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(54) Title: METHOD FOR PRODUCTION METERING OF OIL WELLS

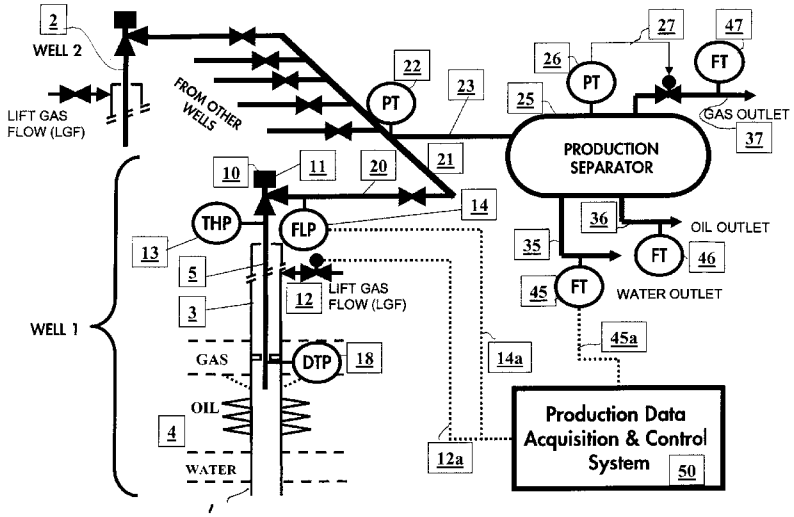


Fig 1: Production from a Cluster of Wells to a Production Separator

(57) Abstract: The present invention relates to a method that allows the determination of the contribution of a well to the production of a cluster of wells, of which the produced streams of well effluents are commingled and routed via a separation assembly in at least nominally separated streams of crude oil, natural gas and water, based on production measurements made on the nominally separated streams of crude oil, natural gas and water downstream of the separation assembly (production and/or bulk separator), and in the absence of a dedicated well test facility for the direct measurement of the production from a tested well.

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METHOD FOR PRODUCTION METERING OF OIL WELLS

BACKGROUND OF THE INVENTION

The present invention relates to a method for determining the contributions of individual wells to the production of a cluster of wells and/or of individual well segments to the production of a well and/or a cluster of wells.

Typically, well effluent fluid streams produced by individual wells of a well cluster are commingled on a header (manifold) and routed via a fluid stabilization and separation assembly (comprising one or more bulk or production separators). The well effluent fluid is separated in the production separator into nominally single-phase streams of oil, water, gas and/or other fluids (or optionally, a gross liquid phase comprising oil and water, and a gas phase). The separated single-phase fluids are thereafter routed to the production separator outlet conduits for metering, transportation and sales.

A problem associated with management of fluid flow at the outlets of the production separator is that this fluid flow stems from the commingled production (or "flux") from some or all the wells of the cluster and at first glance the metering data does not provide information about the oil, water and gas (or liquid and gas) production by the individual wells. Multiphase well effluent meters are often too expensive, have too restricted an operating envelop and are too complex to install on individual well flowlines to allow individual oil, water and gas components of the well production to be measured continuously in real time, particularly as

the well effluent composition and associated flow characteristics may change significantly over the life of the well. Furthermore, multiphase well effluent meters may require calibration at start up and/or from time to time. Consequently, the production of fluids by the individual wells is not customarily tracked accurately continuously, or in real time or instantaneously. Customarily, a well testing facility is consequently made available to be shared among a cluster of wells. The production from the wells are individually in turn routed to the well testing facility in which the individual oil, water and gas components of the production are determined directly, without interruption to the production of the other wells, and used as representative of the well production during normal production.

Well testing facilities and their associated well production routing valve manifolds, in spite of being shared by all the wells in the cluster of wells, are commonly regarded to be expensive, bulky and difficult to operate and maintain. In many cases, such well test facilities are not available.

In the case where well test facilities are not available, individual nominal well productions can be conventionally estimated by three methods. The first method (A) is the simple method of producing each well individually in turn, while all other wells are closed in from production, thus resulting in significant production deferment.

A second approach (B) is "piggy back testing", that is, by testing one well and establishing its nominal production, and thereafter putting a second well into production, thereby computing the estimated nominal production of the second well by subtracting the nominal production from the first well from the measured

production while the second well was also producing and so on.

A third method (C) is "testing by difference" ("TBD"), the practice of shutting in one well and measuring the consequent difference in commingled production before and after the shut in of the well. The difference in production levels is then an estimate of the nominal production of the well. Method (C) causes less production deferment than methods (A) and (B), but is nevertheless has drawbacks, including the deferment of production of the tested well during the test period..

International patent application WO03/046485 discloses a production metering and well testing system, wherein the accumulated production of wells of an entire field is measured downstream of a production separator in which the produced fractions of crude oil, water, natural gas, solids and/or condensates are separated and the flux and composition of the produced crude oil and/or other fractions can be accurately monitored. This accurate measurement of the accumulated production of wells of an entire field is made simultaneously, and compared, with less accurate measurements upstream well effluent flow measurements that are taken simultaneously at each individual well.

Applicant's International patent application PCT/EP2005/055680, filed on 1 November 2005, "Method and system for determining the contributions of individual wells to the production of a cluster of wells" describes a method and system, which are hereafter referred to as "Production Universe Real Time Monitoring" (PU RTM).

The PU RTM method allows accurate real time estimation of the contributions of individual wells to the total commingled production of a cluster of crude oil, gas and/or other fluid production wells, based on

well models derived from well test data and updated regularly using commingled production dynamic data.

In the PU RTM method known from International patent application PCT/EP2005/055680 "well production estimation models" or “fingerprints” are made to identify the production of individual wells under a variety of operating conditions on the basis of "Deliberately Disturbed Well Tests" ("DDWTs") using dedicated well test facilities. DDWTs are well tests in which the well tested is routed to a dedicated well test facility, and thereafter disturbed to activate its intrinsic dynamics and to produce at multiple production rates over its entire potential operating range. The "well production estimation models" generated are then used in conjunction with a dynamic reconciliation system for accurately estimating productions individual well productions continuously in real time. However, in many cases, no well test facility is available, and the interruption of the production of the rest of the wells in a cluster of wells, to directly measure the production of one well using production measurements downstream of the separation assembly (production separator) is not permissible due to the consequent production deferment.

