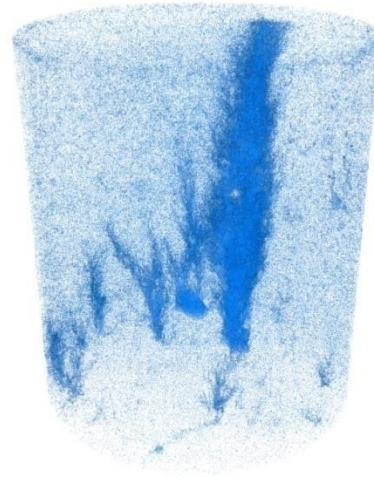


Colloids and Surfaces A: Physicochemical and Engineering Aspects

Development and application of a double action acidic emulsion for improved oil well performance: laboratory tests and field trials

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Abstract:	<p>Emulsified acid has attracted considerable attention of the oil and gas industry due to its delayed action that allows deeper penetration of acid into the formation which essentially facilitates improved well productivity, and at the same time minimizes corrosion of the downhole equipment. In this paper, for the first time, we report a new acidic emulsion suitable for acidizing carbonate reservoirs. The novel emulsion is of a double action type so that it is capable of simultaneously dissolving paraffin deposits and acidizing rocks thus increasing reservoir permeability and porosity. Results of the laboratory experiments and field tests indicate that the new emulsion reacts with carbonate rocks at reduced rate thus enabling the emulsion to penetrate deeper into the reservoir when injected for acidizing. At the same time the emulsion has lower corrosive effect towards steel, thus indicating better compatibility with downhole pumping equipment. Coreflooding experiments confirm the ability of the emulsion to acidize rocks forming highly permeable channels to the flow of hydrocarbons thus stimulating carbonate formations. The initial increase in oil recovery obtained after the acidizing operation suggests that the new emulsion provides better and faster return on investment thus making its use more economically viable. In addition, the developed and tested in this study emulsion requires fewer operations during its field implementation thus significantly reducing the operational costs. The developed novel emulsion, therefore, has characteristics comparable or exceeding those of solutions investigated or used thus far, combining all advantages in a single fluid thus allowing a highly efficient stimulation of production wells that can be achieved in a single operation. Hence, the presented results suggest that the double action emulsion presents a major advancement in acidizing science and technology.</p>



Development and application of a double action acidic emulsion for improved oil well performance: laboratory tests and field trials

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ABSTRACT

Emulsified acid has attracted considerable attention of the oil and gas industry due to its delayed action that allows deeper penetration of acid into the formation which essentially facilitates improved well productivity, and at the same time minimizes corrosion of the downhole equipment. In this paper, for the first time, we report a new acidic emulsion suitable for acidizing carbonate reservoirs. The **novel** emulsion is of a double action type so that it is capable of **simultaneously** dissolving paraffin deposits and acidizing rocks thus increasing reservoir permeability and porosity. Results of the laboratory experiments and field tests indicate that the new emulsion reacts with carbonate rocks at reduced rate thus enabling the emulsion to penetrate deeper into the reservoir when injected for acidizing. At the same time the emulsion has lower corrosive effect towards steel, thus indicating better compatibility with downhole pumping equipment. Coreflooding experiments confirm the ability of the emulsion to acidize rocks forming highly permeable channels to the flow of hydrocarbons thus stimulating carbonate formations. The initial increase in oil recovery obtained after the acidizing operation suggests that the new emulsion provides better and faster return on investment thus making its use more economically viable. In addition, the developed and tested in this study emulsion requires fewer operations during its field implementation thus significantly reducing the operational costs. **The developed novel emulsion, therefore, has characteristics comparable or exceeding those of solutions investigated or used thus far, combining all advantages in a single fluid thus allowing a highly efficient stimulation of production wells that can be achieved in a single operation. Hence, the presented results suggest that the double action emulsion presents a major advancement in acidizing science and technology.**

Keywords: carbonate reservoir, acidic inversed emulsion, corrosion retention, paraffin deposit washing, rock dissolution, cost effective formation acidizing

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49 1. Introduction

50

51 Oil field development efficiency depends on well productivity over the entire
52 life of the field. During the operation of production wells, the reservoir properties such
53 as porosity and permeability in the vicinity of the well gradually deteriorate thus
54 resulting in an increase of the skin factor [1,2]. Clogging of the formation near a
55 production well is caused mainly by the formation of paraffin deposits. Moreover,
56 when reservoir fluid moves to the production well, the particles of the rock tend to
57 clog pores and pore throats [3,4]. Improving productivity and reducing the skin factor
58 is achieved by acid treatment or acidizing. The basic principle of acidizing is to
59 dissolve rock by injection of acidic solution to form a network of microchannels or
60 wormholes in the formation. This technology allows to increase and maintain oil
61 production at the required level [5].

62 The effectiveness of acidizing depends primarily on the depth of penetration of
63 acid into the formation and on the completeness of dissolution of reservoir rock in the
64 acidic solution [6,7]. During the treatment of the formation with hydrochloric acid of
65 concentration of 12-16 wt%, its maximum impact on the rock occurs in the near-
66 wellbore zone. In the remote zone of the formation, the reaction of acid with the rock
67 is less intense due to the loss of part of its activity after chemical interaction with rock
68 in the vicinity of the well [8-10]. It is essential that the reaction between the acidic
69 composition and the formation takes place at a slower rate so that the acid penetrates
70 the rock as far as possible from the well. For this purpose, in practice, the so-called
71 "inhibitor" of acid such as the "Neftenol", "Atsironiks", and "Soling" is used [11].

72 Paraffin deposits are also a typical complication during oil recovery. Paraffin
73 deposits that correspond to specific pressure and temperature conditions clog the pore
74 space thus reducing both the rock permeability and the efficiency of acidizing [12,13].

75 Efficient stimulation of production wells is still a challenging task thus
76 development of effective acidic emulsions has been a focus of scientific research over
77 the past five decades. Specific challenges associated with implementation of acidic
78 emulsions include: i) achieving high efficiency of emulsions to dissolve reservoir
79 rocks thus creating improved pathways to flows (microchannels or wormholes); ii)
80 increasing depth of penetration of injected emulsion that requires an extended duration
81 of acidic activity, which is normally achieved via use of inhibitors; iii) reducing
82 corrosive effect of emulsion to minimize corrosion of well tubing and cements; iv)
83 achieving efficient dissolution of paraffin deposits by the injected solution that leads to
84 further improvement of reservoir petrophysical properties (porosity and permeability);
85 v) keeping viscosity of the injected solution relatively low thus maintaining high
86 mobility of the solution in order to not hindering the flow; and finally vi) developing
87 such solution that allows removal of paraffin deposits and dissolution of rocks at the
88 same time (so-called double action emulsion) thus reducing operational costs and time.

89 Today, many acidic compositions are known in oil and gas industry, but in most
90 cases, they have a single effect of dissolving the rock in order to increase its
91 permeability [12,14,15].

92 Other known technologies aim at dissolving reservoir rocks and removing
93 paraffin deposits in the formation zone thus increasing formation permeability.
94 However, these technologies are implemented in two stages. The first stage is
95 associated with injection of a solvent to clean the bottom-hole zone from paraffin
96 deposits while during the subsequent second stage acidic composition is injected in
97 order to increase the permeability of the rock [5,16,17]. Although the obtained
98 efficiency of rock dissolution and paraffin deposits removal is high in these
99 conventional acidizing jobs, a well workover team is required. For example, although
100 efficiency of paraffin removal was reported to be 33% in [16] and the rock dissolution

101 was 9256.1 mD [12], the use of two-stage acidizing technology and the involvement
102 of a workover team significantly increases the cost of the procedure by \$25,000 [18].

