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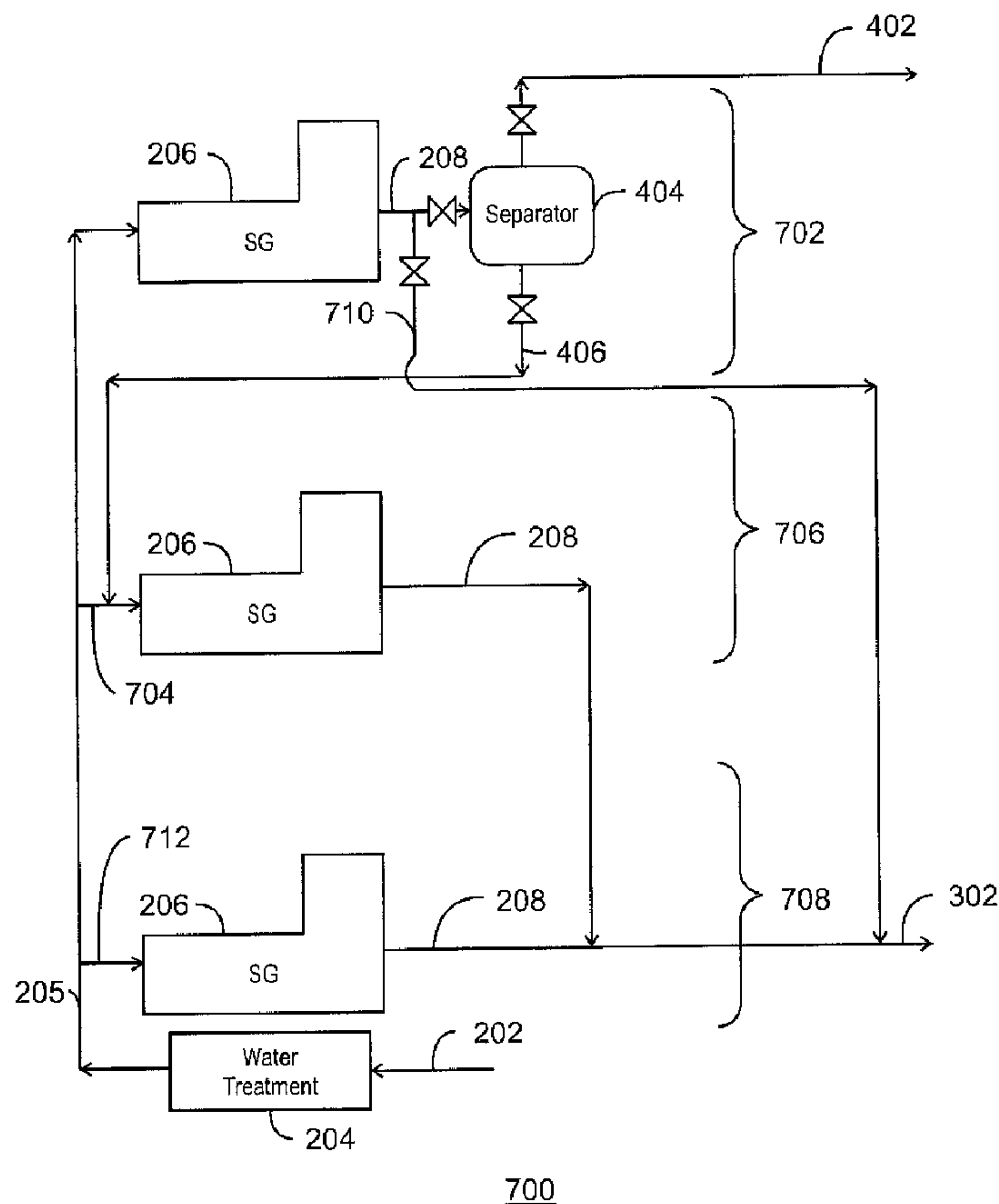
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(54) **Titre : METHODES ET SYSTEMES DE GENERATION DE VAPEUR**

(54) **Title: METHODS AND SYSTEMS FOR PROVIDING STEAM**



(57) **Abrégé/Abstract:**

A system is provided for improved steam generation. The system includes at least two steam systems, wherein a wet steam output from a first steam system is passed through a first separator. The first separator configured to separate dry steam from condensate, and a piping connection is configured to blend the condensate with a boiler feed water stream at the inlet of a second steam system.

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ABSTRACT

[0170] A system is provided for improved steam generation. The system includes at least two steam systems, wherein a wet steam output from a first steam system is passed through a first separator. The first separator configured to separate dry steam
5 from condensate, and a piping connection is configured to blend the condensate with a boiler feed water stream at the inlet of a second steam system.

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METHODS AND SYSTEMS FOR PROVIDING STEAM

FIELD

5 **[0001]** The present techniques provide methods for generating steam. More specifically, the techniques provide methods and systems for adapting steam generation to hydrocarbon recovery processes.

BACKGROUND

10 **[0002]** This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present techniques. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present techniques. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

15 **[0003]** Modern society is greatly dependant on the use of hydrocarbons for fuels and chemical feedstocks. Hydrocarbons are often found in subsurface rock formations that can be termed "reservoirs." Removing hydrocarbons from the reservoirs depends on numerous physical properties of the rock formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the rock formations, and the proportion of hydrocarbons present, among others.

20 **[0004]** Easily harvested sources of hydrocarbon are dwindling, leaving less accessible sources to satisfy future energy needs. However, as the costs of hydrocarbons increase, these less accessible sources become more economically attractive. For example, the harvesting of oil sands to remove hydrocarbons has become more extensive as it has become more economical. The hydrocarbons
25 harvested from these reservoirs may have relatively high viscosities, for example, ranging from 8 API, or lower, up to 20 API, or higher. Accordingly, the hydrocarbons may include heavy oils, bitumen, or other carbonaceous materials, collectively referred to herein as "heavy oil," which are difficult to recover using standard techniques.

30 **[0005]** Several methods have been developed to remove hydrocarbons from oil sands. For example, strip or surface mining may be performed to access the oil sands,

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which can then be treated with hot water or steam to extract the oil. However, deeper formations may not be accessible using a strip mining approach. For these formations, a well can be drilled to the reservoir and steam, hot air, solvents, or combinations thereof, can be injected to release the hydrocarbons. The released hydrocarbons may then be collected by the injection well or by other wells and brought to the surface.

[0006] A number of techniques have been developed for harvesting heavy oil from subsurface formations using thermal recovery techniques. Thermal recovery operations are used around the world to recover liquid hydrocarbons from both sandstone and carbonate reservoirs. These operations include a suite of steam based in situ thermal recovery techniques, such as cyclic steam stimulation (CSS), steamflooding and steam assisted gravity drainage (SAGD) as well as surface mining and their associated thermal based surface extraction techniques.

[0007] For example, CSS techniques includes a number of enhanced recovery methods for harvesting heavy oil from formations that use steam heat to lower the viscosity of the heavy oil. The CSS process raises the steam injection pressure above the formation fracturing pressure to create fractures within the formation and enhance the surface area access of the steam to the heavy oil. The steam raises the temperature of the heavy oil during a heat soak phase, lowering the viscosity of the heavy oil. The injection well may then be used to produce heavy oil from the formation. The cycle is often repeated until the cost of injecting steam becomes uneconomical, for instance if the cost is higher than the money made from producing the heavy oil. However, successive steam injection cycles may reenter earlier created fractures and, thus, the process becomes less efficient over time.

[0008] Solvents may be used in combination with steam in CSS processes, such as in mixtures with the steam or in alternate injections between steam injections. After injection with the steam, the liquid hydrocarbons are transported as vapors to contact heavy oil surrounding steamed areas between adjacent wells. The injected hydrocarbons can be produced as a mixture with the heavy oil phase. The loading of the liquid hydrocarbons injected with the steam can be chosen based on pressure drawdown and fluid removal from the reservoir using lift equipment in place for the CSS.

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[0009] Another group of techniques is based on a continuous injection of steam through a first well to lower the viscosity of heavy oils and a continuous production of the heavy oil from a lower-lying second well. Such techniques may be termed “steam assisted gravity drainage” or SAGD. In SAGD, two horizontal wells are completed into the reservoir. These wells can be started as slant wells at surface or vertical wells and drilled to different depths within the reservoir. Thereafter, using directional drilling technology, the two wells are extended in the horizontal direction that result in two horizontal wells, vertically spaced from, but otherwise vertically aligned with the other. Ideally, the production well is located above the base of the reservoir but as close as practical to the bottom of the reservoir, and the injection well is located vertically 10 to 30 feet (3 to 10 meters) above the horizontal well used for production.

[0010] The upper horizontal well is utilized as an injection well and is supplied with steam from the surface. The steam rises from the injection well, permeating the reservoir to form a vapor chamber that grows over time towards the top of the reservoir. The steam, and its condensate, raise the temperature of the reservoir and consequently reduce the viscosity of the heavy oil in the reservoir. The heavy oil and condensed steam will then drain downward through the reservoir under the action of gravity and may flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface, the condensed steam and heavy oil are separated, and the heavy oil may be diluted with appropriate light hydrocarbons for transport by pipeline.

[0011] As a result of the unique wellbore configuration in SAGD, any condensate, e.g., any liquid water phase, injected into the reservoir with the steam will fall directly to the underlying production well due to the influence of gravity, and thereby not contribute to the recovery of the hydrocarbons. For this reason, the current convention in SAGD projects is to separate the condensate from a wet steam flow and inject the dry steam phase into the injection wells used in the recovery process. As used herein, wet steam is a flow of steam that holds entrained water droplets originating either from incomplete conversion of a water stream into steam or from condensation of the steam. The steam after the condensate has been removed is referred to as dry steam.

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[0012] As discussed above, SAGD is a process where the recovery process benefits from the injection of dry steam. In contrast, CSS, steamflooding and SAGD infill well injectors are examples of processes that make thermally efficient use of wet steam which can also be demonstrated using numerical simulation.

- 5 **[0013]** The vast majority of the commercial thermal recovery schemes produce steam for injection activities through once-through-steam-generators (OTSG) or cogeneration facilities that utilize heat-recovery-steam-generators (HRSG). A common feature of OTSGs and HRSGs is that the steam is generated inside a series of boiler tubes that are heated by combustion of a hydrocarbon fuel external to the boiler tubes.
- 10 As a result of the application of this external heat source a progressively larger fraction of the water inside the boiler tubes is converted to steam as it passes through the steam generator. The quality of the steam is measured as the percentage of vapor by mass of cold water. Thus, an 80 % quality steam is a steam flow containing 80 % of its mass in vapor.
- 15 **[0014]** Due to the presence of contaminants, such as hardness, salts, and silica, the maximum steam quality generated in OTSG and HRSG generators is typically between 60 to 80 %. This means that 20 to 40 % of the water mass entering the steam generator remains as water at the exit of the steam generator. Feed water used for generating steam in OTSGs and HRSGs can come from many sources and, depending
- 20 upon the properties of the raw water, is treated to remove contaminants and render it suitable as a feed stream for a OTSG or HRSG.

[0015] In these styles of generators the maximum steam quality can be limited by the need to ensure that a continuous film of water coats the inner wall of boiler tube surfaces. If the continuous water film is not present, local dry spots will be created,

25 leading to elevated tube temperatures and potential tube overheating. Also, by converting 100 % of the water to steam in these areas, contaminants present in the water entering the steam generator can be deposited on the boiler tubes in the form of scale. These deposits impede heat transfer and further contribute to tube overheating. Significant tube overheating can result in the failure of the boiler tube. Limiting the

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steam quality may ensure that sufficient water remains in the generator to ensure that the contaminants exceed their solubility limit, limiting the potential for scaling.

[0016] In conventional thermal extraction processes, such as steamfloods, CSS projects, SAGD infill wells, and sub-surface and surface mining using surface extraction, the recovery processes are able to effectively utilize a significant fraction of the heat contained within the condensate phase that is either injected into the reservoir or blended with the mined ore. For this reason, wet steam is sufficient for the recovery process.

[0017] Where the in situ recovery process being utilized can effectively utilize the heat contained in the condensate, the wet steam generated in the OTSG or HRSG is transported using pipelines to the wells and injected via wellbores into the hydrocarbon bearing reservoir. The injected steam heats the hydrocarbon, reducing its viscosity and allowing it to be recovered via either the same wells the steam was injected into or via one or more laterally and/or vertically offset production wells. In a surface mining and associated thermal based surface extraction technique the wet steam is used to heat the mined ore to allow its efficient extraction from the reservoir fabric.

[0018] The fluids produced as a result of the thermal recovery process contain liquid hydrocarbons recovered from the reservoir, water from condensed steam, formation water, and various minerals and other constituents which may be dissolved or suspended in the mixture, along with steam and gaseous constituents. The produced fluids are typically transported to a centralized facility and separated, forming vapor, liquid hydrocarbon, and aqueous streams. An aqueous stream, which has as its major component produced water used for in situ recovery processes, can be treated to render it suitable for re-use as boiler feed water in the OTSG or HRSG. This treatment can include the removal of the majority of the hardness and a reduction in both iron and silica levels.

[0019] Where the recovery process being utilized cannot effectively utilize the heat contained in the condensate, the wet steam generated in the OTSG or HRSG is separated into vapor and condensate streams downstream of the generator exit. The resulting dry steam is then transported to the wells via pipeline, while the condensate

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stream contains essentially all of the impurities that were present in the boiler feed water, in addition to a significant quantity of heat.

[0020] As previously noted, the condensate stream can represent between 20 and 40% of the boiler feed water stream, depending on the quality of the steam generated.

5 Managing the condensate can be problematic. If sufficient make-up water capacity and disposal capacity is required, the facility can be designed to maximize the heat recovery from the condensate before disposing of it. If make-up water capacity or disposal capacity is limited, then emphasis is placed on recycling the condensate.

[0021] One common practice is to recycle a portion of the condensate, with or
10 without processing in a water treatment plant, and reusing it as boiler feed water. However, the quantity of condensate that can be recycled is limited by the build-up of dissolved solids in the boiler feed water, which can precipitate in the boiler tubes if a portion of the condensate is not continuously purged from the system. If the development is currently using two recovery processes, one using dry steam and the
15 second using wet steam, a second practice may take the condensate and to blend it with the wet steam being utilized in the second recovery process. This can be an acceptable practice as long as the dry steam demand is small compared to the wet steam needs.

[0022] Various techniques have been developed to improve the quality of a
20 condensate that is to be used as boiler feed water. For example, U.S. Patent No. 7,591,309 to Minnich, et al., discloses an evaporation process for conversion of condensate into a high quality water stream and either a brine or a solids reject stream suitable for disposal. In the method, de-oiled produced water is processed through an evaporator at high pH and high pressure. The evaporator is driven by a commercial
25 boiler. The steam from the evaporator can be used in SAGD. The evaporator blowdown may be further treated in a crystallizing evaporator to provide a zero liquid discharge (ZLD) system. With most produced waters, at least 98 % of the incoming produced water stream can be recovered in the form of high pressure steam.

[0023] U.S. Patent Application Publication No. 2009/0133643 by Suggett, et al.,
30 discloses a method and apparatus for generating steam while reducing the quantity of

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boiler blowdown and, thus, increasing the amount of feed water that is re-used or re-cycled in generating the steam. The application claims that, on a sustained basis, the blowdown stream at the outlet of a once-through steam generator can be routed to the inlet of a second once-through steam generator that is in series with the first, that
5 blowdown stream can be used to generate additional steam in the second once-through steam generator and further reduce the amount of blowdown, and that this can be accomplished without need of any treatment that reduces hardness or silica levels of the blowdown stream prior to its entering or during its entry into the inlet of the second once-through steam generator. The output of this second steam generator is a
10 substantially dry saturated steam vapor stream and, a blowdown stream whose mass rate has been reduced substantially from that of the blowdown stream exiting the first steam generator.

[0024] Similarly, Canadian Patent No. 2,621,991 to Speirs, et al., teaches a separate OTSG (or HRSG), referred to as a boiler blowdown OTSG, which is located in series
15 with one or more other OTSGs (or HRSGs) and can utilize the condensate from the initial OTSGs (or HRSGs) to generate wet steam. Reuse of the condensate in this way results in a significant reduction in the size of the condensate stream and an increase in the effective steam quality being generated. In the process boiler feed water (BFW) of sufficient quality is fed through one or more primary wet steam generators to generate
20 primary wet steam. The primary wet steam is separated into primary dry steam and a primary liquid phase. The primary liquid phase can be fed into one or more secondary steam generators to generate secondary steam. The secondary steam generators may or may not be wet steam generators.

[0025] During the transition from a recovery process that is able to effectively utilize
25 wet steam to a recovery process requiring dry steam the amount of condensate that is reused may need to be changed. The current approaches to increase the reuse of condensate generally have a number of problems. For example, many developments have a much larger requirement for wet steam than dry steam. Changing the reuse of the condensate may lose the benefits of the heat contained in the condensate. New
30 water treatment technology may be needed in the operation. A series of boiler

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blowdown steam generators may be needed in order to match the volume of condensate not being utilized in the dry steam scheme. Further, a large fraction of the installed steam generation capacity may need to be converted to dry steam production in order to allow one of the existing steam generators to be used as a dedicated in series boiler blowdown steam generator.

[0026] As the techniques used to recover resource from a reservoir are adapted to the remaining resource present, the amounts and quality of the steam needed by the development may change. However, none of the references described above disclose tailoring the steam sources or quality to the changing needs of the reservoir over time.

SUMMARY

[0027] An embodiment of the present techniques provides a system for improved steam generation. The system includes at least two steam systems, wherein a wet steam output from a first steam system is passed through a first separator. The first separator is configured to separate dry steam from condensate and a piping connection is used configured to supplement a boiler feed water stream with the condensate at the inlet of a second steam system. The amount of condensate supplementing the boiler feed water stream is changed based, at least in part, on a demand for dry steam.

[0028] Another embodiment provides a method for improving recovery from a hydrocarbon reservoir. The method includes matching a steam quality to a hydrocarbon development, wherein the steam is generated by a steam generation facility comprising a plurality of steam systems. The steam generation facility is adapted to match a change in steam usage caused by a change in the hydrocarbon development, by cascading a condensate stream from a separator on an outlet of at least one steam system to an inlet of another steam system and replacing a portion of boiler feed water stream with the condensate stream at the inlet. The portion of boiler feed water replaced is determined by a ratio of dry steam to wet steam used in the hydrocarbon development.

