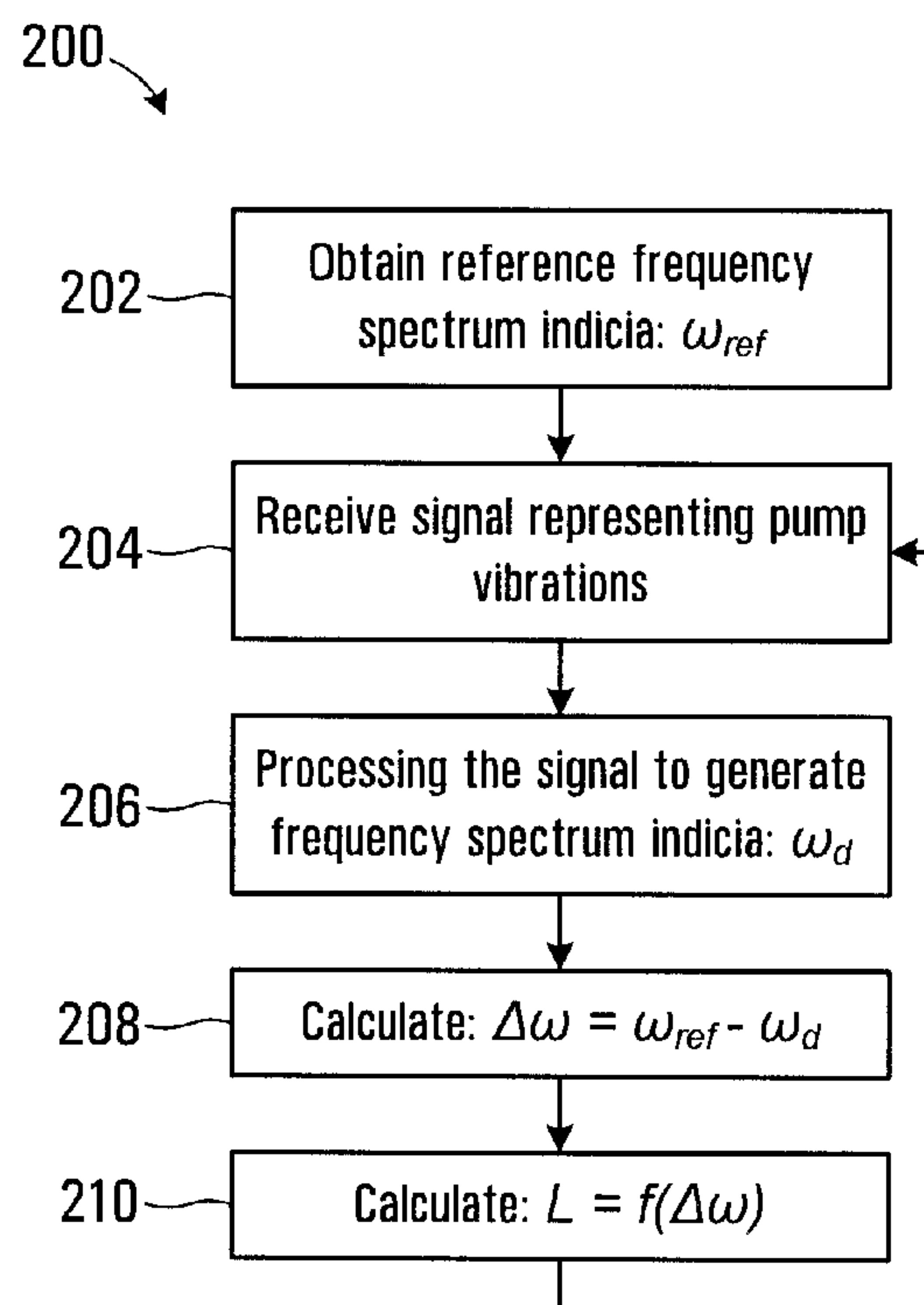




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DOWNHOLE PUMP



(57) **Abrégé/Abstract:**

A method and apparatus for determining a level of a fluid in communication with a downhole pump during a pumping operation is disclosed. The method involves receiving a signal representing pump vibrations generated by operation of the pump during the pumping operation, and based on the signal, generating a vibration value characterizing the pump vibrations. The method also involves using a correlation between pump vibrations and fluid level to generate a fluid level value corresponding to the vibration value.



ABSTRACT

5 A method and apparatus for determining a level of a fluid in communication with a downhole pump during a pumping operation is disclosed. The method involves receiving a signal representing pump vibrations generated by operation of the pump during the pumping operation, and based on the signal, generating a vibration value characterizing the pump vibrations. The method also involves using a correlation between pump vibrations and fluid level to generate a fluid level value corresponding to the vibration value.

METHOD AND APPARATUS FOR DETERMINING A LEVEL OF A FLUID IN COMMUNICATION WITH A DOWNHOLE PUMP

BACKGROUND OF THE INVENTION

5 1. Field of Invention

This invention relates generally to determining fluid level and more particularly to determining a fluid level in communication with a downhole pump.

2. Description of Related Art

10 Downhole pumps may be used to pump fluids out of reservoirs. For example, in hydrocarbon recovery operations, it is common to drill a borehole into an oil reservoir for extracting the hydrocarbons from the reservoir. In operations where the natural pressure of the reservoir is not high enough to cause the hydrocarbon fluids to flow to the surface, artificial lift may be employed to produce the fluids to
15 the surface. One example of an artificial lift system is an electric submersible pump (ESP), which may be disposed at the end of a tubing string, which is lowered into the borehole until the ESP is submerged in the fluid. In such operations there can be some difficulty in determining the fluid level around or proximate an intake of the pump.

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It is desirable that the electric submersible pump be operated such that the accumulated fluid is above the intake by a sufficient height to prevent the pump from drawing air. On the other hand, it is also desirable that fluid does not accumulate to a level too far above the intake, since the resulting increased
25 hydrostatic pressure in the well may reduce production of fluid from the surrounding reservoir, thus reducing production of fluid to the surface.

SUMMARY OF THE INVENTION

In accordance with one aspect of the invention there is provided a method for determining a level of a fluid in communication with a downhole pump during a pumping operation. The method involves receiving a signal representing pump vibrations generated by operation of the pump during the pumping operation, and based on the signal, generating a vibration value characterizing the pump vibrations. The method also involves using a correlation between pump vibrations and fluid level to generate a fluid level value corresponding to the vibration value.

Receiving the signal may involve receiving the signal from a vibration transducer configured to receive pump vibrations and to generate the signal representing the pump vibrations.

The vibration transducer may be coupled to a conduit that is coupled to the pump, the conduit being operable to transmit pump vibrations from the pump to the transducer.

The vibration transducer may be coupled to an electrical conduit housing an electrical cable for supplying electrical power to the pump.

The pump may include an outlet for discharging fluid from the pump and the conduit may include production tubing extending between an outlet of the pump and a wellhead disposed at the surface, and the vibration transducer may be coupled to the production tubing at a location spaced apart from the outlet of the pump along the production tubing.

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The vibration transducer may include a plurality of vibration transducers disposed at spaced apart locations along the production tubing and receiving the signal may involve receiving signals from each of the vibration transducers, each signal representing pump vibrations at the respective transducer locations along the production tubing and the generating the vibration values may involve combining values from the signals to generate the values characterizing the pump vibrations.

The pump may include an inlet in communication with fluid produced from a steam assisted gravity drainage well.

Generating the vibration value may involve processing the signal to generate amplitude values representing an amplitude of the pump vibrations.

Processing the signal to generate the amplitude values may involve processing the signal to generate root mean square (RMS) amplitude values.

The method may involve averaging the RMS amplitude values over a time period to generate an average value representing pump vibrations during the time period.

Using the correlation between pump vibrations and fluid level may involve applying a predetermined relationship between pump vibration amplitude values and fluid level values to generate the fluid level value.

