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BEHAVIOR OF WATER PHASE FROM NATURAL GAS

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Abstract

The paper presents a methodology for determining the conditions in which the liquid phase occurs in the transported natural gas. This methodology allows fast and accurate determination of the phase in which water can be found in natural gas transmission pipelines and also the possibility to highlight the points in the transmission system in which water is in liquid state. A complex function which can describe the phase behavior of water from natural gas has been defined by processing the phase envelopes of the wet natural gas in the field of the Romanian transmission system.

Key words: composition, gas, humidity, phase, liquid

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1. Introduction

Natural gas injected in the National Transmission System (NTS) must meet stringent quality requirements that limit the maximum amount of water permitted per standard cubic meter (i.e. absolute humidity). As a rule, there are local situations which occur with various gas distributors, in which cases these minimal humidity limits are exceeded (Stan and Ionescu, 2001).

Natural gas deposits contain mineralized water, which is extracted with the gas. In the process of transmission, water can be in both liquid and vapor state (Wang and Economides, 2013). Liquid water contains large amounts of salts, which can build up on the walls of the pipelines. Liquid water may also separate, due to gravity, in the lower portions of pipes and, therefore, it may form water plugs. The results obtained by Promkotra (2013) regarding the cricondentherm and cricondenbar points can be useful when controlling and managing natural gas.

As it has recently been shown (Eslamimanesh et al., 2011), the experimental data regarding the water content of gases in equilibrium with the gas hydrate, ice, or liquid water are limited because this is a time

consuming process. This paper aims at emphasizing the criteria that can be defined to specify the state of water aggregation existing in gas.

According to Michelsen (1994) and Neacșu (2009), when gas contains a liquid phase (wet gas, Fig. 1), the two coexisting phases - liquid and gas - have different compositions. Liquid phase is an aqueous solution containing a small amount of hydrocarbons, whereas in the gaseous phase the water contained is in vapor state. The compositions of the vapor and liquid phases are defined by the components' molar fractions y_i , x_i respectively, and the biphasic mixture composition is characterized by z_i fractions. Compositions x_i , y_i and z_i are different. As Bahadori (2014) concluded, the simple methods developed for the estimation of water content have a limited range of validity, while the advanced models can be used for a large scale of gas properties. A complex model was used by Belandria et al. (2011) in order to study phase equilibrium in the carbon dioxide - methane - water system. The model validity was obtained by successfully comparing the measured data with the literature data. The problems arising from using a two-phase equilibrium approximation in reservoir simulation are also shown by Okuno et al. (2010).

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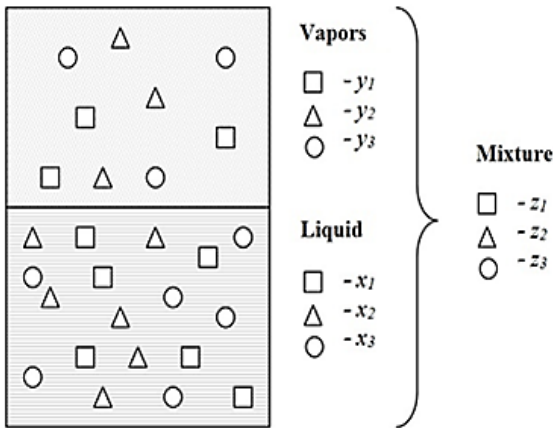


Fig. 1. Water - gas biphasic mixture

2. Phase behavior of wet gas

For dry gas (in chromatographic analysis), the liquid-vapor equilibrium diagram is called phase envelope (Fig. 2). It is the field where the liquid phase and the vapor phase coexist, bounded by the curve of the dew points (dew line) and the curve of the boiling points (bubble line). At their intersection there is the critical point of the mixture. The diagram in Fig. 2 shows that, in a mixture of real gas (presented in Table 1), its behavior in the phase transition area is very different from the behavior of a pure substance (e.g. CH₄) (Ahmed, 1989; Pedersen and Christensen, 2006; Whitson and Brule, 2000). Because of the low liquefaction temperature, the behavior of the CH₄ cannot be presented on the same graph with the one for the mixture of real gas.

Water existing in gas, even in small percentage, determines some behavior in the phase transition area different from that presented in Fig. 2. The phase envelope for wet gas depends on the humidity value (Douglas 1991). Fig. 3 shows the phase envelope for wet gas (presented in Table 1) containing 0.01% water

(molar %), and Fig. 4 presents the phase envelope for wet gas containing 0.075% water.

