



(22) Date de dépôt/Filing Date: 2013/06/27

(41) Mise à la disp. pub./Open to Public Insp.: 2013/12/29

(30) Priorité/Priority: 2012/06/29 (US61/666,166)

(51) Cl.Int./Int.Cl. *E21B 43/24* (2006.01)

(71) Demandeur/Applicant:
NEXEN INC., CA

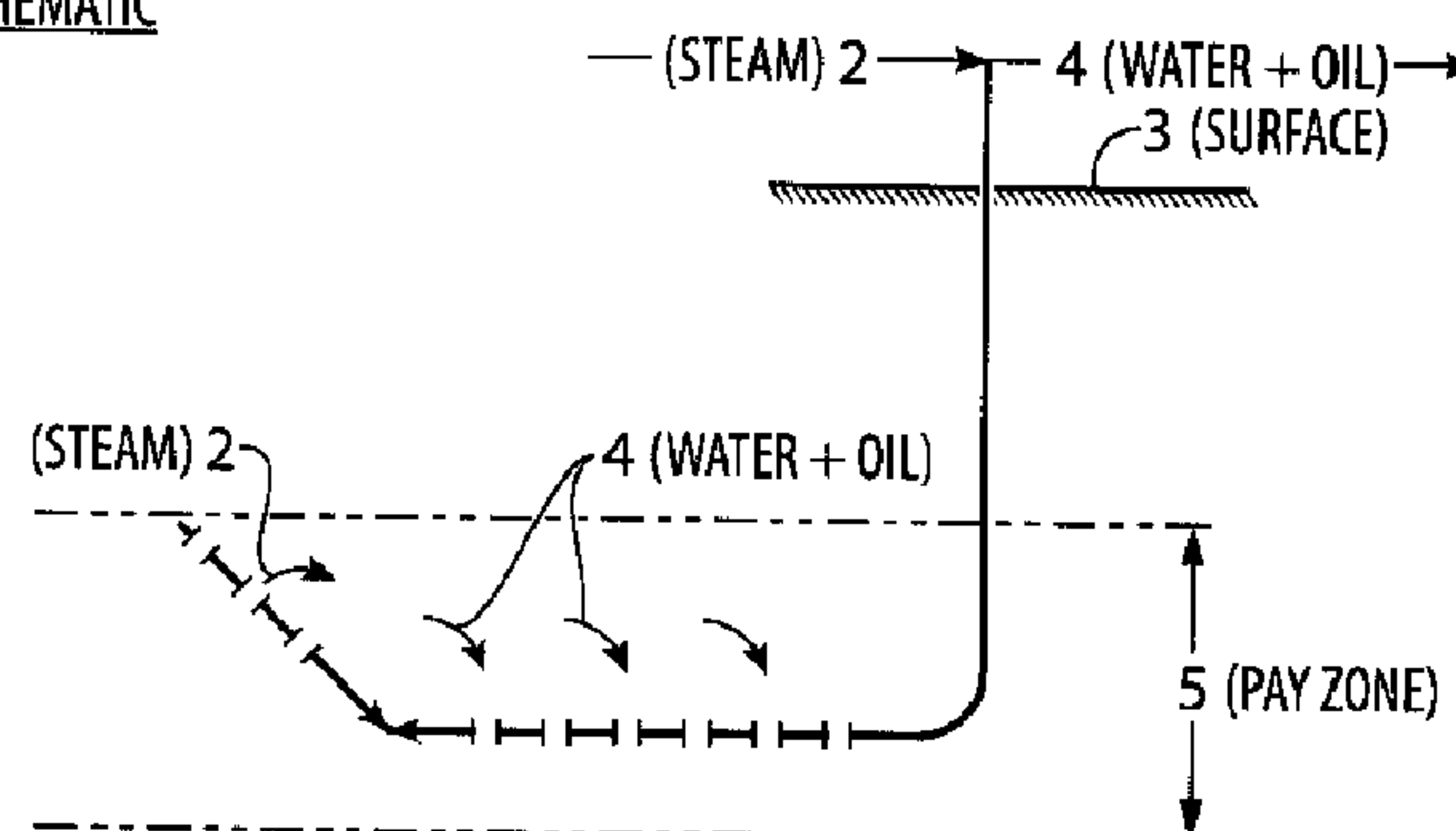
(72) Inventeur/Inventor:
KERR, RICHARD KELSO, CA

(74) Agent: HEENAN BLAIKIE LLP

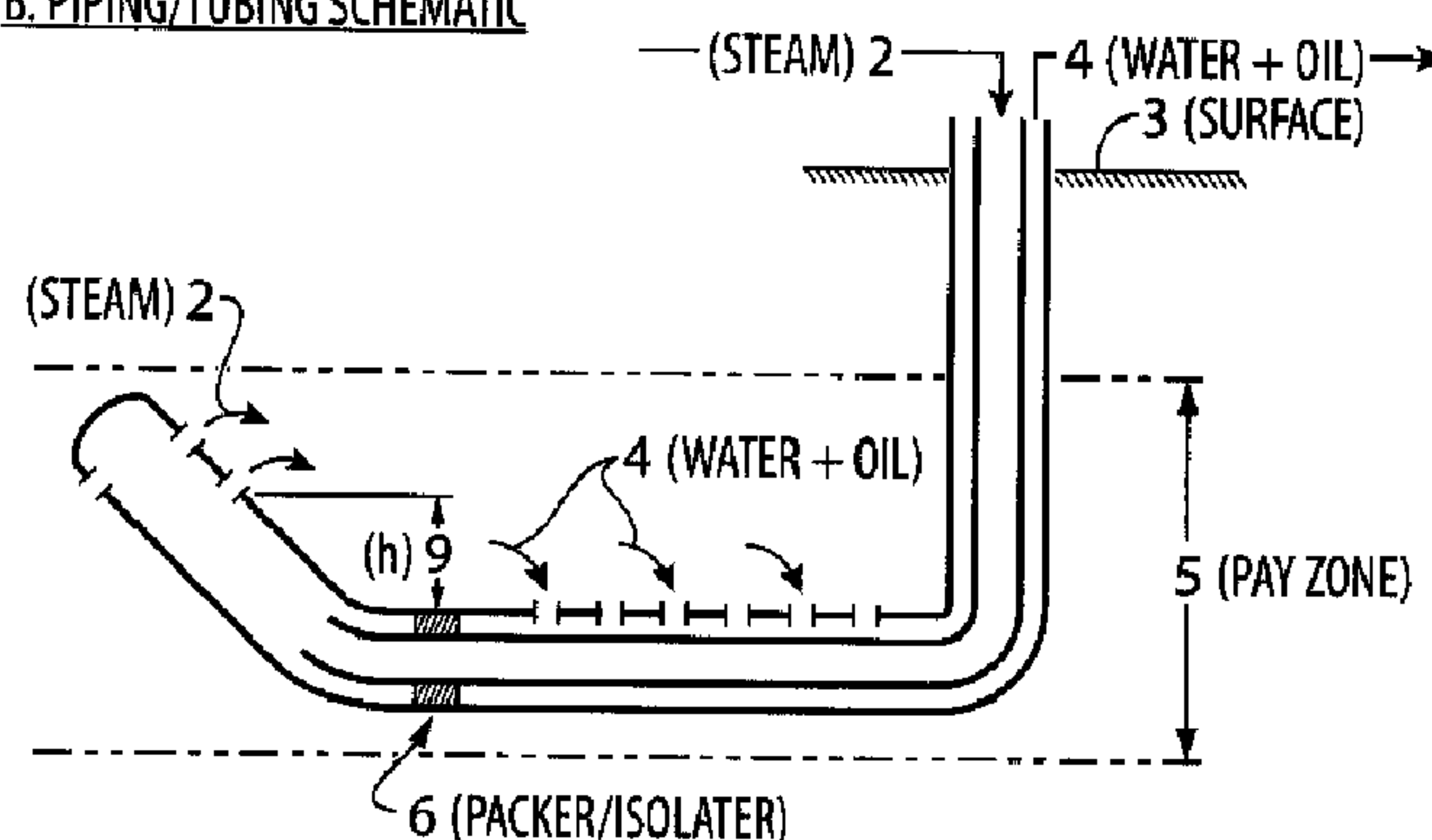
(54) Titre : SYSTÈME ET PROCÉDE DE DRAINAGE PAR GRAVITE ASSISTÉE PAR VAPEUR POUR PUITS UNIQUE
SOULEVE

(54) Title: UPLIFTED SINGLE WELL STEAM ASSISTED GRAVITY DRAINAGE SYSTEM AND PROCESS

A. SCHEMATIC



B. PIPING/TUBING SCHEMATIC



h = STAND OFF BETWEEN STEAM INJECTION AND LIQUID PRODUCTION

SWSAGD (U)

(57) **Abrégé/Abstract:**

A Single Well Steam Assisted Gravity Drainage (SWSAGD) process to recover liquid hydrocarbons from an underground hydrocarbon reservoir, wherein the single well includes a single substantially horizontal well including a heel area and a toe area,



(57) **Abrégé(suite)/Abstract(continued):**

wherein the toe area of the horizontal well extends upwardly into the reservoir, the process including 1- injecting steam into the reservoir via a steam injection area, proximate the toe area of the horizontal well, 2-allowing the steam to condense causing heated hydrocarbon liquids and water to drain into a liquid recovery zone of the horizontal well between the toe area and the heel area of the horizontal well, and 3- recovering the heated hydrocarbon liquids to the ground surface from the liquid recovery zone.

Abstract

A Single Well Steam Assisted Gravity Drainage (SWSAGD) process to recover liquid hydrocarbons from an underground hydrocarbon reservoir, wherein the single well includes a single substantially horizontal well including a heel area and a toe area, wherein the toe area of the horizontal well extends upwardly into the reservoir, the process including 1- injecting steam into the reservoir via a steam injection area, proximate the toe area of the horizontal well, 2- allowing the steam to condense causing heated hydrocarbon liquids and water to drain into a liquid recovery zone of the horizontal well between the toe area and the heel area of the horizontal well, and 3- recovering the heated hydrocarbon liquids to the ground surface from the liquid recovery zone.

