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(54) **Title**: A METHOD FOR DETERMINING NEAR-WELLBORE RESERVOIR PRESSURE IN MULTI-ZONE WELLS

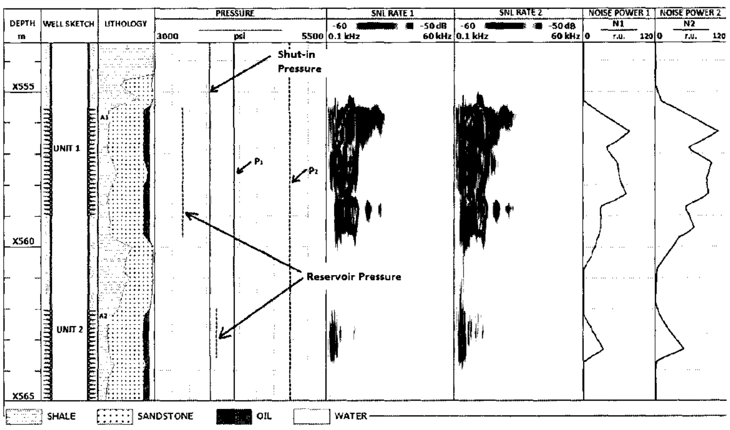

Fig. 2

(57) **Abstract**: This invention pertains to the field of petroleum industry and is applicable in the process of multi-zone well production. This method consists in estimation of reservoir pressure in the near-wellbore zone separately for each flowing reservoir unit based on an analysis of at least one measured parameter characterising well status in steady-state well operating regimes: in Regime 1, as a minimum requirement, and in Regime 2, using spectral noise logging data for the analysis. Technical result: enhancement of measurement reliability and expansion of the area of applicability.

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A METHOD FOR DETERMINING NEAR-WELLBORE RESERVOIR PRESSURE IN MULTI-ZONE WELLS

TECHNICAL FIELD

The invention pertains to the field of petroleum industry and is applicable in the process of multi-zone well operation.

BACKGROUND ART

The methods used for determining reservoir pressure and well efficiency based on experimental approach to pressure build-up and pressure transient tests are known from the prior art (V.V. Schelkachev: Development of Oil- and Water-Saturated Reservoirs in Elastic Drive; M.: Gostoptekhizdat, 1959, Oil Production Handbook / ed. by S.K. Gimatudinov,Dr.Sc.; M.: Nedra, 1974).

There is another method used for determination of reservoir pressure in production and injection wells (USSR Academy of Science, No. 1265303 A1, IPC. E 21 B 47/06, published 23.10.1986) that involves well shutdown, pressure build-up curve recording, and estimation of minimum duration of well shutdown period and calculation of reservoir pressure by formulas. The technical result of the invention consists in reduction of well shutdown time during a survey. Limitations of these methods lie in the necessity of a prolonged well shutdown period and attendance of service personnel at the well site. Long shutdown has a detrimental effect on well performance and impairs reservoir drive mechanism, which affects measurement results and prevents systematic monitoring of reservoir development process, resulting in rapid water encroachment into the reservoir.

Another method of estimating reservoir pressure in an oil well (RF Patent No. 2167289, IPC E 21 B 47/06, published BI No. 14, 2001) includes well shut-in, pressure build-up curve recording using a downhole pressure gauge, and calculation of current pressure increment in the initial section of a curve for a certain selected function and its further extrapolation to the time point at which pressure difference will be zero. The advantage of this method lies in a reduced oil production loss due to a shorter pressure build-up curve recording time.

One of the drawbacks of this method is the error that occurs if the function is extrapolated beyond the range within which the functions coefficients have been determined. As a result, reservoir pressure values determined using this method contain an error that grows larger as the curve recording time is reduced.

Another limitation that is common to all the methods described above is incapability to estimate reservoir pressure separately in each flowing unit because bottomhole pressure is measured inside the wellbore and is, in this case, a sort of weighted average pressure for each formation.

These limitations are not an issue when CHDT (Cased Hole Dynamic Formation Tester) developed by Schlumberger Technology Corporation (http://www.slb.ru/page.php?code=128)is used. The tool performs multiple pressure measurements and takes fluid samples from the cased-hole annulus. The CHDT tool is capable of drilling holes in casing, penetrating into the reservoir, making multiple measurements, taking representative reservoir fluid samples, and then plugging the holes to reseal the casing, - all these in one trip. One of the advantages of this method is the capability of measuring reservoir pressure in a near-wellbore zone of several reservoir units independently for all flowing units.

A substantial drawback of this method is the necessity of breaking casing structural integrity, which might eventually result in development of corrosion. This method also involves high costs due to its technical complexity.

The closest analogue (prototype) of the claimed method is the method of estimating reservoir pressure on the basis of two flow meter measurements taken in different flowing regimes (USA Patent Application No. 2009037113, IPC G01V 9/02, published 05.02.2009). This method has been developed to determine formation properties in the reservoir sequence along the wellbore. After estimation of wellbore flow rate, each inflow is correlated with one or several reservoir units. The measurements are taken with a temperature gauge and spinner-type flowmeters. Then the flow rate data for each unit are processed and reservoir pressure is estimated.

