Proceedings of the 7th International Conference on Gas Hydrates (ICGH 2011),
Edinburgh, Scotland, United Kingdom, July 17-21, 2011.

A PROBABILISTIC APPROACH TO PREVENT THE FORMATION OF HYDRATES IN GAS PRODUCTION SYSTEMS

Marco Montini[1,*], Andrew I. Humphrey[2], Martin J. Watson[1], Adrian E. Johnson[1]

[1]FEESA Ltd,
Westmead House, Farnborough, Hampshire, GU14 7LP,
UNITED KINGDOM

[2]BP Exploration,
Chertsey Road, Sunbury-on-Thames, Middlesex, TW16 7LN,
UNITED KINGDOM

ABSTRACT

The formation of hydrates in gas production systems can be addressed by altering the fluid composition with the addition of thermodynamic inhibitors, such as mono ethylene glycol (MEG), into the process upstream of the location where solids formation is predicted to occur. The Hammerschmidt equation provides a simple and effective method for estimating the inhibitor concentration required to prevent hydrates from forming. A probabilistic approach can be used to assess the most likely inhibitor concentration by considering the uncertainties in the measurement of pressure, temperature, water flowrate and inhibitor injection by means of a Monte Carlo simulation. This methodology applied to the thermal hydraulic conditions calculated by a rigorous integrated production model is used in the analysis of MEG injection for a large offshore gas field and a comparison of the results obtained for different scenarios is presented.

Keywords: gas hydrates, thermodynamic inhibitors, measurement error, statistical analysis

NOMENCLATURE

CGR	Condensate Gas Ratio	[stb/mmscf]
H	Hammerschmidt parameter	[ºC]
IPM	Integrated Production Model	
MEG	Mono Ethylene Glycol	
p	pressure	[bara]
PDF	Probability Density Function	
Q_{MEG}	MEG flowrate	[kg/s]
Q_w	water flowrate	[kg/s]
T	temperature	[ºC]
T_{hyd}	hydrate dissociation temp	[ºC]
x_{MEG}	mass fraction of glycol	[wt%]
k_{1-4}	fitting parameters	

INTRODUCTION

In the oil and gas sector and more specifically in flow assurance, hydrates have caused problems in flowline blockage for several operators and the issue is known and has been addressed for nearly a century [1].

The exploration of ever deeper and harsher waters has rendered the transport of a mixture of hydrocarbons and water to onshore facilities through a single multiphase pipeline the only practical way. Nowadays, the tasks of processing the fluids on site is considered far too demanding because of the cost of building and maintaining complex offshore platforms with processing facilities.

[*]Corresponding author: phone +44 (0)1252 372 321, fax +44 (0)5601 260 899, e-mail marco.montini@feesa.net

An increase in water depth clearly corresponds to ambient conditions at high pressure and also low temperature for subsea operations. These two parameters, along with the production and transport of undesired water, represent the primary factors influencing the formation of hydrates in pipelines.

Gas hydrates

Gas hydrates are a crystalline solid with different structures consisting of light hydrocarbons (usually methane, ethane, propane or butane) and also carbon dioxide or nitrogen trapped into a cage of water molecules [2], as shown in Figure 1.

Figure 1. Typical hydrate structures

The agglomerations of hydrates can result into a slushy snow or slurry and if compacted by pressure surges or other mechanical effects can form plugs (see Figure 2) and lead to loss of production and blockages.