In diagrams from Fig. 3 and 4, one can observe the influence of humidity on phase behavior. Water from the gas mixture determines a dew line different from that of the hydrocarbons mixture. The blue line on the graph represents in fact two very close lines (mixture of gas) and the red one represents the phase equilibrium for vapor water. Depending on the water percent in the natural gas, these three curves can intersect. The area of interest for the natural gas transporter is indicated in Fig. 4 and it is bounded by the pressures and temperatures registered in the pipelines.

Information in this area is essential for the transporter, as it allows the determination of the water aggregation state in the transported gas. Depending on humidity, pressure and local temperature (in the pipeline) one can determine whether water is in liquid or vapor state.

3. Analysis of water phase behavior in gas depending on transmission parameters

In order to analyze phase behavior of the water existing in gas, one takes as reference the dew line corresponding to the measured humidity of the natural gas, as shown in Fig. 5. This curve was determined taking into account the equilibrium envelope, from which there was selected only the segment corresponding to the operating pressures from the transmission systems.

Local pressure and temperature of the gas define a point on the PT diagram. Gas humidity determines the shape of the dew line.

If the position of the point that characterizes the state of the transmitted gas is above the dew line, then water in the gas is in liquid state, and if the point is below, water is in the form of vapors. Fig. 5 presents the two areas, namely the liquid and the vapor state, at a temperature of 10 °C.

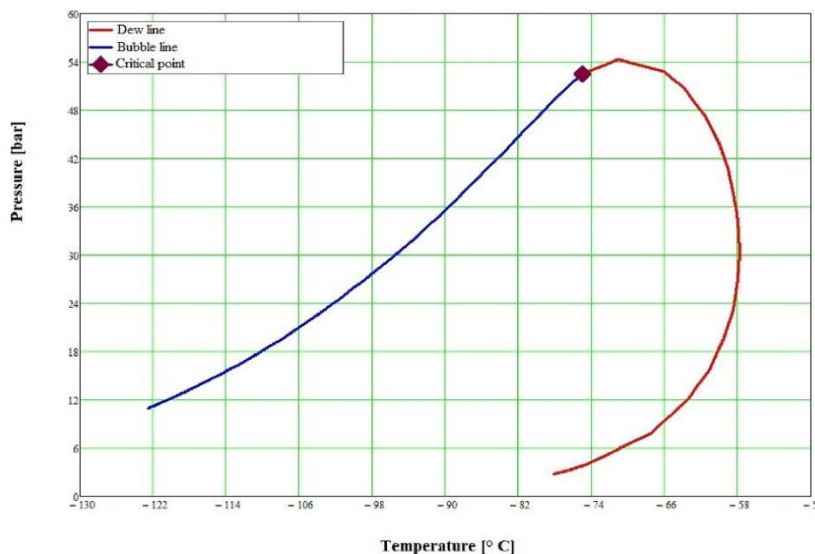


Fig. 2. Phase envelope for natural gas transported through NTS (average composition)

