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Valve rod guides for bottom hole pump assemblies, and related methods and parts

Abstract

A bottom hole pump (BHP) assembly for a reciprocating sucker rod in a production well has: a downhole fluid pump; a valve rod mounted to reciprocate within the downhole fluid pump, the valve rod having a sucker rod connector; and a valve rod guide mounted to the downhole fluid pump around the valve rod and connected to, in use, receive fluids into an internal fluid chamber from an internal bore of the downhole fluid pump and direct the fluids radially outward to an annulus of a well bore through a radial port in the valve rod guide assembly; and in which the valve rod guide has a ceramic wear sleeve that lines an internal valve-rod-receiving cylindrical passage defined by the valve rod guide.

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Background/Summary

TECHNICAL FIELD
(1) This document relates to valve rod guides for bottom hole pump (BHP) assemblies, and related methods and parts.
BACKGROUND
(2) The following paragraphs are not an admission that anything discussed in them is prior art or part of the knowledge of persons skilled in the art.
(3) Deviated wellbores and imperfectly straight sucker rod strings may lead to wear on various parts of a production well. One example of such wear may occur on or in the bottom hole pump assembly. A valve rod guide may be used to centralize and reduce wear on the valve rod (connected to the sucker rod string) during pumping action. Valve rod guides are typically used with carbide inserts that fracture, break, and wear over time.
SUMMARY
(4) A bottom hole pump (BHP) assembly is disclosed for a reciprocating sucker rod in a production well comprising: a downhole fluid pump; a valve rod mounted to reciprocate within the downhole fluid pump, the valve rod having a sucker rod connector; and a valve rod guide mounted to the downhole fluid pump around the valve rod and connected to, in use, receive fluids into an internal fluid chamber from an internal bore of the downhole fluid pump and direct the fluids radially outward to an annulus of a well bore through a radial port in the valve rod guide assembly; and in which the valve rod guide has a ceramic wear sleeve that lines an internal valve-rod-receiving cylindrical passage defined by the valve rod guide.
(5) A production well assembly is disclosed comprising: a sucker rod string within a well that penetrates a formation; a primary mover at a well surface, the primary mover connected to reciprocate the sucker rod string; and a BHP assembly, in which the sucker rod connector of the valve rod is connected to the sucker rod string.
(6) A method is disclosed of operating a production well assembly comprising reciprocating the

sucker rod string using the primary mover to pump well fluids from a fluid inlet of the downhole fluid pump, through the valve rod guide, and up to the well surface.
(7) A valve rod guide is disclosed comprising: a rod guide body defining an open downhole cylindrical pump-barrel-mounting end that defines an internal pump fluid chamber and a radial port to an exterior surface of the rod guide body, the rod guide body being structured for, in use, receiving and directing well fluids pumped through the open downhole cylindrical pump-barrel-mounting end into a wellbore annulus via the radial port, the rod guide body defining a valve rod axial bore therethrough; a ceramic wear sleeve seated within an internal valve-rod-receiving cylindrical passage defined by the rod guide body; and a rod guide cap mounted to an uphole end of the rod guide body to secure an uphole end of the ceramic wear sleeve within the wear sleeve receptacle.
(8) A method is disclosed comprising driving a sucker rod string to pump well fluids from a fluid inlet of a downhole fluid pump, through a valve rod guide, and up to the well surface, in which the valve rod guide has an internal ceramic wear sleeve that lines an interior bore of the valve rod guide and encircles a valve rod, which is driven by the sucker rod string to drive the downhole fluid pump.
(9) In various embodiments, there may be included any one or more of the following features: The ceramic wear sleeve is cylindrical. The valve rod guide comprises: a rod guide body; and a rod guide cap. The rod guide body has an open downhole end that defines the internal fluid chamber and the radial port. The open downhole end defines a threaded female box. The rod guide body defines an uphole-facing internal axial shoulder that seats a downhole end of the ceramic wear sleeve in the internal valve-rod-receiving cylindrical passage. The rod guide cap is threaded to an uphole end of the rod guide body. The rod guide cap defines a downhole-facing internal axial shoulder that secures an uphole end of the ceramic wear sleeve. The rod guide cap has a threaded female box end that mounts to a threaded male end of the rod guide body. The rod guide cap defines a bushing keyway torque slot. The bushing keyway torque slot defines a radial slot at an uphole end of the rod guide cap. A valve rod bushing, of the sucker rod connector or connected to the sucker rod connector, defines a key structured to mate with the bushing keyway torque slot for torque transfer. The downhole fluid pump comprises: a traveling valve mounted to the valve rod; and a standing valve mounted to a downhole fluid inlet of the downhole fluid pump. The ceramic wear sleeve is cylindrical; and the open downhole cylindrical pump-barrel-mounting end defines a threaded female box. The rod guide cap has a threaded female box that mounts to a threaded male end of the rod guide body; and the rod guide cap defines a bushing keyway torque slot.
(10) The foregoing summary is not intended to summarize each potential embodiment or every aspect of the subject matter of the present disclosure. These and other aspects of the device and method are set out in the claims.

