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Analytical study on the optimum design of producing well to increase oil production at severe cold regions

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Abstract−This paper presents a simulation study of fluid flow in the tubing on a reservoir system formed in a severe cold region. The thickness of the permafrost and specific gravity of the oil were applied by field survey. Then, flowing improvement techniques for oil production such as progressive cavity pump (PCP), insulated casing, electric trace heater and gas lifting were applied. For the reservoir located at 1,000 m depth in the Arctic region, the thicker the permafrost layer was, the more the mobility of oil in the tubing declined. By applying the flowing improvement techniques to this reservoir, the effect of the heater increased with the oil containing heavier components, and it was found that the production rate was improved as the heater installation interval became deeper. Despite the gas lifting method showing better productivity compared to other methods, there was an optimal injection rate at which the production rate became maximum. Moreover, it was shown that increasing the temperature of injection gas had little effect on enhancing the oil flow in tubing. Based on these results, flowing improvement techniques were applied to the oil wells in the Ada field. The productivity by PCP of Bashenkol_1X well, which contained comparatively light oil, increased 3.75 times more than natural state. Also, additional installation of insulated casing could yield better production. In the case of Bashenkol_3X in which 19.2 °API of heavy oil was reserved, oil production was impossible without flowing improvement methods. This well was able to produce 158 BOPD of oil by installing PCP with insulated casing and additional installation of heater increased production rate to 267 BOPD. Meanwhile, although the gas lifting method can greatly improve productivity, the applicability and cost should be considered prior to its being applied.

Key words: Permafrost, Heavy Oil, Pumping, Heater, Gas Lifting

INTRODUCTION

The temperature in severe cold regions is extremely low, down to −50 °C at winter season and the thickness of permafrost varies up to 600 m. Fig. 1 shows the thermal gradient in the Western Mackenzie Delta, and it is verified that the temperature of permafrost stays under 0 °C [1]. In the Botoubi gas field in Yakutsk, it is reported that the temperature of the reservoir located at 1,850 m depth was 9 °C. For this reason, oil productivity is very low due to the high fluid viscosity [2]. Another factor of low productivity is the heat loss to the surrounding formation, which occurs when oil in the tubing passes through the permafrost. Also, the formation of gas hydrate under the conditions of high pressure and extremely low temperature can cause serious problem [3,4].

To overcome these problems, many flowing improvement techniques have been developed. These include pumping, insulated casing and electric heating which installs a heater outside of the tubing or at the bottomhole [5]. The other is the hot gas lifting method which injects heated gas through the annulus, gas-lift valve and the tubing to reduce the bottomhole pressure and fluid viscosity [6]. The above methods apply pressure or heat to the producing well to enhance the oil productivity; therefore, to understand the fluid flow in tubing is essential. Kwon et al. [7] developed a model which describes the 2-phase flow in pipeline. Kim et al. [8] comprehended the solid-liquid 2-phase fluid flow effect in unsteady state in horizontal pipe and analyzed the stability of the pipeline.

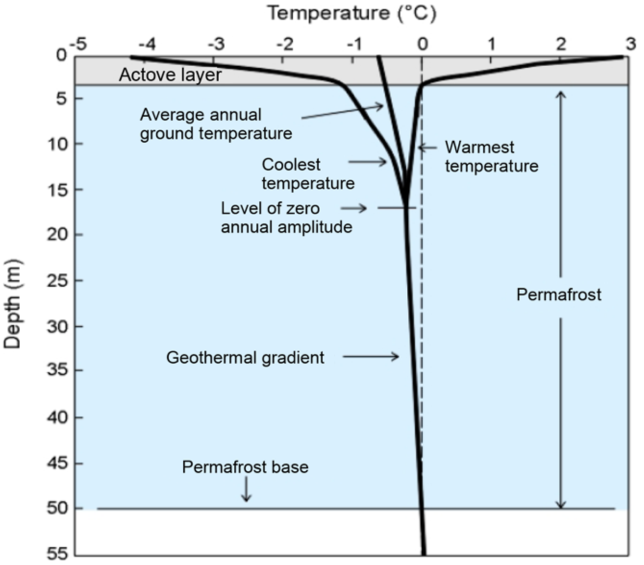

Fig. 1. Temperature profile of permafrost section for the Western Mackenzie Delta.

In this study, for analyzing the oil flow in the severe cold region, sev-

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eral simulations using the commercial pipeline simulator 『PIPESIM』 with the heat transfer computing module were performed. For the simulation, a reservoir system in severe cold region was set with regard to field data and the properties of formation and oil were analyzed. Through this analysis, optimal flowing improvement method was proposed and it was applied to the Ada field.

FLOWING IMPROVEMENT TECHNIQUES IN SEVERE COLD REGION

In a frozen region, as high temperature fluid is produced, heat loss to the adjacent formation occurs. Thus, unfreezing of the frost layer causes the collapse of the formation [9]. The most prevalent way to prevent this is to equip an insulated casing, so this can prevent not only the environmental problem but also the sudden increase in oil viscosity [10]. Also, in the severe cold region, electrical heating or gas lifting can be applied with the insulated casing in combination to promote the fluid flow. Sung et al. [11] observed the phenomenon of the hydrate formation, and performed the production experiments using depressurizing, heating, and injection of chemical additives.

Electrical heating includes not only attaching a heater outside the tubing but also installing a heater at the bottomhole [12]. An electric trace heater which is attached on the outer wall of the tubing introduces heat to the inside of the tubing to control the outbreak of paraffin, asphaltene, sulfur, hydrate and other precipitates [13]. This technique with an electric submersible pump (ESP) was announced as a general method in Northern Alaska [12]. Downhole heating technique is the way to increase oil production by installing a heater at the bottomhole. It applies electrical heat by adjusting the frequency range of the current to the reservoir. In the gas lift method the gas is continuously injected into the annulus through a gas lift valve and the increased gas/liquid ratio decreases the hydrostatic pressure gradient in tubing. However, when the temperature in the tubing is lower than wax appearance temperature, solid deposit of wax or paraffin can be formed; thus, even with the injection of gas, it is hard to increase oil productivity. So, the hot gas lift method by increasing the gas temperature was implemented [14]. Here, the position of the gas lift valve should be deeper than the depth of wax formation. To improve the efficiency of the hot gas lift method, it is important to minimize the heat loss to the adjacent formation by setting up the insulated casing [15]. If the amount of injection gas is excessive, the friction between fluid and the wall of tubing increases, and thus, the decision of optimal injection gas rate is critical [16].