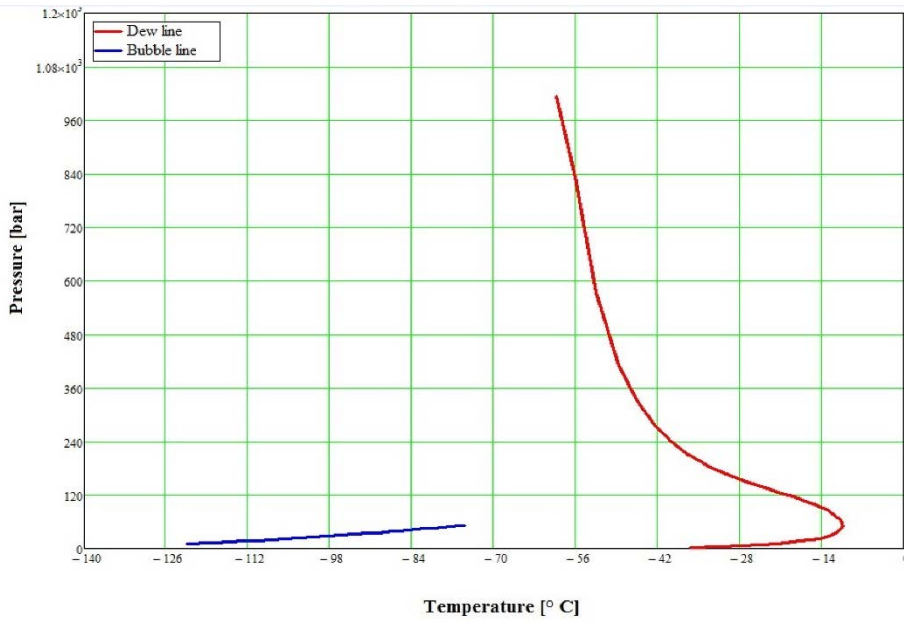


Fig. 3. Phase envelope for wet gas with 0.01% water

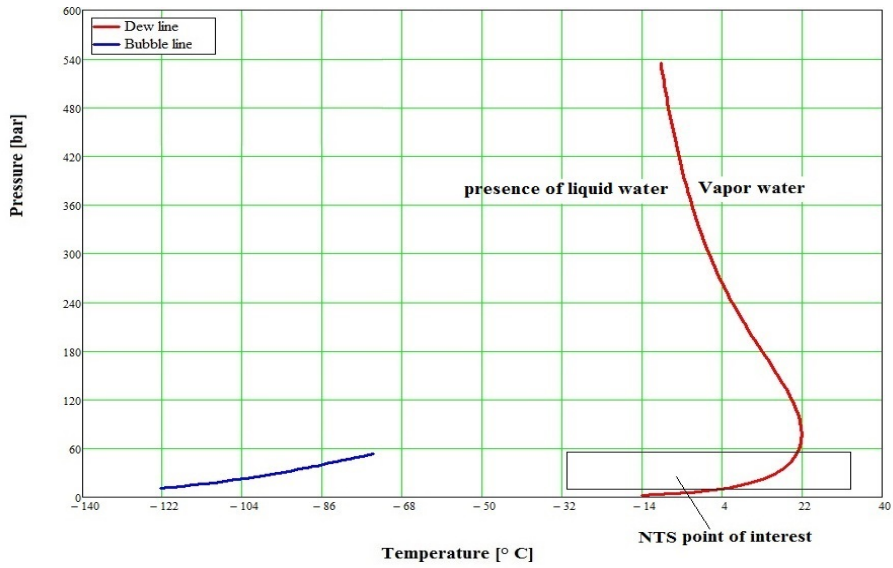


Fig. 4. Phase envelope for wet gas with 0.075% water

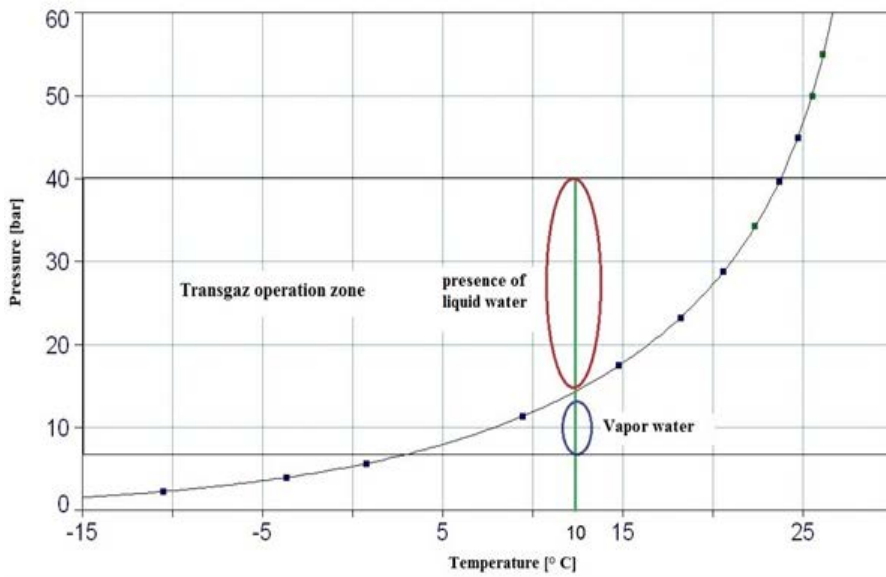


Fig. 5. Phase determination for the water in the transported gas

Table 1 Composition of wet gases

	<i>Component</i>	<i>M</i> [kg/kmol]	<i>Tc</i> [K]	<i>Pc</i> [bar]	<i>acc</i>	<i>Molar %</i> <i>dry gas</i>	<i>g / m³N</i>	<i>Mass %</i>	<i>Molar % wet gas</i>
1	Methane	16.043	190.4	46	0.008	96.6826	693.7867	93.12577	96.6379
2	Ethane	30.07	305.3	48.84	0.098	1.7315	23.2893	3.126082	1.7307
3	Propane	44.097	369.7	42.46	0.152	0.5682	11.2067	1.504256	0.5679
4	Isobutane	58.124	408	36.48	0.176	0.0958	2.4899	0.334215	0.0957
5	N-butane	58.124	425.1	38	0.193	0.0942	2.4486	0.328671	0.0941
6	Neopentane	72.151	469.5	33.74	0.251	0		0	0
7	Isopentane	72.151	469.5	33.74	0.251	0.0187	0.6045	0.081141	0.0187
8	N-pentane	72.151	469.5	33.74	0.251	0.0133	0.4277	0.057409	0.0132
9	2,2- dimethylbutane	86.178	507.3	29.69	0.296	0		0	0
10	2,3- dimethyl-butane	86.178	507.3	29.69	0.296	0		0	0
11	3,3- dimethyl- butane	86.178	507.3	29.69	0.296	0		0	0
12	3-methyl-pentane	86.178	507.3	29.69	0.296	0		0	0
13	2- methyl-pentane	86.178	507.3	29.69	0.296	0		0	0
14	Hexane	86.178	507.3	29.69	0.296	0.0019	0.0733	0.009839	0.0019
15	2,4-dimethyl-pentane	100.205	528.6	34.98	0.453	0		0	0
16	2,2,3-trimethyl-butane	100.205	528.6	34.98	0.453	0		0	0
17	2-methyl-hexane	100.205	528.6	34.98	0.453	0		0	0
18	3-methyl-hexane	100.205	528.6	34.98	0.453	0		0	0
19	3-ethyl-pentane	100.205	528.6	34.98	0.453	0		0	0
20	Heptane+	100.205	528.6	34.98	0.453	0	0	0	0
