SALT CAVERN NATURAL GAS STORAGE – A FLOW ASSURANCE APPROACH FOR AN EFFICIENT CORROSION MANAGEMENT

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ABSTRACT

The study of water accumulation in the flow lines of underground natural gas storages is nowadays an acknowledged approach in GDF SUEZ. In aquifer storages water is produced during gas withdrawal phases. Water accumulation along pipelines could lead to production loss because of, hydrate formation, corrosion and liquid slug and surges at the receiving facilities. These phenomena are potential cause of facility downtime and have to be anticipated. Flow assurance science, by means of dynamic multiphase simulation, consists in predicting the occurrence of these threats contributing towards an optimal production and system integrity.

More particularly, in order to reach an efficient corrosion management, it is necessary to clearly identify the most likely locations for corrosion attacks. Water accumulation is the outweighing factor for corrosion risk assessment in wet gas pipelines. By means of dynamic multiphase simulation it is possible to predict the occurrence of water accumulation zones according to withdrawal conditions.

The CRIGEN (i.e. the GDF SUEZ Gas and New Energies Research Centre) was consulted in order to assess water accumulation likelihood in pipelines of a salt cavern storage where no free water is normally produced. It was highlighted that for wintertime temperature conditions, the water volumes likely to accumulate in salt cavern storage pipelines are not insignificant. Simulations dynamic feature permitted to take into account the salt cavern storage typical flexibility by considering a short-cycle withdrawal periodicity. It was pointed out that water presence in such flow lines is due to vapor condensation. Condensation phenomenon occurs due to near-saturated gas cooling down during its flowing from the well head to the gas plant. Water condenses gradually as the gas cools down along the pipeline. Gas cooling is essentially due to thermal exchange with external ambient. Hence, by modeling accurately thermal exchange during wet gas transport, most likely locations for water accumulation were pointed out.

The CRIGEN formulated pragmatic recommendations concerning withdrawal conditions. More particularly, dewatering strategies were dynamically simulated aiming to evacuate possible accumulated water by specific gas flow rate increasing. The minimum gas flow rate in order to avoid the water condensation onset was also indicated. Therefore, zones possibly submitted to corrosion risk were clearly identified.

This approach leads to an accurate decision-making solution with regard to corrosion management from the very beginning of the engineering project through the formulation of relevant operating guidelines in terms of water accumulation prevention.

INTRODUCTION

Traditionally used to adjust the supply and demand of natural gas and guarantee secure supplies, storage is now meeting new requirements, linked to the development of the natural gas market, in particular in terms of flexibility (especially for gas natural power generation units).

In such a context, underground natural gas storage in salt caverns (Figure 1) represents a great advantage : cavern storage is flexible and allows multiple cycles of gas injection and production within a year. Although storage capacity is generally smaller compared to the depleted reservoirs and aquifers, cavern storage provides significantly greater gas deliverability in comparison to the other forms of underground storage[1].

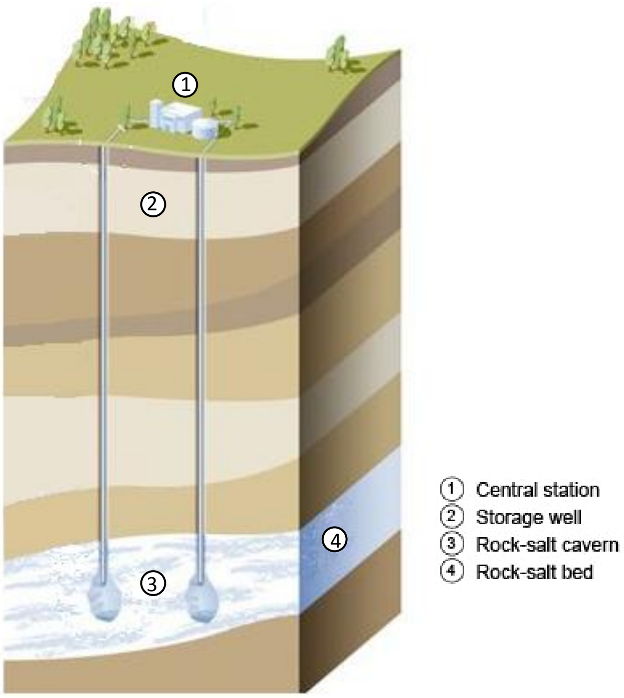

Figure 1 : schematic representation of an underground natural gas storage in salt cavern.

