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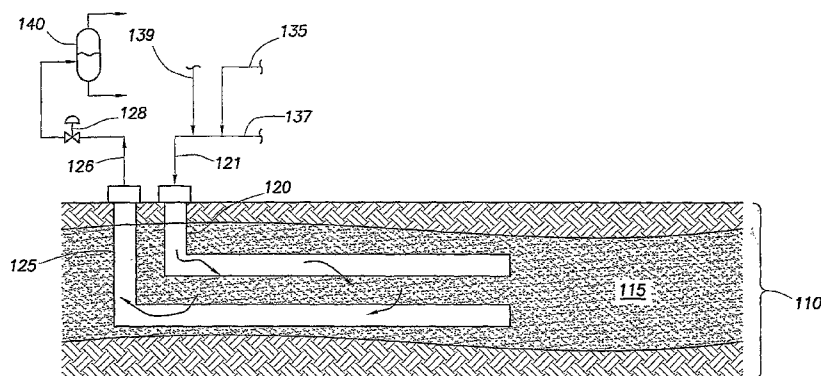


FIG. 1

(57) Abstract: Methods enhance hydrocarbon recovery through gas production control for noncondensable gases in SAGD or ES-SAGD. Steam injected into one or more injection wells heats the hydrocarbons and reduces their viscosity to more easily produce the hydrocarbons. A noncondensable gas may be injected into the injection wells to reduce the steam-to-oil ratio, improving economic recovery. Excessive production of noncondensable gases can adversely suppress hydrocarbon production rates. To counteract this problem, gas production rates may be controlled by limiting the produced gas-to-water ratio. The noncondensable gas may comprise a combustion gas such as flue gas. Advantages include higher efficiencies, lower costs, reduced hydrocarbon extraction time, and in some embodiments, reduced greenhouse gas emissions.

HYDROCARBON RECOVERY THROUGH GAS PRODUCTION CONTROL FOR NONCONDENSABLE SOLVENTS OR GASES

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application is a non-provisional application which claims benefit under 35 USC §119(e) to U.S. Provisional Application Serial No. 61/494,226 filed June 7, 2011, entitled "ENHANCED HYDROCARBON RECOVERY THROUGH GAS PRODUCTION CONTROL FOR NONCONDENSABLE SOLVENTS OR GASES IN SAGD OR ES-SAGD OPERATIONS," which is incorporated herein in its entirety.

FIELD OF THE INVENTION

[0002] The present invention relates generally to methods and systems for enhancing hydrocarbon recovery through gas production control for noncondensable solvents or gases in SAGD or ES-SAGD operations.

BACKGROUND

[0003] Effective production of low mobility reservoirs such as heavy oil and bitumen reservoirs presents significant challenges and thus requires sophisticated technologies to produce hydrocarbons efficiently from these types of reservoirs. These difficulties are due to the complex nature of these types of reservoirs and the low oil mobility at initial reservoir conditions.

[0004] Low mobility reservoirs are characterized by high viscosity hydrocarbons, low permeability formations, and/or low driving forces. Extraction of high viscosity hydrocarbons is typically difficult due to the relative immobility of the high viscosity hydrocarbons. For example, some heavy crude oils, such as bitumen, are highly viscous and therefore immobile at the initial viscosity of the oil at reservoir temperature and pressure. Indeed, such heavy oils may be quite thick and have a consistency similar to that of peanut butter or heavy tars, making their extraction from reservoirs especially challenging.

[0005] Conventional approaches to recovering such heavy oils often focus on methods for lowering the viscosity of the heavy oil so that the heavy oil may be produced from the reservoir, such as heating the reservoir to lower the viscosity of the heavy oil. Commonly used in-situ extraction thermal recovery techniques include a number of

reservoir heating methods, such as steam flooding, cyclic steam stimulation, and Steam Assisted Gravity Drainage (SAGD). SAGD is an enhanced oil recovery technology for producing heavy crude oil and bitumen. It is an advanced form of steam stimulation in which a pair of two superposed, vertically separated horizontal wells is drilled into an oil reservoir, one a few meters above the other, close to the bottom of an oil bearing sand. Steam is continuously injected into the upper wellbore to provide a driving force and simultaneously heat the oil and reduce its viscosity, causing the heated oil to drain under the action of gravity into the lower wellbore, where the oil is then pumped out. This technique has been successfully applied in the field, particularly in Canada, on a commercial scale in the last ten years.

[0006] Steam injection processes, however, are energy and water intensive processes due to the fact that the reservoir rock and fluids must be heated to high temperatures and a significant portion of injected energy is lost to the surrounding overburden and underburden formations. These factors significantly reduce the thermal efficiency of the process and can result in uneconomic production of the hydrocarbons. Generally, approximately 2.5 barrels of water is converted to steam to produce one barrel of oil. In addition, steam generation requires burning of fuel such as natural gas that results in green house gas emissions.

[0007] Solvent injection processes, on the other hand, present other challenges. While solvent injection processes typically require less energy as compared to steam injection processes, the solvent injection processes generally require large volumes of expensive solvent and result in significant, costly solvent loss in the reservoir. These costly solvent losses often render solvent injection process economically disadvantageous.

[0008] Low driving forces can also adversely affect hydrocarbon recovery. Where sufficient reservoir pressure is lacking to motivate hydrocarbons to the surface, hydrocarbon production rates may be limited to an economically unpractical production flow rate. Secondary recovery operations are sometimes used to motivate hydrocarbons suffering from low driving forces toward a production well. One example of a secondary recovery is the use of steam flooding to sweep hydrocarbons toward a production well.

Steam flooding involves the use of injected steam to heat and physically displace hydrocarbons to encourage production of the hydrocarbons.

[0009] Unfortunately, each of these conventional techniques suffers from poor inefficiencies including high steam to oil ratios and high solvent losses. Accordingly, there is a need for more efficient enhanced recovery methods for recovering heavy oils from low mobility reservoirs that address one or more of the disadvantages of the prior art.

SUMMARY

[0010] The present invention relates generally to methods and systems for enhancing hydrocarbon recovery through gas production control for noncondensable solvents or gases in SAGD or ES-SAGD operations.

[0011] One example of a method for enhancing recovery of bitumen or heavy oil from a low mobility reservoir comprises the steps of: providing one or more injection wells wherein the one or more injection wells intersect the heavy oil reservoir; providing one or more production wells wherein the one or more production wells intersect the heavy oil reservoir; wherein the one or more injection wells and the one or more production wells are paired to form a SAGD or ES-SAGD process; producing steam via a steam generator wherein flue gas is produced as a byproduct of the steam generator; introducing the steam into one of the one or more injection wells; introducing the flue gas into one of the one or more injection wells; allowing a production flow to be produced from the one or more production wells wherein the production flow comprises a production gas flow and a production water flow; determining a production gas-to-water ratio as a ratio of the production gas flow to the production water flow; and limiting the production flow to obtain a production gas-to-water ratio in the production flow from about 1 to about 30.

[0012] One example of a method for enhancing recovery of bitumen or heavy oil from a low mobility reservoir comprises the steps of: providing an injection well wherein the injection well extends into the heavy oil reservoir via an upper horizontal well; providing a production well wherein the production well extends into the heavy oil reservoir via a lower horizontal well; continuously introducing steam and a non-condensable gas into the injection well; allowing a production flow to be produced from the production well wherein the production flow comprises a gas flow and a water flow; determining a production gas-to-water ratio as a ratio of the production gas flow to the production water flow; and limiting the production flow to obtain a production gas-to-water ratio from about 1 to about 10.

[0013] The features and advantages of the present invention will be apparent to those skilled in the art. While numerous changes may be made by those skilled in the art, such changes are within the spirit of the invention.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] A more complete understanding of the present disclosure and advantages thereof may be acquired by referring to the following description taken in conjunction with the accompanying figures, wherein:

[0015] Figure 1 illustrates an example of an enhanced heavy oil recovery system in accordance with one embodiment of the present invention.

[0016] Figure 2 illustrates another example of an enhanced heavy oil recovery system incorporating a direct steam generator.

