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(71) Applicants: **GENERAL ELECTRIC COMPANY** [US/US]; 1 River Road, Schenectady, New York 12345 (US). **EXXONMOBIL UPSTREAM RESEARCH COMPANY** [US/US]; CORP-URC-SW 341 P.O. Box 2189, Houston, Texas 77252-2189 (US).

(72) Inventors: **THATCHER, Jonathan Carl**; 300 Garlington Road, Greenville, South Carolina 29615 (US). **WEST, James A.**; 9075 Centre Pointe Drive, West Chester, Ohio 45069 (US). **VOREL, Aaron Lavene**; 300 Garlington Road, Greenville, South Carolina 29615 (US).

(74) Agents: **SWANSON, Tait R.** et al.; P.O. Box 692289, Houston, Texas 77269 (US).

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[Continued on next page]

(54) **Title**: SYSTEMS AND METHODS FOR CONTROLLING EXHAUST GAS FLOW IN EXHAUST GAS RECIRCULATION GAS TURBINE SYSTEMS

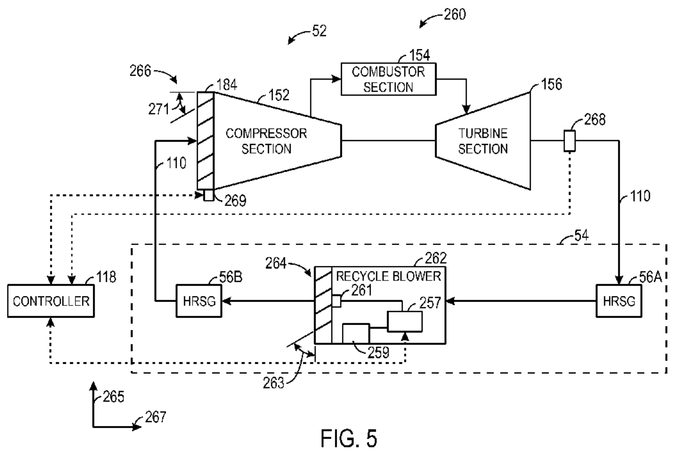

FIG. 5

(57) **Abstract**: A method of controlling an exhaust gas recirculation (EGR) gas turbine system includes adjusting an angle of a plurality of inlet guide vanes of an exhaust gas compressor of the EGR gas turbine system, wherein the plurality of inlet guide vanes have a first range of motion defined by a minimum angle and a maximum angle, and wherein the angle is adjusted based on one or more monitored or modeled parameters of the EGR gas turbine system. The method further includes adjusting a pitch of a plurality of blower vanes of a recycle blower disposed upstream of the exhaust gas compressor, wherein the plurality of blower vanes have a second range of motion defined by a minimum pitch and a maximum pitch, and the pitch of the plurality of blower vanes is adjusted based at least on the angle of the plurality of inlet guide vanes.

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SYSTEMS AND METHODS FOR CONTROLLING EXHAUST GAS FLOW IN EXHAUST GAS RECIRCULATION GAS TURBINE SYSTEMS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to and benefit of U.S. Provisional Patent Application No. 61/841,234, entitled "SYSTEMS AND METHODS FOR CONTROLLING EXHAUST GAS FLOW IN EXHAUST GAS RECIRCULATION GAS TURBINE SYSTEMS," filed on June 28, 2013, and U.S. Non-Provisional Patent Application No. 14/312,659, entitled "SYSTEMS AND METHODS FOR CONTROLLING EXHAUST GAS FLOW IN EXHAUST GAS RECIRCULATION GAS TURBINE SYSTEMS," filed on June 23, 2014, all of which are herein incorporated by reference in their entirety for all purposes.

BACKGROUND

[0002] The subject matter disclosed herein relates to gas turbine engines, and, more specifically, to exhaust gas recirculation (EGR) gas turbine systems.

[0003] Gas turbine engines are used in a wide variety of applications, such as power generation, aircraft, and various machinery. Gas turbine engines generally combust a fuel with an oxidant (e.g., air) in a combustor section to generate hot combustion products, which then drive one or more turbine stages of a turbine section. The turbine stages, when driven by the hot combustion products, transfer rotational power to a shaft. The rotating shaft, in turn, drives one or more compressor stages of a compressor section and can also drive an electrical generator to produce electrical energy. Gas turbine engines may include a variety of controls to improve performance and efficiency, while also reducing pollutants in the exhaust gas. Unfortunately, the controls become complicated for gas turbine systems with exhaust gas recirculation. Therefore, it may be desirable to improve the controls for gas turbine engines with exhaust gas recirculation.

BRIEF DESCRIPTION

[0004] Certain embodiments commensurate in scope with the originally claimed subject matter are summarized below. These embodiments are not intended to limit the scope of the claimed invention, but rather these embodiments are intended only to provide a brief summary of possible forms of the invention. Indeed, the present disclosure may encompass a variety of forms that may be similar to or different from the embodiments set forth below.

[0005] In one embodiment, an exhaust gas recirculation (EGR) gas turbine system includes an exhaust gas compressor positioned along an EGR path and configured to compress a recirculated exhaust gas to produce an exhaust gas diluent. The exhaust gas compressor includes an inlet section having a flow control element configured to modulate a flow of the recirculated exhaust gas into the exhaust gas compressor based on a position of the flow control element. Further, the position of the flow control element is capable of ranging from a maximum open position to a minimum open position. The system includes a recycle blower positioned along the EGR path and upstream of the exhaust gas compressor, wherein the recycle blower is configured to provide the flow of recirculated exhaust gas to the inlet section, and wherein the flow of recirculated exhaust gas ranges from a minimum blower output to a maximum blower output. The system also includes a controller coupled to the flow control element and to the recycle blower, wherein the controller is configured to control the position of the flow control element based on a measured or modeled parameter of the EGR gas turbine system. Further, the controller is configured to control one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section based on the position of the flow control element.

[0006] In another embodiment, a method of controlling an exhaust gas recirculation (EGR) gas turbine system includes adjusting an angle of a plurality of inlet guide vanes of an exhaust gas compressor of the EGR gas turbine system, wherein the plurality of inlet guide vanes have a first range of motion defined by a minimum angle and a maximum angle, and wherein the angle is adjusted based on one or more monitored or modeled parameters of the EGR gas turbine system. The method further includes adjusting a pitch of a plurality of blower vanes of a recycle blower disposed upstream of the exhaust gas compressor, wherein the plurality of blower vanes have a second range of motion defined by a minimum pitch and a maximum pitch, and the pitch of the plurality of blower vanes is adjusted based at least on the angle of the plurality of inlet guide vanes.

[0007] In another embodiment, a non-transitory, computer-readable medium stores instructions executable by a processor of an electronic device. The instructions include instructions adjust an angle of a plurality of inlet guide vanes of a compressor section of a gas turbine system based on one or more modeled or measured parameters of the gas turbine system, wherein the angle ranges from a minimum angle to a maximum angle. The instructions also include instructions to adjust a pitch of a plurality of blower vanes of a blower fluidly coupled to an inlet of the compressor section, wherein the pitch ranges from a minimum pitch to a maximum pitch, wherein the pitch is adjusted based on the angle of the plurality of inlet guide vanes relative to the minimum angle.

DRAWINGS

[0008] These and other features, aspects, and advantages of the present invention will become better understood when the following detailed description is read with reference to the accompanying drawings in which like characters represent like parts throughout the drawings, wherein:

[0009] FIG. 1 is a diagram of an embodiment of a system having a turbine-based service system coupled to a hydrocarbon production system;

[0010] FIG. 2 is a diagram of an embodiment of the system of FIG. 1, further illustrating a control system and a combined cycle system;

[0011] FIG. 3 is a diagram of an embodiment of the system of FIGS. 1 and 2, further illustrating details of a gas turbine engine, exhaust gas supply system, and exhaust gas processing system;

[0012] FIG. 4 is a flow chart of an embodiment of a process for operating the system of FIGS. 1-3;

[0013] FIG. 5 is a diagram of an embodiment a control system for controlling a stoichiometric exhaust gas recirculation (SEGR) gas turbine system of FIGS. 1-3, illustrating components of the exhaust gas recirculation portion of the SEGR gas turbine system;

[0014] FIG. 6 is a graph illustrating recycle gas turbine (RGT) exhaust temperature for the SEGR gas turbine system embodiment of FIG. 5 over time as the inlet guide vane (IGV) angle and the blower vane (BV) pitch are independently varied;

[0015] FIG. 7 is a graph illustrating an embodiment of a control strategy focused on efficiency for use in determining a suitable IGV angle and a suitable BV pitch as the load of the SEGR gas turbine system increases;

[0016] FIG. 8 is a graph illustrating an embodiment of a control strategy focused on responsiveness for use in determining a suitable IGV angle and a suitable BV pitch as the load of the SEGR gas turbine system increases;

[0017] FIG. 9 is a diagram illustrating example limits and inputs that a controller may use to determine a suitable IGV angle and suitable BV pitch when controlling operation of the SEGR gas turbine system, in accordance with an embodiment of the present approach; and

[0018] FIG. 10 is a set of graphs illustrating exhaust or firing temperature, IGV angle, and BV pitch of the SEGR gas turbine system during operation, in accordance with an embodiment of the present approach.

DETAILED DESCRIPTION

[0019] One or more specific embodiments of the present invention will be described below. In an effort to provide a concise description of these embodiments, all features of an actual implementation may not be described in the specification. It should be appreciated that in the development of any such actual implementation, as in an engineering or design project, numerous implementation-specific decisions are made to achieve the specific goals, such as compliance with system-related and/or business-related constraints, which may vary from one implementation to another. Moreover, it should be appreciated that such effort might be complex and time consuming, but would nevertheless be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit of this disclosure.

[0020] Detailed example embodiments are disclosed herein. However, specific structural and functional details disclosed herein are merely representative for purposes of describing example embodiments. Embodiments of the present invention may, however, be embodied in many alternate forms, and should not be construed as limited to only the embodiments set forth herein.

[0021] Accordingly, while example embodiments are capable of various modifications and alternative forms, embodiments thereof are illustrated by way of example in the figures and will herein be described in detail. It should be understood, however, that there is no intent to limit example embodiments to the particular forms disclosed, but to the contrary, example embodiments are to cover all modifications, equivalents, and alternatives falling within the scope of the present invention.

[0022] The terminology used herein is for describing particular embodiments only and is not intended to be limiting of example embodiments. As used herein, the singular forms “a”, “an” and “the” are intended to include the plural forms as well, unless the context clearly indicates otherwise. The terms “comprises,” “comprising,” “includes” and/or “including,” when used herein, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof.

[0023] Although the terms first, second, primary, secondary, etc. may be used herein to describe various elements, these elements should not be limited by these terms. These terms are only used to distinguish one element from another. For example, but not limiting to, a first element could be termed a second element, and, similarly, a second element could be termed a first element, without departing from the scope of example embodiments. As used herein, the term “and/or” includes any, and all, combinations of one or more of the associated listed items.

[0024] Certain terminology may be used herein for the convenience of the reader only and is not to be taken as a limitation on the scope of the invention. For example, words such as “upper,” “lower,” “left,” “right,” “front,” “rear,” “top,” “bottom,” “horizontal,” “vertical,” “upstream,” “downstream,” “fore,” “aft,” and the like; merely describe the configuration shown in the FIGS. Indeed, the element or elements of an embodiment of the present invention may be oriented in any direction and the terminology, therefore, should be understood as encompassing such variations unless specified otherwise.

[0025] As discussed in detail below, the disclosed embodiments relate generally to gas turbine systems with exhaust gas recirculation (EGR), and particularly stoichiometric operation of the gas turbine systems using EGR. For example, the gas turbine systems may be configured to recirculate the exhaust gas along an exhaust recirculation path, stoichiometrically combust fuel and oxidant along with at least some of the recirculated exhaust gas, and capture the exhaust gas for use in various target systems. In addition to controlling the flow of the fuel and/or oxidant, the recirculation of the exhaust gas along with stoichiometric combustion may help to increase the concentration level of CO_2 in the exhaust gas, which can then be post treated to separate and purify the CO_2 and nitrogen (N_2) for use in various target systems. The gas turbine systems also may employ various exhaust gas processing (e.g., heat recovery, catalyst reactions, etc.) along the exhaust recirculation path, thereby increasing the concentration level of CO_2, reducing concentration levels of other emissions (e.g., carbon monoxide, nitrogen oxides, and unburnt hydrocarbons), and increasing energy recovery (e.g., with heat recovery units).

[0026] Indeed, a number of benefits may be realized by utilizing the recirculated exhaust gas within the EGR gas turbine system in accordance with the present disclosure, including increased time-in-operation for various components, wider operating ranges for various components due to enhanced cooling capabilities, and so on. Such embodiments are described in further detail below, with the general components of the EGR gas turbine system first being introduced, followed by specific examples of the manner in which the recirculated exhaust gas may be utilized within the EGR gas turbine system.

[0027] The disclosed embodiments relate to controlling parameters of the EGR gas turbine system (e.g., an exhaust gas temperature or a firing temperature) by controlling a flow of exhaust gas along the exhaust recirculation path. In particular, present embodiments provide systems and methods for controlling the operational parameters of the EGR gas turbine system by controlling the flow of exhaust gas through a recycle blower and into a recycle compressor section disposed along the exhaust recirculation path. Furthermore, as set forth in detail below, the presently disclosed control systems and methods may enable the parameters of the EGR gas turbine system (e.g., exhaust or firing temperature) to be adjusted in a responsive and efficient manner. For example, by improving control of an EGR gas turbine system, the present approach may help enable the system to maintain stoichiometric or near-stoichiometric combustion, to limit combustion temperature (e.g., to limit production of NO_x during combustion), and/or improve the quality of the exhaust gas for downstream applications.

[0028] With the foregoing in mind, FIG. 1 is a diagram of an embodiment of a system 10 having an hydrocarbon production system 12 associated with a turbine-based service system 14. As discussed in further detail below, various embodiments of the turbine-based service system 14 are configured to provide various services, such as electrical power, mechanical power, and fluids (e.g., exhaust gas), to the hydrocarbon production system 12 to facilitate the production or retrieval of oil and/or gas. In the illustrated embodiment, the hydrocarbon production system 12 includes an oil/gas extraction system 16 and an enhanced oil recovery (EOR) system 18, which are coupled to a subterranean reservoir 20 (e.g., an oil, gas, or hydrocarbon reservoir). The oil/gas extraction system 16 includes a variety of surface equipment 22, such as a Christmas tree or production tree 24, coupled to an oil/gas well 26. Furthermore, the well 26 may include one or more tubulars 28 extending through a drilled bore 30 in the earth 32 to the subterranean reservoir 20. The tree 24 includes one or more valves, chokes, isolation sleeves, blowout preventers, and various flow control devices, which regulate pressures and control flows to and from the subterranean reservoir 20. While the tree 24 is generally used to control the flow of the production fluid (e.g., oil or gas) out of the subterranean reservoir 20, the EOR system 18 may increase the production of oil or gas by injecting one or more fluids into the subterranean reservoir 20.

[0029] Accordingly, the EOR system 18 may include a fluid injection system 34, which has one or more tubulars 36 extending through a bore 38 in the earth 32 to the subterranean reservoir 20. For example, the EOR system 18 may route one or more fluids 40, such as gas, steam, water, chemicals, or any combination thereof, into the fluid injection system 34. For example, as discussed in further detail below, the EOR system 18 may be coupled to the turbine-based service system 14, such that the system 14 routes an exhaust gas 42 (e.g., substantially or entirely free of oxygen) to the EOR system 18 for use as the injection fluid 40. The fluid injection system 34 routes the fluid 40 (e.g., the exhaust gas 42) through the one or more tubulars 36 into the subterranean reservoir 20, as indicated by arrows 44. The injection fluid 40 enters the subterranean reservoir 20 through the tubular 36 at an offset distance 46 away from the tubular 28 of the oil/gas well 26. Accordingly, the injection fluid 40 displaces the oil/gas 48 disposed in the subterranean reservoir 20, and drives the oil/gas 48 up through the one or more tubulars 28 of the hydrocarbon production system 12, as indicated by arrows 50. As discussed in further detail below, the injection fluid 40 may include the exhaust gas 42 originating from the turbine-based service system 14, which is able to generate the exhaust gas 42 on-site as needed by the hydrocarbon production system 12. In other words, the turbine-based system 14 may simultaneously generate one or more services (e.g., electrical power, mechanical power, steam, water (e.g., desalinated water), and exhaust gas (e.g., substantially free of oxygen)) for use by the hydrocarbon production system 12, thereby reducing or eliminating the reliance on external sources of such services.

[0030] In the illustrated embodiment, the turbine-based service system 14 includes a stoichiometric exhaust gas recirculation (SEGR) gas turbine system 52 and an exhaust gas (EG) processing system 54. The gas turbine system 52 may be configured to operate in a stoichiometric combustion mode of operation (e.g., a stoichiometric control mode) and a non-stoichiometric combustion mode of operation (e.g., a non-stoichiometric control mode), such as a fuel-lean control mode or a fuel-rich control mode. In the stoichiometric control mode, the combustion generally occurs in a substantially stoichiometric ratio of a fuel and oxidant, thereby resulting in substantially stoichiometric combustion. In particular, stoichiometric combustion generally involves consuming substantially all of the fuel and oxidant in the combustion reaction, such that the products of combustion are substantially or entirely free of unburnt fuel and oxidant. One measure of stoichiometric combustion is the equivalence ratio, or phi (ϕ), which is the ratio of the actual fuel/oxidant ratio relative to the stoichiometric fuel/oxidant ratio. An equivalence ratio of greater than 1.0 results in a fuel-rich combustion of the fuel and oxidant, whereas an equivalence ratio of less than 1.0 results in a fuel-lean combustion of the fuel and oxidant. In contrast, an equivalence ratio of 1.0 results in combustion that is neither fuel-rich nor fuel-lean, thereby substantially consuming all of the fuel and oxidant in the combustion reaction. In context of the disclosed embodiments, the term stoichiometric or substantially stoichiometric may refer to an equivalence ratio of approximately 0.95 to approximately 1.05. However, the disclosed embodiments may also include an equivalence ratio of 1.0 plus or minus 0.01, 0.02, 0.03, 0.04, 0.05, or more. Again, the stoichiometric combustion of fuel and oxidant in the turbine-based service system 14 may result in products of combustion or exhaust gas (e.g., 42) with substantially no unburnt fuel or oxidant remaining. For example, the exhaust gas 42 may have less than 1, 2, 3, 4, or 5 percent by volume of oxidant (e.g., oxygen), unburnt fuel or hydrocarbons (e.g., HCs), nitrogen oxides (e.g., NO_X), carbon monoxide (CO), sulfur oxides (e.g., SO_X), hydrogen, and other products of incomplete combustion. By further example, the exhaust gas 42 may have less than approximately 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 200, 300, 400, 500, 1000, 2000, 3000, 4000, or 5000 parts per million by volume (ppmv) of oxidant (e.g., oxygen), unburnt fuel or hydrocarbons (e.g., HCs), nitrogen oxides (e.g., NO_X), carbon monoxide (CO), sulfur oxides (e.g., SO_X), hydrogen, and other products of incomplete combustion. However, the disclosed embodiments also may produce other ranges of residual fuel, oxidant, and other emissions levels in the exhaust gas 42. As used herein, the terms emissions,

emissions levels, and emissions targets may refer to concentration levels of certain products of combustion (e.g., NO_X, CO, SO_X, O_2, N_2, H_2, HCs, etc.), which may be present in recirculated gas streams, vented gas streams (e.g., exhausted into the atmosphere), and gas streams used in various target systems (e.g., the hydrocarbon production system 12).

