Methods and apparatus for managing wellbore influx in a marine riser. In one embodiment, a method for managing wellbore influx includes identifying a difference between measured values provided by a plurality of sensors longitudinally spaced along a riser. Whether the difference between measured values provided by a given pair of the sensors has changed relative to a difference between measured values previously provided by the given pair of the sensors is determined. Whether wellbore influx is present in the riser is determined based on the change in the difference.
**FIG. 9**

1. **COMPUTE TEMPERATURE DIFFERENCES ACROSS SENSORS**
   - 902

2. **TEMPERATURE GRADIENT CHANGE?**
   - 904
   - YES
   - NO

3. **TEMPERATURE DECREASE?**
   - 906
   - YES
   - NO

4. **TEMPERATURE DECREASE RATE?**
   - 910
   - HIGH?
   - NO

5. **APPLY MUD-GAS SEPARATOR TO FLUID FROM RISER**
   - 912
   - DIVERT FLUID FROM RISER TO BYPASS MUD-GAS SEPARATOR

**FIG. 10**

1. **COMPUTE ACOUSTIC DIFFERENCES ACROSS SENSORS**
   - 1002

2. **ACOUSTIC GRADIENT CHANGE?**
   - 1004
   - YES
   - NO

3. **ACOUSTIC INCREASE OVER TIME?**
   - 1006
   - YES
   - NO

4. **ACOUSTIC INCREASE RATE HIGH?**
   - 1010
   - YES
   - NO

5. **APPLY MUD-GAS SEPARATOR TO FLUID FROM RISER**
   - 1012
   - DIVERT FLUID FROM RISER TO BYPASS MUD-GAS SEPARATOR
WELLOBORE INFLUX DETECTION IN A MARINE RISER

BACKGROUND

[0001] When drilling a borehole through subsurface formations, a wellbore or formation fluid influx, also called a “kick”, can cause an unstable and unsafe condition at the surface or rig. Consequently, it is desirable to detect a wellbore influx at the earliest possible time. When a kick is detected, the blowout preventers associated with the well may be closed and steps taken to regain control of the well.

[0002] In deepwater wells, for example, wellbore influx may sometimes migrate above the blowout preventers before the blowout preventers can be closed. Under such conditions, a mud-gas separator may be applied to the fluid (a mixture of drilling fluid and formation fluid) flowing up to the surface. The mud-gas separator extracts the gas from the drilling fluid and allows the gas to be transported away from the well, while the drilling fluid is processed for recirculation. Although less desirable, the fluid may be diverted to bypass the mud-gas separator. For example, the fluid may be diverted overboard. Use of a mud-gas separator minimizes environmental discharge of wellbore fluids, but if the fluid gas content or discharge rate from the well exceeds the mud-gas separator processing capabilities, then wellbore fluid may be diverted to bypass the mud-gas separator. Determining whether wellbore fluid flow should be diverted or processed through a mud-gas separator can be problematic. Accordingly, improved techniques for determining how wellbore influx upstream of the blowout preventers should be processed are desirable.

SUMMARY

[0003] Methods and apparatus for managing wellbore influx in a marine riser. In one embodiment, a method for managing wellbore influx includes identifying a difference between measured values provided by a plurality of sensors longitudinally spaced along a marine riser. Whether the difference between measured values provided by a given pair of the sensors has changed relative to a difference between measured values previously provided by the given pair of the sensors is determined. Whether wellbore influx is present in the marine riser is determined based on the change in the difference.

[0004] In another embodiment, a system for managing wellbore influx includes a marine riser, an array of sensors, and influx analysis logic. The array of sensors is disposed at intervals along the length of the marine riser. The sensors are configured to measure one or more parameters indicative of wellbore influx within the marine riser. The influx analysis logic is configured to detect wellbore influx in the marine riser based on a difference in measurement values provided by two of the sensors.

[0005] In a further embodiment, a marine riser includes a plurality of riser tubes, sensors distributed along the tubes at least some of the tubes, and a riser monitoring system communicatively coupled to the sensors. The tubes are connected end-to-end and extend from a blowout preventer to a surface installation. The sensors are configured to measure a condition of fluid in the tubes. The riser monitoring system is configured to collect measurement values generated by the sensors, and to detect influx of formation fluid into the riser based on a difference between measurement values provided by two of the sensors.

