Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2874695 A1 2015/06/09

(21) 2 874 695

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) **Date de dépôt/Filing Date:** 2014/12/09
(41) **Mise à la disp. pub./Open to Public Insp.:** 2015/06/09
(30) **Priorité/Priority:** 2013/12/09 (US61/913,737)

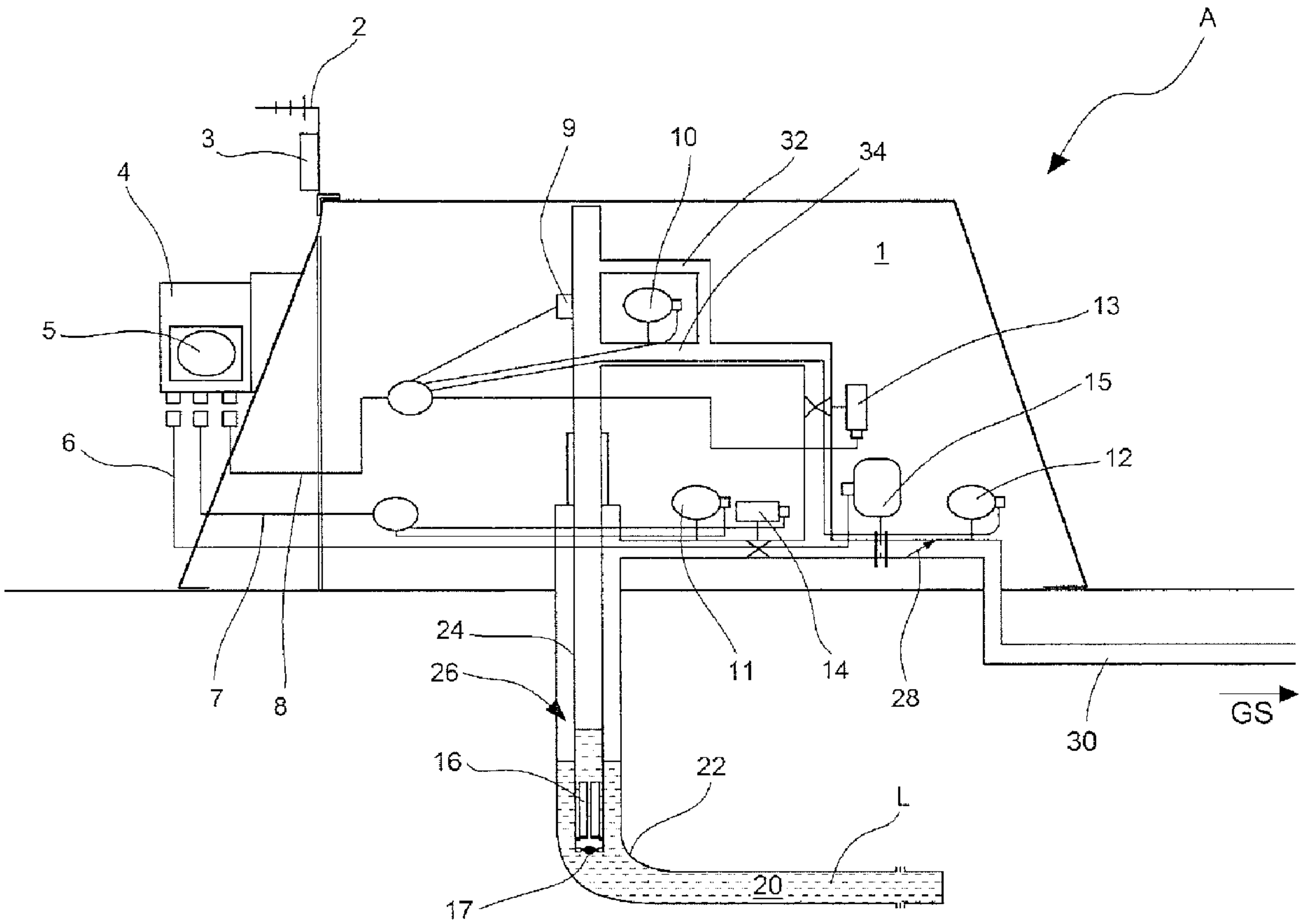
(51) **Cl.Int./Int.Cl.** ***E21B 43/12*** (2006.01), ***E21B 34/06*** (2006.01), ***F04B 47/12*** (2006.01)

(71) **Demandeur/Applicant:**
BIG GREEN TECHNOLOGIES INC., CA

(72) **Inventeur/Inventor:**
HUGHES, ROBERT W., CA

(74) **Agent:** BENNETT JONES LLP

(54) **Titre : SYSTEMES ET PROCEDES DE POMPAGE PNEUMATIQUE**
(54) **Title: PLUNGER LIFT SYSTEMS AND METHODS**




(57) **Abrégé/Abstract:**
Methods and systems for increasing the length of time of effectiveness for the plunger lifting liquid load from a gas well, by allowing the plunger to stay ahead of the liquid inflow into the wellbore. The methods and systems involve a plunger control logic which uses measurements of the liquid load pressure, the casing pressure, the line pressure, and the tubing pressure to time the opening and closing of various valves, in order to optimize the lifting of the liquid load to surface.

## Abstract

Methods and systems for increasing the length of time of effectiveness for the plunger lifting liquid load from a gas well, by allowing the plunger to stay ahead of the liquid inflow into the wellbore. The methods and systems involve a plunger control logic which uses measurements of the liquid load pressure, the casing pressure, the line pressure, and the tubing pressure to time the opening and closing of various valves, in order to optimize the lifting of the liquid load to surface.

# Plunger Lift Systems and Methods

## Priority Application

This application claims priority to US provisional application serial number 61/913,737, filed December 9, 2013.

## Field of the Invention

The invention relates to plunger lift systems and methods for liquid production in a gas well, particularly a deviated or horizontal gas well.

## Background of the Invention

Plunger lift systems have been used in vertical natural gas wells to produce liquid when gas production is compromised by liquid loading. These plunger lift systems are utilized to artificially lift and extract liquid out of a gas well (at surface) once flow rates decline below critical rates resulting in decreased gas production.

Critical rate is generally defined as the minimum flow rate below which liquids cannot be continually produced (brought to surface) in a gas well. If these liquids are not lifted to surface, they settle in the wellbore, thus restricting and impeding the production of natural gas as the gas has to "bubble flow" through the liquids. At this point, the well is in a liquid loading stage. If not dealt with, liquid loading will increase hydrostatic back pressure on the reservoir and reduce the near well gas relative permeability, leading to progressively reduced gas production from the well or even the inability to produce gas (in economical volumes). Artificial lift methods need to be utilized to decrease liquid loading and achieve increased gas production.

Due to continual reduction of reservoir pressure in a producing well, the majority of gas wells will eventually achieve a liquid loading state and, in turn, will require intervention and deployment of artificial lift production techniques to re-establish higher natural gas production rates.

Figure 1 depicts a typical production depletion curve associated with gas wells, and some recognized technologies and techniques used to enhance production are described with reference to Figure 1. Figure 1 shows two curves: an actual decline curve of a gas well ("$DC_A$") and a natural decline curve of the gas well ("$DC_N$"). IG denotes the incremental gain in production required to bring the well from $DC_A$ to $DC_N$.

At stage 20, the gas well is a free flowing gas well ("FFGW"), which is the initial stage of the gas well that has been brought on to production. Production is either with casing production only or with a tubing production string installed upon initial well completion.

At or around stage 22, switching valve technology ("SVT") is used to enable the well to (i) produce up the casing and tubing simultaneously, (ii) shut in tubing and flow casing, or (iii) shut in casing and flow tubing. If the tubing production string is not installed at stage 20, the tubing production string is installed subsequently to utilize SVT.

At or around stage 24, SVT with stop cocking ("SVTSC") may be used to allow the well to close the tubing and casing simultaneously, thereby enabling the well to build up energy to lift liquids when the tubing or casing valves are opened.

At or around stage 26, SVT with plunger lift optimization technology ("SVTPLOT") allows SVT to be used with a plunger lift system, which is installed in the tubing production string at or around stage 26.

At or around stage 28, plunger lift optimization technology ("PLOT") enables the well to only flow up the tubing string. In this embodiment, the casing valve is closed as the casing is only used to allow the well to build up potential energy once the well is closed.

At or around stage 30, artificial lift technology ("ALT"), e.g. down hole pumps, is used to lift liquid when the well requires excessive shut in time to build up potential energy to lift the liquid and the plunger.

In Figure 1, liquid loading starts in a gas well once the flow rate falls below the critical rate for that particular gas well configuration. It is therefore important to understand the degree of liquid loading by measuring the hydrostatic pressure produced from the build-up of liquid.

## Summary of the Invention

In accordance with an aspect of the present invention, there is provided a method of producing liquid load from a horizontal section of a well having a casing in its vertical section, the horizontal section and the vertical section being connected by a heel, and the well having a plunger lift system installed therein, the plunger lift system comprising: a tubing string with an upper end and a lower end, and having a plunger slidably movable therebetween, the tubing string and the casing defining a casing string therebetween, the tubing string being in fluid communication with a line via a tubing valve, the tubing string disposed in the vertical section, with its lower end at or near the heel and having an inlet, the tubing string having a tubing pressure and the line having a line pressure, and the casing string being in fluid communication with the line via a casing valve, the casing string having a casing pressure, the method comprising:

(a) keeping the tubing valve and the casing valve closed for an initial off time;

(b) determining a potential energy pressure at the expiry of the initial off time;

(c) opening tubing valve for a pre-set time;

(d) comparing a plunger arrival time with a preselected range and: (i) keeping the tubing valve open if the plunger arrival time is within the preselected range; (ii) reducing an after-flow time if the plunger arrival time is above the preselected range; or (iii) increasing the after-flow time if the plunger arrival time is below the preselected range;

(e) closing the tubing valve at the expiry of the after-flow time;

(f) determining a liquid load pressure;

(g) keeping the tubing valve and the casing valve closed for the initial off time;

(h) opening the tubing valve partially when the difference between the casing pressure and the line pressure is substantially equal to the potential energy pressure, and keeping the tubing valve open for a pre-set burping time;

(i) closing the tubing valve at the expiry of the pre-set burping time;

(j) opening the tubing valve when the difference between the casing pressure and the line pressure is substantially equal to the potential energy pressure; and

(k) comparing the plunger arrival time with the preselected range and: (i) reducing the pre-set burping time and/or increasing a potential energy pressure time, if the plunger arrival time is above the preselected range; (ii) increasing the liquid load pressure and/or pre-set burping time, if the plunger arrival time is below the preselected range; or (iii) comparing the casing pressure with a flowing clean casing pressure or a lowest recorded casing pressure, if the plunger arrival time is within the preselected range.

It is to be understood that other aspects of the present invention will become readily apparent to those skilled in the art from the following detailed description, wherein various embodiments of the invention are shown and described by way of illustration. As will be realized, the invention is capable for other and different embodiments and its several details are capable of modification in various other respects, all without departing from the spirit and scope of the present invention. Accordingly the drawings and detailed description are to be regarded as illustrative in nature and not as restrictive.

