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A Methodology for Calculating the Productivity of A Hydrocarbon-Geothermal Well

M. I. Fyk [1], V. S. Biletskyi [1], N. A. Desna [2]

[1] National Technical University "Kharkiv Polytechnic Institute" (NTU HPI), 61002, Kharkiv, 21 Kyrpychova Str., Ukraine
[2] Ukrainian State Coal-Chemistry Institute (SE "UKHIN"), 61023, Kharkov, 7 Vesnina Str., Ukraine

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Abstract

The article deals with the development of a refined methodology for calculating the production rate of a hydrocarbon-geothermal well under a non-isothermal lifting mode. The proposed methodology compares favourably with the basic one by taking into account the mutual influence of pressure head losses and those of thermal energy. This problem was solved by taking into consideration the convective component of heat exchange in a vertical (inclined) pipe when assessing hydraulic pressure head losses due to viscous friction. The methodology was tested for the conditions of Kotelev gas condensate field. The discrepancy between the values calculated according to the basic and the proposed methodologies for the heat flow rate constitute 4-7 % on average, while for the fluid flow rate the discrepancy averages 2.5-8.5 %. The possibility was proved of optimizing the dual mode of operation of a hydrocarbon-geothermal well in terms of the combined thermal energy being produced and the caloric heat energy of the gas condensate combustion.

Keywords: *Hydrocarbon-geothermal well; Non-isothermal lifting mode; Flow rate; Fluid.*

1. Introduction

Modern methodologies for calculating the production rate of a hydrocarbon-geothermal well at its head are based on the following main principles [1-2]:

- the flow rate for the geothermal resource being extracted is determined by the known difference in temperature and pressure conditions at the bottom and the head of the production and injection pipe strings;
- the mass flow rate of the product in terms of the fluid is from the start determined with corrections for the non-isothermal nature of lifting through the pump and compressor pipe (PCP) string of the well, the presence of liquid, the flow regime, and the throttling effect;
- the temperature at the bottom of the well is assumed to be equal to the reservoir temperature and a correction is made for the difference between the reservoir temperature and the true well-bottom one after a prolonged operation.

When calculating the flow rate in terms of the fluid of a hydrocarbon (oil and gas) producing well, the percentage of fluid in the lifting pipe string and the actual pressure drop in the well-bottom area and at the well-bottom filter are also taken into account [3]. Theoretically, it is possible to take this into consideration, but the existing methodologies use empirical data from real research in stationary and non-stationary modes of well operation [4]. Complete sets of such studies, including the descent of depth manometers and thermometers, are expensive, and require time and accuracy, which in combination is often difficult to implement in practice [3-4]. A number of papers [5-7] paid attention to the development of methodologies for determining the flow rate in order to have the cost of comprehensive well surveys reduced, which was primarily aimed at improving forecasting and rapid assessment of production in gas condensate wells, whose produce contains liquid, while colmation progresses in the well-bottom area, and the filtration channel degrades.

In papers [8-9], when calculating a horizontal fluid conduit pipe operating under isothermal and non-isothermal environmental conditions, experts come close to understanding the need to take into account the mutual influence of flow rates of fluid and geothermal resource. In particular, in order to account for the energy component of friction losses in the structure of total energy losses, a correction is made for the average temperature and pressure in the conduit pipe under the non-isothermal pumping mode [8]. In this case, the Shukhov-Leibenson formula is used [10].

The main disadvantage of the present-day methodologies is that the flow rate for the fluid of gas condensate fields and for the geothermal resource for vertical flows are determined separately. When calculating the flow rate for the fluid, the pressure head losses are taken into account for the mean logarithmic temperature value, while when determining the flow rate for the geothermal resource, the thermal energy losses are taken account of for the average pressure along the well. The mutual influence of the pressure head losses and those of the thermal energy is not taken into account. In particular, the coordinates of the mean values of the temperature and pressure potentials in a geothermal-hydrocarbon well do not geometrically match, which entails an error in parallel calculations of the thermal energy and fluid flow rates according to the equation of state.

It is forecasting the results of operating such wells using improved methodologies for the possibility of a technical and economic assessment of the efficiency of well production in specified complicated conditions (profitability, payback in terms of primary and current costs) that is especially relevant [11-13].