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DESCRIPTION OF THE DRAWINGS

[0029] The advantages of the present techniques are better understood by referring to the following detailed description and the attached drawings, in which:

5 **[0030]** Fig. 1 is a drawing of a development illustrating the use of both a surface mining recovery process and a steam assisted gravity drainage (SAGD) recovery process to harvest hydrocarbons from a reservoir;

[0031] Fig. 2 is a drawing of a conventional steam generation system that may be utilized to generate steam for thermal or thermal-solvent recovery processes, such as
10 CSS;

[0032] Fig. 3 is a drawing of a steam generation system that uses three steam generators in parallel to generate wet steam for a thermal recovery process;

[0033] Fig. 4 shows a steam generation system that can be utilized to generate dry steam for thermal recovery processes such as SAGD developments;

15 **[0034]** Fig. 5 is a drawing of a steam generation system in a series design in which the condensate from a first steam generator is separated from the dry steam in a separator and used as a feed water stream for a smaller steam generator;

[0035] Fig. 6 is a drawing of a steam generation system using multiple steam generators for the purpose of generating primarily dry steam;

20 **[0036]** Fig. 7 is a drawing of a steam generation system after conversion of one steam generator to the production of dry steam;

[0037] Fig. 8 is a drawing of a steam generation system after conversion of two steam generators to the production of dry steam;

[0038] Fig. 9 is a drawing of a steam generation system that may provide similar
25 production of wet and dry steam as described for Figs. 7 and 8;

[0039] Fig. 10 is a drawing of a steam generation system that may not provide material steam quality improvement, but may provide significant operating flexibility;

[0040] Fig. 11 is a drawing of the system of Figs. 7 and 8 after the third steam system is converted to dry steam service;

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[0041] Fig. 12 is a drawing of a steam generation system in which three steam systems operate in parallel and generate dry steam by cascading the condensate sequentially to the inlet of the adjacent steam system;

[0042] Fig. 13 is a drawing of a steam generation system showing that the cascading process may be applied to steam systems having multiple steam generators operating in parallel;

[0043] Fig. 14 is a drawing of a steam generation system that includes a seventh steam generator installed in a fourth steam system;

[0044] Fig. 15 is a drawing of a steam generator that is modified to increase both throughput and dry steam production; and

[0045] Fig. 16 is a process flow diagram of a method for tailoring the quality of steam production to field needs;

[0046] Fig. 17 is a drawing of a development for which dry steam is separated from the wet steam and the different steam lines are directed to regions of the field where recovery processes efficiently use the wet or dry steam;

[0047] Fig. 18 is a diagram of a SAGD process with infill wells where the efficiency of the process is enhanced by directing dry steam to the SAGD injection wells 1804 and wet steam to the infill well injectors; and

[0048] Fig. 19 is another diagram of a SAGD process with infill wells where the efficiency of the process is enhanced by directing dry steam to the SAGD injection wells 1906 and wet steam to the infill well injectors.

DETAILED DESCRIPTION

[0049] In the following detailed description section, specific embodiments of the present techniques are described. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present techniques, this is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the techniques are not limited to the specific embodiments described below, but rather, include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

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[0050] At the outset, for ease of reference, certain terms used in this application and their meanings as used in this context are set forth. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent.

5 Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments, and terms or techniques that serve the same or a similar purpose are considered to be within the scope of the present claims.

[0051] As used herein, "bitumen" is a naturally occurring heavy oil material. It is
10 often the hydrocarbon component found in oil sands. Bitumen can vary in composition depending upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

15 19 wt. % aliphatics, which can range from 5 wt. %-30 wt. %, or higher;
19 wt. % asphaltenes, which can range from 5 wt. %-30 wt. %, or higher;
30 wt. % aromatics, which can range from 15 wt. %-50 wt. %, or higher;
32 wt. % resins, which can range from 15 wt. %-50 wt. %, or higher; and
some amount of sulfur, which can range in excess of 7 wt. %.

20 In addition bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt. % to in excess of 0.7 wt. %. The metals content, while small, can be removed to avoid contamination of the product synthetic crude oil (SCO). Nickel can vary from less than 75 ppm (part per million) to more than 200 ppm. Vanadium can range from less than 200 ppm to more than 500 ppm. The percentage of the
25 hydrocarbon types found in bitumen can vary.

[0052] As used herein, "condensate" includes liquid water formed by the condensation of steam. Steam may also entrain liquid water, in the form of water droplets. This entrained water may also be termed condensate, as it may arise from condensation of the steam, although the entrained water droplets may also originate
30 from the incomplete conversion of liquid water to steam in a boiler.

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[0053] As used herein, a “development” is a project for the recovery of hydrocarbons using integrated surface facilities and long term planning. The development can be directed to a single hydrocarbon reservoir, although multiple proximate reservoirs may be included.

5 **[0054]** As used herein, “exemplary” means “serving as an example, instance, or illustration.” Any embodiment described herein as “exemplary” is not to be construed as preferred or advantageous over other embodiments.

[0055] As used herein, “facility” as used in this description is a collection of physical equipment through which hydrocarbons and other fluids may be either produced from a
10 reservoir or injected into a reservoir. A facility may also include equipment which can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps,
15 compressors, separators, surface flow lines, steam generation plants, extraction plants, processing plants, water treatment plants, and delivery outlets. In some instances, the term “surface facility” is used to distinguish those facilities other than wells.

[0056] As used herein, a “heat recovery steam generator” or HRSG is a heat exchanger or boiler that recovers heat from a hot gas stream. It produces steam that
20 can be used in a process or used to drive a steam turbine. A common application for an HRSG is in a combined-cycle power plant, where hot exhaust from a gas turbine is fed to the HRSG to generate steam which in turn drives a steam turbine. As described herein, the HRSG may be used to provide steam to an enhanced oil recovery process, such as CSS or SAGD.

25 **[0057]** As used herein, “heavy oil” includes oils which are classified by the American Petroleum Institute (API), as heavy oils or extra heavy oils. In general, a heavy oil has an API gravity between 22.3° (density of 920 kg/m³ or 0.920 g/cm³) and 10.0° (density of 1,000 kg/m³ or 1 g/cm³). An extra heavy oil, in general, has an API gravity of less than 10.0° (density greater than 1,000 kg/m³ or greater than 1 g/cm³). For example, a
30 source of heavy oil includes oil sand or bituminous sand, which is a combination of clay,

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sand, water, and bitumen. The thermal recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature or solvent concentration. Once the viscosity is reduced, the mobilization of fluids by steam, hot water flooding, or gravity is possible. The reduced viscosity makes the drainage quicker and therefore directly
5 contributes to the recovery rate.

[0058] As used herein, a "hydrocarbon" is an organic compound that primarily includes the elements hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. As used herein, hydrocarbons are used to refer to components found in bitumen, or other oil sands.

10 **[0059]** As used herein, a "reservoir" is a subsurface rock or sand formation from which a production fluid can be harvested. The rock formation may include sand, granite, silica, carbonates, clays, and organic matter, such as oil, gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 m) to hundreds of feet (hundreds of m).

15 **[0060]** As used herein, and discussed in detail above, "Steam Assisted Gravity Drainage" (SAGD), is a thermal recovery process in which steam is injected into a first well to lower a viscosity of a heavy oil, and fluids are recovered from a second well. Both wells are usually horizontal in the formation and the first well lies above the second well. Accordingly, the reduced viscosity heavy oil flows down to the second well under
20 the force of gravity, although pressure differential may provide some driving force in various applications.

[0061] As used herein, a "steam generator" may include any number of devices used to generate steam for a process facility, either directly or as part of another process. Steam generators may include, for example, heat recovery steam generators (HRSG),
25 and once through steam generators (OTSG), among others. The steam may be generated at a number of quality levels. Steam quality is measured by the mass fraction of a cold water stream that is converted into a vapor. For example, an 80 % quality steam has around 80 wt. % of the feed water converted to vapor. The steam is generated as wet steam that contains both steam vapor and associated condensate (or
30 water). The wet steam may be passed through a separator to generate a dry steam,

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i.e., without entrained condensate. As a result of the separation, the separator also generates a liquid condensate stream.

[0062] As used herein, a "steam system" includes one or more steam generators running in parallel from a common feed water source and feeding steam to a common outlet. The steam system may include any number or types of steam generators in parallel. Often, the parallel steam generators of the steam system generate steam at a similar quality level.

[0063] As used herein, "substantial" when used in reference to a quantity or amount of a material, or a specific characteristic thereof, refers to an amount that is sufficient to provide an effect that the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context.

[0064] As used herein, "thermal recovery processes" include any type of hydrocarbon recovery process that uses a heat source to enhance the recovery, for example, by lowering the viscosity of a hydrocarbon. These processes may be based on heated water, wet steam, or dry steam, alone, or in any combinations. Further, any of these components may be combined with solvents to enhance the recovery. Such processes may include subsurface processes, such as cyclic steam stimulation (CSS), steamflooding, and SAGD, among others, and processes that use surface processing for the recovery, such as sub-surface mining and surface mining.

[0065] As used herein, a "wellbore" is a hole in the subsurface made by drilling or inserting a conduit into the subsurface. A wellbore may have a substantially circular cross section or any other cross-sectional shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore." Further, multiple pipes may be inserted into a single wellbore, for example, to limit frictional forces in any one pipe.

[0066] *Overview*

[0067] The thermal recovery processes chosen for a particular stage of a development sets the steam quality to be utilized. For example, in the early cycles of a recovery process such as cyclic steam stimulation (CSS) wet steam is sufficient, since

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the majority of recovery mechanisms are not related to gravity drainage, but may include dilation/compaction, solution gas drive, water flashing, and the like. As the CSS recovery process matures, the significance of these additional recovery mechanisms declines and the recovery role of gravity drainage increases. Similarly, conventional steamflood processes for hydrocarbon recovery may use a combination of heating and the imposition of a significant pressure gradient to displace the oil to the offset production wells, allowing the use of wet steam. However, once a significant aqueous or vapor saturation connects the injection wells to the production wells, it may no longer be possible to impose a pressure gradient, and gravity drainage will become dominant recovery mechanism. As gravity drainage becomes more important, it becomes more efficient to use higher quality steam or even dry steam.

[0068] In addition to different stages of the recovery, different recovery processes may be used in a single development. For example, in shallow hydrocarbon deposits certain areas of the deposit may be reached with surface mining and extraction techniques, while other areas can be harvested with in situ recovery techniques. Different types of techniques may utilize different balances of steam or water quality.

[0069] Embodiments described herein provide steam generation designs and methods for transitioning from a recovery process that utilizes wet steam to a recovery process that utilizes dry steam, or vice-versa. The systems and methods may reduce facility costs and make-up water requirements when generating steam in developments that use thermal recovery processes requiring dry steam. In some embodiments, the condensate stream may be cascaded between steam generators. In these embodiments, the residual condensate can be blended with the boiler feed water being fed to an adjacent steam system in such a way that the dissolved contaminants do not compromise steam generator function. As used here, "cascading" indicates that the items are connected successively end to start to form a single path.

[0070] Fig. 1 is a drawing of a development 100 illustrating the use of both a surface mining 102 recovery process and a steam assisted gravity drainage (SAGD) 104 recovery process to harvest hydrocarbons 106 from a reservoir 108. It will be clear that the techniques described herein are not limited to this combination, or these specific

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techniques, as any number of techniques or combinations of techniques may be used in embodiments described herein. The surface mining 102 may be used to reach a portion of the reservoir 108 that is closer to the surface, while the SAGD 104 recovery may be used to access hydrocarbons in a portion of the reservoir 108 that is at a greater depth. In the development 100, a steam generation facility 109 is used to generate steam 110, which can be provided to surface separation facility 112 and an injection facility 114. The steam 110 may include both wet steam and dry steam, for example, carried in different pipes from the steam generation facility 109.

[0071] The surface mining 102 uses heavy equipment 116 to remove hydrocarbon containing materials 118, such as oil sands, from the reservoir 108. The hydrocarbon containing materials are offloaded at the separation facility 112, where a thermal process, such as a Clark hot water extraction (CHWE), among others, may be used to separate a hydrocarbon stream 120 from a tailings stream 122. The tailings stream 122 may be sent to a tailings pond 124, or may be injected into a sub-surface formation for disposal. A water stream 126 may be recycled to the steam generation facility 109. The extraction process may utilize wet steam from the steam generation facility 108.

[0072] The SAGD 104 process injects the steam 110 through injection wells 128 to harvest hydrocarbons by raising the temperature of a portion 130 of the reservoir 108 to lower the viscosity of the hydrocarbons 131, allowing the hydrocarbons 131 to flow to collection wells 132. Although, for the sake of clarity, the injection wells 128 and collection wells 132 are shown as originating from different locations in Fig. 1, these wells 128 and 132 may be drilled from the same surface pads to enable easier tracking between the wells 128 and 132. The resulting streams 134 from the reservoir 108 may include the hydrocarbons 131 and the condensate from the steam 110. The streams 134 can be processed at a surface facility 136 to remove at least some of the water. The SAGD process 104 may utilize higher quality or dry steam from the steam generation facility 109.

[0073] The hydrocarbon stream 138 and water stream 140 from the SAGD process 104 may be sent to a transportation facility 142, which may provide further separation and purification of the incoming streams 120, 138, and 140, prior to sending the

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marketable hydrocarbons 106 on to further processing facilities. The resulting process water 144 can be returned to the steam generation facility 109 for recycling.

[0074] Fig. 2 is a drawing of a conventional steam generation system 200 that may be utilized to generate steam for thermal or thermal-solvent recovery processes, such as CSS. In this figure, a feed water stream 202 is treated in a water treatment facility 204 to reduce the concentration of contaminants that may cause scale to be deposited in the steam generator 206.

[0075] The water treatment facility 204 may use a number of techniques to reduce the contaminants in the feed water stream 202, including, for example, hot lime softening which may lower the concentration of contaminants by forcing their precipitation. Any number of other techniques may also be used alone or in various combinations, including evaporative purification (distillation), membrane purification, chemical purification, ion exchange, and the like.

[0076] The treated water provides a boiler feed water 205 that can be used by a steam generator 206 to generate wet steam 208. The wet steam 208 can be transported via pipeline to a development where it is injected into a reservoir using wells. The steam generator 206 may be any type of steam generator, for example, a once-through steam generator (OTSG), a heat-recovery steam generator (HRSG), and the like. Further, the steam generation system 200 is not limited to a single steam generator 206, but may include any number of steam generators 206 in parallel.

[0077] Fig. 3 is a drawing of a steam generation system 300 that uses three steam generators 206 in parallel to generate wet steam for a thermal recovery process. Like numbered items are as described in the figures above. As noted above, a steam generation system 300 may include a number of parallel steam generators 206, which may be any combinations of OTSG or HRSG units. Each steam generator 206 is supplied with boiler feed water 205 from the water treatment facility 204. The resulting wet steam flow 208 from each steam generator 206 can be combined to form a single wet steam stream 302 that may be transported to the injection wells or used in surface facilities. The steam generation systems 200 and 300, discussed with respect to Figs. 2 and 3, may be adapted to provide dry steam as discussed with respect to Fig. 4.

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[0078] Fig. 4 shows a steam generation system 400 that can be utilized to generate dry steam 402 for thermal recovery processes such as SAGD developments. Like numbered items are as described in the figures above. Once the wet steam 208 exits the steam generator 206 it is sent to a separator 404, which separates the two phases.

5 The vapor phase or dry steam 402 leaves the separator 404 and may then be transported via pipeline to the development where is it injected into a reservoir using wells, for example, as discussed with respect to Fig. 1.

[0079] The liquid phase or condensate 406 can be sent to disposal 408, such as injection into a waste well. A portion 410 of the condensate 406 can be recycled to the inlet 412 of the steam generator 206. Typically, less than 100 % of the condensate 406 will be recycled, as any dissolved salts in the condensate 406 will be concentrated over time and can foul the boiler tubes in the steam generator 206. Therefore, when recycling the condensate 406, at least a portion is continuously purged to disposal 408 and replaced by clean boiler feed water 205.

15 **[0080]** Although not shown in Fig. 4, the condensate 406 that is purged from the system can go through additional processing to recover heat, for example, through the use of heat exchange devices. Further, high quality make-up water may be obtained from the condensate 406, for example, by processing the condensate 406 in the water treatment facility 204. For example, this may be performed by flashing the stream to a lower pressure and condensing the steam stream that results from that pressure change, among other techniques.

[0081] Fig. 5 is a drawing of a steam generation system 500 in a series design in which the condensate 406 from a first steam generator 206 is separated from the dry steam 402 in a separator 404 and used as a feed water stream for a smaller steam generator 502. Like numbered items are as described in the figures above. The wet steam 504 generated by the smaller steam generator 502 can be passed through a second separator 506. The dry steam 508 from the second separator 506 can be combined with the dry steam 402 from the first separator 404 to form a combined dry steam 510, which may be transported to injection wells by a pipeline. The condensate 512 from the second separator 506 may be sent to disposal 408, such as a disposal

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well or pond. A portion of the condensate 512, or even all, may be returned to the water treatment facility 204 to separate impurities and recover the water.

[0082] The smaller steam generator 502 may be termed a “blowdown” steam generator. If contaminants in the condensate 406 are sufficiently below their saturation levels, the use of the two steam generators 206 and 502 in series allows the steam quality to be increased, as measured per unit of boiler feed water 205 utilized.

[0083] Fig. 6 is a drawing of a blowdown steam generation system 600 using similarly sized steam generators 206 and 602. Like numbered items are as described in the figures above. In the blowdown steam-generation system 600, the number of parallel steam generators 206 used to supply a single blowdown steam generator 602 is $1 / (1 - \text{the generated steam quality})$. Thus, if the desired steam quality is 80 %, five parallel steam generators 206 are used ahead of each blowdown steam generator 602, as is represented in Fig. 6. This configuration will often generate a very large quantity of steam and, therefore, may be relevant for large projects.

[0084] *Tailoring steam generation for project development*

[0085] In an embodiment, steam production may be tailored to fit the current needs of the development. This may allow conversion of particular steam generation systems from producing only wet steam to producing a combination of wet and dry steam, or only dry steam. Further, as the development process continues, the proportion of dry steam generated may be increased.

[0086] Although embodiments are not limited to the following conditions, for the purposes of this explanation, it is assumed that an existing commercial development starts by using 100 % of the steam capacity to support a CSS development using wet steam. As the development matures, a steamflood based follow-up process is implemented, resulting in 67 % of the steam capacity being used to support the CSS operation with wet steam, and 33 % being used for the steamflood as dry steam. As the CSS resource continues to be depleted, a SAGD development is implemented, resulting in 33 % of the steam capacity being used for CSS (wet steam), 33 % being used for the steamflood (dry steam) and 33 % now being used in a new SAGD development (dry steam). Later, the CSS operations are completed and 33 % of the steam capacity

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supports a steamflood (dry steam) and 67 % is used to support an expanded SAGD development (dry steam).

[0087] The development with the CSS process may be supported by the steam generation system 300 discussed with respect to Fig. 3, which may represent a starting point for the installed steam capacity of the development. At some point, the CSS production may no longer be economical, and a development decision is made to convert a portion of the existing development to a steamflood. Although, a new steam generation system may be installed to create the dry steam this may be costly. Accordingly, in an embodiment, one of the three steam generators is converted to dry service.

