

(19)



(11)

EP 3 516 228 B1

(12)

EUROPEAN PATENT SPECIFICATION

(45) Date of publication and mention
of the grant of the patent:

13.01.2021 Bulletin 2021/02

(51) Int Cl.:

F04C 28/02 ^(2006.01) **F04C 28/08** ^(2006.01)
F04C 28/12 ^(2006.01) **F04C 28/24** ^(2006.01)
F04C 18/14 ^(2006.01) **F04C 18/16** ^(2006.01)

(21) Application number: **17783742.4**

(86) International application number:

PCT/EP2017/074089

(22) Date of filing: **22.09.2017**

(87) International publication number:

WO 2018/055105 (29.03.2018 Gazette 2018/13)

(54) OPERATION OF A WELLHEAD COMPRESSOR

BETRIEB EINES BOHRLOCHKOPFVERDICHTERS

FONCTIONNEMENT DE COMPRESSEUR DE TÊTE DE PUITS

(84) Designated Contracting States:

**AL AT BE BG CH CY CZ DE DK EE ES FI FR GB
GR HR HU IE IS IT LI LT LU LV MC MK MT NL NO
PL PT RO RS SE SI SK SM TR**

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(43) Date of publication of application:

31.07.2019 Bulletin 2019/31

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Description

Technical field of the invention

[0001] The present disclosure relates to the operation of a wellhead compressor and is particularly, although not exclusively, concerned with the operation of a wellhead compressor in order to improve the efficiency at which gas is extracted from a well.

Background of the invention

[0002] As gas is extracted, the reservoir pressure of the gas field typically reduces, which affects the rate at which gas may be extracted at a given wellhead pressure. As the gas field becomes depleted, it is often necessary to reduce the wellhead pressure in order to continue gathering gas from a well at a desirable flow rate. A wellhead compressor is therefore installed to reduce the wellhead pressure and pump gas from the well.

[0003] A plurality of wells are often located at a single reservoir and the extraction of gas from each of the wells may have an effect of the production of gas from the other wells in the reservoir. Wellhead compressors may be provided at each of the wells and may be operated such that a combined flow rate of gas extracted from the wells meets a production target.

[0004] As the reservoir matures and more energy is being expended to extract gas from the well, obtaining optimal efficiency from each of the wellhead compressors and the overall gas field becomes increasingly important.

[0005] EP25300329 describes a system for gathering gas from a gas field having a high pressure compressor and a measuring unit to measure input mass flow at the gas input.

[0006] US2011/0307227 describes a method for characterising production of a well in terms of expected flow production of the well and in combination with production data, calculating a reservoir drainage area for the well.

Solution according to the invention

[0007] According to a first embodiment of the present invention, there is provided a method of operating a wellhead compressor, the compressor being configured to pump fluid from a well at a tubing pressure, the method comprising: selecting a plurality of operating points of the wellhead compressor, wherein the flow rate of fluid pumped by the wellhead compressor varies between the plurality of operating points; measuring the tubing pressure at the plurality of operating points of the wellhead compressor; determining an efficiency, e.g. a volumetric energy efficiency, achieved by the wellhead compressor when operating at each of the operating points at least partially according to the measured tubing pressure at each of the operating points; generating a production curve of well pressure as a function of flow rate from a combination of measured data and predicted data, se-

lecting an operating point of the wellhead compressor from the production curve at least partially based on the efficiency of the wellhead compressor at the selected operating point; and operating the wellhead compressor at the selected operating point; the method further comprising repeating the steps of the method after operating the wellhead compressor at the selected operating point for a predetermined period of time.

[0008] In this way, an operating point of the wellhead compressor may be selected based on the current, measured production of the well, allowing gas to be extracted from the well at the flow rate at which the wellhead compressor operates most efficiently. In other words, the operating point may be selected such that the amount of energy used in order to extract each cubic meter of gas is minimised.

[0009] The step of measuring the tubing pressure at a plurality of operating points of the wellhead compressor may comprise operating the wellhead compressor at a first operating point at which the compressor provides a first flow rate of fluid; measuring a first tubing pressure at the first operating point; operating the wellhead compressor at a second operating point at which the compressor provides a second flow rate of fluid; and measuring a second tubing pressure at the second operating point.

[0010] The production of a reservoir, e.g. the relationship between tubing pressure and flow rate, may vary with time and as gas is extracted from the well. For example, extracting gas from the well may lead to a reduction in the reservoir pressure, which may affect the wellhead pressure required for gas to be extracted from the well at a particular flow rate. Hence, by repeating the steps of the method, the selected operating point may be updated as the well production varies to improve the ongoing efficiency at which fluid is pumped from the well.

[0011] The method may further comprise measuring a current tubing pressure at a current operating point of the compressor. At the first operating point, the compressor may provide a flow rate that is greater than the flow rate at the current operating point. At the second operating point, the compressor may provide a flow rate that is less than the current operating point. Efficiency may also determine when the compressor is operating at the current operating point.

[0012] In other words, the plurality of operating points may include a current operating point, a first operating point, at which the wellhead compressor provides a flow rate greater than the current operating point, and a second operating point, at which the compressor provides a flow rate less than the current operating point.

[0013] The method may therefore be used to determine whether an increase or decrease in production from a current production rate may lead to an increase in efficiency. The method may comprise determining a rate of change in efficiency of the wellhead compressor at the current operating point. The selected operating point may be determined based on at least the rate of change of

efficiency.

[0014] According to an aspect of the present disclosure, which is not part of the present invention, there is provided a method of operating a wellhead compressor, the compressor being configured to pump fluids from a well at a tubing pressure, the method comprising: operating the wellhead compressor at a first operating point at which the compressor provides a first flow rate of fluid; measuring a first tubing pressure at the first operating point; operating the wellhead compressor at a second operating point at which the compressor provides a second flow rate of fluid; measuring a second tubing pressure at the second operating point; determining energy efficiency achieved by the compressor when operating at the first and second operating points at least partially according to the first and second tubing pressures respectively; and operating the wellhead compressor at a selected operating point, e.g. from the first and second operating points, determined at least partially according to the determined energy efficiencies of the compressor.

[0015] The energy efficiency may be a volumetric energy efficiency, e.g. an energy usage per m³ of pumped fluid.

[0016] According to another aspect of the present disclosure, there is provided a method of operating a wellhead compressor, the compressor being configured to pump fluid from a well at a tubing pressure, the method comprising: determining a well productivity, e.g. a relationship between tubing pressure and fluid flow rate, at a plurality of operating points, e.g. of the wellhead compressor, wherein the flow rate of fluid pumped by the wellhead compressor varies between the plurality of operating points; determining an efficiency achieved by the wellhead compressor when operating at each of the operating points at least partially according to a tubing pressure at each of the operating points; and operating the wellhead compressor at a selected operating point at which the compressor achieves greatest efficiency.

[0017] According to another aspect of the present disclosure, there is provided a method of optimising gas extraction from a reservoir using a plurality of wellhead compressors, the method comprising: operating each of the plurality of wellhead compressors according to any of the above-mentioned methods, wherein the selected operating points of each of the wellhead compressors are selected such that the total flow rate of fluid provided by the plurality of wellhead compressors is equal to or greater than a threshold value.

[0018] In some arrangements, in order to provide a total flow rate from the plurality of wellhead compressors that is equal to or greater than the threshold value, the operating points selected for one, several or each of the compressors may not be the most efficient operating point for the particular compressor. For example, the operating points of one or more of the compressors may be selected such that the flow rate of gas provided is greater than at the most efficient operating point. In such arrangements, the operating points may be selected such that

the combined energy efficiency of the plurality of wellhead compressors is maximised.

[0019] The wellhead compressors may be configured to provide fluid to a main compressor. The operating points of each of the plurality of compressors may be selected such that an inlet pressure and/or mass flow rate to the main compressor is within a desirable range. In this way, the main compressor may be operated efficiently.

[0020] The wellhead compressors may be screw compressors. Screw compressors are particularly well suited for use as wellhead compressors as they are able to operate efficiently over a wide range of operating conditions. They are also compact and produce reduced vibrations compared to other types compressors.

[0021] The capacity of a screw compressor, e.g. the flow rate of fluid pumped by the screw compressor, can be controlled using different control methods, depending on the operating conditions of the screw compressor, such as the running speed and/or inlet pressure. The different control method may have different effects on the efficiency of the screw compressor. When applying the above-mentioned methods to an arrangement comprising a plurality of screw compressors, operating points may be selected for the screw compressors, which allow efficient control of the plurality of compressors.