2. Experimental

2.1. Theory and method

In order to compare the results of calculations of flow rates for the geothermal resource being extracted and flow rates for the fluid, those rates determined by known and improved methodologies, we use the following basic formulas:

- production rate for the geothermal resource being extracted (basic methodology [2]):

$$W_T = M_q \cdot C_p\left(\frac{(T_{wb}-T_{wh})}{ln\frac{T_{wb}}{T_{wh}}}, P_{av}\right) \cdot (T_{wh} - T_{bc}) \tag{1}$$

where W_T- energy production per second – thermal capacity of the geothermal well; T_{wh}- well-head temperature; T_{bc} - reinjection line inlet temperature; T_{wb} – well-bottom temperature; P_{av} – mean pressure; $\frac{(T_{wb}-T_{wh})}{ln\frac{T_{wb}}{T_{wh}}} = T_{av}$ – logarithmic mean of the temperature.

- fluid flow rate (basic methodology [6]):

$$M_q = \frac{\pi \cdot d^{2.5}}{4} \cdot \left(\frac{\left(P_{wb}^2 \cdot e^{\left(\frac{-2 \cdot g \cdot h \cdot ln\frac{T_{wb}}{T_{wh}}}{z \cdot R \cdot (T_{wb}-T_{wh})}\right)} - P_{wh}^2\right) \cdot \left(\sigma - \frac{z \cdot (T_{wb}-T_{wh})}{\Delta \cdot (h^2+dL^2)^{0.5}}\right)}{\lambda \cdot z \cdot R \cdot \frac{(T_{wb}-T_{wh})}{ln\frac{T_{wb}}{T_{wh}}} \cdot \int_0^{(h^2+dL^2)^{0.5}} e^{\frac{2 \cdot g \cdot \left(x \frac{h}{(h^2+dL^2)^{0.5}}\right) \cdot ln\frac{T_{wb}}{T_{wh}}}{z \cdot R \cdot (T_{wb}-T_{wh})}} dx}\right)^{0.5} \tag{2}$$

where dL – well deviation from the vertical between its bottom and the head, h – well depth, d – PCP well inner diameter; Δ - specific density of the gas-condensate mixture referenced to air; g – acceleration of gravity; R – gas constant; z – compressibility factor; λ – hydraulic friction loss of the PCP; σ – specific volumetric gas content of the two-phase mixture.

In order to determine the flow rate for the geothermal resource being extracted, taking into account the impact on it of the fluid flow rate, let us consider the energy balance of the vertical flow of the heated fluid through the PCP [14]:

$$\Delta E_{T\sum wb-wh} = \Delta E_{v-g} + \Delta E_{h-p} + \Delta E_{T-E} \tag{3}$$

where $\Delta E_{T\sum wb-wh}$ - thermal energy change from the well bottom to the wellhead (Newton's law); ΔE_{v-g}- energy change due to the "fluid-PCP" viscous friction (hydraulic friction loss is calculated by the functions of Reynolds, Nikuradze, Colebrook-White, Chen, and Churchill); ΔE_{h-p}- energy change due to the polytropic expansion as a function of height (law of Mendeleyev-Clapeyron); ΔE_{T-E}- energy change due to heat exchange (Fourier's law).

In papers [14-15], the influence in (1) of components ΔE_{h-p} and ΔE_{T-E} on the change in thermal energy was considered, but the authors neglected the influence of term ΔE_{v-g} on the heat balance. With small temperature differences from the bottom of the well to its head, such an approach is justified, but for the dual extraction of hydrocarbon mixture and geothermal resources, it is necessary to take into account the effect of ΔE_{v-g} on the resulting hydraulic losses that determine the flow rate for the fluid. To do that, we use function [14]:

$$M_q = \frac{2d\Delta E_{v-g}}{\lambda v^2 h} \quad (4)$$

where M_q – mass flow rate of the fluid; d, h – diameter and length of the fluid conduit pipe; λ – hydraulic friction loss; υ – fluid velocity.

As we can see from function (4), the mass flow rate is directly proportional to the heat losses due to the "fluid-PCP" viscous friction.

After the corresponding transformations, it follows from (3) and (4), taking into account the impact of the "fluid-PCP" viscous friction, for the flow rate of the geothermal resource being extracted (the developed methodology):

$$W_T = \frac{K_t 2d\Delta E_{v-g}}{\lambda v^2 h} \cdot C_p(T_{av,}P_{av}) \cdot (T_{wh} - T_{bc}) \quad (5)$$

where T_{av} – mean temperature at pressure point P_{av}; K_t – coefficient of heat gain inside the conduit pipe due to the "fluid-PCP" viscous friction.