The electric heating method and gas lift method are implemented in combination with a pump such as PCP, ESP, and twin screw multiphase booster which are widely used in the oil industry.

In this study, 『PIPESIM』 which is commercial software created by Schlumberger, was used for the analysis of the multi-phase fluid flow at steady state condition. In the severe cold region, as high temperature oil is produced, heat loss to the adjacent frozen formation occurs. Therefore, the heat transfer coefficient of the production well components such as tubing, annulus, casing, cement and formation should be calculated (Fig. 2). For this, we developed a model which calculates the heat transfer coefficient of each component, and applied these values to 『PIPESIM』. The equations are as follows [17,18]:

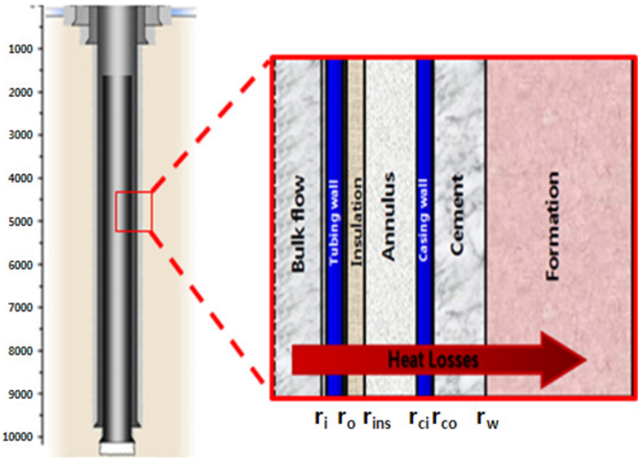

Fig. 2. Schematics of thermal resistances to heat transfer in wells (Michael, 1986).

$$U=\frac{1}{2\pi r_0 R_h} \tag{1}$$

$$R_h=\frac{1}{2\pi}\left[\frac{1}{h_f r_i}+\frac{1}{h_{pi} r_i}+\frac{\ln\left(\frac{r_0}{r_i}\right)}{\lambda_P}+\frac{1}{h_{P_0} r_i}+\frac{\ln\left(\frac{r_{ins}}{r_0}\right)}{\lambda_{ins}}\right.$$
$$\left.+\frac{1}{h_{rc,an} r_{ins}}+\frac{\ln\left(\frac{r_{co}}{r_{ci}}\right)}{\lambda_P}+\frac{\ln\left(\frac{r_w}{r_{co}}\right)}{\lambda_{cem}}+\frac{f(t_D)}{\lambda_E}\right] \tag{2}$$

THE ANALYSIS OF OIL FLOWING BEHAVIOR IN COLD REGION

In this study, data from the Alaska North Slope was used to analyze the mobility of oil in permafrost area. The geothermal gradient was set as 1 °C/m from the surface to −4 m and the formation temperature increased to 0 °C at the bottom of the permafrost layer. Below this depth, 0.033 °C/m of normal geothermal gradient was used to the reservoir depth. The reservoir depth is 1,000 m and tubing diameter is 2.875 inches, casing diameter is 6.370 inches and well head pressure (WHP) is 29 psi. In a cold environment, since the mobility of heavy oil is mostly affected by viscosity, the Hossain correlation, which was verified to be more accurate at low temperature, was used [19]. Also, it was supposed that oil has a different specific gravity of 15, 20, 25 °API and the thickness of frozen layers was set as 0, 100, 200, 400, 600 m (Table 1). The reservoir temperatures according to the thickness of frozen layers were 23.2, 20.97, 18.64, 13.98 and 9.32 °C, respectively (Fig. 3).

First, simulations were carried out where permafrost was not present. When 15 °API heavy oil was produced, pressure, temperature and viscosity with depth are shown in Fig. 4. As shown, the oil temperature decreased from 23.2 °C at reservoir depth to 0.2 °C at the well head. It is because of the influence by adjacent cold formation and, accordingly, viscosity increased from 513 cp at reservoir depth to 103,895 cp at 50 m depth (Fig. 5). In this case, natural flow did

Table 1. Flowing analysis of oil with various frozen depth and specific gravity

γ_o (°API)	FD (m)	Q (BOPD)	μ_{res} (cp)	μ_{max} (cp)	Production by NF
15	0.0	0.0	513	103895	×
	100	0.0	615	121955	×
	200	0.0	752	130189	×
	400	0.0	1173	134576	×
	600	0.0	1962	136094	×
20	0.0	0.0	55	3353	×
	100	0.0	62	3485	×
	200	0.0	71	3549	×
	400	0.0	94	3585	×
	600	0.0	113	3597	×
25	0.0	124.38	23	481	○
	100	100.04	26	565	○
	200	59.66	29	648	○
	400	0.0	37	668	×
	600	0.0	49	675	×

※ NF: Natural Flow, p_{wf}: Wellbore flowing pressure, Q: Production rate

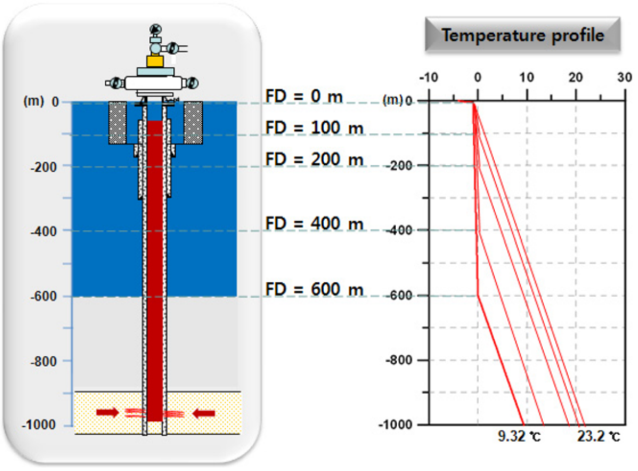

Fig. 3. Temperature profile with the different thickness of permafrost.

not occur because the oil pressure was 0 psi at 50 m depth. However, in the case of 25 °API oil having 23 cp of viscosity at the reservoir depth, the oil mobility was greatly improved compared to 15 °API oil. Therefore, 124 BOPD can be naturally produced without any flowing improvement method due to the low oil viscosity.

Next, simulations were performed by increasing the frozen depth to 600 m. The viscosity of 15 °API oil was 1,962 cp at reservoir depth and increased to 136,094 cp as the oil rose up though the tubing. In this case, oil also was not produced in natural state and oil was stopped at 50 m depth, which is the same as the case of no frozen depth. Meanwhile, the viscosity of 25 °API oil was 49 cp at reservoir depth and increased to 675 cp as the oil flowed upward. Also, oil production was impossible as well, because the oil pressure in the tubing was slightly lower than the WHP.

