It is a matter of general experience that gravitational effects arising during injection of air or steam most often affect adversely the efficiency of thermal EOR methods. Advantages of these methods are generally used where possibility exists of engineering a horizontal displacement.

The present paper centres on certain technological approaches to the use of gravitational effects for improved efficiency of thermal EOR methods.

One of the technologies - a cyclic injection of steam into high-viscosity oil reservoir with bottom water - was applied in 1974 in Yuzhno-Karskiy area of Zybza - Gluboky Yar oil field (trap III), the Krasnodar Territory (Figure 1). Miocene reservoir of the area is defined as a water-supported monocline (Figure 2). Miocene deposits are represented by accumulation of breccia, detritus and terrigenous rocks. Reservoir capacity is made up by voids between the rock debris with up to 30% of the capacity being characterised by extremely high permeability (up to 640 Darcy).

The main geological and physical parameters of the reservoir are as follows:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth of occurrence, m</td>
<td>200-300</td>
</tr>
<tr>
<td>Area, ha</td>
<td>50.3</td>
</tr>
<tr>
<td>Reservoir thickness, m</td>
<td></td>
</tr>
<tr>
<td>average</td>
<td>38</td>
</tr>
<tr>
<td>at the central part</td>
<td>123</td>
</tr>
<tr>
<td>Permeability, Darcy</td>
<td>10-640</td>
</tr>
<tr>
<td>Oil density, t/m³</td>
<td>0.957</td>
</tr>
<tr>
<td>Oil viscosity, mPa-s</td>
<td></td>
</tr>
<tr>
<td>under reservoir conditions (18°C)</td>
<td>4000</td>
</tr>
<tr>
<td>at 50°C</td>
<td>350</td>
</tr>
<tr>
<td>at 100°C</td>
<td>12</td>
</tr>
<tr>
<td>Well spacing density, ha/well</td>
<td>2.5</td>
</tr>
<tr>
<td>Initial oil production rate, t/d</td>
<td>1-30</td>
</tr>
</tbody>
</table>

Within 18 years of reservoir development with depletion drive (since 1956) produced are about 600 Mt of oil, oil recovery reached 21%. Water cut reached 77% due to water encroachment mainly through the reservoir bottom. As a result, the reservoir had transformed into a floating one.

Starting from the second half of year 1974, the reservoir is under development by steam stimulation. In view of a wide water-oil zone existed and abnormally high permeability of the reservoir it was decided to inject steam intermittently into a lowered part of the reservoir to displace oil from a porous reservoir of water-oil zone to the zone of production and to form heat slugs at the oil-water surface of upper reservoir areas.

It was conceived that due to a high rate of the injected steam coming to the water-oil surface a heat slug had to be formed in the upper reservoir areas, heat energy of the slug being consumed for oil heating and oil viscosity breaking.

Penetration of heat slug into oil zone and flow of heated oil to producing wells were provided by bottom-water drive. The process is presented schematically in Figure 3.

In most cases used for injection of steam were wells 205, 424, 431, 433, 428, 628, 789 and 796 where 40 cyclic injections of steam were performed. In an effort to control the process methodical records were made of steam injection characteristics, steam flow rate, production rates of producers and also water cut, wellhead temperature and chemical composition of their produce.
<table>
<thead>
<tr>
<th>Cycle</th>
<th>Injection period</th>
<th>Injection time, months</th>
<th>Volume injected per cycle, Mt</th>
<th>Response by producers</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>well 60</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Temperature response, °C</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Time since the start of inj., months</td>
</tr>
<tr>
<td>1</td>
<td>10.12.74-25.02.75</td>
<td>2.5</td>
<td>16.3</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>04.11.75-10.03.76</td>
<td>4</td>
<td>24.5</td>
<td>1</td>
</tr>
<tr>
<td>3</td>
<td>25.11.78-30.01.79</td>
<td>2</td>
<td>8.4</td>
<td>2</td>
</tr>
</tbody>
</table>

Analysis of the available data indicates that increase of well-head temperature and daily production rates as a result of steam injection were observed in the said wells (Figures 4 and 5, Table 1).
First cycle of injection of 16.3 Mt of steam in well 796 was performed in a period from 10.12.74 to 25.02.75. Temperature of the liquid produced in well 60 increased as early as January, 1975 from 18°C (initial reservoir temperature) to 47°C with the result that oil production rate in December, 1975 increased from 19 t/d to 33 t/d and peak value of 42 t/d was recorded in June, 1975. Then gradual decline in wellhead temperature and oil production rate down to 24 t/d followed. Water cut varied from 40 to 60%.