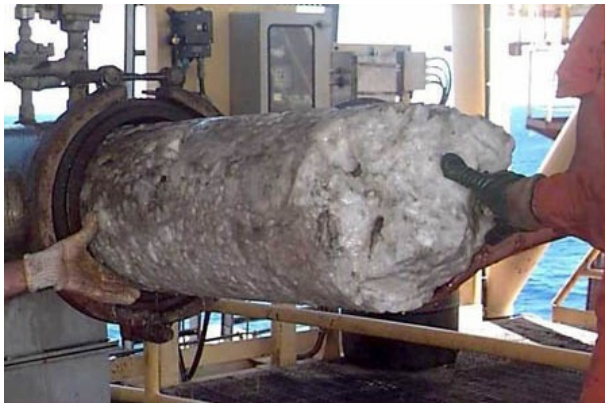

Figure 2. A large gas hydrate plug formed in a subsea hydrocarbon pipeline [Photo courtesy of Petrobras]

Fortunately, the chemico-physical process of hydrates formation is well known and the pressure and temperature ranges for hydrate dissociation and stability can be easily predicted by PVT thermodynamic programs for phase equilibrium calculations [3].

Therefore, high pressure and low temperature conditions can be foreseen and pipelines which lay within the hydrate formation region can be treated accordingly [4].

Hydrate avoidance philosophies are principally divided into four categories:

1. mechanical, by glycol dehydration or pigging
2. operational, by reducing the pressure within the pipe through a blow down
3. thermal, by hot oiling the flowline, circulating hot water, electrically heating the pipe or increasing the insulation
4. chemical, by injecting inhibitors such as methanol and glycol

all of which have advantages and disadvantages both operational and economical which must be accounted for during the system design [5].

The West Nile Delta gas gathering system

The BP West Nile Delta (WND) Gas Development in Egypt is characterised by three different production fields: Raven, which is a Pre-Pliocene age discovery, and Giza Fayoum and Taurus Libra, which are Pliocene age discoveries.

The Pliocene fields are low pressure (<350bara) and low temperature (<65ºC) reservoirs characterised by a low CGR (<7.5stb/mmscf) and low water production. The Pre-Pliocene wells are high pressure (~750bara) and high temperature (~135ºC) reservoirs characterised by a high CGR (~23.5stb/mmscf) and a much higher water production than the Pliocene fields.

A schematic of the layout of wells and flowlines is shown in Figure 3.

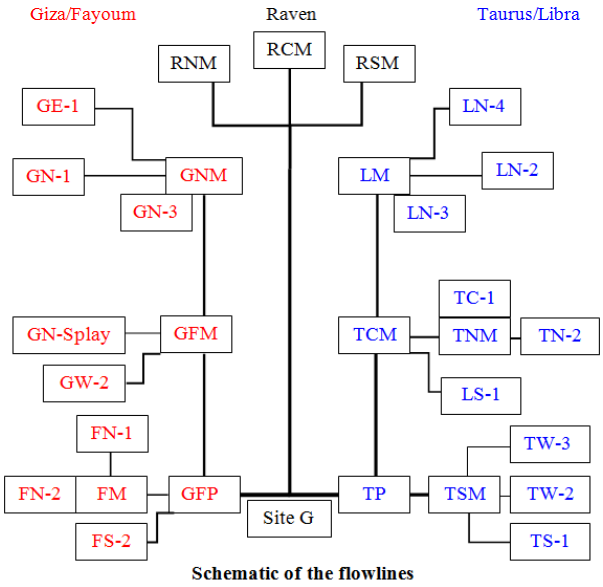

Figure 3. Gas gathering system

The flowlines of all the wells converge into three main trunklines, one for each field, and eventually the three trunklines arrive to the onshore processing facilities (Site G). The development area is situated in deep waters (up to 800m) and the seabed temperature is around 10 to 15ºC.
A typical gas composition for the WND development is characterised by a predominant presence of methane as reported in the composition in Table 1.

