, the following rules apply, including but not limited to.

a) The effectiveness of kinetic inhibitors in controlling hydrates under different degrees of supercooling and dosages should be evaluated experimentally;

b) The induction period for the formation of kinetic inhibitors should be at least 5 hours longer than the time it takes for the fluid to flow from the pipe inlet to the outlet;

c) The concentration of the active ingredient in the kinetic inhibitor should preferably be 0.5% to 3.0% of its concentration in the aqueous solution (by mass fraction). The quantity should be determined based on the laboratory evaluation results;

6.5 Dehydration Control Methods