In order to determine the flow rate of the fluid, taking into account the effect thereon of the flow rate of the geothermal resource being extracted, let us transform (2) considering (3) and (4):

$$M_q = \frac{\pi \cdot d^{2.5}}{4} \cdot \left(\frac{\left((P_{wb} - \Delta P)^2 \cdot e^{\left(\frac{-2\cdot g\cdot h}{z\cdot R\cdot T_{av}}\right)} - P_{wh}^2 \right)\sigma - \frac{z(T_{wb} - T_{wh})}{\Delta\cdot(h^2 + dL^2)^{0.5}}}{\lambda\cdot z\cdot R\cdot T_{av}\cdot \int_0^{(h^2+dL^2)^{0.5}} e^{\frac{2\cdot g\cdot\left(x\frac{h}{(h^2+dL^2)^{0.5}}\right)}{z\cdot R\cdot T_{av}}} dx} \right)^{0.5} \quad (6)$$

Pressure head ΔP that is lost in the process of friction on the wall of a vertical or inclined conduit pipe due to the "fluid-PCP" heat exchange is one of the components of the pressure head loss along the conduit pipe (PCP). This makes it necessary to have a corresponding correction in the formula for determining M_q. The average temperature T_{av} is calculated in the basic methodologies as the mean logarithmic value of temperatures along the PCP length. In the developed refined methodology, the average temperature T_{av} was determined using the modified Shukhov-Leibenson formula that takes into account the non-isothermal nature of the lateral rocks and temperature correction ΔT:

$$T_{av} = \frac{(T_{pl} - T_{s})}{ln\frac{T_{pl}}{T_s}} + \Delta T + \frac{T_{wb} - T_{wh}}{\ln\left[\frac{T_{wb} - \frac{(T_{pl} - T_{s})}{ln\frac{T_{pl}}{T_s}} - \Delta T}{T_{wh} - \frac{(T_{pl} - T_{s})}{ln\frac{T_{pl}}{T_s}} - \Delta T}\right]} \quad (7)$$

where ΔT – temperature correction due to the "fluid-PCP" viscous friction and heat exchange; T_s – temperature at the depth of the neutral layer, assumed to be 280 K; K_T – logarithmic mean of the temperature of the well's lateral rocks;

According to the theoretical conclusions of paper [16],

$$\Delta T \cong \frac{\lambda v^2 h}{2dC_p} \quad (8)$$

While in paper [17], it is proposed to calculate for horizontal sections of product conduit pipes in practice as follows:

$$\Delta T = \frac{\lambda v^2 h}{(1-\frac{K_{out}}{K_{in}})2dC_p} \quad (9)$$

Note that the last formula is true for inclined conduit pipes under the action of radially directed conductive and convective heat transfer, while all the components of the formula, except for K_{in}, are also true for vertical conduit pipes. The K_{in} coefficient for vertical conduit pipes should be supplemented with the convective component of the heat exchange, and, in particular, for ascending and descending well flows, that coefficient can increase by an order of magnitude. It is proposed to calculate that coefficient according to the principle of analogy of operation in heat exchange equipment [1, 11, 17-19], where there are horizontal and vertical sections that are considered in detail.

2.2. Computer modelling of the installation

A comparative analysis of the basic and developed methodologies for calculating the production rate of a hydrocarbon-geothermal well under a non-isothermal lifting mode was carried out for Kotelev gas condensate field. That being the case, the initial body of data for a well with reverse injection of dried natural gas (methane) as part of a cycling process included the following: well depth h – 3500 m; PCP string diameter d – 73 mm; flow-related reservoir temperature T_{pl} – 360 K; initial reservoir temperature – 380 K; flow-related reservoir pressure – 9 MPa; initial reservoir pressure – 20 MPa; flow coefficient in the flow equation A – 0.6 MPa^2/(thousand m^3/day); flow coefficient in the flow equation B – 0.04 MPa^2/(thousand m^3/day); well drainage radius Rk – 301 m, well-bottom filter diameter Rc=0.1 m; effective thickness of the producing reservoir h_{ef} – 20 m; specific density of the fluid under normal conditions ρ_n – 0,763 kg/m^3; specific density of the fluid referenced to air Δ – 0.59; fluid's pseudocritical pressure – P_{pc} 4,61 MPa; pseudocritical temperature T_{pc} – 197.3 K; internal absolute roughness of the PCP – $3\cdot10^{-4}$ m; values range of hydraulic friction losses – λ=0.015-0.03; thermal conductivity coefficient of the lateral rocks of the well – K_T = 2.1 W/mK; values range of the fluid's compressibility factor z – 0,82-0,85; temperature at the depth of the neutral layer T_s – 280 K; dry gas reinjection temperature T_{bc} – 281 K; horizontal deviation of the well bottom from the wellhead at the actual angle of inclination of the well, dL – 150 m.

