I

Technological Fundamentals of Preparation of Natural Hydrocarbons for Transportation

Separation of Multiphase, Multicomponent Systems. E. G. Sinaiski and E. J. Lapiga

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Introduction

The product obtained from wells on petroleum, natural gas and gas-condensate fields is invariably a multi-phase, multi-component mixture. The raw hydrocarbon material produced needs to be processed before it can be transported by pipeline and delivered to gasoline plants, oil refineries, and fractionating plants. In this context, engineers widely employ technological processes based on the principle of division (separation) of the native mixture into liquid and gaseous phases as a result of the action of intrinsic forces such as gravity or inertia.

Gas-oil and gas-condensate systems consist of petroleum and gas or gas and condensate, respectively. The state and properties of these systems are determined by various parameters, the most important of which are pressure, temperature, specific volumes and composition of the phases. The pressure and temperature change continuously during movement of the hydrocarbon system throughout the production chain, i.e. from bed to well to the system of gathering and preparation and thence to the pipeline. As a result, the phase condition of system as well as the composition of the phases change accordingly. Besides, some components of the mixture (liquid, gas, or solid phases) may be introduced into or removed from the system. This also results in a change of both the phase condition and the composition of the mixture.

Natural gas contains hydrocarbon components – methane, ethane, propane, butane, and heavier components (which are designated C_1, C_2, etc.), sour gases – carbon dioxide, hydrogen sulfides, thiols, and other components. Besides the listed components, natural gas also contains water vapor and inorganic admixtures that are removed together with the extracted from wells. The composition of natural gas from a given source does not remain constant, but changes in the course of exploitation as the reservoir pressure falls. Table I.1 gives an overview concerning rates of change of reservoir pressure through data relating to a real gas-condensate field. The numbers in the third row are the projected values of reservoir pressure.

Natural gas and the products of its processing, namely ethane, propane, butane or the wide fraction of light hydrocarbons (WFLH), as well as the condensate, represent fuels for industry and household consumers and initial raw materials for gas-processing plants. If natural gas and the products of its processing are to be used as fuels and raw materials, then they must meet certain requirements, con-

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Table I.1

Years after beginning of the exploitation	1	5	10	15	25
Annual gas extraction, million m^3	3.9	7	7	7	6.38
Reservoir pressure, MPa	26.6–30.1	23.2–25.6	19.6–21.5	16.3–17.8	10–11.4
Wellhead pressure, MPa	16.67	12.37	9.09	6.24	1.86

cerning on the one hand the quality of commodity output and, on the other hand, the restriction of levels of possible environmental contaminations. Specifications and standards concerning natural gas are dependent on where it is delivered. Basic requirements concerning natural gas supplied through a pipeline, and salient quantitative data are presented in Table I.2.

The restriction on the dew point for hydrocarbons is stipulated for natural gas with contents of hydrocarbons C_{5+} not less than 1 g m^{-3}.

Limitations on the dew point for moisture and hydrocarbons are caused by the requirement that hydrates do not form and the condensate does not precipitate as the gas is transported at low temperature. The moisture content in a gas is determined by the given values of dew point temperature and pressure, using nomo-

Table I.2

Attributes	**Climatic area**			
	Moderate		**cold**	
	1.V–30.IX	**1.X–30.IV**	**1.V–30.IX**	**1.X–30.IX**
Dew point, °C:				
at moisture, no more	0	−5	−10	−20
at hydrocarbons, no more	0	0	−5	−10
Mass of mechanical admixtures in 1 m^3 of gas, no more (g)	0.003	0.003	0.003	0.003
Mass of hydrogen sulfide in 1 m^3 of gas, no more (g)	0.02	0.02	0.02	0.02
Mass of a sour sulfur in 1 m^3 of gas, no more (g)	0.035	0.035	0.035	0.035
Volume fraction of oxygen, no more (%)	0.1	0.1	0.1	0.1

grams or empirically-obtained calculating formulas [1]. The dew point for hydrocarbons depends not only on the pressure of the gas, but also on its composition. To find the dew point, we either use special tables or carry out the vapor-liquid balance calculation for our multi-component system [2].