[0017] Figure 3 shows a graph of monthly average water injection rate as a function of time comparing the cases of uncontrolled gas production and controlled gas production.

[0018] Figure 4 shows a graph of injection pressure versus time comparing the cases of uncontrolled gas production and controlled gas production.

[0019] Figure 5 shows a graph of monthly averages of gas-to-water ratios (GWR) versus time comparing the cases of uncontrolled gas production and controlled gas production.

[0020] Figure 6 shows a graph of cumulative oil production versus time comparing the cases of uncontrolled gas production and controlled gas production.

[0021] Figure 7 shows a graph of cumulative steam-to-oil ratio (SOR) versus time comparing the cases of uncontrolled gas production and controlled gas production.

[0022] Figure 8A, 8B, and 8C show a series of performance comparisons. Figure 8A shows a comparison of cumulative SOR. Figure 8B shows a comparison of reduction in percent SAGD SOR. Figure 8C shows a comparison of percent increase in SAGD cumulative oil.

[0023] While the present invention is susceptible to various modifications and alternative forms, specific exemplary embodiments thereof have been shown by way of example in the drawings and are herein described in detail. It should be understood, however, that the description herein of specific embodiments is not intended to limit the invention to the particular forms disclosed, but on the contrary, the intention is to cover all modifications, equivalents, and alternatives falling within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION

[0024] The present invention relates generally to methods and systems for enhancing hydrocarbon recovery through gas production control for noncondensable solvents or gases in SAGD or ES-SAGD operations.

[0025] In certain embodiments, a plurality of wells intersects a low mobility reservoir. Steam may be injected into one or more injection wells to heat the reservoir hydrocarbons and reduce their viscosity so that hydrocarbons may be produced by way of one or more production wells. The injection wells may be arranged and paired with the production wells to form a SAGD process or where solvents are used, an ES-SAGD process. A noncondensable gas may be injected into one or more of the injection wells to beneficially reduce the steam-to-oil ratio thus improving economic recovery. Unfortunately, excessive production of noncondensable gases can adversely suppress hydrocarbon production rates for reasons explained further below. To counteract this problem, gas production rates at the production wells may be controlled to optimize hydrocarbon output by limiting the produced gas-to-water ratio (GWR) to limited ranges, including ranges of about 1 to about 30.

[0026] In certain optional embodiments, the noncondensable gas may comprise a gas from the combustion exhaust of a control device or from a steam generator (e.g. flue gas). By taking advantage of existing sources of flue gas, green house gases emissions may be reduced by providing a useful application of existing flue gas rather than venting the flue gas to the atmosphere.

[0027] Advantages of such enhanced hydrocarbon recovery processes include, but are not limited to, higher production efficiencies, lower steam-to-oil ratios, lower costs, a reduction of total extraction time of in-situ hydrocarbons, and in some embodiments, a reduction of greenhouse gas emissions.

[0028] Reference will now be made in detail to embodiments of the invention, one or more examples of which are illustrated in the accompanying drawings. Each example is provided by way of explanation of the invention, not as a limitation of the invention. It will be apparent to those skilled in the art that various modifications and variations can be made in the present invention without departing from the scope or spirit of the invention. For instance, features illustrated or described as part of one embodiment

can be used on another embodiment to yield a still further embodiment. Thus, it is intended that the present invention cover such modifications and variations that come within the scope of the invention.

[0029] Figure 1 illustrates an example of an enhanced hydrocarbon recovery system in accordance with one embodiment of the present invention. Low mobility reservoir 115 is shown residing in subterranean formation 110. Reservoir 115 suffers from low mobility of the hydrocarbons therein due in part to high viscosity of the hydrocarbons, low permeability, and/or low driving forces.

[0030] Injection well 120 and production well 125 both intersect low mobility reservoir 115. Injection well 120 is provided for introducing injected flow 121 into low mobility reservoir 115 by way of injection well 120, whereas production well 125 is provided for extracting production flow 126 by way of production well 125.

[0031] In this example, injection well 120 is superposed above production well 125. Steam 137 is introduced into injection well 120. In this way, steam 137 enters low mobility reservoir 115, heats the hydrocarbons therein to reduce their viscosity and so, increases their mobility. The heated hydrocarbons flow under the influence of gravity towards production well 125 along with any condensed steam. The hydrocarbons and condensed steam are produced by way of production flow 126 from production well 125. In this way, a circulation pattern develops between injection well 120 and production well 125, and a SAGD steam chamber develops around injection well 120.

[0032] Because SAGD is an energy intensive process, any decrease in the amount of steam that is used to produce a unit of hydrocarbons is economically advantageous. The amount of steam used to generate a corresponding amount of hydrocarbons is frequently measured by a steam-to-oil ratio (SOR). This parameter is frequently used to monitor the efficiency of oil production processes based on steam injection. Another parameter that reflects the efficiency of hydrocarbon recovery processes is the gas-to-water ratio (GWR), which reflects the amount of noncondensable produced per unit of water produced. Both a higher SOR and a higher GWR reflect higher inefficiencies. Any improvement in these ratios is economically desirable.

[0033] Unfortunately, excessive noncondensable gas production can adversely affect hydrocarbon recovery. In particular, excessive noncondensable gas production can

decrease the relative permeability of hydrocarbons near the production well and decrease production.

[0034] Further, noncondensable gas, when injected at steam chamber conditions, exhibits limited solubility in the fluids within the steam chamber at these conditions. Slight changes in temperature can have a substantial effect on the solubility of these noncondensable gases and promote evolution of the noncondensable gas back into the steam chamber. This results in lower temperatures at the hydrocarbon drainage interface due to the partial pressure effects of the noncondensable gas and impacts the rate at which oil is produced. These noncondensable gases also tend to move towards the production well thus increasing the gas saturation and decreasing the permeability of hydrocarbons in the near production well region. These factors can negatively impact performance and adversely affect the economics of oil recovery.

[0035] Gas production rates may be controlled to optimize efficiency of the process. In particular, production flow 126 may be modulated to enhance hydrocarbon recovery by reducing the produced gas-to-water ratio (GWR), leading to reduced steam-to-oil ratios and consequently, higher efficiencies. The gas-to-water ratio may be determined with reference to the ratio of the volume fractions of gas and liquid from liquid/gas separator 140. In certain embodiments, production flow 126 may be modulated by production control valve 126 to achieve a gas-to-water ratio in the production flow of about 1 to about 30, of about 1 to about 10, of about 1 to about 5, of about 1 to about 2, of about 5 to about 10, or any combination thereof. As will be further demonstrated below, limiting the gas-to-water ratio to these ranges can significantly improve production efficiencies.

[0036] Noncondensable gas 135 being injected into injection well 120 may comprise any gas that does not condense at any of the reservoir temperature and pressure conditions. Examples of suitable noncondensable gases include, but are not limited to, methane, ethane, propane, butane, air, oxygen, nitrogen, hydrogen, carbon dioxide, carbon monoxide, combustion gases from a control device or other direct combustion device, combustion gases from a direct steam generator, flue gas, or any combination thereof. In certain embodiments, the amount of noncondensable gas that is introduced varies and may include gas-to-water ratios from about 1 to about 1,000. In certain other

embodiments, the gas-to-water ratio in the injected flow varies from about 20 to about 100. The noncondensable gas may comprise two or more noncondensable gases in some embodiments.

[0037] In certain embodiments, solvent 139 may be introduced to further enhance the efficiency of the hydrocarbon recovery process by, for example, further reducing the viscosity of the low mobility hydrocarbons. Example of suitable solvents include, but are not limited to, carbon dioxide, an aliphatic hydrocarbon having 4 carbons to 30 carbons, a light non-condensable hydrocarbon solvent having 1 to 4 carbons, naptha, syncrude, diesel, an aromatic solvent, toluene, benzene, xylene, hexane, or any combination thereof.

[0038] It is recognized that the steam, solvents, or noncondensable gases described herein may be introduced to the low mobility reservoir continuously or intermittently, sequentially or combined, or any combination thereof as desired.