During a gas withdrawal phase, a near-saturated gas flows from the well head to the gas plant. During its flowing towards the receiving facilities at the site entry, the gas is cooled down by thermal exchange with external ambient soil or air. Hence, condensation of the water vapor is likely to occur during its flowing along the wet gas flow lines and gathering lines. Since the pipelines follow the topography, condensed water is likely to accumulate at the pipes dips[2] (Figure 2).

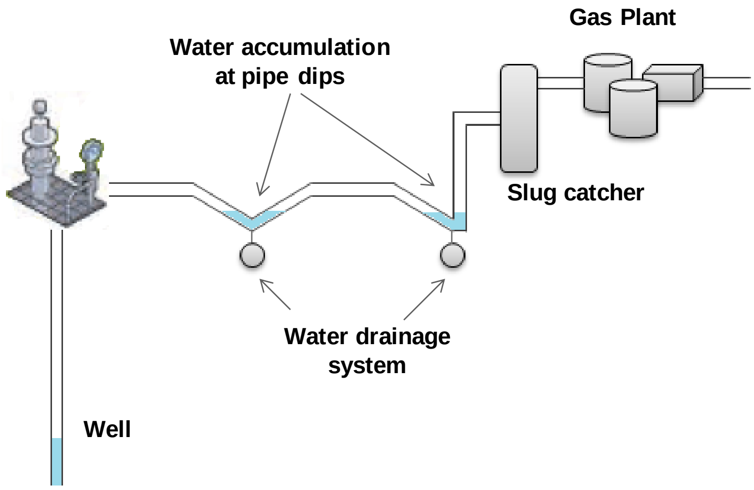

Figure 2 : simplified description of the surface utilities, from the bottom hole to the processing facilities.

In such a context, surface utilities are constantly threatened by operational concerns mostly related with the presence of accumulated water within the pipelines. For instance, the low temperature and high pressure conditions can lead to hydrate formation likely to block the pipelines; slug flow regime may be generated and will cause operational problems to downstream processing facilities. Water accumulation zones can induce important pressure drops and therefore affect the storage productivity. Moreover, corrosion, associated with water accumulation zones, is a damaging process seriously endangering pipe integrity. Corrosion may lead to a failure of the system with potential safety and environmental repercussions and commercial implications due to unexpected facilities downtime.

In order to implement an efficient corrosion management strategy, the activities for monitoring and inspection activities should be defined[3]. Therefore, potential water accumulation zones, with regard to in-situ conditions, have to be accurately identified. Water volumes accumulated at the pipelines low points are also quantified and subsequently described with regard to a permanent or temporary accumulation risk.

The purpose of this paper is to present the flow assurance approach followed to reach this goal by means of multiphase dynamic simulation performed with the OLGA® software.

PROJECT BACKGROUND

With regard to the GDF SUEZ aquifer storages, an important number of studies has already been performed by the CRIGEN, (i.e. the GDF SUEZ Gas and New Energies Research Centre), in order to assess water accumulation phenomenon in wet gas pipelines. For such a purpose, the water produced by each well is quantified on the basis on the water volumes present at the receiving facilities. Field data recorded by the gas plant are used to determine gas flow rates, pressure and temperature variations during withdrawal period. Thus, a Water Gas Ratio (WGR) is associated to each flow line and its variation is taken into account along the gas withdrawal phase.

Such relevant data are used to build an accurate and representative model. Operational conditions changes during the gas withdrawal period are taken into account considering multiple simulation cases. This approach is aimed to describe exhaustively storage operation. Simulations are performed with OLGA®, the market-leading simulator for transient multiphase flows.

Within the scope of the company “Storengy” (GDF SUEZ subsidiary for Under Ground Storage) development and renovation program, new storage facilities are planned in Europe. Particularly, a new salt cavern natural gas storage is under construction. The CRIGEN was consulted in order to assess the water accumulation possibility in the future salt cavern storage flow lines.

The study results, generated before the facilities start-up, will be the basis for a better management of corrosion problems linked with water accumulation during withdrawal cycles.

THE TWO PHASE FLOW MODEL

In the last decades, intense modeling efforts have been made to predict multiphase flow behaviour with greater accuracy. More particularly, the failure of empirical approach to describe accurately multiphase flow in an extended validity range and the required ability to predict time-dependent behaviours during transient operations, lead researchers to focus on the development of sophisticated mechanistic models.

