REAL TIME CLOSED LOOP INTERPRETATION OF TUBING TREATMENT SYSTEMS AND METHODS

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ABSTRACT
A technique facilitates the treatment of a subterranean formation. The technique involves the use of a fluid delivery system that comprises a continuous feedback system. The continuous feedback system utilizes a real time closed loop interpretation technique to instantaneously synchronize and adjust actions at a well site surface relative to measured downhole events. Sensors are used to monitor at least one downhole property in real time. Based on the real time data, the continuous feedback system enables adjustments to be made with respect to the at least one property in a manner designed to influence a downhole event.
<table>
<thead>
<tr>
<th>CONDITION</th>
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<tbody>
<tr>
<td>UNDER-BALANCED</td>
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<td>0.9\times PORE_PRES</td>
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<tr>
<td>BALANCED</td>
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<td>1.1\times PORE_PRES</td>
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<tr>
<td>OVER-BALANCED</td>
<td>1.1\times PORE_PRES</td>
<td>0.8\times FRAC_PRES</td>
</tr>
<tr>
<td>FRAC WARNING</td>
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<td>FRAC_PRES</td>
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<tr>
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**FIG. 4**

**FIG. 5**
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<td>HIGH PRESSURE</td>
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<td>BURST_PRESS</td>
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**FIG. 7**

**FIG. 8**
FIG. 11
**WATER/BRINE MATRIX:**

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<td>&gt; 1.2 PPA</td>
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<tr>
<td><strong>BHP GRADIENT CHANGE</strong></td>
<td>&lt; Y PPG</td>
<td>Y PPG &lt; X &lt; Z PPG</td>
<td>&gt; Z PPG</td>
</tr>
<tr>
<td><strong>CT WEIGHT FLUCTUATION</strong></td>
<td>&lt; 1000 LBS/SEC</td>
<td>1000 LBS/SEC &lt; X &lt; 2000 LBS/SEC</td>
<td>&gt; 2000 LBS/SEC</td>
</tr>
<tr>
<td><strong>OVERBALANCE</strong></td>
<td>&lt; 100 PSI</td>
<td>100 PSI &lt; X &lt; 300 PSI</td>
<td>&gt; 300 PSI</td>
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<tr>
<td><strong>RIH SPEED</strong></td>
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<td>&gt; 1.2CS</td>
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<td><strong>POH SPEED</strong></td>
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**FIG. 14**

**GELLED FLUID MATRIX:**

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<td>&gt; 4 PPA</td>
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<tr>
<td><strong>BHP GRADIENT CHANGE</strong></td>
<td>&lt; Y PPG</td>
<td>Y PPG &lt; X &lt; Z PPG</td>
<td>&gt; Z PPG</td>
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<tr>
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<td>1000 LBS/SEC &lt; X &lt; 2000 LBS/SEC</td>
<td>&gt; 2000 LBS/SEC</td>
</tr>
<tr>
<td><strong>OVERBALANCE</strong></td>
<td>&lt; 100 PSI</td>
<td>100 PSI &lt; X &lt; 300 PSI</td>
<td>&gt; 300 PSI</td>
</tr>
<tr>
<td><strong>RIH SPEED</strong></td>
<td>&lt; 0.9CS</td>
<td>0.9CS &lt; X &lt; 1.2CS</td>
<td>&gt; 1.2CS</td>
</tr>
<tr>
<td><strong>POH SPEED</strong></td>
<td>&lt; 0.9SS</td>
<td>0.9SS &lt; X &lt; 1.2SS</td>
<td>&gt; 1.2SS</td>
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**FIG. 15**
**FOAM MATRIX:**

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<td>&gt; 6 PPA</td>
</tr>
<tr>
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<td>Y PPG &lt; X &lt; Z PPG</td>
<td>&gt; Z PPG</td>
</tr>
<tr>
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<td>1000 LBS/SEC &lt; X &lt; 2000 LBS/SEC</td>
<td>&gt; 2000 LBS/SEC</td>
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<tr>
<td>OVERBALANCE</td>
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**FIG. 16**

**NITROGEN MATRIX:**

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<td>1000 LBS/SEC &lt; X &lt; 2000 LBS/SEC</td>
<td>&gt; 2000 LBS/SEC</td>
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<tr>
<td>OVERBALANCE</td>
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<td>0.9SS &lt; X &lt; 1.2SS</td>
<td>&gt; 1.2SS</td>
</tr>
</tbody>
</table>

**FIG. 17**
REAL TIME CLOSED LOOP INTERPRETATION OF TUBING TREATMENT SYSTEMS AND METHODS

CROSS-REFERENCE TO RELATED APPLICATION

0001. This application claims priority under 35 U.S.C. § 119(c) to U.S. Provisional Application Ser. No. 60/934,258, filed on Jun. 12, 2007, which is incorporated herein by reference.

BACKGROUND

0002. A variety of systems and methods are used for making downhole measurements related to well treatment operations. Downhole measurements are made and the data is conveyed upwardly via fluid pulse signals, electromagnetic wireless signals, or hardwired electric signals. The measurements can be used to determine an event or downhole property/measurement, but existing systems and methods are limited in their ability to provide an operator with a comprehensive understanding of the downhole event/environment. Additionally, the measurements generally are typically performed for a single event.