3. The findings of the research and their discussion

Using the Mathcad software resource, according to the basic methodology and the developed one, as well as formulas (1) - (9), calculations of the production rate of a hydrocarbon-geothermal well were performed taking into account the variability of the operating temperature and fluid pressure.

For calculations according to the basic methodology, formulas (1) - (2) were used, while formulas (3) - (9) were used for calculations according to the proposed methodology.

All calculations for forecasting well production were carried out under the same conditions, and the results for the wellhead pressure scale are shown in Figures 1 and 2. For the reservoir temperature scale, the results are shown in Figures 3 and 4. In the shown results of the comprehensive calculations using the basic and developed methodologies, the model is linked to the reservoir temperatures (350-370 K) and pressures (7-11 MPa) of the field with a correction of the well-bottom pressure and temperature according to the flow equation.

The results of computer forecasting show (Figure 1) that the curve of well mass flow rate M_q as a function of wellhead pressure P_{wh} is decreasing, and has a mildly pronounced non-linear nature. That being the case, in pressure range P_{wh} = 7-11 MPa, flow rate M_q values decrease from 8.8 to 6.7 kg/s. Consequently, the calculation according to the proposed methodology shows 8-9 % lower values of M_q thanks to accounting for losses by the fluid flow of the thermal energy due to the viscous friction. That said, wellhead temperature T_{wh} of the vertical well alters only by 0.5-0.7 degrees.

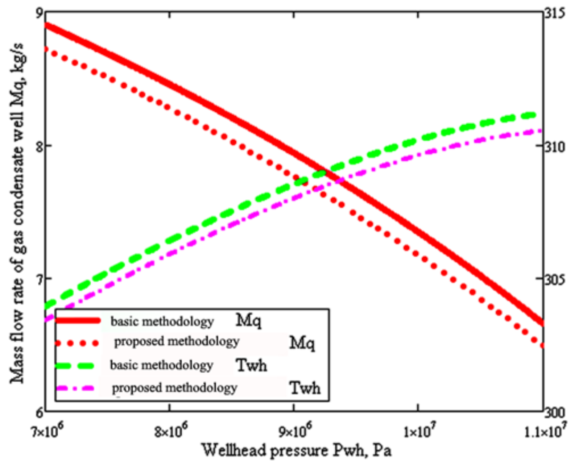

Figure 1 The results of forecasting mass flow rate M_q and wellhead temperature T_{wh} as a function of wellhead pressure P_{wh}

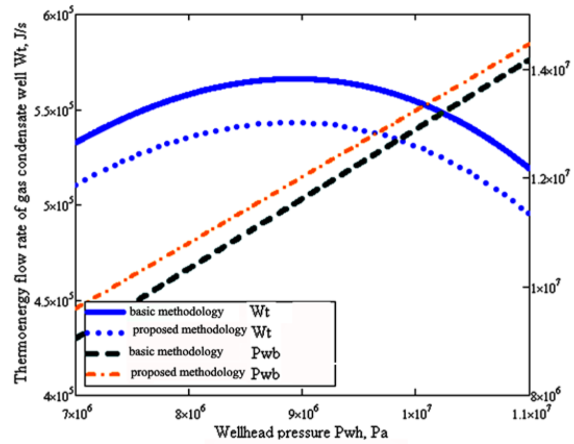

Figure 2 The results of forecasting thermal energy flow rate W_T and well-bottom pressure P_{wb} as a function of wellhead pressure P_{wh}

The curve of changes in thermal energy flow rate W_T of the well as a function of wellhead pressure P_{wh} (Figure 2) has an extremum maximum value W_T = 565 KW at P_{wh} = 9,1 MPa and a strongly pronounced non-linear nature. The presence of an extremum is explained by the dependence of thermal energy flow rate W_T of the well on competing factors, viz. mass flow rate M_q and fluid velocity v. The calculation according to the proposed methodology shows 6-8 % lower values of thermal energy flow rate W_T due to accounting for irreversible heat losses (from pressure head losses under viscous friction) through the well wall into the lateral rocks. In the shown range of operating parameters, the pressure values at the wellhead and at the well bottom are directly proportional. Note that our calculations assume the wellhead pressure as referenced to the conditions at the well bottom.