TITLE OF THE INVENTION

UPLIFTED SINGLE WELL STEAM ASSISTED GRAVITY DRAINAGE SYSTEM AND PROCESS

FIELD OF THE INVENTION

This invention involves completing the horizontal well of a Single Well Steam Assisted Gravity Drainage (SWSAGD) system by drilling upwards, for the toe section of the well, where steam is to be injected, so steam injected proximate the toe section of the well is higher than the liquids production section of the well. Production is improved by inhibition of steam breakthrough. The process is called SWSAGD(U) where the “U” denotes uplift of the toe section.

BACKGROUND OF THE INVENTION

The following acronyms will be used herein:

CNRL	–	Canadian Natural Resources Ltd.
EOR	-	Enhanced Oil Recovery
SWSAGD	–	Single Well SAGD
SWSAGD(U)	–	SWSAGD with Upturned toe
HOSC	–	Heavy Oil Science Center
SAGD	–	Steam Assisted Gravity Drainage
SPE	–	Society of Petroleum Engineers
SF	–	Steam Flood
ICCT	–	Insulated Concentric Coiled Tubing

Single well SAGD (SWSAGD) is a thermal enhanced oil recovery (EOR) alternative for bitumen and heavy oil recovery (Elliott, K. et al, "Simulation of Early-Time Response of SWSAGD" SPE, S4618, 1999), (Elan Energy "Announces...Results", August and November 1996), (Improved Recovery Week, "Thermal System ups Heavy Oil..." December 4, 1995). The process was targeted toward thin-pay resources where SAGD was not practical. The idea was to incorporate steam injection and fluid production (oil & water) into a single horizontal well using a thermal packer to isolate steam injection from fluid production (Figure 1B). Another version of SWSAGD uses no packers, simply tubing to segregate flows (Figure 2B).

Elan Energy was the original proponent of the SWSAGD process. The original reservoir targets were thin, heavy oil deposits in Saskatchewan and Alberta (Ashok, K. et al, "A Mechanistic Study of SWSAGD", SPE, 59333-MS, 2000), (Elan (1996)), (Luft, H.B. et al, "Thermal Performance of Insulated Concentric Coiled Tubing", SPE, 37534-MS, 1997). The first SWSAGD well was drilled at Cactus Lake, Saskatchewan in 1995. Several field tests were conducted by Elan and others in the 1990's, and the following issues were observed (Elliott (1999)), (Saltuklaroglu, M. et al, "Mobil's SAGD Experience at Celtic..." SPE, 99-25, June, 1999):

- The centralized concentric steam line is in contact with the produced fluids (water & oil) (Figures 1 & 2). The produced fluids have a high heat capacity (i.e. SAGD), and normally, the fluids would be at a lower temperature than saturated-steam (i.e. sub-cool control). Heat losses from the steam injector to the produced fluids can be considerable for uninsulated, concentric, carbon steel tubing. The produced fluids are heated rapidly to saturated steam temperatures and the steam quality is reduced considerably before injection to the reservoir. The use of steam trap (sub cool) control for production rates will be difficult, at best. One solution is to use insulated tubing for the steam injection tube. Insulated concentric coiled tubing (ICCT) was developed for this purpose but has not resulted in widespread use today (Luft (1997)), (Falk (1996)).

- Start-up performance was another issue. Even for heavy oil deposits with some steam injectivity and some primary production, start-up was difficult and protracted (Elliott (1999)). Initial production rates were disappointing (Elliott (1999)). At least partially, this problem could have been due to two factors: 1) initial steam quality at the sand face was poor due to heat losses to produced fluids; and 2) the steam injection site occurs at the same elevation as production (Figures 1 & 2). There is no stand-off like SAGD to allow a liquid level to isolate the producer and prevent steam breakthrough. Steam by-passing is an issue (Ashok (2000)). Sand influx problems were another issue (Elliott (1999)). Because of these issues, an alternate start-up procedure using cyclic steam was suggested, but this has not been field tested (Elliott (1999)).
- Even after start up, SWSAGD performance has been disappointing (Saltuklaroglu (1999), Elliot (1999)). Prior to late 1999, Elan Energy drilled 19 SWSAGD wells with seven separate pilots. By the end of 1999, five of the seven pilots had been suspended or converted to other processes due to poor performance (Elliot (1999)). Best results were for high pressure, low viscosity, heavy oils with some primary production as foamy oil and no bottom water. The process was focused on deep thin-pay heavy oil not bitumen. Post 1999, there have been no indications of further SWSAGD developments, particularly none associate with bitumen

Therefore there is need to improve on SWSAGD, and in particular for application in bitumen reservoirs.

SUMMARY OF THE INVENTION

Single Well SAGD (SWSAGD) is a process developed to recover heavy oil or bitumen using a single horizontal well, where steam is injected near the well toe and hot water and hot oil is produced from the center to heel portion of the horizontal well. The process was developed in

the 1990's, and several wells were drilled in thin-pay heavy oil reservoirs in Western Saskatchewan and Eastern Alberta.

SWSAGD process horizontal wells are completed in a horizontal plane, so the steam injection and liquids production occur at the same elevation. This may cause early steam breakthrough to the production well-zone as well as inhibition of steam injection.

According to one aspect of the invention there is provided a Single Well Steam Assisted Gravity Drainage (SWSAGD) process to recover liquid hydrocarbons from an underground hydrocarbon reservoir, preferably bitumen reservoir. The process utilizes a single substantially horizontal well comprising a heel area and a toe area, wherein the toe area of said horizontal well extends upwardly into the reservoir. Said process comprises: 1) injecting steam into the reservoir proximate the toe area of the horizontal well; 2) allowing the steam to condense causing heated hydrocarbon liquids and water to drain into a liquid recovery zone of the horizontal well between the toe area and the heel area of the horizontal well; 3) recovering said heated hydrocarbon liquids to the ground surface from the liquid recovery zone through the heel area of the well by means known in the art. Preferably, the lowest point of the steam injection zone is positioned at least 2 meters above (in elevation) the highest point of the liquids recovery zone.

Preferably, steam injection has an elevation target of at least 2 meters above the highest point of the liquids recovery zone, preferably said target is achieved by drilling up-dip in a dipping reservoir.

Preferably, the hydrocarbon is heavy oil with a density of $10 < \text{API} < 20$. More preferably, the hydrocarbon is bitumen with a density of $\text{API} < 10$.

According to another aspect of the invention, there is provided a SWSAGD substantially horizontal well for hydrocarbon recovery in a hydrocarbon containing reservoir in the ground, said well having a predetermined length, comprising a heel section, and a toe section distant said heel section, wherein said toe section is at a first predetermined depth in the ground and said heel

section is at a second predetermined depth in the ground, such that said heel section is deeper in the ground than said toe section.

Preferably said SWSAGD further comprises a steam injection zone and a liquid recovery zone. Preferably said steam injection zone is proximate said uplifted toe section and said liquid recovery zone is proximate said substantially horizontal well.

According to one aspect of the invention, the toe section for steam injection has a length less than 20 percent of the total horizontal well length. According to another aspect of the invention, the uplifted toe section for steam injection is shorter than 50 meters.

According to another aspect of the invention, the substantially horizontal section of the well is completed closer than 2 meters from the bottom of the reservoir.

According to yet another aspect of the invention there is provided a thermal packer which isolates the steam injection zone from the liquid recovery zone.

According to yet another aspect of the invention the lowest steam injection point is positioned at least 5 meters higher (in elevation) than the highest point of said liquid recovery zone.

According to yet another embodiment of the invention at least one blank pipe section is placed between said steam injection zone and fluid production zone. Preferably more than one pipe is placed in this zone. Preferably the thermal packer is placed in the blank pipe section to isolate the steam injection zone from the liquid recovery zone.

In the preferred embodiment an offset packer is used so that the produced fluids may be pumped out the well.

According to one embodiment of the invention an operating pressure in the reservoir is sufficient to lift the produced fluids to the surface, without using an artificial lift system. According to another embodiment of the invention gas-lift is used to convey the produced fluids to the surface.

According to yet another aspect of the invention a pump is used to convey the fluids to the surface.

According to yet another embodiment of the invention, the steam is conveyed to the toe section of the well using insulated concentric tubing.

According to yet another aspect of the invention there is provided A SWSAGD process, using a single horizontal well, to recover liquid hydrocarbon from a hydrocarbon reservoir, whereby: Steam is conveyed to and injected in to the reservoir at the toe area of the horizontal well, and steam condenses and causes heated hydrocarbon liquids and water to drain into a separate section of the horizontal well that is between the toe section of the heel of the horizontal well, and the toe section of the horizontal well is drilled upward into the reservoir, and the toe section steam injector and the liquid producer section are completed (perforated, slotted...) so the lower point of steam injection is at least 2 meters higher (in elevation) than the highest point of liquids production.

Preferably the hydrocarbon is heavy oil with density $10 < \text{API} < 20$. More preferably, the hydrocarbon is bitumen with density $\text{API} < 10$.

Preferably, the toe section for steam injection is less than 20 percent of the total horizontal well length. More preferably, the toe section for steam injection is less than 50 meters long.

According to one aspect of the invention the elevation target for steam injection (>2 meters) is achieved by drilling up-dip in a dipping reservoir.

Preferably, the horizontal section of the well is completed less than 2 meters above the bottom of the reservoir.

In a preferred embodiment a packer or thermal packer isolates the steam injection from the liquid production section.

According to another preferred embodiment, the lowest steam injection point is located at least 5 meters higher (in elevation) than the highest point of liquids production.

According to still another aspect of the invention one (or more) blank pipe (tubing) section is placed between steam injection and fluid production. Preferably the packer is placed in said blank section.

According to another preferred embodiment an offset packer is used so that the produced fluids may be pumped.

In the preferred embodiment of the process the operating pressure in the reservoir is sufficient to lift the produced fluids to the surface, without using an artificial lift system.

In yet another embodiment a gas-lift is used to convey the produced fluids to the surface.

According to yet another embodiment, steam is conveyed to the toe of the well using insulated concentric tubing.

BRIEF DESCRIPTION OF THE FIGURES

Figures 1A and 1B depict a typical SWSAGD configuration with the use of thermal packers.

Figures 2A and 2B depict a typical SWSAGD configuration without the use of thermal packers.

Figures 3A and 3B depict a typical SWSAGD configuration in good and poor operation conditions respectively.

Figures 4A and 4B depict a SWSAGD and a SWSAGD(U) configuration under hydraulic limitation conditions respectively.