[0088] Fig. 7 is a drawing of a steam generation system 700 after conversion of one steam generator 206 to the production of dry steam. Like numbered items are as described in the figures above. The wet steam 208 produced from the converted steam generator 206 is sent to a separator 404 where the dry steam 402 is separated and then sent to the field via a dry steam pipeline. This may be termed the first steam system 702. The separated condensate 406 from the first steam system 702 can then be cascaded to the inlet 704 of a second steam system 706 that has another steam generator 206. The net effect of the cascading arrangement is a comparable reduction in the boiler feed water 205 provided to the second steam system 706 from the water treatment facility 204. Thus, water consumption, operating costs, and energy consumption are reduced.

[0089] The wet steam 208 generated in the second steam system 706 has an increased level of contaminants, which may necessitate a reduction in the steam quality generated in the second steam system 706. For example, if the concentration of the contaminants in the wet steam 208 from the second steam system 706 exceeds a precipitation limit, the contaminants may precipitate in the tubes of the steam generator 206, causing damage. However, as the wet steam 208 from the second steam system 706 may be used for a recovery process where wet steam 208 is acceptable, a reduction in quality may not materially impact recovery performance. The wet steam 208 from the two remaining steam systems 706 and 708 is combined to form a single

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wet steam stream 302, which is sent to the remaining CSS wells. At some point, as mentioned above, a further reduction in CSS may be desired, and more capacity may be converted to the production of dry steam 402.

[0090] If an increase in wet steam may be useful, a bypass line 710 can be included to allow wet steam 208 from the first steam system 702 to bypass the separator 404 and add to the amount available for the wet steam stream 302. For example, this may be useful if a new portion of the development is opened, increasing the wet steam demand after the conversion. As described below, further increases in dry steam may be achieved by adding directing wet steam 208 from the second steam system 706 to the inlet 704 of the third steam system 712, as described with respect to Fig. 8.

[0091] Fig. 8 is a drawing of a steam generation system 800 after conversion of two steam generators 206 to the production of dry steam. Like numbered items are as described above. Wet steam 208 from the second steam system 706 is sent to a separator 404 where the dry steam 402 is separated, mixed with the dry steam 402 from the first steam system 702, and then sent to the field via a dry steam pipeline. The separated condensate 406 from the second steam system 706 is cascaded to the inlet 712 of the third steam system 708. Again, the net effect of this cascading action is a comparable reduction in the boiler feed water provided to the third steam system 708 from the water treatment facility 204 and, hence, a further reduction in water consumption, operating costs, and energy use.

[0092] The wet steam 208 generated in the third steam system 708 has a further increased level of contaminants, which may also necessitate a reduction in the steam quality generated in this third steam system 708. As the wet steam 208 may be used for a recovery process, e.g., CSS, where wet steam is acceptable, a reduction in quality may not materially impact recovery performance. The wet steam 208 from the remaining steam system 708 is sent to the remaining CSS wells as wet steam stream 302.

[0093] As discussed with respect to Fig. 7, the configuration shown in Fig. 8 may include bypass lines 710 to allow the wet steam 208 from the first steam system 704 and the second steam system 706 to bypass the separators 404. This may allow for an

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easy conversion back to wet steam 208 production from each system, if the amount used for the wet steam stream 302 to the wells increases.

[0094] Fig. 9 is a drawing of a steam generation system that may provide similar production of wet and dry steam as described for Figs. 7 and 8. Like numbered items are as described above. In this case the steam generators 206 each feed a wet steam 208 into a common wet steam header 902. A first portion 904 of the wet steam 208 may be sent to a field as the wet steam stream 302. The remaining portion 906 of the wet steam 208 from the wet steam header 902 is sent to a separator 404, from which the dry steam 402 may be sent to a field. The condensate 406 can be recycled to the feed water header 908, displacing a comparable quantity of boiler feed water 205 from the water treatment facility 204.

[0095] In this design, a reasonably continuous demand for wet steam 208 from all three steam generators 206 may help to ensure that the contaminant levels in the boiler feed water header 908 remain at acceptable levels. Further, the dilution of the condensate 406 in the boiler feed water header 908 may be uniform across the inlets of all three generators 206, uniformly lowering the concentration of contaminants. This design may be more flexible in its ability to respond to short term swings in the demand for wet steam 208 and dry steam 402 than, for example, the configuration shown in Fig. 8.

[0096] Fig. 10 is a drawing of a steam generation system 1000 that may not provide material steam-quality improvement, but may provide significant operating flexibility. Like numbered items are as described above. As described for Fig. 9, the steam generators 206 all feed into a common wet steam header 902, with a portion 906 of the wet steam 208 being sent to a separator 404. From the separator 404, the dry steam 402 can be sent to the injection wells via a dry steam pipeline. The separated condensate 406 can then be combined with the remaining wet steam 208 and sent to the field as wet steam stream 302.

[0097] This design may be beneficial when the expected demand for dry steam 402 is small relative to the demand for wet steam 208, as the impact of the quality of the wet steam 208 will be small. It may also be used when the recovery process utilizing the

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wet steam 208 is not impacted by significant reductions in quality. For example, supplying the heat used for a thermal recovery process used in a surface mining project, such as a Clark hot water process used to extract hydrocarbons from oil sands.

[0098] Fig. 11 is a drawing of the systems of Figs. 7 and 8 after the third steam system 708 is converted to dry steam service. Like numbered items are as described above. In the third steam system 708, wet steam 208 is sent to a separator 404 where the dry steam 402 is separated and then combined with dry steam 402 from the first steam system 702 and the second steam system 706, and sent to the field via a dry steam pipeline. Again, the net effect of the cascading condensate 402 from the first steam system 702 and the second steam system 706 is an increase in the concentration of contaminants in the condensate. As less and less wet steam 208 is used in the development, these contaminants will need to be reduced by other techniques. For example, the condensate 406 from the third steam system 708 may be sent to disposal 408. With no additional wet steam requirements, the existing wet steam pipeline can be converted to dry steam service.

[0099] As for the configurations discussed with respect to Figs. 7 and 8, the conversion process piping has bypass lines 710 to allow the steam generation system 1100 to revert to an increase in production of wet steam 208. Thus, as fluctuations in a balance between wet steam 208 and dry steam 402 change with time, the steam generation system 1100 has the flexibility to adapt to these changing needs. For example, this flexibility allows the steam generation system 1100 to provide a different balance of steam if production is started in a new area of the development.

[0100] The process of cascading the condensate 406 between the parallel steam systems 702, 706, and 708 will result in lower steam systems 706 and 708 operating at a lower pressure than the steam system 702 and 706 from which the condensate 406 was sourced. This will result in the wet steam 208, for example, to be used in the CSS recovery process, being provided at the lowest pressure of the steam systems 702, 706, and 708. While this outcome may be satisfactory if a CSS process is utilizing sub-fracture pressures for steam injection, it may be problematic if higher pressures are useful.

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[0101] In situations where it is useful to operate all of the steam systems 702, 706, and 708 at the same discharge pressure or to operate the wet steam 208 at a higher discharge pressure, the pressure of the condensate 406 being cascaded can be boosted using a pump. If this is to be done while the condensate 406 is hot, the design can account for the frictional pressure drop by increasing the head gain from the base of the separator 404. This may be useful for preventing steam vapor from forming at the pump suction, which could lead to cavitation.

[0102] If the pumping is to be done after the condensate 406 is cooled, then a beneficial use may be made of the heat contained in the condensate 406. For example, one option would be to exchange the heat of the condensate 406 with the boiler feed water stream as it is entering a hot lime softener (HLS) in the water treatment facility 204. This may reduce the steam consumed in the HLS operation.

[0103] Fig. 12 is a drawing of a steam generation system 1200 in which three steam systems 702, 706, and 708 operate in parallel and generate dry steam 402 by cascading the condensate 406 sequentially to the inlet 704 and 712 of the adjacent steam system 706 and 708. Like numbered items are as described above. For purposes of clarity, this drawing has been simplified from the steam generation system of Fig. 11 by the elimination of the bypass lines 710 used to reverse the conversion, e.g., to allow the production of wet steam 208.

[0104] The current techniques allow dry stream 402 to be generated using water with the least quantity of contaminants. Blending the cascaded condensate 406 with the feed water helps to moderate the concentration of the contaminants in an adjacent steam system 706 and 710. In this way the steam systems used for dry steam 402 have the potential to generate higher quality steam than the remaining steam generators being used for wet steam service.

[0105] Fig. 13 is a drawing of a steam generation system 1300 showing that the cascading process may be applied to steam systems 1302, 1306, and 1308 having multiple steam generators 206 operating in parallel. Like numbered items are as described above. Thus, the first steam system 1302 has two steam generators 206 in parallel in this example. The wet steam 208 is passed to a separator 404, with the

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condensate 406 from the separator 404 fed to the inlet 1304 of the two steam generators 206 in the second steam system 1306. Similarly, the condensate 406 from the second steam system 1306 is fed to the inlet 1310 of the two steam generators 206 in the third steam system 1308.

5 **[0106]** The steam generation system 1300 may also be used to present a simplified material balance showing the beneficial effects of cascading the condensate 406 between the steam generators 206 as the steam generators 206 are converted from wet steam service to dry steam service. For purposes of this example, it may be assumed that each of the steam generators 206 is processing 100 units of water and is
10 generating steam with an 80 % quality, i.e., providing 80 units of steam. Thus, the treatment facility 204 may have been designed to process 600 units of feed water stream 202 from point 1 (as indicated by the numbered diamond). At point 2, 200 units of the feed water from the treatment facility 204 are consumed by the first steam system 1302, i.e., 100 units in each steam generator 206. The separator 404 separates the wet
15 steam 208 from the steam generators 206 into 160 units of dry steam at point 3 and 40 units of condensate 406 at point 4. The condensate 406 is sent to the inlet 1304 of the second steam system 1306. Thus, at point 5, 160 units of boiler feed water 205 from the water treatment facility 204 is used to give a total water feed to the second steam system 1306 of 200 units.

20 **[0107]** The wet steam 208 from the steam generators 206 of the second steam system 1306 is fed to a separator 404, which separates the wet steam 208 into 160 units of dry steam at point 6 and 40 units of condensate at point 7. The condensate 406 from the second steam system 1306 is fed to the inlet 1310 of the third steam system 1308. Thus, at point 8, 160 units of boiler feed water 205 from the water treatment
25 facility 204 is used to provide a total water feed of 200 units to the third steam system 1308.

[0108] The wet steam 208 from the steam generators 206 of the third steam system 1308 is fed to a separator 404, providing 160 units of dry steam at point 9. The dry steam 402 from the first steam system 1302, the second steam system 1306, and the
30 third steam system 1308 is combined to give a total of 480 units of dry steam 402 at

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point 10, which may be sent to the injection wells in a development. The 40 units of condensate 406 from the separator 404 of the third steam system 1308 will have the highest concentration of contaminants, and can be sent to disposal at point 11. Thus, by converting all three steam systems 1302, 1306, and 1308 to dry steam service, 80 units of feed water that could be provided from the water treatment facility 204 are freed for other purposes, such as increasing the amount of steam that may be generated.

[0109] Fig. 14 is a drawing of a steam generation system 1400 that includes a seventh steam generator 206 installed in a fourth steam system 1402. Like numbers are as described before, and the mass balance at similarly numbered points is the same as discussed with respect to the steam generation system 1300 of Fig. 13.

[0110] In contrast to disposing of all of the condensate 406 from the third steam system 1308, as shown in Fig. 13, the condensate 406 may be divided into two equal portions. A first portion of 20 units, indicated at point 12, may be fed to the inlet 1404 of the fourth steam system 1402. Thus, the remaining 80 units of capacity from the feed water treatment facility 204 are used to provide 100 units to the fourth steam system 1402 at point 13. The wet steam 208 from the steam generator 206 in the fourth steam system 1402 is passed to a separator 404, resulting in 80 units of dry steam 402 at point 14. The dry steam 402 at point 14 can be combined with the 480 units of dry steam at point 10, to provide 560 units of dry steam 402 to the injection wells at point 15.

[0111] The remaining portion of 20 units of condensate from the separator 404 of the third steam system 1308, at point 16, may be combined with the 20 units of condensate from the separator 404 of the fourth steam system 1402 at point 17, resulting in 40 units of condensate 406 which may be sent to disposal at point 11. As a result all of the available water treatment capacity is being utilized. Although the fourth steam system 1402 generator is shown in dry steam service, it could be used in either wet steam or dry steam service.

[0112] In an embodiment, the surplus capacity for boiler feed water 205 may be utilized by increasing the throughput of the existing steam generators 206. This may be

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done when the objective is to produce dry steam without compromising the design constraints, e.g., by installing more steam generators 206.

[0113] *Modification of a steam generator to increase inherent capacity*

[0114] In an embodiment, a steam generator 206 may be modified to increase capacity by functioning like a series of smaller steam generators. This may also have the additional benefit of increasing the throughput through the steam generator 206.

[0115] Fig. 15 is a drawing of a steam generator 1500 that is modified to increase both throughput and dry steam production. The steam generator 1500 may contain multiple tube bundles arranged into sections, including section A 1502, section B 1504, section C 1506, and section C' 1508. The outlet of each tube bundle provides the inlet feed for the next tube bundle, with the exception of sections C 1506 and C' 1508, which may be placed in parallel to provide a spare section while one tube bundle is out of service for cleaning or tube replacement. Embodiments are not limited to steam generators that have segmented tubing bundles. In some embodiments, the tubing may be contiguous prior to modification, and each tube may be modified to direct the steam and water to a separator. Further, the modification may be done on groups of tubes as a unit.

[0116] In the steam generator 1500, the feed water 1510 is fed into the tube bundle of section A 1502. The feed water 1510 may be boiler feed water 205 from the water treatment facility 204, or may be a blend of boiler feed water 205 and condensate 404. An intermediate take-off 1512, for example, located after tubes in section A 1502, diverts the steam and water from section A 1502 to a separator 1514, which separates the dry steam 1516 from the condensate 1518. The separator 1514 may be a conventional gravity driven separator or may be a centrifugal separator used to form liquid and vapor streams by centripetal force.

[0117] The condensate 1518 is then returned to the steam generator 1500 as the feed to section B 1504. The number, and/or diameters, of tubes in each section 1502 and 1504 do not have to match. For example, a larger number of tubes in section A 1502 may be used to feed a smaller number of tubes in section B 1504 or vice-versa.

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[0118] Similarly, an intermediate take-off 1520 after the tubing bundle of section B 1504 diverts the steam and water to another separator 1522, which separates the dry steam 1524 from the condensate 1526. The condensate 1526 may then be sent to a last section of the steam generator 1500. The separators 1514 and 1522 do not have to
5 be individual.

[0119] The separators 1514, 1522, and 1530 do not have to be individual. In some embodiments, a single separator may be used for all of the take-off points 1512, 1520, and 1528. If a single separator is used, internal weirs or other segmentation devices
10 the mixture of condensate having different levels of contaminants. One or more pumps may be used to boost the pressure of the condensate 1518 or 1526 that is returned to the steam generator 1500.

[0120] The water quality will be poorest in the last section, and thus the risk of scale deposition will be greatest at that point. Accordingly, two "third sections," for example,
15 section C 1506 and C' 1508, can be included in the design to help with the increased risk from scale. The use of two final sections 1506 and 1508 allows the diversion of the condensate 1526 and any hot gases into the replacement section while the tubes are being replaced in an off-line third section. This allows the steam generator 1500 to increase steam quality over a single section, as the steam generator 1500 can be
20 operated much closer to the contaminant solubility limit without the fear of having to shutdown the entire unit in case a tube failure occurs. Thus, the condensate 1526 may be sent to either section C 1506 or section C 1508, depending on which is operational at the time. In some embodiments, both sections 1506 and 1508 may be operated together to increase the overall yield of the steam generator 1500. Further, the extra
25 section may be shared with an adjacent steam generator to provide a spare for two steam generators with lower capital costs.

[0121] As shown, the intermediate take-offs 1512 and 1520 along the boiler tubes preferentially remove the steam to allow the condensate 1518 and 1526 to continue within the steam generator 1500. For example, if an intermediate take-off was located
30 at the point where the steam quality was predicted to first achieve 55 %, and a second

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intermediate take-off was located where the steam quality was predicted to achieve 55 % for a second time, and the final steam quality existing the steam generator 1500 was also 55 %, the overall steam quality created by the steam generator 1500 would be ~90 %, or around 10 % greater than may be generated without the intermediate
5 takeoffs. However, it can be noted that the steam quality produced in each section may or may not be the same.

[0122] The wet steam 1528 from section C 1506 and section C' 1508 is sent to a final separator 1530, which separates the dry steam 1532 from the condensate 1534. The condensate 1534 may be sent to disposal or to a water treatment facility for
10 recycling. If the contaminants are sufficiently low in the condensate 1534, it may be in returned to the inlet of the same steam generator 1500, or to the inlet of a successive steam generator. At least a portion of the condensate 1534 may be treated or disposed to control the build-up of contaminants. Further, a takeoff from the wet steam 1528 may be used to provide a wet steam stream 1538 to a development. In this case, the
15 condensate stream 1534 may be blended with the wet steam stream 1538 for disposal, since the extra contaminants will not harm the wet steam stream 1538.

[0123] The individual separated dry steam 1516, 1524, and 1532 is then combined into a dry steam stream 1536, which may be sent to injection wells via a pipeline. In this example two intermediate take-offs 1512 and 1520 are used to reset the steam quality
20 in the steam generator 1500 back to zero at the beginning of each section 1502, 1504, 1506, and 1508. As a result, the peak velocities in the boiler tubes are reduced allowing the maximum allowable flow rate per boiler tube to be increased. The higher condensate content in the boiler tubes also allows a higher heat flux to be used with the boiler tubes, thereby allowing a higher rate for the boiler feed water 1510, increasing the
25 amount converted to dry steam 1536. Extra boiler feed water 1510 may be added to each of the individual sections 1504, 1506, or 1508, through a feed water line 1540. This enables the modified steam generator 1500 to function in an analogous fashion to the steam generation systems shown in Figs. 7-14.

[0124] The configuration of the steam generator 1500 shown in Fig. 15 may have a
30 number of advantages over current steam generators. For example, the sequential

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removal of steam from the tubing reduces the peak velocities, thereby increasing the maximum allowable flow rate per boiler tube. Further, the higher condensate content in each boiler tube, e.g., due to lower steam quality in the tube, allows a higher heat flux to be used with the boiler tubes, thereby allowing more boiler feed water to be converted to steam. The modified steam generator may be implemented for a wide range of project sizes.

[0125] *Tailoring steam generation to field usage*

[0126] Fig. 16 is a process flow diagram of a method 1600 for tailoring the quality of steam production to field needs. The method 1600 may be used to improve thermal recovery processes for a hydrocarbon reservoir that is exploitable through surface mining, subsurface mining, in situ techniques, or any combinations thereof.

