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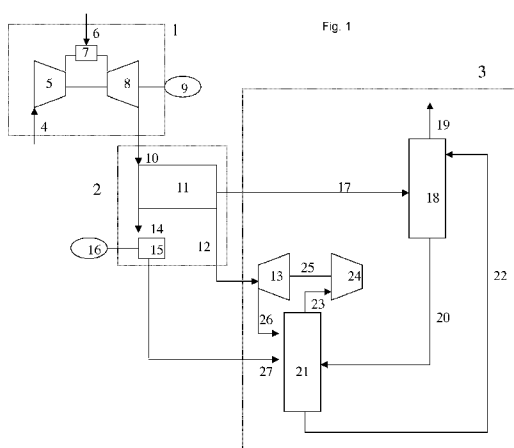
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(54) Title: PROCESS FOR PRODUCING A PRESSURISED CO₂ STREAM IN A POWER PLANT INTEGRATED WITH A CO₂ CAPTURE UNIT



(57) Abstract: A process for producing a pressurised CO₂ stream in a power plant integrated with a CO₂ capture unit, wherein the power plant comprises at least one gas turbine (1) coupled to a heat recovery steam generator unit (2) and the CO₂ capture unit comprises an absorber (18) and a regenerator (21), the process comprising the steps of: (a) introducing hot exhaust gas exiting a gas turbine into a heat recovery steam generator unit to produce a first amount of steam and a flue gas stream (17) comprising CO₂; (b) removing CO₂ from the flue gas stream comprising CO₂ by contacting the flue gas stream with absorbing liquid in an absorber (18) to obtain absorbing liquid enriched in CO₂ (20) and a purified flue gas stream; (c) contacting the absorbing liquid enriched in CO₂ with a stripping gas at elevated temperature in a regenerator (21) to obtain regenerated absorbing liquid and a gas stream enriched in CO₂ (23); (d) pressurising the gas stream enriched in CO₂ using a CO₂ compressor (24) to obtain the pressurised CO₂ stream, wherein a first part of the steam produced in the heat recovery steam generator unit is used to drive the CO₂ compressor (13).

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PROCESS FOR PRODUCING A PRESSURISED CO₂ STREAM IN A POWER
PLANT INTEGRATED WITH A CO₂ CAPTURE UNIT

The invention relates to a process for producing a pressurised CO₂ stream in a power plant integrated with a carbon dioxide (CO₂) capture unit.

5 A substantial portion of the world's energy supply is provided by combustion of fuels, especially natural gas or synthesis gas, in a power plant. Generally the fuel is combusted in one or more gas turbines and the resulting gas is used to produce steam. The steam is then used to generate power. Combustion of fuel results in the
10 production of CO₂, which needs to be disposed of. During the last decades there has been a substantial global increase in the amount of CO₂ emission to the atmosphere. Following the Kyoto agreement, CO₂ emission has to be reduced in order to prevent or counteract unwanted
15 changes in climate. Therefore, removal and disposal of the CO₂ produced is necessary. The CO₂ concentration of a gas turbine flue gas depends on the fuel and the combustion and heat recovery process applied and is generally relatively low, typically in the range of 3-
20 15%. Thus, a reduction in the emission of CO₂ makes it desirable to separate the CO₂ from the exhaust gas because it will be too expensive to compress and deposit the whole flue gas. For this reason, it is advantageous to use a dedicated CO₂ capture unit, to remove CO₂ from
25 the flue gas and generate a concentrated pressurised CO₂ stream, which can be used elsewhere.

A process to produce a pressurised CO₂ stream is described for example in US 6,883,327. In US 6,883,327, a

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CO₂ capture unit with an absorber and a regenerator is used. A stream enriched in CO₂ exiting the CO₂ regenerator is compressed in a compressor. This compressor is driven using a backpressure turbine as a power source.

It has now been found that a pressurised CO₂ stream can be produced using a steam-driven CO₂ compressor, thus eliminating the use of an additional device to generate power to drive a CO₂ compressor.

