Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2678348 C 2014/07/22

(11)(21) 2 678 348

(12) BREVET CANADIEN
CANADIAN PATENT

(13) C

(22) Date de dépôt/Filing Date: 2009/09/11

(41) Mise à la disp. pub./Open to Public Insp.: 2011/03/11

(45) Date de délivrance/Issue Date: 2014/07/22

(51) Cl.Int./Int.Cl. *E21B 43/24* (2006.01),
E21B 43/243 (2006.01)

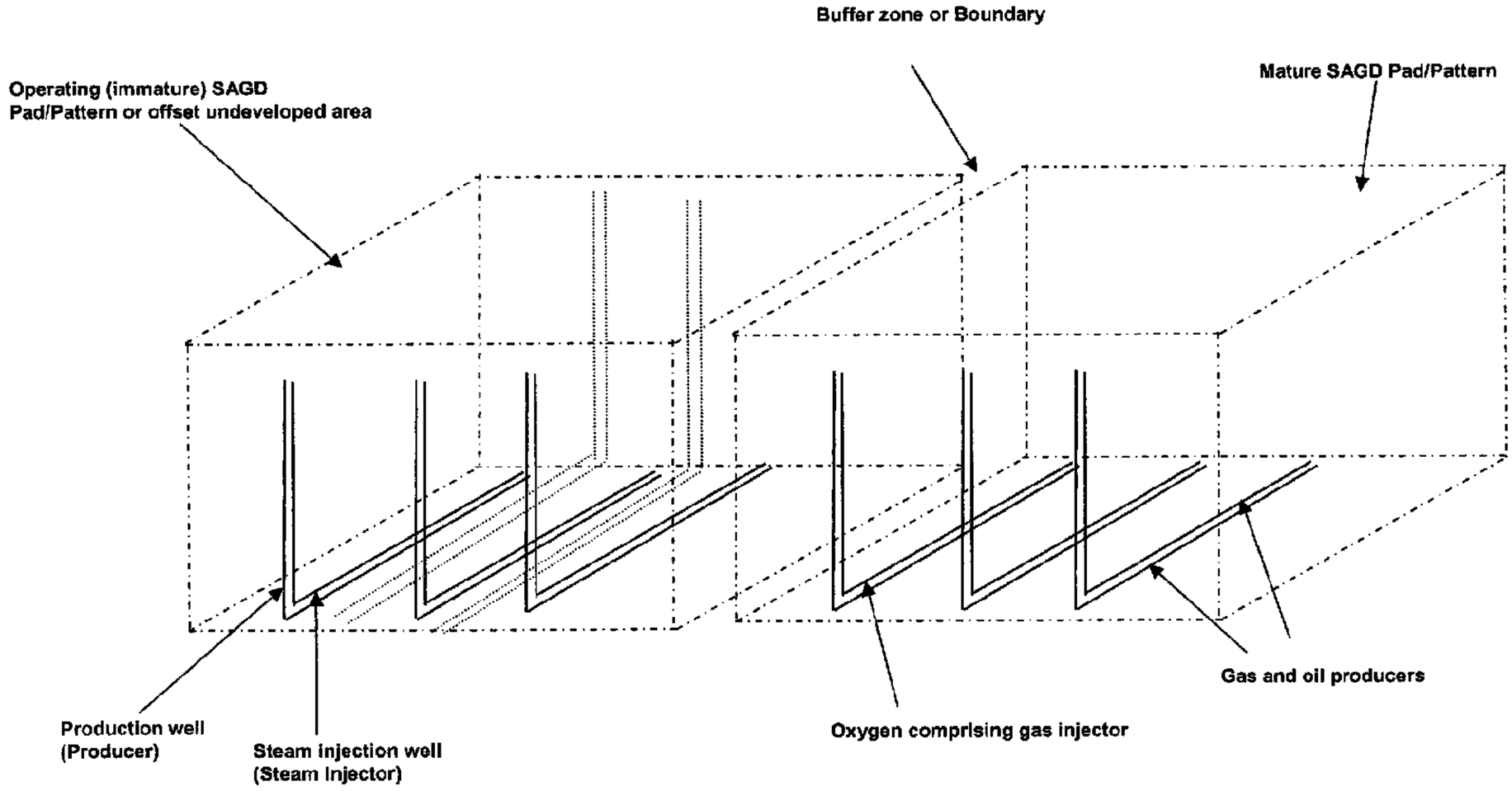
(72) Inventeurs/Inventors:
LI, JIAN, CA;
COULTER, CALVIN R., CA;
CUTHIELL, DAVID LAYTON, CA

(73) Propriétaire/Owner:
SUNCOR ENERGY INC., CA

(74) Agent: SMART & BIGGAR

(54) Titre : REDUCTION DE PERTE DE FLUIDE DE BOITES A VAPEUR EN FONCTIONNEMENT DANS UN DRAINAGE PAR GRAVITE ASSISTE PAR LA VAPEUR POUR AMELIORER LA RECUPERATION D'HYDROCARBURES IN SITU

(54) Title: REDUCTION OF FLUID LOSS FROM OPERATING CHAMBERS IN STEAM ASSISTED GRAVITY DRAINAGE TO INCREASE IN SITU HYDROCARBON RECOVERY



(57) Abrégé/Abstract:
The invention provides for in situ processing a hydrocarbon reservoir which comprises selecting in the reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber. The matured steam chamber further being a warm and depleted former SAGD chamber, and the operating chamber undergoing or being capable of undergoing SAGD processing. An oxygen comprising gas is injected into the matured chamber or generally at a boundary or within a buffer zone between the matured and operating chambers for maintaining pressure within the matured chamber so as to reduce or avoid fluid leaking or cross-flow from the operating chamber into the mature chamber while producing gas, oil and water within the matured chamber, continually performing SAGD in the operating chamber, or a combination thereof.

ABSTRACT

The invention provides for *in situ* processing a hydrocarbon reservoir which comprises selecting in the reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber. The matured steam chamber further being a warm and depleted former SAGD chamber, and the operating chamber undergoing or being capable of undergoing SAGD processing. An oxygen comprising gas is injected into the matured chamber or generally at a boundary or within a buffer zone between the matured and operating chambers for maintaining pressure within the matured chamber so as to reduce or avoid fluid leaking or cross-flow from the operating chamber into the mature chamber while producing gas, oil and water within the matured chamber, continually performing SAGD in the operating chamber, or a combination thereof.

REDUCTION OF FLUID LOSS FROM OPERATING CHAMBERS IN STEAM ASSISTED GRAVITY DRAINAGE TO INCREASE *IN SITU* HYDROCARBON RECOVERY

FIELD OF THE INVENTION

The present invention relates generally to *in situ* hydrocarbon recovery and particularly to increasing *in situ* recovery of hydrocarbons from Steam Assisted Gravity Drainage (SAGD) operations by reducing the loss of fluid from SAGD operating chambers generally adjacent to or proximate to SAGD matured chambers.

BACKGROUND OF THE INVENTION

Heavy oil and extra-heavy oil resources such as, for example, bitumen present significant technical and economic recovery challenges due to their high viscosities at reservoir temperature. Bitumen occurs within a subsurface hydrocarbon bearing zone of a hydrocarbon reservoir as a semi-solid phase having a viscosity greater than 100,000 centipoise. An example of an *in situ* steam injection-based heavy oil recovery process is steam assisted gravity drainage (SAGD) which is effective at extracting oil from oil-containing reservoirs by reducing viscosity of the oil *via* steam injection.

A SAGD system comprises at least one pair of steam injection and oil production wells (a "well pair"). In a well pair generally located in a bottom portion of the hydrocarbon bearing zone of the reservoir, a generally horizontal injection well used for injecting a fluid such as steam into the reservoir is the upper well. The injected steam rises from the generally horizontal injection well and permeates the reservoir to form a vapor chamber which grows over time within the hydrocarbon bearing zone thereby increasing the temperature of the reservoir. The resultant mobilized bitumen and condensate will drain downward through the reservoir under gravity and flow into a generally horizontal production well disposed below the injection

well from which the bitumen is produced. Several well pairs may be arranged within the reservoir to form a well pattern or a pad.

SAGD generally involves four operational stages: start up, ramp up, plateau and wind down. In the start up stage, steam is circulated in both the injection and production wells for about two to four months to heat up the reservoir, which results in the creation of a "steam chamber". The term "steam chamber" relates to a region in the reservoir in which hydrocarbons, steam, steam condensate, and associated non-condensate gases are in communication with the injection wells. During start up, as the steam chamber grows from the injection wells, the hydrocarbons are heated and mobilized to subsequently drain into the production wells. In the ramp up stage of SAGD, the injection and production rates increase as the steam chamber grows to the top of the reservoir, which may take about six to eighteen months depending on the operating conditions and reservoir characteristics. In the plateau stage, the steam chamber has reached the top of the reservoir and begins to expand within the reservoir, including lateral migration. This stage is characterized by peak production rates, which can last anywhere from eighteen to sixty months depending on reservoir quality and thickness. The final wind down stage of SAGD occurs when steam chambers in adjacent well pairs reach the top of the oil sand reservoir and begin to coalesce and expand out of the pattern area as a result of increased heat losses to the overburden and lower bitumen production because the majority of oil has been drained out of the SAGD chamber. For example, in the case of an Underground Test of Facility (UTF), the wind down stage has been estimated to occur when bitumen recovery reaches about 50–60%.

Thermal efficiency of the SAGD process is measured by the cumulative steam-to-oil ratio ("cSOR"), which is the ratio of the cumulative volume of steam injected over the cumulative volume of oil produced. The higher the cSOR, the higher the steam usage, which means more natural gas is combusted per unit volume of produced oil, and consequently the process is less economical. Conversely, a lower cSOR implies a more economical

process. As the oil content in the SAGD operating steam chamber naturally declines, the cSOR increases. When the SAGD operational cost begins to out weigh the oil production value, it may no longer be economically viable to continue steam injection for the SAGD operation, at which time steam injection may be reduced or discontinued for the pads or selected well pairs. In this stage, the steam chamber is referred to as depleted, “mature” or “matured” and is generally associated with a bitumen recovery factor above about 55 %.

In commercial SAGD developments, groups of well pairs or pads are initially drilled and placed on production in a sufficient number so as to fill the plant capacity. When SAGD operations for one pad reach the wind down stage, oil production from the reservoir naturally begins to decline, and as the productivity of the operational wells decreases, additional SAGD well pairs in adjoining geographical areas may be added in the reservoir, which eventually may cover the entire reservoir field.

A reservoir field as a whole will typically comprise pads or well pairs at different operational stages. For example, the reservoir field may comprise one or more operating pads in proximity to one or more matured pads. When the pads or well pairs reach the stage of being “mature” or “matured”, injection of steam into such pads or well pairs ceases to be economical, and is therefore stopped. Steam injection is continued into operating pads or well pairs located adjacent the matured pads or well pairs.

When steam injection is reduced or discontinued in the matured pad(s), the pressure of the chamber falls as the system cools. Eventually, the mature chambers in such pads would become "thief zones" for future SAGD operations in pads generally adjacent to the matured pads. Eventurally, the pressure within the matured pad(s) drops naturally to a level below the temperature and pressure of the operating pads, which creates a driving force for fluid cross-flow (e.g., cross-flow of steam) from the operating chamber into the generally adjacent matured chamber. The matured pad generally adjacent

the operating pad acts as a scavenger of steam and a heat sink for the adjacent operating pad, which reduces the effectiveness and productivity of the operating pad. For example, Suncor's MacKay River SAGD Project production performance shows slower SAGD ramp-up for wells generally adjacent to the mature steam chamber.

Several approaches have been proposed for alleviating the above-mentioned operational challenges. Examples of such approaches include cold water injection with stop steam injection, injection of non-condensable gases (NCGs) such as natural gas or nitrogen, co-injection of natural gas as a mixture in certain volumetric or molar proportions, and blow-down or stage blow-down approaches. Another approach involves leaving a reservoir buffer zone between the operating steam chambers and the matured steam chambers, effectively creating isolation between the chambers.

The proposed approaches have several disadvantages. For example, injection of NCGs or co-injection of NCGs with steam may cause a significant reduction in the temperature of the matured steam chamber. As a result, further addition of costly NCGs may be required to maintain the desired reservoir pressure. Cold water injection reduces the temperature of the matured steam chamber more rapidly, and may create a low temperature heat sink within the reservoir. Furthermore, cold water injection does not utilize the heat stored in the matured steam chamber, and high water mobility may also impair the performance of adjacent operating steam chambers and wells. The blow down method leaves the matured steam chamber to cool, and with the decrease in temperature, the pressure drops, which results in the matured chamber acting as a pressure sink for adjacent operating chambers. Another approach referred to as the buffer zone approach generally results in areas of the reservoir that will not be recovered. Moreover, more cost might be incurred for additional steam and produced fluids piping to re-develop the unrecovered areas in the future when the project has covered a larger area.

Generally, for many commercial SAGD projects, one method of isolating depleted (matured) and undepleted (operating) patterns entails injection of non-condensable gases such as, for example, either natural gas, hydrocarbon gas or flue gas, into the matured pattern to maintain pressure as the steam vapor in the pattern condenses.

Therefore, increasing *in situ* oil recovery from hydrocarbon-containing reservoirs using thermal processes such as SAGD and improving the economical performance of such processes remains challenging.

SUMMARY OF THE INVENTION

In accordance with one aspect of the invention, there is provided an *in situ* process for treating a hydrocarbon reservoir. In various aspects, the process comprises selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber. In various aspects, the operating steam chamber is situated so that a boundary or a buffer zone exists between the matured steam chamber and the operating steam chamber. In various embodiments, the size of the boundary or the buffer zone may vary with operating conditions of the mature and operating chambers. For example, in various embodiments that boundary or the buffer zone may have a width ranging from about 50 to 80 m, about 80 m to 160 m, or about 160 to 200 m. The matured steam chamber has been previously processed using steam assisted gravity drainage (SAGD), and the operating chamber is undergoing or being capable of undergoing SAGD processing. The matured steam chamber further has a residual hydrocarbon content of at least about 0.5 %, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber. For example, the initial temperature may range from about 165°C to about 223°C (the saturate steam temperature may be above 162°C), and the initial pressure may range from about 700 kPa or higher, for example about 700 kPa to about 2500 kPa. In various

embodiments, the mature steam chamber is a warm and depleted former SAGD chamber.

In various aspects, the process further comprises selecting an injection well situated in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber, the injection well also being generally adjacent to the boundary or the buffer zone between the matured steam chamber and the operating steam chamber. The oxygen-comprising gas is injected through the injection well. In various embodiments, the oxygen-comprising gas has a concentration of oxygen sufficient to sustain combustion in the matured steam chamber. A volume of the injected oxygen-comprising gas, the concentration of oxygen or a combination thereof may be modulated to sufficiently pressurize the boundary or the buffer zone such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced or avoided while sustaining combustion in the operating steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable from the operating steam chamber without the injection of the oxygen-comprising gas into the matured steam chamber. Thus, in various embodiments, steam leaking is avoided which results in an improved performance of SAGD in the operating chamber and in the reservoir as a whole. In various embodiments, the oxygen-comprising gas is injected into the warm matured chamber while the combustion gas, oil and water are produced within the matured chamber and while the generally adjacent operating chamber/pad is continually undergoing normal SAGD operation. Thus, according to the various aspects, pressure is maintained in the matured chamber while hydrocarbons are being produced. The hydrocarbons from at least one of the matured steam chamber and the operating steam chamber may be selectively produced. In various aspects, the oxygen-comprising gas may be injected into the mature chamber as a whole and the pressure may be maintained within the matured chamber as a whole rather than generally at the boundary or generally within the buffer zone.

In various aspects, the concentration of oxygen is sufficient to sustain combustion in the matured steam chamber. In various aspects, the concentration of oxygen may range from about 5% to about 100%, and the oxygen-comprising gas may be selected from the group consisting of air, oxygen-enriched air, or a combination thereof. In various aspects, the oxygen-enriched air may comprise a concentration of oxygen above about 21%. In further aspects, the oxygen comprising gas may be wet or dry.

In various aspects, selecting an injection well in the matured chamber comprises selecting several injection wells to achieve a suitable injection pattern proximate or generally adjacent to the boundary or the buffer zone or proximate or generally adjacent to the operating chamber.

In accordance with another aspect of the invention, there is provided an apparatus for *in situ* treatment of a hydrocarbon reservoir. In various aspects, the apparatus comprises means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber. In various aspects, the operating steam chamber is situated so that a boundary or a buffer zone exists between the matured steam chamber and the operating steam chamber. In various embodiments the size of the boundary or the buffer zone may vary with the operating conditions of the mature and operating chambers. For example, in various embodiments the boundary or the buffer zone may have a width ranging from about 50 to 80 m, about 80 m to 160 m, or about 160 to 200 m. The matured steam chamber has been previously processed using steam assisted gravity drainage (SAGD), and the operating chamber is undergoing or being capable of undergoing SAGD processing. The matured steam chamber further has a residual hydrocarbon content of at least about 0.5 %, a, initial temperature, and an initial pressure lower than a pressure in the operating steam chamber. For example, the initial temperature may range from about 165°C to about 223 °C (the saturate steam temperature may be above 162 °C), and the initial pressure may range from

about 700 kPa to about 2500 kPa. In various embodiments, the mature steam chamber is a warm and depleted former SAGD chamber.

In various embodiments, the apparatus further comprises means for selecting an injection well disposed in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber, the injection well also being generally adjacent to the boundary or the buffer zone between the matured steam chamber and the operating steam chamber. The oxygen-comprising gas is then injected through the injection well. In various embodiments, the oxygen-comprising gas has a concentration of oxygen sufficient to sustain combustion in the matured steam chamber. A volume of the injected oxygen-comprising gas, the concentration of oxygen or a combination thereof is modulated to sufficiently pressurize the boundary or the buffer zone such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the operating steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable from the operating steam chamber without the injection of the oxygen-comprising gas into the matured steam chamber. Thus, in various embodiments, steam leaking is avoided according to the various aspects of the present apparatus which results in an improved performance of SAGD in the operating chamber and in the reservoir as a whole. In various embodiments, the oxygen comprising gas is injected into the warm matured chamber while the combustion gas, oil and water are produced within the matured chamber and while the generally adjacent operating chamber/pad is continually undergoing normal SAGD operation. Thus, according to the various aspects of the apparatus, pressure is maintained in the matured chamber while hydrocarbons are being produced. The hydrocarbons from at least one of the matured steam chamber and the operating steam chamber may be selectively produced.

In a further embodiment of the present invention, there is provided an *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the operating steam chamber situated so that a boundary exists between the matured steam chamber and the operating steam chamber, the matured steam chamber having been previously processed using steam assisted gravity drainage (SAGD), the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well situated in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber, the injection well being generally adjacent to the boundary between the matured steam chamber and the operating steam chamber;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the boundary such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable from the operating steam chamber without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

In a further embodiment of the present invention there is provided an *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the matured steam chamber such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber and maintaining a predetermined pressure in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to

production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

The process may further include sustaining combustion in the matured steam chamber including generating a combustion front.

The process may further include advancing the combustion front in a direction from a heel to a toe of the injection well.

The process may further include initially advancing the combustion front in an upward direction away from the injection well, and subsequently advancing the combustion front in a lateral direction along the injection well toward a toe of the injection well.

The combustion front may extend outwardly from a generally vertical portion of the injection well.

The generally vertical portion of the injection well may be perforated.

The injection well may be perforated along substantially all of a generally horizontal portion of the injection well.

The injection well may be perforated along an isolated section of a generally horizontal portion of the injection well.

The oxygen-comprising gas may be injected through the isolated section of the generally horizontal portion of the injection well.

The velocity of the combustion front may be about 0.038 m/day or less.

The velocity of the combustion front may be about 0.02 m/day.

The process may further include a pressure difference between the pressure in the operating steam chamber and the predetermined pressure in the matured steam chamber which may be about 0 kPa to about 200 kPa.

The process may further include a pressure difference between the pressure in the operating steam chamber and the predetermined pressure in the matured steam chamber which may be about 50 kPa.

The initial pressure of the matured steam chamber may be about 700 kPa to about 2500 kPa.

The initial temperature of the matured steam chamber may be about 165°C or greater.

The initial temperature of the matured steam chamber may be about 180°C or greater.

The initial temperature of the matured steam chamber may be about 165°C to about 223°C.

The process may further include an operating temperature of the operating steam chamber is about 180°C or greater.

The operating temperature may be about 225°C or greater.

The operating temperature may be about 270°C or greater.

The operating pressure of the operating steam chamber may be about 1000 kPa to about 6500 kPa.

The injection well may have been previously used for fluid injection.

The fluid may be steam.

The oxygen-comprising gas may be injected proximate to a lower portion of the reservoir.

The concentration of oxygen in the oxygen-comprising gas may range from about 5% to about 100%.

The concentration of oxygen in the oxygen-comprising gas may range from about 5% to about 40%.

The concentration of oxygen in the oxygen-comprising gas may be about 21% or more.

The oxygen-comprising gas may be air, oxygen-enriched air, or a combination thereof.

The oxygen-comprising gas may be wet or dry.

The dry oxygen-comprising gas may be co-injected with flue gas.

The process may further include producing residual hydrocarbons from the matured steam chamber while producing hydrocarbons from the operating steam chamber.

The process may further include about 55% to about 80% of the residual hydrocarbons being recovered from the matured steam chamber.

The process may further include selecting an injection well which may include selecting several injection wells to achieve a suitable injection pattern proximate the boundary.

The process may further include injecting the oxygen-comprising gas which may include cyclical injection.

The injecting the oxygen-comprising gas may include intermittent injection.

The injecting the oxygen-comprising gas may include continuous injection.

In a further embodiment of the present invention, there is provided an *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber and previously having been used for fluid injection, the injection well being generally adjacent to a boundary between the matured steam chamber and the operating steam chamber;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) pressurizing the boundary with the oxygen-comprising gas to achieve an increased pressure generally within the boundary in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the

operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

In a further embodiment of the present invention, there is provided an *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber and previously having been used for fluid injection;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) pressurizing the matured steam chamber with the oxygen-comprising gas to achieve an increased pressure in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

The concentration of oxygen in the oxygen-comprising gas may be sufficient to sustain combustion in the matured steam chamber.

The process may further include sustaining combustion in the matured steam chamber which may include generating a combustion front.

The process may further include advancing the combustion front in a direction from a heel to a toe of the injection well.

The process may further include initially advancing the combustion front in an upward direction away from the injection well, and subsequently advancing the combustion front in a lateral direction along the injection well toward a toe of the injection well.

The combustion front may extend outwardly from a generally vertical portion of the injection well.

The generally vertical portion of the injection well may be perforated.

The injection well may be perforated along substantially all of a generally horizontal portion of the injection well.

The injection well may be perforated along an isolated section of a generally horizontal portion of the injection well.

The oxygen-comprising gas may be injected through the isolated section of the generally horizontal portion of the injection well.

The process may further include a velocity of the combustion front which may be about 0.038 m/day or less.

The process may further include a velocity of the combustion front which may be about 0.02 m/day.

The initial pressure of the matured steam chamber may be about 700 kPa to about 2500 kPa.

The initial temperature of the matured steam chamber may be about 165ºC or greater.

The initial temperature of the matured steam chamber may be about 180ºC or greater.

The initial temperature of the matured steam chamber may be about 165ºC to about 223ºC.

The process may further include an operating temperature of the operating steam chamber which may be about 180ºC or greater.

The operating temperature may be about 225ºC or greater.

The operating temperature may be about 270ºC or greater.

The operating pressure of the operating steam chamber may be about 1000 kPa to about 6500 kPa.

The fluid previously injected through the injection well may be steam.

The oxygen-comprising gas may be injected proximate to a lower portion of the reservoir.

The oxygen-comprising gas may be injected proximate to the operating steam chamber.

The oxygen-comprising gas may be injected proximate to the boundary.

The concentration of oxygen in the oxygen-comprising gas may be about 5% to about 100%.

The concentration of oxygen in the oxygen-comprising gas may be about 5% to about 40%.

The concentration of oxygen in the oxygen-comprising gas may be about 21% or more.

The oxygen-comprising gas may be air, oxygen-enriched air, or a combination thereof.

The oxygen-comprising gas may be wet or dry.

The dry oxygen-comprising gas may be co-injected with flue gas.

The process may further include selecting an injection well which may include selecting several injection wells to achieve a suitable injection pattern proximate the boundary.

The process may further include injecting the oxygen-comprising gas which may include cyclical injection.

The process may further include injecting the oxygen-comprising gas which may include intermittent injection.

The process may further include injecting the oxygen-comprising gas which may include continuous injection.

In a further embodiment of the present invention, there is provided an apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the operating steam chamber situated so that a boundary exists between the matured steam chamber and the operating steam chamber, the matured steam chamber having been previously processed using steam assisted gravity drainage (SAGD), the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, a initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well situated in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber, the injection well being generally adjacent to the boundary between the matured steam chamber and the operating steam chamber;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) means for modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the boundary such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable from the operating steam chamber without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) means for selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

In yet a further embodiment of the present invention, there is provided an apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) means for modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the matured steam chamber such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber and maintaining a predetermined pressure in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of

hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) means for selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

A generally vertical portion of the injection well may be perforated.

The injection well may be perforated along substantially all of a generally horizontal portion of the injection well.

The injection well may be perforated along an isolated section of a generally horizontal portion of the injection well.

The injection well may have been previously used for fluid injection.

The fluid may be steam.

In a further embodiment of the present invention, there is provided an apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the

matured steam chamber and previously having been used for fluid injection, the injection well being generally adjacent to a boundary between the matured steam chamber and the operating steam chamber;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) means for pressurizing the boundary with the oxygen-comprising gas to achieve an increased pressure generally within the boundary in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

In yet a further embodiment of the present invention, there is provided an apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the

matured steam chamber and previously having been used for fluid injection;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) means for pressurizing the matured steam chamber with the oxygen-comprising gas to achieve an increased pressure in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

The apparatus may further include a generally vertical portion of the injection well which may be perforated.

The injection well may be perforated along substantially all of a generally horizontal portion of the injection well.

The injection well may be perforated along an isolated section of a generally horizontal portion of the injection well.

BRIEF DESCRIPTION OF THE DRAWINGS

In accompanying drawings which illustrate embodiments of the invention,

Fig. **1A** illustrates a three dimensional schematic diagram showing a configuration of multi-pad patterns of well pairs for SAGD operations, including a matured steam chamber generally adjacent an operating steam chamber;

Fig. **1B** illustrates a three dimensional schematic diagram showing a configuration of multi-pad patterns of well pairs for SAGD operations, including a matured steam chamber generally adjacent an operating steam chamber;

Fig. **1C** illustrates a three dimensional schematic diagram showing a configuration of multi-pad patterns of well pairs for SAGD operations, including a matured steam chamber generally adjacent an operating steam chamber;

Fig. **1D** illustrates a three dimensional schematic diagram showing a configuration of multi-pad patterns of well pairs for SAGD operations, including a matured steam chamber generally adjacent an operating steam chamber;

Fig. **1E** illustrates a three dimensional schematic diagram showing a configuration of multi-pad patterns of well pairs for SAGD operations, including a matured steam chamber generally adjacent an operating steam chamber;

Fig. **2A** illustrates a temperature profile showing oil saturation distributions in the reservoir after approximately 7 years of SAGD operation in Pad 1;

Fig. **2B** illustrates a temperature profile showing oil saturation distributions in the reservoir after approximately 3 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **2C** illustrates a temperature profile showing oil saturation distributions in the reservoir after approximately 7 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **3A** illustrates a temperature profile showing temperature distributions in the reservoir after approximately 7 years of SAGD operation in Pad 1;

Fig. **3B** illustrates a temperature profile showing temperature distributions in the reservoir after approximately 3 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **3C** illustrates a temperature profile showing temperature distributions in the reservoir after approximately 7 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **4A** illustrates a temperature profile showing gas mole fraction of water distributions in the reservoir after approximately 7 years of SAGD operation in Pad 1;

Fig. **4B** illustrates a temperature profile showing gas mole fraction of water distributions in the reservoir after approximately 3 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **4C** illustrates a temperature profile showing gas mole fraction of water distributions in the reservoir after approximately 7 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **5A** illustrates a temperature profile showing reservoir pressure distributions in the reservoir after approximately 7 years of SAGD operation in Pad 1;

Fig. **5B** illustrates a temperature profile showing reservoir pressure distributions in the reservoir after approximately 3 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **5C** illustrates a temperature profile showing reservoir pressure distributions in the reservoir after approximately 7 years of SAGD operation in Pad 2 and comprising injection of an oxygen-comprising gas in Pad 1;

Fig. **6A** illustrates a temperature profile showing gas mole fraction of oxygen distributions in the reservoir after approximately 7 years of SAGD operation in Pad 1;

Fig. **6B** illustrates a temperature profile showing gas mole fraction of oxygen distributions in the reservoir after approximately 3 years of SAGD operation in Pad 2 comprising injection of oxygen-comprising gas in Pad 1;

Fig. **6C** illustrates a temperature profile showing gas mole fraction of oxygen distributions in the reservoir after approximately 7 years of SAGD operation in Pad 2 comprising injection of oxygen-comprising gas in Pad 1;

Fig. **7** is a graph illustrating steam injection rate and timing for Pad 1 and Pad 2 when SAGD operation is developed during different stages, reservoir pressure, and oxygen-comprising gas injection rate and time;

Fig. **8** is a graph illustrating a comparison of instantaneous steam-oil ratios for Pad 1 and Pad 2 for two cases: case 1 in which Pad 2 undergoes SAGD operation while an oxygen-comprising gas is injected in Pad 1, and case 2 in which Pad 2 undergoes SAGD operation while steam injection is terminated in Pad 1;

Fig. **9** is a graph illustrating comparative cumulative oil production after approximately 7 years of SAGD operation in Pad 1 and after approximately 10 years of SAGD operation in Pad 2, comprising injection of the oxygen-comprising gas in Pad 1 during SAGD operation in Pad 2 for two cases: case 1 in which Pad 2 undergoes SAGD operation while an oxygen-comprising gas is injected in Pad 1, and case 2 in which Pad 2 undergoes SAGD operation while steam injection is terminated in Pad 1;

Fig. **10** illustrates a schematic diagram of a well pair and injection of an oxygen-comprising gas through a selected horizontal portion of a former SAGD horizontal steam injection well configured for injection of the oxygen-comprising gas, upward and lateral propagation of a hot temperature front, and production of fluids (combustion gas, hydrocarbons) though a former SAGD production well;

Fig. **11** illustrates a schematic diagram of a well pair and injection of an oxygen-comprising gas through a selected vertical potion of a former SAGD horizontal steam injection well configured for injection of the oxygen-comprising gas, propagation of a hot front from a heel of the injection well toward a toe of the injection well, and production of fluids (combustion gas, hydrocarbons) through a horizontal portion of a former SAGD production well;

Fig. **12** illustrates a schematic diagram of a well pair and injection of an oxygen-comprising gas according to another embodiment;

Fig. **13** illustrates a schematic diagram of a well pair and injection of an oxygen-comprising gas according to another embodiment;

Fig. **14** illustrates a temperature profile showing an example of results obtained from a multi-well configuration, with the air injector being on the edge well which is the closest to the generally adjacent operating (immature) SAGD pad(s) (Case 1);

Fig. **15** illustrates a temperature profile showing an example of results obtained from a multi-well configuration, with the air injector being an inner well within the mature chamber (Case 2);

Fig. **16** illustrates a temperature profile showing an example of results obtained from a multi-well configuration, with the air injector being an inner well within the mature chamber (Case 3);

Fig. **17** illustrates a temperature profile showing an example of results obtained from a multi-well configuration, with the air injector being on the edge well which is the far end to the generally adjacent operating (immature) SAGD pad(s) (Case 4);

Fig. **18** illustrates a temperature profile showing an example of results obtained from a multi-well configuration, with two air injectors being set side by side (7 years SAGD in Pad 1; 1.5 years of SAGD operation in Pad 2 and air injection in Pad 1) (Case 5);

Fig. **19** is a graph showing the effects of cyclical (periodic) injection of air;

Fig. **20A** illustrates a temperature profile showing injecting air to maintain pressure of Pad 1 case;

Fig. **20B** illustrates a temperature profile showing the effects taking place without pressure maintenance in the mature chamber for comparison with Fig. **20A**;

Fig. **21A** illustrates a temperature profile showing the effect of maintaining pressure in the mature chamber;

Fig. **21B** illustrates a temperature profile for comparison with Fig. **21A**;

Fig. **22A** illustrates a temperature profile showing slowed down temperature drop in the mature SAGD chamber; and

Fig. **22B** illustrates a temperature profile for comparison with Fig. **22A**.