It is an object of the present invention to provide a method and system which allow the determination of the contribution of a well to the production of a cluster of wells, of which the produced streams of well effluents are commingled and routed via a separation assembly in at least nominally separated streams of crude oil, natural gas and water, based on production measurements made on the nominally separated streams of crude oil, natural gas and water downstream of the separation assembly (production and/or bulk separator), and in the absence of a dedicated well test facility for the direct measurement of the production from a tested well.

SUMMARY OF THE INVENTION

In accordance with one aspect of the invention there is provided a method for determining the contributions of individual wells to the production of a cluster of wells of which the well effluent streams are commingled and routed via a fluid separation assembly into fluid outlet conduits for transportation of at least partly separated streams of crude oil, gas and/or other fluids, the method comprising:

a) providing flow meters for measuring fluid flow in the fluid outlet conduits of the fluid separation assembly, and providing well monitoring equipment for monitoring one or more production variables, such as pressure and/or other characteristics, relating to well effluent streams of individual wells;

b) sequentially testing wells of the well cluster by performing a well test during which production from a tested well is varied;

c) monitoring during step b one or more production variables by the monitoring equipment and simultaneously measuring by means of the flow meters at the fluid outlet conduits of the fluid separation assembly any variation of the flow pattern of effluents produced by the cluster of wells, including the tested well, and obtaining from the measured variation an estimate of the production of the tested well during the well test;

d) deriving from steps b and c a well production estimation model for each tested well, which model provides a correlation between variations of one or more production variables monitored by the monitoring equipment and the estimate of the production of the well during the well test as measured by the flow meters;

e) producing oil and/or gas from the cluster of wells whilst a dynamic fluid flow pattern of the accumulated well effluent streams produced by the cluster of wells is

measured by means of the flow meters and one or more production variables of each well are monitored by the well monitoring equipment;

f) calculating during step e an estimated contribution of each well to the production of fluids by the cluster of wells on the basis of the production variables monitored by the well monitoring equipment and the well production estimation model derived in step d;

g) calculating an estimated dynamic flow pattern at the fluid outlets of the fluid separation assembly over a selected period of time by accumulating the estimated contributions of each of the wells made in accordance with step f over the selected period of time; and

h) iteratively adjusting from time to time for each well the well production estimation model for that well until across the selected period of time the accumulated estimated dynamic flow pattern calculated in accordance with step g substantially matches with the monitored dynamic fluid flow pattern monitored by the flow meters in the fluid outlet conduits of the fluid separation assembly.

Optionally, the cluster of wells comprises a number of n wells i, such that $=2,3,\ \ldots\ $, and step h comprises the steps of:

- expressing the well production estimation model for each well i as $y_i(t) = f_i(u_{1i}(t), u_{2i}(t)...)$, wherein $y_i(t)$ is the well effluent fluid flow pattern of well i as monitored at time t, and are production variables of well i, such as pressure and/or other characteristics relating to the well effluent fluid stream in the well monitored during the well test and during normal well production by the monitoring equipment of well i;

- expressing the estimated dynamic fluid flow pattern at the fluid outlets of the fluid separation assembly as

$$y(t)_{estimated} \cong \sum_{i=1}^{n} \gamma_i y_i(t)$$

,

wherein γ_i are initially unknown weight coefficients, which are uniform across the selected period of time;

- expressing the monitored fluid flow pattern, which is measured by the flowmeters in the outlet conduits of the separation assembly, as $y(t)$ monitored;

- comparing $y(t)$ monitored with $y(t)$ estimated and

- estimating a value of each of the weight coefficients γi by iteratively varying the weight coefficients γi until $y(t)$ estimated substantially equals $y(t)$ monitored.

In such case a mathematical reconciliation process may be used to obtain the value of each of the weight coefficients γ_i.

Each of the wells of the well cluster may be tested for characterization by performing a series of actions during which production from a tested well is varied, including closing in the well production for a period of time, and then production of the tested well is started up in steps such that the tested well is induced to produce at multiple production rates over a normal potential operating range of the well, which test is hereinafter referred to as a Deliberately Disturbed Well Testing by Difference (DDWTBD).

Furthermore, a sequence of well tests may be performed such that sequentially each of the wells of the well cluster is tested for characterization by initially closing in all the wells in the cluster, and subsequently starting up one well at a time, in sequence, with wells individually started up in steps to produce at multiple production rates over the normal potential operating range of the well, which sequence of well tests is

referred to as "Deliberately Disturbed Production Testing" (DDPT), from which well tests:

- an estimate of the production of a first well to be started up is directly obtained from the well test of the first well, and the well production estimation model is calculated for that well
- the production from the second well to be started-up up is derived from subtracting the production of the first well using the well model of the first well already established and
- the production and well production estimation model of the third and any subsequently started well are computed in sequence of their start-ups, thereby obtaining the well production estimation model of each well of the well cluster.

Optionally the well production estimation model for each of the wells is constructed by combining data from:

- performing a Testing by Difference (TBD)test, whereby a base well production is established by interrupting the individual well production for a period of time, while monitoring by means of the flowmeters in the fluid outlet conduits of the fluid separation assembly the variation of the flow pattern of effluents produced by the cluster of wells, thereby obtaining an estimate of the base well production of the well of which production has been interrupted, and
- performing an extended Deliberately Disturbed Well Test (eDDPT), during which the measurements from fluid outlets of the fluid separation assembly are recorded over a period of time together with the measurable quantities at all the wells.
- the well production estimation models for all the wells of the well cluster are constructed simultaneously to provide a best fit to the TBD and the eDDPT data collected.

Each well production estimation model may have a static and a dynamic part, wherein the static part is constructed by comparing the outcome of a plurality of alternative curve fitting approaches and the dynamic part is constructed by comparing the outcome of a plurality of alternative dynamic identification approaches.

If two or more well test data set accumulated over a period of time are available, then optionally, the "well production estimation models" can additionally incorporate a "well decline factor" which will be a function of time. The decline factor is computed as a best fit to allow the "well production estimation models" to reflect the decline of well production due to the inherent decrease in well potential as a function of cumulative well production.

The tests "DDPTBD" or "TBD" plus "eDDPT" can both or in combination be used to generate "well production estimation models" for each well in a cluster of wells with commingled production channelled into a production separator with measurements on its single phase outlet flows. It is noted that "eDDPT" data need not be obtained from dedicated testing, but often be directly obtained from the historic production record of the cluster of wells.