Figures 5A and 5B depict the present invention in several embodiments.

Figure 6 depicts the present invention in an up-dip well configuration.

Figure 7 depicts a pump configuration for SWSAGD.

DETAILED DESCRIPTION OF THE INVENTION

Figures 1 and 2 show two versions of traditional SWSAGD. The SWSAGD well is horizontal with steam 2 injected near the toe of the well, and liquids (water and oil) 4 produced in the mid and toe sections of the well. Figures 1A and 1B show SWSAGD, using a thermal packer 6 to isolate the steam injection zone. Figures 2A and 2B show SWSAGD without a packer. The versions of SWSAGD shown produce fluids using a natural lift, where the production zone has enough pressure (controlled by steam injection) to lift the produced fluids to surface 3. A version of SWSAGD using a pump 20 is possible using an offset packer 18 or a “special” pump design (Figure 7).

As best seen in Figure 1B, SWSAGD, using a packer 6 to isolate the steam injection section, is the preferred version because it allows a significant pressure difference between injection and production, at least during start up. A steam drive mechanism is active during this phase. The version of SWSAGD shown in Figures 2A and 2B does not allow any significant pressure differences because the steam injector and liquid producer are in constant communication.

After communication is established between steam injection and fluid production, it is difficult or impossible to sustain significant pressure differentials, so the main production mechanism becomes gravity drainage, not steam drive.

In order to understand issues for SWSAGD, it is instructive to look at conventional SAGD. Referring now to Figures 3A and 3B, conventional SAGD involves a pair of horizontal wells – a steam injector 14 and a fluid producer 10 - separated by about 5 meters, with the steam injector as the higher well and the fluid producer completed near the bottom of the reservoir. At steady-state, mature operation, a steam/liquid interface 12 is formed between the SAGD steam injector 14 and the SAGD liquid producer 10. The interface is controlled to be above the producer using sub-cool (steam-trap) control. The produced fluids are kept at a temperature less than saturated steam T by controlling production rates. The interface 12 is titled because of the pressure drop caused by pumping and/or fluid flow from toe-to-heel of the production well. Ideally, the

interface covers the production well 10 but does not flood the steam injector 14 (Figure 4A). If production rate is too high, the interface 12 can be tilted to partially flood the injector or to uncover part of the producer (Figure 4B). This can cause a reduction in the effective length of the steam injector and/or a steam breakthrough to the production well. The limitations caused by this SAGD effect may be ameliorated by 1) increasing separation between injector/producer, 2) increasing the size (diameter) of the production well, 3) reducing the length of the production well, or 4) cutting back on steam injection and fluid production.

SWSAGD may suffer a similar problem. Figure 4A shows what may happen, for a mature, steady-state operation. It is still desirous to maintain a liquid/steam interface 12 above the production well 10 to prevent steam breakthrough. While heat losses from steam tubing will heat produced fluids to/near saturated steam T, sub-cool control for production rates is difficult. The interface 12 will again be tilted, with the higher end at/near the toe and the lower end at/near the heel of the well. The steam injection zone 11 at the toe will, perforce, be flooded. Steam can bubble up through the liquid, but steam flow and conformance is impaired. Steam by-passing can occur in the well bore, if there is no packer.

Unlike SAGD, SWSAGD has no stand-off between injector and producer. The solution, as described in this invention, is to drill the toe of the SWSAGD horizontal well upwards, so there is a vertical separation between the lowest steam injection perforation (or port, or slot) and the highest fluid production perforation (or port, or slot) as shown in Figures 4B and 5. If the separation is sufficient, the steam/liquid interface 12 will not cover the steam injector section but will cover the liquid producer. The steam injection is not inhibited by liquids, and the liquid producer is protected against steam breakthrough (Figure 4B).

If the lower portion of the steam injector section and/or the final portion of the production section is blank piping (with no perforations), this separation may be enhanced even further.

Another version of SWSAGD(U) is achieved by completing the toe section of the horizontal well in an up-dip direction in a dipping reservoir, as shown in Figure 6.

Other embodiments of the invention will be apparent to a person of ordinary skill in the art and may be employed by a person of ordinary skill in the art without departing from the spirit of the invention.

Claims

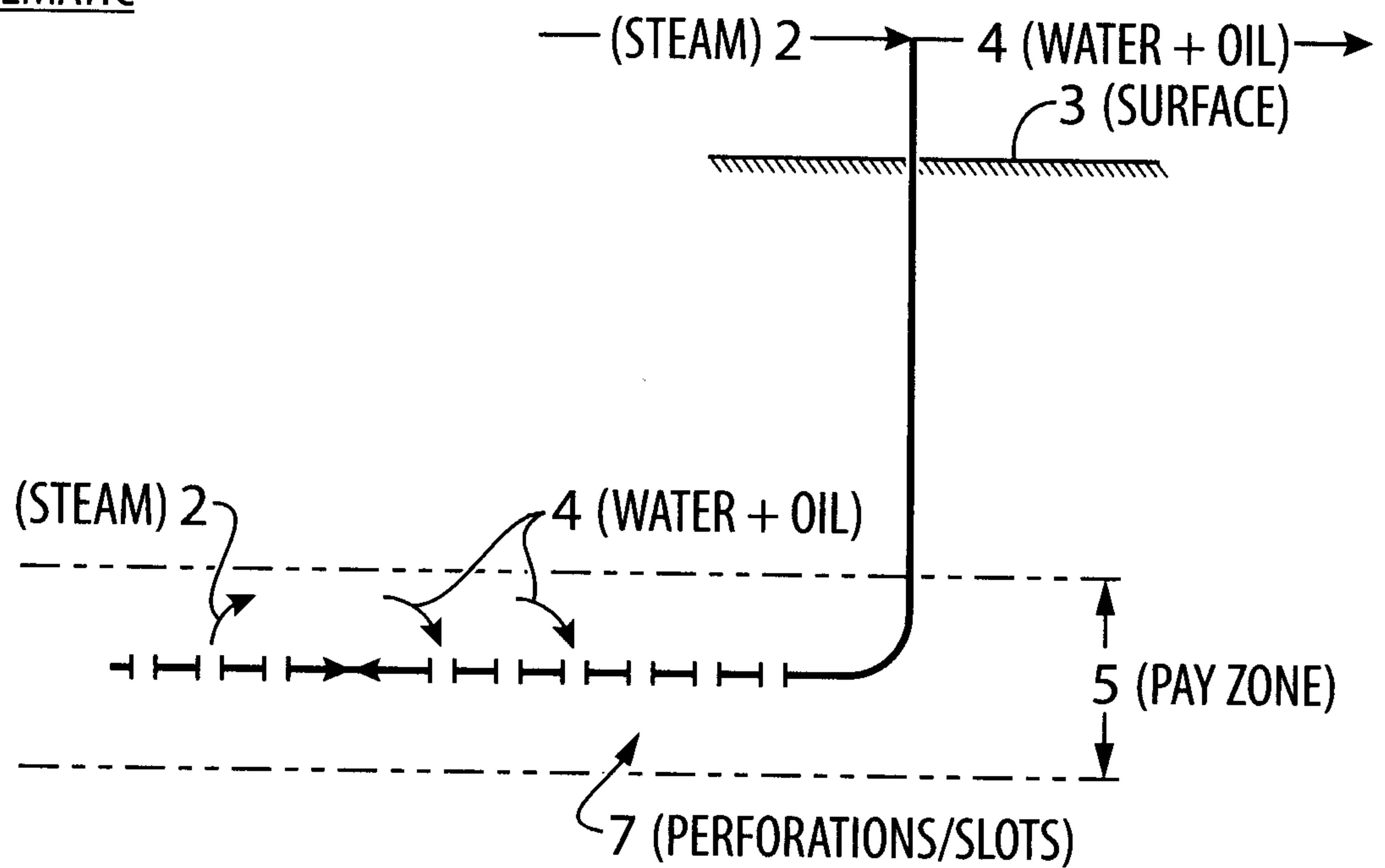
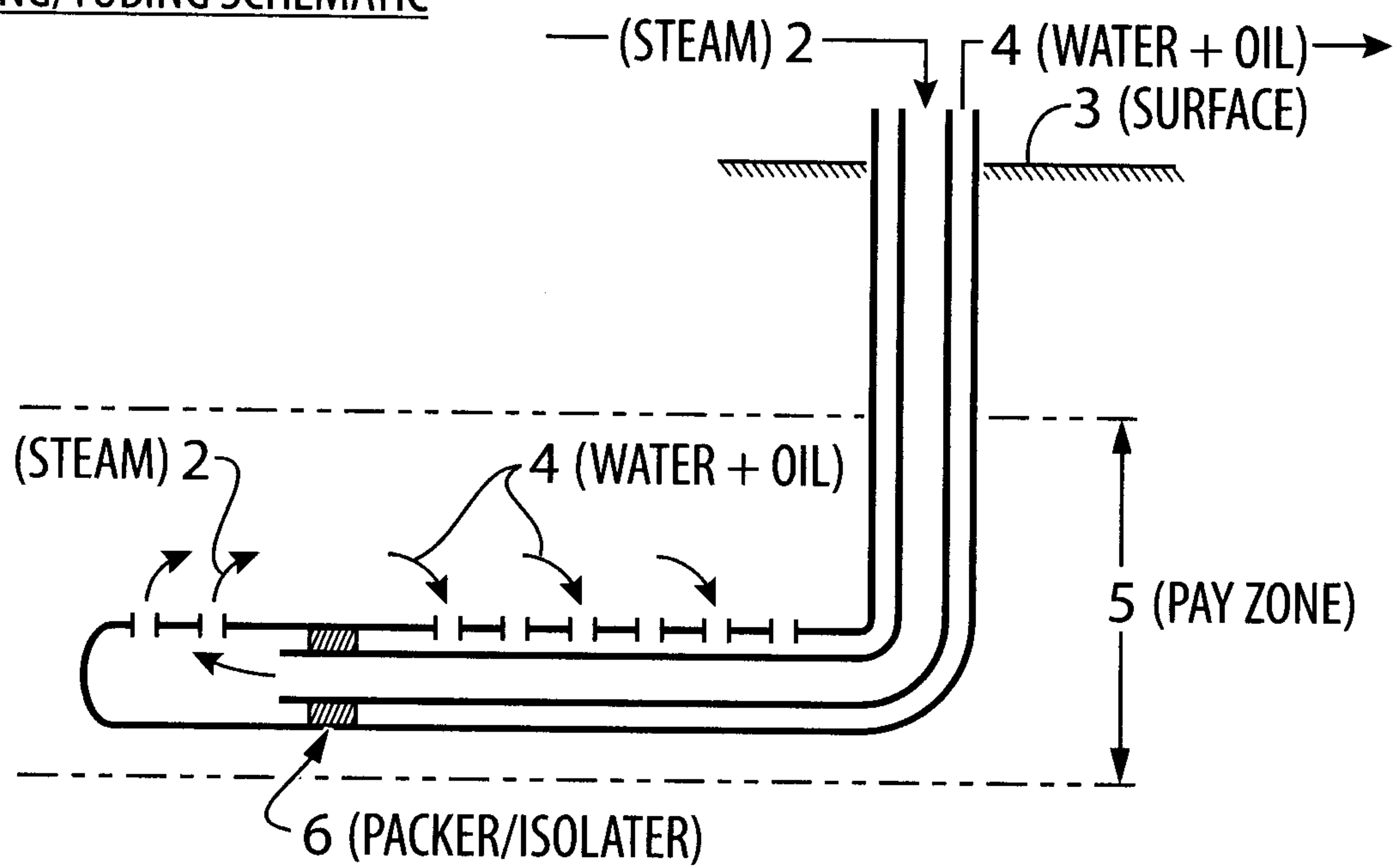
1. A Single Well Steam Assisted Gravity Drainage (SWSAGD) process to recover liquid hydrocarbons from an underground hydrocarbon reservoir, wherein said single well comprises a single substantially horizontal well comprising a heel area and a toe area, wherein the toe area of said horizontal well extends upwardly into the reservoir;
said process comprising 1- injecting steam into the reservoir via a steam injection area, proximate the toe area of the horizontal well, 2- allowing the steam to condense causing heated hydrocarbon liquids and water to drain into a liquid recovery zone of the horizontal well between the toe area and the heel area of the horizontal well, and 3- recovering said heated hydrocarbon liquids to the ground surface from the liquid recovery zone.
2. A SWSAGD substantially horizontal well for hydrocarbon recovery in a hydrocarbon containing reservoir in the ground, said well having a predetermined length, comprising a heel section, and a toe section distant said heel section, wherein said toe section is at a first predetermined depth in the ground and said heel section is at a second predetermined depth in the ground, such that said heel section is deeper in the ground than said toe section.
3. The SWSAGD of claim 2 wherein said SWSAGD further comprises a steam injection zone and a liquid recovery zone.
4. The SWSAGD of claim 3 wherein said steam injection zone is proximate said toe section and said liquid recovery zone is proximate said substantially horizontal well.
5. The SWSAGD of claim 2 wherein said toe section for steam injection has a length less than 20 percent of the total horizontal well length.
6. The SWSAGD of claim 2 further comprising at least one thermal packer isolating the steam injection zone from the liquid recovery zone.
7. The process of claim 1 wherein the hydrocarbon is heavy oil with a density of $10 < \text{API} < 20$.