Description

BRIEF DESCRIPTION OF THE FIGURES
(1) Embodiments will now be described with reference to the figures, in which like reference characters denote like elements, by way of example, and in which:
(2) FIG. **1** is a side elevation view, partially in section, of a production wellhead, with a downhole pump that has a ceramic wear sleeve positioned within a rod guide of the downhole pump.
(3) FIG. **2** is a side elevation view, partially in section, of components of a downhole pump, which has a valve rod guide that mounts a ceramic wear sleeve.
(4) FIG. **3** is a top plan view of the valve rod guide of FIG. **2**.
(5) FIG. **4** is a sectional view taken along the **4-4** section lines of FIG. **3**.
(6) FIG. **5** is a perspective view of the valve rod guide of FIG. **2**.

(7) FIG. **6** is a side elevation view of a rod guide body of the valve rod guide of FIG. **2**.
(8) FIG. **7** is a sectional view taken along the **7-7** section lines of FIG. **6**.
(9) FIG. **8** is a perspective view of the rod guide body of FIG. **6**.
(10) FIG. **9** is a side elevation view of a rod guide cap of the valve rod guide of FIG. **2**.
(11) FIG. **10** is a sectional view taken along the **10-10** section lines of FIG. **9**.
(12) FIG. **11** is a perspective view of the rod guide cap of FIG. **9**.
(13) FIG. **12** is a side elevation view of a ceramic insert wear sleeve of the valve rod guide of FIG. **2**.
(14) FIG. **13** is a top plan view of the ceramic insert wear sleeve of FIG. **12**.
(15) FIG. **14** is a perspective view of the valve rod guide of FIG. **2** positioned downhole of a valve rod and uphole of a lock nut and a barrel.

DETAILED DESCRIPTION

(16) Immaterial modifications may be made to the embodiments described here without departing from what is covered by the claims.

(17) In the life of an oil well there are several phases—drilling, completion, and production. Once a well has been drilled, it is completed to provide an interface with the reservoir rock and a tubular conduit for the well fluids. Well completion is a generic term used to describe the installation of tubulars and equipment required to enable safe and efficient production from an oil or gas well. The production phase occurs after successful completion, and involves producing hydrocarbons through the well from an oil or gas field.

(18) Referring to FIG. **1**, a production wellhead assembly **12** is illustrated. The assembly **12** may be an assembly of components that form the surface termination of a wellbore and includes various production equipment at the surface. A production wellhead assembly may include spools, valves, manifolds, and assorted adapters that provide pressure control of a production well. The assembly **12** may incorporate components, such as a casing bowl or spool **13**, for internally mounting a casing hanger **14** during the well construction phase. The casing hanger **14** suspends a casing string **16**, which may be steel pipe cemented in place during the construction process to stabilize the wellbore. The wellhead or bowl or casing spool **13** may be welded onto the outer string of casing, which has been cemented in place during drilling operations, to form an integral structure of the well.

(19) The assembly **12** may include surface flow-control components, such as the group of components that are sometimes collectively referred to as a Christmas tree **22**. The Christmas tree **22** may installed on top of the casing spool **13**, for example with isolation valves **24**, and choke equipment such as production valves **26** to control the flow of well fluids during production. Other components such as a flow manifold **27**, also known as a flow tee, a bonnet **44** and a rod blowout preventer (BOP) **29** may be provided as part of the production wellhead assembly **12**. Manifold **27**, bonnet **44**, and BOP **29** may be mounted on a spool **31** mounted on the tubing head **18**. The flow manifold **27** may direct produced fluids to processing or storage equipment, such as a surface production tank.

(20) The production wellhead assembly **12** may incorporate a mechanism for hanging production tubing **17**. For example, the assembly **12** may include a tubing head **18** mounted on the casing spool **13**, the tubing head **18** internally mounting a tubing hanger **20**. A tubing hanger **20** is a component used in the completion of oil and gas production wells. It may be set in the Christmas tree **22** or the wellhead and suspends the production tubing **17** and/or casing. Sometimes the tubing hanger **20** provides porting to allow the communication of hydraulic, electric and other downhole functions, as well as chemical injection. The tubing hanger **20** may also serve to isolate the interior bore **38** and production areas (i.e., within the interior of the tubing **17**). The production tubing **17** runs the length of the well to a bottom hole pump assembly **10** (BHP), and serves to isolate the tubing interior from the annulus for production up the interior of the tubing **17**.

(21) A production wellhead assembly **12** may connect to or house part of an artificial lift system

such as a reciprocating rod pump assembly **10** or drive. An artificial lift is a system that adds energy to the fluid column in a wellbore with the objective of initiating and improving production from the well. Artificial-lift systems use a range of operating principles, including rod pumping, gas lift and electric submersible pump. A reciprocating rod drive, such as a pump jack **28**, is an artificial-lift pumping system that uses a surface power source to drive a BHP assembly (pump assembly **10**). A beam and crank assembly in the pump jack **28** converts energy, for example in the form of rotary motion from a prime mover (although the pump jack **28** may be considered part of the prime mover), into a reciprocating motion in a sucker-rod string **30** that connects to a BHP assembly. The BHP may contain a plunger and valve assembly to convert the reciprocating motion to vertical fluid movement.

(22) A pump jack **28** is also known as an oil horse, donkey pumper, nodding donkey, pumping unit, horsehead pump, rocking horse, beam pump, dinosaur, grasshopper pump, Big Texan, thirsty bird, or jack pump in some cases. A pump jack or other artificial lift system may be used to mechanically lift liquid out of the well when there is not enough bottom hole pressure for the liquid to flow all the way to the surface. Pump jacks are commonly used for onshore wells producing little oil. In some cases, a pump jack may be used with the disclosed embodiments, and in other cases, other types of drives may be used, including elevator rotating drives.