Table 1. Typical Gas Composition

Name	**Moles %**
Methane	93.53830
Water	4.759650
Nitrogen	0.110424
Ethane	1.091870
Carbon Dioxide	0.173252
Propane	0.015231
I-Butane	0.076155
N-Butane	0.006664
Salt Component	0.047272
I-Pentane	0.019039
N-Pentane	0.000952
N-Hexane	0.011423
C7	0.004760
C8	0.008567
C9	0.009519
C10	0.016183
C11	0.015231
C12	0.018087
C13	0.021895
C14	0.021895
C15-C16	0.025702
C17-C18	0.006664
C19-C22	0.000952
C23-C57	0.000238

Maximus: an Integrated Production Model

A thermal hydraulic Integrated Production Model (IPM) simulator named Maximus was used to carry out a conceptual study of the large offshore gas gathering field.
Maximus is a steady-state, fully compositional, thermo-hydraulic network solver primarily for the upstream oil and gas industry, although it can be used for any steady state pipeline simulation. It uses modern numerical methods to permit fast and efficient tubing, flowline and riser integrations whilst solving the network without requiring hydraulic look-up tables, black oil compositional assumptions or other over simplifications of the physics commonly used in other tools.
Maximus has been used on various developments since 2005 [6], where it performs the role as both the standard steady state thermal hydraulic flow assurance tool as well as a complementary production profile forecasting tool to reservoir engineering models.
The first use of Maximus on a large subsea gas condensate system was to predict production profiles, investigate preliminary drilling schedules, optimise flowline sizes, predict MEG injection requirements through life and investigate the use of offshore compression to delay future tiebacks [7]. It has since been used on several large oil and gas developments around the world.
For further details on the numerical methods in Maximus see also [8].
This IPM simulator has the advantage of a user definable logic which is a very powerful tool: user defined variables, equations and logic events along with the all the common parameters, can be easily added to operate the system as it would be operated in reality, adjusting the conditions of a life of field simulation according to the calculated parameters.

METHODOLOGY

Prevention of formation and inhibition of hydrates using chemical inhibitors is still a widely used practice and a correct assessment of the risks based on accurate predictions is required to for cost effective design and operation.
In the WND gas development the issue of the formation of hydrates is addressed with the injection of Mono Ethylene Glycol (MEG) downstream of the chokes in the Pliocene fields and at the three manifolds for the Pre-Pliocene field.
In order to obtain the required MEG flowrate necessary to avoid the formation of hydrates in the network of pipelines the following procedure has been followed.
Firstly, a simple Maximus model was set up which is made of three sources and a sink connected to a pipe (see Figure 4).

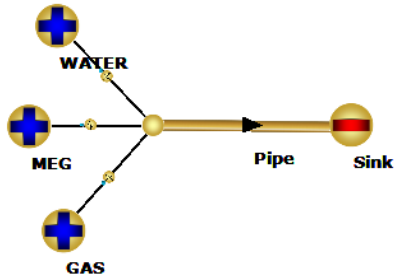

Figure 4. Maximus model for the calculation of hydrate dissociation curves

The geometry of the pipe and the values of pressure and temperature within this simple network are irrelevant, since the idea behind the model is that of simply obtaining the specific composition at the sink by varying the flowrates at the sources.
The composition of the three sources corresponds to pure water, MEG and dry gas. A sensitivity analysis of gas, water and MEG flowrates allows the calculation of the hydrate dissociation curve for different MEG concentrations and different gas compositions.
Maximus has a built-in link to the PVT package Multiflash [9], through which it is easy to calculate the phase envelope and the data at the boundary between different states of the composition, as shown in Figure 5 for the case of hydrate II dissociation.