103 Development and effective use of new acid compositions that can provide deep
104 penetration into the reservoir and, at the same time, allow cleaning the pore space from
105 paraffin deposits, is an important scientific and technological task. This task is of a
106 paramount importance for oil reserves in the Perm Krai where a significant (about 45-
107 50%) share of hydrocarbon reserves is found in carbonate reservoir, similar to the
108 situation with oil reserves in carbonate reservoirs around the world [19,20]. To solve
109 this problem, the authors have developed and tested a new proprietary double-action
110 acidic emulsion termed Emulsion A. **The developed Emulsion A is efficient in
111 removing paraffin deposits, dissolving reservoir rocks, it has relatively low viscosity
112 and therefore is mobile, it has extended duration of strong acidic action thus making it
113 possible for the emulsion to penetrate deeper in the reservoir, and it has low corrosion
114 rate making the acidizing less damaging to well equipment. All these properties make
115 the developed emulsion novel, highly efficient and cost effective, thus significantly
116 advancing the current state of acidizing science and technology.**

117 Emulsion A is an acidic solution dispersed in a hydrocarbon fluid. The
118 continuous phase of Emulsion A is a mixture of liquid hydrocarbons, and the dispersed
119 phase is the hydrochloric acid. At present, the composition of Emulsion A is uniquely
120 designed for oil fields of Perm Krai, Russia. One of the main advantages of the
121 developed composition is that paraffin removal and acidizing is carried out in a single-
122 stage procedure and without setting up a special team for workover thus reducing the
123 costs of carrying out the task. When carrying out the conventional acidizing, the
124 pumping equipment is removed from the wells. Which is done by the well overhaul
125 service. The pumping equipment is removed since the acidic compounds are highly
126 corrosive. The developed Emulsion A has low corrosive activity and therefore it can
127 be injected without lifting the pumping equipment from the well and without involving
128 the workover.

129 Another advantage of Emulsion A over the conventional acid is that when it is
130 used in a carbonate reservoir, emulsified acid can enhance the acid delivery to
131 formation and improve wellbore coverage across the target thickness of the reservoir
132 [21,22]. Moreover, conventional acidic solutions have viscosity similar to that of
133 water. Therefore, they will tend to flow into the formation intervals with higher
134 permeability, leaving the tighter reservoir zones with higher formation damage
135 untreated [23]. This non-uniform coverage of acid in the reservoir could lead to the
136 overall unsuccessful acidizing. Therefore, the Emulsion A, which has viscosity of
137 approximately 50 cp could enhance the zonal coverage, sweep efficiency and acid
138 distribution in heterogeneous reservoirs [24-26].

139 The developed Emulsion A has passed industrial tests at 42 production wells in
140 the Perm Krai and 12 wells in Udmurtia (Russia). In comparison with other solutions
141 used today in different regions of the Perm Krai and elsewhere in Russia, as well as
142 with some acidic compounds that are used in oil fields of China, USA and Canada, the
143 use of Emulsion A results in increase of an average 20-30% [19] in oil recovery.
144 Economic benefits achieved using Emulsion A account for about \$150,000 for
145 treatments carried out in the Perm Krai and Udmurtia over the period of use of the
146 emulsion.

147

148 **2. Materials and Methods**

149

150 *2.1 Fluids*

151

152 *2.1.1 Emulsion A*

153 Oil and gas operators and service companies at the Perm Krai carry out acidizing
 154 operation of a well without workover. This has become possible due to the use of
 155 Emulsion A at the well with a significantly reduced corrosion rate compared to
 156 standard acidic compositions. The main properties of Emulsion A are shown in Table
 157 1. This type of emulsion allows aggressive hydrochloric acid to be dispersed in a
 158 neutral hydrocarbon medium thus reducing the rate of formation and well corrosion
 159 caused by the acid. Also, due to the inverse nature of the emulsion it does not dissolve
 160 in water, while when mixed with formation water the viscosity of the mixture
 161 increases thus reducing its mobility. Moreover, upon contact with crude oil the
 162 emulsion becomes unstable and decomposes into separate hydrocarbon and acid
 163 phases. The hydrocarbon phase cleans the formation of paraffin deposits thus
 164 increasing well productivity. On the other hand, the acid phase reacts with the
 165 carbonate mineral of the reservoir causing its dissolution, which increases the
 166 permeability of the reservoir. In addition, leaving the formation, the acid and the
 167 hydrocarbon phases are no longer able to form emulsions thus adversely affecting the
 168 operation of submersible equipment. The hydrocarbon phase also makes the formation
 169 in the vicinity of the well more hydrophobic and removes paraffin deposits thus
 170 increasing well productivity.

171

172 **Table 1**

173 The properties of Emulsion A.

Property	Value
Density at 20°C, g/cm ³	1.03 – 1.13
Concentration of HCl, % (v/v)	8 – 13
Mass fraction of iron in the emulsion, %	< 0.025
The dissolution rate of steel, ϑ at 20°C g/(m ² ×hour)	< 0.08 – 0.10
Viscosity prior to acidizing procedure, cP (mPa·s)	40 - 50
Viscosity after acidizing procedure, cP (mPa·s)	50 - 65

174

175 *2.1.2 Formation water*

176

177 The characteristics of the formation water used in this study are presented in
 178 Table 2. Produced water was taken directly from the reservoir. To determine the
 179 content of ions in the formation water we used ion chromatography method (ion
 180 chromatography 940 Professional IC Vario, Metrohm).

181

182 **Table 2**

183 Characterization of formation water properties.

Parameter	Range of change
Density, g/cm ³	1.032 – 1.192
Salt content (total dissolved solids), ppm	21000 – 363000
pH	6.085 – 7.985
Viscosity, cP	1.22 – 1.50
Formation water chemistry, ppm	
Na ⁺ + K ⁺	69211 – 85231
Ca ²⁺	16434 – 21861
Mg ²⁺	3550 – 5618
Cl ⁻	153601 – 168850
HCO ₃ ⁻	158 – 455
SO ₄ ²⁻	49.4 – 720
NH ₄ ⁺	137 – 418

Br ⁻	467 – 899
J ⁻	11.4 – 23.0
B ³⁺	7 – 211
Li ⁺	14 – 32

184

185 2.1.3 Crude oil

186

187 The crude oil used in this study is classified as light, low-viscosity, resinous,
188 highly paraffinic, sulphurous with a high yield of light fractions during distillation.
189 The characteristics of the crude oil are presented in Table 3.

190

191 **Table 3**

192 Characterization of the properties of crude oil.

Parameter	Range of change
Density, g/cm ³	0.710 – 0.877
Viscosity, cp	1.16 – 17.5
Gas content, m ³ /m ³	21.3 – 251.3
Melting point of paraffin, °C	51.2 – 54.5
Boiling point, °C	44 – 57
Heavy oil fractions, vol%	
Paraffins	2.71 – 5.4
Resins	6.54 – 18.95
Asphaltenes	0.86 – 7.3
Sulfur	0.32 – 1.53

193

194 Gas dissolved in the oil is characterized by low methane content of 28.28 mol%,
195 high fat content of 50.04 mol% of methane homologues, and medium nitrogen
196 concentration of 21.28 mol%). The hydrogen sulfide in the gas is found to be below
197 the detection limit.

198

199 2.2 Rock samples

200

201 This study used over 300 rock samples from Perm Krai and Udmurtia Republic.
202 A 30 mm diameter, 5-7 mm thick rock samples were used. Rock samples were taken
203 directly from the producing oil reservoir (average depth of rock sampling was 2100 -
204 2200 m). The rock samples are carbonates that consist of mostly calcite and dolomite
205 grains at different ratios. The mineralogy and basic petrophysical properties of rock
206 samples is given in Table 4. **Select rock samples were analyzed using thin sections and
207 a microscope, which allowed to identify minerals comprising the samples. The
208 analyses showed no presence of organic matter such as kerogen. Therefore, we are
209 confident that observed dissolution of the samples, discussed later, cannot be
210 attributed to chemical interaction between Emulsion A and organic matter.** The
211 samples investigated in this study have significant ranges for each of the mineralogical
212 components as well as in their petrophysical properties as can be seen from Table 4.
213 Despite the variability in porosity and permeability, the weighted average values of
214 11.7% and 41 mD were evaluated. There are inclined and sub-vertical cracks, short
215 and long, hollow and partially filled with calcite.