Brief Description of the Drawings

Referring to the drawings, several aspects of the present invention are illustrated by way of example, and not by way of limitation, in detail in the figures, wherein:

Figure 1 is an exemplary graph showing the typical decline of production in a gas well;

Figure 2 is a schematic view of the system according to one embodiment of the present invention;

Figure 3 is a front view of a sample wellhead enclosure;

Figure 4 is a flow chart of a timer mode phase according to an embodiment of the present invention;

Figure 5 is a flow chart of a "burping" process according to an embodiment of the present invention;

Figure 6 is a schematic view of the system during the "burping" process;

Figure 7 is a schematic view of the system wherein the well is shut in;

Figure 8 is a schematic view of the system wherein the well is producing;

Figure 9a is a liquid load production method according to one embodiment of the present invention;

Figure 9b is a liquid load production method according to another embodiment of the present invention; and

Figure 10 is a schematic view of a system according to another embodiment of the present invention.

Detailed Description of Various Embodiments

The description that follows and the embodiments described therein, are provided by way of illustration of an example, or examples, of particular embodiments of the principles of various aspects of the present invention. These examples are provided for the purposes of explanation, and not of limitation, of those principles and of the invention in its various aspects. In the description, similar parts are marked throughout the specification and the drawings with the same respective reference numerals. The drawings are not necessarily to scale and in some instances proportions may have been exaggerated in order more clearly to depict certain features.

Measuring the hydrostatic pressure of the liquid load and lifting the liquid load to surface with a plunger lift system enables the plunger to stay ahead of the liquid inflow into the wellbore, thus increasing the length of time of effectiveness for the plunger lift system. To optimize this, the plunger lift system is preferably controlled from above ground using control algorithms and logic (referred to herein as “Plunger Control logic” or “Plunger Control unit”).

The use of supervisory control and data acquisition ("SCADA") systems in the natural gas production industry is used to achieve improved gas well production through automation. The present invention includes the addition of a Plunger Control unit to a remote terminal unit ("RTU"), which is the control box or “onsite brain” of any SCADA system. For existing SCADA systems, the addition of a Plunger Control unit to the RTU may be achieved on a cost effective basis.

Although many types of plungers may be used in a plunger lift system, a conventional plunger may be used for the purposes the present invention, in conjunction with the Plunger Control logic. Other types of plungers may be used with modifications to the Plunger Control logic.

## I. Timing for Installation of Plunger Control Logic System

On a newly drilled and completed gas well, it may be economically beneficial to install at the time of completion the Plunger Control unit, as well as some or all of the above-ground instrumentation and controls, wellhead enclosure, RTU, SCADA system, cabling, piping, etc.

A natural gas producer can determine whether to flow the well up the casing only or to install a tubing production string as part of the initial well completion. This determination is done on a well-by-well basis, considering calculated gas volumes, calculated liquid volumes, type(s) of liquid, well configuration and other reservoir characteristics.

Once the well advances to the liquid loading stage (i.e. stage 24 in Figure 1), the tubing string (if not already installed), plunger, lubricator and down hole bumper spring assembly are installed, as well as any necessary above-ground instrumentation and controls, etc., in order to implement the present invention. If already installed upon initial well completion as discussed above, the above-ground instrumentation and controls, etc., are already in place and ready for deployment.

Effective use of a plunger lift system is extended until a decision to exercise a down hole pump technology is considered. Also, installation of most or all of the invention as part of the new well drill and/or completion capital cost may: (i) eliminate costly additions to the well when gas and liquid production is lower, (ii) decrease the operating cost of the well and/or (iii) decrease the barrel of oil equivalent (BOE) operating factor.

With reference to Figure 1, the present invention may be installed at or around stage 24, when the liquid loading stage begins. Installing the present invention at an early stage (i.e. the beginning of the liquid loading stage) allows the incremental gain to be captured at an earlier stage in the well's life cycle, thereby permitting the well to follow its natural decline curve while potentially deferring extra capital costs (such as installation of a down hole pump).

## II. Horizontal or Deviated Gas Wells

Horizontal or deviated wells are common in shale gas plays, which, in many cases, are "liquid rich" (i.e. gas condensates). Where the liquids are comprised of condensates, not only is gas production reduced and compromised upon the occurrence of liquid loading of the well, production of condensates is also curtailed and left in the well bore. In light of the market price for condensates, production thereof is often available in economical volumes, and can be advantageous to achieving expeditious cost recovery associated with the implementation, for example, of the invention pertaining to the Plunger Control logic described herein. For purposes hereof and as the context may require, the term "horizontal well" includes horizontal gas wells and deviated gas wells.

In a horizontal well, reducing bottom hole flowing pressure by reducing hydrostatic pressure in the vertical and deviation zone of the well bore decreases back pressure on the reservoir.

In accordance with an embodiment of the present invention, two systems and methods of removing liquid load in a horizontal well using the Plunger Control algorithms in a SCADA system are described herein.

**System A: Tubing String into the Deviation Zone**

Determining where to land a plunger lift system in a horizontal well is an important task as the deeper the plunger is landed the more liquid load may be lifted to surface. In most horizontal wells, the horizontal leg of the well bore generally has some less restricted gas production as the liquids tend to drop to the lower part of the well bore. Therefore, by lifting the liquid load in the vertical and heel section of the horizontal well can: (i) decrease the back pressure on the reservoir, (ii) increase the gas flow from the horizontal section, and (iii) keep the top perforations of the well semi-dry.

Figure 2 shows the components for a plunger lift System A for use with the plunger lift landing methods described hereinbelow. For existing wells, some of the components of the System may already be installed or present at the gas well.

A well 20 has a substantially vertical section connected to a substantially horizontal section by a heel 22. System A comprises a tubing production string 24 that is provided down hole, in the vertical section. The annulus formed between the outer surface of string 24 and the inner surface of the well casing defines a casing production string 26. A lower end of the string 24, extending into a portion of the heel 22, includes an inlet, which in this embodiment is a standing valve 17, a plunger 16, and a lift bumper spring assembly (not shown). Standing valve 17 may be part of a standard plunger lift standing valve system, and is preferably installed below the plunger lift bumper spring assembly to allow liquids to be held in the tubing string when the well is shut in. Further, plunger control algorithms may be used with a variety of different plungers.

The casing production string 26 is selectively in communication with a gathering system GS (not shown) via a line 30. Line 30 includes a casing pressure transmitter 11, a casing valve 14, a line pressure transmitter 12, and a multi-variable transmitter 15 ("MVT"). Line 30 may include a check valve 28.

The upper end of string 24 is in communication with variety of above-ground equipment, including a plunger arrival switch 9, a tubing pressure transmitter 10, and line 30 via a tubing valve 13.

The plunger arrival switch 9 detects when the plunger lift travels past the switch. The plunger arrival switch is preferably installed between a flow tee 32 and the bypass piping 34 below a lubricator spring (not shown) at or near the upper end of string 24.

The tubing pressure transmitter 10 detects the pressure in the tubing production string 24 in gauge pressure. The casing pressure transmitter 11 detects the pressure in the casing production string 26 in gauge pressure. The line pressure transmitter 12 detects the pressure in the gathering system pressure at the point of access of the well to the gathering system in gauge pressure. Preferably, the line pressure transmitter 12 is installed downstream of check valve 28.

Tubing valve 13 allows the selective opening and restriction of fluid communication between string 24 and the GS in a stepping action as required by the Plunger Control logic. Preferably, tubing valve 13 is electrically actuated. Casing valve 14 allows the selective opening and restriction of fluid communication between casing production string 26 and the GS in a stepping action as required by the Plunger Control logic. Preferably, casing valve 14 is electrically actuated.

The MVT 15 measures gas production from the well, preferably in compliance with American Gas Association (AGA) gas measuring standards.

The system includes an antenna 2, which may be a directional or omni antenna, and may be used on a cell phone or spread spectrum radio or the like. If there is an existing SCADA system at the well site, the antenna is likely already previously installed.

While there may be various alternate power sources, solar power is commonly used with SCADA systems. In one embodiment, at least one solar panel 3 is included in the system. The solar panel 3 is preferably sized according to the location of the well, with sizing also being a function of the instrumentation required. If there is an existing SCADA system at the well site, the solar panel may be previously installed, though any existing solar panel may be upgraded to accommodate additional power requirements for the additional instrumentation of the present invention.

An RTU with battery(ies) 4 is preferably housed in a cabinet for protection from outdoor climate conditions. The battery is preferably sized according to the location, power requirements, and autonomy (i.e. how many days without battery charging from the solar panel 3 can the system handle). If an existing SCADA system is installed, the RTU is likely already on site. The battery may be upgraded to accommodate additional power requirements for the instrumentation.

A Plunger Control unit 5 may be installed in close proximity to the RTU, for example inside or outside the RTU cabinet. The Plunger Control unit 5 controls the plunger control logic. The Plunger Control unit acts as a "slave" to the RTU and communicates (most commonly) via a modbus protocol.

Cables 6, 7, and 8 are used to electrically connect the various components of the system. In one embodiment, cable 6 connects the MVT 15 to the RTU 4; cable 7 connects each of the casing pressure transmitter 11 and the casing valve 14 to the RTU; and cable 8 connects each of the plunger arrival switch 9, tubing pressure transmitter 10, line pressure transmitter 12, and tubing valve 13 to the RTU.

The system may include a wellhead enclosure 1 for enclosing one or more components of the system. In the illustrated embodiment shown in Figure 2, the plunger arrival switch, tubing pressure transmitter, casing pressure transmitter, line pressure transmitter, tubing valve, casing valve, MVT, and a portion of cables 6, 7, and 8 are housed in enclosure 1. The enclosure 1 is for minimizing any potential adverse effects of weather on the components. A sample wellhead enclosure is shown in Figure 3, but of course other types of enclosures may be used. Optionally, a catalytic heater may also be used to protect the components from extremely low temperatures.

**Plunger Lift Control Logic**

The methods of the present invention involve determining where to land the plunger lift system in the deviation zone of the well. The determination of where to land the plunger lift system in the deviation zone helps optimize the unloading of liquid from a horizontal gas well. To help determine where to land the plunger lift system, it is preferred that the following data be obtained for evaluation and assessment prior to installation of the plunger lift system:

- a candidate well;
- a current well profile in respect of the candidate well;
- flow and pressure data preferably for the last 30 days of the producing candidate well;
- prior to installing the plunger lift system, a "fluid shot" in the well bore should be performed and given to the equipment supplier to ensure the liquid level is as close to the heel as possible; and
- the liquid in the well is cleaned or swabbed out until the depth of the liquid (calculated by the fluid shot) is close to or equal to the expected landed depth of the plunger. The casing pressure is then monitored and recorded - this pressure is

referred to herein as the "clean casing pressure" ($P_{CC}$). After the plunger lift system is installed, a "fluid shot" is performed again when the well is not flowing, and the well is swabbed out as required to the bumper spring assembly. This will calculate the $P_{CC}$. The well is then allowed to flow for a short period of time and the casing pressure is recorded again - this pressure is referred to herein as the "flowing clean casing pressure" ($P_{FCC}$).

The flowing clean casing pressure $P_{FCC}$ is a pressure value based on the configuration of the particular well and is a function of various factors, including all pressures in the well due to restrictions, friction loss, liquids, plunger, etc., that are observed when the well is flowing after the initial installation of the plunger lift system.

The plunger lift system may be installed with a qualified wire line crew with accurate instruments to measure the landing depth of the plunger.