[0031] Although the SEGR gas turbine system 52 and the EG processing system 54 may include a variety of components in different embodiments, the illustrated EG processing system 54 includes a heat recovery steam generator (HRSG) 56 and an exhaust gas recirculation (EGR) system 58, which receive and process an exhaust gas 60 originating from the SEGR gas turbine system 52. The HRSG 56 may include one or more heat exchangers, condensers, and various heat recovery equipment, which collectively function to transfer heat from the exhaust gas 60 to a stream of water, thereby generating steam 62. The steam 62 may be used in one or more steam turbines, the EOR system 18, or any other portion of the hydrocarbon production system 12. For example, the HRSG 56 may generate low pressure, medium pressure, and/or high pressure steam 62, which may be selectively applied to low, medium, and high pressure steam turbine stages, or different applications of the EOR system 18. In addition to the steam 62, a treated water 64, such as a desalinated water, may be generated by the HRSG 56, the EGR system 58, and/or another portion of the EG processing system 54 or the SEGR gas turbine system 52. The treated water 64 (e.g., desalinated water) may be particularly useful in areas with water shortages, such as inland or desert regions. The treated water 64 may be generated, at least in part, due to the large volume of air driving combustion of fuel within the SEGR gas turbine system 52. While the on-site generation of steam 62 and water 64 may be beneficial in many applications (including the hydrocarbon production system 12), the on-site generation of exhaust gas 42, 60 may be particularly beneficial for the EOR system 18, due to its low oxygen content, high pressure, and heat derived from the SEGR gas turbine system 52. Accordingly, the HRSG 56, the EGR system 58, and/or another portion of the EG processing system 54 may output or recirculate an exhaust gas 66 into the SEGR gas turbine system 52, while also routing the exhaust gas 42 to the EOR system 18 for use with the hydrocarbon production system 12. Likewise, the exhaust gas 42 may be extracted directly from the SEGR gas turbine system 52 (i.e., without passing through the EG processing system 54) for use in the EOR system 18 of the hydrocarbon production system 12.

[0032] The exhaust gas recirculation is handled by the EGR system 58 of the EG processing system 54. For example, the EGR system 58 includes one or more conduits, valves, blowers, exhaust gas treatment systems (e.g., filters, particulate removal units, gas separation units, gas purification units, heat exchangers, heat recovery units, moisture removal units, catalyst units, chemical injection units, or any combination thereof), and controls to recirculate the exhaust gas along an exhaust gas circulation path from an output (e.g., discharged exhaust gas 60) to an input (e.g., intake exhaust gas 66) of the SEGR gas turbine system 52. In the illustrated embodiment, the SEGR gas turbine system 52 intakes the exhaust gas 66 into a compressor section having one or more compressors, thereby compressing the exhaust gas 66 for use in a combustor section along with an intake of an oxidant 68 and one or more fuels 70. The oxidant 68 may include ambient air, pure oxygen, oxygen-enriched air, oxygen-reduced air, oxygen-nitrogen mixtures, or any suitable oxidant that facilitates combustion of the fuel 70. The fuel 70 may include one or more gas fuels, liquid fuels, or any combination thereof. For example, the fuel 70 may include natural gas, liquefied natural gas (LNG), syngas, methane, ethane, propane, butane, naphtha, kerosene, diesel fuel, ethanol, methanol, biofuel, or any combination thereof.

[0033] The SEGR gas turbine system 52 mixes and combusts the exhaust gas 66, the oxidant 68, and the fuel 70 in the combustor section, thereby generating hot combustion gases or exhaust gas 60 to drive one or more turbine stages in a turbine section. In certain embodiments, each combustor in the combustor section includes one or more premix fuel nozzles, one or more diffusion fuel nozzles, or any combination thereof. For example, each premix fuel nozzle may be configured to mix the oxidant 68 and the fuel 70 internally within the fuel nozzle and/or partially upstream of the fuel nozzle, thereby injecting an oxidant-fuel mixture from the fuel nozzle into the combustion zone for a premixed combustion (e.g., a premixed flame). By further example, each diffusion fuel nozzle may be configured to isolate the flows of oxidant 68 and fuel 70 within the fuel nozzle, thereby separately injecting the oxidant 68 and the fuel 70 from the fuel nozzle into the combustion zone for diffusion combustion (e.g., a diffusion flame). In particular, the diffusion combustion provided by the diffusion fuel nozzles delays mixing of the oxidant 68 and the fuel 70 until the point of initial combustion, i.e., the flame region. In embodiments employing the diffusion fuel nozzles, the diffusion flame may provide increased flame stability, because the diffusion flame generally forms at the point of stoichiometry between the separate streams of oxidant 68 and fuel 70 (i.e., as the oxidant 68 and fuel 70 are mixing). In certain embodiments, one or more diluents (e.g., the exhaust gas 60, steam, nitrogen, or another inert gas) may be pre-mixed with the oxidant 68, the fuel 70, or both, in either the diffusion fuel nozzle or the premix fuel nozzle. In addition, one or more diluents (e.g., the exhaust gas 60, steam, nitrogen, or another inert gas) may be injected into the combustor at or downstream from the point of combustion within each combustor. The use of these diluents may help temper the flame (e.g., premix flame or diffusion flame), thereby helping to reduce NO_X emissions, such as nitrogen monoxide (NO) and nitrogen dioxide (NO_2). Regardless of the type of flame, the combustion produces hot combustion gases or exhaust gas 60 to drive one or more turbine stages. As each turbine stage is driven by the exhaust gas 60, the SEGR gas turbine system 52 generates a mechanical power 72 and/or an electrical power 74 (e.g., via an electrical generator). The system 52 also outputs the exhaust gas 60, and may further output water 64. Again, the water 64 may be a treated water, such as a desalinated water, which may be useful in a variety of applications on-site or off-site.

[0034] Exhaust extraction is also provided by the SEGR gas turbine system 52 using one or more extraction points 76. For example, the illustrated embodiment includes an exhaust gas (EG) supply system 78 having an exhaust gas (EG) extraction system 80 and an exhaust gas (EG) treatment system 82, which receive exhaust gas 42 from the extraction points 76, treat the exhaust gas 42, and then supply or distribute the exhaust gas 42 to various target systems. The target systems may include the EOR system 18 and/or other systems, such as a pipeline 86, a storage tank 88, or a carbon sequestration system 90. The EG extraction system 80 may include one or more conduits, valves, controls, and flow separations, which facilitate isolation of the exhaust gas 42 from the oxidant 68, the fuel 70, and other contaminants, while also controlling the temperature, pressure, and flow rate of the extracted exhaust gas 42. The EG treatment system 82 may include one or more heat exchangers (e.g., heat recovery units such as heat recovery steam generators, condensers, coolers, or heaters), catalyst systems (e.g., oxidation catalyst systems), particulate and/or water removal systems (e.g., gas dehydration units, inertial separators, coalescing filters, water impermeable filters, and other filters), chemical injection systems, solvent based treatment systems (e.g., absorbers, flash tanks, etc.), carbon capture systems, gas separation systems, gas purification systems, and/or a solvent based treatment system, exhaust gas compressors, any combination thereof. These subsystems of the EG treatment system 82 enable control of the temperature, pressure, flow rate, moisture content (e.g., amount of water removal), particulate content (e.g., amount of particulate removal), and gas composition (e.g., percentage of CO_2, N_2, etc.).

[0035] The extracted exhaust gas 42 is treated by one or more subsystems of the EG treatment system 82, depending on the target system. For example, the EG treatment system 82 may direct all or part of the exhaust gas 42 through a carbon capture system, a gas separation system, a gas purification system, and/or a solvent based treatment system, which is controlled to separate and purify a carbonaceous gas (e.g., carbon dioxide) 92 and/or nitrogen (N_2) 94 for use in the various target systems. For example, embodiments of the EG treatment system 82 may perform gas separation and purification to produce a plurality of different streams 95 of exhaust gas 42, such as a first stream 96, a second stream 97, and a third stream 98. The first stream 96 may have a first composition that is rich in carbon dioxide and/or lean in nitrogen (e.g., a CO_2 rich, N_2 lean stream). The second stream 97 may have a second composition that has intermediate concentration levels of carbon dioxide and/or nitrogen (e.g., intermediate concentration CO_2, N_2 stream). The third stream 98 may have a third composition that is lean in carbon dioxide and/or rich in nitrogen (e.g., a CO_2 lean, N_2 rich stream). Each stream 95 (e.g., 96, 97, and 98) may include a gas dehydration unit, a filter, a gas compressor, or any combination thereof, to facilitate delivery of the stream 95 to a target system. In certain embodiments, the CO_2 rich, N_2 lean stream 96 may have a CO_2 purity or concentration level of greater than approximately 70, 75, 80, 85, 90, 95, 96, 97, 98, or 99 percent by volume, and a N_2 purity or concentration level of less than approximately 1, 2, 3, 4, 5, 10, 15, 20, 25, or 30 percent by volume. In contrast, the CO_2 lean, N_2 rich stream 98 may have a CO_2 purity or concentration level of less than approximately 1, 2, 3, 4, 5, 10, 15, 20, 25, or 30 percent by volume, and a N_2 purity or concentration level of greater than approximately 70, 75, 80, 85, 90, 95, 96, 97, 98, or 99 percent by volume. The intermediate concentration CO_2, N_2 stream 97 may have a CO_2 purity or concentration level and/or a N_2 purity or concentration level of between approximately 30 to 70, 35 to 65, 40 to 60, or 45 to 55 percent by volume. Although the foregoing ranges are merely non-limiting examples, the CO_2 rich, N_2 lean stream 96 and the CO_2 lean, N_2 rich stream 98 may be particularly well suited for use with the EOR system 18 and the other systems 84. However, any of these rich, lean, or intermediate concentration CO_2 streams 95 may be used, alone or in various combinations, with the EOR system 18 and the other systems 84. For example, the EOR system 18 and the other systems 84 (e.g., the pipeline 86, storage tank 88, and the carbon sequestration system 90) each may receive one or more CO_2 rich, N_2 lean streams 96, one or more CO_2 lean, N_2 rich streams 98, one or more intermediate concentration CO_2, N_2 streams 97, and one or more untreated exhaust gas 42 streams (i.e., bypassing the EG treatment system 82).

[0036] The EG extraction system 80 extracts the exhaust gas 42 at one or more extraction points 76 along the compressor section, the combustor section, and/or the turbine section, such that the exhaust gas 42 may be used in the EOR system 18 and other systems 84 at suitable temperatures and pressures. The EG extraction system 80 and/or the EG treatment system 82 also may circulate fluid flows (e.g., exhaust gas 42) to and from the EG processing system 54. For example, a portion of the exhaust gas 42 passing through the EG processing system 54 may be extracted by the EG extraction system 80 for use in the EOR system 18 and the other systems 84. In certain embodiments, the EG supply system 78 and the EG processing system 54 may be independent or integral with one another, and thus may use independent or common subsystems. For example, the EG treatment system 82 may be used by both the EG supply system 78 and the EG processing system 54. Exhaust gas 42 extracted from the EG processing system 54 may undergo multiple stages of gas treatment, such as one or more stages of gas treatment in the EG processing system 54 followed by one or more additional stages of gas treatment in the EG treatment system 82.

[0037] At each extraction point 76, the extracted exhaust gas 42 may be substantially free of oxidant 68 and fuel 70 (e.g., unburnt fuel or hydrocarbons) due to substantially stoichiometric combustion and/or gas treatment in the EG processing system 54. Furthermore, depending on the target system, the extracted exhaust gas 42 may undergo further treatment in the EG treatment system 82 of the EG supply system 78, thereby further reducing any residual oxidant 68, fuel 70, or other undesirable products of combustion. For example, either before or after treatment in the EG treatment system 82, the extracted exhaust gas 42 may have less than 1, 2, 3, 4, or 5 percent by volume of oxidant (e.g., oxygen), unburnt fuel or hydrocarbons (e.g., HCs), nitrogen oxides (e.g., NO_X), carbon monoxide (CO), sulfur oxides (e.g., SO_X), hydrogen, and other products of incomplete combustion. By further example, either before or after treatment in the EG treatment system 82, the extracted exhaust gas 42 may have less than approximately 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 200, 300, 400, 500, 1000, 2000, 3000, 4000, or 5000 parts per million by volume (ppmv) of oxidant (e.g., oxygen), unburnt fuel or hydrocarbons (e.g., HCs), nitrogen oxides (e.g., NO_X), carbon monoxide (CO), sulfur oxides (e.g., SO_X), hydrogen, and other products of incomplete combustion. Thus, the exhaust gas 42 is particularly well suited for use with the EOR system 18.

[0038] The EGR operation of the turbine system 52 specifically enables the exhaust extraction at a multitude of locations 76. For example, the compressor section of the system 52 may be used to compress the exhaust gas 66 without any oxidant 68 (i.e., only compression of the exhaust gas 66), such that a substantially oxygen-free exhaust gas 42 may be extracted from the compressor section and/or the combustor section prior to entry of the oxidant 68 and the fuel 70. The extraction points 76 may be located at interstage ports between adjacent compressor stages, at ports along the compressor discharge casing, at ports along each combustor in the combustor section, or any combination thereof. In certain embodiments, the exhaust gas 66 may not mix with the oxidant 68 and fuel 70 until it reaches the head end portion and/or fuel nozzles of each combustor in the combustor section. Furthermore, one or more flow separators (e.g., walls, dividers, baffles, or the like) may be used to isolate the oxidant 68 and the fuel 70 from the extraction points 76. With these flow separators, the extraction points 76 may be disposed directly along a wall of each combustor in the combustor section.

[0039] Once the exhaust gas 66, oxidant 68, and fuel 70 flow through the head end portion (e.g., through fuel nozzles) into the combustion portion (e.g., combustion chamber) of each combustor, the SEGR gas turbine system 52 is controlled to provide a substantially stoichiometric combustion of the exhaust gas 66, oxidant 68, and fuel 70. For example, the system 52 may maintain an equivalence ratio of approximately 0.95 to approximately 1.05. As a result, the products of combustion of the mixture of exhaust gas 66, oxidant 68, and fuel 70 in each combustor is substantially free of oxygen and unburnt fuel. Thus, the products of combustion (or exhaust gas) may be extracted from the turbine section of the SEGR gas turbine system 52 for use as the exhaust gas 42 routed to the EOR system 18. Along the turbine section, the extraction points 76 may be located at any turbine stage, such as interstage ports between adjacent turbine stages. Thus, using any of the foregoing extraction points 76, the turbine-based service system 14 may generate, extract, and deliver the exhaust gas 42 to the hydrocarbon production system 12 (e.g., the EOR system 18) for use in the production of oil/gas 48 from the subterranean reservoir 20.

[0040] FIG. 2 is a diagram of an embodiment of the system 10 of FIG. 1, illustrating a control system 100 coupled to the turbine-based service system 14 and the hydrocarbon production system 12. In the illustrated embodiment, the turbine-based service system 14 includes a combined cycle system 102, which includes the SEGR gas turbine system 52 as a topping cycle, a steam turbine 104 as a bottoming cycle, and the HRSG 56 to recover heat from the exhaust gas 60 to generate the steam 62 for driving the steam turbine 104. Again, the SEGR gas turbine system 52 receives, mixes, and stoichiometrically combusts the exhaust gas 66, the oxidant 68, and the fuel 70 (e.g., premix and/or diffusion flames), thereby producing the exhaust gas 60, the mechanical power 72, the electrical power 74, and/or the water 64. For example, the SEGR gas turbine system 52 may drive one or more loads or machinery

106, such as an electrical generator, an oxidant compressor (e.g., a main air compressor), a gear box, a pump, equipment of the hydrocarbon production system 12, or any combination thereof. In some embodiments, the machinery 106 may include other drives, such as electrical motors or steam turbines (e.g., the steam turbine 104), in tandem with the SEGR gas turbine system 52. Accordingly, an output of the machinery 106 driven by the SEGR gas turbines system 52 (and any additional drives) may include the mechanical power 72 and the electrical power 74. The mechanical power 72 and/or the electrical power 74 may be used on-site for powering the hydrocarbon production system 12, the electrical power 74 may be distributed to the power grid, or any combination thereof. The output of the machinery 106 also may include a compressed fluid, such as a compressed oxidant 68 (e.g., air or oxygen), for intake into the combustion section of the SEGR gas turbine system 52. Each of these outputs (e.g., the exhaust gas 60, the mechanical power 72, the electrical power 74, and/or the water 64) may be considered a service of the turbine-based service system 14.

[0041] The SEGR gas turbine system 52 produces the exhaust gas 42, 60, which may be substantially free of oxygen, and routes this exhaust gas 42, 60 to the EG processing system 54 and/or the EG supply system 78. The EG supply system 78 may treat and delivery the exhaust gas 42 (e.g., streams 95) to the hydrocarbon production system 12 and/or the other systems 84. As discussed above, the EG processing system 54 may include the HRSG 56 and the EGR system 58. The HRSG 56 may include one or more heat exchangers, condensers, and various heat recovery equipment, which may be used to recover or transfer heat from the exhaust gas 60 to water 108 to generate the steam 62 for driving the steam turbine 104. Similar to the SEGR gas turbine system 52, the steam turbine 104 may drive one or more loads or machinery 106, thereby generating the mechanical power 72 and the electrical power 74. In the illustrated embodiment, the SEGR gas turbine system 52 and the steam turbine 104 are arranged in tandem to drive the same machinery 106. However, in other embodiments, the SEGR gas turbine system 52 and the steam turbine 104 may separately drive different machinery 106 to independently generate mechanical power 72 and/or electrical power 74. As the steam turbine 104 is driven by the steam 62 from the HRSG 56, the steam 62 gradually decreases in temperature and pressure. Accordingly, the steam turbine 104 recirculates the used steam 62 and/or water 108 back into the HRSG 56 for additional steam generation via heat recovery from the exhaust gas 60. In addition to steam generation, the HRSG 56, the EGR system 58, and/or another portion of the EG processing system 54 may produce the water 64, the exhaust gas 42 for use with the hydrocarbon production system 12, and the exhaust gas 66 for use as an input into the SEGR gas turbine system 52. For example, the water 64 may be a treated water 64, such as a desalinated water for use in other applications. The desalinated water may be particularly useful in regions of low water availability. Regarding the exhaust gas 60, embodiments of the EG processing system 54 may be configured to recirculate the exhaust gas 60 through the EGR system 58 with or without passing the exhaust gas 60 through the HRSG 56.

[0042] In the illustrated embodiment, the SEGR gas turbine system 52 has an exhaust recirculation path 110, which extends from an exhaust outlet to an exhaust inlet of the system 52. Along the path 110, the exhaust gas 60 passes through the EG processing system 54, which includes the HRSG 56 and the EGR system 58 in the illustrated embodiment. The EGR system 58 may include one or more conduits, valves, blowers, gas treatment systems (e.g., filters, particulate removal units, gas separation units, gas purification units, heat exchangers, heat recovery units such as heat recovery steam generators, moisture removal units, catalyst units, chemical injection units, or any combination thereof) in series and/or parallel arrangements along the path 110. In other words, the EGR system 58 may include any flow control components, pressure control components, temperature control components, moisture control components, and gas composition control components along the exhaust recirculation path 110 between the exhaust outlet and the exhaust inlet of the system 52. Accordingly, in embodiments with the HRSG 56 along the path 110, the HRSG 56 may be considered a component of the EGR system 58. However, in certain embodiments, the HRSG 56 may be disposed along an exhaust path independent from the exhaust recirculation path 110. Regardless of whether the HRSG 56 is along a separate path or a common path with the EGR system 58, the HRSG 56 and the EGR system 58 intake the exhaust gas 60 and output either the recirculated exhaust gas 66, the exhaust gas 42 for use with the EG supply system 78 (e.g., for the hydrocarbon production system 12 and/or other systems 84), or another output of exhaust gas. Again, the SEGR gas turbine system 52 intakes, mixes, and stoichiometrically combusts the exhaust gas 66, the oxidant 68, and the fuel 70 (e.g., premixed and/or diffusion flames) to produce a substantially oxygen-free and fuel-free exhaust gas 60 for distribution to the EG processing system 54, the hydrocarbon production system 12, or other systems 84.