0003. Furthermore, existing systems and methods fail to enable sufficient control of downhole conditions and/or events. Surface measurements must be correlated with downhole measurements before an action can be taken. No continuous feedback loop is provided to enable real time decisions, and substantial dependence on operator input is required to achieve a desired output and/or event downhole. The existing systems are not well-suited for use at the surface in a manner that enables synchronization and rapid adjustment in response to events happening in the well. These limitations reduce downhole efficiency and/or reservoir optimization.

SUMMARY

0004. In general, the present invention provides a system and method for treating a subterranean formation. The system and method utilize a fluid delivery apparatus that comprises a continuous feedback system utilizing a real time closed loop interpretation technique to instantaneously synchronize and adjust actions at a well site surface relative to measured downhole events. Sensors are used to monitor at least one downhole property/measurement, in real time. Based on the real time data from surface and downhole, adjustments can be made to manage and to influence a downhole event or environment.

BRIEF DESCRIPTION OF THE DRAWINGS

0005. Certain embodiments of the invention will hereafter be described with reference to the accompanying drawings, wherein like reference numerals denote like elements, and:

0006. FIG. 1 is a schematic front elevation view of a well treatment system positioned to deploy a fluid to a well formation, according to an embodiment of the present invention;

0007. FIG. 2 is a graphical representation of real time data output from a subterranean location in a form that can be displayed via a graphical user interface, according to an embodiment of the present invention;

0008. FIG. 3 is a schematic front elevation view of another example of a well treatment system positioned to obtain data in multiple well zones, according to an embodiment of the present invention;

0009. FIG. 4 is another example of a displayed output based on data obtained from a downhole location, according to an embodiment of the present invention;

0010. FIG. 5 is another example of a graphical user interface for providing information and enabling operator input, according to an embodiment of the present invention;

0011. FIG. 6 is another example of a graphical user interface for providing information and enabling operator input, according to an embodiment of the present invention;

0012. FIG. 7 is another example of a graphical user interface for providing information based on downhole data, according to an embodiment of the present invention;

0013. FIG. 8 is another example of a graphical user interface for providing information and enabling operator input, according to an embodiment of the present invention;

0014. FIG. 9 is a graph illustrating pressure versus true vertical depth during a run-in-hole, according to an alternate embodiment of the present invention;

0015. FIG. 10 is an illustration similar to that of FIG. 9;

0016. FIG. 11 is a schematic front elevation view of a well treatment system being run-in-hole and the resultant change in fluid level, according to an embodiment of the present invention;

0017. FIG. 12 is a graph illustrating true vertical depth, pressure and gradient versus time, according to an embodiment of the present invention;

0018. FIG. 13 is another example of a graphical user interface for providing information and enabling operator input, according to an embodiment of the present invention;

0019. FIG. 14 illustrates a matrix that can be utilized to determine the level of risk associated with a given well treatment operation, according to an embodiment of the present invention;

0020. FIG. 15 illustrates another matrix that can be utilized to determine the level of risk associated with a given well treatment operation, according to an embodiment of the present invention;

0021. FIG. 16 illustrates another matrix that can be utilized to determine the level of risk associated with a given well treatment operation, according to an embodiment of the present invention;

0022. FIG. 17 illustrates another matrix that can be utilized to determine the level of risk associated with a given well treatment operation, according to an embodiment of the present invention; and

0023. FIG. 18 is another example of a graphical user interface for providing information and enabling operator input, according to an embodiment of the present invention.

DETAILED DESCRIPTION

0024. In the following description, numerous details are set forth to provide an understanding of the present invention. However, it will be understood by those of ordinary skill in the art that the present invention may be practiced without these details and that numerous variations or modifications from the described embodiments may be possible.

0025. The present invention generally relates to a system and method for closed loop interpretation during fluid treatment of a subterranean reservoir using a fluid delivery apparatus including a tubing string that may be formed of coiled...
tubing. In one embodiment, the system and method relate to a real time closed loop interpretation method for coiled tubing services to synchronize and adjust actions at the surface with events happening downhole to improve downhole efficiency and/or reservoir optimization. The improvements in downhole efficiency and reservoir optimization can result from improved pressure management, load management, downhole tool management, reservoir management, and/or management of other aspects of the fluid treatment operation. The system and methodology provide solutions to a need for control over the operation by enabling synchronization and adjustment of actions at the surface relative to prior, current, or future downhole events through real time closed loop interpretation of subterranean treatments.

[0026] The real time control technique can be used in relationship to one or more downhole events. For example, detection and adjustment in real time of downhole events related to pressure management may include making adjustments related to stuck potential, diversion indicators, stimulation indicators, staying on target (over and under a set downhole pressure), and treatment fluid nozzle efficiency. Adjustment of the downhole event also may relate to load management and include downhole events related to weight on downhole tools and real time extended reach control. Detection and control also can be related to downhole tool management and include control of downhole devices that are sensitive to pressure differentials, spikes, changes in slope (increasing, flat or decreasing), and compressive, tensile or torsional forces. The detection and control also can be related to reservoir management and include downhole events characterized as injectivity profiles, placement of treatment fluids, location and volume characterization of deposited scale in the tubulars and reservoir, testing reservoir properties (e.g. capacity, deliverability), and characterization, predicting and identifying injection profiles.