[0039] Figure 2 illustrates another example of an enhanced hydrocarbon recovery system. In this example, steam generator 230 is shown generating steam 237 from water feed 231. A fuel source 233 such as natural gas and an oxidant 232 (e.g. air or oxygen) are fed to direct steam generator 230 to provide the combustion heat necessary to generate heat required to convert water feed 231 to steam 237. As fuel source 233 is combusted, it converts to combustion products, namely flue gas 235. Flue gas 235 may be introduced to injection well 220 as a noncondensable gas similar to noncondensable gas 135 depicted in Figure 1. Here, however, using flue gas 235 advantageously reduces green house gas emissions by diverting flue gas 235 to a useful application.

[0040] Likewise, any other effluent from a control device or other effluent from direct combustion device may be substituted for flue gas 235 as desired. In certain embodiments, a fraction of fuel source 233 may be combined with flue gas 235 to achieve optimal compositions of injection flow 221. As before, flue gas 235 combines with steam 237 to form combined injection flow 221 which is introduced into injection well 220. Hydrocarbons along with condensed steam and any noncondensable gases are produced via production well 225 to form combined production flow 226.

[0041] The process may be controlled to limit total production flow 226 to an amount that optimizes the gas-to-water ratio. One way of achieving this control is illustrated by the control loop depicted in Figure 2. Gas meter 241 measures the flow rate

of gas flow 241, and liquid meter 242 measures the flow rate of liquid flow 242. These flow rates may be converted to a ratio of volume fractions and transmitted to controller 245 which modulates control valve 228 to achieve a desired gas-to-water ratio. By limiting total production flow 226 to a desired gas-to-water ratio, more efficient production of hydrocarbons may be realized.

[0042] In certain alternate embodiments, it is recognized that a direct steam generator (DSG) could be substituted in place of steam generator 230. Naturally, because direct steam generators output the steam and flue gas as a single combined stream, in such a case, steam 237 and noncondensable gas 235 would be combined into a single output stream which would then be available for introducing into wellbore 220. As in previous examples, it is recognized that a solvent 239 could be optionally introduced into wellbore 220.

[0043] To facilitate a better understanding of the present invention, the following examples of certain embodiments are given. In no way should the following examples be read to limit, or define, the scope of the invention.

EXAMPLE

[0044] The following numerical simulations demonstrate the efficacy of the methods described herein. Here, process simulations were performed on a numerical simulator (i.e. CMG-STARs) to evaluate the potential benefits of co-injecting a noncondensable gas, in this case, butane, with steam for improving hydrocarbon recovery as compared to steam injection processes.

[0045] An Athabasca oil sands reservoir of 100 m in width by 30 m in height by 850 m in length was used for the study. Two (850 m long) horizontal wells were placed near the bottom, and in the middle, of the reservoir and separated by 5 m in the vertical direction. The lower horizontal well was placed 1 m above the bottom of the oil bearing sands. Initially, a pre-heating period of 90 days was used to heat the region between the wells by circulating steam in both the injection and production wells (similar to field pre-heating for SAGD).

[0046] A baseline case where steam-only was injected (SAGD) was used for comparison with a steam-butane case where the butane gas production rate was controlled and a steam-butane case where butane gas production rate was uncontrolled. In

all cases, a maximum bottom hole injection pressure of 3.5 MPa was used. In the base case, following pre-heating, steam was injected into the top well and oil and water was produced from the bottom well. In the steam-butane cases, following pre-heating, a mixture of steam-butane at a volume fraction of 0.016 steam and 0.984 butane gas was injected into the top well and oil, water and butane was produced from the bottom well. The volume fraction was selected to demonstrate the concept. However; other butane volume fractions ranging from about 0.001 to about 0.999 may be used. The objective of adding the butane to steam was to evaluate the potential for oil production with less energy as compared to steam alone. The injected gas would help in maintaining the reservoir pressure and reduce oil viscosity and hence reduce steam energy requirements.

[0047] The numerical simulator adjusted the total fluid injection rate (steam in the case of SAGD and steam-gas in the case of butane co-injection) to maintain the maximum injection bottom-hole pressure at 3.5 MPa. Figure 3 shows that the steam injection rate for the SAGD process was the highest and for the steam-butane with controlled gas production rate was the lowest. This data illustrates a significant saving in steam requirements for the controlled gas production case as compared to the SAGD process. Figure 4 illustrates that a maximum injection bottom-hole pressure of 3.5 MPa was practically maintained throughout the entire period of injection, 5,000 days, for all three cases. After 5,000 days, injection was stopped and production continued for all cases.

[0048] As described above, however, excessive production of noncondensable gases may result in the suppression of hydrocarbon production rate due to decreasing the relative permeability of oil near the producer and limiting the production. Additionally, excessive production of noncondensable gases may result in the suppression of hydrocarbon production rate due to noncondensable gases and light hydrocarbons, when injected at steam chamber conditions; exhibit limited solubility in the fluids within the steam chamber at these conditions. Therefore, slight changes in temperature can have a substantial effect on the solubility of these noncondensable gases and light hydrocarbons and promote evolution of the co-injected gases back into the steam chamber. This results in lower temperatures at the oil drainage interface due to the partial pressure effects of the noncondensable gases and impacting the rate at which oil is produced. Some gases also

tend to move towards the producer, thus, increasing the gas saturation and decreasing the permeability of oil in the near production well region. These can negatively impact performance and affect the economics of oil recovery.

[0049] To address these problems, gas production rate at the producer was controlled to optimize efficiency of the process. This control limited the produced gas-to-water ratio (GWR) to a range of about 1 to about 10. This control may be implemented in the field via a control loop in conjunction with a gas/liquid meter and a control valve installed on the production well at the surface. Figure 5 illustrates a comparison between the controlled and uncontrolled produced GWR. In the uncontrolled case, a produced GWR as high as 55 was obtained and this negatively impacted the performance of the process. By using the gas production control concept, the process performed at a significantly improved level as compared to SAGD and the uncontrolled gas production rate cases.

[0050] Figure 6 illustrates that at the end of the injection period, 5,000 days, the controlled gas production case produced more oil as compared to SAGD and the uncontrolled gas production cases (613,649 m³ versus 542,410 m³ and 596,341 m³; respectively). Figure 7 illustrates that a cumulative steam-to-oil ratio (SOR) of 1.6 was obtained from the new concept as compared to 3.2 for SAGD and 2.1 for the uncontrolled gas production case. This results in significant improvement in energy efficiency and reduced water requirement and greenhouse gas emissions by using the new concept. In addition, Figure 7 demonstrates that the improved thermal efficiency is maintained throughout the life of the process, thus improving the overall economics of recovery. Furthermore, Figure 7 shows that if the processes was to be terminated at an economic SOR of 2, then the SAGD process would be terminated after approximately 1,500 days and the uncontrolled gas production process after 5,000 days; however, the controlled gas production process would have continued to produce for a much longer time than the other two cases and much more oil would be produced before reaching the same cut-off SOR of 2.

[0051] Table 1 below and Figure 8 summarize the benefits of the produced gas control concept as compared to SAGD and the uncontrolled gas production cases.

Table 1: Summary of Performance Comparison

	SAGD	Uncontrolled Gas Production	Controlled Gas Production
Cumulative oil (m³)	542,410	596,341	613,649
Percent recovery (IOIP) (%)	77	85	87
Cumulative SOR	3.1	2.1	1.6
Percent increase in SAGD cumulative oil	-	10	13
Percent reduction in SAGD SOR	-	32	48

[0052] The simulations were conducted using butane as the non-condensable solvent however, other wide variety of noncondensable gases and solvents maybe used. Suitable examples include, but not limited to, methane, ethane, propane, butane, air, oxygen, nitrogen, hydrogen, carbon dioxide, carbon monoxide, combustion gases from a control device or other direct combustion device, combustion gases from a direct steam generator, flue gas, or any combination thereof. The flue gas may be obtained from any industrial fuel burning installation for example, a steam generator, a direct steam generator (DSG), or a combustion device. In addition, the non-condensable additive was injected with the steam in a continuous manner; however, an alternative injection strategy may include injecting the additives intermittently or sequentially with steam at different time intervals. Furthermore, the concept maybe used in any steam injection processes including SAGD and steam flooding.