21	2,2,4-trimethyl-pentane	114.232	552.3	31.23	0.491	0		0	0
22	N-octane	114.232	552.3	31.23	0.491	0	0	0	0
23	Methyl-cyclohexane	98.189	552.3	31.23	0.491	0		0	0
24	Cyclohexane	82.146	528.6	34.98	0.453	0		0	0
25	Benzene	78.114	528.6	34.98	0.453	0		0	0
26	Toluene	92.141	552.3	31.23	0.491	0		0	0
27	Hydrogen	2	33	13	0	0		0	0
28	Carbon monoxide	28.01	132.9	35	0.066	0		0	0
29	Hydrogen sulfide	34	373.6	88.9	0	0		0	0
30	Helium	4	5.2	2.26	0	0		0	0
31	Argon	39.848	150.7	48.98	0	0		0	0
32	Nitrogen	28.013	126	33.94	0.04	0.7402	9.2743	1.244873	0.7398
33	Oxygen	31.99	154.6	50.4	0.025	0.0058	0.0829	0.011128	0.0058
34	Carbon dioxide	44.01	304.1	73.76	0.225	0.0479	0.9428	0.12655	0.0479
35	Water	18.015	647.3	221.3	0.334		0.373	0.050067	0.0463
	Total					100	744.6267	100	100

4. Determining water percentage in the composition of wet gas

Dry gas composition is indicated in chromatographic analysis reports in the form of volume, molar and mass fractions, as well as in g/m_N^3 . Because absolute humidity is expressed in g/m_N^3 , calculation starts using the data from the last column of the chromatographic analysis report. The mass of water m_{apa} corresponding to gas humidity is added to the total mass of the gas mixture from the last column (Kazim, 1996; Pedersen and Christensen, 2006). With the obtained value of the total mass (i.e. gas and water), mass fractions are recalculated, as well as the molar fractions of the wet gas. If to the composition shown in the chromatographic analysis report, one adds a specified amount of water equal to 0.373 g/m_N^3 , there are obtained the values indicated in Table 1 for wet gases.