(23) A reciprocating rod drive such as a pump jack **28** may connect via a bridle **32** to a piston known as a polished rod **34** that passes through a stuffing box **36** to enter the wellbore. The polished rod **34** is the uppermost joint in the sucker rod string **30** used in a rod pump artificial-lift system. The polished rod **34** enables an efficient hydraulic seal to be made by the stuffing box **36** around the reciprocating rod string. Thus, the polished rod **34** is able to move in and out of the stuffing box without production fluid leakage. The bridle **32** follows the curve of the horse head **33** as it lowers and raises to create a nearly vertical stroke. The polished rod **34** is connected to a long string **30** of rods called sucker rods, which run through the tubing **17** to the down-hole pump, usually positioned near the bottom of the well.

(24) The sucker rod string **30** may have a suitable structure, and be made up of a plurality of sucker rods. A sucker rod may be a steel rod, typically between 25 and 30 feet (7 to 9 meters) in length, and usually threaded at both ends, and that is used to join together the surface and downhole components of a reciprocating piston pump assembly **10** installed in an oil well. The pumpjack **28** may make up the visible above-ground drive for the well pump, and be connected to the BHP assembly **10** at the bottom of the well by a series of interconnected sucker rods, forming a sucker rod string **30**. Sucker rods may be terminated in metallic threaded ends, for example a female box at one end and a male pin at the other end. At the bottom of the sucker rod string **30** may be located the down-hole pump assembly **10**. Referring to FIGS. **1** and **2**, a BHP assembly **10** may have dual valves such as two ball check valves, such as valve assemblies **63** and **68**, for example a stationary valve at bottom called the standing valve or standing valve assembly **68**, and a valve on the piston of the pump connected to the bottom of the sucker rods that travels up and down as the rods reciprocate, known as the traveling valve or travelling valve assembly **63**. Fluid may enter the pump assembly **10** from a formation **49** into the bottom of the borehole through perforations that have been made through the casing and cement. When pumpjack **28** is going through an upstroke, the sucker rods are travelling up, the traveling valve is closed and the standing valve is open (due to the drop in pressure in the pump). Consequently, the pump fills with the fluid from the formation as the traveling piston lifts the previous contents of the pump upwards. At the same time (upstroke), any fluid that is located in the pump assembly **10** uphole from the traveling valve will be forced in the uphole direction, into the tubing **17** and up the well. When the pumpjack **28** begins a downstroke, the traveling valve opens and the standing valve closes (due to an increase in pressure in the pump). The traveling valve passes through the fluid in the pump assembly **10**, which has been sucked in during the upstroke. The pump assembly **10** then reaches the end of its stroke and begins its path upwards again, repeating the process.

(25) The successful operation of the polished rod and sucker rod string **30** requires careful alignment from surface to formation **49**. At surface, a tight seal is required between the polished rod **34** and the seals (not shown) of the stuffing box **36**. If the polished rod **34** becomes damaged, for example scored, the rod **34** must be replaced before damage is done to the stuffing box **36**. In some cases, the seals also must be replaced. During use, damage to the polished rod **34** and rod string **30** may be caused from continued contact with internal components of the production wellhead assembly **12**, the tubing **17**, or the components of the BHP assembly **10**. Even in a perfectly vertical well, or a well nominally deviated from vertical near the surface, the rod string **30** may reciprocate with continual or intermittent contact with various above-ground and downhole parts of the production well. In some wells that deviate from true vertical measured with respect to the surface of the earth, rod **34** or rod string **30** may be drawn to one side where contact can occur to a greater degree than other locations or orientations. A fluid leak may be caused if damage is done to the rod **34**, such leak leading to potential environmental damage and cleanup cost. Wear on the rod string **30** and/or BHP assembly **10** may also cause leakage or inefficient/non-functioning pumping action below surface. Production wellheads are often unmanned and in remote areas in many cases, and thus, even a relatively small fluid leak or inefficiency carries a potential for exacerbated negative effects because the leak or damage may go unnoticed for days and sometimes weeks. Replacing the rod **34** or rod string **30** may require a well service entity to temporarily kill the well, lift the damaged rod out of the well, connect a new rod, and repair any damaged parts of the production well before reassembling and re-initiating the well back into production. In many cases the new rod **34** or rod string **30** may itself become damaged in a short period of time, because the underlying cause of the damage still exists, namely the deviated well. In some cases, a well operator will install roller guides or centralizers **40** on the rod **34** or rod string **30** at various spaced locations to ride along the rod string **30** or guide the rod string into alignment below the tubing hanger **20**.
(26) Minor deviations from vertical often occur naturally in the wellbore. Such deviations may be related to formation properties, such as dip angle and hardness, and other factors. Deviation of the wellbore can cause wear on sucker rods, which may eventually ruin the sucker rods, or damage the downhole components of the pump assembly **10**, potentially causing the entire well to fail. A rod rotator is one solution that has been used to extend the lifespan of the sucker rod string **30**. A rod rotator may function by incrementally rotating the sucker rod with each stroke of the pumpjack to evenly distribute wear around the rods and couplings, rather than limiting the wear to one side of the sucker rods. However, the use of a rod rotator is not a permanent solution as wear will still ultimately degrade and ruin the sucker rods, which will eventually cause the pump to lose efficiency as the fit of the sucker rods within the well is modified by the wear.
(27) Within a BHP assembly **10**, a valve rod guide **80** may be used to centralize the valve rod **50** of the pump assembly **10** along an axis **88** of the pump assembly **10**. A conventional valve rod guide **80** may carry a carbide insert (not shown), which acts as a sacrificial material, as such will wear down itself over time, preventing or delaying the valve rod **50** from being worn down at the same rate. Once the carbide insert has been sufficiently worn down, only the insert may be needed to be replaced with a new carbide insert, thus decreasing usage costs if the insert can be used to avoid or delay replacement of the rod string **30**, the BHP assembly **10** or part of either. However, since carbide is a relatively hard material, when the carbide insert wears out, pieces may break off of the carbide insert, or the insert may fail entirely—defeating the purpose of the insert and leading to rod string **30** wear and eventual pump failure. Broken pieces from the carbide insert are known to jam up the pump **48** and any piece that runs through the guide.
(28) Referring to FIGS. **2-8**, a valve rod guide **80** is illustrated, for use in a BHP assembly **10**. In use, the BHP assembly **10** may comprise a downhole pump **48**, a valve rod **50** and the valve rod guide **80**. The valve rod **50** may be mounted to reciprocate within the downhole fluid pump **48**. The valve rod **50** may have a sucker rod connector, for example an uphole male cylindrical threaded