[0027] As described in greater detail below, novel systems and methodology utilize real time closed loop interpretation for subterranean treatment services that provide distinct advantages and benefits. The advantages and benefits arise come at least in part, from the ability to predict the dynamic behaviors and/or events both at the surface and downhole, to provide feedback related to the downhole events or control of those events, and to control or adjust the downhole events. Furthermore, the control system enables monitoring of one or more properties that can be used in exercising control over multiple downhole events. The detection and control of the specific downhole events are enabled based on monitoring and evaluation of properties, such as pressure, load, velocity, and other indicative properties, with data available both downhole and at a surface location.

[0028] According to one embodiment of the invention, real time closed loop interpretation is used with coiled tubing systems and methods to predict a desired output for a desired a downhole event. Downhole properties are measured, and the measurements are sent to the surface as feedback. The feedback is used by a control system that can change the properties downhole and affect the downhole event. Values can be input into the control system to affect control over the downhole event as desired by a well operator.

[0029] In other embodiments, downhole properties may be measured, and the measurement data can be evaluated with a suitable control device located within the wellbore. The control device can be used to monitor feedback and to influence or control the downhole event based on the feedback information. Additionally, the monitoring and evaluation can be accomplished by a combined surface control system and downhole control system. Furthermore, the techniques for monitoring downhole properties and controlling downhole events in treatment operations are amenable for use with coiled tubing services and systems, but they also can be used with other suitable formation treatment techniques and equipment.

[0030] The system and methodology is useful for real time closed loop interpretation of coiled tubing services that involve characterizing an event, determining the trajectory, estimating the likelihood and potential severity of an occurrence of a specific downhole event, and displaying the information to an operator. The technique also can be used to optimize a service plan by first selecting an initial plan, determining the likelihood and severity of a downhole event, adjusting a parameter of the initial plan, reevaluating the likelihood and severity of the downhole event, and then repeating the process of adjusting and reevaluating as desired. The technique also can be used to provide a real time closed loop interpretation of coiled tubing services involving predicting in real time the tendency toward an event by acquiring both surface and downhole data. The data is used to determine and predict the ensuing operations and treatment outcome tendencies with closed loop calculations.

[0031] Similarly, the system and methodology can be used to provide a real time closed loop interpretation of coiled tubing services involving a system for warning of coiled tubing/pipe sticking by monitoring downhole and surface data. Ongoing data can be obtained and compared for differences. If sufficient differences arise, an alarm can be raised to indicate the onset of a downhole event due to changing parameters. The alarm enables intervention by an operator or automatic intervention by a control system able to take remedial action.

[0032] The technique also can be used to provide real time closed loop interpretation of coiled tubing services involving a method for determining one or more properties of a well treatment related event or plan by estimating the properties at one position in the wellbore and then at a second position. After estimating the properties, the well is flowed, and the measurements are repeated at the first and second positions. This process can be repeated as necessary to enable the verification of baselines and to make the necessary changes as baselines change. In some embodiments, the data from repeated measurements at the first and second positions is transmitted to the surface and recorded for determination of flow properties.

[0033] Referring generally to FIG. 1, one embodiment of a well treatment system 20 is illustrated as deployed for use in a real time closed loop interpretation of tubing services, e.g. coiled tubing services. The system provides the ability to predict the dynamic behaviors/events both at the surface and downhole and to exercise control over downhole events based on feedback. The feedback can be gained by measuring and evaluating downhole properties, such as pressure, load, velocity, and other suitable properties. These properties can be measured both downhole and at the surface.

[0034] As illustrated in FIG. 1, well treatment system 20 may comprise or be in the form of a fluid delivery system or apparatus comprising a continuous feedback system 22 that utilizes a real time closed loop interpretation technique to instantaneously synchronize and adjust actions at the surface relative to measured downhole events. The continuous feed-
back system 22 comprises a well treatment tubing string 24 deployed in a wellbore 26, a sensor system 28, and a control system 30 that may comprise a data acquisition, analysis, and control system.

[0035] Well treatment tubing string 24 comprises a treatment tool 32 deployed downhole to a desired location in wellbore 26 proximate a surrounding subterranean formation 34 that is to be treated. Treatment tool 32 is conveyed through wellbore 26 via a tubing 36, such as coiled tubing, that is conveyed downhole from suitable surface equipment 38 positioned at a surface location 40. Surface equipment 38 may comprise a coiled tubing rig designed to selectively deliver coiled tubing downhole and withdraw the coiled tubing and treatment tool 32.

[0036] During a well treatment operation, a treatment fluid is pumped downhole by suitable pumping equipment 42 that also may be positioned at surface location 40. Control system 30 also may be coupled to pumping equipment 42 to control delivery of treatment fluid based on monitored properties, and thereby influence/control downhole events. The treatment fluid is flowed down through tubing 36 and out through treatment tool 32, as represented by arrows 44. From treatment tool 32, the treatment fluid is forced outwardly into formation 34 through, for example, perforations 46 formed in a well casing 48. The treatment fluid and the configuration of treatment tool 32 can vary depending on the specific treatment operation and the environment in which the operation is conducted.

[0037] Sensor system 28 can be used to detect, in real time, at least one downhole property or measurement that can be used as an indicator for at least one downhole item, e.g., an event or an environment. For example, sensor system 28 may have a plurality of sensors 50 comprising, for example, one or more pressure sensors, temperature sensors, load sensors, casing collar locator sensors, fluid characteristic sensors, e.g., fluid velocity sensors, acoustic sensors, infrared sensors, optical sensors, flow sensors, and other types of sensors designed to detect and monitor one or more properties that can be used as an indicator of a downhole event. Depending on the property measured and the downhole event/environment, changes in the property/measurement can be an indication of the future occurrence, the current occurrence or the past occurrence of a downhole item of interest, such as an event or an environment. Sensors 50 also can be positioned at other locations, such as surface locations to provide, for example, comparison data that can be used for comparing, calibrating, or verifying downhole data.