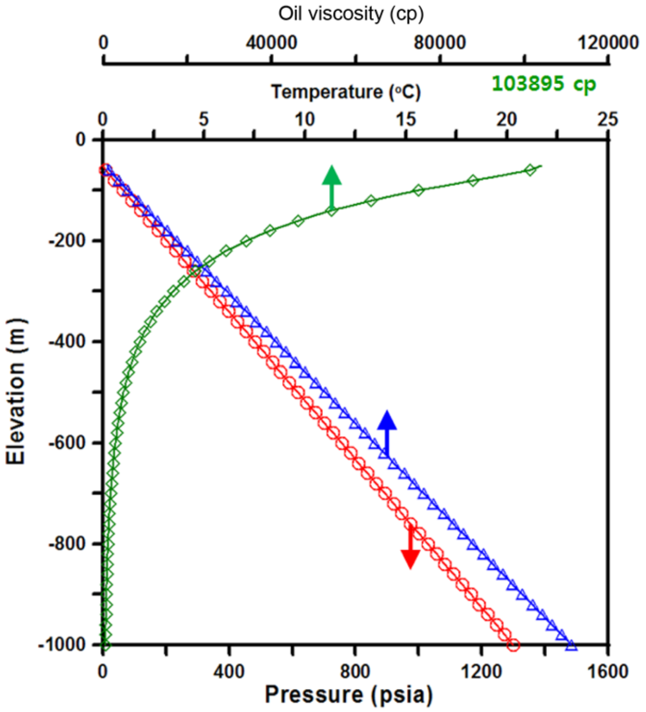

Fig. 4. Pressure, temperature and viscosity of 15 °API oil for the frozen depth=0 m.

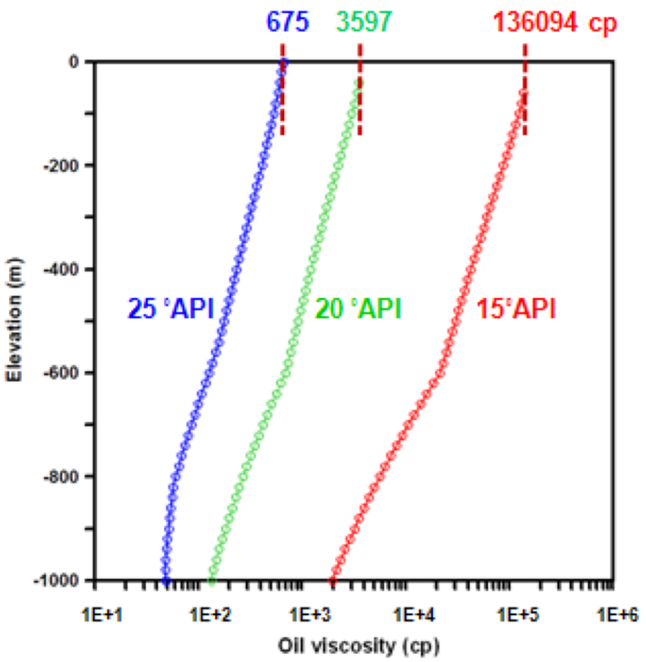

Fig. 5. Viscosity for the different specific gravity in frozen depth= 600 m.

As shown in Table 1, these results indicate that the productivity of heavy oil in permafrost area is extremely low without flowing improvement methods such as pump, insulation, heater and gas lift. Therefore, proper flowing improvement methods must be selected and designed to improve the mobility of heavy oil. In the next section, we attempt to decide the optimum flowing improvement method

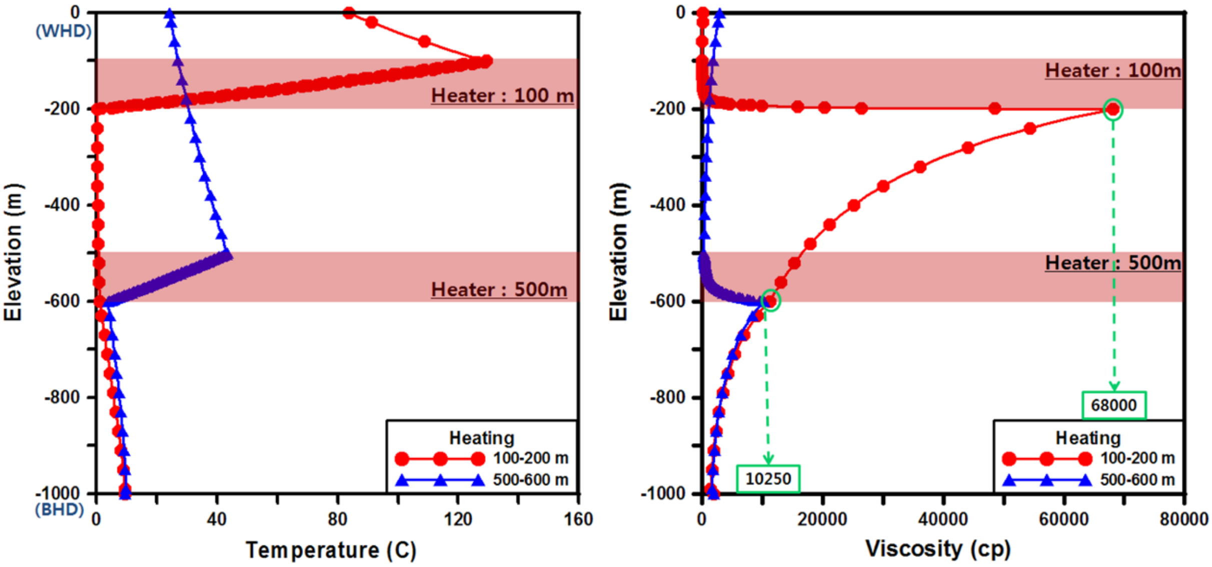

Fig. 6. Temperature and viscosity of 15 °API oil for different installation depth of heater in frozen depth=600 m.

by implementing these methods to the system having 600 m thick of frozen layer.

