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CONCEPTUAL PROJECT OF PIPELINE DRAINAGE SYSTEM

Liquid accumulation process may take place after gas-oil separation plant gas oil separation plant to pipeline connection points both in main cross-country pipelines and trunk lines or flow-line system. This liquid accumulation is formed by natural gas liquid and deposit or condensed water located at the lowest point of the pipeline. Condensate and water increases the pressure drop during gathering and transportation since must be removed using conventional or principal new methods. But first researcher or field specialist should find and prove the location of liquid slugs and also estimate its oriental volume. The article shows the description of the method: how to find the liquid accumulation in the pipeline using only the technological parameters of gathering or processing system, how to find exact location place of this slug and how to remove liquid from the pipeline without stopping of gathering or transportation process. Method has the wide area of applications and can be used both at the natural gas production and transportation companies. The method is complex one: from searching the reason of water accumulation to its volumetric estimation and further removal from the pipeline using drainage tube and modern technology of connection. But the price of implementation the method is several times less than the value of relieving gas from pipeline and period of downtime.

Keywords: *pipeline, liquid, volume, drainage, system, pressure.*

Problem statement

The development of any oil and gas field broadly can be divided on three main stages [1]:

- early stage with great when the value of reservoir pressure is quite enough for hydrocarbons to be extracted from reservoir, gathered at the field processing facilities (FPF), processed using low-temperature dehydration method, and transported to the central processing facilities (CPF) or customer. A lot of new well is drilled in the early period thus increasing of total flow rate is observed.

- stabilization of the flow rate stage is characterized by slight decreasing the operating pressure (wellhead pressure) over time, drilling of new gas production wells, replacement of low-temperature separation by adsorption or absorption, LNG or water vapor removing);

- cessation of production (or final period) is characterized by great operating pressure and flow rate drops, appearance of great amount of connate and deposits water in casing, tubing and flow-lines, obsolete and outdated equipment. Operating company should put into the operating new booster station and a lot of activities should be carried out to increase the extracting of hydrocarbons from reservoir.

90% of Ukrainian oil, gas and condensate fields are at the final stage of development. To stabilize the production rate in this case means to lower the wellhead (operating) pressure. Two ways can be recommended as the perfect ones: put into the operation small compressors at the wellheads or decreasing the value of hydraulic resistance of flow-line and processing systems, trunk lines and transmission lines. This articles shows the essence of second method application for oil and gas fields.

Raw natural gas from the well consists of methane as well as many other smaller fractions of heavier hydrocarbons, and various other components. Natural gas has to be separated into marketable fractions and treated to trade specifications and to protect equipment from contaminants.

Many upstream facilities include the gathering system in the processing plant. However, for distributed gas production systems with many (often small) producers, there are little processing at each location and gas production from thousands of wells over an area instead feed into a distributed gathering system. This system in general is composed of [2]:

• **Flowlines (gathering line)**: A line connecting the wellhead with a field gathering station (FGS), in general equipped with a fixed or mobile type pig launcher.

• **FGS** is a system allowing gathering of several flowlines and permits transmission of the combined stream to the central processing facility (CPF) and measures the oil/water/gas ratio. Each FGS is composed of:

- Pig receiver (fixed/mobile);
- Production header where all flowlines are connected;
- Test header where a single flowline is routed for analysis purposes (GOR Gas to oil ratio, water cut);
- Test system (mainly test separator or multiphase flow meter);
- Pig trap launcher.

•**Trunk line (transmission line)** – pipeline connecting the FGS with the CPF. Trunk line is equipped with a pig receiver at the end.

Several schemes can be recommended for field processing and separation of natural gas, but the specific solution is usually a function of the composition of the gas stream, the location of the source, and the markets available for the products obtained. Broadly we can divide all processes that occur with natural gas in upstream and midstream sectors at 3 parts:

- gathering;
- processing;
- transportation.

Broadly the gathering and transportation process is shown at the figure 1 [3].