In this example, it may be seen that the molar percentage of water is $y_{\text{water}} = 0.0463$. With this value, there can be determined, based on Dalton's law (also

used for real gas), the partial pressure of the water vapors existing in gas (Eq. 1):

$$p_{\text{water}} = (p + 1.013)y_{\text{water}} \quad (1)$$

Supposing that gas pressure is 22.5 bar, the partial pressure of the water vapors has the value (Eq. 2):

$$p_{\text{water}} = (22.5 + 1.013) \cdot 0.000463 = \\ p_{\text{water}} = 0.01088651 \text{ [bar]} \quad (2)$$

To this value there corresponds a temperature of the dew point $t_{\text{WDP}} = 8.2 \text{ }^\circ\text{C}$. If only the temperature of the dew point is known, calculation may be done in reverse, so that there results absolute humidity. To exemplify, it is considered a temperature of the dew point $t_{\text{WDP}} = 5.8 \text{ }^\circ\text{C}$ and it is determined the corresponding saturation pressure, which represents the partial pressure of the water vapors $p_{s \text{ water}} = 0.0092248 \text{ bar}$. With this value, it is determined an absolute humidity equal to 0.315 g/m_N^3 .

5. Determining water phase behavior in natural gas

In order to define phase behavior of water, which is gas humidity, there were processed phase envelopes of the wet natural gas corresponding to molar fractions ranging from 0.01% to 2%. Phase envelopes were examined and processed in the range of interest for the transmission system, which is pressure varying between 2 and 60 bar and temperatures ranging from -30 °C to 30 °C.

For each diagram in the interest field, there was defined a function that describes phase behavior of water existing in natural gas. These functions are presented in graphical form in Fig. 6. Starting from them, there was designed a complex function which

allows continuous defining of the phase behavior from 0.01% to 2 mol% of moisture.

For some of the data measured in situ, where there were registered higher humidity values, phase behavior of the water in gas was analyzed. The results are graphically shown in Fig. 7 and Fig. 8. The determination of water phase behavior in wet gas aims to highlight the points in the transmission system where water is in liquid state. In this situation, there appears a shift between liquid water and gas due to their different speeds. Given the pipelines profile, water will accumulate in lower areas, phenomenon that may trigger difficulties in the transmission system.