1. Electrical Heating

In this section, the efficiency of electric heating was analyzed for the well already PCP-300 psi and insulated casing equipped. First, 100 m length of trace heater was attached to tubing varying installation interval. The injected quantity of heat was 100 kBtu/hr. As shown in Fig. 6, the viscosity of 15 °API oil was 10,250 cp at 600 m depth when a heater was installed between 500 m and 600 m. For a heater installed between 100 m and 200 m depth, however, the viscosity was already 68,000 cp before the oil passed heater installed interval. From these results, the production rate was increased to 174 BOPD when the heater installed at the lower part compared with the 16.86 BOPD of production rate without a heater. Similarly, the production rate for the 25 °API oil was increased as the heater was installed at the lower part. The reason why the production efficiency by heating for 15 °API oil was greater than one for 25 °API oil is that the oil velocity in the tubing is too fast to be sufficiently heated (Fig. 7).

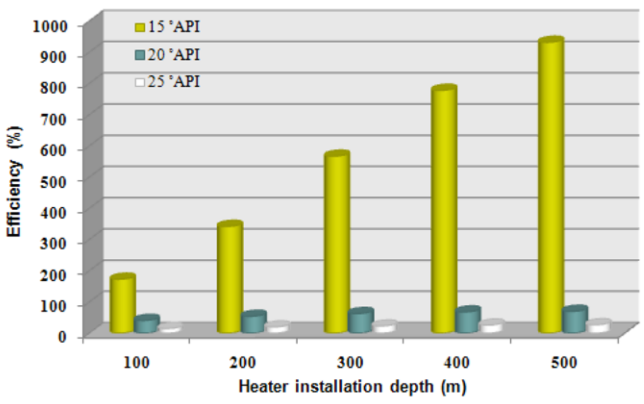

Fig. 7. Efficiency of electric heating with various installation depth and specific gravity.

Second, the analysis for heat capacity was performed by changing injected quantity of heat from 50 to 300 kBtu/hr (Fig. 8). In case of 15 °API oil, the viscosity decreased from 479 to 64 cp at heater installed depth as injection quantity of heat was increased from 50 to 300 kBtu/hr. The temperature was also increased from 33 to 77 °C at the same depth and then the production rate was 106 BOPD and 297 BOPD, respectively (Table 2). However, the heating efficiency decreased from 2.14 to 1.0 as injection quantity of heat increased. Therefore, accurate estimate of the optimum injection quantity of heat is essential to decide appropriate injection heat capacity.

2. Hot Gas Lift

The main objective in this section is to analyze the productivity of 15 °API oil for the system having 600 m of permafrost with gas lift technique. The depth at which the gas lift valve can be located depends on the gas injection pressure available. Generally, it is known that locating the gas lift valve at the bottomhole shows the most favorable efficiency. In this simulation, the injection gas temperature was 50 °C and the injection gas pressure was set as 800 psi by gas lift performance curve.

First, oil production rate was analyzed for several gas injection rates from 0.2 to 4.0 MMSCFD. As a result, it was not efficient below 0.4 MMSCFD of injection gas rate because the injection gas was too small to reach the valve. The oil production rate gradually increased above this value of injection gas rate, and 854 BOPD of maximum production rate was yielded at 2.4 MMSCFD (Fig. 9). However, injecting over 2.4 MMSCFD of gas decreased the oil production rate. This happened because excessively high gas injection rate causes slippage, which gas phase moves faster than liquid and, thus, bottomhole pressure increased.

Second, oil production rate was analyzed for the 800, 900, 1,000 psi of gas injection pressure. Here, injection of gas with higher pressure caused the reduction of the oil production rate from 854 to 786 BOPD, because condensed gas into the tubing yielded large amount of gas and it obstructed oil production (Fig. 10).

Next, several simulations were carried out by changing injection gas temperatures from 50 to 400 °C. The production rate was 854

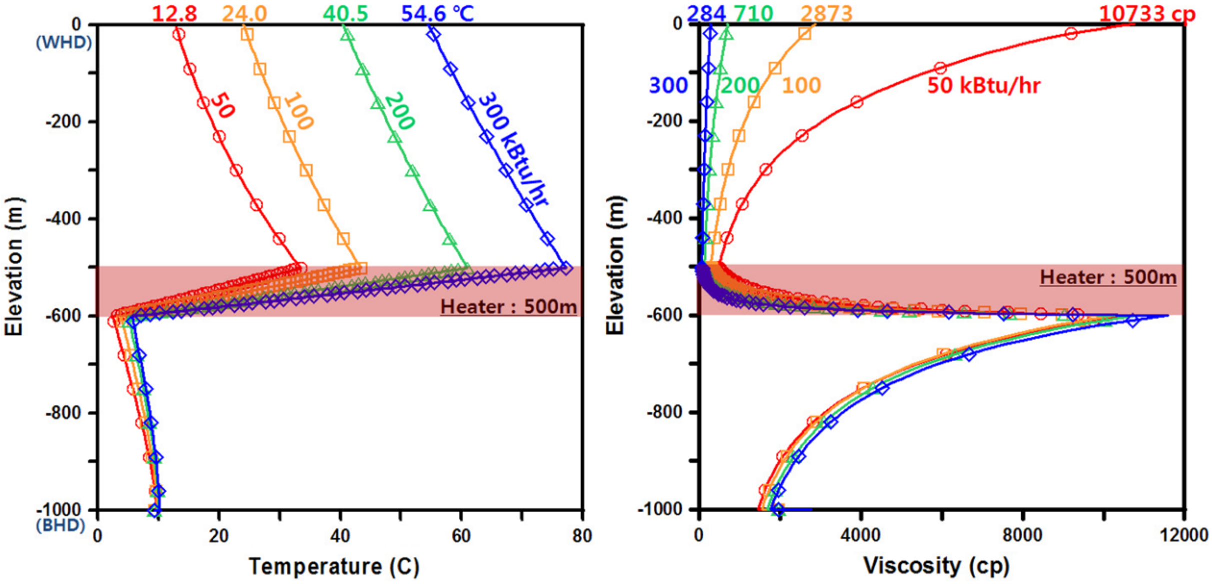

Fig. 8. Temperature and viscosity with the heat injected for 15 °API in the insulated well.