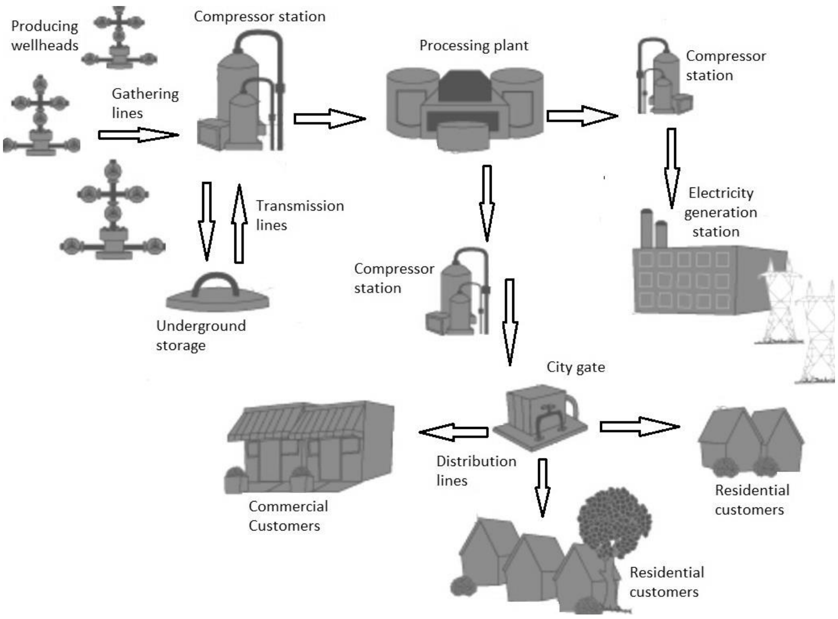


Figure 1. The way gas flows from the wells to the customers

Natural gas is extracted from the reservoir by using the underground (tubing, casing) and surface (X-mas tree of production wells equipment.

Then gas flows through the flow line to the flow-line (manifolds, chock) center of GOSP. Flow line center (it is also called header) is the first unit of GOSP – the place where all flow lines are ended. Flow line center is the block equipped with the lot of valves and lines that help to control the technological regime of all production wells and re-switch the flows.

After gathering at the flow line center natural gas must be processed. All processing equipment locates at GOSP. And first as much as it`s possible operator have to remove the maximum volume liquid from natural gas flow. This liquid is dissolved with natural gas and represented by big drops and vapor of:

- undesirable water from the reservoir;

- really useful natural gas liquid (propane-butane fraction and condensate).

That is why first gas is routed by technological pipelines to the first stage separator, where the largest drops of water and NGL are removed, then gas flows to the second and further stages of separation to remove the vapor of water and NGL from the preliminary treated natural gas.

Analysis of recent researches and publications

From the midstream sector specialist point of view the final stage of oil and gas field development is most complicated one because of depending on equipment technical condition and booster station technological regime. Despite the fact that the main task of booster station is to compress natural or associated gas from header control point pressure to the pressure in main cross-country pipeline`s system most of booster compressors are used to compressed natural gas to the pressure needed for effective removal of NGL and water vapor at adsorption or absorption equipment). So stopping the compression of natural gas for some (even small) period of time can lead to ineffective dehydration processes. The result of it – NGL or water drops and vapors move with gas stream from GOSP to the pipeline.

Two-phase flow lines and pipelines tend to accumulate liquids in low spots in the lines. When the level of liquid in these low spots rises high enough to block the gas flow, then the gas will push the liquid along the line as a slug. Depending on the flow rates, flow properties, length and diameter of the flow line, and the elevation change involved, these liquid slugs may contain large liquid volumes.

Situations in which liquid slugs may occur should be identified prior to the design of a separator. The normal operating level and the high-level shutdown on the vessel must be spaced far enough apart to accommodate the anticipated slug volume. If sufficient vessel volume is not provided, then the liquid slugs will trip the high-level shutdown.

When liquid slugs are anticipated, slug volume for design purposes must be established. Then the separator may be sized for liquid flow-rate capacity using the normal operating level. The location of the high-level set point may be established to provide the slug volume between the normal level and the high level. The separator size must then be checked to ensure that sufficient gas capacity is provided even when the liquid is at the high-level set point. This check of gas capacity is particularly important for horizontal separators because, as the liquid level rises, the gas capacity is decreased. For vertical separators, sizing is easier as sufficient height for the slug volume may be added to the vessel’s seam-to-seam length.

If liquid slugs are anticipated in cross-country pipeline or modern trunk-lines equipped with ball valves and launcher-receiver units the removal of NGL and water is the pigging process (see figure 2) [4].