end **50**A, which may connect to a sucker rod of a sucker rod string **30** (not shown in FIGS. **2-8**). The valve rod guide **80** may be mounted to, for example within, the downhole fluid pump **48**, for example at or near an uphole end **48**A of the pump **48**. The guide **80** may be mounted to encircle the valve rod **50** in use and may be connected to receive fluids into an internal fluid chamber **82**G-**1** (for example of a rod guide body **82** of the guide **80**) from an internal bore **48**C of the downhole fluid pump **48**. The valve guide **80** may be structured to direct received fluids radially outward to an annulus **17**C of a well bore (defined in the example of FIG. **2** as the interior of the tubing **17**) in use through a radial port **82**F in the valve rod guide **80** assembly. The valve rod guide **80** may define an internal valve-rod-receiving cylindrical passage **82**G-**2**, which may form part of an interior bore **80**C of the guide **80**. The side slots (radial ports) in the guide may be provided for fluid transfer to allow fluid to escape from and lubricate the guide.

(29) Referring to FIGS. **2-8**, the valve rod guide **80** may have a ceramic insert wear sleeve **84**. The sleeve **84** may line a portion of the interior bore **80**C of the valve rod guide **80**, for example, the sleeve **84** may line at least a portion of the passage **82**G-**2**. A ceramic material may be made from any of the various hard, brittle, heat-resistant and corrosion-resistant materials made by shaping and then firing an inorganic, nonmetallic material, such as clay, at a high temperature. Ceramics are known to be abrasion resistance, and may show plastic deformation. However, because of the rigid structure of ceramic material they may deform very slowly. To overcome the brittle behavior, ceramic material development has introduced the class of ceramic matrix composite materials, in which ceramic fibers are embedded and with specific coatings are forming fiber bridges across any crack. This mechanism substantially increases the fracture toughness of such ceramics. Ceramics may be chemically resistant and can be used in wet environments where other parts would rust. The ceramic wear sleeve **84** may have a suitable shape, for example the sleeve **84** may be cylindrical. In other cases, the ceramic wear sleeve **84** may be any shape which allows for the ceramic wear sleeve **84** to extend the life of the well.

(30) Referring to FIGS. **2-8** the valve rod guide **80** may comprise various parts, such as a rod guide body **82**, the ceramic insert wear sleeve **84**, and a rod guide cap **86**. The rod guide body **82** may define an open downhole end, such as a cylindrical pump-barrel-mounting end, such as a downhole female box threaded end **82**B. The end **82**B or other portion of the body **82** may define internal pump fluid chamber **82**G-**1** and radial port **82**F to an exterior surface **82**E-**1** of the rod guide body **82**. The valve rod guide body **82** may be structured for, in use, receiving and directing well fluids pumped through the open downhole end **82**B, into a wellbore annulus (such as annulus **17**C defined by tubing **17**) via the radial port **82**F. The ceramic wear sleeve **84** may be seated within a wear sleeve receptacle **82**J, which may form part of the passage **82**G-**2**. The receptacle **82**J may define an interior sidewall **82**J-**3** that extends between an uphole axial end **82**J-**1** and a downhole shoulder end **82**J-**2** of the receptacle **82**J. The rod guide body **82** may define an uphole-facing internal axial shoulder, in this case forming end **82**J-**2** of the receptacle **82**J, which may seat a downhole end, such as downhole axial shoulder end **84**B, of the ceramic wear sleeve **84** in the internal valve-rod-receiving cylindrical passage **82**G-**2**. Referring to FIGS. **2-4**, another part of the guide **80** may abut or retain the uphole end **84**A of the sleeve **84**, for example, the rod guide cap **86** may be mounted to an end of the rod guide body **82**, for further example uphole cylindrical male threaded end **82**A of body **82**, to secure uphole end **84**A of the ceramic wear sleeve **84** within the wear sleeve receptacle **82**J. In the example shown, the rod guide cap **86** defines a downhole-facing internal axial shoulder **86**G that secures uphole end **84**A of the ceramic wear sleeve **84**. During assembly, the ceramic wear sleeve **84** may be inserted into the ceramic insert receptacle **82**J by a suitable manner, such as axially passing the sleeve **84** through the uphole open axial ends **82**J-**1** and **82**A of body **82**, and may thereafter be seated upon the uphole-facing axial shoulder end **82**J-**2** of the ceramic insert receptacle **82**J. Referring to FIG. **4**, the ceramic insert wear sleeve **84** may be sized so that an exterior cylindrical surface **84**C of the ceramic wear sleeve **84** abuts the interior cylindrical sidewall **82**J-**3** of the ceramic insert receptacle **82**J. The wear sleeve **84** may fit loosely

or tightly within the receptacle **82**J as desired. Referring to FIG. **2**, the rod guide cap **86** and body **82** may collectively define the interior bore **80**C, which is structured to receive and pass the valve rod **50** during use.