[0022] When a wellhead compressor comprises a screw compressor, the above-mentioned method of controlling the capacity of a screw compressor may be applied when adjusting, controlling or changing between the operating points of the wellhead compressors as part of any of the above-mentioned methods.

[0023] According to a second embodiment of the present invention, there is provided a device for operating a wellhead compressor, the compressor being configured to pump fluids from a well at a tubing pressure, the device comprising: a processor; and a memory configured to store instructions which when executed by the processor cause the processor to perform the steps of the method of operating a wellhead compressor according to the first embodiment.

[0024] The compressor is configured to pump fluids, e.g. gas, from a well at a tubing pressure, the device comprising: a processor; and a memory configured to store instructions which, when executed by the processor, cause the processor to: select a plurality of operating points of the wellhead compressor, wherein the flow rate of fluid pumped by the wellhead compressor varies between the plurality of operating points; measure the tubing pressure at a plurality of operating points of the wellhead compressor, wherein the flow rate of fluid pumped by the wellhead compressor varies between the plurality of operating points; determine an efficiency achieved by the wellhead compressor when operating at each of the operating points based on at least the tubing pressure at each of the operating points; generate a production curve of well pressure as a function of flow rate from a combination of measured data and predicted data, select an

operating point based at least on the efficiency of the wellhead compressor at the selected operating point; and operate the wellhead compressor at the selected operating point.

[0025] According to other arrangements of the disclosure, the memory may be configured to store instructions which, when executed by the processor, cause the processor to perform any of the above mentioned methods.

[0026] The device may be provided within a system comprising the plurality of wellhead compressors and optionally the main compressor.

[0027] To avoid unnecessary duplication of effort and repetition of text in the specification, certain features are described in relation to only one or several aspects or embodiments of the invention. However, it is to be understood that, where it is technically possible, features described in relation to any aspect or embodiment of the invention may also be used with any other aspect or embodiment of the invention.

Brief Description of the Drawings

[0028] The above mentioned attributes, features, and advantages of this invention and the manner of achieving them, will become more apparent and understandable (clear) with the following description of embodiments of the invention in conjunction with the corresponding drawings, wherein:

Figure 1 is a schematic view of a system for extracting gas from a reservoir comprising a plurality of well head compressors;

Figure 2 is an example set of production curves for a gas field well, showing the evolution of the production over time;

Figure 3 shows a method of operating a plurality of wellhead compressors according to arrangements of the present disclosure;

Figure 4 shows a schematic view of a system for operating one or more wellhead compressor according to arrangements of the present disclosure;

Figure 5a and 5b are schematic views of a previously proposed screw compressor;

Figure 6 shows a method of controlling the capacity of a screw compressor according to arrangements of the present disclosure;

Figure 7 shows a method of controlling the capacity of a screw compressor according to another arrangement of the present disclosure; and

Figure 8 shows a schematic view of a system for controlling the capacity of a screw compressor ac-

cording to arrangements of the present disclosure.

Description of the preferred embodiments

[0029] With reference to Figure 1, a system 100 for gathering gas from a gas field 170 will now be described. Gas from the gas field is extracted through a plurality of boreholes. At each borehole a respective wellhead arrangement 151-154 is provided. Delivery valves 161-164 are provided downstream of each of the respective wellhead arrangements 151-154 and are operable to control the flow of gas from each of the wellhead arrangements 151-154.

[0030] In order to increase the amount of gas gathered from each of the boreholes as the reservoir pressure of the gas field reduces, the system 100 comprises a wellhead compressor 141-144 provided downstream of each of the delivery valves 161-164. Each wellhead compressor 141-144 may be configured to generate a pressure difference across the wellhead compressor 141-144 to pump gas from a respective borehole of the gas field 170.

[0031] The wellhead compressors 141-144 may supply the pumped gas to a main compressor 101 at a first pressure p_1 and first mass flow rate m_1 . The main compressor 101 may increase the pressure of the extracted gas to a second pressure p_2 and may supply a second flow rate m_2 of the gas at the second pressure p_2 to a gas export system 130, such as a pipe line or a gas fuelled generator.

[0032] A portion of the gas pumped by the compressor may be recirculated via a return flow tubing 103. The recirculated portion may be injected into the flow of gas entering the main compressor such that the first mass flow rate m_1 is equal to or greater than a desired inlet mass flow rate of the main compressor 101.

[0033] In some arrangements, the main compressor 101 may be a centrifugal compressor configured to operate at a high efficiency over a specific range of inlet pressure conditions. It may therefore be desirable to operate the wellhead compressors 141-144 such that the first pressure p_1 is within this range of inlet pressures.

[0034] The main compressor 101 may be operated such that the second mass flow rate of gas m_2 and/or the second pressure p_2 are equal to or greater than desired values. It may therefore be desirable for each of the wellhead compressors 141-144 to be operated such that a combined flow rate of gas extracted from each of the boreholes is equal to or greater than the desired flow rate.

[0035] Figure 2 shows an example of a set of production curves for a gas well as the well becomes depleted. As shown, the tubing pressure, e.g. a pressure at which gas may be extracted from the well, plotted on the Y axis, varies as a function of a flow rate of gas being extracted from the well, plotted on the X axis. It can be seen that adjusting the flow rate of gas pumped by each of the wellhead compressors affects the inlet pressure at which the wellhead compressors are operating.

[0036] The power consumption of the wellhead compressors 141-144 when delivering fluid at a particular outlet pressure may vary according to the inlet pressure, e.g. the tubing pressure of the well. Hence, the efficiency at which the wellhead compressor is able to extract a volume of gas from the well varies according to the flow rate at which it is extracted.

[0037] Before an operator begins running a wellhead compressor, the operator may predict a production curve for a gas well. The operating point of the compressor may be selected as a compromise between a desired flow rate of gas to be pumped by the compressor and the efficiency at which the fluid can be pumped, e.g. according to the tubing pressure required to pump gas at the desired flow rate. In many cases it is desirable to select an operating point of the compressor such that the efficiency at which gas is gathered from the well is maximised. In other words, such that the energy used to gather a cubic meter of gas is minimised.

[0038] As gas is extracted from the gas field, the reservoir pressure may reduce, which may affect the production curve of the well, e.g. the relationship between the tubing pressure at which gas is extracted and the flow rate of gas. As depicted in Figure 2, a series of production curves may be predicted, which represent the change in production of the well as the reservoir becomes depleted.

[0039] Although multiple production curves may be predicted, the reservoir pressure and therefore the production curve of the well may vary constantly as gas is being gathered from the well. Furthermore, when the gas field approaches depletion, the production curve may vary significantly and may become more difficult to predict. At the same time, more energy may be required in order to extract each cubic meter of gas from the well. Hence, operating the wellhead compressor at the most efficient operating point may become increasingly important as the well becomes depleted.

[0040] With reference to Figure 3, in order to improve the efficiency of the wellhead compressor, e.g. in order to minimise the energy required to gather each cubic meter of gas, the wellhead compressor may be operated using a method 300 according to arrangements of the present disclosure.

[0041] The method 300 comprises a first step 302 in which the tubing pressure, e.g. the inlet pressure of the compressor, is measured at a plurality of operating points of the wellhead compressor. For example, the wellhead compressor may be operated at a first operating point, at which the compressor gathers a first flow rate of gas from the well, and the inlet pressure of the compressor may be measured, e.g. using a pressure sensor. The wellhead compressor may then be operated at a second operating point, at which the wellhead compressor gathers a second flow rate of gas from the well, and the inlet pressure of the compressor may be measured. The compressor may be operated at one or more further operating points and corresponding inlet pressures, e.g. tubing pressures, may be measured. The flow rate of gas gathered

by the wellhead compressor may vary between each of the operating points.

[0042] By measuring the inlet pressure at a plurality of operating points, e.g. at which different flow rates of gas are gathered from the well, a portion of the production curve of the well pressure may be determined directly from measured data rather than predicted data. This may provide a more accurate representation of the current productivity of the well.

[0043] In a second step 304 of the method 300, the efficiency of the wellhead compressor, e.g. the energy required to gather a cubic meter of gas from the well, may be determined for each operating point of the wellhead compressor, e.g. each operating point considered in the first step 302. For example, the inlet pressure at each operating point may be referred to a data model or look-up table, which relates the inlet pressure of the compressor to a power absorbed by the compressor.