Heavy hydrocarbons condensed from a gas during its extraction form a condensate enriched with a group of hydrocarbons C_{5+}. This by-product of gas-producing and gas-processing industries is an important commodity. The condensate is used as a raw material by oil refineries and in the production of natural gasoline. The fractional composition of condensates varies from one gas field to another. One should make a distinction between a stable condensate containing C_{5+}, and an unstable one, containing the lighter components excluding C_{5+}. The condensate grade is characterized by the vapor pressure p_{sat} and by the evaporation of up to 25–85% at the temperature of 50 °C and the atmospheric pressure. The vapor pressure of the stable condensate should be such as to assure its storage in the liquid state at 37.8 °C.

Thus, both natural gas and gas condensate must be thoroughly processed in order to achieve the required conditions before we can feed it into a pipeline, whether on a gas-transporting factory or in the communal distribution network. This processing includes the following procedures:

1) Isolation of mechanical admixtures from the gas, precipitation of moisture and condensate. This process is called the separation;
2) Removal of water vapors from the gas. This process is called gas dewatering (dehydration). Since dehydration causes a decrease in the threshold temperature of hydrate formation, this procedure often includes additional steps intended to prevent the formation of hydrates.
3) Extraction of heavy hydrocarbons from the gas.

The procedures detailed here are performed by special devices for the complex preparation of gas (DCPG), which are located at the gas field. In their heavy concentration of machinery and the complexity of technological processes involved, DCPG's come close to industrial plants.

Petroleum is a heavier liquid than gas condensate because it contains much more oils, paraffin and other high-molecular compounds. Many types of petroleum are more than 99% hydrocarbons, of which paraffin and the naphthenic series are most widely submitted. Other classes of organic compounds – oxygen compounds, sulphurous compounds, asphalt-tars and others – are also present in small amounts. The majority of sulphurous and oxygen-containing compounds are surface-active compounds. They are aggressive with respect to metal and cause heavy corrosion. Yet another common admixture in petroleum is mineralized water, which causes significant complications for its collection and transportation. The harmful feature of oil-field brines is their ability to form water-oil emulsion that complicates preparation and refining of oil, as well as the movement of petroleum in pipelines (water can accumulate in bends and then freeze, resulting in pipeline breakage). The surface-active agents (surfactants) promote formation of emulsions and therefore are called emulsifiers. The presence of surfactants in oil facilitates formation of emulsions and increases their stability (the property to keep emulsion for a long time). Oil also contains low-molecular components, which are especially abundant in light oil. These components can be present in liquid as well as in gaseous phase. The change of pressure and temperatures during the movement of petroleum throughout the chain: bed–well–system of gathering and preparation-pipeline results in intense separation of the lighter components, accompanied by an increase in the gas factor (gas volume per unit volume of oil mixture, m^3/m^3).

The presence of free gas in oil (oil gas) also causes complications in production, gathering, preparation, and transportation of oil. A gas breakthrough in productive wells from the gas cap of the geological horizon or from gas-bearing horizons is sometimes observed. It leads to an increase of the gas factor of produced oil.

In Russia, the government-imposed standards (SAST) define petroleum as fit for delivery to oil refineries if it contains no more than 0.1% of water and no more than 40 mg liter^{-1} of chlorine salts. Besides these two requirements there are also others. Therefore, before petroleum is pumped into the pipeline, it must be subjected to processing that includes the following operations:

1) Removal of the light gases contained in the oil in free or dissolved state. This process is called separation;
2) Removal of water from the oil. This process is called oil dehydration or dewatering;
3) Extraction of salts dissolved in the oil. This process is called oil desalting.

More information about the properties and processes of gathering and preparation of natural gases and oils can be found in Refs. [3, 4].