(31) Referring to FIG. **4**, the rod guide cap **86** may have various suitable characteristics. The rod guide cap **86** may be threaded to an uphole end of the rod guide body **82**, for example a downhole female box threaded end **86**B of the rod guide cap **86** may be threaded to an uphole cylindrical threaded male end **82**A of the rod guide body **82**. The threaded male end **82**A of the rod guide body **82** may define a neck **82**D, which may project from an uphole shoulder end **82**C-**1** of an axial cap shoulder **82**C of the body **82**. The axial cap shoulder **82**C may define uphole shoulder end **82**C-**1**, and a downhole shoulder end **82**C-**2**. A diameter **82**C-**3** of the axial cap shoulder **82**C may be larger than a of the diameter **82**D-**1** of the neck **82**D, but commensurate with a maximum outer diameter **86**K of the cap **86**. An outer diameter **82**E-**2** of a base **82**E of the guide body **82** may be wider than diameters **82**C-**3** and **86**K to define annulus **17**C (FIG. **2**) and facilitate uphole passage of fluids through. An inner diameter **84**F of the wear sleeve **84** may be defined by the interior cylindrical surface **84**D, which may form an interior bore **84**E. The inner diameter **84**F of the interior bore **84**E may be sized as the minimum internal dimension of the valve guide **80**, and may be equal to or larger than an outer diameter (not shown) of the valve rod **50**. In other cases, the cap **86** and/or body **82** may define external slots (not shown) to permit axial fluid passage to the annulus **17**C of tubing **17** (or well bore). The downhole female box threaded end **86**B may define a gasket ring slot **86**H (for fitting of a gasket, not shown), which may facilitate the rod guide cap **86** to seal to the uphole male threaded end **82**A of the rod guide body **82**. When the rod guide cap **86** is threadedly connected to the rod guide body **82**, the downhole axial nose shoulder **86**G of the rod guide cap **86** may secure an uphole end **84**A of the ceramic wear sleeve **84**, as above. Referring to FIGS. **2**-**4** and **9**-**11**, the rod guide cap **86** may define a cylindrical collar body **86**C, and may define an uphole axial shoulder end **86**A and downhole female box threaded end **86**B. An interior cylindrical sidewall **86**C-**1** of the collar body **86**C may define an interior bore **86**L of the cap **86**. An uphole end of the bore **86**L may be tapered, for example to form a conical mouth guide **86**M, to facilitate axial entry of the valve rod **50** to pass into and through the interior bore **86**L.

(32) Referring to FIGS. **2**-**4**, **9** and **11**, the rod guide cap **86** may be structured for torque transfer from an axial uphole location. The cap **86** may define a bushing keyway torque slot **86**E. The bushing keyway torque slot **86**E may comprise a radial slot along (for example at) the uphole end **86**A of the rod guide cap **86**. The radial slot **86**E may be defined between and by the uphole facing torque ridges **86**D, which in the example shown are arcuate ridges when viewed in an axial direction along rod guide axis **90**. Referring to FIG. **2**, in use, a downhole valve rod bushing **52**, which may be connected to or form part of the sucker rod connector, may define a key **52**B-**1** structured to mate with the bushing keyway torque slot **86**E for torque transfer therebetween. The valve rod bushing **52** may be connected (for example as shown) to the sucker rod connector of the valve rod **50**, such as by threaded connection between an uphole male threaded end **50**A of the valve rod **50** to a downhole female threaded box **52**B of the valve rod bushing **52**. In use, the key **52**B-**1** of the valve rod bushing **52** may be axially moved downhole relative to the cap **86** to mate with the keyway slot **86**E of the rod guide cap **86** for torque transfer therebetween. The key **52**B-**1** may have a suitable structure, for example a central radial ridge as shown, although other mating connections may be used, such as splines, male and female parts, and in some cases, the valve rod bushing **52** may define a slot and the cap **86** may define a keyway.

(33) Referring to FIGS. **1** and **2**, the valve rod guide **80** may be used in a production well assembly **12**. The production well assembly **12** may comprise a sucker rod string **30** within a well that penetrates a formation **49**. A primary mover at a well surface, such as a pumpjack **28**, may be connected to reciprocate the sucker rod string **30**. The BHP assembly **10** may be configured in such a way so that the sucker rod connector, such as the uphole threaded male end **50**A, of the valve rod **50** is connected to the sucker rod string **30**, for example through the use of the valve rod bushing