To this end, the invention provides a process for producing a pressurised CO₂ stream in a power plant integrated with a CO₂ capture unit, wherein the power plant comprises at least one gas turbine coupled to a heat recovery steam generator unit and the CO₂ capture unit comprises an absorber and a regenerator, the process comprising the steps of:

(a) introducing hot exhaust gas exiting a gas turbine into a heat recovery steam generator unit to produce a first amount of steam and a flue gas stream comprising CO₂;

(b) removing CO₂ from the flue gas stream comprising CO₂ by contacting the flue gas stream with absorbing liquid in an absorber to obtain absorbing liquid enriched in CO₂ and a purified flue gas stream;

(c) contacting the absorbing liquid enriched in CO₂ with a stripping gas at elevated temperature in a regenerator to obtain regenerated absorbing liquid and a gas stream enriched in CO₂;

(d) pressurising the gas stream enriched in CO₂ using a CO₂ compressor to obtain the pressurised CO₂ stream, wherein a first part of the steam produced in the heat

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recovery steam generator unit is used to drive the CO₂ compressor.

In the process, the CO₂ compressor is driven using high-pressure steam from the heat recovery steam generator unit. Thus, no separate device is needed to
5 generate electricity to drive the CO₂ compressor.

In the process, a power plant comprising at least one gas turbine is used. Typically, fuel and an oxygen-containing gas are introduced into a combustion section
10 of the gas turbine. In the combustion section of the gas turbine, the fuel is combusted to generate a hot combustion gas. The hot combustion gas is expanded in the gas turbine, usually via a sequence of expander blades arranged in rows, and used to generate power via a
15 generator. Suitable fuels to be combusted in the gas turbine include natural gas and synthesis gas.

In step (a), hot exhaust gas exiting the gas turbine is introduced into to a heat recovery steam generator unit, where heat contained in the hot exhaust gas is used
20 to produce a first amount of steam.

The heat recovery steam generator unit is any unit providing means for recovering heat from the hot exhaust gas and converting this heat to steam. For example, the heat recovery steam generator unit can comprise a
25 plurality of tubes mounted stackwise. Water is pumped and circulated through the tubes and can be held under high pressure at high temperatures. The hot exhaust gas heats up the tubes and is used to produce steam.

Suitably, the heat recovery steam generator unit can be designed to produce one, two or three types of steam:
30 high-pressure steam, intermediate pressure steam and low-pressure steam. Preferably, the steam generator is designed to produce at least a certain amount of high-

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pressure steam, because high-pressure steam can be used to generate power. Suitably, high-pressure steam has a pressure in the range of from 90 to 150 bara, preferably from 90 to 125 bara, more preferably from 100 to 115
5 bara. Suitably, low-pressure steam is also produced, the low-pressure steam preferably having a pressure in the range of from 2 to 10 bara, more preferably from to 8 bara, still more preferably from 4 to 6 bara. This low-pressure steam is used for the regeneration of the
10 absorbing liquid comprising CO₂.

The heat recovery steam generator unit emits a flue gas comprising CO₂. The composition of the flue gas depends inter alia on the type of fuel used in the gas turbine. Suitably, the flue gas comprises in the range of
15 from 0.25 to 30 % (v/v) of CO₂, preferably from 1 to 20 % (v/v). The flue gas usually also comprises oxygen, preferably in the range of from 0.25 to 20 % (v/v), more preferably from 5 to 15% (v/v), still more preferably from 1 to 10 % (v/v).

20 In step (b), CO₂ is removed by contacting the flue gas with an absorbing liquid in an absorber. The absorbing liquid may be any absorbing liquid capable of removing CO₂ from a flue gas stream. In particular, absorbing liquids capable of removing CO₂ from flue gas
25 streams, which flue gas streams comprise oxygen and further have relatively low concentrations of CO₂, are suitable. Such absorbing liquids may include chemical and physical solvents or combinations of these.

Furthermore, in the event that the flue gas stream
30 comprises an appreciable quantity of oxygen, suitably in the range of from 1 to 20 % (v/v) of oxygen, preferably a corrosion inhibitor is added to the absorbing liquid.

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Suitable corrosion inhibitors are described for example in US 6,036,888.

Suitable physical solvents include dimethylether compounds of polyethylene glycol.

5 Suitable chemical solvents include ammonia and amine compounds.

10 In one embodiment, the absorbing liquid comprises one or more amines selected from the group of monethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), methyldiethanolamine (MDEA) and triethanolamine (TEA). MEA is an especially preferred amine, due to its ability to absorb a relatively high percentage of CO₂ (volume CO₂ per volume MEA). Thus, an absorbing liquid comprising MEA is suitable to remove CO₂ from flue gases having low
15 concentrations of CO₂, typically 3-10 volume % CO₂.