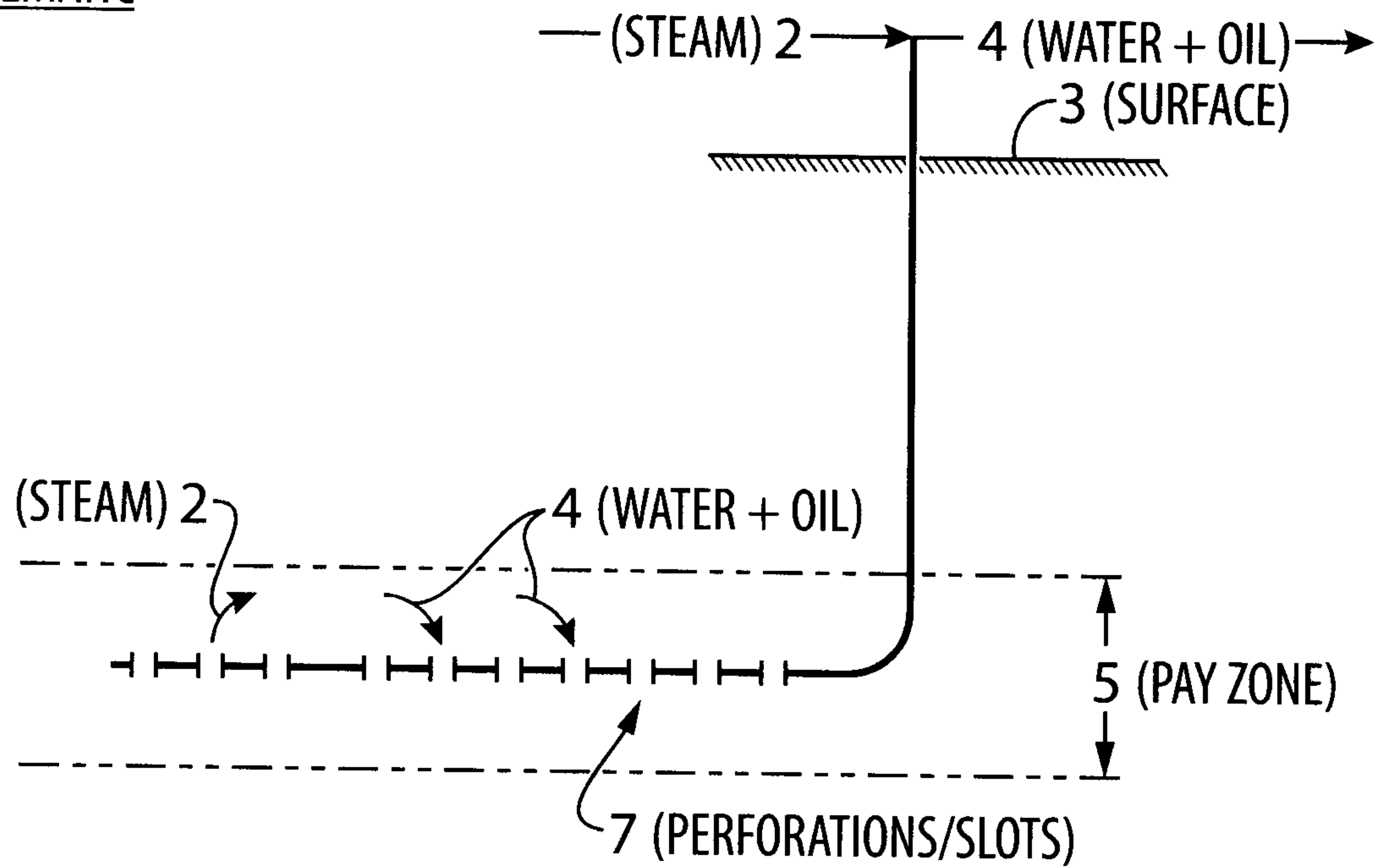
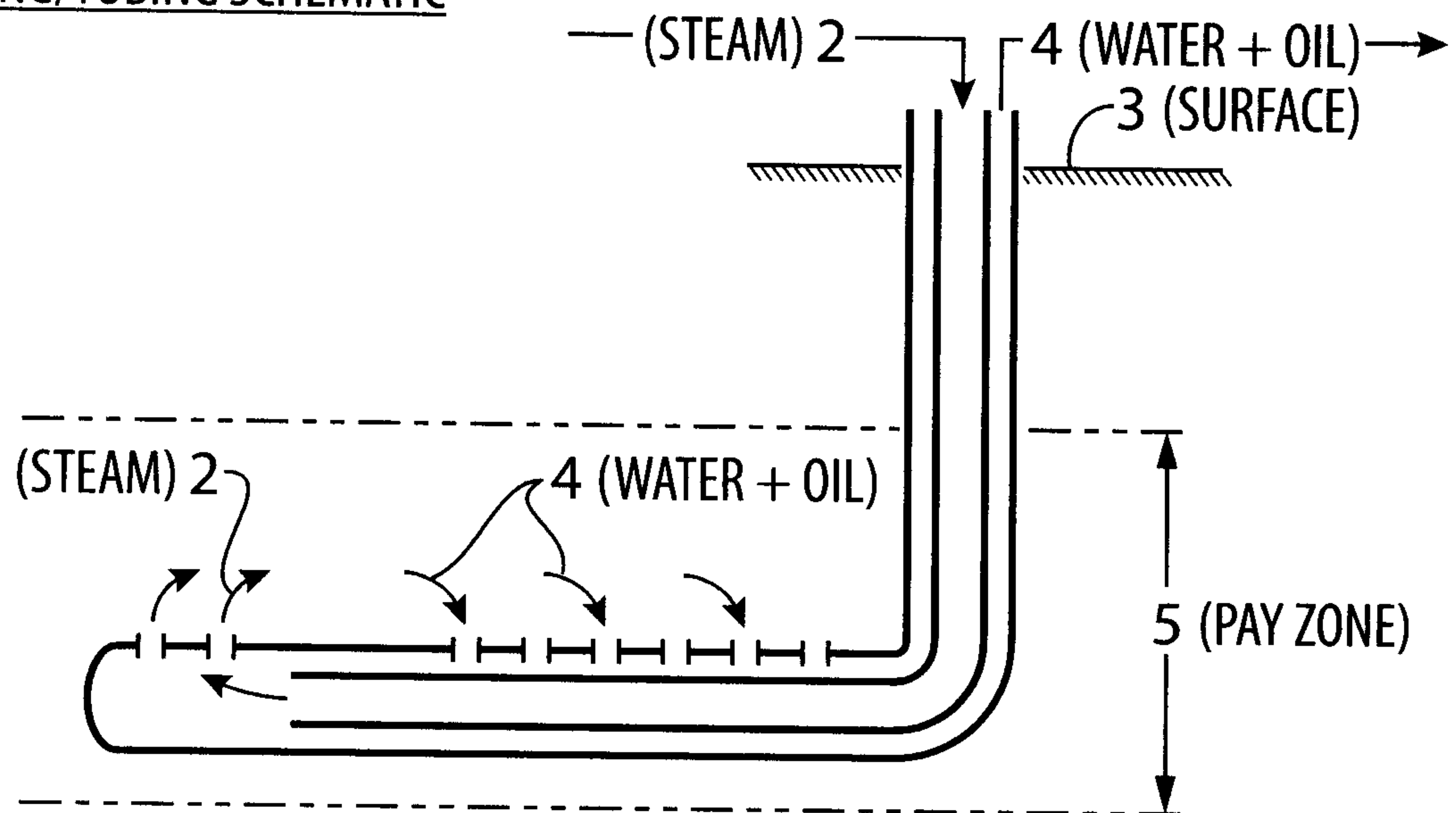
8. The process of claim 7 wherein the hydrocarbon is bitumen with density of $API < 10$.
9. The process of claim 1 wherein the toe area for steam injection constitutes less than 20 percent of the total horizontal well length.
10. The process of claim 1 wherein steam injection has an elevation target of greater than about 2 meters above the bottom of said reservoir.
11. The process of claim 10 wherein said elevation target is achieved by drilling up-dip in a dipping reservoir.
12. The process of claim 1 wherein the substantially horizontal section of the well is completed closer than 2 meters from the bottom of the reservoir.
13. The process of claim 1 wherein the toe section for steam injection is shorter than 50 meters.
14. The process of claim 1 further comprising isolating the steam injection from the liquid recovery zone via a packer (thermal packer).
15. The process of claim 1 with a steam injection point at least 5 meters higher than the highest point of liquid recovery zone.
16. The process of claim 1 wherein at least one blank pipe section is placed between the steam injection area and liquid recovery zone.
17. The process of claim 16 wherein at least one packer is placed in the blank pipe section isolating the steam injection area from the liquid recovery zone.
18. The process of claim 1 further comprising pumping produced fluids out of the well via an offset packer.