[0053] It is recognized that any of the elements and features of each of the devices described herein are capable of use with any of the other devices described herein with no limitation. Furthermore, it is explicitly recognized that the steps of the methods herein may be performed in any order except unless explicitly stated otherwise or inherently required otherwise by the particular method.

[0054] Therefore, the present invention is well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the present invention may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered or modified and all such variations and equivalents are considered within the scope and spirit of the present invention. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee.

What is claimed is:

1. A method for enhancing recovery of bitumen or heavy oil from a low mobility reservoir comprising the steps of:
 - providing one or more injection wells wherein the one or more injection wells intersect the heavy oil reservoir;
 - providing one or more production wells wherein the one or more production wells intersect the heavy oil reservoir;
 - wherein the one or more injection wells and the one or more production wells are paired to form a SAGD or ES-SAGD process;
 - producing steam via a steam generator wherein flue gas is produced as a byproduct of the steam generator;
 - introducing the steam into one of the one or more injection wells;
 - introducing the flue gas into one of the one or more injection wells;
 - allowing a production flow to be produced from the one or more production wells wherein the production flow comprises a production gas flow and a production water flow;
 - determining a production gas-to-water ratio as a ratio of the production gas flow to the production water flow; and
 - limiting the production flow to obtain a production gas-to-water ratio in the production flow from about 1 to about 30.
2. The method of claim 1 wherein the step of introducing steam comprises the step of continuously introducing the steam into one of the one or more injection wells and wherein the step of introducing the flue gas comprises the step of continuously introducing the flue gas into one of the one or more injection wells.
3. The method of claim 1 wherein the step of introducing steam comprises the step of intermittently introducing the steam into one of the one or more injection wells and wherein the step of introducing the non-condensable gas comprises the step of intermittently introducing the non-condensable gas into one of the one or more injection wells.

4. The method of claim 1 wherein the steam and the non-condensable gas are combined into a single stream for injection into the one or more injection wells.

5. The method of claim 2 wherein the steam and the non-condensable gas are combined into a single stream for injection into the one or more injection wells.

6. The method of claim 1 wherein the production gas-to-water ratio is about 1 to about 10.

7. The method of claim 1 wherein the production gas-to-water ratio is about 1 to about 5.

8. The method of claim 1 wherein the production gas-to-water ratio is about 5 to about 10.

9. A method for enhancing recovery of bitumen or heavy oil from a low mobility reservoir comprising the steps of:

providing an injection well wherein the injection well extends into the heavy oil reservoir via an upper horizontal well;

providing a production well wherein the production well extends into the heavy oil reservoir via a lower horizontal well;

continuously introducing steam and a non-condensable gas into the injection well;

allowing a production flow to be produced from the production well wherein the production flow comprises a gas flow and a water flow;

determining a production gas-to-water ratio as a ratio of the production gas flow to the production water flow; and

limiting the production flow to obtain a production gas-to-water ratio from about 1 to about 10.

10. The method of claim 9 wherein the injection well and the production well are paired to form a SAGD or ES-SAGD process.

11. The method of claim 9 wherein the non-condensable gas is butane.
12. The method of claim 9 wherein the non-condensable gas is methane, ethane, propane, butane, air, oxygen, nitrogen, hydrogen, carbon dioxide, carbon monoxide, combustion gases from a control device or other direct combustion device, combustion gases from a direct steam generator, flue gas, or any combination thereof.
13. The method of claim 9 further comprising the step of providing a direct steam generator wherein the direct steam generator produces a combined output stream of steam and flue gas, wherein the non-condensable gas is the flue gas from the direct steam generator.
14. The method of claim 13 wherein the production gas-to-water ratio is about 1 to about 10.
15. The method of claim 13 wherein the production gas-to-water ratio is about 1 to about 5.
16. The method of claim 13 wherein the production gas-to-water ratio is about 5 to about 10.
17. The method of claim 13 wherein the step of continuously introducing steam and a non-condensable gas into the injection well further comprises the step of continuously introducing steam and a non-condensable gas into the injection well to form an injection flow that comprises an injection gas flow and an injection water flow, wherein the method further comprises the step of determining an injection gas-to-water ratio as a ratio of the injection gas flow to the injection water flow, wherein the injection gas-to-water ratio is from about 50 to about 100.
18. The method of claim 13 further comprising the step of introducing a solvent into the injection well.

19. The method of claim 17 wherein the solvent comprises hexane.
20. The method of claim 17 wherein the solvent is carbon dioxide, an aliphatic hydrocarbon having 4 carbons to 30 carbons, naptha, syncrude, diesel, an aromatic solvent, toluene, benzene, xylene, or any combination thereof.
21. The method of claim 20 wherein the solvent is a light non-condensable hydrocarbon solvent having one to four carbons.
22. The method of claim 10 further comprising:
providing a direct steam generator wherein the direct steam generator produces a combined output stream of steam and flue gas, wherein the non-condensable gas is the flue gas from the direct steam generator;
wherein the non-condensable gas is methane, ethane, propane, butane, air, oxygen, nitrogen, hydrogen, carbon dioxide, carbon monoxide, combustion gases from a control device or other direct combustion device, combustion gases from a direct steam generator, flue gas, or any combination thereof;
wherein the production gas-to-water ratio is about 1 to about 5; and
introducing a solvent into the injection well; and
wherein the solvent is carbon dioxide, an aliphatic hydrocarbon having 4 carbons to 30 carbons, naptha, syncrude, diesel, an aromatic solvent, toluene, benzene, xylene, or any combination thereof.