A disadvantage of this method is low sensitivity of spinner-type flowmeters and poor accuracy of volumetric inflow measurements. Another disadvantage consists in the fact that spinner flowmeter can register flow rates only within perforated casing sections, while the reservoir could have some other flowing zones (above or below the perforated zone, in case some behind-casing cross-flows exist). In consequence of this, it is impossible, using this method, to estimate near-wellbore pressure in the zones that have not been perforated but have direct communication with perforated zones, which results in lower reliability of measurements. Besides, this method is only applicable to production wells. As this method is based on temperature measurements and their analysis, the limitation of this method in respect of injection wells would consist in the fact that injection fluid temperature does not produce any tangible disturbances in the wellbore temperature and, even if it does, the entire historical injection would have to be taken into account (which this method does not make any reference to) and it would be therefore impossible to estimate reservoir parameters using this particular method.

The proposed method of estimating reservoir pressure using spectral noise logging data is free of the above-mentioned drawbacks, in particular, the limitations related to well type.

SUMMARY OF THE INVENTION

The object of this invention and desired technical result to be achieved when this invention is used, is to develop a new technique of estimating reservoir pressure in the near-wellbore zone of multi-zone wells and to enhance reliability of measurements when estimating reservoir pressure in the near-wellbore zone of multi-zone wells, at the same time expanding the area of its application.

The object and desired technical results of this invention are achieved by the method of estimating reservoir pressure in the near-wellbore zone separately for each flowing reservoir unit on the basis of measured data analysis of at least one parameter that characterizes well status at least in the first steady-state well operating regime and then in the second well operating regime, wherein, in accordance with this invention, spectral noise logging data are used; and wherein additional measurements are made in unperforated zones; and wherein current reservoir noise and current wellbore pressure are measured in the first well operating regime and then the second operating regime is established; and wherein for this purpose bottomhole pressure is changed by an amount sufficient for the said second regime to be established, preferably by at least 30% of the current (first) regime, or volumetric flow rate is changed by an amount sufficient for the said second operating regime to be established, changing the volumetric flow rate by at least 30% of the current (first) well operating regime, and establishing the second operating regime after the well has been flowing for at least 12 hours or, preferably, 24 hours, and then the current reservoir noise is measured in the second well operating regime using a sound meter when the said meter is run in/pulled out of the hole, or at stations when the said meter is run in/pulled out of the hole, with the said meter being preferably equipped with centralisers; and wherein current wellbore pressure is measured in the second well operating regime using a high-sensitivity pressure gauge at a constant running speed or with the said gauge being at stations inside the wellbore; and wherein the first well operating regime is established by means of setting the current flow rate and/or bottomhole pressure and then analyzing the data acquired in the first and second well operating regimes by at least one parameter to estimate reservoir pressure in the near-wellbore zone, and then determining noise power profile on the basis of spectral noise density panel in the first regime and noise power profile on the basis of spectral noise density panel in the second regime with the derived profile being averaged within the active flowing reservoir units, and estimating reservoir pressure in the near-wellbore zone in each flowing unit on the basis of the averaged profiles.

One of the distinctive features of this invention is application of SNL data in two flowing regimes, thus making it possible by using the proposed method to avoid any substantial changes in well flowing regime in particular and reservoir drive in general and, at the same time, to estimate and take into account the pressure in the near-wellbore zone within unperforated intervals that have direct communication with perforated zones, thereby enhancing reliability of near-wellbore zone pressure measurements both in production and injection wells separately for each flowing unit, i.e. ensuring achievement of the specified technical results, viz. enhancement of measurement reliability and expansion of the scope of application.

BRIEF DESCRIPTION OF DRAWINGS

Fig. 1 - are shown measured data acquired with a wideband sound level meter (Spectral Noise Logging Tool) in an injection well and filtered data (SND Panels).

Fig. 2 - are shown SNL data recorded in an injection well .

Fig. 3 - are shown SNL data recorded in a production well.

INVENTION DISCLOSURE

The method of reservoir pressure estimation in the near-wellbore zone includes measurements of bottomhole pressure in two flowing regimes (at two different volumetric flow rates and/or bottomhole pressures), measurement of reservoir noise power in two regimes, and processing of the resulting data. The distinctive feature of this method consists in the fact that reservoir flow is characterized by noise power spectral density data and pressure within the active reservoir zone.

The first regime corresponds to current well operation regime (current bottomhole pressure and flow rate). If static pressure survey data (taken after 3-5 days of well shut-in) are available, then the second regime must correspond to bottomhole pressures that amount to, for example, a half of the current value.

In this case, the well operation time in the second regime will be essential because it would take some time for the new flowing regime to stabilize. Duration of this period depends on petrophysical properties of the reservoir. The higher the reservoir permeability, the sooner the well will reach a steady-state regime. Actual duration can only be determined after the results of well pressure tests are known.