19. The process of claim 1 further comprising providing an operating pressure in the reservoir sufficient to lift the produced liquids to the surface, without using an artificial lift system.

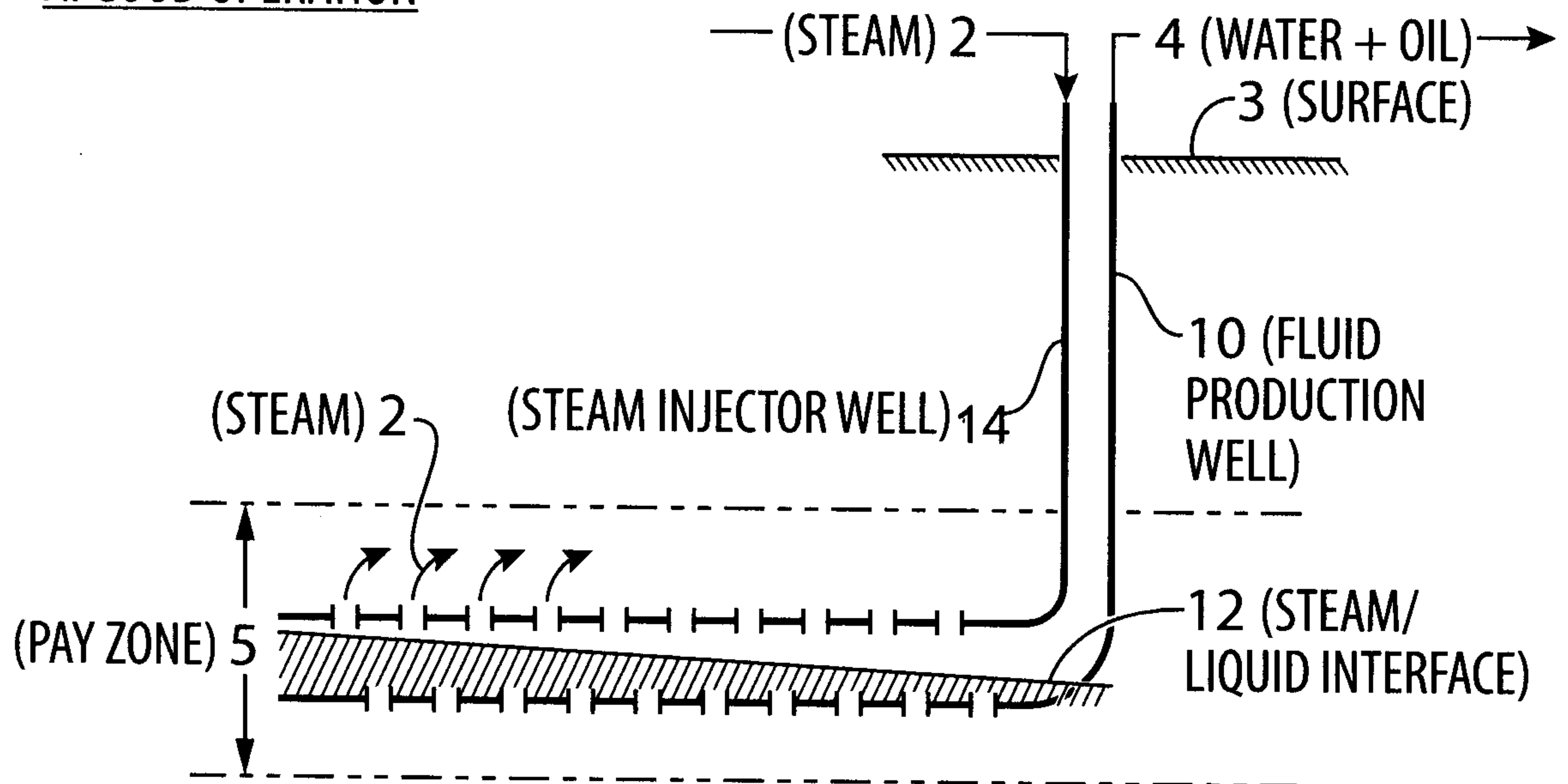
20. The process of claim 1 further comprising conveying the produced liquids to the surface via a gas-lift.

21. The process of claim 1 further comprising conveying steam to the toe area of the well via insulated concentric tubing.