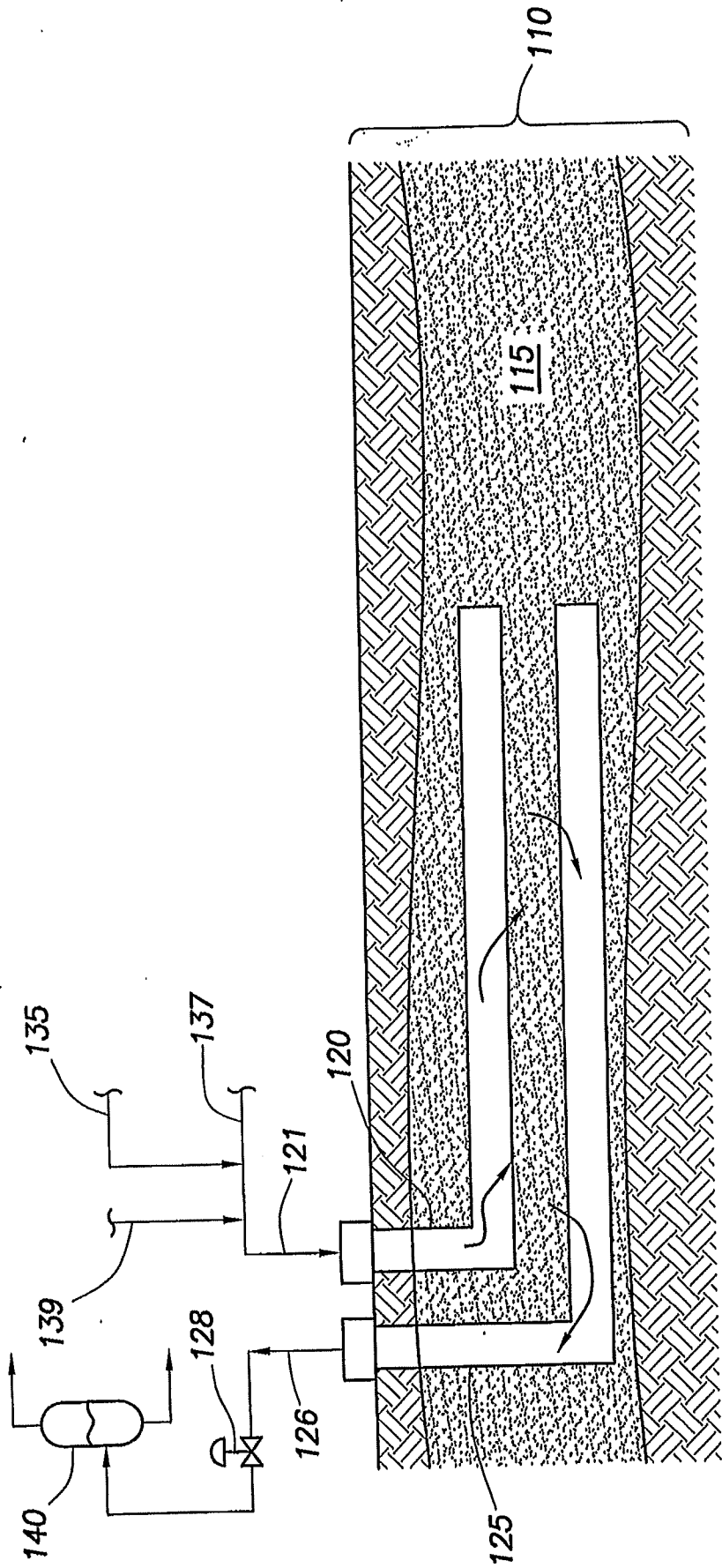


FIG.1

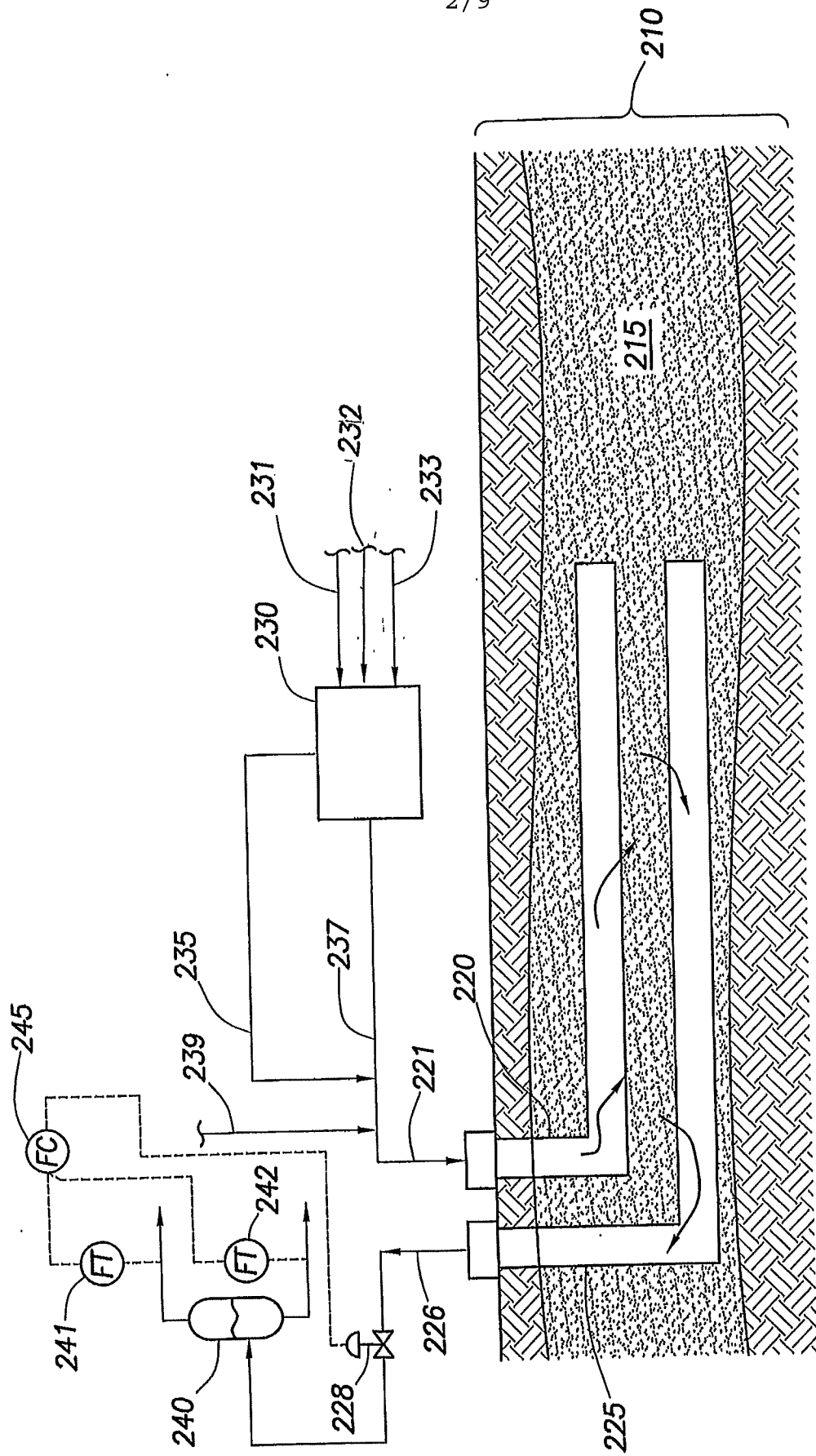


FIG.2

Figure 3: Monthly Average Water Injection Rate versus Time