20 In another embodiment, the absorbing liquid comprises one or more amines selected from the group of methyldiethanolamine (MDEA), triethanolamine (TEA), N,N'-di(hydroxyalkyl)piperazine, N,N,N',N'-tetrakis(hydroxyalkyl)-1,6-hexanediamine and tertiary alkylamine sulfonic acid compounds.

Preferably, the N,N'-di(hydroxyalkyl)piperazine is N,N'-d-(2-hydroxyethyl)piperazine and/or N,N'-di-(3-hydroxypropyl)piperazine.

25 Preferably, the tetrakis(hydroxyalkyl)-1,6-hexanediamine is N,N,N',N'-tetrakis(2-hydroxyethyl)-1,6-hexanediamine and/or N,N,N',N'-tetrakis(2-hydroxypropyl)-1,6-hexanediamine.

30 Preferably, the tertiary alkylamine sulfonic compounds are selected from the group of 4-(2-hydroxyethyl)-1-piperazineethanesulfonic acid, 4-(2-hydroxyethyl)-1-piperazinepropanesulfonic acid, 4-(2-

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hydroxyethyl)piperazine-1-(2-hydroxypropanesulfonic acid) and 1,4-piperazinedi(sulfonic acid).

In yet another embodiment, the absorbing liquid comprises N-ethyldiethanolamine (EDEA).

5 In an especially preferred embodiment, the absorbing liquid comprises ammonia.

It has been found that, especially when using an absorbing liquid comprising an amine, better absorption of CO₂ is achieved when absorption takes place at
10 relatively low temperature and at elevated pressure. As the pressure of the flue gas will typically be low, preferably the flue gas is pressurised prior to entering the absorber. As the temperature of the flue gas will typically be relatively high, preferably the flue gas is
15 cooled prior to entering the absorber.

In step (c), the absorbing liquid enriched in CO₂ is regenerated by contacting the absorbing liquid enriched in CO₂ with a stripping gas at elevated temperature in a regenerator to obtain regenerated absorbing liquid and a
20 gas stream enriched in CO₂. It will be understood that the conditions used for regeneration depend inter alia on the type of absorbing liquid and on the conditions used in the absorption step. In the event that the absorbing liquid comprises an amine, preferred regeneration
25 temperatures are in the range of from 100 to 200 °C. In the event that the absorbing liquid comprises an aqueous amine, regeneration preferably takes place at pressure in the range of from 1 to 5 bara.

In the event that the absorbing liquid comprises ammonia, suitably the absorbing step is performed at
30 temperatures below ambient temperature, preferably in the range of from 0 to 10 °C, more preferably from 2 to 8 °C. The regeneration step is suitably performed at

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temperatures higher than used in the absorption step. When using an absorbing liquid comprising ammonia, the gas stream enriched in CO₂ exiting the regenerator has an elevated pressure. Suitably, the pressure of the gas stream enriched in CO₂ is in the range of from 5 to 8 bara, preferably from 6 to 8 bara. In applications where the gas stream enriched in CO₂ needs to be at a high pressure, for example when it will be used for injection into a subterranean formation, it is an advantage that the gas stream enriched in CO₂ is already at an elevated pressure. Normally, a series of compressors is needed to pressurise the gas stream enriched in CO₂ to the desired high pressures. A gas stream enriched in CO₂ which is already at elevated pressure is easier to further pressurise.

In step (d), the gas stream enriched in CO₂ is pressurised using a CO₂ compressor to obtain the pressurised CO₂ stream. A first part of the steam produced in the heat recovery steam generator unit is used to drive the CO₂ compressor. In a preferred embodiment, the first part of the steam produced in the heat recovery steam generator unit is led to an expander, which expander is coupled to the CO₂ compressor, for example via a shaft. The expander thus drives the CO₂ compressor, without the need to first produce electricity to drive the CO₂ compressor. In an especially preferred embodiment, the discharge of the expander comprises low-pressure steam, which low-pressure steam is used to provide at least part of the heat required by the regenerator. Thus, depending on the heat/power demand ration of the CO₂ capture unit, the pressure of the high

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pressure steam heat requirements of the regeneration step are at least partly met by combusting an amount of fuel in the heat recovery steam generator unit to produce a second amount of steam. Preferably, the pressurised CO₂ stream has a pressure in the range of from 40 to 300 bara, more preferably from 50 to 300 bara. A CO₂ stream having a pressure in these preferred ranges can be used for many purposes, in particular for enhanced recovery of oil, coal bed methane or for sequestration in a subterranean formation. Especially for purposes wherein the pressurised CO₂ stream is injected into a subterranean formation, high pressures are required. In a preferred embodiment, the pressurised CO₂ stream is used for enhanced oil recovery. By injecting CO₂ into an oil reservoir, the oil recovery rate can be increased. Typically, the pressurised CO₂ stream is injected into the oil reservoir, where it will be mixed with some of the oil which is present. The mixture of CO₂ and oil will displace oil which cannot be displaced by traditional injections.