[0127] The method 1600 starts at block 1602 by matching thermal recovery processes with specific reservoir regions within the development to achieve optimal resource recovery. To begin, the reservoirs expected to be developed over the life of the project are delineated. Reservoir delineation typically occurs through the combined use of delineation wells, remote sensing technologies such as 2D and 3D seismic studies, studies of modern analogs and outcrop studies of the target reservoir, for example, if parts of the reservoir outcrop on surface, or studies of other reservoirs with comparable depositional setting. Remote sensing technologies, modern analogs, and outcrop studies allow the prediction of the spatial distribution of the reservoir attributes through the reservoir.

[0128] Delineation wells are used to collect core samples of the target reservoir and to collect log data, both for openhole and cased hole wells. The cores may be used to gain an understanding of the depositional settings present in the reservoir, porosity and oil content distributions, horizontal and vertical permeability distributions, oil density and viscosity information, sand grain size analyses and reservoir rock samples that can be used to understand how the reservoir material will respond to heating with steam or water. The core samples may be used to identify the ease with which the hydrocarbons can be separated from the reservoir fabric during surface extraction operations. The delineation wells may also be used to collect data detailing the ability of the reservoir

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caprock to withstand increases in pressure as a result of steam injection, and the initial pressure distribution in the reservoir. Further, they can aid the identification of the presence and areal extent of any pressure sinks, or intervals that may require dewatering, such as top gas, top or bottom water. This may include interstitial intervals with the reservoir that have initial enhanced water mobility, present in or in proximity to the oil bearing sections. Further, the data may be used to identify locations and capacities, of water make-up sources and water disposal intervals.

[0129] The data can be used to create a geologic model for each reservoir that is expected to be developed as part of the overall development. These geologic models can be constructed using a geologic modeling software program. The available open hole and cased hole log, core, 2D and 3D seismic data, and knowledge of the depositional environment setting may be used in the construction the geologic model.

[0130] The attributes of various recovery processes can be used to interrogate the geologic models to identify the areas of the reservoirs that have attributes amendable to the various recovery processes. For example, a recovery process that relies on the ability to cycle pressures, such as CSS, would not be a preferred recovery process when developing a portion of a reservoir where an extensive top gas interval is present. Further, a surface mining process would not work for a deep reservoir.

[0131] At block 1604 the overall depletion strategy is designed to optimize the field design, steam generation and water treatment facilities for the entire life of the recovery project. For each combination of reservoir description and recovery technology, a series of performance predictions can be made using a reservoir simulation program, or a mine planning program. It may also be possible to use simple empirical or analog based models for performance prediction.

[0132] In many cases, follow-up recovery processes can be used to further enhance the recovery of the hydrocarbon. These options to extend recovery can be considered during the planning phase to assist in determining designs for resources.

[0133] A combination of simple economic models, performance expectations for a recovery process, and field layout and infrastructure considerations can be used to optimize the overall sequence for the development. This knowledge may then be used

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to identify the remaining acquisition requirements for reservoir data and the timing of their capture.

[0134] As further data is acquired, the geologic models will continue to evolve over time. Once the geologic models have demonstrated the capability to reasonably predict the results for a planned recovery technology, for example, as observed in recently drilled delineation wells, the geologic data collected may be considered sufficient. In addition, a commercial thermal development may typically have an operating life of 20 – 50+ years. Thus, the existing thermal recovery processes may continue to evolve and new thermal recovery processes will continue to develop. Accordingly, the steam generation facility can be designed to respond to future shifts in steam quality used by the development.

[0135] At block 1606, the factors are identified that indicate the time to convert to a different steam quality to support a different mix of recovery processes. To this point in the development planning process, the actual design of the steam generation facilities is not considered, other than keeping the design flexible with regard to steam quality. For example, it may be useful for a steam generation facility to initially generate only wet steam and then, over time, see a need to generate progressively larger fractions of dry steam ending with a need for only dry steam. Similarly, it may be useful to switch back and forth between generating primarily wet steam to primarily dry steam multiple times over the life of the development.

[0136] At block 1608, the steam generation facility is installed during development of the field. The wells are completed to the reservoir, and any surface mining processes are started. The initial thermal recovery processes that use the wells, such as CSS, may be started at this point. To illustrate the process, various thermal recovery processes are described herein. However, embodiments are not limited to the processes described, but may be used with any thermal recovery process. The steam used for the initial thermal recovery processes may be wet, as discussed above.

[0137] As production from the CSS falls, a portion of the wells may be converted to steamflood. Further, other wells may be drilled in the reservoir to begin SAGD recovery

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processes in other regions. Primary SAGD processes are known to be more effective when dry steam is used.

[0138] At block 1610, the steam generation facility is transitioned from producing mostly or all wet steam to producing some amount of dry steam, for example, by converting a first steam system to dry steam production. For a development scenario where a newly started thermal recovery process requires dry steam, wet steam can also be generated, for example, using parallel or adjacent steam systems as described herein.

[0139] In an embodiment, at the exit of a first steam system, the steam and condensate can be separated with the condensate being directed to the inlet of an adjacent steam system where it is used as a part of the feed water. At the exit of the second steam system, the steam and condensate can be separated with the condensate being directed to the inlet of the adjacent steam system where it is used as a part of the boiler feed water stream. The cascading may be continued across as many multiple steam systems to meet the demand for wet steam versus dry steam.

[0140] This cascading of condensate between parallel steam systems so arranged allows a higher overall steam quality to be generated, as measured per unit of boiler feed water. The improvement in steam quality is irrespective of the number of steam systems being used in the development. In addition, if one of the parallel steam systems is down for repair, the condensate can be cascaded to the next available steam system, thus, maintaining the expected benefits.

[0141] At block 1612, the water reuse is balanced against the steam generation quality. As discussed, the concentration of contaminants present in the boiler feed water will increase in a predictable fashion along a row of cascaded steam systems.

For example, if the steam quality generated is 80 % in each steam system, the sequential blending of the condensate with the boiler feed water will cause the contaminant loading to increase by 80 % with each incremental cascading of the condensate.

[0142] If the contaminant loading at the exit of the last steam system in the cascade is predicted to be less than the solubility limit, the opportunity exists to reduce the level

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of the boiler water treatment, saving operating costs, and potentially capital. However, if the contaminant loading at the exit of the last parallel steam generator is predicted to be above the solubility limit, then the steam quality generated in the last parallel steam generators can be reduced to maintain solubility. Further, if the contaminant loading at the exit of the last parallel steam system is predicted to be above the solubility limit, then the steam systems can be formed from parallel groups of two or more steam generators, with the condensate cascaded between these steam systems. The number of generators per steam system can be chosen to ensure that solubility is maintained in the last group of generators.

[0143] The processing of the condensate from the last steam system in the cascade may be determined by a number of factors. These may include the ability of the condensate to keep the contaminants dissolved at the temperatures expected in the disposal process or formation. If the potential for further concentration of the condensate exists, the condensate can be dropped to a lower pressure which will allow a portion of the water to flash to steam. This steam can then be used as a heat source within the plant or condensed and utilized as a make-up water source. Further, if water is in short supply, the condensate may be passed to a water treatment facility to remove a portion of the contaminants.

[0144] As described, the cascading of condensate between steam systems may result in each steam system operating at a progressively lower pressure. The hot condensate can be mixed with current boiler feed water stream downstream of the high pressure pump to ensure flashing does not occur in the next steam system. As a result, the cooler temperatures can lower the pressure. If it is desired to have all of the parallel steam systems operating at the same pressure, or to have the later steam systems in the cascading arrangement operate at a higher pressure than the earlier steam system, pumps can be used to boost the pressure of the condensate cascaded between the operated in parallel steam generators.

[0145] Continuing with this example, as development activities evolve in this scenario and wet steam demand occurs, for example, due to development in new areas of the field, the last steam generator in the cascading arrangement can be returned to

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wet steam service by bypassing the separation step at the exit of the steam system. If the demand for wet steam increases further, additional steam generators near the end of the cascading arrangement can be converted to wet steam service. Conversely, if the short or long term demand for dry steam were to increase, starting with the most recently converted wet steam generator, the steam generators can be easily converted back to dry steam service by completing the separation step at the exit of the generator.

[0146] The techniques described herein may be applied to new thermal development schemes or expansions to existing thermal development schemes. They may also be retrofitted into existing thermal based development schemes. The thermal recovery processes can include surface mining, subsurface mining, such as slurrified production of oil sands, and in situ opportunities, such as CSS, steamflood, SAGD, and the like. The conversion of a facility initially designed to generate wet steam to one capable of generating dry steam, using the technique by cascading the condensate between parallel steam system frees boiler feed water treating capacity. If the development plan confirms that sufficient surplus boiler feed water treating capacity will be available for a sustained period of time, a new steam system, such as a single OTSG or HRSG, can be installed to generate additional steam using the now idle boiler feed water treatment capacity. By applying the strategies outlined herein, this opportunity can be identified early and, thus, plot space could be left to allow for the future installation of this new steam system.

[0147] For both new development schemes and expansions to existing development schemes, a novel configuration is available once it is recognized that two design constraints in OTSG or HRSG design are the exit velocity of the fluids and the heat flux along the tubing. To decrease erosion, the maximum quantity of water fed into each boiler tube can be constrained such that the maximum velocity constraint is not exceeded at the exit of the boiler tubes. To help prevent localized dry out conditions, and scale deposition in the boiler tubes, the maximum heat flux can also be constrained, especially where it is anticipated that the steam quality in the boiler tube will be higher.

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[0148] By following the method for improving thermal recovery processes from a subsurface hydrocarbon reservoir described herein, either the cascading steam generation design, or the internally segmented steam generator design, or a combination of both, may provided the desired flexibility to meet both short and long term shifts in the demand for wet and dry steam. For example, Figs. 17-19 show examples of developments that can take advantage of the steam systems discussed herein. Although a particular steam system is shown for all three figures, corresponding to the system of Fig. 10, it can be noted that any of the systems in Figs. 7-15 could be used to supply steam for the developments.

[0149] Fig. 17 is a drawing of a development 1700 for which dry steam is separated from the wet steam and the different steam lines are directed to regions of the field where recovery processes efficiently use the wet or dry steam. Like numbered items are as discussed with respect to the prior figures. Although the steam system shown in Figs. 17-19 is essentially the system 1000 discussed with respect to Fig. 10, it can be understood that any of the systems discussed with respect to Figs. 7-15 may be used. In this application, the dry steam 402 is supplied to the injection well 1702 of a SAGD pair. Hydrocarbons may then be harvested from the collection or production well 1704. The wet steam 302 from the steam generators 206 may be directly supplied to a series of steamflood wells 1706. The condensate 406 from the separator (or any comparable condensate stream in Figs. 7-15) can be added to the wet steam 302 to reduce contaminates.

[0150] Fig. 18 is a diagram of a SAGD process 1800 with infill wells 1802 where the efficiency of the process is enhanced by directing dry steam to the SAGD injection wells 1804 and wet steam to the infill well injectors. As for the development 1700 of Fig. 17, the SAGD process 1800 may allow any excess condensate 406 to be blended with the wet steam 302 for injection into the reservoir 1806.

[0151] Fig. 19 is a drawing of configurations that may be used for the co-injection of solvent and steam. In these configurations, the solvent may be heated heat exchanging with the wet steam 302, as indicated by heat exchangers 1902 and 1904. The heat exchange may vaporize the solvent before it is injected into the dry steam 402, and

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injected with the dry steam 402 into the SAGD injection wells 1906. The wet steam 302 may be injected into infill wells 1908, with or without mixing in excess condensate 406. Although the solvent may be injected without the heating, the energy used to vaporize the solvent will cause a fraction of the steam to condense in the dry steam 402, lowering the efficiency of the process. If more heat is needed, for example, to decrease the amount of condensation in the wet steam, the solvent may be preheated by heat exchanging with the feed water stream 202, for example, using another heat exchanger 1910.

[0152] The above-described embodiments of the invention are intended to be examples only. Alterations, modifications, and variations can be effected to the particular embodiments by those of ordinary skill in the art without departing from the scope of the invention, which is defined solely by the claims appended hereto.

EXEMPLARY EMBODIMENTS

[0153] An exemplary embodiment provides a system for improved steam generation that includes at least two steam systems, wherein a wet steam output from a first steam system is passed through a first separator. The first separator is configured to separate dry steam from condensate. A piping connection is configured to supplement a boiler feed water stream with the condensate at the inlet of a second steam system. The amount of condensate supplementing the boiler feed water stream is changed based, at least in part, on a demand for dry steam.

[0154] In some embodiments, a steam system includes a once-through steam generator, or a heat recovery steam generator, or a combination thereof.

[0155] In some embodiments, the system includes a hydrocarbon development such as a cyclic steam stimulation process, a steamflood process, a steam assisted gravity drainage process, a thermal solvent process, a sub-surface mining operation, or a surface mining operation, or any combinations thereof.

[0156] In some embodiments, the system is configured to produce wet steam, dry steam, or a combination thereof.

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[0157] In some embodiments, the system includes a second separator on the wet steam output from the second steam system configured to separate dry steam from condensate and piping to feed the condensate to an inlet on a third steam system in a blend with boiler feed water.

5 **[0158]** In some embodiments, the system includes a number of thermal recovery processes in a hydrocarbon development. A first portion of the plurality of thermal recovery processes may be configured to use a wet steam stream and a second portion of the plurality of thermal recovery processes may be configured to use a dry steam stream.

10 **[0159]** Another exemplary embodiment provides a method for improving recovery from a hydrocarbon reservoir. The method includes matching a steam quality to a hydrocarbon development, wherein the steam is generated by a steam generation facility that includes a number of steam systems. The steam generation facility is adapted to match a change in steam usage caused by a change in the hydrocarbon
15 development. As used herein, adapting includes cascading a condensate stream from a separator on an outlet of at least one steam system to an inlet of another steam system and replacing a portion of boiler feed water stream with the condensate stream at the inlet. The portion of boiler feed water replaced is determined by a ratio of dry steam to wet steam used in the hydrocarbon development.

20 **[0160]** In some embodiments, the method includes performing a plurality of thermal recovery processes on regions within the hydrocarbon development, wherein different recovery processes are used for different regions or at different times.

[0161] In some embodiments, the method includes performing a solvent assisted thermal recovery process in a hydrocarbon development. In the solvent assisted
25 thermal recovery process, a solvent stream can be vaporized by a heat exchanger sourcing heat from a wet steam line. The vaporized solvent stream can then be combined with dry steam.

[0162] In some embodiments, the method includes transitioning the steam generation facility from wet steam to dry steam.

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[0163] In some embodiments, the method includes balancing water reuse with steam generation to keep dissolved solids from precipitating in a steam system.

[0164] In some embodiments, the method includes sequentially converting a number of steam systems from wet steam service to dry steam service to match a change in the steam quality used in the hydrocarbon development. A portion of the steam systems can be reverted to wet steam service to match a change in the steam quality used in the hydrocarbon development.

[0165] In some embodiments, the method includes adjusting the steam quality at the exit of each of the plurality of steam systems to ensure that contaminants present in a boiler feed water remain soluble in the steam system.

[0166] In some embodiments, the method includes adding a steam system to the plurality of steam systems to utilize surplus boiler feed water freed when converting a steam system from wet steam service to dry steam service.

[0167] In some embodiments, the method includes shutting-in steam systems as a result of a reduction in boiler feed water resulting from a conversion of a portion of the steam systems from wet steam service to dry steam service.

[0168] In some embodiments, the method includes drilling a number of infill steam injection wells between each of a number of steam assisted gravity drainage (SAGD) wellpairs. Dry steam can be injected into a steam injection wells in the SAGD wellpairs; and wet steam can be injected into the infill steam injection wells.

[0169] In some embodiments, the method includes injecting dry steam into a plurality of steam injection wells in a plurality of steam assisted gravity drainage (SAGD) wellpairs, and injecting wet steam into a plurality of steamflood wells.

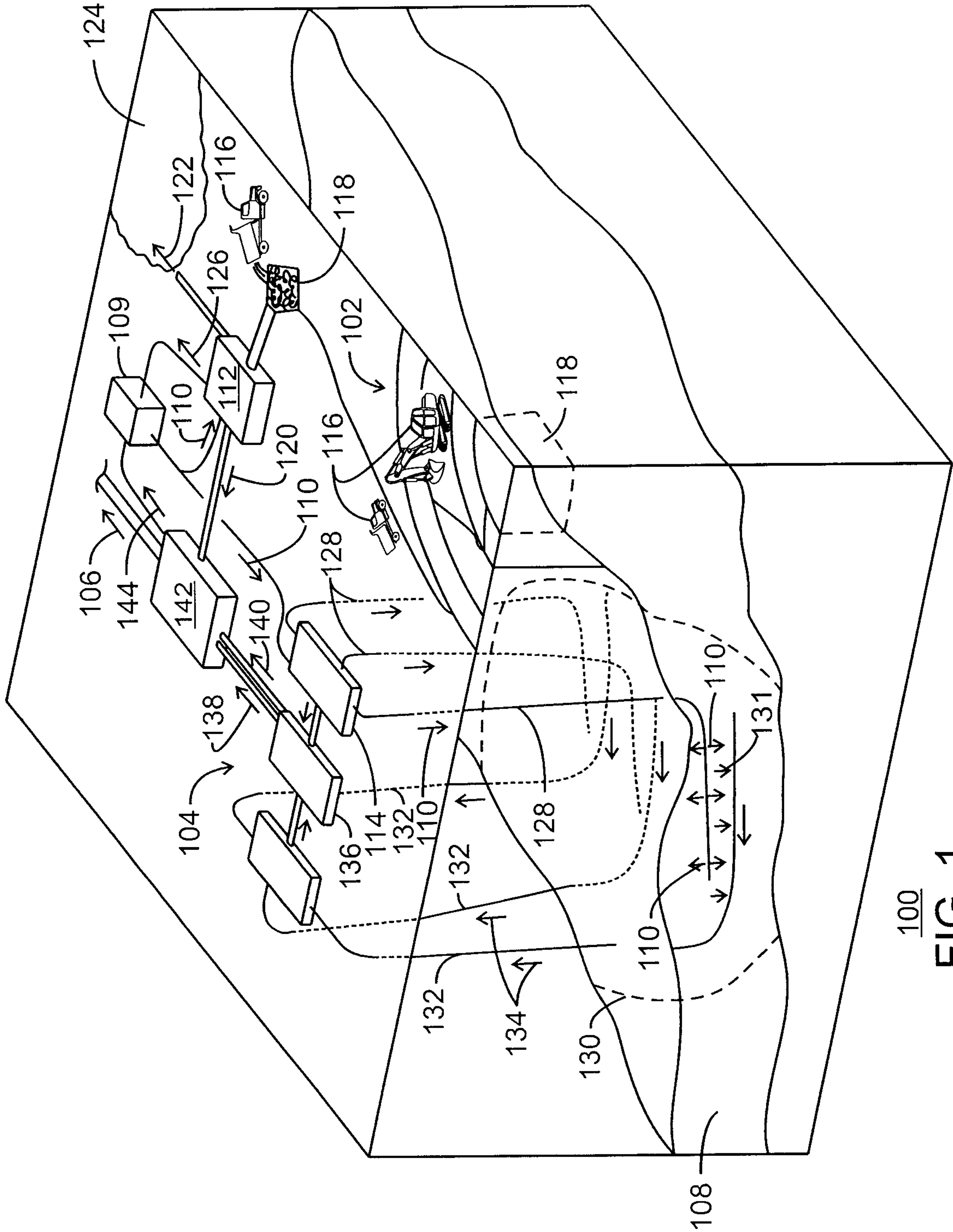
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CLAIMS

1. A method for improving recovery from a hydrocarbon reservoir, the method comprising:
 - matching a steam quality to a hydrocarbon development, wherein the steam is generated by a steam generation facility comprising a plurality of steam systems; and
 - adapting the steam generation facility to match a change in steam usage caused by a change in the hydrocarbon development, wherein adapting comprises:
 - cascading a condensate stream from a separator on an outlet of at least one steam system to an inlet of another steam system; and
 - replacing a portion of a boiler feed water stream with the condensate stream at the inlet, wherein the portion of boiler feed water replaced is determined by a ratio of dry steam to wet steam used in the hydrocarbon development.
2. The method of claim 1, comprising performing a plurality of thermal recovery processes on regions within the hydrocarbon development, wherein different recovery processes are used for different regions or at different times.
3. The method of claim 1, comprising performing a solvent assisted thermal recovery process in the hydrocarbon development.
4. The method of claim 3, comprising:
 - vaporizing a solvent stream in a heat exchanger sourcing heat from a wet steam line; and
 - combining the vaporized solvent stream with dry steam.
5. The method of claim 1, comprising transitioning the steam generation facility from wet steam to dry steam.