It is observed that the optional "DDWTBD", "TBD" and/or "eDDPT" tests apply to two specific but economically important special cases. The first special case is that of oil and gas production wells that have multiple individual producing zones, each with its own production control devices and measurement. The second special case is that where multiple subsea wells share a single pipeline to surface production facilities, and which have no subsea well test facilities or dedicated pipeline for routing flow from individual wells to surface well testing facilities. In both the above

cases, the method according to the invention is essential to allow the derivation of "well (or zone) production estimation models" of each individual well in the well cluster, at an acceptable deferment of production, which in turn allows the continuous real time production monitoring of the production of individual well zones or subsea wells.

Optionally the methods (A), (B) and (C) above, in particular the methods (B) and (C), may be incorporated in the method according to the invention.

In a preferred embodiment of the invention use is made of commonly available real time or instantaneous measurements at each surface or sub-sea well or subsurface zone, preferably one or more of the following measurements: well tubing head or casing head or flow line or down hole tubing and annulus pressures, temperatures, surface or sub-sea well choke valve positions, subsurface zone interval control valve positions, and measures of energy applied for artificial lift of the individual well production, including lift gas or hydraulic fluid injection flows, electric submersible pump or beam pump power and so on.

In accordance with another aspect of the invention there is provided a method in accordance with claim 14 for determining the contributions of one or more segments of an segmented inflow region of a multi-zone and/or multilateral well to the production of the multi-zone and/or multilateral well and/or of a cluster of wells.

These and further embodiments, advantages and features of the method according to the invention are described in the accompanying claims, abstract and the following detailed description of a preferred embodiment of the method according to the invention in which reference is made to the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 schematically shows a crude oil and/or natural gas production system comprising a cluster of wells; and

FIG.2 illustrates a multi-zone well with segments that form different inflow regions.

DETAILED DESCRIPTION OF PREFERED EMBODIMENTS OF THE INVENTION

A preferred embodiment of the computation of the "well production estimation model" either from "TBD" for each well, and a "eDDPT", or from a set of "DDWTBD" for each well, is as follows:

- The cluster of wells may comprise a number of n wells indexed $i=1,2,\ldots,n$, and the method may comprise the steps of
- expressing the "well production estimation model" for each well i as $y_i(t)=\alpha_i+f_i(\beta_i,u_{1i}(t),u_{2i}(t),\ldots)$, wherein the vector $y_i(t)$ is the well effluent fluid flow pattern of well i as monitored throughout the period of time t of the well test , $u_{1i}(t),u_{2i}(t),\ldots$ are the dynamic measurements at well i that are determined during the well test, and $\alpha_i+f_i(\beta_i,u_{1i}(t),u_{2i}(t),\ldots)$ is the "well production estimation model" (alternatively dynamic fingerprint / mathematical functional) relating $y_i(t)$ to $u_{1i}(t),u_{2i}(t)\ldots$, parameterised by vectors α_i and β_i, with $f_i(\beta_i,\hat{u}_{1i},\hat{u}_{2i},\ldots)=0$ for all β_i for some nominal set of well operating measurements $\hat{u}_{1i},\hat{u}_{2i},\ldots$. In this embodiment of the mathematics, $f_i(\beta_i,u_{1i}(t),u_{2i}(t),\ldots)$ can be viewed as the "gain" of the "well production estimation model" about the nominal operating point $\hat{u}_{1i},\hat{u}_{2i},\ldots$, and α_i can be viewed as the "bias" or "offset" or "anchor" about that operating point, and the function(al) $f_i(\beta_i,u_{1i}(t),u_{2i}(t),\ldots)$ can be linear or non-linear but in any case parameterised by the vector β_i;

- computing α_i from a "TBD" on the well i for wells, via a straightforward averaging and subtraction process, and thereafter computing β_i simultaneously for all the wells from "eDDPT" data, for example, via a mathematical best fit using least squares.

- or, optionally, computing α_i and β_i from a "DDWTBD" for each well, for example, via a mathematical best fit using least squares.

The foregoing procedure is further explained hereinbelow.

The "well production estimation model" obtained from the preceding steps for each individual well may then be inserted into "PU RTM".

FIG.1 schematically shows a crude oil and/or natural gas production system comprising a cluster of wells, including wells 1 and 2. No dedicated well testing facility where the production of a well can be separately and directly metered, with no interruption to the production of the other wells, is available.

The well 1 (typical for well 2, and the other wells) comprises a well casing 3 secured in a borehole in the underground formation 4 and a production tubing 5 extending from surface to the underground formation. The well 1 further includes a wellhead 10 provided with well measurement equipment, typically a pressure transmitter 13 for measuring Tubing Head Pressure (THP). Optionally, there may be a Flowline Pressure (FLP) transmitter 14, or lift gas flow measurement 12, or subsurface pressure gauges and/or other downhole production measurement equipment available, for example a downhole Downhole Tubing Pressure (DTP) gauge 18 (also Fig. 2, item 66), or flowline differential pressure meters, for example wet gas meters (not shown). The well 1 also may have means of adjusting production, such as a production control choke 11, a fixed bean choke (not shown) and / or lift-

gas injection 12 or downhole interval control valves (Fig. 2, item 67).

The production system further includes well effluent well production flow lines 20, extending from the wellheads 10 to a production header 21, and a production separator 25.

The production separator 25 is provided with outlets for water, oil and gas 35, 36 and 37 respectively. Each outlet 35, 36 or 37 is provided with flow metering devices, 45, 46 and 47 respectively. Optionally, the water and oil outlets can be combined. The production separator pressure 26 may be controlled by regulating the gas flow from gas outlet 37, thereby affecting the flowline pressure 14 and the production of the individual wells.

The well measurements comprising at least data from 13 and optionally from 14, 18, lift gas injection rate from 12, position of production choke 11, and so on, are continuously transmitted to a Production Data Acquisition and Control System 50. Similarly, the commingled production measurements 45, 46, 47 are continuously transmitted to the Production Data Acquisition and Control System 50. The data transferred to the Production Data Acquisition and Control System is stored for real time and subsequent data retrieval for analysis and "well production estimation model" construction as outlined in this patent. The typical data transmission paths are illustrated as 14a and 45a. The data in the Production Data Acquisition and Control System are also accessed by PU RTM in real time for use in conjunction with "well production estimation models" for the continuous real time estimation of individual well productions.