Within 3 months after termination of steam injection in well 796 increase of well-head temperature was observed on well 806; the temperature peaked at 24°C and then dropped to 15°C in November, 1975. It should be mentioned that oil production rate declined sharply prior to arrival of heat effect to the well but since February, 1975 (termination of steam injection) the rate of decline slowed down markedly and then oil production rate increased up to 22 t/d. Water cut increased from 67 to 80% and remained constant till the second cycle of steam injection with increase of fluid production from 101 to 127 t/d. Within 5 months after termination of steam injection in well 796 increase of temperature from 18 to 24°C took place in producing well 851 and oil production rate started to grow slowly from 3 t/d to 22 t/d and then its decline followed. It is necessary to stress that such a high growth in oil production was registered in the second cycle as well, which fact is to be discussed later.

Between 04.11.75 and 10.03.76 the second cycle of steam stimulation was conducted in well 796 with injection volume of 24.5 Mt of steam. As early as within a month after the start of steam injection the temperature of the liquid produced in well 60 increased up to 40°C (as of January, 1975) and then began to lower gradually down to 23°C. Within three months of steam injection commencement oil production rate increased from 24.5 to 36 t/d and then its continuous decline followed over a period of 2.5 years down to a value of 16 t/d.

It should be emphasized that such a high oil production rate in well 60 was maintained not only through injection of steam into well 796, but also due to injection of 47.8 Mt of steam into well 789 during the same period.

Temperature response of well 806 to the second cycle of injection into well 796 was observed in January, 1976 (i.e. after 3 months), the temperature increased from 20 to 30°C (04.76) and then varied within a range of 23-28°C and only by the end of year 1978 it lowered to 22°C. Increase of oil production rate from 15 t/d to 24.5 t/d (07.76) was registered after 5 months (since the beginning of cycle II) following which the oil production rate varied in the range of 18-20 t/d and stabilized at the level of 14 t/d since July, 1977.

Increase of temperature in producer 851 started in 3-5 months (over a span of 2-3 months temperature was not registered after 5 months (since the beginning of cycle II), following which the oil production rate varied in the range of 18-20 t/d and stabilized at the level of 14 t/d for a period of 2.5 years down to a value of 16 t/d.

The third cycle of steam injection on well 796 was performed in the period of 25.11.78 to 30.01.79. Volume of injection made 8.4 Mt. Within 5-6 days after start of the injection the temperature of liquid produced from well 60 increased from 23 to 29°C, and then elevated gradually and reached 48°C by 29.01.79. Oil production rate increased in December, 1978 from 16 t/d to 21.8 t/d, water cut reduced from 78 to 72% with constant liquid production of 75-80 t/d. In January, 1979 oil production rate began to decline dramatically and as early as February the well was completely drowned.

Injection of steam in well 796 was terminated on 30.01.79. In 37 days well 60 was returned to production. Oil production rate restored to 17 t/d, water cut reduced from 80 to 75% and liquid production declined from 80 to 70 t/d (Figure 4).

Just in a month, i.e. on 25.12.78, increase of temperature from 22 to 25°C was registered in well 806 and on 01.03.79 it peaked at 40°C.

In December, 1978 oil production rate was 19 t/d, water cut reduced from 80 to 73% and as early as January and later on through October, 1979 oil production rate varied between 13 to 15 t/d and liquid production rate ranged from 75 to 90 t/d with water cut of 80-85%.

So, injection of steam into well 796 provided stabilization of oil production in well 806 at the level of year 1978.

In about 35-37 days, i.e. since 2.01.79, the temperature in well 851 started to increase from 22°C up to 30°C in March, 1979 (Figure 5). Since the response oil production rate increased from 14 to 16 t/d in 01-02.79 and then declined to 12-13 t/d.

Results of electrical analog simulation of the process for heat-carrier injection in various zones of the reservoir revealed [2] that filtration from injection wells is deformed in the direction of reservoir roof. This is determined by strong influence of filtration from the external reservoir boundary. This property of filtration during steam injection in well 796 is presented as an illustration in Figure 6.

In the course of electrical analog simulation it was also found that termination of heat-carrier injection causes no interruption to the process of thermal stimulation. Heat front continues its advance toward the reservoir periphery due to active water drive and by this means oil displacement continues due to thermal expansion and capillary soak.

The study made it apparent that in the development of oil fields with active water drive advance of a heat slug through the reservoir upon termination of heat-carrier injection can be realized through controlled liquid production from producing wells.