The CRIGEN owns a OLGA® licence. OLGA®[4] based on an extended two-fluid model which comprises three separate phases : gas, bulk liquid and liquid droplets. Separate continuity equations are applied for each phase. Two momentum equations are used in the model : one for the continuous liquid phase and the other for the combination of gas and liquid droplets. For temperature calculations, a mixture energy equation is used assuming an homogenous temperature. System closure equations are empirical correlations such as frictional factor and mass transfer between phases. Those correlations were determined on the basis of large-scale laboratory results. Moreover, within the framework of OLGA® Verification and Improvement Project[5,6,7,8] (OVIP) an huge amount of relevant field data was shared by major oil and gas companies in order to improve model accuracy. Fluid characterisation necessary for fluid flow simulations is implemented by means of thermodynamic tables generated by PVTsim®. PVTsim® is the thermodynamic and physical property package coupled with OLGA®. OLGA® is currently the market-leading simulator for transient multiphase flow behaviour description. Moreover, previous works have already shown the consistency of OLGA® model for the simulation of hydrodynamic behaviour of wet gas gathering lines[9].

SIMULATION ASSUMPTIONS DEFINITION

Since water presence is associated with gas cooling along the pipeline and condensation phenomenon, the pipes which are likely to cause a water accumulation concern are the ones with the longest elevation profile. In terms of water accumulation, the difference in level has also to be taken into account. However, the region of the storage is not an hilly area and the pipeline length was the only criterion for pipe choice. Therefore, the first studied pipeline was the longest pipe, i.e. a 2500 m long 20’’ diameter pipe.

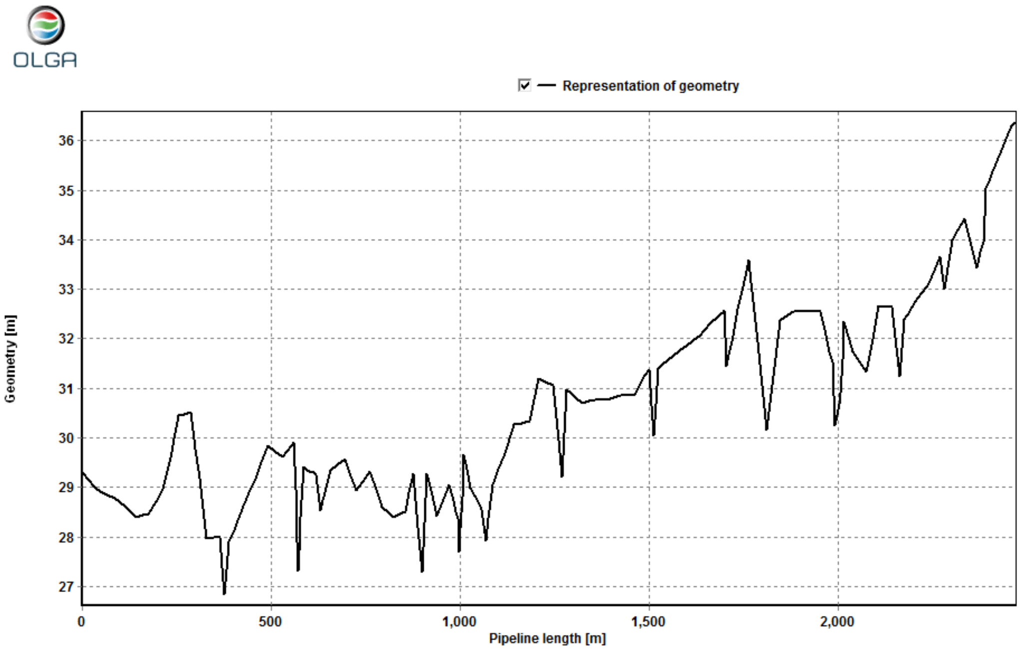

Figure 3 : pipeline elevation profile.

With regard to the operating data, the operator provided values of gas temperature, pressure and flow rates assumed to be reached during a withdrawal phase. Since, the number of caverns connected to the gathering line will vary, both low gas flow rate value and high gas flow rate value were taken into account. Alike, gas pressure and temperature values may suffer great variations when gas is withdrawn for a long time. Basically, simulation cases were divided in high pressure (HP), medium pressure (MP) and low pressure (LP). According to the boundary conditions definition in OLGA®, the pressure at the gas plant was taken into account. A gas temperature at the well head conditions was considered for each case. Based on the operating data provided, six cases (Table 1) were designed to investigate the effect of withdrawal conditions on water accumulation. For all the cases, an ambient temperature of 0°C was chosen as a characteristic wintertime temperature for the area.