Based on the results of multiple pilot surveys, the typical well operation time in Regime 2 has been found to be 24 hours.

Measurement are made when the sound level meter (SNL tool) is run in/pulled out of the hole. Measurements can also be made at stations when the tool is run or pulled out. The measurements made on the up pass are preferable because in this case the cable to which the toolstring is fixed will be constantly in tension and the trip will be steadier. Each tool station should be at least 40 seconds long and the distance between stations at least 1 metre. It should be noted that the proposed duration of at least 40 seconds is just one of the options in actual implementation of the invention and is only intended to illustrate certain aspects of its application and does not in any way limit the scope of this invention, i.e. it should be understood that the duration could be less than 40 seconds provided that the selected stationary time would be sufficient to ensure reliability of measurements.

Raw data recorded with SNL tool are analysed using one of the spectral analysis methods, for example, Fourier transformation.

The resulting spectra (or spectral noise power densities) will be averaged for each tool station.

After averaging, the results of spectral analysis can be represented in the form of colour spectral panels where depth is laid off vertically and frequency horizontally, and where spectrum amplitudes are designated in colours.

Active reservoir zones are identified on the basis of visual spectral panel analysis.

Noise amplitude in the frequency domain above a certain value must be higher than the background noise. The background noise level is determined by noise amplitude uniformly distributed on the spectral panels and also within unperforated zones where there are no high-frequency noise (higher than, for example, 5 kHz).

The reservoir flow noise must be distinguished from the noise generated by fluid flow inside the casing. This noise is distributed at a greater distance (more than 30 metres) and is concentrated in the low-frequency range (below 1-5 kHz).

One of the several data-filtering methods can be selected to identify reservoir noise, for example, the one based on wavelet thresholding principle or another one based on median trend subtraction (SND Panels - Spectral Noise Drift). In this case, background noise and noise generated by wellbore flow are eliminated from the spectral colour panel.

One of the methods of automatic identification of active flow zones based on the principle of distinguishing such zones when noise amplitude exceeds a certain threshold value can also be used.

One of the options described below can be used to estimate noise power generated by the reservoir.

Option One: Total noise power (as quadratic sum of Fourier spectrum amplitudes) is estimated in the entire frequency range (when Spectral Noise Logging Tool is used, with the measurement range from 0.117 - 60 KHz or 30 KHz, depending on the tool version; see red area in Fig. 1 - Regime 1). Depth interval is selected on the basis of medium frequency domain analysis.

Option Two: Noise power is estimated in the frequency range corresponding to reservoir flow (normally, 3-5 kHz or higher). See yellow area in Fig. 1 (Regime 2). Extensive low-frequency noise corresponds to wellbore flow. Medium and high-frequency noise concentrated in a certain depth range corresponds to noise generated by reservoir unit.

Another option is application of an additional filtering method, for example, a wavelet thresholding filter. The filter must exclude large-scale spectral features by depth, such as noise produced by wellbore flow. We call it SND - Spectral Noise Drift (Panels Two and Four in Fig. 1). A median trend normalisation by depth can also be used as such a filter. Any of these filtering methods will calculate the noise power in the entire frequency range by filtered data.

Calculations are based on the assumption that noise power *(N)* of a flowing reservoir zone is proportional to pressure overbalance (underbalance) $(P-P_{rs})$ raised to n power.

$$N = K \cdot \left(P - P_{пл}\right)^n \quad \text{(Equation 1)}$$

This equation dependence is semi-empirical. In one of the research papers (McKinley, R.M. 1994. Temperature, Radioactive Tracer, and Noise Logging for Well Integrity: 112-156) a similar equation can be encountered but it appears in the following form: $N = K \cdot Q \cdot \left(P - P_{пл}\right)$, where Q is volumetric flow rate. It follows from Darcy's law that there is a relation $Q = K \cdot \left(P - P_{пл}\right)$ and, therefore, this expression was generalised to common power relation. Similar dependences were derived as the experiments were run.

Therefore, the relation of the reservoir noise power in the first operational regime N_1 to the reservoir noise power in the second operational regime N_2 will can be written in the following form:

$$P_{пл} = \frac{P_1 - \left(\frac{N_1}{N_2}\right)^{1/n} P_2}{1 - \left(\frac{N_1}{N_2}\right)^{1/n}} \quad \text{(Equation 2)}$$

The above dependence represents a simple solution of two Equations (1), when the measurements were taken in two regimes. The n-th degree depends on the type of well fluid. For water and oil, this degree is assumed to equal 2 and, as the dependence is originally semi-empirical, then this degree is an experimental fact. However, as we know that in case of such fluids as oil and water the flow rate is proportional to the first degree of overbalance (differential pressure), then the noise power will be proportional to the second power of the differential pressure. Darcy's Law does not apply to gaseous fluids and the flow rate/pressure dependence will be quadratic and we therefore think that the exponential order for gas will be different (for example, 3) or functional relationship will be different.