Figure 3 shows the results of forecasting mass flow rate M_q and wellhead temperature T_{wh} of the well fluid as a function of reservoir temperature T_{pl}.

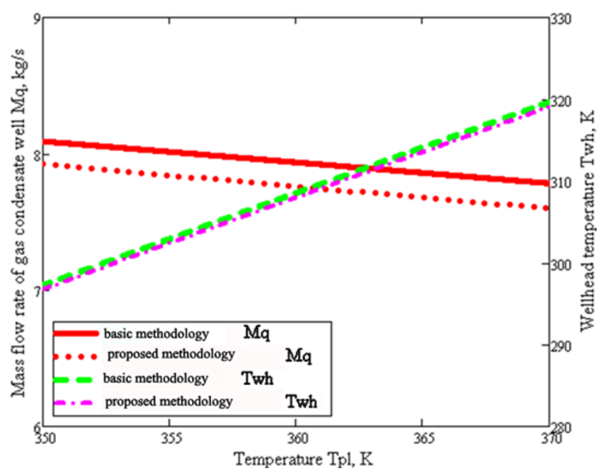

Figure 3. The results of forecasting mass flow rate M_q and wellhead temperature T_{wh} as a function of reservoir temperature T_{pl}

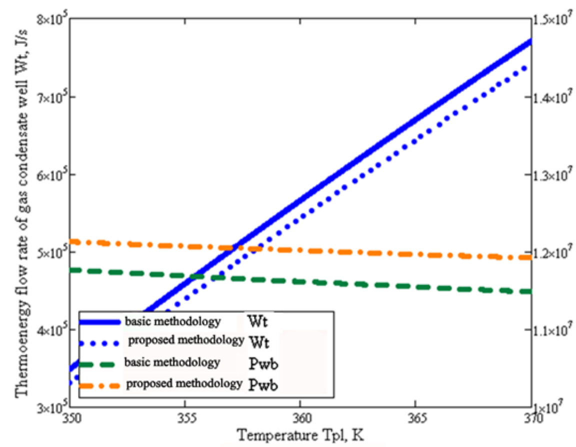

Figure 4. The results of forecasting thermal energy flow rate W_T and well-bottom pressure P_{wb} as a function of reservoir temperature T_{pl}

The curve of mass flow rate M_q of the well as a function of reservoir temperatures T_{pl} is decreasing, and has a linear nature. That being the case, the flow rate values obtained using the proposed methodology are 2-3 % lower in the range of reservoir temperatures of 350-370 K. Wellhead temperature T_{wh} consistently grows in direct proportion to the reservoir temperature.

Figure 4 shows changes in thermal energy flow rate W_T and well-bottom pressure P_{wb} as a function of reservoir temperature T_{pl}.

It is easy to see that thermal energy production rate W_T linearly depends on the reservoir temperature T_{pl}. The calculated result of modelling using the proposed methodology is 3-5 % lower than that using the basic one, which is explained by taking into account the energy loss due to friction. That being the case, the difference between the calculated values increases by 2 % with the increase in reservoir temperature in the range of 350-370 K. The referenced well-bottom pressure depends weakly on the reservoir temperature, while the results of its calculation using the proposed methodology are 6-7 % higher. With a fixed wellhead back pressure, a higher referenced well-bottom pressure will result in a lower mass flow rate. From Figures 3 and 4, the opposite is also obvious, viz.: when using the basic methodology, the pressure difference between the wellhead and the well bottom is larger, which means there is a higher mass flow rate.

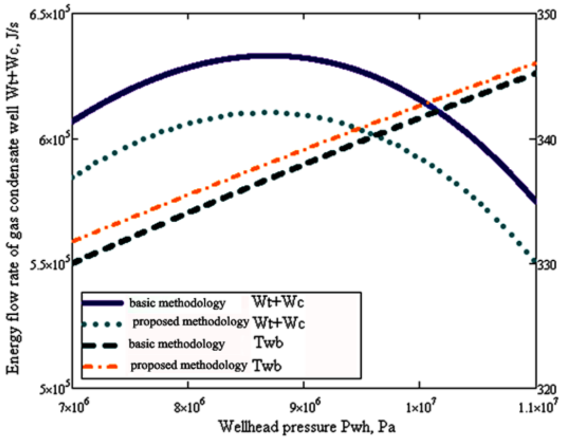

Figure 5 Combined thermal energy flow rate and caloric heat energy of the gas condensate combustion $W_T + W_c$ as a function of wellhead pressure P_{wh}

Figure 5 shows combined thermal energy flow rate and caloric heat energy of the gas condensate combustion $W_T + W_c$ as a function of wellhead pressure P_{wh}.