52. In use, the sucker rod string **30** may be reciprocated using the primary mover to pump well fluids from a fluid inlet **72**E of the downhole fluid pump **48**, through the valve rod guide **80**, and up to the well surface A (FIG. **1**). Prior to reciprocating, the operator of the well may install the rod guide **80**, for example by assembling the rod guide **80** as par of the BHP assembly **10**. In some cases, assembly is carried out at surface and the BHP assembly **10** is thereafter passed downhole by assembly and insertion into the well of the sucker rod string **30**. In other cases, the rod guide **80** may be installed by passing the various parts downhole along an existing sucker rod string **30**.
(34) Referring to FIG. **2**, an example of a downhole pump **48** is illustrated, incorporating the valve rod guide **80**. The connections in the example will now be described, although it should be understood that the pump **48** shown in FIG. **2** is just an example and other configurations of pumps may be used. The valve rod bushing **52** of sucker rod string **30** may define an uphole threaded male end **52**A, which may connect to a sucker rod female collar **30**C of or connected to a sucker rod. The downhole female threaded box **52**B of the valve rod bushing **52** may connect to the uphole male threaded end **50**A of the valve rod **50**. The valve rod bushing **52** may form a coupling to permit reciprocating action of the sucker rod string **30** to be transferred to the travelling valve via the valve rod **50**. As described further below, the valve rod **50** extends centrally through the pump **48** to a downhole end **50**B that threads to an uphole female box end **60**A of a top plunger coupling **60** of the pump **48**.
(35) A downhole female box end **82**B of the rod guide body **82** may connect to an uphole male cylindrical threaded end **54**A of a seating mandrel **54**. The seating mandrel **54** may comprise a cylindrical body **54**C, the body **54**C defining an exterior sidewall **54**D and an interior bore **54**J. The cylindrical body **54**C may narrow toward a downhole male cylindrical threaded end **54**B, and may define a seating ring stop ridge **54**E and a seating ring radial seat neck **54**F. The stop ridge **54**E and the seat neck **54**F may allow for a series of seating cups **54**G and spacer rings **54**H to encompasses the seat neck **54**F of the seating mandrel **54**. The seating cups **54**G and the spacer rings **54**H may be secured in place on the seat neck **54**F by a lock nut **55**. The cups **54**G and rings **54**H may seal to a downhole end **17**A of the tubing **17**, which may secure to the pump **48** by a suitable mechanism (not shown). An uphole end **55**A of the lock nut **55** may abut the most downhole seating cup **54**G. The lock nut **55** may comprise a threaded cylindrical body **55**C, which may be threadedly connected to the downhole male cylindrical threaded end **54**B of the seating mandrel **54**.
(36) The downhole male cylindrical threaded end **54**B of the seating mandrel **54** may threadedly connect to an uphole female box threaded end **56**A of a barrel bushing **56**. The barrel bushing **56** may connect to the same male threaded end **54**B as the lock nut **55**, and may define a cylindrical body **56**C with an interior bore **56**D. A downhole cylindrical male threaded end **56**B of the barrel bushing **56** may connect to an uphole female box threaded end **58**A of a barrel **58**. The barrel **58** may define a cylindrical body **58**C, an external sidewall **58**D, an internal sidewall **58**E, and an interior bore **58**F.
(37) The interior bore **58**F of the barrel **58** may house the valve and stroke volume of the downhole fluid pump. The downhole fluid pump may comprise a traveling valve assembly **63** mounted to the valve rod **50** and a standing valve assembly **68** mounted to (for example at) a downhole fluid inlet **72**E. The barrel **58** may also house a top plunger coupling **60** and a plunger **62**. An exterior cylindrical sidewall **62**E may form the cylindrical body **62** of the plunger **62**. The top plunger coupling **60** may connect to the downhole male threaded end **50**B of the valve rod **50** via an uphole female threaded end **60**A. The plunger coupling **60** may be connected to an uphole male threaded cylindrical end **62**A of the plunger **62** via a downhole female threaded end **60**B. An interior bore **60**F of the plunger coupling **60** may receive downhole fluid from an interior bore **62**F of the plunger **62**. The downhole fluid may exit the interior bore **60**F through a radial port **60**G of the plunger coupling **60** into an annulus **60**H. The annulus **60**H may be formed between the interior sidewall **58**E of the barrel **58** and an exterior surface of the neck portion **60**C of the top plunger coupling **60**. A body portion **60**D of the plunger coupling **60** may form an exterior cylindrical

sidewall **60**E and the cylindrical sidewall **60**E may extend to and abut the interior sidewall **58**E, which may prevent the downhole fluid from back flowing.

(38) A downhole male threaded cylindrical end **62**B of the plunger **62** may connect to an uphole female threaded box end **64**A of a traveling valve cage body **64**. The traveling valve assembly **63** may comprise the traveling valve cage body **64**, a seat plug **65**, a seat ring **66** and a ball **67**. An uphole male threaded end **65**A of the seat plug **65** may connect to a downhole female threaded box end **64**B of the traveling valve cage body **64**. The traveling valve assembly **63** may be contained within the barrel **58**, and an exterior cylindrical sidewall **64**D of the cylindrical body **64** may abut the interior sidewall **58**E of the barrel **58**. The exterior cylindrical sidewall **64**D may form the cylindrical body **64**C of the cage body **64**. The seat plug **65** may abut and hold the seat ring **66** into place, for example, the seat plug **65** may abut the downhole shoulder end **66**B of the seat ring **66**. The seat plug **65** may press an uphole shoulder end **66**A seat ring **66** against the seat plug retainer stop ring **64**H of the traveling valve cage body **64**. The seat **66**C of the seat ring **66** may be structured to seal against the ball **67**, to retain the ball **67** within an interior bore **64**J of the traveling valve cage body **64** and prevent back flow during upstroke. The ball **67** may be retained within the interior bore **64**J at the uphole end of the interior bore **64**J through the use of an inverse conical valve retainer **64**E. The seat plug **65** may comprise an interior bore **65**C, which may allow fluid to pass through. The interior bore **64**J may comprise bypass slots **64**F, which may allow the downhole fluid to pass around the ball **67** while the ball **67** is being retained by the inverse conical valve retainer **64**E during upstroke, to feed fluid uphole through the pump **48**.

