

19



Europäisches Patentamt  
European Patent Office  
Office européen des brevets

11 Publication number:

**0 400 921  
A2**

12

**EUROPEAN PATENT APPLICATION**

21 Application number: **90305734.7**

51 Int. Cl.<sup>5</sup>: **E21B 4/16**

22 Date of filing: **25.05.90**

The title of the invention has been amended  
(Guidelines for Examination in the EPO, A-III,  
7.3).

71 Applicant: **WEIR PUMPS LIMITED**  
**149 Newlands Road, Cathcart**  
**Glasgow G44 4EX Scotland(GB)**

30 Priority: **30.05.89 GB 8912396**

72 Inventor: **Ryall, Michael Leslie**  
**18 Drumbeg Loan**  
**Killearn, Glasgow, G63 9LG, Scotland(GB)**

43 Date of publication of application:  
**05.12.90 Bulletin 90/49**

64 Designated Contracting States:  
**AT BE CH DE DK ES FR GB GR IT LI LU NL SE**

74 Representative: **McCallum, William Potter et al**  
**Cruikshank & Fairweather 19 Royal**  
**Exchange Square**  
**Glasgow G1 3AE Scotland(GB)**

54 **Drill bit assembly with concentric rotatable cutting elements and method of drilling.**

57 The invention relates to a drilling system and a drill bit assembly therefor, said drill bit assembly incorporating at least two concentric rotatable cutting elements (9,11 and 30,33) of which one cutting element (9,30) is adapted to be rotated at a rotational speed which is different from that of the other cutting element (11,33).

**EP 0 400 921 A2**

## DRILL BIT FOR USE IN A SYSTEM FOR DRILLING OIL AND GAS WELLS

This invention relates to a drill bit for use in a system for drilling deep wells, typically for the production of oil and gas, or for geothermal energy. It has as its main objective the attainment of faster rates of penetration (ROP) while drilling than can be achieved by known existing drilling methods without prejudice to drill bit life, in terms of the footage which can be drilled before drill bit performance deteriorates due to wear of the cutters. It is particularly suited to the drilling of the long straight sections of both vertical and deviated wells. A feature of this invention is that it makes maximum possible use of existing topside and downhole drilling equipment used for rotary drilling and for drilling by downhole mud motors or turbines.

For many years, two principal methods have been used to drill deep wells for oil and gas production. Both methods rely on the rotation of a drill bit at the bottom end of the drill string, mud at high pressure being supplied down the inside of the drill string to nozzles in the drill bit, the mud returning to the surface via the annulus between the bore of the well and the outer surface of the drill string. The mud serves a variety of functions, including cooling and lubricating the bit, transporting the rock cuttings to the surface via the annulus, consolidation of the well bore and pressurising the formation at the base of the well to prevent "blow out" of gas or oil when the oil or gas bearing formation is reached.

In the first method, known as "rotary drilling", power is supplied to the drill bit by fixedly attaching the bit to an assembly connected to the bottom of the drill string and rotating the entire drill string by the input of power at the wellhead by means of a rotating table or power swivel. Because this method of drilling requires the rotation of a drill string whose length is frequently in excess of 10,000 feet, in the case of many oil and gas wells, the rotary drilling method is characterised by comparatively low rotational speed of the drill bit, generally 150 RPM or less. Comparatively high torque may be applied, the maximum torque being limited by considerations of fatigue or shear failure of the drill string. The limitation of speed results in a corresponding limit of power which can be applied to the drill string at the surface. When drilling the deeper sections of wells, because of friction losses between the rotating drill string and bore of the wells (particularly in deviated wells) only a proportion of this surface power supplied to the drill string is delivered to the drill bit itself, so rates of penetration tend to fall when drilling the deeper sections of wells.

Thus rotary drilling, although it remains the

most widely used drilling method, has two fundamental limitations to the rate of penetration (ROP) which can be achieved.

These are:

1. rotational horsepower input at the surface, and
2. deductions from this input horsepower due to drill string friction which further limits the cutting power of the bit.