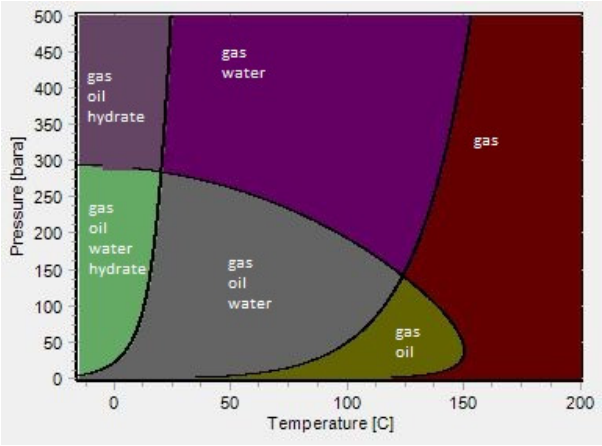

Figure 5. GUI for Multiflash in Maximus

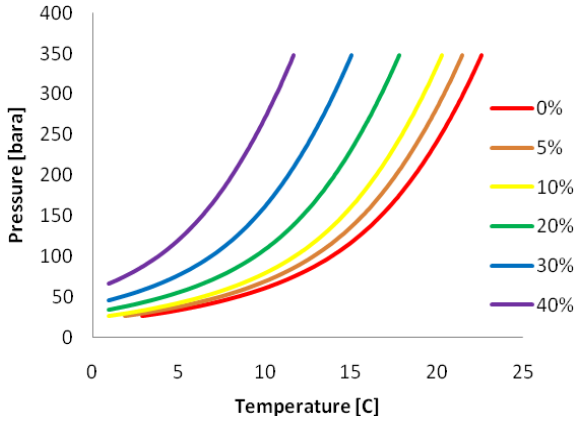

Figure 6. Hydrate dissociation curve for different MEG concentrations

A series of hydrate dissociation curves has, therefore, been calculated at different MEG concentrations and an example of these sets of curves is given in Figure 6.
A relationship which rapidly provides a method to calculate the MEG concentration for a specific point in the pressure temperature diagram can be given by the following modified Hammerschmidt equation [1],

$$x_{MEG} = \frac{\Delta T_{hyd}}{H + \Delta T_{hyd}} \quad (1)$$

$$\Delta T_{hyd} = T_{hyd} - T \quad (2)$$

$$T_{hyd} = k_1 \ln(p) + k_2 \quad (3)$$

$$H = k_3 \ln(p) + k_4 \quad (4)$$

where x_{MEG} is the mass fraction of glycol required in the aqueous phase to avoid hydrates formation when ΔT_{hyd} is the difference between the hydrate dissociation temperature (T_{hyd}) and the actual flowing temperature (T); moreover, H represents the Hammerschmidt coefficient, which is a constant in the original equation [1] while in this study is a function of the pressure for a better fit to the data.
The parameters k_1 to k_4 have been tuned so to give the best fit for equation (1) to the aforementioned hydrate dissociation curves obtained by Multiflash for the specific compositions (Figure 6).
However, some considerations must be taken into account. The amount of water, produced according to the IPM simulation, is considered pure: this is a conservative assumption since the presence of salt further inhibits the formation of hydrates. A more detailed analysis on the quality of water and the way in which it affects the formation of hydrates is left for future work.
The present analysis is based on hydrate dissociation curves and does not take into account the meta-stable region between the limits of dissociation and formation of hydrates: again this is a rather conservative assumption which increases the safety margin of the calculations. Also, the calculated MEG concentration refers to the condition of being exactly on the hydrate curve and does not take into account any specific safety margin.
Moreover, the methodology proposed is based on a condition of normal operation and does not consider unplanned shutdown pressures which are larger than pressure at normal operation and would require a higher amount of MEG.

In the following step, the Hammerschmidt equation with the four fitted parameters is introduced in the user defined logic of the Maximus model.
Therefore, by tuning equation (1) to the specific data of pressure, temperature and water flowrate calculated by the Maximus IPM model during life of field simulations, it is possible to calculate the required MEG flowrate for each injection point at the wellhead.
Moreover, the amount of MEG in pipelines without their own MEG injector downstream of a wellhead, if any additional is needed after considering the amount required by upstream flowlines, is redistributed to the upstream MEG sources in proportion to their water flowrate.
Once the system is set up for each junction in the network of flowlines, by evaluating equation (1) and calculating the water flowrate through each pipeline, Maximus determines if any point of the system is at risk of hydrates formation and calculates automatically the MEG flowrate required to dose that point out of the hydrate envelope for each timestep in the life of field simulation.
Since the MEG is normally regenerated on-shore to be reintroduced in the injection system, the MEG supplied offshore always contains some water. This obviously must be taken into account in the definition of the necessary MEG flowrate, once the concentration is calculated thorough the Hammerschmidt-like equation (1). In this specific study, the mixture of regenerated MEG has been assumed to be 90% pure MEG and 10% water.

