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Research Article

Areas of effective application of submersible centrifugal pump installations with and without a gas separator

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Abstract Operating modes study on the use of submersible centrifugal pumps, with and without gas separator, in wells has been performed. It showed that the use of a gas separator with a constant separation coefficient does not always lead to an increase in the well production. The study showed also that in the area of low gas content, the supply of the pump with a gas separator is slightly less than without it. While at high gas contents, the use of a gas separator leads to an increase in the well production - the greater well production, the higher the gas content at the pump inlet.

1. Introduction

The use of a gas separator (GS) is one of the most effective ways to reduce the negative effect of free gas on the operation of submersible centrifugal pumps (ESP). However, the use of a gas separator, improving the performance of the pump at high input gas content, leads to a decrease in the use of useful gas work in pump-compressor pipes (tubing) [1 , 2].

The main part of the free gas separated at the pump intake by the gas separator goes into the annulus of the well [3] . Therefore, an interesting and important question is under what conditions the gas separator leads to an increase in oil production by the pump from the well, and under what conditions it does not. In modern publications, this problem is often presented insufficiently correctly. For example, from the diagram presented in [4] (Fig. 1), it follows that submersible pumps are generally impractical to use when pumping out a gas-liquid mixture without pre-connected devices (gas separators, dispersants, multiphase sections, etc.).

2. Experimental work

To clarify the issue under consideration, analytical calculations were performed to determine the areas of effective use of the gas separator.In the calculations, we analyzed the operating modes in the wells of the pumps ESP5–80–1200, ESP5–130–1200, ESP5–200–800 with and without a gas separator at various pressures at the pump inlet (Pin). Table 1 shows the initial data for oil wells from different fields used in the calculations. Gas saturations of oils (Sg) for fields A, B and C were respectively 48.9, 125.1 and 209.5 m3 / m3.

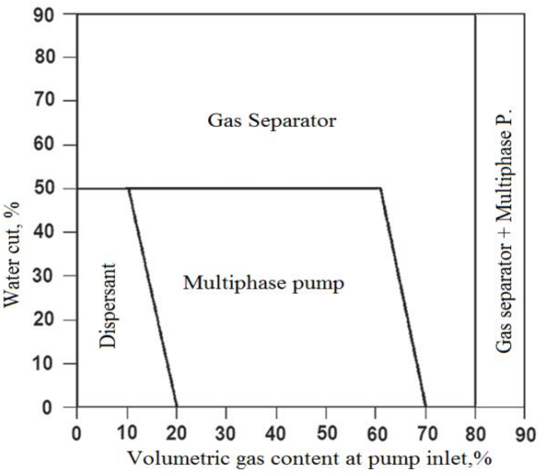

Figure: 1 Scopes of upstream devices (gas separators, dispersants, multiphase sections) [1]

Table 1: Parameters of oils and wells

Parameter	Field		
	A	B	C
Gas saturation, $м^3/м^3$	48,9	125,1	209,5
Saturation pressure, MPa	8,9	12,0	20,0
Formation Volume Factor	1,16	1,51	1,67
Density , kg/m^3:			
Separated oil	856	849	807
Gas	1,3	1,3	1,2
Associated water	–	1000	–
Separated oil viscosity at t = 20°C, mPa • s	6,7	16,7	3,3

Calculations were performed for two values of foaming properties of oils, 30 and 60 mm. The foaming properties (foaming) of a liquid, as is known, are one of the important factors that determine the degree of influence of free gas on the operation of the ESP [5].
In fact, the foam values of 30 and 60 mm practically cover the range of foaming properties of most oil fields [6].
Calculations were performed for pumping oil and gas mixtures for all the above-mentioned pumps and oils.
Furthermore, in order to assess the effect of water cut in well production, the operating modes of the ESP5-130-1200 pump were calculated on water-oil-gas mixtures with water cut of 0.4 and 0.8 for oil with Sg = 125.1 m3 / m3.
In the calculations, the bottom-hole pressure and well production for each pump size were chosen so that the performance of the reservoir-pump-well system at zero gas content at the ESP intake would correspond to the optimal flow rate and operating mode of this pump.
Table 2 shows the accepted values of well production for various calculations.