216

217 **Table 4**

The mineralogy and petrophysical properties of rock samples used in this study.

Property	Value
Mineralogy Calcite	42.5 – 95.7%

Dolomite	0 – 55.7%
Other (quartz, mudstones, siltstones)	1.2 – 34.5%
Cements	5 – 10%
Pore size	0.02 – 0.9 mm
Porosity	7.0 – 20.7%
Absolute permeability	0.52 – 641 mD

218

219 *2.3 Methods*

220

221 *2.3.1 Laboratory, free volume*

222

223 The following parameters of Emulsion A were investigated in 5 different free
 224 volume experiments: 1) the rock dissolution rate experiment expanded towards the
 225 effectiveness of the reaction inhibitors used in the composition and duration of the
 226 neutralization of the emulsion; 2) compatibility with reservoir fluids; 3) oil-emulsion
 227 interfacial tension (IFT); 4) corrosion rate; and 5) dissolving (washing) ability of
 228 paraffin deposits [6,12,19]. These experiments are described in more detail below.

229

230 1) To evaluate the effectiveness of the inhibitors used in the emulsion studies
 231 were carried out both for the Emulsion A and for 12% HCl solution and for three
 232 acidic compositions (Solution 1 Solution 2 and Solution 3), all of which are commonly
 233 used in Russia. First, the initial mass of rock samples is measured. Further the clean
 234 dried samples were heated in an oven to a temperature of 35°C that corresponds to the
 235 reservoir conditions. Then Emulsion A was poured into special containers (50 ml) and
 236 heated to reservoir temperature and the investigated rock sample was placed into a
 237 container with Emulsion A. Rock samples was allowed to react with the emulsion over
 238 the period of one minute, after which the sample was removed from the container,
 239 dried and its mass was measured again.

239

240 The rate of dissolution of the rock ($\vartheta_{dissolution}$) was determined by the rate of
 241 change in rock mass relative to the initial surface area of the sample:

241

$$\vartheta_{dissolution} = \frac{(m_1 - m_2)}{S \cdot t} \quad (1)$$

242

243 where m_1 is the initial mass of the rock sample in [g]; m_2 is the mass of the rock
 244 sample after reacting with Emulsion A in [g]; S is the initial surface area of the rock
 245 sample in [m^2]; t is the reaction time in [min];

245

246 To evaluate the time of neutralization of the emulsion, a 30 mm diameter, 5-7
 247 mm thick rock samples were used. The experimental protocol is similar to that
 248 described in 1) with the only difference being in the duration of the reaction. In this
 249 experiment, the rock sample was allowed to react with the emulsion until no further
 250 rock dissolution was observed. The termination of the reaction between the rock and
 251 the emulsion was evaluated in two ways: visually and by measuring pH of the
 252 emulsion. Visual determination of the termination of the reaction was confirmed by
 253 cessation carbon dioxide emission (bubbling) that accompanied the reaction between
 254 acidic solution and carbonates. We used the S47 Seven Multi instrument for regular
 255 pH measurements, so that stabilization of pH reading indicated the end of the reaction
 256 of the rock with the emulsion. This experiment was carried out in order to determine
 257 the reaction time of Emulsion A with the rock under reservoir conditions.

257

258 2) The following approaches were used to evaluate and characterize the
 259 interaction between the emulsion and formation fluids:

259

260 • Characterization of the interaction of the emulsion with formation water was
 261 conducted by mixing the two in a volumetric ratio of 1:1 with a paddle mixer with the
 262 speed of 500-600 rpm. Then the mixture was placed in a heating cabinet, where it was

262 kept for one hour at reservoir temperature of 35°C. After that, the condition of the
263 mixture was visually assessed for presence of deposits. It was passed through a filter
264 paper (pore size 1-2 µm), which, after drying, was examined under a microscope to
265 investigate the composition of the deposits. The emulsion was considered to be stable
266 and compatible with formation water in the absence of any precipitation or deposited
267 flakes.

268 • The investigation of the interaction between the emulsion and reservoir oil was
269 the most important step in a series of laboratory experiments that aimed at designing
270 effective technique and emulsion formulation for acidizing. Investigation of the
271 interaction between the reservoir oil and Emulsion A was carried out using three
272 different fluids:

273 ✓ Pure Emulsion A. The reservoir oil and the emulsion were mixed in
274 volumetric ratios of 25:75, 50:50, 75:25 with a paddle mixer with a speed of 500-600
275 rpm, and placed in a heating cabinet, where they were kept for one hour at reservoir
276 temperature. Then, the state of the mixture was evaluated visually for the presence of
277 deposits and/or phase separation. The mixture was filtered through a sieve with a 100-
278 mesh cell while recording the absence or presence of any residue on the sieve.

279 ✓ Emulsion A mixed with 2000 ppm or 5000 ppm of Fe³⁺, which served as an
280 inhibitor. The mixture of Emulsion A and target concentration of Fe³⁺ was prepared by
281 adding 0.5 mg or 2 mg of FeCl₃ into 50 mL (equal to 50g) of Emulsion A. Thus, the
282 emulsion with Fe³⁺ content of 2000ppm and 5000 ppm was then mixed with reservoir
283 oil in volumetric ratios of 25:75, 50:50, 75:25 using the paddle mixer and held for one
284 hour at reservoir temperature. Then the mixture was filtered through a sieve with a
285 100-mesh cell while recording the absence or presence of any residue on the sieve.

286 ✓ Emulsion A mixed with 2000 ppm or 5000 ppm of Fe³⁺ and equilibrated
287 with marble. The emulsion with Fe³⁺ content of 2000 ppm and 5000 ppm was
288 equilibrated with marble cube until stable pH of approximately 4.5 (pH was measured
289 every 3-4 minutes using an S47 Seven Multi) was established. Stable pH values were
290 considered to indicate the end of reaction and some degree of neutralization of the
291 acidic component of the solution. Note that initial pH of 0.5 was measured prior to the
292 equilibration process and the marble cube was allowed to equilibrate with Emulsion A
293 for 7 hours until stabilization at 4.5 pH units. The equilibrated emulsion was then
294 mixed with the test oil in volumetric ratios of 25:75, 50:50, 75:25 and held for one
295 hour at reservoir temperature. Then the mixture was filtered through a sieve with a
296 100-mesh cell while recording the absence or presence of any residue on the sieve.

297 3) The emulsion-oil IFT was determined using an automatic tensiometer. We
298 used the DataPhysics DCAT tensiometer (measuring range – 1-2000 mN/m; resolution
299 - ±0.001 mN/m) and two measurements methods: i) the Wilhelmy plate, and ii) Du
300 Noüy method. Each measurement was repeated 3 times to yield inaccuracies
301 associated with repeatability of the measurement.

302 4) The corrosion rate caused by the emulsion was evaluated by the gravimetric
303 method according to GOST 9.502-82 "Unified system of protection against corrosion
304 and aging. Corrosion Test Methods" [27]. In this experiment, flat rectangular steel
305 plates with dimensions of 5.0 cm width, 1.2 cm height and 0.025 cm thickness were
306 used. The plates were weighed, then dipped into a container with the emulsion and
307 placed in a heated cabinet with a pre-set reservoir temperature. Samples of metal
308 plates were aged for 24 hours, after which the steel plates were removed, washed, and
309 dried, and their mass was measured. The corrosion rate ($\vartheta_{corrosion}$) g/(m²×hour) is
310 defined as:

311
$$\vartheta_{corrosion} = \frac{m_1 - m_2}{S \cdot t}, \quad (2)$$

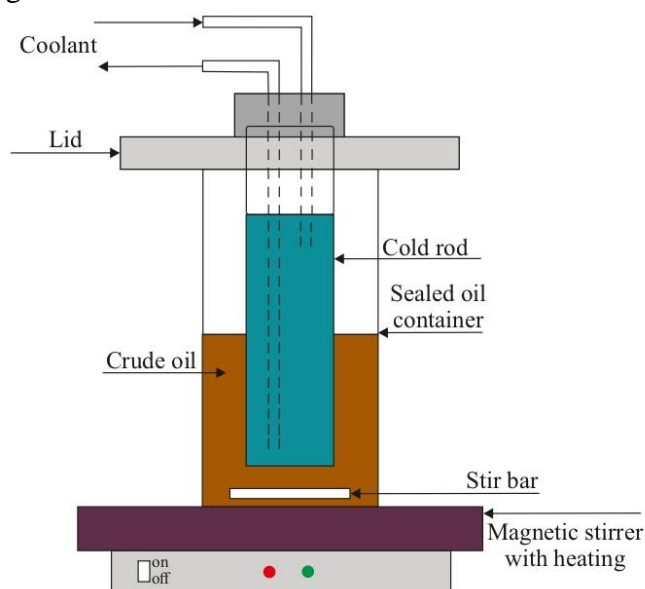
312 where m_1 is the mass of the metal plate before the test, [g]; m_2 is the mass of the
 313 metal plate after the test, [g]; S is the initial surface area of the metal plate, [m^2]; t is
 314 test duration, [hrs].