[0044] In one or more arrangements of the present disclosure, one of the operating points considered in the first step 302 may be a current operating point, e.g. a point at which the wellhead compressor was operating prior to the method 300 being performed (or repeated). The first operating point may be an operating point at which the flow rate of gas being extracted from the well is greater than at the current operating point and the second operating point may be an operating point at which the flow rate of gas being extracted is less than at the current operating point. This may allow a gradient of the production curve at the current operating point to be determined and/or may provide an indication of whether the efficiency of the wellhead compressor may be increased by increasing or reducing the rate at which gas is gathered.

[0045] In a third step 306 of the method 300, an operating point for the wellhead compressor may be selected at which the efficiency of the wellhead compressor is maximised. In a fourth step 308, the wellhead compressor may be operated at the selected operating point.

[0046] As mentioned above, the production curve of a well may vary as the well becomes depleted. The steps of the method 300 may therefore be repeated after the wellhead compressor has been operating at the selected operating point for a predetermined period of time. The predetermined time may be constant or may be varied as gas is gathered from the well. For example, the predetermined time may be reduced as the well becomes depleted.

[0047] As shown in Figure 1, a plurality of wellhead compressors 141-144 may be provided to gather gas from a gas field 170. In one or more arrangements of the disclosure, each of the wellhead compressors 141-144 may be operated using the method 300 and the method 300 may be used as a method of optimising the extraction of gas from a plurality of wells using a plurality of wellhead compressors.

[0048] The wellhead compressors are configured to deliver gas to the main compressor 101 at a combined

mass flow rate that is equal to or greater than a desired value. However in some conditions, e.g. conditions of the reservoir, if each of the wellhead compressors 141-144 was operated at its most efficient respective operating point, the combined mass flow rate of gas provided to the main compressor 101 may be less than the desired value. Hence, in such conditions it may not be desirable to operate each of the wellhead compressors at their most efficient operating points. Instead, operating points of each of the compressors may be selected such that a mass flow rate of gas may be supplied to the main compressor 101 that is equal to or greater than the desired value. The operating points of the wellhead compressors may be selected such that the combined efficiency of the wellhead compressors 141-144 is maximised.

[0049] With reference to Figure 4, a system 400, according to arrangements of the present disclosure, may be used to implement the method 300. The system 400 comprises a computing device 402 comprising a processor 404, and memory, 406. Optionally, the computing device also includes a network interface 408 for communication with other computing devices, for example with computing devices according to other arrangements of the present disclosure, such as the computing device 702 described below.

[0050] In some arrangements of the disclosure, a network of such computing devices may be provided. Optionally, the computing device also includes one or more input mechanisms 410 such as keyboard and mouse, and a display unit 412 such as one or more monitors. The components are connectable to one another via a bus 414.

[0051] The memory 406 may include a computer readable medium, which term may refer to a single medium or multiple media (e.g., a centralized or distributed database and/or associated caches and servers) configured to carry computer-executable instructions or have data structures stored thereon. Computer-executable instructions may include, for example, instructions and data accessible by and causing a general purpose computer, special purpose computer, or special purpose processing device (e.g., one or more processors) to perform one or more functions or operations. Thus, the term "computer-readable storage medium" may also include any medium that is capable of storing, encoding or carrying a set of instructions for execution by the machine and that cause the machine to perform any one or more of the methods of the present disclosure. The term "computer-readable storage medium" may accordingly be taken to include, but not be limited to, solid-state memories, optical media and magnetic media. By way of example, and not limitation, such computer-readable media may include non-transitory computer-readable storage media, including Random Access Memory (RAM), Read-Only Memory (ROM), Electrically Erasable Programmable Read-Only Memory (EEPROM), Compact Disc Read-Only Memory (CD-ROM) or other optical disk storage, magnetic disk storage or other magnetic storage devices,

or flash memory devices (e.g., solid state memory devices).

[0052] The processor 404 is configured to control the computing device 402 and execute processing operations, for example executing code stored in the memory 404 to implement the various different step of the method 300 described here and in the claims. The memory 406 stores data being read and written by the processor 404. As referred to herein, a processor may include one or more general-purpose processing devices such as a microprocessor, central processing unit, or the like. The processor may include a complex instruction set computing (CISC) microprocessor, reduced instruction set computing (RISC) microprocessor, very long instruction word (VLIW) microprocessor, or a processor implementing other instruction sets or processors implementing a combination of instruction sets. The processor may also include one or more special-purpose processing devices such as an application specific integrated circuit (ASIC), a field programmable gate array (FPGA), a digital signal processor (DSP), network processor, or the like. In one or more embodiments, a processor is configured to execute instructions for performing the operations and steps discussed herein.

[0053] The display unit 412 may display a representation of data stored by the computing device and may also display a cursor and dialog boxes and screens enabling interaction between a user and the programs and data stored on the computing device. The input mechanisms 410 may enable a user to input data and instructions to the computing device.

[0054] The network interface (network I/F) 408 may be connected to a network, such as the Internet, and is connectable to other such computing devices via the network. The network I/F 408 may control data input/output from/to other apparatus via the network. Other peripheral devices such as microphone, speakers, printer, power supply unit, fan, case, scanner, trackball etc may be included in the computing device.

[0055] The steps of the method 300 may comprise processing instructions stored on a portion of the memory 406, using the processor 404 to execute the processing instructions, and using a portion of the memory 406 to store the measured tubing pressure values or any other data generate during the execution of the processing instructions. The measured tubing pressures or other data may be stored on the memory 406 and/or on a connected storage unit.

[0056] Methods according to arrangements of the present disclosure may be carried out on a computing device such as that illustrated in Figure 4. Such a computing device need not have every component illustrated in Figure 4, and may be composed of a subset of those components. A method according to arrangements of the present disclosure may be carried out by a single computing device in communication with one or more data storage servers via a network. The computing device may be a data storage itself.

[0057] A method according to arrangements of the present disclosure may be carried out by a plurality of computing devices operating in cooperation with one another. One or more of the plurality of computing devices may be a data storage server.

[0058] The system 400 may further comprise one or more of the components of the system 100 described above with reference to Figure 1. For example, the system 400 may comprise the wellhead compressors 141-144 and/or the main compressor 101.

[0059] Each of the wellhead compressors may comprise any desirable type of compressor, such as a screw compressor, reciprocating compressor or centrifugal compressor. Screw compressors may be capable of operating efficiently over a range of operating conditions and may therefore be particular suitable for use as wellhead compressors.

[0060] With reference to Figures 5a and 5b, a previously proposed screw compressor 500 comprises a casing 510, a female rotor 520 and a male rotor 530. The female and male rotor 520, 530 are housed within the casing 510 and are configured to rotate about first and second axes 522, 532 respectively. The compressor further comprises a drive system 560 configured to rotate the female and male rotors at a running speed of the drive system.

[0061] The female rotor 520 defines a plurality of flutes 524 and the male rotor 530 defines a plurality of lobes 534 configured to meshingly engage the flutes 524. The female and male rotors 520, 530 are together configured such that the flutes and lobes progressively disengage and reengage over a length of the rotors as the rotors rotate about their respective axes 522, 532.

[0062] The casing 510 comprises an inlet 512 formed in a wall of the casing. The inlet may be a radial inlet. In other words, fluid may flow into the inlet in a radial direction relative to the first and second axes to enter the compressor. The inlet 512 is arranged such that lobes of the male rotor disengage from the flutes of the female rotor at a location adjacent to the inlet 512 and create a void between a particular lobe of the male rotor, a corresponding flute of the female rotor and the walls of the casing 510. Fluid may be drawn into the compressor 500 through the inlet 512 to fill the void. An inlet volume of the compressor may be defined as the largest volume created between the lobe, corresponding flute and the casing whilst the volume is in fluid communication with the inlet 512.

[0063] As the rotors rotate within the casing and the particular lobe reengages with the corresponding flute, an engagement point between the lobe and corresponding flute seals the volume of fluid between the lobe, the flute and casing from the inlet 512. As the lobe and corresponding flute continue to reengage, the sealed volume reduces and the fluid is compressed. The fluid continues being compressed until the rotors have rotated into a position in which the sealed volume comes into fluid communication with a radial outlet 514 of the casing

510. Fluid may exit the compressor 500 through the radial outlet 514.

[0064] The volume of the sealed volume when it comes into fluid communication with the radial outlet 514 may be referred to as the outlet volume of the compressor. The ratio between the inlet volume and outlet volume of compressor defines the internal compression ratio of the compressor 500.

[0065] The casing 510 further comprises an axial outlet 516 defined at an end of the casing. Fluid that does not flow out of the compressor at the radial outlet 514 may exit the compressor at the axial outlet 516.