(39) The standing valve assembly **68** of the pump assembly **10** may comprise a standing valve cage body **70**, a cage bushing **72**, a seat ring **73** and a ball **74**. An uphole cylindrical male threaded end **70**A of the standing valve cage body **70** may connect to a downhole female box threaded end **58**B of the barrel **58**, and may abut a downhole shoulder end **65**B of the seat plug **65**. An uphole cylindrical male threaded end **72**A of the cage bushing **72** may connect to a downhole cylindrical male threaded end **70**B of the standing valve cage body **70**. An exterior side wall **70**D may form the cylindrical body **70**C of the cage body **70**. The cage bushing **72** may abut and hold the seat ring **73** into place, for example, the cage bushing **72** may abut the downhole shoulder end **73**B of the seat ring **73**. An exterior side wall **72**D may form the cylindrical body **72**C of the cage bushing **72**. The cage bushing **72** may press an uphole shoulder end **73**A seat ring **73** against the seat plug retainer stop ring **70**H of the standing valve cage body **70**. The seat **73**C of the seat ring **73** may be structured to seal against the ball **74** to retain the ball **74** within an interior bore **70**J of the standing valve cage body **70** to prevent backflow during downstroke. The ball **74** may be retained within the interior bore **70**J at the uphole end of the interior bore **70**J through the use of an inverse conical valve retainer **70**E. The interior bore **70**J may comprise bypass slots **70**F, which may allow the downhole fluid to pass around the ball **74** while the ball **74** is being retained by the inverse conical valve retainer **70**E.

(40) Referring to FIGS. **1** and **2**, the sucker rod string **30** may use the primary mover, for example a pump jack **28**, to pump well fluids from a fluid inlet, for example the fluid inlet **72**E, of the downhole fluid pump, through the valve rod guide **80**, and up to the well surface A. The upward stroke of the pump jack **28** may draw the downhole fluid into the pump assembly **10**. The upward stroke of the pump jack **28** may lift the polished rod **34**, which via the sucker rod string **30** and valve rod **50** may lift the traveling valve assembly **63**. When the pump jack **28** performs an upward stroke, the traveling valve assembly **63** is lifted, causing a drop in pressure in the barrel **58**. The drop of pressure may cause the traveling valve assembly **63** to close by forcing the ball **67** onto the seat **66**C of the seat ring **66**, and the standing valve assembly **68** to open, allowing downhole fluid to enter the pump assembly **10** through the downhole axial fluid inlet **72**E, pass through the seat ring **73** and into the interior bore **58**F of the barrel **58**, while also pushing fluids uphole that are located uphole of the travelling valve.

(41) Referring to FIGS. **1** and **2**, the downward stroke of the pump jack **28** may lower the travelling

valve in the pump **48** through a volume of fluid to be lifted thereafter. The downward stroke of the pump jack **28** may move the polished rod **34** in a downward direction, causing the traveling valve assembly **63** to be lowered, which may cause an increase in pressure in the barrel **58**. The increase of pressure may cause the traveling valve assembly **63** to open by lifting the ball **67** off of the seat **66**C, and the standing valve assembly **68** to close, by forcing the ball **74** onto the seat **73**C of the seat ring **73**. The downward motion of the traveling valve assembly **63** causes the valve assembly **63** to move down through the fluid contained within the barrel **58** until the pump jack **28** reaches the bottom of the downstroke. The process may then be repeated and the pump jack **28** may thereafter begin another upstroke, closing and moving the traveling valve assembly **63** in the upward direction, causing the traveling valve assembly **63** to lift the fluid contained within the interior bore **58**F of the barrel **58** into the interior bore **62**F of the plunger **62**. With each stroke, the fluid may rise from the interior bore **62**F of the plunger **62** to the interior bore **60**F of the top plunger coupling **60**. The fluid may then move from the interior bore **60**F through the port **60**G into the annulus **60**H. The fluid may be lifted into the interior bore **56**D of the barrel bushing **56**, and into the interior bore **80**C of the valve rod guide **80**. The fluid may then move through the side ports **82**F of the rod guide body **82** into an interior bore **38** (such as annulus **17**C of the tubing **17**) of the casing string **16**, where the fluid may continue to be lifted until it reaches the surface.