Generating the vibration value may involve processing the signal to generate frequency spectrum indicia values and using the correlation between pump vibrations and fluid level may involve using a predetermined correlation between

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reference frequency spectrum indicia and fluid level values to generate the fluid level value.

5 Processing the signal to generate the frequency spectrum indicia may involve determining a fundamental frequency of the pump vibrations.

10 Using the correlation between pump vibrations and fluid level to generate the fluid level value may involve determining a reference fundamental frequency of the pump vibrations under the reference fluid level conditions, and determining a difference between the fundamental vibration frequency and the fundamental vibration frequency of the pump under the reference fluid level conditions.

15 The pump may include an alternating current motor coupled to a variable frequency drive for providing drive power to the motor and generating the fluid level value may involve determining a frequency offset between the fundamental frequency of the pump vibrations and a frequency of the drive power supplied to the motor.

20 The pump may include a reciprocating piston pump coupled to an actuator operable to provide a reciprocating drive for driving the pump and generating the fluid level value may involve determining a frequency offset between the fundamental frequency of the pump vibrations and an operating frequency associated with the actuator.

25 The method may involve generating the correlation between pump vibrations and fluid level.

Generating the correlation may involve obtaining reference vibration values associated with operating the pump under reference fluid level conditions.

5 Obtaining reference vibration values may involve determining the reference fluid level by performing a fluid level measurement that is independent of pump vibration, receiving a reference signal representing pump vibration under the reference pump operating conditions, and generating the reference vibration values based on the reference signal.

10 Obtaining reference vibration values may involve obtaining reference vibration amplitude values.

Obtaining reference vibration values may involve obtaining reference frequency spectrum indicia values.

15 Obtaining the reference vibration values may involve obtaining reference vibration values associated with operating the pump in communication with a reference fluid having reference fluid constitution and using the correlation may involve determining a constitution of the fluid in communication with the pump,
20 and applying a correction to the correlation for a fluid of the determined constitution.

25 In accordance with another aspect of the invention there is provided an apparatus for determining a level of a fluid in communication with a downhole pump during a pumping operation. The apparatus includes a receiver operably configured to receive a signal representing pump vibrations generated by operation of the pump during the pumping operation. The apparatus also includes a signal processor operably configured to generate a vibration value

characterizing the pump vibrations based on the signal. The apparatus further includes a comparator operably configured to use a correlation between pump vibrations and fluid level to generate a fluid level value corresponding to the vibration value.

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The apparatus may include a vibration transducer configured to receive pump vibrations and to generate the signal representing the pump vibrations.

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The vibration transducer may be coupled to a conduit that is coupled to the pump, the conduit being operable to transmit pump vibrations from the pump to the transducer.

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The vibration transducer may be coupled to an electrical conduit housing an electrical cable for supplying electrical power to the pump.

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The pump may include an outlet for discharging fluid from the pump and the conduit may include production tubing extending between an outlet of the pump and a wellhead disposed at the surface, and the vibration transducer may be coupled to the production tubing at a location spaced apart from the outlet of the pump along the production tubing.

25

The vibration transducer may include a plurality of vibration transducers disposed at spaced apart locations along the production tubing and operably configured to generate respective signals, each signal representing pump vibrations at the respective transducer locations along the production tubing and the signal processor may be operably configured to generate the vibration value by combining values from the signals to generate the values characterizing the pump vibrations.

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The pump may include an inlet in communication with fluid produced from a steam assisted gravity drainage well.

- 5 The signal processor may be operably configured generate the vibration value by processing the signal to generate amplitude values representing an amplitude of the pump vibrations.

- 10 The signal processor may be operably configured to process the signal to generate root mean square (RMS) amplitude values.

- 15 The signal processor may be operably configured to average the RMS amplitude values over a time period to generate an average value representing pump vibrations during the time period.

The comparator may be operably configured to apply a predetermined relationship between pump vibration amplitude values and fluid level values to generate the fluid level value.

- 20 The signal processor may be operably configured to generate the vibration value by processing the signal to generate frequency spectrum indicia values and the comparator may be operably configured to use a predetermined correlation between reference frequency spectrum indicia and fluid level values to generate the fluid level value.

- 25 The signal processor may be operably configured to process the signal to generate the frequency spectrum indicia by determining a fundamental frequency of the pump vibrations.

5 The comparator may be operably configured to determine a reference fundamental frequency of the pump vibrations under the reference fluid level conditions, and to determine a difference between the fundamental vibration frequency and the fundamental vibration frequency of the pump under the reference fluid level conditions.

10 The pump may include an alternating current motor coupled to a variable frequency drive for providing drive power to the motor and the comparator may be operably configured to generate the fluid level value by determining a frequency offset between the fundamental frequency of the pump vibrations and a frequency of the drive power supplied to the motor.

15 The pump may include a reciprocating piston pump coupled to an actuator operable to provide a reciprocating drive for driving the pump and the comparator may be operably configured to generate the fluid level value by determining a frequency offset between the fundamental frequency of the pump vibrations and an operating frequency associated with the actuator.

20 The apparatus may include a processing system operably configured to generate the correlation between pump vibrations and fluid level.

25 The processing system may be operably configured to generate the correlation by obtaining reference vibration values associated with operating the pump under reference fluid level conditions.

The processing system may be operably configured to obtain reference vibration values by determining the reference fluid level by performing a fluid level

measurement that is independent of pump vibration, receiving a reference signal representing pump vibration under the reference pump operating conditions, and generating the reference vibration values based on the reference signal.

- 5 The processing system may be operably configured to obtain reference vibration amplitude values.

The processing system may be operably configured to obtain reference frequency spectrum indicia values.

10

The processing system may be operably configured to obtain reference vibration values associated with operating the pump in communication with a reference fluid having reference fluid constitution and the processing system may be further operably configured to determine a constitution of the fluid in communication with the pump, and apply a correction to the correlation for a fluid of the determined constitution.

15

Certain implementations may have one or more of the following advantages. Since the fluid level may be produced during operation of the pump, there is no need to interrupt production of a well to perform fluid level determinations. In another aspect the disclosed embodiments are capable of providing a continuous fluid level, thereby facilitating optimal operation of the pump for extracting produced fluids from a well. In some implementations, vibration transducers may be located at the wellhead thereby avoiding introducing sensors into the borehole, which takes up limited space and may interfere with other downhole tools. In other implementations the vibration transducers may be located away from the downhole pump along the production tubing, avoiding placement of

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sensors on the downhole pump where the sensors will be more susceptible to damage.

Other aspects and features of the present invention will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

In drawings which illustrate embodiments of the invention,

Figure 1 is a cross section of an oil well and an apparatus in accordance with a first embodiment of the invention;

Figure 2 is a block diagram of a processing system shown in Figure 1;

Figure 3 is a block diagram of a processor circuit for implementing the processing system shown in Figure 2;

Figure 4 is a flowchart of a process for determining fluid level implemented on the processor circuit shown in Figure 3; and

Figure 5 is a cross section of the oil well shown in Figure 1 and an apparatus in accordance with an alternative embodiment of the invention.

DETAILED DESCRIPTION

Downhole pumps are used in a variety of applications including oil recovery operations, conventional water supply boreholes, source water boreholes used in the oil industry for providing source water for processing, and a numerous other applications. An exemplary oil well embodiment is shown generally at **100** in Figure 1. Referring to Figure 1, the oil well **100** includes a borehole **102** and a wellhead **104**. The wellhead **104** is disposed at a surface **106** of the well. The borehole **102** may extend far below the surface **106** and may include several casing layers **108** of concrete and steel. A portion **110** of the borehole **102** is in communication with a surrounding reservoir **112** for extraction hydrocarbon fluids from the reservoir. In one embodiment, the portion **110** includes perforations (not shown) through the casing **108** to permit fluids in the surrounding reservoir **112** to pass through the casing into the borehole **102**. Alternatively, in the case of a SAGD well, the borehole portion **110** may be in communication with a generally horizontal section of borehole for receiving fluids drained from the reservoir. In SAGD operations, steam is injected into an upper generally horizontal borehole to heat viscous hydrocarbons within the reservoir **112** to cause the hydrocarbons to drain to a lower generally horizontal borehole. Extracted fluids **114** may be accumulated within the borehole **102** as a fluid column and may be produced to the surface **106** by an electric submersible pump (ESP) **116** through a production tubing **136**.