For "Testing by Difference" ("TBD") and "DDWT by Difference" ("DDWTBD"), the well measurements from the

wells in the cluster, particularly the tubing head pressures 13 of the wells, and the commingled production measurements 45, 46, 47 are initially monitored to confirm a period of stable production for all wells in the cluster. The well to be tested by difference, say well 1, is then shut in, for example, by fully closing its production choke valve 11. The production flow measurements 45, 46, 47 are then monitored. The tubing head pressures for the other wells are also monitored and preferably, if the tubing head pressures of the other wells substantially change after the shutdown of the well on test, the production choke valves of the other wells, or optionally, the pressure of the separator, should be adjusted to return the tubing head pressures of the wells not on test to the pressures prior to the shutdown of the well on test. Similarly, as the well on test is ramped in steps up to its normal production as part of the "DDWTBD", adjustments should be made to return the tubing head pressures of the wells not on test to the pressures prior to the shutdown of the well on test.

It is noted that a fundamental challenge to the characterization of wells during "TBD" or "DDWTBD" is that the baseline production of other wells may increase during the close-in of the well under test. This is due to the flow phenomenon of "well interaction" in which changes of commingled production at the production separator or the production header will cause corresponding changes in production separator pressure or header pressure. The phenomenon is more prominent if the wells are producing at low tubing head pressures with respect to the flowline pressures, or when the production separator pressure is not regulated at a setpoint, but is left to depend on gas export outlet pressure. Conversely, the phenomenon is less prominent and negligible if the wells are all producing at high tubing head pressures

with respect to the flowline pressures, and when the production separator pressure is regulated at a setpoint.

Let the commingled oil, water and gas flow measurements at the production separator be denoted by the vector

$$s(t)=\sum_{i=1}^{N}\bar{y}_i(t),$$

where $\bar{y}_i(t)$ are the corresponding vector of actual well production flows from well i. Let $S_1 := average(s(t)),\ t\in T_1$, where T_1 is the interval during the close in of the well under test. The estimate of the production of the well i over the interval T_2 of the DDWTBD test is then $\breve{y}_i(t) := s(t) - S_1$, for $t\in T_2$. Given the model structure, $y_i(t)=\alpha_i + f_i(\beta_i, u_{1i}(t), u_{2i}(t),...)$, where $y_i(t)$ the estimate of well i production at time t, then the modelling process reduces to one of minimizing an appropriate mathematical norm of the modelling fit error $y_i(t)-(s(t)-S_1)$ over the interval T_2 by choosing appropriate vectors α_i and β_i.

For "Extended Deliberately Disturbed Production Testing" ("eDDPT"), a "TBD" requires to first be performed for all wells. For each well i, a "TBD" is conducted to estimate the well production. As for DDWTBD, the well measurements from the wells in the cluster, particularly the tubing head pressures 13 of the wells, and the commingled production measurements 45, 46, 47 are initially monitored to confirm a period of stable production for all wells in the cluster. Let $\hat{u}_{1i}, \hat{u}_{2i}, ...$ then be the nominal set of well i operating measurements in the initial period, T_0, and let $S_0 := average(s(t)),\ t\in T_0$. Hence if $S_1 := average(s(t)),\ t\in T_1$, where T_1 is the interval during the close in of the well i under test, then $\alpha_i = S_0 - S_1$ can be viewed as the "bias" or "offset" or

"anchor" about operating point $\hat{u}_{1i},\hat{u}_{2i},\cdots$. The procedure is repeated for all wells $i=1,2,\ldots,n$ for which models need to be constructed via eDDPTs. "eDDPT" data is then gathered for a period T_3 in which all the wells have variations about their nominal operation points. Using the "eDDPT" production measurement data, $s(t)$, then the vectors β_i for $i=1,2,\ldots,n$ are computed to minimize an appropriate mathematical norm of the modelling fit error

$$s(t)-\sum_{i=1}^{n} y_i(t) \quad = \quad s(t)-\sum_{i=1}^{n}\alpha_i + f_i(\beta_i,u_{1i}(t),u_{2i}(t),\ldots)$$

over the interval T_3.

In the case where multiple data sets are available over a period of time, then the "well production estimation model" for each well i can be expressed as $y_i(t)=\alpha_i(t)+f_i(\beta_i,t,u_{1i}(t),u_{2i}(t),\ldots)$ or optionally $y_i(t)=d(t)\left[\alpha_i(t)+f_i(\beta_i,t,u_{1i}(t),u_{2i}(t),\ldots)\right]$, where an explicit decline function $d(t)$ has been inserted. The computations for the models then follow as before. The application the decline factor is important in the case where test data has been accumulated over a long period of time, or if the duration T_3 in the eDDPT is significant.

The invention has important and significant application to oil, water and gas production systems in the case where one or more wells in the cluster of wells have, at subsurface (or downhole) level, multiple fluid producing zones or branches. In the sequel the details are illustrated by reference to a multizone well, but the principles are equally applicable to a multi-branch or a multilateral well.

FIG.2 illustrates a multizone well 60 with tubing 5 extending to well segments, which form three distinct producing zones 62, 63, 64. Each zone has means of measuring the variations of thermodynamic quantities of

the fluids within zone as the fluid production from the zone varies, and these can include downhole tubing pressure gauges 66 and downhole annulus pressure gauges 65. Each zone may also have a means for remotely adjusting the production through the zone from the surface, for example, an interval control valve 67, either on-off or step-by-step variable or continuously variable. The multizone well 60 further includes a wellhead 10 provided with well measurements, for example, "Tubing Head Pressure" 13 and "Flowline Pressure" 14. The well 60 may also have some means of adjusting production at the surface, for example a production control choke 11. The well 60 produces into a multiphase well effluent flowline 20, extending from the well to a production header (already shown on FIG.1).