BRIEF DESCRIPTION OF THE DRAWINGS

[0006] For a detailed description of exemplary embodiments of the invention, reference is now made to the figures of the accompanying drawings. The figures are not necessarily to scale, and certain features and certain views of the figures may be shown exaggerated in scale or in schematic form in the interest of clarity and conciseness.

[0007] FIG. 1 shows a schematic view of an offshore system including wellbore influx detection in accordance with principles disclosed herein;

[0008] FIG. 2 shows a schematic view of a marine riser configured to detect wellbore influx in accordance with principles disclosed herein;

[0009] FIG. 3 shows a block diagram of a sensor module and a power/telemetry module for monitoring conditions within a marine riser in accordance with principles disclosed herein;

[0010] FIG. 4 shows a schematic view of a marine riser that includes optical fiber sensors for detecting wellbore influx in accordance with principles disclosed herein;

[0011] FIG. 5 shows a block diagram for a riser monitoring system configured to manage wellbore influx in accordance with principles disclosed herein;

[0012] FIG. 6 schematically shows an exemplary wellbore influx occurring in a marine riser that is configured in accordance with principles disclosed herein; and

[0013] FIGS. 7-10 show flow diagrams for methods for managing wellbore influx in accordance with principles disclosed herein.

NOTATION AND NOMENCLATURE

[0014] In the following discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to . . . ”. Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be through direct engagement of the devices or through an indirect connection via other devices and connections. The recitation “based on” means “based at least in part on.” Therefore, if X is based on Y, X may be based on Y and any number of other factors.

DETAILED DESCRIPTION

[0015] The following discussion is directed to various exemplary embodiments of the invention. The embodiments disclosed should not be interpreted, or otherwise used, to limit the scope of the disclosure, including the claims. In addition, one skilled in the art will understand that the following description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to intimate that the scope of the disclosure, including the claims, is limited to that embodiment.

[0016] Conventional influx management techniques rely on surface measurements to determine the condition of fluid circulating through the wellbore. Unfortunately, surface measurements may fail to provide adequate and/or timely information regarding wellbore influx. More specifically, the sur-
face measurements may not provide sufficient information to allow a well control system to determine whether fluid should be diverted to bypass a mud-gas separator (e.g., diverted overboard) or processed through the mud-gas separator. Embodiments of the present disclosure advantageously provide real-time measurement of fluid condition from sensors distributed along the marine riser. Based on the measurements made along the riser, embodiments can determine the nature of wellbore influx present in the riser, and determine whether the fluid discharged from the riser should be diverted or processed through a mud-gas separator.

[0017] FIG. 1 shows a schematic view of an offshore system 100 including wellbore influx detection in accordance with principles disclosed herein. Embodiments of the system 100 may be used to drill and/or produce the wellbore 118. The system 100 includes an offshore platform 110 equipped with a derrick 108 that supports a hoist (not shown) for raising and/or lowering a tubing string 106, such as a drill string. A marine riser 104 extends from the platform 110 to a subsea blowout preventer (BOP) 112. The BOP 112 is disposed atop a wellhead 114 at the seafloor. The wellbore 118 extends from the wellhead 114 into the earthen formations 120.

[0018] The tubing string 106 may include drill pipe, production tubing, coiled tubing, etc., and extends from the platform 110 through the riser 104, the BOP 112, and the wellhead 114 into the wellbore 118. A downhole tool 116 is connected to the lower end of the tubing string 106 for carrying out operations in the wellbore 118. The downhole tool 116 may include any tool suitable for performing downhole operations such as, drilling, completing, evaluating, and/or producing the wellbore 118. Such tools may include drill bits, packers, testing equipment, perforating guns, and the like. During downhole operations, tubing string 106 and tool 116 may move axially, radially, and/or rotationally relative to the riser 104 and the BOP 112.

[0019] The BOP 112 is configured to controllably seal the wellbore 118. Some embodiments of the BOP 112 may engage and seal around the tubing string 106, thereby closing off the annulus between the tubing string 106 and the riser 104. Some embodiments of the BOP 112 may include shear rams or blades for severing the tubing string 106 and sealing off wellbore 118 from riser 104. Transitioning the BOP 112 from open to closed positions and vice versa may be controlled from the surface or subsea.