To estimate the reservoir noise power, the spectral noise logging data need to be pre-processed. To do so, the spectral noise power is to be calculated first. The total noise power of the spectral components corresponding to the reservoir noise is identified on the basis of thresholding algorithms. Then the noise power is averaged over depth for a zone with uniform reservoir flowing conditions.

APPLICATION OF THE INVENTION

The proposed method includes the following phases:

First, the current reservoir noise is measured (Regime 1) with Regime 1 being in keeping with the current well operating conditions (current flow rate, bottomhole pressure, and choke size).

Then the current wellbore pressure is measured (Regime 1) using a high-sensitivity pressure gauge with measurements taken in motion at a constant running speed or at stations when the tool is run into the hole (or while pulling out of the hole in one continuous pass).

After that, the current reservoir noise is measured (Regime 2). This regime implies that either the bottomhole pressure can be changed two times maximum (preferably, by at least 30% of the initial pressure) or volumetric flow (preferably, by at least 30%). It should be noted that the above-mentioned figure of at least 30%

change only serves the purpose of illustrating certain aspects of application of the invention and does not in any way limit the scope of its application, i.e. it must be understood that this figure could be less than 30% provided that it would be sufficient for Regime 2 to be established as specified in the invention without compromising the reliability of measurements. To put the well into steady Regime 2, it needs to be flowing for at least 12 hours under those conditions (24-hours period is recommended). After that, the current wellbore pressure is measured (Regime 2).

Once this has been done, the noise power profiles are derived on the basis of Spectral Noise Density Panels (Regime 1 and Regime 2), the noise power profiles are averaged (Regime 1 and Regime 2) within the active flow zones, and reservoir pressure in the near-wellbore zone is calculated on the basis of the derived values.

Some examples of the proposed method application, which do not in any way limit its scope, are given below to illustrate some aspects of the invention implementation.

Example 1. Estimation of reservoir pressure in an injection well (Fig. 2).

First, reservoir noise and wellbore pressure measurements were taken in Regime 1 at a volumetric flow rate of 157 BPD. The results are shown in Fig. 2: SNL Panel (Regime 1) and continuous black line P_1 on Pressure Panel. Then reservoir noise and wellbore pressure measurements were taken in Regime 2 at a volumetric flow rate of 585 BPD. The results are shown in Fig. 2: SNL Panel (Regime 2) and dashed black line P_2 on Pressure Panel.

Based on the Spectral Noise Density Panels (SNL - Regime (1) and SNL - Regime (2)) the total noise power profiles were derived in the frequency band of 117 Hz - 60 kHz. The profiles are shown on the two rightmost panels (Noise Power (1) and Noise Power (2)). Then the profiles were averaged within the active flow zone intervals: for Upper Reservoir Unit 1 in the interval X555-X559 and for Lower Reservoir Unit 2 in the interval X562-X563.

The following values were taken for calculations:

For Reservoir Unit 1:

P_1= *4149 psi* - bottomhlole pressure in Regime 1 (volumetric flow rate Q_1=157 BPD)

P_2= *4986 psi* - bottomhole pressure in Regime 2 (volumetric flow rate Q_2=585 BPD)

N_1= *24 per unit value* - average reservoir noise power in Regime 1

N_2= *96 per unit value* - average reservoir noise power in Regime 2

Calculated reservoir pressure in the near-wellbore zone ***$Pres_1$=3312 psi***

For Reservoir Unit 2:

P_1= *4160 psi* - bottomhlole pressure in Regime 1 (volumetric flow rate Q_1=157 BPD)

P_2= *4999 psi* - bottomhole pressure in Regime 2 (volumetric flow rate Q_2=585 BPD)

N_1= *12 per unit value* - average reservoir noise power in Regime 1

N_2= *32 per unit value* - average reservoir noise power in Regime 2

Calculated reservoir pressure in the near-wellbore zone ***$Pres_2$=2834 psi***

The calculated values are shown as dashed lines in Pressure Panel (Fig. 2) and it can be concluded from them that the pressure in the Lower Reservoir Unit is higher than in the Upper one. The obtained data are essential in selecting optimum bottomhole pressures for development of each Reservoir Unit with maximum oil sweep efficiency.

Example 2. Estimation of reservoir pressure in a production well (Fig. 3).

First, reservoir noise and wellbore pressure measurements were taken in Regime 1 at a volumetric flow rate of 2300 BPD. The results are shown in Fig. 3: SNL Panel (Regime 1) and continuous black line P_1 on Pressure Panel. Then reservoir noise and wellbore pressure measurements were taken in Regime 2 at a volumetric flow rate of 2260 BPD. The results are shown in Fig. 3: SNL Panel (Regime 2) and dashed black line P_2 on Pressure Panel.

Based on the Spectral Noise Density Panels (SNL - Regime (1) and SNL - Regime (2)) the total noise power profiles were derived in the frequency band of 117 Hz - 30 kHz. The profiles are shown on the two rightmost panels (Noise Power (1) and Noise Power (2)). Then the profiles were averaged within the active flow zone intervals: for Upper Reservoir Unit 1 in the interval X545-X570 and for Lower Reservoir Unit 2 in the interval X600-X610.