Table 2: Values of productivity factors

Gas saturation of oil, m3 / m3	Water cut of products	Well productivity factor, m3 / day / MPa		
		ESP5-80-1200	ESP5-125-1200	ESP5-200-800
48,9	0	8,62	11,3	23,4
125,1	0	8,81	11,7	24,2
209,5	0	4,49	6,21	10,9
125,1	0,4	–	30,2	–
125,1	0,8	–	15,7	–

The characteristics of the ESP when operating on oil and gas and water-oil and gas mixtures were calculated according to the method [7]. This method is sufficient for practical purposes accuracy to determine the operation parameters of ESP on gas-liquid mixtures in a wide range of gas contents both in cavitation-free and cavitation modes, in the entire water cut of the pumped out liquid. This methodology was supplemented with a block that takes into account changes in the saturation, pressure and degassing curves of oil passing through the pump, depending on the separation of part of the gas into the annulus, according to the recommendation [8].

The pressure distribution curves in the tubing string and in the wellbore were calculated by the method proposed in [9], which has good agreement with the experimental data. The separation coefficient Sc in the case of operation of the ESP without a gas separator was calculated by the formula of PD Lyapkov and AS Gurevich [10]. When operating the ESP with a gas separator, the Sc = 0.85 was taken.

Figures 2 and 3 present a comparison of the calculated and actual parameters of the ESP and pressure distribution curves in the tubing without a gas separator and with it (Pp is the pressure developed by the pump, Pin is the pressure at the inlet, QL.st is the liquid supply under standard conditions, βin is the gas content at the pump inlet).

3. Results and discussion

The actual modes were obtained during experimental work. The oil foam content dc = 35 mm, used in calculating the ESP characteristics, was determined at the well from an oil sample just taken from the wellhead. The input parameters for calculating the ESP characteristics were taken as the arithmetic mean values of the corresponding values for the actual modes. Thus, the actual values of the absolute pressure at the pump inlet Pin when the pump was operated without a gas separator in four modes varied from 5.12 to 5.22 MPa; the arithmetic mean value Pin = 5.18 MPa was taken in the calculations, and so on.

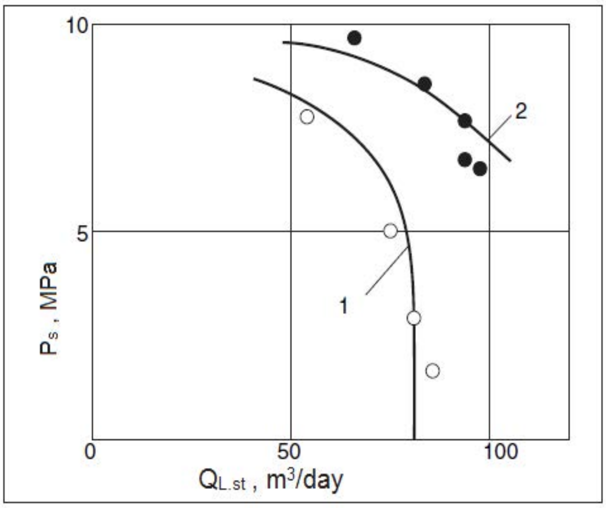

Figure 2: Comparison of the calculated and actual characteristics of the ESP5-130-1200 : 1 - the calculated Ps – QL.st curve for a pump without a gas separator at Pin = 5.18 MPa, dc = 35 mm, water cut 0.051 and βin = 0,38 ; o - actual operating modes of the pump without a gas separator at Pin = 5.12–5.22 MPa, water cut 0.017–0.100, βin = 0.37 – 40 ; 2 - calculated curve Ps – QL.st for a pump with a gas separator at Pin = 3.1 MPa, dc = 35 mm, zero water cut, βin = 0.61 and Sc = 0.85 ; ● - actual operating modes of the pump with a gas separator at Pin = 2.9–3.45 MPa, zero water cut, βin = 0.57–0.63 and Sc = 0.75–1.0.