The well is preferably left in the shut in part of the plunger cycle when the plunger installation is complete. When the plunger installation is complete, a new fluid shot is preferably performed to ensure additional liquid load has built up or accumulated.

**i) Timer Mode Phase**

After installing the plunger, the well is ready to proceed to a timer mode phase. The purpose of starting the well in the timer mode phase is to stabilize and prepare the well prior to proceeding with the implementation and/or commissioning of any production optimization techniques, such as using the Plunger Control unit and related equipment and materials.

Figure 4 shows a process flow chart for the timer mode phase 100. The gas well is preferably shut in for an initial off time $T_i$ of the plunger algorithm (step 102). The initial off time $T_i$ is preferably at least equal to the amount of time for the plunger to drop to a bumper spring assembly generally anchored in an XN or R Nipple at the lower end of the tubing string 24, plus about 25%. For example, if the average plunger drop time is about 30 minutes, the initial off time $T_i$ would be about 37.5 minutes.

The plunger lift suppliers guide usually provides average drop times of the supplied plunger (i.e. about 60 meters per minute is considered an average time).

Once the initial off time has been reached, the Plunger Control unit reads and captures the potential energy pressure $P_U$ (step 104). The potential energy pressure $P_U$ is the difference between the casing pressure $P_C$, as determined by the casing pressure transmitter, and the line pressure $P_L$, as determined by the line pressure transmitter, at this stage. This is the potential energy available to lift the plunger to surface.

At step 106, a command is then sent by the Plunger Control unit to open the tubing valve 13 for a pre-set time, which is customized for each individual well. The pre-set time is the plunger arrival time (i.e. time for the plunger 16 to vertically travel in the tubing string 24 from the bumper spring assembly to the plunger arrival switch 9) plus a calculated after-flow time, as described below. If the well has not run a plunger lift system before, a rule of thumb is to make the after-flow time about 50% of what the shut in time is initially set at. However, if the plunger lift system was not installed in the well before, a qualified operator should be on site on the first few arrivals to slow down the plunger by pinching the tubing valve if the plunger is arriving excessively fast (early).

The plunger arrival time is monitored and recorded as “early” “fast”, “slow” or “non-arrival”. The goal is to try to obtain consistent normal plunger arrivals (i.e. arrival time between “fast” and “slow”) within a narrow range of times. For example, if the plunger supplier suggests a normal arrival time of about 10 minutes, based on depth of the well (wherein the average arrival time for a conventional plunger is about 260 meters/minute), the normal arrival range may be set at approximately 9.8 minutes (“fast” arrival) to approximately 10.2 minutes (“slow” arrival). If the arrival time is in this range (step 108), the well is then allowed to flow in the tubing production string until the after-flow time expires (step 110).

If the arrival time is not in this range (steps 108 and 116), adjustments to the after-flow time (i.e. time of producing the well after the plunger passes the plunger arrival switch) are then made automatically by the Plunger Control unit. Using the above example, if the plunger arrival time is above 10.2 minutes, the after-flow time is reduced (step 118); conversely, if the arrival time is below 9.8 minutes, the after-flow is increased (step 120). After adjustments to the after-flow time are made, the well is then allowed to flow in the tubing production string until the after-flow time expires (step 110).

When the after-flow time expires, a command is sent from the Plunger Control unit to close the tubing valve 13 (step 112) to allow the plunger to fall to the bumper spring assembly and the Plunger Control unit captures and records the liquid load pressure $P_{LL}$ (step 114). The liquid load pressure $P_{LL}$ is the casing pressure $P_C$ minus the tubing pressure $P_T$.

In a preferred embodiment, once the liquid load pressure is measured, the well is shut in again (step 102), so that the timer mode phase restarts to cycle the plunger until a minimum of five consecutive normal plunger arrivals have been realized. Once at least five consecutive plunger arrivals have been achieved within the normal arrival time range, the Plunger Control unit then averages the $P_{LL}$ and $P_U$ values captured from each consecutive normal arrival. The averaged $P_{LL}$ and $P_U$ values from the at least five consecutive normal arrivals then become the constants used for the next phases, as described below. When at least five consecutive plunger arrivals have been recorded, the Plunger Control unit makes no further adjustments to the after-flow time, and the Plunger Control unit indicates and records that the gas well is stabilized.

**ii) Burping Phase**

After the well is stabilized, the plunger lift system is controlled on the liquid load and required potential energy pressure values, $P_{LL}$ and $P_U$, which have been previously captured and recorded in the timer mode phase as discussed above.

With reference to Figures 5 to 8, the burping process 200 begins with the initial off time $T_i$ (step 202) and, once reached, continues to keep the tubing valve 13 closed (step 206) until the real-time difference between the $P_C$ and $P_L$ is substantially equal to or greater than the potential energy pressure $P_U$, as determined in the timer mode phase (step 204). When the potential energy pressure is met (step 204), the Plunger Control unit sends a command to partially open the tubing valve 13 (e.g. about 20%) for the pre-set "burping" time, usually in the range of about 10 to about 30 seconds, (step 208), as shown in Figure 6, thereby initiating the "burping phase" of the well to force more liquid load (denoted by "L" in the Figures) into the tubing production string. This step is referred to as “burping”, wherein the plunger rises up string 24 off the bumper spring assembly.

The tubing valve 13 is only partially opened (e.g. about 20%) to allow the potential energy buildup in the casing to disperse slowly. The more the valve 13 is opened, the quicker the potential energy buildup is released. By opening tubing valve 13 only partially in the burping phase reduces the potential energy buildup time thereafter (i.e. when the tubing valve 13 is closed after the burping phase.

The rise of the plunger generates negative pressure on the standing valve 17, causing valve 17 to be unseated, thereby allowing some liquid load into the tubing string 24 from the well

After the pre-set "burping" time, tubing valve 13 is closed and shut in (step 210), as shown in Figure 7, until the real-time difference between the casing pressure $P_C$ and the line pressure $P_L$ is substantially equal to the potential energy pressure $P_U$, as determined in the timer mode phase (step 214). When valve 13 is closed, the plunger eventually lowers to reach the bumper spring assembly. The lowering of the plunger increases fluid pressure above the standing valve, which causes the standing valve to return to its seat, thereby restricting liquid load into the tubing string 24.

Once the potential energy pressure $P_U$ is met (step 214), the Plunger Control logic sends a command to tubing valve 13 to open same to about 100%, as shown in Figure 8, and allow the valve stay open at about 100% (step 216). Almost simultaneously, the Plunger Control logic checks that casing valve 14 is closed (step 218), and if not, the Plunger Control logic closes casing valve 14 (step 220). The Plunger Control logic may include an option to allow the tubing valve to be throttled back to reduce the plunger velocity before it contacts the lubricator spring, which may help reduce wear and tear of the lubricator spring.

With reference to Figure 8, when tubing valve 13 is open, the plunger rises from the bumper spring assembly to the upper end of the tubing string, passing the plunger arrival switch 9 along the way. The plunger arrival time is monitored and recorded as “early” “fast”, “slow” or “non- arrival”. The goal is to maintain substantially consistent normal plunger arrivals (i.e. an arrival time between “fast” and “slow”) in a narrow range of times as previously set up in the timer mode phase. If the arrival time is not in this range (step 222), adjustments to (i) the liquid load pressure value $P_{LL}$ (as determined in the timer mode phase) or the potential energy pressure time $T_U$ (i.e. time of producing the well after the plunger passes the plunger arrival switch) and/or (ii) the pre-set "burping" time are made automatically by the Plunger Control logic. For example, if the arrival time is slow (step 224), the pre-set “burping” time is reduced and/or the potential energy pressure time $T_U$ is increased by the Plunger Control logic (step 226); conversely, if the arrival time is fast (step 224), the liquid load pressure value $P_{LL}$ is increased and/or the pre-set “burping” time is increased (step 228).

The rise of plunger 16 causes standing valve 17 to open, thereby allowing fluid load into the tubing string 24. The well is then allowed to produce in the tubing string, lifting gas and liquids from the well to surface via string 24. While the gas well is producing, the Plunger Control logic is continuously or periodically monitoring the flow rate in string 24, the line pressure $P_L$, and the build-up of liquid load in the well. As mentioned above, liquid load pressure $P_{LL}$ is the difference between the casing pressure $P_C$ and the tubing pressure $P_T$. Monitoring the line pressure at the same time as the liquid load pressure helps ensure that any fluctuations in the liquid load pressure are not effected by above-surface line pressure fluctuations.

The casing pressure is monitored by the Plunger Control logic, and when the casing pressure $P_C$ reaches the previously calculated flowing clean casing pressure or the lowest casing pressure observed (which is monitored and recorded) (step 230), production continues in the tubing production string 24 and/or in the casing production string in an after-flow mode as outlined in methods 1 and 2 below.

**iii) After-flow Mode**

**Method 1 (Process 300)**

With reference to Figures 7 and 9a, as long as the line pressure $P_L$ stays below the tubing pressure $P_T$, the well continues to flow via the tubing string 24. The Plunger Control logic monitors the difference between the real-time casing pressure $P_C$ and tubing pressure $P_T$.

A load allowed set point $P_{LASP}$ is pre-set in the Plunger Control logic. The load allowed set point $P_{LASP}$ is equal to the liquid load pressure $P_{LL}$ (as determined and adjusted in the burping phase) plus the flowing clean casing pressure $P_{FCC}$ previously observed and recorded.

A load allowed pressure $P_{LA}$, calculated by the Plunger Control unit in real-time, is equal to the real-time difference between the casing pressure $P_C$ and tubing pressure $P_T$ plus the $P_{FCC}$ (as determined previously). When the load allowed pressure $P_{LA}$ reaches and/or exceeds the load allowed set point $P_{LASP}$ (step 302), the Plunger Control logic sends a command to close tubing valve 13 (step 304), as shown in Figure 7, and the real-time load allowed pressure $P_{LA}$ is recorded (step 306).

This concludes the first cycle of the system, after which the plunger drops to the bumper spring assembly, as shown in Figure 7, and the Plunger Control unit starts the next cycle of the system (process 200) by shutting in the well for the initial off time $T_i$ (step 202).

**Method 2 (Process 400)**

With reference to Figures 7, 8, and 9b, the Plunger Control logic sends a command to the casing valve 14 to start to partially throttle open same (step 402), allowing gas in the well to produce up the casing and/or tubing strings until the casing pressure reaches a casing pressure rise set point $P_{CRSP}$, assuming the line pressure remains substantially steady. The casing pressure rise set point $P_{CRSP}$ is generally a pressure that is slightly above the already observed $P_{FCC}$, e.g. about 5 kPa above the $P_{FCC}$. The $P_{CRSP}$ is pre-set in the Plunger Control logic. If the plunger arrival time is fast, the $P_{CRSP}$ is increased. If the plunger arrival time is slow, the $P_{CRSP}$ is decreased.

The amount of time the casing pressure rises from the flowing clean casing pressure $P_{FCC}$ to the casing pressure rise set point $P_{CRSP}$ or the lowest casing pressure observed determines the degree of throttling in the casing valve 14, which can be determined through routine experimentation.