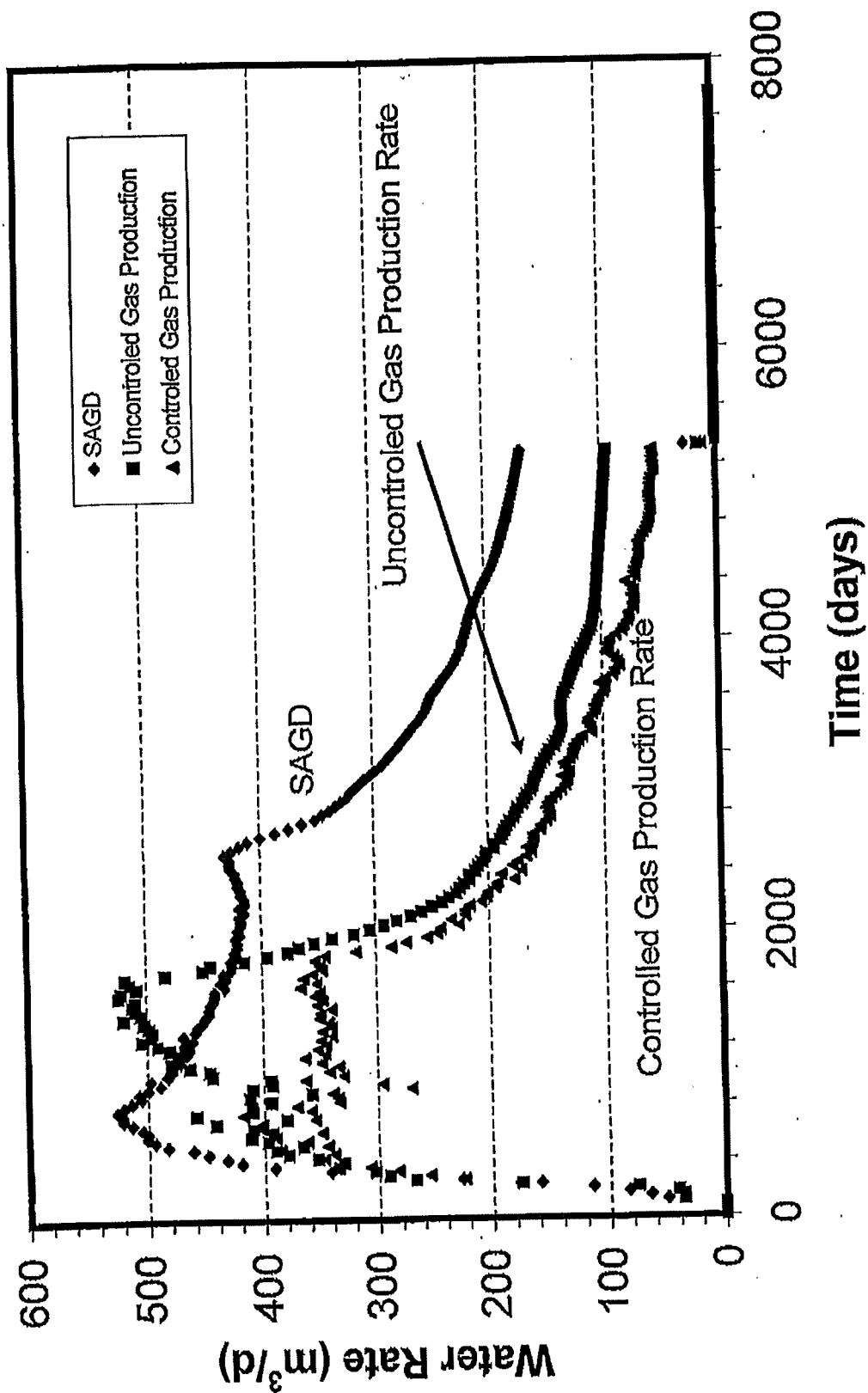


Figure 4: Injection Pressure versus Time

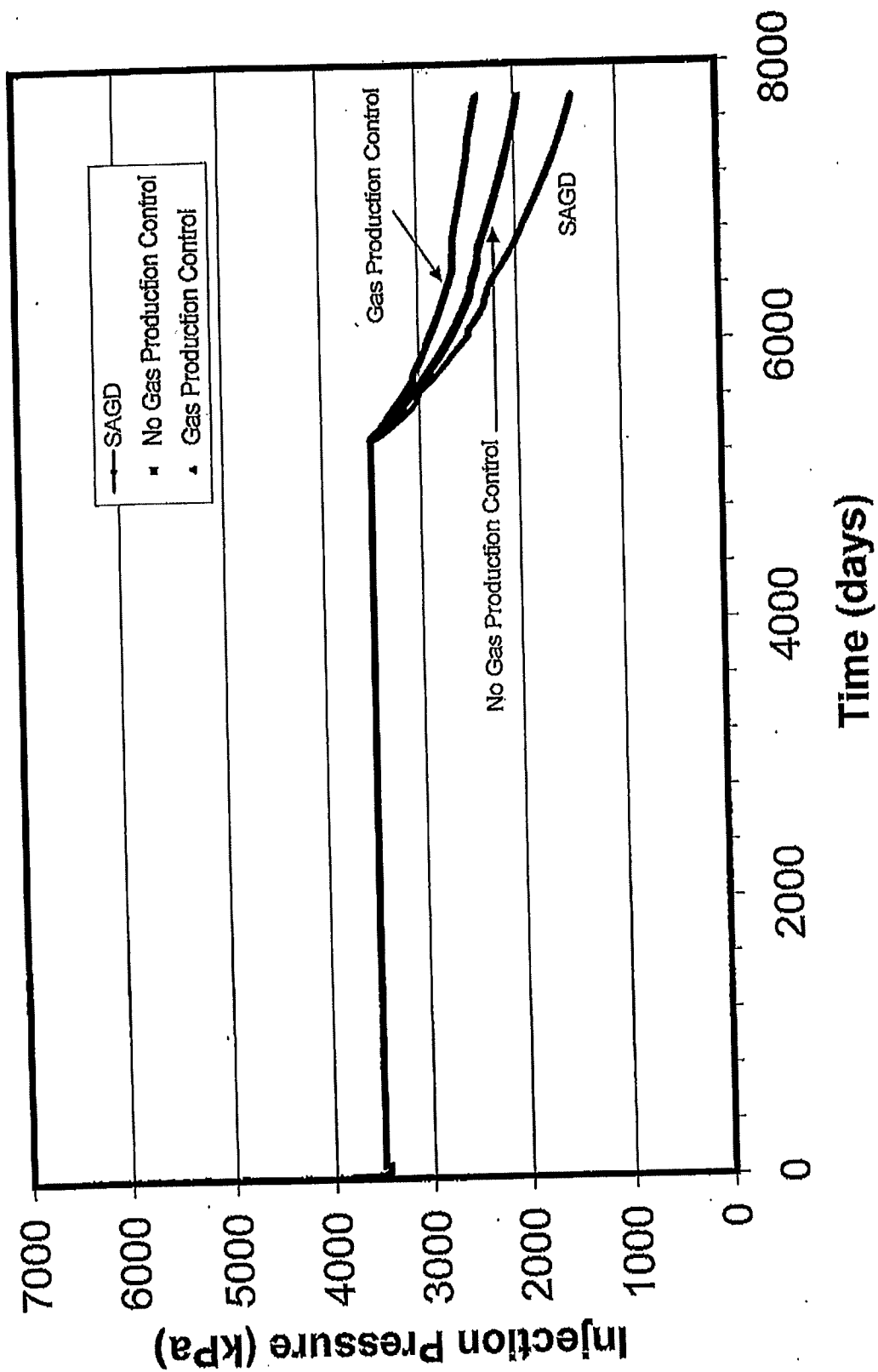


Figure 5: Monthly Average Produced Gas-to-Water Ratio (GWR)

