A cooling system comprising a coolant-conducting cooling line in association with said subsea element. The cooling line extends from a surface location to said subsea element. The cooling line comprises a coolant delivery line between the surface location and the subsea element, and a coolant return line. The coolant return line is arranged in association with a hydrocarbon flow line extending from the hydrocarbon facility.
Cooling system for subsea elements

According to a first aspect, the present invention relates to cooling of subsea elements used in subsea hydrocarbon production. According to a second aspect of the present invention, it relates to flow assurance of subsea hydrocarbon transport lines, such as a hydrocarbon pipe extending from a subsea well to a shore or surface location and other subsea elements that need flow assurance.

Background

A well stream flowing out of seabed wells can have a large amount of thermal energy. Hence it is known to cool the well stream in order to protect piping and associated subsea equipment. One known way of cooling is to employ the ambient sea water, either as a passive coolant or by forced cooling wherein the sea water is forced past the equipment or an associated heat exchanger.

The use of ambient sea water as coolant has an advantage in that the coolant is always available and cool, such as about 4 °C. A disadvantage is however that sea water contains salts and organisms which may lead to corrosion of the cooling equipment and scaling and fouling. Countermeasures include coating of the surfaces in contact with the sea water. However, this reduces the heat transfer between the coolant and the warm equipment.

Moreover, such solutions using the sea water as coolant will not make use of the heat drawn from the warm subsea equipment. Instead, the heat is simply transferred into the sea.

Prevention of hydrate formation is always the case, and in some cases prevention of wax formation. Both hydrate formation and waxing can be prevented by chemical injection.

The chemicals injected to prevent hydrates are anti-freeze liquids, of which MEG (mono-ethylene-glycol) is the most common. Typically 70 %-weight of free water can be injected. Consumption of MEG would represent a significant OPEX element as well as an environmental problem. MEG is therefore normally
regenerated in a MEG regeneration plant that represents a significant CAPEX element, and some environmental concern still remains.

Another method for flow assurance is Direct Electric Heating (DEH). Current technology is however limited to in the range of 30 km step out, and significant development and qualification work is remaining for step out in the range of 50 to 200 km, if at all technically obtainable.

**The invention**

According to a first aspect of the present invention there is provided a cooling system cooling one or more subsea elements of a subsea hydrocarbon facility. It comprises a coolant conducting cooling line in association with said subsea element. A pump is adapted to pump the coolant through the cooling line. According to the invention, the cooling line extends from a surface location to said subsea element. The cooling line comprises a coolant delivery line between the surface location and the subsea element and a coolant return line. Moreover, the coolant return line is arranged in association with a hydrocarbon flow line extending from the hydrocarbon facility, thereby heating the hydrocarbon flow line.

In this manner, the coolant which is heated by the warm subsea elements is used to heat the hydrocarbon flow line. This is in contrast to known subsea cooling systems that discharge heat energy from the warm subsea equipment into the sea water.

The surface location shall be understood as comprising any location above the sea surface, such as on land or on an offshore installation. Preferably it should also be understood as comprising a location in immediate proximity to land or an offshore structure, such as a few meters below the sea surface, in which location the operator will benefit from the proximity to land or the structure.

A subsea hydrocarbon facility shall be understood as any facility arranged on the seabed that treats and/or conducts hydrocarbons originating from one or more subsea wells. For instance, a subsea hydrocarbon facility may involve a header
or a subsea hydrocarbon compression facility, or a simple hydrocarbon conducting pipe.

In a preferred embodiment of the first aspect of the invention, the coolant is fresh water. Advantageously the freshwater can be freshwater that has been cleaned by means of filtration and/or ion exchange. The freshwater may also be distilled. By using fresh water as coolant, the pipes conducting the coolant will be less exposed to corrosion and coating.

The coolant may comprise an anti-freeze chemical. Such a chemical may advantageously be MEG, which is well known to the person skilled in the art.

In another embodiment the coolant is an oil. An oil will also protect the coolant conducting pipes from corrosion, scaling and fouling.

The coolant return line and the hydrocarbon flow line can advantageously form a pipe-in-pipe configuration. The hydrocarbon fluid can then flow in the inner pipe and the coolant can flow in the annulus space between the inner and outer pipe. Advantageously there is arranged heat insulation on the outer pipe in order to reduce heat loss to the ambient sea water. Such a configuration will provide effective heat transfer from the warmed-up coolant to the flow of hydrocarbon fluid in the flow line.