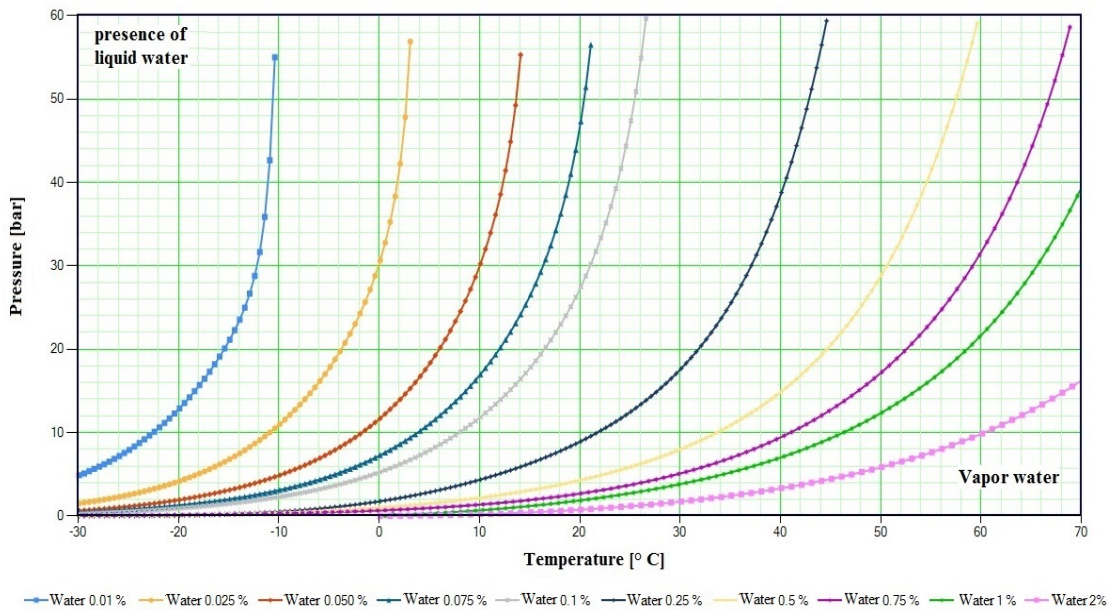


Fig. 6. Functions that define phase behavior for different humidities

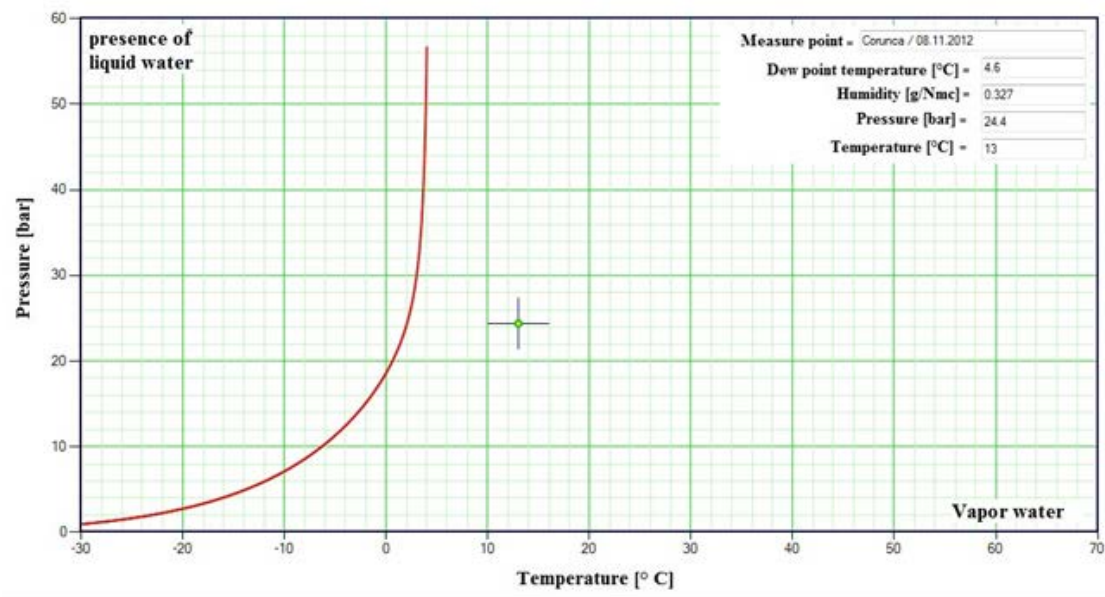


Fig. 7. Measured values – water in vapor state

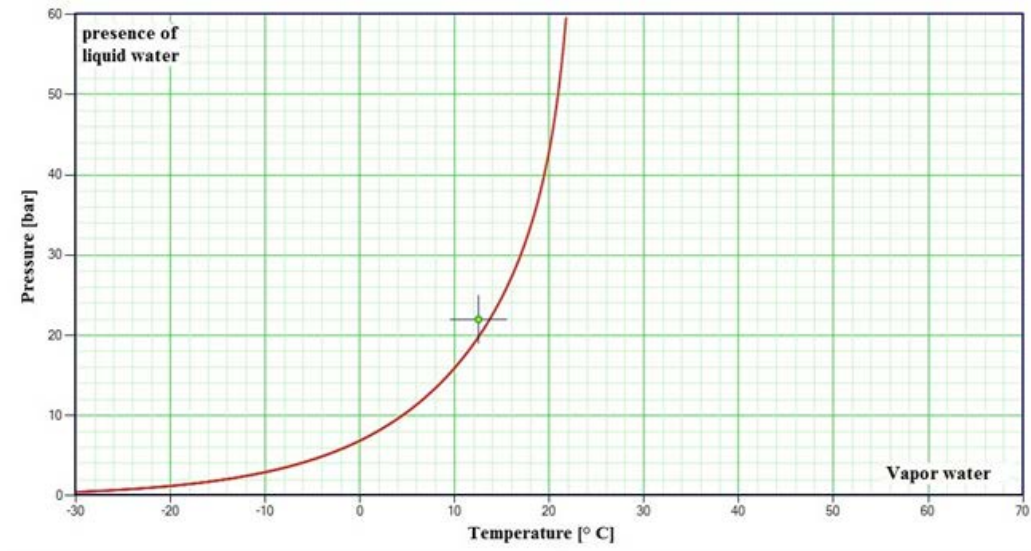


Fig. 8. Measured values – water in liquid state

6. Conclusions

Natural gas contains a certain percentage of water coming from water reservoirs. If water is in liquid state, it may cause difficulties as a result of its accumulation in the lower areas of the transmission system. In order to avoid incidents caused by water existing in gas, besides constant monitoring of the humidity at the input points of the system, one should also know the conditions in which liquid phase occurs.

Liquid or gaseous state of the water in natural gas may be determined on the basis of composition and local state parameters (i.e. pressure and temperature).

The methodology to determine the aggregation state of the water from gas presented in this paper is based on liquid-vapor equilibrium diagrams and allows fast, accurate determination of the phase in which water exists in the transmitted gas.

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