[0066] The screw compressor 500 further comprises a slide-valve 540 provided within the casing 510. The slide-valve comprises a first component 542 and a second component 544. The first and second components 542, 544 of the slide-valve are movable, e.g. slidable, within the casing 510. The first and second components 542, 544 may be moved together. Additionally, the second component 544 may be moved separately from the first component.

[0067] When the first and second components 542, 544 are moved together, the outlet volume of the compressor may be adjusted whilst the inlet volume remains constant. Adjusting the position of the slide valve 540 in this way therefore varies the internal compression ratio of the screw compressor 500.

[0068] Alternatively, as shown in Figure 5b, if the second component 544 is moved separately from the first component 542, the outlet volume of the compressor may be reduced and a recirculation channel may be opened that permits fluid to be recirculated from the sealed volume back to the radial inlet 512. Opening the recirculation channel reduces the effective inlet volume of the compressor. Adjusting the position of the second component 544 relative to the first component 542 may therefore adjust both the inlet and outlet volumes of the compressor by substantially the same proportions. The slide valve 540 can therefore be used to reduce the capacity of the compressor, e.g. a flow rate of fluid pumped by the compressor, whilst maintaining the volume ratio of the compressor at a substantially constant value.

[0069] The capacity of the compressor, e.g. the flow rate of fluid pumped by the compressor, is equal to the inlet volume of each flute of the compressor multiplied by the number of flutes 522 on the female rotor 520 multiplied by the rotational speed of the rotors of the compressor. The capacity of the compressor may therefore be adjusted by using the slide valve 540 to control the inlet volume of the compressor or by adjusting the running speed of the drive system 560.

[0070] The torque absorbed by the compressor when operating at a particular inlet pressure may be independent of the running speed of the compressor. Hence, reducing the capacity of the compressor by reducing the running speed of the compressor, leads to a proportional reduction in the power required to drive the compressor. In contrast to this, reducing the capacity of the compres-

sor using the slide valve 540, as described above, may not lead to a proportional reduction in the power required to drive the compressor. In other words, when the capacity of the compressor is reduced using the slide valve, the efficiency of the compressor may be affected, e.g. reduced. It may therefore be desirable to adjust the capacity of the compressor by reducing the running speed of the drive system 560 when possible.

[0071] In some arrangements of the disclosure, the drive system 560 may comprise an electric motor. The torque that the electric motor is able to provide may depend on the running speed of the electric motor. In some cases the electric motor may not be capable of providing a desired torque to drive the screw compressor 500 if the running speed of the electric motor were to be reduced. In this case, if it is desirable to reduce the capacity of the compressor 500, the slide valve 540 may be used in preference to reducing the running speed of the compressor.

[0072] With reference to Figure 6, in order to ensure that the compressor operates most efficiently, the capacity of the compressor may be controlled, e.g. reduced, using a method 600, according to arrangements of the present disclosure.

[0073] The method 600 comprises a first step 602, in which an operating condition of the screw compressor is determined. The operating condition may be at least one of an inlet pressure, an outlet pressure of the compressor and a absorbed torque of the compressor. The inlet and/or outlet pressures of the compressor may be used together with the flow rate of fluid being pumped by the compressor to determine a torque being absorbed by the compressor. For example, the value of inlet and/or outlet pressure may be referred to a data model or look-up table in order to determine the torque. Additionally or alternatively, torque being absorbed by the compressor 500 may be measured directly, for example, using a strain gauge coupled to a drive shaft of the drive system 560.

[0074] In a second step 604 of the method 600, a method of controlling the capacity of the compressor 500 may be selected at least partially according to the operating condition of the compressor. As described above, the capacity of the compressor may be controlled by adjusting the running speed of the compressor, e.g. by adjusting the running speed of the drive system configured to rotate the rotors of the compressor, or by operating the slide valve 540 to adjust the inlet and outlet volumes of the compressor. Additionally or alternatively, capacity of the compressor may be controlled by another method. In the second step 604, a method or combination of method of controlling capacity of the compressor may be selected.

[0075] As described above, reducing the capacity of the compressor by reducing the running speed of the compressor may be more efficient than reducing the capacity through another method. Hence, the second step 604 may comprise determining whether the running speed of the drive system can be reduced, and the method of reducing capacity by reducing the running speed

of compressor may be selected, if the speed of the drive system can be reduced.

[0076] The ability of the drive system to operate the compressor at a reduced running speed may depend on the torque required to drive the compressor and the maximum torque available from the drive system at the running speed. If the drive system is currently operating to provide the maximum available torque, it may not be desirable to reduce the running speed of the drive system. The second step 604 may comprise determining a maximum torque available from the drive system at the running speed. If the drive system is operating, e.g. currently operating, to supply the maximum torque available from the drive system, the capacity of the compressor may be adjusted by adjusting the position of the slide valve, e.g. the position of the second component of the slide valve relative to the first component.

[0077] In a third step 606 of the method 600, the capacity of the screw compressor may be reduced using the selected method.

[0078] With reference to Figure 7, a method of controlling the capacity of a screw compressor according to another arrangement of the present disclosure comprises first steps 702a, 702b, in which operating conditions of the compressor, such as torque and/or speed of the drive system, and/or inlet pressure, outlet pressure and/or flow rate of gas being pumped by the compressor are determined, e.g. measured.

[0079] In a second step 704, a first range of capacities over which the capacity of the compressor can be controlled by adjusting the running speed of the drive system may be determined. The first range may be determined at least partially based on the current operating conditions of the compressor determined in the first steps 702a, 702b. Additionally or alternatively, a second range of capacities may be determined over which the capacity of the compressor can be controlled by adjusting the position of the slide valve 540.

[0080] In a third step 706, a method of adjusting the capacity of the compressor may be selected. The method may be selected based on the range of capacities that the compressor is currently operating within. For example, if the compressor is currently operating within the first range of capacities, the method of controlling capacity by adjusting the running speed of the drive system may be selected. Alternatively, if the compressor is currently operating within the second range, the method of controlling capacity by adjusting the position of the slide valve 540 may be selected.

[0081] The method comprises a fourth step 708 in which the capacity is controlled by adjusting the running speed of the drive system and a fifth step 710 in which the capacity is controlled by adjusting the position of the slide valve. The method proceeds from the third step 706 to the fourth step 708 or the fifth step 710 depending on the method that is selected in the third step 706.

[0082] The method 600 or the method 700 may be used when capacity of the wellhead compressors included

within the system 100 is being controlled, for example as part of the method 400.

[0083] With reference to Figure 8, a system 800, according to arrangements of the present disclosure, may be used to implement the method 600 or the method 700. The system 800 comprises a computing device 802 comprising a processor 804, and memory, 806. Optionally, the computing device also includes a network interface 808 for communication with other computing devices, for example with computing devices according to other arrangements of the present disclosure, such as the computing device 402.

[0084] In some arrangements of the disclosure, a network of such computing devices may be provided. Optionally, the computing device also includes one or more input mechanisms 810 such as keyboard and mouse, and a display unit 812 such as one or more monitors. The components are connectable to one another via a bus 814.

[0085] The memory 806 may include a computer readable medium and may be similar to the memory 406 described above.

[0086] The processor 804 is configured to control the computing device 802 and execute processing operations, for example executing code stored in the memory 804 to implement the various different steps of the method 600 or the method 700 described here and in the claims. The memory 806 stores data being read and written by the processor 804.

[0087] The display unit 812 may display a representation of data stored by the computing device and may also display a cursor and dialog boxes and screens enabling interaction between a user and the programs and data stored on the computing device. The input mechanisms 810 may enable a user to input data and instructions to the computing device.

[0088] The network interface (network I/F) 808 may be connected to a network, such as the Internet, and is connectable to other such computing devices via the network. The network I/F 808 may control data input/output from/to other apparatus via the network.

[0089] Other peripheral devices such as microphone, speakers, printer, power supply unit, fan, case, scanner, trackerball etc may be included in the computing device.

[0090] The steps of the method 600 and the method 700 may comprise processing instructions stored on a portion of the memory 806, the processor 804 then executing those processing instructions, and a portion of the memory 806 to store data, e.g. relating to the operating condition of the compressor 500 during the execution of the processing instructions. The method of controlling the capacity selected during the method 600 and the method 700 may be stored on the memory 806 and/or on a connected storage unit.

[0091] Methods according to arrangements of the present disclosure may be carried out on a computing device such as that illustrated in Figure 8. Such a computing device need not have every component illustrated

in Figure 8, and may be composed of a subset of those components. A method according to arrangements of the present disclosure may be carried out by a single computing device in communication with one or more data storage servers via a network. The computing device may be a data storage itself.