The following values were taken for calculations:

For Reservoir Unit 1:

P_1= 1222 psi - bottomhlole pressure in Regime 1 (volumetric flow rate Q_1=2300 BPD)

P_2= 1244 psi - bottomhole pressure in Regime 2 (volumetric flow rate Q_2=2260 BPD)

N_1= 84 per unit value - average reservoir noise power in Regime 1

N_2= 42 per unit value - average reservoir noise power in Regime 2

Calculated reservoir pressure in the near-wellbore zone ***$Pres_1$=1270 psi***

For Reservoir Unit 2:

P_1= 1250 psi - bottomhlole pressure in Regime 1 (volumetric flow rate Q_1=2300 BPD)

P_2= 1272 psi - bottomhole pressure in Regime 2 (volumetric flow rate Q_2=2260 BPD)

N_1= 91 per unit value - average reservoir noise power in Regime 1

N_2= 72 per unit value - average reservoir noise power in Regime 2

Calculated reservoir pressure in the near-wellbore zone ***$Pres_2$=1500 psi***

Calculated reservoir pressure in the near-wellbore zone ***$Pres_2$=1500 psi***

The calculated values are shown as dotted lines in Pressure Panel (Fig. 3) and it can be concluded from them that the pressure in the Lower Reservoir Unit is higher than in the Upper one. This, in its turn, indicates that there is cross-flow from the Lower Unit into Upper one. These data enable taking timely actions to maintain reservoir pressure in the Upper Unit. The obtained data are essential in determining allowable bottomhole pressures, volumes of produced fluid and gas, and estimating water encroachment rate, which is required to achieve maximum oil recovery factor.

Therefore, as follows from Examples 1 and 2, the use of noise logging data in two regimes does not result in any considerable changes in the operating regime of the well or any particular reservoir unit but still enables the user to estimate pressure in the near-wellbore zone within unperforated intervals that have direct communications with perforations or in open-hole sections, thus enhancing reliability of measurements in the near-wellbore zone in each of the active flow intervals both in injection (Example 1) and production (Example 2) wells, i.e. making it possible to achieve the desired technical result, viz. improvement of logging data reliability, expanding, at the same time the scope of application.

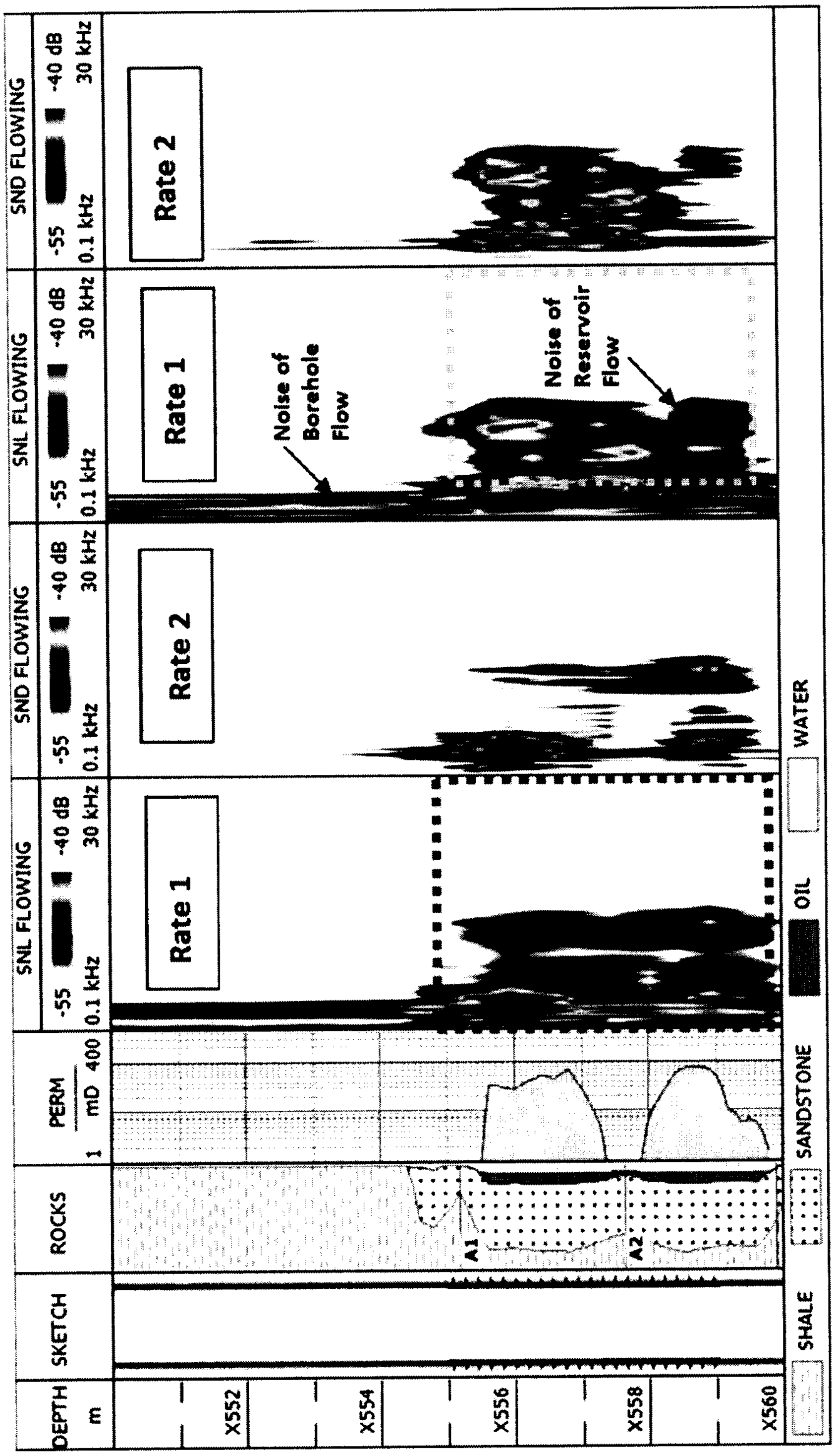
The claimed invention can be used for estimation of reservoir pressure in the near-wellbore zones of injection and production wells based on the results of current bottomhole pressure and reservoir noise power measurements in two different regimes. In addition to this, the claimed invention can be used for estimation of pressure in vertical injection and production wells, low-angle and horizontal wells thereby expanding the scope of this invention application, unlike its prototype that cannot be used in horizontal wells as a flow meter due to its technical features (spinner-type).