1
Technological Schemes of Complex Oil, Gas and Condensate Processing Plants

The product obtained from wells on gas and gas condensate fields is always a complex heterogeneous mixture that contains a mixture of gases (saturated with water vapor and heavy hydrocarbons), liquid hydrocarbons (oil or gas condensate) and water, solid particles of rock, and other components. In order for the gas delivered to the consumer to meet all requirements placed upon it, it is necessary to eliminate the solid and liquid phases and also a part of the water vapor and heavy hydrocarbons before feeding it in the gas-transmission pipeline. These processes are carried out in special field devices of the complex preparation of a gas and condensate (DCPG). The typical design of the DCPG apparatus at a gas-condensate field is shown schematically in Fig. 1.1. The preparation of the gas is carried out by the method of low-temperature separations (LTS).

In Fig. 1.1 the following designations are used: S1, S2, S3 are separators used in the I, II, and III step, respectively; D1 and D2 are the three-phase dividers for the I and II steps; T1, T2, T3 are throttles; H1, H2, H3 are heat exchangers; TEA is a turbo-expander set (or evaporative refrigerator); F is flare.

Table 1.1 shows the approximate values of pressure and temperatures at the relevant points of the technological scheme.

Gas enters the DCPG with the temperature of 35 °C at the pressure of 15.5 MPa. Before the Step I separator a throttle (T1) is located. Here gas pressure is reduced to 13.1 Mpa, and the temperature drops to 21 °C. In the Step I separator (S1) drops of liquid are separated from the gas. The dehydrated gas is cooled in the heat exchanger H1 to 0 °C, and the condensate that forms as a result of cooling is separated from the gas in the Step II separator S3. The condensate from the first two separators gets collected and, passing through throttle T2, goes to the three-phase divider D1, where gas containing light hydrocarbons is separated from the condensate.

Condensate stabilization occurs in the divider. Deep cooling of gas (up to -30 °C) occurs as the result of consecutive cooling in the heat exchanger H2 and throttling in T3. As the wellhead pressure decreases with time, the pressure in DCPG also falls. Therefore after a while, the pressure in T3 might no longer be sufficient to achieve the required temperature of -30 °C. To overcome this predicament, the scheme envisages the possibility of adding a turboexpander TEA for additional cooling of gas. Cooled gas with high flow rate interfuses in the ejec-

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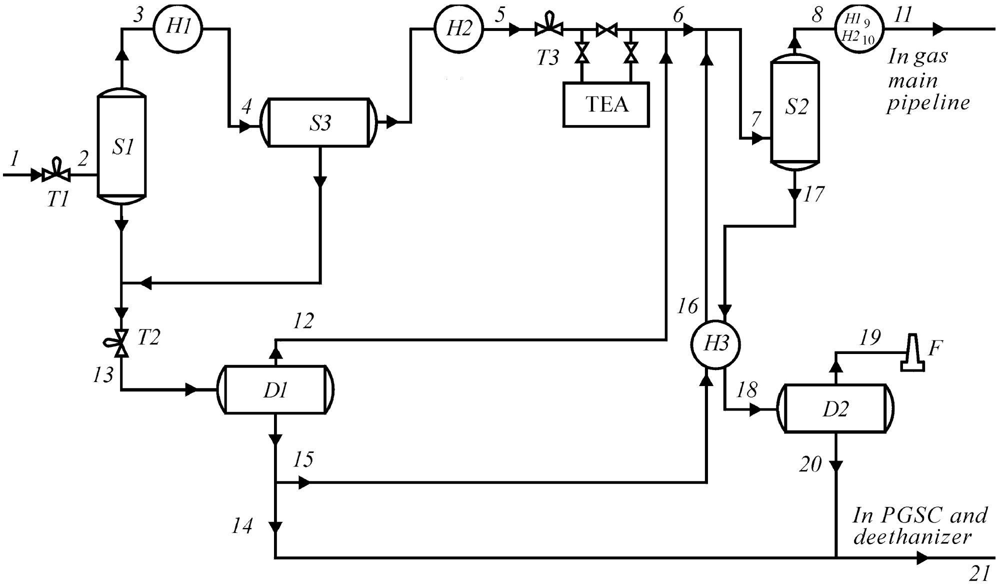

Fig. 1.1 Scheme of the low-temperature separation (LTS).