[0020] The riser 104 includes multiple riser sections or joints of riser tubing connected end to end. Drilling fluid is circulated down to the wellbore 118 through the tubing string 106, and back to the platform 118 through the annulus 122 formed between the interior wall of the riser 104 and the tubing string 106. If formation fluids flow into the wellbore 118, the formation fluids may propagate to the surface via the annulus 122.

[0021] Embodiments of the riser 104 disclosed herein include sensors distributed along the length of the riser 104. The sensors detect conditions within the annulus 122 that may be indicative of the presence and degree of wellbore influx flowing into the riser 104. Information from the sensors is provided, via a riser telemetry system, to a riser monitoring system 102. The riser monitoring system 102 processes the measurements to determine whether, and what amount of wellbore influx is present in the annulus 122. If the riser monitoring system 102 detects wellbore influx in the annulus 122, then the riser monitoring system 102 may determine whether the fluid discharged from the riser 104 can be processed through a mud-gas separator on the platform 110. The mud-gas separator extracts gas from the drilling fluid, but has limited fluid processing and gas extraction capacity. Gas in excess of mud-gas separator capacity may be released into the atmosphere proximate the platform 110 increasing the risk of uncontrolled ignition. Accordingly, if the riser monitoring system 102 detects an amount of wellbore influx in the annulus 122 that exceeds the capacity of the mud-gas separator, then the riser monitoring system 102 may determine that the drilling fluid discharged from the riser 104 should be diverted overboard or otherwise bypass the mud-gas separator rather than processed in the mud-gas separator.

[0022] FIG. 2 shows a schematic view of an embodiment of the marine riser 104. In the embodiment of FIG. 2, the riser 104 includes a plurality of sensor modules 202, longitudinally spaced along the interior of the riser 104, and a plurality of power/telemetry modules 204 spaced along the exterior of the riser 104. The sensor modules 202 measure conditions on the interior of the riser 104. In some embodiments, the sensor modules 202 transmit the measurements through the wall of the riser 104 to the power/telemetry modules 204. The sensor modules 202 and the power/telemetry modules 204 may communicate magnetically through the wall of the riser 104. The power/telemetry modules 204 provide measurements received from the sensor modules 202 to the riser monitoring system 102 via a telemetry network 206 (e.g., a conductive or optical signal communication network). The sensor modules 202 and/or the power/telemetry modules 204 may be installed at manufacture of the tubes of the riser 104, or installed during or after assembly of the riser 104 at the wellsite. The sensor modules 202 may be fixed to the interior wall of the riser 104 via magnets or other suitable retention devices.

[0023] FIG. 3 shows a block diagram of the sensor module 202 and the power telemetry module 204 in accordance with various embodiments. The sensor module 202 includes sensors 302, a power receiver 304, and a data transceiver 306. The sensors 302 include one or more different types of sensors 302 that measure conditions within the annulus 122. For example, the sensors 302 may include one or more of temperature sensors, pressure sensors, flow rate sensors, acoustic sensors, resistivity sensors, etc. The power receiver 304 receives power signals wirelessly transmitted through the wall of the marine riser 104 from the power/telemetry module 204, and provides power to the sensors 302, the data transceiver 306, and other components of the sensor module 202. The data transceiver 306 receives measurement values from the sensors 302 and provides the measurement values to the power/telemetry module 204 wirelessly through the wall of the riser 104. The data transceiver 306 may also receive information (e.g., commands) from the power/telemetry module 204 and provide the received information to other components of the sensor module 202. The sensor module 202 may be disposed in a housing or encapsulant 314 suitable to allow for operation of the sensor module 202 in the annulus 122.

[0024] The power/telemetry module 204 includes a riser power and data telemetry interface 308, a power transmitter 310, and a data transceiver 312. The riser power and data telemetry interface 308 is coupled to the power/data network 206 that distributes power along the exterior of the riser 104, and provides communication with the riser monitoring system 102. The riser power and data telemetry interface 308 receives power signals from the network 206 and provides power to the power transmitter 310, the data transceiver 312
and other components of the power/telemetry module 204. The power transmitter 310 receives power signals from the riser power and data telemetry interface 308 and wirelessly transmits power signals to the sensor module 202 through the wall of the riser 104. The data transceiver 312 receives measurement values wirelessly transmitted through the wall of the riser 104 by the sensor module 202, and wirelessly transmits power signals to the riser power and data telemetry interface 308 for transmission to the riser monitoring system 102. The power/telemetry module 204 is disposed in a housing or encapsulant 316 suitable for operation of the power/telemetry module 204 in the marine environment around the riser 104. In some embodiments, the power/telemetry module 204 may be implemented as separate power and telemetry modules.