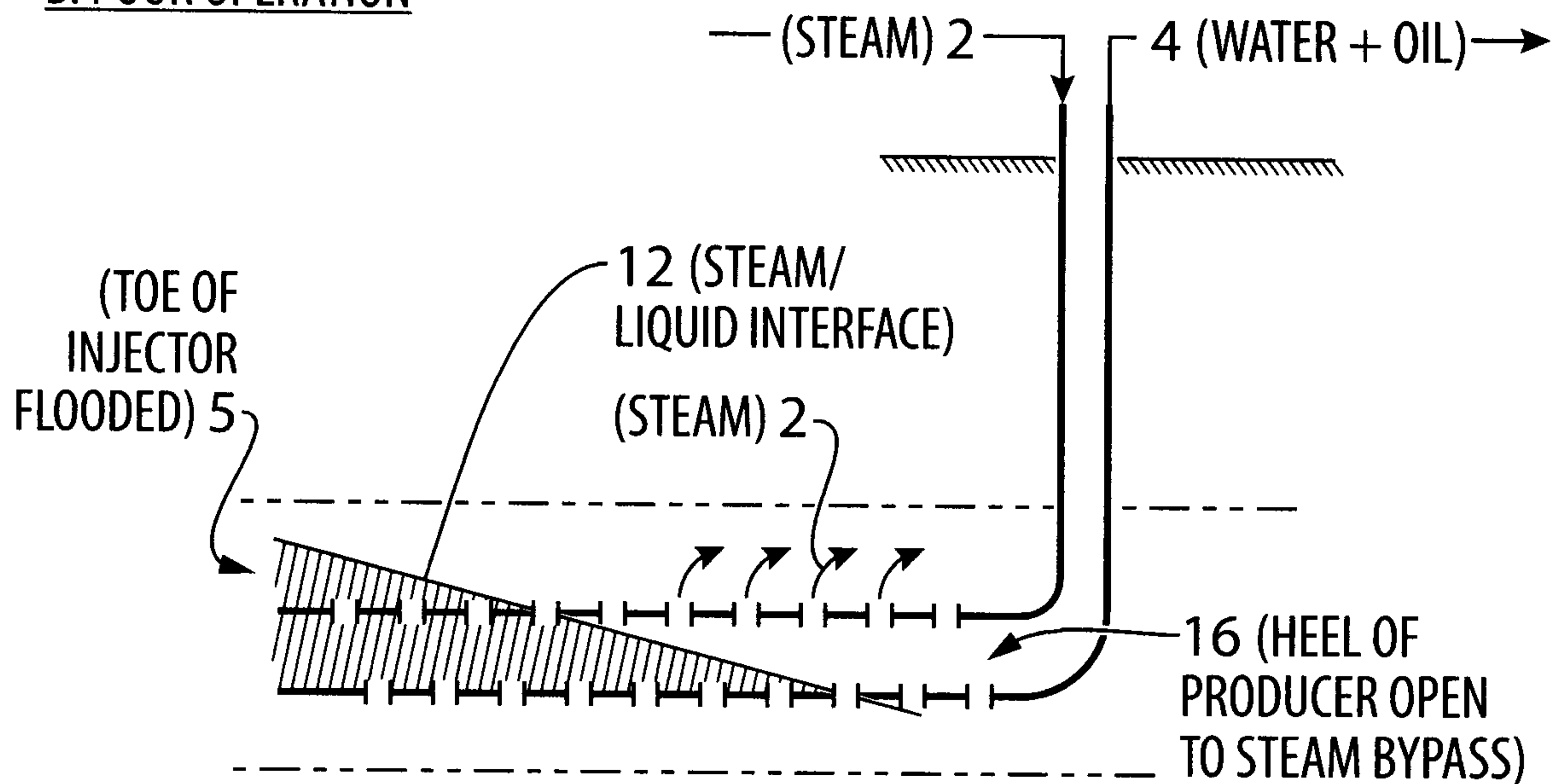
A. SCHEMATICB. PIPING/TUBING SCHEMATICSWSAGD**FIG.1**

A. SCHEMATICB. PIPING/TUBING SCHEMATICSWSAGD**FIG.2**

A. GOOD OPERATION

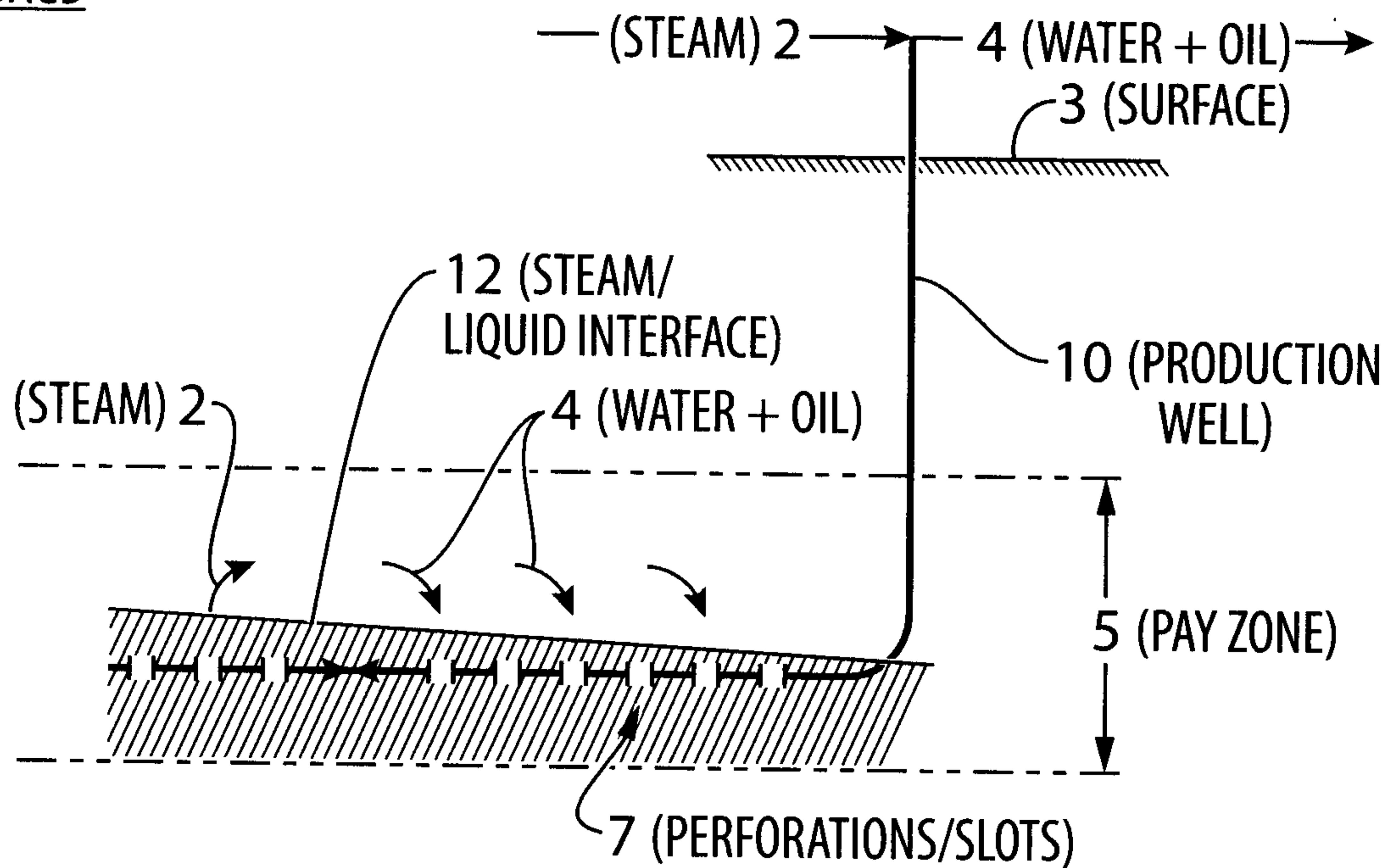
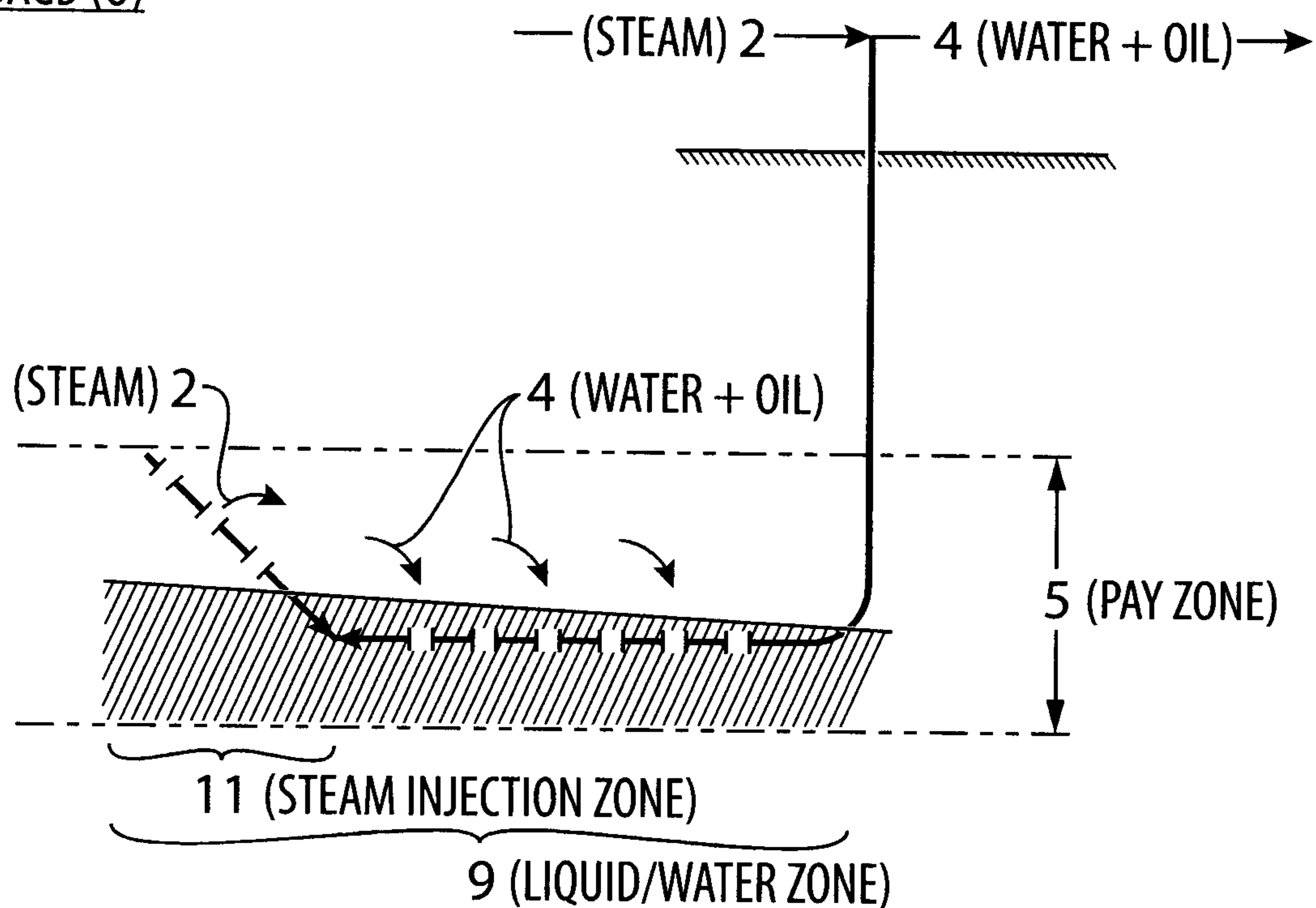