Once the casing pressure rise set point has been reached (step 412), the Plunger Control logic sends a signal to close the casing valve 14 (step 414), so that well fluid is only allowed to produce through the tubing string 24, as shown in Figure 8. As long as the line pressure $P_L$ stays below the tubing pressure $P_T$, the well continues to flow via the tubing string 24. The Plunger Control logic monitors the difference between the real-time casing pressure $P_C$ and tubing pressure $P_T$.

When the load allowed pressure $P_{LA}$ reaches and/or exceeds the load allowed set point $P_{LASP}$ (step 416), the Plunger Control logic sends a command to close tubing valve 13 (step 418), as shown in Figure 7, and the real-time load allowed pressure $P_{LA}$ is recorded (step 420).

This concludes the first cycle of the system, after which the plunger drops to the bumper spring assembly, as shown in Figure 7, and the Plunger Control unit starts the next cycle of the system (process 200) by shutting in the well for the initial off time $T_i$ (step 202).

In a preferred embodiment, for both Methods 1 and 2, these cycles continue until at least five consecutive normal arrivals have occurred, indicating that the well has been stabilized by processes 200, and 300 or 400. When at least five consecutive plunger arrivals have been recorded, the Plunger Control unit makes no further adjustments to the pre-set burping time or to $T_U$, and the Plunger Control unit indicates and records that the gas well is stabilized. Once the well is stabilized, the Plunger Control logic continues to increase the liquid load pressure $P_{LL}$ incrementally to help optimize production time and minimize shut in time.

If the plunger arrival times start to stray out of the normal plunger arrival range, the Plunger Control logic stops increasing the liquid load pressure $P_{LL}$. If the plunger arrivals are consistently slow, the Plunger Control logic reverts back to processes 300 or 400 to re-stabilize the well.

**System B: Liquid Load Siphon String**

According to another embodiment of the present invention, the above described Plunger Control logic may be used with a system that uses a liquid load siphon string (LLSS) instead of a standing valve at the lower end of the tubing production string.

With reference to Figure 10, a System B comprises an antenna 2, solar panel 3, RTU with batteries 4, plunger control unit 5, cables 6, 7, and 8, plunger arrival switch 9, tubing pressure transmitter 10, casing pressure transmitter 11, line pressure transmitter 12, tubing valve 13, casing valve 14, MVT 15, a plunger 16 within a tubing string 24, an optional switch 28, and line 30, all as described above with respect to System A. A lower portion of the tubing string is placed down a well 120, with its lower end at or near the kick off point 23 of the deviation zone and above the heel 22 of the horizontal section of the well.

The tubing string of System B has an inlet, which in this embodiment is a LLSS 117 extending from the lower end of the tubing string 24 to at least a portion of the horizontal section of the well. The LLSS 117 allows fluid communication between the horizontal section of the well and the tubing string 24. Since the LLSS extends further into the well than a typical plunger lift system, the LLSS may allow access to well liquids at greater depths. The LLSS 117 may be a standard siphon string commonly used in the gas production industry.

System B further comprises a liquid level monitor 118, an instrument configured to measure the real time liquid level in the well bore. Monitor 118 may assist in ensuring that the level of the liquid in the well bore does not completely flood the siphon string 117. The potential casing energy build up when the well is shut in required to "u tube" the liquid through the siphon string is minimal if the liquid level is monitored in real time.

Optionally, the liquid level monitor may also be used with System A for collecting real time well liquid level data.

System B uses the same Plunger Control logic, including Methods 1 and 2, as described above for landing the plunger lift system at the below the kick off point of the deviation zone and above the heel of the horizontal well.

The LLSS is preferably used in horizontal wells that are deviated (i.e. where the angle at the heel is gradual and the horizontal section is not at 90 degrees, but toe up, with respect to the vertical section of the well), because it is difficult to predict if the lower end of the LLSS may land in any solids accumulated on the bottom half of the horizontal section, which may block and/or obstruct the entrance to the LLSS.

Another concern is adding back pressure to the reservoir as a certain amount of potential energy built up in the casing is required (i.e. more than in System A above) to "u-tube" the liquid load up the siphon string and into the tubing production string.

However, if the well meets the abovementioned deviated well criteria and has strong reservoir pressure that builds up potential gas energy quickly therein when shut in, then

System B may be considered and applied, as System B may produce greater amounts of liquids on each plunger cycle along with an increase in gas production.

The previous description of the disclosed embodiments is provided to enable any person skilled in the art to make or use the present invention. Various modifications to those embodiments will be readily apparent to those skilled in the art, and the generic principles defined herein may be applied to other embodiments without departing from the spirit or scope of the invention. Thus, the present invention is not intended to be limited to the embodiments shown herein, but is to be accorded the full scope consistent with the claims, wherein reference to an element in the singular, such as by use of the article "a" or "an" is not intended to mean "one and only one" unless specifically so stated, but rather "one or more". All structural and functional equivalents to the elements of the various embodiments described throughout the disclosure that are known or later come to be known to those of ordinary skill in the art are intended to be encompassed by the elements of the claims. Moreover, nothing disclosed herein is intended to be dedicated to the public regardless of whether such disclosure is explicitly recited in the claims. No claim element is to be construed under the provisions of 35 USC 112, sixth paragraph, unless the element is expressly recited using the phrase "means for" or "step for".

Claims:

1. A method of producing liquid load from a horizontal section of a well having a casing in its vertical section, the horizontal section and the vertical section being connected by a heel, and the well having a plunger lift system installed therein, the plunger lift system comprising:

a tubing string with an upper end and a lower end, and having a plunger slidably movable therebetween, the tubing string and the casing defining a casing string therebetween, the tubing string being in fluid communication with a line via a tubing valve, the tubing string disposed in the vertical section, with its lower end at or near the heel and having an inlet, the tubing string having a tubing pressure and the line having a line pressure, and

the casing string being in fluid communication with the line via a casing valve, the casing string having a casing pressure,

the method comprising:

(a) keeping the tubing valve and the casing valve closed for an initial off time;

(b) determining a potential energy pressure at the expiry of the initial off time;

(c) opening tubing valve for a pre-set time;

(d) comparing a plunger arrival time with a preselected range and: (i) keeping the tubing valve open if the plunger arrival time is within the preselected range; (ii) reducing an after-flow time if the plunger arrival time is above the preselected range; or (iii) increasing the after-flow time if the plunger arrival time is below the preselected range;

(e) closing the tubing valve at the expiry of the after-flow time;

(f) determining a liquid load pressure;

(g) keeping the tubing valve and the casing valve closed for the initial off time;

(h) opening the tubing valve partially when the difference between the casing pressure and the line pressure is substantially equal to the potential energy pressure, and keeping the tubing valve open for a pre-set burping time;

(i) closing the tubing valve at the expiry of the pre-set burping time;

(j) opening the tubing valve when the difference between the casing pressure and the line pressure is substantially equal to the potential energy pressure; and

(k) comparing the plunger arrival time with the preselected range and: (i) reducing the pre-set burping time and/or increasing a potential energy pressure time, if the plunger arrival time is above the preselected range; (ii) increasing the liquid load pressure and/or pre-set burping time, if the plunger arrival time is below the preselected range; or (iii) comparing the casing pressure with a flowing clean casing pressure or a lowest recorded casing pressure, if the plunger arrival time is within the preselected range.

2. The method of claim 1 further comprising repeating steps (a) to (f) until the plunger arrival time is within the preselected range for at least five consecutive cycles.

3. The method of claim 1 further comprising comparing a load allowed pressure with a load allowed set point, if the casing pressure is substantially equal to the flowing clean casing pressure or the lowest recorded casing pressure.

4. The method of claim 3 further comprising closing the tubing valve when the load allowed pressure is substantially equal to the load allowed set point.

5. The method of claim 1 further comprising throttling open the casing valve if the casing pressure is substantially equal to the flowing clean casing pressure or the lowest recorded casing pressure.

6. The method of claim 5 further comprising closing the casing valve when the casing pressure is substantially equal to a casing pressure rise set point.

7. The method of claim 6 further comprising closing the tubing valve when a load allowed pressure is substantially equal to a load allowed set point.

8. The method of claim 4 further comprising repeating steps (a) to (k).

9. The method of claim 7 further comprising repeating steps (a) to (k).

10. The method of claim 1 wherein the inlet is a standing valve.

11. The method of claim 1 wherein the inlet is a siphon string extending into at least a portion of the horizontal section.