The second method of drilling incorporates a mud motor or turbine attached to the bottom of the drill string to rotate the drill bit, and provision of a high pressure supply of drilling mud to the drill string. This high pressure mud is used to power the motor or turbine at base of the drill string so that it is not necessary to rotate the drill string to rotate the drill bit. Thus, drill string rotational friction losses are either eliminated or greatly reduced (should the drill string be rotated very slowly to improve directional control) thereby making mud motor or turbine drilling particularly suited to deviated wells and deeper sections of wells.

A characteristic of mud motors and turbines is that the torque which they can deliver to the drill bit is generally much less than can be applied by rotary drilling. This torque limitation is offset by the higher rotational speed applied to the bit by motors and turbines. In the case of the latter, it is possible to apply a higher horsepower to the drill bit (albeit at a much lower torque) than with rotary drilling.

The fundamental limitations of drilling by downhole motors and turbines are:

1. The lower torque capability is not ideal for modern polycrystalline diamond composite (PDC) drill bits, which work most effectively with high applied torques.
2. The drilling cost per hour is higher than that of rotary drilling because of the extra cost of the downhole equipment and large mud pumps at the surface.

These limitations have confined mud motors and turbines to comparatively specialised drilling situations, particularly offshore, where, in particular, the directional performance achievable with downhole motors gives them a key niche in the market.

An object of the present invention is to provide a means whereby advantageous features of both rotary drilling and either mud motors or turbodrills can be combined into one drilling system with higher power thus being made available to the drill bit, and a drill bit design which is capable of utilising this higher power for the achievement of higher penetration rates without prejudice to drill bit life.

According to the present invention, there is

provided a drill bit assembly for use in a system for drilling a borehole of an oil or gas well, characterised in that said drill bit assembly comprises at least two concentric rotatable cutting elements of which one cutting element is adapted to be rotated at a rotational speed which is different from that of the other cutting element.

Preferably, the drill bit comprises two radially inner and outer cutting elements, the inner cutting element being adapted to be driven at a higher rotational speed than the outer cutting element.

Preferably also, the inner and outer cutting elements are rotatable in the same direction.

According to a further aspect of the present invention there is provided a drilling system for drilling a borehole of an oil or gas well comprising a rotatable drill string having a mud-driven power unit mounted adjacent the lower end thereof characterised in that there is provided a drill bit having a first radially outer cutting element mounted for rotation on rotation of the drill string, and a second radially inner cutting element rotatable by said mud-driven power unit.

According to yet another aspect of the present invention, there is provided a method of drilling a borehole of an oil or gas well comprising rotating a drill string to effect rotation of a first cutting element located adjacent the lower end of said drill string, and simultaneously actuating a downhole motor or turbine to rotate a second cutting element located adjacent the lower end of said drill string.

An embodiment of the present invention will now be described, by way of example, with reference to the accompanying drawings, in which:-

Fig. 1 is a general diagrammatic representation of a drilling system according to this invention;

Fig. 2 is a sectional view, to an enlarged scale, of a first embodiment of two part drill bit incorporated in the drilling system of Fig. 1; and

Fig. 3 is a sectional view to an enlarged scale, of a second embodiment of two part drill bit also suitable for incorporation in the drilling system of Fig. 1.

In the drilling system shown in Fig. 1, as in conventional drilling systems, drilling mud is supplied at high pressure by a mud pump 1 via a power swivel or rotary table 2 at the well head to a drill string 3. Attached to the bottom of the drill string 3 are drill collars 4 and a power unit in the form of a downhole drill motor or turbine 5 which is guided in the bore 6 of the well by stabilisers 7. The weight of the entire drill string and bottom hole assembly is supported by drill rig 8.

At the lower end of the drill motor or turbine 5 is mounted a drill bit made up of two separate concentric components forming cutting elements.

In the embodiment shown in Fig. 2, a radially inner annular cutting element 9 of the drill bit is

attached to the lower end of drive shaft 10 of the downhole motor or turbine 5, while a radially outer annular cutting element 11 of the bit is attached to the lower end of an outer casing 12 of the motor or turbine 5. A small radial clearance 13 is maintained between the two cutting elements 9, 11 of the bit. Drilling mud can be fed via a hollow bore 10a of the drive shaft 10 to nozzles 14 in the inner cutting element 9, and via labyrinths 15 between the drive shaft 10 and casing 12 to radial clearance 13. Mud can also be fed via duct means in the wall of the motor casing 12 to additional nozzles in the outer annular cutting element 11. As shown in Fig. 2, cutter profiles 18 and 19 of the inner and outer drill bit cutting element 9 and 11 respectively may be arranged to overlap radially, with an axial clearance 20 between them, to prevent entry of rock cuttings into clearance 13. The cutting elements 9 and 11 are also substantially in transverse alignment.