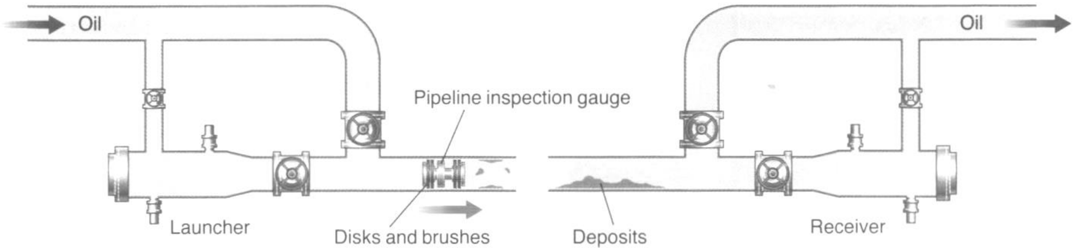


Figure 2. Pipeline launcher-receiver system

Often the potential size of the slug is so great that it is beneficial to install a large pipe volume upstream of the separator. The geometry of these pipes is such that they operate normally empty of liquid, but fill with liquid when the slug enters the system. This is the most common type of “slug catcher” used when two-phase pipelines are routinely pigged. Figure 3 is a schematic of a liquid finger slug catcher [5].

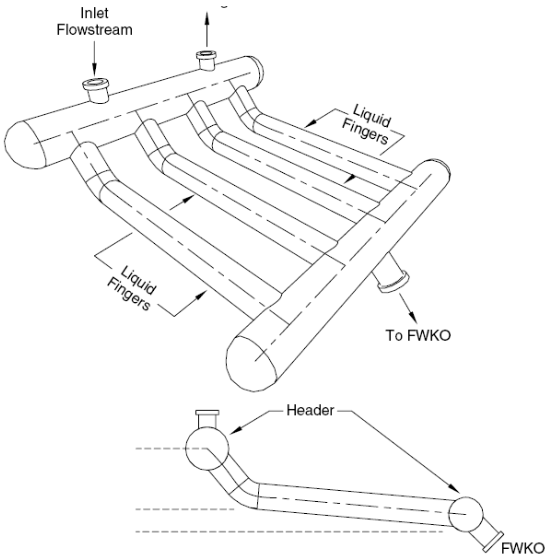
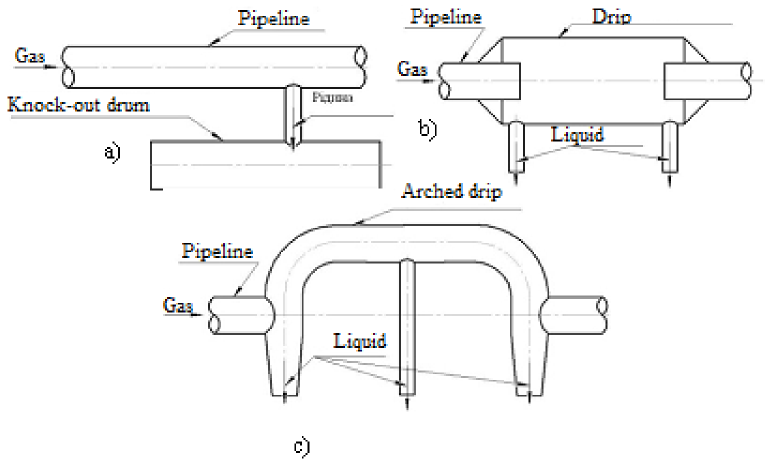


Figure 3. Schematic of a two-phase horizontal slug catcher with liquid “fingers.”

The implementation of pigging is the great problem for both the trunk and flow-lines (especially obsolete and outdated ones equipped with valves in the form of a trapezoid) and old transmission (cross-country) pipelines, since the process of reconstruction of them is expensive and economically unjustified.

In this case, such types of pipelines are equipped with stable devices for draining liquid, normally called drips or deposits catchers (figure 4). The operating of these devices can be either periodical or regular [6].

If operating company wants to save the money or simply has not enough personals for observing the changes in flow-line or trunk line system, the system can be equipped with drainage pipe. The principal is the removal of NGL and water into the special field facilities or vehicles under the operating pressure of natural gas [7].



a) simple drip; b) drip: expanding pipe; c) arched drip

Figure 4. Types of drips

Frequently these stable devices are out of operation over time thus liquid stills in some points inside pipelines.

Statement of base material

To understand how water and NGL create the liquid accumulation in pipeline let us consider why this process is taking place in trunk line from GOSP Hayi (Western Ukraine production region) equipped with the drip using for water removing from pipeline into the underground liquid storage facilities. The water and NGL is removed by drainage pipes 89-mm diametres.

In this case, natural and associated gas is flowing though the main 219-mm pipeline with operating temperature of 17 ^{0}C after compression and quite small velocity of 1 m/s. The composition the natural gas contains a lot of water vapor and drops. This water settles in the expansion chamber due to the force of gravity in chamber with diameter three times larger than the diameter of the main pipe.