12. The method of claim 1 further comprising monitoring the liquid level in the well.

13. The method of claim 11 wherein the plunger lift system further comprises a liquid level monitor.

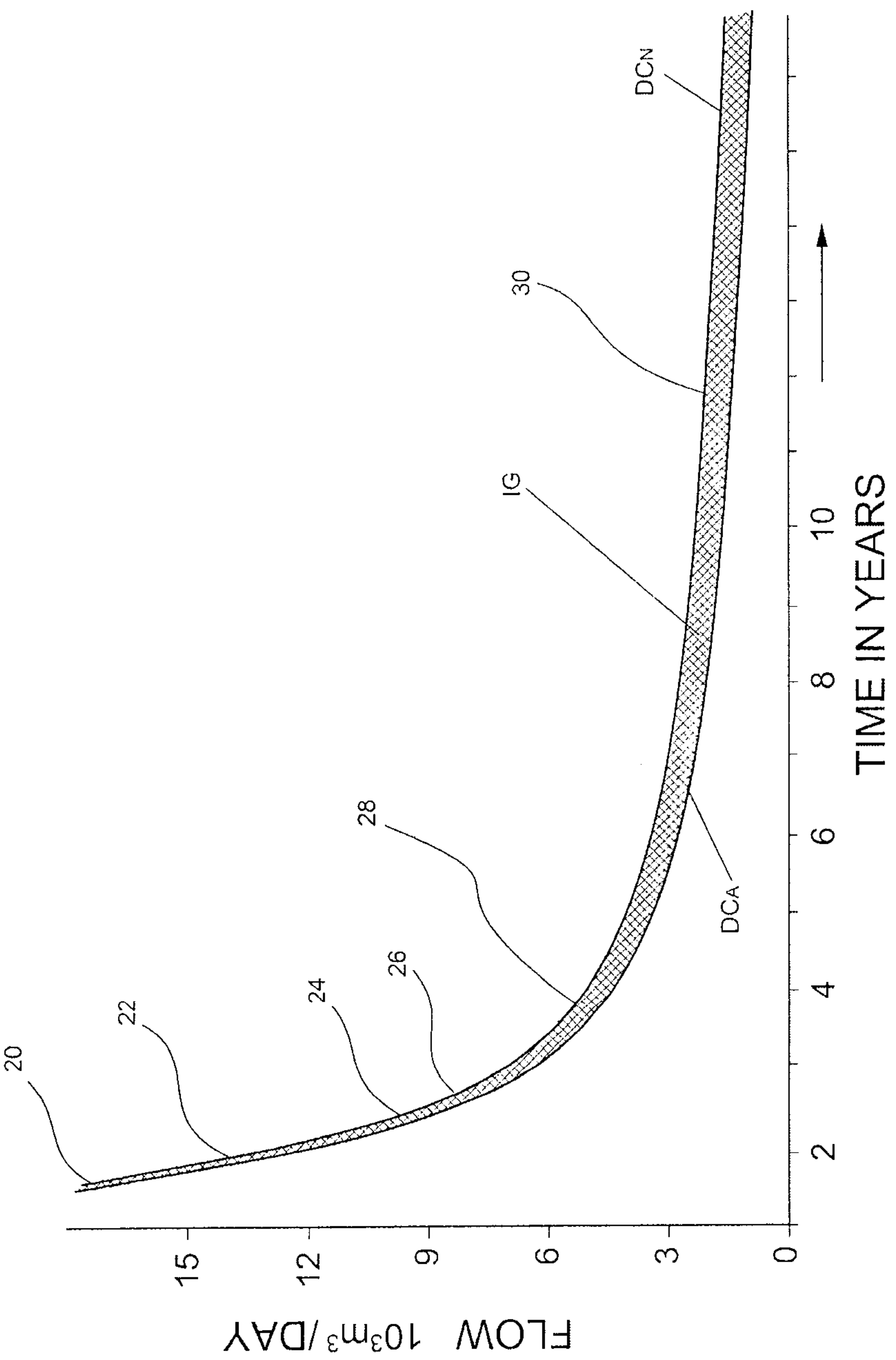

FLOW 10³m³/DAY
15
12
9
6
3
0
2
4
6
8
10
TIME IN YEARS
20
22
24
26
28
IG
30
DCA
DCN

FIG. 1

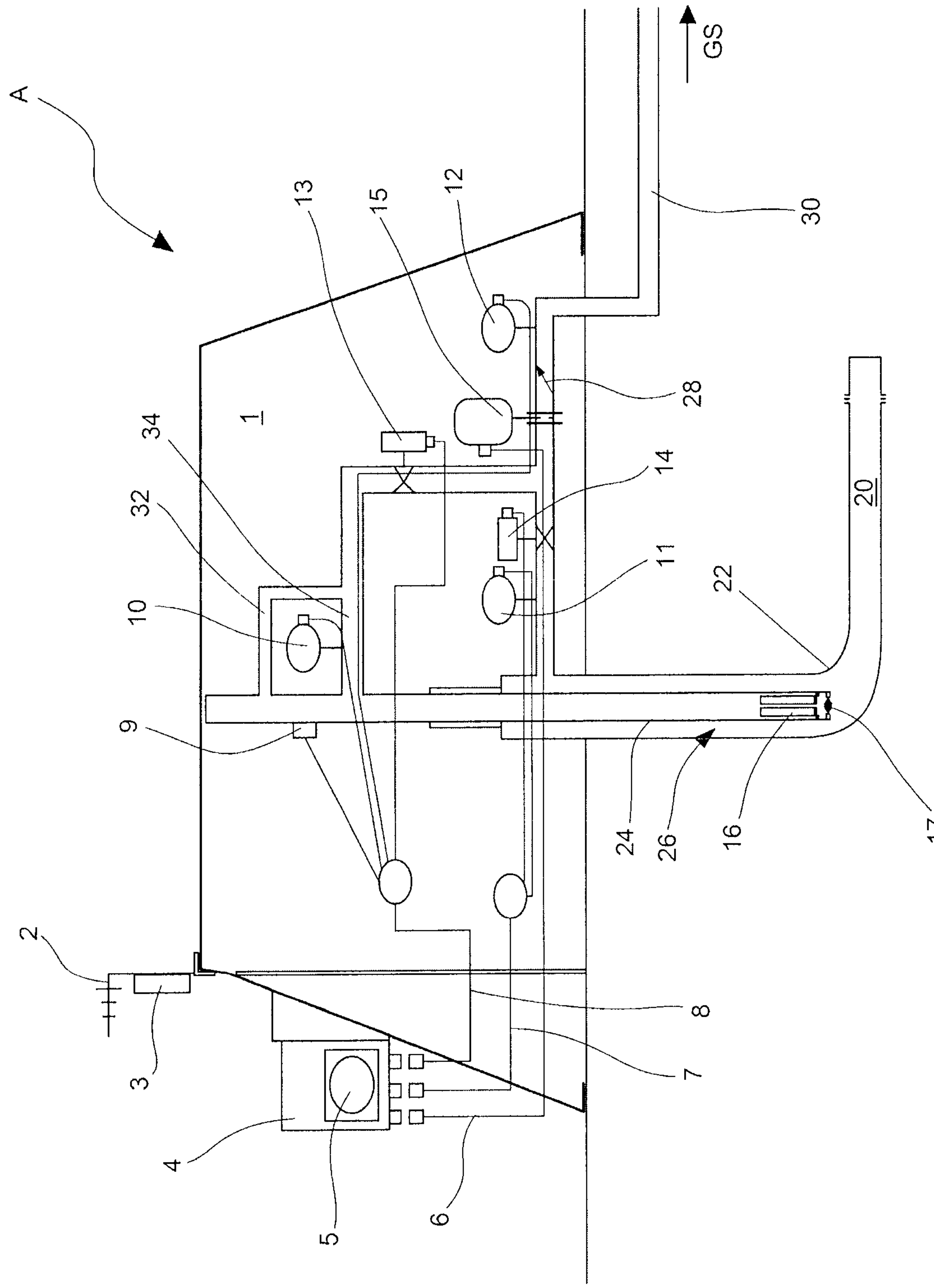



FIG. 2

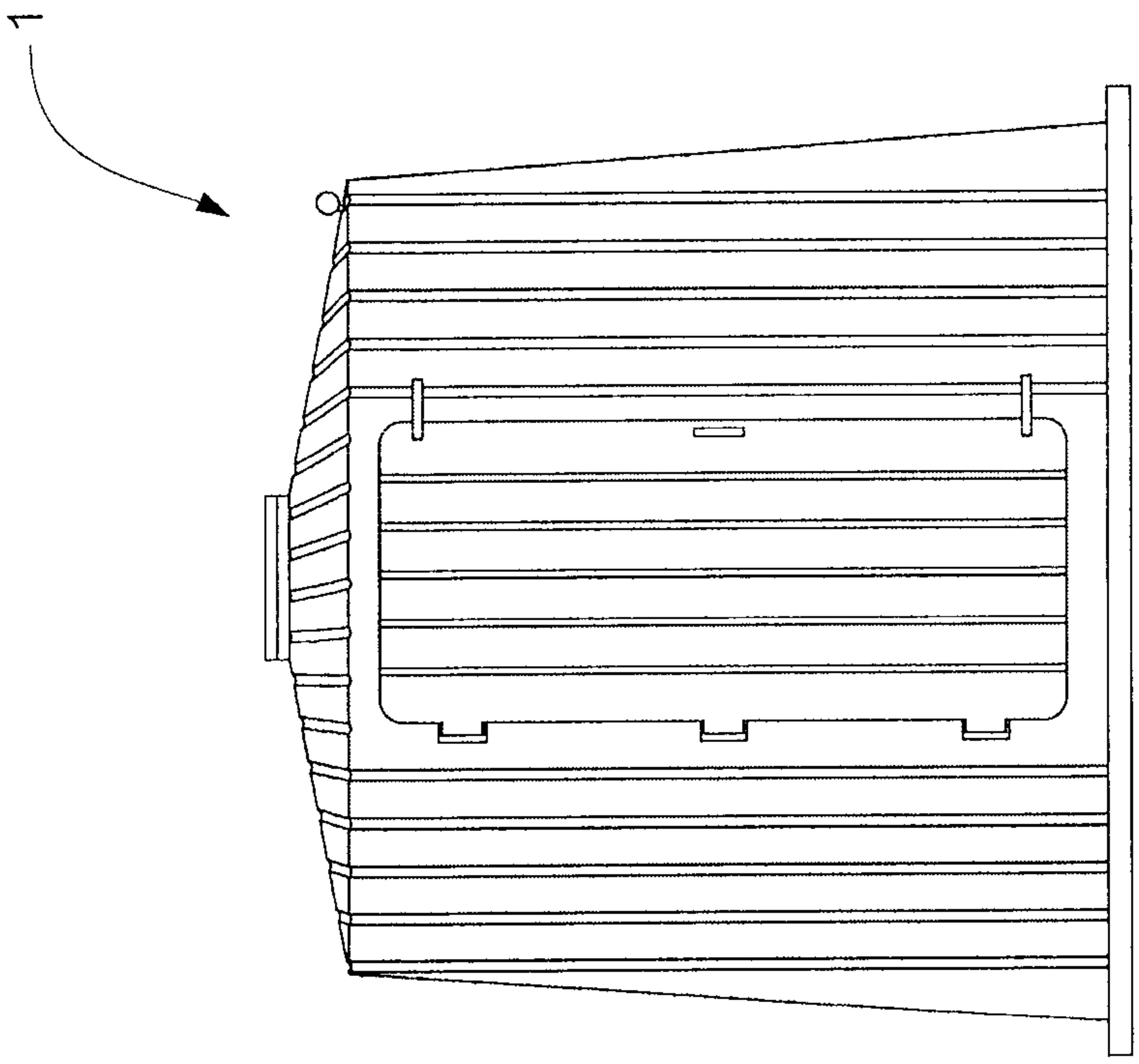



FIG. 3

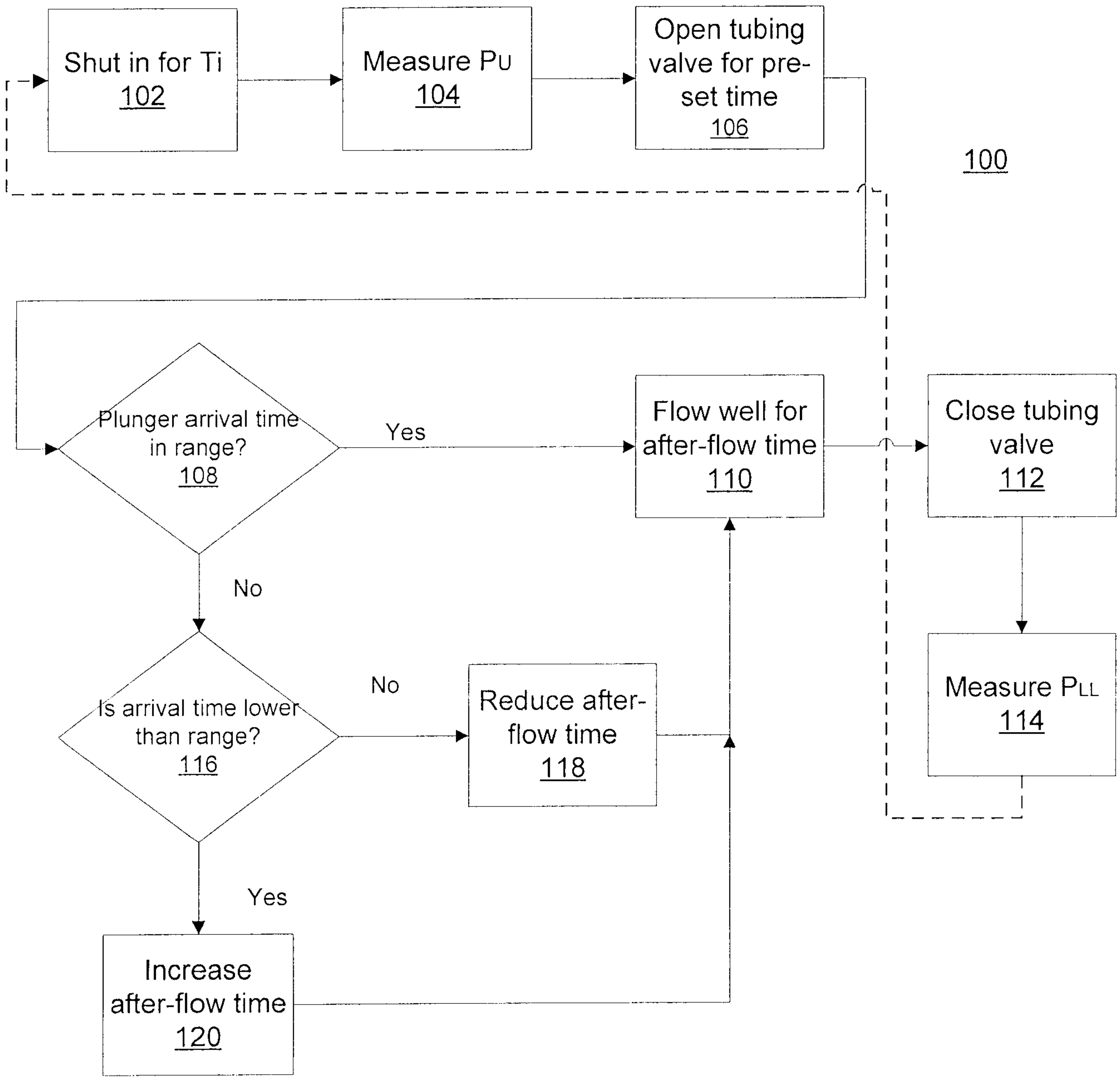

Shut in for Ti
102
Measure Pu
104
Open tubing valve for pre-set time
106
100
Plunger arrival time in range?
108
Yes
Flow well for after-flow time
110
Close tubing valve
112
No