In an especially preferred embodiment, the process further comprises an additional step (e) of combusting an amount of fuel in the heat recovery steam generator unit to produce a second amount of steam, wherein the amount of fuel is such that the second amount of steam is sufficient to provide at least 80% of the heat needed for the regeneration of the absorbing liquid. Preferably the second amount of steam is sufficient to provide at least 90% of the heat needed for the regeneration of the absorbing liquid. Preferably, low pressure steam piping is used to deliver the heating steam from the heat recovery steam generator to the CO₂ capture unit. This

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low pressure steam piping is suitably arranged in a closed loop to segregate the steam produced which is used for power production from steam used in process heat exchangers. Combusting an amount of fuel in the heat recovery steam generator unit has the advantage that the total power output of the power plant will be independent of whether or not the CO₂ capture unit is in operation. The amount of fuel needed to provide for the regeneration heat requirements can for example be determined by monitoring the power generated by the heat recovery steam generator unit and adjusting the amount of fuel introduced into the heat recovery steam generator unit in dependence of the amount of power generated. As explained earlier, in the heat recovery steam generator unit preferably high pressure steam is produced in a steam turbine, which high pressure steam is converted to power, for example via a generator coupled to the steam turbine. The power output of the generator coupled to the steam turbine will decrease when the CO₂ capture unit is in operation, due to the amount of steam extracted from the heat recovery steam generator unit needed to heat up the regenerator of the CO₂ capture unit. By monitoring the output of generator coupled to the steam turbine of the heat recovery generator unit, the amount of fuel combusted in the heat recovery steam generator unit can be adjusted. In the event that the output decreases, the amount of fuel combusted can be increased. Preferably, the amount of fuel to be combusted in order to enable fulfilling the heat requirements of the regenerator of the CO₂ capture unit without significantly diminishing the power output of the generator coupled to the steam turbine is predetermined. The power output of the generator coupled to the steam turbine when the CO₂

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capture unit is not in operation is taken as a base case and the amount of fuel to be combusted in order to achieve the same output is then determined.

5 Suitable fuels for combustion in the heat recovery steam generator unit include natural gas and synthesis gas.

10 Combustion of the amount of fuel in the heat recovery steam generator unit requires the presence of oxygen. This oxygen can be supplied to the heat recovery steam generator unit, but preferably the hot exhaust gas comprises oxygen and at least part of this oxygen is used in the combustion of the fuel in the heat recovery steam generator unit. As a result of using oxygen from the hot exhaust gas, the amount of oxygen in the flue gas exiting the heat recovery steam generator unit will be lower. 15 This is favourable for the CO₂ absorption process, especially when an amine absorbing liquid is used. Oxygen can cause amine degradation and can lead to the formation of degradation products in the absorbing liquid. A lower oxygen content of the flue gas will therefore result in less amine degradation. 20

 The invention will now be illustrated, by means of example only, with reference to the accompanying figure 1.

25 In figure 1, a power plant comprising a gas turbine (1), a heat recovery steam generator unit (2) and a CO₂ capture unit (3) is shown. In the gas turbine, an oxygen-containing gas is supplied via line 4 to compressor 5. Fuel is supplied via line 6 to combustor 7 and combusted in the presence of the compressed oxygen-containing gas. 30 The resulting combustion gas is expanded in a first expander 8 and used to generate power in generator 9. Remaining exhaust gas comprising CO₂ and oxygen is led