By way of illustration Figure 7 shows producing history for wells 60, 788, 806, 847, 848 and 851 which makes it obvious that adoption of steam stimulation process contributed to greatly enhanced oil production and improved oil recovery.

Introduction of steam stimulation upon the whole reservoir since 1974 made it possible to more than double the oil recovery and bring it up to a rather high value of 48.9% as of 01.01.94. For similar-in-structure Zybza area of Zybza - Gluboky Yar oil field where steam stimulation was realized on a minor scale and process of development was going on mainly by depletion drive, oil recovery ratio reached only 25.2%. Figure 8 shows that annual production resulted from steam stimulation declined much slower in Yuzhno-Kariskyi area than in Zybza area. All that is an unambiguous evidence of steam stimulation efficiency with the existence of bottom water.

Over the whole period of development prior to termination of steam stimulation process the reservoir produced 1377.8 Mt of oil and 6414.9 Mm³ of water. Injected into the reservoir were 1160.7 Mt of steam, additionally produced were 448.6 Mt of oil. Oil recovery and degree of depletion made 48.9 and 92.8 % respectively. Cumulative steam-oil ratio was 0.85 t/t (estimated for the total production) and 2.6 t/t (estimated for additional oil production) and represented high efficiency of the process.

At the expense of thermal energy previously delivered into the reservoir and realization of recommended geological and technical measures oil production from the reservoir during 1995-1996 stabilized at the level of 13.5 Mt with 16 wells in operation.

As of 01.01.97 the reservoir produced 1413 Mt of oil, 462.6 Mt of additional oil included, with average cumulative steam-oil ratio of 2.5 t/t. Current oil recovery made 50.2%, degree of oil reserves depletion was 95.2%.

Another method to improve process for steam stimulation of reservoir and its bottom-hole zone is to use a steam-gas mixture as a heat-carrier; the mixture is generated by a steam-gas generating unit of special design by TERMNEFT Research & Production Association. Heat-carrier generated by this unit comprises 60-70% of steam by weight while fuel gas is composed of nitrogen and carbon dioxide for the most part. Existence of free gas in the steam makes the steam condensation point lower and it follows that with the same heat energy consumption the reservoir area under thermal stimulation can be enlarged significantly (by 15-30%) as compared to injection of steam alone.

It is of particular importance for relatively deep reservoirs when high reservoir pressure predetermines high level of saturated steam temperature (above 200°C) which is unnecessary for efficient displacement of high-viscosity oil but impairs the efficiency of reservoir steam stimulation.

As for the carbon dioxide present in fuel gas, it diffuses into oil, dilutes it and expands its volume resulting eventually in additional oil recovery. But it is nitrogen of fuel gas which is of primary importance in oil recovery improvement by steam-gas injection. Being persistently in a free gaseous phase for the most part, nitrogen moves upwards to the reservoir roof accompanied by ahead steam override towards the reservoir roof. This results, firstly, in improved oil recovery from near-roof reservoir area which is known to be depleted inadequately by conventional technologies. It is obvious that the importance of this mechanism grows with the increase of reservoir thickness in case of using steam-gas mixture instead of steam. Secondly, hot water produced by steam condensation in the near-roof reservoir area moves downwards to the reservoir bottom due to gravitational effects. The process is shown schematically in Figure 9. Ultimately all the above mentioned mechanisms of gravitational effects accelerate the process of reservoir thermal stimulation with steam-gas mixture instead of steam, extend reservoir sweep by thermal stimulation, enhance oil production and improve oil recovery of the reservoir.

Finally, in case of thermal stimulation of bottom-hole zone at the production stage free gas accumulated in peripheral area of the stimulated portion of the reservoir improves the process of oil displacement toward a well due to accumulated elastic energy.
Activities on application of cyclic steam-gas stimulations of well bottom-hole zones in high-viscosity oil fields of the Krasnodar Territory started in 1988. Since that time 25 wells have been stimulated under different conditions.

Given below are major results of field tests on steam-gas application in two areas of Zybza - Glubokoy Yar high-viscosity oil field:

1) Yuzhno-Zybenskiy area - Pontian deposits, initial stage of development [3, 4];
2) Yuzhno-Karskiy area - Miocene deposits (II trap), development completed in 1982 [4, 5].