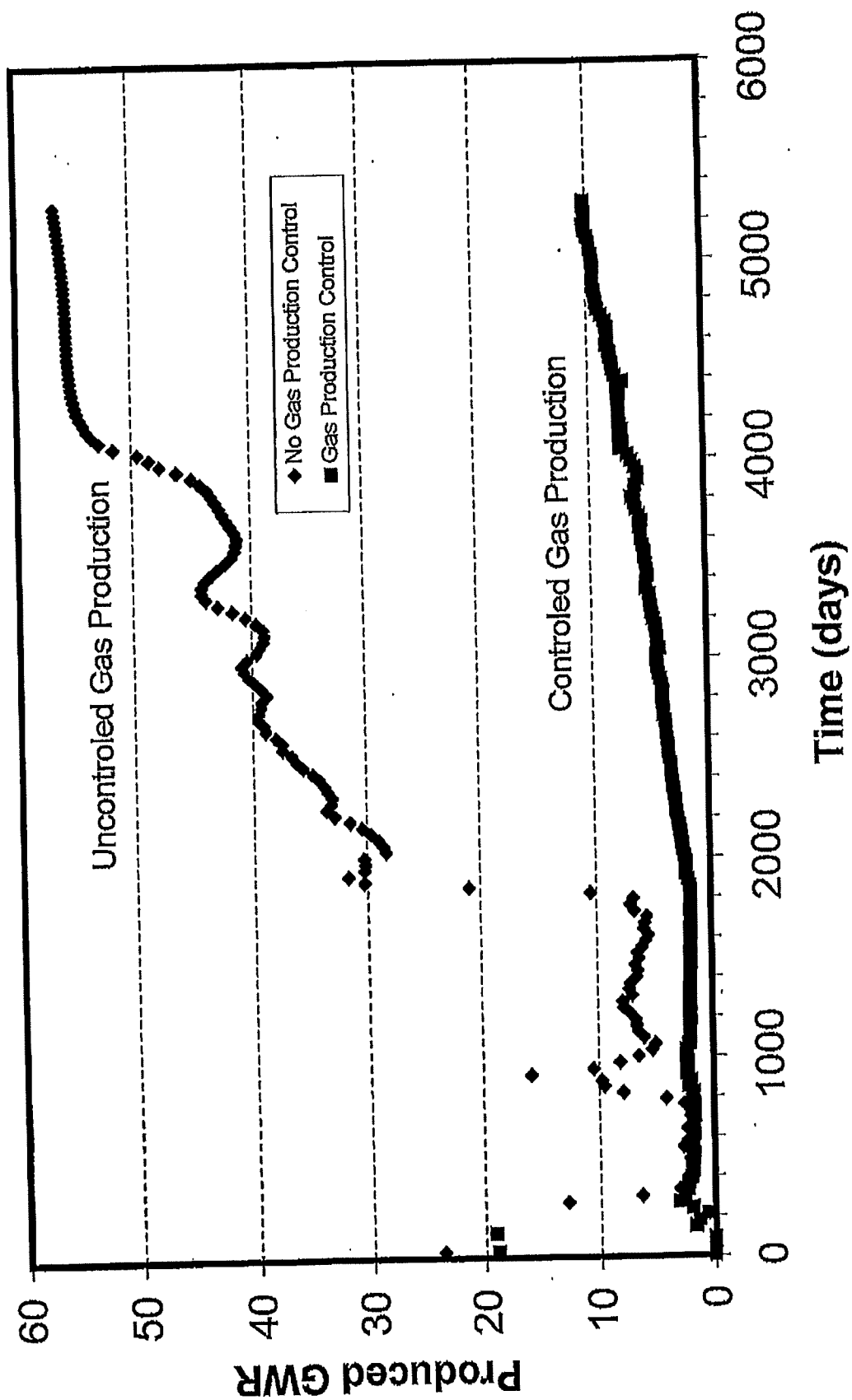


Figure 6: Cumulative Oil Production versus Time

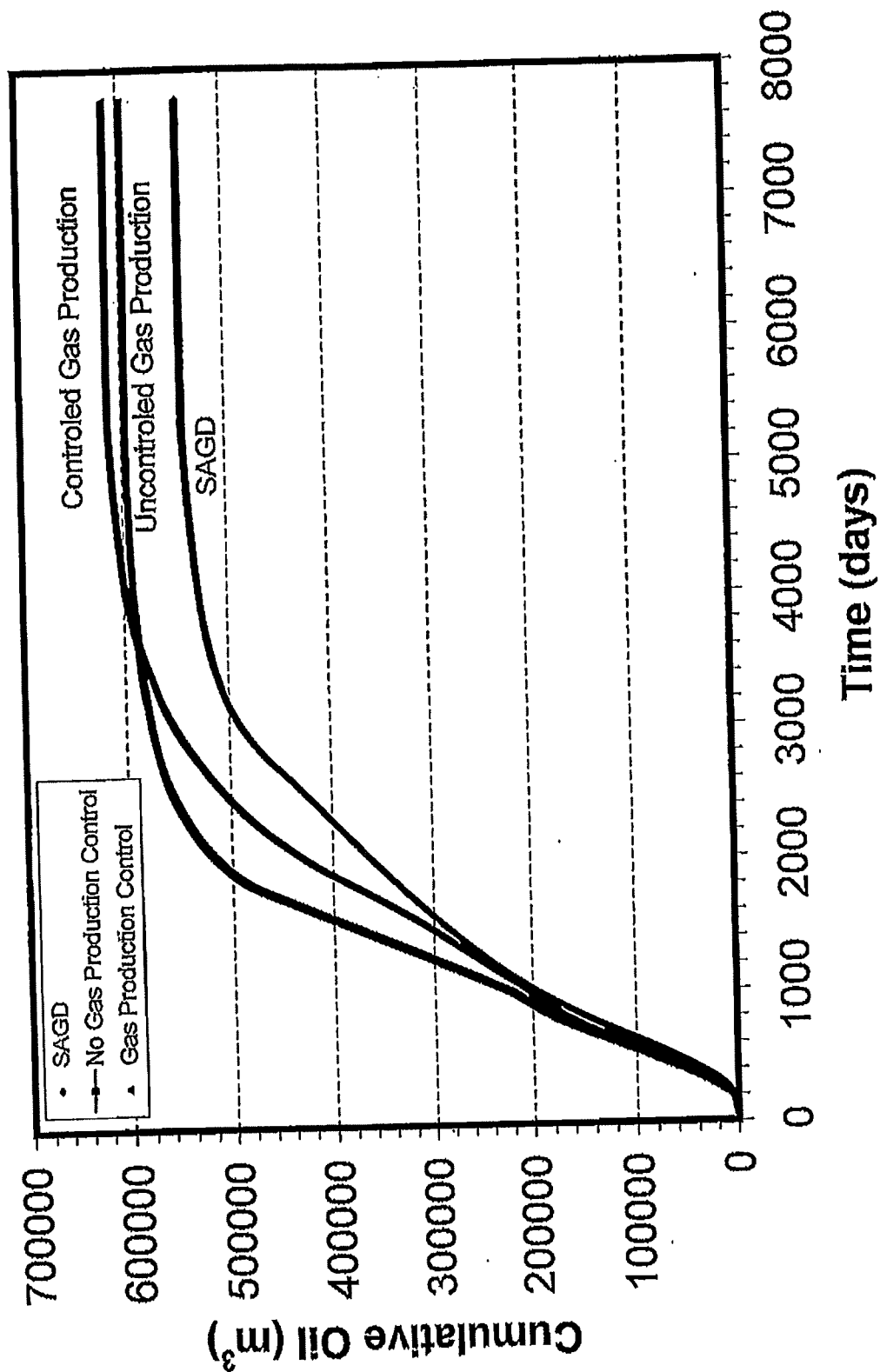
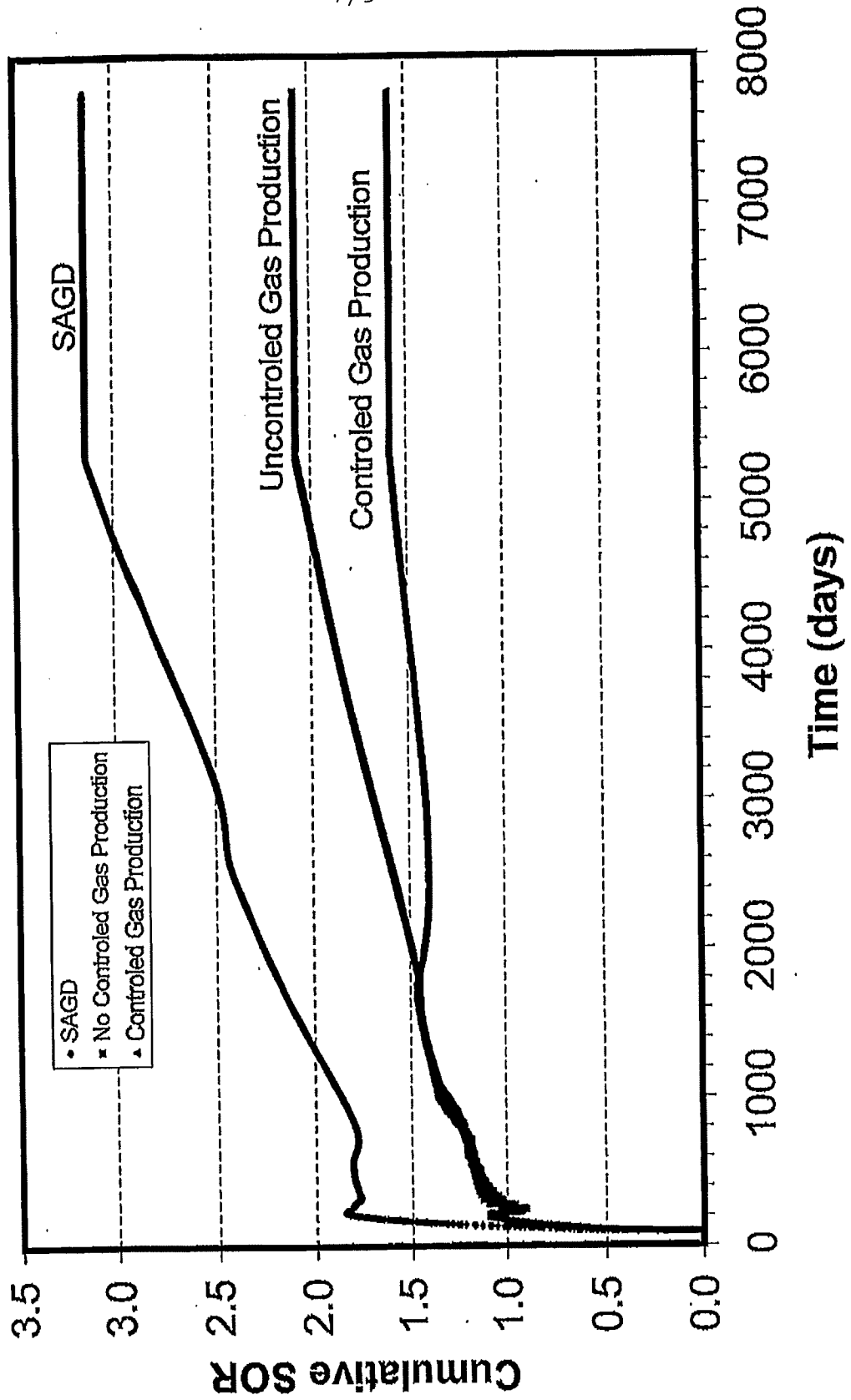