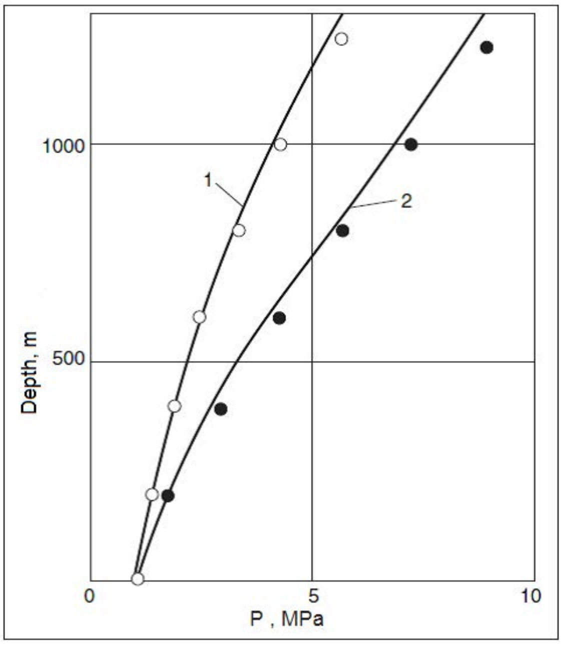

Figure 3: Comparison of calculated curves and actual points of pressure distribution in tubing : 1 o - pump operation without a gas separator, βin = 0.53 and QL.st = 62 m3 / day; 2 ● - operation of the pump with a gas separator, βin = 0.62 and QL.st = 97 m3 / day

As can be seen from Fig. 2 and 3, there is a fairly good agreement between the calculated and actual values, which once again confirms the applicability of the methods [11] and [12] for practical use. The modes of joint operation of the ESP with and without a gas separator for the initial data given in tables 1 and 2 were determined using the recommendations of previous works[11 , 12] , as follows (Fig. 4 and 5).

The curves of the pressure distribution along the wellbore and tubing were plotted for the given values of Pin and fluid supply under standard conditions QL.st.. From these curves, for a given Pin value, we found the values of the pressure required for lifting QL.st, respectively, when the pump operates without a gas separator (P1) and with a gas separator (P2). Then this procedure was repeated for other values of QL.st and the dependences of the pressure required for lifting the borehole production on the supply of QL.st at given Pin were constructed (curves 3 — without a gas separator and 4 - with a gas separator, Fig. 5). While the curves that were superimposed on the characteristics of the pump without a gas separator are curve 1 and with it curve 2.

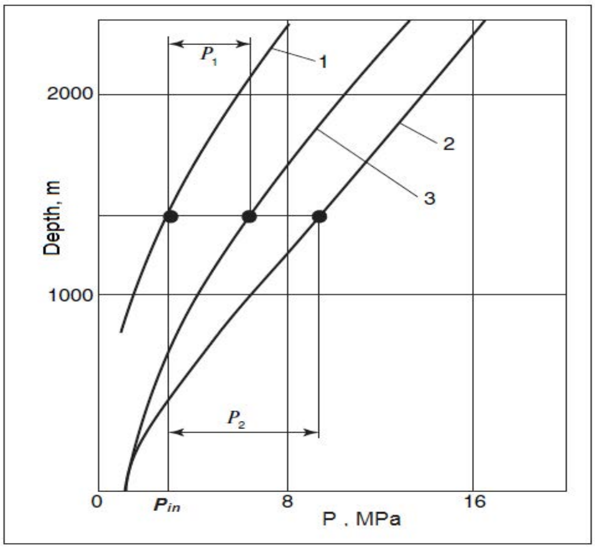

Figure 4: Determination of the required pressure for lifting well production, pressure distribution curves: 1 - along the casing; 2, 3 - along the tubing during operation of the ESP with and without a gas separator