The example electric submersible pump **116** shown includes a motor **118**, a seal section **120**, an intake **122**, and a pump section **124**. The motor **118** includes an electrical input **126**, which is connected to a cable **128** for receiving an electrical drive current. In this embodiment the motor operates on an alternating current power supply provided by a variable frequency drive (VFD) **130** via the cable **128**. The pumping speed of the pump **116** is controlled by changing the

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frequency of the alternating current drive to the motor **118**, and in this embodiment the VFD **130** includes an input **132** for receiving a control signal for controlling the drive frequency, and hence the pumping speed. It should be understood that a differently configured pump can be used, and the pump **116** shown is but one illustrative example.

During extraction operations of the well **100**, fluid flows into the borehole **102** from the reservoir **112**, either due to pressure within the reservoir or due to gravity drainage. The accumulated fluid **114** may comprise water, hydrocarbons in a liquid, solid, and/or gaseous state, or any combination thereof. In heavy hydrocarbon extraction, a portion of the hydrocarbons may combine with water, air, and other gaseous products to form froth, at least a portion of which may float to a surface of the fluid column **114** and form a froth layer **134**. It is desirable that the pump **116** be operated such that the fluid **114** accumulates to a level L that is located above the intake **122** by a sufficient operating margin height to prevent the pump **116** from drawing gas or froth **134** into the intake. While typical electric submersible pumps will have load sensing system that protect the pump from damage when drawing froth or gas, such events when they occur result in loss of production from the well.

The pump speed control signal received at the input **132** of the VFD **130** may be adjusted by well control system (not shown) or by a well operator based on a current operating level L of the fluid **114**. Since the electric submersible pump **116** may be anywhere from a few hundred to several thousands of meters below the surface **106**, accurate determination of the level L of fluid **114** is important for efficient production of hydrocarbons from the well **100**.

The well **100** further includes an apparatus **150** for determining a level of the fluid **114** in communication with the pump **116**. The apparatus **150** includes a transducer **152** coupled a portion **154** of the well completion structure (in this case to the wellhead **104**) for generating a signal representing vibrations generated by the pump **116** during pumping operations. The apparatus **150** also includes a processing system **156** having a transducer signal input **160** for receiving the signal representing vibrations. The processing system **156** is configured to generate a vibration value characterizing the pump vibrations and also includes a fluid level output **168** for producing a signal representing fluid level. In other embodiments the transducer **152** may include a plurality of transducers coupled to the well completion structure. For example, additional transducers may be coupled to downhole portions of the production tubing **136**.

An example embodiment of the processing system **156** is shown in Figure 2. Referring to Figure 2, the processing system **156** includes a receiver **158** having the transducer signal input **160** for receiving a signal representing pump vibrations generated by operation of the pump **116** during pumping operations. The processing system **156** also includes a signal processor **162** operably configured to process the vibration signals received by the receiver **158** to generate a vibration value characterizing the pump vibrations. The processing system **156** also includes a store **164** for holding a correlation between pump vibrations and fluid level. The processing system **156** further includes comparator **166**, which receives the vibration value from the signal processing system **162** and the correlation between pump vibrations and fluid level from the store **164** and generates a fluid level value. The fluid level value is made available at the output **168** of the processor system **156** in an analog or digital signal format suitable for driving a display (not shown), for providing a fluid level readout, or for coupling to a well control system as a control input. In one

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embodiment the processing system **156** may be implemented using a microprocessor circuit configured to perform the functions of the blocks **158** – **166** shown in Figure 2. Alternatively, the processing system **156** may be implemented using analog and/or logic circuitry, and application specific integrated circuit (ASIC), or a configurable electronic device such as a field-programmable gate array (FPGA) or mixed-signal FPGA, for example.

In one embodiment the processing system **156** may be located at the wellhead **104**, but in other embodiments portions of the processing system may be remotely located with respect to the wellhead. For example, in one embodiment the receiver **158** may be located proximate the wellhead **104** for receiving the transducer signal **160**, and the receiver **158** may further include an interface (not shown) for communicating either wirelessly or over a wired connection with a remotely located signal processor **162**, and/or comparator **166** and/or correlation store **164**. In such embodiments the determination of the fluid level could be performed remotely and transmitted back to the wellhead **104**.

In the embodiment shown in Figure 1, the transducer signal (received at the input **160** of the processing system **156**) is provided by the transducer **152**, which is coupled to receive vibrations from portion **154** of the wellhead **104**. In this embodiment, the transducer **152** is located at the surface, and pump vibrations are transmitted from the pump **116** along the production tubing **136** to the wellhead **104**. Alternatively, the vibration transducer **152** may be coupled to receive vibrations along an electric cable connection to the pump, either through a cable sheath or through the cable conductors. In other embodiments the vibration transducer **152** may be located downhole proximate the electric submersible pump **166**, or at another location along the production tubing **136**

and the signal may be transmitted to the surface **106** wirelessly, or through a cable or optical fiber (not shown).

5 In some implementations, the processing system **156** can be implemented as a microprocessor circuit. An example microprocessor circuit embodiment of the processing system **156** is shown in Figure **3** at **250**. Referring to Figure **3**, the processor circuit **250** includes a microprocessor **252**, a program memory **254**, a variable memory **256**, a media reader **260**, and an input output port (I/O) **262**, all of which are in communication with the microprocessor **252**. Program codes for directing the microprocessor **252** to carry out various functions for determining fluid level are stored in the program memory **254**, which may be implemented as a random access memory (RAM) and/or a hard disk drive (HDD), or a combination thereof. For example, the program memory **254** may include instructions, e.g., program codes, for configuring the microprocessor **252** to operate as the signal processor **162** and instructions, e.g., codes, for configuring the microprocessor **252** to act as the comparator **166**.

15 The media reader **260** facilitates loading program codes into the program memory **254** from a computer readable medium **264**, such as a CD ROM disk **266**, or a computer readable signal **268**, such as may be received over a computer network.

25 The I/O **262** includes an interface **270** having an input **272** for receiving the signal representing the pump vibrations from the transducer **152**. The interface **270** acts as the receiver **158** shown in Figure **2**, and may comprise an analog to digital converter that converts the signal generated by the transducer **152** into a digital representation to facilitate further processing. In this embodiment, the I/O **262** further includes an interface **274** for receiving a signal representing the drive

frequency of the drive power provided by the variable frequency drive **130**. The I/O **262** further includes a first output **278** for producing the fluid level signal.

5 The variable memory **256** includes a plurality of storage locations including a store **280** for storing correlation data, which in this implementation corresponds to the store **164** shown in Figure 2.

10 In the embodiment shown in Figure 3, the signal representing pump vibrations received at the input **272** of the interface **270** is used in generating a vibration value characterizing the pump vibrations. In one embodiment generating the vibration value involves causing the microprocessor **252** to process the signal to generate amplitude values representing an amplitude of the pump vibrations and to use a correlation between pump vibrations and fluid level to generate a fluid level value corresponding to the vibration value. In another embodiment
15 generating the vibration value involves causing the microprocessor **252** to generate frequency spectrum indicia values and to use a correlation between reference frequency spectrum indicia and fluid level values to generate the fluid level value. These embodiments are described in greater detail below.

20 Frequency spectrum embodiment

Referring to Figure 4, a flowchart depicting an example computer-implemented process **200** for determining a fluid level is shown. The process **200** can be implemented by the processor circuit **250** shown in Figure 3, although a differently configured system can be used. For illustrative purposes, the process
25 **200** is described in the context of the processor circuit **250**. In this example, the blocks generally represent instructions that may be read from the computer readable medium **264**, and stored in the program memory **254**, for directing the microprocessor **252** to perform various functions related to the fluid level

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determination. The instructions to implement each block may be written in any suitable program language, such as C, C++ and/or assembly code, for example.