[0043] As noted above with reference to FIG. 1, the hydrocarbon production system 12 may include a variety of equipment to facilitate the recovery or production of oil/gas 48 from a subterranean reservoir 20 through an oil/gas well 26. For example, the hydrocarbon production system 12 may include the EOR system 18 having the fluid injection system 34. In the illustrated embodiment, the fluid injection system 34 includes an exhaust gas injection EOR system 112 and a steam injection EOR system 114. Although the fluid injection system 34 may receive fluids from a variety of sources, the illustrated embodiment may receive the exhaust gas 42 and the steam 62 from the turbine-based service system 14. The exhaust gas 42 and/or the steam 62 produced by the turbine-based service system 14 also may be routed to the hydrocarbon production system 12 for use in other oil/gas systems 116.

[0044] The quantity, quality, and flow of the exhaust gas 42 and/or the steam 62 may be controlled by the control system 100. The control system 100 may be dedicated entirely to the turbine-based service system 14, or the control system 100 may optionally also provide control (or at least some data to facilitate control) for the hydrocarbon production system 12 and/or other systems 84. In the illustrated embodiment, the control system 100 includes a controller 118 having a processor 120, a memory 122, a steam turbine control 124, a SEGR gas turbine system control 126, and a machinery control 128. The processor 120 may include a single processor or two or more redundant processors, such as triple redundant processors for control of the turbine-based service system 14. The memory 122 may include volatile and/or non-volatile memory. For example, the memory 122 may include one or more hard drives, flash memory, read-only memory, random access memory, or any combination thereof. The controls 124, 126, and 128 may include software and/or hardware controls. For example, the controls 124, 126, and 128 may include various instructions or code stored on the memory 122 and executable by the processor 120. The control 124 is configured to control operation of the steam turbine 104, the SEGR gas turbine system control 126 is configured to control the system 52, and the machinery control 128 is configured to control the machinery 106. Thus, the controller 118 (e.g., controls 124, 126, and 128) may be configured to coordinate various sub-systems of the turbine-based service system 14 to provide a suitable stream of the exhaust gas 42 to the hydrocarbon production system 12.

[0045] In certain embodiments of the control system 100, each element (e.g., system, subsystem, and component) illustrated in the drawings or described herein includes (e.g., directly within, upstream, or downstream of such element) one or more industrial control features, such as sensors and control devices, which are communicatively coupled with one another over an industrial control network along with the controller 118. For example, the control devices associated with each element may include a dedicated device controller (e.g., including a processor, memory, and control instructions), one or more actuators, valves, switches, and industrial control equipment, which enable control based on sensor feedback 130, control signals from the controller 118, control signals from a user, or any combination thereof. Thus, any of the control functionality described herein may be implemented with control instructions stored and/or executable by the controller 118, dedicated device controllers associated with each element, or a combination thereof.

[0046] In order to facilitate such control functionality, the control system 100 includes one or more sensors distributed throughout the system 10 to obtain the sensor feedback 130 for use in execution of the various controls, e.g., the controls 124, 126, and 128. For example, the sensor feedback 130 may be obtained from sensors distributed throughout the SEGR gas turbine system 52, the machinery 106, the EG processing system 54, the steam turbine 104, the hydrocarbon production system 12, or any other components throughout the turbine-based service system 14 or the hydrocarbon production system 12. For example, the sensor feedback 130 may include temperature feedback, pressure feedback, flow rate feedback, flame temperature feedback, combustion dynamics feedback, intake oxidant composition feedback, intake fuel composition feedback, exhaust composition feedback, the output level of mechanical power 72, the output level of electrical power 74, the output quantity of the exhaust gas 42, 60, the output quantity or quality of the water 64, or any combination thereof. For example, the sensor feedback 130 may include a composition of the exhaust gas 42, 60 to facilitate stoichiometric combustion in the SEGR gas turbine system 52. For example, the sensor feedback 130 may include feedback from one or more intake oxidant sensors along an oxidant supply path of the oxidant 68, one or more intake fuel sensors along a fuel supply path of the fuel 70, and one or more exhaust emissions sensors disposed along the exhaust recirculation path 110 and/or within the SEGR gas turbine system 52. The intake oxidant sensors, intake fuel sensors, and exhaust emissions sensors may include temperature sensors, pressure sensors, flow rate sensors, and composition sensors. The emissions sensors may includes sensors for nitrogen oxides (e.g., NO_X sensors), carbon oxides (e.g., CO sensors and CO_2 sensors), sulfur oxides (e.g., SO_X sensors), hydrogen (e.g., H_2 sensors), oxygen (e.g., O_2 sensors), unburnt hydrocarbons (e.g., HC sensors), or other products of incomplete combustion, or any combination thereof.

[0047] Using this feedback 130, the control system 100 may adjust (e.g., increase, decrease, or maintain) the intake flow of exhaust gas 66, oxidant 68, and/or fuel 70 into the SEGR gas turbine system 52 (among other operational parameters) to maintain the equivalence ratio within a suitable range, e.g., between approximately 0.95 to approximately 1.05, between approximately 0.95 to approximately 1.0, between approximately 1.0 to approximately 1.05, or substantially at 1.0. For example, the control system 100 may analyze the feedback 130 to monitor the exhaust emissions (e.g., concentration levels of nitrogen oxides, carbon oxides such as CO and CO_2, sulfur oxides, hydrogen, oxygen, unburnt hydrocarbons, and other products of incomplete combustion) and/or determine the equivalence ratio, and then control one or more components to adjust the exhaust emissions (e.g., concentration levels in the exhaust gas 42) and/or the equivalence ratio. The controlled components may include any of the components illustrated and described with reference to the drawings, including but not limited to, valves along the supply paths for the oxidant 68, the fuel 70, and the exhaust gas 66; an oxidant compressor, a fuel pump, or any components in the EG processing system 54; any components of the SEGR gas turbine system 52, or any combination thereof. The controlled components may adjust (e.g., increase, decrease, or maintain) the flow rates, temperatures, pressures, or percentages (e.g., equivalence ratio) of the oxidant 68, the fuel 70, and the exhaust gas 66 that combust within the SEGR gas turbine system 52. The controlled components also may include one or more gas treatment systems, such as catalyst units (e.g., oxidation catalyst units), supplies for the catalyst units (e.g., oxidation fuel, heat, electricity, etc.), gas purification and/or separation units (e.g., solvent based separators, absorbers, flash tanks, etc.), and filtration units. The gas treatment systems may help reduce various exhaust emissions along the exhaust recirculation path 110, a vent path (e.g., exhausted into the atmosphere), or an extraction path to the EG supply system 78.

[0048] In certain embodiments, the control system 100 may analyze the feedback 130 and control one or more components to maintain or reduce emissions levels (e.g., concentration levels in the exhaust gas 42, 60, 95) to a target range, such as less than approximately 10, 20, 30, 40, 50, 100, 200, 300, 400, 500, 1000, 2000, 3000, 4000, 5000, or 10000 parts per million by volume (ppmv). These target ranges may be the same or different for each of the exhaust emissions, e.g., concentration levels of nitrogen oxides, carbon monoxide, sulfur oxides, hydrogen, oxygen, unburnt hydrocarbons, and other products of incomplete combustion. For example, depending on the equivalence ratio, the control system 100 may selectively control exhaust emissions (e.g., concentration levels) of oxidant (e.g., oxygen) within a target range of less than approximately 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 250, 500, 750, or 1000 ppmv; carbon monoxide (CO) within a target range of less than approximately 20, 50, 100, 200, 500, 1000, 2500, or 5000 ppmv; and nitrogen oxides (NO_X) within a target range of less than approximately 50, 100, 200, 300, 400, or 500 ppmv. In certain embodiments operating with a substantially stoichiometric equivalence ratio, the control system 100 may selectively control exhaust emissions (e.g., concentration levels) of oxidant (e.g., oxygen) within a target range of less than approximately 10, 20, 30, 40, 50, 60, 70, 80, 90, or 100 ppmv; and carbon monoxide (CO) within a target range of less than approximately 500, 1000, 2000, 3000, 4000, or 5000 ppmv. In certain embodiments operating with a fuel-lean equivalence ratio (e.g., between approximately 0.95 to 1.0), the control system 100 may selectively control exhaust emissions (e.g., concentration levels) of oxidant (e.g., oxygen) within a target range of less than approximately 500, 600, 700, 800, 900, 1000, 1100, 1200, 1300, 1400, or 1500 ppmv; carbon monoxide (CO) within a target range of less than approximately 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 150, or 200 ppmv; and nitrogen oxides (e.g., NO_X) within a target range of less than approximately 50, 100, 150, 200, 250, 300, 350, or 400 ppmv. The foregoing target ranges are merely examples, and are not intended to limit the scope of the disclosed embodiments.

[0049] The control system 100 also may be coupled to a local interface 132 and a remote interface 134. For example, the local interface 132 may include a computer workstation disposed on-site at the turbine-based service system 14 and/or the hydrocarbon production system 12. In contrast, the remote interface 134 may include a computer workstation disposed off-site from the turbine-based service system 14 and the hydrocarbon production system 12, such as through an internet connection. These interfaces 132 and 134 facilitate monitoring and control of the turbine-based service system 14, such as through one or more graphical displays of sensor feedback 130, operational parameters, and so forth.

[0050] Again, as noted above, the controller 118 includes a variety of controls 124, 126, and 128 to facilitate control of the turbine-based service system 14. The steam turbine control 124 may receive the sensor feedback 130 and output control commands to facilitate operation of the steam turbine 104. For example, the steam turbine control 124 may receive the sensor feedback 130 from the HRSG 56, the machinery 106, temperature and pressure sensors along a path of the steam 62, temperature and pressure sensors along a path of the water 108, and various sensors indicative of the mechanical power 72 and the electrical power 74. Likewise, the SEGR gas turbine system control 126 may receive sensor feedback 130 from one or more sensors disposed along the SEGR gas turbine system 52, the machinery 106, the EG processing system 54, or any combination thereof. For example, the sensor feedback 130 may be obtained from temperature sensors, pressure sensors, clearance sensors, vibration sensors, flame sensors, fuel composition sensors, exhaust gas composition sensors, or any combination thereof, disposed within or external to the

SEGR gas turbine system 52. Finally, the machinery control 128 may receive sensor feedback 130 from various sensors associated with the mechanical power 72 and the electrical power 74, as well as sensors disposed within the machinery 106. Each of these controls 124, 126, and 128 uses the sensor feedback 130 to improve operation of the turbine-based service system 14.

[0051] In the illustrated embodiment, the SEGR gas turbine system control 126 may execute instructions to control the quantity and quality of the exhaust gas 42, 60, 95 in the EG processing system 54, the EG supply system 78, the hydrocarbon production system 12, and/or the other systems 84. For example, the SEGR gas turbine system control 126 may maintain a level of oxidant (e.g., oxygen) and/or unburnt fuel in the exhaust gas 60 below a threshold suitable for use with the exhaust gas injection EOR system 112. In certain embodiments, the threshold levels may be less than 1, 2, 3, 4, or 5 percent of oxidant (e.g., oxygen) and/or unburnt fuel by volume of the exhaust gas 42, 60; or the threshold levels of oxidant (e.g., oxygen) and/or unburnt fuel (and other exhaust emissions) may be less than approximately 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 200, 300, 400, 500, 1000, 2000, 3000, 4000, or 5000 parts per million by volume (ppmv) in the exhaust gas 42, 60. By further example, in order to achieve these low levels of oxidant (e.g., oxygen) and/or unburnt fuel, the SEGR gas turbine system control 126 may maintain an equivalence ratio for combustion in the SEGR gas turbine system 52 between approximately 0.95 and approximately 1.05. The SEGR gas turbine system control 126 also may control the EG extraction system 80 and the EG treatment system 82 to maintain the temperature, pressure, flow rate, and gas composition of the exhaust gas 42, 60, 95 within suitable ranges for the exhaust gas injection EOR system 112, the pipeline 86, the storage tank 88, and the carbon sequestration system 90. As discussed above, the EG treatment system 82 may be controlled to purify and/or separate the exhaust gas 42 into one or more gas streams 95, such as the CO_2 rich, N_2 lean stream 96, the intermediate concentration CO_2, N_2 stream 97, and the CO_2 lean, N_2 rich stream 98. In addition to controls for the exhaust gas 42, 60, and 95, the controls 124, 126, and 128 may execute one or more instructions to maintain the mechanical power 72 within a suitable power range, or maintain the electrical power 74 within a suitable frequency and power range.

[0052] FIG. 3 is a diagram of embodiment of the system 10, further illustrating details of the SEGR gas turbine system 52 for use with the hydrocarbon production system 12 and/or other systems 84. In the illustrated embodiment, the SEGR gas turbine system 52 includes a gas turbine engine 150 coupled to the EG processing system 54. The illustrated gas turbine engine 150 includes a exhaust compressor section 152, a combustor section 154, and an expander section or turbine section 156. The exhaust compressor section 152 includes one or more exhaust gas compressors or compressor stages 158, such as 1 to 20 stages of rotary compressor blades disposed in a series arrangement. Likewise, the combustor section 154 includes one or more combustors 160, such as 1 to 20 combustors 160 distributed circumferentially about a rotational axis 162 of the SEGR gas turbine system 52. Furthermore, each combustor 160 may include one or more fuel nozzles 164 configured to inject the exhaust gas 66, the oxidant 68, and/or the fuel 70. For example, a head end portion 166 of each combustor 160 may house 1, 2, 3, 4, 5, 6, or more fuel nozzles 164, which may inject streams or mixtures of the exhaust gas 66, the oxidant 68, and/or the fuel 70 into a combustion portion 168 (e.g., combustion chamber) of the combustor 160.

[0053] The fuel nozzles 164 may include any combination of premix fuel nozzles 164 (e.g., configured to premix the oxidant 68 and fuel 70 for generation of an oxidant/fuel premix flame) and/or diffusion fuel nozzles 164 (e.g., configured to inject separate flows of the oxidant 68 and fuel 70 for generation of an oxidant/fuel diffusion flame). Embodiments of the premix fuel nozzles 164 may include swirl vanes, mixing chambers, or other features to internally mix the oxidant 68 and fuel 70 within the nozzles 164, prior to injection and combustion in the combustion chamber 168. The premix fuel nozzles 164 also may receive at least some partially mixed oxidant 68 and fuel 70. In certain embodiments, each diffusion fuel nozzle 164 may isolate flows of the oxidant 68 and the fuel 70 until the point of injection, while also isolating flows of one or more diluents (e.g., the exhaust gas 66, steam, nitrogen, or another inert gas) until the point of injection. In other embodiments, each diffusion fuel nozzle 164 may isolate flows of the oxidant 68 and the fuel 70 until the point of injection, while partially mixing one or more diluents (e.g., the exhaust gas 66, steam, nitrogen, or another inert gas) with the oxidant 68 and/or the fuel 70 prior to the point of injection. In addition, one or more diluents (e.g., the exhaust gas 66, steam, nitrogen, or another inert gas) may be injected into the combustor (e.g., into the hot products of combustion) either at or downstream from the combustion zone, thereby helping to reduce the temperature of the hot products of combustion and reduce emissions of NO_X (e.g., NO and NO_2). Regardless of the type of fuel nozzle 164, the SEGR gas turbine system 52 may be controlled to provide substantially stoichiometric combustion of the oxidant 68 and fuel 70.

[0054] In diffusion combustion embodiments using the diffusion fuel nozzles 164, the fuel 70 and oxidant 68 generally do not mix upstream from the diffusion flame, but rather the fuel 70 and oxidant 68 mix and react directly at the flame surface and/or the flame surface exists at the location of mixing between the fuel 70 and oxidant 68. In particular, the fuel 70 and oxidant 68 separately approach the flame surface (or diffusion boundary/interface), and then diffuse (e.g., via molecular and viscous diffusion) along the flame surface (or diffusion boundary/interface) to generate the diffusion flame. It is noteworthy that the fuel 70 and oxidant 68 may be at a substantially stoichiometric ratio along this flame surface (or diffusion boundary/interface), which may result in a greater flame temperature (e.g., a peak flame temperature) along this flame surface. The stoichiometric fuel/oxidant ratio generally results in a greater flame temperature (e.g., a peak flame temperature), as compared with a fuel-lean or fuel-rich fuel/oxidant ratio. As a result, the diffusion flame may be substantially more stable than a premix flame, because the diffusion of fuel 70 and oxidant 68 helps to maintain a stoichiometric ratio (and greater temperature) along the flame surface. Although greater flame temperatures can also lead to greater exhaust emissions, such as NO_X emissions, the disclosed embodiments use one or more diluents to help control the temperature and emissions while still avoiding any premixing of the fuel 70 and oxidant 68. For example, the disclosed embodiments may introduce one or more diluents separate from the fuel 70 and oxidant 68 (e.g., after the point of combustion and/or downstream from the diffusion flame), thereby helping to reduce the temperature and reduce the emissions (e.g., NO_X emissions) produced by the diffusion flame.

[0055] In operation, as illustrated, the exhaust compressor section 152 receives and compresses the exhaust gas 66 from the EG processing system 54, and outputs a compressed exhaust gas 170 to each of the combustors 160 in the combustor section 154. Upon combustion of the fuel 60, oxidant 68, and exhaust gas 170 within each combustor 160, additional exhaust gas or products of combustion 172 (i.e., combustion gas) is routed into the turbine section 156. Similar to the exhaust compressor section 152, the turbine section 156 includes one or more turbines or turbine stages 174, which may include a series of rotary turbine blades. These turbine blades are then driven by the products of combustion 172 generated in the combustor section 154, thereby driving rotation of a shaft 176 coupled to the machinery 106. Again, the machinery 106 may include a variety of equipment coupled to either end of the SEGR gas turbine system 52, such as machinery 106, 178 coupled to the turbine section 156 and/or machinery 106, 180 coupled to the exhaust compressor section 152. In certain embodiments, the machinery 106, 178, 180 may include one or more electrical generators, oxidant compressors for the oxidant 68, fuel pumps for the fuel 70, gear boxes, or additional drives (e.g. steam turbine 104, electrical motor, etc.) coupled to the SEGR gas turbine system 52. Non-limiting examples are discussed in further detail below with reference to TABLE 1. As illustrated, the turbine section 156 outputs the exhaust gas 60 to recirculate along the exhaust recirculation path 110 from an exhaust outlet 182 of the turbine section 156 to an exhaust inlet 184 into the exhaust compressor section 152. Along the exhaust recirculation path 110, the exhaust gas 60 passes through the EG processing system 54 (e.g., the HRSG 56 and/or the EGR system 58) as discussed in detail above.

[0056] Again, each combustor 160 in the combustor section 154 receives, mixes, and stoichiometrically combusts the compressed exhaust gas 170, the oxidant 68, and the fuel 70 to produce the additional exhaust gas or products of combustion 172 to drive the turbine section 156. In certain embodiments, the oxidant 68 is compressed by an oxidant compression system 186, such as a main oxidant compression (MOC) system (e.g., a main air compression (MAC) system) having one or more oxidant compressors (MOCs). The oxidant compression system 186 includes an oxidant compressor 188 coupled to a drive 190. For example, the drive 190 may include an electric motor, a combustion engine, or any combination thereof. In certain embodiments, the drive 190 may be a turbine engine, such as the gas turbine engine 150. Accordingly, the oxidant compression system 186 may be an integral part of the machinery 106. In other words, the compressor 188 may be directly or indirectly driven by the mechanical power 72 supplied by the shaft 176 of the gas turbine engine 150. In such an embodiment, the drive 190 may be excluded, because the compressor 188 relies on the power output from the turbine engine 150. However, in certain embodiments employing more than one oxidant compressor is employed, a first oxidant compressor (e.g., a low pressure (LP) oxidant compressor) may be driven by the drive 190 while the shaft 176 drives a second oxidant compressor (e.g., a high pressure (HP) oxidant compressor), or vice versa. For example, in another embodiment, the HP MOC is driven by the drive 190 and the LP oxidant compressor is driven by the shaft 176. In the illustrated embodiment, the oxidant compression system 186 is separate from the machinery 106. In each of these embodiments, the compression system 186 compresses and supplies the oxidant 68 to the fuel nozzles 164 and the combustors 160. Accordingly, some or all of the machinery 106, 178, 180 may be configured to increase the operational efficiency of the compression system 186 (e.g., the compressor 188 and/or additional compressors).