The multizone well 60 can be part of a cluster of wells producing to a production separator with or without a dedicated well test facility, or optionally, the multizone well 60 can have a dedicated well effluent meter that directly measures its production. In any case, if more than one zone of the well is producing, the direct measurement of the production from one of the zones is not possible without interruption of the continued production from the other zones. As such, both the approaches of:

- "DDWT by Difference" ("DDWTBD");
- "Testing by Difference" ("TBD") followed by "Extended Deliberately Disturbed Production Testing" ("eDDPT");

are directly applicable for the characterization of the production of the individual zones to generate Zone Production Estimation Models that relate $z_j(t)$, the well effluent fluid flow pattern of zone j, where $j=1,2,\ldots,m$, for a well with m zones, at time t to $u_{1j}(t),u_{2j}(t),\ldots$, the dynamic measurements at zone j. Continuous real time

estimates of zone j production can then be generated using Zone Production Estimation Models based on the measurements $u_{1j}(t),u_{2j}(t),\ldots$ available continuously in real time.

The Zone Production Estimation Models can be parameterized to be of the form $z_j(t)=\alpha_j+f_j(\beta_j,u_{1j}(t),u_{2j}(t),\ldots)$ with vectors α_j and β_j, and with $f_j(\beta_j,\hat{u}_{1j},\hat{u}_{2j},\ldots)=0$ for all β_j for some nominal set of zone operating measurements $\hat{u}_{1j},\hat{u}_{2j},\ldots$. The vectors α_j and β_j are computed using best fit methods based on DDWTBD or TBD plus eDDPT as outlined above.

If the production at the surface is then estimated or measured as $y_{MZ}(t)$ then dynamic reconciliation over a time period T_{MZ} can be used to improve the continuous real time estimates of the production from each zone. This is can be achieved by computing the set γ_j, $j=1,2,\ldots,m$, so that

$$\sum_{j=1}^{m}\gamma_j z_j(t)$$

have best fit to $y_{MZ}(t)$ over the period of time T_{MZ}. The improved estimates for zone j production at time t are then given by $\gamma_j z_j(t)$.

C L A I M S

1. A method for determining the contributions of individual wells to the production of a cluster of wells of which the well effluent streams are commingled and routed via a fluid separation assembly into fluid outlet conduits for transportation of at least partly separated streams of crude oil, gas and/or other fluids, the method comprising:

a) providing flow meters for measuring fluid flow in the fluid outlet conduits of the fluid separation assembly, and providing well monitoring equipment for monitoring one or more production variables, such as pressure and/or other characteristics, relating to well effluent streams of individual wells;

b) sequentially testing wells of the well cluster by performing a well test during which production from a tested well is varied;

c) monitoring during step b one or more production variables by the monitoring equipment and simultaneously measuring by means of the flow meters at the fluid outlet conduits of the fluid separation assembly any variation of the flow pattern of effluents produced by the cluster of wells, including the tested well, and obtaining from the measured variation an estimate of the production of the tested well during the well test;

d) deriving from steps b and c a well production estimation model for each tested well, which model provides a correlation between variations of one or more production variables monitored by the monitoring equipment and the estimate of the production of the well during the well test as measured by the flow meters;

e) producing oil and/or gas from the cluster of wells whilst a dynamic fluid flow pattern of the accumulated

well effluent streams produced by the cluster of wells is measured by means of the flow meters and one or more production variables of each well are monitored by the well monitoring equipment;

f) calculating during step e an estimated contribution of each well to the production of fluids by the cluster of wells on the basis of the production variables monitored by the well monitoring equipment and the well production estimation model derived in step d;

g) calculating an estimated dynamic flow pattern at the fluid outlets of the fluid separation assembly over a selected period of time by accumulating the estimated contributions of each of the wells made in accordance with step f over the selected period of time; and

h) iteratively adjusting from time to time for each well the well production estimation model for that well until across the selected period of time the accumulated estimated dynamic flow pattern calculated in accordance with step g substantially matches with the monitored dynamic fluid flow pattern monitored by the flow meters in the fluid outlet conduits of the fluid separation assembly.

2. The method of claim 1, wherein the cluster of wells comprises a number of n wells i, such that $i = 1,2,3,\ldots,n$, and step h comprises the steps of

- expressing the well production estimation model for each well i as $y_i(t) = f_i(u_{1i}(t), u_{2i}(t)\ldots)$, wherein $y_i(t)$ is the well effluent flow pattern of well i as monitored at time t, and $u_{1i}, u_{2i}\cdots$ are production variables of well i, such as pressure and/or other characteristics relating to the well effluent stream in the well monitored during the well test and during normal well production by the monitoring equipment of well i;

- expressing the estimated dynamic fluid flow pattern at the fluid outlets of the fluid separation assembly as

$$y(t)_{estimated} \cong \sum_{i=1}^{n} \gamma_i y_i(t)$$

,

wherein γ_i are initially unknown weight coefficients, which are uniform across the selected period of time;

- expressing the monitored fluid flow pattern, which is measured by the flowmeters in the outlet conduits of the separation assembly, as $y(t)$ monitored;

- comparing $y(t)$ monitored with $y(t)$ estimated and

- estimating a value of each of the weight coefficients γi by iteratively varying the weight coefficients γi until $y(t)$ estimated substantially equals $y(t)$ monitored.

3. The method according to claim 2, wherein a mathematical reconciliation process is used to obtain the value of each of the weight coefficients γ_i.

4. The method according to claim 1, wherein each of the wells of the well cluster is tested for characterization by performing a series of actions during which production from a tested well is varied, including closing in the well production for a period of time, and then production of the tested well is started up in steps such that the tested well is induced to produce at multiple production rates over a normal potential operating range of the well, which test is referred to as a Deliberately Disturbed Well Testing by Difference (DDWTBD).

5. The method according to claim 1, wherein a sequence of well tests is performed such that sequentially each of the wells of the well cluster is tested for characterization by initially closing in all the wells in the cluster, and subsequently starting up one well at a time, in sequence, with wells individually started up in steps to produce at multiple production rates over the normal potential operating range of the well, which

sequence of well tests is referred to as Deliberately Disturbed Production Testing (DDPT), from which well tests:

- an estimate of the production of a first well to be started up is directly obtained from the well test of the first well, and the well production estimation model is calculated for that well
- the production from the second well to be started-up up is derived from subtracting the production of the first well using the well model of the first well already established and
- the production and well production estimation model of the third and any subsequently started well are computed in sequence of their start-ups, thereby obtaining the well production estimation model of each well of the well cluster.