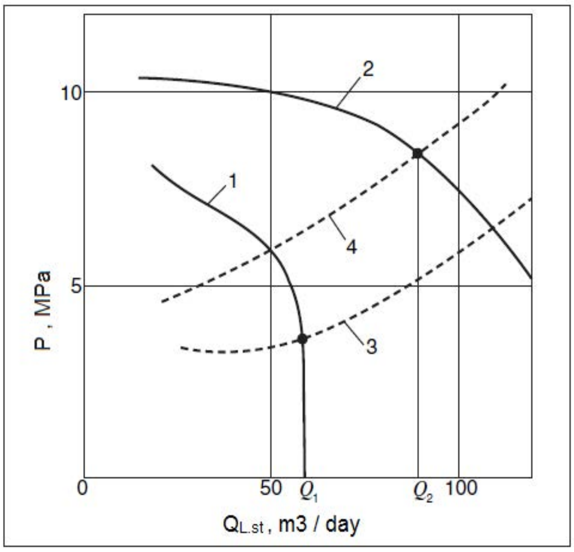

Figure 5: Determination of modes of joint operation of the "reservoir - pump - well" system (at Pin = 3.1 MPa). 1 and 2 - respectively, the characteristics of the Ps – QL.st pump without a gas separator and with a gas separator; 3 - dependence P1 – QL.st; 4 - dependence P2 – QL.st .

The intersection points of the required pressure dependences on the supply of QL.st and the ESP characteristics determine the modes of joint operation of the pump, well and reservoir.
So, from Fig. 5 it can be seen that at Pin = 3.1 MPa, the supply of liquid Q2 by a pump with a gas separator significantly exceeds the supply of a conventional serial pump. By plotting graphs similar to those shown in Fig. 4 and 5 for different RFCs, it is possible to determine the dependences of Q1 and Q2 feeds on the gas content βin.

Figure 6 shows such dependences for pumps ESP5–80–1200, ESP5–130–1200 and ESP5–200–800, pumping out waterless - oil and gas mixture with dc = 60 mm and Sg = 48.9 m3 / m3. The figure shows that up to a gas content of about 17%, the flow rate of the liquid provided by the pump without a gas separator is slightly higher than with it.

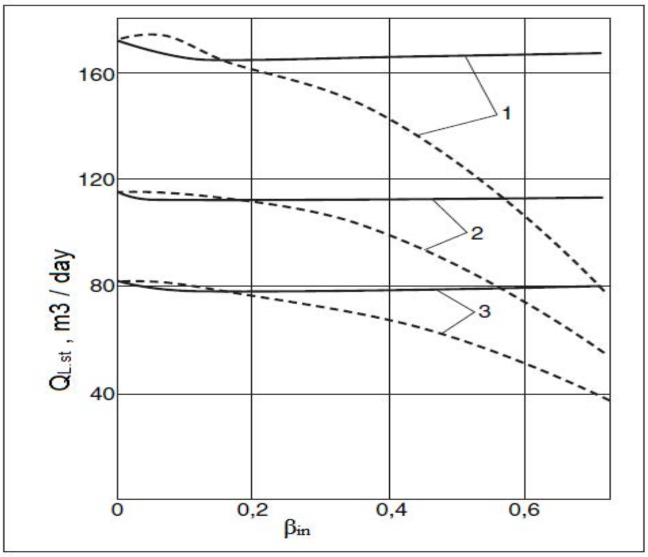

Figure 6: Curves of changes in the productivity of the "reservoir - pump - well" system with the gas content of the pumped mixture (Sg = 48.9 m3 / m3 and dc = 60 mm) with GS (solid line) and without it (dashed line): 1 - for ESP5-200-800; 2 - for ESP5-130-1200; 3 - for ESP5-80-1200.

With a further increase in βin, the liquid flow rate under standard conditions during the operation of the ESP without a gas separator significantly decreases due to the strong influence of the gas on the pump operation (see Fig. 6). While when the pump operates with a gas separator, the liquid flow rate remains approximately constant or even slightly increases. The latter is associated with an increase in the pressure created by the pump due to an increase in density and a decrease in the volumetric ratio of the liquid flowing in the pump. The higher the gas content, the greater the excess of the pump supply with a gas separator than the supply of a conventional serial ESP, i.e., the more profitable is the use of the gas separator.