Some changes of operating temperature and pressure is happened along the pipeline according to SCADA system data (figure 5).

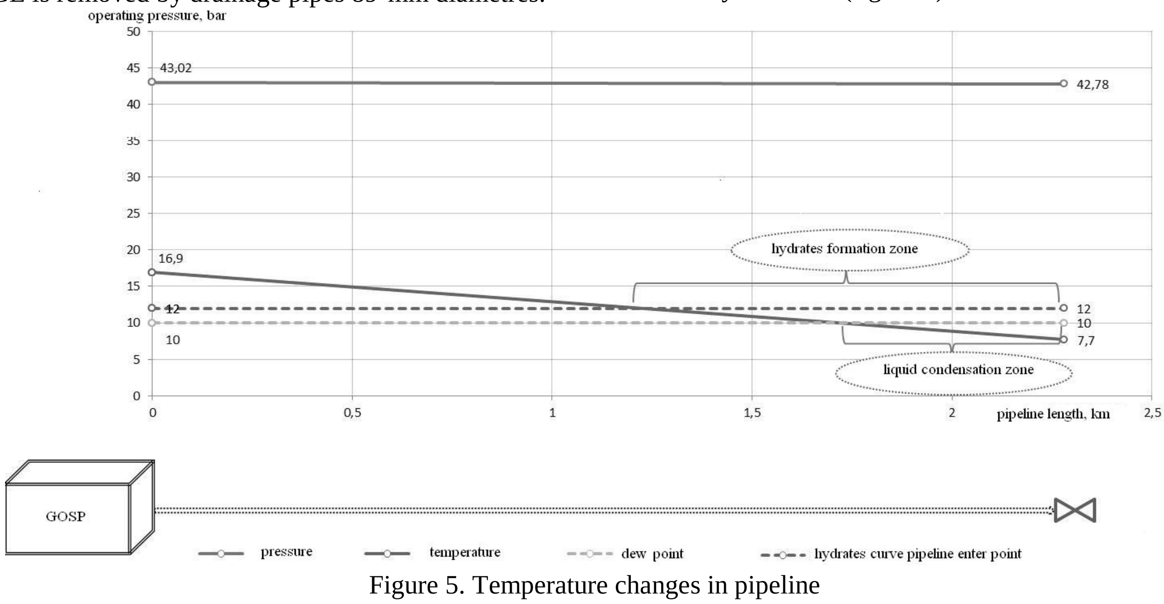


Figure 5. Temperature changes in pipeline

The principal of problem is laying in the temperature drop curve, because gas entering into the underground pipeline starts sharply decrease its temperature and the temperature of natural gas in some point is becoming lower than the temperature of hydrate formation (7.7 deg Celcium lower than 12 deg Celcium). The figure shows brightly that drip is situated in the hydration zone since hydrates are creating in the narrow places of drip such as 89-mm drainage pipes.

It`s the convenient example of ineffective operation of the field equipment. Besides, drips can be out of service or simply not available at the gas pipeline. In such cases pipelines should be stopped for pressure relief and further drainage operations. The cost of such complex work (for above mentioned pipelined) consists of value of relieving gas from pipeline (2,000 m^3) and period of downtime value (for 1 day – 135,000 m^3 of natural gas production). Even taking into account only the cost of the above variables (without any of other operation such as pipe cutting) will achieve 45,000$. The more the case occurs, the more operating cost is needed. Naturally, operating company can put into the operation new dehydration equipment at GOSP, but it is expensive and the lasting process (at least half a year from the moment of emergency identification).

Here complex solution must take place. And the fundamentals for its implementation are technological process data, experience and the results of research works.

This scientific work represents an integrated approach to solving the problem basing at three main points:

- to understand why the emergency situation took place (find reason);
- to find the place of deposit location (the borders of potential warning zone);
- to make right decision of the problem removal (save time, money and resources).

According to the temperature drop curve, line of hydrate and condensation formation, one can find the place of liquid localization (like it is shown on the previous figure). But if the velocity of natural gas inside pipeline will be higher than 5 m/sec, liquid tries to leave the lowest place of the relief pipeline. All these lowest places are natural trap of NGL and water in relief pipeline because of geodesic heights of points (figure 6) and the difference of gravity between the water, NGL and natural gas. The more geodesic difference between two closest points of pipeline, the greater the probability of liquid locations.