DETAILED DESCRIPTION

Reference will now be made in detail to implementations and embodiments of various aspects and variations to the invention, examples of which are illustrated in the accompanying drawings.

In various aspects, the present invention involves increasing *in situ* recovery of hydrocarbons from Steam Assisted Gravity Drainage (SAGD) operations by reducing the loss of fluid from SAGD operating chambers generally adjacent or generally proximate to SAGD matured chambers in a hydrocarbon-containing reservoir field. In various embodiments, the present process and apparatus is applicable to previous SAGD developments when the production at previous SAGD well(s) in such a development declines. In various embodiments, new wells may be added into reservoir and put bitumen production on line.

Fig. **1A** to **1E** (hereinafter "Fig. **1**") shows schematic diagrams in various embodiments in which a reservoir with operating and matured pads comprises operating and matured steam chambers (also referred to as operating chambers and matured chambers). As illustrated in the various embodiments shown in Fig. **1**, a matured chamber is generally adjacent to an operating chamber. In various embodiments, there may be a buffer zone having variable width or thickness between the matured and operating steam chambers. The buffer zone may also be referred to as a boundary. In various embodiments, the width or thickness of the buffer zone may vary with varying reservoir properties such as, for example, reservoir thickness, fluid properties and saturations (e.g., formation water and bitumen), initial reservoir pressure, steam injection pressure and volume, and steam quality. In various embodiments, when multiple SAGD well pairs are present as pad(s) in the reservoir, each SAGD well producer/pad drains bitumen from the reservoir within its own region. As a result, in some embodiments, there may be generally no flow in the reservoir across the well's drainage area (i.e. a defined area is created with generally no production-affected or generally no drainage interference from edges of drainage areas between SAGD wells or SAGD pads). The drainage areas are time dependent or dynamic in nature,

and within the increase in heat transfer, some of the previous non-communicating systems may become communicating systems due to viscosity reduction as a result of steam injection, so that the boundary between the operating and matured chambers might be changed (e.g., width and properties such as permeability may change) with changes in operation. In various embodiments, the minimum distance of an "edge" well to the boundary or buffer zone of a pad may be about half the distance of the well spacing of an inner well pair. In various embodiments the boundary or buffer zone may have a width ranging from about 50 to 80 m, about 80 m to 160 m, or about 160 to 200 m (including for "T" type well configurations).

The boundary may be defined by the following physical characteristics:

1. any kind of fluid inflow (water, heated bitumen, steam, non-condensable gas);
2. pressure;
3. temperature;
4. a combination of the above factors.

In various embodiments for example, if one detects movement of fluids within an area of the operating chamber generally adjacent the matured chamber in a reservoir, reservoir pressure and formation temperature rising or being higher than the initial reservoir pressure and temperature in a certain area of the operating chamber generally adjacent the matured chamber, one may conclude that this area is within the boundary and may be regarded as forming the boundary. The properties of the boundary, including its width, will vary in various embodiments depending on the properties of the reservoir due to numerous factors including, for example, the reservoir thickness, fluid content, initial reservoir pressure, operating steam injection pressure, steam quality.

According to a first embodiment, the present invention involves injection of an oxygen-comprising gas into the matured steam chamber that is generally adjacent to or proximate to the adjacent operating steam chamber in a SAGD

pad so as to create and maintain a selected pressure within the matured chamber, the pressure being sufficient to reduce a cross-flow of fluid such as steam from the operating chamber into the matured chamber. In various embodiments, it is the pressure difference that is one of the dominant factors resulting in fluid flow through porous media in the reservoir (e.g., steam cross flow). For example, if the injection of steam is stopped, the rate of pressure drop may range from about 1 to about 3.9 kPa/d for a SAGD chamber. If there is generally no pressure difference between matured chamber and operating immature chamber, there would be generally no fluid flow between these chambers. In various embodiments the selected pressure in the matured steam chamber may range from about 0 kPa to about 200 kPa, which results in a reduction of the cross-flow of fluid such as steam between the chambers.

In another embodiment, the present invention involves injection of the oxygen-comprising gas into a region of the matured steam chamber that is generally adjacent to the adjacent operating chamber such that the pressure within that region of the matured chamber can generally reach a value referred to as an "optimum pressure value" (also referred to as "sufficient pressure value"). The sufficient pressure value may be a pressure value slightly lower than the pressure of the adjacent operating chamber. In various embodiments, the sufficient pressure value may change depending on the geology, operational conditions, the degree of depletion and the duration of depletion of the matured chamber. For example, in selected embodiments, to achieve the sufficient pressure value, a pressure difference between the pressure in the operating steam chamber and the pressure in the matured steam chamber or generally within the region of the matured steam chamber generally adjacent the operating steam chamber may range from about 0 kPa to about 200 kPa, which results in a reduction of the cross-flow of fluid such as steam between the chambers.

In another embodiment, the present invention involves injection of the oxygen-comprising gas into a region of the matured steam chamber that is generally proximate to the adjacent operating chamber such that the pressure within the

region can generally reach a sufficient pressure value relative to the pressure of the adjacent operating chamber. The sufficient pressure value may range from about 0 kPa to about 200 kPa, which results in a reduction of the cross-flow of fluid such as steam between the chambers.

In an alternative embodiment, one or more of the former steam injectors may be converted into an oxygen-comprising gas injector(s). The well location of the oxygen-comprising gas injector(s) may be the location of any previous steam injector. For example, in various embodiments, an edge well pair or any well generally away from the edge well in the mature chamber or matured pad/pattern which is generally adjacent to the operating (immature) chamber or operating SAGD well pairs may be selected, so long as sufficient pressure (i.e., an optimum pressure value) is achieved within the matured steam chamber relative to the pressure in the operating steam chamber to reduce the cross-flow of fluid from the operating chamber into the adjacent matured chamber. In this embodiment, the sufficient pressure value in the matured steam chamber may range from about 0 kPa to about 200 kPa. In various embodiments, when one or more of the oxygen comprising gas injector(s) is selected, other previous steam injectors within the mature SAGD chamber may be converted into producers to produce oil and gas.

Therefore, in various aspects of the invention, injection of the oxygen-comprising gas into the matured steam chamber adjacent to the operating steam chamber results in creating a pressure barrier operable to reduce steam leaking from the operating chamber into the matured chamber. In some embodiments, it may be preferable to inject the oxygen-comprising gas into a region of the matured steam chamber that is generally adjacent to or proximate to the buffer zone (also referred to as the boundary) between the matured and operating chambers because such injection may allow using lower volumes of the oxygen-comprising gas. In various embodiments, the injection of the oxygen-comprising gas according to the embodiments described above may be used as a strategy for increasing the recovery of hydrocarbons from the reservoir as a whole.

In various embodiments, the oxygen-comprising gas is injected into the matured steam chamber through a former SAGD injection well that is the closest to the generally adjacent SAGD operating well pairs (for example, the previous steam injector is converted into an oxygen comprising gas injector), and the previous SAGD producers remain open to producing the gas and oil. In various embodiments, the parameters for those wells are set to meet the requirements for pressure maintenance under the specific operating conditions. In various embodiments, if the reservoir conditions (e.g., temperature, pressure, oxygen concentration) are appropriate, ignition or combustion may be initiated in the matured steam chamber which results in oxidation reactions between the oxygen in the oxygen-comprising gas and the remaining residual hydrocarbons such as bitumen which may have a concentration of about 5% or more.

In various embodiments, the term "hydrocarbon" relates to mixtures of varying compositions comprising hydrocarbons in the gaseous, liquid or solid states, which may be in combination with other fluids (liquids and gases) that are not hydrocarbons. The terms "heavy oil", "extra heavy oil", and "bitumen" refer to hydrocarbons occurring in semi-solid or solid form having a viscosity in the range of about 100,000 to over 1,000,000 pascal-second measured at original *in situ* deposit temperature. The terms "hydrocarbon", "oil" and "bitumen" are used interchangeably.

Depending on the *in situ* density and viscosity of the hydrocarbon, the hydrocarbon may comprise, for example, a combination of heavy oil, extra heavy oil and bitumen. Heavy crude oil may be defined as any liquid petroleum hydrocarbon having an API gravity less than about 20°, specific gravity greater than about 0.933 (g/ml), and viscosity greater than 100 mill-centipoise (m Pa•s). Oil may be defined as a hydrocarbon mobile at reservoir conditions. Extra heavy oil from the Orinoco region, for example, may be defined as having a viscosity of over 100,000 mill-centipoise (m Pa•s) and about 10° API gravity. The API gravity of bitumen ranges from about 12° >

API > about 7° and the viscosity is greater than about 100,000,000 m Pa•s. Bitumen is generally non-mobile at reservoir conditions.

In various embodiments, the term "reservoir" refers to a hydrocarbon-comprising formation having an upper portion and a bottom portion. The reservoir may comprise a single formation or one or more formations having varying characteristics, which may also be viewed as individual "reservoirs". A SAGD reservoir is a formation which has been or is being processed using SAGD. The SAGD reservoir as a whole may comprise regions undergoing various stages of SAGD operations (e.g., operating steam chambers in ramp up and plateau stages, matured steam chambers in wind down stages, coalesced steam chambers).

In various embodiments, the terms "chamber" or "steam chamber" generally relate to a region within the reservoir, and in particular a hydrocarbon-bearing zone of the reservoir, where reservoir fluids are in communication with a particular well or wells. In various embodiments, the term "steam chamber" relates to a portion of the reservoir into which steam or other fluid (e.g., a solvent in combination with steam) has been injected, and which forms a region which may grow vertically and horizontally in the reservoir. In SAGD, the steam chamber is a region in which bitumen, steam condensate, and associated non-condensate gases in the reservoir are in communication with a steam injection well and where mobilized hydrocarbons primarily drain into a production well. The term "steam chamber" also relates to the volume of the reservoir in which mobile steam exists for an extended period of time. Within the steam chamber, rock temperature rises to a point at which steam vapor can be sustained at reservoir pressure conditions. The steam chamber may be generally found in the upper portion of the reservoir between the injection and production wells where steam has broken through to the production well. With time, the steam chamber may expand to cover an entire area of a pad development ("Thermal Recovery of Oil & Bitumen", Roger M. Butler, 1991, ISBN 013-914953-8, pp.287-289, Prentice Hall, Englewood Cliffs, New Jersey 07632).

In various embodiments, the steam chamber in the SAGD reservoir has generally uniform temperature and pressure. Depending on the stage of a particular SAGD process, the steam chamber may be a relatively high pressure steam chamber such as, for example, the operating steam chamber in SAGD from which production of hydrocarbons occurs, or a relatively low pressure steam chamber such as, for example, the matured steam chamber in SAGD generally depleted of hydrocarbons. In various embodiments, the operating steam chamber may have a pressure in the range from about 1000 kPa to about 6,500 kPa, and a temperature in the range from about 180°C to over 270°C during SAGD operation. In SAGD, when the operating steam chamber nears depletion and steam injection is discontinued, steam vapor condenses and the reservoir pressure drops, at which point the steam chamber is matured. In various embodiments, in the wind down stage of SAGD, the matured steam chamber may have, for example, a pressure in the range from about 700 kPa to about 2500 kPa and a temperature in the range of about 160°C to about 225°C, about 162 °C to about 223 °C, or about 165 °C to about 223 °C. In particular embodiments, the temperature may be, for example, about 162 °C, 180°C or about 200°C.

In various embodiments, the term “operating steam chamber” also broadly relates to a steam chamber in an undepleted or partially depleted *in situ* hydrocarbon reservoir into which steam or other fluid has been injected through one or more injection wells, and from which economic production of oil (e.g., production where RF> about 55%) may be obtained through one or more corresponding production wells using, for example, SAGD. In the SAGD reservoir, a steam chamber or a reservoir region may be considered as “operating” when it has been operating for about eighteen to about sixty months since the start up or circulation stage up to a point when the economical benefits of oil production are outweighed by the costs.

In various embodiments, the term “matured steam chamber” broadly relates to a steam chamber in a hydrocarbon-containing reservoir that has been

depleted in the hydrocarbons through previous *in situ* operations. For example, in SAGD, a steam chamber or a reservoir region may be considered as "matured" when it has reached a stage where greater than about 55% of the original hydrocarbon content in the reservoir has been recovered and where the steam-to-oil ratio is above a value which indicates that it is no longer economical to produce residual oil.

In various embodiments, a suitable matured steam chamber in the SAGD reservoir comprises former injection wells through which steam or other fluid was previously injected into the reservoir, and production wells through which the hydrocarbons and other fluids were recovered. In various embodiments, the process and system of the present invention utilizes existing SAGD wells and well pattern layouts, which may include one or more SAGD well pads or patterns consisting of two or more well pairs per well pad. In various embodiments, original SAGD well pairs, such as previous steam injection wells, are converted into injection wells for injecting the oxygen-comprising gas. In various embodiments, the oxygen-comprising gas may be injected in various ways, including cyclical and intermittent injection. The original wells in the matured steam chamber in the SAGD reservoir may be modified in various ways to facilitate the process and system of the present invention. In various embodiments, the spacing between the wells in SAGD is generally about 100 m and the length of the horizontal well is generally about 500 m or above. Thus, the resultant surface area is relatively large, and therefore it may be more economical in some embodiments to use only a portion of the well for perforation and injection of the oxygen-comprising gas. Thus, in various embodiments, in order to use the minimum oxygen-comprising flux injected, the oxygen-comprising gas may be injected via a portion or several portions of the initial horizontal wellbore of the steam injector as is shown in Fig. **10** and Fig. **11**. Figs. **10** and **11** show injection and production well pairs, wherein the injection well is situated generally above the production well.

In the embodiment in Fig. **10**, the injection well is perforated along generally substantially all or a portion of the horizontal portion of the former steam

injection well. In this embodiment, the combustion front generated rises upwardly toward the upper portion of the reservoir. The mobilized hydrocarbon may be collected by the production well situated generally below the oxygen comprising gas injection well. In this respect, a parker may be used to isolate the horizontal wellbore section, and the oxygen-comprising gas such as air may be injected through the selected portion.

In another embodiment, a vertical section in the bitumen bearing zone may be prorated and a dual completion system may be employed as is shown in Fig. **11**. Air may be injected into the formation through perforations and vent combustion gas may be vented through tubing along the horizontal well section of the original steam injection well.

In Fig. **11**, the injection well is perforated along generally substantially all or a portion of the vertical portion of the previous or former steam injection well for injection of the oxygen comprising gas. The combustion front created according to the embodiment in Fig. **11** extends outwardly from the generally vertical portion of the injection well (i.e., from heel to toe), and the combustion gases drain into the generally horizontal portion of the injection well. As is shown in the embodiment in Fig. **11**, the mobilized hydrocarbons may drain into the generally horizontal portion of the production well.

Although the wells in the matured steam chamber have been functionally identified as production or injection wells, such identification does not imply that the wells are to be used exclusively for the particular purpose. As is illustrated in the Examples, the wells may have one or more functions (e.g., for injecting the oxygen-comprising gas and venting a combustion gas formed during pressurization of the matured steam chamber).

As was described above, after steam injection is terminated in a SAGD operation, injection of the oxygen comprising gas may be initiated instead of steam. In SAGD, the injected steam is wet whereas in the various embodiments of the present invention, the injected oxygen comprising gas

may be generally dry. In various other embodiments, the oxygen comprising gas may be generally wet. For example, if the oxidation reactions are high temperature oxidation reactions or if combustion dominates, more heat will be generated in-situ. In such embodiments, in which air may be used as the oxygen-comprising gas, water-air (wet air) co-injection may be used to utilize the heat generated from combustion. Liquid water may be evaluated and becomes steam. However, in such embodiments, wet combustion may result in a lower peak temperature of combustion as compared with dry combustion. The injection of water with air improves the *in situ* combustion process by lowering fuel and air requirements and increasing front velocity. Both fuel and air are reduced up to 20% at high water-to-air ratios (WAR), when compared to dry combustion (WAR=0). Because of its high heat capacity, water scavenges most of the generated heat stored behind the burning front and carries superheated steam over the front to the steam plateau region where the oil bank is found in front of the combustion front. The water injected may be cold water, hot water or steam. (e.g., US Patent 4729431 - Oil recovery by quenched in situ combustion). The combustion front velocity increases with increases in WAR. But at very high WAR values, the water zone approaches the burning zone from behind the front.

In various embodiments, once combustion has been initiated, an adequate supply of the oxygen-comprising gas is important. For example, once the combustion front has propagated a sufficient distance away from the wellbore to achieve a generally stabilized burn, it may be preferred, but not essential, to convert the dry combustion drive to a water and oxygen comprising gas co-injection. This may be done by injecting water concurrently or alternately with the oxygen-comprising gas through the injection well or wells. In various embodiments, it may be preferred to initially inject water at a WAR of about 50 to about 500 bbls/MMCFair. After the combustion within the mature SAGD chamber has generally stabilized, the WAR can be increased.

In various embodiments, a generally dry oxygen-comprising gas may be co-injected with another fluid, such as flue gas (e.g., mainly nitrogen and carbon

dioxide) in order to maintain the pressure, the temperature or a combination thereof within the boundary between the matured and operating chambers in a range which reduces or prevents fluid cross-flow from the operating chamber into the matured chamber. In various embodiments, the term "oxygen-comprising gas" relates to a fluid such as for example air, enriched air, pure oxygen, or above 5% concentration of oxygen-comprising non-condensable gas mixture. In various embodiments, the concentration of oxygen in the oxygen-comprising gas may range from about 5% to about 100%, about 5 % to about 40%, or about 7% to about 40%. For example, the oxygen-comprising gas may be air, which comprises about 21% oxygen. In various embodiments, the oxygen-comprising gas has the capability of supporting *in situ* combustion. In particular embodiments, the amount of oxygen in the oxygen-comprising gas may be tailored to achieve a desired level of *in situ* combustion as a strategy for reducing fluid leak from the operating steam chamber into the adjacent matured steam chamber. The combustion and the heat generated will help to maintain the pressure generally within the boundary of the matured steam chamber and the adjacent operating steam chamber. In various embodiments, the oxygen-comprising gas may comprise about 5 % to about 100 % of oxygen and the residual bitumen content may range from about 0.05 % to about 5 % for achieving ignition and sustaining combustion while avoiding the risk of an explosion.

Depending on the content of oxygen in the oxygen-comprising gas and the residual hydrocarbon content in the matured steam chamber, the generation of heat and flue gases (e.g., N_2 and CO_2) through oxidation reactions occurring within the matured steam chamber may be modulated to obtain the desired conditions for maximizing hydrocarbon recovery from the generally adjacent operating steam chamber(s) and, in some embodiments, simultaneous recovery of the residual hydrocarbons from the matured steam chamber. In various embodiments, the pressure, temperature, oxygen concentration, rate of injection and volume of the oxygen-comprising gas injected may all be modulated to achieve a certain degree of *in situ* combustion in the matured steam chamber and the desired level of

pressurization of the matured steam chamber as a whole or generally within the boundary adjacent to or proximate to the operating steam chamber. In various embodiments, an artificial ignition source may be required, which may for example comprise auto-ignition. In some embodiments, if the temperature in the matured steam chamber is below about 200°C, the artificial ignition source may be required to help initiate *in situ* combustion in the matured steam chamber. The oxygen-comprising gas may have a temperature in the range of about 180°C to about 270°C and pressure in the range of about 1000 kPa to about 6500 kPa prior to injection into the matured steam chamber. The matured steam chamber may have a temperature above 180°C and pressure about 200 kPa less than the pressure in the operating steam chamber. The temperature of the matured steam chamber prior to injection of the oxygen-comprising gas will vary depending on the production stages of the adjacent operational steam chambers and reservoir properties. The volume of the oxygen comprising gas required will vary depending on the operational conditions, and may be modulated to achieve desired levels of combustion.

In various embodiments, it is important to control the combustion in the matured steam chamber by controlling the rate of injection of the oxygen-comprising gas (e.g., air or air enriched with oxygen), the content of oxygen, or a combination thereof.

For example, Nelson and McNeil (Nelson, T.W., and McNeil, J.S., How to Engineer an In Situ Combustion Project; The Oil and Gas Journal, p. 58, June 5, 1961) proposed a minimum velocity required to sustain the propagation of a high temperature combustion was 0.038m/day. The minimum oxygen flux (Ufin) required maintaining this velocity may be estimated based on the following relationship.

$$U_{fm} = Ar \times U_{bm}$$

where:

Ar: Oxygen-comprising gas requirement ($m^3(ST)/m^3$)

U_{bm}: Minimum burn front velocity (m/hour)

U_{fin}: Minimum oxygen flux (m^3(ST)/m^2-hour)

In various embodiments, a flux of the oxygen comprising gas may be calculated from the oxygen gas flux based on the oxygen concentration within the oxygen comprising gas, and is one parameter used to control the combustion and thus the temperature of the matured chamber. If air is used, oxygen gas flux may be called air flux. The flux of the oxygen comprising gas allows modulating the size of the combustion front. Based on R.G. Moore etc. (R.G.Moore, C.J. Laureshen, S.A.Mehta, M.G. Ursenbach, Observations and Design Considerations for In Situ Combustion Projects, Journal of Canadian Petroleum Technology, Special Edition 1999, Vol.38, No.13, 1999), Canadian heavy oils, the air requirement may normally fall in the range from 250 to 350 m^3(ST)/m^3. If an air requirement is assumed to be about 350 m^3(ST)/m^3 for Athabasca type of bitumen, and Nelson and McNeil's minimum velocity of 0.038m/day, the air flux may be about 13.30 m^3(ST)/m^2-day. Once the air requirement is fixed, the air flux determines the velocity of combustion front movement within the reservoir.

The velocity of combustion front generated according to the various embodiments may be kept even lower than that suggested by Nelson and McNeil (i.e. lower than 0.038m/day, around about 0.02m/day), as compared to conventional in-situ combustion process (such as THAI (also known as toe-to-heel air injection for example) where the air (or oxygen-comprising gas) flux is higher than the number that Nelson and McNeil suggested. Moore (1999) indicated for a possible in-situ combustion process, it is possible for a minimum air flux to be greater than 1.0 m^3(ST)/m^2-hour (or 24.0 m^3(ST)/m^2-day).

The minimum air is proportional to both the fuel deposition and heat loss (Partha Sarathi, S., In Situ Combustion Handbook – Principles and Practices, National Petroleum Technology Report, U.S. Department of Energy, Tulsa, Oklahoma, 1999). The higher the fuel deposition, the more air requirement is required, resulting in higher air flux. Similarly, the higher the heat loss from the

formation to overburden and underburden formation, the higher air flux is needed. In the various embodiments, the matured steam chamber is generally warm or hot, and in various embodiments may have a temperature ranging from about 165°C or greater. When the formation is heated, heat loss will be smaller than is the case for conventional in-situ combustion processes, including the THAI process. The fuel deposition also will be less than the post-SAGD case (Sarathi (1999), Beglave (2006)).

Several differences may be identified between the various aspects of the present invention and other operations such as THAI and EnCana's post-SAGD air injection process. For example:

1. Oxygen-comprising gas such as, for example air is injected into a matured SAGD chamber where bitumen saturation (or saturation of oil or other hydrocarbons) is much lower than the initial bitumen saturation.
    - Generally, the saturation may be approximately below about 30%, which is lesser than a case of conventional in-situ combustion and THAI process (above 70%);
    - Since the matured chamber is generally warm (or hot in some embodiments, with a temperature of, for example, above about 201°C), the viscosity of remaining bitumen is much lower than that in THAI for example, so that the mobility of liquid (bitumen, and condensate water) is higher.
    - In the various embodiments of the present invention, pressure maintenance is maintained in the matured chamber generally adjacent the operating chamber or at a boundary of the generally adjacent matured and operating chambers; whereas, EnCana's post-SAGD air injection process and THAI are focussed on bitumen recovery rather than maintaining pressure in the matured steam chamber or at the boundary.
2. In various embodiments, the present invention discloses various approaches for delivering air or oxygen comprising gas into the

matured chamber or into the region at the boundary of generally adjacent matured and operating chambers.

3. In various embodiments, existing multi-well SAGD pairs in the matured steam chamber, air injector(s)/(oil producers and gas producers) are utilized e.g., within an original SAGD pad, one or more of the previous steam injector(s) is converted into an air injector; the other steam injector will be converted into gas producers to vent out combustion gas. The previous producers may remain open for production. In various embodiments, both the gas producers and oil producers operating parameters are adjusted to the well constraints to achieve the desired pressure maintenance. This combination may be used to separate combustion gas and liquid within the reservoir:

    a. To deliver air injection for each injector
        i. To perforate the vertical section of the previous horizontal steam injector, and by using the dual-completion system, i.e., to inject air through perforations of the vertical section where it penetrates through the bitumen bearing zone, and then to produce combustion gas back from the horizontal section and flow through the tubing back to surface. The combustion front moves forward from the heel to the toe; or
        ii. To distribute air only through a part of the previous horizontal section of the steam injector.

High mobility in the matured steam chamber is created because the chamber is relatively hot, whereas in THAI, the chamber is cold. Furthermore, in various embodiments of the present invention, the combustion front may expand from heel-to-toe unlike in THAI (Fig. **11**) or upwardly from a generally horizontal portion of the injection well toward the upper portion of the reservoir (Fig. **11**). The combustion zone or "hot spot" in the various aspects of the present invention develops rapidly, the combustion gas will fill the mature SAGD chamber to reach the sufficient or optimum pressure, which in turn

results in good performance for the adjacent operating SAGD pad or pattern (i.e., the adjacent operating immature SAGD pad or pattern).

In the process of the present invention, the temperature generally travels within the reservoirs a much shorter distance than the pressure. In various embodiments, this may be a consideration with regard to the volume of air or oxygen containing gas injected in order not to move the high temperature or combustion front too fast, which is controlled by the rate of injection. In various embodiments, combustion gas or flue gas (mainly N_2 and CO_2) are generated through the oxidation reactions *in-situ* and fill the void space of the mature SAGD chamber. By injecting the oxygen comprising gas according to the various embodiments, the pressure in the matured steam chamber is maintained which allows one to mitigate the matured steam chamber from becoming a thief zone for future or ongoing SAGD pattern nearby the matured steam chamber.

Injection of the oxygen-comprising gas according to various embodiments allows mobilizing the residual oil (unrecovered or remaining oil left in place from previous *in situ* recovery such as, for example, SAGD) in the matured steam chamber while simultaneously increasing oil production from adjacent operating steam chambers in the reservoir as a whole such that in the wind down stage minimal oil content will remain. The recovery of residual oil in the matured steam chamber may range from about 55% to above about 80%.

The production rate for recovering the residual hydrocarbons in the matured steam chamber may be controlled through the production rates of fluids, combustion gas, water and oil from the reservoir. To obtain an improved performance of the operating steam chambers adjacent to or proximate to the matured steam chamber, an optimum pressure should be maintained in the matured steam chamber as a whole or generally within the boundary between the matured steam chamber and the operating steam chamber to facilitate the operations, which may be generally similar or up to about 200 kPa lower than the pressure in the adjacent or proximate operating steam chamber. The

optimum pressure will also depend on the properties of one or more pads surrounding the matured steam chamber. For example, if the pads adjacent the matured steam chamber comprise operating steam chambers at various stages of SAGD, the pressure required to increase hydrocarbon production from several of the operating steam chambers may be different from the pressure required to increase hydrocarbon production in instances where only one operating steam chamber is adjacent the matured steam chamber.

In various embodiments, monitoring the reservoir pressure and other parameters such as produced gas compositions, temperature of oxygen-comprising gas injector(s) and producer(s) in both the operating and matured steam chambers may be performed in order to determine optimal injection rates of the oxygen-comprising gas for achieving an increased oil production as compared to oil production that may be achieved without injecting the oxygen-comprising gas into the matured steam chamber.

In various embodiments, the timing to commence the injection of the oxygen-containing gas into the matured steam chamber may be important to achieving suitable operational efficiencies. For example, injection of the oxygen-comprising gas into the matured steam chamber may be performed cyclically, and the injection cycle may depend on the properties and layout of the adjacent operating steam chambers. For example, the oxygen-comprising gas may be injected for a certain length of time and then shut in for a selected time interval. The injection rate and timing may be adjusted for each cycle based on the requirements for pressure maintenance design and target oil production. The production of oil and combustion gases can also operate cyclically. In various embodiments, free oxygen may be scrubbed from the matured steam chamber through the oxidation reactions. Utilizing the residual heat in the reservoir after steam injection has been stopped, will also assist with oxidation reactions, and in some embodiments, may influence the amount and composition of the oxygen-comprising gas to be injected into the matured steam chamber. In various embodiments, hydrocarbons may be

recovered selectively from the operating chamber, the matured chamber or from both the operating and matured chambers.