Reference frequency spectrum indicia are obtained (Block **202**). In this example, the reference frequency spectrum indicia are pre-determined and stored as reference indicia values in the variable memory **256** and are obtained by the microprocessor **252**.

The reference frequency spectrum indicia values may be pre-determined by operating the pump **116** in the absence of the fluid **114** (i.e. under a starvation condition). Under these conditions vibrations of the pump is un-damped by fluid and will generate a first vibration frequency spectrum s_{ref} . The values stored in the store **280** may be signature values associated with the spectrum s_{ref} , such as an amplitude and a frequency of a dominant spectral component ω_{ref} in the spectrum.

A signal representing a frequency spectrum s_d of the pump vibrations for the operating conditions under which it is desired to determine the fluid level is received (Block **204**). In this example, the signal is received by the interface **270** of the I/O **262** and transmitted to the microprocessor **252**. When the fluid **114** surrounds any portion of the pump **116**, the fluid can alter the frequency spectrum of the pump vibrations, thus causing a change in frequency spectrum from the reference frequency spectrum generated under the reference operating conditions.

A frequency spectrum indicia is generated for the spectrum s_d (Block **206**), in this example by the microprocessor **252**. For example, the indicia may be signature

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values associated with the spectrum s_d , such as for example an amplitude and a frequency of a dominant spectral component ω_d in the spectrum s_d .

A difference $\Delta\omega$ is calculated between the frequency spectrum indicia ω_{ref} and ω_d (Block **208**), in this example by the microprocessor **252**. The difference $\Delta\omega$ is attributable to the fluid **114** in communication with the pump **116**.

The fluid level L associated with the difference $\Delta\omega$ is determined (Block **210**), in this example by the microprocessor **252**. In one embodiment, it is assumed that the motor acts as a simple harmonic oscillator, in which case the displacement of a particle $x(t)$ from its initial resting position is defined by the following equation derived from Newton's second law of motion:

$$x(t) = x_m \cos(\omega_0 t + \varphi) \quad (\text{Eqn 1})$$

where $x(t)$ is the change in length;

x_m is the amplitude;

ω_0 is the undamped angular frequency of the oscillator; and

φ is the phase constant.

The vibration of particles of the motor would have corresponding oscillations, these oscillations would differ in x_m , $\cos(\omega_0 t + \varphi)$ variables.

When a fluid is in communication with the pump, friction between the fluid and the oscillating mass (i.e. the pump) acts to dampen the oscillation. The frictional damping force may be written as:

$$F_d = -bv \quad (\text{Eqn 2})$$

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where F_d is the frictional force exerted due to the fluid resisting the vibration or oscillation;

b is the damping constant depending on the fluid constitution and the interface between the pump and the fluid; and

v is the velocity into the damped fluid.

From Hook's law of elasticity, the oscillatory force is given by:

$$F_s = -kx \quad (\text{Eqn 3})$$

where k is the spring constant. For an undamped oscillator, the natural frequency of oscillation is:

$$\omega_0 = \sqrt{\frac{k}{m}} \quad (\text{Eqn 4})$$

Combining Eqn 2 and Eqn 3, yields the net force on the body for damped oscillations:

$$\Sigma F = -kx - bv; \quad (\text{Eqn 5})$$

which may be rewritten as:

$$m\ddot{x} = -kx - b\dot{x}. \quad (\text{Eqn 6})$$

Solving the differential Eqn 6 may yields:

$$x(t) = x_m e^{-bt/2m} \cos(\omega_d t + \varphi) \quad (\text{Eqn 7})$$

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where ω_d is the angular frequency of the oscillator as damped by the fluid **114**;
 and
 m is the mass of the oscillating particle.

5 The damped frequency is then given by:

$$\omega_d = \sqrt{\frac{k}{m} - \frac{b^2}{4m^2}}. \quad (\text{Eqn 8})$$

10 The damped frequency ω_d is thus dependent on the damping constant b , which
 is a property of the fluid **114** in communication with the pump **116**. If the
 damping constant for the fluid **114** is known or remains constant over a period of
 interest, then the change in frequency $\Delta\omega$ (in this case the difference between ω_0
 and ω_d) may be related to a fluid level L . In practice, it is difficult to directly
 determine the mass m in Eqn 7. However, a calibration of the system may be
 15 obtained by taking an independent measurement of fluid level, and relating the
 measured fluid level to a measured frequency difference $\Delta\omega$. Alternatively, the
 pump may be operated under a plurality of different fluid levels, which may be
 combined with measured frequency differences to generate a plurality of values
 for a look-up table or for fitting to an interpolation formula, thereby facilitating
 20 conversion of frequency differences into fluid level L .

In one implementation of the process shown in Figure 4, a starved pump is used
 as a reference operating condition which may be assumed to approximate the
 undamped natural frequency ω_0 . When the fluid **114** is in communication with
 25 the pump **116**, the level of damping provided by the fluid is dependent on the
 mass of the fluid surrounding the pump, which in turn is dependent on both fluid
 constitution and fluid level. Accordingly, to accurately determine the fluid level L ,

knowledge of constitution of the fluid or at least the density of the fluid is used. For example, a fluid having a greater proportion of aerated froth would provide less damping, and therefore a smaller difference $\Delta\omega$ than a fluid having little or no froth component. While the fluid constitution may change over time, such changes are expected to be small. Example of determinations of fluid density include computing a density based on a known or assumed constitution of the fluid, or performing laboratory testing of a fluid sample.

In another embodiment, the reference frequency indicia may be selected in accordance with a drive frequency f_d of the electrical drive power supplied to the pump **116**. For example, in embodiments where the pump **116** includes an alternating current electrical motor that receives power from a variable frequency drive (not shown), the rotational speed of the pump would depend on the drive frequency. Since pump vibrations would generally be associated with the rotation, the frequency spectrum of the pump vibrations would be expected to have a strong frequency component due to rotation that changes when the drive frequency changes. The drive frequency may thus provide useful indicia for use as a reference frequency spectrum indicia.

Amplitude embodiment

In an alternative embodiment, the processing system **156** may be configured to receive and process more than one transducer. Referring to Figure 5, an embodiment is shown in which an apparatus for determining a level of the fluid **114** in the oil well **100** is shown at **350**. The apparatus **350** includes a processing system **352**, which may be implemented using a microprocessor circuit similar to that shown in Figure 3, with provision for receiving additional transducer signals at a plurality of inputs **366**. The processing system **352** also includes an output **368** for producing a fluid level signal. In the embodiment shown the apparatus

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350 includes a pair of transducers **354** and **356** at the wellhead **104**, and three transducers **358**, **360**, and **362** along the production tubing **136**. Portions of the cable **128** for providing electrical drive current to the pump **116** have been omitted in Figure **5** to more clearly show the transducer locations. As an example, for an electric submersible pump **116** disposed in the borehole **102** at a depth of about 40 meters below the surface, the transducers **358**, **360**, and **362** may be respectively located at 5, 15, 25, and 35 meters below the surface.

In one embodiment the transducers **354** – **362** may be tri-axial accelerometers that are operable to produce signal components characterizing vibration in an x-axis direction aligned with the length of the production tubing, and y-axis and z-axis directions generally aligned in a cross sectional plane through the production tubing, as shown at **364** in Figure **5**. Each transducer **354** – **362** would thus generate three signal components. Depending on the well completion and configuration of the wellhead **104**, different vibration components for each respective transducer may have higher or lower amplitudes. For example, at the wellhead **104**, the z-axis and y-axis components may be more attenuated by the rigidity of the wellhead structure than the same components from transducers along the production tubing **136** where less structural constraint is present.