(42) Referring to FIG. **2**, the valve rod guide **80** may extend the lifespan of the pump assembly **10**. In order to connect to the uphole female threaded end **60**A of the top plunger coupling **60**, the valve rod **50** may run through the interior bore **80**C of the valve rod guide **80**, the interior bore **54**J of the seating mandrel **54**, the interior bore **56**D of the barrel bushing **56** and the interior bore **58**F of the barrel **58**. The valve rod guide **80** may extend the lifespan of the pump assembly **10** by keeping the moving parts of the pump assembly **10**, such as the valve rod **50**, the top plunger coupling **60**, the plunger **62** and the traveling valve assembly **63**, in line with a pump axis **88**. Keeping the moving parts of the pump assembly **10** in line with the pump axis **88** and out of rubbing connection with steel stationary parts of the pump **48** may reduce the wear on the parts by allowing them to move smoothly when in use. The ceramic sleeve **84** of the valve rod guide **80** may assist in keeping the valve rod **50** in line with the pump axis **88**. The ceramic sleeve **84** may be able to keep the valve rod **50** in line with the pump axis **88**, preventing excess wear on the valve rod **50**. The ceramic sleeve **84** may accumulate wear faster than the valve rod **50**, and once the sleeve **84** is worn, the sleeve **84** may be replace with a new ceramic sleeve **84** in order to continue to keep the valve rod **50** in line with the pump axis. In some cases, the embodiments may be used in deviated or horizontal applications, where the severity of a dog leg in the well may otherwise cause more wear on the parts, if not centralized. Wear on the side of the valve rod and the side of the guide may otherwise cause a loss of pulling power.

(43) In the claims, the word “comprising” is used in its inclusive sense and does not exclude other elements being present. The indefinite articles “a” and “an” before a claim feature do not exclude more than one of the feature being present. Each one of the individual features described here may be used in one or more embodiments and is not, by virtue only of being described here, to be construed as essential to all embodiments as defined by the claims.

Claims

1. A bottom hole pump (BHP) assembly for a reciprocating sucker rod in a production well comprising: a downhole fluid pump; a valve rod mounted to reciprocate within the downhole fluid pump, the valve rod having a sucker rod connector; and a valve rod guide mounted to the downhole fluid pump around the valve rod and connected to, in use, receive fluids into an internal fluid chamber from an internal bore of the downhole fluid pump and direct the fluids radially outward to an annulus of a well bore through a radial port in the valve rod guide assembly; in which the valve rod guide has a ceramic wear sleeve that lines an internal valve-rod-receiving cylindrical passage

defined by the valve rod guide; and in which the valve rod guide comprises: a rod guide body; and a rod guide cap that defines a bushing keyway torque slot.
2. The BHP assembly of claim 1 in which the ceramic wear sleeve is cylindrical.
3. The BHP assembly of claim 1 in which the rod guide body has an open downhole end that defines the internal fluid chamber and the radial port.
4. The BHP assembly of claim 3 in which the open downhole end defines a threaded female box.
5. The BHP assembly of claim 3 in which the rod guide body defines an uphole-facing internal axial shoulder that seats a downhole end of the ceramic wear sleeve in the internal valve-rod-receiving cylindrical passage.
6. The BHP assembly of claim 5 in which the rod guide cap is threaded to an uphole end of the rod guide body.
7. The BHP assembly of claim 6 in which the rod guide cap defines a downhole-facing internal axial shoulder that secures an uphole end of the ceramic wear sleeve.
8. The BHP assembly of claim 6 in which the rod guide cap has a threaded female box end that mounts to a threaded male end of the rod guide body.
9. The BHP assembly of claim 1 in which the bushing keyway torque slot defines a radial slot at an uphole end of the rod guide cap.
10. The BHP assembly of claim 1 in which a valve rod bushing, of the sucker rod connector or connected to the sucker rod connector, defines a key structured to mate with the bushing keyway torque slot for torque transfer.
11. The BHP assembly of claim 1 in which the downhole fluid pump comprises: a traveling valve mounted to the valve rod; and a standing valve mounted to a downhole fluid inlet of the downhole fluid pump.
12. A production well assembly comprising: a sucker rod string within a well that penetrates a formation; a primary mover at a well surface, the primary mover connected to reciprocate the sucker rod string; and the BHP assembly of claim 1 in which the sucker rod connector of the valve rod is connected to the sucker rod string.
13. A method of operating the production well assembly of claim 12 comprising reciprocating the sucker rod string using the primary mover to pump well fluids from a fluid inlet of the downhole fluid pump, through the valve rod guide, and up to the well surface.
14. A valve rod guide comprising: a rod guide body defining an open downhole cylindrical pump-barrel-mounting end that defines an internal pump fluid chamber and a radial port to an exterior surface of the rod guide body, the rod guide body being structured for, in use, receiving and directing well fluids pumped through the open downhole cylindrical pump-barrel-mounting end into a wellbore annulus via the radial port, the rod guide body defining a valve rod axial bore therethrough; a ceramic wear sleeve seated within an internal valve-rod-receiving cylindrical passage defined by the rod guide body; and a rod guide cap mounted to an uphole end of the rod guide body to secure an uphole end of the ceramic wear sleeve within the wear sleeve receptacle, in which: the rod guide cap has a threaded female box that mounts to a threaded male end of the rod guide body; and the rod guide cap defines a bushing keyway torque slot.
15. The valve rod guide of claim 14 in which: the ceramic wear sleeve is cylindrical; and the open downhole cylindrical pump-barrel-mounting end defines the threaded female box.
16. The valve rod guide of claim 14 in which the bushing keyway torque slot comprises a radial slot along an uphole end of the rod guide cap.
17. A method comprising driving a sucker rod string to pump well fluids from a fluid inlet of a downhole fluid pump, through a valve rod guide, and up to the well surface, in which the valve rod guide has a rod guide body, a rod guide cap that defines a bushing keyway torque slot, and an internal ceramic wear sleeve that lines an interior bore of the valve rod guide and encircles a valve rod, which is driven by the sucker rod string to drive the downhole fluid pump.