	LP cases		MP cases		HP cases	
Gas temperature [°C]	5		24		40	
Total flow [m^3(n)/h]	20,000	100,000	30,000	100,000	30,000	100,000
Time duration [d]	5	5	15	15	15	15
Case name	LP-A	LP-B	MP-A	MP-B	HP-A	HP-B

Table 1 : description of the different simulation cases.

PVTSim® was used to generate thermodynamic tables used by OLGA® on the basis of a gas composition communicated by the field operator. Then 70 % of its water saturation content was added in order to simulate gas at different well-head conditions. Therefore, three different water contents were used :

Case name	LP-A, LP-B	MP-A, MP-B	HP-A, HP-B
Water content [mgH_2O/m^3(n)]	121	273	571

Table 2 : different water contents implemented according to the simulation case well head conditions.

Since liquid water formation is linked to the condensation phenomenon, thermal exchange has a special importance. Heat exchange occurs by internal convection with the inner wall steel layer, then by conduction through the steel and soil layers and finally by external convection with the surrounding air. The outer wall layer is represented by the soil. It is important to stress that heat transfer model used in our calculations, is anisotropic according to a buried pipeline configuration. In order to take into account a not symmetrical heat transfer, a pseudo-thickness of the soil was used to account for the asymmetries of the system.

RESULTS AND DISCUSSION

Table 3 summarizes the predicted water accumulation volume and the final gas temperature for each simulation case. These results show that water condensation can take place only in warm gas temperature conditions. In fact, for LP cases water condensation temperature is not reached even for low gas flow rates. On the other hand, for MP and HP cases for which gas temperature at well head conditions is above 24°C, water condensation temperature is always reached even for high gas flow rates simulation cases. Nevertheless, the occurrence of water condensation is not directly associated with water accumulation. MP and HP simulation cases with high gas flow rates conditions do not show any water accumulation. It can be assumed that high gas flow rate enable condensed water to be swept away even at pipelines low points. It is important to stress the fact that for MP-A and HP-A cases, no steady-state conditions were reached after 15 days of simulation time. Main study result is that water volumes likely to accumulate in salt cavern storage gathering lines are not insignificant for warm wet gas conditions at low gas flow rates.

Case name	LP-A	LP-B	MP-A	MP-B	HP-A	HP-B
Water condensation temperature [°C]	0		19		34	
Final gas temperature [°C]	1.2	2.4	10.4	16.6	18.1	29.3
Water accumulation [m^3]	NO	NO	0.95	NO	3.3	NO

Table 3 : summary of calculations results obtained with T_{air}=0°C

Figure 4 shows in detail different profiles of relevant parameters for HP-A simulation case. A special focus is made on this case since it presents the highest water accumulation volume pointed out in this study. An abrupt drop in water vapour mass flow rate indicates that condensation takes place. This behavior is due to the fact that a near-saturated gas is present at the well head conditions. Therefore, fluid temperature has to reach water dew point in order to initiate water condensation phenomenon. It is shown that water holdup in the pipeline increases just downstream water condensation beginning point.

Influence of air temperature was investigated for this case. Table 4 shows the results of a parametric study aiming to assess the impact of surrounding conditions on the accumulated water volume :

Air temperature [°C]	0	5	10	15
Total water content in branch [m^3]	3.3	2.9	2.4	1.9

Table 4 : influence of air temperature upon accumulated water volume.

It is shown that for hot gas, gas condensation occurs even for air temperatures up to 15°C. Consequently, gas at high temperature is likely to cause water accumulation in the pipeline even for mild surrounding ambient conditions.