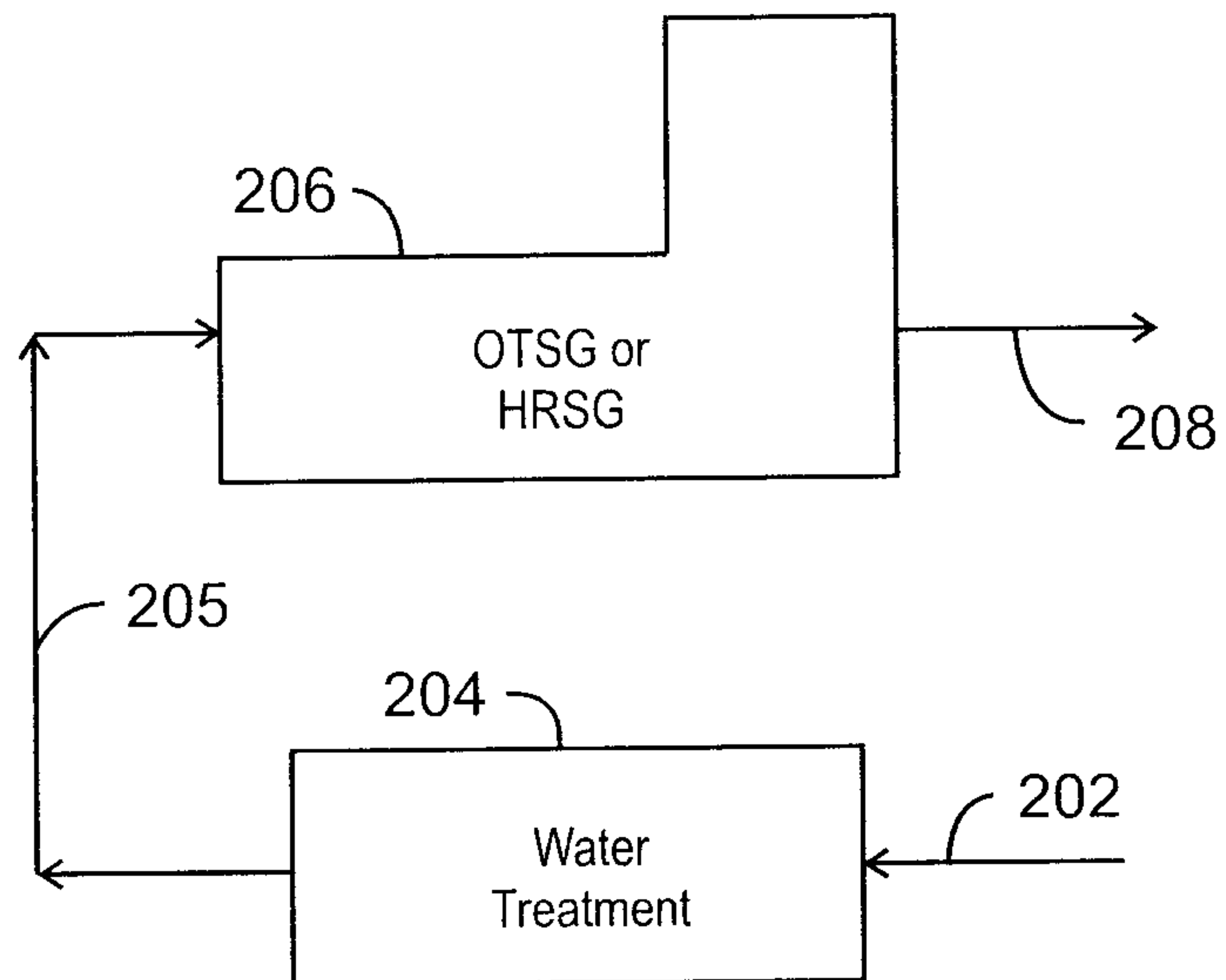
6. The method of claim 1, comprising balancing quantity of condensate reused with the quality of the steam generated to keep dissolved solids from precipitating in a steam system.
7. The method of claim 1, comprising sequentially converting a plurality of steam systems from wet steam service to dry steam service to match a change in the steam quality used in the hydrocarbon development.
8. The method of claim 7, comprising reverting a portion of the plurality of steam systems to wet steam service to match a change in the steam quality used in the hydrocarbon development.
9. The method of claim 7, comprising adjusting the steam quality at an exit of each of the plurality of steam systems to ensure that contaminants present in a boiler feed water remain soluble in the steam system.
10. The method of claim 7, comprising adding a steam system to the plurality of steam systems to utilize surplus boiler feed water freed when converting a steam system from wet steam service to dry steam service.
11. The method of claim 7, comprising shutting-in steam systems as a result of a reduction in boiler feed water resulting from a conversion of a portion of the steam systems from wet steam service to dry steam service.
12. The method of claim 1, comprising:
 - drilling a plurality of infill steam injection wells between each of a plurality of steam assisted gravity drainage (SAGD) wellpairs;
 - injecting dry steam into a plurality of steam injection wells in the plurality of SAGD wellpairs; and
 - injecting wet steam into the plurality of infill steam injection wells.

13. The method of claim 1, comprising:
injecting dry steam into a plurality of steam injection wells in a plurality of steam assisted gravity drainage (SAGD) wellpairs; and
injecting wet steam into a plurality of steamflood wells.