[0025] In some embodiments, the power transmitter 310 and the power receiver 304 are configured to pass signals magnetically through the wall of the riser 104 (e.g., the power transmitter 310 and the power receiver 304 are inductively coupled). Similarly, the data transceivers 306 and 312 may be configured to pass signals magnetically through the wall of the riser 104. Thus, the power transmitter 310, power receiver 304, and data transceivers 306, 312 may include coils or other antennas, modulators, demodulators, etc. that provide transmission and/or reception of magnetic signals through the wall of the riser 104. Power and data signals may be provided in different frequency bands. In some embodiments, the power transmitter 310 and the data transceiver 312 may be combined, and/or the power receiver 304 and the data transceiver 306 may be combined.

[0026] FIG. 4 shows a schematic view of a marine riser 104 that includes optical fiber sensors for detecting wellbore influx. In the embodiment shown in FIG. 4, the riser 104 includes one or more optical fibers 402 extending along the length of the riser tubes. In various embodiments, the optical fibers 402 may be affixed to either the inside of the riser tubes or the outside of the riser tubes after the riser tubes have been installed at the wellsite. The optical fibers 402, and any buffering, coating, or housing protecting the optical fibers 402, may be attached to the wall of the riser 104 magnetically, or via an alternative retention technique suitable for subsea or in-riser use. The optical fibers 402 may be arranged to form a helix about the interior or exterior of the riser tubes in some embodiments.

[0027] The optical fibers 402 may be configured to provide temperature sensing, pressure sensing, acoustic sensing, etc. The optical fibers 402 reflect a portion of the light transmitted through the optical fibers 402 from the surface (e.g., a light source (e.g., laser) associated with the riser monitoring system 102). The light reflected by the optical fibers 402 is a function of environmental factors, such as temperature, pressure, or strain, that affect the optical fibers 402. Consequently, changes in the temperature, pressure, strain, etc., can be identified via analysis of changes in the reflected light. The reflected light is analyzed and measurement values are derived (e.g., temperature values, pressure values, flow values, etc.).

[0028] The optical fibers 402 may implement any of various optical sensing techniques. In Distributed Temperature Sensing (DTS), the entire length of the optical fiber 402 acts as a sensor. Reflections of a light pulse transmitted down the optical fiber 402 from the surface are analyzed by the riser monitoring system 102 to determine the temperature at various locations along the riser 104. In Array Temperature Sensing (ATS), the optical fiber 402 includes Bragg gratings at predetermined measurement locations. Temperature, pressure, strain, etc. affect the Bragg gratings and in turn affect the light reflected by the Bragg gratings. Light reflected by each of the Bragg gratings is analyzed and temperature, pressure, etc. at the Bragg grating is determined by the riser monitoring system 102.

[0029] FIG. 5 shows a block diagram of the riser monitoring system 102. The riser monitoring system 102 includes one or more processors 502, storage 504, and a power/data telemetry interface 516. The power/data telemetry interface 516 may include power supplies that provide power for use by the sensor modules 202 and/or the power/telemetry module 204, and transceivers for transmitting to and receiving information from (e.g., measurement values) the sensor modules 202 and/or the power/telemetry modules 204. In embodiments employing optical fiber sensors, the interface 516 may include light sources and reflection detectors.

[0030] The processor(s) 502 may include, for example, one or more general-purpose microprocessors, digital signal processors, microcontrollers, or other suitable instruction execution devices known in the art. Processor architectures generally include execution units (e.g., fixed point, floating point, integer, etc.), storage (e.g., registers, memory, etc.), instruction decoding peripherals (e.g., interrupt controllers, timers, direct memory access controllers, etc.), input/output systems (e.g., serial ports, parallel ports, etc.) and various other components and sub-systems.