When the drilling system is in operation, the drill string is rotated, typically at speeds between 100 RPM and 150 RPM by the topside drive means 2. This causes the outer cutting element 11 of the drill bit to rotate at the same speed. At the same time the high pressure mud, fed from the surface via drill string 3 to the motor or turbine 5, causes the output drive shaft 10 of the downhole motor or turbine 5 to rotate. It is generally preferable to rotate the output shaft 10 in the same direction as that of the drill string 5, so that the inner cutting element 9 of the drill bit is rotated in the same direction as the outer cutting element 11, but at a higher rotational speed. The rotational speed of the inner drill bit cutting element will generally be in the range 250 to 750 RPM, depending on the type of downhole motor used (i.e. positive displacement mud motor or turbine).

Rotation of the two inner and outer cutting elements of the drill bit causes shearing or crushing of the rock formation and the formation cuttings are swept by the drilling mud into and up an annulus 21 between the drill string 3 and the bore 6 of the well, to the surface.

In a second embodiment of the invention as shown in Fig. 3, there is shown the lower end of a drilling system similar to that illustrated in Figs. 1 and 2. In this alternative embodiment like components are indicated by the same reference numerals as in Figs. 1 and 2.

In the arrangement of Fig. 3, the drive shaft 10 of a downhole motor or turbine has fitted thereto at its free end, through an intermediate screw-threaded connector 29, the inner cutting element 30 of a drill bit. Drilling mud can be fed through the hollow bore 10a of the drive shaft 10 and bore 31 in connector 29 to nozzles 37 in connector 29 and 32 in the inner cutting element 30 and via labyrinth 15 between the drive shaft 10 and the drill casing 12

and bearing clearance 35 between connector 39 and bearing 36 to a second radially outer drill bit cutting element 33. The radially outer cutting element 33 is carried on the lower end of the drill casing 12 of the motor or turbine. Bearing 36 is mounted within the bore of the outer cutting element 33.

As can be seen from Fig. 3, the outer cutting element 33 is of greater external diameter than the inner cutting element 30 and is spaced axially from the inner cutting element 30 by distance A.

In operation of the drilling system incorporating a drill bit as shown in Fig. 3, drilling mud is fed via the hollow bore 10a and bore 31 to the inner cutting element 30 and via a passageway 34 and nozzles 37 to the outer cutting element 33. As in the embodiment shown in Fig. 2 the inner cutting element 30 is caused to rotate at a greater rotational speed than the outer cutting element 33 and preferably in the same direction.

The arrangement shown in Fig. 3 in which the outer cutting element 33 is axially distanced from the inner cutting element 30 has the principal advantage that for a given outer diameter of cutters 18, the diameter of the bore of the cutting element 33 in Fig. 3 can be arranged to be less than is possible with the cutting element 11 in Fig. 2, thus affording comparatively greater radial wall thickness and mechanical strength to cutting element 33.

Thus in the drilling system as described above in relation to Figs. 1 to 3, power to the outer cutting element 11 or 33 of the drill bit is provided by rotational means at the surface, and power to the inner cutting element 9 or 30 is provided both by this rotational means and by the high pressure hydraulic energy in the drilling mud fed to the hydraulic motor or turbine 5. It is thereby possible, particularly in higher strength rock formations, by this increase in total power which is made available to the drill bit to drill the well at a rate of penetration significantly higher than is possible by existing drilling methods which use only one of these means to supply the energy to the bit. Although in the above-described embodiment, two concentric, independently rotatable drill bit cutting elements are described, it will be apparent that a drill bit incorporating more than two such drill bit cutting elements can be provided.

## Claims

1. A drill bit assembly for use in a system for drilling a borehole of an oil or gas well, characterised in that said drill bit assembly comprises at least two concentric rotatable cutting elements (9,11 and 30,33) of which one cutting element (9,30) is adapted to be rotated at a rotational speed

which is different from that of the other cutting element (11,33).