In various embodiments, the number of wells required for injecting the oxygen-comprising gas may vary based on operational requirements. In various embodiments, the physical arrangement of the wells on adjacent pads for injecting the oxygen-containing gas may vary. For example, the wells may have parallel-type side by side and toe-heel series-type side-by-side arrangements. In various embodiments, the injection wells in the matured steam chamber may be configured such that the oxygen-comprising gas is injected near the bottom of the reservoir to mobilize the residual hydrocarbons in the matured steam chamber for combustion, recovery or a combination thereof. In various embodiments, one or more injection wells may be positioned in the proximity of the production well for injecting the oxygen-comprising gas. In various embodiments, new injection wells may also be formed to achieve a desired configuration in the matured steam chamber for increasing the recovery of hydrocarbons.

In various embodiments, the extent of fluid communication between the operating and matured steam chambers may differ. The following factors may affect the extent of fluid communication: initial steam chamber size and chamber development, steam injection temperature and pressure, geological conditions (e.g., reservoir heterogeneity, pressure differences), injection pressure for the oxygen-comprising gas, cumulative oil produced, steam injected, and chamber cooling.

In various embodiments, reservoir geology may be an important consideration for maximizing the oil recovery from the reservoir. For example, if the reservoir comprises high permeability streaks or channels, channeling and early steam and oxygen breakthrough may occur. There may be a potential risk that the oxygen-comprising gas injected into the matured steam chamber may be captured by the production wells in the matured steam chamber. If the free oxygen is not consumed through oxidation or combustion, it may pose a

safety concern. In various embodiments, it is therefore contemplated that the levels of oxygen in the matured steam chamber and in the production wells of the matured steam chamber will be controlled to reduce the probability of an explosion. In order to reduce this kind of risk, knowledge of the reservoir geology and the oil production history in the reservoir is important. For example, integrated reservoir and geology information may be considered when choosing suitable injection wells for injecting the oxygen-comprising gas. In various embodiments, the injection rate of the oxygen-containing gas, for example, air or air enriched with oxygen, may be modulated so that high temperature oxidation or combustion will dominate in a high temperature regime within the matured steam chamber. As a result, efficiency of scrubbing the oxygen can be improved and the formation of low temperature oxidation products can be decreased or prevented. In various embodiments, oxygen and other gas monitoring devices may be installed on production facilities to reduce safety risks. Thus, monitoring the produced gas compositions may be used as an indication for combustion activity in the reservoir, and for moderating safety risks associated with gas levels.

In an embodiment comprising two SAGD pads for example, SAGD operation is performed on Pad 1 until recovery of hydrocarbons from Pad 1 becomes uneconomical, at which point steam injection is stopped and the operating steam chamber becomes “matured”. One or more of the injection wells in Pad 1 are then modified for injecting the oxygen-comprising gas such as, for example, air or oxygen-enriched air into the matured steam chamber. In various embodiments, SAGD operation on Pad 2 comprising the operating chamber, generally adjacent to Pad 1, may be performed simultaneously with the injection of the air or oxygen-enriched air into Pad 1. The rate of injection of the air or oxygen-enriched air, and the duration for injection in Pad 1 may be modulated based on, for example, the performance and operating conditions of Pad 2, the level of pressure to be maintained, the desired level of hydrocarbon recovery from Pad 1, Pad 2 or both, and the rate of fluid production (water, combustion gases). In various embodiments, an injection strategy for injecting the oxygen-containing gas is important for operational

control of both the oxygen-containing gas injection wells and the generally adjacent SAGD operations.

Injection of the oxygen-comprising gas such as air or oxygen-enriched air into the matured chamber provides several economic advantages over the use non-condensable gases (NCGs) such as, for example, N_2, CO_2, or CH_4. Injection of the NCGs may cause a significant reduction in the temperature of the matured steam chamber as there will be no combustion within the reservoir. Conversely, the use of the oxygen-comprising gas for pressurizing the matured steam chamber according to the various embodiments of the invention is more effective because the oxygen in the oxygen-comprising gas will combust. Thus, injection of the oxygen-comprising gas into the matured steam chambers allows generation of heat energy *in situ* through oxidation reactions within the matured steam chamber. Thus, injection of the oxygen-containing gas allows for the pressure to be generated and maintained not only through injection of a suitable volume of the gas but also through heat generation by combustion with the residual hydrocarbons in the matured steam chamber, which provides economic operational advantages.

The injection of the oxygen-comprising gas into the matured steam chamber generally within the boundary between the matured steam chamber and the adjacent or proximate operating steam chamber provides a method of isolating the matured steam chamber or a pattern of matured steam chambers from the adjacent to or proximate to operating steam chambers. The injection of the oxygen-comprising gas will allow one to maintain the reservoir pressure and slow down the temperature drop as the steam vapour in the matured steam chamber condenses. The oxygen-comprising gas injection will also reduce steam cross flow between the matured steam chamber patterns and the generally adjacent or proximate operating steam chamber patterns. Therefore, the performance of the operating steam chambers may be improved due to more efficient utilization of the steam, which will reflect a lower cSOR.

A further advantage of using the oxygen-comprising gas is that there is no supply limitation for the various sources of the oxygen-comprising gas (e.g., air or oxygen-enriched air), and thus this use is an economically attractive option. When combustion is initiated, energy utilization becomes more efficient for oxidation occurring within the matured steam chamber, and the natural temperature decline in the matured steam chamber is slowed by the heat energy. Furthermore, in various embodiments, utilization of the existing wells for the injection of the oxygen-comprising gas reduces material costs associated with implementing the process and system.

Duration of the injection of the oxygen-comprising gas into the matured chamber will vary depending on the properties of the matured steam chamber prior to injection (e.g., temperature, pressure) and on the operational stages of the operating steam chambers proximal to or generally adjacent the matured steam chamber. For example, if the operational steam chambers are in the early stages of SAGD, the interval for injecting the oxygen-comprising gas into the matured steam chamber may be longer than in circumstances where the operational steam chambers are in later stages of SAGD.

In various embodiments, the various ranges and ratios described may be derived from laboratory experiments, computer simulations or both to mimic the particular *in situ* extraction process and system, reservoir properties, effects of well layout, and desired injection of the oxygen-comprising gas.

In various embodiments, the mature chamber includes a chamber in which bitumen recovery factor has reached more than about 50 % to about 55 % during SAGD operation, in which the pressure may be above 1000 kPa, the temperature may be above 180°C, and the steam chamber is going to be abandoned with respect to further operation due to non-economic factors, or a combination thereof. Typically, steam injection may be continued into such a chamber as the normal SAGD operation is being terminated.

According to various embodiments, the oxygen-comprising gas, e.g., air, is injected into the mature (depleted) chamber. The process and apparatus of the present invention utilize the heat and flue gas generated *in situ* from the oxidation reactions between the oxygen-comprising gas injected and the bitumen remaining in the mature SAGD chamber (i.e., residual unrecovered bitumen). In various embodiments, combustion or oxidation reactions will occur when the oxygen containing gas (e.g. air) is injected into a warm chamber (which, in some embodiments, may be about 180°C or greater) and depleted bitumen bearing formation (matured chamber with residual bitumen), with high water saturation. In various embodiments, some energy, such high temperature and flue gas comprising mainly nitrogen and carbon dioxide will be generated within the mature SAGD chamber, which helps to prevent the mature chamber pressure from falling and slows down the temperature cooling when steam injection is terminated. Furthermore, the flue gas will fill the void spaces in the matured chamber.

In various embodiments, the maintained mature SAGD chamber pressure will "blunt" the steam chamber of the edge well(s) for the operating immature SAGD chamber(s) that are located generally adjacent to the mature SAGD chamber or well(s), which lessens steam cross flow (also referred to as steam leakage) from the operating (immature) SAGD chamber or well(s) into the generally adjacent mature chamber.

In various embodiments, various previous steam injector(s) that are located in the mature chamber may be kept open to produce combustion gases and hydrocarbon vapor gas and liquids (bitumen and water) while the producers located in the operating SAGD chamber continually produce bitumen. Various parameters associated with the injection and production wells in the matured and operating chambers such as, for example, minimum bottom pressure, maximum production rate for liquid and gas, may be modulated/controlled based on the level of pressure maintenance desired under particular operating and reservoir conditions.

In various embodiments, the rate of injection of the oxygen comprising gas (e.g., air rate of injection) may be kept as low as possible, which allows the combustion front to propagate from the injector at a rate of as low as about 0.038 m/day.

In various embodiments, it is preferable to maintain the pressure difference between the mature SAGD pad(s) or chamber and the generally adjacent or generally proximate operating SAGD pad(s) or chamber as low as possible. In various embodiments, a suitable pressure difference that reduces or avoids fluid cross flow from the operating chamber into the adjacent matured chamber may have a value about 50 kPa.

Various aspects of the invention may be implemented into multi-SAGD-well patterns/or pad(s) in the reservoir. In various aspects, the oxygen comprising gas (e.g., air) may be injected into the mature chamber via different configurations (or well patterns) as is shown in the Figures. In various aspects, the injection of the oxygen comprising gas may be performed in a continuous manner, intermittent or cyclical (periodic). For example, as is shown in the figures, in an embodiments involving cyclical injection of the oxygen comprising gas, the oxygen comprising gas may be continually injected for 3 months, the injection may be stopped for 2 months, and subsequently the injection may be resumed. In various embodiments, one or more injectors may be used for injecting the oxygen comprising gas. In embodiments in which a single injector is used for injecting the oxygen comprising gas, injection may be performed, for example, in a heel-to-toe manner or through a selected horizontal portion of the injection over a selected distance along the horizontal portion (e.g., about 50 m to about 200 m). Examples of the above described embodiments are further illustrated in the Figures.

EXAMPLES

Various aspects presented in the Figures in connection with the present invention have been modeled in a computer reservoir simulation, the Steam, Thermal, and Advanced Processes Reservoir Simulator (STARS), provided by Computer Modelling Group (CMG), based on a selected location of the geology model. Parameters for the simulations are chosen to mimic the parameters for the particular reservoir and the operating conditions for the operating and matured chambers/pads in the reservoir.

The following parameters were used for the simulation model:

TABLE **1**

Simulator	CMG STARS 2009 version		
Simulation components	Water, Bitumen (two pseudo components: Asphaltene and Maltene fractions), CO_2, Oxygen, Nitrogen, and Coke		
Formation properties	Fort McMurray type formation, the geology model for simulation is similar to the one used as the previous ASOSTRA UTF (Underground Test Facility)		
		Rich sand	Lean Sand
	Horizontal Permeability (md)	8000- 10000	3890
	Vertical Permeability (md)	3303 -5600	1945
	Porosity (faction)	0.35	0.30
	Oil saturation (fraction)	0.85	0.75
	Initial temperature (^oC)	9	9
	Initial Pressure (kPa)	530-840 kPa	
	Gross formation thickness (m)	48m	
Fluid properties	Bitumen properties are taken as Athabasca bitumen, which are accepted in the industry		

Figs. **1A** to **1C** illustrate schematic diagrams of three examples of layout or arrangement wells for a SAGD pad development, showing a reservoir comprising matured steam chambers generally adjacent to operating steam

chambers. As is shown in the figures, there is a "buffer" between the matured SAGD pad/pattern and an operating SAGD pad/pattern. The buffer forms a separation between the operating (immature) SAGD well pair and the mature well pair which may be over and above the nominal drainage width of both well pairs. An edge well pair within a pad is disposed to leave at least half distance of the inner well pair spacing to the boundary/edge of a particular approved development area.

Figs. **2A** to **2C** illustrate representations of oil profiles at various time periods for SAGD operations in an operating (immature) pad and injection of the oxygen comprising gas for pressure maintenance in a generally adjacent matured pad as an example of multiple well operation. Figures **2A** to **2C** each illustrate schematic representations of a vertical cross section of two SAGD Pads (patterns) as examples of multiple well operations. In these figures, each pad shown has four well pairs. The two pads are developed in the different time scheme. SAGD operation in Pad 1 on the right hand side of the figure was initiated seven years earlier than in Pad 2 on the left hand side of the figure. When Pad 1 reaches the matured stage after about 7 years SAGD operation, with the steam chamber coalescing and oil production declining, steam injection is stopped. Any one of the previous steam injectors which were located in the mature chamber in Pad 1 can be converted to injectors of an oxygen-comprising gas. As shown in these examples, the oxygen-comprising gas injector is selected so that it is the closest to the operating (immature) SAGD Pad 2. The adjacent operating (immature) SAGD pad (Pad 2) is operated according to conventional SAGD operations.

Figure **2A** illustrates oil saturation within the reservoir under initial conditions in which Pad 1 is at the end of former SAGD operation and Pad 2 is in an initial SAGD recovery process. The injection pressure for oxygen comprising gas injection is kept at the desired level for maintaining the pressure in the mature chamber. The previous steam injectors in the matured SAGD chamber are converted into producers for producing the combustion gas and liquid. The various embodiments shown utilizing the injection of oxygen comprising gas into

the matured chamber allow one to maintain a certain pressure in the mature SAGD chamber to reduce or avoid cross flow of fluid while producing the remaining hydrocarbons within the operating chamber and in some embodiments within the mature SAGD chamber.

The conditions of the reservoir in Figure **2B** and **2C** as simulated are representative of field reservoir conditions (bitumen saturation distribution) that may be selected with the timing of the oxygen-comprising gas injection into the mature SAGD chambers for pressure maintenance. Figure **2C** illustrates a later stage of this embodiment of the process of the invention. The embodiments in these three figures demonstrate using oxygen comprising gas injection into a mature SAGD pad (which is initially warm or hot), pressurizing the mature pad/pattern to achieve a desired pressure within the matured steam chamber such that cross flow of fluid from generally adjacent operating (immature) chamber is reduced or avoided. The area closet to the oxygen containing gas injector shows lowest of the oil saturation, which indicates that some oil within the mature chamber has been displaced out by the combustion front.

Figures **3A** to **3C** illustrate temperature profiles over time in the same well pair pattern and operation conditions as is described above in connection with Figures **2A** to **2C**. Figure **3A** shows the temperature distributions within the reservoir after Pad 1 matured and steam injection is stopped. Figure **3B** illustrates the temperature profiles after oxygen comprising gas injection is initiated in the matured steam chambers. In this embodiment, for example, oxygen comprising gas may be injected from the edge well which is generally adjacent to the operating (immature) SAGD chamber(s). The high temperature reaction zone or combustion front, which in this example is a temperature about 500°C to about 600°C, rising and moving toward the right side of the mature steam chamber where the producers are located. In the figures, the high temperature reaction zone or combustion front rises and moves toward the right side of the mature steam chamber where the gas venting-well is located. The process utilizes the high temperature generated from the combustion reactions as a result of injection of the oxygen comprising gas which slows down

cooling of the mature steam chamber while the matured steam chamber is pressurized (as a whole or at a region adjacent the operating chamber) and in which desired pressure is maintained to reduce or avoid cross flow of fluid from the operating (immature) steam chamber into the matured steam chamber.

Figures **4A** to **4C** show a time series of the gas mole fraction of water phase which represent steam saturation distribution within the reservoir according to various embodiments. These results are, in the same well or pad configuration and operation stages described above. Figure **4A** shows the vapor phase of water saturation distribution within the reservoir, which may be viewed as being indicative of steam saturation profiles before the termination of SAGD operation in the mature SAGD steam chamber for Pad 1. Figure **4B** illustrates steam saturation within the reservoir, especially in the operating (immature) steam chamber for Pad 2, when the normal SAGD process is operated before the individual SAGD steam chambers coalesce. There appears to be generally no steam cross flow between the mature steam chamber and the operating chamber. Figure **4C** shows a later stage indicating that the individual steam chambers in Pad 2 are now coalesced. The gradient of gas mole fraction of water shows that steam cross flow does not appear to be significant for this stage, which may be attributed to the oxygen containing gas being injected into the mature chamber to maintain the desired pressure in the mature chamber.

Figure **5A** to **5C** illustrate pressure profiles in the reservoir, with the same well or pad configuration and operation stages described above. Figure **5A** illustrates that the pressure at the moment of steam injection is terminated in the mature steam chamber in Pad 1. The pressure distribution in the matured steam chamber and the adjacent operating steam chamber indicates that the matured steam chamber becomes a pressure sink as the system is cooling.

Figure **5B** shows the reservoir pressure profile at the stage during which the oxygen comprising gas is initiated in the mature chamber in Pad 1. The heat energy and combustion gases (mainly comprising nitrogen, carbon dioxide, carbon monoxide, sulphur dioxide, hydrogen sulphur and water vapour) are generated by the oxidation reactions within the mature SAGD chamber. The

hot combustion gases tend to rise up from the oxygen comprising gas injection well and fill the reservoir where the chambers are depleted of oil and water condensate. The pressure is maintained at a desired level. Figure **5C** displays the pressure profile when the steam chamber in Pad 2 coalesces. The pressure in Pad 1 is maintained at a value generally similar to the pressure for ongoing SAGD operation in Pad 2.

Figures **6A** to **6C** illustrate the gas mole fraction of oxygen distribution when steam injection is stopped in Pad 1 and SAGD operation is started in Pad 2. Figure **6B** shows the gas mole fraction of oxygen at time points during which the oxygen comprising gas is injected into the same well configurations described above. Figure **6C** displays the continued injection of the oxygen-comprising gas, and oxygen spread and movement toward the mature chamber.

Figure **7** illustrates a graph demonstrating the timing of SAGD operation both in Pad 1 and Pad 2, steam injection rate and the timing and rate of injection of the oxygen comprising gas when the SAGD operation is mature. The timing for steam injection displays Pad 1 and Pad 2 are under different development stages. The reservoir pressure is maintained when oxygen comprising gas injection is implemented while the normal SAGD process is operated in Pad 2 with a slightly higher pressure than the pressure of oxygen comprising gas injection.

Figure **8** is a graph comparing the instantaneous steam-oil ratios for the two individual pads, Pad 1 and Pad 2, for two cases: 1) SAGD operation in Pad 2 while the oxygen containing gas is injected in Pad 1 (green line), and 2) SAGD operation in Pad 2 while steam injection is terminated in Pad 1. The steam chamber is blowdown. The steam-oil ratio is improved by maintaining the pressure in the mature steam chamber in Pad 1.

Figure **9** is a graph comparing the cumulative oil production for the reservoir as a whole and oil production for each pads after 7 years SAGD operation in Pad 1 and 10 years of operation in Pad 2 with steam injection terminated in Pad 1 and

the steam chamber being blowdown. The cumulative oil production appears to be improved by maintaining the pressure in the mature steam chamber in Pad 1.

Figure **10** shows an example of the manner in which the oxygen comprising gas may be injected into the mature chamber. In this example, the injection well is perforated along generally substantially all or a portion of the horizontal portion of the previous steam injection well. The combustion front generated rises upwardly toward the upper portion of the reservoir. The mobilized hydrocarbon may be collected by the production well situated generally below the oxygen comprising gas injection well. In this respect, a parker may be used to isolate the horizontal wellbore section, and the oxygen containing gas such as air may be injected through the selected portion.

Figure **11** illustrates another embodiment showing injection of the oxygen comprising gas via the injector. A vertical section in the bitumen bearing zone may be prorated and a dual completion system may be employed to inject the oxygen comprising gas. Air may be injected into the formation through perforations and combustion gas may only be vented through tubing from the portion of horizontal section at the toe of the original steam injection well. The combustion front created extends outwardly from the generally vertical portion of the oxygen comprising gas injection well (i.e., from heel to toe), and the combustion gases drain into the generally horizontal portion of the injection well. As is shown in the embodiment in Figure **11**, the mobilized hydrocarbons may drain into the generally horizontal portion of the production well below.

Figures **12** and **13** show further examples of individual well pair configurations for injecting the oxygen-comprising gas. Figure **12** shows that two horizontal well sections are employed, upper and lower HW wells. These two wells are located within the mature SAGD chamber, and previously functioned as a SAGD steam injector and a bitumen producer. In this example, the upper well was selected as the air injector, and the air is injected *via* a vertical section which is perforated. The air is injected through perforations. As is indicated in

Figure **12**, the reaction zone or front is propagating from the heel to the toe of the horizontal well. The lower well is also open for fluid production. In the example shown in Figure **13**, the upper well is selected as the air injector and the air is injected *via* a whole HW section or a selected horizontal section, for example, along about 50 m to 200 m of the horizontal section. The air is injected through tubing and then distributed into the formation. As is shown in Figure **13**, the reaction zone or front is propagating upwards first and then laterally. The lower well is also open for fluid production.

In various embodiments, the oxygen-comprising gas injector (air injector in this example) is a former steam injector and may be located anywhere in the mature SAGD chamber. For example, the air injector may be either close to or far way from the adjacent operating SAGD chamber/pad. The air may be injected continuously via the air injector. Figures **14** to **18** (cases 1 to 5) are examples of embodiments of multi-well configuration of the air injector(s) and producers in the mature SAGD chamber (right hand side of the graph) and where SAGD operation is being simultaneously performed in the adjacent operating (immature) SAGD pad (left hand side of the graph). The temperature profiles shown within the reservoir are under conditions in which the air is injected into a mature SAGD chamber, and steam is injected into the operating (immature) chamber. In this example, the temperature peak observed in the matured chamber is above about 500°C, which indicates high temperature oxidation reactions or combustion occurring due to the air injection.

Figure **19** is an example of an embodiment in which the air is injected cyclically. The air (oxygen-comprising gas) may be injected in a shut in cycle in a multi-well pattern for example. The results in this figure were generated by injecting air for three months and shutting in for two months *via* the edge well pair in the mature SAGD chamber. This was followed by another cycle of air injection and shutting in. In various embodiments, the oxygen-comprising gas having variable composition may be used for the various cyclical stages of injection.

Figures **20A** and **20B** are examples of data showing a beneficial effect of injecting the oxygen comprising gas to achieve pressure maintenance within the mature chamber and to prevent fluid cross flow from the operating chamber into the mature chamber. In these figures, water vapor mole fraction comparisons are presented for two cases:

(1) to inject air into the mature chambers (5 years air injection, in the right hand side of the graph), while normal SAGD process is being performed in the operating (immature) chambers (5 years SAGD operation, in the left hand side of the graph); and

(2) to perform normal SAGD operation in the operating (immature) SAGD chamber (5 years SAGD operation, in the left hand side of the graph), while the steam chamber is cooling after steam injection is terminated.

The deep red color in Figures **20A** and **20B** represents water vapor at the current reservoir pressure. The results show that if suitable pressure in the matured chamber is not maintained, steam leaking (cross flow) from the operating chamber into the mature chamber will occur (Figure **20B**).

Figures **21A** and **21B** show pressure distributions within the reservoir for the two cases:

(1) to inject air into the mature chambers (5 years air injection, in the right hand side of the graph), while normal SAGD process is performed in the operating (immature) chambers (5 years SAGD operation, left hand side of the graph); and

(2) to perform normal SAGD operating in the operating (immature) SAGD chamber (5 years SAGD operation, left hand side of the graph), while steam chamber is cooling after steam injection is terminated.

The deep red color in Figures **21A** and **21B** represents water vapor at the current reservoir pressure. The results show that if suitable pressure in the

matured chamber is not maintained, steam leaking (cross flow) from the operating chamber into the mature chamber will occur (Figure **21B)**.

Figures **22A** and **22B** show slowed down temperature drop in the mature SAGD chamber.

Thus as is demonstrated in the above embodiments, in various aspects, the invention provides an apparatus and process for *in situ* processing a hydrocarbon reservoir. The processing comprises selecting in the reservoir a matured steam chamber and an operating steam chamber generally adjacent to or generally proximal to and in fluid communication with the matured steam chamber. The matured steam chamber further being a warm and depleted former SAGD chamber, and the operating chamber undergoing or being capable of undergoing SAGD processing. An oxygen comprising gas is injected into the matured chamber or generally into a region of the matured chamber generally at a buffer zone or a boundary between the matured and operating chambers for maintaining pressure within the matured chamber or within the region of the matured chamber generally at the buffer zone or at the boundary so as to reduce or avoid fluid leaking or cross-flow from the operating chamber into the mature chamber while producing gas, oil (hydrocarbons) and water within the matured chamber, continually performing SAGD in the operating chamber or a combination thereof. The various embodiments of the apparatus and process allow use of multi-well pairs and multi pad operations, and various oxygen-comprising gas injector and producer configurations, as well as improvement in the SAGD performance of individual pads and of the reservoir undergoing SAGD as a whole. The various embodiments of the apparatus and process further allow using lower rates for injection (e.g., lower air rate), which in various embodiments may be based on keeping the combustion front moving at a speed of less than about 0.038 m/day.

Although specific embodiments of the invention have been described and illustrated, such embodiments should not to be construed in a limiting sense.

Various modifications of form, arrangement of components, steps, details and order of operations of the embodiments illustrated, as well as other embodiments of the invention, will be apparent to persons skilled in the art upon reference to this description. It is therefore contemplated that the appended claims will cover such modifications and embodiments as fall within the true scope of the invention. In the specification including the claims, numeric ranges are inclusive of the numbers defining the range. Citation of references herein shall not be construed as an admission that such references are prior art to the present invention.

The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. An *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the operating steam chamber situated so that a boundary exists between the matured steam chamber and the operating steam chamber, the matured steam chamber having been previously processed using steam assisted gravity drainage (SAGD), the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well situated in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber, the injection well being generally adjacent to the boundary between the matured steam chamber and the operating steam chamber;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the boundary such that migration of fluid from the operating steam chamber into the matured steam chamber is

reduced while sustaining combustion in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable from the operating steam chamber without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

2. An *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the matured steam chamber such that migration of fluid

from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber and maintaining a predetermined pressure in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

3. The process of claim 1 or 2, wherein sustaining combustion in the matured steam chamber comprises generating a combustion front.

4. The process of claim 3, further comprising advancing the combustion front in a direction from a heel to a toe of the injection well.

5. The process of claim 3, further comprising initially advancing the combustion front in an upward direction away from the injection well, and subsequently advancing the combustion front in a lateral direction along the injection well toward a toe of the injection well.

6. The process of claim 3, wherein the combustion front extends outwardly from a generally vertical portion of the injection well.

7. The process of claim 6, wherein the generally vertical portion of the injection well is perforated.

8. The process of any one of claims 1-5, wherein the injection well is perforated along substantially all of a generally horizontal portion of the injection well.

9. The process of any one of claims 1-5, wherein the injection well is perforated along an isolated section of a generally horizontal portion of the injection well.

10. The process of claim 9, wherein the oxygen-comprising gas is injected through the isolated section of the generally horizontal portion of the injection well.

11. The process of any one of claims 3-10, wherein a velocity of the combustion front is about 0.038 m/day or less.

12. The process of claim 11, wherein the velocity of the combustion front is about 0.02 m/day.

13. The process of claim 2, wherein a pressure difference between the pressure in the operating steam chamber and the predetermined pressure in the matured steam chamber is about 0 kPa to about 200 kPa.

14. The process of claim 2, wherein a pressure difference between the pressure in the operating steam chamber and the predetermined pressure in the matured steam chamber is about 50 kPa.

15. The process of any one of claims 1-14, wherein the initial pressure of the matured steam chamber is about 700 kPa to about 2500 kPa.

16. The process of any one of claims 1-15, wherein the initial temperature of the matured steam chamber is about 165°C or greater.

17. The process of any one of claims 1-15, wherein the initial temperature of the matured steam chamber is about 180°C or greater.

18. The process of any one of claims 1-15, wherein the initial temperature of the matured steam chamber is about 165°C to about 223°C.

19. The process of any one of claims 1-18, wherein an operating temperature of the operating steam chamber is about 180°C or greater.

20. The process of claim 19, wherein the operating temperature is about 225°C or greater.

21. The process of claim 19, wherein the operating temperature is about 270°C or greater.

22. The process of any one of claims 1-21, wherein the operating pressure of the operating steam chamber is about 1000 kPa to about 6500 kPa.

23. The process of any one of claims 1-22, wherein the injection well has been previously used for fluid injection.

24. The process of claim 23, wherein the fluid is steam.

25. The process of any one of claims 1-24, wherein the oxygen-comprising gas is injected proximate to a lower portion of the reservoir.

26. The process of any one of claims 1-25, wherein the concentration of oxygen in the oxygen-comprising gas ranges from about 5% to about 100%.

27. The process of any one of claims 1-25, wherein the concentration of oxygen in the oxygen-comprising gas ranges from about 5% to about 40%.

28. The process of any one of claims 1-25, wherein the concentration of oxygen in the oxygen-comprising gas is about 21% or more.

29. The process of any one of claims 1-28, wherein the oxygen-comprising gas is air, oxygen-enriched air, or a combination thereof.

30. The process of claim 29, wherein the oxygen-comprising gas is wet or dry.

31. The process of claim 30, wherein the dry oxygen-comprising gas is co-injected with flue gas.

32. The process of any one of claims 1-31, further comprising producing residual hydrocarbons from the matured steam chamber while producing hydrocarbons from the operating steam chamber.

33. The process of claim 32, wherein about 55% to about 80% of the residual hydrocarbons are recovered from the matured steam chamber.

34. The process of any one of claims 1-33, wherein selecting an injection well comprises selecting several injection wells to achieve a suitable injection pattern proximate the boundary.

35. The process of any one of claims 1-34, wherein injecting the oxygen-comprising gas comprises cyclical injection.

36. The process of any one of claims 1-34, wherein injecting the oxygen-comprising gas comprises intermittent injection.

37. The process of any one of claims 1-34, wherein injecting the oxygen-comprising gas comprises continuous injection.

38. An *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the

operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber and previously having been used for fluid injection, the injection well being generally adjacent to a boundary between the matured steam chamber and the operating steam chamber;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) pressurizing the boundary with the oxygen-comprising gas to achieve an increased pressure generally within the boundary in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

39. An *in situ* process for treating a hydrocarbon reservoir, the process comprising:

(a) selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having

an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber and previously having been used for fluid injection;

(c) injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) pressurizing the matured steam chamber with the oxygen-comprising gas to achieve an increased pressure in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

40. The process of claim 38 or 39, wherein the concentration of oxygen in the oxygen-comprising gas is sufficient to sustain combustion in the matured steam chamber.

41. The process of claim 40, wherein sustaining combustion in the matured steam chamber comprises generating a combustion front.