B. POOR OPERATION



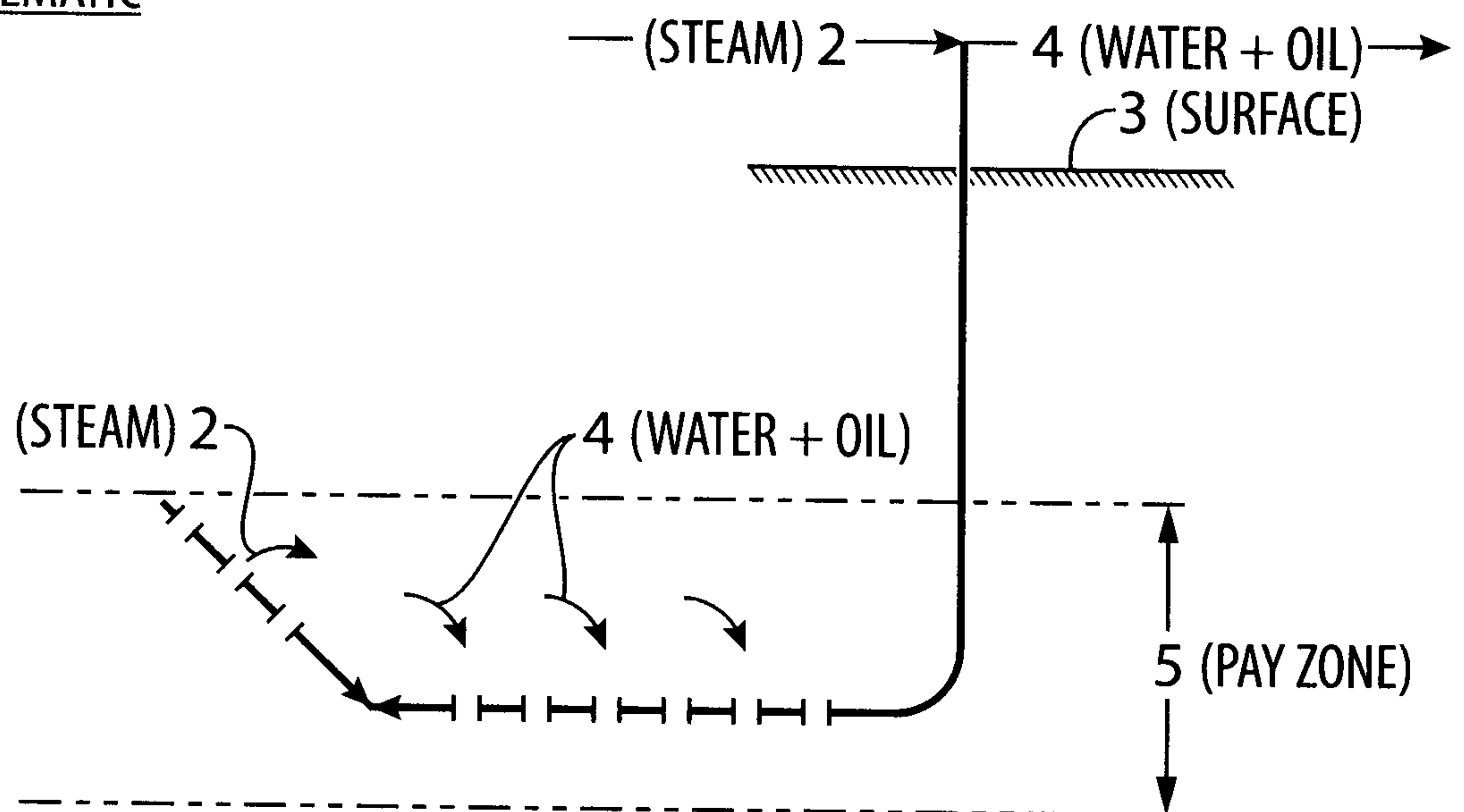
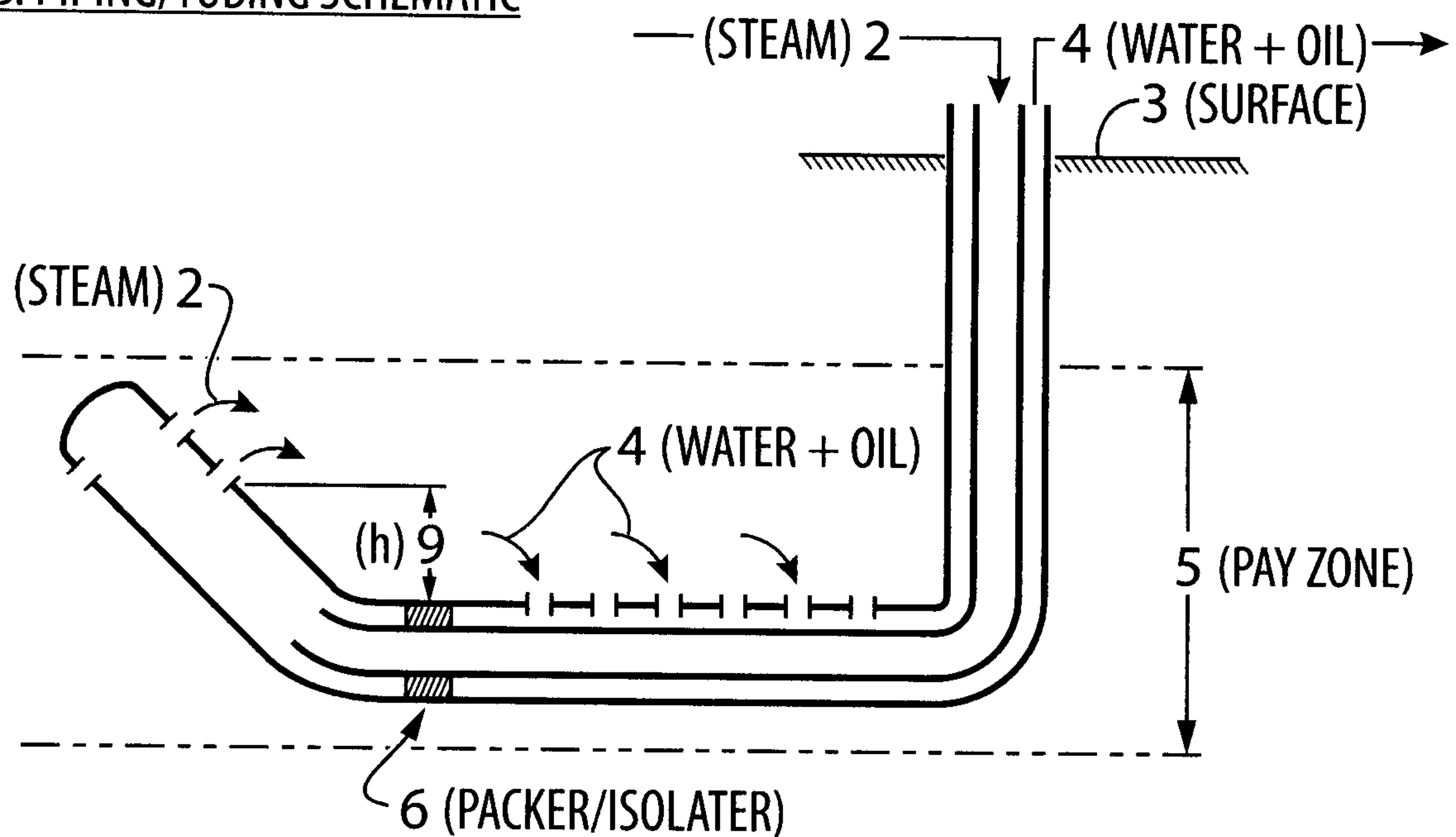
SAGD HYDRAULIC LIMITATIONS

FIG.3

A. SWSAGDB. SWSAGD (U)

SWSAGD/SWSAGD (U) HYDRAULIC LIMITATIONS
(MATURE OPERATIONS) (STEADY-STATE)

FIG.4

A. SCHEMATICB. PIPING/TUBING SCHEMATIC

h = STAND OFF BETWEEN STEAM INJECTION AND LIQUID PRODUCTION

SWSAGD (U)

FIG.5

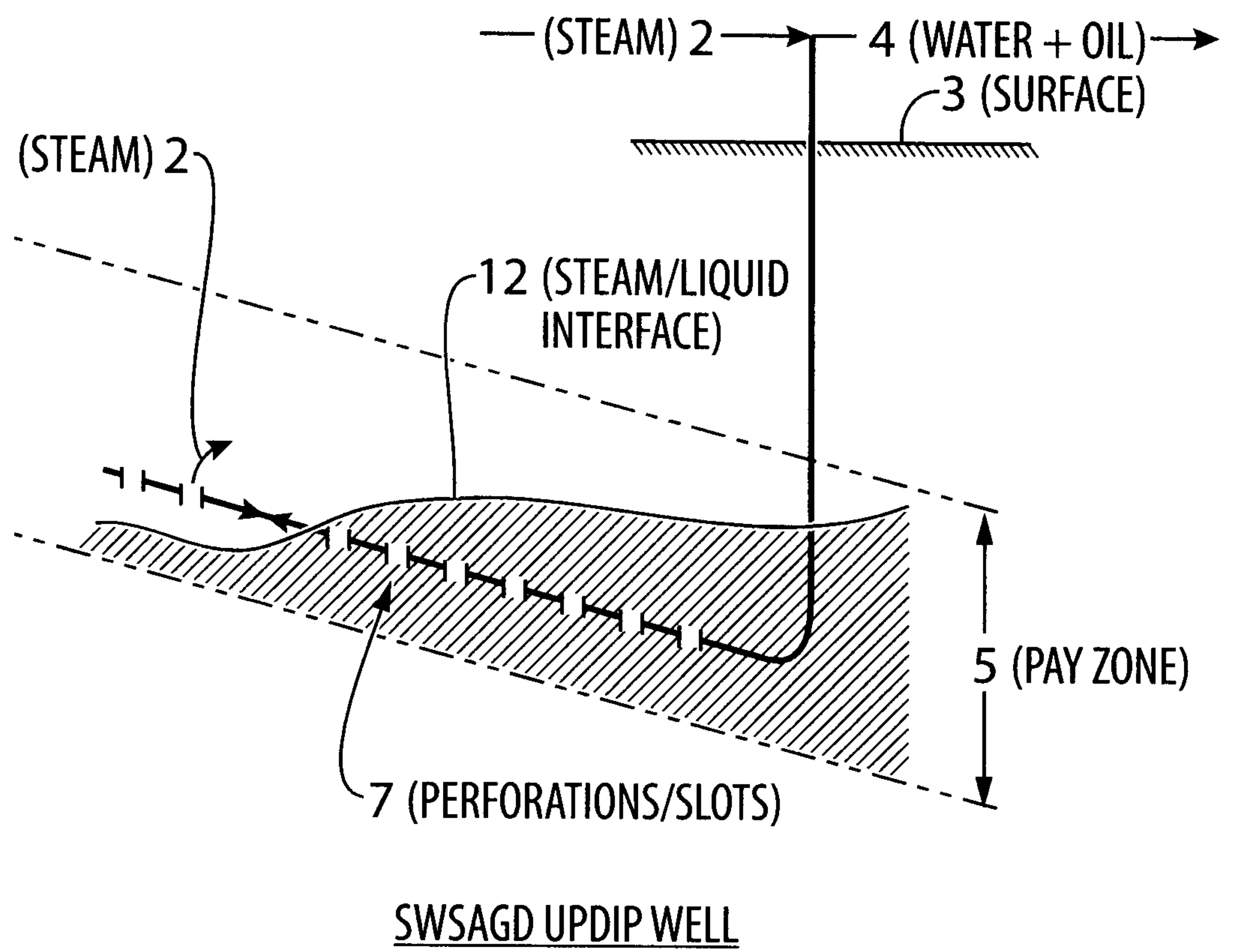
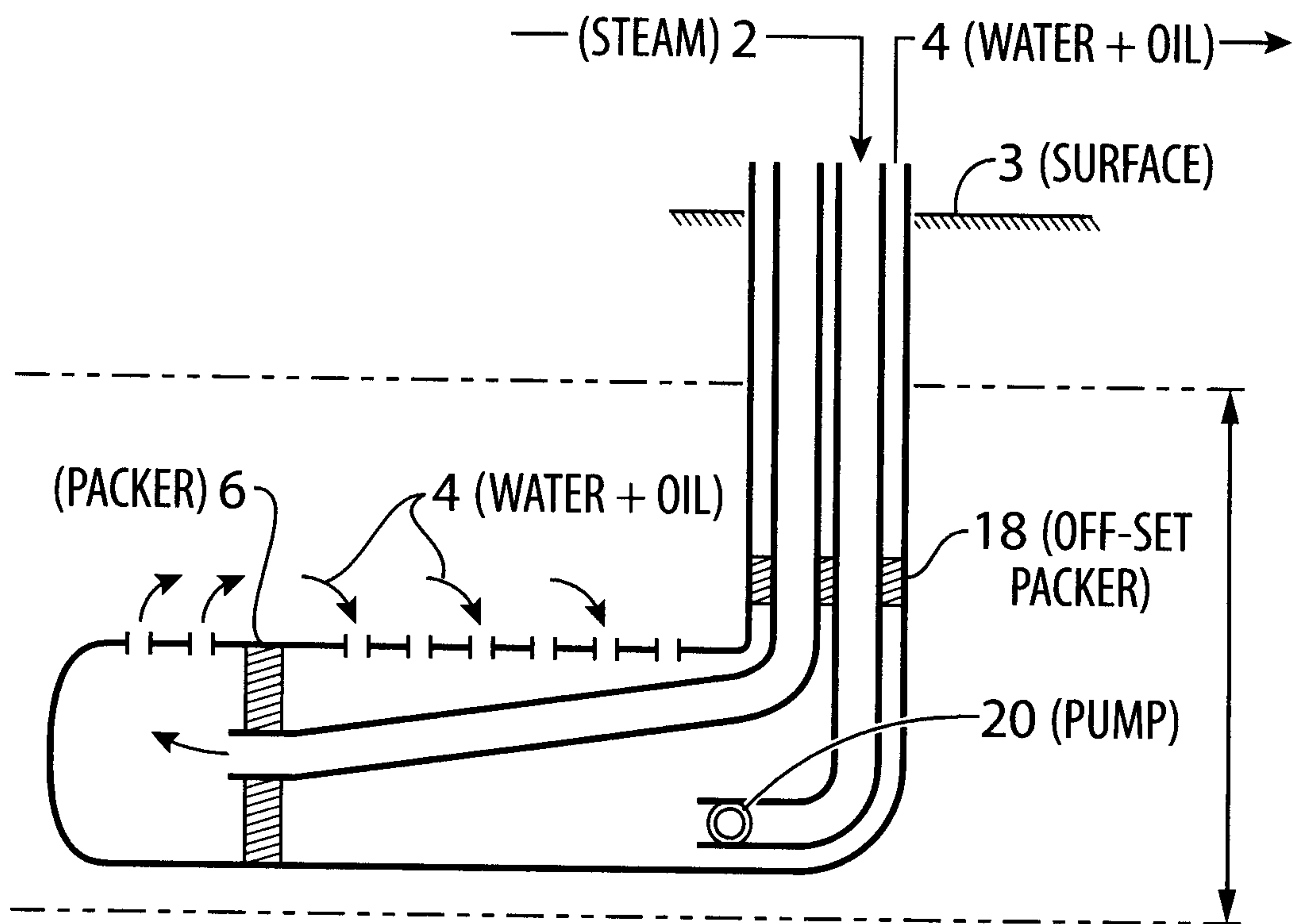