100
FIG. 1

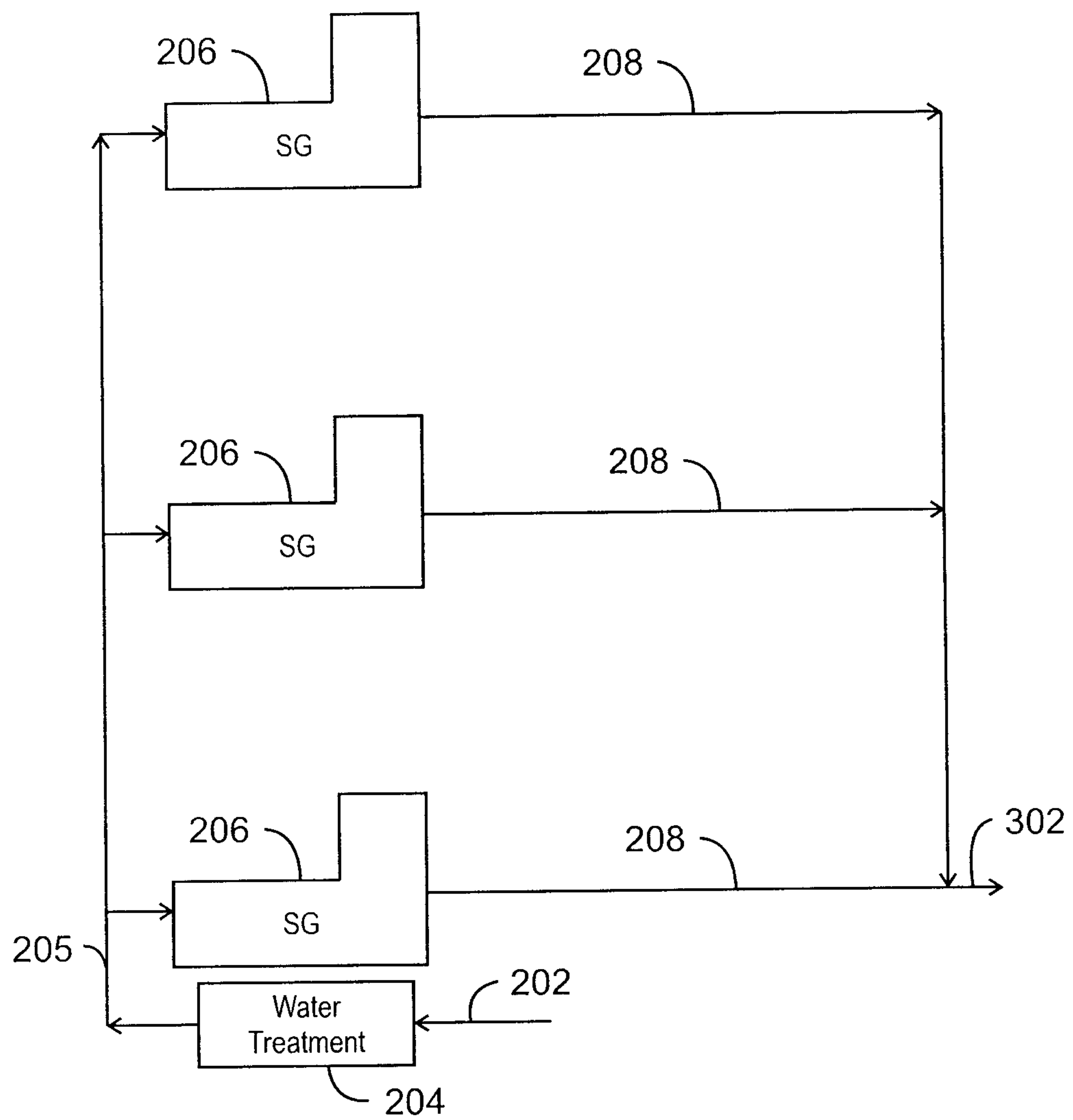
2/19



PRIOR ART

200
FIG. 2

3/19

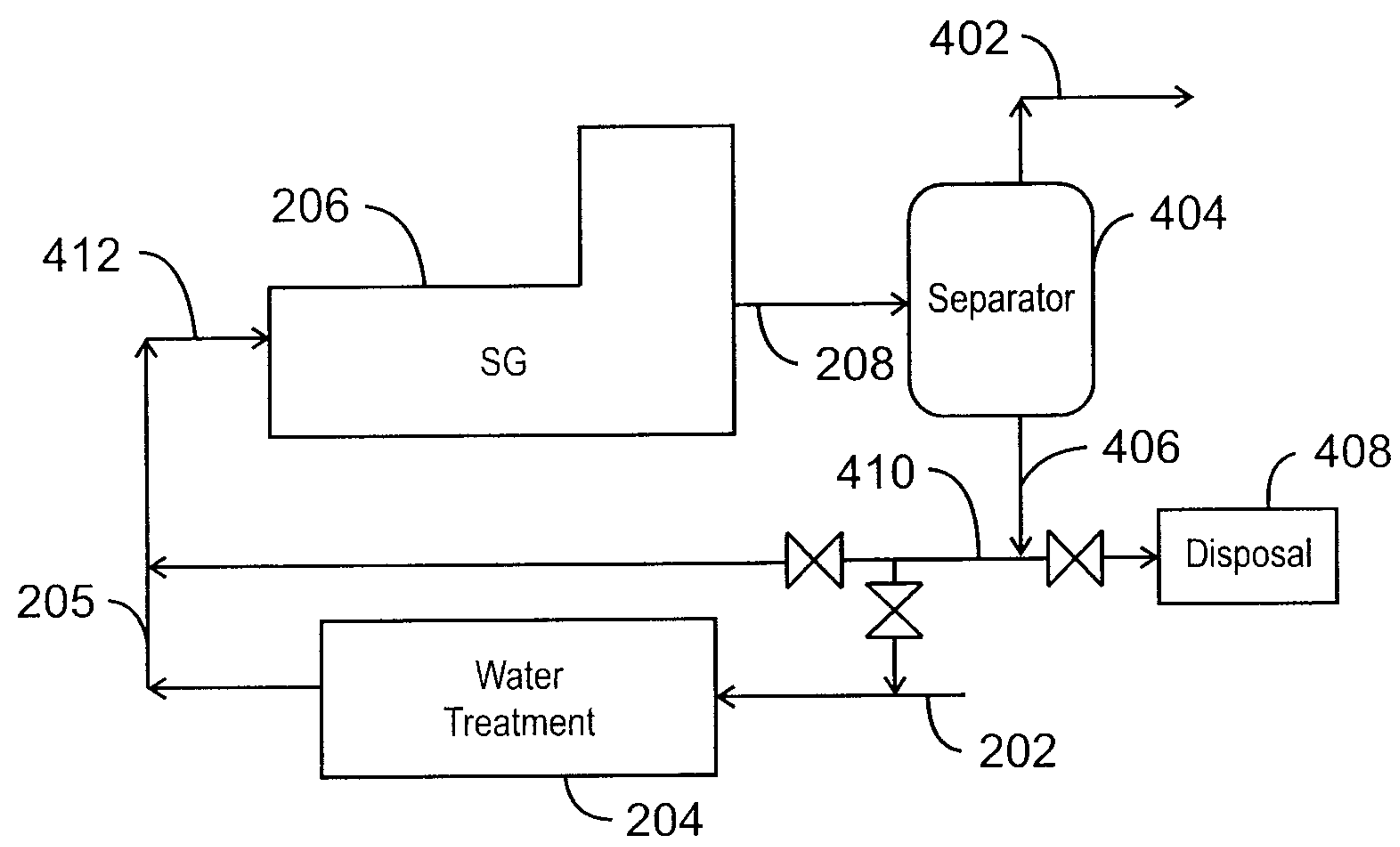


PRIOR ART

300

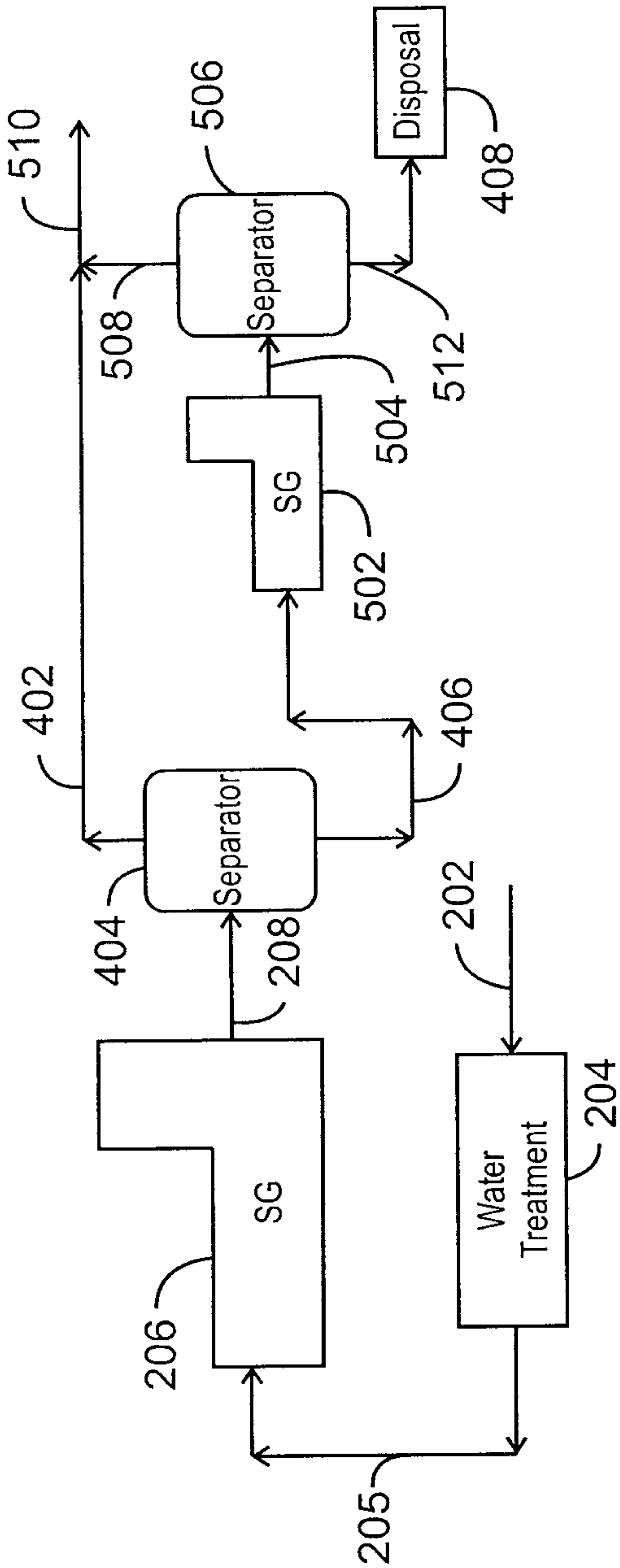
FIG. 3

4/19



PRIOR ART

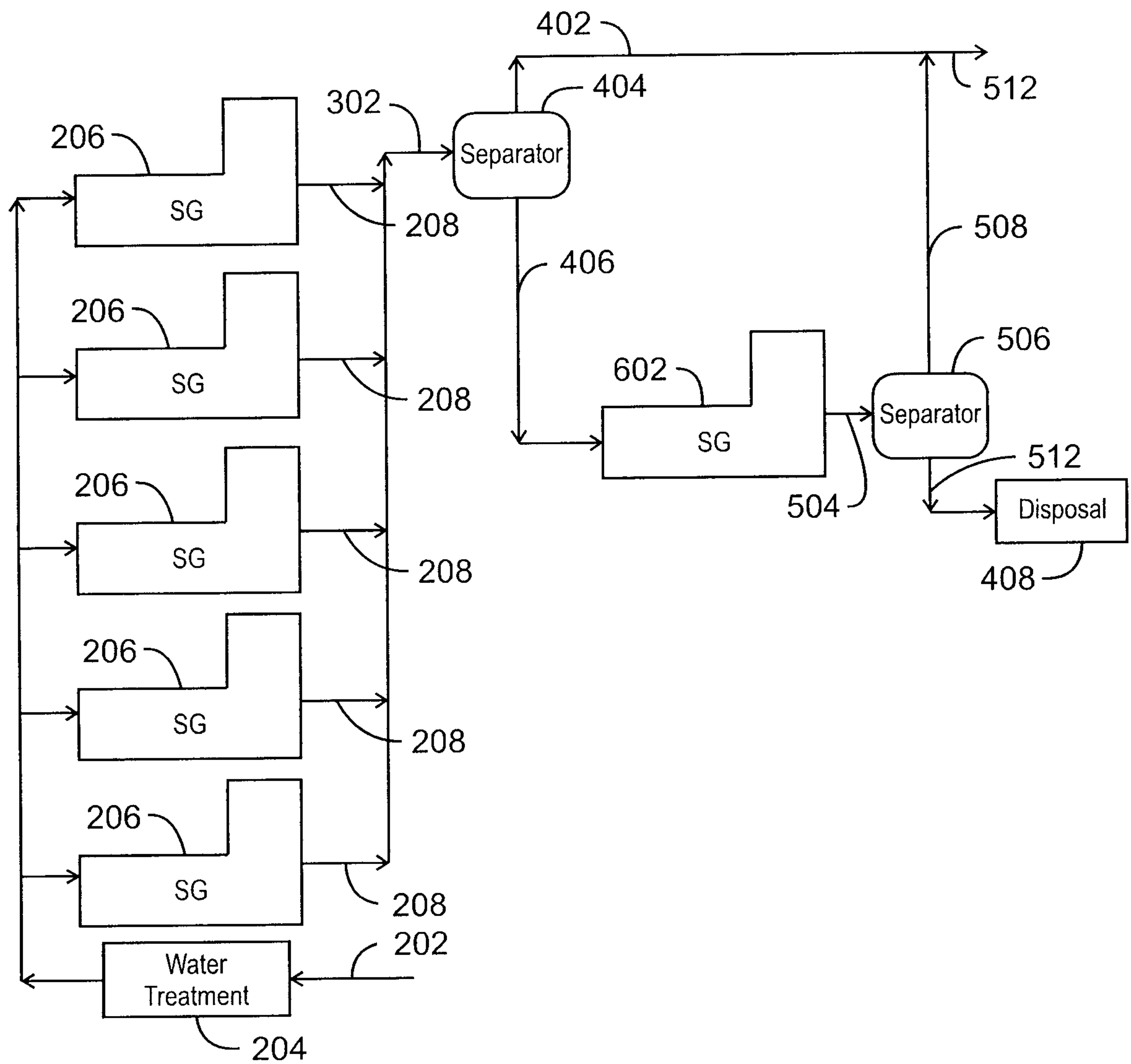
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FIG. 4