42. The process of claim 41, further comprising advancing the combustion front in a direction from a heel to a toe of the injection well.

43. The process of claim 41, further comprising initially advancing the combustion front in an upward direction away from the injection well, and subsequently advancing the combustion front in a lateral direction along the injection well toward a toe of the injection well.

44. The process of claim 41, wherein the combustion front extends outwardly from a generally vertical portion of the injection well.

45. The process of claim 44, wherein the generally vertical portion of the injection well is perforated.

46. The process of any one of claims 38-43, wherein the injection well is perforated along substantially all of a generally horizontal portion of the injection well.

47. The process of any one of claims 38-43, wherein the injection well is perforated along an isolated section of a generally horizontal portion of the injection well.

48. The process of claim 47, wherein the oxygen-comprising gas is injected through the isolated section of the generally horizontal portion of the injection well.

49. The process of any one of claims 41-48, wherein a velocity of the combustion front is about 0.038 m/day or less.

50. The process of claim 49, wherein the velocity of the combustion front is about 0.02 m/day.

51. The process of any one of claims 38-50, wherein the initial pressure of the matured steam chamber is about 700 kPa to about 2500 kPa.

52. The process of any one of claims 38-51, wherein the initial temperature of the matured steam chamber is about 165°C or greater.

53. The process of any one of claims 38-51, wherein the initial temperature of the matured steam chamber is about 180°C or greater.

54. The process of any one of claims 38-51, wherein the initial temperature of the matured steam chamber is about 165°C to about 223°C.

55. The process of any one of claims 38-54, wherein an operating temperature of the operating steam chamber is about 180°C or greater.

56. The process of claim 55, wherein the operating temperature is about 225°C or greater.

57. The process of claim 55, wherein the operating temperature is about 270°C or greater.

58. The process of any one of claims 38-57, wherein the operating pressure of the operating steam chamber is about 1000 kPa to about 6500 kPa.

59. The process of any one of claims 38-58, wherein the fluid previously injected through the injection well is steam.

60. The process of any one of claims 38-59, wherein the oxygen-comprising gas is injected proximate to a lower portion of the reservoir.

61. The process of any one of claims 38-59, wherein the oxygen-comprising gas is injected proximate to the operating steam chamber.

62. The process of any one of claims 38-59, wherein the oxygen-comprising gas is injected proximate to the boundary.

63. The process of any one of claims 38-62, wherein the concentration of oxygen in the oxygen-comprising gas is about 5% to about 100%.

64. The process of any one of claims 38-62, wherein the concentration of oxygen in the oxygen-comprising gas is about 5% to about 40%.

65. The process of any one of claims 38-62, wherein the concentration of oxygen in the oxygen-comprising gas is about 21% or more.

66. The process of any one of claims 38-65, wherein the oxygen-comprising gas is air, oxygen-enriched air, or a combination thereof.

67. The process of claim 66, wherein the oxygen-comprising gas is wet or dry.

68. The process of claim 67, wherein the dry oxygen-comprising gas is co-injected with flue gas.

69. The process of any one of claims 38-68, wherein selecting an injection well comprises selecting several injection wells to achieve a suitable injection pattern proximate the boundary.

70. The process of any one of claims 38-69, wherein injecting the oxygen-comprising gas comprises cyclical injection.

71. The process of any one of claims 38-69, wherein injecting the oxygen-comprising gas comprises intermittent injection.

72. The process of any one of claims 38-69, wherein injecting the oxygen-comprising gas comprises continuous injection.

73. An apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in

fluid communication with the matured steam chamber, the operating steam chamber situated so that a boundary exists between the matured steam chamber and the operating steam chamber, the matured steam chamber having been previously processed using steam assisted gravity drainage (SAGD), the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, a initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well situated in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber, the injection well being generally adjacent to the boundary between the matured steam chamber and the operating steam chamber;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) means for modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the boundary such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable from the operating steam chamber without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) means for selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

74. An apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber further having a residual hydrocarbon content of at least about 0.5%, an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen sufficient to sustain combustion in the matured steam chamber;

(d) means for modulating a volume of the injected oxygen-comprising gas, the concentration of oxygen, or a combination thereof to sufficiently pressurize the matured steam chamber such that migration of fluid from the operating steam chamber into the matured steam chamber is reduced while sustaining combustion in the matured steam chamber and maintaining a predetermined pressure in the matured steam chamber to achieve an increased production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber; and

(e) means for selectively producing hydrocarbons from at least one of the matured steam chamber and the operating steam chamber.

75. The apparatus of claim 73 or 74, wherein a generally vertical portion of the injection well is perforated.

76. The apparatus of claim 73 or 74, wherein the injection well is perforated along substantially all of a generally horizontal portion of the injection well.

77. The apparatus of claim 73 or 74, wherein the injection well is perforated along an isolated section of a generally horizontal portion of the injection well.

78. The apparatus of any one of claims 73-77, wherein the injection well has been previously used for fluid injection.

79. The apparatus of claim 78, wherein the fluid is steam.

80. An apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the

matured steam chamber and previously having been used for fluid injection, the injection well being generally adjacent to a boundary between the matured steam chamber and the operating steam chamber;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) means for pressurizing the boundary with the oxygen-comprising gas to achieve an increased pressure generally within the boundary in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

81. An apparatus for *in situ* treatment of a hydrocarbon reservoir, the apparatus comprising:

(a) means for selecting in the hydrocarbon reservoir a matured steam chamber and an operating steam chamber generally adjacent to and in fluid communication with the matured steam chamber, the matured steam chamber having been previously processed using SAGD, the operating steam chamber undergoing or being capable of undergoing SAGD processing, the matured steam chamber having an initial temperature, and an initial pressure lower than a pressure in the operating steam chamber;

(b) means for selecting an injection well in the matured steam chamber, the injection well being in fluid communication with the matured steam chamber and previously having been used for fluid injection;

(c) means for injecting an oxygen-comprising gas through the injection well, the oxygen-comprising gas having a concentration of oxygen; and

(d) means for pressurizing the matured steam chamber with the oxygen-comprising gas to achieve an increased pressure in the matured steam chamber sufficient to generally avoid migration of fluid from the operating steam chamber into the matured steam chamber and to increase production of hydrocarbons from the operating steam chamber relative to production of hydrocarbons recoverable without the injection of the oxygen-comprising gas into the matured steam chamber.

82. The apparatus of claim 80 or 81, wherein a generally vertical portion of the injection well is perforated.

83. The apparatus of claim 80 or 81, wherein the injection well is perforated along substantially all of a generally horizontal portion of the injection well.

84. The apparatus of claim 80 or 81, wherein the injection well is perforated along an isolated section of a generally horizontal portion of the injection well.

Fig. 1A

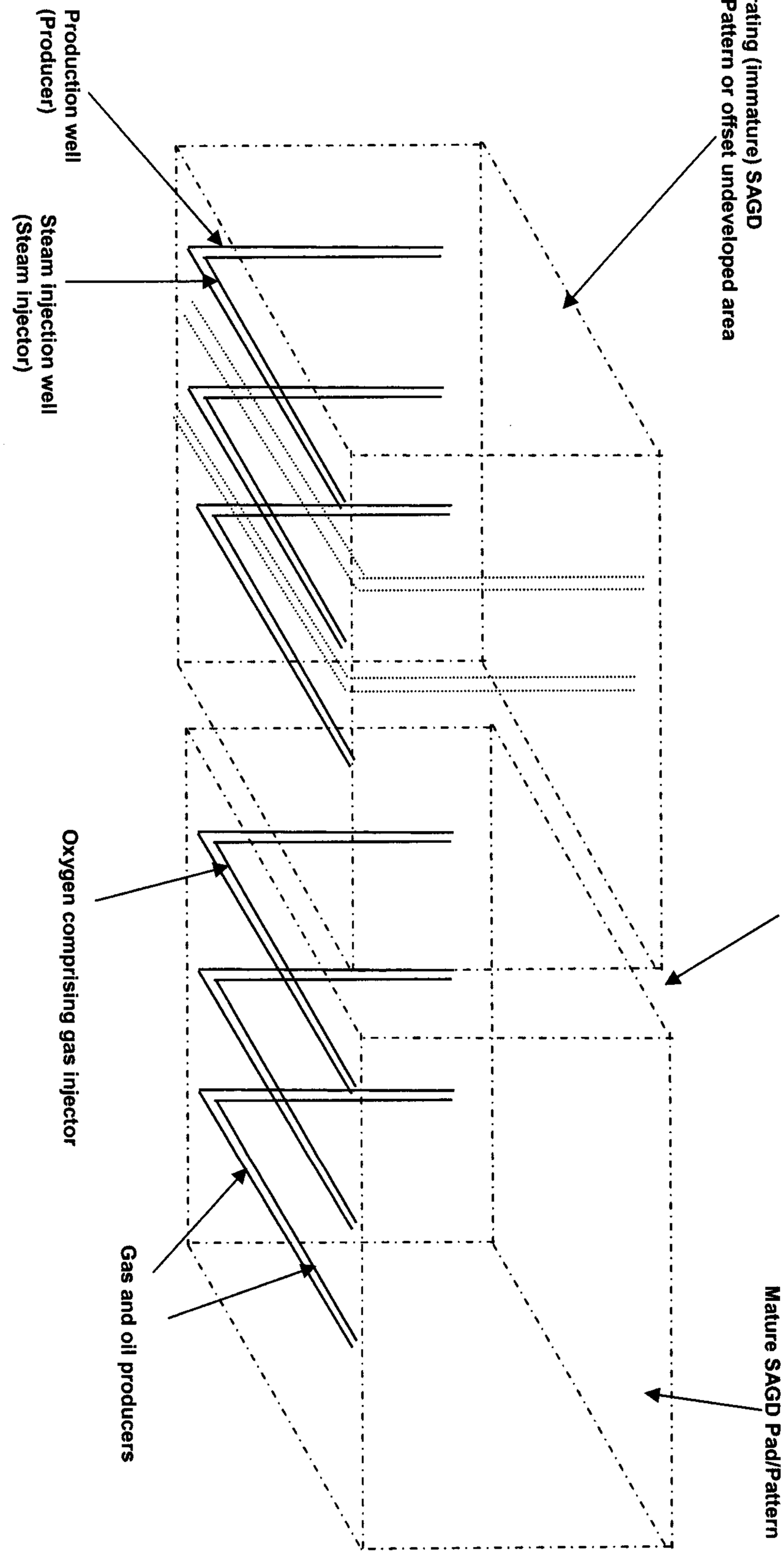

Production well
(Producer)
Steam injection well
(Steam injector)
Oxygen comprising gas injector
Gas and oil producers
Buffer zone or Boundary
Mature SAGD Pad/Pattern
Operating (immature) SAGD
Pad/Pattern or offset undeveloped area

Fig. 1B

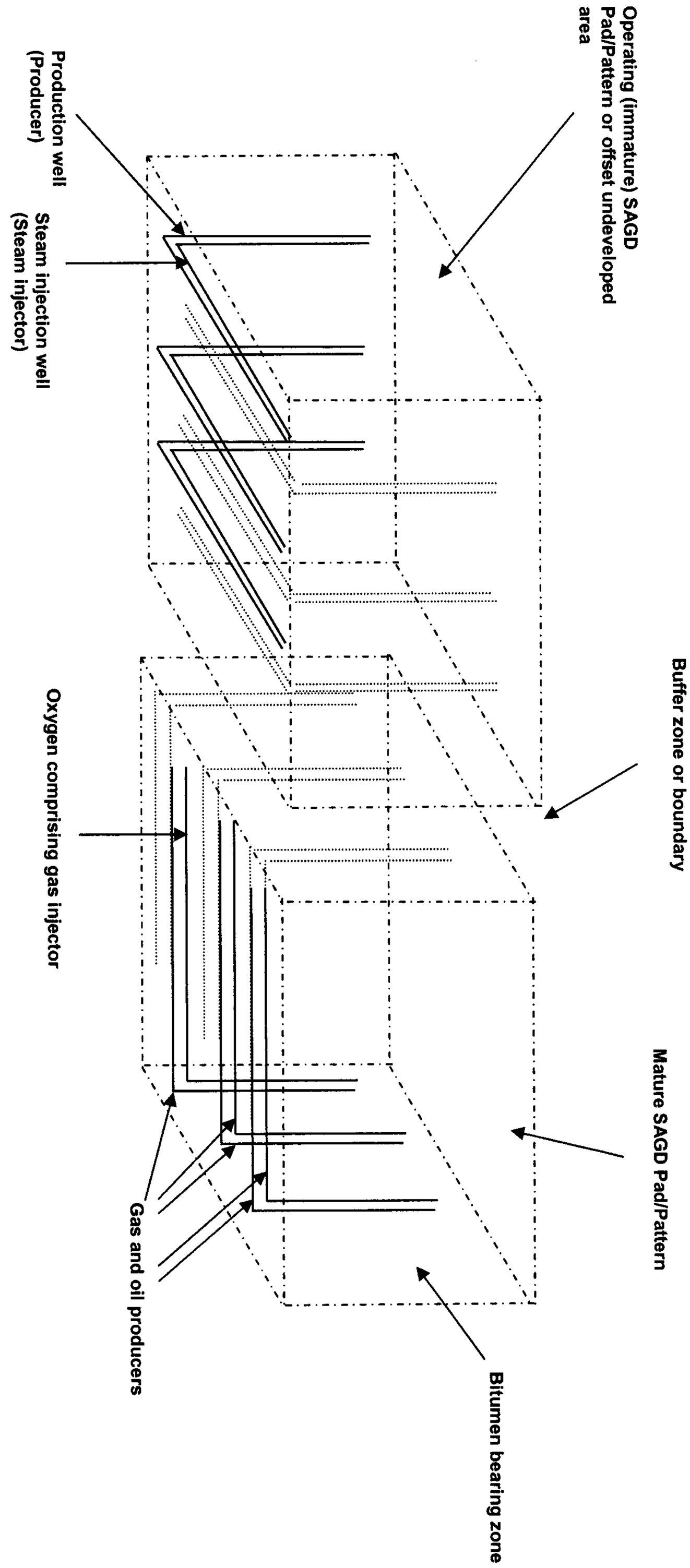
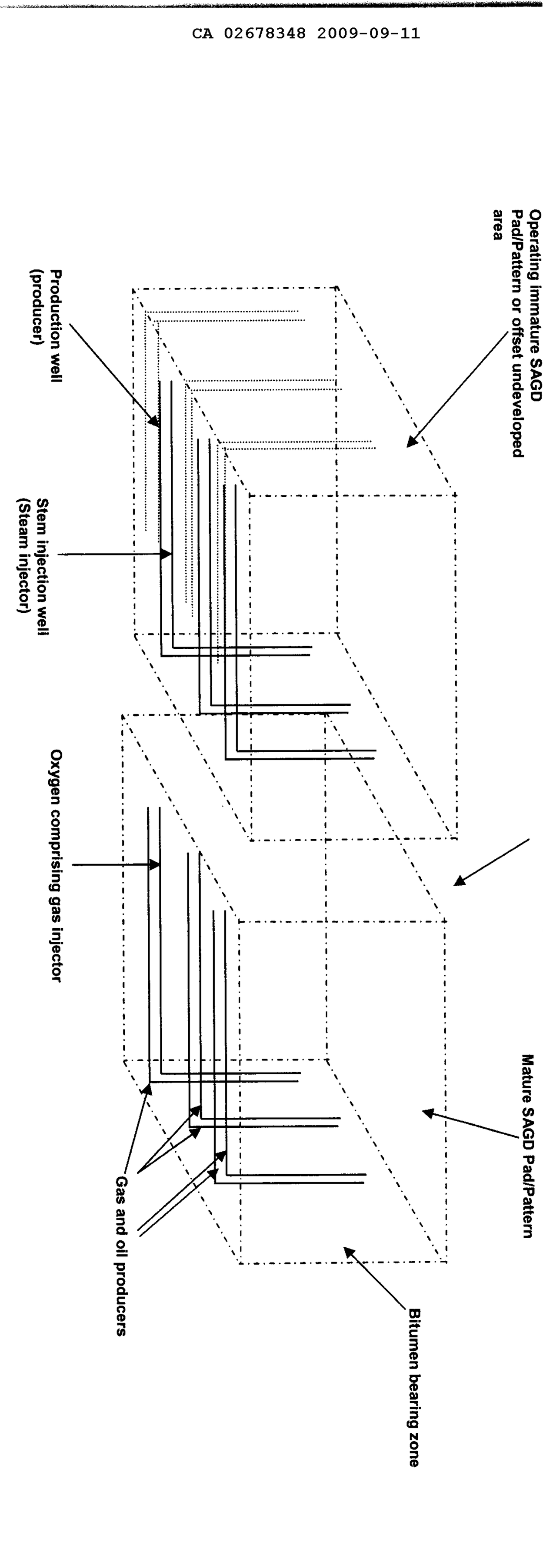

Operating (immature) SAGD Pad/Pattern or offset undeveloped area
Production well (Producer)
Steam injection well (Steam injector)
Buffer zone or boundary
Oxygen comprising gas injector
Mature SAGD Pad/Pattern
Gas and oil producers
Bitumen bearing zone

Fig. 1C


Operating immature SAGD Pad/Pattern or offset undeveloped area
Production well (producer)
Stem injection well (Steam injector)
Oxygen comprising gas injector
Buffer zone or boundary
Mature SAGD Pad/Pattern
Gas and oil producers
Bitumen bearing zone

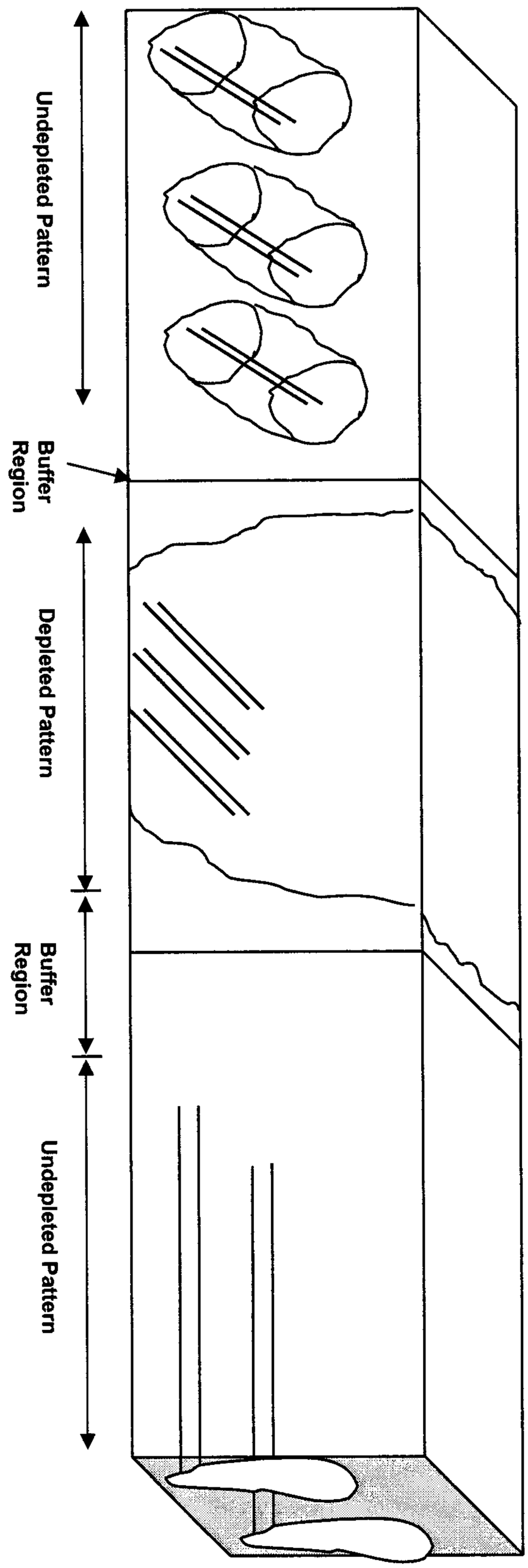

Undepleted Pattern
Buffer Region
Depleted Pattern
Buffer Region
Undepleted Pattern

Fig. 1D

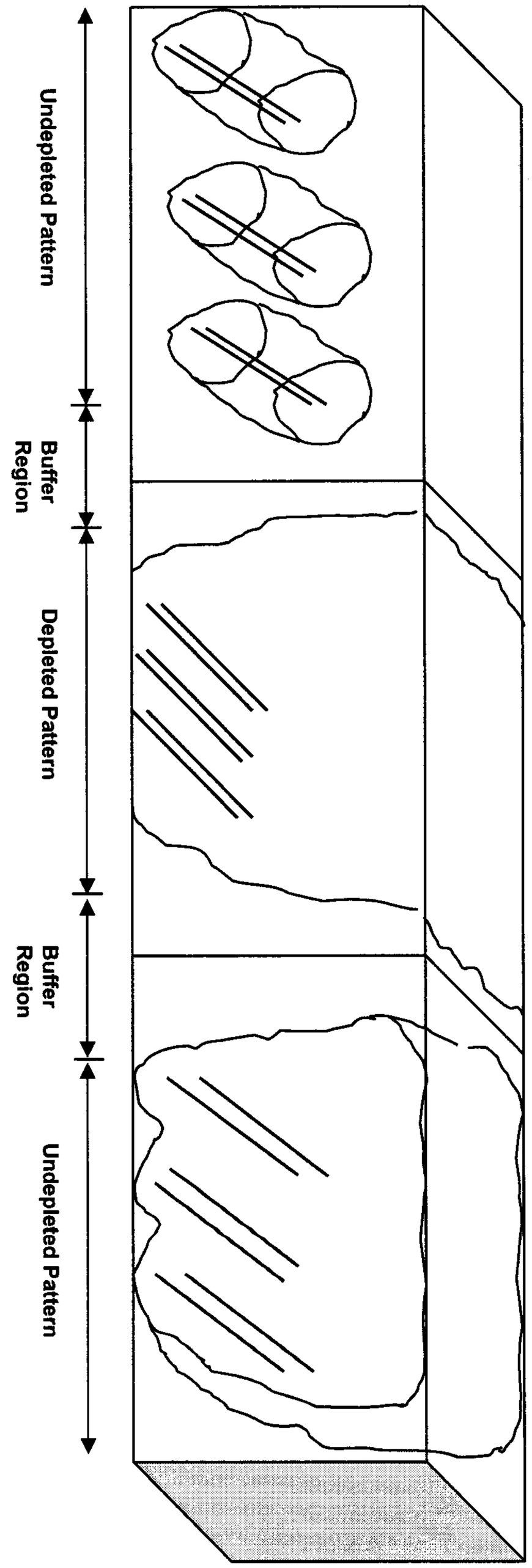
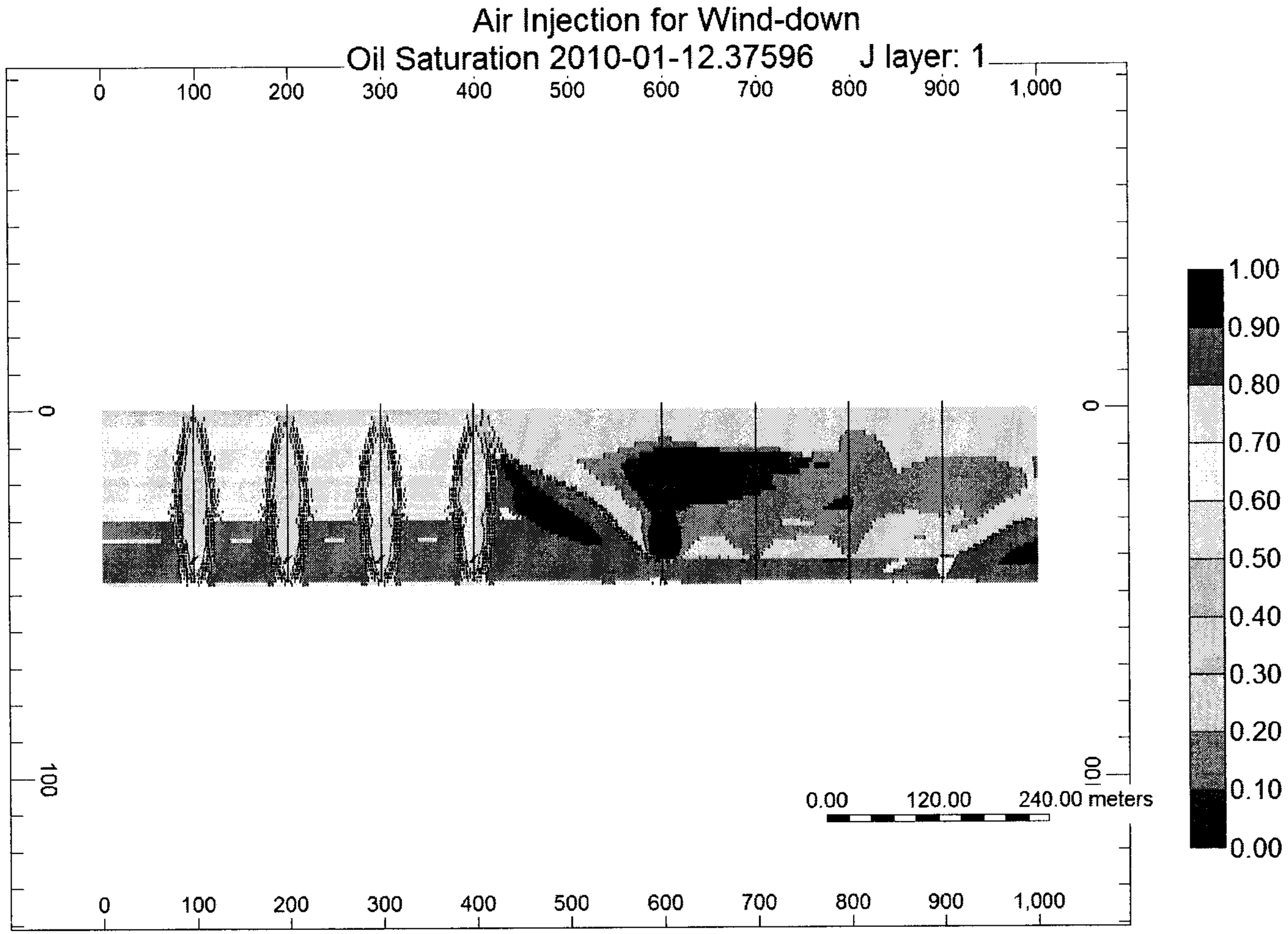

Undepleted Pattern
Buffer Region
Depleted Pattern
Buffer Region
Undepleted Pattern