The coolant return line can be arranged in association with one or more flow conducting elements of the subsea facility. This is in order to assure flow in the flow conducting elements. I.e. the temperature of various flow conducting elements is kept above a certain temperature, below which flow assurance problems are known to arise. Typically the temperature of such elements is kept above hydrate formation temperature and/or wax formation temperature. One manner of keeping such flow conducting elements above a desired temperature is to enclose them in an enclosure and to flow heated coolant through the enclosure, from an inlet to an outlet.
The employed heat exchanger / "forced cooler" can be of any appropriate type. Advantageously a shell-and-tube type can be used. Then the hydrocarbon flow which shall be cooled can preferably be in the tube and the coolant can be in the annulus or space between the tube and the shell.

According to a preferred embodiment, in the cooling line there is arranged a subsea buffer tank for heated coolant, at a subsea location. Preferably the subsea buffer tank is arranged close to, or in association to the subsea hydrocarbon facility.

In one embodiment, the subsea buffer tank can be arranged upstream of the subsea elements. In another embodiment the subsea tank can be arranged downstream of the subsea elements. The subsea buffer tank can preferably comprise an electric heater arranged to heat the coolant in the buffer tank.

One can also imagine an embodiment with two subsea buffer tanks, wherein one is arranged upstream of the subsea elements and the other is arranged downstream of the subsea elements, however upstream of the hydrocarbon flow line. After a shut down, in a situation in which much of the subsea equipment as well as the flow line is cold, the subsea buffer tanks can provide heated coolant to the cold equipment to provide for flow assurance before startup.

The coolant return line can extend between the one or more subsea elements and the surface location, and the cooling line can be a closed loop to which a coolant pump is connected. Any chemicals added to the coolant will then not have to be refilled. Also one will not have to clean or distill the coolant after each pass through the loop. Preferably, the coolant pump is arranged at surface, such as onshore or on topsides (on a platform). However, it is also technically feasible to arrange the coolant pump below the sea surface.

The cooling system according to the first aspect of the invention can also comprise a surface buffer tank adapted to provide heated coolant. In one embodiment the coolant pump and associated flow valves can then be operated to flow heated coolant from the surface location and into the coolant return line.
Thereby the heated coolant can heat the hydrocarbon flow line. As with the subsea buffer tank, the surface buffer tank, arranged at the surface location, may advantageously comprise an electric heater arranged for heating the coolant. In this way, the cooling line, i.e. the coolant return line in this embodiment, can be used as a heating line and be employed for flow assurance in the hydrocarbon flow line also without recovering heat from the subsea element(s). This may typically take place during shut downs. Then coolant is heated and routed in reversed flow by a valve arrangement at the pump or by having a separate dedicated reverse flow pump. The coolant will be heated sufficient to achieve flow assurance where needed. This embodiment will be described in more detail below, with reference to the drawings.

Preferably, the subsea elements from which heat can be recovered by the cooling line, as well as other subsea equipment, for instance flow conducting elements, can be provided with temperature sensors in order to make the operator capable of monitoring the temperature at the respective elements of the subsea facility. Furthermore, a plurality of remotely actuated valves can preferably be arranged to the cooling line, and particularly to the various branches of the cooling line. In one embodiment, the valves can be controlled automatically on the basis of the temperature sensors, such as with an associated microcontroller or similar. Bypass lines around the subsea elements can also be arranged for tuning of the temperature of the flow to be cooled and the temperature of the heated coolant.

According to a second aspect of the present invention there is provided a flow assurance system arranged in association with a hydrocarbon conducting flow line arranged on the seabed. According to the invention the system comprises a heating line conducting a heating medium, which heating line extends from a surface or shore location and along the flow line and with heat transferring contact with the flow line. The heat transferring contact provides for transmission of heat from the heating medium to the hydrocarbon-containing fluid in the flow line when the heating medium is warmer than the said fluid. The heating medium conducting heating line is a heating line that conducts a heating medium. The
heating medium can advantageously be fresh water, such as described above in association with the first aspect of the invention.

In one embodiment the heating line can comprise a delivery line extending from the surface location to one or more subsea heat sources, and a return line extending from the subsea heat source(s) to the surface or shore location. The return line is arranged with heat transferring contact with the flow line.

In another embodiment the heating line can comprise a delivery line extending from a surface buffer tank at the surface location and the heating line can be arranged with heat transferring contact with the flow line.