In one embodiment, the transducers **354** – **362** are configured to produce vibration samples at a rate of about 600 samples per second, while the fluid level *L* in the borehole **102** would generally only vary over several minutes. Accordingly, averaging may be applied to reduce noise in the vibration signals. In one embodiment, the vibration samples are processed to extract root-mean-square (RMS) amplitude values. The RMS values may be further averaged over a time period (for example **30** seconds) to further reduce signal noise effects by applying a moving-window filter of to the RMS values. Additional signal

processing may be applied to remove noise or other disturbances from the vibration signals.

5 As described above for the frequency spectrum embodiment, a correlation between vibration values and fluid level may be generated under reference conditions for independently determined fluid levels. In this embodiment, the correlation may be saved in the store **164** as a calibration value relating vibration amplitude to fluid level, or as a set of calibration values for combining vibration amplitude component values obtained from the transducers **354** – **362** to
10 generate a fluid level value.

As in the frequency spectrum embodiment described above, a fluid density increase between the fluid used to obtain the correlation values and the actual fluid **114** in communication with the pump **116** would cause greater attenuation of
15 the vibration values thus providing a source of error in the generated fluid level. Accordingly, in one embodiment where the reference vibration values are obtained for a reference fluid having a reference fluid constitution, correlating may further involve determining a constitution of the fluid **114** in communication with the pump and applying a correction to the correlation for a determined fluid
20 constitution.

The above described embodiments result in the generation of a fluid level signal that may be displayed to an operator of the oil well **100**, and/or used in other control systems as a control input. For example the well control system
25 described above may receive the fluid level signal and generate the pump speed control signal (shown in Figure 1) based on the fluid level such that when the fluid level is too low the pump speed control signal at the input **132** of the VFD **130** causes the pump speed to be reduced allowing the fluid level to rise in the

borehole **102**. Similarly, when the fluid level is too high, the pump speed control signal may cause the pump speed to be increased to lower the fluid level in the borehole **102**. Advantageously, the fluid level is produced during operation of the pump **116**, and there is thus no need to interrupt production of the well **100** to perform fluid level determinations. The disclosed embodiments are also capable of providing a continuous fluid level, thereby facilitating optimal operation of the pump **116** for extraction of produced fluids from the well **100**.

In other embodiments, the downhole pump may be a reciprocating piston pump, which is coupled to an actuator for providing a reciprocating drive to the piston pump. A pumpjack is one example of such an actuator and the term is used to refer to the above-ground drive system for a reciprocating piston pump. A pumpjack actuator may comprise a rotating electric motor or engine in combination with a mechanical coupling that converts rotary motion of the motor into a vertical reciprocating motion for driving the pump piston.

While the above embodiments have been described in relation to an oil well, the disclosed methods and apparatus may be used in pumping operations other than oil extraction and recovery. For example, the above embodiments may be adapted for use in implementations in which water is pumped out of a reservoir using an ESP or other downhole pump. While specific embodiments of the invention have been described and illustrated, such embodiments should be considered illustrative of the invention only and not as limiting the invention as construed in accordance with the accompanying claims.

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What is claimed is:

1. A method for determining a level of a fluid in communication with a downhole pump during a pumping operation, the method comprising:

5 receiving a signal representing pump vibrations generated by operation of the pump during the pumping operation;

 based on the signal, generating a vibration value characterizing the pump vibrations; and

 using a correlation between pump vibrations and fluid level to
10 generate a fluid level value corresponding to the vibration value.
2. The method of claim 1 wherein receiving the signal comprises receiving the signal from a vibration transducer configured to receive pump vibrations and to generate the signal representing the pump vibrations.
3. The method of claim 2 wherein the vibration transducer is coupled to a
15 conduit that is coupled to the pump, the conduit being operable to transmit pump vibrations from the pump to the transducer.
4. The method of claim 3 wherein the vibration transducer is coupled to an electrical conduit housing an electrical cable for supplying electrical power to the pump.
- 20 5. The method of claim 3 wherein the pump includes an outlet for discharging fluid from the pump and wherein the conduit comprises production tubing extending between an outlet of the pump and a

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wellhead disposed at the surface, and wherein the vibration transducer is coupled to the production tubing at a location spaced apart from the outlet of the pump along the production tubing.

- 5 6. The method of claim 5 wherein the vibration transducer comprises a plurality of vibration transducers disposed at spaced apart locations along the production tubing and wherein receiving the signal comprises receiving signals from each of the vibration transducers, each signal representing pump vibrations at the respective transducer locations along the production tubing and wherein the generating the vibration values comprises combining values from the signals to generate the values characterizing the pump vibrations.
- 10
7. The method of claim 5 wherein the pump includes an inlet in communication with fluid produced from a steam assisted gravity drainage well.
- 15 8. The method of claim 1 wherein generating the vibration value comprises processing the signal to generate amplitude values representing an amplitude of the pump vibrations.
- 20 9. The method of claim 8 wherein processing the signal to generate the amplitude values comprises processing the signal to generate root mean square (RMS) amplitude values.
10. The method of claim 9 further comprising averaging the RMS amplitude values over a time period to generate an average value representing pump vibrations during the time period.

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11. The method of claim 8 wherein using the correlation between pump vibrations and fluid level comprises applying a predetermined relationship between pump vibration amplitude values and fluid level values to generate the fluid level value.
- 5 12. The method of claim 1 wherein generating the vibration value comprises processing the signal to generate frequency spectrum indicia values and wherein using the correlation between pump vibrations and fluid level comprises using a predetermined correlation between reference frequency spectrum indicia and fluid level values to generate the fluid level value.
- 10 13. The method of claim 12 wherein processing the signal to generate the frequency spectrum indicia comprises determining a fundamental frequency of the pump vibrations.
14. The method of claim 13 wherein using the correlation between pump vibrations and fluid level to generate the fluid level value comprises:
- 15 determining a reference fundamental frequency of the pump vibrations under the reference fluid level conditions; and
- determining a difference between the fundamental vibration frequency and the fundamental vibration frequency of the pump under the reference fluid level conditions.
- 20 15. The method of claim 13 wherein the pump comprises an alternating current motor coupled to a variable frequency drive for providing drive power to the motor and wherein generating the fluid level value comprises

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determining a frequency offset between the fundamental frequency of the pump vibrations and a frequency of the drive power supplied to the motor.

5 **16.** The method of claim **13** wherein the pump comprises a reciprocating piston pump coupled to an actuator operable to provide a reciprocating drive for driving the pump and wherein generating the fluid level value comprises determining a frequency offset between the fundamental frequency of the pump vibrations and an operating frequency associated with the actuator.

10 **17.** The method of claim **1** further comprising generating the correlation between pump vibrations and fluid level.

18. The method of claim **17** wherein generating the correlation comprises obtaining reference vibration values associated with operating the pump under reference fluid level conditions.

15 **19.** The method of claim **18** wherein obtaining reference vibration values comprises:

 determining the reference fluid level by performing a fluid level measurement that is independent of pump vibration;

 receiving a reference signal representing pump vibration under the reference pump operating conditions; and

20 generating the reference vibration values based on the reference signal.

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20. The method of claim **18** wherein obtaining reference vibration values comprises obtaining reference vibration amplitude values.

21. The method of claim **18** wherein obtaining reference vibration values comprises obtaining reference frequency spectrum indicia values.

5 **22.** The method of claim **18** wherein obtaining the reference vibration values comprises obtaining reference vibration values associated with operating the pump in communication with a reference fluid having reference fluid constitution and wherein using the correlation comprises:

10 determining a constitution of the fluid in communication with the pump; and

 applying a correction to the correlation for a fluid of the determined constitution.

23. An apparatus for determining a level of a fluid in communication with a downhole pump during a pumping operation, the apparatus comprising:

15 a receiver operably configured to receive a signal representing pump vibrations generated by operation of the pump during the pumping operation;

 a signal processor operably configured to generate a vibration value characterizing the pump vibrations based on the signal; and

20 a comparator operably configured to use a correlation between pump vibrations and fluid level to generate a fluid level value corresponding to the vibration value.