Fig. 1E

CA 2678348 2009-09-11

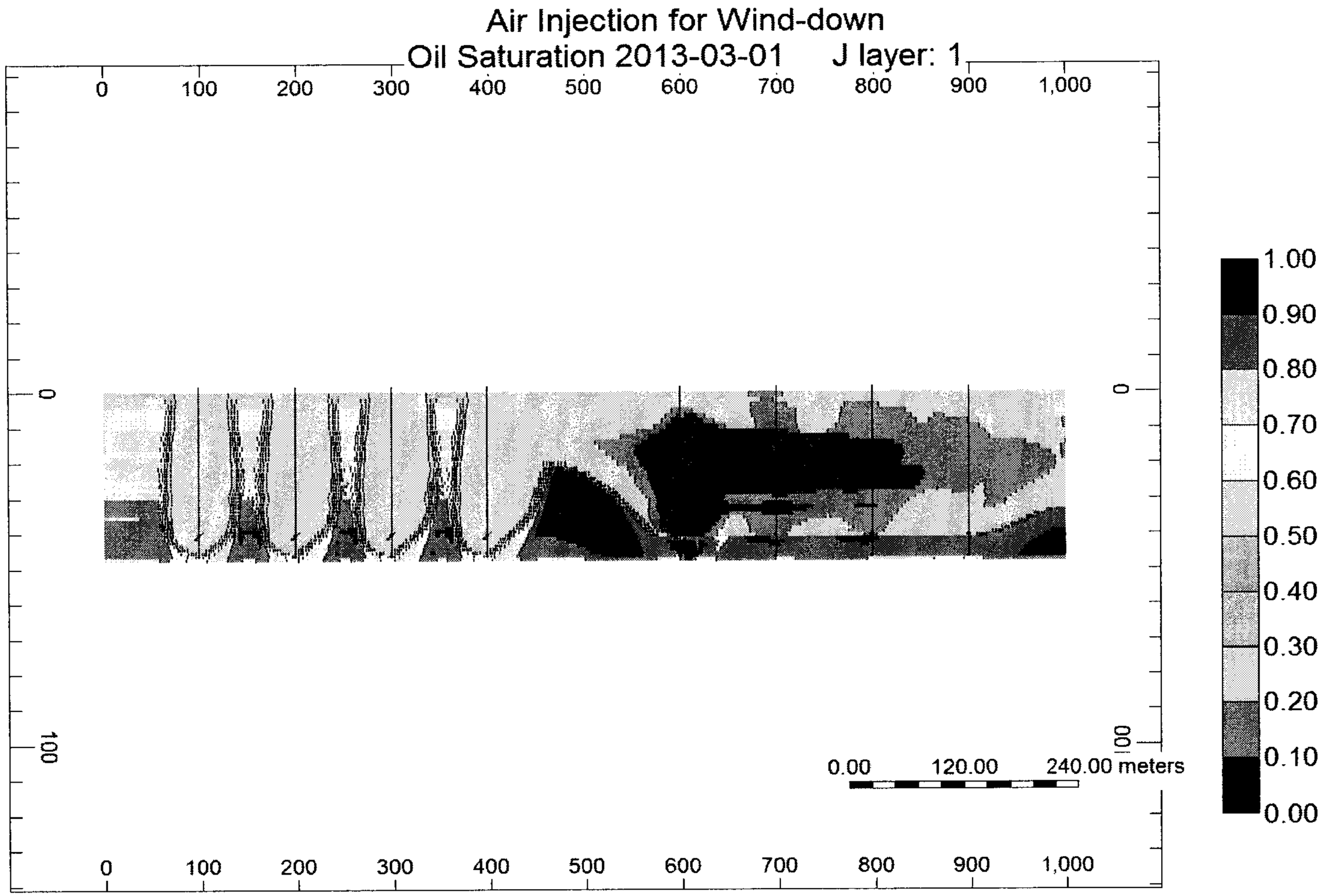
Fig. 2A



Legend: bitumen or oil saturation; scale unit: fraction

CA 02678348 2009-09-11

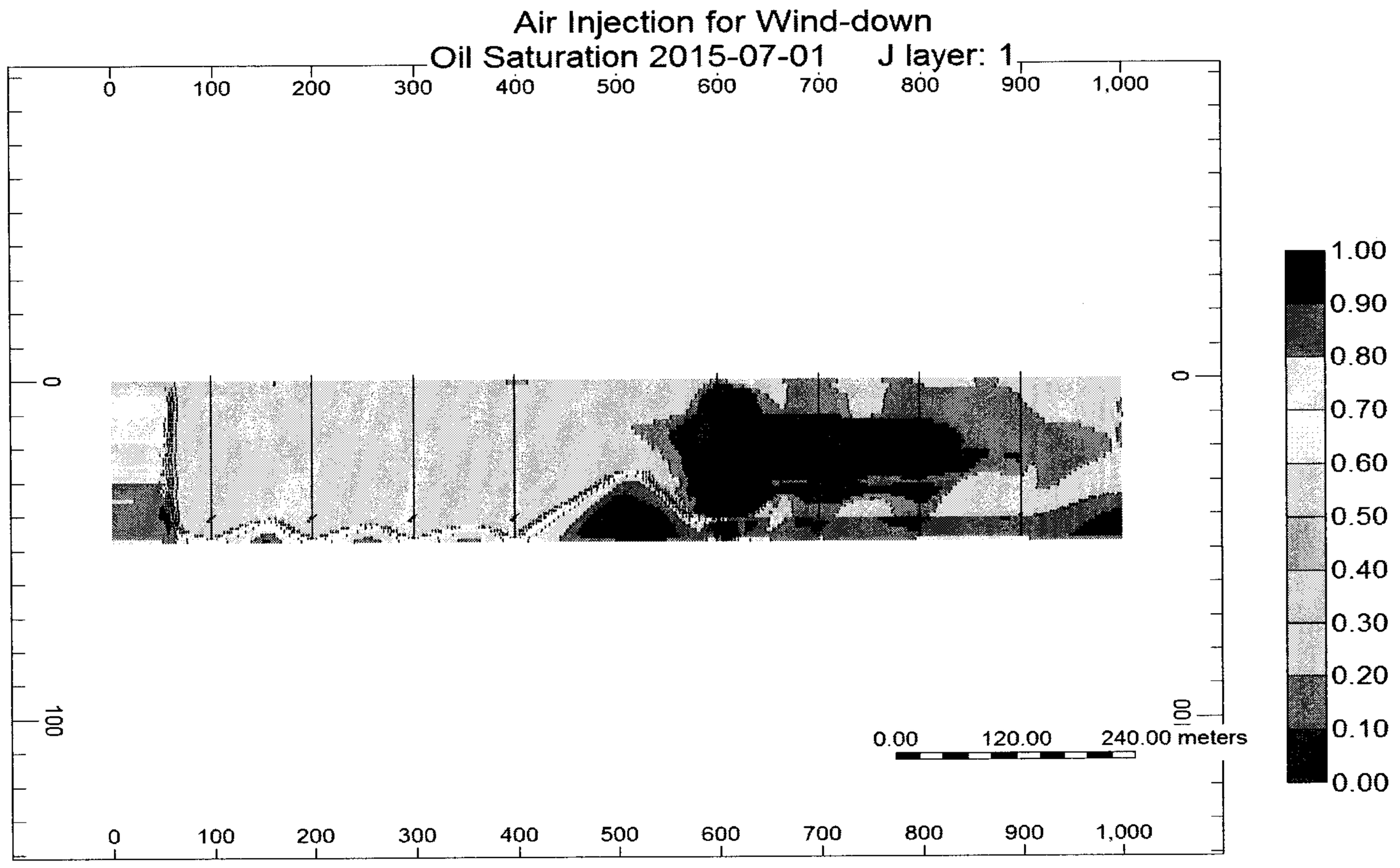
Fig. 2B



Legend: bitumen or oil saturation; scale unit: fraction

CA 2678348 2009-09-11

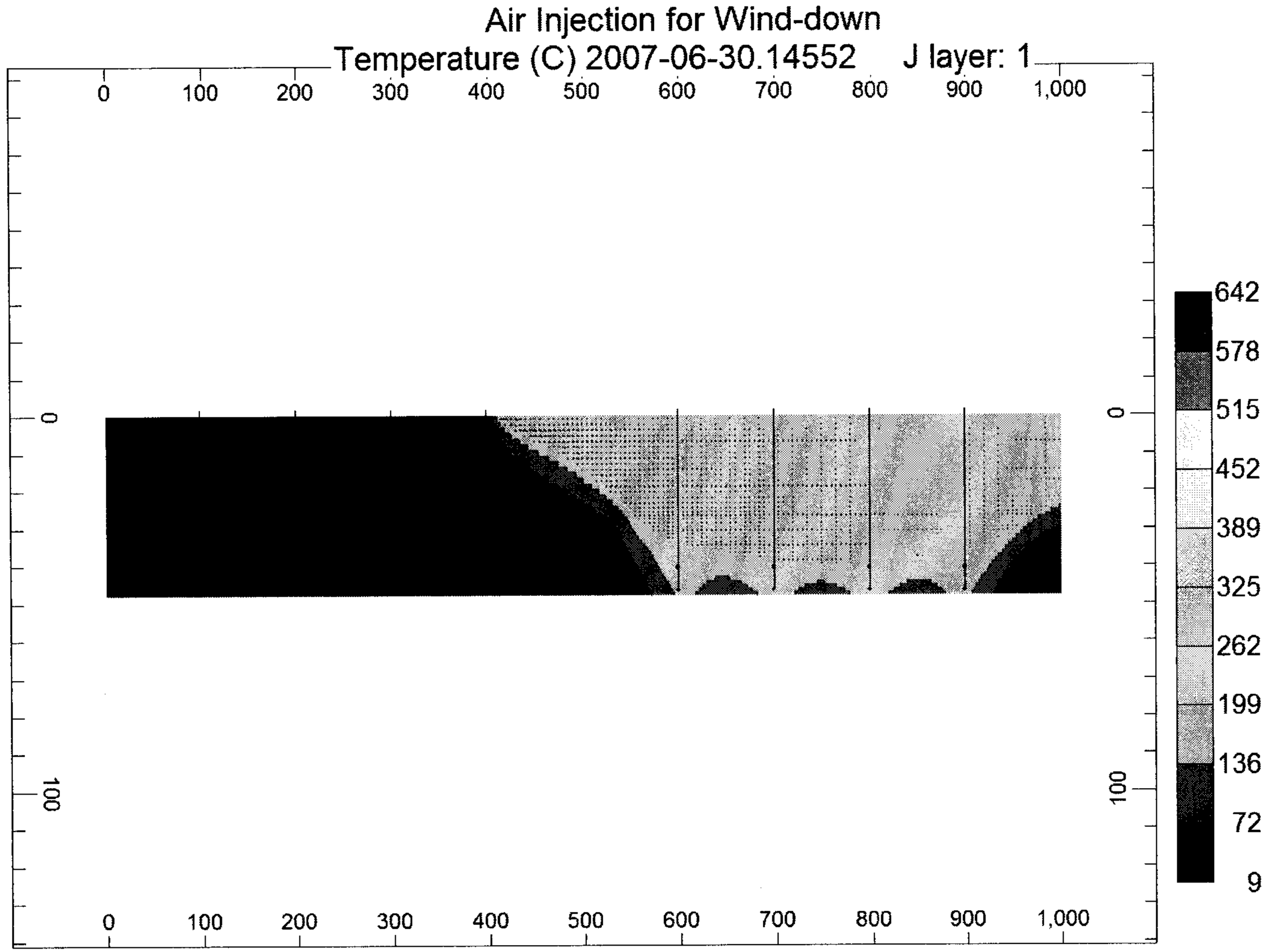
Fig. 2C



Legend: bitumen or oil saturation; scale unit: fraction

CA 2678348 2009-09-11

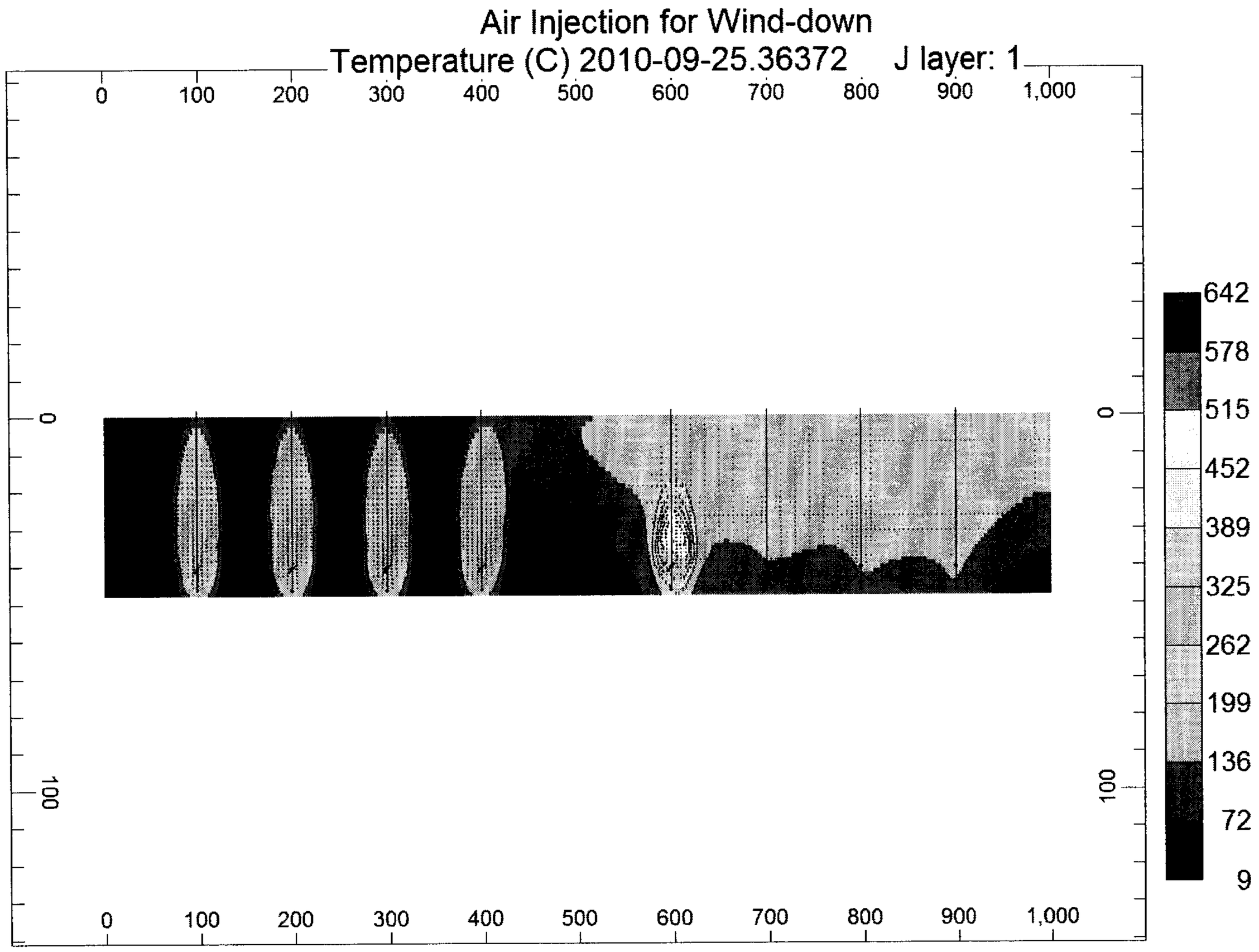
Fig. 3A



Legend: temperature; scale unit: degree Celsius °C

CA 02678348 2009-09-11

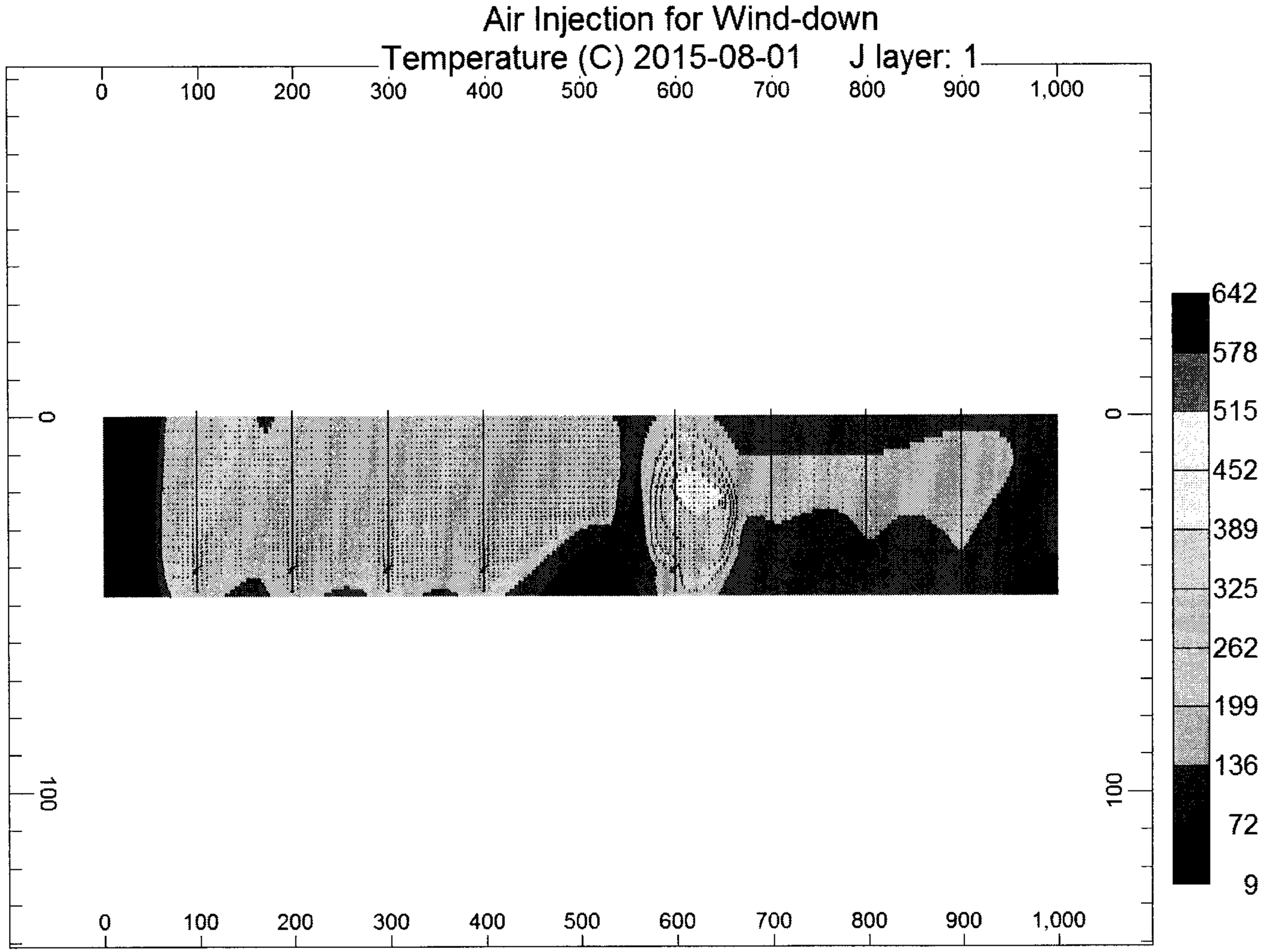
Fig. 3B



Legend: temperature; scale unit: degree Celsius °C

CA 2678348 2009-09-11

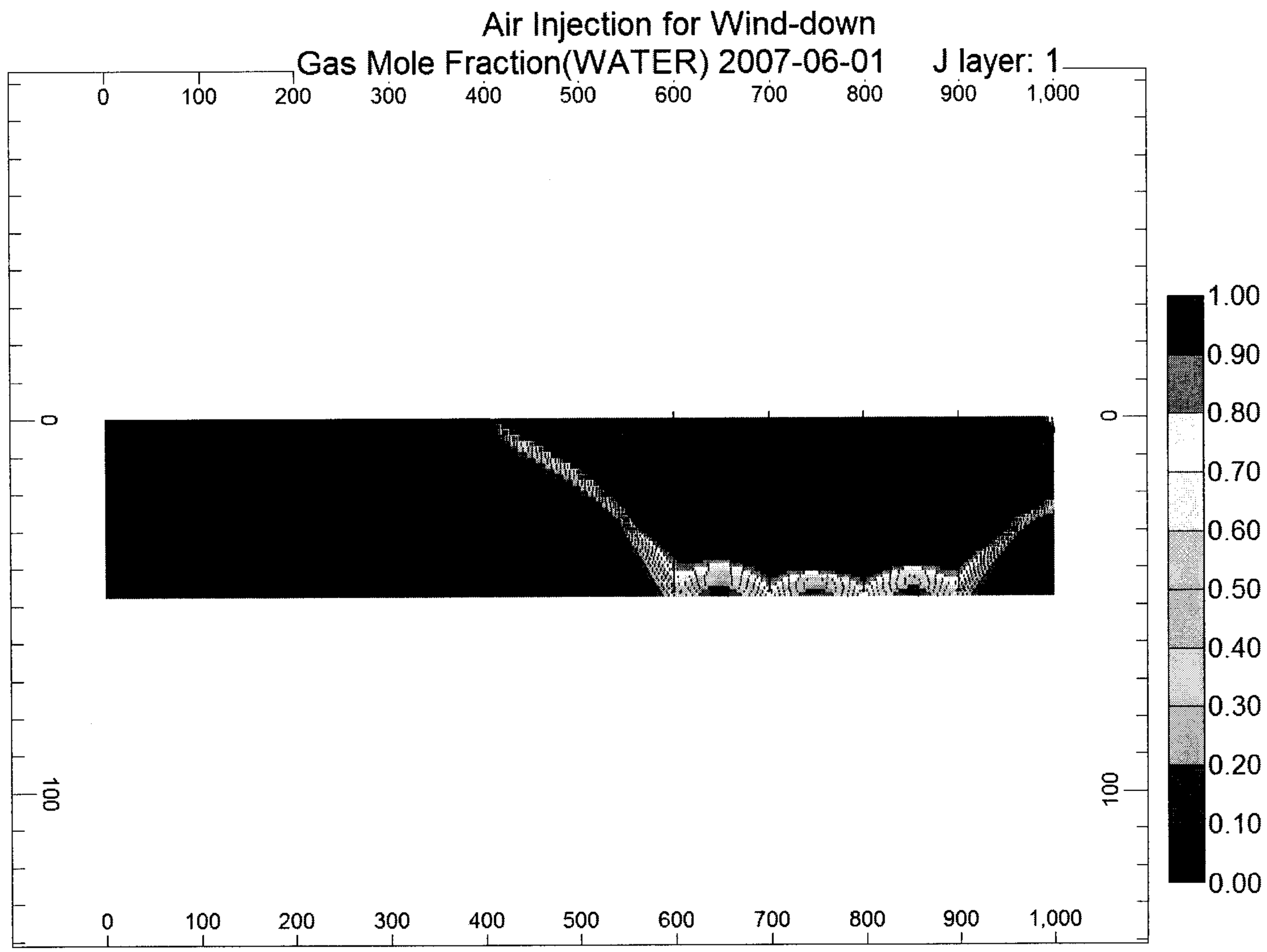
Fig. 3C



Legend: temperature; scale unit: degree Celsius ºC

CA 02678348 2009-09-11

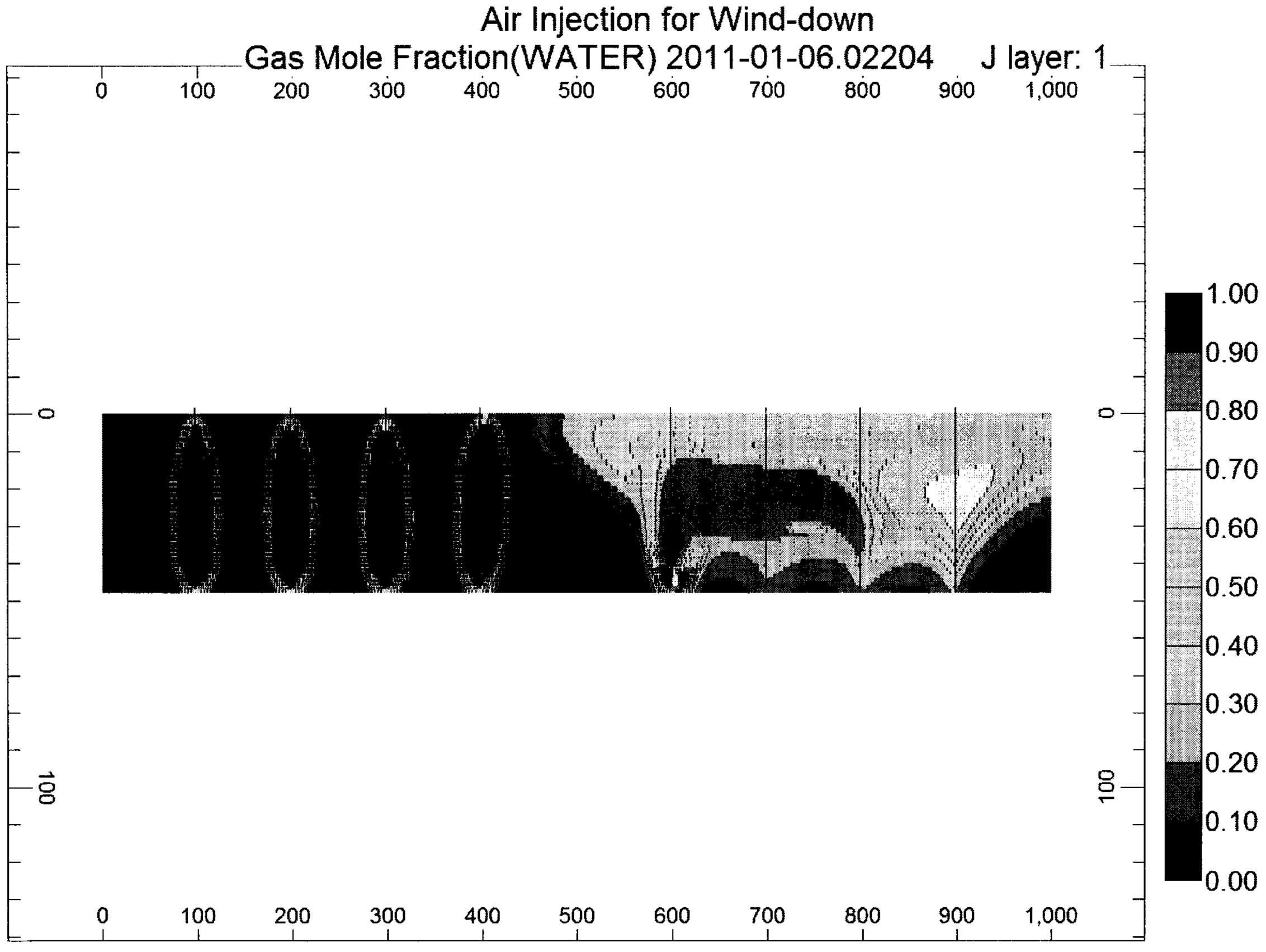
Fig. 4A



Legend: gas saturation of water phase (steam); scale unit: fraction

CA 02678348 2009-09-11

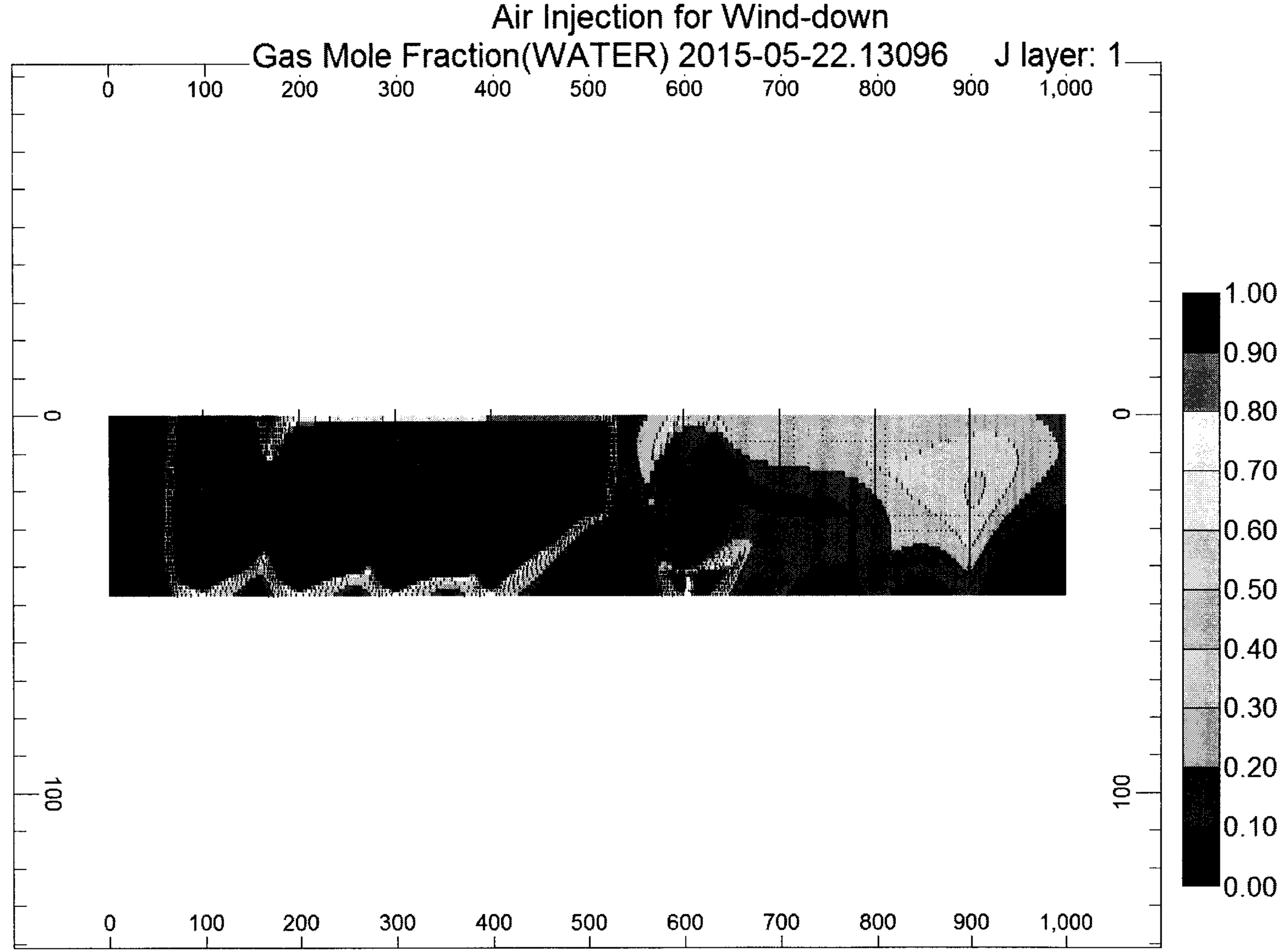
Fig. 4B



Legend: gas saturation of water phase (steam); scale unit: fraction

CA 02678348 2009-09-11

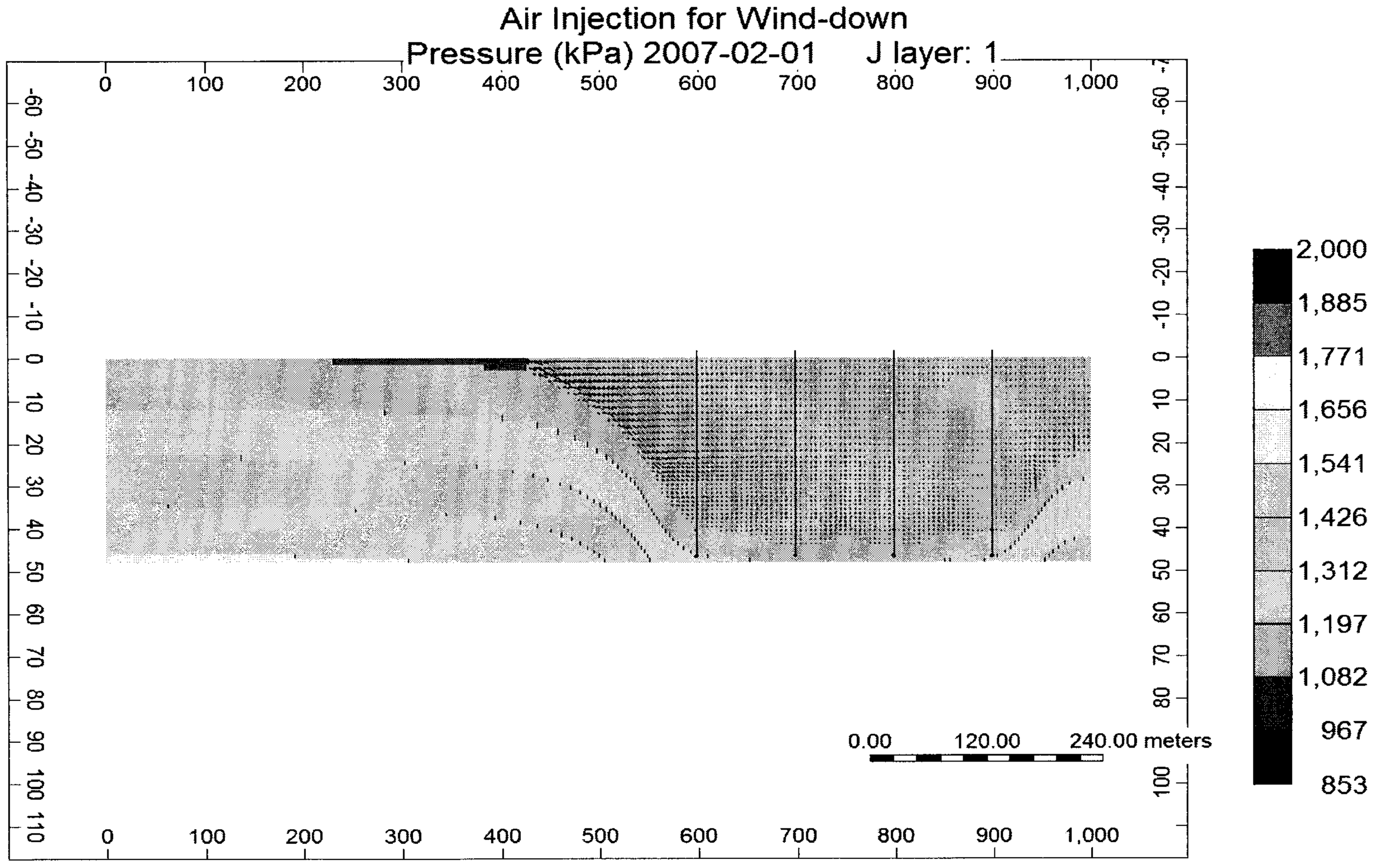
Fig. 4C



Legend: gas saturation of water phase (steam); scale unit: fraction