Is arrival time lower than range?
116
No
Reduce after-flow time
118
Measure PLL
114
Yes
Increase after-flow time
120

FIG. 4

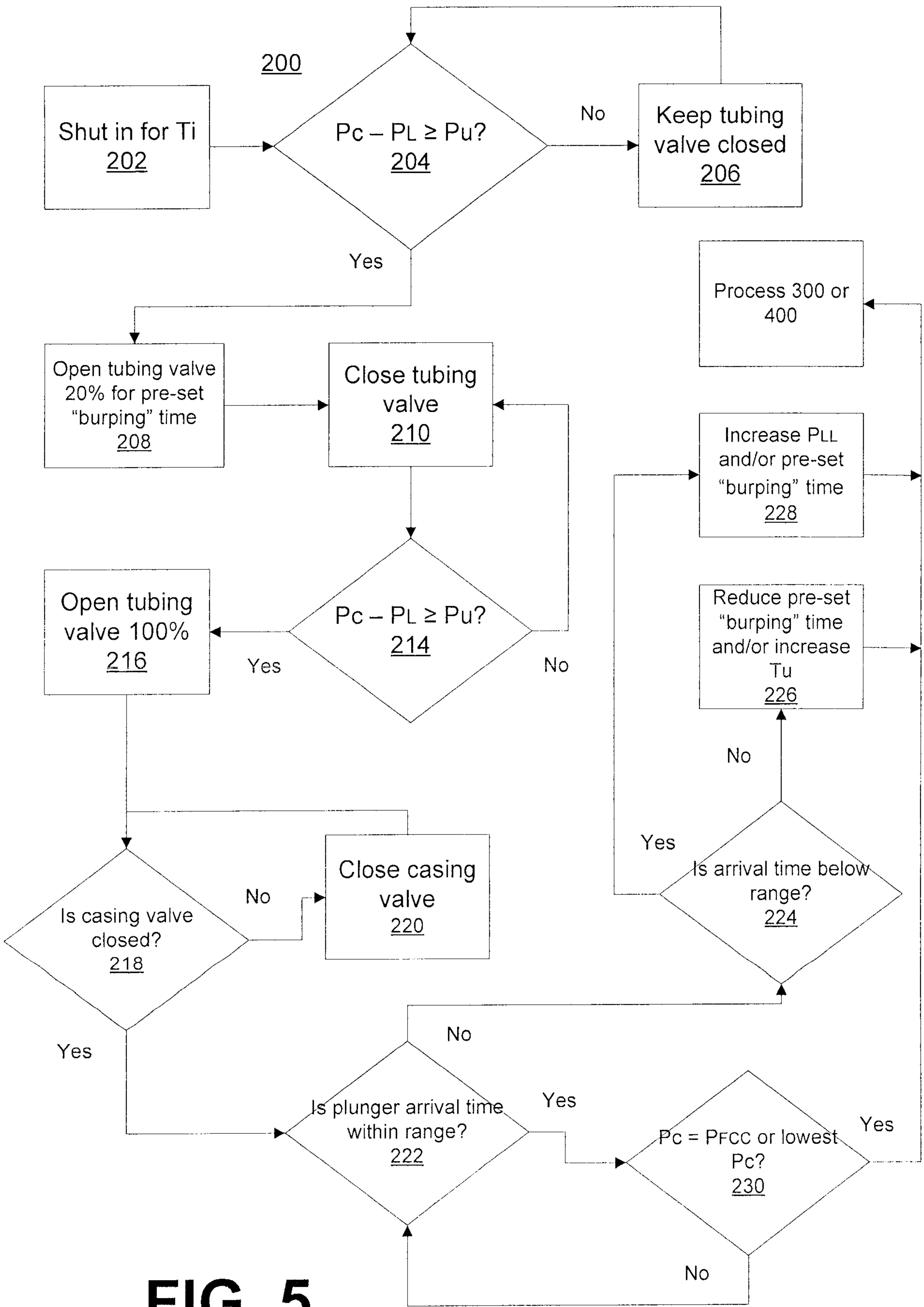

200
Shut in for Ti
202
Pc – PL ≥ Pu?
204
No
Keep tubing valve closed
206
Yes
Process 300 or 400
Open tubing valve 20% for pre-set "burping" time
208
Close tubing valve
210
Increase PLL and/or pre-set "burping" time
228
Open tubing valve 100%
216
Pc – PL ≥ Pu?
214
Yes
No
Reduce pre-set "burping" time and/or increase Tu
226
No
Yes
Is arrival time below range?
224
Close casing valve
220
No
Is casing valve closed?
218
Yes
No
Is plunger arrival time within range?
222
Yes
Pc = PFCC or lowest Pc?
230
Yes
No