Various particulars described with reference to the first aspect of the present invention will also apply to the second aspect of the invention. For instance, the heating medium can be freshwater, the system can comprise a surface buffer tank and/or a subsea buffer tank with electric heating. The system can also comprise appropriate valves, bypass lines, and temperature sensors.

In an embodiment example of the first aspect of the invention, for a subsea hydrocarbon compression facility with a 6 MW compressor, it has been calculated that the energy recovered from a corresponding well stream can be typically 7 MW by cooling it from 100 to 35 °C. By use of fresh water supplied by pipe from surface as coolant, these 7 MW can be recovered as large quantity of hot water at 80 °C. From the discharge cooler of the compressor, typically 5 MW can be recovered. This hot water can then be utilised for flow assurance, i.e. prevention of hydrate formation and in other cases also of wax formation and perhaps also prevention of formation of other damaging components at low temperature.

The coolant flowing in the coolant delivery line from the surface location, will after some few kilometres be cooled down to seawater temperature due to free convection heat exchange.
If the distance from the surface location to the subsea facility should be short, additional cooling of the coolant in the coolant delivery line can be arranged, e.g. by inserting a passive cooler in the delivery line or an active heat exchanger for enhanced heat exchange with the seawater.

It should be noted that when not circulating the pressure of the coolant is close to equal to the seawater pressure along the cooling loop. During operation the coolant will have overpressure to overcome the frictional losses caused by circulation, and this can typically be in the range of "some hundred bars", e.g. 300 bar at the inlet to the coolant delivery line. The pressure rating must be accordingly.

Preliminary cost estimates has demonstrated that use of such recovered heat will be much cheaper than use of MEG with or without regeneration plant.

Use of hot water from recovered heat will also be much lower in CAPEX and OPEX than Direct Electric Heating (DEH). Moreover it will be more reliable (well proven water pipelines and tanks). Development effort of the heat recovery and heating system will be very short with perhaps no TQPs (technology qualification program), while DEH has a long, expensive and risky development ahead.

It is important to note that the invention can be used for flowlines without any boosting, flowlines with multiphase boosting and for flowlines with gas boosting.

Cost calculations comparing the flow assurance cost according to the present invention and by chemicals, such as by MEG and DEH, have been performed and reveal that the systems according to the present invention is superior. Furthermore, the reliability of the invention is also assumed to be high because all components are simple and the majority well proven from subsea application.

**Detailed example of embodiment**

Whereas the aspects of the present invention have been presented in general terms above, a more detailed example of embodiment is presented below with reference to the drawings, in which
Fig. 1 shows a principle drawing of a hydrocarbon conducting flow line arranged on the seabed, extending between a subsea production facility and a shore location;

Fig. 2 shows a principle arrangement of a subsea hydrocarbon compression facility;

Fig. 3 shows an embodiment of a cooling system according to the first aspect of the invention;

Fig. 4 shows a pipe-in-pipe configuration of a well stream and a coolant return line;

Fig. 5 shows another embodiment of a cooling system according to the first aspect of the invention;

Fig. 1 is a principle drawing of a flow line 1 arranged on the seabed that conducts a flow of hydrocarbons from a subsea facility 3 to an onshore location 5. To the subsea facility 3 there is associated a plurality of subsea wells 7. Hydrocarbon flow from the wells 7 is conducted to the subsea facility 3 to the flow line 1 and to the shore location 5. In this embodiment the subsea facility 3 includes a production facility 4 and a compression facility 6.

Reference is now made to Fig. 2, showing a principle configuration of the subsea compression facility 6. The gas and liquid phases are commingled after the compressor and pump, and transported as well stream to the shore location 5 through the flow line 1. Another option, not shown, is to transport gas and liquid in separate pipes, to the same or to different destinations if this is beneficial.

The well stream flowing from the subsea wells 7 is warm and needs to be cooled. In order to cool this well stream, it is flown through a first heat exchanger through which a coolant is flown, as will be described in further detail below. This first heat exchanger is referred to as a first heat source, HS1. Another significant heat source is the compressor discharge cooler, HS4. Other components that need cooling are also marked as heat sources, HS2, HS3, HS5 and HS6, although they may not contribute positive to production of hot water, however they are
preferably cooled. The invention allows however these to be efficiently cooled in compact indirect heat exchangers.