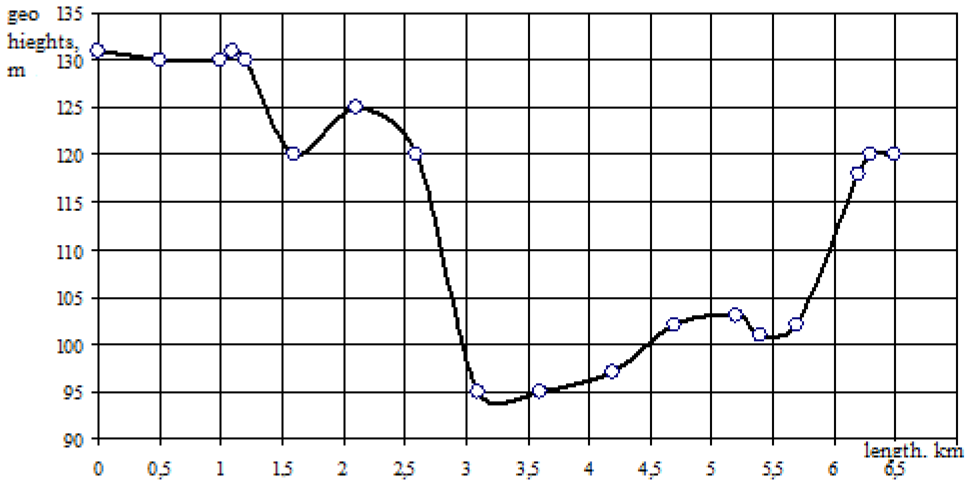


Figure 6. The real pipeline technological diagram

Simple ISO parametrical method of deposits identification inside the pipeline is fully described in the book of Boyko V.S. in transportation problem chapter [8]. This method allows estimating:

- hydraulic efficiency of flow-line, trunk line or transmission line (broadly: probability of deposits creation inside pipeline);
- temperature and pressure drops from initial to the final point of the pipeline;
- the line velocity of the gas.

Using the invention of Bratakh M.I. (Ukrainian research institute of natural gas) one can calculate the level of overlap free diameter of the pipeline and estimate the volume of liquid deposits [9].

$$V = a \cdot \frac{\pi D_{в}^{2}}{4} L, \qquad (1)$$

here are: *a* – level of overlap (table 1); *D* - inside diameter; *L* – length of the water mirror inside the pipeline.