Table 1.1

Point	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Pressure, Mpa	17	13	13	13	13	8	7.8	7.8	7.7	7.5	7.4
Temperature, °C	35	21	21	0	−15	−30	−30	−30	−9	−12	−10
Point	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	
Pressure, Mpa	7.8	8	7.2	7.9	7.8	7.8	7.8	7.6	7.2	7.2	
Temperature, °C	13	13	13	13	−22	−30	−25	−25	−25	−1	

tor with the gas that comes from divider D1 with a relatively low flow rate. Step 3 separator (a.k.a. the end separator) is responsible for the final separation of condensate from the gas. The separated gas gets heated in the heat exchangers H1 and H2 and goes into the gas pipeline, while the condensate is channelled to the three-phase divider D2. The free gas from D2 goes toward the flare F, or to the ejector where it interfuses with the basic stream of the separation gas. The condensate from D1 and D2 goes into the condensate pipeline and next to the plant for gathering and stabilization of condensate (PGSC) or to a condensate deethanizer.

Let's note some more features of the above-described technological scheme of DCPG. The heat exchangers used in the scheme (except for H1) cool or warm up the moving medium (gas or liquid), employing the already cooled (or heated) streams. So, for example, the cooling of gas in H3 is carried out with the help of the cold condensate that comes from the end separator S3. As a rule, engineers use the shell-and-tube heat exchanger where the previously cooled (or heated) gas or liquid moves in internal tubes. The actuating medium (gas or liquid) is moving in the intertubular space and is cooled (or heated) by contact with the tube surface. The second peculiarity of the scheme is the opportunity to feed a part of the condensate gathered in divider D1 through the ejector into the stream of separated gas. Since the temperature of the condensate is higher than the temperature of the separated gas (compare conditions in points 6 and 16), the condensate injected into the gas can actively absorb the heavy hydrocarbons (C_{3+} and C_{5+}). Thus, it helps achieve one of the purposes of gas preparation – to extract from the gas as many heavy hydrocarbons as possible.

In the scheme represented in Fig. 1.1, a plant for gas dehydration is absent. Dehydration is carried out by injecting highly concentrated methanol solution into the gas stream before the DCPG. In this way we achieve two goals at once. First, water vapors are eliminated from the gaseous phase; secondly, the temperature of hydrate formation is reduced. Some technological schemes call for the installation of special absorbing units that utilize liquid absorbents for gas dehydration. Diethyleneglycol (DEG) and triethylene glycol (TEG) are the most common absorbents. The use of glycols results in the necessity to establish additional equipment for capture, removal, and regeneration of exhausted absorbent.

For a natural gas field with methane content of more than 95% and small contents of heavy hydrocarbons, there is no need for such complex DCPGs. For such gas fields, the gas processing scheme needs only to ensure the separation and dehydration of gas.

Another scheme of gas preparation on the gas-condensate field is presented in Fig. 1.2. In this scheme the process of low-temperature absorption (LTA) is used.

In Fig. 1.2, we introduce the following designations: T1, T2, T3, T4 are throttles; H1, H2, H3 are heat exchangers; A1 is the absorber for gas dehydration; A2 is the absorber for the extraction of heavy hydrocarbons; T is the turbine; S1, S2, S3 are separators; D1, D2 are three-phase dividers; DA is the deflationer of the absorber; DPC is a complex that includes a compressor of the turboexpander, an air refrigerator and a heat exchanger. The gas at the entrance to DPC has the pressure of 15 MPa and the temperature of 26.8 °C (Table 1.2).