Table 2. Flowing analysis of oil with the amount of heat injected

	50 kBtu/hr	100 kBtu/hr	200 kBtu/hr	300 kBtu/hr
Production rate (BOPD)	106.9	173.9	251.4	297.1
Temperature (°C)	33.0	43.4	61.0	77.0
Viscosity (cp)	479.0	282.5	124.3	64.0

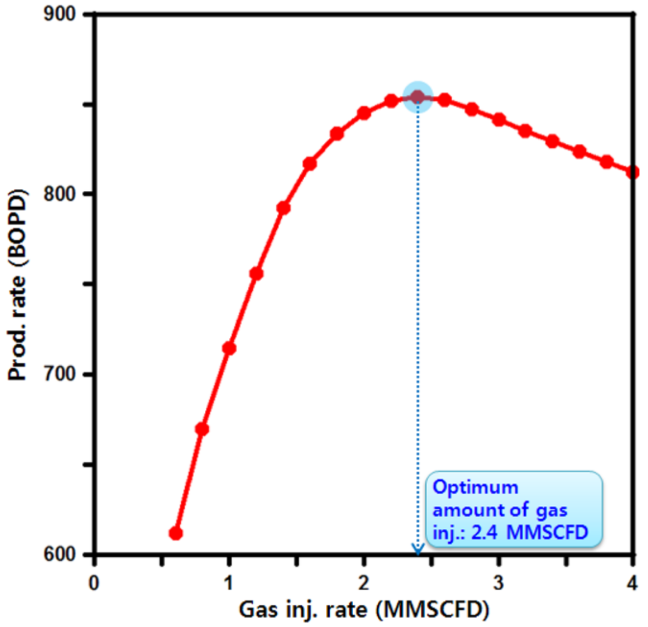

Fig. 9. Gas lift performance curve.

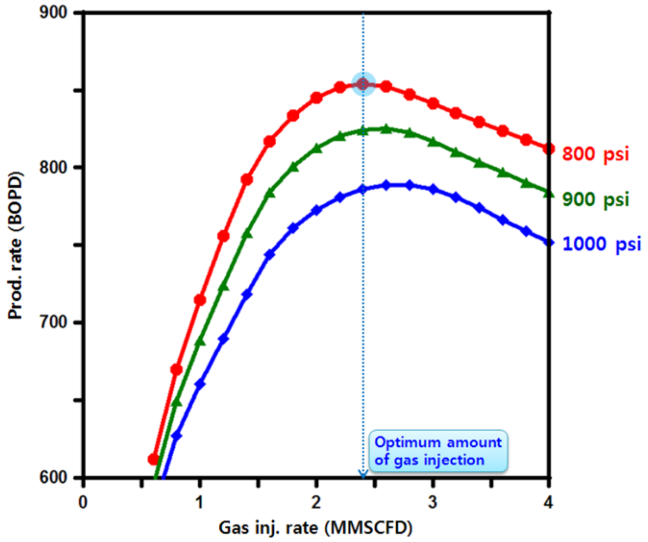

Fig. 10. Flowing analysis of oil with various gas injection pressure.

BOPD with 50 °C of injection gas temperature and 871 BOPD with 400 °C. The increased production rate was not proportional to the temperature. From these results, oil mobility in tubing was greatly improved by using the gas lift technique with optimum injection gas rate and pressure. Also, the hot gas lift method was not effective for this system.

FIELD STUDIES [ADA FIELD IN KAZAKHSTAN]

In the Ada field, the seasonal temperature change is extreme: the temperature in the winter is –35 °C, and 40 °C in the summer. To prevent productivity decline caused by low temperature in the winter, surface pipes are insulated and laid 2-3 m deep. It is reported

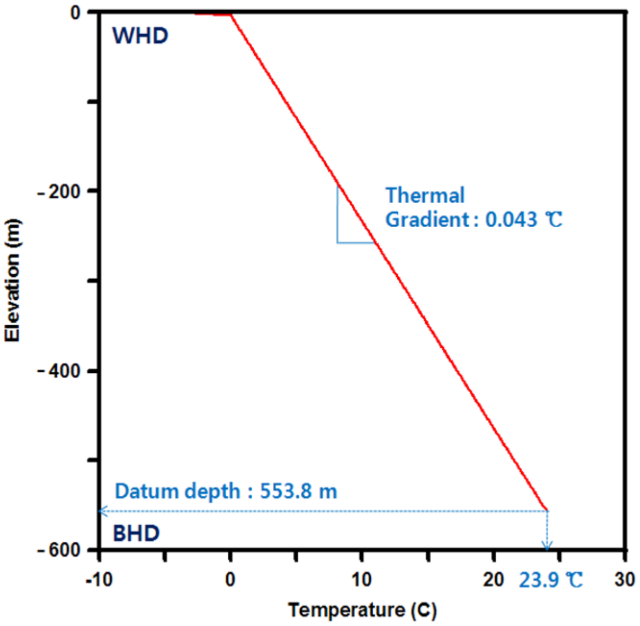

Fig. 11. Temperature profile of Bashenkol_1X along with the depth.

that the frozen depth in the winter is not over 3 m. Considering the frozen depth, the thermal gradient of the formation was set as shown in Fig. 11. In the Ada field, PCP is installed in all Bashenkol wells.

Presently, production tests for the five wells (1X, 2X, 3X, 4X, 5X) are in progress. Among them, 1X, 2X and 5X have similar properties, so analysis of 1X was presented in this study. Meanwhile, 4X was excluded because it has very favorable productivity. Therefore, only 1X and 3X were analyzed.

1. Bashenkol_1X

DST in the Bashenkol_1X has been performed at 767 m depth with 6.276 inch producing casing. As a result, up to 128 BOPD, of which specific gravity is 27.5 °API, has been produced. According to the analysis about pressure build-up, flow capacity was calculated as 11,889 md·ft, permeability was 115 md, and corruption index of the well was −1.2. Based on the data, it was reported that the reservoir consisted of sandstone and the well was hardly damaged. The reservoir pressure was 776.7 psi, GOR was 86 SCF/STB, and the productivity index of the well was 0.714 STB/psi (Table 3). The mole fraction of C12+ is 80.76%, and C36+ is 3.01 mol%. For the viscosity calculation, the Hossain correlation, which is highly reliable to heavy oil viscosity calculation at low temperature, was adopted because the viscosity data measured had little consistency.