RESULTS

Figure 7 to Figure 9 present the results of a Maximus simulation obtained with the procedure described above for the required amount of MEG and they refer to the Raven subfield only and not the whole WND network. Only the trunkline and the RSM flowline require the injection of a certain amount of MEG to avoid the formation of hydrates during the whole life of the WND field.
The first of these three plots shows the mass concentration of MEG calculated by means of the Hammerschmidt equation, while in the second this concentration is multiplied by the water flowrate to give the necessary MEG flowrate to avoid the formation of hydrates. Here the two peaks towards the end of the simulation represent the point at which two of wells start watering before being shut in. The increased amount of water produced is the cause of the increased amount of MEG required to maintain the correct concentration.
The last plot gives an indication of the amount of MEG each of the three sources at the three Raven manifolds should inject to satisfy the demand of MEG in the trunkline.

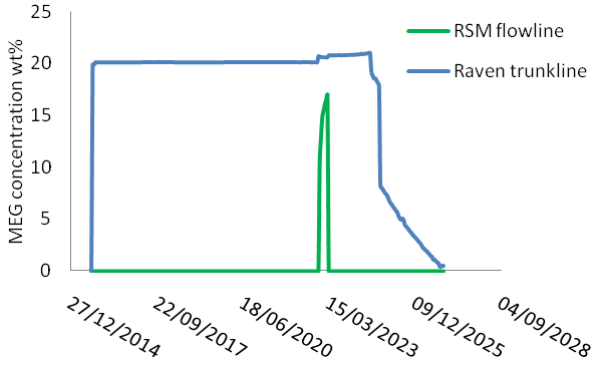

Figure 7. MEG concentration

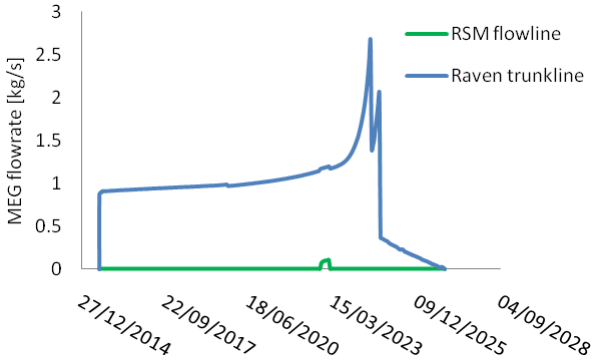

Figure 8. Required MEG flowrate

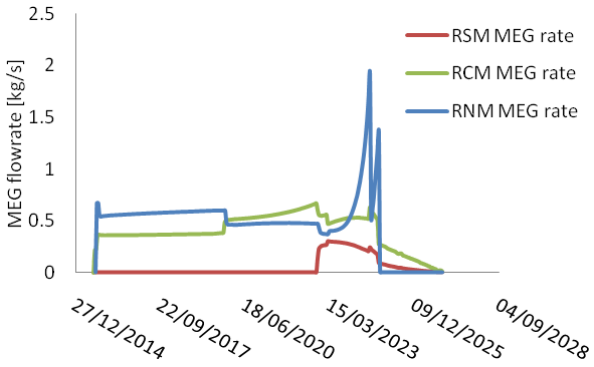

Figure 9. Source MEG flowrate

As mentioned before, all the results presented so far do not consider any safety margin in the calculation of the required MEG. However, a condition which corresponds exactly to flowing on

the hydrate curve is not desirable due to a series of uncertainties present in the measurement of pressure, temperature water flowrate and MEG flowrate.