PRIOR ART

500
FIG. 5

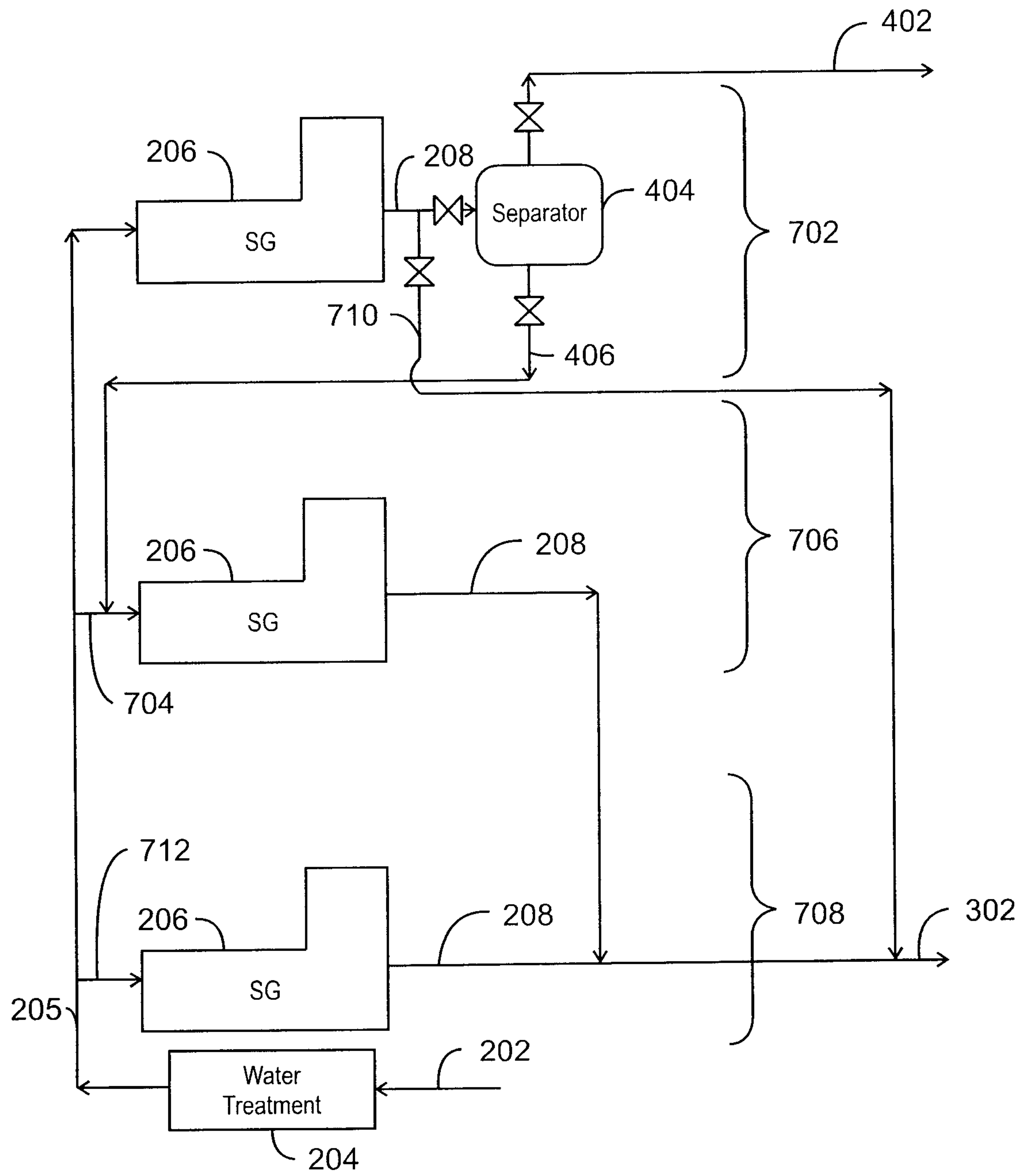
6/19



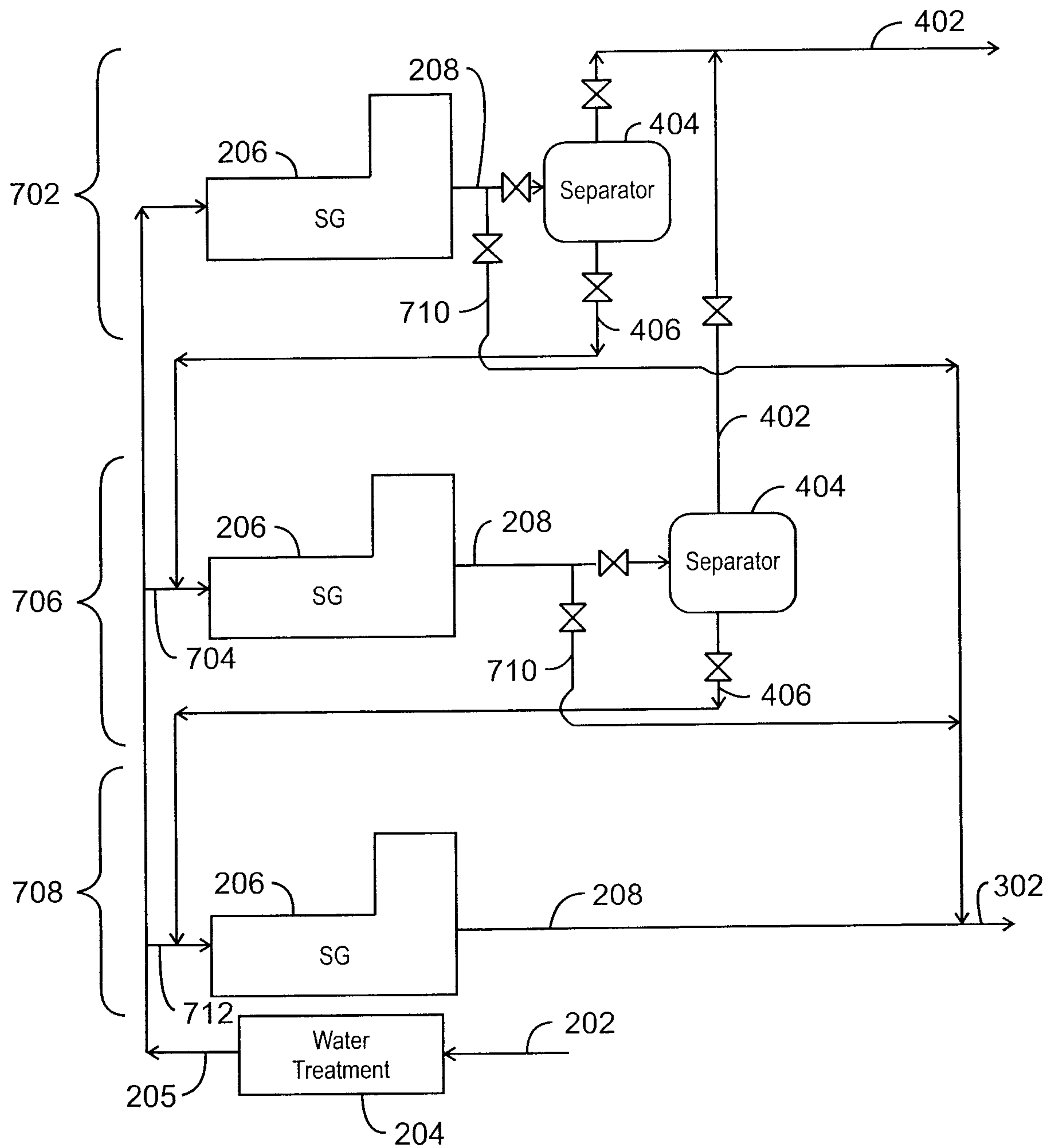
PRIOR ART

600
FIG. 6

7/19

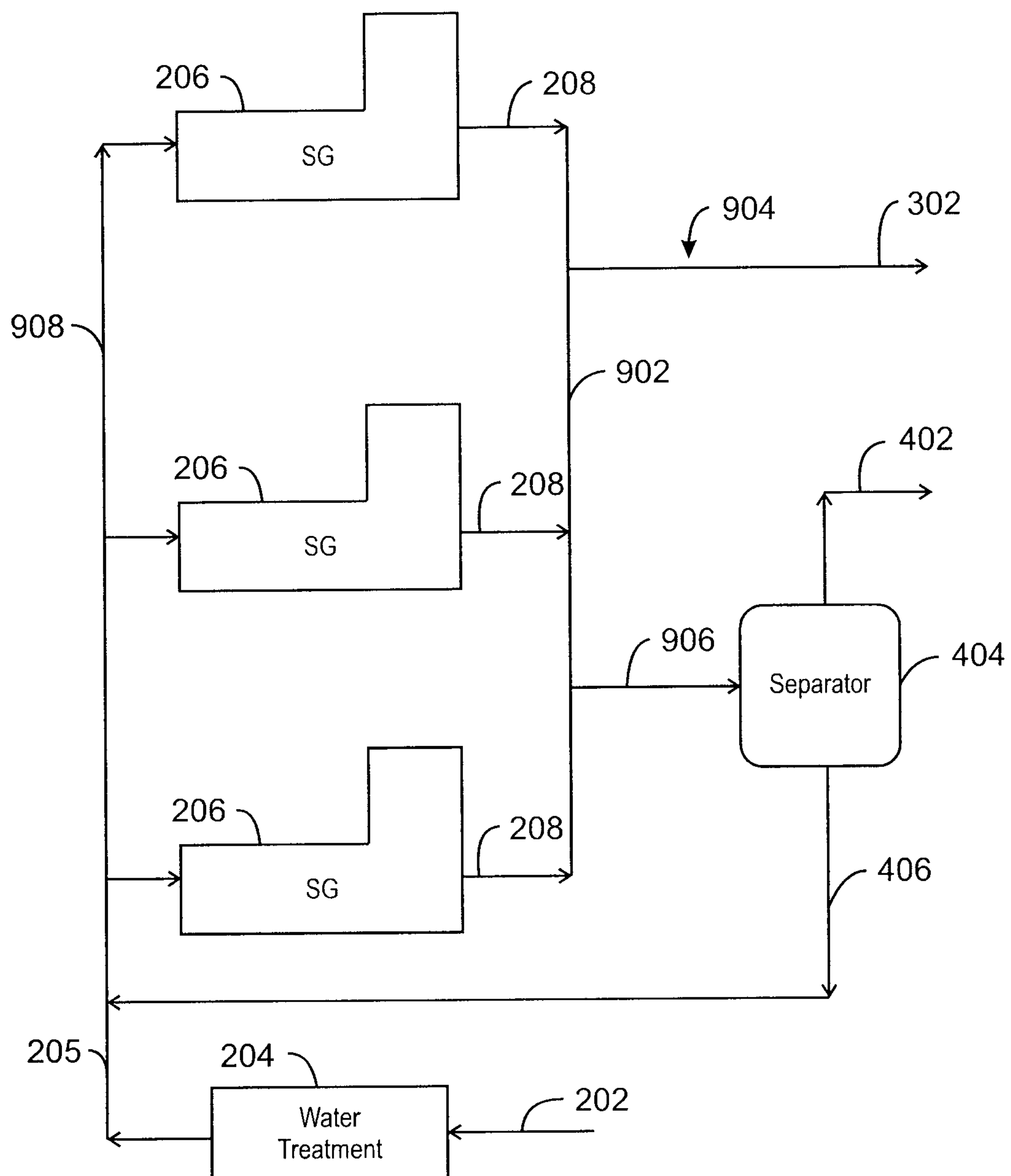


700
FIG. 7



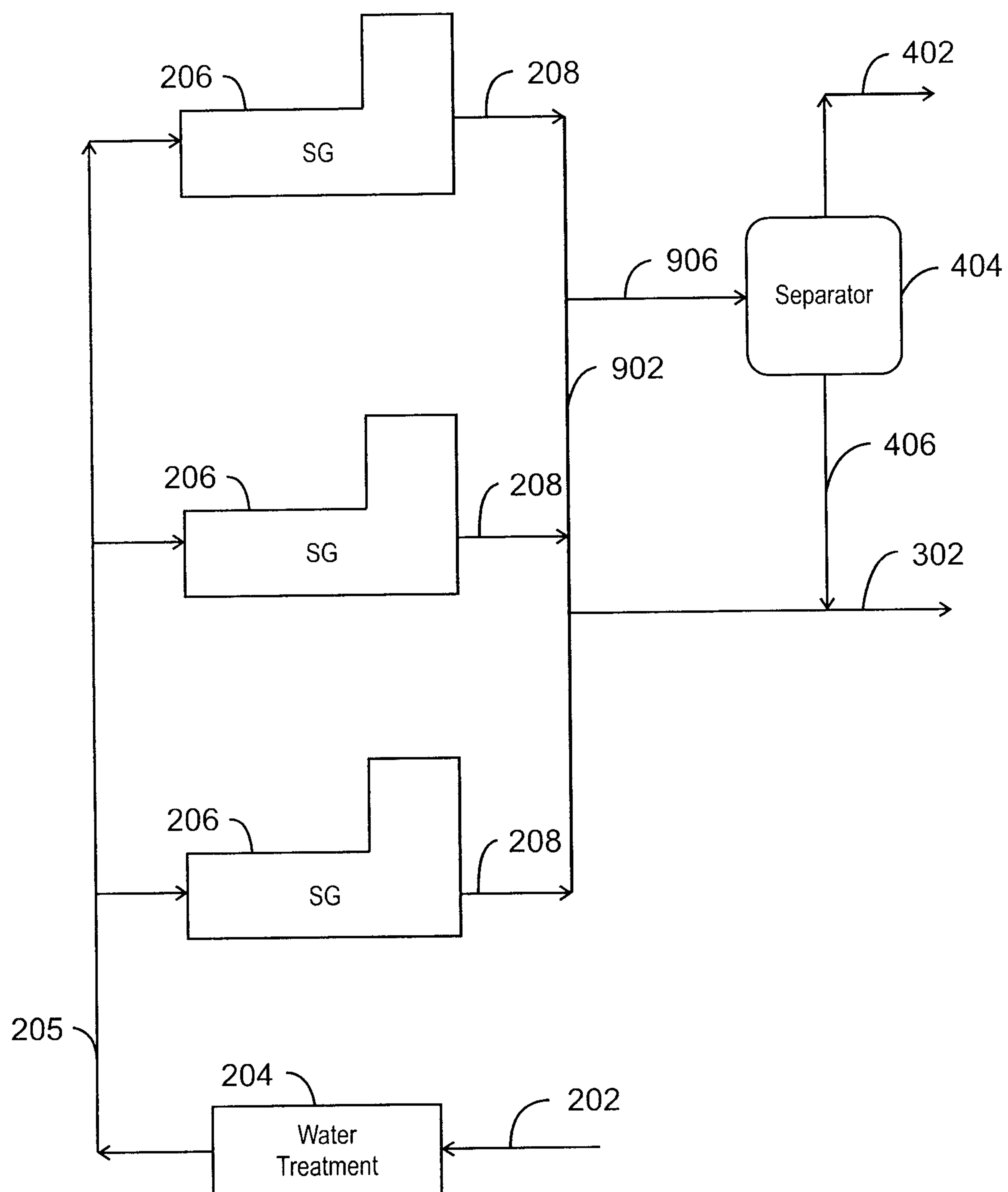
800
FIG. 8

9/19



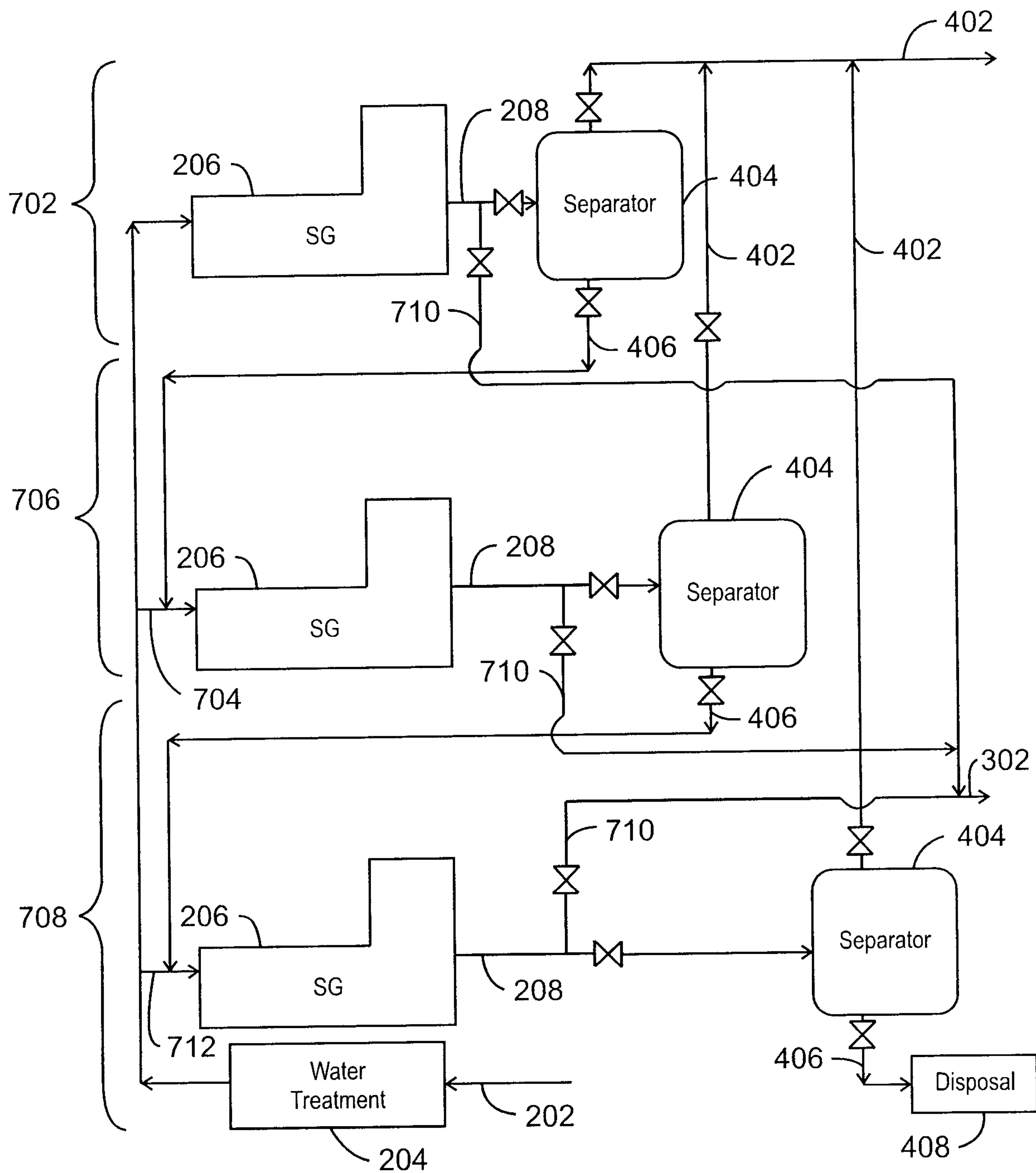
900
FIG. 9

10/19



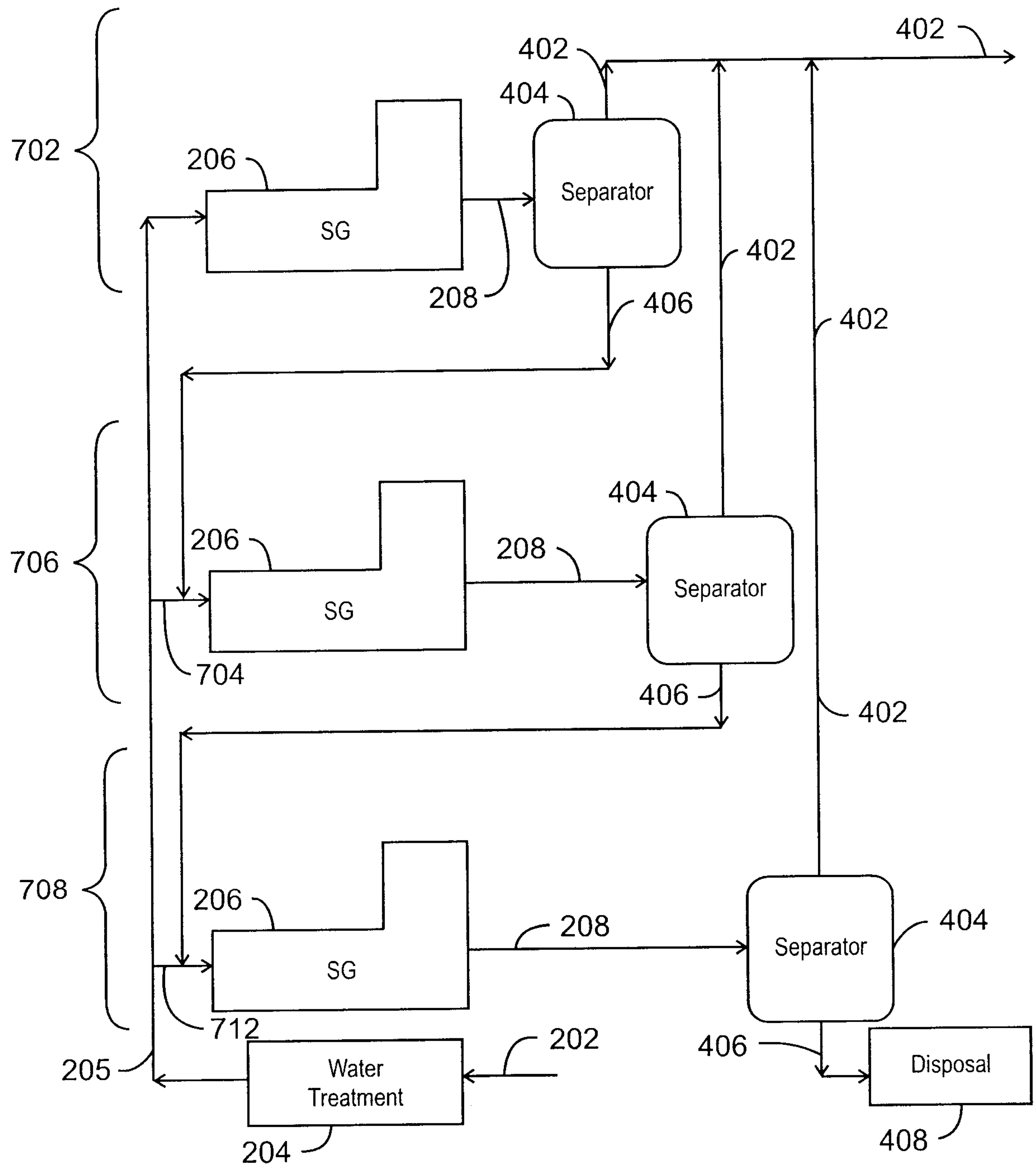
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FIG. 10