6. The method according to claim 1, wherein the well production estimation models are constructed by combining data from:

- performing a Testing by Difference (TBD)test, whereby a base well production is established by interrupting the individual well production for a period of time, while monitoring by means of the flow meters in the fluid outlet conduits of the fluid separation assembly the variation of the flow pattern of effluents produced by the cluster of wells, thereby obtaining an estimate of the base well production of the tested well , and
- performing an extended Deliberately Disturbed Production Test (eDDPT), during which the measurements by the flow meters in the fluid outlet conduits of the fluid separation assembly are recorded over a period of time together with the measurable quantities at all the wells.
- the well production estimation models for all the wells of the well cluster are constructed simultaneously

to provide a best fit to the TBD and the eDDPT data collected.

7. The method of claim 1, wherein the well production estimation model has a static and a dynamic part and the static part is constructed by comparing the outcome of a plurality of alternative curve fitting approaches and the dynamic part is constructed by comparing the outcome of a plurality of alternative dynamic identification approaches.

8. The method of claim 1, wherein the method is applied to oil and gas production wells that have multiple individual producing zones or branches subsurface, each with its own production control and measurement devices.

9. The method of claim 1, wherein the method is applied to a cluster of oil and gas production wells located subsea, which share a single pipeline to surface production facilities, and which have no subsea well test facilities or dedicated pipeline for routing flow from individual wells to surface well testing facilities.

10. The method according to claim 1, wherein during the well test in accordance with step b production of the tested well is varied whereas production from other wells of the well cluster is maintained substantially constant.

11. The method of claim 1, wherein the wells of the well cluster traverse a single underground oil and/or gas bearing formation.

12. The method of claim 1, wherein the wells of the cluster of wells traverse a plurality of oil and/or gas bearing formations and/or production zones that optionally are subject to different commercial or legal production conditions.

13. The method of claim 1, wherein the monitoring equipment comprises means for monitoring one or more of the following production variables, such as pressure

and/or other characteristics relating to the well effluent stream:

- well tubing head pressure;
- well flowline pressure;
- well tubing head temperature;
- well flowline temperature;
- differential pressures across a well production choke valve;
- differential pressures across any differential pressure producer ,such as a wet gas venturi, on a well flowline;
- flow meters,such as flow meters nominally suitable only for single phase flow, that are used as inputs to well estimation models, even when wells have multiphase flow;
- well production choke valve opening;
- state or position of any means of reversible and controlled closing in and opening up of a well;
- well lift-gas injection rate;
- well jet pump hydraulic fluid injection rate;
- well production casing pressure;
- well electrical submersible pump (ESP) speed;
- well ESP intake pressure;
- well ESP down hole pump discharge pressure;
- well ESP down hole venturi differential pressure;
- well ESP power;
- well ESP motor phase current ;
- well rod pump motor power input;
- well rod pump motor speed;
- well rod pump stroke displacement;
- well rod pump load cell;
- beam pump gear box shaft position;
- well rod pump differential speed, including motor/gear box slip;
- downhole well tubing pressure;
- downhole well annulus pressure;

- downhole well tubing temperature, or various derivations thereof from distributed temperature sensors;
- downhole well annulus temperature, or various derivations thereof from distributed temperature sensors;
- downhole well interval or well segment control valve opening,
- amplitude of a selection of sound frequencies from one or more sound sensors mounted on a well flowline;
- propagation delay of correlated sound patterns at a selection of frequencies from two or more sound sensors mounted in an upstream-downstream direction on well flowline.

14. A method for determining the contributions of one or more segments of a segmented inflow region of a multi-zone and/or multilateral well to the production of a cluster of segments of a multi-zone and/or multilateral well and/or of a cluster of wells, wherein well effluent streams produced by the segments of the multi-zone and/or multilateral well and optionally by other oil, gas and/or other fluid production wells of the cluster of wells, are commingled and routed via a fluid separation assembly into fluid outlet conduits for transportation of at least partly separated streams of crude oil, gas and/or other fluids, the method comprising:

a) arranging a flow meter in each fluid outlet conduit of the fluid separation assembly, and providing for each of the well segments for which real time production estimates are required, well segment monitoring equipment for monitoring one or more well segment production variables , such as pressure and/or other characteristics, relating to the well segment effluent stream;

b) sequentially testing segments of the multi-zone and/or multilateral well by performing a well test during which production from the tested well segment is varied;

c) monitoring during step b variations of one or more production variables relating to the well segment effluent stream by the well monitoring equipment and simultaneously measuring by means of the flow meters at the fluid outlet conduits of the fluid separation assembly during each well test the variation of the flow pattern of effluents produced by the cluster of wells, including the tested well segment, and obtaining from the measured variations an estimate of the production of the tested well segment during the well segment test;

d) deriving from steps b and c a well segment production estimation model for each tested well segment, which model provides a correlation between variations of the pressure and/or other characteristics relating to the well segment effluent stream and the estimate of the production of the well segment during the well test as monitored by the flow meters;

e) producing oil and/or gas from the cluster of wells whilst a dynamic fluid flow pattern of the accumulated well effluent streams of well effluents produced by the cluster of wells is monitored by means of the flow meters at the fluid outlets of the fluid separation assembly and the one or more well segment production variables are monitored by the well segment monitoring equipment;

f) calculating during step e an estimated contribution of each well segment to the production of fluids by the cluster of wells on the basis of the one or more production variables relating to the well segment effluent stream monitored by the well segment monitoring equipment and the well segment production estimation model derived in step d;

g) calculating an estimated dynamic flow pattern at the fluid outlets of the fluid separation assembly over a selected period of time by accumulating the estimated

contributions of each well segment made in accordance with step f over the selected period of time; and

h) iteratively adjusting from time to time for each well segment the well segment production estimation model for that well segment until across the selected period of time the accumulated estimated dynamic flow pattern calculated in accordance with step g substantially matches with the monitored dynamic fluid flow pattern monitored by the flow meters in the fluid outlet conduits of the fluid separation assembly.

15. The method of claim 1 or 14, wherein if two or more well or well segment test data sets accumulated over a prolonged period of time are available, any difference between the "well or well segment production estimation models" derived from well or well segment test data before and after a prolonged period of production by one or more wells or well segments provide an indication of a "well or well segment decline factor" which is represented as a function of time and which is computed as a best fit to allow any difference between the generated "well or well segment production estimation models" to reflect any decline of well production due to an inherent decrease in well or well segment potential as a function of cumulative well or well segment production.