A first approach to dealing with this problem can be to simply add a margin of 3°C to the margin, ΔT_{hyd}, from the hydrate curve. This is a preliminary and crude approximation since the formation of hydrates is a function of the pressure as well, and the same temperature margin for high pressures is equivalent to a higher margin from the hydrate dissociation curve than at lower pressures.

A better and more precise risk analysis was carried out through a statistical assessment of the uncertainties in the measurements of pressure, temperature, water flowrate and MEG flowrate, assuming that these uncertainties are of random nature and therefore normally distributed.

A spreadsheet was set up with which it is possible to perform a Monte-Carlo simulation, for each combination of the four parameters above, and obtain as a result an average value of the required MEG flowrate along with its standard deviation and the value of the 99th percentile, which correspond to a probability of 99% of the results being outside of the hydrate dissociation curve.

Two approaches in the definition of the measurement uncertainties are proposed which lead to different results. In both cases, a normal distributed probability density function is assumed (see Figure 10 to Figure 12 for some examples).

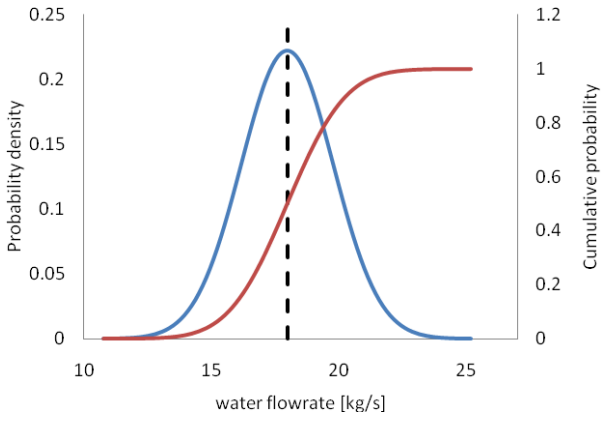

Figure 10. Uncertainty on water flow rate measurement

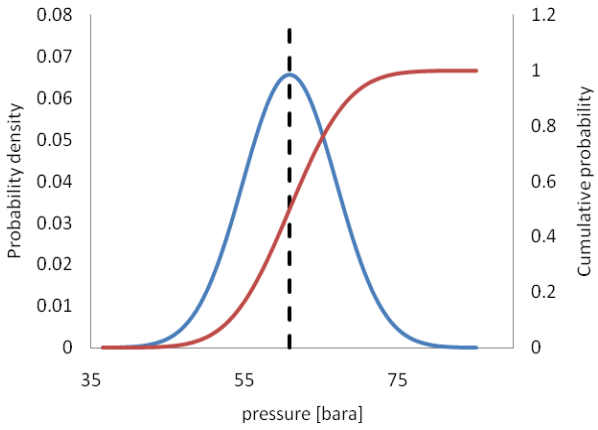

Figure 11. Uncertainty on pressure measurement

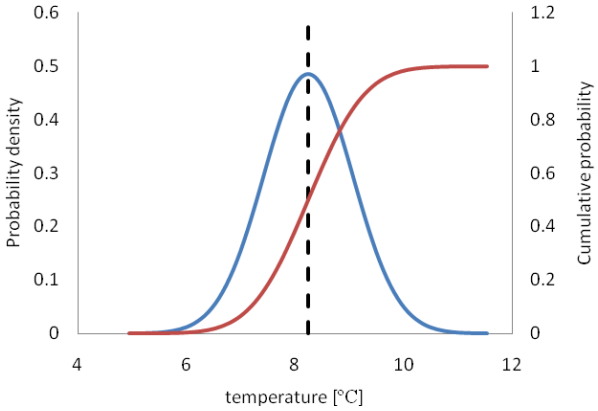

Figure 12. Uncertainty on temperature measurement

In the first approach, an error relative to the measured value was assumed in the first instance, corresponding to four standard deviations from the average value and, therefore, to a probability of 99.994% of the results being inside the confidential interval. Two different scenarios have been analysed, assuming an uncertainty of 10% and 2.5% for all the measurement instruments.