[0038] Data from sensor system 28 is output in real time to data acquisition, analysis, and control system 30. Control system 30 may have a variety of forms and may be located in whole or in part at the well site/surface location 40 or at remote locations. Additionally, control system 30 may be a processor based control system, such as a computer control system in which data from sensor system 28 is processed on one or more computers. Control system 30 also can be automated to automatically provide predetermined control signals based on the real time detection of the at least one downhole property/measurement. For example, changes in the downhole property/measurement may cause control system 30 to take an automated control action to change the downhole property/measurement and to thereby influence and/or control a downhole event or environment.

[0039] In the example illustrated, sensor system 28 communicates with control system 30 via one or more control lines 52. The control line 52 may comprise a wired control line, a wireless control line, or combinations of wired and wireless segments for conveying signals from sensors 50 to control system 30 in real time. By way of example, the control system 30 may comprise a plurality of input/output units 54, and at least one or more of the units 54 may comprise computers 56 for processing and analyzing data received from sensor system 28 in real time. A variety of software programs can be loaded on the computer or computers 56 depending on the downhole property/measurement being monitored. Additionally, a plurality of the computers 56 can be used in cooperation by processing certain data on one computer and other data on another computer.

[0040] As illustrated, each unit 54 may comprise a display 58 to display information to an operator, and an input device 60, such as a keypad or touchscreen, to enable the operator to input information. In many applications, one or more of the displays 58 can be used to provide a graphical user interface 62 for displaying information and for prompting the operator to input detection, analysis, and control-related information. Depending on the structure of control system 30, a variety of other components can be used to convey and evaluate data. For example, a router or other suitable equipment 64 can be used to disseminate information to a plurality of units 54. Additionally, a variety of transmitters and receivers 66 can be used to receive and transmit from, for example, a remotely-located computer.

[0041] The continuous feedback system 22 can be used in a variety of applications for sensing many types of properties that facilitate the control of many types of potential downhole events. By way of example, the measured downhole property/measurement may comprise pressure, load, fluid velocity, fluid direction, temperature, fluid pH, fluid solids content, fluid density, and other properties. Individual properties or combinations of properties can be detected and used as an indicator of specific downhole events and/or environments.

Examples of such downhole events include stuck potential, diversion, stimulation, over/under balance, nozzle efficiency, downhole tool load, real time extended reach, pressure differential, pressure spikes, changes in measurement over time slope (increasing, flat or decreasing), injectivity profile, fluid placement, volume characterization of deposited scale, and a variety of reservoir properties. The description below provides a variety of examples with respect to uses of continuous feedback system 22; however, the system can be used in other applications and environments.

[0042] For example, in some embodiments of the invention, pressure management can be achieved by obtaining data from one or more of the downhole sensors 50. The control system 30 serves as an acquisition and analysis system and also displays various information and indicators to an operator via one or more displays 58. For example, the control system can be used to provide a real-time indicator based on changes in a downhole pressure measurement and/or changes in other measurements, such as temperature or casing collar locator measurements.

[0043] Information can be displayed via displays 58 in a variety of formats, including a horizontal time log 68, as illustrated in FIG. 2. In this example, control system 30 creates a time-based horizontal log and can perform a variety of operations on the time log, including annotations, printing, scale changes, add/delete tracks, or multiple time log windows. Additionally, specific channels can be selected for display on horizontal time log 68 from a predetermined list of
channels available or downloaded on the control system 30. In addition to existing downhole sensors/measurements channels, the list also can include calculated channels, such as foam quality, calculated bottom hole pressure, and derivative temperature. In FIG. 2, for example, graph lines 70 illustrate display channels representative of foam quality measurements or of a variety of other downhole property measurements. Additionally, the time based log can be used to display selected threshold values, as referenced by graph lines 72. The selected threshold values can be entered by an operator via graphical user interface 62 or via another suitable input device.

[0044] By way of example, when the measured downhole property is foam quality suitable threshold values are selected, e.g. foam quality limits at 60% to 70%, and those values are displayed via graph lines 72. The foam quality is determined by control system 30 based on pressure and temperature measurements relayed from downhole sensors 50 in real time. The foam quality values are calculated by control system 30 and displayed. For example, control system 30 can be used to provide an API Logs template on which the calculated values are displayed as API logs. An operator can enter the boundary values (see graph lines 72) to provide an indication of the suitable range for calculated foam quality values. Movement of the foam quality values outside of the boundaries is an indicator of a downhole event requiring changes to the treatment operation. Control system 30 can be used to influence or control the foam quality by changing aspects of the well treatment operation.