All cyclic stimulations of reservoir bottom-hole zones were performed by technological process [6] comprising three basic stages: injection of heat-carrier into the reservoir, well soaking and well operation with resulting formation of two zones by convention in the bottom-hole zone of oil-saturated reservoir in case of using steam-gas - central zone containing predominantly liquid phase of a heat-carrier and peripheral zone containing gaseous phase of a heat-carrier. Formation of the like zones provides for additional effect of oil viscosity breaking due to carbon dioxide dissolving in the oil at the stage of soaking and rational utilization of elastic energy of noncondensable gas (nitrogen predominantly) at the stage of well operation.

Producing formation of Pontian deposits is represented by alternation of sands, siltstones and clays with average geological and physical parameters as follows:

- Depth of occurrence, m: 24-350
- Reservoir thickness, m: 3-5
- Permeability, mcm²: 1.2-4.8
- Porosity, unit fractions: 0.31-0.4
- Oil density, g/cm³: 700-3500
- Oil viscosity, mPa·s at 18°C: 700-3500
- Water cut, %: 98

Table 2 presents major technological results of well steam stimulations in the pilot areas and Figure 10 by way of example shows well 27 response to the stimulation.

Table 2

<table>
<thead>
<tr>
<th>Characteristics of the process</th>
<th>Type of deposits</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pontian</td>
</tr>
<tr>
<td>Total amount of heat-carrier injected, t</td>
<td>9746.2</td>
</tr>
<tr>
<td>Total amount of additional oil produced by the method, t</td>
<td>4412</td>
</tr>
<tr>
<td>Total amount of water consumed for generation of heat-carrier, t</td>
<td>5838.0</td>
</tr>
<tr>
<td>Total amount of diesel fuel (compressor + generator) consumed for generation of heat-carrier, t</td>
<td>378.15</td>
</tr>
<tr>
<td>Total steam-gas/oil ratio, t/t</td>
<td>2.21</td>
</tr>
<tr>
<td>Total steam-gas injection in two areas, t</td>
<td>12097.7</td>
</tr>
<tr>
<td>Total production of additional oil, t</td>
<td>5763</td>
</tr>
<tr>
<td>Average steam-gas/oil ratio, t/t</td>
<td>2.1</td>
</tr>
</tbody>
</table>

Generalization and analysis of technological results for pilot operations testify to the following:

1. Use of steam-gas for thermal stimulation of wells involves lower consumption of heat energy to produce oil as compared to steam injection. Thus, in pilot areas steam-gas/oil ratio made 2.1 t/t while for steam injection in the same oil field it was 5.7 t/t.
2. Use of steam-gas mixture was followed by multiple increase of oil production rate in the stimulated wells.
3. It is advisable to conduct steam-gas stimulations in groups of wells located in a separate areas because it provides more efficient utilization of both heat energy and elastic energy of gaseous components of a heat-carrier. By and large specific heat-carrier consumption per a metre of oil-saturated thickness was not above 30 t for group stimulations and reached as high as 70 t for individual stimulations.
4. Cyclic steam-gas stimulations of reservoir bottom-hole zones containing high-viscosity oil are applicable for oil fields at both early and advanced stages of their development.
5. Technical support of the technological process requires no additional capital construction and oil field construction and eliminates the necessity of chemical water treatment for heat-carrier generation.
Gravitational effects were used to improve the efficiency of the project on testing a method for air injection in Gnedzntzy light oil field (reservoir II) [7, 8]. This reservoir is a sheet and roof one with good reservoir properties (see Table 3). By the commencement of pilot operations the reservoir development by active natural elastic water drive was essentially completed. At the initial stage of the reservoir development the wells were flowing with production rates of 200-500 t/d and at the final stage they were operated by artificial lift. The oil recovery attained by the commencement of pilot operations was estimated as 60%. The oil was produced mainly from the roof area of the reservoir with water cut of the order of 96-97%. The purpose of the pilot operations was to assess the potentialities of carrying out the in-situ combustion process after waterflooding and technological efficiency of the process.

Table 3

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth of occurrence, m</td>
<td>1750-1800</td>
</tr>
<tr>
<td>Oil-saturated thickness of reservoir, m</td>
<td>4-15</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>19.7</td>
</tr>
<tr>
<td>Permeability, mcm²</td>
<td>0.19</td>
</tr>
<tr>
<td>Oil saturation, %</td>
<td></td>
</tr>
<tr>
<td>initial</td>
<td>70</td>
</tr>
<tr>
<td>current</td>
<td>29</td>
</tr>
<tr>
<td>Reservoir temperature, ºC</td>
<td>48</td>
</tr>
<tr>
<td>Oil viscosity under reservoir conditions, mPa·s</td>
<td>1.6</td>
</tr>
</tbody>
</table>

In the planning of a system for the stimulation assumptions were as follows:
- high probability of active manifestation of gravitational forces predetermining primary advance of the injected air and combustion gases towards roof area of the reservoir;
- existence of active elastic water drive;
- significant production of liquid from roof reservoir area causing intensive flow of edge water towards roof;
- location of well 170 in marginal reservoir area where substantial amounts of edge water pass through.