In the second approach an absolute measurement error has been considered for all the four quantities. This approach is based on the idea that the measurement uncertainty is usually an error which depends on the accuracy of the instrument used and is independent from the measured value. However, the following results validate the methodology used and represent an initial indication of the risk assessment for an economic design of the gas gathering system.

The errors considered in this study are summarised in Table 2.

Table 2 - Measurement errors

quantity	symbol	unit	error
pressure	p	bara	±2
temperature	T	°K	±0.2
water flowrate	Q_w	kg/s	±0.1
MEG flowrate	Q_{MEG}	kg/s	±0.05

Figure 13 and Figure 14 show a comparison between the four different methodologies used to assess the risk of hydrate formation:

1. an arbitrary 3°C margin
2. a 2.5% error
3. a 10% error
4. an absolute error on the measurements.

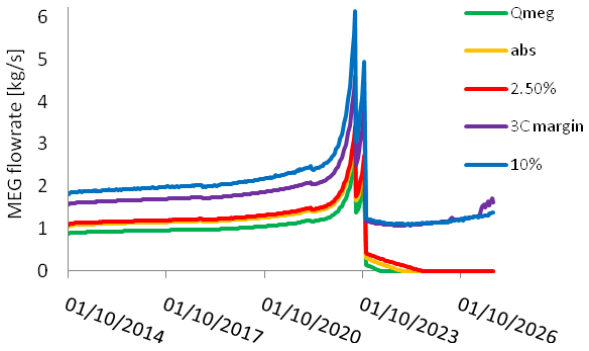

Figure 13. Comparison between MEG flowrates with different errors for the Raven trunkline

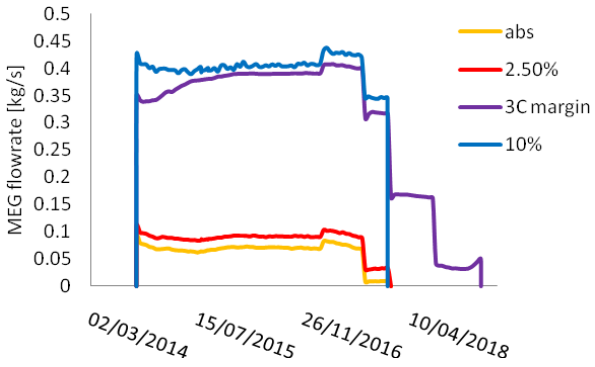

Figure 14. Comparison between MEG flowrates with different errors for the GNM-GFP flowline

In the case of the Raven trunkline, the higher the error the more MEG is required, which was expected. More interesting is the case of the end of life for the Raven trunkline and of the flowlines in the Pliocene fields.

An example is the GFM-GFP flowline in the Giza-Fayoum field, which did not require any MEG injection in the first analysis but was flowing at temperature and pressure conditions very close to the hydrate curve. Indeed a certain amount of MEG is required once a safety margin is considered in the calculations. Although there is a large percentage difference between the results obtained with the different approaches (Figure 14), the actual amount of MEG injected is relatively small and in absolute terms this difference is small.

As a further clarification, Figure 15 shows the statistical analysis applied to the Raven trunkline at a point towards the end of life of the field. The exact calculations predict the flowrate of MEG necessary to be on the hydrate curve as a negative value of -1.267kg/s, which means that no MEG is required. However, once all the uncertainties on the measurement are taken into account the resulting probability density function (PDF) shows that there is a certain risk of hydrate formation and in order to be 99% confident of flowing outside the hydrate region, an amount of MEG equivalent to 1.386kg/s is required.