[0045] An additional example of a downhole property that can be used as an indicator of a specific downhole event is estimated bottom hole pressure at formation depth while acquisition is running. The calculation is based on the following parameters: bottom hole pressure measurement obtained from the downhole sensors 50; true vertical depth (TVD) where bottom hole pressure (bBHP) is based on the coiled tubing depth and the trajectory information entered as borehole surveys; TVD of the location where bottom hole pressure is calculated, based on the measured depth entered by user and trajectory information; and density of the fluid below the tool. It should be noted the density is initially entered as a fixed parameter, but this parameter can change during a treatment job which can affect the parameter calculations. Bottom hole pressure at formation depth (cBHP) can be calculated with the following formula:

cBHP = cBHP_{ref} + \rho_{ref} \cdot (Depth_{ref} - Depth_{meas})

[0046] Calculated bottom hole pressure can be monitored versus formation pressure and fracturing pressure, which can be entered into control system 30 by an operator. The calculated bottom hole pressure, formation pressure, and fracturing pressure also can be displayed on horizontal time log 68. As illustrated in FIG. 3, the calculated bottom hole pressure can be determined for a plurality of well zones 74 in which each zone has its own depth, fracturing pressure and formation pressure. Again, the appropriate values for each of these well zones 74 can be entered into control system 30.

[0047] Downhole properties/measurements also can provide an under balance/overbalance indicator in real time. In this example, the measured downhole property may comprise pressure which is monitored by a suitable downhole sensor 50 and transmitted to the surface data acquisition, analysis and control system 30. The measurement can be used to predict bottom hole pressure (cBHP) at formation depth in different zones. Differences in the bottom hole calculation can arise from differences in fluid density. Accordingly, an operator can select different fluids, and thus different fluid densities, for each well zone 74 to enable independent pressure calculations in each well zone 74. Fluid types can be entered by the operator via graphical user interface 62 or another suitable input device. The calculated bottom hole pressure is used, along with formation properties, to provide indicators to the operator regarding the pressure condition at defined well zones. In this example, pore pressure can be entered as well as the fracturing pressure for each zone. Control system 30 is then able to create different pressure intervals that are indicative of specific downhole events relative to the under balance/over balance condition of the well. Although the information can be displayed in a variety of formats, one format example is illustrated in FIG. 4 and provides minimum and maximum pressure conditions for a plurality of listed downhole events 76. For example, pressure balance ranges can be provided for under balanced, balanced, overbalanced, fracture warning, and fracture conditions.

[0048] The minimum and maximum boundaries listed in FIG. 4 for downhole events 76 are only examples of initial suggestions/values that can be provided by control system 30. Additionally, an operator can interface with control system 30 to change values and/or to turn off or turn on the monitoring of specific well zones. Additionally, a variety of graphs can be displayed to show the historical progress of one or more well zones conditions over time.

[0049] One example of a suitable graphical user interface 62 is illustrated in FIG. 5. In this example, the interface 62 provides an indicator 78 that points to selected downhole conditions, e.g. under balance/over balance conditions, as represented by pressure segments 80. The pressure segments 80 may correspond with ranges for predicting downhole events 76. In this example, a bar graph section 82 is used to illustrate a history of the wellbore condition according to colored indicators that match the color of pressure segments 80. Additionally, the graphical user interface 62 provides an input 84 for starting and/or stopping the monitoring of specific well zones. A fluid selection window 86 also enables the selection of fluid for use in making bottom hole pressure calculations at each well zone, as described above. Additionally, a zone property input 88 can be used to select or change a variety of values used to characterize a specific reservoir or interval. For example, changes can be made to the values for pore pressure, fracturing pressure, and the pressure ranges for a wellbore condition (over balanced, under balanced, and other conditions). A display area 90 also can be used to display a variety of additional information, such as the depth of specific well zones.

[0050] Similar interfaces can be displayed simultaneously on one or more of the graphical user interfaces 62. In the example illustrated in FIG. 6, interfaces are displayed for four different well zones, although the number of interfaces displayed can be greater or lesser depending on the treatment application and the number of well zones. In the embodiment of FIG. 6, each interface provides an under balanced/over balanced indicator for each zone, however multiple interfaces can be provided to indicate the occurrence of other or additional downhole events.

[0051] Pressure and/or other downhole properties can be monitored and analyzed as an indicator of the level of differential pressure between the inside and outside of coiled tubing 36. Sensors 50 comprise pressure sensors that are capable
of measuring the pressure inside and outside of the coiled tubing 36 which can serve as predictive indicators of downhole events related to use of the coiled tubing. In some well treatment operations, such as those in which treatment tool 32 comprises a nozzle at the end of coiled tubing 36, it is desirable to maintain the differential pressure within a certain range. Having the differential pressure too low can cause coiled tubing to collapse. However, having the differential pressure too high can cause the coiled tubing to burst.

When using continuous feedback system 22 to monitor pressure inside and outside of the coiled tubing, an operator is prompted to enter three pressure ratings into control system 30 via, for example, graphical user interface 62. The three pressure ratings may comprise a coiled tubing design delta pressure rating for the specific coiled tubing used in the well treatment operation. The three pressure ratings also may comprise a collapse rating for the coiled tubing and a burst rating for the coiled tubing.

In one embodiment, control system 30 uses the ratings to create a plurality of intervals/downhole events 92, as illustrated in FIG. 7. In one example, the intervals 92 are displayed with associated color coding. As illustrated, the plurality of intervals 92 are established for differential pressure states related to the coiled tubing 36 and may include collapse, near collapse, low pressure, operating pressure, high pressure, and burst states as well as additional states.