Fig. 3 shows an embodiment of a cooling system 100 according to the present invention. In this embodiment, the heat exchanger HS1 is employed to cool a warm well stream originating from a subsea well 7. Said well stream is conducted by means of the flow line 1 indicated schematically with the horizontal dotted line.

A coolant is provided to the heat exchanger HS1 by a cooling line 101. The cooling line 101 comprises a coolant delivery line 103 and a coolant return line 105. In order to flow the coolant through the cooling line 101, there is arranged a coolant pump 107 to the coolant delivery line 103.

In this embodiment, the coolant pump 107 is arranged on shore, as illustrated with the vertical dotted line representing schematically the boarder between sea and land. Moreover, the coolant that has passed through the cooling line 101 is returned to the coolant pump 107 so that it may be pumped a consecutive round. One can however also imagine that the coolant return line 105 ends before reaching back to the coolant pump 107. One may for instance let the coolant flow freely out into the sea when it can no longer be used for heating the flow line 1, provided the coolant may be delivered to the sea (typically if the coolant is sea water or fresh water without environmentally dangerous additives).

The flow direction of the coolant is indicated with the two arrows. When the coolant reaches the heat exchanger HS1, it has been cooled by the ambient sea water, which at the seabed typically can be about 4 °C and with a normal variation from -2 °C to 10 °C, dependent of the location. Thus, a well stream flowing through the heat exchanger HS1 will be cooled, for instance from 100 to 35 °C, whereas the coolant flowing through the cooling line 101 will be heated. The well stream will thus not be too warm for the equipment through which it flows, however it will not be so cold that the formation of wax and hydrates will arise.
When transporting the well stream to the shore location 5 (cf. Fig. 1), it will flow through a long pipe on the seabed. In order to prevent the well stream from being excessively cooled by the ambient sea water, the heated coolant in the cooling line 101 is used to maintain a required temperature in the flow line 1. An advantageous solution to provide this temperature is to arrange a pipe-in-pipe flow line 1. The well stream can then advantageously flown through the inner pipe, whereas the heated coolant flows through the space between the inner and outer pipe. In order to prevent excessive heat loss to the ambient sea water, the outer pipe is covered with a required thickness of isolation. As will be appreciated by the person skilled in the art, other configurations of the joined well stream and coolant return line 105 are possible in stead of the pipe-in-pipe solution. For instance, the pipe with warm water can be coiled around the flow line 1, or two pipes may be arranged in parallel to each other. It is also possible to flow the coolant in the inner pipe and the well stream in the outer pipe.

Fig. 4 illustrates the pipe-in-pipe configuration of the flow line 1 with a well stream conducting pipe within an outer pipe that constitutes at least a part of the coolant return line 105. On the outer pipe there is arranged insulation 106.

Fig. 5 illustrates a more complex embodiment of the first aspect of the present invention. Basically it has the same configuration as the embodiment shown in Fig. 3. However it exhibits some additional features.

In this embodiment the cooling system 100 is used to cool the six heat exchangers or heat sources H1, H2, H3, H4, H5, and H6 shown in Fig. 2. The number of heat sources and what the various heat sources are will be chosen by the operator according to the solution in question. In addition, the cooling system 100 comprises a subsea buffer tank 109 which can hold a volume of coolant. The subsea buffer tank 109 is advantageously insulated to prevent excessive heat losses to the ambient seawater. It is arranged in the coolant return line 105 and is thus adapted to hold heated coolant, which has been heated in one or more of the heat sources H1 to H6. In a particularly preferred embodiment, the subsea buffer tank 109 is provided with an electric heater 111 arranged to heat the coolant in the subsea buffer tank 109. Thus, if the coolant is not sufficiently warm
to heat the well stream or other subsea equipment in need of heating, the operator will employ the electric heater 111 to provide sufficiently warm coolant. This can typically occur after or during a shut down.

In the embodiment shown in Fig. 5, there is arranged a coolant return line branch 105b adapted to heat various components 113 of the subsea facility 3, for instance an anti-surge valve or dead legs.