Under these conditions the planned wet combustion was performed with water-air ratio of the order of 0.016-0.018 m³/m³ and peak temperature at steam plato of about 200-300ºC.

Figure 11 shows area of response to the process including wells with the change in composition of combustion gases, oil properties, productivity, water cut, temperature and pressure. At the same time an area was determined by convention at the beginning of operations to estimate additional oil and so-called “technological” effect (i.e. response to the technology applied) with the inclusion of only those wells where breakthrough of combustion gases took place.

Injected into the reservoir during 1980 to 1994 were about 300 MMm³ of air. The typical rate of air injection was 50-60 Mm³/d and the maximum one made 100-110 Mm³/d. In 1980-1983 a single well 170 was under injection and from 1983 to 1987 - two wells (170 and 124). In 1987 injection of air in well 172 located beyond the oil-water contact started and at the present time the process is performed with the rate of 28 Mm³/d.

Advance of fluids towards the roof reservoir area resulted in gas cap formation. The gas cap formation was in progress up till 1985, when amounts of air injected and combustion gases produced were balanced.

Analysis of physical and chemical parameters of the produced fluids indicated increase in viscosity and density of oil produced in the zone of response. It is explained by conversion of a part of light fractions of oil into combustion gases which fact is supported by 2-3 fold increase of light fractions content in the produced gases (Figure 12).

Figure 13 presents oil production performance and dynamics of air injection for the zone of response. Additional oil production totals 215 Mt of oil.

Comprehensive analysis of all practical data revealed that major portion of additional oil was produced due to existence of mechanism of gas stimulation. Thus, according to the estimates by UKRGPONHINEFT Institute about 79 Mt (87%) out of 91 Mt of oil by “technological” effect were produced by gas stimulation. The highest technological efficiency of the process was registered in 1983-1984, then it was declining up till 1989. A certain increase in the production was recorded in 1989 in connection with the approach of heat front to well 61 located 400 m away from the injector. This was evidenced by elevation of temperature at the well bottom-hole up to 55-60ºC.
Nonetheless, it should be emphasized that oil production in the area was three times higher than the base one in the recent years as well.

It follows from Figure 13 that oil production growth in the area started within about two years after air injection. Cumulative value of air-oil ratio is 2910 nm³/t.

Oil recovery increment is estimated as high as 6%. Finally, it should be mentioned that oxygen content in the produce was insignificant during pilot operations. Infrequent raises of the content up to a few percents are related to high rates of air injection. This points to the fact that even at a moderately high reservoir temperature (48°C) the process of air injection can be engineered with the observance of reliable conditions for safe operations.

Gravitational effects are projected to be used in realization of air injection method in light oil fields with elevated reservoir temperature (above 65-70°C). At such a temperature the air injected into the reservoir enters into active oxidizing reactions with oil resulting in formation of nitrogen and carbon dioxide in the main. This gas in its turn is getting enriched with light fractions of oil as a result of multicontact process while advancing through the reservoir. Eventually the injected air transforms into highly efficient gaseous agent providing partial or complete miscible displacement of oil. Such concept of a mechanism for in-situ processes during air injection in light oil fields is supported by a large body of laboratory and field data. There are plans to apply the method in an oil field of the Krasnodar Territory by way of developing artificial gas cap from transformed gaseous agent and engineering gravitational (vertical) displacement of oil. The distinctive feature of the process will be engineering of gas cap by injection of air not into upper portions of the reservoir but into lower ones down to and including edge portions. It is generally recommended to develop a gas cap by injection of gas or oxidizing agent into upper part of the reservoir with subsequent migration of displacement front from the top down. During the process of displacement a heat zone takes its form due to in-situ oxidizing processes. Thereby conditions are improved for conversion of light components of oil into gaseous phase and their transfer to unheated reservoir zone where formation of solvent slug starts upon condensation.