[0031] The storage 504 is a non-transitory computer-readable storage device and includes volatile storage such as random access memory, non-volatile storage (e.g., a hard drive, an optical storage device (e.g., CD or DVD), FLASH storage, read-only-memory) or combinations thereof. The storage 504 includes sensor measurements 514 received from the sensor modules 202 or the optical fiber 402, and inflow analysis logic 506. The inflow analysis logic 506 includes instructions for processing the sensor measurements 514 and determining whether the sensor measurements 514 indicate that formation fluid is present in the marine riser 104. Processors execute software instructions. Instructions alone are incapable of performing a function. Therefore, any reference herein to a function performed by software instructions, or to software instructions performing a function is simply a shorthand means for stating that the function is performed by a processor executing the instructions. In some embodiments, at least some portions of the power/monitoring system 202 (e.g., the processors 502 and/or the storage 504) may be embodied in a computer, such as a rackmount computer, desktop computer, or other computing device known in the art.

[0032] The inflow analysis logic 506 includes sensor gradient computation 508, gradient rate change computation 510, and thresholding 512. The sensor gradient computation 508 identifies differences or gradients in measured values provided by pairs of the sensor modules 202. For example, the riser system of FIG. 2 includes four sensor modules 202. From the four sensor modules 202, the sensor gradient computation 508 may determine measured value differences for six different pairings of the four sensor modules 202, determine the direction of any changes in measurement value differential for the pairings, and determine whether the direction of change is indicative of wellbore influx.

[0033] The gradient rate change computation 508 determines a rate of change of a measured value difference between sensor module 202 pairings based on current and previously measured values. The thresholding 512 compares
the determined rate of change to a threshold value. The results of the threshold value comparison may indicate an action to be taken to process the wellbore influx. For example, if the determined rate exceeds the threshold, then fluid discharged from the riser 104 may be diverted (e.g., diverted overboard), otherwise, the mud-gas separator may be applied.

[0034] FIG. 6 illustrates influx of formation fluid into the wellbore and the marine riser 104. In FIG. 4, the riser 104 includes four sensor modules 202, labeled 202a-202d. At time t=0, formation fluid 602 enters the wellbore, but an influx or kick is not yet detected because the influx is below the deepest or lowermost sensor 202a. At t=1, the deepest or lowermost positioned annular sensor 202a is the first sensor to measure, for example, a pressure decrease. At t=2, as the formation fluid 602 expands and additional formation fluid 602 enters the wellbore, the second deepest annular pressure sensor 202b measures an annular pressure decrease. In addition, the gradient between sensors 202a and 202b is increasing. At t=3, the sensor module 202c higher in the riser 104 measures a further increasing pressure drop, and the gradients between all the sensor modules continue to increase. At t=4, the sensor module 202d highest in the riser 104 measures a pressure drop, and the annular pressure and gradients between all the sensor modules 202a-202d increase rapidly.

[0035] FIG. 7 shows a flow diagram for a method 700 for managing wellbore influx in accordance with principles disclosed herein. Though depicted sequentially as a matter of convenience, at least some of the actions shown can be performed in a different order and/or performed in parallel. Additionally, some embodiments may perform only some of the actions shown. At least some of the operations of the method 700 can be performed by the processor(s) 502 of the riser monitoring system 102 executing instructions read from a computer-readable medium (e.g., storage 504). In the method 700 the marine riser 104 is installed between the platform 110 and the BOP 112. The sensor modules 202 and the power/telemetry modules 204 have been installed on the riser 104 along with telemetry network 206 that communicatively couples the sensor modules 202 to the riser monitoring system 102. Optical fiber sensors 402 may be used in some embodiments. In the method 800, wellbore influx into the riser 104 is detected based on changes in flow level in the annulus 122.

[0041] In block 802, sensor modules 202 measure the flow in the annulus 122 of the riser 104, and provide the measurement values to the riser monitoring system 102. For example, a self-heating thermistor may be used to measure flow based on changes in thermistor resistance caused by changes in thermistor heat dissipation due to changes in flow about the thermistor. The riser monitoring system 102 computes the flow difference across all pairings of sensor modules 202.

[0042] In block 804, the riser monitoring system 102 determines whether the flow differences (i.e., gradients) have changed from those of a previous measurement. In some embodiments the riser monitoring system 102 determines whether the change exceeds a predetermined threshold. If no change, or insufficient change, is detected, then monitoring continues in block 802.

[0043] If change in inter-sensor module flow difference is detected, then in block 806, the riser monitoring system 102 determines whether the flow is increasing over time. If the flow is decreasing rather than increasing, then monitoring continues in block 802. If the flow is increasing, then the riser monitoring system 102 determines the rate of flow increase over time in block 808.