CLAIMS

1. The proposed method for estimating reservoir pressure in the near-wellbore zone separately for each flowing reservoir unit based on an analysis of at least one measured parameter specific to steady-state well operating regimes: in Regime 1, as a minimum requirement, and in Regime 2, is claimed to have a distinctive feature of using spectral noise logging data for such analysis.
2. The method recited in claim 1 wherein measurements are additionally performed in unperforated zones or open-hole sections of the wellbore.
3. The method recited in claim 1 wherein current reservoir noise is measured in well operating Regime 1.
4. The method recited in claim 1 wherein current wellbore pressure is measured in well operating Regime 1.
5. The method recited in claim 1 wherein Regime 2 is established in the well.
6. The method recited in claim 5 wherein bottomhole pressure is changed to establish Regime 2.
7. The method recited in claim 6 wherein bottomhole pressure is changed by an amount sufficient for well operating Regime 2 to be established.
8. The method recited in claim 6 wherein bottomhole pressure is changed by at least 30% of the current well operating regime (Regime 1).
9. The method recited in claim 5 wherein volumetric flow rate is changed to establish Regime 2.
10. The method recited in claim 9 wherein volumetric flow rate is changed by an amount sufficient for well operating Regime 2 to be established.
11. The method recited in claim 9 wherein volumetric flow rate is changed by at least 30% of the current well operating regime (Regime 1).

12. The method recited in claim 5 wherein well operating Regime 2 is to be established after the well has been flowing for at least 12 hours or, preferably, 24 hours.
13. The method recited in claim 1 wherein current reservoir noise is measured in well operating Regime 2.
14. The method recited in claim 2 and claim 13 wherein the measurements are made with a sound-level meter.
15. The method recited in claim 14 wherein the measurements are made with a sound-level meter being run in and/or pulled out of the hole.
16. The method recited in claim 13 wherein the measurements are made with a sound-level meter at stations when it is run in and/or pulled out of the hole.
17. The method recited in claim 13 wherein a sound-level meter is equipped with centralizers.
18. The method recited in claim 1 wherein the current wellbore pressure is measured in well operating Regime 2.
19. The method recited in claim 3 and claim 18 wherein pressure is measured with a high-sensitivity pressure gauge at a constant running speed or when the gauge is at stations in the wellbore.
20. The method recited in claim 1 wherein Regime 1 is established by setting current flow rate and/or bottomhole pressure.
21. The method recited in claim 1 wherein the data acquired in well operating Regime 1 and Regime 2 are analysed by at least one parameter to estimate reservoir pressure in the near-wellbore zone.
22. The method recited in claim 21 wherein the noise power profile is derived on the basis of Spectral Noise Density Panel in Regime 1 and Spectral Noise Density Panel in Regime 2.
23. The method recited in claim 22 wherein the derived profiles are averaged within the active reservoir units.