CA 2678348 2009-09-11

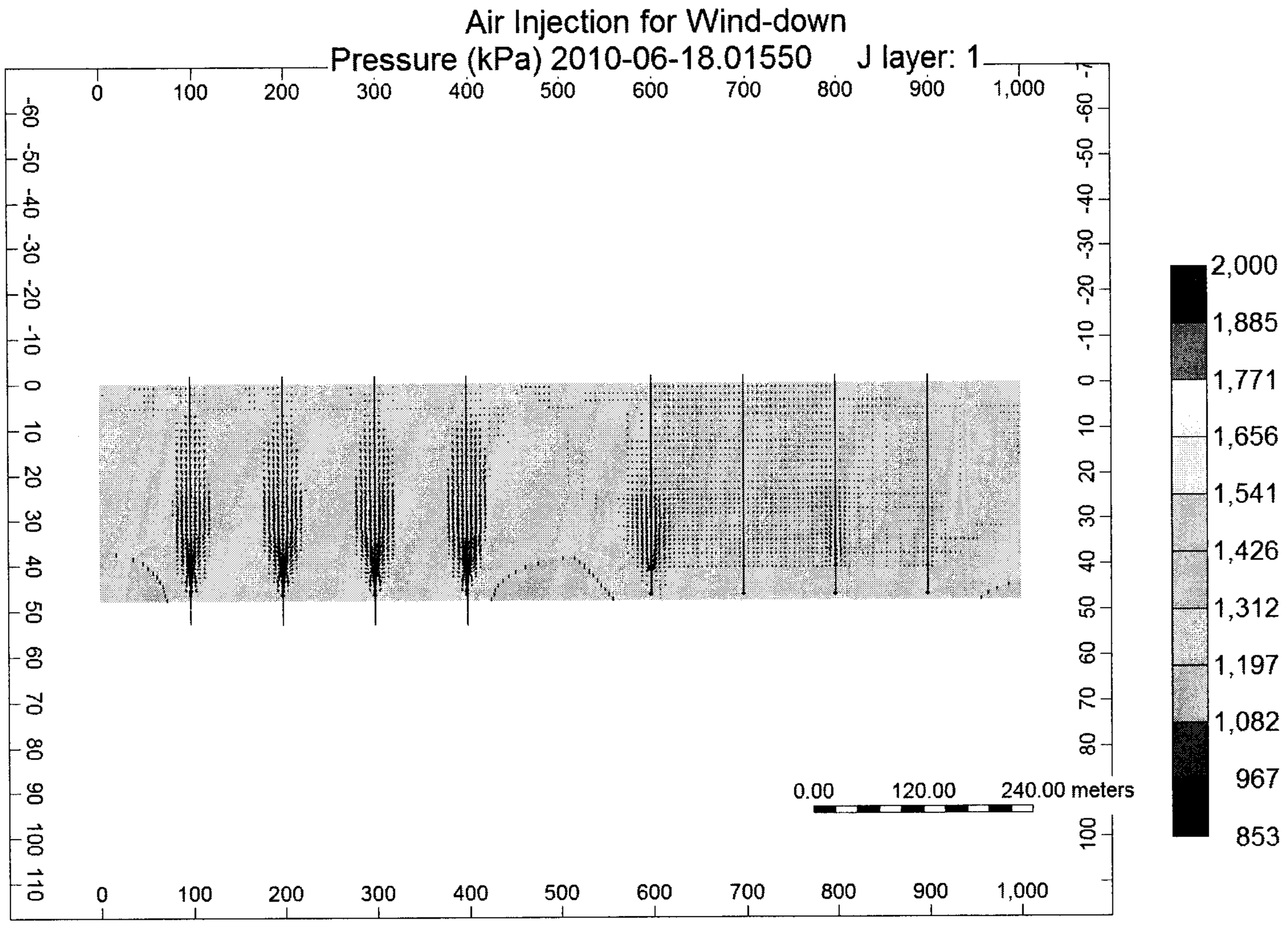
Fig. 5A



Legend: gas saturation of water phase; reservoir pressure; scale unit: kPa

CA 02678348 2009-09-11

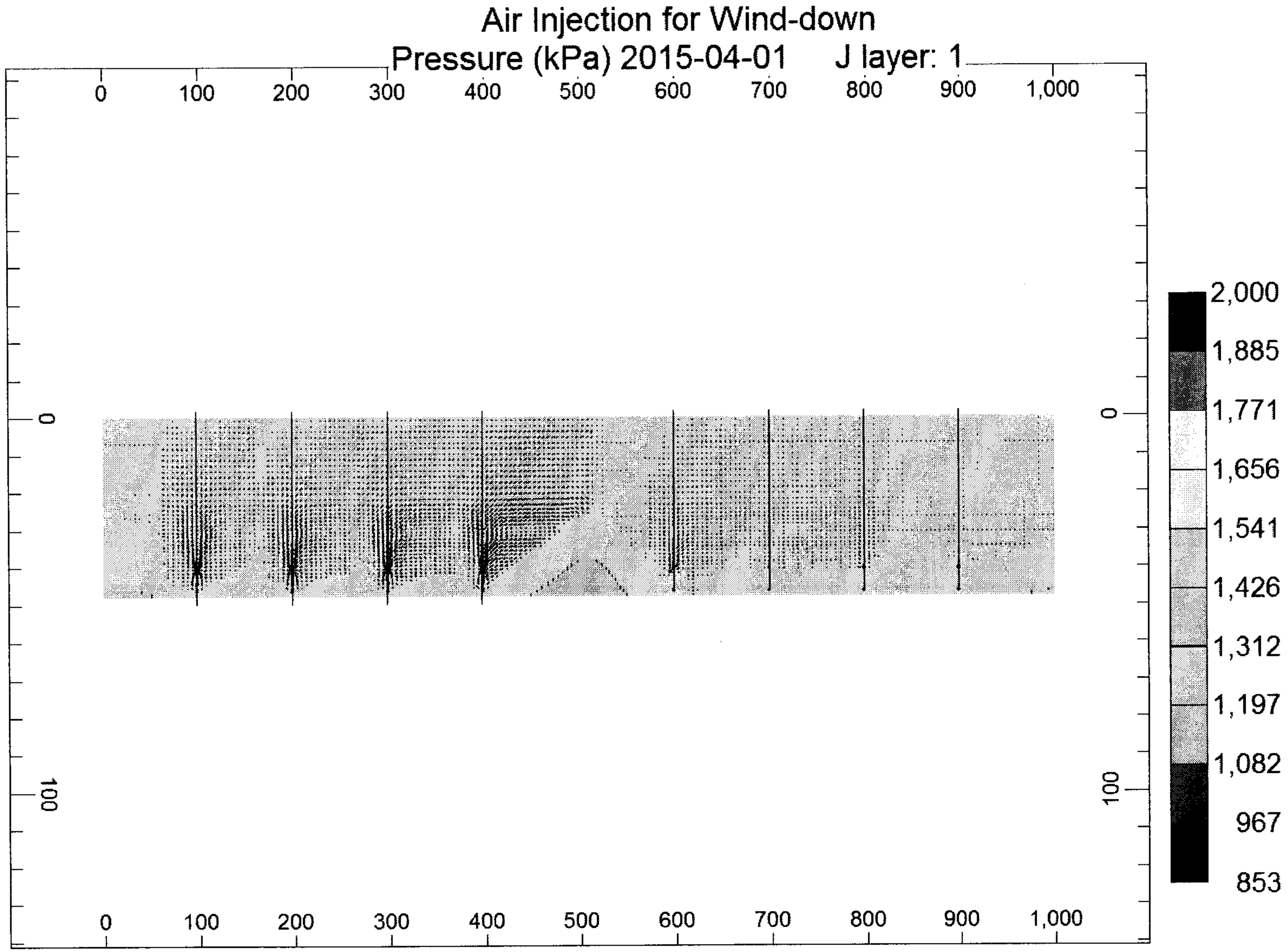
Fig. 5B



Legend: reservoir pressure; scale unit: kPa

CA 02678348 2009-09-11

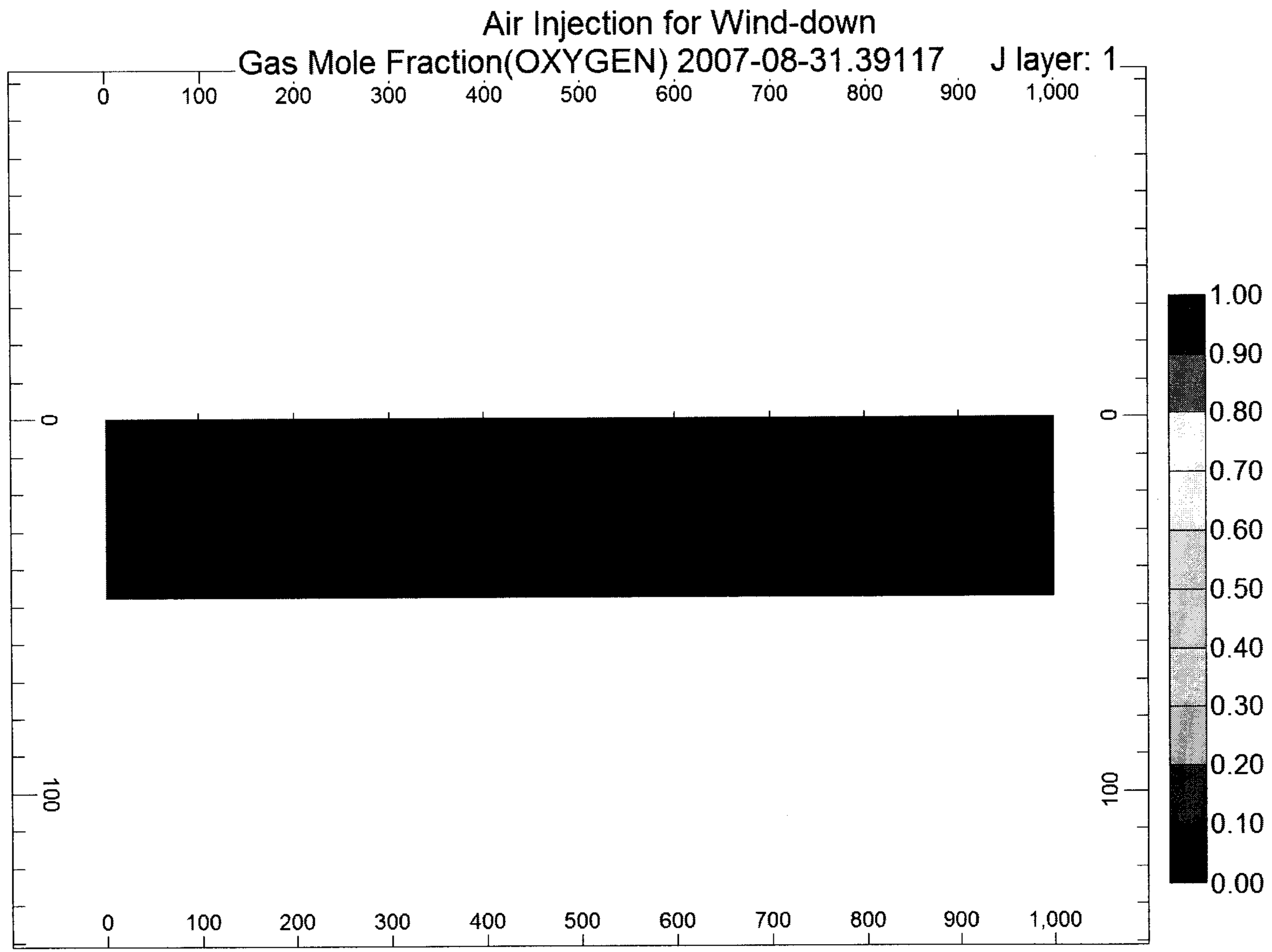
Fig. 5C



Legend: reservoir pressure ; scale unit: kPa

CA 02678348 2009-09-11

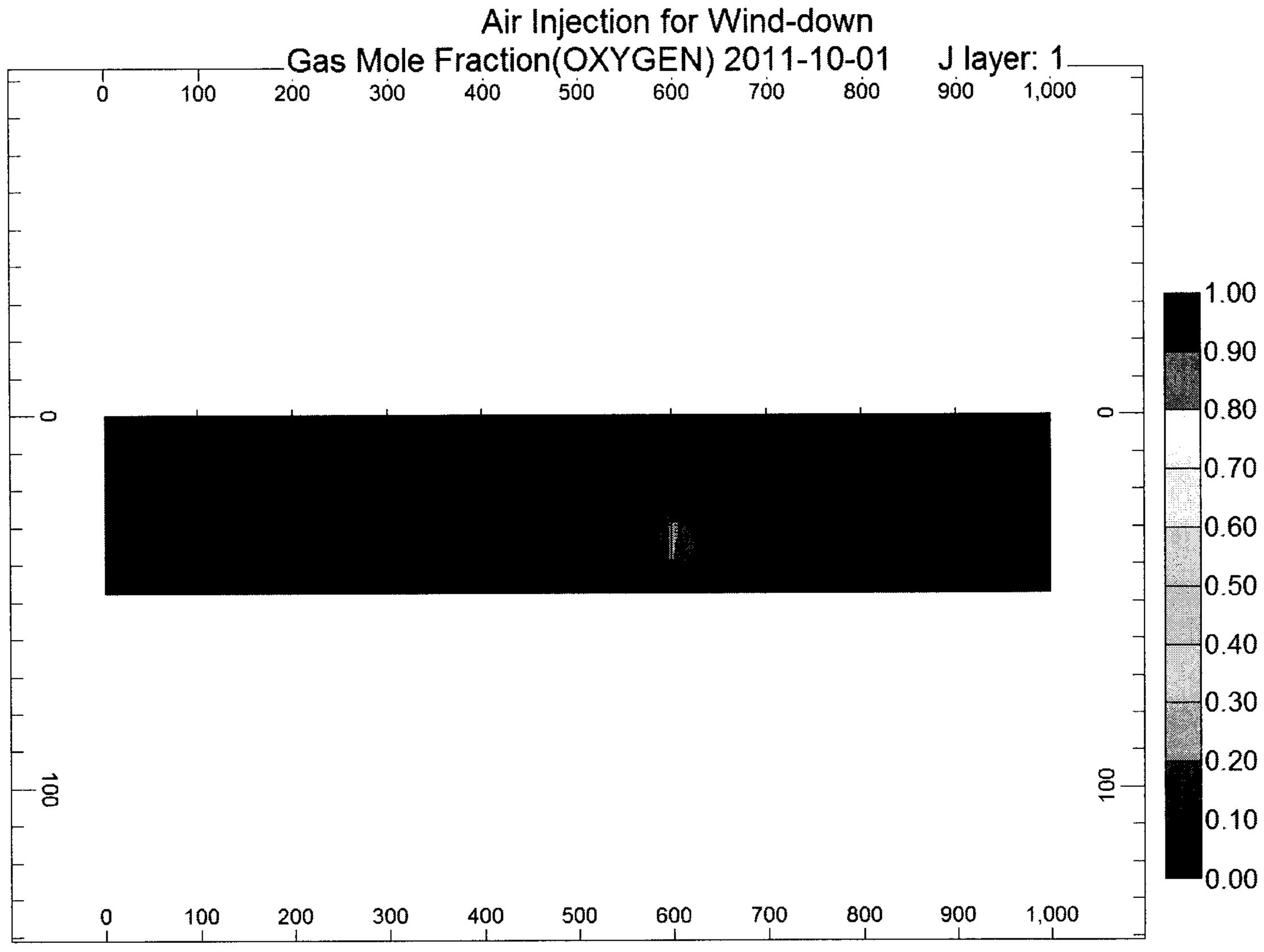
Fig. 6A



Legend: gas mole fraction of oxygen in the reservoir; scale unit: fraction

CA 2678348 2009-09-11

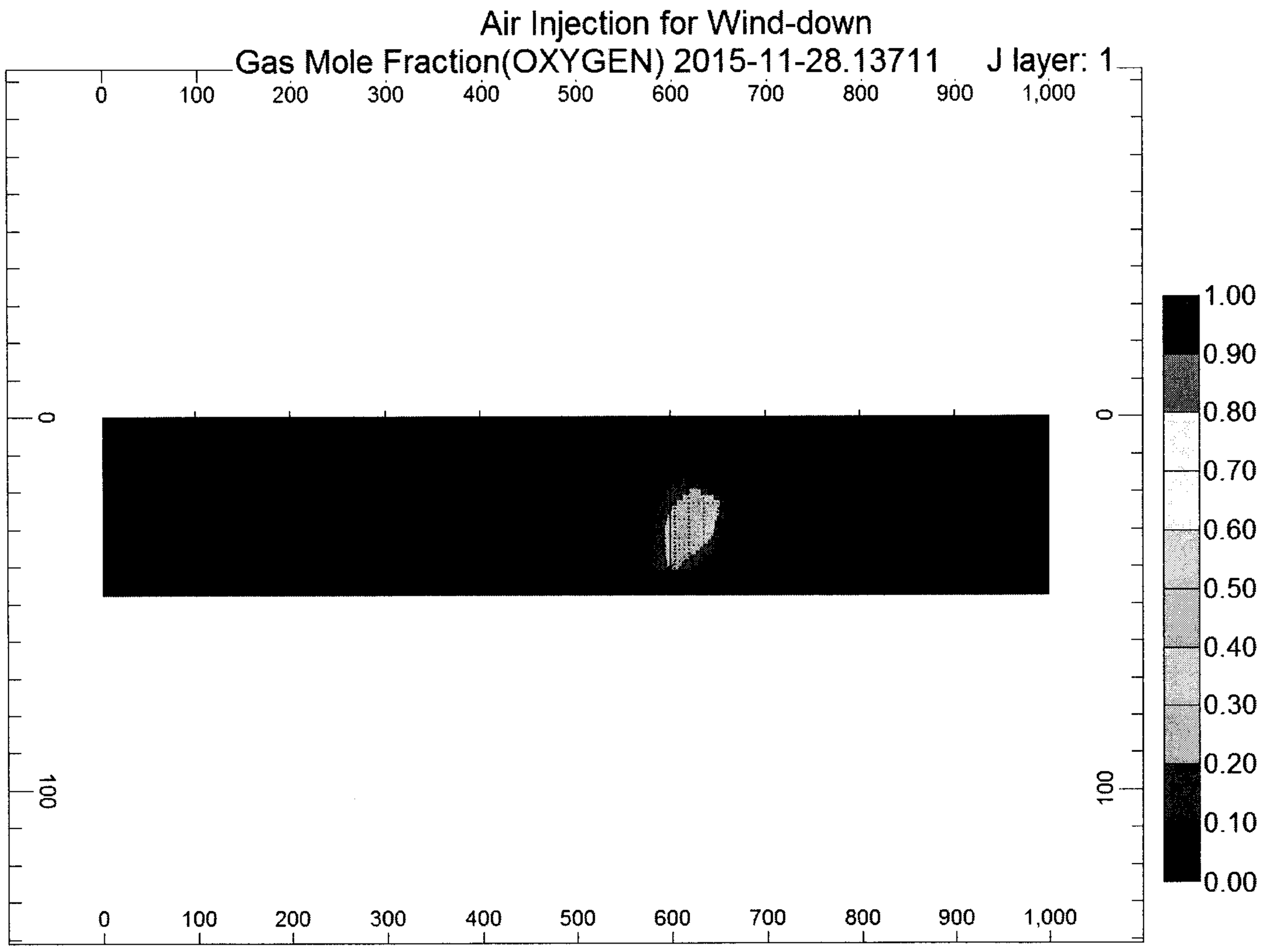
Fig. 6B



Legend: gas mole fraction of oxygen in the reservoir; scale unit: fraction

CA 2678348 2009-09-11

Fig. 6C



Legend: gas mole fraction of oxygen in the reservoir; scale unit: fraction

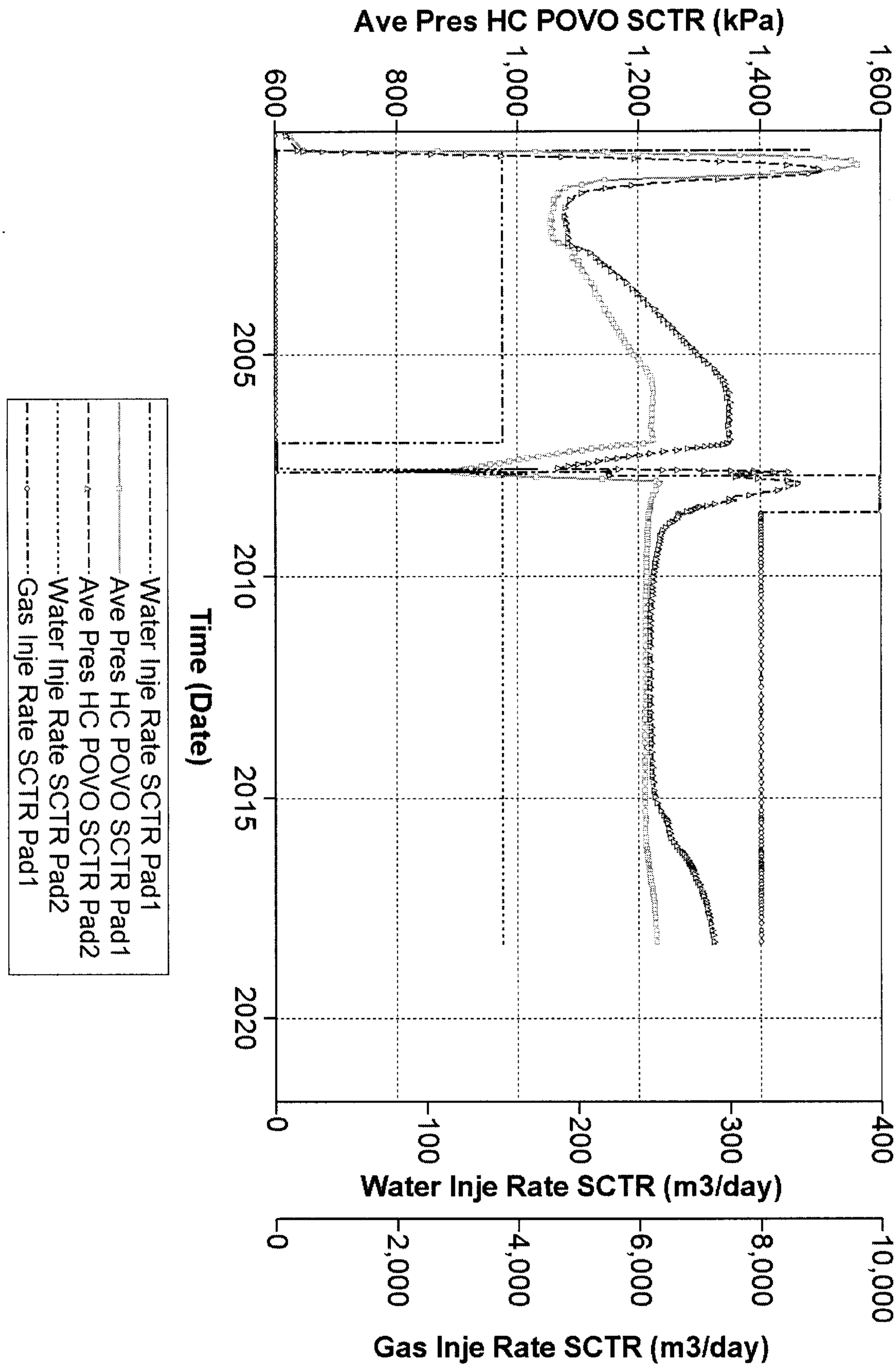
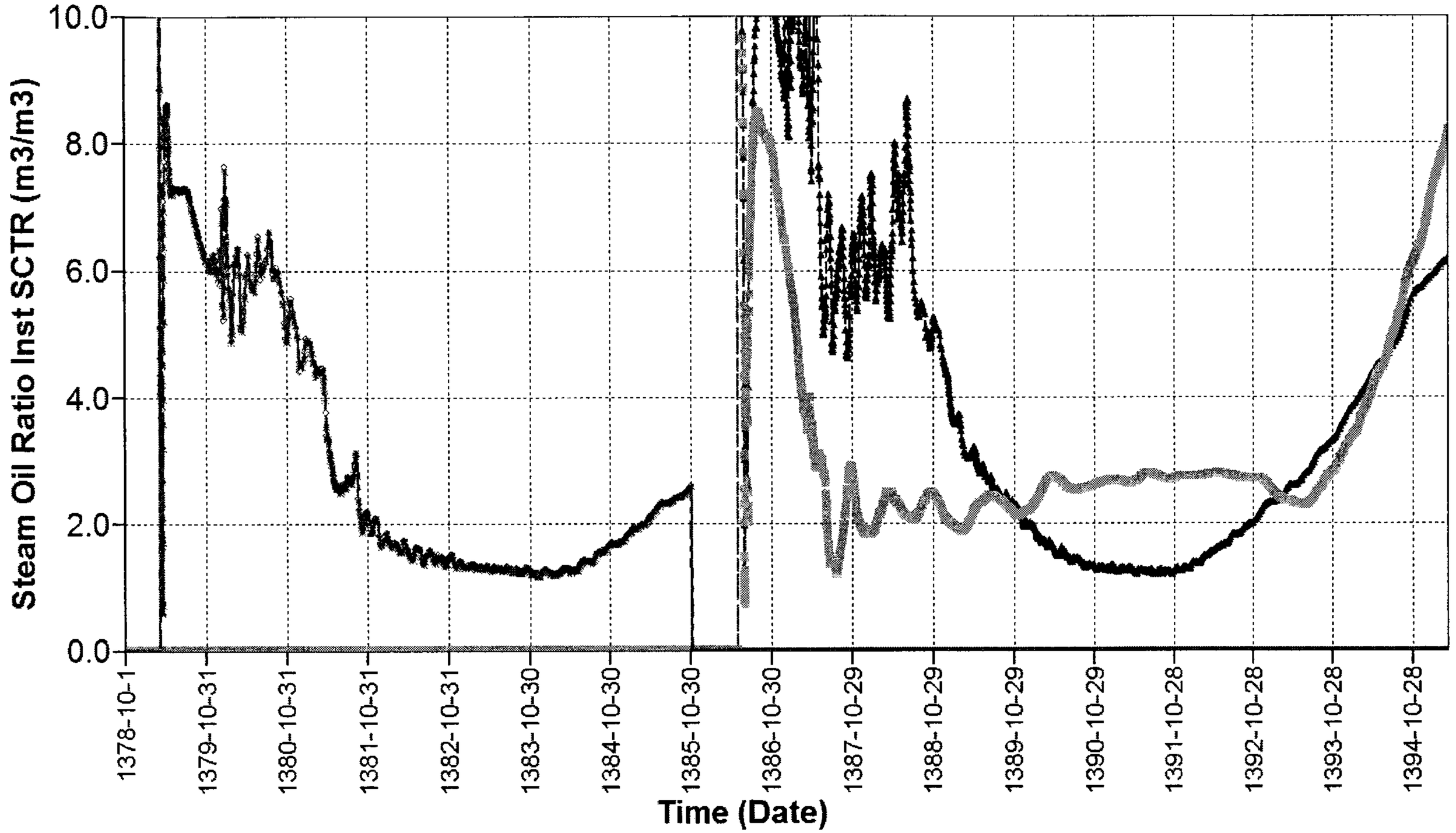

Ave Pres HC POVO SCTR (kPa)
600
800
1,000
1,200
1,400
1,600
2005
2010
2015
2020
Time (Date)
Water Inje Rate SCTR Pad1
Ave Pres HC POVO SCTR Pad1
Ave Pres HC POVO SCTR Pad2
Water Inje Rate SCTR Pad2
Gas Inje Rate SCTR Pad1
0
100
200
300
400
Water Inje Rate SCTR (m3/day)
0
2,000
4,000
6,000
8,000
10,000
Gas Inje Rate SCTR (m3/day)