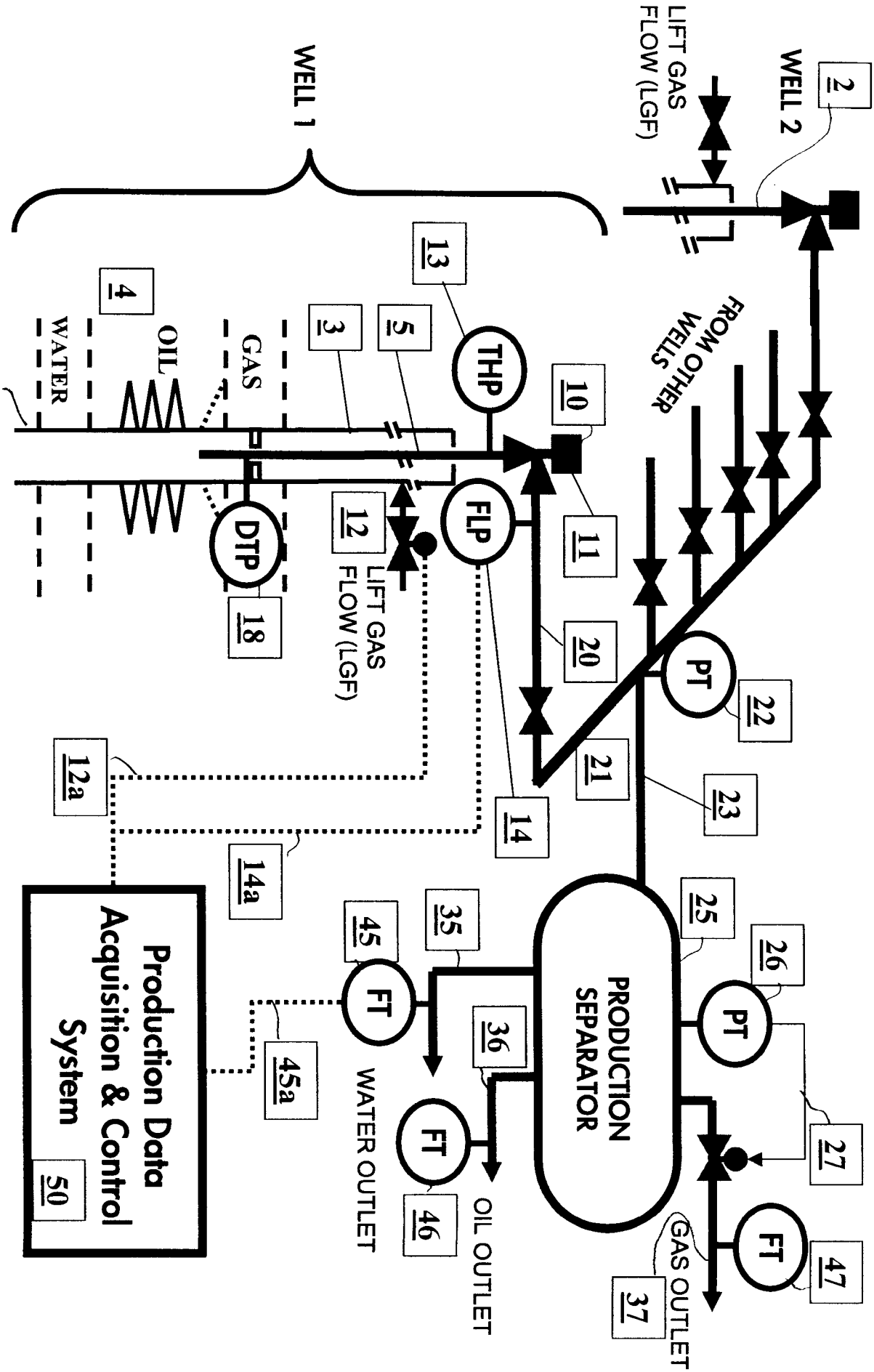


Fig 1: Production from a Cluster of Wells to a Production Separator

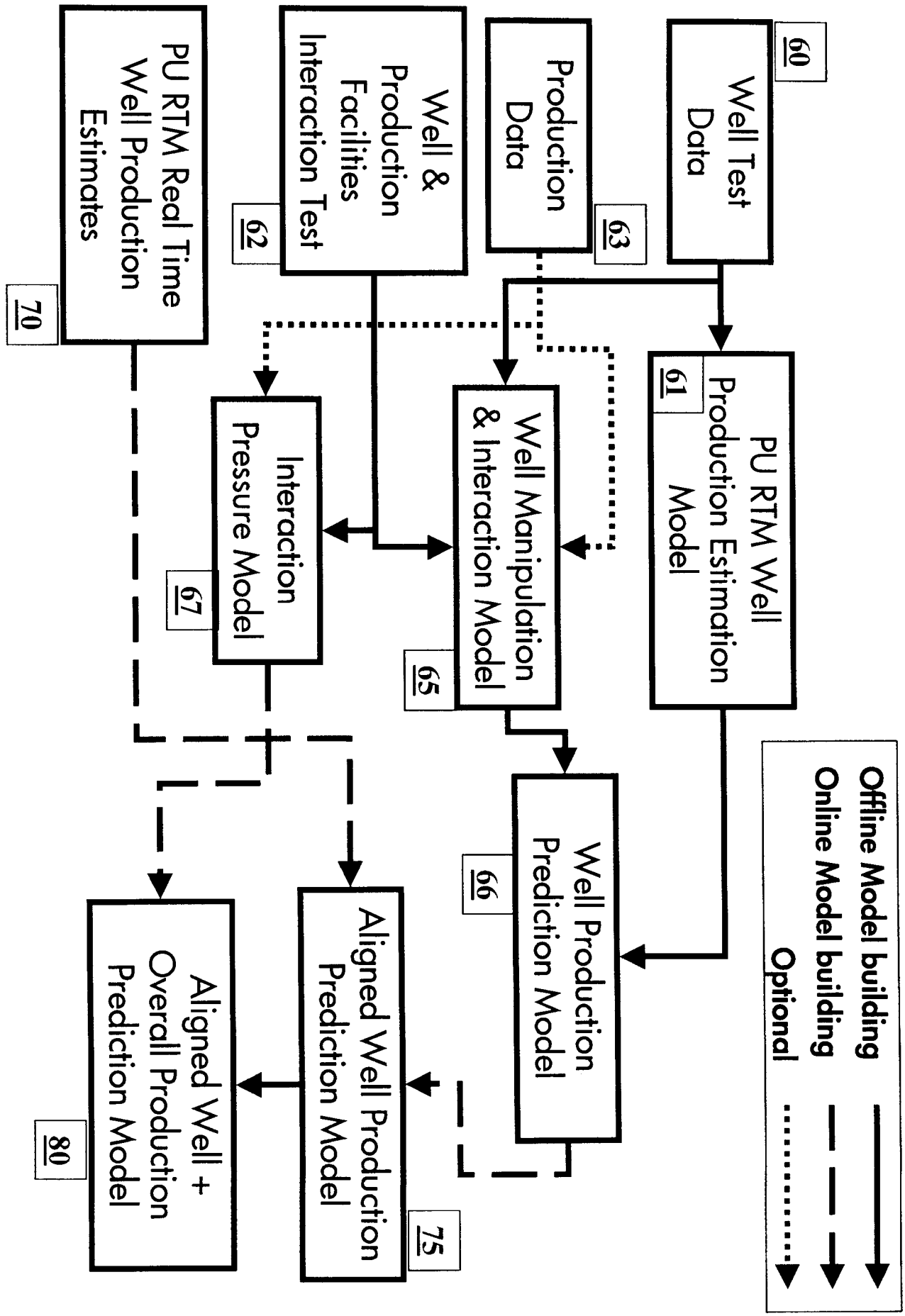


Fig 2: Setup of Well + Overall Production Prediction Models

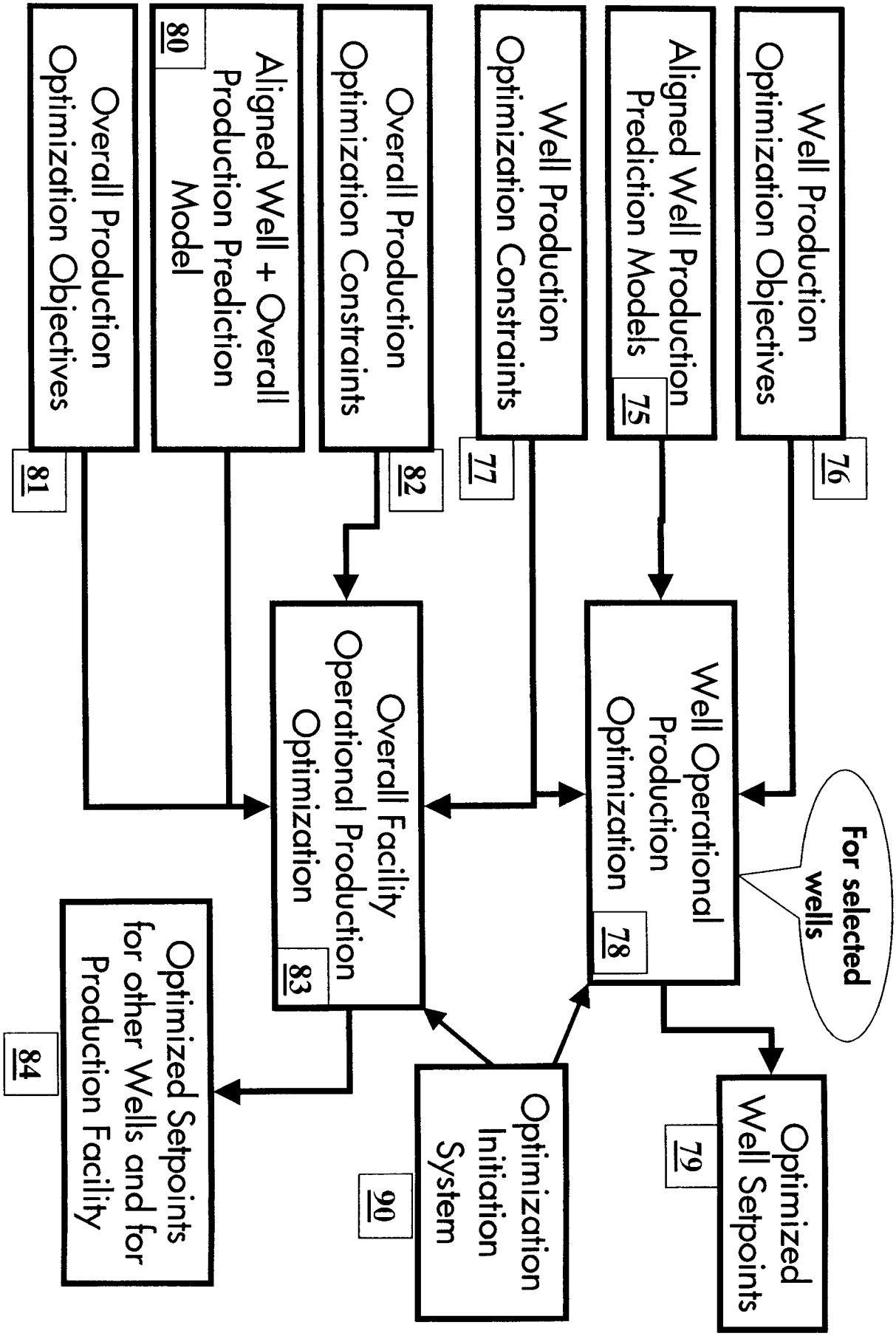


Fig 3: Procedure for Optimization

INTERNATIONAL SEARCH REPORT

International application No
PCT/EP2007/053345

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B49/08 E21B41/00 G01F1/74 G01F15/08

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B G01F

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
EPO-Internal, WPI Data, TULSA

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO 03/046485 A (PHILLIPS PETROLEUM COMPANY; ECK, DANIEL, J) 5 June 2003 (2003-06-05) page 8, line 24 - page 10, line 20 figures 1-3	1,14
A	US 2004/225464 A1 (MELBO HALLGEIR ET AL) 11 November 2004 (2004-11-11) the whole document	1,14
A	RON CRAMER ET AL: "Using Cost Effective Tools to "Bring the Wells to the Operators "" SPE 90691, 26 September 2004 (2004-09-26), pages 1-6, XP002393964 page 6, column 1, paragraph 3 - column 2, paragraph 2	1,14

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents :

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
21 May 2007	29/05/2007

Name and mailing address of the ISA/	Authorized officer
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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/EP2007/053345

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WO 03046485 A	05-06-2003	AU 2002315200 A1	10-06-2003
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