[0092] A method according to arrangements of the present disclosure may be carried out by a plurality of computing devices operating in cooperation with one another. One or more of the plurality of computing devices may be a data storage server.

[0093] The system 800 may further comprise the compressor 500.

[0094] A method of controlling the capacity of a screw compressor assembly, the assembly comprising: a screw compressor having: a casing defining an inlet and an outlet of the screw compressor; a first rotor comprising a plurality of flutes; a second rotor comprising a plurality of lobes configured to meshingly engage the flutes of the first rotor; and a slide valve, a position of the slide valve being selectively variable in order to control a capacity of the screw compressor; and a drive system configured to rotate the first and second rotors at a running speed, in order to compress a fluid within the flutes, wherein the method comprises: determining an operating condition of the screw compressor comprising at least one of an inlet pressure, an outlet pressure and an absorbed torque of the screw compressor; selecting a method of controlling capacity based at least on the operating condition; and reducing the capacity of the screw compressor using the selected method.

[0095] More than one method is available for controlling the capacity of a screw compressor, each having a different effect on the efficiency of the compressor. By selecting a suitable method based on an operating condition of the screw compressor, the efficiency of the compressor may be improved when operating at different capacities across multiple operating conditions.

[0096] The slide valve may be operable to adjust the inlet and outlet volumes of the compressor to reduce the effective swept volume of the flutes, thereby reducing the capacity of the compressor, without significantly affecting the volume ratio or compression ratio of the compressor.

[0097] The method may comprise determining a range, e.g. of capacities, over which the capacity of the screw compressor can be controlled using a first method, such as adjusting the running speed of the drive system. Additionally, the method may comprise determining a range, e.g. of capacities, over which the capacity of the screw compressor can be controlled using a second method, such as adjusting the position of the slide valve.

[0098] The method of controlling capacity of the screw compressor may be selected from adjusting the running speed of the drive system and adjusting the position of the slide valve.

[0099] The inlet and outlet pressures of the compressor may be used to determine a torque desired from the drive system to drive the rotors of the screw compressor.

Selecting a method of capacity control based on the torque, or using other operating parameters from which torque may be derived, beneficially permits the capacity of the compressor to be controlled by adjusting the speed of the drive system in preference to adjusting the position of the slide valve when the drive system is able to supply the desired torque at a reduced running speed.

[0100] The step of selecting a method of capacity control may comprise determining, based on the current operating condition of the screw compressor, whether the speed of the drive system may be reduced. For example, whether the drive system will be able to supply sufficient torque to drive the screw compressor at a reduced running speed, e.g. without overheating. A method of controlling capacity by adjusting the speed of the drive system may be selected if the speed of the drive system may be reduced. Alternatively, if the speed of the drive system may not be reduced, a method of controlling capacity by adjusting the position of the slide valve may be selected.

[0101] Controlling the capacity of the compressor by controlling the speed of the drive system may allow the power consumed by the compressor to be reduced by a greater amount than when capacity is controlled using an alternative method.

[0102] The step of selecting a method of capacity control may comprise determining a maximum torque available from the drive system at the running speed. For example by referring to a data model or look up table for the drive system relating running speed of the drive system with maximum available torque. A method of controlling capacity by adjusting the position of the slide valve may be selected if the drive system is operating to supply the maximum available torque. Alternatively, if the drive system is not operating to supply the maximum available torque, a method of controlling capacity by adjusting the speed of the drive system may be selected.

[0103] The drive system may comprise an electric motor. Electric motors may be well suited for use as the drive system for the screw compressor in many applications and operating conditions. However, electric motors may be capable of delivering less torque when the running speed of the electric motor is reduced, e.g. due to reduced cooling being provided to the electric motor at the reduced running speed. Hence, when the drive system comprises an electric motor, operating the screw compressor may be beneficial.

[0104] A device may be provided for controlling the capacity of a screw compressor assembly, the assembly comprising: a screw compressor having: a casing defining an inlet and an outlet of the screw compressor; a first rotor comprising a plurality of flutes; a second rotor comprising a plurality of lobes configured to meshingly engage the flutes of the first rotor; and a slide valve, a position of the slide valve being selectively variable in order to control a capacity of the screw compressor; and a drive system configured to rotate the first and second rotors at a running speed, in order to compress a fluid within the flutes, wherein the system comprises: a processor;

and a memory configured to store instructions, which when executed by the processor cause the processor to: determine an operating condition of the screw compressor comprising at least one of an inlet pressure, an outlet pressure, a flow rate and an absorbed torque of the screw compressor; select a method of controlling capacity at least partially based on the operating condition; and reduce the capacity of the screw compressor using the selected method.

[0105] According to other arrangements of the disclosure, the memory may be configured to store instructions which, when executed by the processor, cause the processor to perform any of the above-mentioned methods of controlling the capacity of a screw compressor.

[0106] The device for controlling the capacity of a screw compressor assembly may be provided within a system further comprising the screw compressor assembly.

[0107] It will be appreciated by those skilled in the art that although the invention has been described by way of example, with reference to one or more exemplary examples, it is not limited to the disclosed examples and that alternative examples could be constructed without departing from the scope of the invention as defined by the appended claims.

Claims

1. A method of operating a wellhead compressor, the compressor (141-144) being configured to pump fluid from a well at a tubing pressure, the method comprising:

selecting a plurality of operating points of the wellhead compressor (141-144), wherein the flow rate of fluid pumped by the wellhead compressor varies between the plurality of operating points;

measuring (302) the tubing pressure at the plurality of operating points of the wellhead compressor;

determining (304) an efficiency achieved by the wellhead compressor when operating at each of the operating points based on at least the measured tubing pressure at each of the operating points;

generating a production curve of well pressure as a function of flow rate from a combination of measured data and predicted data,

selecting (306) an operating point of the wellhead compressor from the production curve based on at least the efficiency of the wellhead compressor at the selected operating point; and operating (308) the wellhead compressor at the selected operating point;

the method further comprising repeating the steps of the method after operating the wellhead

compressor at the selected operating point for a predetermined period of time.

2. The method of claim 1, wherein the step of measuring (302) the tubing pressure at a plurality of operating points of the wellhead compressor comprises operating the wellhead compressor (141-144) at a first operating point at which the compressor provides a first flow rate of fluid; measuring a first tubing pressure at the first operating point; operating the wellhead compressor at a second operating point at which the compressor provides a second flow rate of fluid; and measuring a second tubing pressure at the second operating point.
3. The method of claim 1 or 2, wherein the plurality of operating points include a current operating point, a first operating point at which the wellhead compressor (141-144) provides a flow rate greater than the current operating point, and a second operating point at which the compressor provides a flow rate less than the current operating point.
4. A method of optimising gas extraction from a reservoir using a plurality of wellhead compressors, the method comprising:
operating each of the plurality of wellhead compressors (141-144) according to the method of any of claims 1 to 3, wherein the selected operating points of each of the wellhead compressors are selected such that the total flow rate of fluid provided by the plurality of wellhead compressors is equal to or greater than a threshold value.
5. The method of claim 4, wherein the operating points of each of the plurality of compressors (141-144) are selected such that the combined energy efficiency of the plurality of wellhead compressors is maximised.
6. The method of claim 4 or 5, wherein the wellhead compressors (141-144) are configured to provide pumped fluid to a main compressor (101), wherein the operating points of each of the plurality of compressors are selected such that an inlet pressure and/or mass flow rate to the main compressor is within a desirable range.
7. The method of any of claims 1 to 6, wherein the wellhead compressor (141-144) is a screw compressor.
8. A method according to any of claims 1 to 7, wherein the energy efficiency comprises a volumetric energy efficiency, in particular, an energy usage per m³ of pumped fluid.
9. A device for operating a wellhead compressor, the compressor being configured to pump fluids from a

well at a tubing pressure, the device comprising:

a processor (404); and
a memory (406) configured to store instructions which when executed by the processor cause the processor to perform the steps of the method of operating a wellhead compressor according to claim 1.