FIG. 5

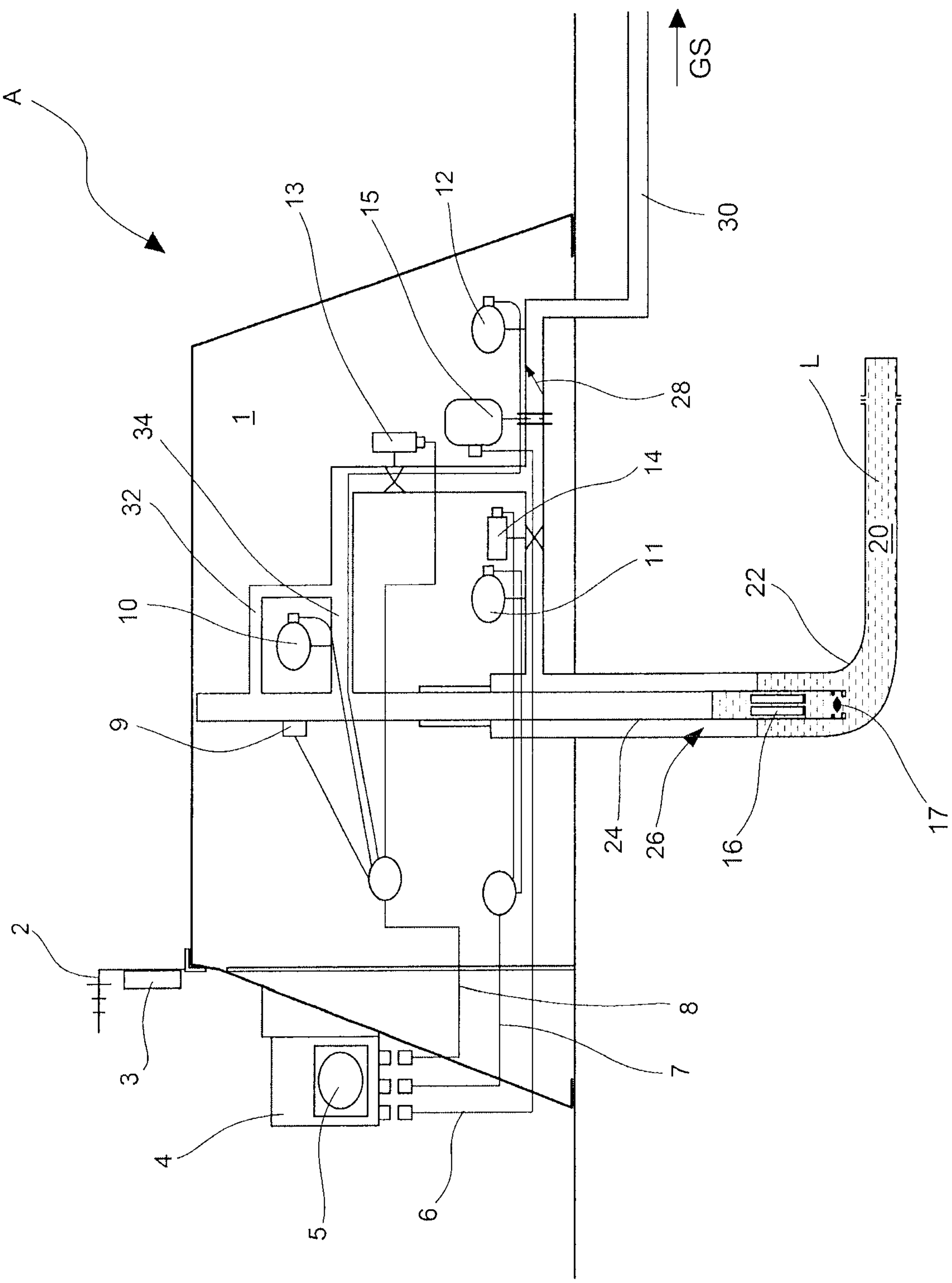



FIG. 6

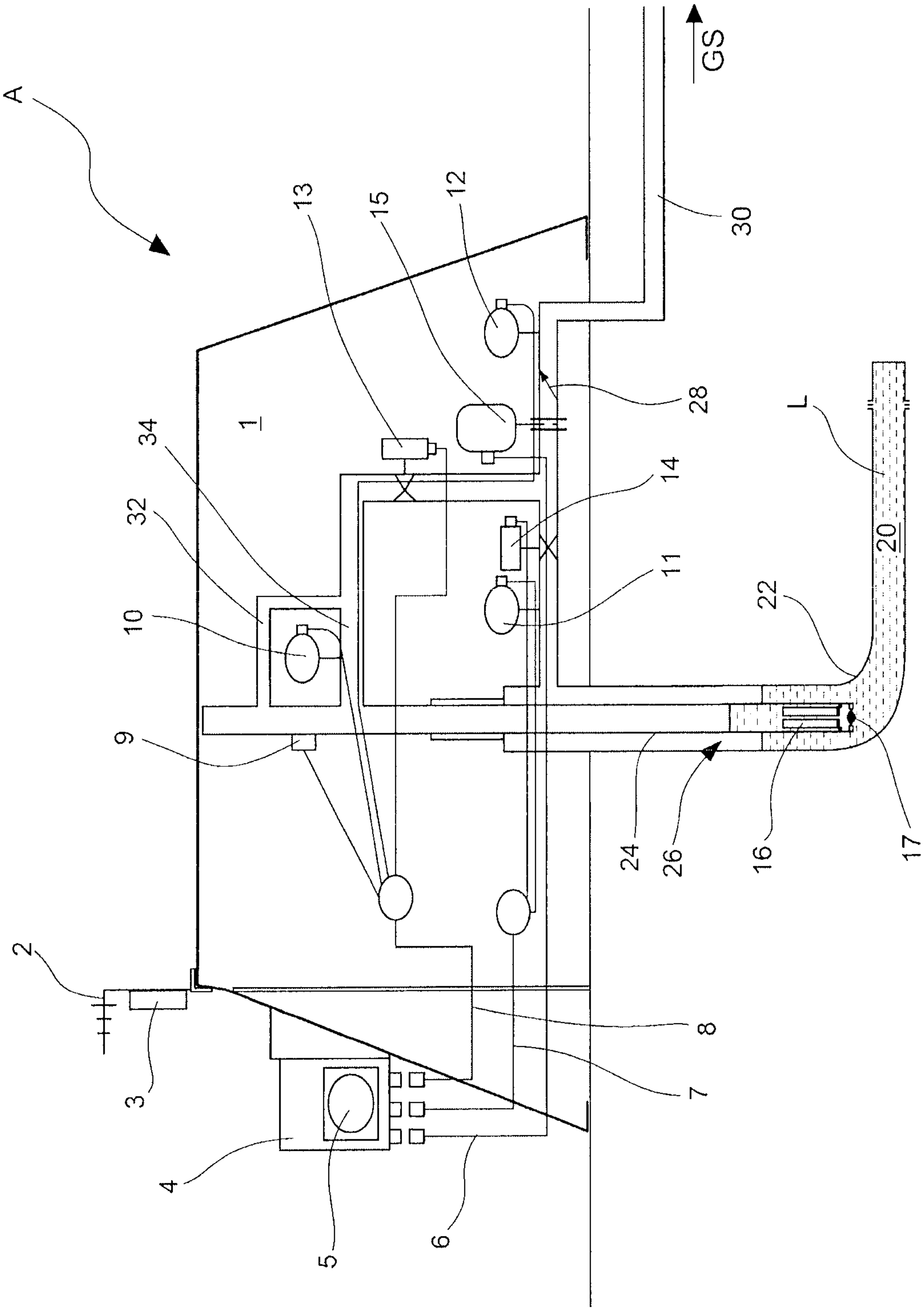



FIG. 7

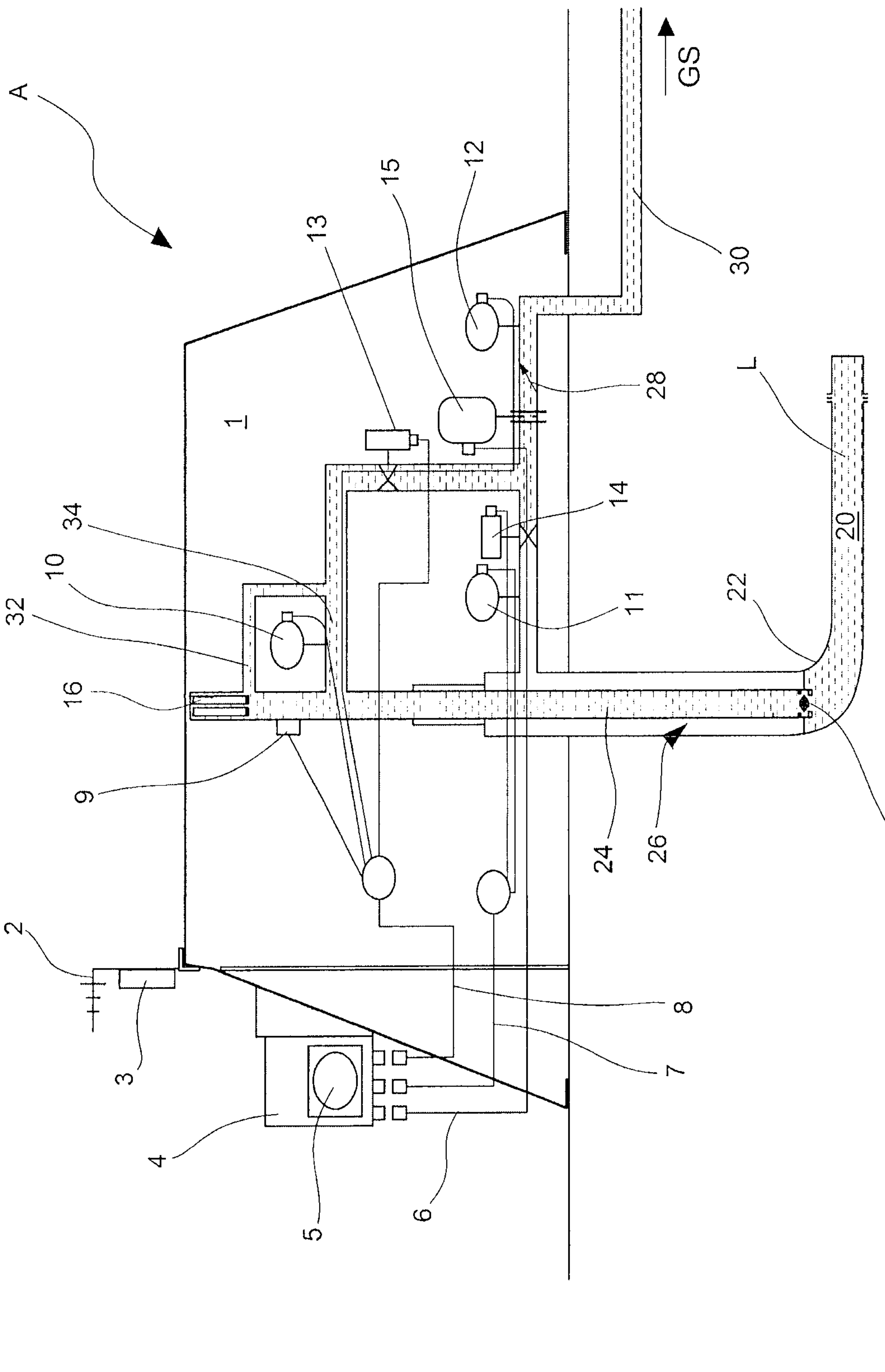



FIG. 8

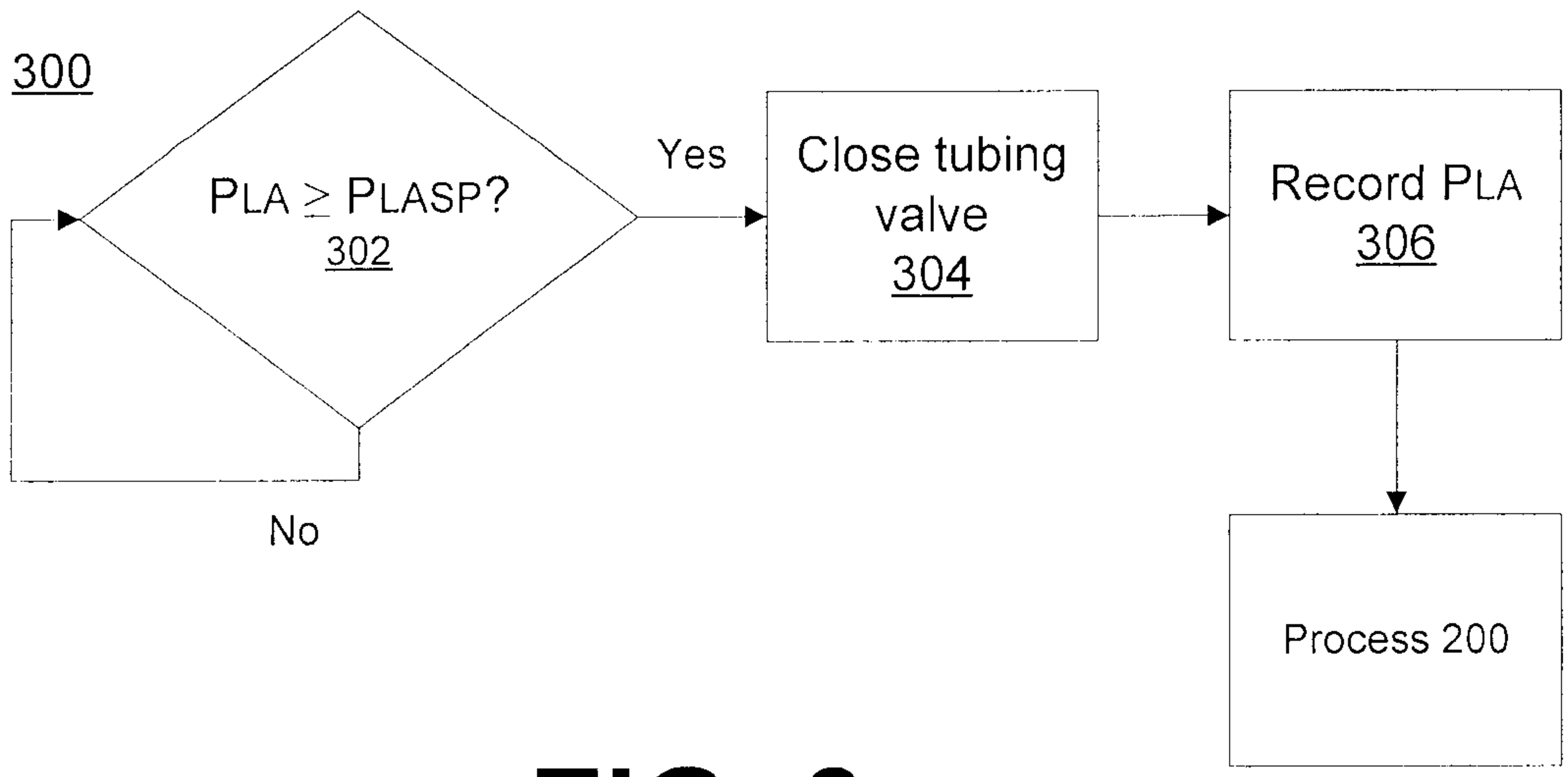

300
PLA ≥ PLASP?
302
Yes
No
Close tubing valve
304
Record PLA
306
Process 200

FIG. 9a

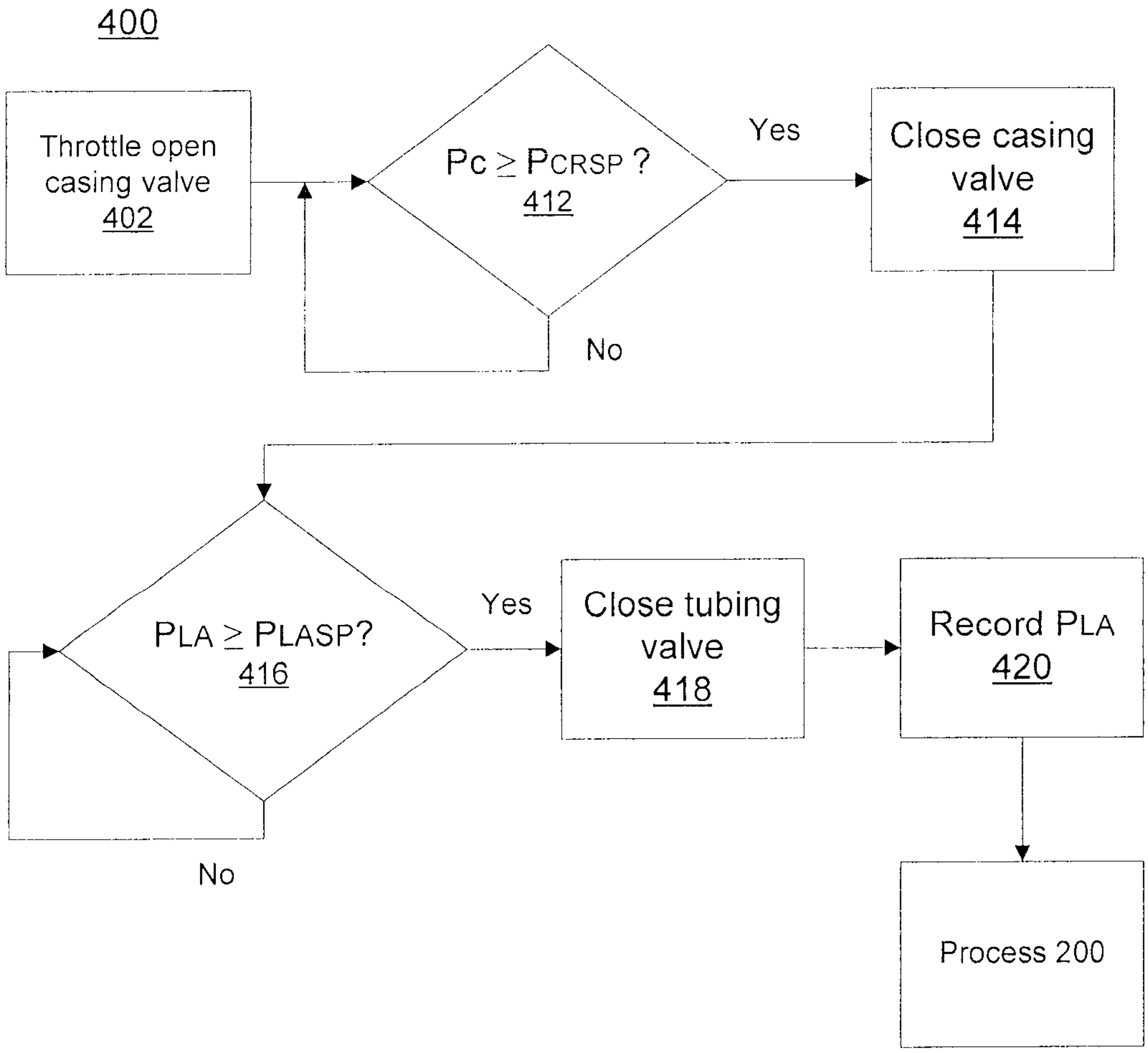

400
Throttle open casing valve
402
Pc ≥ PCRSP ?
412