Fig. 7

CA 02678348 2009-09-11

Fig. 8



CA 026783348 2009-09-11

Fig. 9

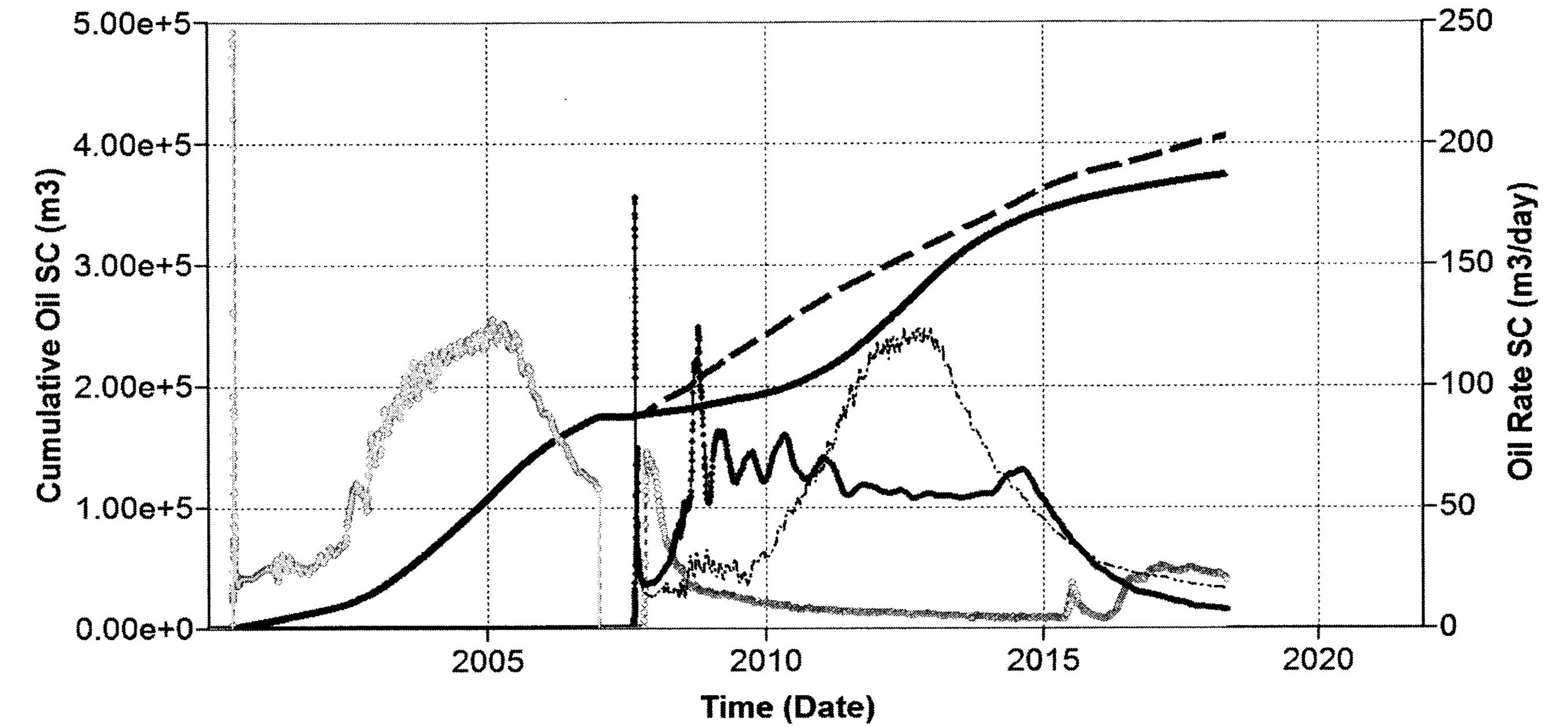
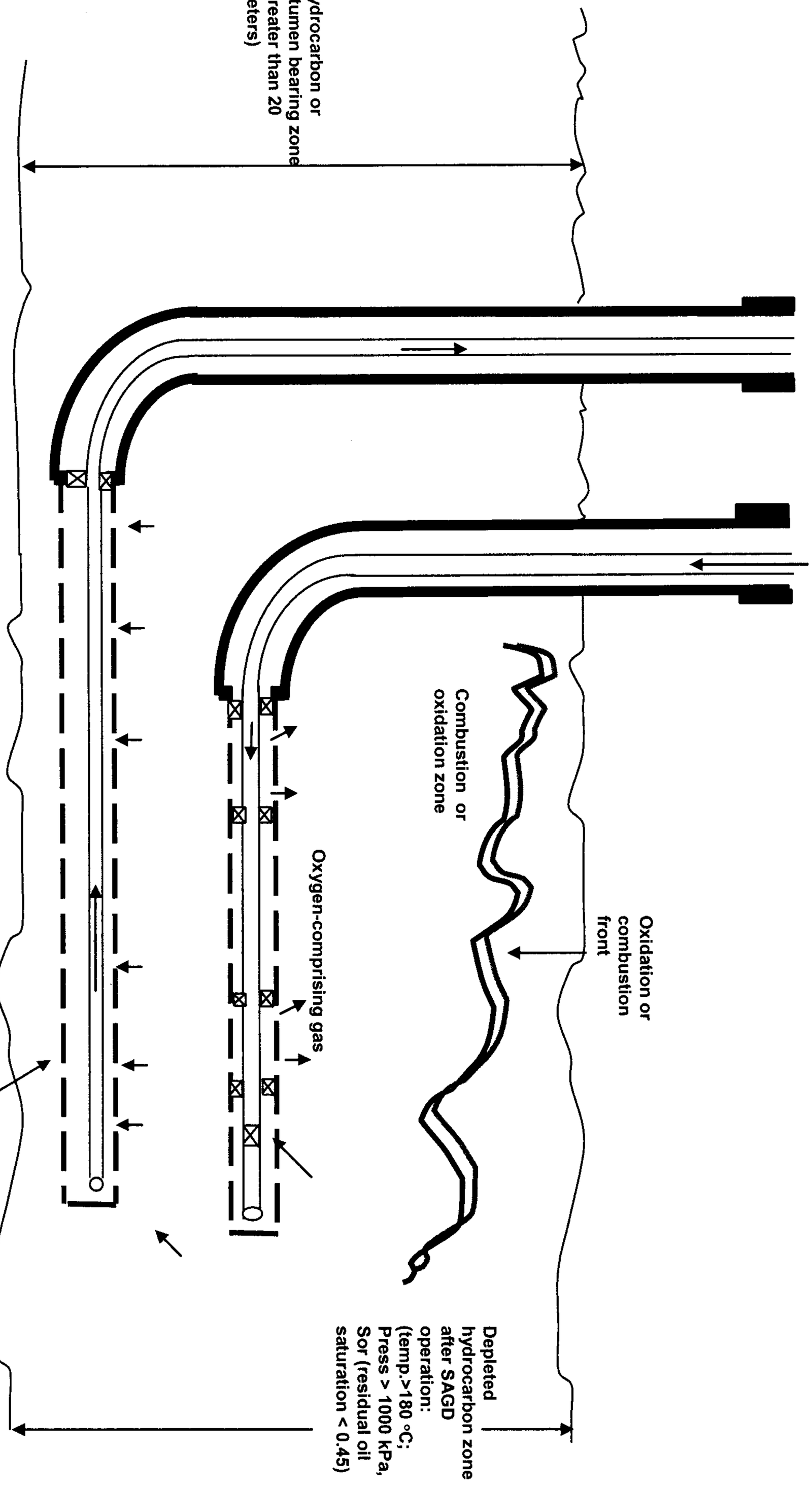


Fig. 10


Hydrocarbon or bitumen bearing zone (greater than 20 meters)
Combustion or oxidation zone
Oxidation or combustion front
Oxygen-comprising gas
Depleted hydrocarbon zone after SAGD operation: (temp.>180 °C; Press > 1000 kPa, Sor (residual oil saturation < 0.45)

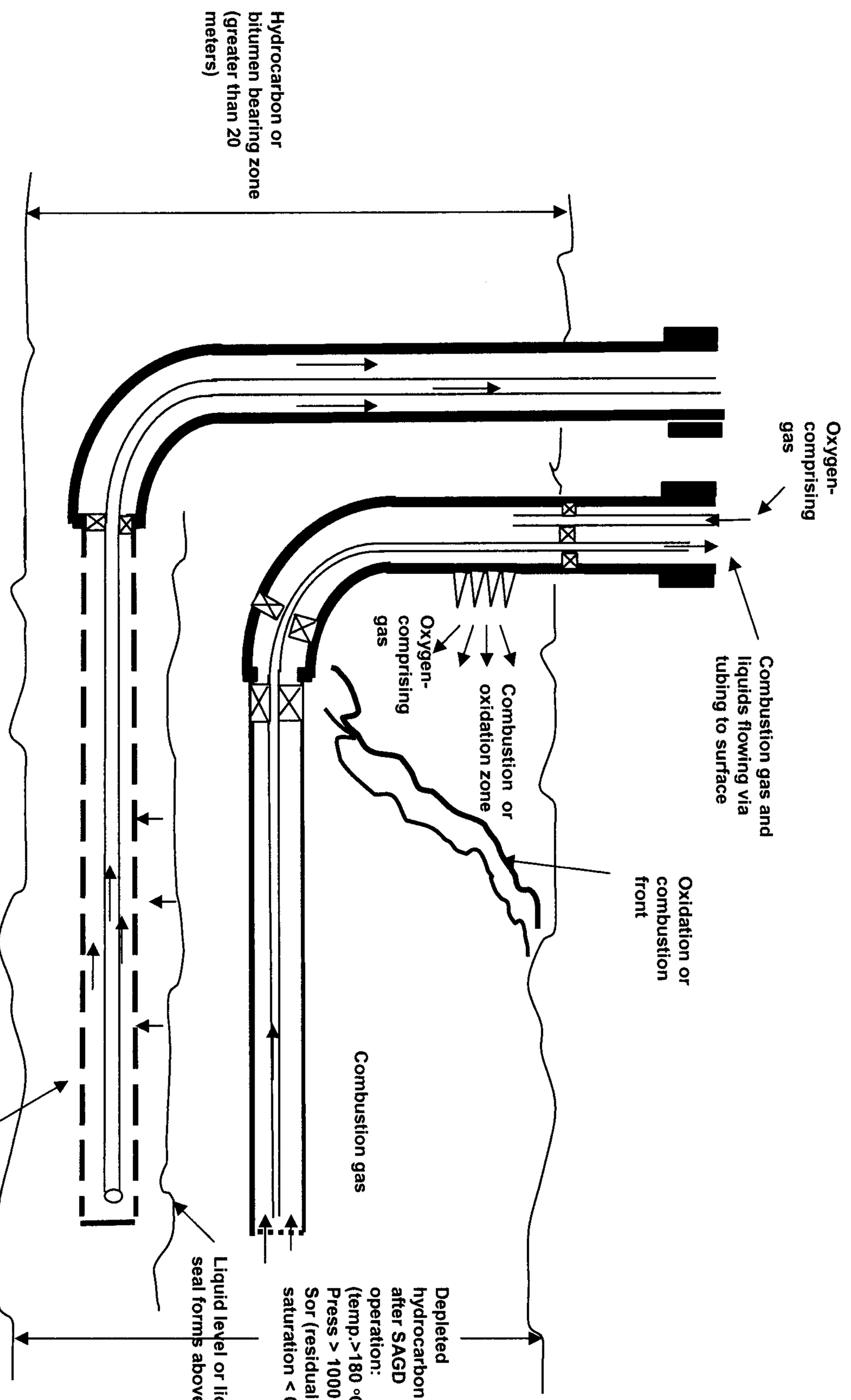

Hydrocarbon or bitumen bearing zone (greater than 20 meters)
Oxygen-comprising gas
Combustion gas and liquids flowing via tubing to surface
Oxygen-comprising gas
Combustion or oxidation zone
Oxidation or combustion front
Combustion gas
Depleted hydrocarbon zone after SAGD operation: (temp.>180 °C; Press > 1000 kPa, Sor (residual oil saturation < 0.45)
Liquid level or liquid hydraulic seal forms above the producer
Produced bitumen, water condensate will drain down

Fig. 11

CA 02678348 2013-12-20

Fig. 12

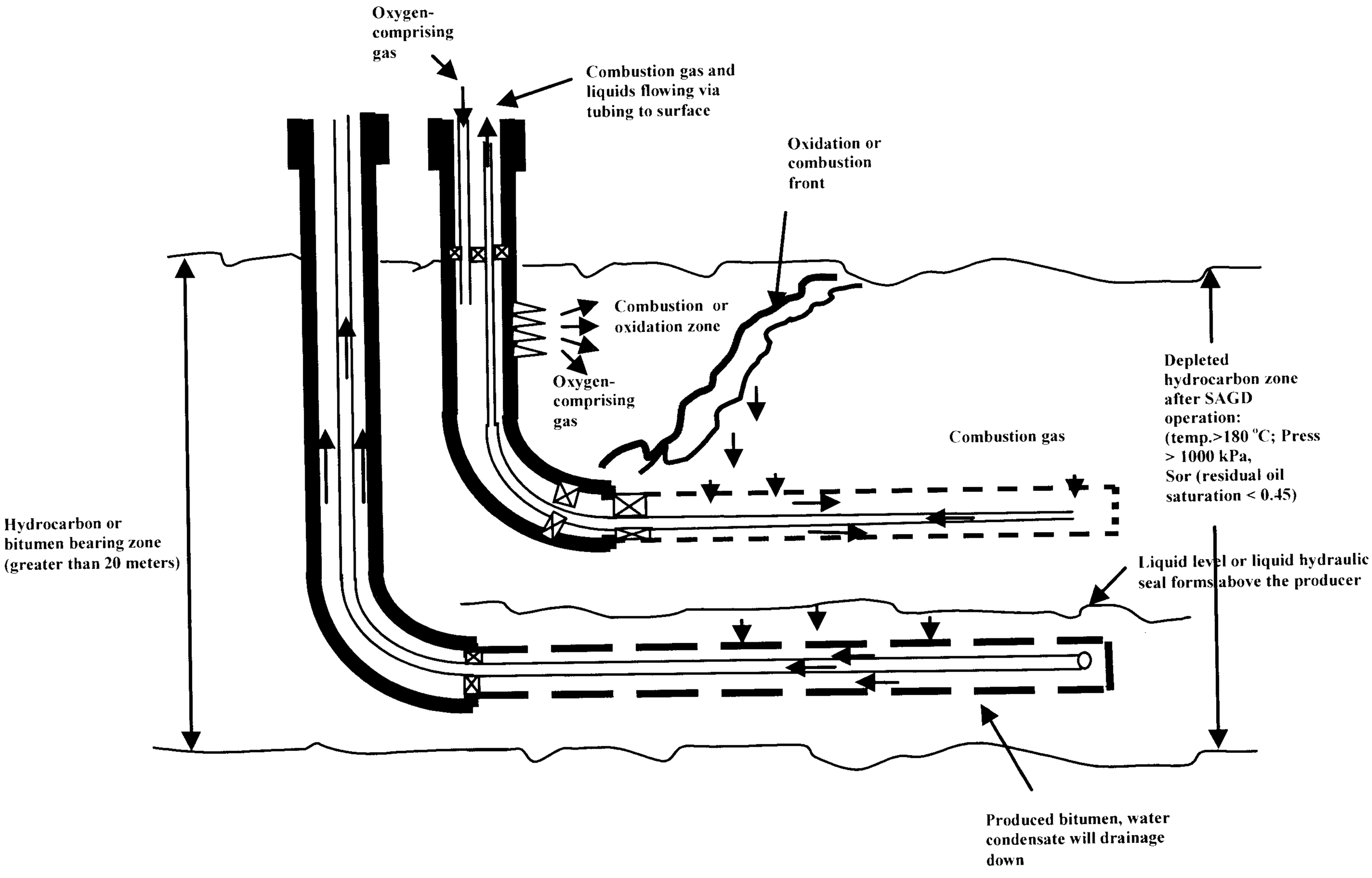
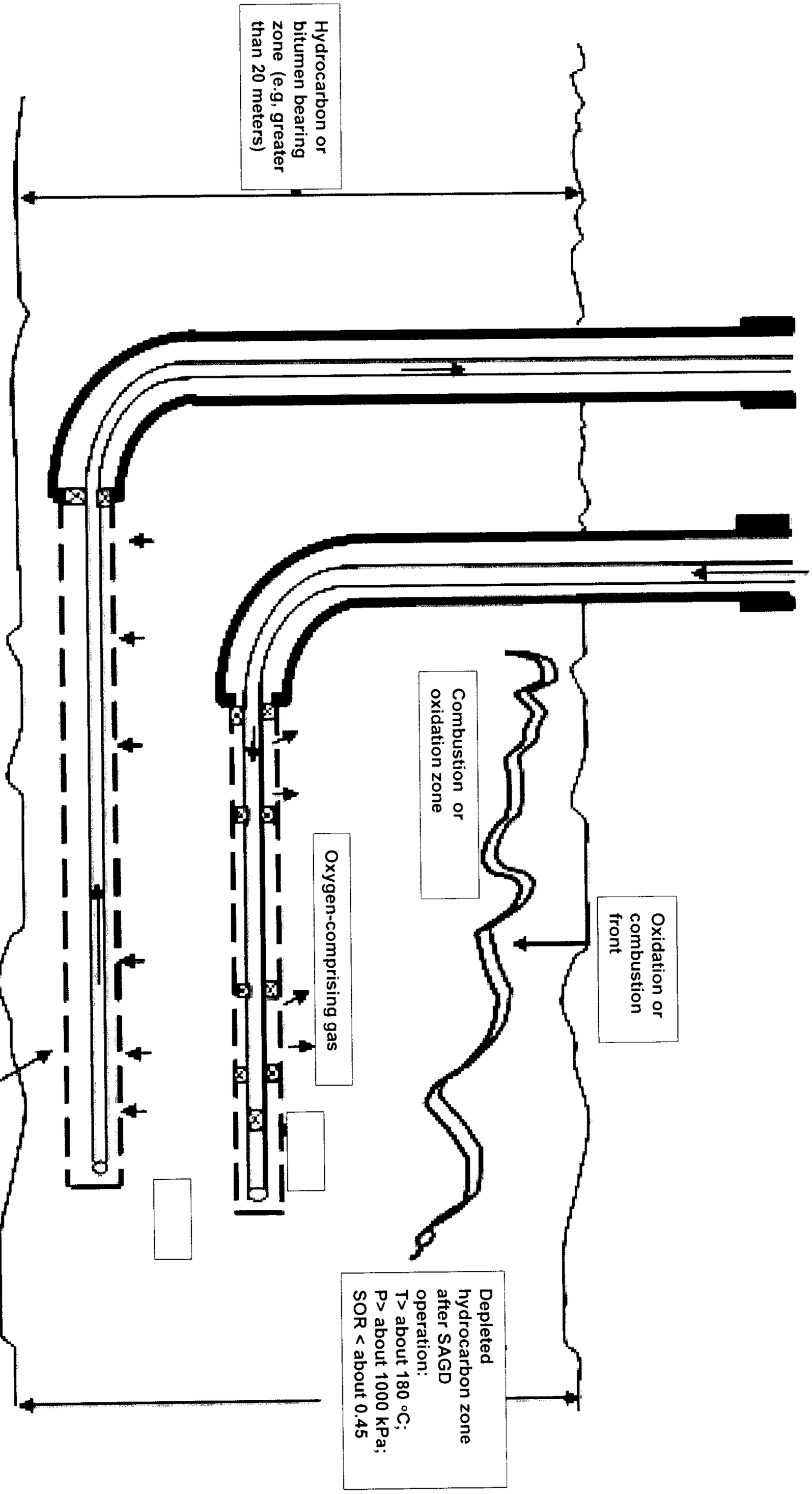
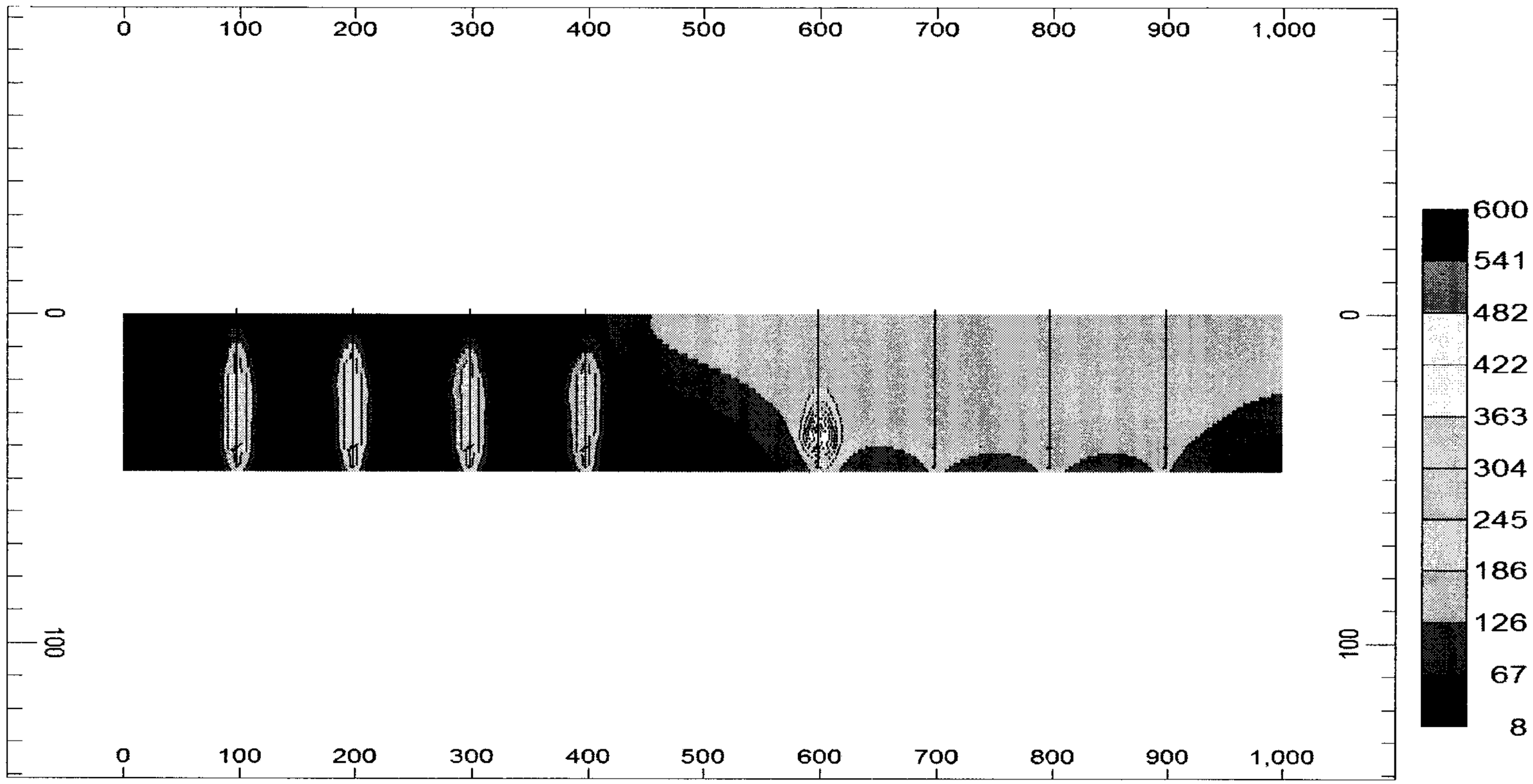


Fig. 13


Hydrocarbon or bitumen bearing zone (e.g, greater than 20 meters)
Combustion or oxidation zone
Oxidation or combustion front
Oxygen-comprising gas
Depleted hydrocarbon zone after SAGD operation:
T> about 180 °C;
P> about 1000 kPa;
SOR < about 0.45
Produced bitumen, water condensate will drain down and combustion gas may vent out