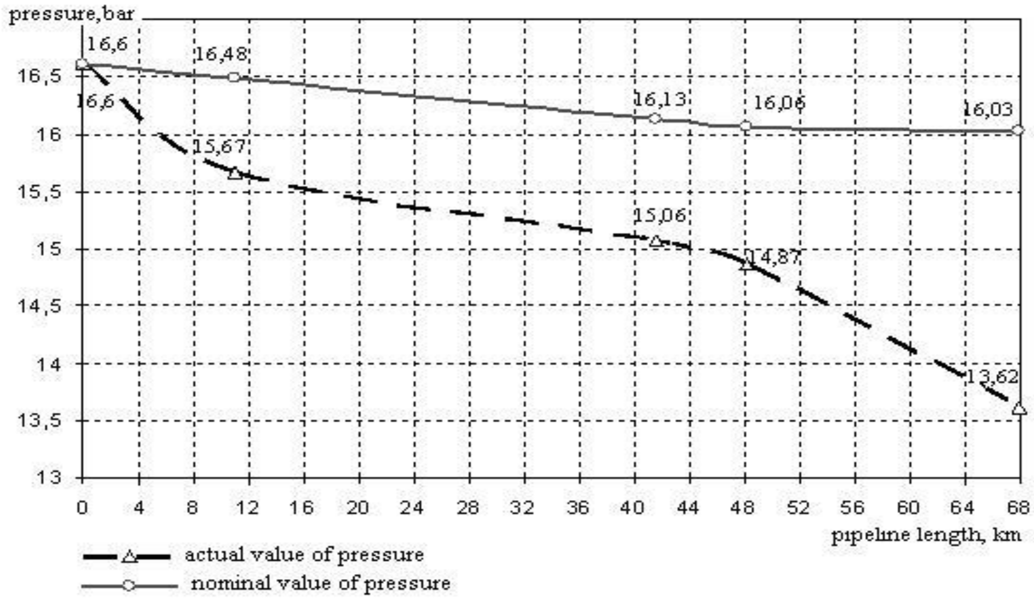
Table 1. The level of overlap formulas

The angle of horizontal pipeline	Equation of curve describing the level of overlap behavior
1,0	$a=0,0878E^3+0,003E^2-0,2612E+0,1709$
0,9	$a=0,1012E^3-0,0362E^2-0,3125E+0,2446$
0,8	$a=0,0888E^3-0,0517E^2-0,3602E+0,3156$
0,7	$a=0,0218E^3+0,0366E^2-0,4553E+0,3912$
0,6	$a=-0,0486E^3+0,1307E^2-0,5534E+0,4672$
0,5	$a=-0,0724E^3+0,1431E^2-0,6104E+0,5379$
0,4	$a=-0,1265E^3+0,2087E^2-0,6941E+0,6121$
0,3	$a=-0,2023E^3+0,3122E^2-0,797E+0,6887$
0,2	$a=-0,2321E^3+0,3354E^2-0,8594E+0,7602$
0,1	$a=-0,2851E^3+0,399E^2-0,9422E+0,8342$
0,05	$a=-0,5001E^3+0,761E^2-1,1498E+0,8927$
0	$a=-0,7857E^3+1,2464E^2-1,4195E+0,9591$

Then simply align the curves of temperature, pressure drop and hydrate formation and condensation of liquids lines with a relief pipeline route. And as the result you will find the point of liquid location inside the pipeline at some kilometers from the initial point.

The example of hydrate zones and condensing liquids definition in the existing pipeline DN 1000 is shown in Figure 7 below.

а)



б)

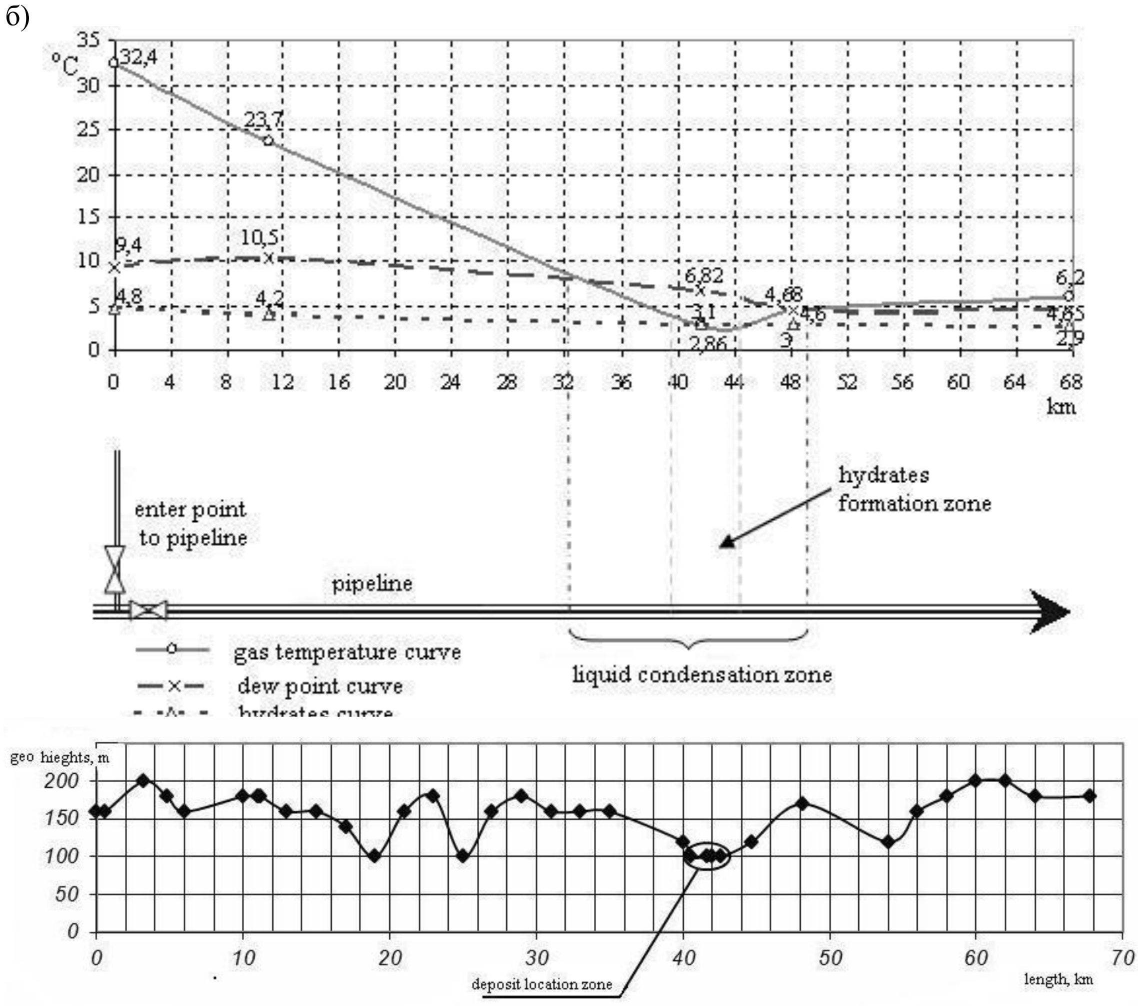


Figure 7. Searching location of liquids deposits

The algorithm to determine the conditions of hydrate and liquid formation following:

- The dotted line at the graph **a** shows change of operating pressure in the control points of the pipeline, upper curve shows the behavior of the pressure in the case of “clean” pipeline;

- The graph b shows the changes of natural gas temperature, measured at the control points, dew point and estimated hydrate creation temperature according to operation pressure at the upper graph.

Zone of the hydrates formation and liquid accumulation will be match to the place where the curve of temperature change of the gas flow is located below the dew point curve hydrate formation curve. This zone must be matched zone of the operating pressure curve at the graph a with enlarged pressure drop. The least squares methods must be applied to create all of above presented curves.

Naturally, the lowest point of this zone must be determined by GPS.

There remains little, we are close to end of presentation. So, we have already known why the liquid is accumulating in pipeline and where it is localized. Only one thing should do now – remove it, but without stopping the gathering or transportation process.

In fact, we can use a standard design of the drainage tube (figure 8) or modern one from Ukrainian or foreign producer (figure 9).

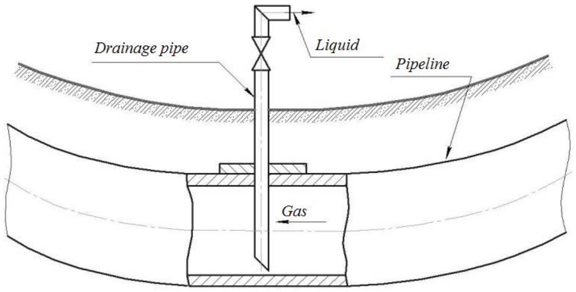


Figure 8. Simple drainage tube

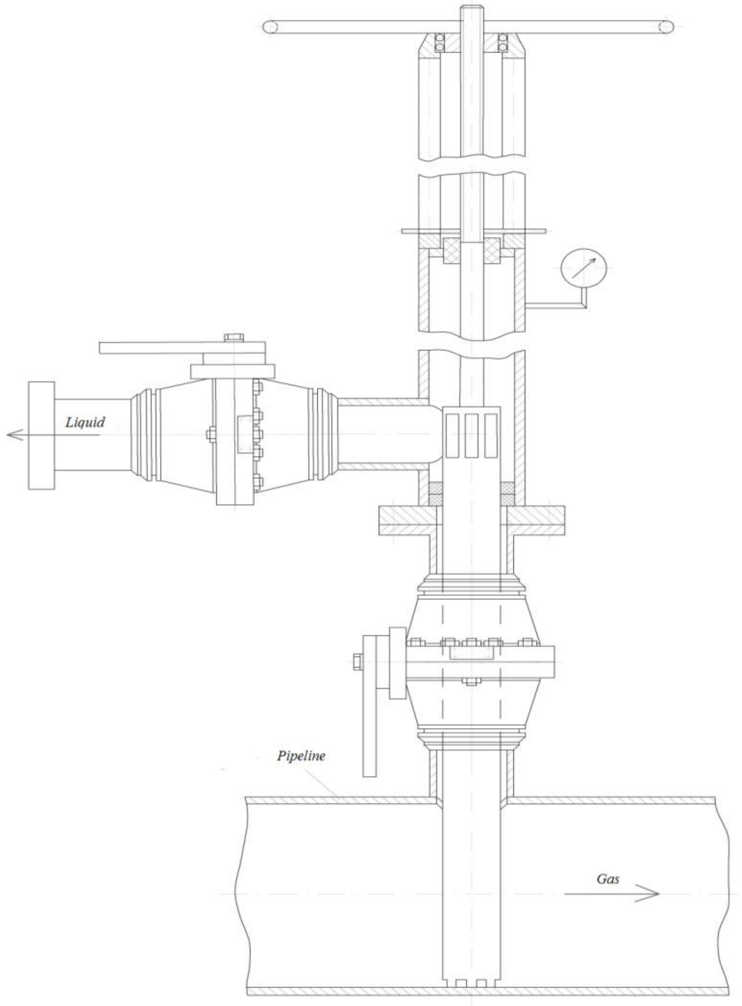
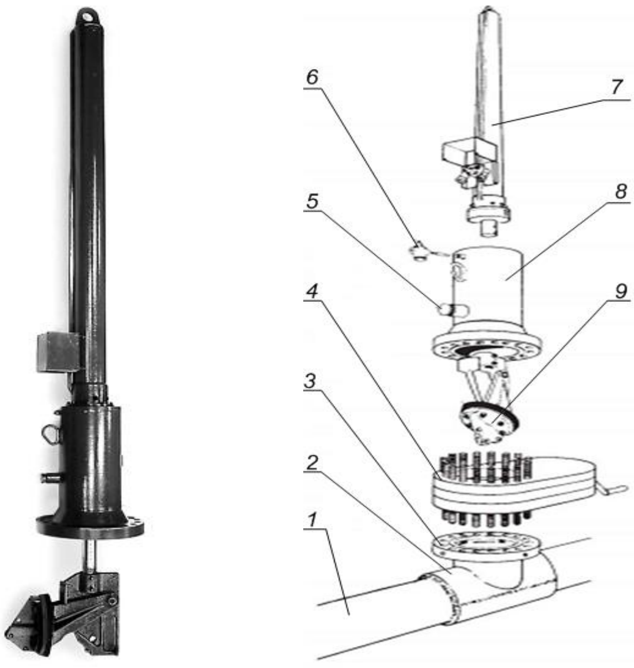