315 According to the guideline outlined in GOST 9.502-82 "Unified system of
 316 protection against corrosion and aging. Corrosion Test Methods" [27] the maximum
 317 corrosion rate for acid compositions should not exceed 0.2 g/($m^2 \times$ hour) [Technical
 318 conditions 2458-264-05765670-99 "Inhibited hydrochloric acid"].

319 5) To determine the ability of the emulsion to dissolve (wash) paraffin deposits
 320 in static and dynamic modes, experiments were carried out using the Coldfinger Test
 321 Method, which are shown schematically in Fig. 1 [28-32]. The experimental setup
 322 consists of a glass container with a lid into which a so-called cold rod is mounted. The
 323 cold rod is a stainless-steel hollow cylinder equipped with a cap with embedded
 324 system to supply and discharge the coolant (water). Glass container is sealed with a
 325 cold rod lid and placed on a magnetic stirrer with heating element at the bottom. As a
 326 result of heating the container, a temperature difference develops between the glass
 327 container and the cold rod. Typically, the temperature in the glass container was kept
 328 5°C above the temperature at which crystallization of paraffins begins. As a result of
 329 established temperature difference between the glass container and the cold rod, the
 330 temperature of the latter was 5°C below the temperature at which crystallization of
 331 paraffins begins. Therefore, paraffins begin to deposit on the surface of the cold rod.
 332 After the paraffins crystallized on a cold rod, the crude oil in the container was
 333 replaced with Emulsion A. Experiments to determine the washing ability of the
 334 Emulsion A continued for 8 hours (exposure of the Emulsion A for more than 8 hours
 335 did not lead to increased washing ability). Every hour, the weight loss of the paraffin
 336 wax was measured on the cold rod. The studies were carried out in two modes: static
 337 (the stir bar was not moving) and dynamic (the stir bar was moving). The washing
 338 ability of the emulsion to dissolve paraffin deposits is estimated using:

$$339 \quad K = ((C_2 - C_1)/C_2) \cdot 100 \quad (3)$$

340 where K is the coefficient of washing ability, [%]; C_1 is the amount of paraffin in
 341 grams on the cold rod after entering Emulsion A; C_2 is the amount of paraffin on the
 342 rod before entering Emulsion A.



343
 344 **Fig. 1.** Sketch of the Coldfinger Test Method apparatus.

345
 346 2.3.2 Filtration (permeability) tests
 347

348 Filtration tests on cylindrical rock samples (about 300 samples with 30 mm
349 diameter from oil fields of the Perm Krai and Udmurtia Republic were used) were
350 carried out using an AFS-300 (TEMCO Inc., USA) core holder at reservoir conditions
351 in the following order. Initially, clean and dry core samples were saturated with
352 kerosene in a vacuum chamber for 24 hrs to assure 100% kerosene saturation. The
353 samples were then placed in the core holder, pressured to 22 MPa of confining
354 pressure and heated to reservoir temperature of 30°C. Then, 3 pore volumes (PV) of
355 kerosene were pumped through the rock sample in one direction at a constant rate of 1
356 cm³/min to determine the absolute rock permeability. The samples were subsequently
357 cleaned in a Soxhlet extractor using methanol and toluene and following the procedure
358 described by AlRoudhan et al. [33].

359 The clean and dry samples were saturated with water in the vacuum chamber for
360 further 24 hrs to assure 100% water saturation. The samples were placed in the core
361 holder and drained with crude oil at a constant rate of 1 cm³/min, confining pressure of
362 22 MPa and temperature of 30°C. The injection of oil continued until no more water
363 was produced, thus reaching the irreducible water saturation. At the end of the
364 drainage experiment the effective end-point permeability to oil at irreducible water
365 saturation (K_1) was measured. After drainage Emulsion A was pumped in the opposite
366 direction at a flow rate of 1 cm³/min until no more oil was produced. Finally oil was
367 pumped again in the same direction as during the drainage until cessation of emulsion
368 production. At the end of this stage, the new effective permeability to oil (K_2) that
369 corresponds to the value post-acidizing was determined after. Note, that Emulsion A is
370 immiscible in water and there was no water production at any stage after the
371 completion of drainage. Therefore, the irreducible water saturation was assumed
372 constant throughout the emulsion and oil reinjection stages. The coefficient of
373 restoration of permeability, β , was evaluated as:

$$374 \beta = K_2 / K_1 \quad (4)$$

375

376 2.3.3 X-ray Compute Tomography

377

378 The development of modern porous rock imaging methods relies on the
379 acquisition of three-dimensional reconstructions from a series of two-dimensional
380 projections taken at different angles: the sample is rotated and the absorption of X-rays
381 in different directions is recorded and used to produce a three-dimensional (3D)
382 representation of the rock. We imaged rock samples at the resolution of 3.43 μm voxel
383 size, and image size of 8×10^9 voxels using X-ray micro-computer tomography XT H
384 225 (Nikon Metrology, Japan). Computer reconstruction of rock samples using the
385 produces 2D images was carried out using the Avizo Fire software package. The
386 software Avizo Fire was also used to calculate the pore volume and porosity of the
387 rock samples before and after acidizing following the methodology outlined in [34-
388 36].

389

390 2.3.4 Fields tests

391

392 Upon completion of all laboratory tests, Emulsion A has undergone field trials in
393 42 production wells in the Perm Krai fields and 12 production wells in Udmurtia
394 Republic. The geological and petrophysical features of the trial oil fields in which
395 industrial tests of Emulsion A were carried out are provided in Table 5.

396

397

398

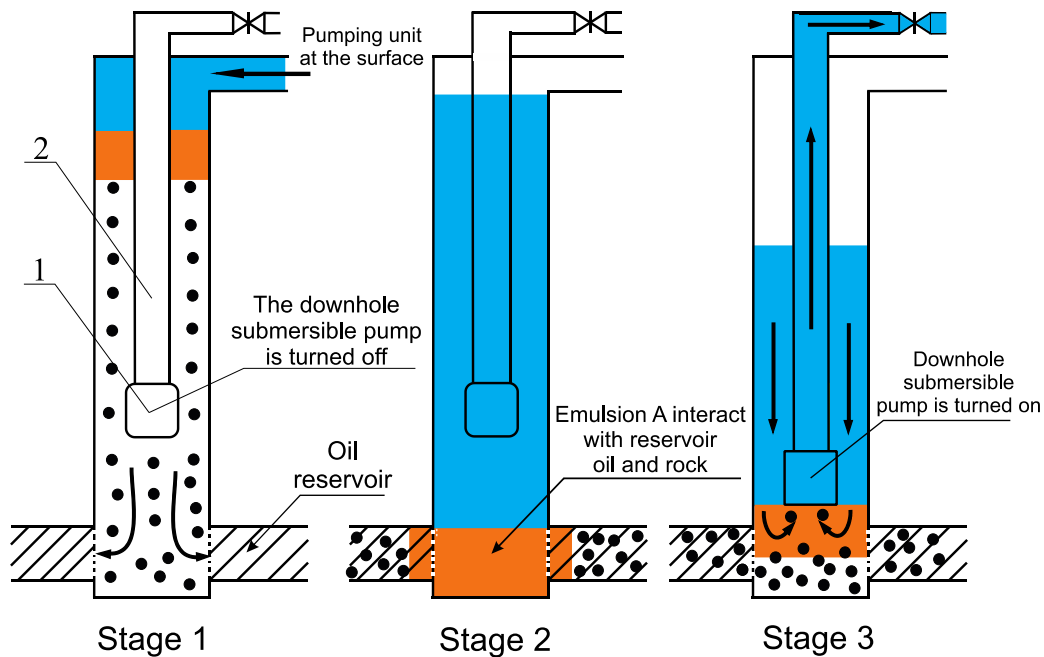
399

400 **Table 2**
 401 Geological descriptions of the oil fields Perm Krai and Udmurtia Republic. The ranges
 402 of the reported parameters correspond to variability across 2800 tested rock samples
 403 from Perm Krai and 1600 samples from Udmurtia Republic.