[0044] In block 810, the riser monitoring system 102 compares the rate of flow increase to a flow increase rate threshold value. The flow increase rate threshold value may be related to an amount of gas that the mud-gas separator can process. If the rate of flow increase exceeds the threshold value, then, in block 814, the riser monitoring system 102 may divert the fluid flow from the riser 104 to bypass the mud-gas separator (e.g., divert the fluid overboard). If the rate of flow increase does not exceed the threshold value, then the riser monitoring system 102 may direct the fluid flow from the riser 104 to be processed by the mud-gas separator in block 812.

[0045] FIG. 9 shows a flow diagram for a method 900 for managing wellbore influx in accordance with principles disclosed herein. Though depicted sequentially as a matter of convenience, at least some of the actions shown can be performed in a different order and/or performed in parallel.
closed herein. Though depicted sequentially as a matter of convenience, at least some of the actions shown can be performed in a different order and/or performed in parallel. Additionally, some embodiments may perform only some of the actions shown. At least some of the operations of the method 900 can be performed by the processor(s) 502 of the riser monitoring system 102 executing instructions read from a computer-readable medium (e.g., storage 504). In the method 900 the marine riser 104 is installed between the platform 110 and the BOP 112. The sensors modules 202 and the power/telemetry modules 204 have been installed on the riser 104 along with telemetry network 206 that communicatively couples the sensor modules 202 to the riser monitoring system 102. In the method 900, wellbore influx into the riser 104 is detected based on changes in temperature in the annulus 122.

[0046] In block 902, sensor modules 202 measure the temperature in the annulus 122 of the riser 104, and provide the measurement values to the riser monitoring system 102. The riser monitoring system 102 computes the temperature difference across all pairings of sensor modules 202.

[0047] In block 904, the riser monitoring system 102 determines whether the temperature differences (i.e., gradients) have changed from those of a previous measurement. In some embodiments, the riser monitoring system 102 determines whether the change exceeds a predetermined threshold. If no change, or insufficient change, is detected, then monitoring continues in block 902.

[0048] If change in inter-sensor module temperature difference is detected, then in block 906, the riser monitoring system 102 determines whether the temperature is increasing rather than decreasing, then monitoring continues in block 902. If the temperature is decreasing, then the riser monitoring system 102 determines the rate of temperature decrease over time in block 908.

[0049] In block 910, the riser monitoring system 102 compares the rate of temperature decrease to a temperature decrease rate threshold value. The temperature decrease rate threshold value may be related to an amount of gas that the mud-gas separator can process. If the rate of temperature decrease exceeds the threshold value, then, in block 914, the riser monitoring system 102 may divert the fluid flow from the riser 104 to bypass the mud-gas separator (e.g., divert the fluid overboard). If the rate of temperature decrease does not exceed the threshold value, then the riser monitoring system 102 may direct the fluid flow from the riser 104 to be processed by the mud-gas separator in block 912.

[0050] FIG. 10 shows a flow diagram for a method 1000 for managing wellbore influx in accordance with principles disclosed herein. Though depicted sequentially as a matter of convenience, at least some of the actions shown can be performed in a different order and/or performed in parallel. Additionally, some embodiments may perform only some of the actions shown. At least some of the operations of the method 1000 can be performed by the processor(s) 502 of the riser monitoring system 102 executing instructions read from a computer-readable medium (e.g., storage 504). In the method 1000 the marine riser 104 is installed between the platform 110 and the BOP 112. The sensors modules 202 and the power/telemetry modules 204 have been installed on the riser 104 along with telemetry network 206 that communicatively couples the sensor modules 202 to the riser monitoring system 102. In the method 1000, wellbore influx into the riser 104 is detected based on changes in acoustic pressure in the annulus 122.

[0051] In block 1002, sensor modules 202 measure the acoustic pressure in the annulus 122 of the riser 104, and provide the measurement values to the riser monitoring system 102. The riser monitoring system 102 computes the acoustic pressure difference across all pairings of sensor modules 202.

[0052] In block 1004, the riser monitoring system 102 determines whether the acoustic pressure differences (i.e., gradients) have changed from those of a previous measurement. In some embodiments the riser monitoring system 102 determines whether the change exceeds a predetermined threshold. If no change, or insufficient change, is detected, then monitoring continues in block 802.