Patentansprüche

1. Verfahren zum Betreiben eines Bohrlochkopfverdichters, wobei der Verdichter (141-144) dazu konfiguriert ist, Fluid aus einem Bohrloch mit einem Rohrdruck zu pumpen, wobei das Verfahren Folgendes umfasst:

Auswählen einer Mehrzahl von Betriebspunkten des Bohrlochkopfverdichters (141-144), wobei die Durchflussmenge des von dem Bohrlochkopfverdichter gepumpten Fluids zwischen der Mehrzahl der Betriebspunkte variiert,
Messen (302) des Rohrdrucks an der Mehrzahl von Betriebspunkten des Bohrlochkopfverdichters,
Bestimmen (304) eines von dem Bohrlochkopfverdichter erreichten Wirkungsgrads, wenn er an jedem der Betriebspunkte auf Grundlage von mindestens dem an jedem der Betriebspunkte gemessenen Rohrdruck arbeitet,
Erzeugen einer Förderkurve von Bohrlochdruck als eine Funktion einer Durchflussmenge aus einer Kombination von gemessenen Daten und vorhergesagten Daten,
Auswählen (306) eines Betriebspunkts des Bohrlochkopfverdichters aus der Förderkurve auf Grundlage von mindestens dem Wirkungsgrad des Bohrlochkopfverdichters an dem ausgewählten Betriebspunkt und
Betreiben (308) des Bohrlochkopfverdichters an dem ausgewählten Betriebspunkt, wobei das Verfahren ferner das Wiederholen der Schritte des Verfahrens nach dem Betreiben des Bohrlochkopfverdichters an dem ausgewählten Betriebspunkt für eine vorbestimmte Zeitspanne umfasst.

2. Verfahren nach Anspruch 1, wobei der Schritt des Messens (302) des Rohrdrucks an einer Mehrzahl von Betriebspunkten des Bohrlochkopfverdichters das Betreiben des Bohrlochkopfverdichters (141-144) an einem ersten Betriebspunkt, an dem der Bohrlochkopfverdichter eine erste Durchflussmenge von Fluid bereitstellt, das Messen eines ersten Rohrdrucks an dem ersten Betriebspunkt, das Betreiben des Bohrlochkopfverdichters an einem zweiten Betriebspunkt, an dem der Bohrlochkopfver-

ichter eine zweite Durchflussmenge von Fluid bereitstellt, und das Messen eines zweiten Rohdrucks an dem zweiten Betriebspunkt umfasst.

3. Verfahren nach Anspruch 1 oder 2, wobei die Mehrzahl von Betriebspunkten einen aktuellen Betriebspunkt, einen ersten Betriebspunkt, an dem der Bohrlochkopfverdichter (141-144) eine erste Durchflussmenge bereitstellt, die größer als der aktuelle Betriebspunkt ist, und einen zweiten Betriebspunkt, an dem der Verdichter eine Durchflussmenge bereitstellt, die kleiner als der aktuelle Betriebspunkt ist, einschließt. 5
4. Verfahren zur Optimierung der Gasförderung aus einer Lagerstätte unter Verwendung einer Mehrzahl von Bohrlochkopfverdichtern, wobei das Verfahren Folgendes umfasst:
Betreiben eines jeden der Mehrzahl von Bohrlochkopfverdichtern (141-144) gemäß dem Verfahren nach einem der Ansprüche 1 bis 3, wobei die ausgewählten Betriebspunkte von jedem der Bohrlochkopfverdichter so ausgewählt sind, dass die Gesamtdurchflussmenge des von der Mehrzahl von Bohrlochkopfverdichtern bereitgestellten Fluids gleich wie oder größer als ein Schwellenwert ist. 10 20 25
5. Verfahren nach Anspruch 4, wobei die Betriebspunkte eines jeden der Mehrzahl von Verdichtern (141-144) so ausgewählt sind, dass der kombinierte Energiewirkungsgrad der Mehrzahl von Bohrlochkopfverdichtern maximiert wird. 30
6. Verfahren nach Anspruch 4 oder 5, wobei die Bohrlochkopfverdichter (141-144) dazu konfiguriert sind, gepumptes Fluid zu einem Hauptverdichter (101) zu liefern, wobei die Betriebspunkte eines jeden der Mehrzahl von Verdichtern so ausgewählt sind, dass ein Einlassdruck und/oder eine Massendurchflussmenge zu dem Hauptverdichter innerhalb eines wünschenswerten Bereichs ist. 35 40
7. Verfahren nach einem der Ansprüche 1 bis 6, wobei der Bohrlochkopfverdichter (141-144) ein Schraubenverdichter ist. 45
8. Verfahren nach einem der Ansprüche 1 bis 7, wobei der Energiewirkungsgrad einen volumetrischen Energiewirkungsgrad, insbesondere einen Energieverbrauch pro m³ gepumpten Fluids umfasst. 50
9. Vorrichtung zum Betreiben eines Bohrlochkopfverdichters, wobei der Bohrlochkopfverdichter dazu konfiguriert ist, Fluide aus einem Bohrloch mit einem Rohdruck zu pumpen, wobei die Vorrichtung Folgendes umfasst: 55

einen Prozessor (404) und

einen Speicher (406), der dazu konfiguriert ist, Anweisungen zu speichern, die, wenn sie durch den Prozessor ausgeführt werden, den Prozessor veranlassen, die Schritte des Verfahrens zum Betreiben eines Bohrlochkopfverdichters nach Anspruch 1 auszuführen.

Revendications

1. Procédé de fonctionnement d'un compresseur de tête de puits, le compresseur (141-144) étant configuré en vue de pomper du fluide à partir d'un puits à une pression de colonne de production, le procédé consistant :

à sélectionner une pluralité de points de fonctionnement du compresseur (141-144) de tête de puits, étant entendu que le débit de fluide pompé par le compresseur de tête de puits varie entre la pluralité de points de fonctionnement ;
à mesurer (302) la pression de colonne de production en la pluralité de points de fonctionnement du compresseur de tête de puits ;
à déterminer (304) un rendement atteint par le compresseur de tête de puits en fonctionnement pour chacun des points de fonctionnement sur la base au moins de la pression de colonne de production mesurée en chacun des points de fonctionnement ;
à créer une courbe de production de la pression du puits en fonction du débit à partir d'une combinaison de données mesurées et de données prédites ;
à sélectionner (306) un point de fonctionnement du compresseur de tête de puits à partir de la courbe de production sur la base au moins du rendement du compresseur de tête de puits au point de fonctionnement sélectionné, et
à faire fonctionner (308) le compresseur de tête de puits au point de fonctionnement sélectionné, le procédé consistant par ailleurs à répéter les étapes du procédé après avoir fait fonctionner le compresseur de tête de puits au point de fonctionnement sélectionné pendant un laps de temps prédéterminé.
2. Procédé selon la revendication 1, étant entendu que l'étape consistant à mesurer (302) la pression de colonne de production en une pluralité de points de fonctionnement du compresseur de tête de puits consiste à faire fonctionner le compresseur (141-144) de tête de puits à un premier point de fonctionnement auquel le compresseur fournit un premier débit de fluide, à mesurer une première pression de colonne de production au premier point de fonctionnement, à faire fonctionner le compresseur de tête de puits à un deuxième point de fonctionne-

ment auquel le compresseur fournit un deuxième débit de fluide, et à mesurer une deuxième pression de colonne de production au deuxième point de fonctionnement.

3. Procédé selon la revendication 1 ou 2, étant entendu que la pluralité de points de fonctionnement inclut un point de fonctionnement en cours, un premier point de fonctionnement auquel le compresseur (141-144) de tête de puits fournit un débit supérieur à celui du point de fonctionnement en cours, et un deuxième point de fonctionnement auquel le compresseur fournit un débit inférieur à celui du point de fonctionnement en cours.

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4. Procédé d'optimisation de l'extraction de gaz d'un réservoir au moyen d'une pluralité de compresseurs de tête de puits, le procédé consistant :

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 à faire fonctionner chaque compresseur de la pluralité de compresseurs (141-144) de tête de puits conformément au procédé selon l'une quelconque des revendications 1 à 3, étant entendu que les points de fonctionnement sélectionnés pour chacun des compresseurs de tête de puits sont sélectionnés de telle sorte que le débit total de fluide fourni par la pluralité de compresseurs de tête de puits est égal ou supérieur à une valeur seuil.
5. Procédé selon la revendication 4, étant entendu que les points de fonctionnement de chaque compresseur de la pluralité de compresseurs (141-144) sont sélectionnés de telle sorte que le rendement énergétique combiné de la pluralité de compresseurs de tête de puits soit maximisé.

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6. Procédé selon la revendication 4 ou 5, étant entendu que les compresseurs (141-144) de tête de puits sont configurés en vue de fournir du fluide pompé à un compresseur principal (101), étant entendu que les points de fonctionnement de chaque compresseur de la pluralité de compresseurs sont sélectionnés de telle sorte qu'une pression d'admission et/ou un débit massique vers le compresseur principal se situe dans une plage souhaitable.