2. A drill bit assembly as claimed in claim 1, in which the radially inner cutting element (9,30) is rotatable at a higher rotational speed than the radially outer cutting element (11,33).

3. A drilling system for drilling a borehole of an oil or gas well comprising a rotatable drill string (3) having a mud-driven power unit (5) mounted adjacent the lower end thereof characterised in that there is provided a drill bit having a first radially outer cutting element (11,33) mounted for rotation on rotation of the drill string (3), and a second radially inner cutting element (9,30) rotatable by said mud-driven power unit (5).

4. A drilling system as claimed in claim 3, in which the mud-driven power unit (5) is a mud motor or turbine having an outer casing (12) in which is carried a drive shaft (10) for rotation relative thereto, the first cutting element (11,33) being mounted adjacent the lower end of said outer casing (12) and the second cutting element (9,30) being mounted on said drive shaft (10).

5. A drilling system as claimed in claim 3 or 4, in which the first and second cutting elements (9,11 and 30,33 respectively) are in substantial transverse alignment.

6. A drilling system as claimed in claim 3 or 4, in which the first cutting element (33) is axially spaced relative to the second cutting element (30) in a direction away from the lower end of the drilling system.

7. A drilling system as claimed in any of claims 3 to 6, in which the second cutting element (9,30) is rotatable at a higher rotational speed than the first cutting element (11,33).

8. A drilling system as claimed in any of claims 5 to 7, in which the first and second cutting elements (11,33 and 9,30) are rotatable in the same direction.

9. A drilling system as claimed in any of claims 3 to 8, in which passage means (10a,13,14 and 10a,31,34,37) are provided for directing drilling mud past said first and second cutting means (9,11 and 30,33) to clean same.

10. A downhole drilling system for use with a drill bit comprising a downhole drilling motor or turbine (5) including a housing (12) and means (5) for rotating a drill bit element (9,30) relative to said housing about an axis of rotation; and cutting means (11,33) connected to said housing of said downhole drilling motor or turbine wherein said cutting means (11,33) extends radially outwardly relative to the axis of rotation of said drill bit to a greater extent than does said drill bit element (9,30).

11. A method of drilling a borehole of an oil or gas well comprising rotating a drill string (3) to

effect rotation of a first cutting element (11,33) located adjacent the lower end of said drill string (3), and simultaneously actuating a downhole motor or turbine (5) to rotate a second cutting element (9,30) located adjacent the lower end of said drill string.

5

12. A method as claimed in claim 11, comprising rotating the second cutting element (9,30) at a higher rotational speed than that of the first cutting element (11,33).