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via line 10 to a heat recovery steam generator unit 2. In the heat recovery steam generator unit, water is heated against the hot exhaust gas in heating section 11 to generate steam. A first part of the steam is led via line 12 to a second expander 13. A second part of the steam is led via line 14 to a steam turbine 15 coupled to generator 16 to produce additional power. Optionally, an amount of fuel is led (not shown) to the heat recovery steam generator unit and combusted, using oxygen from the exhaust gas, to produce additional steam. Hot flue gas comprising CO₂ and oxygen is led via line 17 to an amine absorber 18. Preferably, the hot flue gas is first cooled in a cooler (not shown) and the cooled flue gas is pressurised using a blower (not shown) prior to entering the amine absorber. In amine absorber 18, CO₂ is transferred at elevated pressure from the flue gas to the amine liquid contained in the amine absorber. Purified flue gas, depleted in CO₂, is led from the amine absorber via line 19. Amine liquid, enriched in CO₂ is led from the amine absorber via line 20 to a regenerator 21. In the regenerator, amine liquid enriched in CO₂ is depressurised and contacted with a stripping gas at elevated temperature, thereby transferring CO₂ from the amine liquid to the stripping gas to obtain regenerated amine liquid and a gas stream enriched in CO₂. Regenerated amine liquid is led from the regenerator via line 22 to the amine absorber 18. The gas stream enriched in CO₂ is led from the regenerator via line 23 to a CO₂ compressor 24. High-pressure steam from expander 13 is led via a shaft 25 to the CO₂ compressor 24 and is used to drive the CO₂ compressor. Low-pressure steam is led from expander 13 via line 26 to the regenerator and

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provides at least part of the heat needed to heat up the regenerator. The remaining part of the heat requirements of the regenerator are fulfilled using low pressure from the second steam turbine, which low pressure is led to
5 the regenerator via line 27.

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C L A I M S

1. A process for producing a pressurised CO₂ stream in a power plant integrated with a CO₂ capture unit, wherein the power plant comprises at least one gas turbine coupled to a heat recovery steam generator unit and the CO₂ capture unit comprises an absorber and a regenerator, the process comprising the steps of:
- 5 (a) introducing hot exhaust gas exiting a gas turbine into a heat recovery steam generator unit to produce a first amount of steam and a flue gas stream comprising CO₂;
- 10 (b) removing CO₂ from the flue gas stream comprising CO₂ by contacting the flue gas stream with absorbing liquid in an absorber to obtain absorbing liquid enriched in CO₂ and a purified flue gas stream;
- 15 (c) contacting the absorbing liquid enriched in CO₂ with a stripping gas at elevated temperature in a regenerator to obtain regenerated absorbing liquid and a gas stream enriched in CO₂;
- 20 (d) pressurising the gas stream enriched in CO₂ using a CO₂ compressor to obtain the pressurised CO₂ stream, wherein a first part of the steam produced in the heat recovery steam generator unit is used to drive the CO₂ compressor.
2. A process according to claim 1, wherein part of the steam produced in the heat recovery steam generator unit is led to an expander, which expander is coupled to the CO₂ compressor.
- 25 3. A process according to claim 1 or 2, wherein power is generated by leading another part of the steam produced

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in the heat recovery steam generator unit to a steam turbine, which steam turbine is coupled to a generator and power is produced by the generator.

4. A process according to claim 2 or 3, wherein the expander discharges low pressure steam, which low-pressure steam is used to provide at least part of the heat needed for the regeneration of the absorbing liquid.

5. A process according to any of the preceding claims, further comprising the step of:

(e) combusting an amount of fuel in the heat recovery steam generator unit to produce a second amount of steam, wherein the amount of fuel is such that the second amount of steam is sufficient to provide at least 80% of the heat needed for the regeneration of the absorbing liquid.