A comparative analysis of extremal curves $W_T (P_{wh})$ (Figure 2) and $W_T + W_c (P_{wh})$ (Figure 5) shows the shift of the optimum point to the left by 0.4 MPa. This is explained by the asymmetry of the $M_q (P_{wh})$ curve (Fig. 1) that determines function $W_c (P_{wh})$. Refining the extremum coordinate for dual flow rate $W_T + W_c$ makes it possible to maximize the production of the simulated well increasing it by approximately 0.5-0.7 %.

A separate analysis of the average deviations of the mass flow rate and the heat flow rate in the range of the shown operating parameters of industrial testing according to Figures 1-4 has demonstrated the difference between the methodologies being compared in terms of calculated values: for the well's heat flow rate, it was 4-7 %, while for the well's fluid mass flow rate, it was 2.5-8.5 %.

4. Conclusions

A refined methodology has been developed for calculating the production rate of a hydrocarbon-geothermal well under a non-isothermal lifting mode, which differs from the basic one by taking into account the mutual influence of pressure head losses and those of thermal energy. This problem was solved by taking into consideration the convective component of heat exchange in a vertical (inclined) pipe when assessing hydraulic pressure head losses due to the "fluid-PCP" viscous friction.

A comparative analysis of the basic and developed methodologies for calculating the production rate of a well has been carried out for the conditions of Kotelev gas condensate field. The discrepancy between the values calculated according to the basic and the proposed methodologies for the heat flow rate constitute 4-7 % on average, while for the fluid flow rate the discrepancy averages 2.5-8.5 %.

The possibility has been shown of optimizing the dual operation mode of a hydrocarbon-geothermal well in terms of the combined thermal energy produced and the calorific heat energy of the gas condensate combustion, as well as separately in terms of thermal energy.

Symbols

W_T	*energy production per second – thermal capacity of the geothermal well;*
T_{wh}	*wellhead temperature;*
T_{bc}	*reinjection line inlet temperature;*
T_{wb}	*well-bottom temperature;*
P_{av}	*mean pressure;*
P_{wh}	*wellhead pressure;*
T_{av}	*logarithmic mean of the temperature;*
dL	*well deviation from the vertical between its bottom and the head;*
h	*well depth;*
d	*PCP well inner diameter;*
Δ	*specific density of the gas-condensate mixture referenced to air;*
g	*acceleration of gravity;*
R	*gas constant;*
z	*compressibility factor;*
λ	*hydraulic friction loss of the PCP;*
σ	*specific volumetric gas content of the two-phase mixture;*
$\Delta E_{T\sum wb-wh}$	*thermal energy change from the well bottom to the wellhead (Newton's law);*
ΔE_{v-g}	*energy change due to the "fluid-PCP" viscous friction (hydraulic friction loss is calculated by the functions of Reynolds, Nikuradze, Colebrook-White, Chen, and Churchill);*
ΔE_{h-p}	*energy change due to the polytropic expansion as a function of height (law of Mendeleyev-Clapeyron);*
ΔE_{T-E}	*energy change due to heat exchange (Fourier's law);*
M_q	*mass flow rate of the fluid;*
d	*fluid conduit pipe diameter;*
h	*fluid conduit pipe length*
λ	*hydraulic friction loss;*
υ	*fluid velocity*
T_{av}	*mean temperature at pressure point P_{av};*
K_t	*coefficient of heat gain inside the conduit pipe due to the "fluid-PCP" viscous friction;*
ΔT	*temperature correction due to the "fluid-PCP" viscous friction and heat exchange;*
T_s	*temperature at the depth of the neutral layer, assumed to be 280 K;*
K_τ	*logarithmic mean of the temperature of the well's lateral rocks;*
K_{in}	*coefficient for vertical conduit pipes;*
Rk	*well drainage radius;*
Rc	*well-bottom filter diameter;*
h_{ef}	*effective thickness of the producing reservoir;*
P_{pc}	*fluid's pseudocritical pressure;*
T_{pc}	*pseudocritical temperature;*
T_{bc}	*dry gas reinjection temperature;*
P_{wb}	*well-bottom pressure;*
T_{pl}	*reservoir temperature.*

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To whom correspondence should be addressed: Dr. Mykhailo Fyk, National Technical University "Kharkiv Polytechnic Institute" (NTU HPI), 61002, Kharkiv, 21 Kyrpychova Str., Ukraine, mfyk@ukr.net