[0057] The variety of components of the machinery 106, indicated by element numbers 106A, 106B, 106C, 106D, 106E, and 106F, may be disposed along the line of the shaft 176 and/or parallel to the line of the shaft 176 in one or more series arrangements, parallel arrangements, or any combination of series and parallel arrangements. For example, the machinery 106, 178, 180 (e.g., 106A through 106F) may include any series and/or parallel arrangement, in any order, of: one or more gearboxes (e.g., parallel shaft, epicyclic gearboxes), one or more compressors (e.g., oxidant compressors, booster compressors such as EG booster compressors), one or more power generation units (e.g., electrical generators), one or more drives (e.g., steam turbine engines, electrical motors), heat exchange units (e.g., direct or indirect heat exchangers), clutches, or any combination thereof. The compressors may include axial compressors, radial or centrifugal compressors, or any combination thereof, each having one or more compression stages. Regarding the heat exchangers, direct heat exchangers may include spray coolers (e.g., spray intercoolers), which inject a liquid spray into a gas flow (e.g., oxidant flow) for direct cooling of the gas flow. Indirect heat exchangers may include at least one wall (e.g., a shell and tube heat exchanger) separating first and second flows, such as a fluid flow (e.g., oxidant flow) separated from a coolant flow (e.g., water, air, refrigerant, or any other liquid or gas coolant), wherein the coolant flow transfers heat from the fluid flow without any direct contact. Examples of indirect heat exchangers include intercooler heat exchangers and heat recovery units, such as heat recovery steam generators. The heat exchangers also may include heaters. As discussed in further detail below, each of these machinery components may be used in various combinations as indicated by the non-limiting examples set forth in TABLE 1.

[0058] Generally, the machinery 106, 178, 180 may be configured to increase the efficiency of the compression system 186 by, for example, adjusting operational speeds of one or more oxidant compressors in the system 186, facilitating compression of the oxidant 68 through cooling, and/or extraction of surplus power. The disclosed embodiments are intended to include any and all permutations of the foregoing components in the machinery 106, 178, 180 in series and parallel arrangements, wherein one, more than one, all, or none of the components derive power from the shaft 176. As illustrated below, TABLE 1 depicts some non-limiting examples of arrangements of the machinery 106, 178, 180 disposed proximate and/or coupled to the compressor and turbine sections 152, 156.

106A	**106B**	**106C**	**106D**	**106E**	**106F**
MOC	GEN				
MOC	GBX	GEN			
LP MOC	HP MOC	GEN			
HP MOC	GBX	LP MOC	GEN		
MOC MOC	GBX	GEN			
HP MOC	GBX	GEN	LP MOC		
MOC MOC	GBX GBX	GEN DRV			
DRV	GBX	LP MOC	HP MOC	GBX	GEN
DRV	GBX	HP MOC	LP MOC	GEN	
HP MOC	GBX CLR	LP MOC	GEN		
HP MOC	GBX CLR	LP MOC	GBX	GEN	
HP MOC	GBX HTR STGN	LP MOC	GEN		
MOC	GEN	DRV			
MOC	DRV	GEN			
DRV	MOC	GEN			
DRV	CLU	MOC	GEN		
DRV	CLU	MOC	GBX	GEN	

TABLE 1

[0059] As illustrated above in TABLE 1, a cooling unit is represented as CLR, a clutch is represented as CLU, a drive is represented by DRV, a gearbox is represented as GBX, a generator is represented by GEN, a heating unit is represented by HTR, a main oxidant compressor unit is represented by MOC, with low pressure and high pressure variants being represented as LP MOC and HP MOC, respectively, and a steam generator unit is represented as STGN. Although TABLE 1 illustrates the machinery 106, 178, 180 in sequence toward the exhaust compressor section 152 or the turbine section 156, TABLE 1 is also intended to cover the reverse sequence of the machinery 106, 178, 180. In TABLE 1, any cell including two or more components is intended to cover a parallel arrangement of the components. TABLE 1 is not intended to exclude any non-illustrated permutations of the machinery 106, 178, 180. These components of the machinery 106, 178, 180 may enable feedback control of temperature, pressure, and flow rate of the oxidant 68 sent to the gas turbine engine 150. As discussed in further detail below, the oxidant 68 and the fuel 70 may be supplied to the gas turbine engine 150 at locations specifically selected to facilitate isolation and extraction of the compressed exhaust gas 170 without any oxidant 68 or fuel 70 degrading the quality of the exhaust gas 170.

[0060] The EG supply system 78, as illustrated in FIG. 3, is disposed between the gas turbine engine 150 and the target systems (e.g., the hydrocarbon production system 12 and the other systems 84). In particular, the EG supply system 78, e.g., the EG extraction system (EGES) 80), may be coupled to the gas turbine engine 150 at one or more extraction points 76 along the exhaust compressor section 152, the combustor section 154, and/or the turbine section 156. For example, the extraction points 76 may be located between adjacent compressor stages, such as 2, 3, 4, 5, 6, 7, 8, 9, or 10 interstage extraction points 76 between compressor stages. Each of these interstage extraction points 76 provides a different temperature and pressure of the extracted exhaust gas 42. Similarly, the extraction points 76 may be located between adjacent turbine stages, such as 2, 3, 4, 5, 6, 7, 8, 9, or 10 interstage extraction points 76 between turbine stages. Each of these interstage extraction points 76 provides a different temperature and pressure of the extracted exhaust gas 42. By further example, the extraction points 76 may be located at a multitude of locations throughout the combustor section 154, which may provide different temperatures, pressures, flow rates, and gas compositions. Each of these extraction points 76 may include an EG extraction conduit, one or more valves, sensors, and controls, which may be used to selectively control the flow of the extracted exhaust gas 42 to the EG supply system 78.

[0061] The extracted exhaust gas 42, which is distributed by the EG supply system 78, has a controlled composition suitable for the target systems (e.g., the hydrocarbon production system 12 and the other systems 84). For example, at each of these extraction points 76, the exhaust gas 170 may be substantially isolated from injection points (or flows) of the oxidant 68 and the fuel 70. In other words, the EG supply system 78 may be specifically designed to extract the exhaust gas 170 from the gas turbine engine 150 without any added oxidant 68 or fuel 70. Furthermore, in view of the stoichiometric combustion in each of the combustors 160, the extracted exhaust gas 42 may be substantially free of oxygen and fuel. The EG supply system 78 may route the extracted exhaust gas 42 directly or indirectly to the hydrocarbon production system 12 and/or other systems 84 for use in various processes, such as enhanced oil recovery, carbon sequestration, storage, or transport to an offsite location. However, in certain embodiments, the EG supply system 78 includes the EG treatment system (EGTS) 82 for further treatment of the exhaust gas 42, prior to use with the target systems. For example, the EG treatment system 82 may purify and/or separate the exhaust gas 42 into one or more streams 95, such as the CO_2 rich, N_2 lean stream 96, the intermediate concentration CO_2, N_2 stream 97, and the CO_2 lean, N_2 rich stream 98. These treated exhaust gas streams 95 may be used individually, or in any combination, with the hydrocarbon production system 12 and the other systems 84 (e.g., the pipeline 86, the storage tank 88, and the carbon sequestration system 90).

[0062] Similar to the exhaust gas treatments performed in the EG supply system 78, the EG processing system 54 may include a plurality of exhaust gas (EG) treatment components 192, such as indicated by element numbers 194, 196, 198, 200, 202, 204, 206, 208, and 210. These EG treatment components 192 (e.g., 194 through 210) may be disposed along the exhaust recirculation path 110 in one or more series arrangements, parallel arrangements, or any combination of series and parallel arrangements. For example, the EG treatment components 192 (e.g., 194 through 210) may include any series and/or parallel arrangement, in any order, of: one or more heat exchangers (e.g., heat recovery units such as heat recovery steam generators, condensers, coolers, or heaters), catalyst systems (e.g., oxidation catalyst systems), particulate and/or water removal systems (e.g., inertial separators, coalescing filters, water impermeable filters, and other filters), chemical injection systems, solvent based treatment systems (e.g., absorbers, flash tanks, etc.), carbon capture systems, gas separation systems, gas purification systems, and/or a solvent based treatment system, or any combination thereof. In certain embodiments, the catalyst systems may include an oxidation catalyst, a carbon monoxide reduction catalyst, a nitrogen oxides reduction catalyst, an aluminum oxide, a zirconium oxide, a silicone oxide, a titanium oxide, a platinum oxide, a palladium oxide, a cobalt oxide, or a mixed metal oxide, or a combination thereof. The disclosed embodiments are intended to include any and all permutations of the foregoing components 192 in series and parallel arrangements. As illustrated below, TABLE 2 depicts some non-limiting examples of arrangements of the components 192 along the exhaust recirculation path 110.

194	196	198	200	202	204	206	208	210
CU	HRU	BB	MRU	PRU				
CU	HRU	HRU	BB	MRU	PRU	DIL		
CU	HRSG	HRSG	BB	MRU	PRU			
OCU	HRU	OCU	HRU	OCU	BB	MRU	PRU	
HRU CU	HRU CU	BB	MRU	PRU				
HRSG OCU	HRSG OCU	BB	MRU	PRU	DIL			
OCU	HRSG OCU	OCU	HRSG OCU	OCU	BB	MRU	PRU	DIL
OCU	HRSG ST	HRSG ST	BB	COND	INER	WFIL	CFIL	DIL
OCU HRSG ST	OCU HRSG ST	BB	COND	INER	FIL	DIL		
OCU	HRSG ST	HRSG ST	OCU	BB	MRU HE COND	MRU WFIL	PRU INER	PRU FIL CFIL
CU	HRU COND	HRU COND	HRU COND	BB	MRU HE COND WFIL	PRU INER	PRU FIL CFIL	DIL

TABLE 2

[0063] As illustrated above in TABLE 2, a catalyst unit is represented by CU, an oxidation catalyst unit is represented by OCU, a booster blower is represented by BB, a heat exchanger is represented by HX, a heat recovery unit is represented by HRU, a heat recovery steam generator is represented by HRSG, a condenser is represented by COND, a steam turbine is represented by ST, a particulate removal unit is represented by PRU, a moisture removal unit is represented by MRU, a filter is represented by

FIL, a coalescing filter is represented by CFIL, a water impermeable filter is represented by WFIL, an inertial separator is represented by INER, and a diluent supply system (e.g., steam, nitrogen, or other inert gas) is represented by DIL. Although TABLE 2 illustrates the components 192 in sequence from the exhaust outlet 182 of the turbine section 156 toward the exhaust inlet 184 of the exhaust compressor section 152, TABLE 2 is also intended to cover the reverse sequence of the illustrated components 192. In TABLE 2, any cell including two or more components is intended to cover an integrated unit with the components, a parallel arrangement of the components, or any combination thereof. Furthermore, in context of TABLE 2, the HRU, the HRSG, and the COND are examples of the HE; the HRSG is an example of the HRU; the COND, WFIL, and CFIL are examples of the WRU; the INER, FIL, WFIL, and CFIL are examples of the PRU; and the WFIL and CFIL are examples of the FIL. Again, TABLE 2 is not intended to exclude any non-illustrated permutations of the components 192. In certain embodiments, the illustrated components 192 (e.g., 194 through 210) may be partially or completed integrated within the HRSG 56, the EGR system 58, or any combination thereof. These EG treatment components 192 may enable feedback control of temperature, pressure, flow rate, and gas composition, while also removing moisture and particulates from the exhaust gas 60. Furthermore, the treated exhaust gas 60 may be extracted at one or more extraction points 76 for use in the EG supply system 78 and/or recirculated to the exhaust inlet 184 of the exhaust compressor section 152.

[0064] As the treated, recirculated exhaust gas 66 passes through the exhaust compressor section 152, the SEGR gas turbine system 52 may bleed off a portion of the compressed exhaust gas along one or more lines 212 (e.g., bleed conduits or bypass conduits). Each line 212 may route the exhaust gas into one or more heat exchangers 214 (e.g., cooling units), thereby cooling the exhaust gas for recirculation back into the SEGR gas turbine system 52. For example, after passing through the heat exchanger 214, a portion of the cooled exhaust gas may be routed to the turbine section 156 along line 212 for cooling and/or sealing of the turbine casing, turbine shrouds, bearings, and other components. In such an embodiment, the SEGR gas turbine system 52 does not route any oxidant 68 (or other potential contaminants) through the turbine section 156 for cooling and/or sealing purposes, and thus any leakage of the cooled exhaust gas will not contaminate the hot products of combustion (e.g., working exhaust gas) flowing through and driving the turbine stages of the turbine section 156. By further example, after passing through the heat exchanger 214, a portion of the cooled exhaust gas may be routed along line 216 (e.g., return conduit) to an upstream compressor stage of the exhaust compressor section 152, thereby improving the efficiency of compression by the exhaust compressor section 152. In such an embodiment, the heat exchanger 214 may be configured as an interstage cooling unit for the exhaust compressor section 152. In this manner, the cooled exhaust gas helps to increase the operational efficiency of the SEGR gas turbine system 52, while simultaneously helping to maintain the purity of the exhaust gas (e.g., substantially free of oxidant and fuel).

[0065] FIG. 4 is a flow chart of an embodiment of an operational process 220 of the system 10 illustrated in FIGS 1-3. In certain embodiments, the process 220 may be a computer implemented process, which accesses one or more instructions stored on the memory 122 and executes the instructions on the processor 120 of the controller 118 shown in FIG. 2. For example, each step in the process 220 may include instructions executable by the controller 118 of the control system 100 described with reference to FIG. 2.

[0066] The process 220 may begin by initiating a startup mode of the SEGR gas turbine system 52 of FIGS. 1-3, as indicated by block 222. For example, the startup mode may involve a gradual ramp up of the SEGR gas turbine system 52 to maintain thermal gradients, vibration, and clearance (e.g., between rotating and stationary parts) within acceptable thresholds. For example, during the startup mode 222, the process 220 may begin to supply a compressed oxidant 68 to the combustors 160 and the fuel nozzles 164 of the combustor section 154, as indicated by block 224. In certain embodiments, the compressed oxidant may include a compressed air, oxygen, oxygen-enriched air, oxygen-reduced air, oxygen-nitrogen mixtures, or any combination thereof. For example, the oxidant 68 may be compressed by the oxidant compression system 186 illustrated in FIG. 3. The process 220 also may begin to supply fuel to the combustors 160 and the fuel nozzles 164 during the startup mode

222, as indicated by block 226. During the startup mode 222, the process 220 also may begin to supply exhaust gas (as available) to the combustors 160 and the fuel nozzles 164, as indicated by block 228. For example, the fuel nozzles 164 may produce one or more diffusion flames, premix flames, or a combination of diffusion and premix flames. During the startup mode 222, the exhaust gas 60 being generated by the gas turbine engine 156 may be insufficient or unstable in quantity and/or quality. Accordingly, during the startup mode, the process 220 may supply the exhaust gas 66 from one or more storage units (e.g., storage tank 88), the pipeline 86, other SEGR gas turbine systems 52, or other exhaust gas sources.

[0067] The process 220 may then combust a mixture of the compressed oxidant, fuel, and exhaust gas in the combustors 160 to produce hot combustion gas 172, as indicated by block 230. In particular, the process 220 may be controlled by the control system 100 of FIG. 2 to facilitate stoichiometric combustion (e.g., stoichiometric diffusion combustion, premix combustion, or both) of the mixture in the combustors 160 of the combustor section 154. However, during the startup mode 222, it may be particularly difficult to maintain stoichiometric combustion of the mixture (and thus low levels of oxidant and unburnt fuel may be present in the hot combustion gas 172). As a result, in the startup mode 222, the hot combustion gas 172 may have greater amounts of residual oxidant 68 and/or fuel 70 than during a steady state mode as discussed in further detail below. For this reason, the process 220 may execute one or more control instructions to reduce or eliminate the residual oxidant 68 and/or fuel 70 in the hot combustion gas 172 during the startup mode.

[0068] The process 220 then drives the turbine section 156 with the hot combustion gas 172, as indicated by block 232. For example, the hot combustion gas 172 may drive one or more turbine stages 174 disposed within the turbine section 156. Downstream of the turbine section 156, the process 220 may treat the exhaust gas 60 from the final turbine stage 174, as indicated by block 234. For example, the exhaust gas treatment 234 may include filtration, catalytic reaction of any residual oxidant 68 and/or fuel 70, chemical treatment, heat recovery with the HRSG 56, and so forth. The process 220 may also recirculate at least some of the exhaust gas 60 back to the exhaust compressor section 152 of the SEGR gas turbine system 52, as indicated by block 236. For example, the exhaust gas recirculation 236 may involve passage through the exhaust recirculation path 110 having the EG processing system 54 as illustrated in FIGS. 1-3.

[0069] In turn, the recirculated exhaust gas 66 may be compressed in the exhaust compressor section 152, as indicated by block 238. For example, the SEGR gas turbine system 52 may sequentially compress the recirculated exhaust gas 66 in one or more compressor stages 158 of the exhaust compressor section 152. Subsequently, the compressed exhaust gas 170 may be supplied to the combustors 160 and fuel nozzles 164, as indicated by block 228. Steps 230, 232, 234, 236, and 238 may then repeat, until the process 220 eventually transitions to a steady state mode, as indicated by block 240. Upon the transition 240, the process 220 may continue to perform the steps 224 through 238, but may also begin to extract the exhaust gas 42 via the EG supply system 78, as indicated by block 242. For example, the exhaust gas 42 may be extracted from one or more extraction points 76 along the exhaust compressor section 152, the combustor section 154, and the turbine section 156 as indicated in FIG. 3. In turn, the process 220 may supply the extracted exhaust gas 42 from the EG supply system 78 to the hydrocarbon production system 12, as indicated by block 244. The hydrocarbon production system 12 may then inject the exhaust gas 42 into the earth 32 for enhanced oil recovery, as indicated by block 246. For example, the extracted exhaust gas 42 may be used by the exhaust gas injection EOR system 112 of the EOR system 18 illustrated in FIGS. 1-3.

[0070] It may be appreciated that, as the exhaust gas 42 is extracted from the one or more extraction points 76, as indicated in FIG. 3, the SEGR gas turbine system 52 may generally seek to maintain a mass balance. That is, it may be generally desirable that the flow of exhaust gas extracted from the one or more extraction points 76 be approximately equal to the flow of fuel 70 and oxidant 68 being added into the combustors 160 of the SEGR gas turbine system 52. Accordingly, maintaining this mass balance may enable the SEGR gas turbine system 52 to maintain suitable pressures during operation.

[0071] FIG. 5 schematically depicts an embodiment of a control system 260 configured to control the operation of the SEGR gas turbine system 52. In particular, the control system 260 enables the control of one or more parameters (e.g., flow rate or pressure) of the exhaust gas 60 as it is recirculated along the exhaust recirculation path 110. Among various flow-adjusting features, the control system 260 includes the controller 118, which may include a series of modules or computer programs capable of implementing the flow control techniques described herein. In one embodiment, the controller 118 may include one or more tangible, non-transitory, machine-readable media collectively storing one or more sets of instructions and one or more processing devices configured to execute the stored instructions to perform the exhaust flow control techniques described herein. The one or more sets of instructions, for example, may collectively or individually include modules for adjusting one or more exhaust flows through the SEGR gas turbine system 52. It should be noted that the modules disclosed herein may be implemented at a centralized workstation (e.g., an on-site or off-site workstation as one or more applications), or a distributed system in which one or more workstations, panels, or automated controllers may be distributed throughout the SEGR gas turbine system 52, such as proximate various control valves, conduit junctions, and so forth. It should also be noted that only certain features of the control system 260 and the SEGR gas turbine system 52 are illustrated in FIG. 5 for discussion purposes; however, certain embodiments of the control system 260 may include other features (e.g., features set forth in FIGS. 1-4) that are not explicitly shown in FIG. 5.

[0072] The SEGR gas turbine system 52 illustrated in FIG. 5 includes an embodiment of the EG processing system 54 having particular components to facilitate the movement and preparation of the exhaust gas within the SEGR gas turbine system 52. In particular, the illustrated EG processing system 54 includes two HRSG elements, 56A and 56B, disposed on opposite sides (e.g., an upstream side and a downstream side) of a recycle blower 262 (also referred to as a booster blower) along the recirculation path 110 of the SEGR gas turbine system 52. In other embodiments, more than one recycle blower 262 may be coupled to the exhaust recirculation path 110, either in serial or in parallel. Further, the recycle blower 262 may include a control unit 257 to control operation of the recycle blower. For example, in certain embodiments, the control unit 257 may control one or more motors 259 and actuators 261 of the recycle blower 262 based on instructions from the controller 118, as discussed in detail below.

[0073] The recycle blower 262 may include a number of blower vanes (BVs) 264 whose position may be controlled by the one or more actuators 261 of the recycle blower 262. Based on a pitch or angle 263 of the BVs 264 (e.g., relative to a radial direction 265), a flow rate of exhaust through the recycle blower 262 may be increased or decreased. For example, in certain embodiments, when the BVs 264 have a minimum BV pitch 263, (e.g., 0, 1, 2, 3, 4, 5, 10, 15, 20, 25, 30, or 35 degrees, or another suitably low BV pitch), the recycle blower 262 may provide a minimum output (e.g., minimum exhaust gas flow or minimum pressure rise across the recycle blower 262). Conversely, in such embodiments, when the BVs 264 are set to a maximum BV pitch 263 (e.g., 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90 degrees or another suitable relatively higher angle), the recycle blower 262 may provide a maximum output (e.g., a maximum exhaust gas flow and/or maximum pressure rise). By specific example, in certain embodiments, the BVs 264 may have a range of motion that extends between 25 degrees and 80 degrees. It may be appreciated that, in other embodiments, the BV pitch 263 may be determined relative to another direction (e.g., axial design reference direction 267) and, accordingly, a minimum BV pitch 263 may correspond to a maximum output of the recycle blower 262, and *vice versa*. Further, it may be appreciated that, in certain embodiments, the one or more actuators 261 may be adjusted to affect the BV pitch 263 subject to deadband (e.g., 1, 2, 3, 4, 5, 6, 7, 8, 9, or 10 degrees) or in a continuously variable manner.

[0074] The control unit 257 of the recycle blower 262 illustrated in FIG. 5 is communicatively coupled to the controller 118 to enable the controller 118 to monitor and adjust the BV pitch 263 in order to control the exhaust gas output of the recycle blower 262. For example, as discussed in detail below, the controller 118 may cause the control unit 257 to adjust the BV pitch 263 (e.g., using the one or more actuators 261) to alter a flow rate of exhaust gas 60 downstream from the recycle blower 262, a pressure rise in the exhaust gas flow across the recycle blower 262, and so forth. In certain embodiments, any one or a combination of other parameters (e.g., power, voltage, or revolutions per minute (RPMs)) of the recycle blower 262 may additionally or alternatively be adjusted (e.g., by the controller 118 and the control unit 257) to control the exhaust gas output of the recycle blower 262 in accordance with the present approach. Further, as discussed in detail below, during operation of the SEGR gas turbine system 52, the controller 118 may consider a number of parameters and limitations of the various components of the SEGR gas turbine system 52 to determine a suitable output for the recycle blower 262 (e.g., a suitable BV pitch 263) under a particular set of conditions.

[0075] After traversing the EG processing system 54 illustrated in FIG. 5, the exhaust gas 60 may continue to flow down the exhaust recirculation path 110 to reach the exhaust compressor section 152. More specifically, the exhaust recirculation path 110 may direct the exhaust gas 60 to the exhaust inlet 184 of the exhaust compressor section 152, so that the exhaust gas 60 may be introduced into the exhaust compressor section 152 for compression, as discussed above. Further, the exhaust inlet 184 of the exhaust compressor section 152 illustrated in FIG. 5 includes a flow control mechanism, such as one or more inlet guide vanes (IGVs) 266 or another suitable flow control mechanism, to control or regulate the flow of exhaust gas into the exhaust compressor section 152. The flow control mechanism (e.g., IGVs 266) may be set to a particular position to limit or block (e.g., control or adjust) a portion of the exhaust gas flow from passing through the exhaust inlet 184 and into the exhaust compressor section 152. For example, the IGVs 266 may be adjusted to a particular angle (e.g., inlet guide vane (IGV) angle 271 by one or more actuators 269 to allow a particular amount of the exhaust gas flow received at the exhaust inlet 184 to enter the exhaust compressor section 152 for compression.

[0076] Accordingly, the one or more actuators 269 of the IGVs 266 illustrated in FIG. 5 are communicatively coupled to the controller 118 to enable the controller 118 to monitor and adjust the IGV angle 271 to control how much of the exhaust gas flow is introduced into the exhaust compressor section 152. For example, the IGVs 266 may, at times, be set by the controller 118 to a maximum open position, such as approximately 0 degrees or another suitable low angle (e.g., between 0 and 25 degrees, between 1 and 20 degrees, between 2 and 15 degrees, or between 3 and 10 degrees, between 4 and 5 degrees), relative to the axial design reference direction 267, to provide a maximum exhaust flow into the exhaust compressor section 152. Further, the IGVs 266 may, at times, be set by the controller 118 to a minimum open position, such as approximately 75 degrees or another suitable high angle (e.g., between 25 and 75 degrees, between 35 and 65 degrees, between 45 and 60 degrees, or between 50 and 55 degrees) relative to the axial design reference direction 267, to provide a minimum exhaust flow into the exhaust compressor section 152. In certain embodiments, the one or more actuators 269 may adjust the IGV angle 271 subject to deadband (e.g., 1, 2, 3, 4, 5, 6, 7, 8, 9, or 10 degrees) or in a continuously variable manner. By specific example, in certain embodiments, the BV pitch 263 may be adjusted subject to deadbands while the IGV angle 271 may be adjusted in a continuously variable manner. It may be appreciated that, in other embodiments, the IGV angle 271 may be determined relative to another direction (e.g., radial direction 265) and, accordingly, a maximum IGV angle may correspond to a maximum flow of exhaust gas into the exhaust compressor section 152, and *vice versa*. As discussed in detail below, during operation of the SEGR gas turbine system 52, the controller 118 may consider certain parameters and limits of components of the SEGR gas turbine system 52 to determine a suitable IGV angle 271.

[0077] As set forth above, the flow of exhaust gas 60 through the exhaust gas recirculation path 110 illustrated in FIG. 5 is regulated, at least in part, by the position of the flow control element (e.g., IGVs 266) at the exhaust inlet 184 of the exhaust compressor section 152 and the output of the recycle blower 262. Accordingly, in certain embodiments, the controller 118 may control the flow of exhaust gas 60 through the exhaust gas recirculation path 110 by controlling both the IGV angle 271 and the BV pitch 263. Further, it may be appreciated that, in certain embodiments, the controller 118 may adjust the IGV angle 271 and the BV pitch 263 to maintain (e.g., at a target value, within a target range, or below a particular threshold value) certain parameters of the SEGR gas turbine system 52, while still accounting for the limitations of the components of the SEGR gas turbine system 52.

[0078] For example, the controller 118 may use one or more sensors (e.g., temperature sensor 268) to determine a temperature of the exhaust gas 60 exiting the turbine section 156. In certain embodiments, the controller 118 may generally adjust the positions of the IGVs 266 and/or the BVs 264 to maintain an exhaust gas temperature below a threshold value or at a particular set point value. Additionally or alternatively, the controller 118 may model (e.g., using real-time or near-real-time computer modeling software) a firing temperature (e.g., a combustion temperature) within a combustor section 154 of the SEGR gas turbine system 52 based on the exhaust temperature measured by the one or more sensors (e.g., the temperature sensor 268), and may operate to maintain a firing temperature below a threshold value or within a particular operating range at least partially by controlling the IGVs 266 and/or BVs 264.

[0079] With the foregoing in mind, FIG. 6 illustrates how the recycle gas turbine (RGT) exhaust temperature of the SEGR gas turbine system 52 may be affected by changes to the IGV angle 271 compared to changes in the BV pitch 263. That is, the graph 280 of FIG. 6 demonstrates how the RGT exhaust temperature may vary over time while adjusting either the IGV angle 271 (line 282) or the BV pitch 263 (line 284) in an open loop manner while other effectors of the SEGR gas turbine system 52 are generally fixed. As will be appreciated with reference to the graph 280, line 282 illustrates a dramatic change in the RGT exhaust temperature as the IGV angle 271 is reduced by an angular amount (e.g., 1, 2, 3, 4, 5, 6, 7, 8, 9, or 10 degrees), which enables an even greater exhaust flow through the exhaust inlet 184 into the exhaust compressor section 152. Because of the increased flow of exhaust gas 60, the firing temperature and the resulting RGT exhaust temperature are reduced due to the presence of more diluent exhaust gas, relative to fuel and oxidant, in the combustion process.

[0080] In contrast, line 284 of the graph 280 in FIG. 6 illustrates the more gradual change in the RGT exhaust temperature as the BV pitch 263 is increased by an angular amount (e.g., 1, 2, 3, 4, 5, 6, 7, 8, 9, or 10 degrees), providing a greater flow of exhaust to the exhaust inlet 184. For comparison of the two lines 282 and 284, the dashed line 286 denotes a particular point in time (e.g., 5, 7, 10, or 15 seconds after either adjustment). At the time 286, the change in the RGT exhaust temperature provided by the adjustment of the BV pitch 263 (i.e., line 284) reflects an RGT exhaust temperature change that is approximately 40% smaller than the change provided by the adjustment of the IGV angle 271 (e.g., line 282). As such, the graph 280 illustrates that, since the BVs 264 are farther removed from the combustor section 154 than the IGVs 266 (i.e., as illustrated in FIG. 5), changes to the BV pitch 263 may not generally affect the RGT exhaust temperature (or the firing temperature within the combustor section 154) as fast as (or to the same extent as) changes to the IGV angle 271.

[0081] Accordingly, the RGT exhaust or firing temperature of the SEGR gas turbine system 52 may generally respond faster to changes in the IGV angle 271 than to changes in the BV pitch 263. Of further consideration, the recycle blower 262 may generally consume more power when the BVs 264 are set to a higher BV pitch 263, or the output of the recycle blower 262 is otherwise increased. With these considerations in mind, it may be beneficial from an efficiency standpoint, in one control strategy, to only operate the recycle blower 262 a minimal amount of time. For example, turning to FIG. 7, a graph 290 illustrates a control strategy, focused on efficiency, which the controller 118 may use to determine a suitable IGV angle 271 and a suitable BV pitch 263 to respond to an increasing RGT load, which corresponds to increasing RGT firing and exhaust temperatures, in the SEGR gas turbine system 52. In other words, for the control strategy illustrated by FIG. 7, the recycle blower 262 operates a minimal amount of time.

[0082] The graph 290 of FIG. 7 illustrates that, as the RGT load increases, the IGV angle 271 (illustrated by line 292) may be decreased by the controller 118, enabling a greater flow of exhaust gas into the exhaust compressor section 152. Eventually, if the RGT load continues to increase, the IGV angle 271 may reach a minimal angle (e.g., a minimal set point, such as 0°), wherein the IGVs 266 may be in a maximum open position, enabling maximum flow through the IGVs 266. Beyond this point, if the RGT load continues to increase further, then the BV pitch 263 (illustrated by 294) of the recycle blower 262 may be increased (e.g., from a minimum pitch) by the controller 118, causing the recycle blower 262 to consume additional power.

However, as set forth above, adjusting the BV pitch 263 does not affect the RGT exhaust or firing temperature of the SEGR gas turbine system 52 as fast as adjusting the IGV angle 271. Accordingly, while the control strategy illustrated by FIG. 7 emphasizes efficiency (e.g., minimal use of the recycle blower 262), fine control or responsiveness of the RGT exhaust or firing temperature of the SEGR gas turbine system 52 may be reduced significantly across the region 296, which is the period of time that the recycle blower 262 is used to control the RGT exhaust or firing temperature. Similarly, the SEGR gas turbine system 52 may also be limited in its ability to quickly respond to changes in load demand when being controlled as illustrated in FIG. 7.

[0083] FIG. 8 illustrates a graph 300 depicting an example of another control strategy (focused on responsiveness) that the controller 118 may use to determine a suitable IGV angle 271 and a suitable BV pitch 263 to respond to an increasing RGT load. As noted above, increasing RGT load may correspond to increasing RGT firing and exhaust temperatures in the SEGR gas turbine system 52. In the graph 300 of FIG. 8, as the as the RGT load of the SEGR gas turbine system 52 steadily increases, the IGV angle 271 (illustrated by line 302) may initially be decreased by the controller 118, allowing a greater flow of exhaust gas 60 into the exhaust compressor section 152. However, in contrast to the graph 290, as the RGT load continues to increase, the IGVs 266 may eventually reach a particular set point angle or position 301 (e.g., 5 degrees or 5% from the maximum open position). It may be appreciated that the particular set point angle or position 301 of the IGVs 266 may be any suitable angle or position that allows a sufficient headspace 303 for the control purposes set forth above and below.

[0084] For example, in certain embodiments, the particular set point angle or position 301 of the IGVs 266 may be approximately 50%, 45%, 40%, 35%, 30%, 25%, 20%, 15%, 10%, 7%, 5%, or 3% of the range of motion of the IGVs 266 from the maximum open position to provide the desired headspace 303. In certain embodiments, the particular set point angle or position 301 of the IGVs 266 may be between approximately 50% and approximately 2%, between approximately 40% and approximately 3%, between approximately 30% and approximately 4%, between approximately 20% and 5%, or between approximately 10% and approximately 5% of the range of motion of the IGVs 266 from the maximum open position. By further example, in certain embodiments, the particular set point angle or position 301 of the IGVs 266 may be approximately 50, 45, 40, 35, 30, 25, 20, 15, 10, 7, 5, or 3 degrees from the maximum open position. In certain embodiments, the particular set point angle or position 301 of the IGVs 266 may be between approximately 50 degrees and approximately 2 degrees, between approximately 40 degrees and approximately 3 degrees, between approximately 30 degrees and approximately 4 degrees, between approximately 20 degrees and approximately 5 degrees, or between approximately 10 degrees and approximately 5 degrees from the maximum open position.

[0085] As illustrated in the graph 300 of FIG. 8, once the IGVs 266 reach the set point angle or position 301, if the RGT load continues to increase, the BV pitch 263 (illustrated by line 304) may then be adjusted to increase the output of the recycle blower 262 such that the set point angle or position 301 of the IGVs 266 may generally be maintained. In other words, the BV pitch 263 may be adjusted such that the IGVs 266 maintain a particular headspace 303 (e.g., 5 degrees or 5% from the maximum open position of the IGVs 266). It may be appreciated that, as discussed above with respect to FIG. 6, the headspace 303 may allow sufficient movement of the IGVs 266 such that the controller 118 may adjust the IGV angle 271 to quickly adjust the RGT exhaust or firing temperature of the SEGR gas turbine system 52.

[0086] As illustrated in FIG. 8, in the region 306, as the RGT load of the SEGR gas turbine system 52 continues to increase, the BVs 264 may eventually reach a maximum BV pitch 263, corresponding to a maximum output of the recycle blower 262 (as illustrated by line 307). At that point, if the RGT load of the SEGR gas turbine system 52 increases further, the controller 118 may forego maintaining headspace 303, and may reduce the IGV angle 271 to increase exhaust flow into the exhaust compressor section 152 to satisfy other limitations of the SEGR gas turbine system 52 (e.g., an RGT exhaust or firing temperature limit discussed below). It may be appreciated that, for the control strategy illustrated in FIG. 8, the RGT exhaust or firing temperature of the SEGR gas turbine system 52 may be controlled in a more responsive manner across the region 306. Further, while the control strategy represented by FIG. 8 may be slightly less efficient than the control strategy represented in FIG. 7 (e.g., due to additional power consumption by the recycle blower 262 when maintaining the aforementioned IGV headspace 303), this approach may generally enable the controller 118 to use the more responsive input (e.g., the IGV angle 271) to control the RGT exhaust or firing temperature control across the region 306.

[0087] FIG. 9 is a hybrid block-flow diagram illustrating the limits and inputs that the controller 118 may utilize in certain embodiments to determine a suitable IGV angle 271 and a suitable BV pitch 263 when controlling operation of the SEGR gas turbine system 52. For the embodiment illustrated in FIG. 9, the controller 118 may determine the appropriate IGV angle 271 based on the current measured RGT exhaust temperature or current modeled RGT firing temperature 312 of the SEGR gas turbine system 52. The controller 118 may accordingly determine whether to increase or decrease the IGV angle 271 based on the current exhaust or firing temperature 312 relative to a RGT exhaust or firing temperature limit 314 (e.g., upper threshold, lower threshold, or range).

[0088] Additionally, as illustrated in FIG. 9, the controller 118 may also take into consideration certain limitations of the SEGR gas turbine system 52 (e.g. limitations of the IGVs 266 and the exhaust compressor section 152) when determining the appropriate IGV angle 271. For example, in certain embodiments, the controller 118 may restrict the IGV angle 271 to remain below (e.g., remain more open than) a minimum open angle or position based, at least in part, on a recycle compressor stall limit 316 to prevent the exhaust compressor section 152 from stalling. Further, in certain embodiments, the controller 118 may additionally restrict the IGV angle 271 based, at least in part, on a minimum IGV open limit 318 and a maximum IGV open limit 320, which may define the mechanical limits to the range of motion of the IGVs 266. In other words, the controller 118 may select an appropriate IGV angle 271 that satisfies all of the limitations of the SEGR gas turbine system 52 (e.g., the RGT exhaust or firing temperature limit 314, recycle compressor stall limit 316, IGV minimum open limit 318, and an IGV maximum open limit 320) based on the current RGT exhaust or firing temperature 312 of the SEGR gas turbine system 52.

[0089] Similarly, as illustrated in FIG. 9, a suitable BV pitch 263 may be determined by the controller 118 based on various inputs and limitations of the SEGR gas turbine system 52. For the embodiment illustrated in FIG. 9, the controller 118 determines an appropriate BV pitch 263 based on the current IGV angle 271 relative to the IGV maximum open limit 320. That is, in certain embodiments, the controller 118 may be programmed to adjust the BV pitch 263 to provide the IGVs 266 with a particular headspace 303 (as illustrated in FIG. 8), wherein the current headspace 303 may be defined by the difference between the current IGV angle 271 and the IGV maximum open limit 318 or another suitable maximum open limit of the IGVs 266.

[0090] However, as illustrated in FIG. 9, the controller 118 may also take into consideration other limitations of the SEGR gas turbine system 52 (e.g., limitations of the recycle blower 262 and the exhaust compressor section 152) when determining the appropriate BV pitch 263. For example, as illustrated in FIG. 9, the controller 118 may take into consideration a compressor maximum inlet pressure limit 326, which define the upper limits of the BV pitch 263 (e.g., the upper bounds output of the recycle blower 266) to enable suitable operability of the SEGR gas turbine system 52. Further, in the embodiment illustrated in FIG. 9, the controller 118 may take into consideration a recycle blower stall limit 328, an exhaust gas recycle (EGR) minimum pressure limit 330, and an EGR minimum pressure rise limit 332, which may define the lower limits of the BV pitch 263 (e.g., the lower bounds output of the recycle blower 266) to enable suitable operability of the SEGR gas turbine system 52. In other words, the controller 118 may select an appropriate BV pitch 263 that satisfies all of the limitations of the SEGR gas turbine system 52 and recycle blower 266 (e.g., the compressor maximum inlet pressure limit 326, recycle blower stall limit 328, exhaust gas recycle (EGR) minimum pressure limit 330, and EGR minimum pressure rise limit 332) based on the current IGV angle 271 relative to the maximum IGV open limit 320. Furthermore, in certain embodiments, as illustrated by the line 333, the controller 118 may also consider the current BV pitch 263 when determining a suitable IGV angle 271. For example, in certain embodiments, the controller 118 may determine that the BV pitch 263 has reached a maximum BV pitch 263 and, accordingly, the controller 118 may forego maintaining the headspace 303 (e.g., as set forth in the discussion of FIG. 8 above).

[0091] FIG. 10 is a set of graphs 340 illustrating different parameters of an embodiment of the SEGR gas turbine system 52 using the control strategy of FIGS. 8 and 9. In particular, a top graph 342 of FIG. 10 represents the RGT exhaust or firing temperature 312 of the SEGR gas turbine system 52 during operation. A middle graph 344 of FIG. 10 represents the IGV angle 271, and a bottom graph 346 represents the BV pitch 263, as set by the controller 118. Furthermore, the set of graphs 340 illustrate four points in time, illustrated by lines 348, 350, 352, and 354, respectively, to facilitate discussion of changes to the these parameters of the SEGR gas turbine system 52 during operation.

[0092] As illustrated by top graph 342 of FIG. 10, during operation of the SEGR gas turbine system 52, the RGT exhaust or firing temperature 312 of the SEGR gas turbine system 52 initially is slowly increasing toward the RGT exhaust or firing temperature limit 314, for example, due to a fluctuation in fuel mixture or the RGT load. Additionally, as illustrated in middle graph 344, the IGV angle 271 may initially be maintained by the controller 118 at or above a particular set point angle or position 301 to provide the headspace 303 and to control the RGT exhaust or firing temperature 312. Furthermore, as illustrated in bottom graph 346, the BV pitch 263 may initially be relatively low since the IGV angle 271 is at or above (e.g., more open than) the set point angle or position 301.

[0093] As illustrated by top graph 342 of FIG. 10, at the time 348, the RGT exhaust or firing temperature 312 exceeds the RGT exhaust or firing temperature limit 314. In response, as illustrated by middle graph 344 at time 348, the controller 118 may adjust the IGV angle 271 such that it falls below the desired headspace 303 associated with a particular set point angle or position 301, as set forth above. Further, as illustrated by bottom graph 346 at time 348, when the controller 118 determines that the IGV angle 271 has fallen below the desired headspace 303 at time 348, the controller 118 may increase the BV pitch 263 in an attempt to bring the IGV angle 271 back to the set point angle and the desired headspace 303.

[0094] As illustrated by top graph 342, at time 350, in response to the altered IGV angle 271, as well as the altered BV pitch 263, the RGT exhaust or firing temperature 312 begins to stabilize. However, since the RGT exhaust or firing temperature 312 still exceeds the RGT exhaust or firing temperature limit 314, as illustrated by middle graph 344 at time 350, the IGV angle 271 may be decreased by the controller 118, allowing more exhaust gas into the exhaust compressor section 152 in an attempt to bring the RGT exhaust or firing temperature 312 back below the limit. Furthermore, as illustrated by bottom graph 346 at time 350, the controller 118 may also determine that the previous adjustment to the BV pitch 263 was not sufficient to bring the IGV angle 271 back to the set point angle or position 301 to provide the desired headspace 303, and, accordingly, may further augment the BV pitch 263 as illustrated.

[0095] As illustrated by top graph 342 at time 352, in response to the altered IGV angle 271, as well as the altered BV pitch 263, the RGT exhaust or firing temperature 312 falls below the RGT exhaust or firing temperature limit 314. As such, in middle graph 344 at time 352, the controller 118 may increase the IGV angle 271 toward the set point angle or position 301 to provide the desired headspace 303. However, since the IGV angle 271 is still below the set point angle or position 301 to provide the desired headspace 303, as illustrated by bottom graph 346 at time 352, the controller 118 may continue to increase the BV pitch 263 of the recycle blower 262.

[0096] As illustrated in top graph 342 at time 354, the cause for the temperature fluctuation has abated (e.g., the RGT load has decreased), and the RGT exhaust or firing temperature 312 continues to fall below the RGT exhaust or firing temperature limit 314. Furthermore, in graph 342 at time 354, the IGV angle 271 has been adjusted by the controller 118 back to the set point angle or position 301 to provide the desired headspace 303. Additionally, as illustrated by graph 344 at time 354, since the IGV angle 271 is at or above the set point angle, restoring the desired headspace 303, the controller 118 may reduce the BV pitch 263 to conserve power.

[0097] Technical effects of the present approach include improved responsiveness when controlling EGR gas turbine systems, such as SEGR gas turbine systems. In particular, the present approach enables a controller to control parameters of the

SEGR gas turbine system, such as the recycle gas turbine (RGT) exhaust or firing temperature, in a responsive manner by controlling various inputs (e.g., IGV angle and BV pitch) in a particular manner along the exhaust recirculation path. More specifically, in certain embodiments, the present approach enables the controller to adjust the BV pitch such that the IGVs of the recycle compressor maintain a particular headspace. Further, this IGV headspace enables the controller to use the more responsive input (e.g., the IGV angle) to control the RGT exhaust or firing temperature of SEGR gas turbine system during operation.

ADDITIONAL DESCRIPTION

[0098] As set forth above, the present embodiments provide systems and methods for using treated exhaust gas for temperature control, pressure control, humidity control, purging, clearance control, and/or sealing of various components of turbine-based service systems. It should be noted that any one or a combination of the features described above may be utilized in any suitable combination. Indeed, all permutations of such combinations are presently contemplated. By way of example, the following clauses are offered as further description of the present disclosure:

Embodiment 1. An exhaust gas recirculation (EGR) gas turbine system, comprising: an exhaust gas compressor positioned along an EGR path and configured to compress a recirculated exhaust gas to produce an exhaust gas diluent, wherein the exhaust gas compressor comprises an inlet section comprising a flow control element configured to modulate a flow of the recirculated exhaust gas into the exhaust gas compressor based on a position of the flow control element, wherein the position of the flow control element is capable of ranging from a maximum open position to a minimum open position; a recycle blower positioned along the EGR path and upstream of the exhaust gas compressor, wherein the recycle blower is configured to provide the flow of recirculated exhaust gas to the inlet section, wherein the flow of recirculated exhaust gas ranges from a minimum blower output to a maximum blower output; and a controller coupled to the flow control element and to the recycle blower, wherein the controller is configured to control the position of the flow control element based on a measured or modeled parameter of the EGR gas turbine system, wherein the controller is configured to control one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section based on the position of the flow control element.

Embodiment 2. The system of any preceding embodiment, wherein the flow control element comprises a plurality of inlet guide vanes.

Embodiment 3. The system of any preceding embodiment, wherein the controller is configured to control the one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section based on the position of the flow control element relative to the maximum open position.

Embodiment 4. The system of any preceding embodiment, wherein the measured or modeled parameter comprises an exhaust temperature, a firing temperature, or a combination thereof, of the EGR gas turbine system.

Embodiment 5. The system of any preceding embodiment, wherein the minimum open position is based on a stall limit of the exhaust gas compressor and a minimum open limit of the flow control element.

Embodiment 6. The system of any preceding embodiment, wherein the maximum open position is based on a maximum open limit of the flow control element.

Embodiment 7. The system of any preceding embodiment, wherein the minimum blower output is based on a stall limit of the recycle blower, a minimum pressure limit of the recycle blower, and a minimum pressure rise limit of the recycle blower.

Embodiment 8. The system of any preceding embodiment, wherein the maximum blower output is based on a maximum pressure limit at the inlet section.

Embodiment 9. The system of any preceding embodiment, wherein the recycle blower comprises a plurality of blower vanes, and wherein the one or more operational parameters comprise a pitch of the plurality of blower vanes.

Embodiment 10. The system of any preceding embodiment, wherein the one or more operational parameters comprise a rotational speed of the recycle blower, an amount of electrical power applied to the recycle blower, or a combination thereof.

Embodiment 11. The system of any preceding embodiment, wherein the controller is configured to control the one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section such that the position of the flow control element generally remains at a set point position.

Embodiment 12. The system of any preceding embodiment, wherein the set point position is greater than approximately 75% of a range from the minimum open position to the maximum open position.

Embodiment 13. The system of any preceding embodiment, wherein the set point position is greater than approximately 90% of a range from the minimum open position to the maximum open position.

Embodiment 14. The system of any preceding embodiment, wherein the set point position is approximately 95% of a range from the minimum open position to the maximum open position.

Embodiment 15. The system of any preceding embodiment, wherein the flow control element is configured by the controller to generally remain at the set point position until the flow of exhaust gas is set to the minimum blower output or the maximum blower output by the controller.

Embodiment 16. The system of any preceding embodiment, wherein the EGR gas turbine system is a stoichiometric exhaust gas recirculation (SEGR) gas turbine system.

Embodiment 17. The system of any preceding embodiment, comprising a turbine combustor configured to combust a fuel in the presence of an oxidant and the exhaust gas diluent at an equivalence ratio between approximately 0.95 and 1.05.

Embodiment 18. A method of controlling an exhaust gas recirculation (EGR) gas turbine system, comprising: adjusting an angle of a plurality of inlet guide vanes of an exhaust gas compressor of the EGR gas turbine system, wherein the plurality of inlet guide vanes have a first range of motion defined by a minimum angle and a maximum angle, and wherein the angle is adjusted based on one or more monitored or modeled parameters of the EGR gas turbine system; and adjusting a pitch of a plurality of blower vanes of a recycle blower disposed upstream of the exhaust gas compressor, wherein the plurality of blower vanes have a second range of motion defined by a minimum pitch and a maximum pitch, and the pitch of the plurality of blower vanes is adjusted based at least on the angle of the plurality of inlet guide vanes.

Embodiment 19. The method of any preceding embodiment, wherein adjusting the pitch of the plurality of blower vanes comprises adjusting the pitch of the plurality of blower vanes based on the angle of the plurality of inlet guide vanes relative to the minimum angle of the plurality of inlet guide vanes.

Embodiment 20. The method of any preceding embodiment, wherein the plurality of parameters comprise an exhaust temperature, a firing temperature of the EGR gas turbine system, or a combination thereof.

Embodiment 21. The method of any preceding embodiment, wherein the pitch of the plurality of blower vanes is adjusted based, at least in part, on a stall limit of the recycle blower, a minimum pressure limit of the recycle blower, and a minimum pressure rise limit of the recycle blower.

Embodiment 22. The method of any preceding embodiment, wherein adjusting the pitch comprises adjusting the pitch to enable the angle of the plurality of inlet guide vanes to substantially remain at a set point angle.

Embodiment 23. The method of any preceding embodiment, wherein the set point angle is less than approximately 20% of the second range of motion of the plurality of inlet guide vanes from the minimum angle to the maximum angle of the plurality of inlet guide vanes.

Embodiment 24. The method of any preceding embodiment, wherein the set point angle is approximately 5% of the range of motion of the plurality of inlet guide vanes from the minimum angle to the maximum angle of the plurality of inlet guide vanes.

Embodiment 25. The method of any preceding embodiment, comprising generally maintaining the angle of the plurality of inlet guide vanes at the set point angle until after the pitch of the plurality of blower vanes has been adjusted to the minimum pitch or the maximum pitch.

Embodiment 26. The method of any preceding embodiment, wherein the EGR gas turbine system is a stoichiometric exhaust gas recirculation (SEGR) gas turbine system.

Embodiment 27. A non-transitory, computer-readable medium storing instructions executable by a processor of an electronic device, the instructions comprising: instructions to adjust an angle of a plurality of inlet guide vanes of a compressor section of a gas turbine system based on one or more modeled or measured parameters of the gas turbine system, wherein the angle ranges from a minimum angle to a maximum angle; and instructions to adjust a pitch of a plurality of blower vanes of a blower fluidly coupled to an inlet of the compressor section, wherein the pitch ranges from a minimum pitch to a maximum pitch, wherein the pitch is adjusted based on the angle of the plurality of inlet guide vanes relative to the minimum angle.

Embodiment 28. The medium of any preceding embodiment, wherein the instructions adjust the pitch of the plurality of blower vanes to maintain a headspace between the angle of the plurality of inlet guide vanes and the minimum angle.

Embodiment 29. The medium of any preceding embodiment, wherein the headspace is less than or equal to approximately 10% of the range of the angle of the plurality of inlet guide vanes.

Embodiment 30. The medium of any preceding embodiment, wherein the headspace is less than or equal to approximately 5% of the range of the angle of the plurality of inlet guide vanes.

Embodiment 31. The medium of any preceding embodiment, wherein the compressor section is a recycle compressor section and the blower is a recycle blower of an exhaust gas recirculation (EGR) turbine system.

Embodiment 32. The medium of any preceding embodiment, wherein the gas turbine system is a stoichiometric exhaust gas recirculation (SEGR) gas turbine system.

[0099] While only certain features of the invention have been illustrated and described herein, many modifications and changes will occur to those skilled in the art. It is, therefore, to be understood that the appended claims are intended to cover all such modifications and changes as fall within the true spirit of the invention.

CLAIMS:

1. An exhaust gas recirculation (EGR) gas turbine system, comprising:

an exhaust gas compressor positioned along an EGR path and configured to compress a recirculated exhaust gas to produce an exhaust gas diluent, wherein the exhaust gas compressor comprises an inlet section comprising a flow control element configured to modulate a flow of the recirculated exhaust gas into the exhaust gas compressor based on a position of the flow control element, wherein the position of the flow control element is capable of ranging from a maximum open position to a minimum open position;

a recycle blower positioned along the EGR path and upstream of the exhaust gas compressor, wherein the recycle blower is configured to provide the flow of recirculated exhaust gas to the inlet section, wherein the flow of recirculated exhaust gas ranges from a minimum blower output to a maximum blower output; and

a controller coupled to the flow control element and to the recycle blower, wherein the controller is configured to control the position of the flow control element based on a measured or modeled parameter of the EGR gas turbine system, wherein the controller is configured to control one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section based on the position of the flow control element.

2. The EGR gas turbine system of claim 1, wherein the flow control element comprises a plurality of inlet guide vanes.

3. The EGR gas turbine system of claim 1, wherein the controller is configured to control the one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section based on the position of the flow control element relative to the maximum open position.

4. The EGR gas turbine system of claim 1, wherein the measured or modeled parameter comprises an exhaust temperature, a firing temperature, or a combination thereof, of the EGR gas turbine system.

5. The EGR gas turbine system of claim 1, wherein the minimum open position is based on a stall limit of the exhaust gas compressor and a minimum open limit of the flow control element, and wherein the maximum open position is based on a maximum open limit of the flow control element.

6. The EGR gas turbine system of claim 1, wherein the minimum blower output is based on a stall limit of the recycle blower, a minimum pressure limit of the recycle blower, and a minimum pressure rise limit of the recycle blower, and wherein the maximum blower output is based on a maximum pressure limit at the inlet section.

7. The EGR gas turbine system of claim 1, wherein the recycle blower comprises a plurality of blower vanes, and wherein the one or more operational parameters comprise a pitch of the plurality of blower vanes, rotational speed of the recycle blower, an amount of electrical power applied to the recycle blower, or a combination thereof.

8. The EGR gas turbine system of claim 1, comprising a turbine combustor configured to combust a fuel in the presence of an oxidant and the exhaust gas diluent at an equivalence ratio between approximately 0.95 and 1.05.

9. The EGR gas turbine system of claim 1, wherein the controller is configured to control the one or more operational parameters of the recycle blower to control the flow of recirculated exhaust gas to the inlet section such that the position of the flow control element generally remains at a set point position.

10. The EGR gas turbine system of claim 9, wherein the flow control element is configured by the controller to generally remain at the set point position until the flow of exhaust gas is set to the minimum blower output or the maximum blower output by the controller.

11. The EGR gas turbine system of claim 9, wherein the set point position is greater than approximately 75% of a range from the minimum open position to the maximum open position.

12. The EGR gas turbine system of claim 9, wherein the set point position is greater than approximately 90% of a range from the minimum open position to the maximum open position.

13. A method of controlling an exhaust gas recirculation (EGR) gas turbine system, comprising:

adjusting an angle of a plurality of inlet guide vanes of an exhaust gas compressor of the EGR gas turbine system, wherein the plurality of inlet guide vanes have a first range of motion defined by a minimum angle and a maximum angle, and wherein the angle is adjusted based on one or more monitored or modeled parameters of the EGR gas turbine system; and

adjusting a pitch of a plurality of blower vanes of a recycle blower disposed upstream of the exhaust gas compressor, wherein the plurality of blower vanes have a second range of motion defined by a minimum pitch and a maximum pitch, and the pitch of the plurality of blower vanes is adjusted based at least on the angle of the plurality of inlet guide vanes.

14. The method of claim 13, wherein adjusting the pitch of the plurality of blower vanes comprises adjusting the pitch of the plurality of blower vanes based on the angle of the plurality of inlet guide vanes relative to the minimum angle of the plurality of inlet guide vanes.

15. The method of claim 13, wherein the plurality of parameters comprise an exhaust temperature, a firing temperature of the EGR gas turbine system, or a combination thereof.

16. The method of claim 13, wherein the pitch of the plurality of blower vanes is adjusted based, at least in part, on a stall limit of the recycle blower, a

minimum pressure limit of the recycle blower, and a minimum pressure rise limit of the recycle blower.

17. The method of claim 13, wherein adjusting the pitch comprises adjusting the pitch to enable the angle of the plurality of inlet guide vanes to substantially remain at a set point angle.

18. The method of claim 17, wherein the set point angle is less than approximately 20% of the second range of motion of the plurality of inlet guide vanes from the minimum angle to the maximum angle of the plurality of inlet guide vanes.

19. The method of claim 17, wherein the set point angle is approximately 5% of the range of motion of the plurality of inlet guide vanes from the minimum angle to the maximum angle of the plurality of inlet guide vanes.

20. The method of claim 17, comprising generally maintaining the angle of the plurality of inlet guide vanes at the set point angle until after the pitch of the plurality of blower vanes has been adjusted to the minimum pitch or the maximum pitch.

21. A non-transitory, computer-readable medium storing instructions executable by a processor of an electronic device, the instructions comprising:

instructions to adjust an angle of a plurality of inlet guide vanes of a compressor section of a gas turbine system based on one or more modeled or measured parameters of the gas turbine system, wherein the angle ranges from a minimum angle to a maximum angle; and

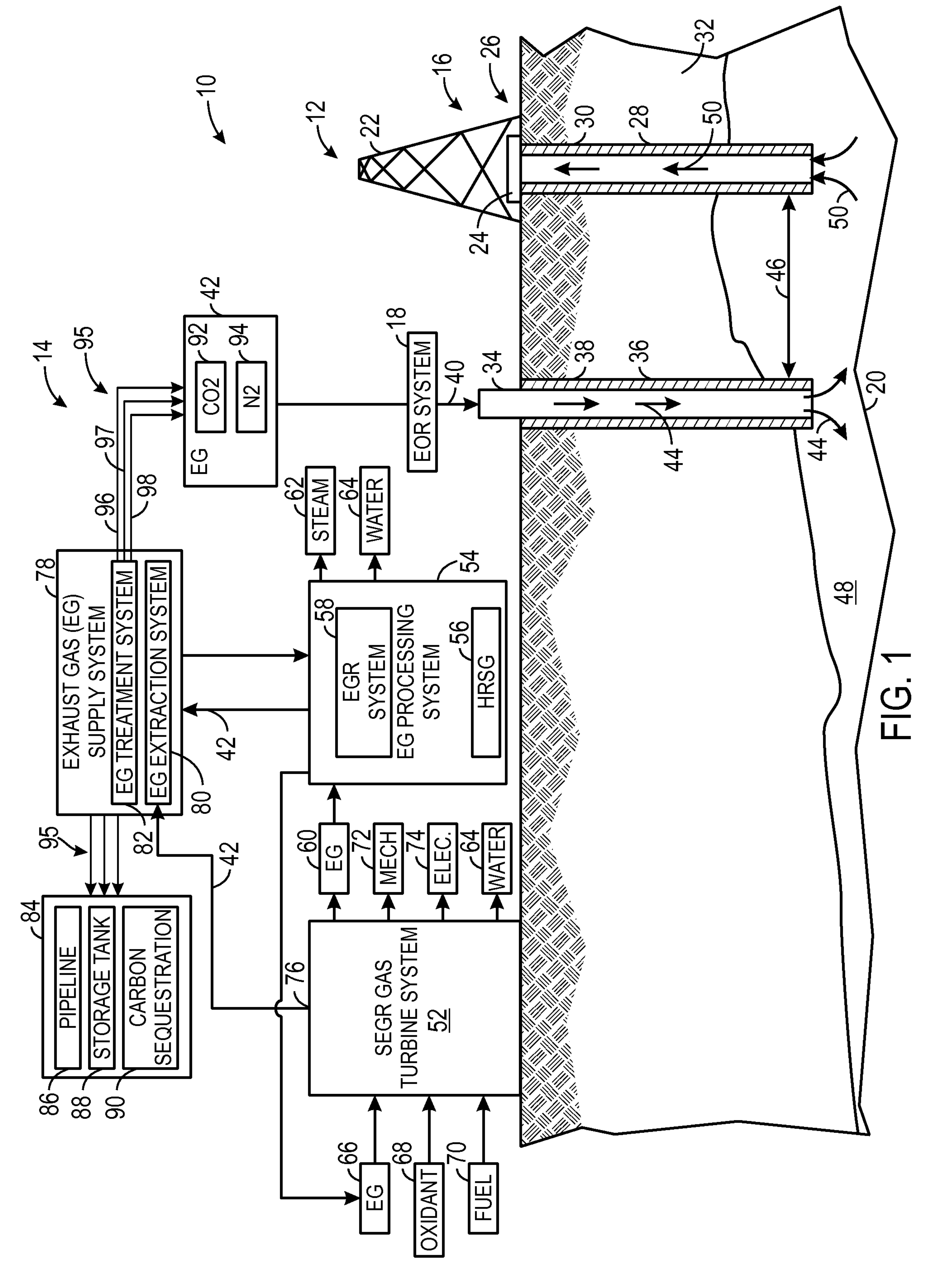
instructions to adjust a pitch of a plurality of blower vanes of a blower fluidly coupled to an inlet of the compressor section, wherein the pitch ranges from a minimum pitch to a maximum pitch, wherein the pitch is adjusted based on the angle of the plurality of inlet guide vanes relative to the minimum angle.

22. The medium of claim 21, wherein the compressor section is a recycle compressor section and the blower is a recycle blower of an exhaust gas recirculation (EGR) turbine system.

23. The medium of claim 21, wherein the instructions adjust the pitch of the plurality of blower vanes to maintain a headspace between the angle of the plurality of inlet guide vanes and the minimum angle.

24. The medium of claim 23, wherein the headspace is less than or equal to approximately 10% of the range of the angle of the plurality of inlet guide vanes.

25. The medium of claim 23, wherein the headspace is less than or equal to approximately 5% of the range of the angle of the plurality of inlet guide vanes.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CO2
N2
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48
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52
SEGR GAS TURBINE SYSTEM
54
EG PROCESSING SYSTEM
56
HRSG
58
EGR SYSTEM
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EG
62
STEAM
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WATER
66
EG
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OXIDANT
70
FUEL
72
MECH
74
ELEC.
76
78
EXHAUST GAS (EG) SUPPLY SYSTEM
80
EG EXTRACTION SYSTEM
82
EG TREATMENT SYSTEM
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PIPELINE
88
STORAGE TANK
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CARBON SEQUESTRATION
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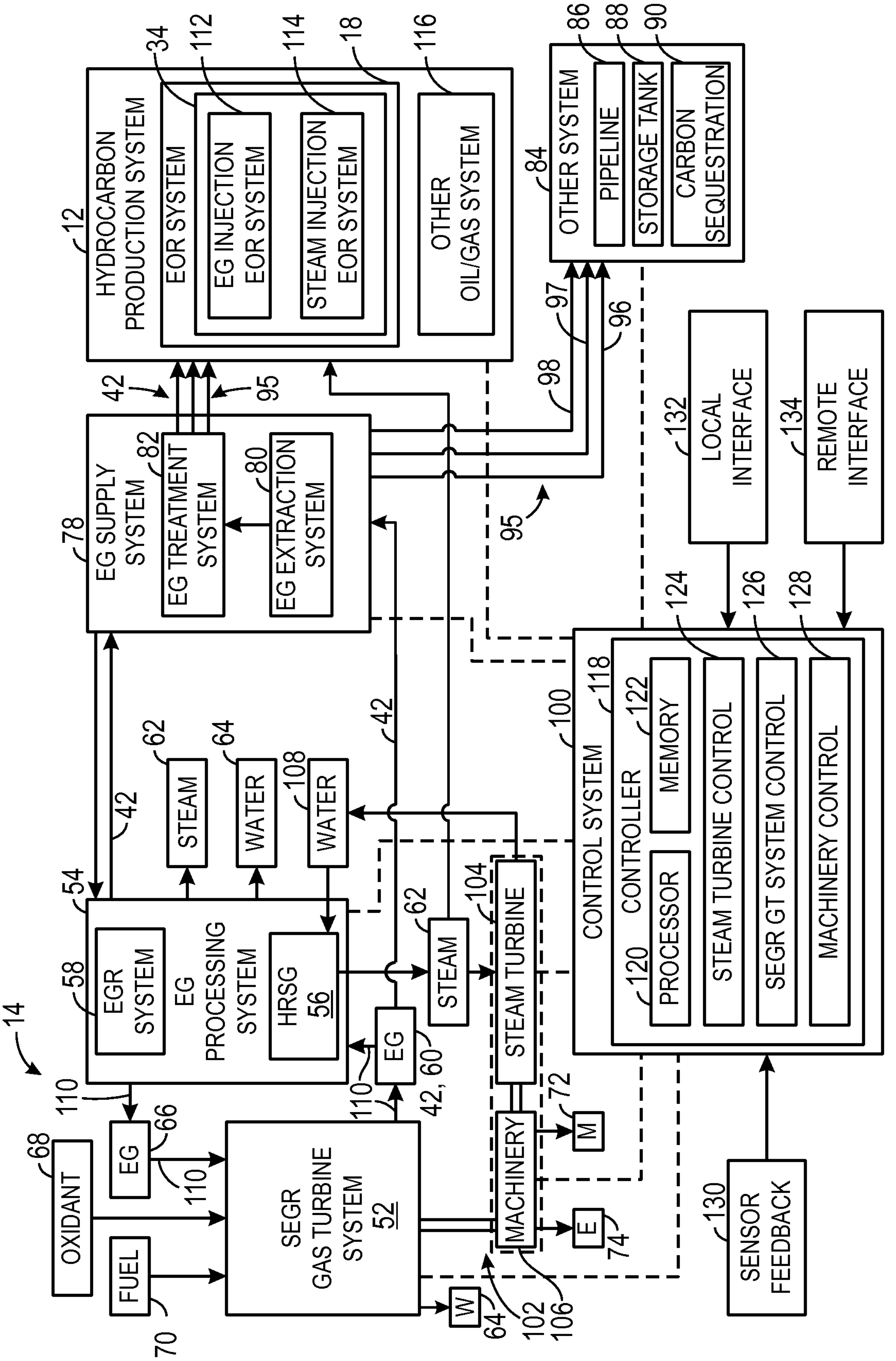
FIG. 1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EG INJECTION EOR SYSTEM
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OTHER OIL/GAS SYSTEM
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EG SUPPLY SYSTEM
EG TREATMENT SYSTEM
EG EXTRACTION SYSTEM
LOCAL INTERFACE
REMOTE INTERFACE
STEAM
WATER
WATER
EGR SYSTEM
EG PROCESSING SYSTEM
HRSG 56
EG
STEAM
STEAM TURBINE
CONTROL SYSTEM
CONTROLLER
MEMORY
PROCESSOR
STEAM TURBINE CONTROL
SEGR GT SYSTEM CONTROL
MACHINERY CONTROL
OXIDANT
FUEL
EG
SEGR GAS TURBINE SYSTEM 52
MACHINERY
M
E
W
SENSOR FEEDBACK
12
34
112
114
18
116
84
86
88
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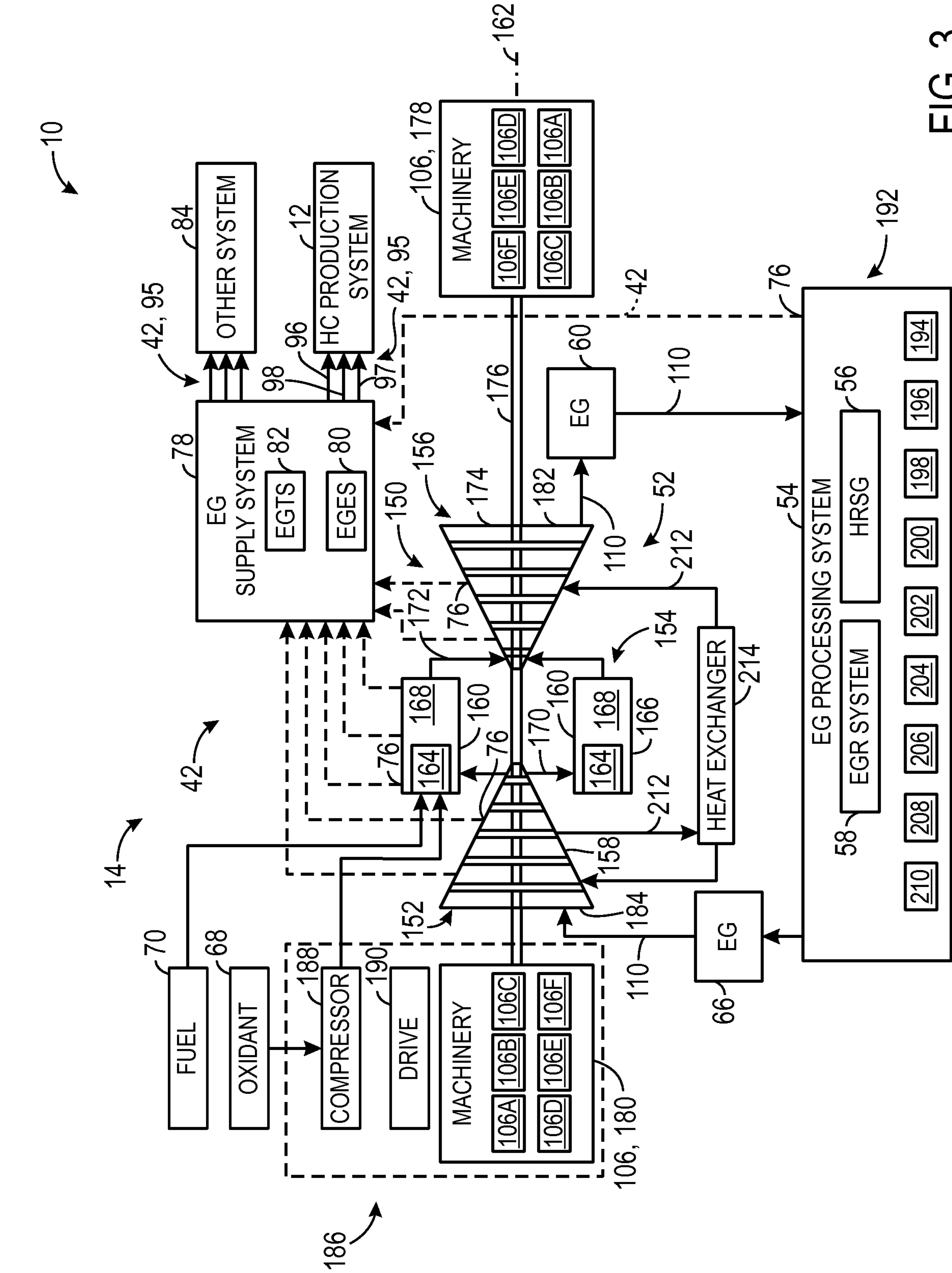
FIG. 2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MACHINERY
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106E
106D
106C
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106A
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EG
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212
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42
160
168
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170
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HEAT EXCHANGER
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FUEL
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OXIDANT
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COMPRESSOR
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DRIVE
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MACHINERY
106, 180
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EG
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HRSG
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EGR SYSTEM
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FIG. 3

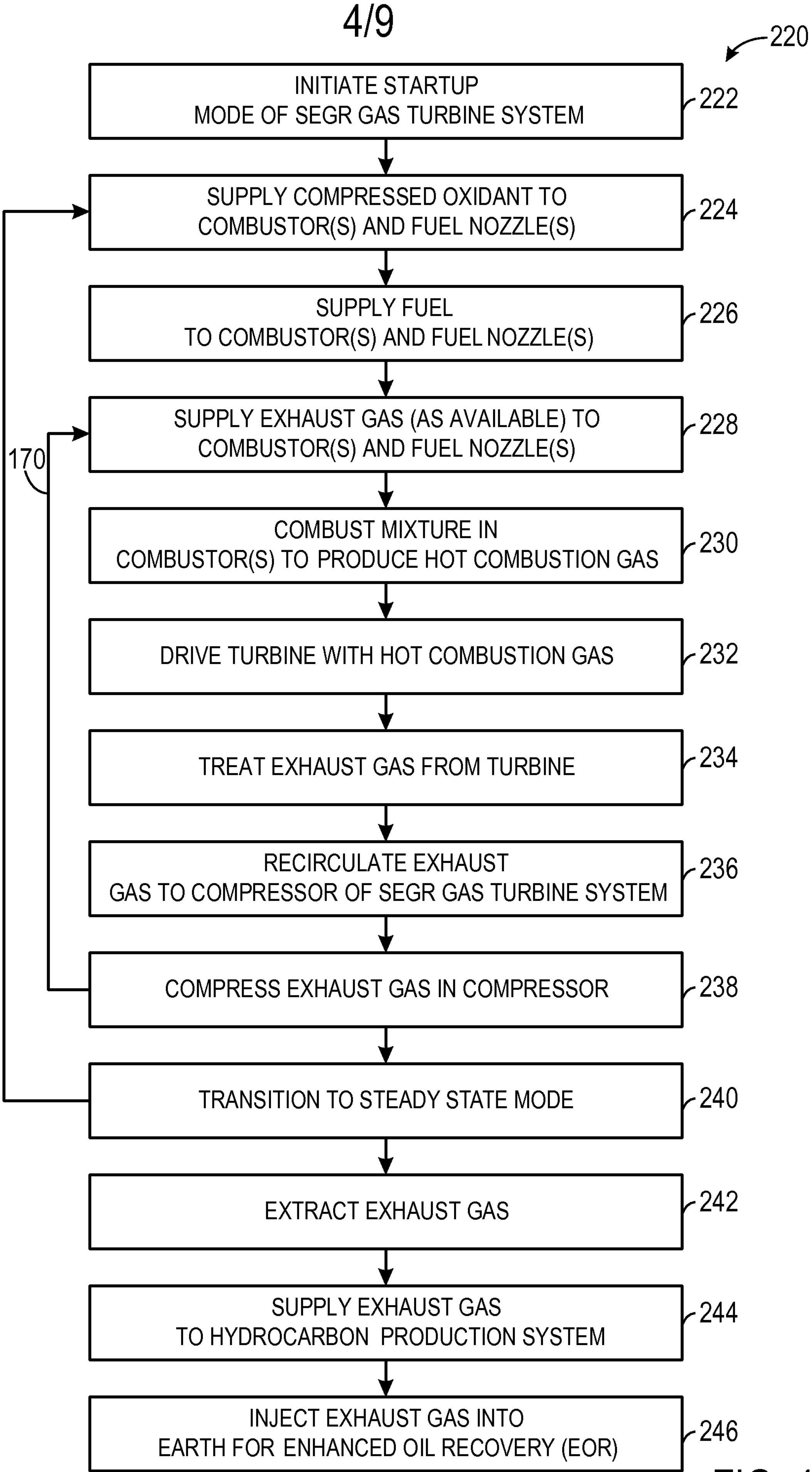
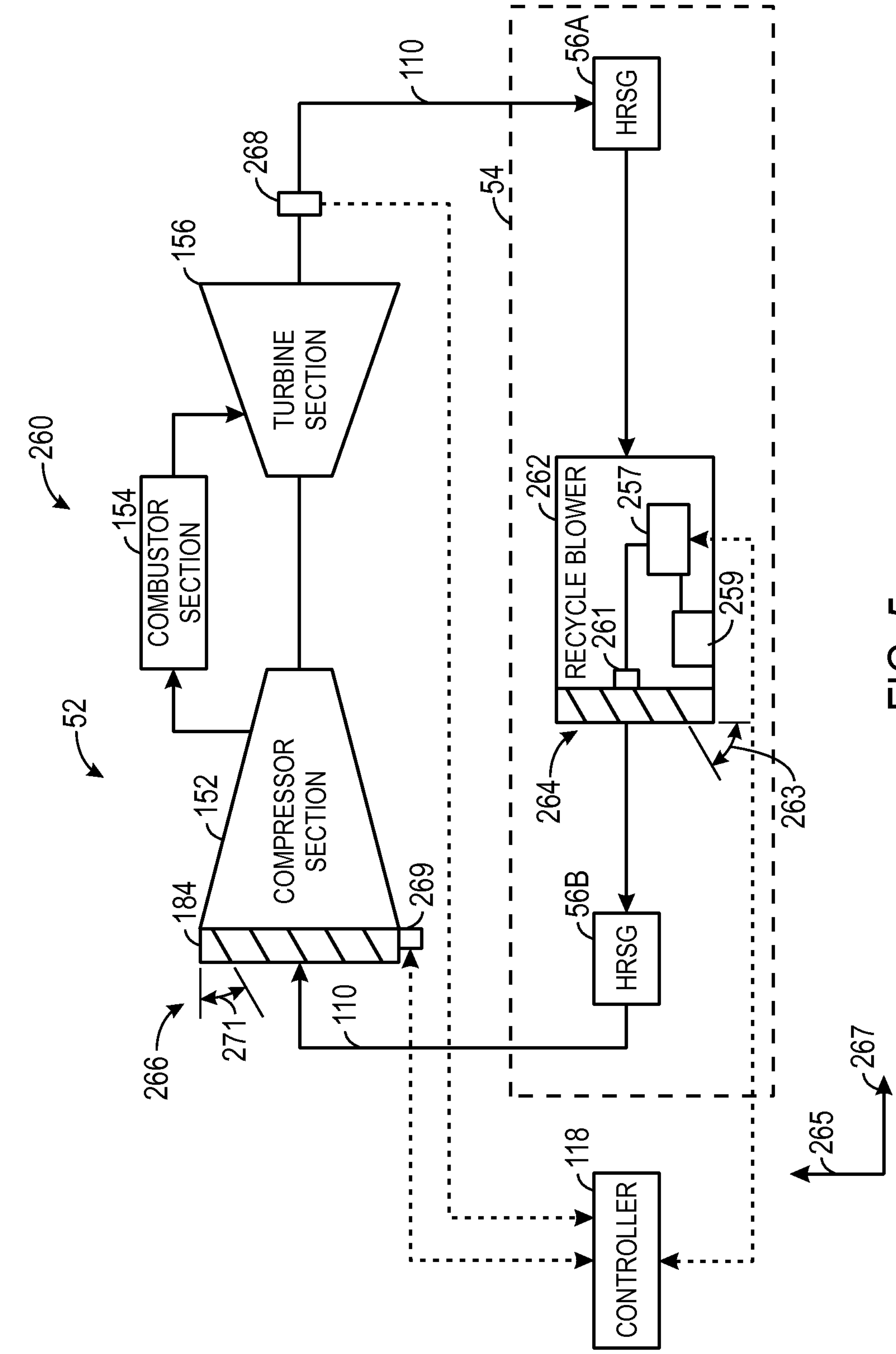

220
INITIATE STARTUP MODE OF SEGR GAS TURBINE SYSTEM
222
SUPPLY COMPRESSED OXIDANT TO COMBUSTOR(S) AND FUEL NOZZLE(S)
224
SUPPLY FUEL TO COMBUSTOR(S) AND FUEL NOZZLE(S)
226
SUPPLY EXHAUST GAS (AS AVAILABLE) TO COMBUSTOR(S) AND FUEL NOZZLE(S)
228
170
COMBUST MIXTURE IN COMBUSTOR(S) TO PRODUCE HOT COMBUSTION GAS
230
DRIVE TURBINE WITH HOT COMBUSTION GAS
232
TREAT EXHAUST GAS FROM TURBINE
234
RECIRCULATE EXHAUST GAS TO COMPRESSOR OF SEGR GAS TURBINE SYSTEM
236
COMPRESS EXHAUST GAS IN COMPRESSOR
238
TRANSITION TO STEADY STATE MODE
240
EXTRACT EXHAUST GAS
242
SUPPLY EXHAUST GAS TO HYDROCARBON PRODUCTION SYSTEM
244
INJECT EXHAUST GAS INTO EARTH FOR ENHANCED OIL RECOVERY (EOR)
246

FIG. 4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52
COMBUSTOR SECTION
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TURBINE SECTION
156
COMPRESSOR SECTION
152
184
269
266
271
110
268
110
54
56A
HRSG
262
RECYCLE BLOWER
257
259
261
264
263
56B
HRSG
118
CONTROLLER
265
267

FIG. 5

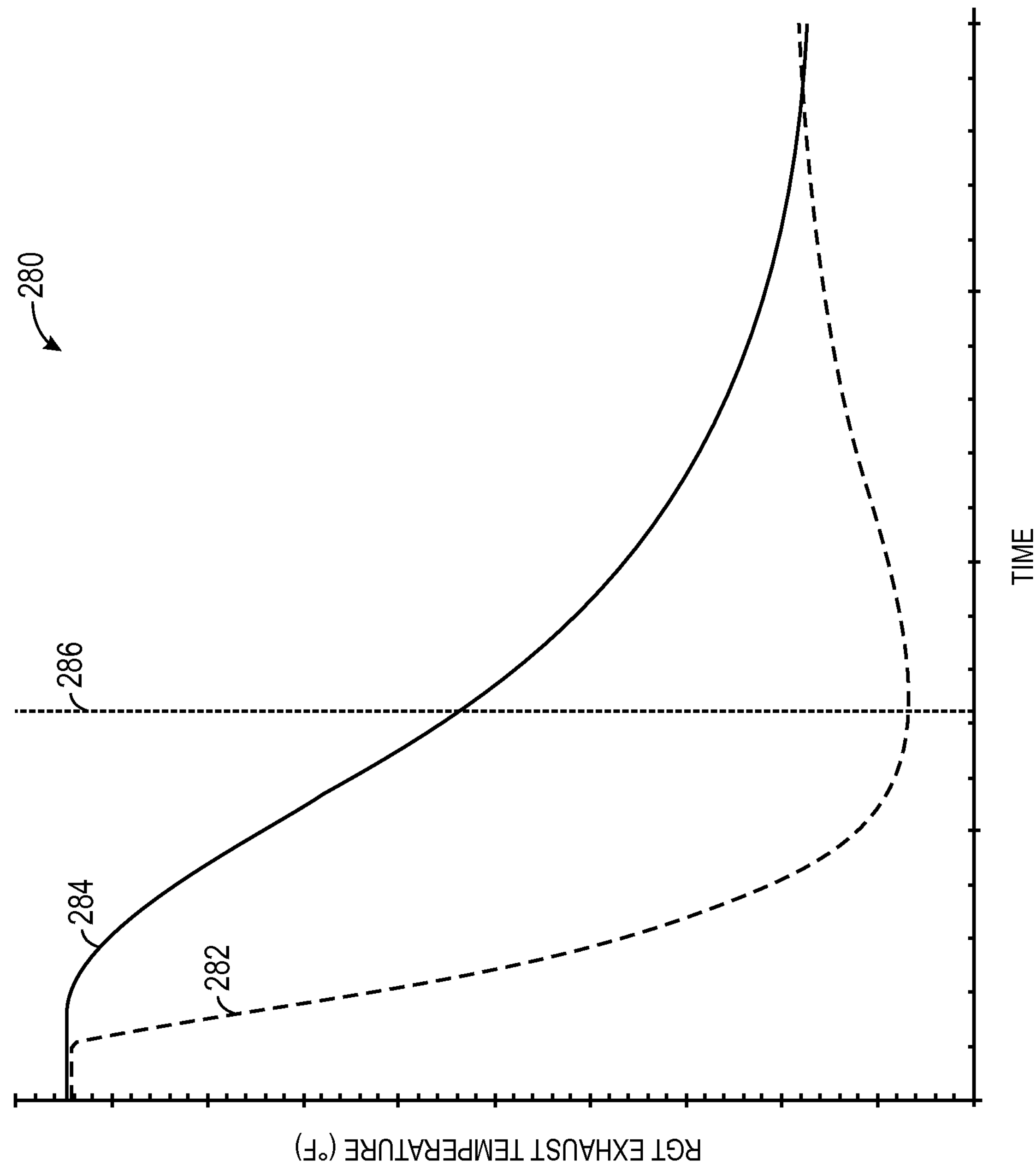
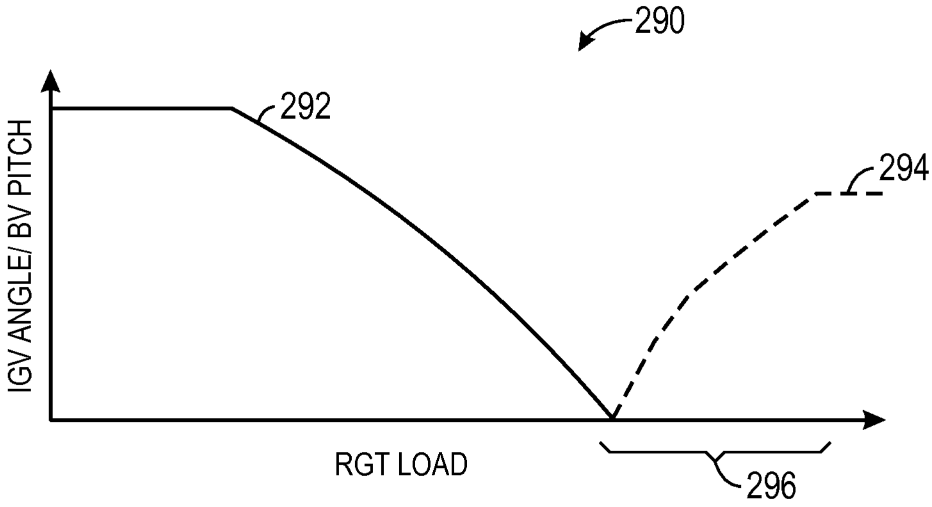


FIG. 6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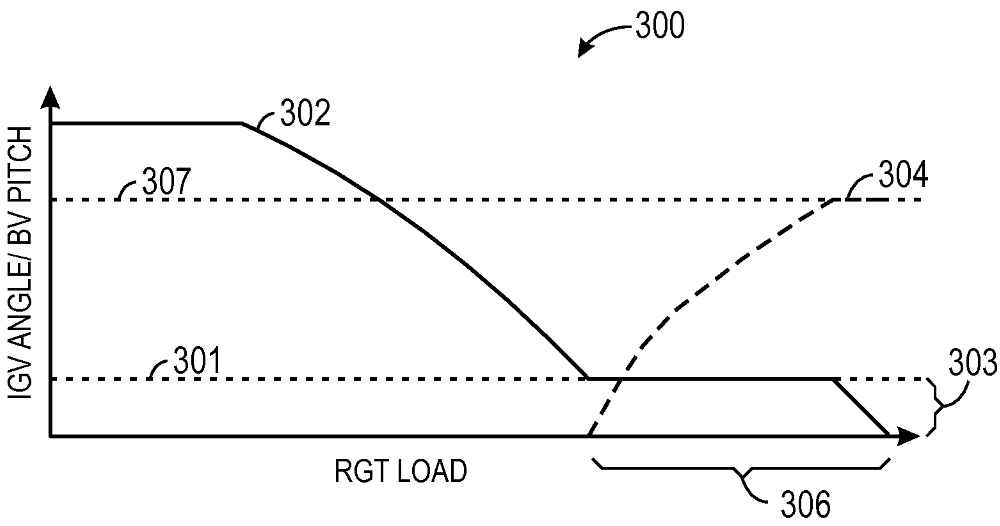
IGV ANGLE/ BV PITCH
RGT LOAD
296

FIG. 7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301
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IGV ANGLE/ BV PITCH
RGT LOAD
306

FIG. 8

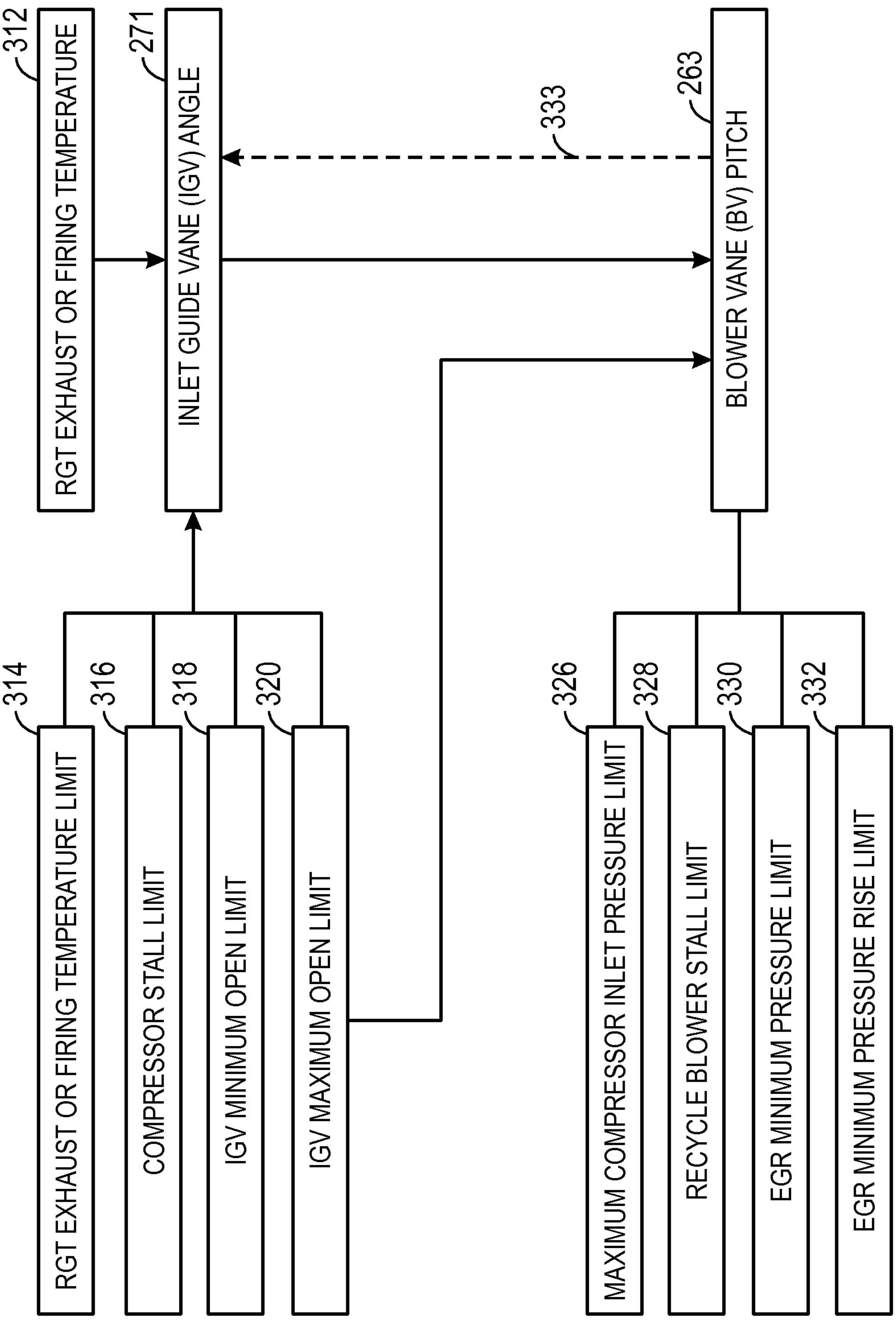
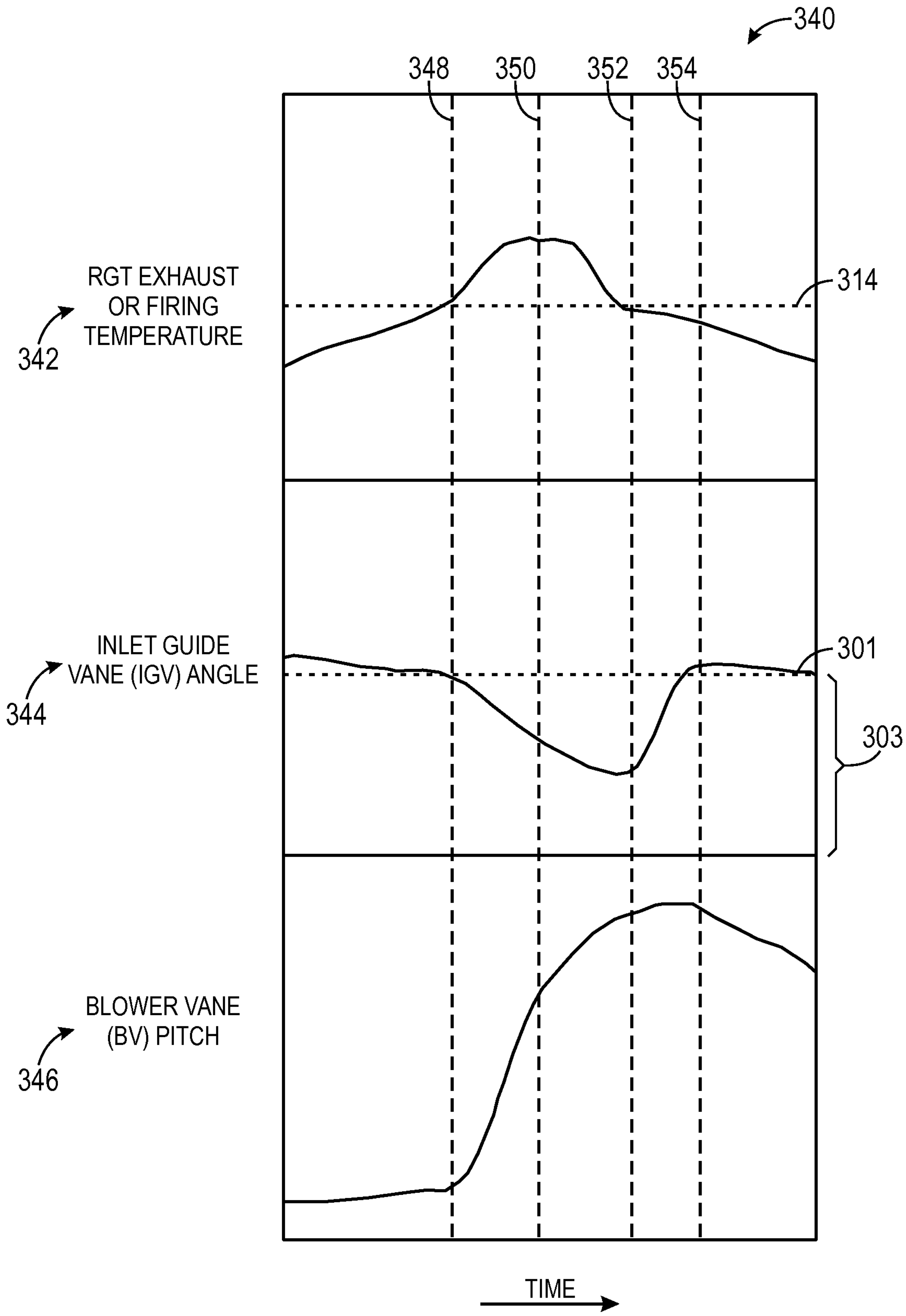

312
RGT EXHAUST OR FIRING TEMPERATURE
271
INLET GUIDE VANE (IGV) ANGLE
333
263
BLOWER VANE (BV) PITCH
314
RGT EXHAUST OR FIRING TEMPERATURE LIMIT
316
COMPRESSOR STALL LIMIT
318
IGV MINIMUM OPEN LIMIT
320
IGV MAXIMUM OPEN LIMIT
326
MAXIMUM COMPRESSOR INLET PRESSURE LIMIT
328
RECYCLE BLOWER STALL LIMIT
330
EGR MINIMUM PRESSURE LIMIT
332
EGR MINIMUM PRESSURE RISE LIMIT

FIG. 9



340
348
350
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354
RGT EXHAUST OR FIRING TEMPERATURE
342
314
INLET GUIDE VANE (IGV) ANGLE
344
301
303
BLOWER VANE (BV) PITCH
346
TIME

FIG. 10

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2014/043971

A. CLASSIFICATION OF SUBJECT MATTER
INV. F02C3/34 F02C6/18 F02C1/08 F01D17/14 F02C7/042
F02C7/057 F02C9/20 F02C1/06 F02C9/22 F02C9/54
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
F02C F01D F02B

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

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

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	EP 2 597 288 A2 (GEN ELECTRIC [US]) 29 May 2013 (2013-05-29)	1-12
Y	paragraphs [0022] - [0028] paragraphs [0032] - [0054] figures	13-25
X	US 5 771 868 A (KHAIR MAGDI K [US]) 30 June 1998 (1998-06-30)	1-12
Y	column 4, line 24 - column 6, line 52 figures	13-25
X	US 2010/058758 A1 (GILCHRIST III GEORGE MARTIN [US] ET AL) 11 March 2010 (2010-03-11) abstract paragraphs [0031] - [0093] figures	1-12

-/--

[X] Further documents are listed in the continuation of Box C.

[X] See patent family annex.

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
10 October 2014	17/10/2014

Name and mailing address of the ISA/
European Patent Office, P.B. 5818 Patentlaan 2
NL - 2280 HV Rijswijk
Tel. (+31-70) 340-2040,
Fax: (+31-70) 340-3016

Authorized officer
Rini, Pietro

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2014/043971

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

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X	US 2012/023946 A1 (ERNST TIMOTHY C [US] ET AL) 2 February 2012 (2012-02-02) paragraphs [0005] - [0007] paragraphs [0012] - [0039] figures	1,3-6, 8-12
X	WO 2012/018458 A1 (EXXONMOBIL UPSTREAM RES CO [US]; MITTRICKER FRANKLIN F [US]; HUNTINGTO) 9 February 2012 (2012-02-09) paragraphs [0031] - [0093] figures	1-12
X	EP 2 584 166 A1 (ALSTOM TECHNOLOGY LTD [CH]) 24 April 2013 (2013-04-24) paragraphs [0012] - [0080] figures	1-12
A	DE 34 25 115 A1 (GASPAROVIC NEBOJSA PROF DR ING) 16 January 1986 (1986-01-16) abstract figures	1-25

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/US2014/043971

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