Parameter	Oil fields Perm Krai	Oil fields Udmurtia Republic
Top of the reservoir depth	2000 - 2264.8 m	1855 - 2487 m
Initial reservoir pressure, P_i	18.0 - 22.3 MPa	19.8 - 30.2 MPa
Formation temperature	27 - 33°C	30 - 45°C
Initial solution gas-oil ratio R_s (or GOR)	18 - 293.8 m ³ /m ³	50.5 - 184 m ³ /m ³
Bubble-point pressure, P_b	10.5 - 14.5 MPa	12.4 - 20.6 MPa
Reservoir oil viscosity	1.76 - 85.5 cp	35.8 - 112.8 cp
Initial oil formation volume factor, FVF	1.01 - 1.21	1.05 - 1.41
Reservoir thickness	3.2 - 26.7 m	1.8 - 18.4 m
Effective permeability	20 - 641 mD	5 - 411 mD
Average porosity	5.4 - 18.9 %	3.1 - 22.8 %

404
 405 Well acidizing operation using Emulsion A was carried out without well
 406 workover crew. Prepared Emulsion A is delivered to the wellhead in special containers
 407 and a pumping unit is used to pump the emulsion into the well with subsequent
 408 injection of formation water, which is used as a spacer fluid.

409 The emulsion injection standard operating procedure is shown schematically in
 410 Figure 2. The downhole submersible pump is turned off during injection of Emulsion
 411 A. A certain volume of emulsion, calculated based on the reservoir thickness, is
 412 pumped into the well using a pumping unit at the surface (Stage 1 in Fig.2). Emulsion
 413 A is pushed to the production interval by the injected water. The emulsion then
 414 penetrates into the reservoir and stays there for 8 hours to interact with reservoir oil
 415 and rock (Stage 2). When inside the reservoir, Emulsion A breaks into separate
 416 hydrocarbon and acidic phases so that the hydrocarbon phase cleans the formation
 417 from paraffin deposits, while the acid phase dissolves the rock. After 8 hours of this
 418 acidizing operation the downhole submersible pump is turned on to initiate production
 419 of water from the well (Stage 3). Once the pump produces the volume of water and
 420 emulsion equal to that of injected into the well, it starts producing formation fluids to
 421 the surface.



Legend:

- Reservoir fluid
- Emulsion A
- Water

- 1 Downhole submersible pump
- 2 Tubing

422

423

424 **Fig. 2.** Schematic representation of the standard operating procedure of injection of
 425 Emulsion A into the well. Stage 1 - injection of the Emulsion A into the well using a
 426 surface pumping unit. Stage 2 - displacement Emulsion A inside the formation. Stage
 427 3 - pumping out Emulsion A and water from a well using the downhole submersible
 428 pump.

428

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3. Results and discussion

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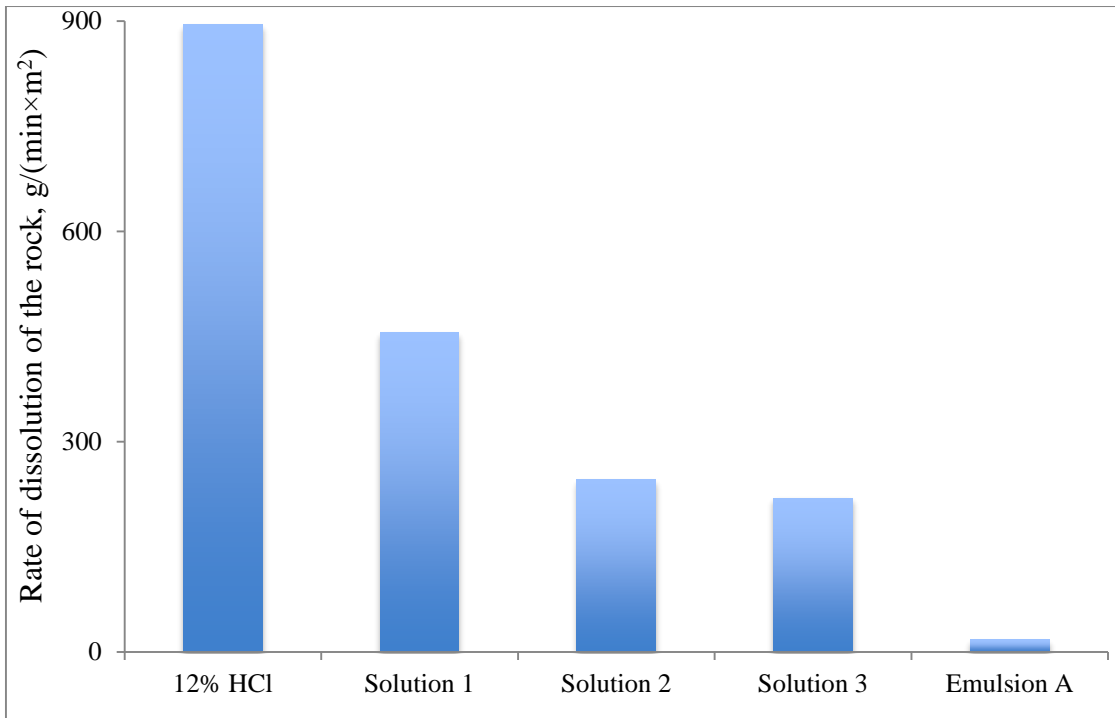
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The results of the laboratory tests (free volume, filtration and X-ray CT scanning) will be discussed prior to the analyses of the field test and the correlation between the two.

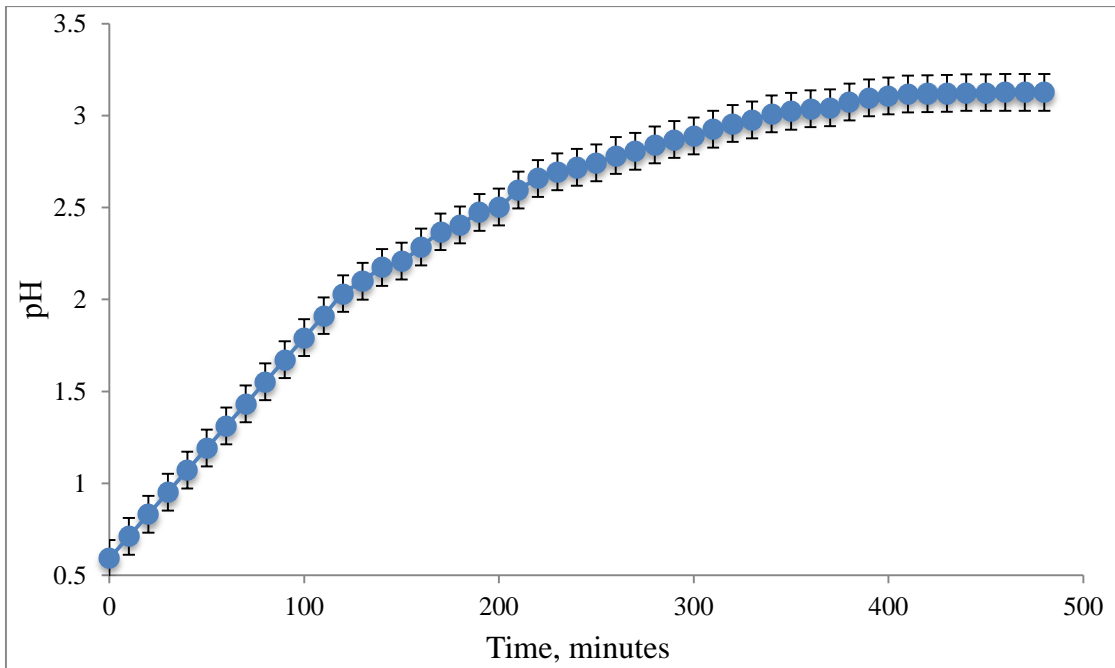
3.1 Analysis of the laboratory experiments