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7. Procédé selon l'une quelconque des revendications 1 à 6, étant entendu que le compresseur (141-144) de tête de puits est un compresseur à vis.
8. Procédé selon l'une quelconque des revendications 1 à 7, étant entendu que le rendement énergétique consiste en un rendement énergétique volumétrique, en particulier une utilisation d'énergie par m³ de fluide pompé.

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9. Dispositif servant à faire fonctionner un compresseur de tête de puits, le compresseur étant configuré en vue de pomper des fluides à partir d'un puits à une

pression de colonne de production, le dispositif comprenant :

un processeur (404), et
 une mémoire (406) configurée en vue de conserver des instructions, qui, quand elles sont exécutées par le processeur, amènent le processeur à exécuter les étapes du procédé consistant à faire fonctionner un compresseur de tête de puits selon la revendication 1.

FIG 1

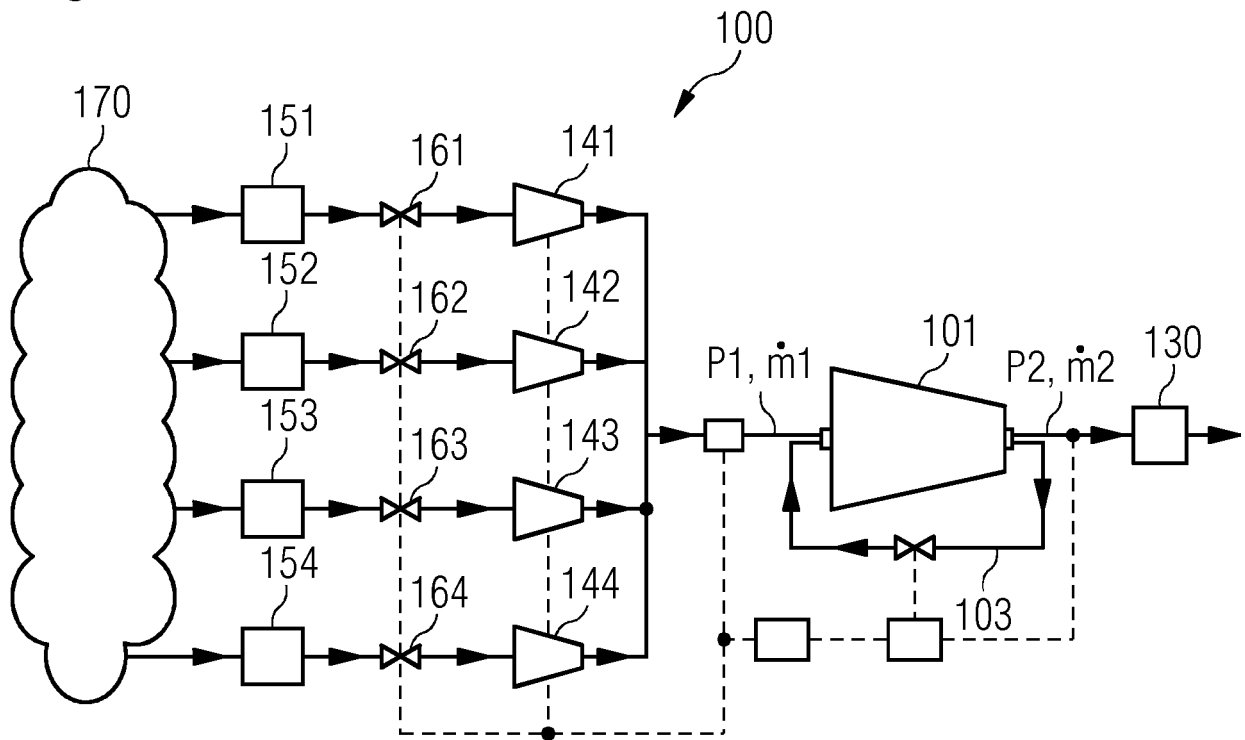


FIG 2

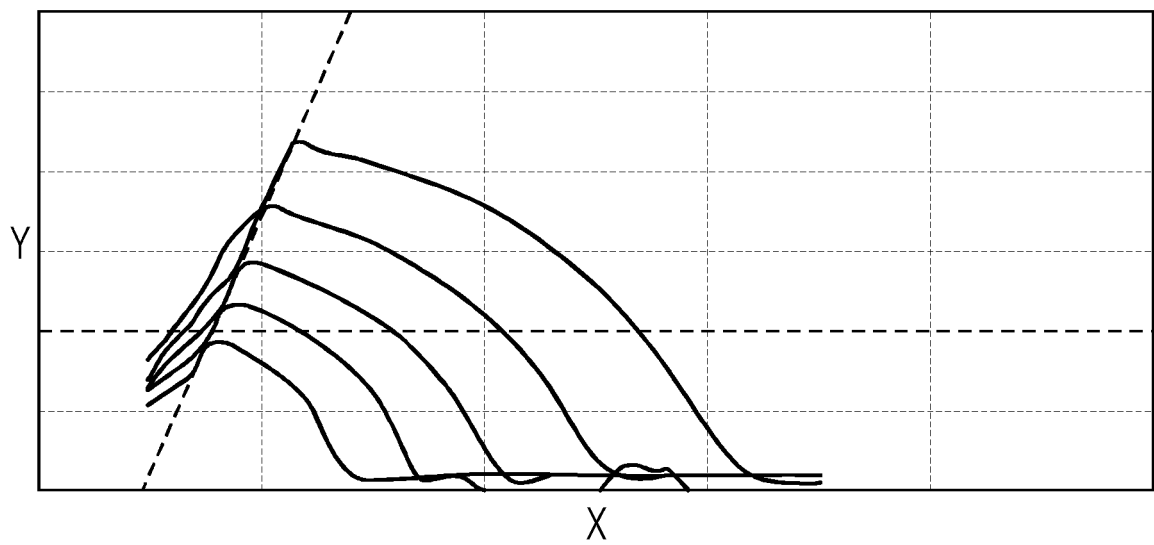


FIG 3

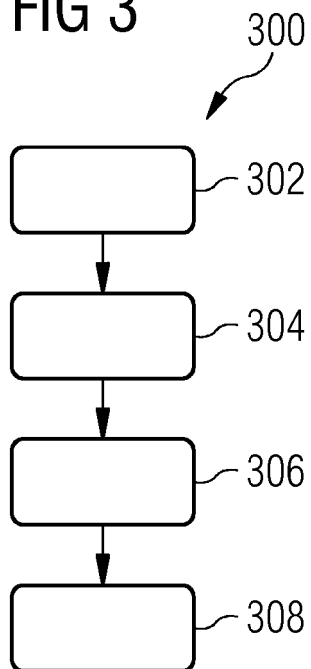


FIG 4

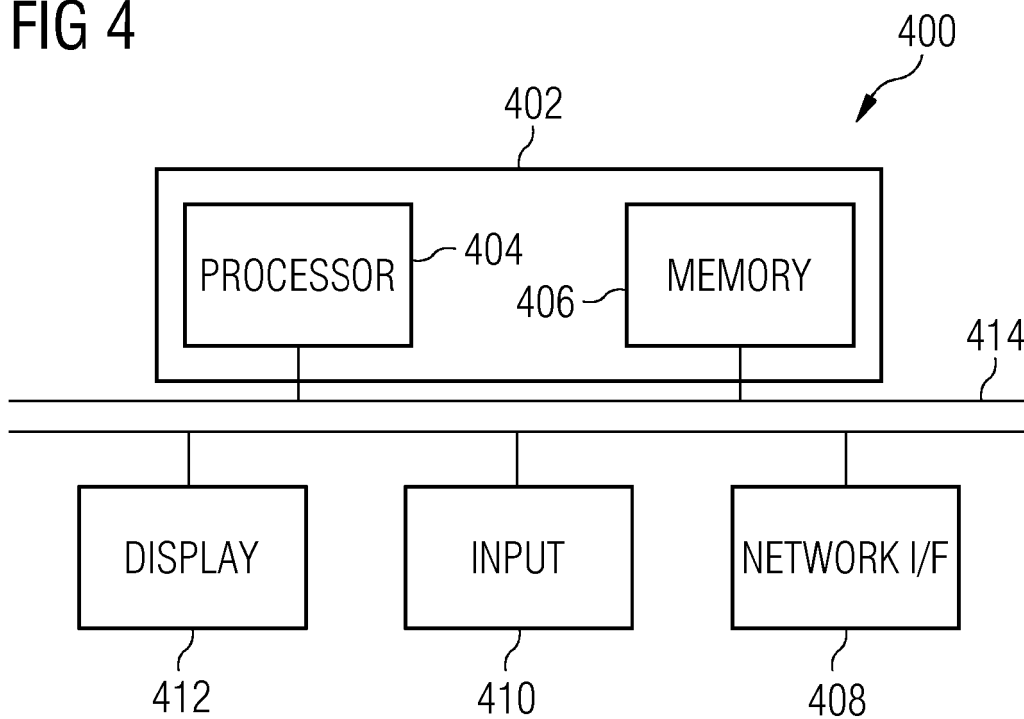


FIG 5A

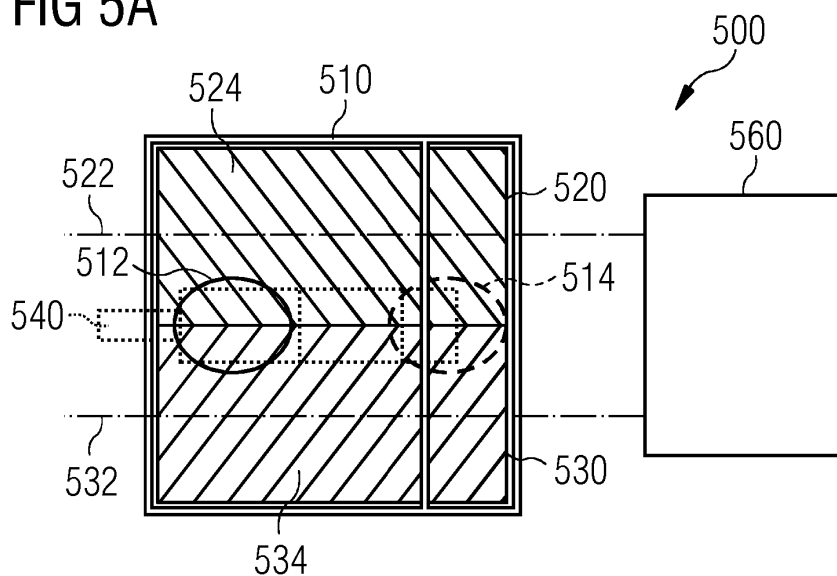


FIG 5B

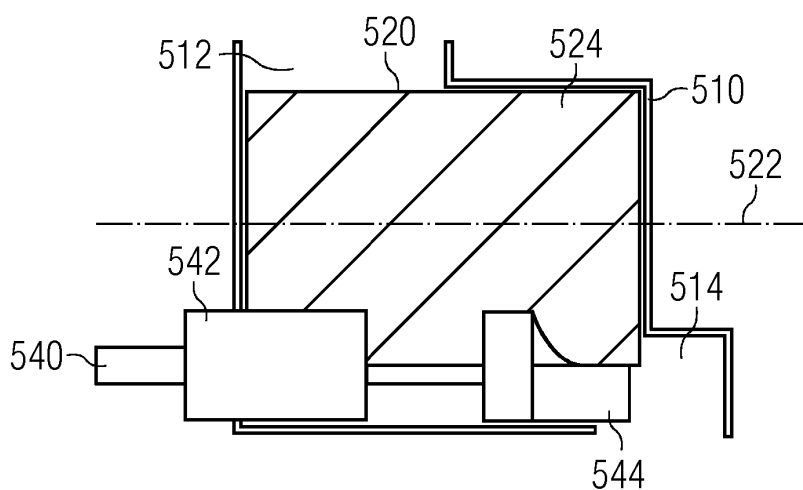


FIG 6

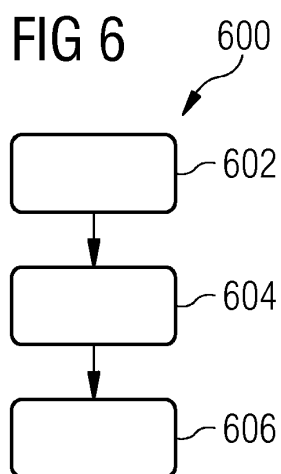


FIG 7

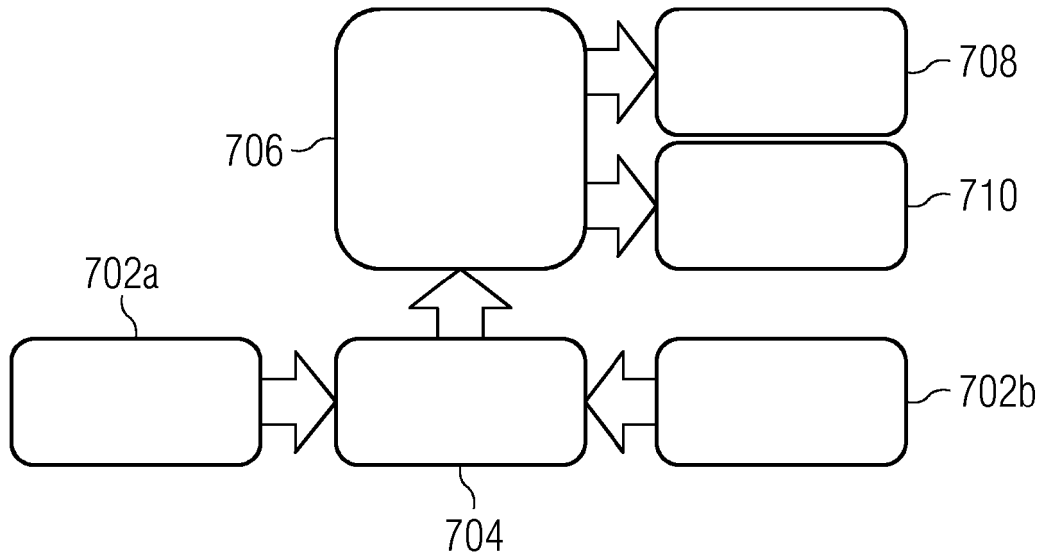
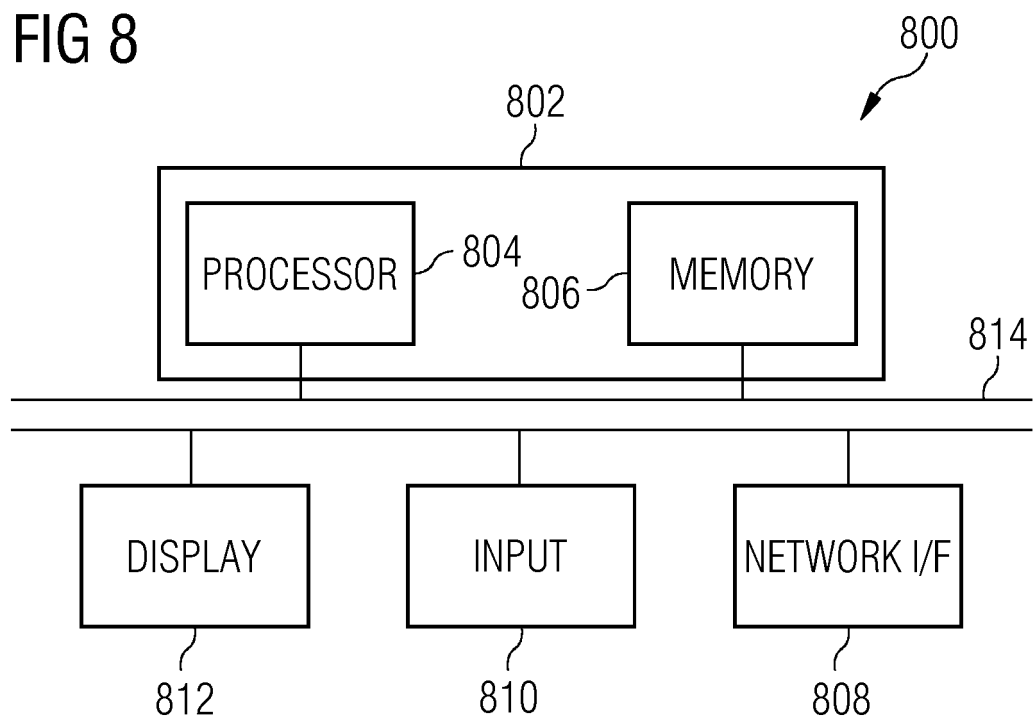


FIG 8



REFERENCES CITED IN THE DESCRIPTION

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