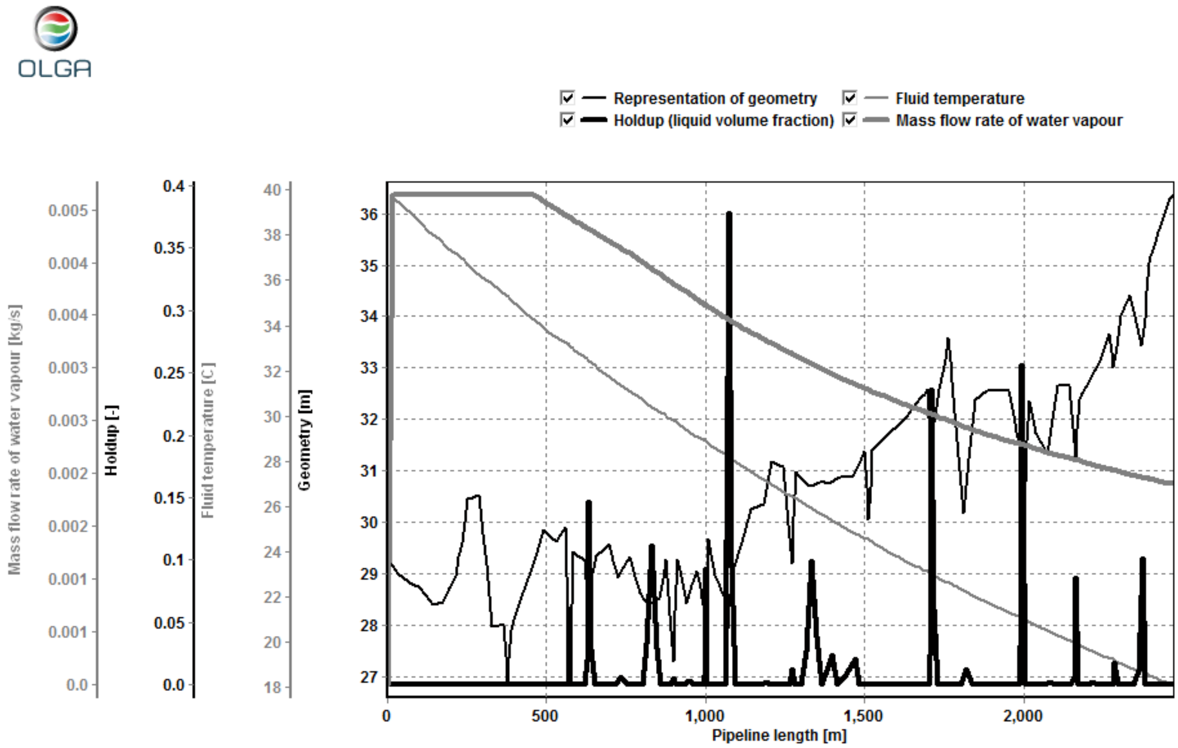

Figure 4 : profiles of mass flow rate of water vapour, liquid holdup and fluid temperature for HP-A case conditions after 15 days of simulation time.

For the simulation cases presenting a water accumulation issue, i.e. MP-A and HP-A, the water accumulation onset flow rate and the liquid flush flow rate were determined. The obtained results are presented in Table 5.

Case name	MP-A	HP-A
Water accumulation onset flow rate [$m^3(n).h^{-1}$]	60,000	90,000
Liquid entrainment flow rate [$m^3(n).h^{-1}$]	105,000	250,000

Table 5 : predictive gas flow rates for dewatering strategy implementation.

These two predictive flow rates must be considered as operational recommendations and a part of a dewatering strategy implementation. In order to determine these two flow rates, the gas withdrawal flow rate was gradually increased until no water accumulation is observed (Figure 5). The primary difference between these two parameters lies in the initial conditions used for the parametric study carried out for their determination. For water accumulation onset flow rate determination, the gathering line is initially dry. On the other hand, for liquid entrainment determination, pipeline initial conditions were taken at the end of the simulation case previously carried out. Hence, the initial water volume present in the pipeline corresponds to the values shown in Table 3.