Figure 3 shows the results from rock dissolution tests. Rock dissolution rate of 17.37 [g/(min×m²)] was obtained with Emulsion A in comparison with an average rate of 894.37 [g/(min×m²)] obtained with 12% v/v HCl, which is routinely used in Russia [37,38]. Moreover, rock dissolution rate reported in [39,40] is greater by a factor of 2-3 relative to the rate obtained with Emulsion A. This suggests a slower reaction between Emulsion A and the reservoir rock thus providing evidence to a deeper penetration of Emulsion A into the reservoir. Results from dissolution tests carried out on carbonate rock samples using three other acidic solutions, also commonly used in Russia are shown in Figure 3 for comparison. Solution 1 Solution 2 and Solution 3, all of which are commonly used in Russia [37,38]. The composition of the three standard solutions 1, 2 and 3 used in Russia are: 11.5% HCl (Fluxocor-210), 10% HCl (NPS-K) and 8% HCl (KSPEO-2), respectively.



449
 450 **Figure 3.** Comparison of carbonate rock dissolution rates obtained with Emulsion A
 451 relative to other conventionally used solutions.
 452

453 Figure 4 shows the neutralization time of Emulsion A when in contact with
 454 rock samples. The figure shows that after approximately 7 hours of interaction
 455 between carbonate rock sample with Emulsion A, the pH readings stabilize at 3.12
 456 units. This suggests that Emulsion A actively interacts with the rock during the first 7
 457 hours, after which no further reaction between Emulsion A and the rock takes place.
 458 Based on this observation, the residence time of Emulsion A in the formation of 8
 459 hours was used in the field tests as described in Section 2.3.4.



460
 461 **Figure 4.** Temporal variation of pH of Emulsion A during interaction with rock
 462 samples. The error bars represent the accuracy and repeatability of the measurements.
 463

464 The neutralization time of approximately 6 hrs and stabilization of pH at 3
 465 shown in Fig.4 suggests that the developed Emulsion A has comparable or improved

466 neutralization time and similar or lower stabilized pH compared with previous studies,
467 where stabilization time varied between 5-10 hrs and pH between 2.5 and 5.5
468 [37,38,39]. Therefore, Emulsion A remains highly efficient in dissolving reservoir
469 rocks for a longer period of time thus improving the penetration depth for acidizing
470 action. Moreover, previous studies that reported long neutralization time and low pH
471 only investigated emulsions that were only capable of dissolving rock but were
472 ineffective in removing paraffin deposits [38]. In a different study [41], the
473 neutralization time was reported to be 2-3 hrs, while at the same time, the resulting
474 permeability to oil after acidizing was only 78-203.5 mD, which is much lower than
475 the permeability obtained with Emulsion A suggesting that rock dissolution efficiency
476 is significantly higher for the emulsion presented in this study.

477 Figure 5 shows visual changes in rock samples after 8 hours of interaction with
478 Emulsion A. After 8 hours of neutralization of Emulsion A, the mass of the rock
479 samples decreases by 50-55%, which is greater than the emulsions presented in the
480 works [38,42,43] where the reported weight change is 35-40%. Besides the measured
481 change in sample mass, its shape and permeability also change significantly as can be
482 seen from the figure and will be discussed in detail later.



483
484 **Figure 5.** The figure shows rock samples before (left) and after (right) 8 hours of
485 neutralization with Emulsion A.

486
487 Ability of Emulsion A to efficiently interact with reservoir fluids was also
488 studied in the laboratory. Figure 6 shows the results of stability tests carried out with
489 Emulsion A mixed with crude oil. The mixture was filtered through a 100-mesh sieve
490 and it was found that it completely passes through the sieve. No lumps remain on the
491 sieve as can be seen from the right sub-picture of Fig.6. Thus, if the mixture of crude
492 oil and Emulsion A is capable of passing through the 100-mesh screen without being
493 hindered or leaving residues, its viscosity is assumed to be similar to that of water. If
494 Emulsion A mixed with crude oil formed highly viscous stable emulsions, clots would
495 be deposited on the sieve. As a result, most of the mixture between Emulsion A and
496 crude oil would remain on the sieve, rather than seeping through it, as shown in Fig. 6.
497 This result suggests that Emulsion A is stable with crude oil and no deposits are
498 expected in the reservoir.

499 Previous studies [16,44] reported acidic solutions forming high viscosity
500 emulsions with crude oil. The viscosity of these emulsions was found to be in the
501 range 100-850 cP, so that when filtered through a 100-mesh sieve 50-80% of the
502 emulsion remained on the sieve. Such high values of emulsion viscosity would
503 inevitably result in decreased mobility of reservoir fluids and therefore in reduced well
504 efficiency [e.g. 45]. Therefore, Emulsion A performs significantly better than

505 previously used solutions with no significant increase in viscosity (Table 1) and no
 506 residues on the sieve after filtration.



507
 508 **Figure 6.** The results of filtration of Emulsion A mixed with crude oil through a 100-
 509 mesh sieve that corresponds to approximately 150 μm diameter pores. The left picture
 510 shows that the mixture of crude oil with Emulsion A retains properties of a single-
 511 phase fluid capable of flowing through 150 μm pores of the reservoir. The middle and
 512 right picture show no residues on the filter after flowing the mixture of Emulsion A
 513 and crude oil.

514
 515 Interactions between Emulsion A and reservoir fluids were further investigated
 516 via IFT measurements. The results of measured IFT between Emulsion A and
 517 reservoir oil are shown in Table 6. The use of Emulsion A results in significant
 518 reduction of IFT from 18 mN/m to less than 1.5 mN/m, which is lower compared with
 519 the values of 3 mN/m, 7 mN/m and 10 mN/m which were measured with the same
 520 crude oil and conventional Solutions 1, 2 and 3, respectively [37,38]. Therefore, the
 521 low interfacial tension between Emulsion A and crude oil allows the emulsion to
 522 penetrate into low-permeability (smaller pores and pore throats) oil-saturated layers by
 523 lowering the capillary entry pressure.

524
 525 **Table 6**
 526 The results of measured IFT between Emulsion A and reservoir oil. The initial
 527 (without Emulsion A) measurements were carried out on a kerosene-crude oil system.
 528 The value of IFT obtained with 12% HCl is taken from [38].

	Initial (without Emulsion A)	Final (with Emulsion A)	12% HCl
IFT, mN/m	18	1.5	15

529
 530 To make sure Emulsion A is also compatible with the well pumping equipment,
 531 corrosion tests were performed using steel 316 to evaluate how corrosive the emulsion
 532 is. The tests were carried out with steel billets made of the same grade steel as the one
 533 used for downhole pumps. The results of these tests indicate a low corrosiveness of
 534 Emulsion A to metal. The corrosion rate of steel in Emulsion A at 20°C is found to be
 535 0.08 g/(m²×hour), well below the rate required by GOST 9.502-82 for conventional
 536 acid compositions is 0.2 g/(m²×hour). This finding indicates that the developed
 537 Emulsion A will not have a negative effect on the downhole pumping equipment.