Yes
No
Close casing valve
414
PLA ≥ PLASP?
416
Yes
No
Close tubing valve
418
Record PLA
420
Process 200

FIG. 9b

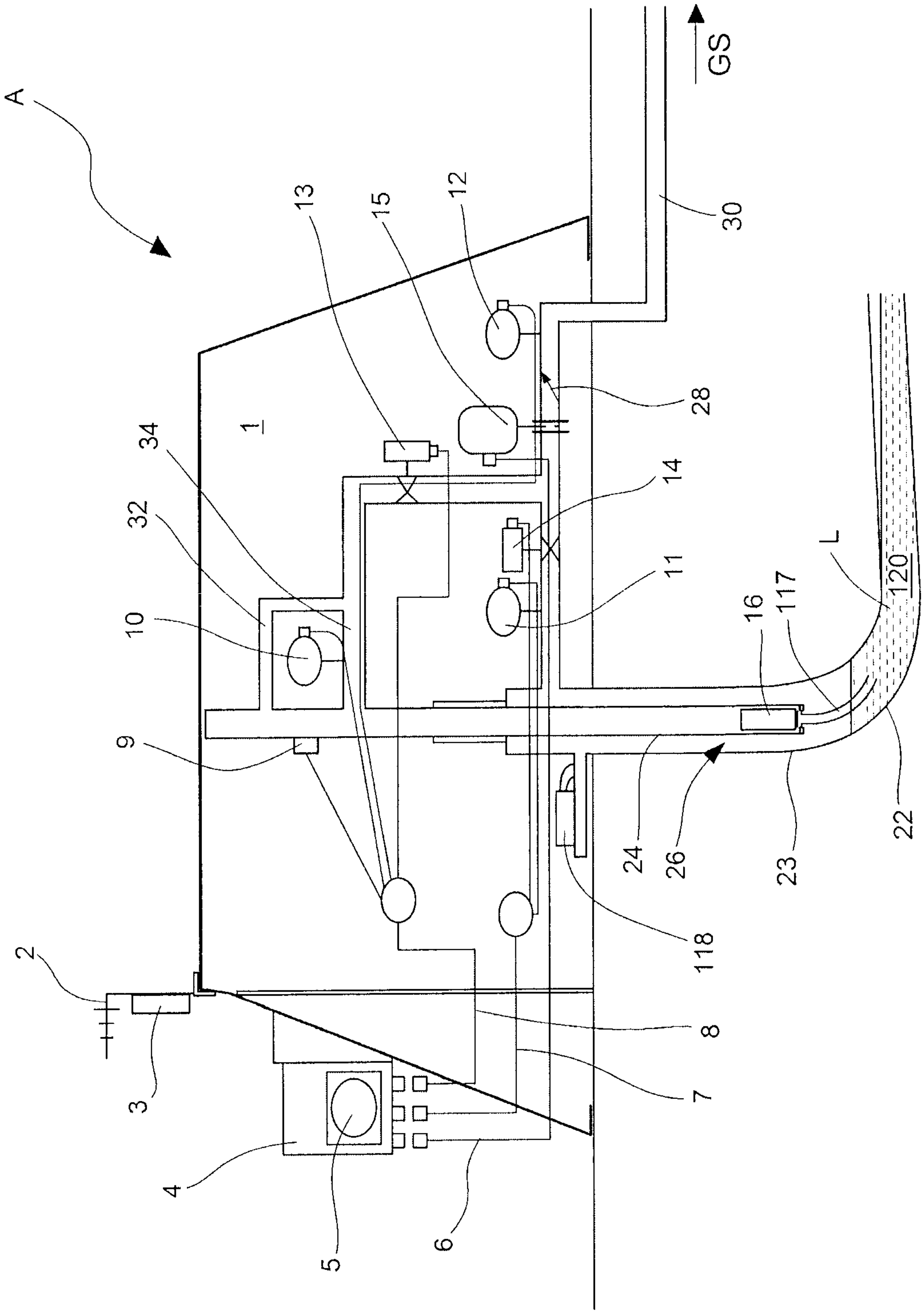
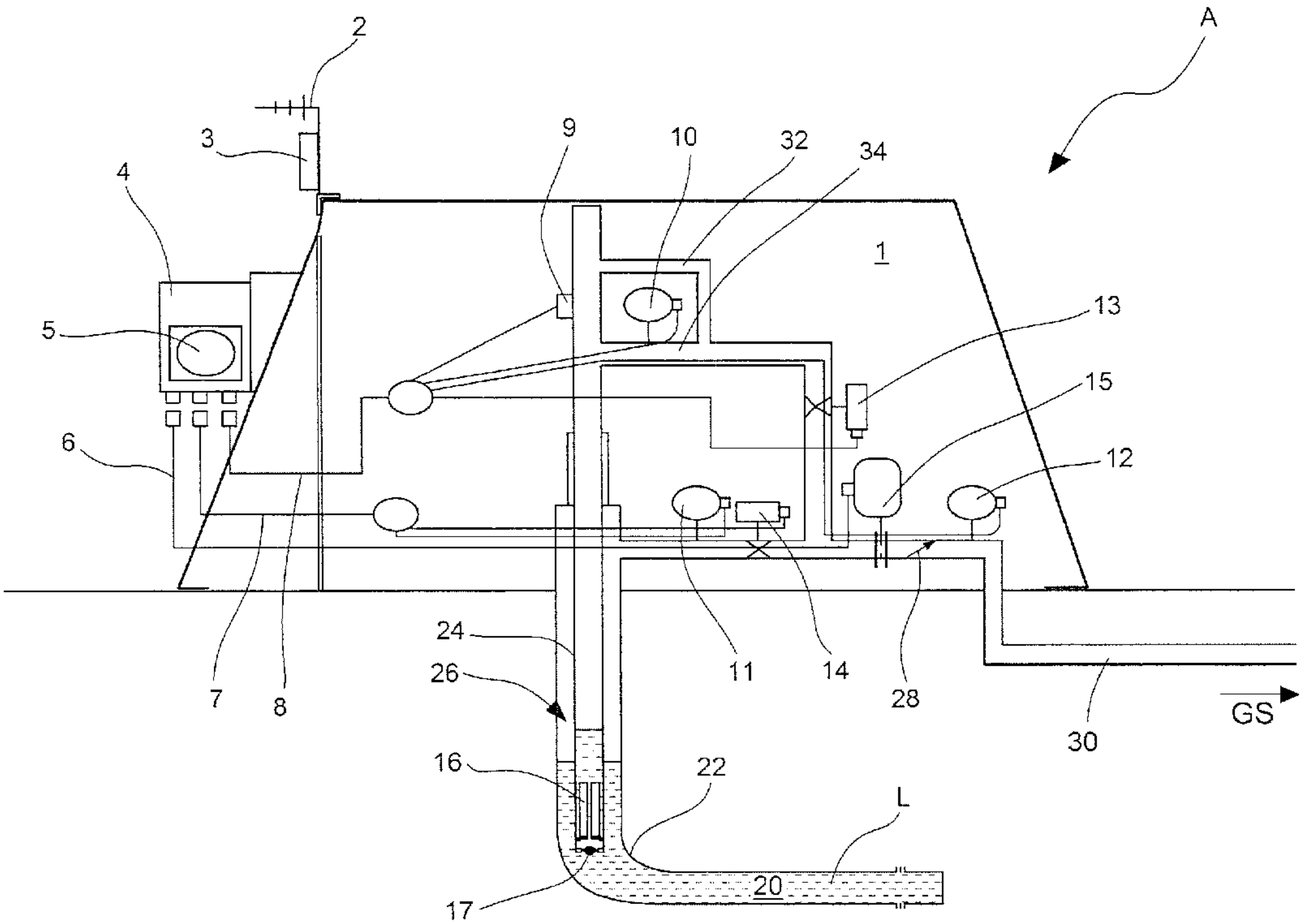

A
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
22
23
24
26
28
30
32
34
117
118
120
L
GS

FIG. 10



A
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
20
22
24
26
28
30
32
34
L
GS