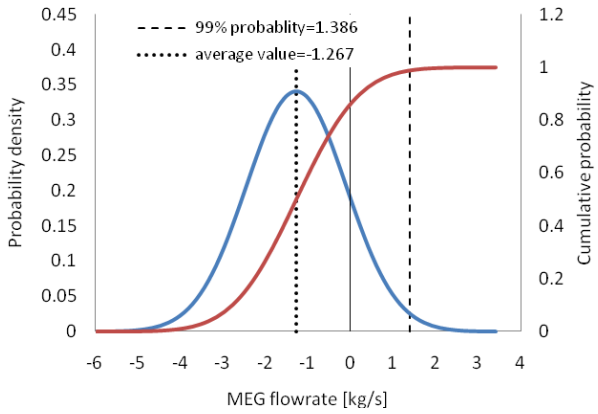

Figure 15. Results of the statistical analysis

CONCLUSIONS

A methodology to assess the risk of hydrate formation in a large gas gathering system has been presented with the aim of optimising a hydrate inhibition strategy with the injection of MEG.

The hydrate formation is predicted by means of a modified version of the Hammerschmidt equation which was tuned for a better fit to data specific to the case considered in this study. It has been shown that through a statistical analysis on the measurement errors based on a Monte Carlo

simulation it is possible to appraise the amount of MEG to be injected in the network of pipelines to avoid hydrate formation.

Different scenarios have been analysed. In the case of a relative measurement error, the predicted MEG flowrate is higher in the early life of the field when temperature and pressures are generally higher and, therefore, so are the uncertainties. In late life those uncertainties decrease along with temperature and pressures and as a result virtually no MEG flowrates are required.

On the other hand, for the case of absolute errors, the calculated uncertainty on the MEG flowrate is constant during the life of field and the MEG flowrates are more evenly distributed for those flowlines, the pressure and temperature of which represent a condition close to the hydrate dissociation curve.

Finally, the results suggest that the uncertainties in the measurements play a fundamental role in the assessment of the optimal MEG injection. To improve the accuracy of the calculations, it is therefore recommended to refine the assumptions on these errors in consultations with the BP WND project and instruments specialist.

REFERENCES

[1] Hammerschmidt EG. *Formation of gas hydrates in natural gas transmission lines*. Ind. Eng. Chem. 1934; 26:851-855.

[2] Sloan ED. *Fundamental principles and applications of natural gas hydrates*, Nature, 2003, 426:353-359.

[3] Edmonds B, Moorwood RAS, Szczepanski R. *A unified framework for calculating solid deposition from petroleum fluids including waxes, asphaltenes, hydrates and scales*, Fluid Phase Equilibria, 1999, 481:158-160.

[4] Sum AK, Koh CA, Sloan ED. *Clathrate Hydrates: From Laboratory Science to Engineering Practice,* Ind. Eng. Chem. Res., 2009, 48:7457–7465.

[5] Elgibaly A, Elkamel A. *Optimal Hydrate Inhibition Policies with the Aid of Neural Networks,* Energy & Fuels, 1999, 13:105-113.

[6] Watson MJ, Hawkes NJ, Pickering PF, Elliott J, Studd LW. *Integrated Flow Assurance Modelling of the BP Angola Block 18 Western Area. In: SPE Projects, Facilities & Construction, June 2007. SPE 101826-PA.*

[7] Watson MJ, Hawkes NJ, Pickering PF, Brown LD. *Efficient Conceptual Design of an Offshore Gas Gathering Network. In: SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia,2008. SPE-116593-PP.*

[8] Pickering PF, Hawkes NJ, Watson MJ. *Application of Chemical Engineering Methods to Integrated Production Modelling. In: Chemeca, Burswood Entertainment Complex, Perth, Australia, 27-30 September 2009.*

[9] *Multiflash for Windows, Version 3.5*, Infochem Computer Services Ltd, 1 February 2006.