538 The results of the washing tests that investigate the capability of Emulsion A to
 539 wash (dissolve) paraffins are shown in Table 7. The coefficient of washing ability of
 540 the emulsion is found to be 42.6% in static tests while, the efficiency of 54.2% is
 541 obtained in dynamic tests. The obtained results of the washing ability of Emulsion A
 542 indicate that the coefficient of washing ability is approximately 20-30% higher
 543 compared with conventionally used emulsions [41,46,47]. Thus, Emulsion A allows a
 544 significantly better dissolution of paraffins while being significantly less corrosive to

545 the downhole pumping equipment and lower crude oil-Emulsion A IFT allowing the
 546 emulsion to penetrate smaller pores.

547

548 **Table 7**

549 Results of washing ability Emulsion A.

Interaction time, hrs	1	2	3	4	5	6	7	8
	Static test							
Coefficient of washing ability, %	6.7	11.8	16.4	24.1	29.7	33.8	38.1	42.6
	Dynamic test							
Coefficient of washing ability, %	9.7	15.2	20.1	29.4	35.7	40.1	46.8	54.2

550

551 Coreflooding experiments were conducted in order to evaluate the effect of
 552 acidizing rock samples saturated with crude oil and irreducible water. The results of
 553 the filtration experiments are presented in Table 8 (presents the main results covering a
 554 significant range of relative permeability from 0.56 to 453.7 mD), allowed to establish
 555 the following: the use of Emulsion A leads to an increase in the relative permeability
 556 of core samples to oil.

557

558 **Table 8**

559 The results of filtration test of the Emulsion A. The appearance of high permeability
 560 values (100s of D) provides an experimental evidence to formation of highly
 561 hydraulically conductive channels as a result of acidizing.

Rock sample (irreducible water saturation, S_{wirr})	Initial effective permeability to oil, mD	Effective permeability to oil after acidizing with Emulsion A, mD
1 (10.6)	0.56	8.74
2 (8.3)	1.1	79.20
3 (3.4)	1.39	217.95
4 (17.2)	2.74	437.58
5 (14.1)	2.89	593.61
6 (12.4)	2.97	993.47
7 (18.8)	6.5	581.10
8 (17.2)	8.51	132.76
9 (9.7)	11.2	3865.12
10 (14.2)	15.6	3110.64
11 (7.6)	18.79	3780.55
12 (20.4)	26.78	26844.27
13 (12.7)	27.65	23615.87
14 (22.5)	28.06	14063.67
15 (15.4)	31.58	11510.91
16 (17.6)	36.33	15298.56
17 (9.1)	42.61	45013.20
18 (16.4)	47.48	46744.06
19 (8.9)	54.9	6708.78
20 (14.6)	57.9	116442.69
21 (18.9)	64.5	36410.25

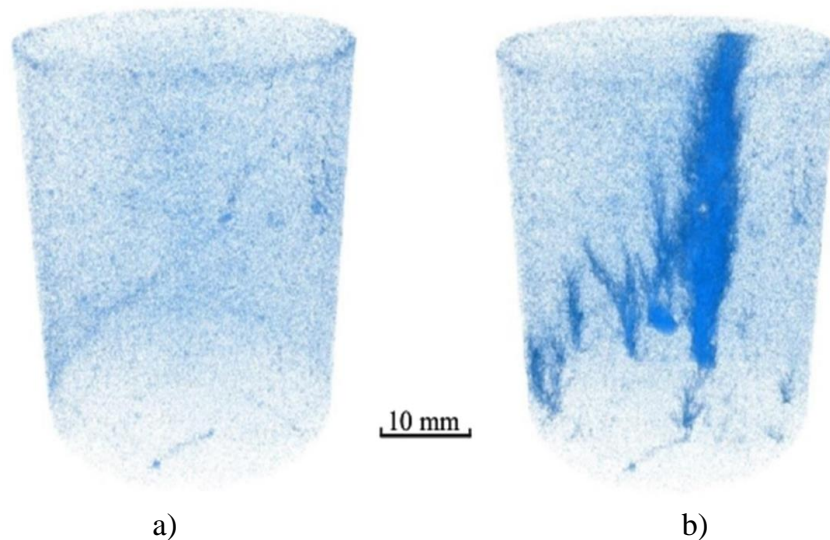
22 (21.7)	114.5	22957.25
23 (11.9)	128.49	40538.60
24 (24.1)	141.8	30118.32
25 (18.8)	181.2	664170.48
26 (24.3)	194.6	1543.10
27 (21.4)	201.5	197248.35
28 (18.6)	272.5	147722.25
29 (42.5)	336.79	332613.80
30 (37.1)	453.7	614672.76

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The increased permeability of reservoir rocks shown in Table 8 is comparable with results obtained with previously investigated acidic emulsions [37,38,39] which reported permeabilities between 155 mD and 864 D after the acidizing process. However, the reported high permeability values were achieved via a 2-stage injection, in which 15%-60% of paraffin deposits were first removed using surfactants, followed by injection of acidic emulsion to dissolve reservoir rocks. The achieved rock dissolution (final permeability) and paraffin deposits removal reported in [16,37,38] is comparable with the performance of Emulsion A. However, the implementation of this 2-stage process resulted in increased operational costs by \$70,000 - \$150,000 compared with a single-stage injection of Emulsion A.

In addition to filtration tests, X-ray computer tomography was carried out on selected rock samples and the results are presented in Figures 7 and 8. The images were taken before and after acidizing rock samples with Emulsion A, and Tables 9 and 10 show the corresponding changes in porosity of the rock samples after acidizing tests with Emulsion A.

Figure 7b shows that as a result of exposure to the Emulsion A, a highly conductive filtration channel, a "wormhole", is formed in the sample, which is clearly visible on the CT images of the rock sample. The permeability of the core sample shown in Fig.7 has increased from 114.5 mD to 22957.25 mD (increase in permeability by a factor of 200), while the porosity of the sample increased from 18.88% to 22.04% (Table 9).



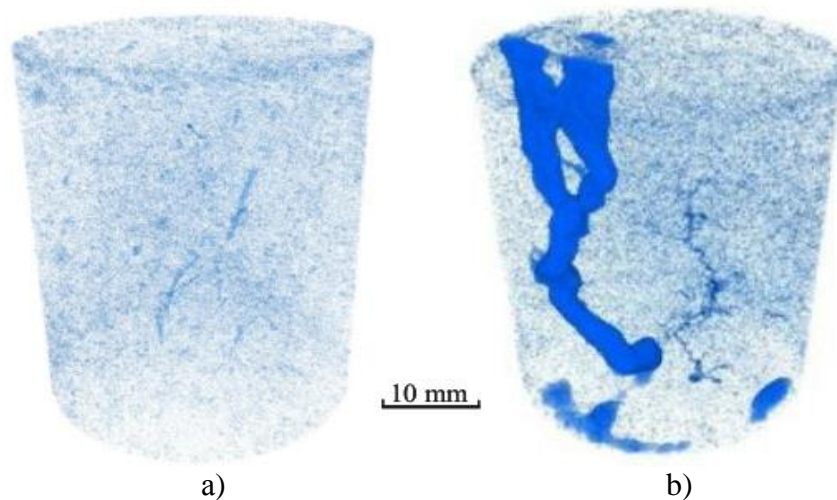
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Fig. 7. CT images of a rock sample with initial permeability of order of 100 mD: a) before exposure to Emulsion A; b) after exposure to Emulsion A.

592 **Table 9**
 593 The change in pore volume and porosity of the rock sample shown in Figure 7 after
 594 exposure to Emulsion A.

Pore volume in [mm ³] and porosity in %			
before acid exposure		after acid exposure	
2283.20 mm ³	18.88%	2652.71 mm ³	22.04%

595
 596 Analysis of the X-ray tomography data obtained with another rock sample with
 597 different initial permeability also confirms the formation of a highly hydraulically
 598 conductive channels as a result of the acidizing effect of Emulsion A on the rock
 599 sample (Fig. 8b). The permeability of the tested core sample increased from 201.5 mD
 600 to 197248.35 mD (increase in permeability by a factor of 978), while porosity
 601 increased from 11.76% to 17.34% (Table 10).