In this embodiment, a variety of graphical user interfaces 62 also can be used. One example of a suitable graphical user interface 62 is illustrated in FIG. 8 and includes a scale 94 having a plurality of color-coded markers 96 indicating the differential pressure levels for the various differential pressure states. Additionally, the graphical user interface 62 comprises a variety of inputs 98 that can be used to enter values for pressure ratings and pressure intervals. As with other graphical user interfaces discussed above, a variety of additional displays, inputs, and screens can be incorporated into the illustrated interface.

Another example of a downhole event that can be detected in real time based on monitoring of one or more downhole properties involves static bottom hole pressure. In some embodiments, wellbore fluid density and pore pressure (formation pressure) can be used in the cBHP calculation and the indicators as user entries. Control system 30 can provide a facility and procedure to estimate these values to prevent false user entries. If the well condition prior to the well treatment is such that a steady fluid column has been established, e.g. after a period of shut-in, the formation pressure is equal to the static bottom hole pressure, which can be determined by the fluid level and the wellbore fluid density. Wellbore fluid density can be estimated at the start of the job as the coiled tubing is run-in-hole by using the bottom hole pressure measurement from an appropriate sensor 50 on treatment tool 32.

According to one procedure, calculations are made to estimate the wellbore fluid density and the pore pressure. In this procedure, the pumps delivering treatment fluid downhole are turned off or set as low as reasonably possible. Subsequently, a coiled tubing depth correction is performed. Assuming the well is not full, a noticeable slope change is expected when the coiled tubing meets the liquid level in the well. When the end of the coiled tubing enters the liquid in the well, the slope of the pressure curve is used to give the density of the wellbore liquid. As the coiled tubing is moved downhole, the liquid level continues to rise due to the volume displaced by the coiled tubing but this can be taken into account in a density computation. As illustrated by the graphs in FIGS. 9 and 10, the measurement of pressure versus true vertical depth varies depending on whether the well is topped off before running the coiled tubing in hole. When the coiled tubing string 24 enters liquid in the well, the scope of the “measured pressure vs. TVD” changes fairly abruptly, as illustrated in FIG. 9. Otherwise, the scope remains more constant, as illustrated in FIG. 10.

In this example, an operator can enter the liquid level (TVDn) into control system 30, and then enter/select whether or not the well is to be topped off with liquid. The control system 30 is designed to compute and plot the gradient (Gr) while running-in-hole when there is no pumping or minimal pumping of treatment fluid downhole. As the tubing string 24 moves into the fluid within the well, the fluid level changes, as illustrated in FIG. 11, and this can affect the gradient. In FIG. 11, DCT represents the outer diameter of the tubing; Dn represents the diameter of the coiled tubing; and h represents liquid level rise. In a first case where the wellbore is not full, liquid level changes occur during deployment of tubing string 24 as a result of the coiled tubing volume. The liquid level rise can be determined as follows:

\[ h = \frac{(D_{TVDn}^2 - D_{CT}^2)}{2g} \times \frac{(TVD - TVDn)}{(TVD - TVD_{\text{limit}})} \]

The liquid height above the coiled tubing end is determined by:

\[ L = (TVD - TVD_n) + h = (TVD - TVD_n) \times \frac{D_{CT}}{D_{TVDn}^2 - D_{CT}^2} \]

The gradient Gr may then be computed as follows while TVD>TVDlimit (TVDlimit is the coiled tubing depth when the fluid level reaches the top):

\[ Gr = \frac{P - WHP}{L}, \]

\[ TVD_{\text{top}} = TVD_n \times \frac{D_{TVDn}^2}{D_{CT}^2} \]

WHP equals wellhead pressure.

In a second case, when TVD>TVDlimit and alternatively when the wellbore is topped off, the gradient is computed as follows:

\[ Gr = \frac{P - WHP}{TVD}. \]

In FIG. 10, a graph is provided illustrating the gradient Gr plotted against time by graph line 100. Additionally, the graph illustrates a pressure graph line 102 and a TVD graph line 104 plotted against time. The graph, or a similar output, can be computed and displayed via control system 30. The calculated gradient Gr is monitored to determine when a
stable gradient baseline $G_{05}$ is achieved. The $G_{05}$ value can be entered in a designated field by an operator, or control system 30 can be used to automatically record the value. The control system 30 uses this value in computing wellbore fluid density, $\rho_{o0}$, via, for example, the following expression:

$$\rho_{o0} = \frac{G_{05}}{\text{gravity}}$$

Reservoir pressure estimates can be computed at selected reservoir depths, such as TVDress1 and TVDress2 as follows:

$$P_{\text{res}} = G_{05} (\text{TVDres} - \text{TVDb})$$
$$P_{\text{res2}} = G_{05} (\text{TVDres2} - \text{TVDb})$$

[0060] ... [0061] One example of a display format/graphical user interface 62 is illustrated in FIG. 13 and provides a representation of a gradient baseline 106. Additional plots of pressure 108 and TVD 110 also can be displayed. In this embodiment, a user/operator is able to select a gradient baseline by selecting and moving a displayed drag bar 112. A related display window 114 can be used to display corresponding parameters, such as density and gradient values as drag bar 112 is moved or changed. One or more additional displays 116 also can be used to display a variety of other parameters, such as calculated pore pressure, at different zones. By way of further example, an input area 118 can be provided to enable an operator to enter the liquid level for a given wellbore. These and other features may be incorporated into the graphical user interface of control system 30.