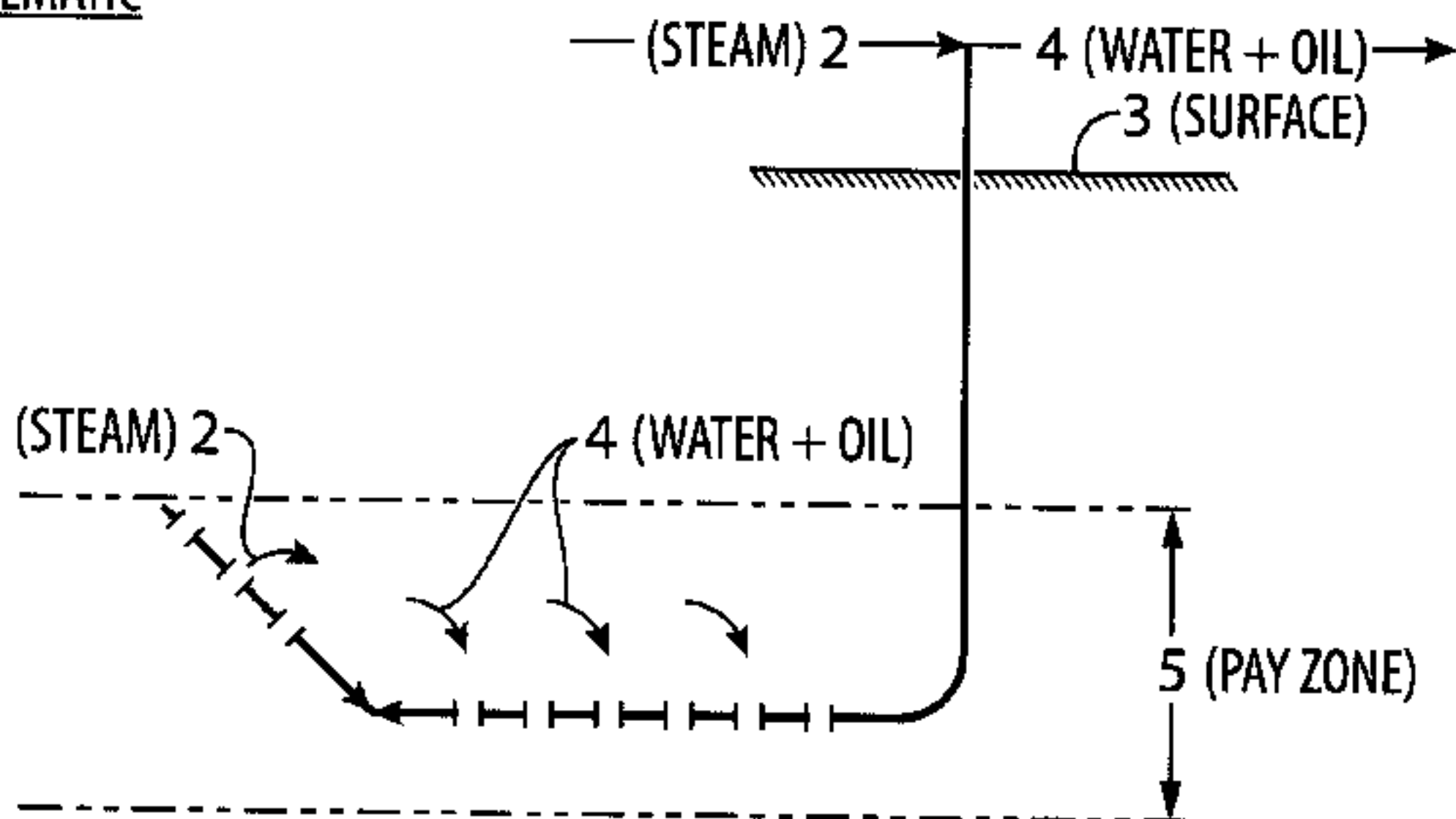
FIG.6



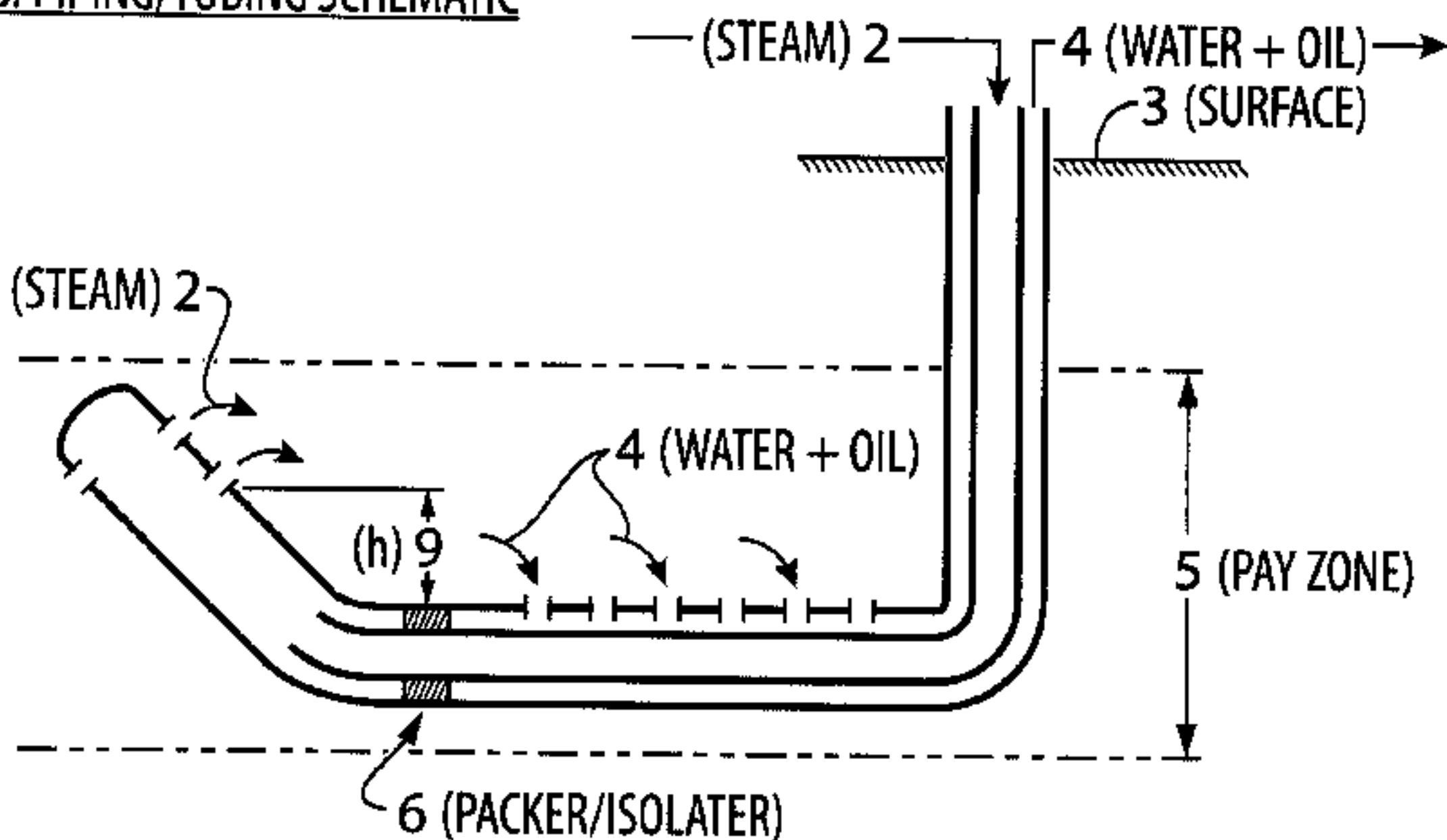
SWSAGD PUMP (PIPING SCHEMATIC)

FIG.7

A. SCHEMATIC



B. PIPING/TUBING SCHEMATIC



h = STAND OFF BETWEEN STEAM INJECTION AND LIQUID PRODUCTION

SWSAGD (U)