10

15

20

25

30

35

40

45

50

55

5

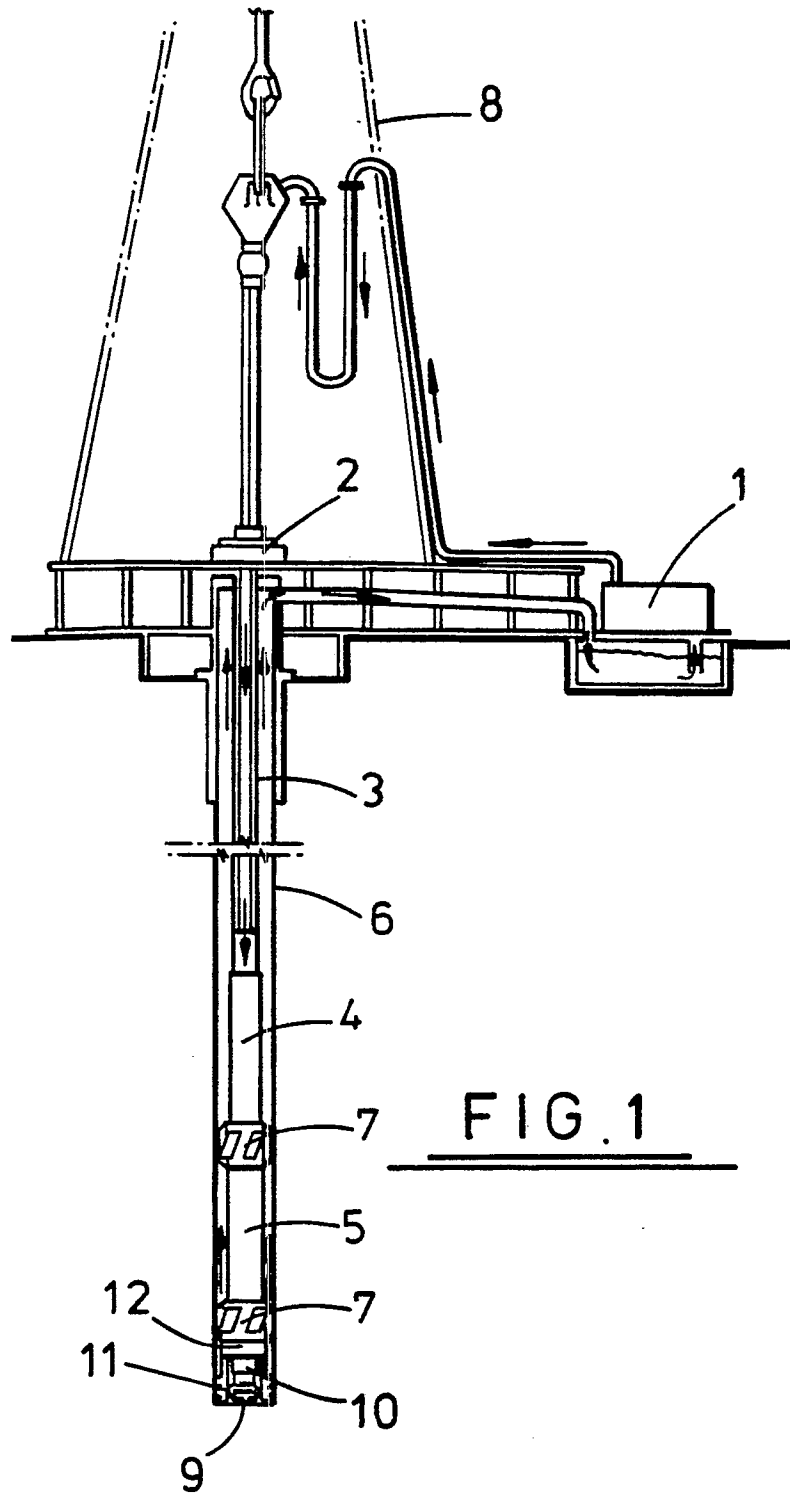


FIG. 1