The yielded pressure, temperature and viscosity profile are shown

Table 3. Reservoir and fluid properties of Bashenkol_1X, 3X

	1X	3X
γ_o (API)	27.5	19.2
Gross thickness (m)	43.5 (NGR: 73.6%)	10.5 (NGR: 85.7%)
BHT (°C)	20	18.5
FWHP (psi)	29	29
WHT (°C)	−34.65 (winter)	−34.65 (winter)
Initial BHP (psi)	762.0	786.5
k (md)	115	37
PI (STB/psi)	0.714	0.84
GOR (SCF/STB)	83	56
Flow capacity (mdft)	11,889	1,458

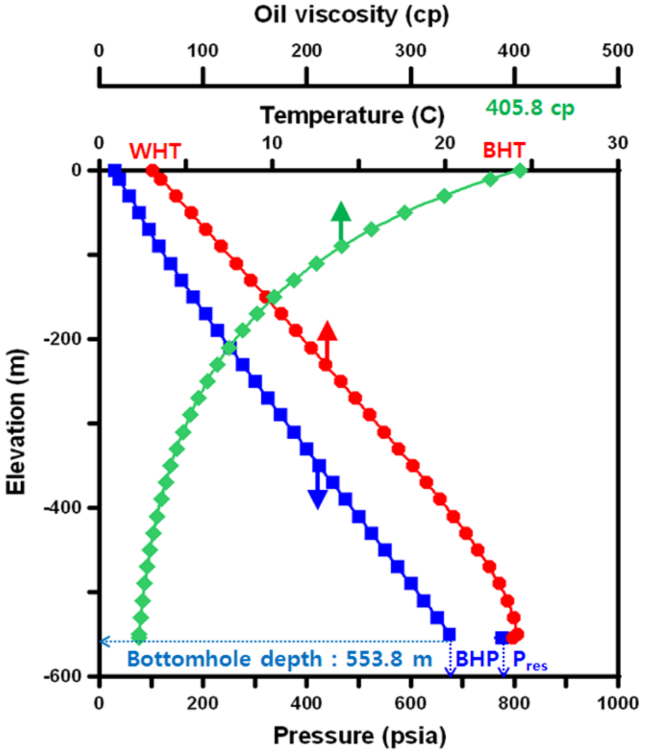

Fig. 12. Pressure, temperature and viscosity of Bashenkol_1X along with the depth.

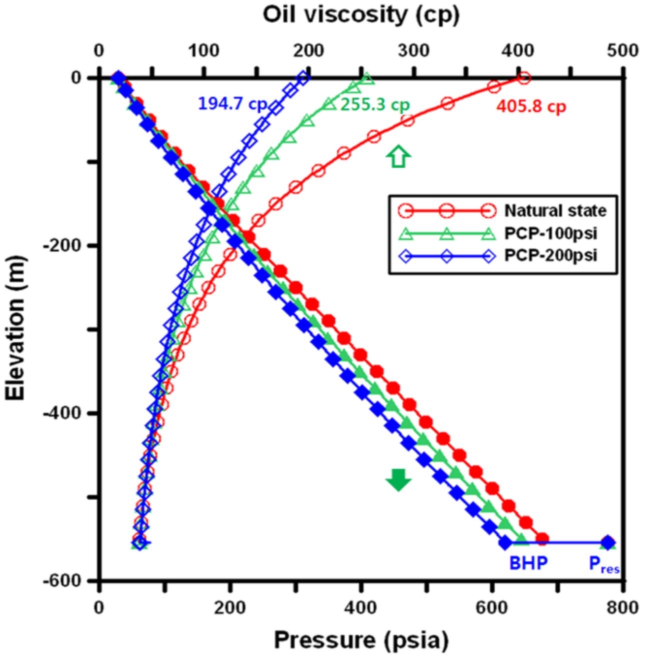

Fig. 13. Pressure and viscosity of Bashenkol_1X with the PCP installed.

in Fig. 12. From this result, WHP should be at least 29 psi for transportation to storage tank; thus, the bottomhole pressure at 767 m depth was calculated as 681 psi. By the pressure difference, the well in the natural state can produce 68 BOPD without insulated tubing or PCP. The oil temperatures at bottomhole and wellhead are 24 °C and 2.6 °C, respectively, so the viscosity of oil which was 38.5 cp at the reservoir condition increased to 405 cp as it came up to the surface.

Bashenkol_1X is producing oil without insulated tubing at present. According to the data obtained from the Ada field, the pressurizing by the PCP was set as 100 psi and 200 psi, and then flow analyses were performed as shown in Fig. 13. As a result, by applying PCP, heat losses to the adjacent formation were reduced and the oil viscosities at the wellhead were 250 cp and 190 cp, respectively. For this reason, the production rate was increased to 162 BOPD and 255 BOPD from 68 BOPD in natural state.

Next, oil flow in the insulated tubing without PCP was simulated. The oil temperature in the tubing was maintained higher than natural state as shown in Fig. 14. According to the temperature preserved by the insulation, 405 cp of oil viscosity in natural state has been significantly decreased to 150 cp. Since specific gravity of oil was not very heavy, 16 BOPD has been additionally produced compared with natural state.

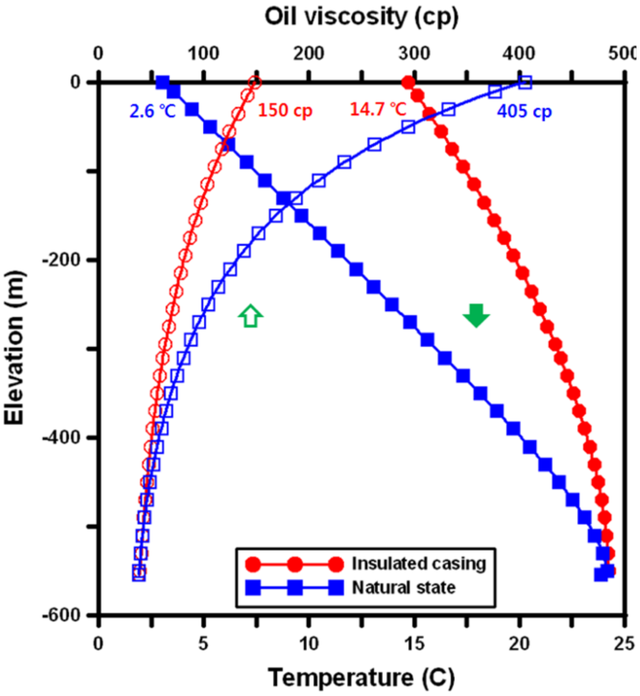

Fig. 14. Temperature and viscosity along with the depth.

Table 4. Analysis of oil flow for Bashenkol_1X with the flowing enhancement methods

	μ_o at WHD (cp)	Q_o (BOPD)	Remarks
Natural state	405	68	-
PCP-200 psi	190	255	3.75
Insulation	150	84	1.2
PCP-200 psi & insulation	100	284	4.17

※ μ_o at reservoir condition: 38.5 cp

In this well, the PCP-200 psi and the insulated casing were applied at the same time. By doing this, the well produced 284 BOPD, which was remarkably increased and the viscosity of oil at the wellhead was shown as 100 cp, which was the most favorable. From this result, it was shown that the insulated casing with PCP made the efficiency higher than PCP alone (Table 4).