Before the entrance to separator S1, gas is throttled through T1, achieving the pressure of 10.5 MPa and the temperatures of 15 °C. The separated gas leaving S1 is then dehydrated in the absorber A1, and then, after consecutive compression in the compressor and cooling in the heat exchanger, enters the intermediate separator S2. The separated gas is further cooled in TEA as a result of performing work on the turbine and then moves to the bottom part of the contact chamber of

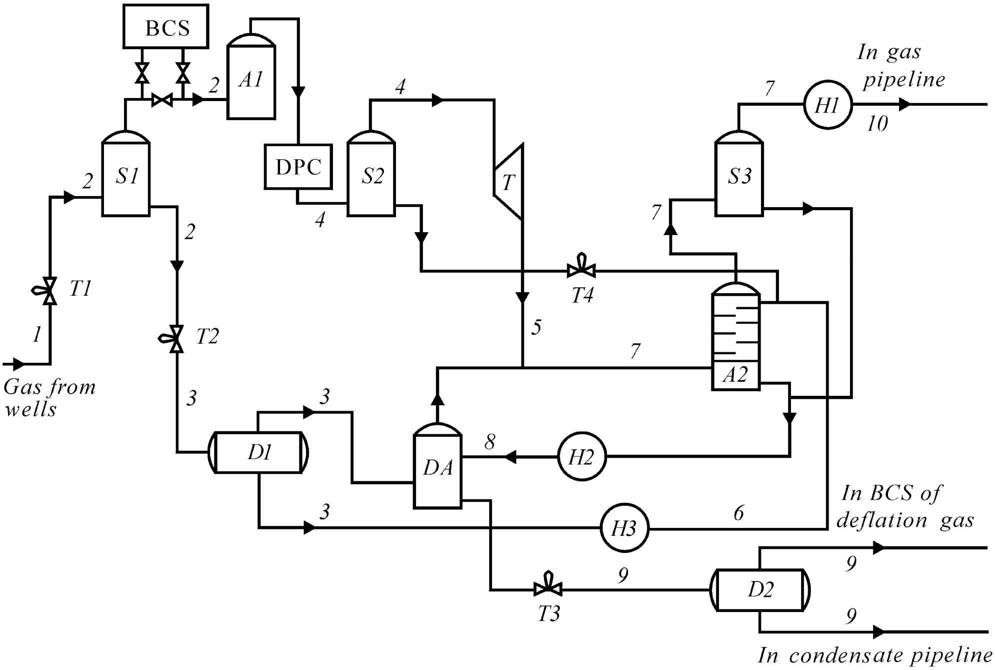

Fig. 1.2 Scheme of the low-temperature absorption (LTA).

Table 1.2

point	1	2	3	4	5	6	7	8	9	10
p, Mpa	15	10.5	7.7	12	7.65	7.7	7.65	7.7	3.5	7.4
T, °C	26.8	15	11.56	−3.4	−25.1	−15.1	−23.9	5.8	−3.9	−2.1

the hydrocarbon absorber A2. The condensate, which comes from the divider D1 and from Step 2 separator S2, enters the top part of the contact chamber. As a result of contact between the gas and the condensate, where the latter serves as an absorbent, heavy hydrocarbons are extracted from the gas. Afterwards, the gas from A2 is separated in the end separator S3, undergoes heating in H1, and moves into the gas pipeline. The used condensate is removed from absorber A2, undergoes heating in H2, and enters the deflationer DA, where light hydrocarbons evaporate from the condensate.

The obtained vaporous phase is pushed again into the contact chamber of the absorber to eliminate from it any remaining heavy hydrocarbons. The condensate formed (after aeration) in DA is throttled through T3 and goes to the divider D2 where its final stabilization occurs. From D2, the condensate goes into the condensate pipeline, and the vaporous phase goes to the booster compressor station BSC.

The scheme considered above calls for the installation of the booster compressor station (BCS), which starts to operate when the pressure at the entrance of DCPG will be less than the required pressure in the entrance separator.