Figure 9. Modern drainage system

One can find a lot of analogues in the scientific sources, but the process is the same in all of them: removing liquid through the narrow tube by the pressure of natural gas inside the pipeline. We need to find how to connect drainage tube to the main pipeline. Of course, the simplest one method of connection is flanged joint, but have to create this type of joint at the main pipeline without stopping the transportation process.

This type of joint you can stick on the main pipeline using Ukrainian research institute of natural gas technology (Cancov Iv.I. – investigator [10]) or weld it to the main pipeline using Paton Boris technology of welding. Widely used technology is STOPPLE IIb by TD Williamson. This technology help you to weld the flanged joint based on coupling to the pipeline, make the hole inside the upper part of the main pipeline and control the flow using sandwich valve (figure 10).



a) *б)*

a) device common view, b) the using diagram

1 – pipeline; 2 – fitting STOPPLE; 3 – flanged joint LOC-O-RING; 4 – valve SANDWICH; 5 – pressure relief pipeline; 6 – pressure relief valve; 7 – hydraulic cylinder; 8 – cover adapter; 9 –header.

Figure 10. T.D. Williamson cutting system

Reliability of depicting joint technology is the same, difference is laying in details shown in the patent and licensees.

Conclusions

The essence is that flanged joint for drainage tube connects to preliminary welded coupling at the main pipeline with its own flanged joint and liquid is starting to leave the main pipeline through the narrow drainage tube under the natural gas pressure after opening sandwich valve.

The method is complex one: from searching the reason of water accumulation to its volumetric estimation and further removal from the pipeline using drainage tube and modern technology of connection. But the price of implementation the method is several times less than the value of relieving gas from pipeline and period of downtime.

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КОНЦЕПТУАЛЬНИЙ ПРОЕКТ ПРИСТРОЮ ДЛЯ ДРЕНУВАННЯ РІДИНИ З ПОРОЖНИНИ ТРУБОПРОВОДУ

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В статті представлено методику визначення місць трасою діючих трубопроводів, де можлива локалізація рідинних забруднень із оцінкою їх кількісного об'єму, та обґрунтовано вибір найбільш оптимального методу очистки газопроводів системи збору і транспортування газу родовищ із тривалим терміном експлуатації, базуючись на аналізі і систематизації вітчизняного і закордонного досвіду.

Ключові слова: трубопровід, рідина, об'єм, дренування, система, тиск.

КОНЦЕПТУАЛЬНЫЙ ПРОЕКТ УСТРОЙСТВА ДЛЯ ДРЕНИРОВАНИЯ ЖИДКОСТИ ИЗ ПОЛОСТИ ТРУБОПРОВОДА

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В статье представлена методика определения мест по трассе действующих трубопроводов, где возможна локализация загрязнений жидкостного типа с оценкой их количественного объема, а также выбор оптимального метода очистки газопроводов систем сбора и транспорта газа месторождений со значительным сроком эксплуатации, базируясь на анализе и систематизации отечественного и зарубежного опыта

Ключевые слова: трубопровод, жидкость, объем, дренирование, система, давление.