2. Bashenkol_3X

DST in the Bashenkol_3X was performed down to 700 m depth through 6.276 inch-casing and 70 BOPD of oil having 19.25 °API was produced. The flow capacity was 1,458 md·ft, the permeability was 37 md and the corruption index of well yielded 6.0. The reservoir pressure was 786.5 psi, and GOR was 56 SCF/STB. A PVT analysis for the fluid samples was performed and the mole fraction of C12+ was 74.92%. As the oil contained 14.03 mol% of C36+ components, it was heavier than that of 1X. Accordingly, the oil viscosity was 295.7 cp at the 18.5 °C of reservoir temperature; thus it showed low flow capacity. This low pressure and high viscosity made the oil not to be produced in the natural state even though it reached to the wellhead (Fig. 15). Here, the oil viscosity at the wellhead, as Fig. 16 shows, increased to 5,684 cp. This increase may interrupt the oil flow in the tubing. In case of this well, unlike 1X, the oil velocity in the tubing is relatively low due to the low reservoir pressure, and it causes more heat loss to the adjacent formation; therefore, the effect by the insulation was insignificant.

In this well, while oil was not produced in the natural state, 128 BOPD was produced by installing PCP-200 psi and the oil viscosity at the wellhead was 2,371 cp (Fig. 16). Meanwhile, when insulated casing was additionally applied, the oil temperature in the tubing was kept high. Therefore, the oil viscosity at the wellhead was in-

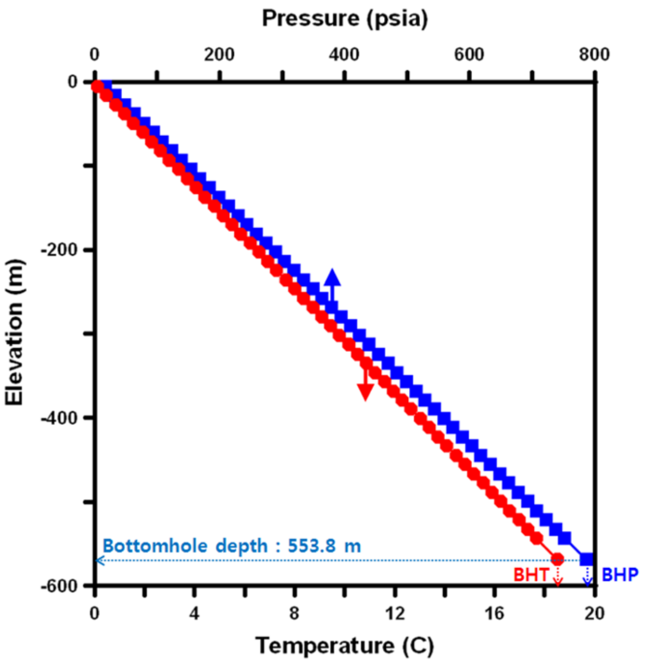

Fig. 15. Pressure and temperature profile of Bashenkol_3X along with the depth.

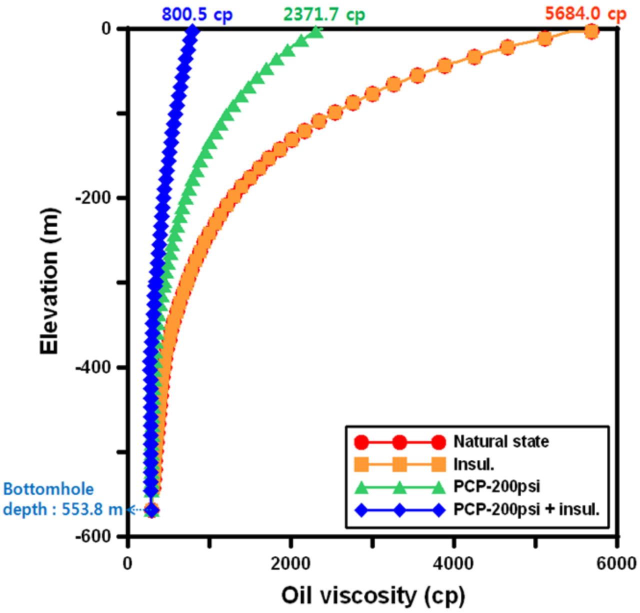

Fig. 16. Oil viscosity of Bashenkol_3X with the various flowing enhancement methods.

creased to only 800 cp and oil production increased to 158 BOPD, which was higher by 30 BOPD.

Since 3X produces heavy oil, the installation of heater or gas lift technique can greatly improve oil productivity. Accordingly, a heater with insulated casing was simulated.

The result showed that the installation of a trace heater at 400-500 m, around the wellbore, made better efficiency. Therefore, the heater installation interval was decided down on 400-500 m depth and the quantity of the heat injected was set to the general value in the range, 200 kBtu/hr. As oil passed through the interval of heater, the oil viscosity dropped to 3.8 cp, and then it increased to 29.5 cp at the wellhead (Fig. 17). By enhanced viscosity, oil production rate increased to 87.7 BOPD. It is lower than 158 BOPD, which was yielded by PCP and insulated casing because of this low reservoir pressure. Further analysis of this well has been performed with PCP additionally installed. The productivity was remarkably improved to 267 BOPD (Table 5).

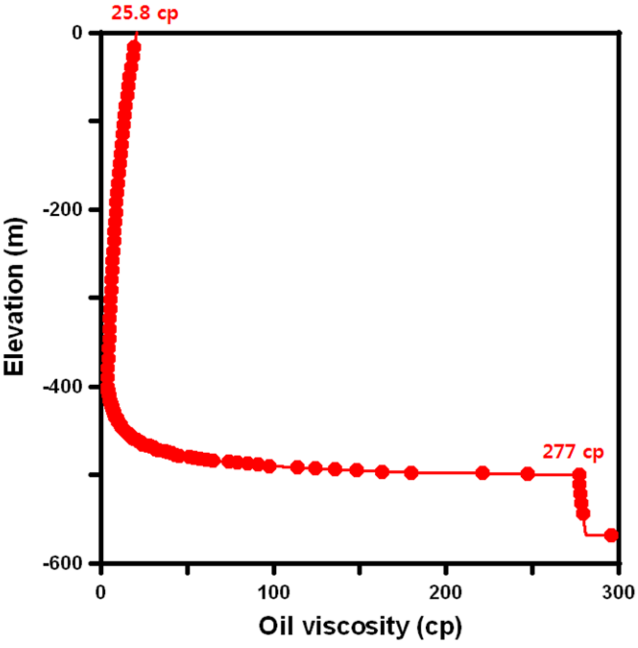

Fig. 17. Oil viscosity of Bashenkol_3X for heater installation depth =500 m.