The embodiment in Fig. 5 also exhibits another advantageous feature. On the shore location 5, where the coolant pump 107 is arranged, there is arranged a surface buffer tank 115 which, corresponding to the subsea buffer tank 109. The surface buffer tank 115 is also provided with an electric heater 117. After a shut down, or if sufficient heat cannot be recovered from the well stream, the surface buffer tank 115 can be employed to supply heated coolant in order to heat the flow line 1 containing hydrocarbons. To do this, the reverse flow valves 119b (in black) must be opened, while the forward flow valves 119a (in white) must be closed, to reverse the flow direction of the coolant. Alternatively the flow direction of the coolant pump 107 can be changed. During normal flow, the forward flow valves 119a are open and the reverse flow valves 119b are closed. In stead of the configuration shown in Fig. 5, one could also imagine other configurations of the valves 119a, 119b and the surface buffer tank 115. For instance, the surface buffer tank could be arranged in the branch extending vertically in the figure and with a reverse flow valve 119b. The coolant would then flow through the buffer tank 115 only during reverse flow mode, while not in the forward/normal flow mode. Alternatively a separate dedicated reverse flow pump with a suitable piping and valve arrangement can be installed.

In Fig. 5, the solid line arrows indicate the normal flow direction of the coolant and correspond to the arrows in Fig. 3. The dotted line arrows indicate the reversed flow direction of the coolant, as used when the surface buffer tank 115 is employed to heat coolant that is provided for heating the flow line 1.
The embodiments shown in Fig. 3 and Fig. 5 exhibit a closed loop cooling line 101. One may however also imagine a cooling line which is not in the form of a closed loop.

Furthermore, the embodiments of Fig. 3 and Fig. 5 show a coolant pump 107 arranged on land. It could also be arranged on an offshore structure, either floating or fixed. To provide for easier maintenance and access, it is preferably arranged above the water surface. However, it would also be technically feasible to arrange it below water surface.

The drawings in Fig. 3 and Fig. 5 also depict embodiments of the second aspect of the present invention, namely a flow assurance system. For the second aspect of the present invention, the line referred to as the coolant return line 105 in the description of the first aspect of the invention, will be the heating line. The heating line conducts a heating medium.

In one embodiment of the second aspect of the invention (i.e. a flow assurance system), the heating line conducts the heating medium to one or more subsea heat sources HS1, HS2, HS3, HS4, HS5, HS6, where the heating medium is heated. Then the heating medium is guided to hydrocarbon carrying lines, such as the flow line 1, which shall be heated to provide flow assurance.

In another embodiment of the second aspect of the invention, the heating medium is heated at the surface location 5, and then conducted to the hydrocarbon carrying flow line 1. In such an embodiment, heat from the well stream or heat emitting subsea equipment is not recovered.

Various particulars which are described in association with the first aspect of the invention may also apply to the embodiments of the second aspect of the invention. For instance, the heating medium may advantageously be fresh water and a pump for the heating medium may preferably be arranged on the surface location 5.
Thus, the shown embodiments are systems that may both provide for cooling of subsea equipment that need cooling as well as for heating of subsea equipment that need heating. Moreover, the systems employ recovered heat from the cooled equipment to heat the equipment that needs heating.

Efficient cooling of motors both allows higher power of the motors, and extends their life time due to lower internal temperatures that is beneficial for soft materials.

In the embodiments of the first aspect of the invention, where the cooling line extends from land to a subsea hydrocarbon facility, the latter may in some cases be arranged far from land, such as more than 50 km or even more than 200 km from land. The same applies for the heating line of the second aspect of the invention.

There could also be cases where the gas phase or the liquid phase is re-injected by injection compressor or pump respectively.

In all indicated cases, flow assurance is a concern, and solutions have to be applied dependent on the flow assurance problem from case to case.

As will be understood by the person skilled in the art, the invention makes possible accurate temperature control of coolant as well as fluids that shall be cooled (hydrocarbon flow).

The invention can be applied for all types of subsea production systems and subsea processing systems if sufficient heat is available in the wellstream and other sources including also the buffer tank with electric heating.

In the drawings are included components that are helpful in describing and understand the invention. For instance are some valves, temperature transmitters, and bypass lines for temperature control of the coolant and of fluids to be cooled not included. An expansion system for the coolant, which will
change volume with temperature, is also not included as this is regarded as known to the skilled person.

As mentioned above, the power performance in kW for motors for pumps and compressors can be increased by cooling. The invention will make it possible to cool well, say keep motor temperatures below for instance 30 °C compared to below 70 °C with free convection (passive) coolers. Low temperature also prolongs the life time of soft (polymeric) materials of motors and hence improves the reliability. The same arguments are valid for the VSD.