602
 603
 604 **Fig. 8.** CT images of a rock sample with initial permeability of order of 200 mD: a)
 605 before exposure to Emulsion A; b) after exposure to Emulsion A.

606
 607 **Table 10**
 608 The change in pore volume and porosity of the rock sample shown in Figure 8 after
 609 exposure to Emulsion A.

Pore volume in [mm ³] and porosity in [%]			
before acid exposure		after acid exposure	
1404.15 mm ³	11.76%	1842.17 mm ³	17.34 %

610
 611 From the X-ray CT images of selected rock samples we establish that after
 612 acidizing with Emulsion A, porosity of the rock samples increases on average by 20%
 613 relative to the initial value, and the pore volume increases by 18%. This result suggests
 614 that Emulsion A performs significantly better compared with conventional emulsions
 615 used worldwide, with which the average increase in porosity is in the range between
 616 10 to 15% [19,48-51].

617 **It is well established that carbonate rocks are chemically reactive with acids in**
 618 **general and with HCl solutions in particular. Previous studies [e.g. 52-55] showed**
 619 **significant dissolution of tested carbonate rock samples exposed to HCl solutions with**
 620 **increased porosity and permeability, similar to and consistent with the results of this**
 621 **study. Thin section analyses of our rock samples did not show any noticeable inclusion**
 622 **of organic matter (e.g. kerogen) in the samples, thus the majority of minerals exposed**
 623 **to Emulsion A are those listed in Table 4, with calcite and dolomite being prone to**
 624 **dissolution in acidic solutions [52]. Therefore, we are confident that the increased**
 625 **porosity and permeability of the samples after acidizing result from dissolution of**

626 carbonate material in acidic solution. The laboratory experiments with Emulsion A
 627 show that the emulsion:

- 628 • reacts with carbonate rocks with reduced rate, which implies that Emulsion
 629 A will be able to penetrate deeper into the reservoir when injected for acidizing;
- 630 • efficiently acidizes rock samples, thus resulting in significant increase of
 631 porosity and permeability, which is evident from the filtration tests and X-ray
 632 CT images showing formation of additional channels highly conductive for
 633 flow;
- 634 • has lower corrosive effect towards steel of the same grade as the downhole
 635 equipment, thus indicating better compatibility of Emulsion A with downhole
 636 pumping equipment;
- 637 • prevents formation of highly viscous stable emulsions when interacting
 638 with reservoir fluids **thus staying hydraulically mobile in the reservoir after**
 639 **injection**;
- 640 • is highly efficient in dissolving paraffin deposits **thus further improving**
 641 **reservoir properties**.

642 Based on a complex of the laboratory studies, recommendations were given for
 643 conducting industrial tests and the results of these tests are discussed below.

644

645 3.2 Results of fields implementation of Emulsion A

646

647 The results fields tests Emulsion A carried out on production wells in Perm Krai
 648 and Udmurtia are summarized in Tables 11 and 12, respectively.

649

650 **Table 11**

651 Results of field implementation of Emulsion A in oil fields of the Perm Krai.

Indicator	Emulsion A	Standard solution
The average initial actual increase in oil production, [tons/day]	4.3	3.9
Ultimate incremental oil recovery, [%OIIP]	1.68	1.0
Number of operations performed	42	50

652

653 **Table 12**

654 Results of field tests of the Emulsion A in the oil fields of the Udmurtia.

Indicator	Emulsion A	Standard solution
The initial actual increase in oil production, [tons/day]	3.8	3.5
Ultimate incremental oil recovery, [%OIIP]	1.34	0.87
Number of operations performed	12	20

655

656 The results shown in Tables 11 and 12 indicate that Emulsion A leads to
 657 improved well productivity, which ultimately results in higher final oil recovery form
 658 acidized well compared with wells acidized with conventional solutions. The benefit
 659 of using the emulsion lies in its ability to dissolve carbonate rocks via acidizing with
 660 HCl, and at the same time via dissolving the paraffin deposits thus increasing rock
 661 permeability and improving reservoir's sweep efficiency. Moreover, the initial
 662 increase in oil recovery obtained after acidizing with Emulsion A suggests that the

663 emulsion also provides better and faster return on investment thus making the use of
664 Emulsion A more economically viable. In addition, the developed and tested in this
665 study Emulsion A requires fewer operations during its field implementation thus
666 significantly reducing the operation costs.

667

668

669 4. Conclusions

670

671 In this paper we report laboratory experiments and field tests of a new acidic
672 emulsion of hydrochloric acid in a continuous hydrocarbon phase. This emulsion,
673 termed Emulsion A allows the aggressive hydrochloric acid to be enclosed in a neutral
674 hydrocarbon shell, which significantly reduces the corrosive effect. Moreover,
675 Emulsion A does not easily dissolve in water thus increasing the viscosity of high
676 salinity formation water. On the other hand, upon contact with liquid hydrocarbons,
677 the emulsion becomes unstable and decomposes into hydrocarbon and the acid phases,
678 so that the former phase efficiently dissolved paraffin deposits in the formation while
679 the acidic phase reacts with carbonate reservoir rocks which results in increased
680 permeability and porosity of the reservoir.

681 The laboratory experiments and field tests have shown that Emulsion A has
682 several advantages in comparison with acidic compositions that are routinely used in
683 Russia and worldwide.

684

- 685 • The developed Emulsion A has low IFT at the interface with crude oil, which
686 allows the emulsion to penetrate into low-permeability (smaller pores and pore
throats) oil-saturated layers by lowering the capillary entry pressure;

- 687 • The acidic component of Emulsion A causes corrosion of steel at a lower rate
688 compared with conventional solutions, which allows to implement the
emulsion for acidizing in a single operation thus reducing the operational costs;

- 689 • Emulsion A breaks into acidic and hydrocarbon phases upon contact with
690 reservoir oil, which delays the acidizing of reservoir rock thus increasing the
691 penetration depth towards more remote areas of the formation;

- 692 • Emulsion A improves the acidizing coverage of the formation by flattening the
693 acidizing front and increasing its penetration depth;

- 694 • Implementation of Emulsion A increases well productivity through both, the
695 dissolution of the carbonate rock by the acidic component of the emulsion, and
696 by dissolution of paraffin deposits that clog the pore space of the rock.

697 **Wettability alteration during injection of Emulsion A could also be responsible**
698 **for improved oil recovery. However, to confirm or refute this hypothesis the**
699 **wetting state of the intact samples used in this study could not be determined as**
700 **the methods for such analyses (e.g. Amott Wettability Index) are based on the**
701 **assumption that petrophysical properties of rock (porosity and absolute**
702 **permeability) remain constant during the spontaneous and forced imbibition**
703 **stages of the experiment, whereas these properties did significantly change**
704 **during acidizing process reported in this paper.**

- 705 • **Emulsion A combines two main actions in a single fluid – it is highly efficient**
706 **i) in dissolving rocks and ii) in removing paraffin deposits. At the same time,**
707 **the developed emulsion maintains relatively low viscosity thus making it**
708 **mobile in the reservoir, it is not strongly corrosive towards well equipment,**
709 **and it has a prolonged activity of the acidic component thus improving the**
710 **depth of its penetration into reservoirs. These properties of Emulsion A make it**
711 **a significant improvement and advancement of the currently available**
712 **technologies. The developed novel emulsion also advances the scientific**
713

714 research in the area and allows the acidizing to be carried out in a single-stage
715 operation thus significantly reducing operational costs.

716 The abovementioned advantages of Emulsion A combined with its cost
717 comparable with that of conventional solutions makes the use of Emulsion A also
718 economically preferable.

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CRedit authorship contribution statement

Dmitriy A. Martyushev: conceptualization, data curation, methodology development, processing and analysis of results, writing the original draft. **Jan Vinogradov:** discussion and analysis of results, data curation, writing, revision and editing of the manuscript.

Declaration of interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: