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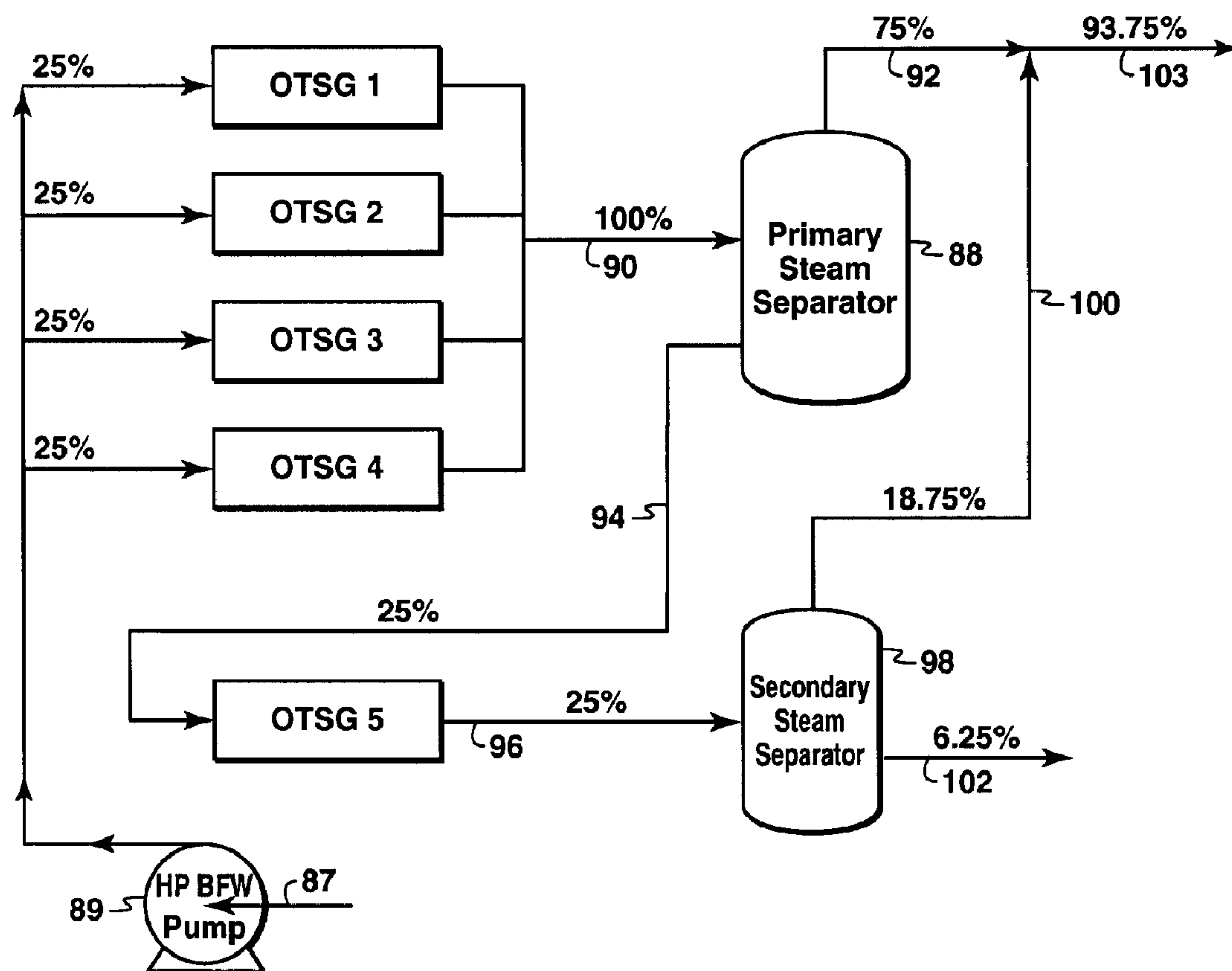
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(57) Abrégé/Abstract:

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(57) **Abrégé(suite)/Abstract(continued):**

steam generators to generate primary wet steam therefrom; separating the primary wet steam into primary dry steam and a primary liquid phase; and feeding the primary liquid phase into one or more secondary steam generators to generate secondary steam therefrom. The secondary steam generators may or may not be wet steam generators. This unique serial configuration results in increased steam production per unit of inlet BFW, as well as an overall reduction of liquid waste or boiler blowdown, when compared to the conventional SAGD wet steam generation configuration. A system for carrying out the process is also provided.

**ABSTRACT**

The present invention provides a novel method and system for generating steam in the oil and gas industry, in particular, in the heavy oil industry. The process comprises feeding boiler feed water (BFW) of sufficient quality through one or more primary wet steam generators to generate primary wet steam therefrom; separating the primary wet steam into primary dry steam and a primary liquid phase; and feeding the primary liquid phase into one or more secondary steam generators to generate secondary steam therefrom. The secondary steam generators may or may not be wet steam generators. This unique serial configuration results in increased steam production per unit of inlet BFW, as well as an overall reduction of liquid waste or boiler blowdown, when compared to the conventional SAGD wet steam generation configuration. A system for carrying out the process is also provided.

## **METHOD AND SYSTEM FOR GENERATING STEAM IN THE OIL INDUSTRY**

### **FIELD OF THE INVENTION**

The present invention relates generally to steam generation. More particularly, the present invention relates to a new method and system for generating steam in the oil industry utilizing steam generators configured in series.

### **BACKGROUND OF THE INVENTION**

Oil sand deposits, located in many regions of the world, comprise mixtures of sand, water, clay, minerals, and crude bitumen that can be extracted and processed for fuel. The oil sands of Alberta, Canada, contain some of the largest deposits of hydrocarbons in the world. Bitumen is classified as an "extra heavy oil", with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute (API) Scale. "Heavy oil" has an API gravity in the range of about 22.3° to about 10°. Heavy oil or bitumen extracted from oil sand may be processed or upgraded to produce light synthetic crude oil having an API gravity of about 31° to about 33°. The terms heavy oil and bitumen are used interchangeably herein since they may be extracted using the same processes.

Bitumen can be recovered from oil sands by various methods, the most common of which include surface or strip mining and in-situ heavy oil recovery methods. In-situ oil recovery methods, including thermal in-situ oil recovery methods, are applied when the bitumen is buried deep within a reservoir and cannot be mined economically due to the depth of the overburden. In general, the focus of an in-situ recovery process is to reduce the viscosity of the bitumen or heavy oil in a formation to enable it to flow and be produced from a well.

Thermal in-situ recovery processes use heat, typically provided by injection of steam into a formation, to reduce the viscosity of the bitumen in a reservoir and thereby render it more flowable. Examples of thermal in-situ recovery processes include but are not limited to steam-assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), and various derivatives thereof, such as solvent-assisted SAGD (SA-SAGD), steam and gas push (SAGP), combined vapor and steam extraction (SAVEX), expanding solvent SAGD (ES-SAGD), constant steam drainage (CSD), and liquid addition to steam enhancing recovery (LASER), as well as water flooding and steam flooding processes. The use of steam renders these processes highly water intensive.

In a typical gravity-driven thermal in-situ oil recovery process, such as SAGD, two substantially horizontal wells are drilled into a reservoir. A lower horizontal well, ideally located near the bottom of the reservoir, serves as a production well and a horizontal well located above the production well serves as an injection well. Steam is injected into the injection well from the surface (with or without the addition of a hydrocarbon solvent) to heat the bitumen trapped in the reservoir and lower its viscosity. As the viscosity of the bitumen is lowered, it flows into the production well, along with condensed steam, and these production fluids are pumped to the surface. Due to the nature of the SAGD recovery process, dry steam is preferred. In the industry, dry steam is understood to be substantially free of water, or dry-saturated, a thermodynamic definition that defines the steam as having no free water, but at the same pressure and temperature as a wet steam.

Although several water treatment and steam generation schemes have been proposed, the heavy oil industry generally relies upon two primary methods of steam generation, those being once-through steam generation and drum boiler steam generation. In the heavy oil industry, oilfield once-through steam generators (OTSGs) are currently the most predominant method used to produce steam, wherein steam is generated from treated feed water through tubes heated by gas or oil burners. This approach generates wet steam of approximately 60% to 85% steam quality, typically 70% - 80% steam quality. For processing requiring dry steam, such as SAGD processes, the wet steam is separated into a liquid component and a dry steam component. The dry steam may then be injected into the reservoir or used for other purposes where dry steam is required or desired.

In an effort to eliminate the liquid-steam separation step during the steam generation process, as well as to minimize the total volume of liquid phase produced, the heavy oil industry began to utilize drum boilers (also referred to as packaged boilers) to produce steam in SAGD operations. Each steam generation system has different advantages and attributes. Although the water quality requirements for the OTSG are not as stringent as for drum boilers, the system is burdened with the extra cost of handling a high pressure, high temperature liquid stream produced from the OTSG (commonly referred to as the liquid phase or boiler blowdown). In comparison, the drum boiler generates dry steam but requires significantly higher water quality than an OTSG to prevent scaling. Typical boiler feed water quality requirements for an OTSG and a drum boiler are shown in Table 1, adapted from U.S. Patent No. 7,077,201 to Heins.

**Table 1.** Typical BFW Specifications for current OTSGs and Drum Boilers.

| Constituent                                                              | OTSG      | Drum Boiler                 |
|--------------------------------------------------------------------------|-----------|-----------------------------|
| Hardness ( $\text{Ca}^{2+}$ & $\text{Mg}^{2+}$ ), ppm as $\text{CaCO}_3$ | < 1.0     | < 0.05 (ND for > 7000 kPag) |
| Total Fe, ppm                                                            | < 0.25    | < 0.01                      |
| $\text{SiO}_2$ , ppm                                                     | < 100     | < 5                         |
| TDS, ppm as $\text{CaCO}_3$                                              | <12,000   | <2.6                        |
| $\text{O}_2$ , ppb                                                       | < 7       | < 7                         |
| pH                                                                       | 7.5 - 9.4 | 8.8 - 9.6                   |
| Oil and Grease, ppm                                                      | < 0.5     | < 0.20                      |

Although the recommended specifications for OTSG boiler feed water quality are not universal, the American Petroleum Institute's recommended practice standards for boilers indicates that TDS as high as 20% of saturation (i.e. 60,000 ppm for NaCl), pH operating range of 7 – 12, and silica levels up to 150 ppm, can be tolerated for operation of an OTSG (see, Recommended Practice for Installation and Operation of Wet Steam Generators API Recommended Practice 11T Second Edition, November 1, 1994).

There are numerous methods by which to achieve the boiler feed water specifications for steam generation. To achieve the water quality specifications required for OTSG, produced water is chemically treated to reduce total hardness, iron and silica concentrations in order to minimize scaling in the steam generator tubes.

A main disadvantage of the conventional water treatment and steam generation processes is the generation of a large volume high temperature waste stream, referred to in the industry as the liquid phase or boiler blowdown. The blowdown stream accounts for about 15% v/v to about 40% v/v of the initial boiler feed water. A typical blowdown stream, based on 75% steam quality, contains 25% v/v of the initial feed water. Current methodologies used to treat this waste stream include simple heat recovery and disposal, as well as combinations of heat recovery, partial recycling, and the implementation of zero liquid discharge (ZLD) systems. Thus, the typical boiler feed water treatment process is not only focused on providing high quality water for steam generation but also processing and handling of the boiler blowdown stream.

Several alternative processes, to the conventional approach depicted in Figure 1, have been proposed to generate boiler feed water and reduce the volume of the waste streams. Heins (see, for example, U.S. Patent Nos. 7,150,320, 7,077,201 and 6,733,636, and U.S. Patent Application Nos. 2003/0127226, 2005/0022989, 2005/0279500 and 2006/0032630) has proposed various boiler feed water treatment processes using evaporation technologies, utilizing mechanical vapor compression (MVC), with falling film heat exchangers and the addition of seeded slurry technology. Kresnyak et al. (see, for example, U.S. Patents Nos. 6,536,523 and 6,984,292, and U.S. Patent Application No. 2003/0127400) have proposed similar evaporation schemes, but with plate and frame heat exchangers. PCT Patent Publication WO 2005/054746 promotes the use of a conventional drum boiler operating in a closed cycle. Steam is generated from clean water, then used as a heat transfer medium to generate steam from the produced water at a high pressure. All of these schemes claim a 95% – 98% v/v recovery of produced water and can thus result in a boiler blowdown stream ranging between 2% and 5% by volume, where ZLD is not utilized in the process configuration.

The use of MVC technology to recover high quality (or clean) water for drum boiler steam generation from either produced water and/or the blowdown stream has been implemented where water conservation is required. Zero Liquid Discharge (ZLD) systems have been incorporated where disposal zones for the evaporator concentrate are not available. These systems usually consist of the MVC system, plus the addition of a crystallizer to remove the total dissolved solids as dry solids. Due to the characteristics of these solids, some schemes also include the use of a kiln to dry the solids in order to meet handling and disposal specifications. Schemes that use the higher quality water from an evaporation system to feed an OTSG have also been proposed (see, for example, Fig. 5 of U.S. Patent No. 7,077,201 to Heins).

While mostly effective, there are several disadvantages associated with schemes utilizing these evaporation systems. In particular, these schemes are highly capital expensive and have high operating costs. They require the use of high alloy materials for construction as well as significant heat and electricity. In addition, a significant amount of chemical treatment is still required (i.e. defoamers, pH adjustment, etc.) to carry out these processes.

There are economic and environmental incentives for improving efficiencies in steam generation in the bitumen and heavy oil industry. It is therefore desirable to provide improved methods and systems for generating steam. An improved technology process that minimizes waste stream volumes while still providing a robust and economical technology is particularly desirable.

## **SUMMARY OF THE INVENTION**

It is an object of the present invention to obviate or mitigate at least one disadvantage of previous methods and systems for generating steam to support an oil recovery operation. The present invention provides a novel method and system for generating steam using steam generators configured in series to increase steam production per unit of water, compared to the conventional SAGD OTSG configuration, and to reduce liquid waste or boiler blowdown.

In a first aspect, the present invention provides a process for generating steam. The process comprises feeding boiler feed water (BFW) of sufficient quality through one or more primary wet steam generators to generate primary wet steam therefrom; separating the primary wet steam into at least primary steam and a primary liquid phase; and feeding the primary liquid phase into one or more secondary steam generators to generate secondary steam therefrom. The primary steam is preferably dry steam.

In one embodiment, the one or more secondary steam generators comprise one or more secondary wet steam generators for generating secondary wet steam from the primary liquid phase. The process may further comprise separating the secondary wet steam into secondary dry steam and a secondary liquid phase.

In another aspect, the present invention provides a system for generating steam. The system comprises one or more primary wet steam generators for generating primary wet steam from boiler feed water (BFW) of sufficient quality; at least one primary steam separator in communication with the one or more primary wet steam generators for receiving the wet steam and separating it into primary steam and a primary liquid phase; and one or more secondary steam generators in communication with the at least one steam separator for receiving the primary liquid phase and generating secondary steam therefrom. The primary steam is preferably dry steam.

In one embodiment, the one or more secondary steam generators are secondary wet steam generators for generating secondary wet steam.

In a further embodiment, the system further comprises at least one secondary steam separator in communication with the one or more secondary wet steam generators, the at least one secondary separator for receiving the secondary wet steam and separating it into secondary dry steam and a secondary liquid phase.

In certain embodiments, the wet steam generators are once-through steam generators (OTSGs), heat recovery steam generators (HRSGs), or a combination thereof.

The wet or dry steam generated may be used to support an oil recovery or mining operation. In a preferred embodiment, the steam generated is used to support an in-situ heavy oil recovery operation. In one embodiment, the in-situ heavy oil recovery operation is a steam-assisted gravity drainage (SAGD) operation and the dry steam produced is utilized for reservoir injection.

In another aspect, the invention provides a process for generating steam to support an in-situ heavy oil recovery operation. The process comprises the steps of feeding boiler feed water (BFW) of sufficient quality through 2 to 12 primary once-through steam generators (OTSGs) configured in parallel to generate primary wet steam having a steam quality of about 60% to about 85%; separating the primary wet steam in a primary steam separator to produce primary dry steam having a steam quality of greater than about 90% and a primary liquid phase; feeding the primary liquid phase to a secondary once-through steam generator configured in series to generate secondary wet steam having a steam quality of about 60% to about 85%; and separating the secondary wet steam in a secondary steam separator to produce secondary dry steam having a steam quality of greater than about 90% and a secondary liquid phase.

In one embodiment, 4 primary OTSGs are configured in parallel.

Other aspects and features of the present invention will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

## **BRIEF DESCRIPTION OF THE DRAWINGS**

Embodiments of the present invention will now be described, by way of example only, with reference to the attached Figures, wherein:

Fig. 1 exemplifies a conventional SAGD water treatment process using OTSG to generate steam;

Fig. 2 exemplifies a conventional prior art configuration for OTSG steam generation for a typical SAGD operation;

Fig. 3a exemplifies a serial steam generator configuration in accordance with an aspect of the present invention, wherein wet steam (WS) from one or more primary wet steam generators is separated into dry steam and a liquid phase (LP), and the LP is then sent to one or more secondary steam generators for further steam generation;

Fig. 3b exemplifies a serial steam generation configuration in accordance with an aspect of the present invention, wherein wet steam (WS) from one or more primary wet steam generators is separated into dry steam and a liquid phase (LP), and the LP is then sent to one or more secondary wet steam generators for further steam generation followed by steam separation to produce more dry steam;

Fig. 4 exemplifies an OTSG configuration in accordance with a first embodiment of the invention;

Fig. 5 exemplifies a second embodiment of the present invention wherein heat is exchanged from the primary liquid phase to the BFW;

Fig. 6 exemplifies a third embodiment of the present invention comprising a heat exchanger on the dry steam line from the primary steam separator;

Fig. 7 exemplifies a fourth embodiment of the present invention wherein the liquid from the primary separation vessel is flashed to a lower pressure to generate low pressure steam for utility purposes, concomitantly concentrating the TDS in the liquid and reducing blowdown volume;

Fig. 8 exemplifies a fifth embodiment of the present invention comprising a heat exchanger on the low pressure side of the HP pumps with an optional atmospheric flash of the liquid phase recovered from the secondary separation vessel for further disposal reduction; and

Fig. 9 exemplifies a sixth embodiment of the present invention wherein wet steam produced from the secondary OTSG in series is sent to the primary steam separator and the liquid phase is commingled with the liquid phase from primary OTSGs 1 - 4 in a parallel configuration.

**DETAILED DESCRIPTION**

Generally, the present invention provides an improved method and system for generating steam in the oil industry. More particularly, the present invention provides a novel method and system for generating steam, preferably to support an oil recovery or mining operation, the process utilizing steam generators configured in series. This unique configuration results in increased steam production per unit of inlet boiler feed water, as well as an overall reduction of liquid waste or boiler blowdown, when compared to the conventional SAGD OTSG configuration for steam generation. An oil recovery operation, as contemplated herein, may include any oil or gas recovery operation where steam generation is required or desired and, in particular, includes heavy oil recovery operations. The steam generated may be used for various purposes to support an oil recovery or mining operation, including but not limited to reservoir injection, feed for steam turbines, and any other utility purposes.

In accordance with an aspect of the invention, one or more primary steam generators are configured in series with one or more secondary steam generators. The steam generators utilized for the primary steam generation step are preferably a wet steam generators. As used herein, wet steam generator includes any forced circulation once-through wet steam generation device, including but not limited once-through steam generators (OTSGs), for example, as described in API RP 11T (American Institute of Petroleum, Recommended Practice for Installation and Operation of Wet Steam Generators, API Recommended Practice 11T, Second Edition, November 1, 1994), and those configured as Heat Recovery Steam Generators (HRSGs). The steam generator(s) utilized for the secondary steam generation step may be any steam generator(s) capable of handling the liquid phase from the one or more primary steam generators, including wet steam generators.

This unique serial configuration results in increased steam generation per unit of inlet boiler feed water and reduced liquid waste, or boiler blowdown, compared to the conventional OTSG configuration where feed water is passed once through the OTSGs to generate wet steam, followed by steam separation to produce dry steam.

Figure 1 exemplifies a conventional prior art SAGD water treatment and steam generation process utilizing OTSG to generate dry steam, also referred to in the industry as

100% quality steam, from produced water. Dry steam (12) and optionally solvent are injected into the injection well (14). The hot steam reduces the viscosity of bitumen trapped in the formation. As the viscosity of the bitumen is lowered, it flows into the production well (18), along with condensed steam, to form the production fluids (16), which are pumped to the surface via the production well (18). The production fluids (16) typically comprise about 70% produced water and about 30% bitumen and produced gases, although the exact proportions can vary. The production fluids (16) are sent to a flow splitter (20), or Free Water Knock Out (FWKO), to separate the production fluids (16) into two or more separate streams. In Figure 1, the exemplified flow splitter separates the production fluids into a produced water stream (22), a wet bitumen stream (24) and a produced gas stream (26). The bitumen and gas streams each undergo further processing to generate a bitumen product (28) and a gas product (30).

The produced water (PW) stream (22) also undergoes further treatment. The PW stream (22) first undergoes PW Deoiling (32), generally via resident time in a skim tank, Induced Gas Floation (IGF), Induced Static Floation (ISF) or another suitable method, and optionally passage through oil removal filters. The Oil Free Water stream (34) is then sent for hardness, iron and silica removal to produce boiler feed water of sufficient quality for steam generation. In this process, oil free water (34) is sent to primary hardness removal vessels (36), such as Hot Lime Softeners (HLS), Warm Lime Softeners (WLS) or the like, for treatment. From there, the softened water stream (38) is directed through After Filters (40) to secondary hardness removal vessels (42), for example, vessels for Weak Acid Cation Exchange (WAC) or Strong Acid Cation Exchange (SAC), to produce boiler feed water (BFW) (44) of sufficient quality for steam generation. The BFW (44) is fed into the once-through steam generators (OTSGs) (46) to generate saturated or wet steam (47). Wet steam (47) exiting the OTSGs is then sent to a steam separator (48), such as a high pressure steam separator, to generate dry steam (12) for injection into the reservoir.

This conventional set up results in numerous waste streams that must be handled appropriately. The liquid phase (50), or boiler blowdown, from the steam separator (48) is a high pressure high temperature waste stream that contains all of the total dissolved solids (TDS) initially present in the BFW (44). Heat may be recovered from the blowdown stream prior to disposal (52).

The TDS concentration in the liquid phase is increased compared to the original BFW, generally according to Formula 1:  $[\text{Liquid Phase TDS}] = [\text{BFW TDS}] \times 100 / (100 - \% \text{ Steam Quality})$ .

For example, if it is assumed that the concentration of TDS in the boiler feed water is 10,000 ppm and an OTSG produces an 80% steam quality, the concentration of TDS in the resultant liquid phase will be about 50,000 ppm.

The liquid phase cannot be continually recycled through the water treatment process since the concentration of TDS will gradually increase beyond tolerable OTSG boiler feed water specifications. The amount of recycling possible is, in large part, dependent on the inlet TDS concentration. The typical OTSG guidelines are presented above in Table 1. Although water quality guidelines for a typical OTSG are required to maximize steam generation, some water quality excursion can be easily tolerated by the robust OTSGs. This is an advantage of utilizing OTSGs over other systems for generating steam. If scaling of the boiler tubes in the OTSGs occurs and a shut down is required, these steam generators can be readily cleaned through chemical or mechanical means, such as pigging, and repaired. OTSGs and HRGSs have relatively few parallel passes, which can be isolated for cleaning. OTSGs generally have 4 or less parallel passes and HSRGs generally have 24 or less parallel passes. Drum boilers have many parallel path tubes that do not have inherent isolation, such that mechanical cleaning is impractical.

A conventional approach to steam generation utilizing OTSGs is exemplified in Figure 2, wherein OTSGs 1 - 5 are configured in parallel with one another wherein each OTSG receives about 20% of the BFW (54) stream. In this configuration, the BFW (54) is pumped through the OTSGs by a high pressure BFW pump (55) and wet steam (56) is generated therefrom. The wet steam (56) is discharged to a steam separator (58), such as a high pressure wet steam separator, which in this exemplary case, yields about 75% dry steam (60), suitable for injection into a reservoir, and about 25% liquid phase (62) or boiler blowdown. The liquid phase (62) produced from the OTSGs contains about 4 times the concentration of hardness ions, silica, and overall TDS, as the initial BFW (54). A conventional OTSG typically generates between about 60 - 85% steam quality.

A serial configuration, in accordance with a general embodiment of the present invention, is shown in Figure 3a, where BFW of sufficient quality (64) is passed through one or more primary wet steam generators (66) to generate wet steam (68), typically of 60% to

85% steam quality. The wet steam (68) is then separated in at least one primary steam separator (69) into primary steam (70) and a primary liquid phase (72). The primary steam is preferably dry steam. The liquid phase (72) is passed through one or more secondary steam generators (74) to generate additional steam (76) from the primary liquid phase (72). The additional steam (76) generated from the primary liquid phase (72) may be wet steam or dry steam depending on the equipment and process selected. Figure 3b shows an extension of this general embodiment, wherein the one or more secondary steam generators are wet steam generators (78) configured in series with the one or more primary wet steam generators (66), to generate a stream of secondary wet steam (80) from the primary liquid phase (72), which is then separated in a secondary steam separator (82) to generate additional or secondary dry steam (84) and a concentrated secondary liquid phase (86) or boiler blowdown. All or a portion of the steam generated by this process may be used for reservoir injection or all or a portion of the steam may be utilized for other purposes. The concentrated secondary liquid phase (86), or blowdown stream, may be treated by any suitable means, including heat recovery, or simply sent to disposal.

"Dry steam", as used herein, typically refers to steam having a steam quality greater than about 90%, preferably greater than about 95%, more preferably greater than about 99%. In the industry, "dry steam" is often referred to as "quality steam" or "100% quality steam". Where a wet steam generator is utilized, "dry steam" refers to the steam discharged from the steam separator, which has a steam quality higher than the wet steam exiting the wet steam generator. Dry steam is typically preferred for reservoir injection.

A first particular embodiment of the invention is exemplified in Figure 4, which depicts four primary OTSGs (OTSG 1-4) operating in parallel and configured in series with a fifth OTSG (OTSG 5) positioned downstream from the primary OTSGs. BFW of sufficient quality (87) is pumped into the primary OTSGs using a high pressure BFW pump (89). The primary OTSGs (OTSG 1-4), operating in parallel, discharge to a primary steam separator (88), preferably a high pressure (HP) wet steam separator, and the primary wet steam (90) is separated to produce primary dry steam (92) and a primary liquid phase (94). The primary dry steam (92) may be sent to the reservoir for injection downhole. In contrast with the conventional parallel approach depicted in Figure 2, the primary liquid phase (94) produced by steam separation is further processed in a secondary OTSG (OTSG 5), configured in series and downstream from the primary OTSGs 1-4, to generate additional or secondary

wet steam (96). In accordance with the embodiment of Figure 4, the operating pressure of the high pressure boiler feed water pump (89) is sufficient to move the liquid phase from the primary OTSGs 1-4 through the secondary OTSG 5 without an additional pressure boost. The secondary wet steam (96) from secondary OTSG 5 may then be separated in a secondary steam separator (98) to produce secondary dry steam (100) and a concentrated secondary liquid phase (102) or boiler blowdown.

The secondary dry steam (100) from OTSG 5 may be combined with the primary dry steam (92) to form a stream of common dry steam (103) if conditions are suitable and the dry steam can be directed to the reservoir. Alternatively, the primary and secondary dry steam (92, 100) may remain in separate streams. If desired, all or a portion of the dry steam produced may be utilized for purposes other than reservoir injection, including utility purposes. In accordance with the embodiment of Figure 4, all of the dry steam generated is utilized for reservoir injection. It is recognized that some of the primary or secondary wet steam produced could be slipstreamed and used for alternative purposes but preferably these streams are entirely directed to the steam separators to generate dry steam.

Thus, this embodiment utilizes OTSGs in parallel (OTSG 1-4) and in series (OTSG 5), in contrast to the conventional configuration with only a parallel configuration. In the exemplified embodiment, the overall process uses the same number of steam generators as the conventional approach of Figure 2 but in a unique configuration that results in an increased yield of dry steam per unit of inlet BFW (93.75% compared to 75%) about 25% v/v higher than the volume of steam generated in the conventional prior art approach shown in Figure 2. This process also significantly reduces the boiler blowdown fraction (6.25% compared to 25%) by about 75% - 80% compared to the prior art approach, to volumes similar to recently proposed evaporative technologies, such as MVC systems. This embodiment of the invention also provides for a significant reduction in capital and operating expense, compared to other known processes, and results in improved environmental performance.

The concentrated liquid phase (102) from the secondary steam separator (98) may be sent to disposal or to any other treatment scheme known in the art, including but not limited to heat recovery, evaporation, crystallization, or membrane filtration. However, it is also recognized that a third steam generator could be configured in the series, and so on, if

the concentrated liquid phase (102) from the secondary separator (98) meets tolerable boiler feed water specifications for a steam generator.

A water treatment process is preferably utilized to provide BFW of sufficient quality to the inlet of the primary OTSGs for the generation of primary wet steam. After steam separation, it is desirable that the primary liquid phase be discharged directly to secondary OTSG without further treatment, thus it is preferable that the water treatment process utilized deliver a boiler feed water stream to the inlet of the primary OTSGs that is of sufficient quality that the primary liquid phase produced can be discharged to the secondary OTSG 5 without resulting in significant damage to the process or to the secondary steam generation equipment.

Knowing that the TDS concentration in the primary liquid phase is increased compared to the original BFW, generally according to Formula 1, where  $[\text{Liquid Phase TDS}] = [\text{BFW TDS}] \times 100 / (100 - \% \text{ Steam Quality})$ , it is possible to calculate suitable BFW TDS specifications by plugging the desired specifications for the secondary steam generator into the  $[\text{Liquid Phase TDS}]$  field and solving for  $[\text{BFW TDS}]$ . Thus, suitable BFW TDS specifications could be calculated based on general Formula 2:  $[\text{BFW TDS}] = [\text{Liquid Phase TDS}] \times (100 - \% \text{ Steam Quality})/100$ .

In accordance with the exemplified embodiment, a suitable BFW for the primary OTSGs 1 - 4 would have about 25% or less of the normal total hardness, iron, silica and TDS specifications for a conventional OTSG, based on a typical steam quality of 75%. Where 80% quality steam is generated, the BFW would preferably have about 20% or less of the normal total hardness, iron, silica and TDS content compared to conventional BFW specifications. The enhanced BFW water quality supplied to the primary OTSGs 1-4 results in a primary liquid phase that still meets conventional BFW specifications for OTSGs. This permits direct discharge of the primary liquid phase to a secondary conventional OTSG configured in series.

It is recognized that the primary liquid phase could be treated or partially treated by any suitable technology, including conventional water softening or reverse osmosis, or subjected to trim treatment, prior to discharge to the secondary steam generator, if desired. It is also recognized that BFW, or water from any other suitable source, could be blended with the primary liquid phase and optionally treated prior to entering the secondary OTSG, if desired. If the primary liquid phase is treated and/or blended prior to discharge to the

secondary OTSG, the need for increased BFW quality at the inlet of the primary OTSGs is minimized or eliminated. The quality of the primary liquid phase will, in large part, determine the type of generator that may be used in the secondary steam generation step. For example, if the primary liquid phase is sent to a reverse osmosis unit for treatment, the resultant quality water would be suitable for steam generation in a drum boiler. A skilled operator can weigh the benefits and disadvantages of treating the initial BFW to sufficient quality such that the primary liquid phase can be discharged to the secondary steam generator without treatment, against treating or blending the primary liquid phase prior to discharge to the secondary steam generator. A combination of the two approaches may also be utilized.

The water treatment scheme used to achieve boiler feed water specifications for the primary OTSGs may be any process known in the art. Where produced water is used to make BFW, make up water from any suitable water source, including but not limited to fresh, brackish, surface, subterranean, or process affected water, or combinations thereof, may optionally be combined with the produced water, before or after treatment, to produce the BFW. Alternatively, the BFW may be generated entirely from water sources other than produced water, with produced water going to other uses.

Suitable or tolerable BFW specifications can be determined by a person of skill in the art, for example, to accommodate for higher or lower steam quality or modifications to the OTSGs. Where 75% steam quality is generated, for example, the BFW specifications could be about 25% of the API specifications or lower. Where 80% steam quality is generated, for example, the BFW specifications could be about 20% of the API specifications or lower. Boiler feed water specifications typically target an upper limit only. Once this upper limit is reached or exceeded in a conventional SAGD treatment process, regeneration of secondary softening equipment (ex. WAC, SAC or the like) is required. The lower permissible limit of the ranges for BFW specifications will typically be about or equal to zero (0). Values near the lower limits of the specifications may not be detectable by standard analysis methods.

Although the specifications for OTSG feed water quality are not universally agreed upon, API RP-11T standards indicate that TDS concentrations of up to about 20% of saturation (i.e. 60,000 ppm for NaCl), and silica levels up to 150 ppm, can be tolerated for operation of an OTSG. The lower limit of such ranges is zero (0 ppm). A pH operating range of 7 – 12 will generally be tolerated by the robust OTSGs. Bowman et. al describe

operational experience with high TDS water and silica levels up to 300 ppm (SPE Ther. Oper. & Heavy Oil Int. Symp., Bakersfield, CA, 2/10-12/97, Proc. pp.143-154, 1997. (SPE-37528)).

Non-limiting exemplary BFW specifications for conventional primary OTSGs (based on 75% steam quality) are presented in Table 2 below. The table exemplifies the effect of increasing initial BFW quality, such that the primary liquid phase produced after steam separation is suitable for processing in the secondary OTSG. These figures are based on the current OTSG water specifications presented in Table 1. Thus, a suitable BFW for inlet to the primary OTSGs in this embodiment could have any of the following specifications: hardness less than 0.25 ppm as  $\text{CaCO}_3$ , total Fe less than 0.05 ppm, TDS less than 12,000 ppm. However, using the API guidelines for NaCl, a TDS of approximately 15,000 ppm could be used when producing 75% quality steam. In one embodiment, silica is less than 25 ppm, although higher silica could be tolerated. In one embodiment, the pH is in the range of 7.0 to 12.0. In one embodiment, the pH is in the range of 7.5 to 9.5. In one embodiment,  $\text{O}_2$  content is less than 2 ppb, and oil and grease content less than 0.1 ppm. The OTSGs are quite robust however, and can tolerate a range of BFW qualities. Appropriate BFW specifications for OTSGs may be determined by a person of skill in the art.

The values in any of the tables presented herein are based on the current industry specifications illustrated in Table 1 and are not intended to limit the scope of the invention. As BFW specifications change, due to changes in OTSG technology, changes in industry standards, chemical additives, or the like, a skilled person is expected to apply the concepts taught herein to adapt to the new specifications.

In accordance with the embodiment of Figure 4, based on 75% steam quality, the primary liquid phase (94) produced from primary OTSGs 1-4 contains approximately 4 times the concentration of hardness ions, silica, TDS, etc. as the BFW (87) at the inlet of the primary OTSGs. In combination with the tighter BFW specifications used for the primary OTSGs 1-4, the quality of the primary liquid phase (94) recovered from the primary steam separator (88) is still of sufficient quality to meet current OTSG BFW specifications for OTSG 5. The modified specifications for the primary OTSGs, while more stringent than the conventional OTSG requirements, is still significantly lower quality than that required by drum boilers.

**Table 2.** Exemplary water specifications for primary and secondary OTSGs, in accordance with an embodiment of the invention.

| Constituent                                                              | OTSG 1-4  | OTSG 5    |
|--------------------------------------------------------------------------|-----------|-----------|
| Hardness ( $\text{Ca}^{2+}$ & $\text{Mg}^{2+}$ ), ppm as $\text{CaCO}_3$ | < 0.25    | < 1.0     |
| Total Fe, ppm                                                            | < 0.05    | < 0.25    |
| $\text{SiO}_2$ , ppm                                                     | < 25      | < 100     |
| $\text{O}_2$ , ppb                                                       | < 2       | < 7       |
| pH                                                                       | 7.5 - 9.4 | 7.5 - 9.4 |
| Oil and Grease, ppm                                                      | < 0.1     | < 0.5     |
| TDS, ppm                                                                 | < 3,000   | < 15,000  |

Although 4 primary OTSGs are depicted in this embodiment, a skilled person will appreciate that this number could be modified without departing from the scope of the invention. In one embodiment, a 1:1 configuration of primary wet steam generator to secondary wet steam generator is utilized, wherein a primary HRSG discharges to a secondary OTSG. In other embodiments, two to or more primary OTSGs will be configured in parallel with each other and in series with one or more secondary OTSGs. The exact configuration can be modified and optimized by the skilled person based on, for example, BFW quality, steam quality generated, design and capacity of the steam generators, or design and capacity of the steam separators utilized.

In certain embodiments, from 2 to 24 primary wet steam generators are configured in parallel with each other and in series with one secondary steam generator. In one embodiment, 2 to 12 primary wet steam generators are configured in parallel. In another embodiment, 2 to 8 primary wet steam generators are configured in parallel. In another embodiment, 3 to 6 primary wet steam generators are configured in parallel. The term parallel is used loosely to indicate that two or more primary wet steam generators feed into a common steam separator to produce a common liquid phase that is directed to one or more secondary steam generators for further processing. Of course, various networks can be

configured wherein the primary wet steam generators feed into multiple primary steam separators, which then feed, in whole or in part, into one or more secondary steam generators. Also, multiple primary steam separators may feed into a common secondary steam generator, or a common steam separator could be used to separate the primary liquid phase and the secondary liquid phase. Once having an understanding of the inventive concept taught herein, a skilled person will be able to design the optimal configuration for a given operation.

The primary and secondary steam generators may individually vary in design, capacity, or operation, including operating temperatures and pressures. That is, the primary wet steam generators may vary with respect to one another, and may also vary in respect to the secondary steam generators, which may also vary with respect to one another and with respect to the primary wet steam generators. As an example, the liquid phase from a primary HRSG could feed a secondary OTSG. Moreover, the primary and secondary steam generators need not be positioned adjacent one another in a steam plant. The steam generators may be separated by some distance from one another in the configuration and may even be separated by geographic location. The maximum permissible distance is limited only by practicality and cost, not technology. For example, it is contemplated that two (or more) in-situ thermal oil recovery plants, such as a SAGD and CSS plant, could be integrated with one water treatment facility, wherein the liquid blowdown from one could feed remote steam generation.

There is a general consensus in the industry that operating an OTSG at lower quality steam generation minimizes scaling of tubes, and extends run life between tube cleaning, with an optimum quality being around 70 to 80%, generally not greater than about 80%. The operation of the secondary OTSG may be varied to achieve different steam quality than the primary OTSGs, with the target steam quality dependent, in large part, on concentration of ionic species in the inlet boiler feed water. The upper steam quality limit for both the primary and the secondary OTSGs is determined by a combination of water chemistry, tube temperature, flame shape control (i.e. flame impingement), tube metallurgy, and risk tolerance, among other factors known to those skilled in the art.

In a second embodiment, exemplified in Figure 5, which is an extension of the embodiment of Figure 4, a heat exchange unit (104) is used to transfer a portion of heat from the primary liquid phase (94), exiting the primary high pressure steam separator (88), to the

BFW (87). Thus, the primary liquid phase (94) is cooled before entering OTSG 5. In accordance with this embodiment, all 5 OTSGs could operate with similar water inlet and stack gas temperatures, assuming substantially identical operation, and hence could be of substantially identical design. In an embodiment where the primary and secondary OTSGs are of substantially identical design, the OTSG inlet and discharge piping may advantageously be arranged such that any OTSG could be operated as a primary or secondary unit, such that the series operation could continue even if the normally designated secondary OTSG was out of service.

In a third embodiment of the invention, exemplified in Figure 6, a pressure regulating device (106), such as a control valve, is added on the line carrying the primary dry steam (92) from the high pressure primary steam separator (88), and a heat exchange element (108) is added on the steam line downstream of the pressure regulating device (106). In order for the secondary dry steam (100) from the secondary steam separator (98) to enter a main line or common steam line (109) with the primary dry steam (92), the pressure of primary dry steam (92) should be lowered. If the pressure drop is large, a consequence of lowering the pressure is to cause the dry steam to become a lower temperature and pressure steam (110) and to become wet. The higher temperature of the primary liquid phase (94) from the primary steam separator (88), which has not undergone a pressure drop, can be used to transfer heat to the lower temperature and pressure steam (110) to increase the steam quality. For instance, if the primary dry steam (92) is reduced in pressure from 12 MPa (324°C) to 9 MPa (303°C), the resulting quality will be about 96%. Cooling the liquid from 324°C to 303°C would vaporize almost all of the liquid phase, such that the resulting stream is near 100% quality.

Alternatively, the pressure of the liquid phase from the primary separator can be boosted by the required amount prior to entering the secondary OTSG so that no pressure drop of the dry steam is required to combine the two streams, thereby removing the drop in quality which would otherwise occur. This can be accomplished by any method known in the art, such as pumps, pressure exchangers, ejectors or the like. A liquid-liquid ejector could be advantageously used if dilution of the liquid phase with primary BFW was desired.

In a fourth embodiment, exemplified in Figure 7, a pressure regulating device (116), such as a control valve, is added downstream of the high pressure primary steam separator (88). The primary liquid phase (94) is flashed to a lower pressure in a flash vessel (112) to

generate low pressure steam (114) for utility purposes. As an example, if the saturated primary liquid phase (94) is at 12 MPa and is subsequently flashed to 1 MPa, approximately 36% of the liquid phase would vapourize at 180°C. This steam would be available for utility purposes or heat and water recovery. In this example, the desired pressure drop and thus the amount of generated steam would ideally be chosen to match the internal utility steam consumption requirements of the operating facility.

Although the net dry steam to field is reduced by the internal consumption of utility steam, compared to the embodiment of Figure 4, there is a reduction in the total volume of secondary liquid phase (102) that must be disposed of or treated. The flash process has the effect of pre-concentrating all of the ionic species in the resulting blowdown water, however, the water quality of the secondary liquid feed (95) to the secondary OTSG (OTSG 5) remains within current operational specifications as shown in Table 3. The process exemplified in Figure 7 utilizes a HP BFW pump (118) to raise the pressure to permit the discharge to mix with the main steam header. The drop in temperature that occurs with the flashing enables the use of conventional pumps. More importantly, the flash pressure can be advantageous to minimize the final waste stream volumes and/or maximize steam to field volume (see Tables 3 and 4).

**Table 3.** TDS Concentration (ppm) utilizing a Single Step Flash with 75% Steam Quality (Figure 7).

|                                                                              | Typical SAGD Operation |
|------------------------------------------------------------------------------|------------------------|
| BFW                                                                          | 1,000 ppm              |
| Primary separation liquid<br>(OTSG 1-4 liquid phase)                         | 4,000 ppm              |
| Post flash liquid -<br>BFW to secondary OTSG<br>(flash from 12 MPa to 1 MPa) | 6,250* ppm             |
| Secondary separation liquid –<br>OTSG 5 liquid phase                         | 25,000* ppm            |
| Volume of liquid waste                                                       | 4%                     |

\* note that the TDS is lower than for CSS boiler feed water

In a process where a zero liquid discharge operation is desired, the 9 units of utility steam shown in Figure 7 could be used to provide energy to a crystallizer. The concentrated liquid emanating from the secondary separation vessel (98) is at high temperature. As exemplified in Figure 8, a subsequent flash to atmospheric pressure using a second pressure regulating device (119) and a second flash vessel (120), would increase the concentration of solids in the final blowdown stream (124) and reduce the volume of the final blowdown stream (124) to about 2% of inlet BFW (2 units). Thus, compared to the conventional approach, with the addition of two flash vessels and one additional separator, a low liquid waste system is achieved without the use of costly evaporators. The heat in the vapour (122) could be used for any process purpose, such as, combustion air preheat, HVAC purposes, with the condensate returned as boiler feed water. In addition, any waste feeds generated by the water treatment process (i.e. HLS/ WLS waste etc.) could be fed into a crystallizer to eliminate the requirement for temporary disposal sludge ponds.

Combinations and extensions of the embodiments described herein can also be used, for instance, the heat exchanger (104) of the embodiment of Figure 5 could be used in conjunction with the embodiment of Figure 7. The cooler temperature of the liquid would enhance the reliability of the BFW pump positioned upstream of OTSG 5. As exemplified in Figure 8, a heat exchange unit (104) could be positioned on the low pressure side of the HP BFW pump (89), the location being facilitated by the lower temperature of the water.

A sixth embodiment of the present invention, exemplified in Figure 9, requires only one high pressure steam separator. Primary wet steam (90) from the primary OTSGs 1-4 and secondary wet steam (128) from the secondary OTSG 5 is sent to a common steam separator (124) to produce dry steam (130) and a common liquid phase (132), which is a blend of liquid separated from the primary wet steam (90) and the secondary wet steam (128). It is recognized that TDS will increase in the common liquid phase (132), however the TDS concentration can be controlled by utilizing a purge or slipstream (134). A slipstream (134) could optimally be created to prevent TDS levels in the common liquid phase (132) fed to OTSG 5 from exceeding about 20% of saturation, roughly 50,000 ppm. In this fashion, the volume of disposal via the slipstream (134) is about 2% original BFW volume.

**Table 4.** Exemplary TDS Concentration (ppm) utilizing a Two Stage Flash with 75% Steam Quality (Figure 8).

|                                                                                                                     | Typical SAGD Operation             |
|---------------------------------------------------------------------------------------------------------------------|------------------------------------|
| BFW                                                                                                                 | 1,000 ppm                          |
| Primary separation liquid -<br>OTSG 1-4 liquid phase                                                                | 4,000 ppm                          |
| Post flash liquid -<br>BFW to secondary OTSG<br>(flash from 12 MPa to 1 MPa)                                        | 6,250 ppm                          |
| Secondary separation liquid -<br>OTSG 5 liquid phase                                                                | 25,000 ppm                         |
| Volume of liquid to<br>atmospheric flash vessel                                                                     | 4% of BFW                          |
| Subsequent flash from 12 MPa<br>to atmosphere (47.5%<br>vapour). Remaining liquid to<br>disposal or to crystallizer | 2.1% of BFW volume<br>~ 47,600 ppm |

A skilled person will recognize that the steam generators utilized in accordance with the present invention need not be of the same design, capacity or operation. They may vary and may be customized to a particular operation. Although the exemplary embodiments disclosed herein illustrate 4 primary OTSGs configured in parallel with one another and in series with one secondary OTSG, the invention is in no way limited by the exemplary embodiments. The exact configuration and equipment utilized can be optimized by the skilled person depending on the particular operation. The scope of the invention is in not limited to typical operations or conventional steam generators. Networks of steam generators configured in parallel and in series with one another may be designed without departing from the scope of the invention.

**EXAMPLE 1**

The following provides an illustrative comparison between an exemplary OTSG steam generation process, in accordance with an embodiment of the present invention, and a conventional prior art steam generation approach.

Assume that each OTSG is identical and has a boiler feed water design flow rate of 2500 m<sup>3</sup>/d and generates 75% v/v quality steam, and that the daily operation is expected to generate 9375m<sup>3</sup>/d of dry steam. In the conventional prior art approach, if the dry steam requirement is 9375 m<sup>3</sup>/d, a total of five conventional OTSG units in parallel would be required. In addition, a total of 12,500m<sup>3</sup>/d water treatment capacity would be needed to supply sufficient boiler feed water for steam generation. Moreover, at 75% steam quality, the total boiler blowdown stream from the five OTSGs configured in parallel would total 3125 m<sup>3</sup>/d.

By comparison, utilizing the process configuration exemplified in Figure 4 to generate about 9375 m<sup>3</sup>/d dry steam, water treatment capacity would be reduced by about 20% to 10,000 m<sup>3</sup>/d. The four primary OTSGs configured in parallel would generate 7500 m<sup>3</sup>/d of dry steam, and the secondary OTSG would utilize the blowdown from the primary OTSGs and convert the liquid to an additional 1875 m<sup>3</sup>/d of dry steam and 625 m<sup>3</sup>/d of liquid phase. Although this configuration still utilizes 5 OTSG units operating at 75% quality, this scheme has the advantage of significantly reducing the blowdown requirements by 80% while generating the same volume of total dry steam (9375 m<sup>3</sup>/d) and reducing the water treatment capacity by 20%. The production of higher quality boiler feed water for the primary OTSGs can be achieved relatively easily with commercial technologies.

Table 5 below presents an illustrative comparison of a steam generation process of the invention versus the prior art approach, at OTSG steam qualities of 75% and 80%.

**Table 5.** Illustrative Comparison of Novel versus Conventional Steam Generation Approach at 75% and 80% Steam Quality.

|                                                                                       | 4 Parallel OTSGs + 1 Series OTSG |        | 5 Parallel OTSGs |        |
|---------------------------------------------------------------------------------------|----------------------------------|--------|------------------|--------|
| Steam Quality                                                                         | 75%                              | 80%    | 75%              | 80%    |
| Boiler feed water, m <sup>3</sup> /d                                                  | 10,000                           | 10,000 | 12,500           | 12,000 |
| Total Dry Steam, m <sup>3</sup> /d                                                    | 9,375                            | 9,600  | 9,375            | 9,600  |
| Total Liquid Phase, m <sup>3</sup> /d                                                 | 625                              | 400    | 3,125            | 2,400  |
| Liquid waste, % of total BFW                                                          | 6.25                             | 4.00   | 25               | 20     |
| Liquid waste reduction vs. conventional approach, %                                   | 80                               | 83     | -                | -      |
| Reduction in total feed BFW requirements vs. conventional approach, m <sup>3</sup> /d | 2,500                            | 2,000  | -                | -      |

Note: Table assumes OTSG rated at 2500 m<sup>3</sup>/d BFW targeting nominal 9,500 m<sup>3</sup>/d dry steam

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 skill in the art without departing from the scope of the invention, which is defined solely by the claims appended hereto.

**CLAIMS:**

1. A process for generating steam, comprising:
  - (a) feeding boiler feed water of suitable quality through one or more primary wet steam generators to generate primary wet steam therefrom;
  - (b) separating the primary wet steam into primary steam and a primary liquid phase; and
  - (c) feeding the primary liquid phase into one or more secondary steam generators to generate secondary steam therefrom.
2. The process of claim 1, wherein the primary steam is primary dry steam.
3. The process of claim 2, wherein the primary dry steam has a steam quality of 90% or higher.
4. The process of claim 3, wherein the primary dry steam has a steam quality of 95% or higher.
5. The process of claim 4, wherein the primary dry steam has a steam quality of 99% or higher.
6. The process of any one of claims 1 to 5, wherein the one or more secondary steam generators comprise one or more secondary wet steam generators for generating secondary wet steam from the primary liquid phase.
7. The process of claim 6, further comprising:
  - (d) separating the secondary wet steam into secondary dry steam and a secondary liquid phase.
8. The process of claim 6 or claim 7, wherein the one or more primary wet steam generators and the one or more secondary wet steam generators comprise once-through steam generators, heat recovery steam generators, or a combination thereof.

9. The process of claim 8, wherein the boiler feed water is fed into 2 to 24 said primary wet steam generators configured in parallel.
10. The process of claim 9, wherein the boiler feed water is fed into 2 to 12 said primary wet steam generators configured in parallel.
11. The process of claim 10, wherein the boiler feed water is fed into 2 to 8 said primary wet steam generators configured in parallel.
12. The process of claim 11, wherein the boiler feed water is fed into 3 to 6 said primary wet steam generators configured in parallel.
13. The process of claim 12, wherein the boiler feed water is fed into 4 said primary wet steam generators configured in parallel.
14. The process of any one of claims 8 to 13, wherein the primary wet steam generators are once-through steam generators.
15. The process of any one of claims 1 to 14, wherein in step (c) the primary liquid phase is fed into one said secondary steam generator configured in series with said one or more primary wet steam generators.
16. The process of claim 15, wherein the secondary steam generator is an once-through steam generator.
17. The process of any one of claims 1 to 15, wherein the one or more primary wet steam generators and the one or more secondary steam generators are each once-through steam generators.
18. The process of claim 17, wherein each said once-through steam generator is substantially identical in design and operation.
19. The process of claim 7, wherein the boiler feed water is fed into one said primary wet steam generator and wherein the primary liquid phase is fed into one said secondary wet steam generator.

20. The process of claim 19, wherein the primary wet steam generator is a heat recovery steam generator and the secondary wet steam generator is a once-through steam generator capable of handling the primary liquid phase from the heat recovery steam generator.

21. The process of any one of claims 1 to 20, wherein the boiler feed water quality is selected such that the primary liquid phase is suitable for processing in the one or more secondary steam generators.

22. The process of claim 21, wherein the quality of the boiler feed water, based on total dissolved solids as ppm, is selected based on the following formula, wherein:

$$\begin{array}{l} \text{total dissolved solids in} \\ \text{the boiler feed water in ppm} \end{array} = \begin{array}{l} \text{total dissolved solids in} \\ \text{the liquid phase in ppm} \end{array} \times \frac{100 - \% \text{ steam quality}}{100}$$

23. The process of any one of claims 6 to 22, wherein the primary wet steam and the secondary wet steam generated is of about 60% to about 85% steam quality.

24. The process of claim 23, wherein the primary and secondary wet steam generated is of about 75% to about 80% steam quality.

25. The process of claim 24, wherein the primary and secondary wet steam generated is of about 80% steam quality and the boiler feed water has a hardness, iron and total dissolved solids concentration about 20% of conventional boiler feed water specifications or lower.

26. The process of claim 24, wherein the primary and secondary wet steam generated is of about 75% steam quality and the boiler feed water has a hardness, iron and total dissolved solids concentration about 25% of conventional boiler feed water specifications or lower.

27. The process of any one of claims 1 to 26, wherein the boiler feed water has the following specifications: hardness less than 0.25 ppm as  $\text{CaCO}_3$ ; total Fe less than 0.05 ppm; and total dissolved solids less than 12,000 ppm.

28. The process of claim 27, wherein the boiler feed water has the following additional specifications: silica less than 25 ppm; pH in the range of 7.0 to 12.0;  $\text{O}_2$  content less than 2 ppb; and oil and grease content less than 0.1 ppm.

29. The process of any one of claims 1 to 28, wherein the primary liquid phase meets conventional boiler feed water specifications prior to being fed into the one or more secondary steam generators.
30. The process of any one of claims 1 to 29, wherein the boiler feed water and the primary liquid phase are moved through the primary and secondary steam generators in the absence of a pressure boost therebetween.
31. The process of any one of claims 1 to 30, further comprising the step of cooling the primary liquid phase prior to entry into the one or more secondary steam generators such that the boiler feed water and the primary liquid phase are of substantially the same temperature upon entering the primary and secondary steam generators, respectively.
32. The process of claim 31, wherein the primary liquid phase is cooled by transferring a portion of heat from the primary liquid phase to the boiler feed water.
33. The process of any one of claims 7 to 14, 16, 18 to 20, 22, 24 to 26 or 28, further comprising the step of adjusting the pressure of the primary dry steam or the secondary dry steam, or both, such that the respective pressures are compatible; and combining the two streams into a common stream.
34. The process of claim 33, wherein the pressure of the primary dry steam is reduced to produce a reduced pressure steam prior to combining the reduced pressure steam with the secondary dry steam.
35. The process of claim 34, wherein a portion of heat from the primary liquid phase is transferred to the reduced pressure steam to improve the quality thereof prior to being combined with the secondary dry steam, and to thereby cool the primary liquid phase prior to being fed into the secondary steam generator.
36. The process claim 33, wherein the pressure of the secondary dry steam is increased to produce an increased pressure steam prior to combining the increased pressure steam with the primary dry steam.
37. The process of any one of claims 1 to 29, further comprising a flash step to reduce the pressure of the primary liquid phase to thereby generate low pressure utility steam and a

concentrated primary liquid phase for discharge to the one or more secondary steam generators.

38. The process of claim 37, wherein a portion of heat from the concentrated primary liquid phase is transferred to the boiler feed water to cool the concentrated primary liquid phase prior to entry into the one or more secondary steam generators.

39. The process of claim 38, wherein the pressure of the cooled concentrated primary liquid phase is boosted prior to entry into the secondary steam generator.

40. The process of any one of claims 37 to 39, further comprising a flash step to reduce the pressure of the secondary liquid phase to generate low pressure steam or vapour and a concentrated secondary liquid phase.

41. The process of claim 40, wherein the flash step reduces the pressure of the secondary liquid phase to atmospheric pressure.

42. The process of claim 6, wherein the primary wet steam and the secondary wet steam are fed into a common steam separator to generate a common liquid phase that is discharged to the one or more secondary wet steam generators.

43. The process of claim 42, wherein the common liquid phase is cooled prior to entry into the one or more secondary wet steam generators.

44. The process of claim 43, wherein the common liquid phase is cooled by transferring a portion of heat therefrom to the boiler feed water.

45. The process of any one of claims 42 to 44, wherein the primary and secondary wet steam generators are once-through steam generators, heat recovery steam generators, or a combination thereof.

46. The process of claim 45, wherein the primary and secondary wet steam generators are once-through steam generators.

47. The process of any one of claims 2 to 5, 7 to 14, 16, 18 to 20, 22 to 26, 28, 32 to 36 or 38 to 46, wherein all or a portion of the dry steam produced is injected into a reservoir.

48. The process of claim 47, wherein all of the dry steam produced is injected into the reservoir.

49. The process of any one of claims 2 to 46, wherein the wet or dry steam generated is used to support an oil recovery or mining operation.

50. The process of claim 49, wherein the wet or dry steam generated is used to support an oil recovery operation, and wherein the oil recovery operation is a thermal in-situ heavy oil recovery operation.

51. The process of claim 50, wherein the thermal in-situ heavy oil recovery operation is steam-assisted gravity drainage, cyclic steam stimulation or a derivative thereof.

52. The process of claim 51, wherein the derivative thereof is solvent-assisted steam-assisted gravity drainage, steam and gas push, combined vapor and steam extraction, expanding solvent steam-assisted gravity drainage, constant steam drainage, liquid addition to steam enhancing recovery, or a water flooding or steam flooding process.

53. The process of claim 52, wherein the thermal in-situ oil recovery operation is steam-assisted gravity drainage.

54. A system for generating steam, comprising:

(a) one or more primary wet steam generators for generating primary wet steam from boiler feed water of suitable quality;

(b) at least one primary steam separator in communication with the one or more primary wet steam generators for receiving the wet steam and separating it into primary steam and a primary liquid phase; and

(c) one or more secondary steam generators in communication with the at least one steam separator for receiving the primary liquid phase and generating secondary steam therefrom.

55. The system of claim 54, wherein the primary steam generated is primary dry steam.

56. The system of claim 55, wherein the one or more secondary steam generators are secondary wet steam generators for generating secondary wet steam.

57. The system of claim 56, further comprising at least one secondary steam separator in communication with the one or more secondary wet steam generators, the at least one secondary separator for receiving the secondary wet steam and separating it into secondary dry steam and a secondary liquid phase.

58. The system of claim 56 or claim 57, wherein the one or more primary wet steam generators and the one or more secondary wet steam generators comprise once-through steam generators, heat recovery steam generators, or a combination thereof.

59. The system of any one of claims 54 to 58, wherein 2 to 24 said primary wet steam generators are configured in parallel.

60. The system of claim 59, wherein 2 to 12 said primary wet steam generators are configured in parallel.

61. The system of claim 60, wherein 2 to 8 said primary wet steam generators are configured in parallel.

62. The system of claim 61, wherein 3 to 6 said primary wet steam generators are configured in parallel.

63. The system of claim 62, wherein 4 primary wet steam generators are configured in parallel.

64. The system of any one of claims 58 to 63, wherein the primary wet steam generators are once-through steam generators.

65. The system of any one of claims 54 to 64, wherein one said secondary steam generator is configured in series with said one or more primary wet steam generators.

66. The system of claim 65, wherein the secondary steam generator is a once-through steam generator.

67. The system of any one of claim 54 to 65, wherein the one or more primary wet steam generators and the one or more secondary steam generators are each once-through steam generators.

68. The system of claim 67, wherein each said once-through steam generator is substantially identical in design and operation.

69. The system of claim 58, wherein one said primary wet steam generator is configured in series with one said secondary wet steam generator.

70. The system of claim 69, wherein the primary wet steam generator is a heat recovery steam generator and the secondary wet steam generator is a once-through steam generator capable of handling the primary liquid phase from the heat recovery steam generator.

71. The system of any one of claims 56 to 70, wherein the primary and secondary wet steam generators are suitable for operation at about 60% to about 85% steam quality.

72. The system of claim 71, wherein primary and secondary wet steam generators are suitable for operation at about 75% to about 80% steam quality.

73. The system of any one of claims 54 to 72, wherein a high pressure boiler feed water pump is positioned upstream of the one or more primary steam generators.

74. The system of claim 73, further comprising a heat exchange element for transferring a portion of heat from the primary liquid phase to the boiler feed water to reduce the temperature of the primary liquid phase prior to being fed to the secondary steam generator.

75. The system of claim 74, wherein the heat exchange element is positioned downstream of the high pressure boiler feed water pump and upstream of the one or more primary wet steam generators.

76. The system of any one of claims 57 to 75, further comprising a primary dry steam line from the primary steam separator for carrying the primary dry steam; a secondary dry steam line from the secondary steam separator for carrying the secondary dry steam; and a common dry steam line connected to the primary and secondary dry steam lines in which the primary dry steam and the secondary dry steam are combined.

77. The system of claim 76, further comprising at least one pressure regulating device for adjusting the pressure in the primary dry steam line, the secondary dry steam line, or both, such that the pressures are compatible prior to combination in the common dry steam line.

78. The system of claim 77, wherein the at least one pressure regulating device is a pressure regulator positioned on the primary dry steam line for reducing the pressure of the primary dry steam to produce a reduced pressure primary steam.

79. The system of claim 78, further comprising a heat exchange element positioned downstream of the pressure regulator, wherein a portion of heat from the primary liquid phase is transferred to the reduced pressure primary steam to improve the quality thereof and to thereby cool the primary liquid phase prior to entering the secondary steam generator.

80. The system of claim 77, wherein the at least one pressure regulating device is a pressure boosting device positioned on the secondary dry steam line for increasing the pressure of the secondary dry steam.

81. The system of any one of claims 72 to 80, further comprising a flash unit comprising a pressure regulating device and a flash vessel positioned downstream of the primary steam separator for reducing the pressure of the primary liquid phase to generate a low pressure utility steam and a concentrated primary liquid phase, wherein the concentrated primary liquid phase is directed to the secondary steam generator.

82. The system of claim 81, further comprising a high pressure pump positioned downstream of the flash vessel for boosting the pressure of the concentrated primary liquid phase prior to entry into the secondary steam generator.

83. The system of claim 72 to 82, further comprising a flash unit comprising a pressure regulator and a flash vessel positioned downstream of the secondary steam separator for reducing the pressure of the secondary liquid phase to generate a low pressure utility steam or vapour and a concentrated secondary liquid phase.

84. The system of any one of claims 81 to 83, further comprising a crystallizer.

85. The system of claim 84, wherein all or a portion of the utility steam generated is used to power the crystallizer.

86. The system of claim 56, wherein the primary wet steam separator is a common wet steam separator for receiving the primary wet steam and the secondary wet steam and

generating a common liquid phase therefrom that is discharged to the one or more secondary wet steam generators.

87. The system of claim 86, wherein the primary and secondary wet steam generators are once-through steam generators.

88. The system of claim 86 or 87, further comprising a heat exchange element for transferring a portion of heat from the common liquid phase to the boiler feed water to thereby cool the common liquid phase prior to being fed to the one or more secondary steam generators.

89. The system of any one of claims 54 to 88, wherein all or a portion of the dry steam produced is injected into a reservoir.

90. The system of any one of claims 54 to 88, wherein the steam generated is used to support an oil recovery or mining operation.

91. The system of claim 90, wherein the steam generated is used to support an oil recovery operation, and wherein the oil recovery operation is a thermal in-situ heavy oil recovery operation.

92. The system of claim 91, wherein the thermal in-situ heavy oil recovery operation is steam-assisted gravity drainage, cyclic steam stimulation or a derivative thereof.

93. The system of claim 92, wherein the derivative thereof is solvent-assisted steam-assisted gravity drainage, steam and gas push, combined vapor and steam extraction, expanding solvent steam-assisted gravity drainage, constant steam drainage, liquid addition to steam enhancing recovery, or a water flooding or steam flooding process.

94. The system of claim 92, wherein the thermal in-situ oil recovery operation is steam-assisted gravity drainage.

95. A process for generating steam to support an in-situ heavy oil recovery operation, comprising:

(a) feeding boiler feed water of suitable quality through 2 to 12 primary once-through steam generators configured in parallel to generate primary wet steam having a steam quality of about 60% to about 85%;

(b) separating the primary wet steam in a primary steam separator to produce primary dry steam having a steam quality of greater than about 90% and a primary liquid phase;

(c) feeding the primary liquid phase to a secondary once-through steam generator configured in series to generate secondary wet steam having a steam quality of about 60% to about 85%; and

(d) separating the secondary wet steam in a secondary steam separator to produce secondary dry steam having a steam quality of greater than about 90% and a secondary liquid phase.

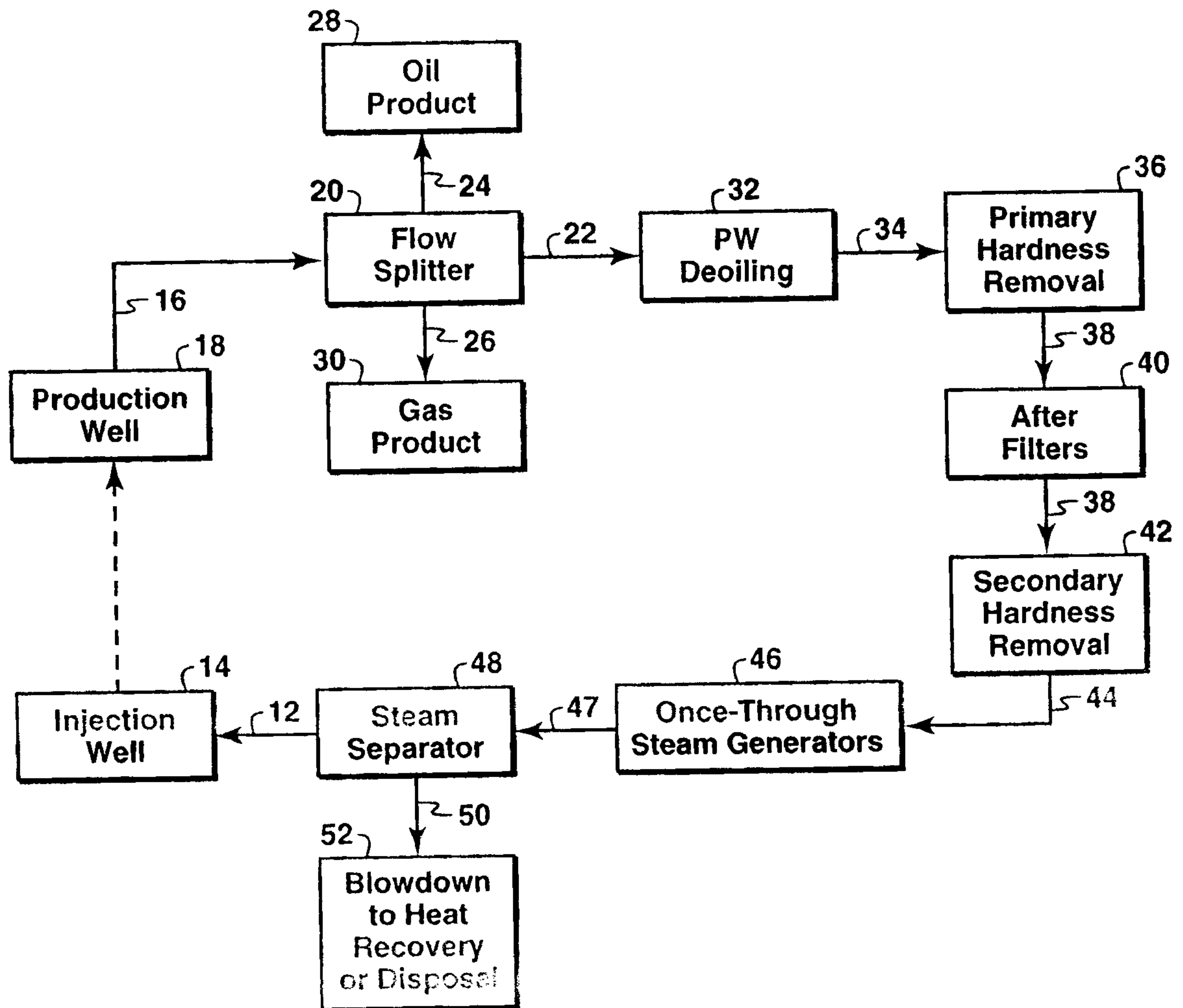
96. The process of claim 95, wherein 4 to 8 primary once-through steam generators are configured in parallel.

97. The process of claim 96, wherein 4 primary once-through steam generators are configured in parallel.

98. The process of any one of claims 95 to 97, wherein the primary and secondary wet steam has a steam quality of about 75% to about 80%, and wherein the primary and secondary dry steam has a steam quality of greater than about 95%.

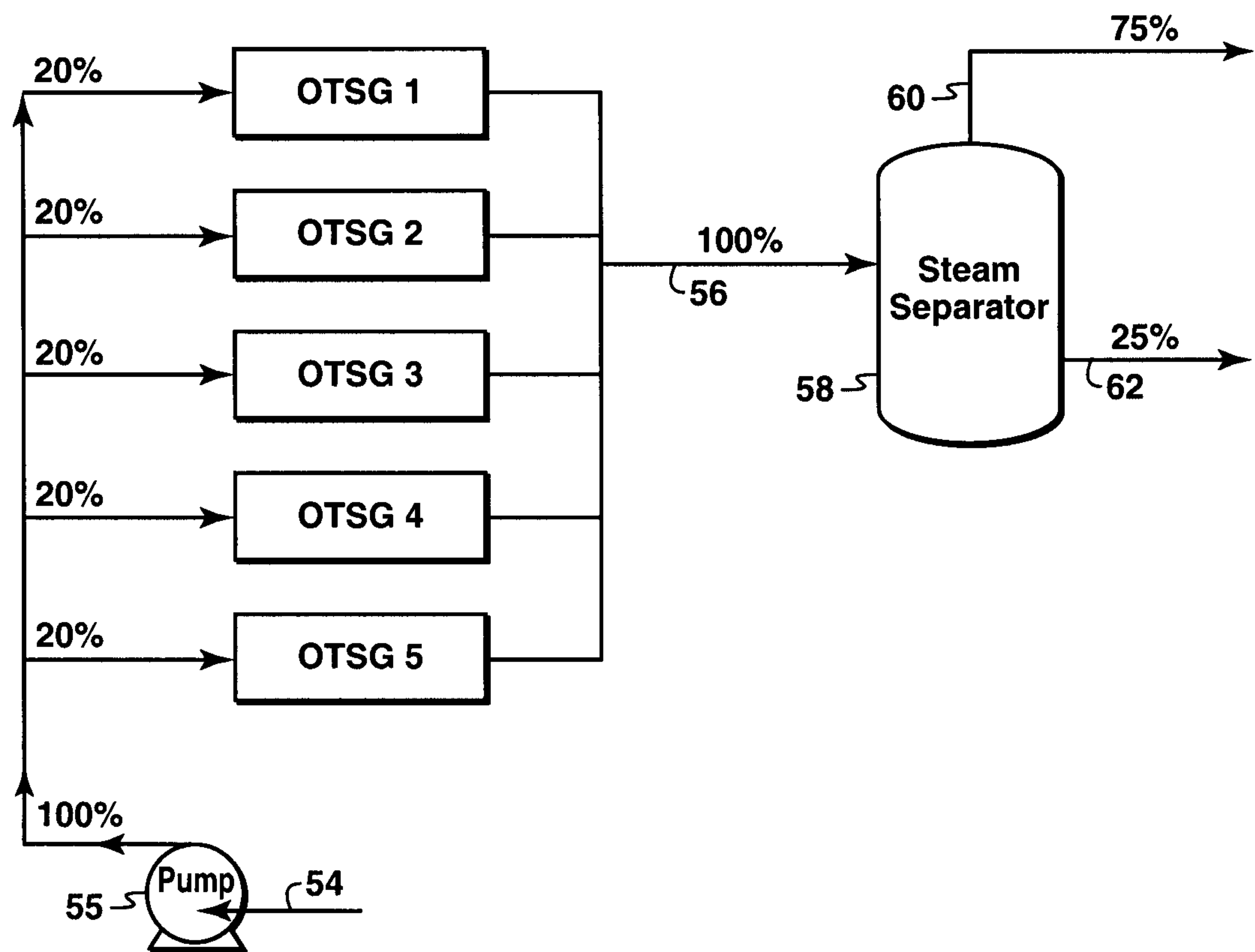
99. The process of any one of claims 95 to 98, wherein the in-situ heavy oil recovery operation is a steam-assisted gravity drainage operation and wherein the dry steam produced is utilized for reservoir injection.

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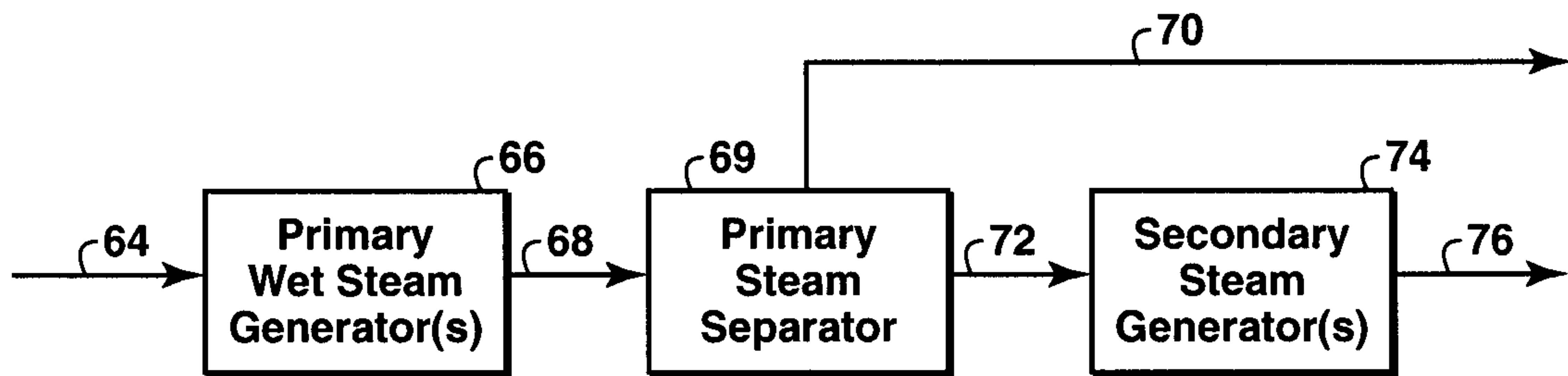
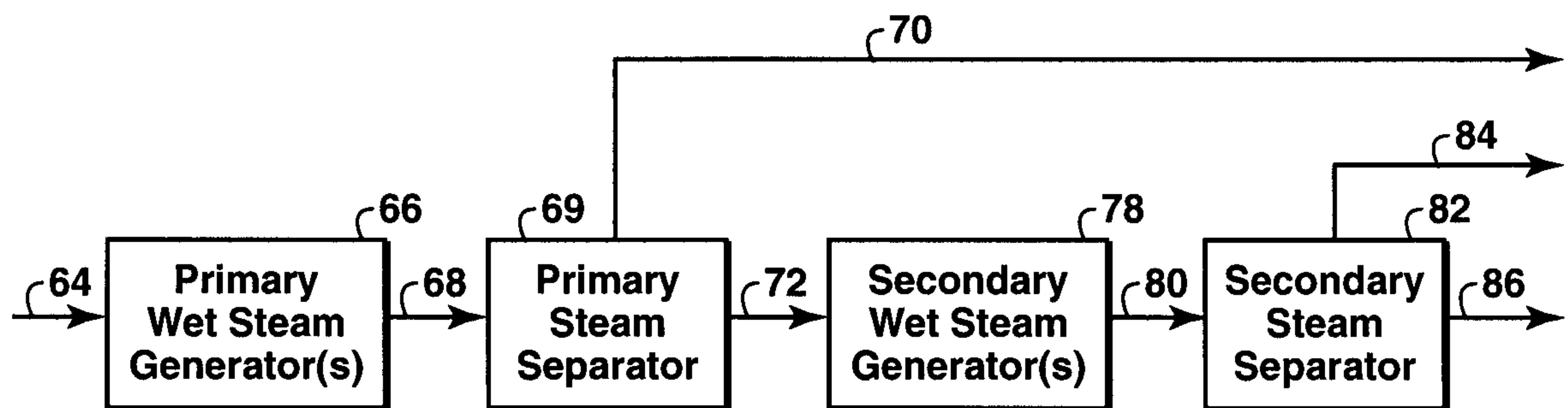
**FIG. 1**

(PRIOR ART)

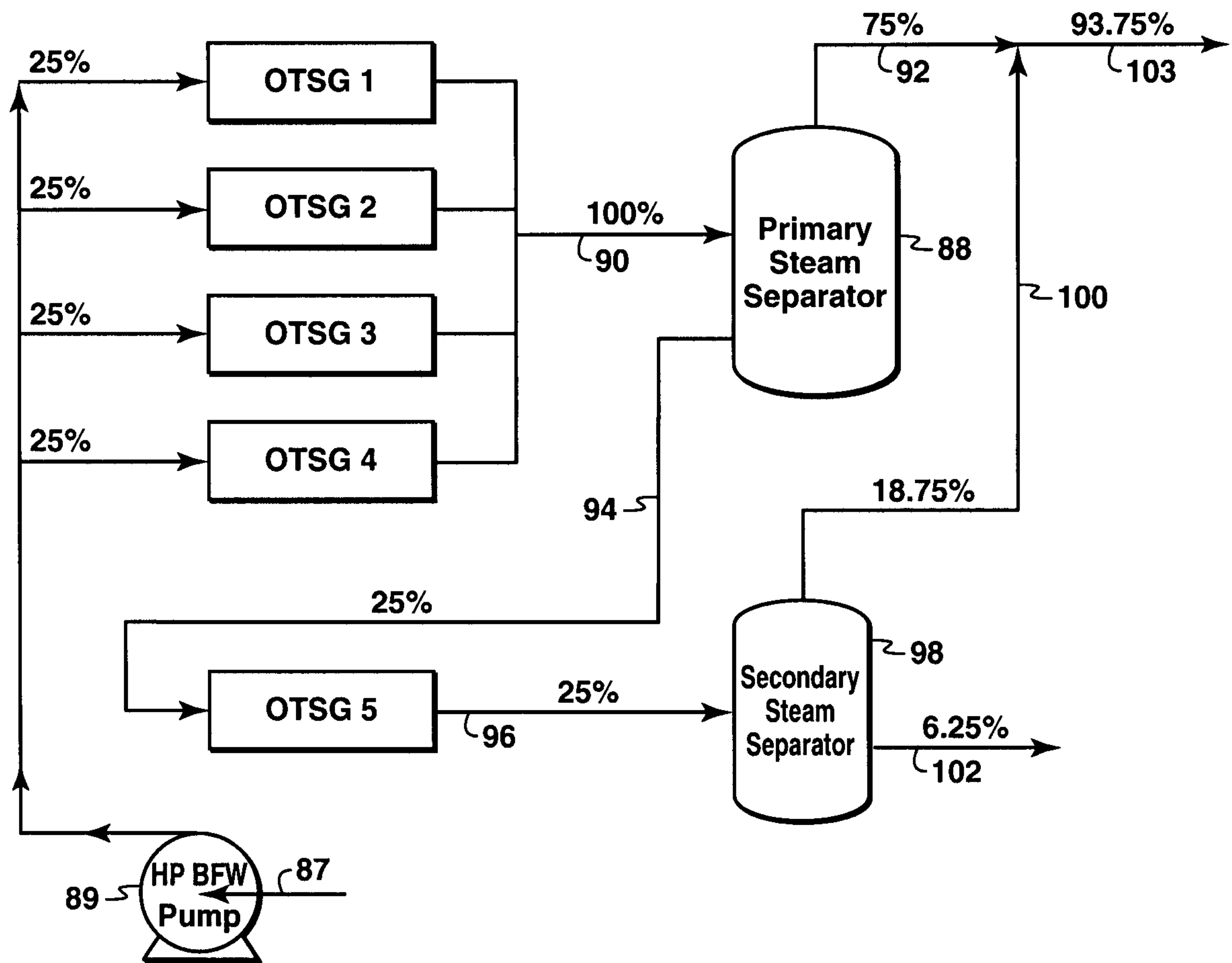
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**FIG. 2**

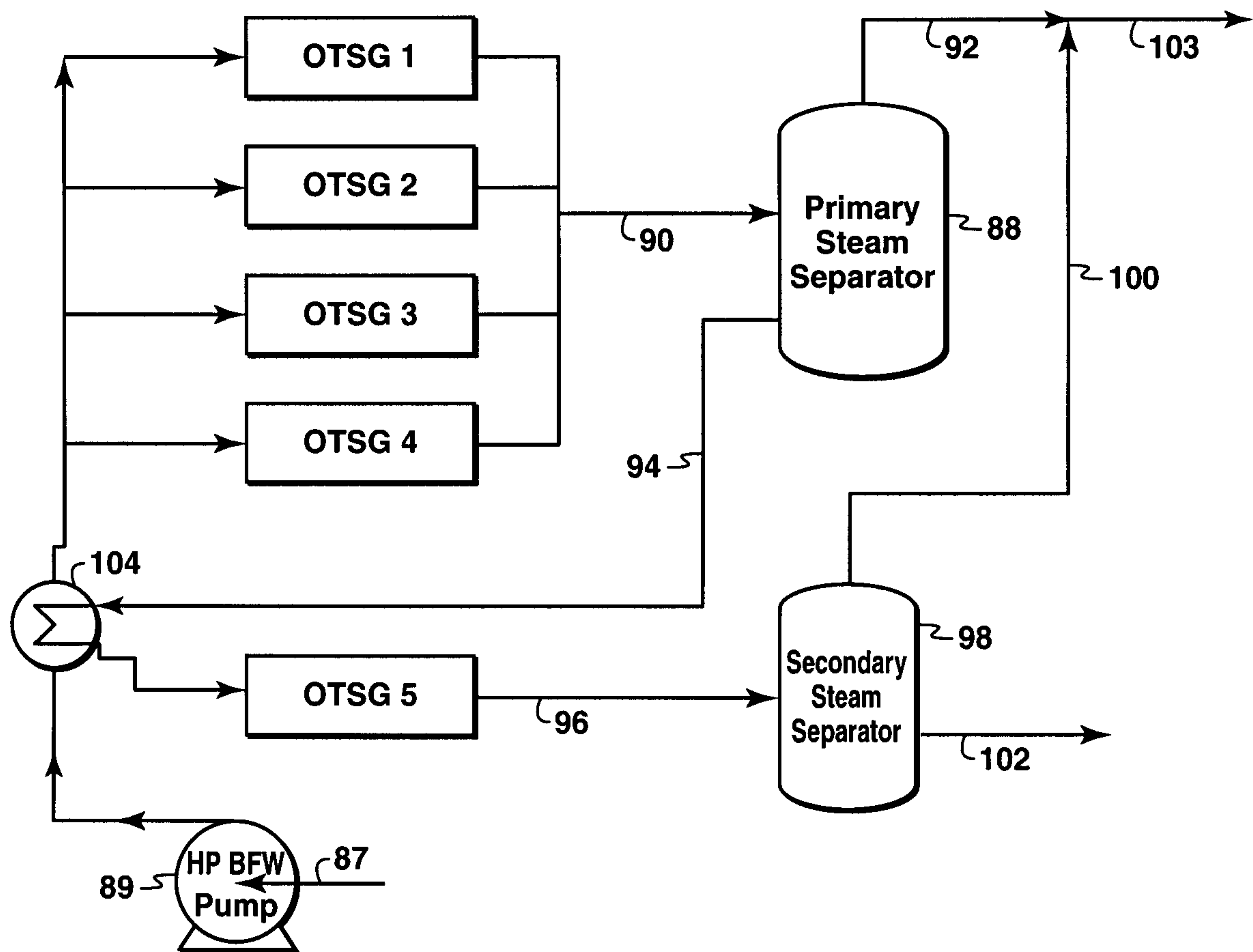
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**FIG. 3A****FIG. 3B**

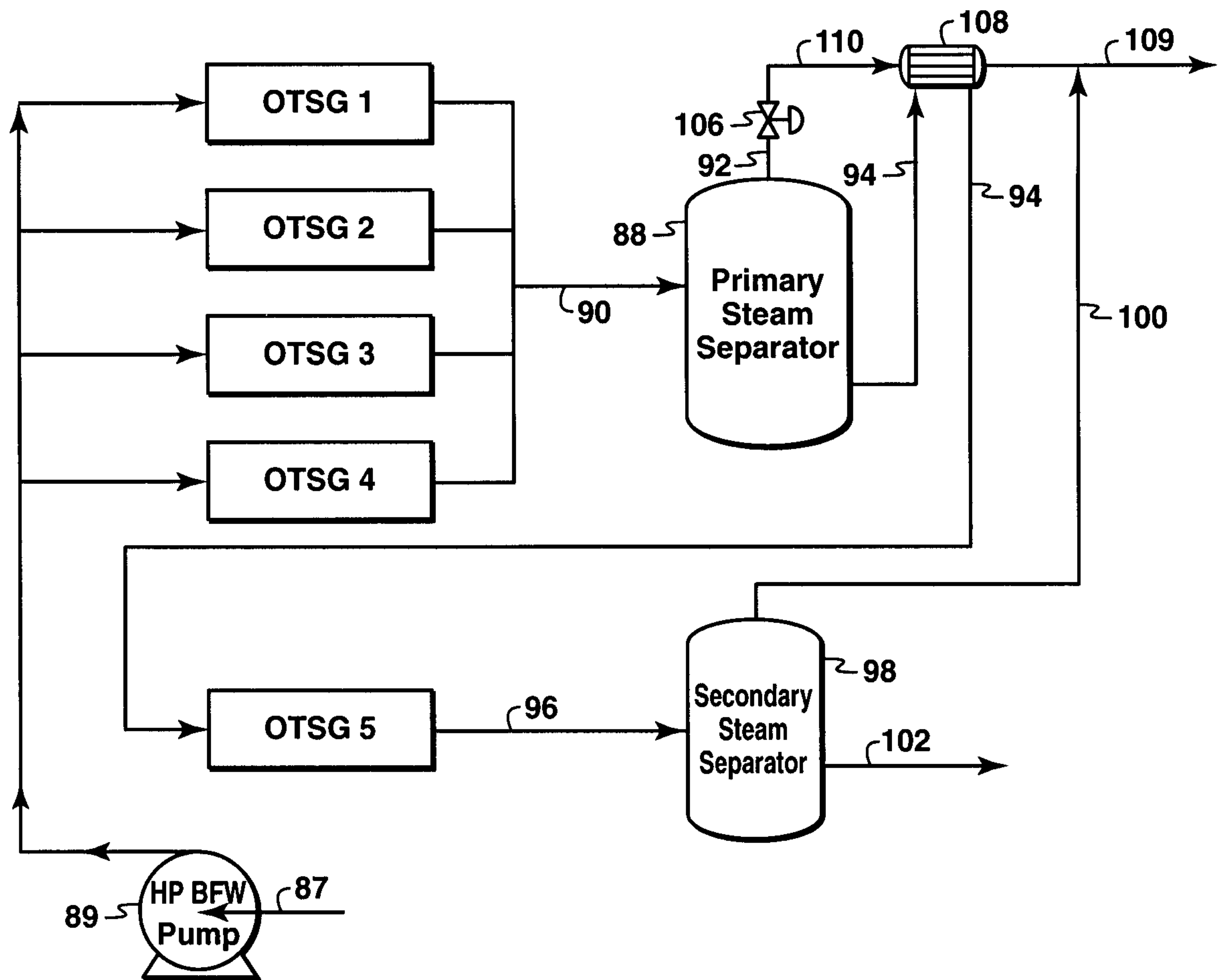
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**FIG. 4**

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**FIG. 5**

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**FIG. 6**

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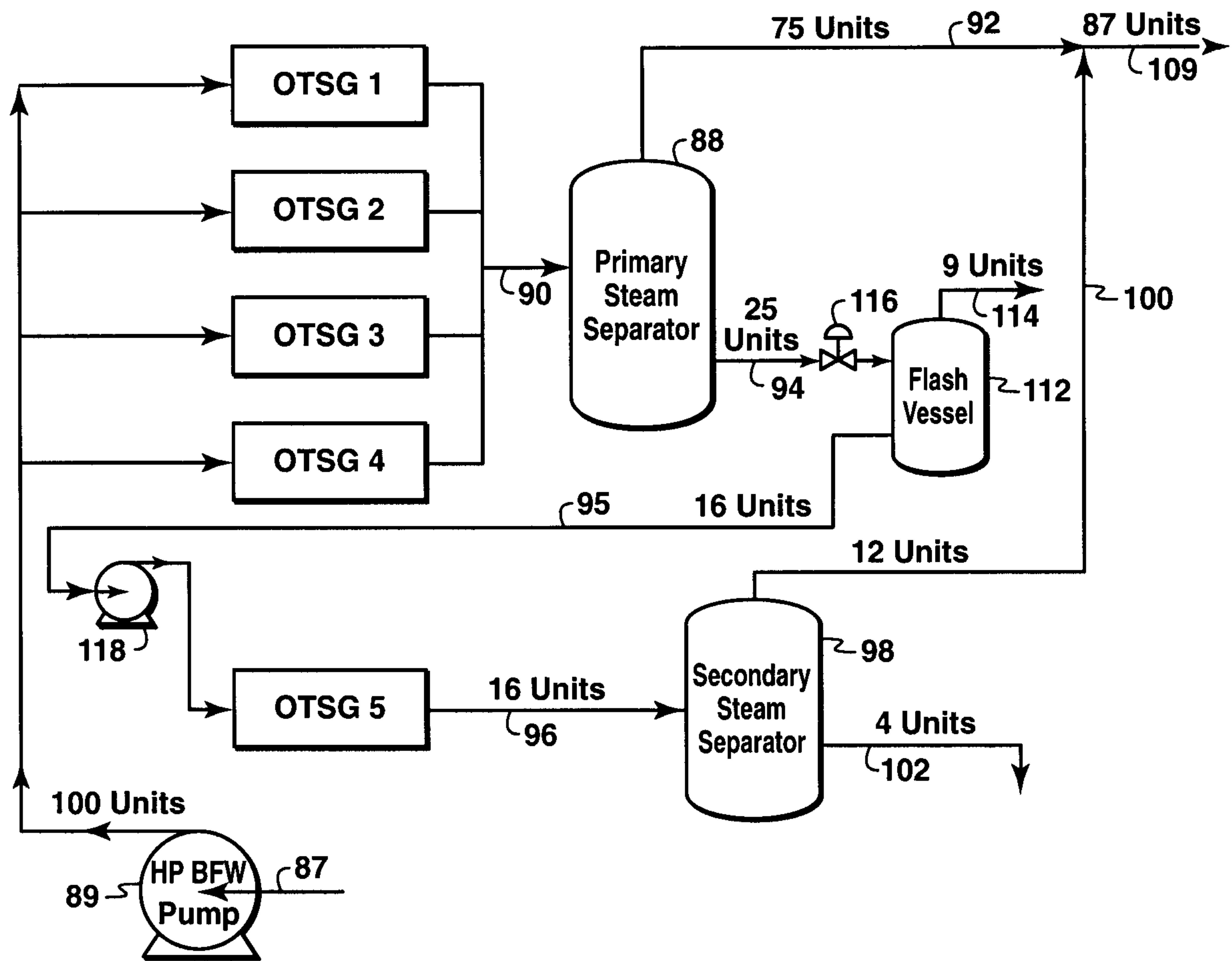


FIG. 7

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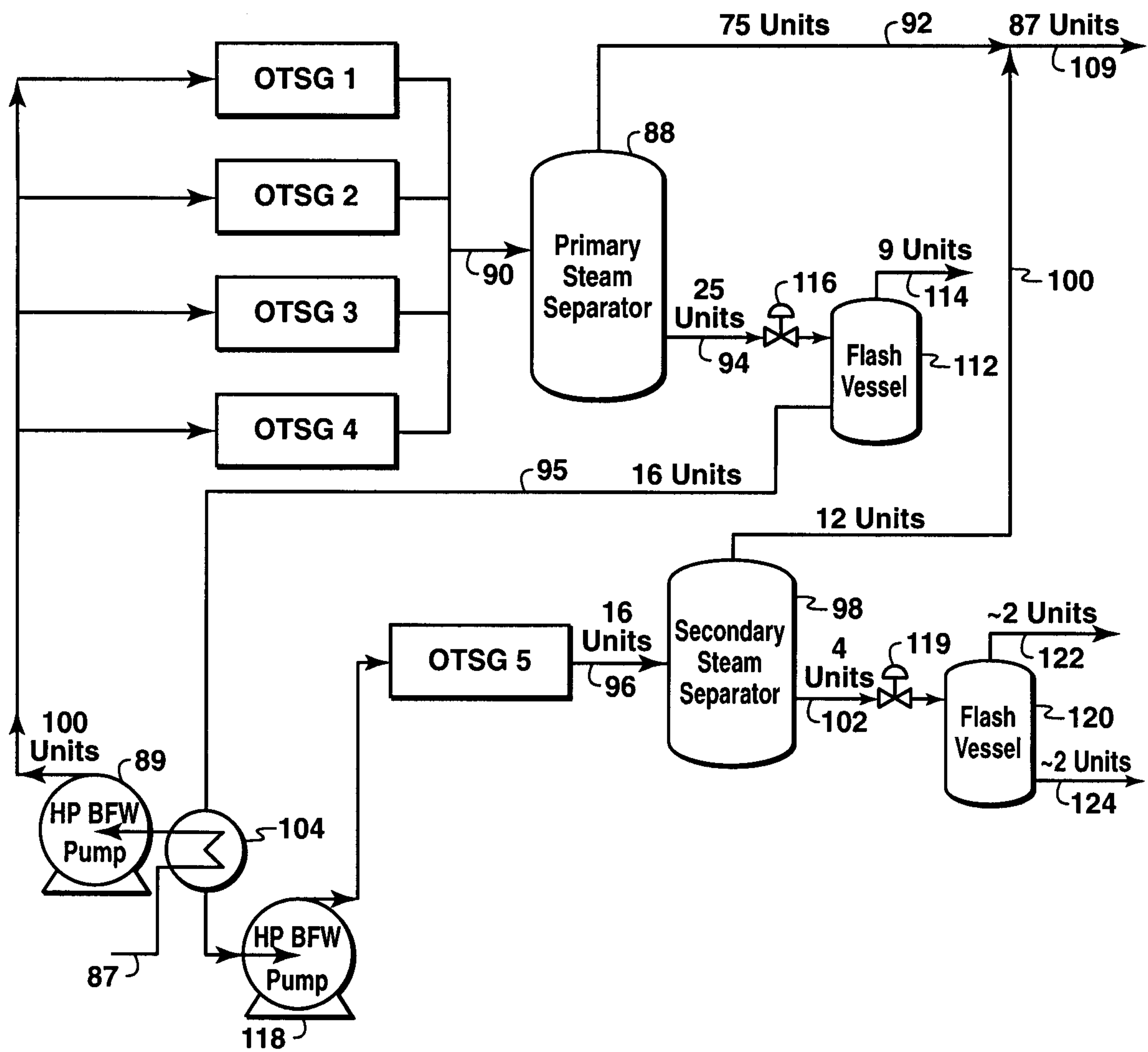
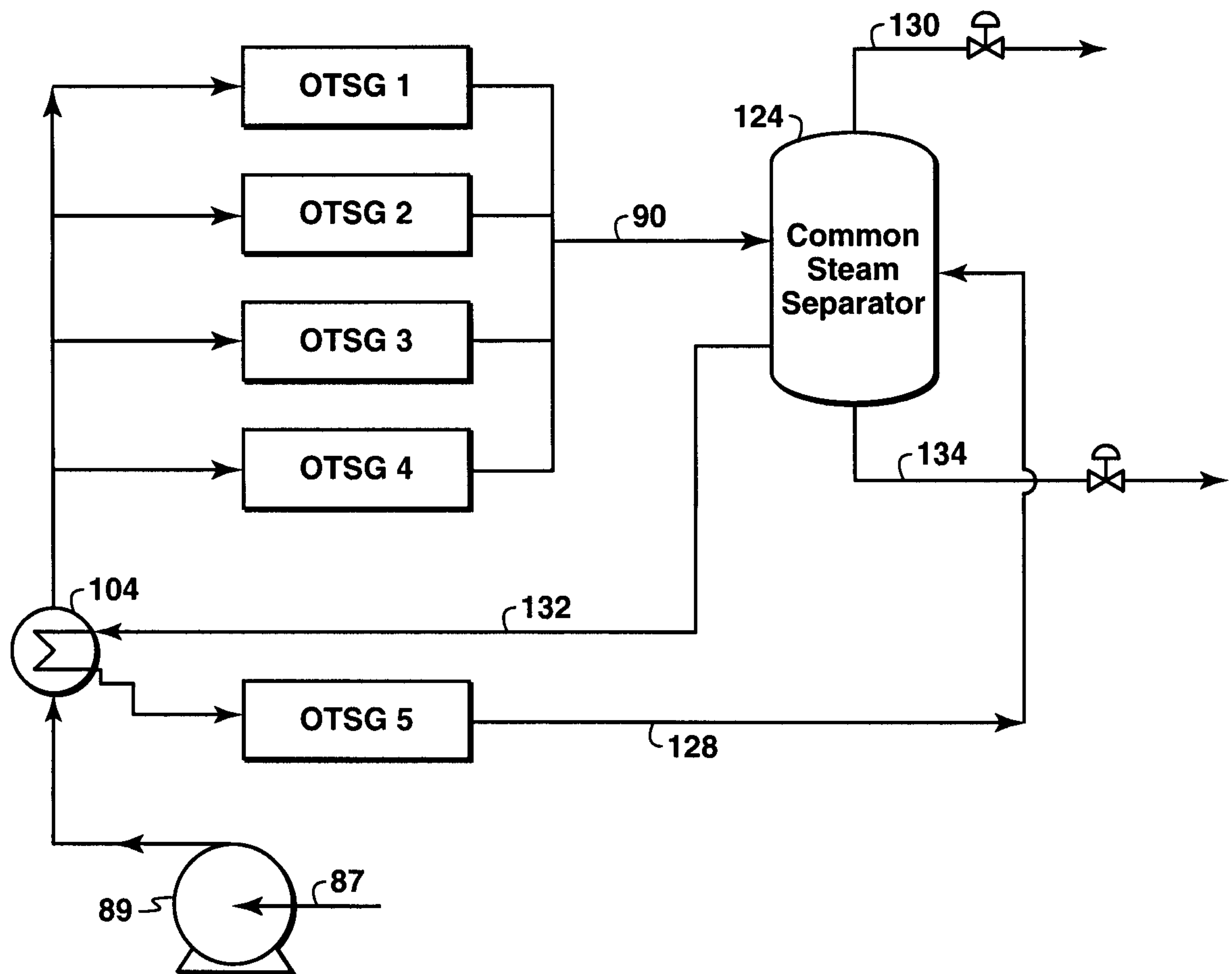


FIG. 8

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**FIG. 9**