Figure 7: Cumulative Steam-to-Oil Ratio (SOR) versus Time



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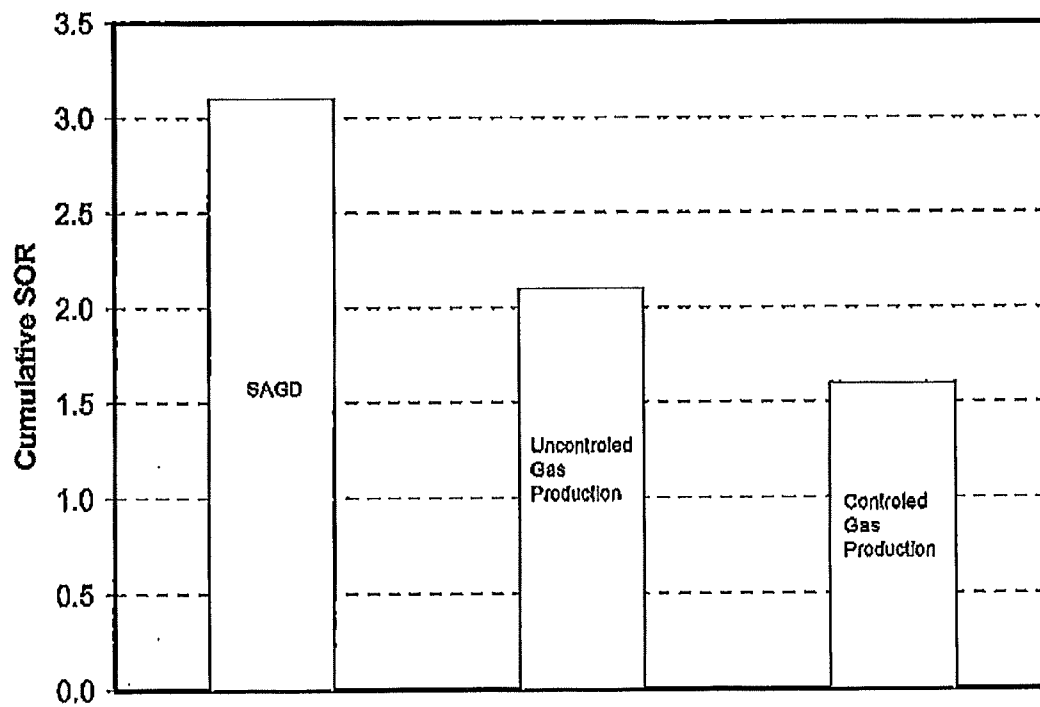


FIG. 8A

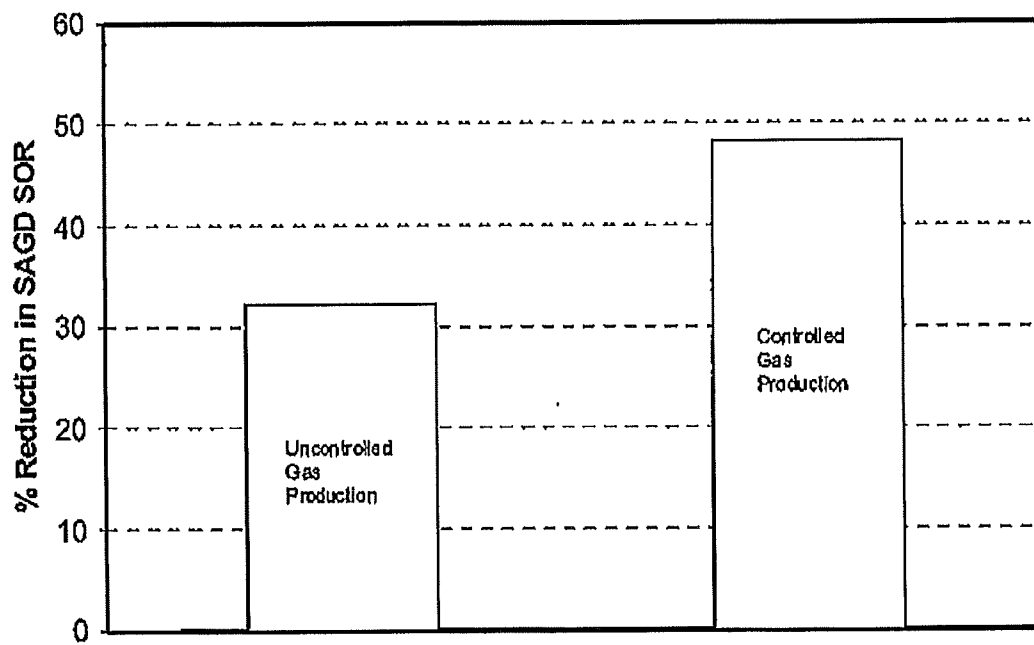


FIG. 8B

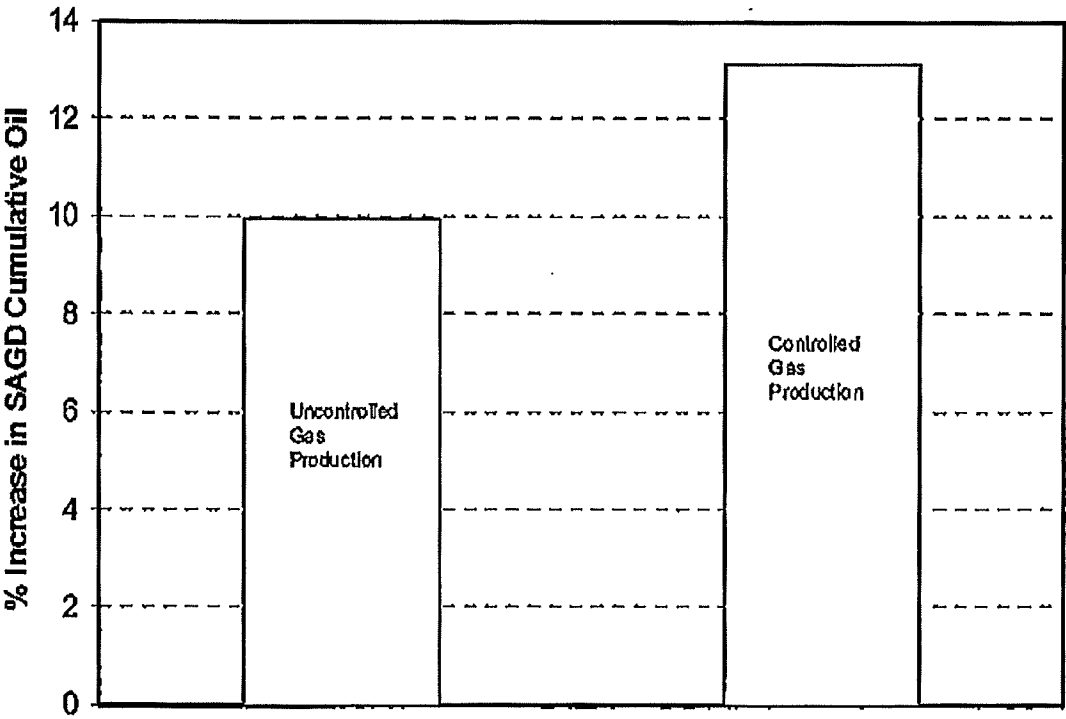


FIG. 8C