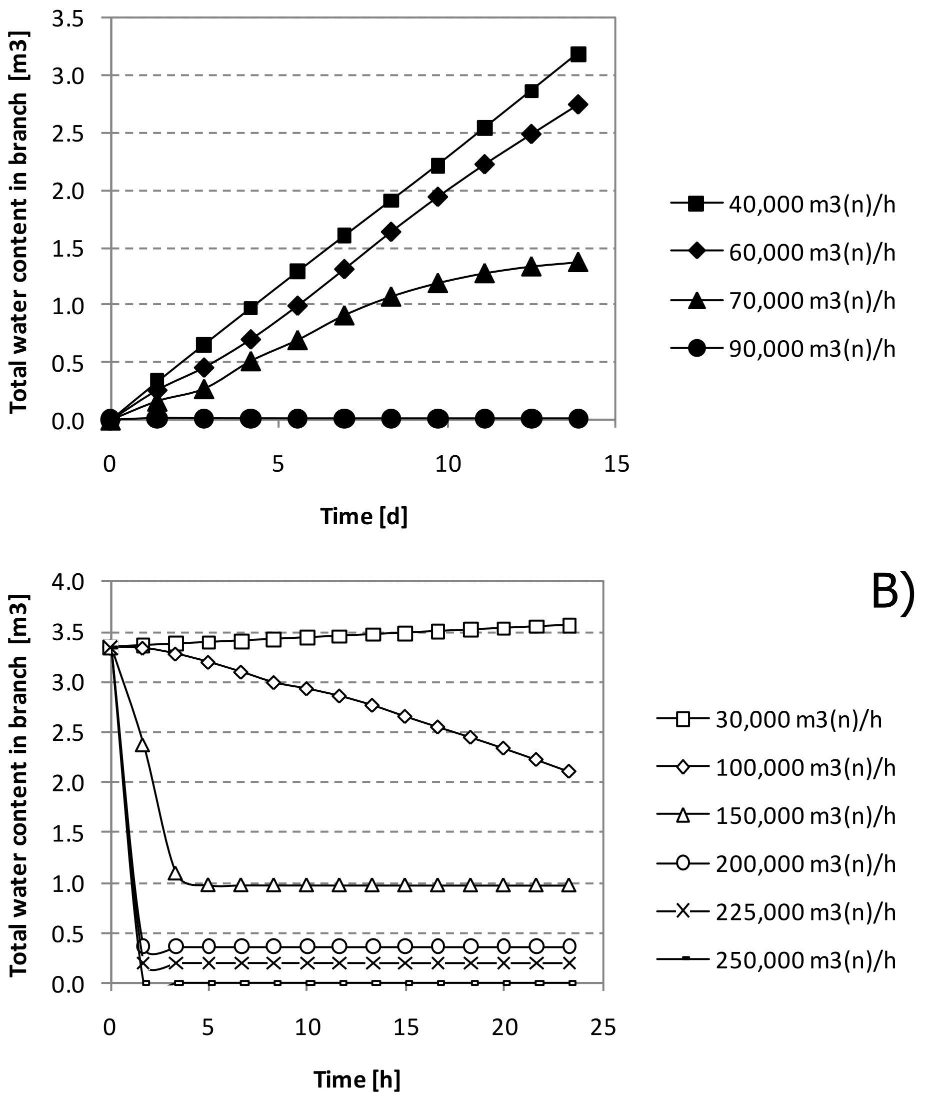

Figure 5 : gas flow rate effect on total water content in branch: A) initial conditions are taken at the beginning of HP-A case simulation, i.e. dry pipeline, B) initial conditions are taken after a 15 days simulation time with HP-A conditions.

CONCLUSIONS

The goal of this study is to assess the possibility of water condensation and accumulation in the pipelines during a withdrawal cycle. Water accumulation in wet gas pipelines is intimately linked with corrosion prevention. In order to estimate water accumulation, simulations were performed with OLGA®. As the gas withdrawn from the facility will be a almost water saturated natural gas, it may generate water accumulation by condensation. The driving force for water condensation is the gas cooling along the pipeline by the process of heat transfer with the surrounding ambient. The longest pipeline, hence the most likely to cause water accumulation problems, was chosen for calculations.

Different simulations cases were taken into account, in order to browse several withdrawing conditions, in terms of gas pressure and temperature at the well head and overall gas flow rate.

It was pointed out that the very irregular pipeline profile avoids the occurrence of water accumulation in a few specific dips (Figure 4). Hence, no design recommendation concerning the installation of low points drain for pipeline dewatering were formulated.

On the other hand, cooperatively with the field operator, realistic operation guidelines in terms of flow gas flow rates were defined. This approach is aimed to define suitable conditions in order to avoid water accumulation during gas withdrawal. A dewatering strategy based on operation guidelines avoids additional CAPEX costs, related to water low points drain, and its compliance contributes to OPEX reduction. Hence, this study's main conclusions are listed below :

- cold gas (5°C) and low pressure conditions do not generate water condensation even for low gas flow rates (20,000 m^3(n)/h) ;
- for warm gas (24°C) and medium pressure conditions, gas withdrawal with flow rates above 60,000 m^3(n)/h is recommended ;
- hot gas (40°C) and high pressure conditions cause water condensation for ambient temperatures up to 15°C, gas withdrawal with flow rates above 90,000 m^3(n)/h is recommended.

The compliance with these guidelines, in terms of withdrawal gas flow rate, it is supposed to avoid any water accumulation at the above mentioned pressure and temperature conditions. It is important to stress that the applicability of these guidelines was checked with the field operator. In fact, the reachable flow gas flow rate was confirmed with regard to the number of available cavities for the flow line.

These conclusions, particularly in terms of withdrawal guidelines, shall be confirmed by additional calculations and field data analysis once the facility will be operated.

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