As you can see, the basic distinction of the scheme in Fig. 1.2 from the scheme in Fig. 1.1 consists in the following:

1. The process of gas dehydration occurs in the special absorber A1, which ensures a higher quality of dehydration.
2. The extraction of heavy hydrocarbons from the gas is conducted in a special multistage absorber equipped with devices for condensate deflation. A higher efficiency of extraction of heavy hydrocarbons from the separated gas and a higher quality of condensate stabilization is achieved as the result.
3. The employment of turboexpander (TDA) for gas cooling allows us to decrease pressure by 4 MPa and to cool the gas by more than 20 °C. It should be noted that the same pressure drop on a throttle would cool the gas by only 12 °C.

It is worthwhile to note that the blocks A2, S3, and DA are installed in one three-stage vertical apparatus, which allows for a considerable reduction of the area set aside for the DCPG installation.

Modern on-site plants that perform complex preparation of gas and condensate come close to specialized factories in terms of complexity, multifunctionality, and quality of treatment of natural hydrocarbons. In Russia, the basic creator of the equipment for DCPGs is the central engineering office of the oil-production machinery company (CEOM).

Thus, in the process of gas and condensate preparation for transportation the most common elements of equipment are separators, dividers, absorbers, heat exchangers and turboexpander aggregates.

The oil preparation scheme should also provide for the arrangement of processes of oil degassing, dehydration, and demineralization (desalting). Figure 1.3

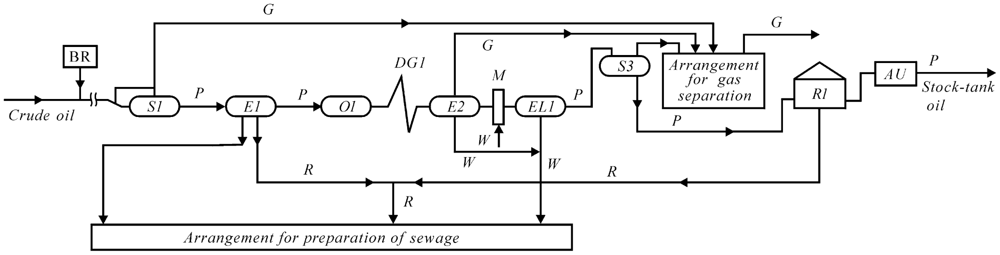

Fig. 1.3 Scheme of oil preparation: P – oil, W – water, R – residuum, G – gas.

shows just such a typical technological scheme for the preparation of oil. This scheme includes the following elements: BR is the dosage block for the reagent that destroys the water-oil emulsion in the gathering collector; S1 is the 1st stage separator; DG1 is the drop-generator; E1 is the settler for preliminary oil dehydration; O1 is the furnace for emulsion heating; E2 is settler for deep dehydration; M is the agitator for mixing fresh water W with dewatered oil for its preliminary demineralization; EL1 is the electrodehydrator for deep oil demineralization; S3 is hot third stage separator; R1 is the reception tank for stock-tank oil; AU is the automatic device that measures the quality and quantity of oil. A gas separation arrangement is provided as well. There is also an arrangement for the preparation of sewage, i.e. water formed during dewatering and used in the course of demineralization.

A few words must be said about some special features of oil preparation process. Degassing of oil (oil separation) is usually carried out in several separators connected in series. In each separator, a pressure drop occurs, as a result of successive extraction of a certain fraction of light hydrocarbon components from oil. If degassing occurs without gas being siphoned off from the system then such separation is called a "contact separation". If in the course of degassing the separated gas is siphoned off, then the procedure is referred to as "differential separations". The other feature is the organization of oil dehydration and oil demineralization processes. The main challenge here is to eliminate small water droplets from oil. For this purpose, one can reduce the viscosity of oil by warming it. Another method is cohesion of water drops into a liquid emulsion, with the help of an electric field in an electrical dehydrator.

Analysis and mathematical modeling of processes occurring in the above-mentioned technological schemes are the subject of the book. They are successively considered in their corresponding sections. Further on, we shall consider the basic mechanisms of separation processes for multi-phase, multi-component hydrocarbonic systems to which natural gases and oil belong. In the next chapter, we consider constructional features of some elements of technological schemes: separators, dividers, settlers, absorbers, heat exchangers, and turboexpanders.