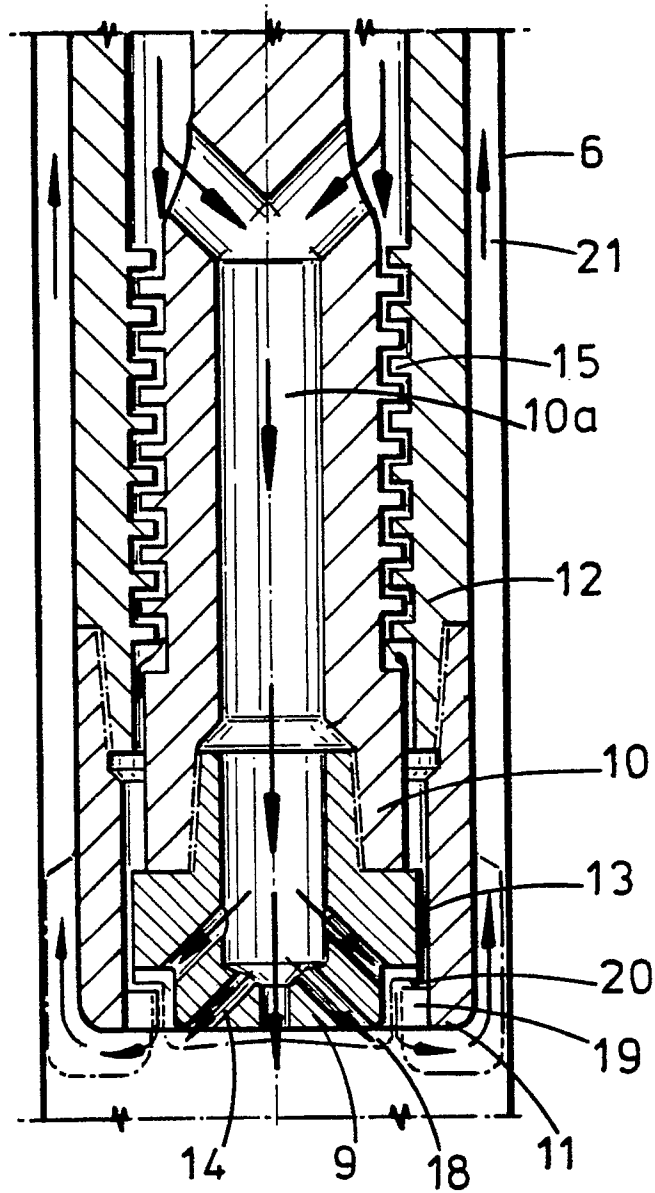


FIG. 2

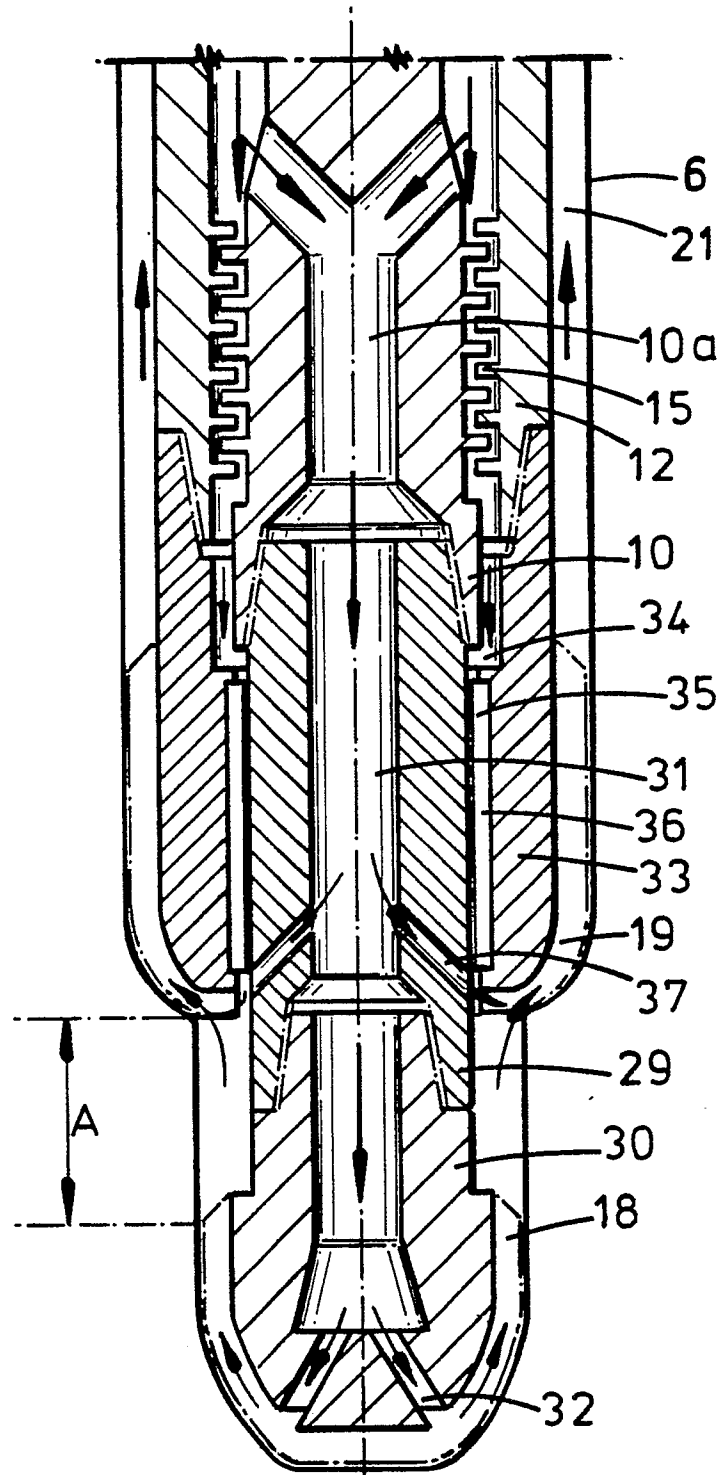


FIG. 3