[0053] If change in inter-sensor module acoustic pressure difference is detected, then in block 1006, the riser monitoring system 102 determines whether the acoustic level is increasing. If the acoustic pressure is decreasing rather than increasing, then monitoring continues in block 1002. If the acoustic pressure is increasing, then the riser monitoring system 102 determines the rate of acoustic pressure increase over time in block 1008.

[0054] In block 1010, the riser monitoring system 102 compares the rate of acoustic pressure increase to an acoustic pressure increase rate threshold value. The acoustic pressure increase rate threshold value may be related to an amount of gas that the mud-gas separator can process. If the rate of acoustic pressure increase exceeds the threshold value, then, in block 1014, the riser monitoring system 102 may divert the fluid flow from the riser 104 to bypass the mud-gas separator (e.g., divert the fluid overboard). If the rate of acoustic pressure increase does not exceed the threshold value, then the riser monitoring system 102 may direct the fluid flow from the riser 104 to be processed by the mud-gas separator in block 1012.

[0055] The above discussion is meant to be illustrative of principles and various exemplary embodiments of the present invention. Numerous variations and modifications will become apparent to those skilled in the art once the above disclosure is fully appreciated. It is intended that the following claims be interpreted to embrace all such variations and modifications.

What is claimed is:

1. A method for managing wellbore influx, comprising:
   identifying a difference between measured values provided by a plurality of sensors longitudinally spaced along a riser;
   determining whether a difference between measured values provided by a given pair of the sensors has changed relative to the difference between measured values previously provided by the given pair of the sensors;
   determining based on the change in the difference whether wellbore influx is present in the riser.

2. The method of claim 1, wherein the sensors comprise one or more of pressure sensors, temperature sensors, flow rate sensors, resistivity sensors, and acoustic sensors.

3. The method of claim 1, further comprising installing the sensors in an interior of the riser after subsea installation of the riser at a wellsite.

4. The method of claim 1, further comprising:
   installing a power transmission system along a length of an exterior of the riser; and
wirelessly transmitting power to the sensors in an interior of the riser through a wall of the riser.

5. The method of claim 4, wherein installing the power transmission system comprises installing the power transmission system after subsea installation of the riser at a wellsite.

6. The method of claim 1, further comprising:
   installing a data telemetry system along a length of an exterior of the riser; and
   wirelessly transmitting measurements from the sensors to the data telemetry system through a wall of the riser.

7. The method of claim 6, further comprising transmitting the measurements to a riser monitoring system at the surface.

8. The method of claim 1, wherein the measured values are pressure values and the difference indicates a decrease in pressure between the given sensors.

9. The method of claim 1, wherein the measured values are flow values and the difference indicates an increase in flow between the given sensors.

10. The method of claim 1, wherein the measured values are temperature values and the difference indicates a decrease in temperature between the given sensors.

11. The method of claim 1, further comprising:
   determining a rate of change of the difference;
   determining whether fluid flow from the riser will be processed by a mud-gas separator based on the determined rate of change; and
   determining whether fluid flow from the riser will be diverted to bypass the mud-gas separator based on the determined rate of change.

12. The method of claim 11, wherein the measured values are pressure values; and further comprising:
   determining that the fluid flow from the riser is to be diverted to bypass the mud-gas separator based on a rate of decrease of the difference being greater than a predetermined pressure threshold; and
   determining that the fluid flow from the riser is to be processed by the mud-gas separator based on the rate of decrease of the difference being not greater than the predetermined pressure threshold value.

13. The method of claim 11, wherein the measured values are flow values; and further comprising:
   determining that the fluid flow from the riser is to be diverted to bypass the mud-gas separator based on a rate of increase of the difference being greater than a predetermined flow increase threshold value; and
   determining that the fluid flow from the riser is to be processed by the mud-gas separator based on the rate of increase of the difference being not greater than the predetermined flow increase threshold value.

14. The method of claim 11, wherein the measured values are temperature values; and further comprising:
   determining that the fluid flow from the riser is to be diverted to bypass the mud-gas separator based on a rate of decrease of the difference being greater than a predetermined temperature threshold; and
   determining that the fluid flow from the riser is to be processed by the mud-gas separator based on the rate of decrease of the difference being not greater than the predetermined temperature threshold value.