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24. The apparatus of claim **23** further comprising a vibration transducer configured to receive pump vibrations and to generate the signal representing the pump vibrations.
- 5 25. The apparatus of claim **24** wherein the vibration transducer is coupled to a conduit that is coupled to the pump, the conduit being operable to transmit pump vibrations from the pump to the transducer.
26. The apparatus of claim **25** wherein the vibration transducer is coupled to an electrical conduit housing an electrical cable for supplying electrical power to the pump.
- 10 27. The apparatus of claim **25** wherein the pump comprises an outlet for discharging fluid from the pump and wherein the conduit comprises production tubing extending between an outlet of the pump and a wellhead disposed at the surface, and wherein the vibration transducer is coupled to the production tubing at a location spaced apart from the outlet
15 of the pump along the production tubing.
- 20 28. The apparatus of claim **27** wherein the vibration transducer comprises a plurality of vibration transducers disposed at spaced apart locations along the production tubing and operably configured to generate respective signals, each signal representing pump vibrations at the respective transducer locations along the production tubing and wherein the signal processor is operably configured to generate the vibration value by combining values from the signals to generate the values characterizing the pump vibrations.

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29. The apparatus of claim **27** wherein the pump comprises an inlet in communication with fluid produced from a steam assisted gravity drainage well.
- 5 30. The apparatus of claim **23** wherein the signal processor is operably configured generate the vibration value by processing the signal to generate amplitude values representing an amplitude of the pump vibrations.
- 10 31. The apparatus of claim **30** wherein the signal processor is operably configured to process the signal to generate root mean square (RMS) amplitude values.
32. The apparatus of claim **31** wherein the signal processor is operably configured to average the RMS amplitude values over a time period to generate an average value representing pump vibrations during the time period.
- 15 33. The apparatus of claim **30** wherein the comparator is operably configured to apply a predetermined relationship between pump vibration amplitude values and fluid level values to generate the fluid level value.
- 20 34. The apparatus of claim **23** wherein the signal processor is operably configured to generate the vibration value by processing the signal to generate frequency spectrum indicia values and wherein the comparator is operably configured to use a predetermined correlation between reference frequency spectrum indicia and fluid level values to generate the fluid level value.

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35. The apparatus of claim **34** wherein the signal processor is operably configured to process the signal to generate the frequency spectrum indicia by determining a fundamental frequency of the pump vibrations.

36. The apparatus of claim **35** wherein the comparator is operably configured to:

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determine a reference fundamental frequency of the pump vibrations under the reference fluid level conditions; and

determine a difference between the fundamental vibration frequency and the fundamental vibration frequency of the pump under the reference fluid level conditions.

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37. The apparatus of claim **35** wherein the pump comprises an alternating current motor coupled to a variable frequency drive for providing drive power to the motor and wherein the comparator is operably configured to generate the fluid level value by determining a frequency offset between the fundamental frequency of the pump vibrations and a frequency of the drive power supplied to the motor.

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38. The apparatus of claim **35** wherein the pump comprises a reciprocating piston pump coupled to an actuator operable to provide a reciprocating drive for driving the pump and wherein the comparator is operably configured to generate the fluid level value by determining a frequency offset between the fundamental frequency of the pump vibrations and an operating frequency associated with the actuator.

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39. The apparatus of claim **23** further comprising a processing system operably configured to generate the correlation between pump vibrations and fluid level.

5 **40.** The apparatus of claim **39** wherein the processing system is operably configured to generate the correlation by obtaining reference vibration values associated with operating the pump under reference fluid level conditions.

41. The apparatus of claim **40** wherein the processing system is operably configured to obtain reference vibration values by:

10 determining the reference fluid level by performing a fluid level measurement that is independent of pump vibration;

 receiving a reference signal representing pump vibration under the reference pump operating conditions; and

15 generating the reference vibration values based on the reference signal.

42. The apparatus of claim **40** wherein the processing system is operably configured to obtain reference vibration amplitude values.

43. The apparatus of claim **40** wherein the processing system is operably configured to obtain reference frequency spectrum indicia values.

20 **44.** The apparatus of claim **40** wherein the processing system is operably configured to obtain reference vibration values associated with operating the pump in communication with a reference fluid having reference fluid

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constitution and wherein the processing system is further operably configured to:

determine a constitution of the fluid in communication with the pump; and

5 apply a correction to the correlation for a fluid of the determined constitution.