Dividing Q2 by Q1 with the same βin, we obtain the dimensionless value of the relative flow ¯Q. It shows whether the use of the gas separator leads to an increase in the flow rate of the well at a constant βin (if Q >1, then it leads, if Q ≤1, then it does not), as well as the degree of change in the flow rate when using the gas separator.

Calculations have shown that the dependences of Q on βin at given dc and other oil properties for all three pump sizes are described by single curves.

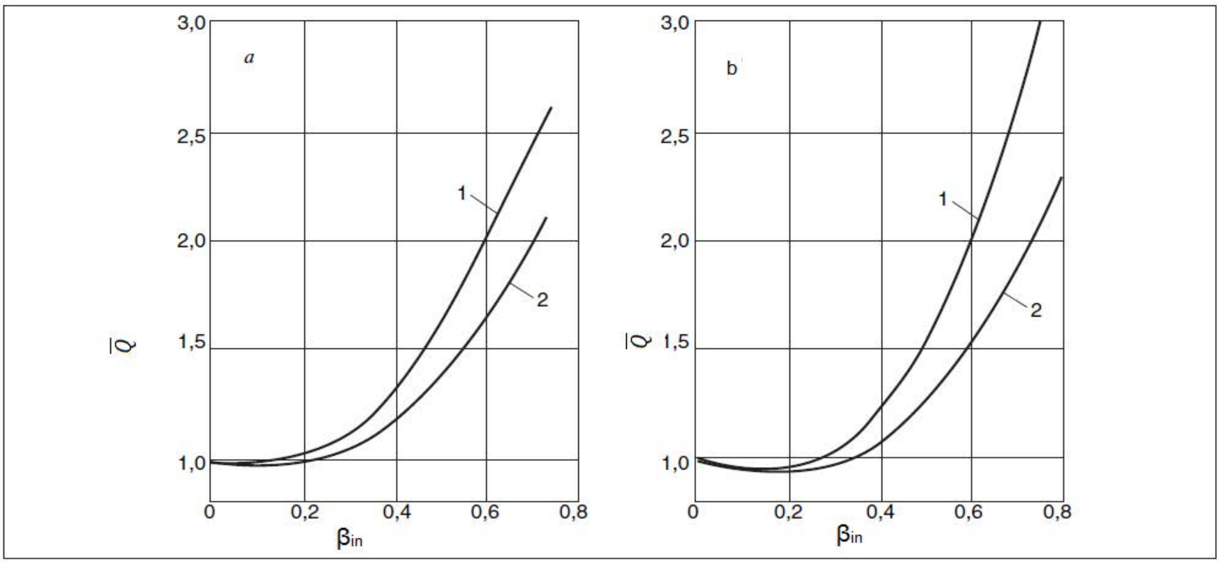

Figure 7: Dependences of the relative flow rate on the gas content of the pumped mixture for oil with Sg = 48.9 m3 / m3 (a), with Sg = 125.1 m3 / m3 (b): 1 - dc = 30 mm; 2 - dc = 60 mm