[0062] Some applications of the present system and methodology provide diversion and stimulation indicators based on measurements from downhole tools, such as treatment tool 32, via sensors 50. By way of example, when the injection rate of treatment fluid is non-zero and constant, the rate of bottom hole pressure change can be used to determine if the diversion or stimulation occurring is based on the fluid pumped during the treatment procedure. In one example, the following matrix can be used to determine the state of diversion or stimulation downhole:

<table>
<thead>
<tr>
<th>DIVERSION INDICATOR</th>
<th>Diversion</th>
<th>No Diversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate of BHP change</td>
<td>slope &gt; 5 psi/min or p increase &gt; 100 psi</td>
<td>slope &lt; 5 psi/min and p increase &lt; 100 psi</td>
</tr>
</tbody>
</table>

[0063] The bottom hole pressure (BHP) value can be calculated via control system 30 for specific well zones as defined or selected by an operator via a suitable graphical user interface. The selection of bottom hole pressure values helps ensure that BHP is calculated for a fixed point and is not affected by coiled tubing movement. In some applications, the BHP measurement can have substantial noise, but a variety of algorithms can be used to smooth the data. For example, a smoothing algorithm can be based on averaging over a sliding window. A default sliding window size for the averaging/smoothing of data can be selected, e.g., 30 seconds, and the rate can be calculated by comparing the average current value with the value calculated at the previous interval, e.g., 30 second interval.

[0064] The threshold values used in the matrix provided above are the default values and can be changed by an operator. The control system 30 enables the operator to save modified values for use in other well treatments or for later analysis. In one embodiment, the graphical user interface displays a diversion indicator that becomes “live” only when a diverter is exiting the coiled tubing end. Similarly, a stimulation indicator becomes “live” only when an acid is exiting the coiled tubing end.

[0065] Other applications of the present system and methodology provide a warning to an operator if downhole measurements via, for example, sensors 50 indicate the possibility of a stuck or embedded coiled tubing 36 or treatment tool 32. The determination may be made based on a variety of input variables, such as carrier fluid type; carrier fluid density; fill type and density; reservoir pressure; reservoir depth (intervals); completion—casing and tubing size and depth; coiled tubing outer diameter; clean out speed; sweep speed; and other related parameters. The carrier treatment fluid may be water, brine, gelated fluid, foam, slick water, energized fluid, nitrogen, carbon dioxide, and other suitable carrier fluids. By way of example, the following list provides fill types and corresponding densities:

<table>
<thead>
<tr>
<th>Fill type</th>
<th>S.G.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand</td>
<td>2.65</td>
</tr>
<tr>
<td>Carbolite</td>
<td>2.73</td>
</tr>
<tr>
<td>Intermediate Strength Ceramic</td>
<td>3.20</td>
</tr>
<tr>
<td>High Strength Ceramic</td>
<td>3.50</td>
</tr>
<tr>
<td>Sintered Bauxite</td>
<td>3.45</td>
</tr>
<tr>
<td>Resin Coated Sand</td>
<td>2.55</td>
</tr>
<tr>
<td>Resin Coated Ceramic</td>
<td>2.73</td>
</tr>
<tr>
<td>Calcium Carbonate Scale</td>
<td>2.70</td>
</tr>
<tr>
<td>Calcium Sulfate Scale</td>
<td>2.30</td>
</tr>
<tr>
<td>Barium Sulfate Scale</td>
<td>4.50</td>
</tr>
</tbody>
</table>

[0066] Determination of the potential for being stuck during an operation is evaluated based on matrices that establish a defined set of parameters indicative of the risk for being stuck. The parameters can include, for example, angular velocity, concentration of solid in suspension (volume), bottom hole pressure gradient rate of change, coiled tubing weight variations, over/under balance, run-in-hole/pull-out-of-hole speed, and other parameters.

[0067] Several matrix examples are provided in FIGS. 14 through 17. In FIG. 14, for example, a water/brine risk matrix is provided. In FIG. 15, one example of a gelled fluid matrix is provided. Similarly, FIG. 16 provides one example of a foam risk matrix. FIG. 17 provides one example of a nitrogen matrix. Within these matrices, a variety of terms are listed that can be used in system or method calculations. For example,
PPA refers to the pounds of solids added per gallon of carrier fluid; CS is the clean out speed in feet per minute (value can be input by operator); SS refers to the sweep speed in feet per minute (value can be input by operator); Y is the density corresponding to a low risk PPA limit; and Z is the density corresponding to a high risk PPA limit. The Y and Z PPG calculations can be made using the following formula:

\[
\text{PPG} = \frac{(\text{Carrier fluid density}) + \text{PPA}}{1 + \frac{\text{PPA}}{(\text{SG fill})(8.32)}} - \text{Carrier fluid density}
\]

Realtime PPG can be determined by:

\[
\text{PPG} = \frac{\text{PTC pressure}}{(\text{Corrected depth})(0.052)} - \text{Carrier fluid density}
\]

[0068] Referring generally to FIG. 18, another example of a graphical user interface 62 is illustrated. In this example, the graphical user interface displays the stuck/embedding potential via a risk bar 120. Additionally, a plurality of input windows 122 are provided to enable an operator to enter the various parameters used in calculating the risk as discussed above with respect to FIGS. 14 through 17.