11/19



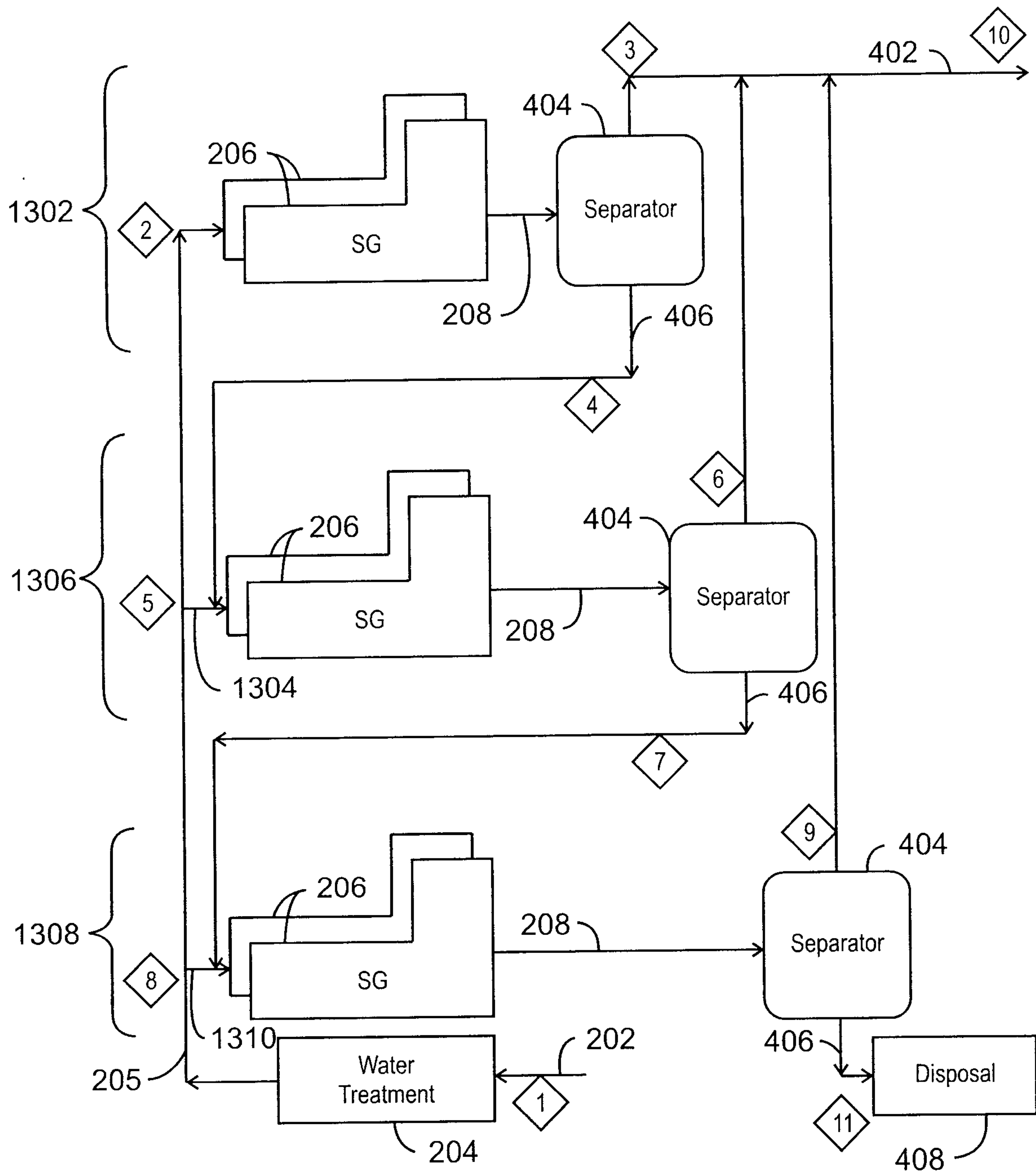
1100
FIG. 11

12/19

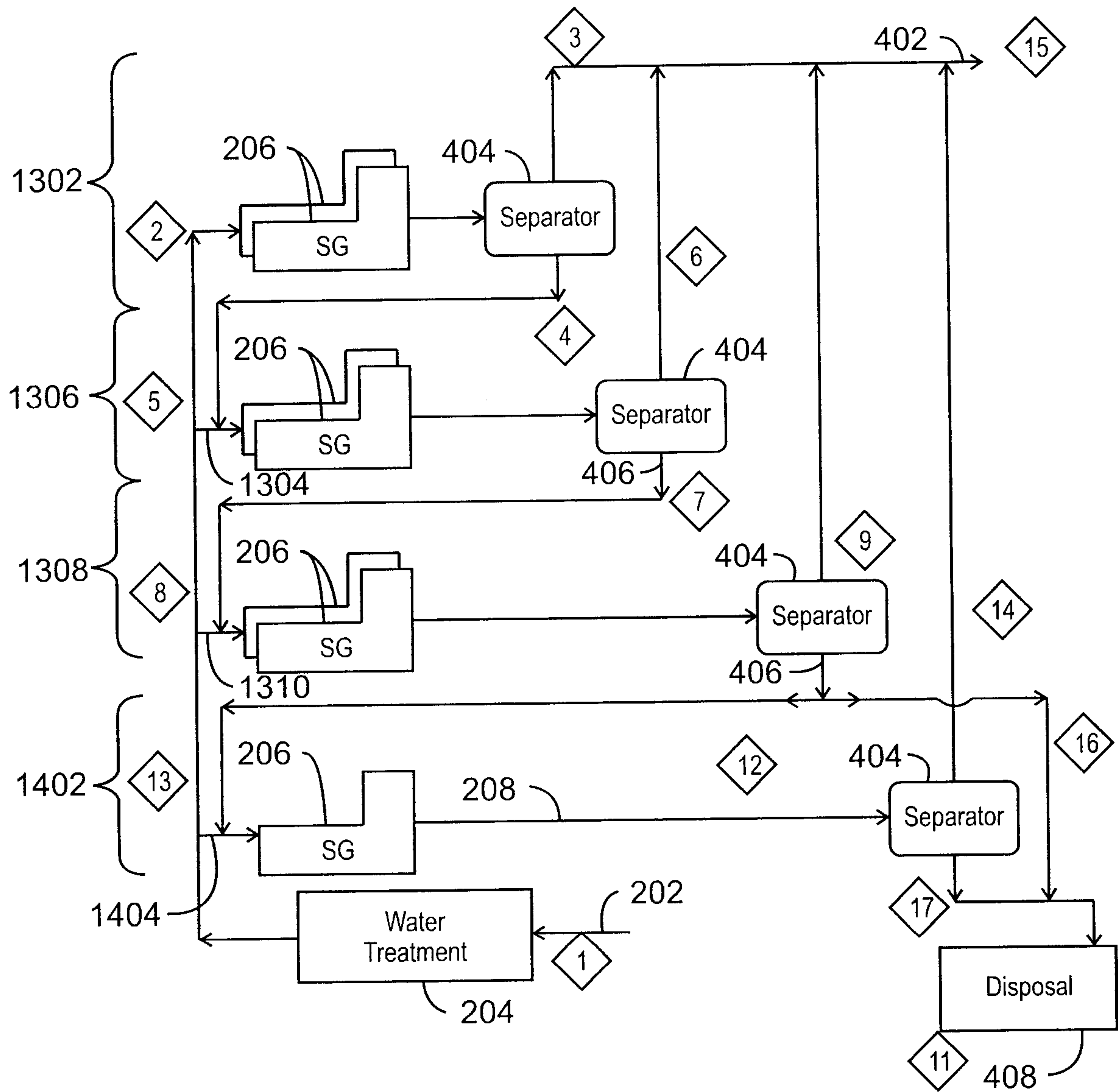


1200
FIG. 12

13/19

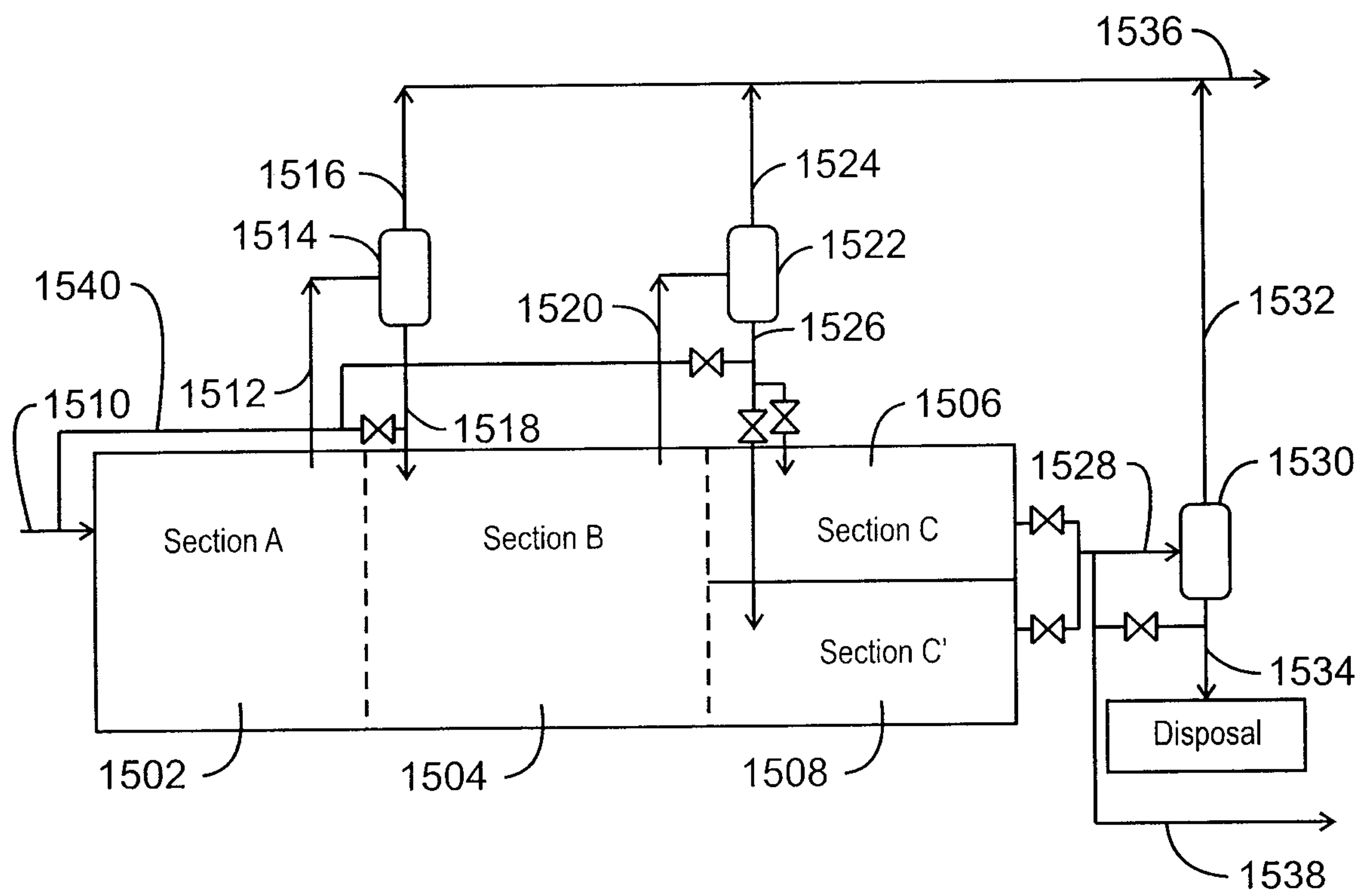


1300
FIG. 13



1400
FIG. 14

15/19



1500
FIG. 15

16/19

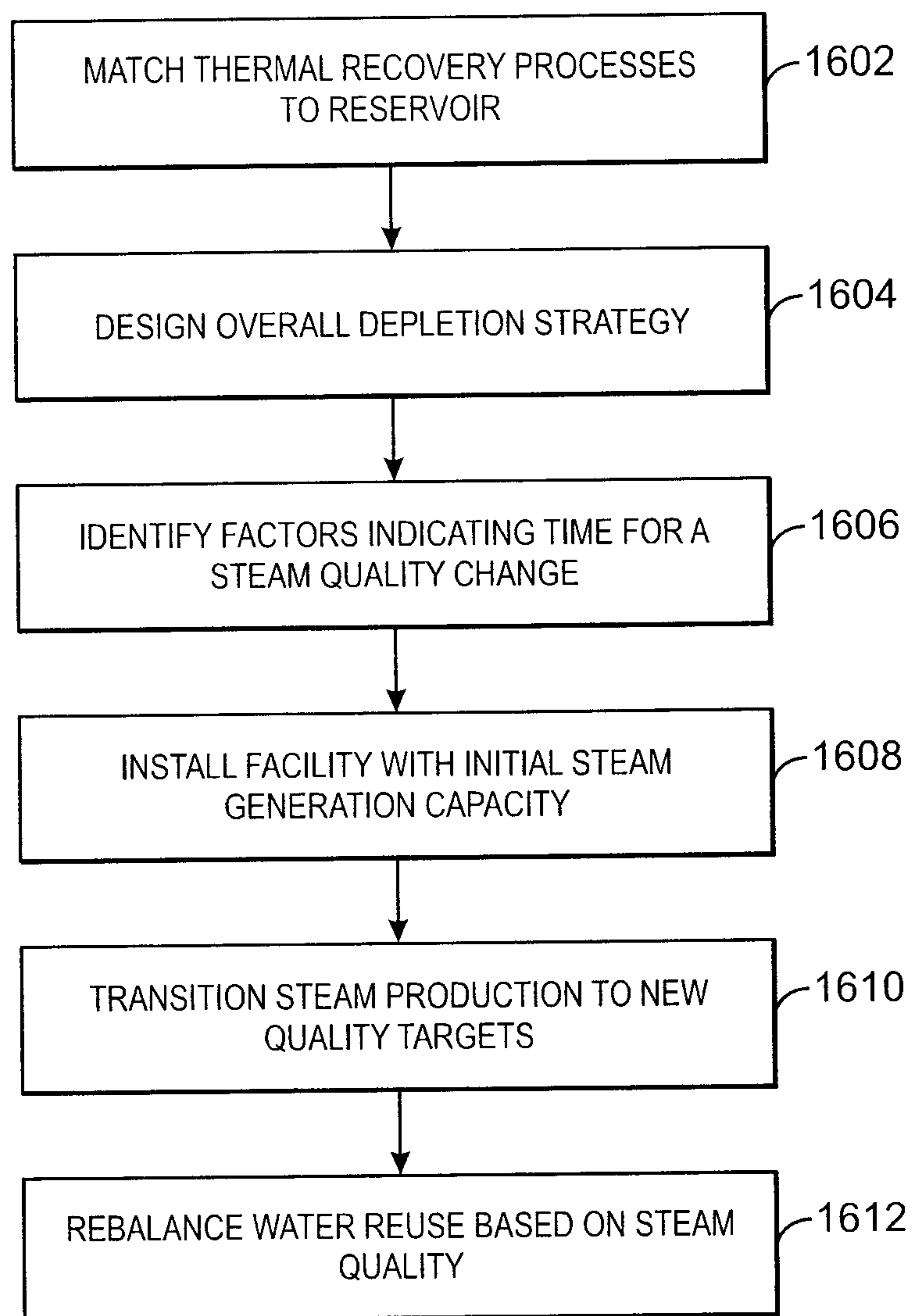
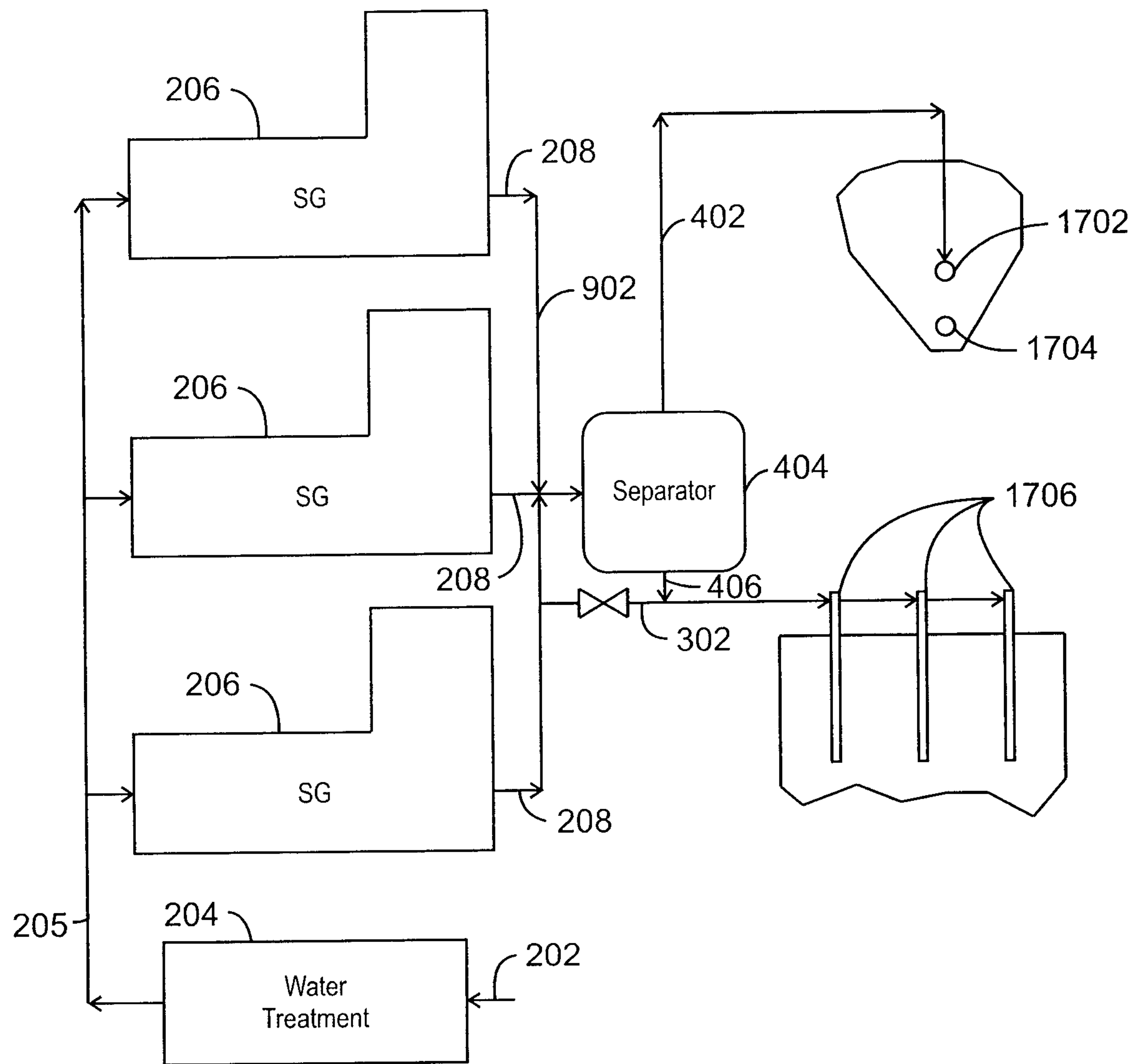
1600

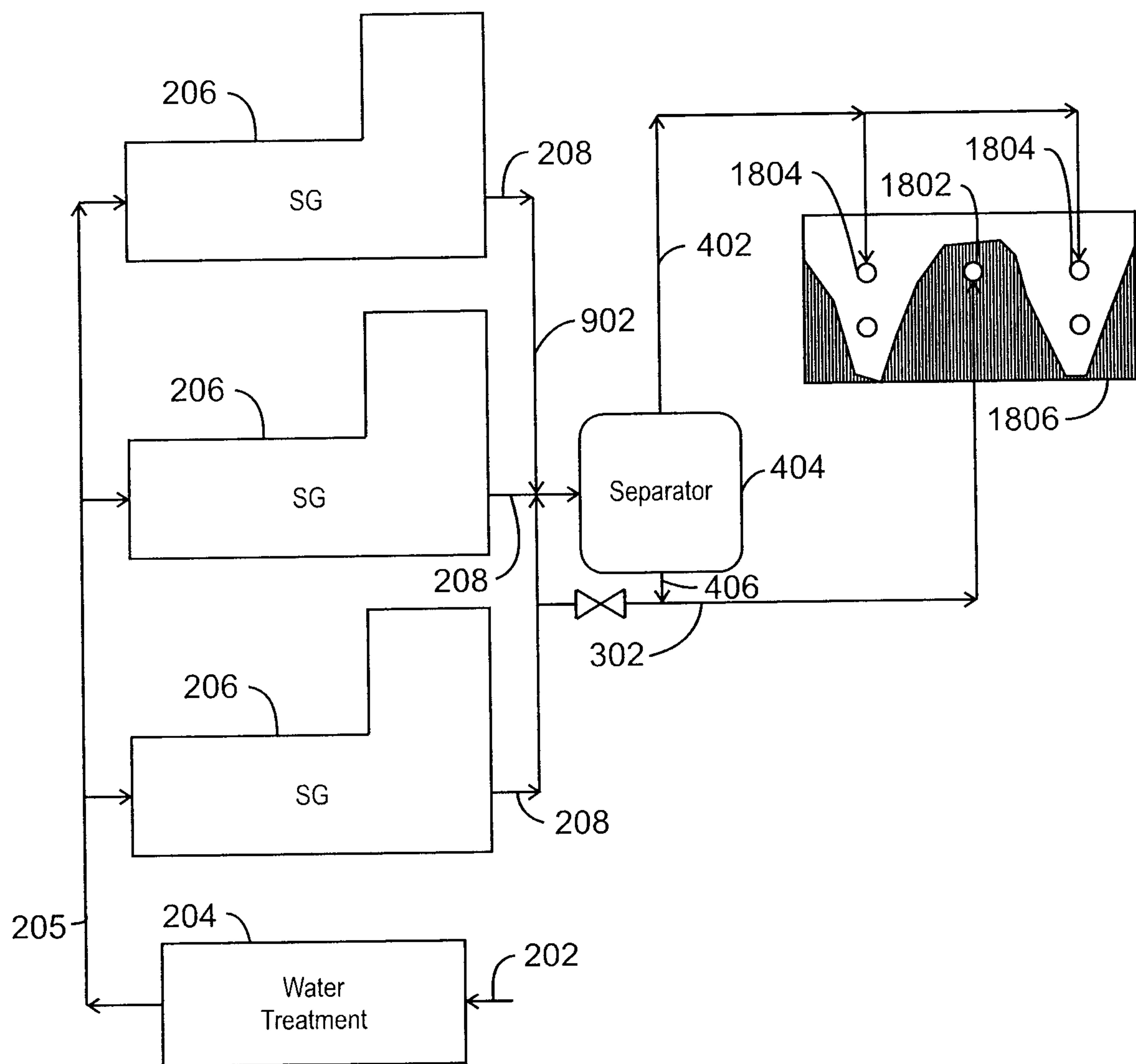
FIG. 16

17/19



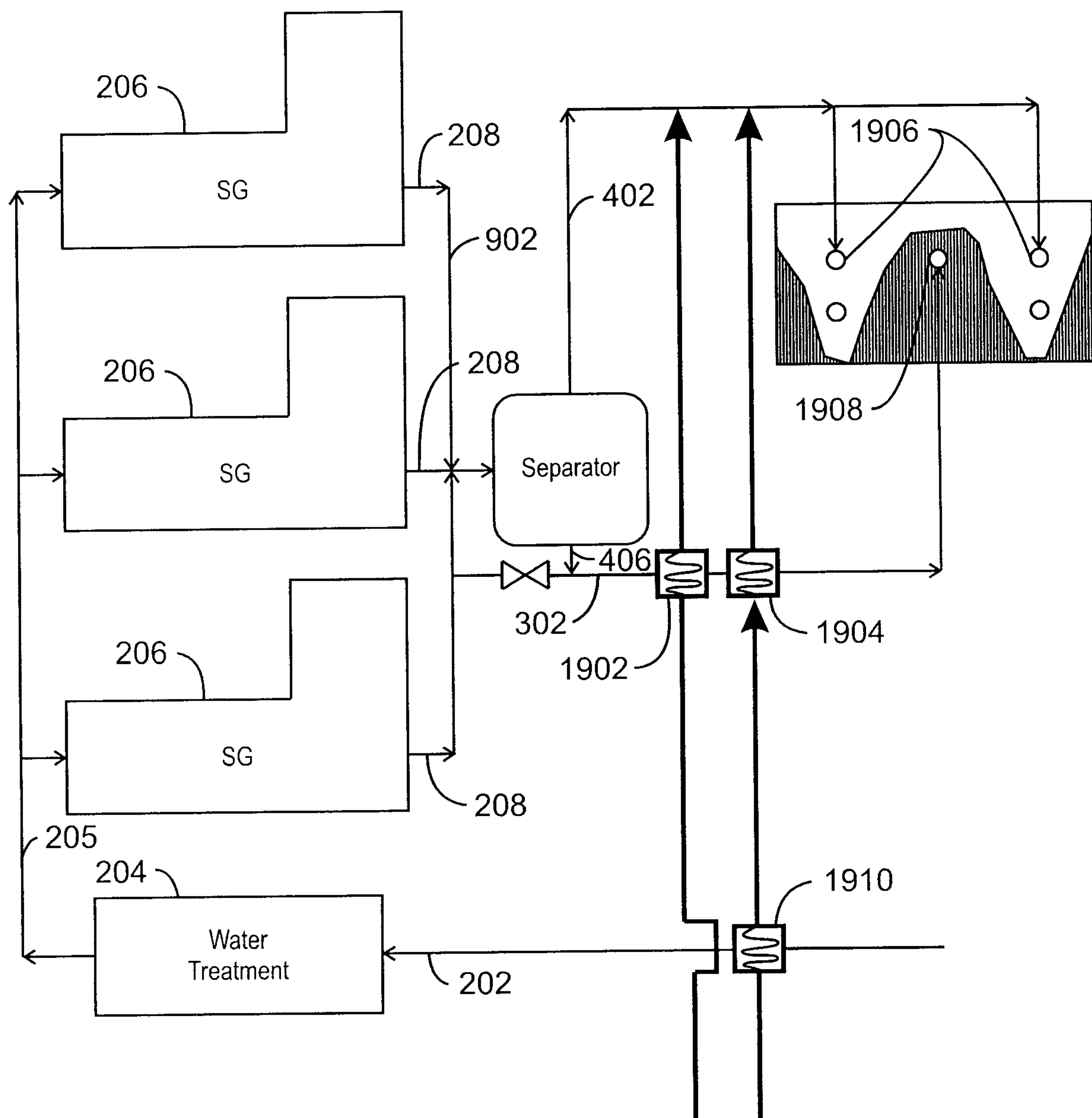
1700
FIG. 17

18/19

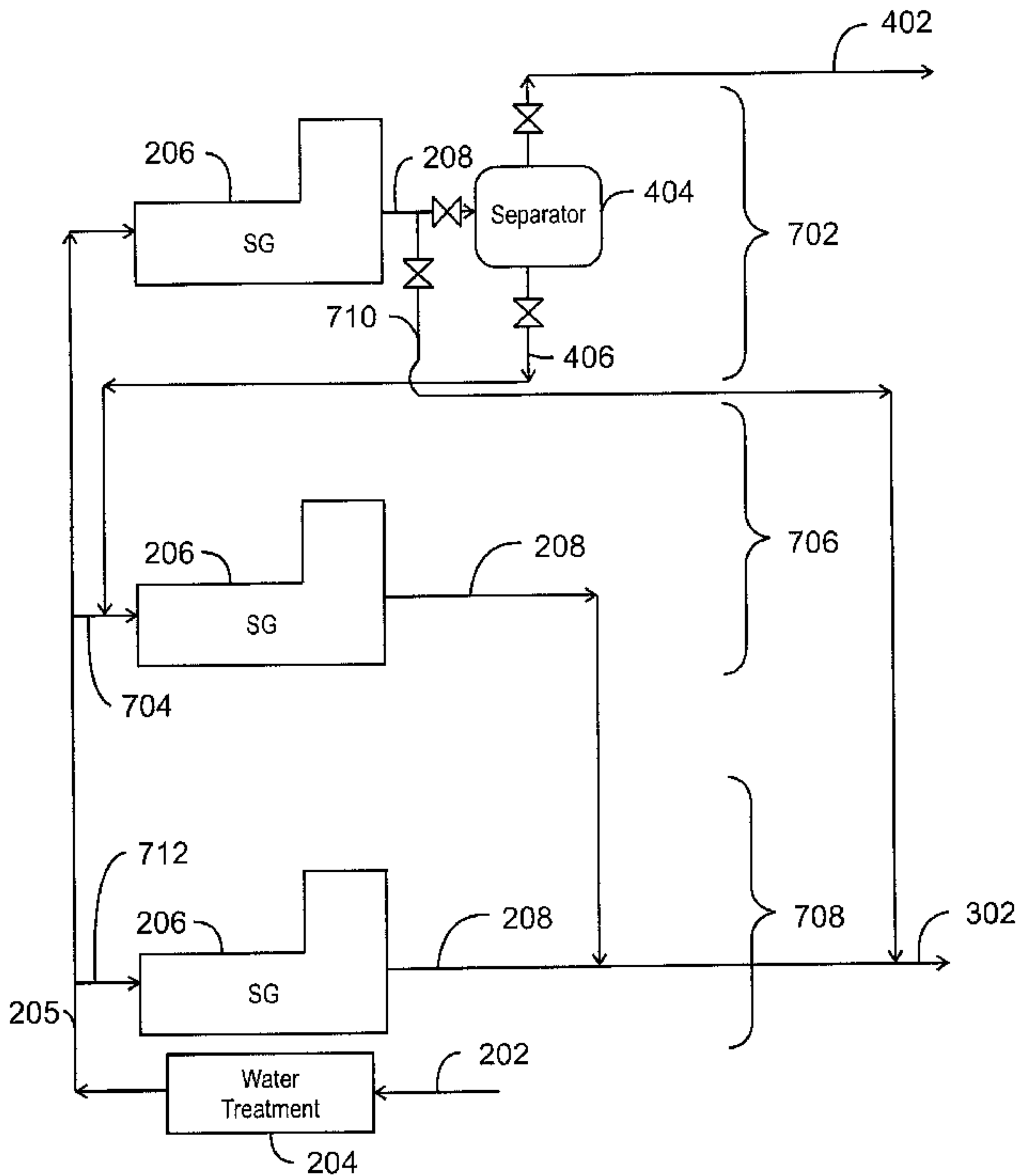


1800
FIG. 18

19/19



1900
FIG. 19



700