Table 5. Analysis of oil flow for Bashenkol_3X with the flowing enhancement methods

	μ_o at WHD (cp)	Q_o (BOPD)	Remarks
Natural state	8312	0	0
PCP-200psi	2371.7	128	-
Insulation	5684	0	0
PCP-200psi & insulation	800	158	1.23
Heater & insulation	295.7	87.7	0.69
Heater & PCP-200 psi & insulation	61.4	266.9	2.09
Gas lifting & insulation	1202.7	402.2	3.14

Next, the gas lift method was applied. The optimal location of gas lift valve was calculated as 490 m by 『PIPESIM』. The gas injection pressure and temperature was set to 500 psi and 50 °C, respectively. Since the change of oil production rate depends on the amount of the gas injected, the optimal amount of gas injection was yielded as 0.9 MMSCFD, as shown in Fig. 18. With this injection gas rate, the oil production rate was significantly increased to 402.2 BOPD. Meanwhile, when the hot gas lift method was applied, which increased injection gas temperature to 200 °C, oil temperature at wellhead was 13.1 °C. For this reason, production rate was slightly increased by 4.9 BOPD, so that we concluded that the efficiency of the hot gas lift was low in this case.

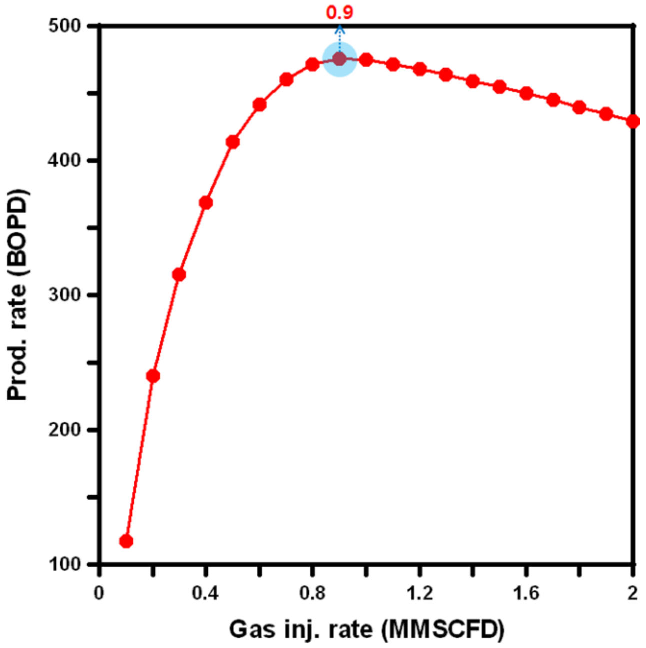

Fig. 18. Gas lift performance curve in Bashenkol_3X.

Consequently, the gas lift method showed the best production behavior in Bashenkol_3X. However, the compatibility and cost must be considered in advance.

CONCLUSION

In the severe cold region, the productivity was analyzed with respect to the permafrost depth and oil gravity. Based on the results, flowing enhancement techniques were applied to the Ada field in Kazakhstan. The results are as below:

1. As a result of productivity of reservoir located at 1,000 m depth in severe cold region, it was impossible to produce 15 °API and 20 °API oil irrespective of permafrost depth. Meanwhile, in case of 25 °API of oil, it was able to be produced naturally where the thickness of permafrost was thinner than 200 m. However, where there was more than 400 m of permafrost, it was impossible to produce oil.
2. As a result of electric heating, the deeper the installation depth of the heater, the mobility was improved. Also, the productivity was increased because the oil viscosity was sensitive to the temperature range of heating. Although the production rate was improved, the efficiency with the increase of heat was decreased. Therefore, the optimal heat capacity should be determined beforehand.
3. When gas was injected at more than optimum rate, the production rate was decreased. Also, as the injection pressure was higher, the production rate of oil was decreased due to the slippage effect of injected gas. It was also confirmed that the efficiency of hot gas lifting was not good.
4. The Bashenkol_1X of the Ada field was producing light oil of 27.5 °API and the PCP is installed at present. As a result of analyzing the production rate by PCP, compared to the natural state, the production rate was 255 BOPD, which was increased to 3.75 times than natural state. Meanwhile, in the case of using only insulated tubing without PCP, there was little effect. However, when insulated tubing was used with PCP, the production rate was greatly increased. Accordingly, it is not necessary to apply electric heating or gas lifting in this well.
5. In the case of the Bashenkol_3X, oil was not able to be produced in natural state. By applying the insulated casing with the PCP, it was shown that 158 BOPD could be produced. Also, when a heater was installed in combination with PCP, 267 BOPD, which was the similar production rate of 1X, was produced. Meanwhile, although the gas lift method can greatly improve productivity, the compatibility and cost should be considered prior to its application.

NOMENCLATURE

d : tubing diameter, inch
g_G : geothermal gradient [°C/m]
h_f : film coefficient of heat transfer between the fluid inside the pipe and the pipe wall [Btu/ft^2-day-°F]
h_{fc} : the coefficient of heat transfer due to forced convection [Btu/ft^2-day-°F]
h_{Pi} : the coefficient of heat transfer across any deposits of scale of dirt at the inside wall of the pipe [Btu/ft^2-day-°F]
h_{Po} : the coefficient of heat transfer across the contact between pipe and insulation [Btu/ft^2-day-°F]
$h_{rc,\,an}$: radiation and convection coefficient of heat transfer for the annulus [Btu/ft^2-day-°F]
P_{res} : reservoir pressure [psi]
r_{ci} : the radius of the inner casing [ft]
r_{co} : the radius of the outer casing [ft]
R_h : specific thermal resistance [Btu/ft^2-day-°F]$^{-1}$
r_i : the inner radius of the pipe [ft]
r_{ins} : the external radius of the insulation [ft]
r_o : the outer radius of the pipe [ft]
r_w : the wellbore radius [ft]
t_D : the time from start of heating [dimensionless]
U : the overall heat transfer coefficient [Btu/day-°F]
λ : the thermal conductivity [Btu/ft-day-°F]
λ_{cem} : the thermal conductivity of the cement [Btu/ft-day-°F]
λ_E : the thermal conductivity of the earth [Btu/ft-day-°F]
λ_{ins} : the thermal conductivity of the insulation [Btu/ft-day-°F]
λ_P : the thermal conductivity of the pipe [Btu/ft-day-°F]
BHP : bottom hole pressure
BHT : bottom hole temperature
BOPD : barrel oil per day
WHD : well head depth
WHP : well head pressure
WHT : well head temperature

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