[0069] As described above, well treatment system 20 can be constructed in a variety of configurations for use in many environments and applications. Additionally, control system 30 can be constructed with a central controller or a plurality of cooperating controllers located proximate the well site or remote from the well site. A variety of sensors 50, treatment tools 32, and tubing 36 also can be used depending on the treatment operation and the properties monitored in real time. The data obtained and provided by sensors 50 also can be used in a variety of formulas, algorithms, and models to aid in the detection of one or more downhole events based on the monitoring of one or more downhole properties. The control system 30 and a sensors 50 cooperate to provide a continuous feedback system utilizing a real time closed loop interpretation technique that enables control system 30 to instantaneously synchronize and adjust well treatment actions at a surface location, e.g., adjust pumping equipment 42, to affect a downhole event. The data can be used to detect the actual occurrence or the potential for specific events. Control system 30 can be programmed to automatically react in specific ways to the detected or calculated properties for exercising control over the treatment operation in a manner that influences or controls the downhole event.

[0070] Accordingly, although only a few embodiments of the present invention have been described in detail above, those of ordinary skill in the art will readily appreciate that many modifications are possible without materially departing from the teachings of this invention. Such modifications are intended to be included within the scope of this invention as defined in the claims.

What is claimed is:

1. A method of treating a subterranean formation, comprising:

- providing a fluid delivery apparatus, wherein the fluid delivery apparatus comprises a continuous feedback system including a real time closed loop interpretation technique to instantaneously synchronize and adjust actions at a well site surface relative to measured downhole items of interest;
- introducing the fluid delivery apparatus into a wellbore penetrating a subterranean formation;
- monitoring and evaluating, in real time, at least one downhole property or measurement to detect in real time at least one downhole item of interest; and
- upon detection of the at least one downhole item, adjusting in real time at least one parameter to influence and/or control the downhole item.

2. The method as recited in claim 1, wherein providing comprises forming the fluid delivery apparatus with coiled tubing.

3. The method as recited in claim 1, wherein providing further comprises forming the fluid delivery apparatus with a data acquisition, analysis, and control system.

4. The method as recited in claim 1, wherein detecting the at least one downhole item comprises detecting one of stuck potential, diversion, stimulation, over/under balance, nozzle efficiency, downhole tool load, real time extended reach, pressure differential, pressure spike, changes in measurement over time slope, injectivity profile, fluid placement, and volume characterization of deposited scale.

5. The method as recited in claim 1, wherein monitoring and evaluating comprises monitoring and evaluating at least one of pressure, load, fluid velocity, fluid direction, temperature, fluid pH, fluid solids content, and fluid density.

6. The method as recited in claim 1, further comprising measuring the at least one downhole property or measurement using at least one of an acoustic sensor, an infrared sensor, an optical sensor, and a flow sensor.

7. A system for treating a subterranean formation, comprising:

- a tubing string to deliver a fluid through a wellbore to a subterranean formation;
- a sensor positioned downhole to measure a downhole property able to provide an indication of a downhole event or environment; and
- a continuous feedback system coupled to the sensor, wherein the continuous feedback system utilizes a real time, closed loop interpretation technique to instantaneously synchronize and adjust actions at a surface location to offset the downhole event or environment.

8. The system as recited in claim 7, wherein the continuous feedback system comprises a control system used for adjustment of at least one parameter in real time to offset the downhole event or environment.

9. The system as recited in claim 8, wherein the control system comprises a processor based control system at a surface location.

10. The system as recited in claim 9, wherein the control system is located proximate the wellbore.

11. The system as recited in claim 9, wherein the control system is located remote from the wellbore.

12. The system as recited in claim 7, wherein the tubing string comprises coiled tubing.

13. The system as recited in claim 7, wherein the sensor comprises a plurality of sensors.

14. The system as recited in claim 13, wherein the plurality of sensors are used to monitor a plurality of downhole properties.

15. A method of treating a subterranean formation, comprising:
performing a fluid treatment operation downhole;
monitoring in real time at least one downhole property
related to the fluid treatment operation;
using a real time closed loop interpretation technique on a
continuous feedback system to evaluate data obtained
from monitoring in real time the at least one downhole
property; and
adjusting the at least one downhole property based on the
evaluation of data to provide a desired influence down-
hole.

16. The method as recited in claim 15, wherein performing
comprises delivering a treatment fluid downhole through a
coiled tubing.

17. The method as recited in claim 15, wherein monitoring
comprises monitoring pressure at a desired downhole loca-
tion.

18. The method as recited in claim 15, wherein monitoring
comprises monitoring temperature at a desired downhole
location.

19. The method as recited in claim 15, wherein monitoring
comprises monitoring a treatment fluid characteristic at a
desired downhole location.

20. The method as recited in claim 15, wherein adjusting
comprises using a data acquisition, analysis and control sys-
tem to adjust the at least one downhole property.

21. A system, comprising:
the fluid delivery apparatus comprising a continuous
feedback system having a real time closed loop interpre-
tation technique to instantaneously synchronize and
adjust actions relative to measured downhole items of
interest.

22. The system as recited in claim 21, wherein the well
treatment system further comprises a data acquisition, anal-
ysis and control system to monitor and evaluate in real time at
least one downhole property used as an indicator of a down-
hole event or environment.

23. The system as recited in claim 22, wherein the well
treatment system comprises a plurality of sensors located
downhole to monitor the at least one downhole property.

24. The system as recited in claim 23, wherein the fluid
delivery apparatus comprises coiled tubing.