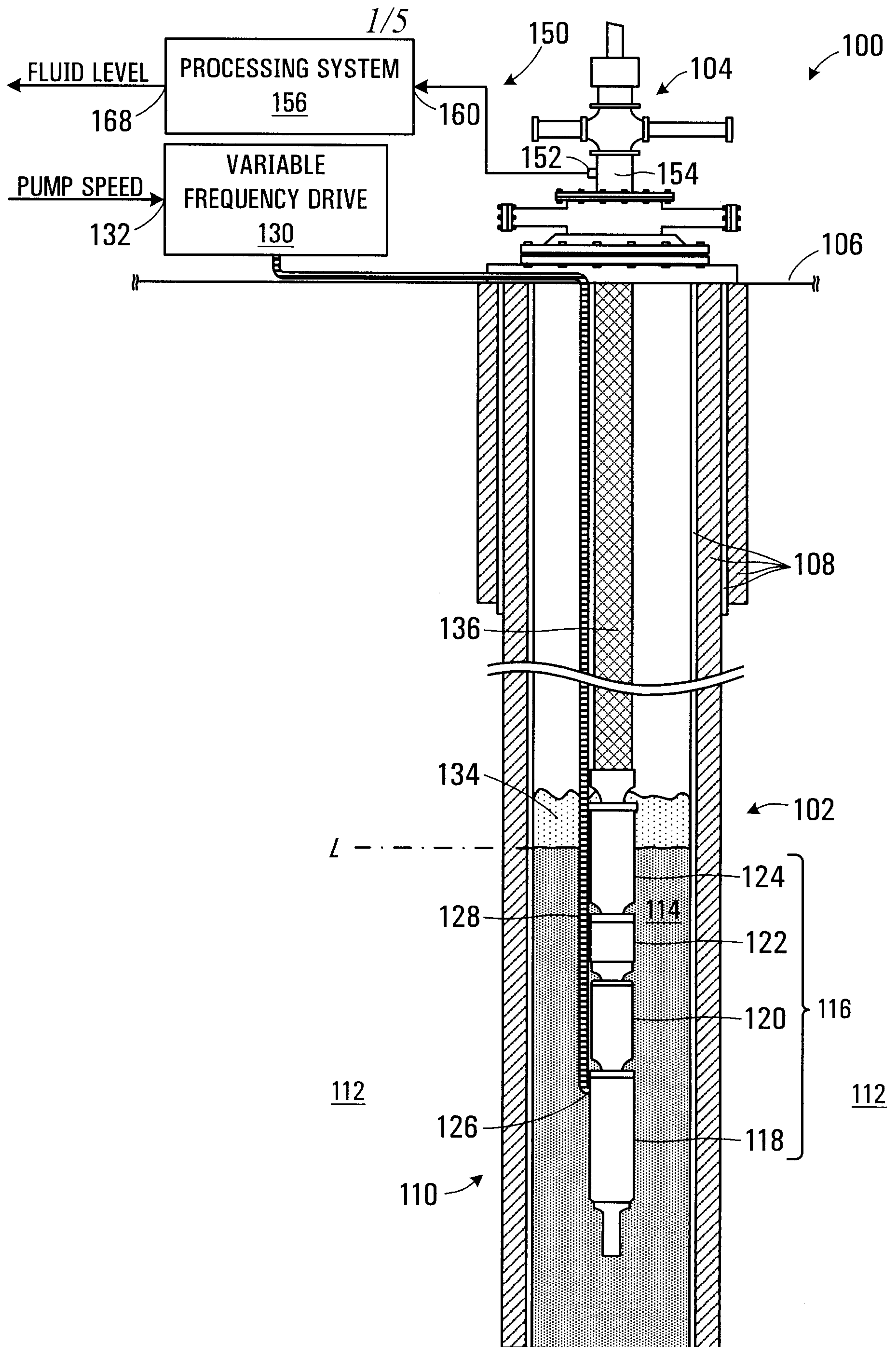
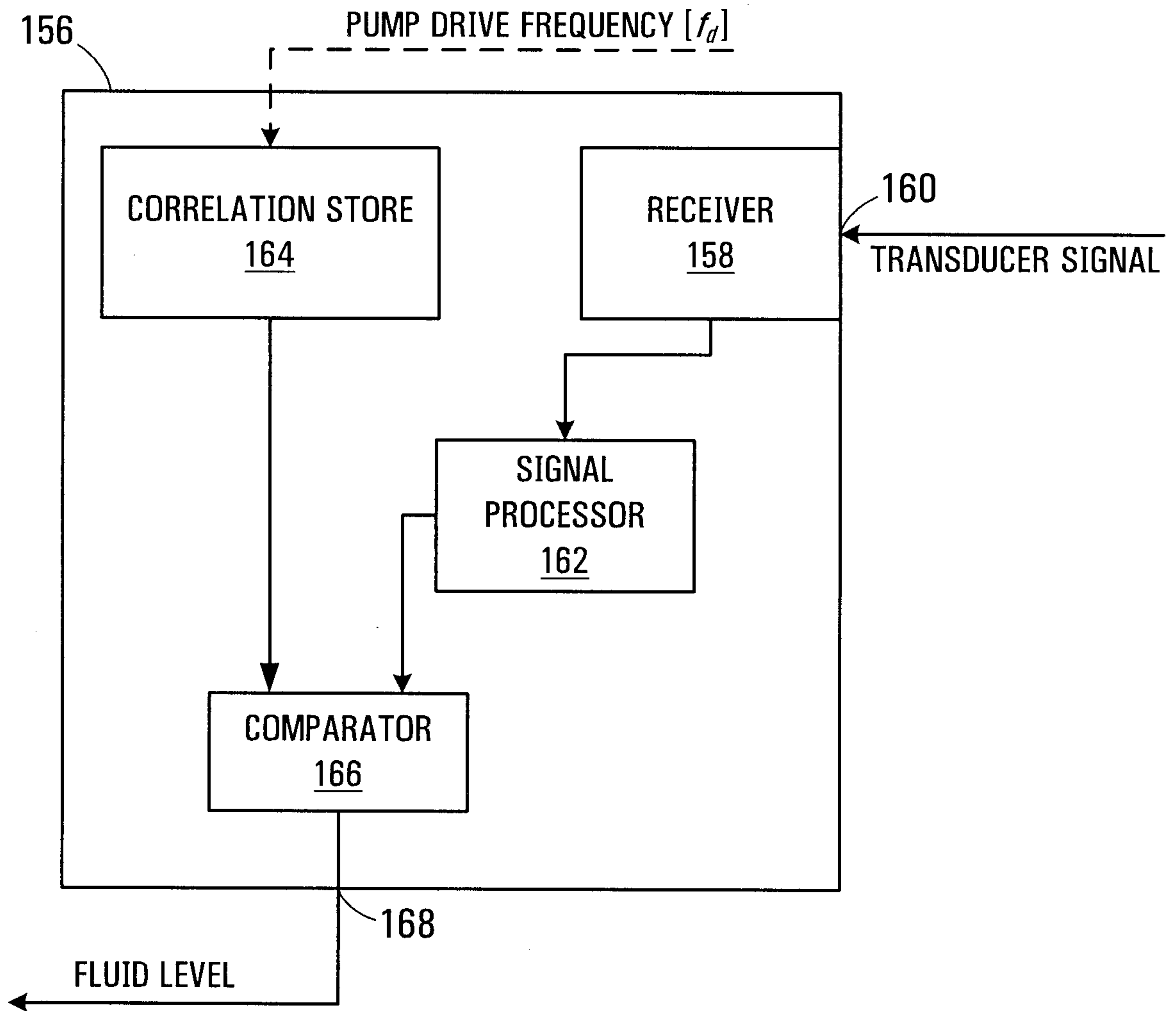
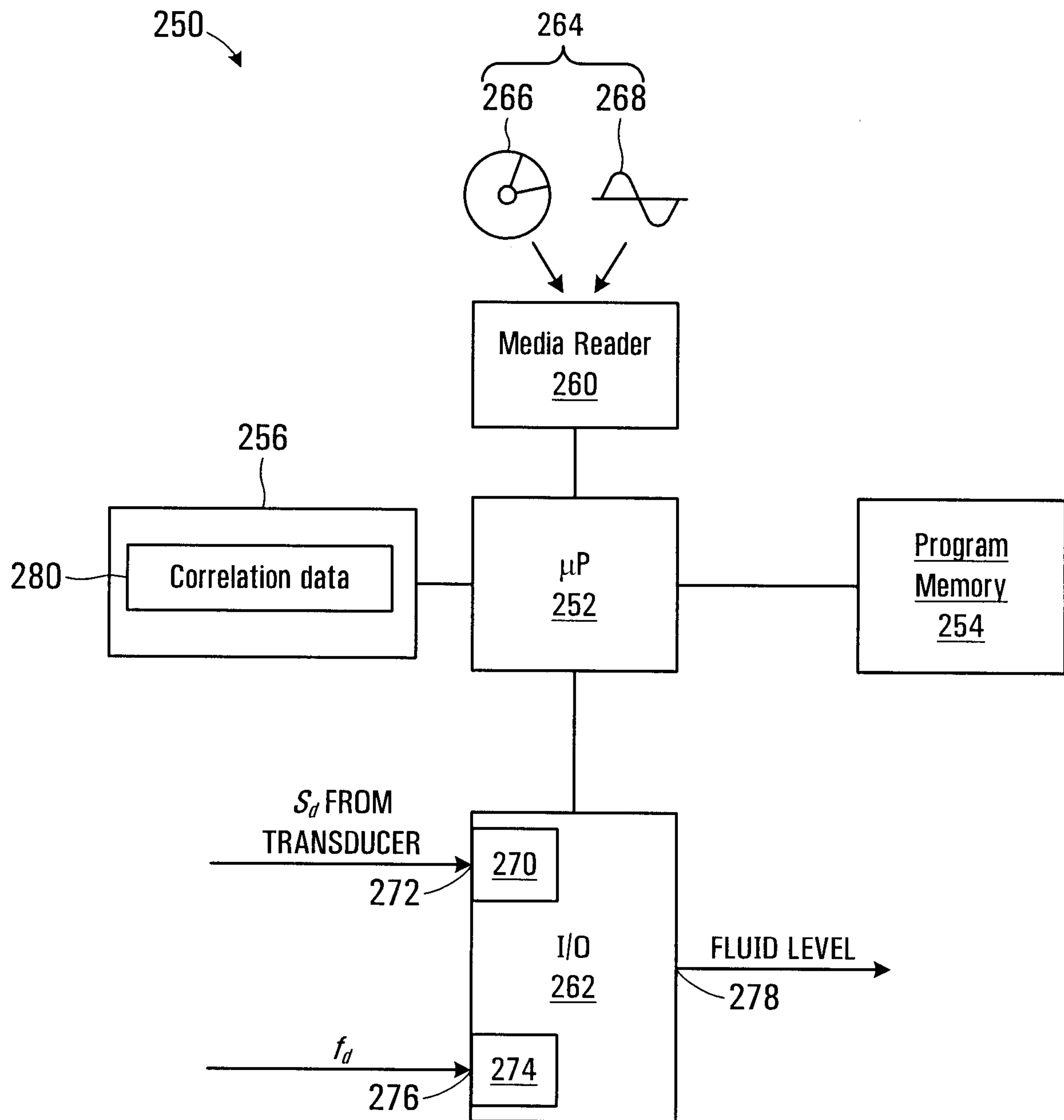