24. The method recited in claim 23 wherein reservoir pressure in each of the active reservoir units are calculated on the basis of the data derived by means of averaging the profiles.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SND FLOWING
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0.1 kHz 30 kHz
Rate 2
SNL FLOWING
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0.1 kHz 30 kHz
Rate 1
Noise of Borehole Flow
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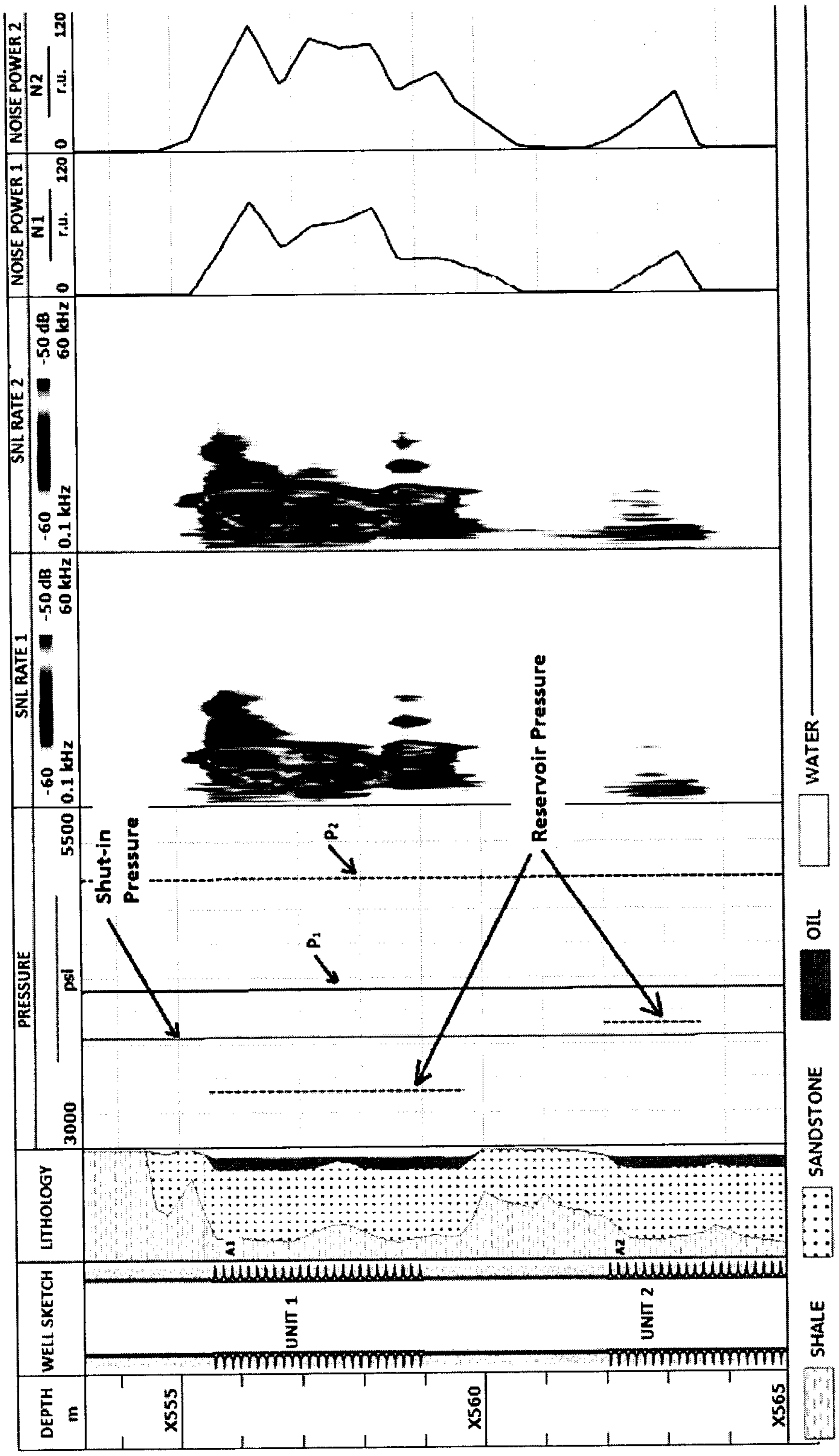
Rate 2
SHALE
SANDSTONE
OIL
WATER