Forced coolers (active coolers) of some kind, and favourably Shell & Tube coolers, will be applied in the invention. Forced coolers are very efficient compared to free convection coolers (passive coolers). The overall heat transfer coefficient (OHTC) of active coolers can typically be 1000-1500 W/(m³*K) while typically 150-200 W/(m³*K) for passive coolers. This results in much smaller cooler area, dimensions and weight for active coolers compared to passive. Because the coolant of the invention is clean and non-corrosive, corrosion control will be easier than for passive coolers exposed to the saline sea water. Another important difference is that the coolers of the invention are not subject to neither temperature induced nor CP (cathodic protection) induced carbonate scaling and coating, which reduces the OHTC significantly, is not necessary for the coolers of the invention.
Claims

1. Cooling system cooling one or more subsea elements (HS1, HS2, HS3, HS4, HS5, HS6) of a subsea hydrocarbon facility (3, 4, 6), the cooling system (100) comprising a coolant conducting cooling line (101) in association with said subsea element (HS1, HS2, HS3, HS4, HS5, HS6), wherein a pump (107) is adapted to pump the coolant through the cooling line (101), characterized in that the cooling line (101) extends from a surface location (5) to said subsea element (HS1, HS2, HS3, HS4, HS5, HS6);

2. Cooling system according to claim 1, characterized in that the coolant is freshwater.

3. Cooling system according to claim 1 or 2, characterized in that the coolant comprises an anti-freeze chemical.

4. Cooling system according to claim 1, characterized in that the coolant is an oil.

5. Cooling system according to claim 1, characterized in that the coolant return line (105) and the hydrocarbon flow line (1) form a pipe-in-pipe configuration, wherein hydrocarbon flows in the inner pipe and the coolant flows in the annulus space between the inner and outer pipe.

6. Cooling system according to one of the claims 1 or 5, characterized in that the coolant return line (105) is arranged in association with flow conducting elements (113) of the subsea facility (3, 4, 6) to assure flow in the flow conducting elements (113).
7. Cooling system according to one of the claims 1, 5, or 6, characterized in that in the cooling line (101) there is arranged a subsea buffer tank (109) for heated coolant, at a subsea location.

8. Cooling system according to claim 7, characterized in that the buffer tank (109) comprises an electric heater (111).

9. Cooling system according to any one of the preceding claims, characterized in that the coolant return line (105) extends between the subsea element (HS1, HS2, HS3, HS4, HS5, HS6) and the surface location (5), and that the cooling line (101) is a closed loop to which a coolant pump (107) is connected.

10. Cooling system according to claim 9, characterized in that it comprises a surface buffer tank (115) adapted to provide heated coolant, and that the coolant pump (107) and associated flow valves (119a, 119b) can be operated to flow heated coolant from the surface location (5) and into the coolant return line (105), thereby heating said hydrocarbon flow line (1).

11. Flow assurance system arranged in association with a hydrocarbon conducting flow line (1) arranged on the seabed, characterized in that it comprises a heating medium conducting heating line (101) that extends from a surface location (5) and along the flow line (1) and with heat transferring contact with the flow line (1).

12. Flow assurance system according to claim 11, characterized in that the heating line (101) comprises a delivery line (103) extending from the surface location (5) to a subsea heat source (HS1, HS2, HS3, HS4, HS5, HS6), and a return line (105) extending from the subsea heat source to the surface location, wherein the return line (105) is arranged with heat transferring contact with the flow line (1).

13. Flow assurance system according to claim 11, characterized in that the heating line (101) comprises a delivery line (105) extending from a surface buffer tank (115) at the surface location (5) and that the heating line (105) is arranged with heat transferring contact with the flow line (1).
### A. CLASSIFICATION OF SUBJECT MATTER

E21B 36/00 (2006.01) , E21B 43/01 (2006.01) , F16L 53/00 (2006.01)

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, F16L, F28D

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

DK, NO, SE, FI: Classes as above.

### Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPODOC, WPI, FULL TEXT: ENGLISH, GERMAN, FRENCH

### C. DOCUMENTS CONSIDERED TO BE RELEVANT

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<td>A</td>
<td>US 5803161 A (WAHLE, H. W. et al.) 1998.09.08 Column 1 lines 21-25, 50-67, column 3 lines 23-26, column 5 lines 36-39, column 5 line 58-column 6 line land fig. 1.</td>
<td>1-10, 12</td>
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Further documents are listed in the continuation of Box C. See patent family annex.

* Special categories of cited documents:
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