And yet natural potential is used only in part for enrichment of gas cap with light components of oil during its formation or restoration and as a consequence generation of a slug of solvent or enriched gas (due to gravity segregation) at the gas-oil surface. That is why mechanism of miscible displacement ahead of heat zone is ruled out at the stage of formation and advancement of heat bank. Moreover, formation of a gas cap by injection of air into upper reservoir area is related to creation of combustion front and its movement down the dip. This imposes rather stringent requirements as to the rate of air injection. With light oils air injection later should be sufficiently high resulting from necessity of installing compressor with boost injection pressure and flow rate. In case of low reservoir permeability realization of the process may turn problematic.

Advantages and features of this method are as follows:
1. Gas cap formation is provided by spontaneous in-situ oxidizing processes converting air into combustion gases in lower portions of the reservoir with their gravity override into the upper portions. There is no need in formation of a combustion front under these conditions because transformation of air into combustion gases occurs mostly due to low-temperature oxidation processes. Consequently, there are no special requirements to the rates of air injection and characteristics of compressor equipment.
2. Accelerated formation of enriched gas slug within gas cap is effected since combustion gases accumulate the greatest possible (according to reservoir thermodynamics) amount of light hydrocarbons while advancing towards upper reservoir areas.
3. With the injection of air into marginal or edge reservoir areas transformation of air into combustion gases occurs for the most part due to oxidation of unrecoverable oil dissipated in these portions of the reservoir. Thereby the amount of oil produced from the main portions of the reservoir is increased (by about 5-10%).
4. Existence of a wide zone of oxidizing reactions ensures reliable conditions for safe operations.
5. Injection of air into marginal and edge reservoir areas makes it possible to use exploratory or other wells located within these zones with adequate economic efficiency through the dropped out drilling of special injecting wells.

Thus, the main feature of this method lies in the fact that the governing factor of the process in terms of oil recovery enhancement is not thermal stimulation but formation of efficient displacement gaseous agent directly in the reservoir. Great importance of thermal stimulation and in-situ oxidizing processes specifically is that they transform air into combustion gases which are enriched with light fractions while advancing through the reservoir.
Conclusions

1. There are certain favourable geologic conditions which made feasible resource-saving technological processes using gravitational effects for improved reservoir thermal stimulation. Among these are:
   - high permeability of productive reservoirs;
   - massive character of a reservoir, great thickness of productive reservoirs, steep dipping of reservoirs;
   - existence of active water drive area.
2. Feasibility of formation and advancement of steam slugs due to edge-water drive (with no injection of water from the surface) is validated under field conditions. The major effect is enhanced recovery of oil from the upper reservoir areas inadequately depleted by conventional technologies.
3. Realized are wet and super-wet combustions (with no injection of water into the reservoir as well) by way of engineering advancement of the injected air and edge waters towards roof reservoir areas.
4. Use of steam-gas mixture as alternative to steam results in improved depletion of the upper areas of productive reservoirs and their deeper heating.
5. With injection of air in light oil fields (massive or steep dipping ones) with elevated reservoir temperature (above 65-70°C) it seems advisable to inject air into marginal or edge reservoir areas. In such a case:
   a) accelerated formation of enriched gas slug within gas cap is effected as combustion gases accumulate the greatest possible amount of light hydrocarbons while advancing towards the upper reservoir areas;
   b) reliable conditions are provided for safe operations due to existence of a wide zone of oxidizing reactions.

REFERENCES

Figure 1. Cumulative production chart for Yuzhno-Karskiy area of Zyba-Glubokly Yar oil field.

Figure 2. Geologic profile section of Miocene reservoir between wells 934 - 701 in Yuzhno-Karskiy area of Zyba - Glubokly Yar oil field.
Figure 3. Scheme of using heat slugs in the reservoir with active bottom water.

1 oil-saturated portion
2 water-encroached portion
3 heat slug
Figure 4. Production rates of wells 60, 806, 851 as a response to steam injection in well 796.

Figure 5. Dynamics of wellhead temperatures in wells 60, 806 and 851 vs steam injection in well 796.
Figure 6: Pattern of filtration distribution during injection of steam in well 796.
**Figure 7. Well operation diagrams.**
Figure 8. Diagrams of annual oil production in Zybza and Yuzhno-Karskiy areas.
Figure 9. Reservoir steam stimulation concept.
Prior to steam-gas stimulation

After steam-gas stimulation

Figure 10. Diagram of well 27 operation prior to and after 1 cycle of steam-gas stimulation.
Figure 11. Plan of pilot area in Gnedynty oil field.
Figure 12. Variation in concentration of gases in Gnedyntzy oil field.

Figure 13. Dynamics of oil production and air injection in Gnedyntzy oil field.