Fig. 1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WATER

Fig. 2

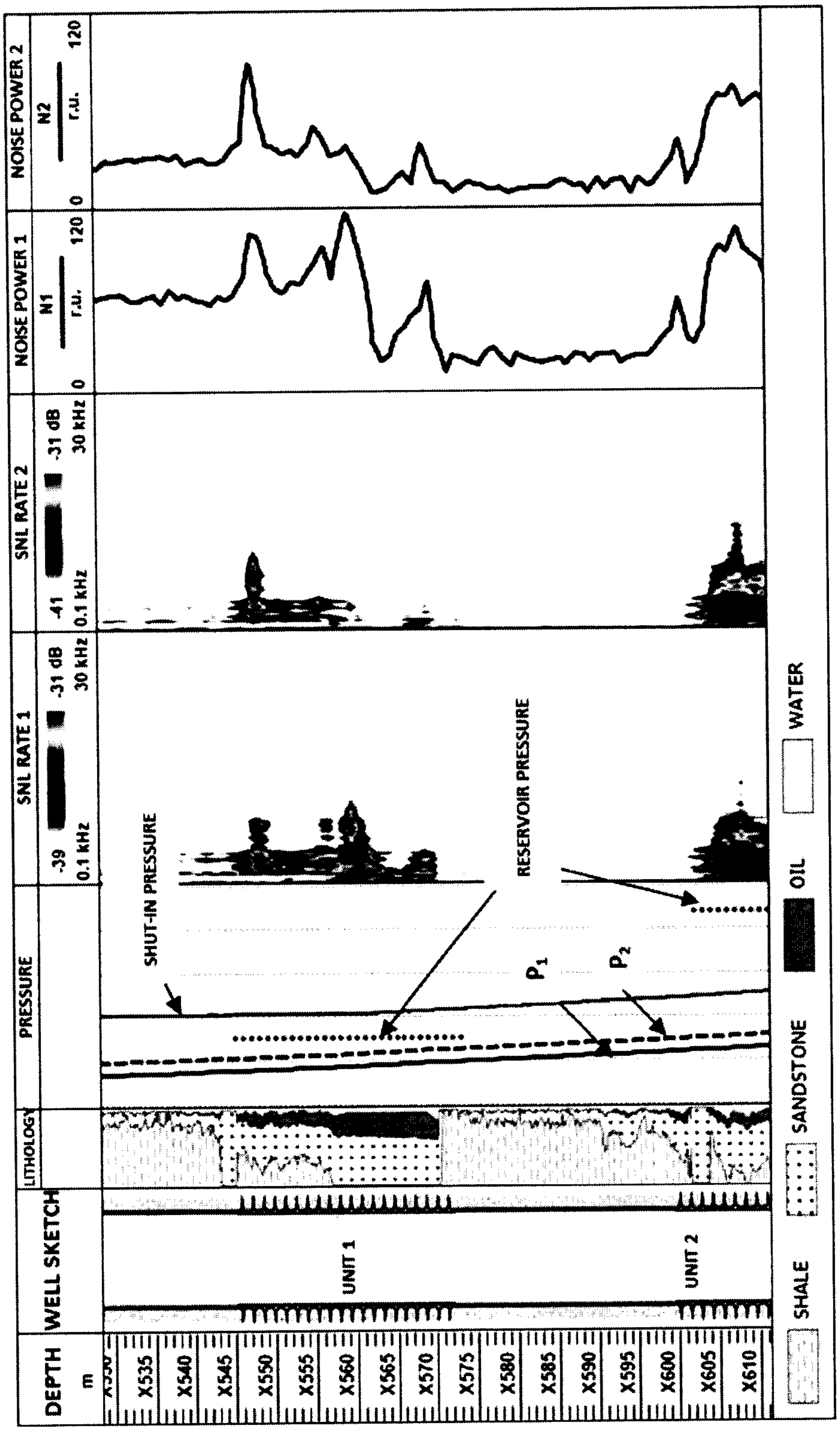
DEPTH
m
X535
X540
X545
X550
X555
X560
X565
X570
X575
X580
X585
X590
X595
X600
X605
X610
WELL SKETCH
UNIT 1
UNIT 2
LITHOLOGY
PRESSURE
SHUT-IN PRESSURE
RESERVOIR PRESSURE
P_1
P_2
SNL RATE 1
-39
-31 dB
0.1 kHz
30 kHz
SNL RATE 2
-41
-31 dB
0.1 kHz
30 kHz
NOISE POWER 1
N1
r.u.
0
120
NOISE POWER 2
N2
r.u.
0
120
SHALE
SANDSTONE
OIL
WATER

Fig. 3

INTERNATIONAL SEARCH REPORT

International application No.

PCT/RU 2014/000993

A. CLASSIFICATION OF SUBJECT MATTER

E21B 47/06 *(2006.01)*

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B 47/00,47/06, 47/10, 47/107, 47/12, 49/00, G01V 1/00, 1/40, 1/48, 9/00

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

PatSearch (RUPTO internal), USPTO, PAJ, Esp@cenet, DWPI, EAPATIS, PATENTSCOPE, Information Retrieval System of FIPS

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A, D	US 2009/0037113 A1 (SCHLUMBERGER TECHNOLOGY CORPORATION) 05.02.2009	1-24
A	RU 2499283 C1 (TGT OIL AND GAS SERVICES FZE) 20.11.2013	1-24
A	US 4046220 A (MOBIL OIL CORPORATION) 06.09.1977	1-24
A	US 2006/0133203 A1 (SIMON JAMES et al.) 22.06.2006	1-24
A	MARFIN E. A. Skvazhinnaya shumometriya i vibroakusticheskoe vozdeistvie na flyuidonasyschennye plasty. Kazan, Izdatelstvo Kazansky universitet, 2012, p. 8-25	1-24

☐ Further documents are listed in the continuation of Box C.

☐ See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier document but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

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"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
13 April 2015 (13.04.2015)	23 April 2015 (23.04.2015)

Name and mailing address of the ISA/RU:	Authorized officer
Federal Institute of Industrial Property, Berezhkovskaya nab., 30-1, Moscow, G-59, GSP-3, Russia, 125993 Facsimile No: (8-495) 531-63-18, (8-499) 243-33-37	T. Grigoryan Telephone No. 499-240-25-91