FIG. 1

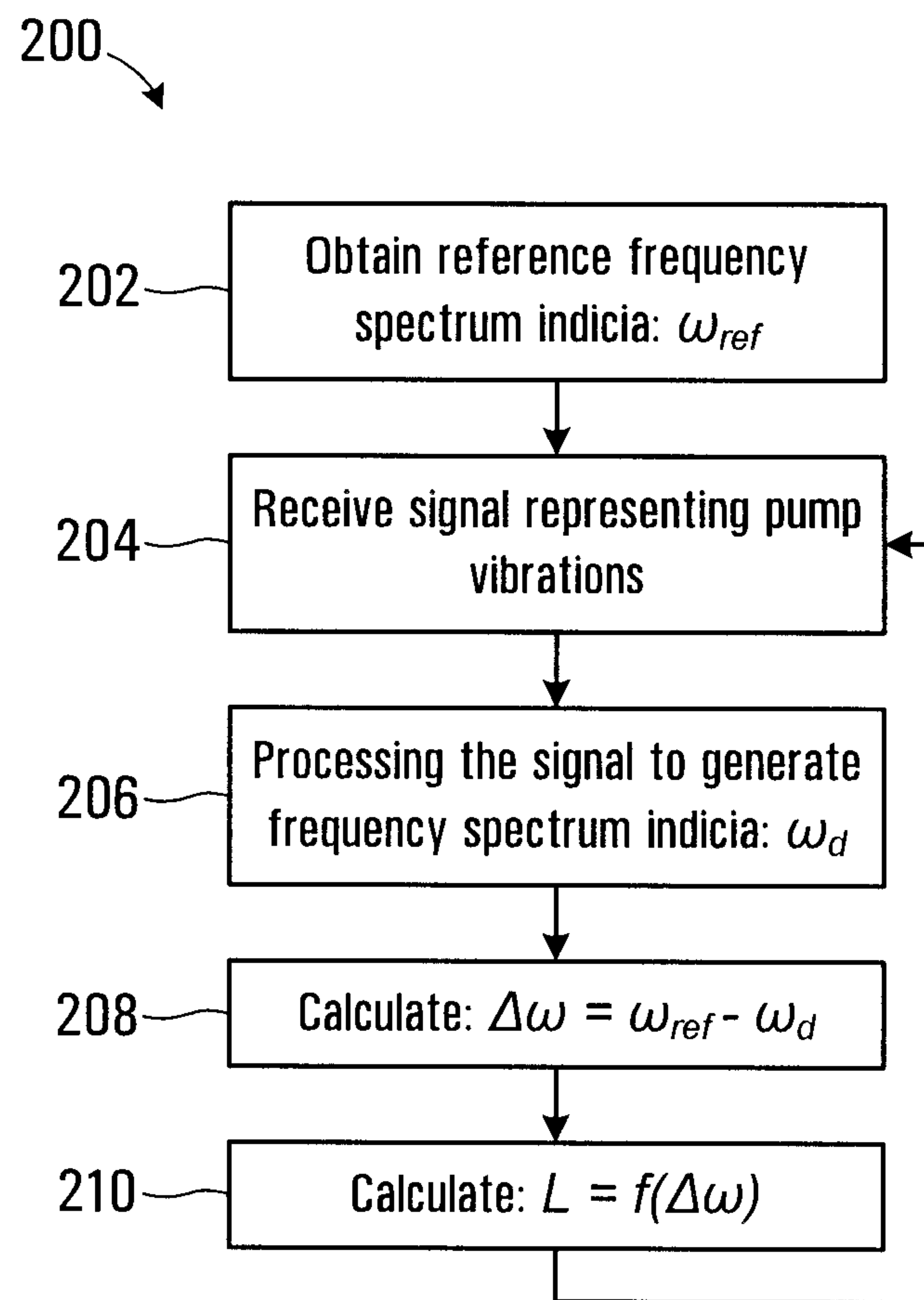
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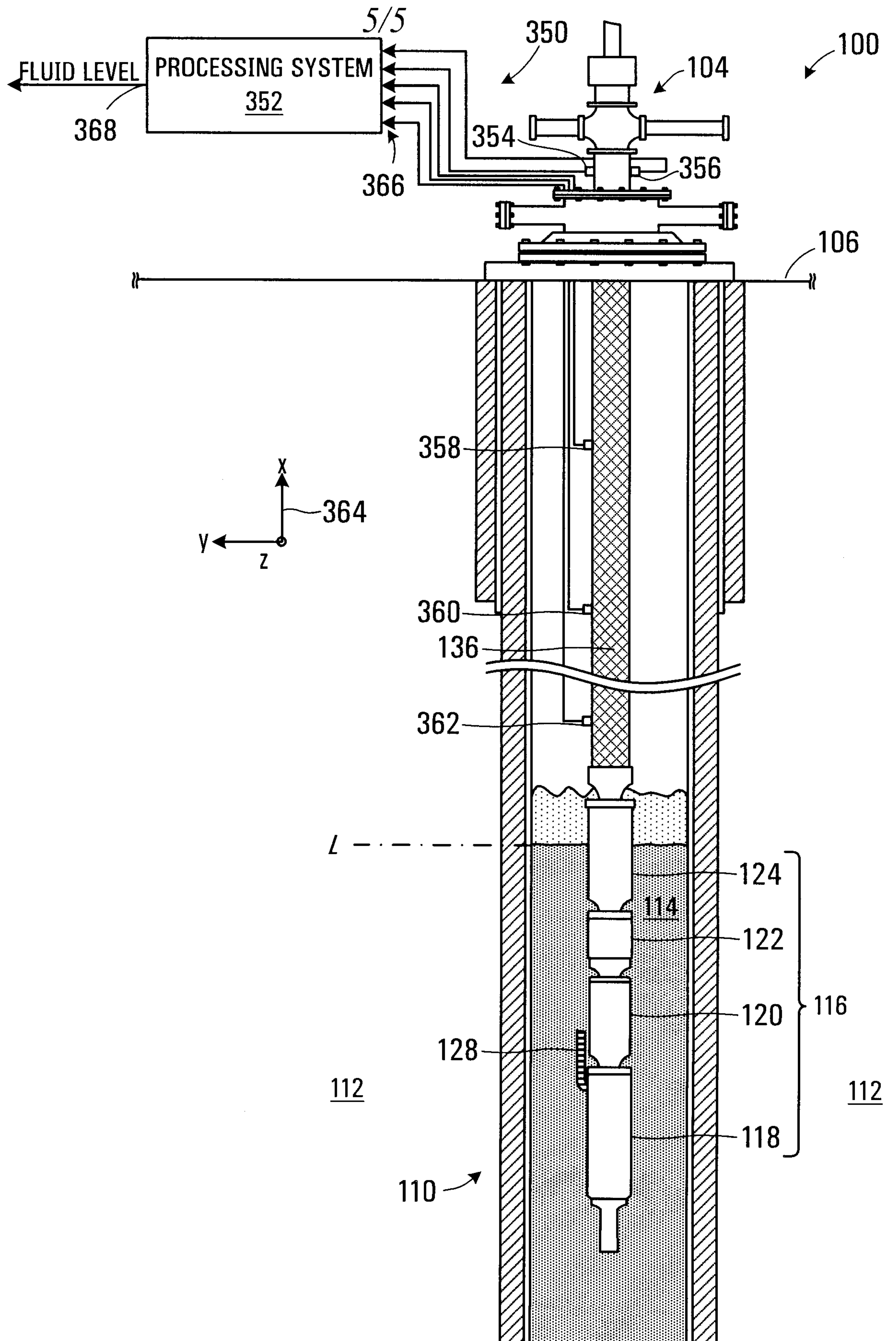
**FIG. 2**

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**FIG. 3**

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**FIG. 4**

**FIG. 5**

200

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Obtain reference frequency
spectrum indicia: ω_{ref}

204

Receive signal representing pump
vibrations

206

Processing the signal to generate
frequency spectrum indicia: ω_d

208

Calculate: $\Delta\omega = \omega_{ref} - \omega_d$

210

Calculate: $L = f(\Delta\omega)$