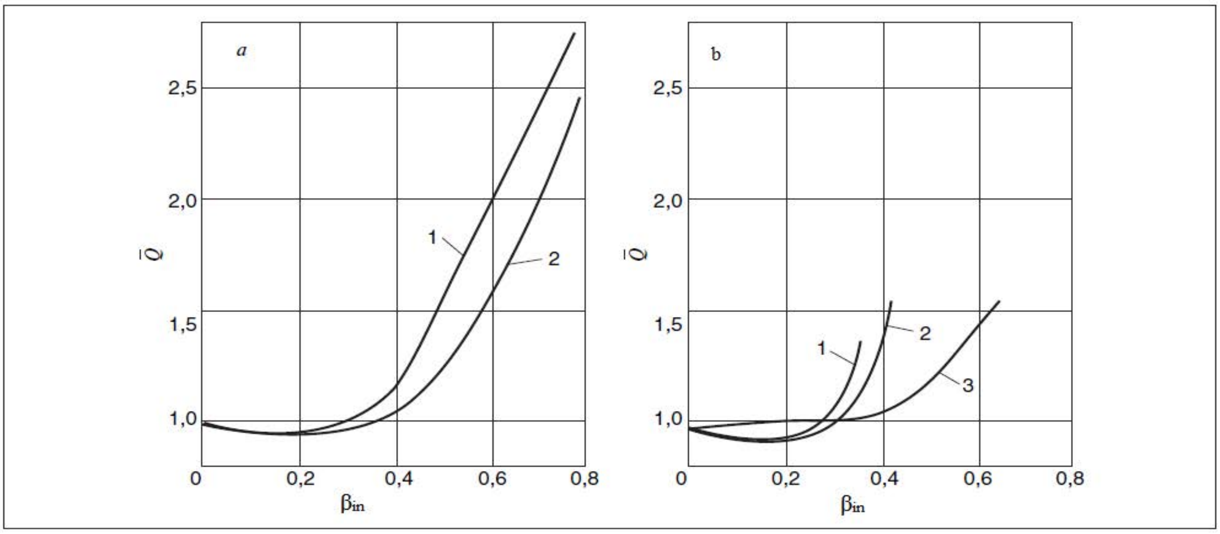

Figure 8: Dependences of the relative flow rate on the gas content of the pumped mixture for waterless oil with Sg = 209.5 m3 / m3 (a) and oil with Sg = 125.1 m3 / m3 with a water cut of 0.4 (b): 1 - dc = 30 mm ; 2 - dc = 60 mm; 3 - oil with a water cut of 0.8

Analyzing these dependencies, the following can be noted. The relative flow rate decreases slightly (by 2-5%) with an increase in βin in an waterless oil and gas mixture up to 15-35% (depending on the properties of the oil), and then increases rapidly, increasing up to 2 or more times. At the same time, the use of a gas separator gives a greater effect with lower values of foam. The presence of water in the pumped out product does not change the general nature of the behaviour of the Q (βin) dependences. With water cut of 0.4, the relative flow for values βin ≥ 35% increases sharply, and the dependences Q (βin) become almost vertical. This is apparently explained by an increase in the harmful effect of gas on ESP performance without the gas separator because of a decrease in the foam content of the liquid due to an increase in the water cut of the produced product. In addition, when pumping out water cut production, the density of the mixture in the wellbore is higher than the density of the mixture in the tubing due to the higher relative sliding velocity of water, oil, and gas, due to which the pressure required to lift the liquid increases.

Thus, for the considered service conditions determining input data for the calculation, the analysis of operating modes (in wells) of ESP with gas separator and without showed that the use of the gas separator with a constant separation coefficient Sc = 0.85 does not always lead to an increase in well production.

In the region of low gas concentrations up to certain values of βin, the pump supply with a gas separator is slightly less than without it. With an increase in gas content, the use of a gas separator leads to an increase in the well flow rate — the greater the higher the value of βin.

4. Conclusions

Based on the analysis of the results of the research and preliminary calculations, it can be concluded that the use of gas separators leads to an increase in the liquid production from the well. This increment takes place in the area of gas content of the pumped out gas-liquid mixture at the pump inlet

- βin over 0.17 - 0.20 for oils with gas saturation Sg = 46, 9 m3 / m3,
- βin> 0.26 - 0.32 for oils with gas saturation Sg = 125.1 m3 / m3 and
- βin> 0.28 - 0.34 for oils with gas saturation Sg = 209.5 m3 / m3.

It should be noted that the obtained values of βin do not take into account the positive impact of gas separator on the development of wells that are difficult to output for continuous operation and on the reliability of equipment.

If the above factors are taken into account, the minimum gas content value, starting from which it is advisable to use gas separator, is shifted towards lower gas contents.

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