15. The method of claim 11, wherein the measured values are acoustic pressure values; and further comprising:
   determining that the fluid flow from the riser is to be diverted to bypass the mud-gas separator based on a rate of increase of the difference being greater than a predetermined acoustic pressure increase threshold value; and
   determining that the fluid flow from the riser is to be processed by the mud-gas separator based on the rate of increase of the difference being not greater than the predetermined acoustic pressure increase threshold value.

16. A system for managing wellbore influx, comprising:
   an array of sensors disposed at intervals along the length of the riser, the sensors configured to measure one or more parameters indicative of wellbore influx within the riser;
   and
   influx analysis logic configured to detect wellbore influx in the riser based on a difference in measurement values provided by two of the sensors.

17. The system of claim 16, wherein the influx analysis logic is configured to determine whether the difference in measurement values provided by a given pair of the sensors has changed relative to a previous difference in the measurement values provided by the given pair of the sensors.

18. The system of claim 16, wherein the sensors comprise one or more of pressure sensors, temperature sensors, flow rate sensors, resistivity sensors, and acoustic sensors.

19. The system of claim 16, wherein the sensors comprise an optical fiber extending over the length of the riser, the optical fiber configured to measure at least one of temperature, pressure, and acoustics along the length of the riser.

20. The system of claim 16, further comprising a power distribution network disposed on an outside surface of the riser, the power distribution network configured to wirelessly provide power to the sensors in an interior of the riser through a wall of the riser.

21. The system of claim 16, further comprising a data telemetry network disposed on an outside surface of the riser, the data telemetry network configured to:
   wirelessly receive measurements from the sensors in an interior of the riser through a wall of the riser; and
   provide the measurements to the influx analysis logic.

22. The system of claim 16, wherein the measurement values are indicative of one of pressure and temperature, and the influx analysis logic is configured to detect wellbore influx based on a decrease in one of pressure and temperature between the sensors.

23. The system of claim 16, wherein the measurement values are indicative of flow and acoustic pressure, and the influx analysis logic is configured to detect wellbore influx based on an increase in one of flow and acoustic pressure between the sensors.

24. The system of claim 16, wherein the influx analysis logic is configured to:
   determine a rate of change in the difference;
   determine whether fluid flow from the riser will be processed by the mud-gas separator based on the determined rate of change; and
   determine whether fluid flow from the riser will be diverted to bypass the mud-gas separator based on the determined rate of change.

25. The system of claim 16, wherein the influx evaluation system is configured to:
   divert fluid flow from the riser to bypass a mud-gas separator based on a rate of decrease in the difference being greater than a predetermined threshold value; and
apply the mud-gas separator to process the fluid flow from the riser based on the rate of decrease in the difference being not greater than the predetermined threshold value;
wherein the threshold value is one of a pressure threshold value and a temperature threshold value.

26. The system of claim 16, wherein the influx evaluation system is configured to:
divert fluid flow from the riser to bypass a mud-gas separator based on a rate of increase in the difference being greater than a predetermined threshold value; and
apply the mud-gas separator to process the fluid flow from the riser based on the rate of increase in the difference being not greater than the predetermined threshold value;

27. The system of claim 16, wherein the sensors are magnetically fixed to an interior of the riser.

28. A marine riser, comprising:
a plurality of riser tubes connected end-to-end and extending from a blowout preventer to a surface installation;
sensors distributed along at least some of the tubes, the sensors configured to measure a condition of fluid in the tubes; and

29. The marine riser of claim 28, wherein the sensors comprise one or more of pressure sensors, temperature sensors, flow rate sensors, resistivity sensors, and acoustic sensors.

30. The marine riser of claim 28, wherein the sensors are magnetically fixed to an interior surface of the tubes.

31. The marine riser of claim 28, further comprising a power distribution network disposed on an outside surface of the tubes, the power distribution network configured to wirelessly provide power to the sensors in an interior of the tubes through a wall of the tubes.

32. The marine riser of claim 28, further comprising a data telemetry network disposed on an outside surface of the riser, the data telemetry network configured to:
wirelessly receive measurements from the sensors in an interior of the riser through a wall of the riser; and
provide the measurements to the riser monitoring system.

33. The marine riser of claim 28, wherein the sensors comprise an optical fiber extending over the length of the tubes, the optical fiber configured to measure one of pressure, temperature, and acoustics along a length of the riser.

34. The marine riser of claim 28, wherein the riser monitoring system is configured to estimate an amount of formation fluid in the riser based on an amount of change in the difference between measurement values provided by two of the sensors over time.

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