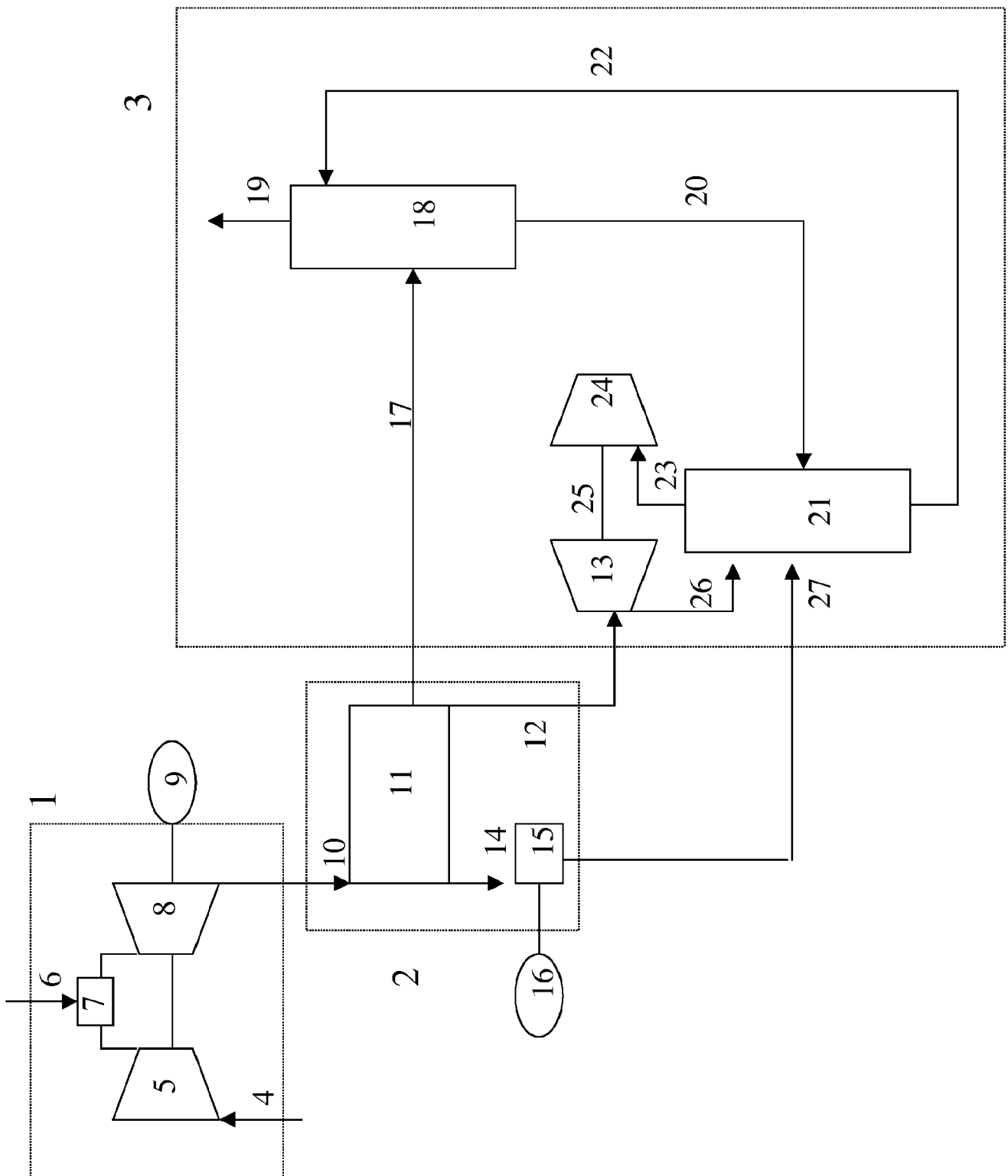
6. A process according to any one of the preceding claims, wherein the high-pressure steam has a pressure in the range of from 90 to 125 bara, more preferably from 100 to 115 bara and/or the low-pressure steam has a pressure in the range of from 3 to 8 bara, more preferably from 4 to 6 bara.

7. A process according to any one of the preceding claims, wherein the pressurised gas stream enriched in CO₂ has a pressure in the range of from 40 to 300 bara, more preferably from 50 to 300 bara.

8. A process according to any one of the preceding claims, wherein the absorbing liquid comprises an amine, preferably one or more amines selected from the group of monethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), methyldiethanolamine (MDEA), triethanolamine (TEA), N-ethyldiethanolamine (EDEA), N,N'-di(hydroxyalkyl)piperazine, N,N,N',N'-tetrakis(hydroxyalkyl)-1,6-hexanediamine and tertiary alkylamine sulfonic acid compounds.

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9. A process according to any one of claims 1 to 8 wherein the absorbing liquid comprises a physical solvent, preferably a dimethylether of polyethylene glycol.
- 5 10. A process according to any one of claims 1 to 7, wherein the absorbing liquid comprises ammonia.



INTERNATIONAL SEARCH REPORT

International application No
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A. CLASSIFICATION OF SUBJECT MATTER
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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)
B01D F01K

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

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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Y	column 1, lines 53-57 column 1, lines 59-63 column 1, line 64 - column 2, line 7 column 2, lines 4-12 column 2, lines 37-42 column 3, lines 11-14 column 7, lines 37-42 figure 2 ----- -/--	9,10

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

☒ See patent family annex.

* Special categories of cited documents:

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INTERNATIONAL SEARCH REPORT

International application No

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C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

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Information on patent family members

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