CA 2678348 2009-09-11

Fig. 14

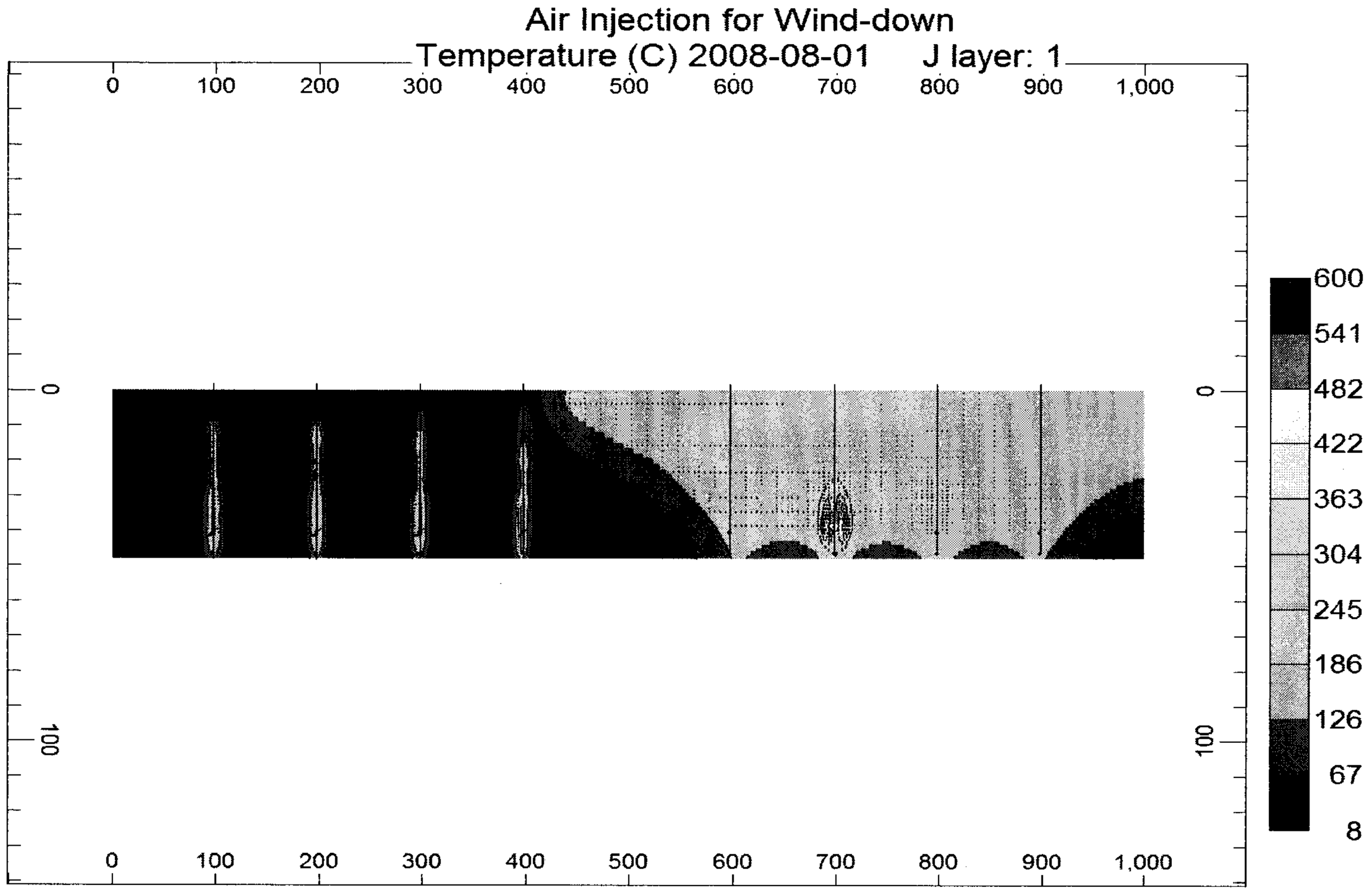


Case 1

Legend: temperature; scale unit: degree Celsius ºC

CA 02678348 2009-09-11

Fig. 15

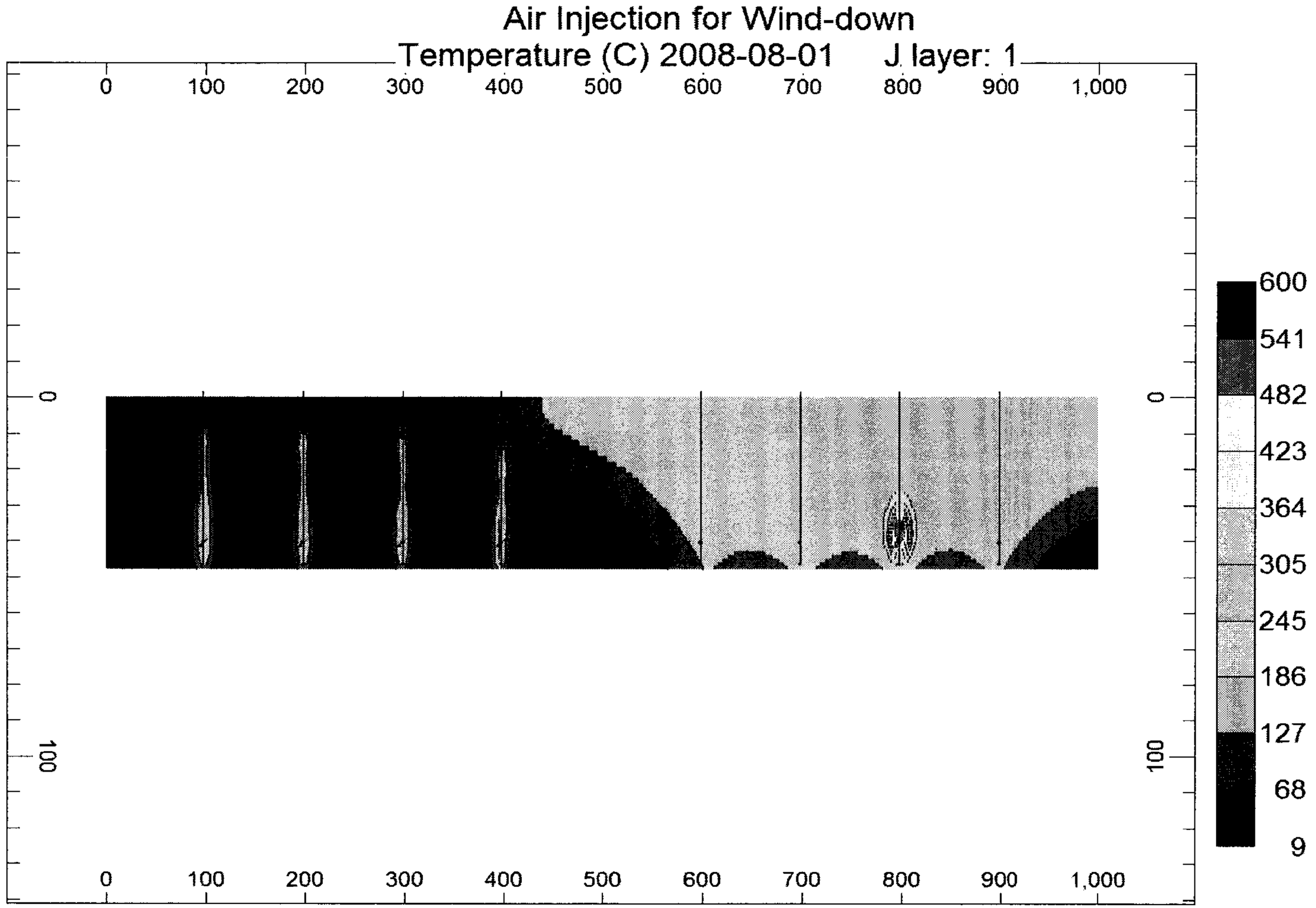


Case 2

Legend: temperature; scale unit: degree Celsius ºC

CA 2678348 2009-09-11

Fig. 16

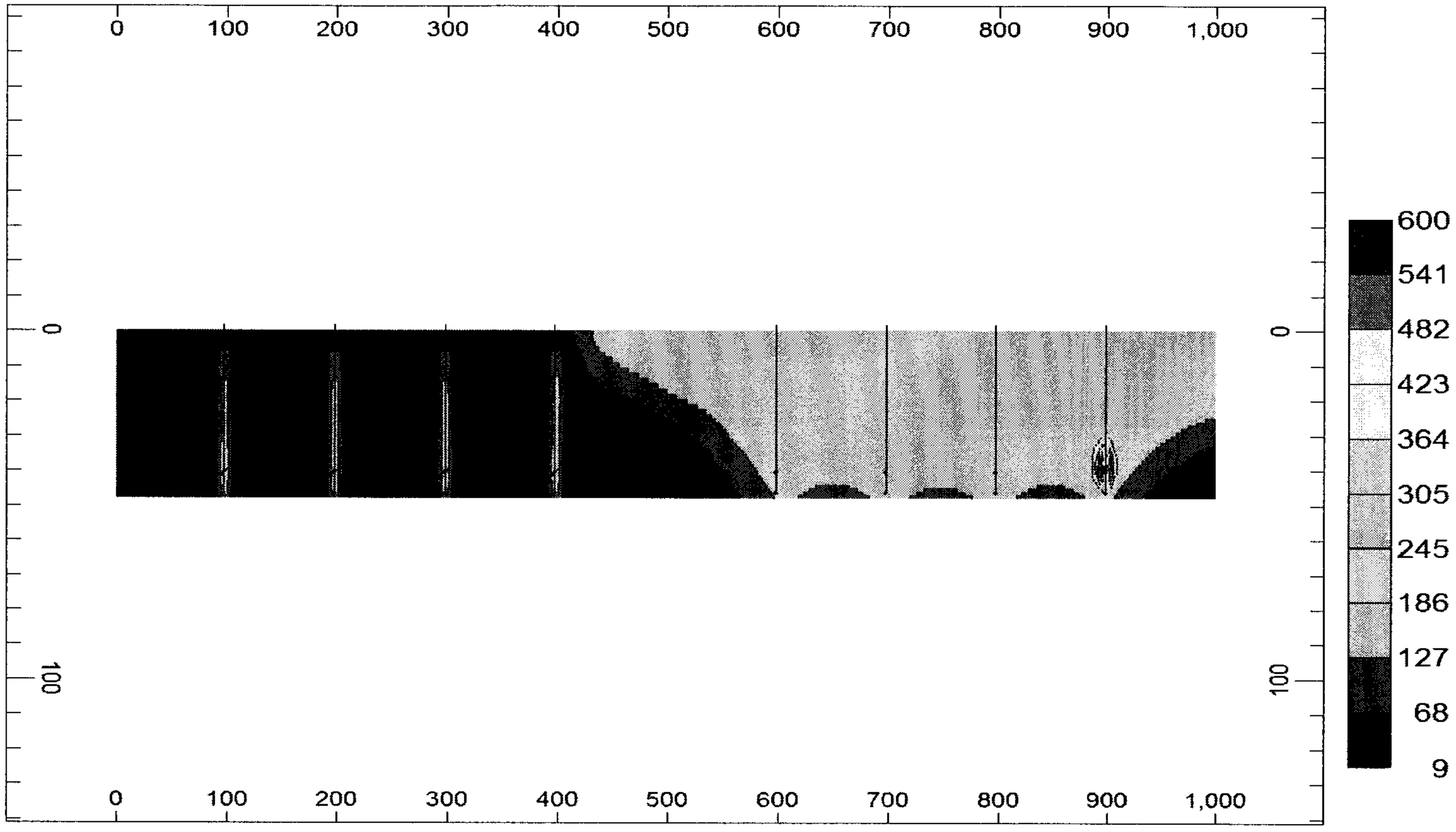


Case 3

Legend: temperature; scale unit: degree Celsius °C

CA 02678348 2009-09-11

Fig. 17

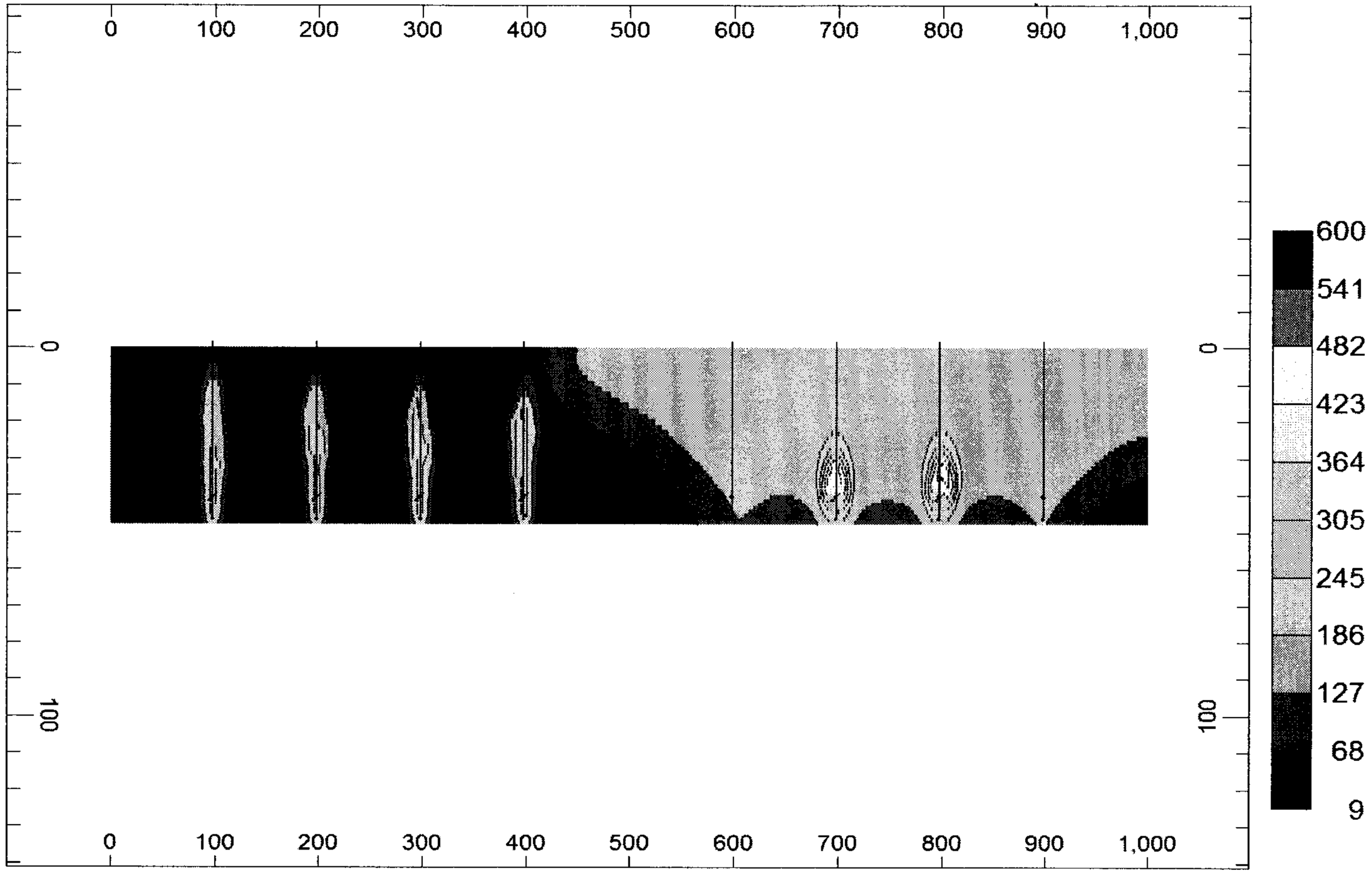


Case 4

Legend: temperature; scale unit: degree Celsius ºC

CA 02678348 2009-09-11

Fig. 18



Case 5

Legend: temperature; scale unit: degree Celsius ^{o}C

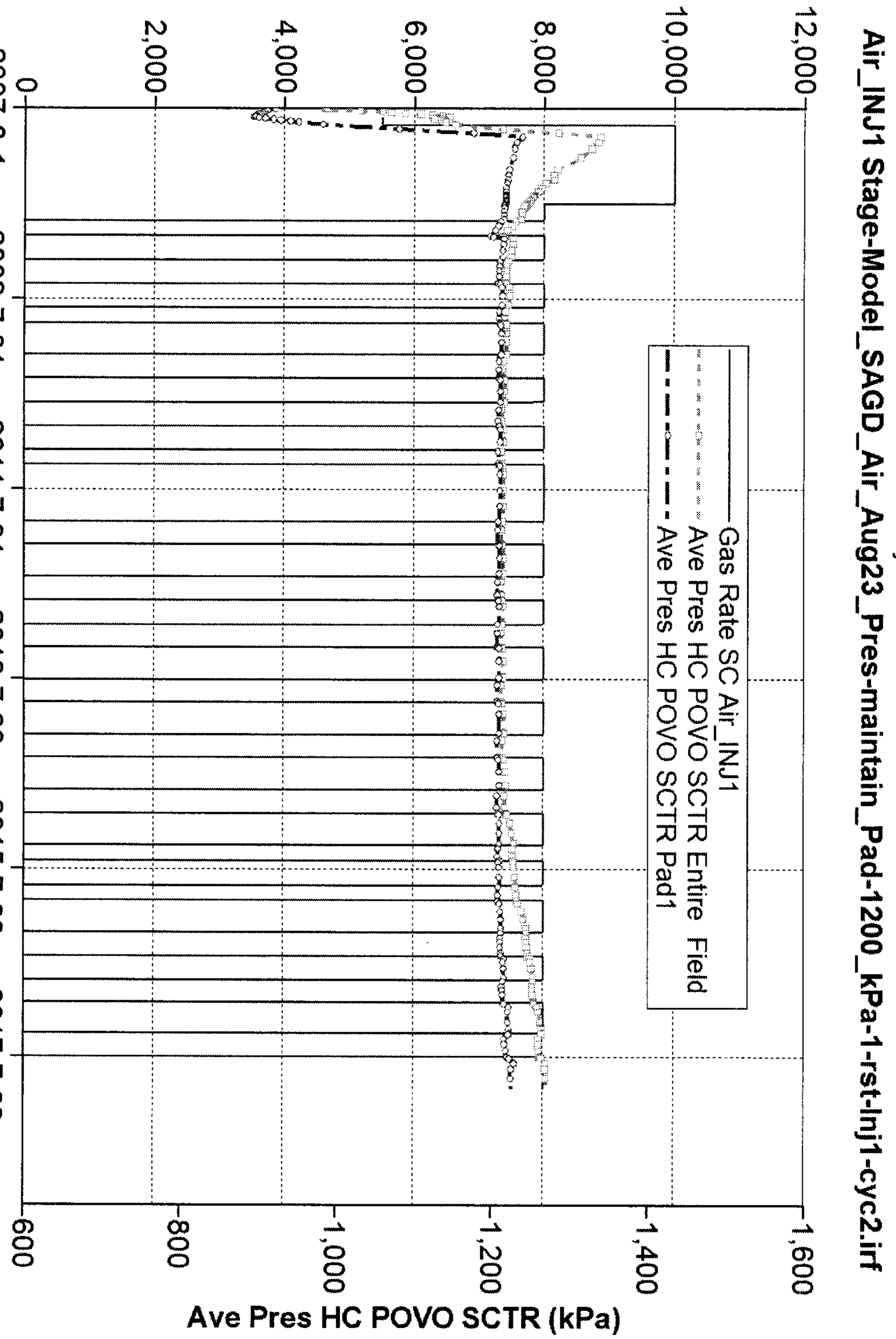
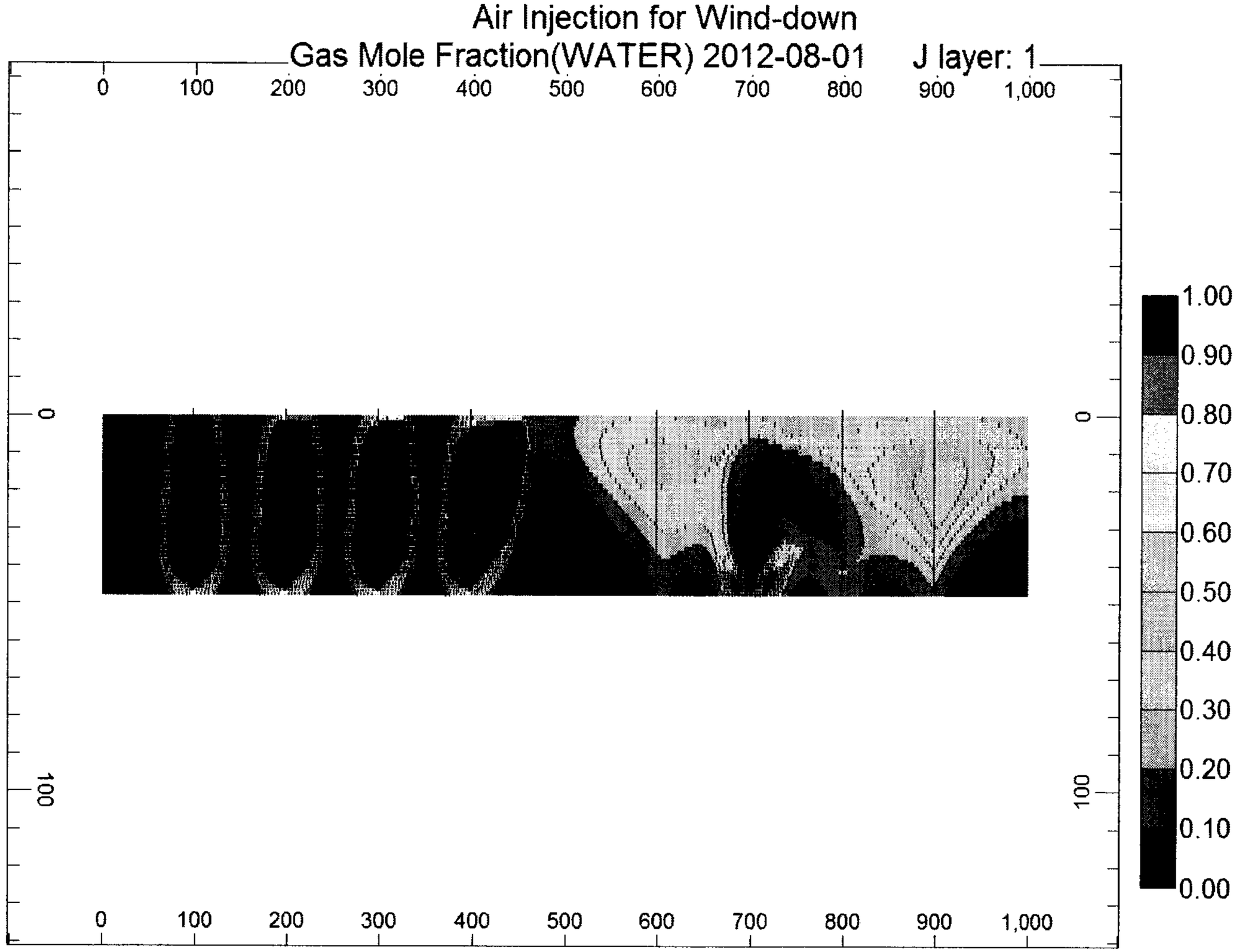

Air Injection for Wind-down
Air_INJ1 Stage-Model_SAGD_Air_Aug23_Pres-maintain_Pad-1200_kPa-1-rst-Inj1-cyc2.irf
Gas Rate SC Air_INJ1
Ave Pres HC POVO SCTR Entire Field
Ave Pres HC POVO SCTR Pad1
Gas Rate SC (m3/day)
0
2,000
4,000
6,000
8,000
10,000
12,000
2007-8-1
2009-7-31
2011-7-31
2013-7-30
2015-7-30
2017-7-29
Time (Date)
600
800
1,000
1,200
1,400
1,600
Ave Pres HC POVO SCTR (kPa)

Fig. 19

CA 02678348 2009-09-11

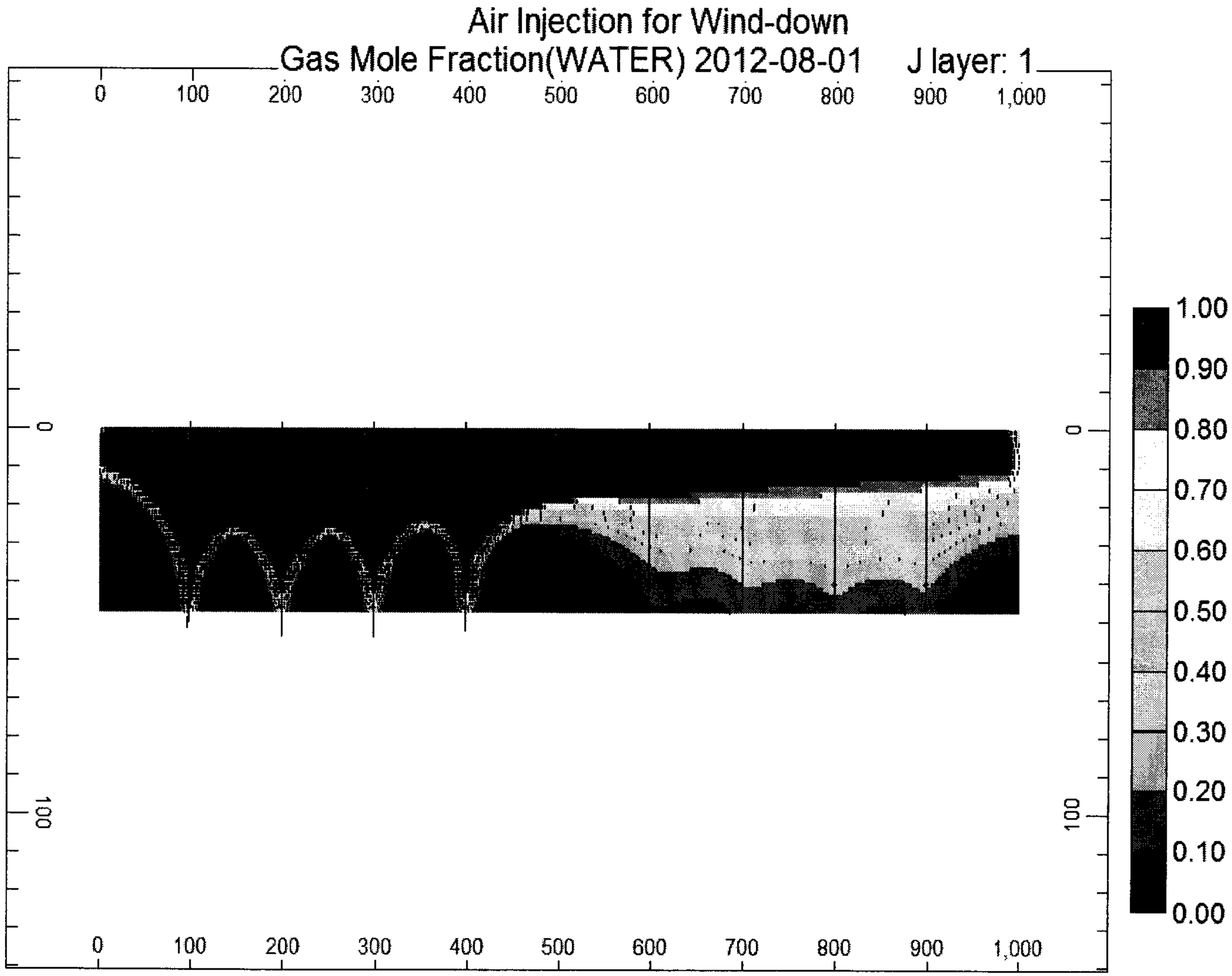
Fig. 20A



Legend: temperature; scale unit: degree Celsius ºC

CA 2678348 2009-09-11

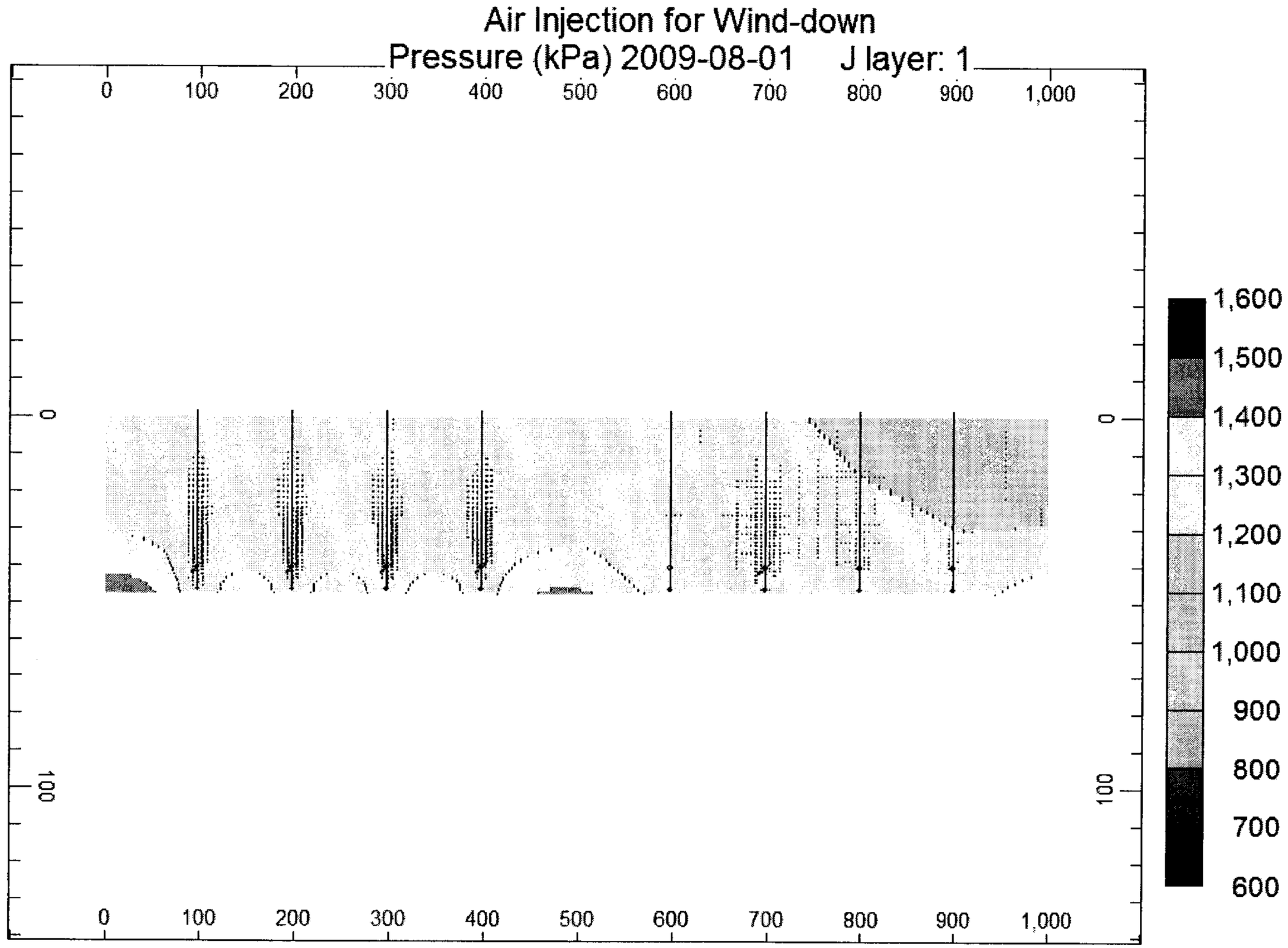
Fig. 20B



Legend: temperature; scale unit: degree Celsius ºC

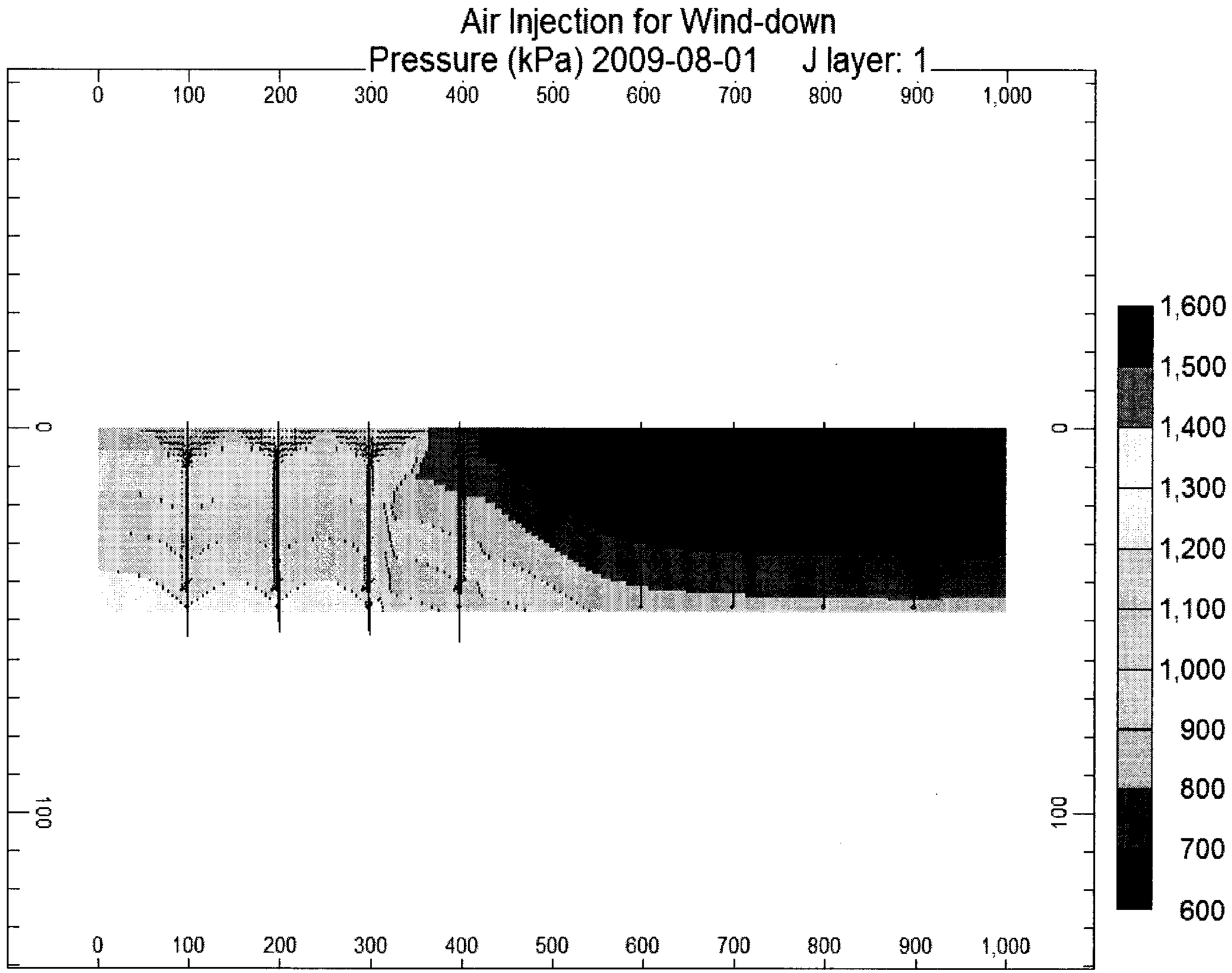
CA 2678348 2009-09-11

Fig. 21A



Legend: temperature; scale unit: degree Celsius ºC

Fig. 21B

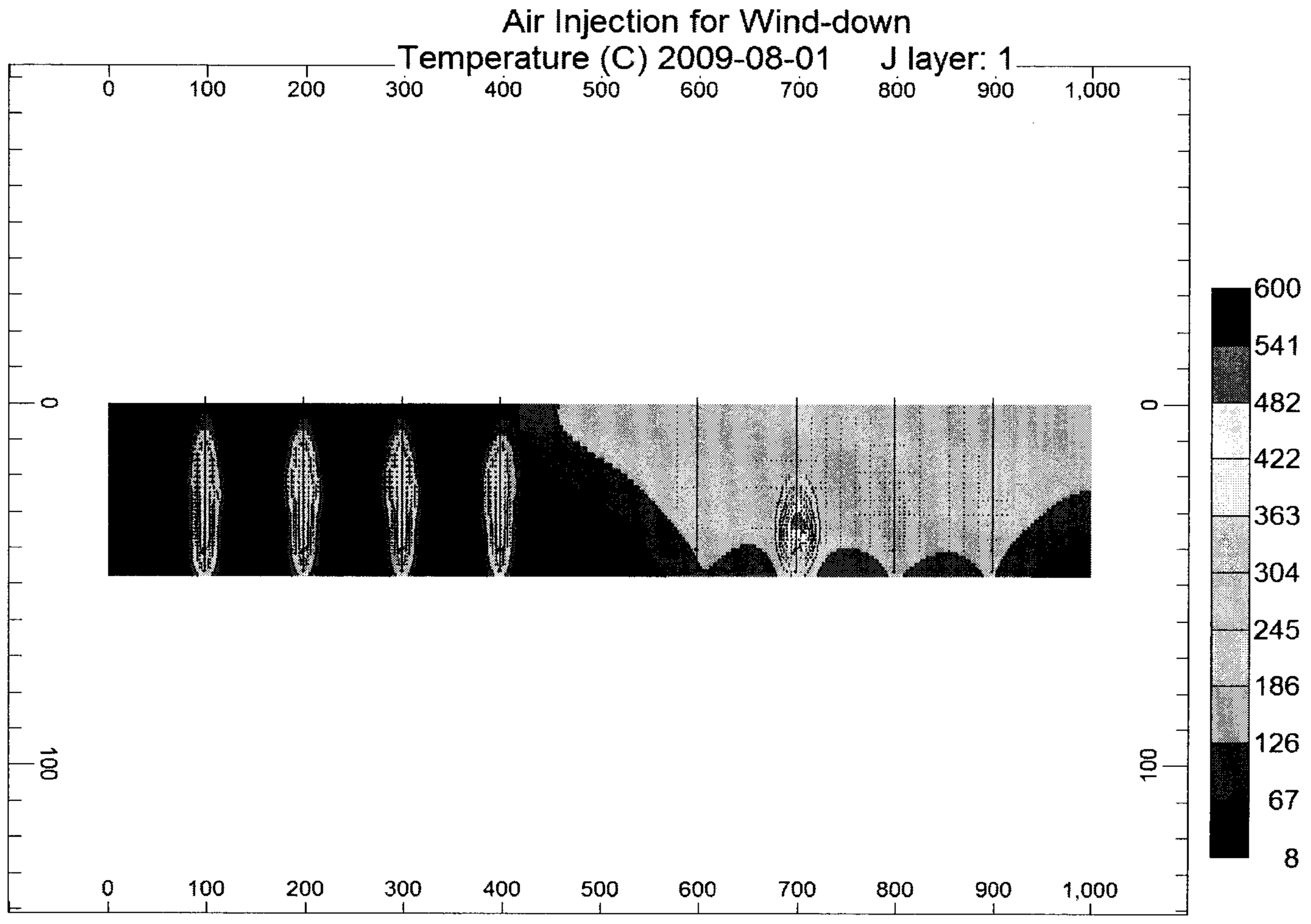


Legend: temperature; scale unit: degree Celsius ºC

CA 02678348 2009-09-11

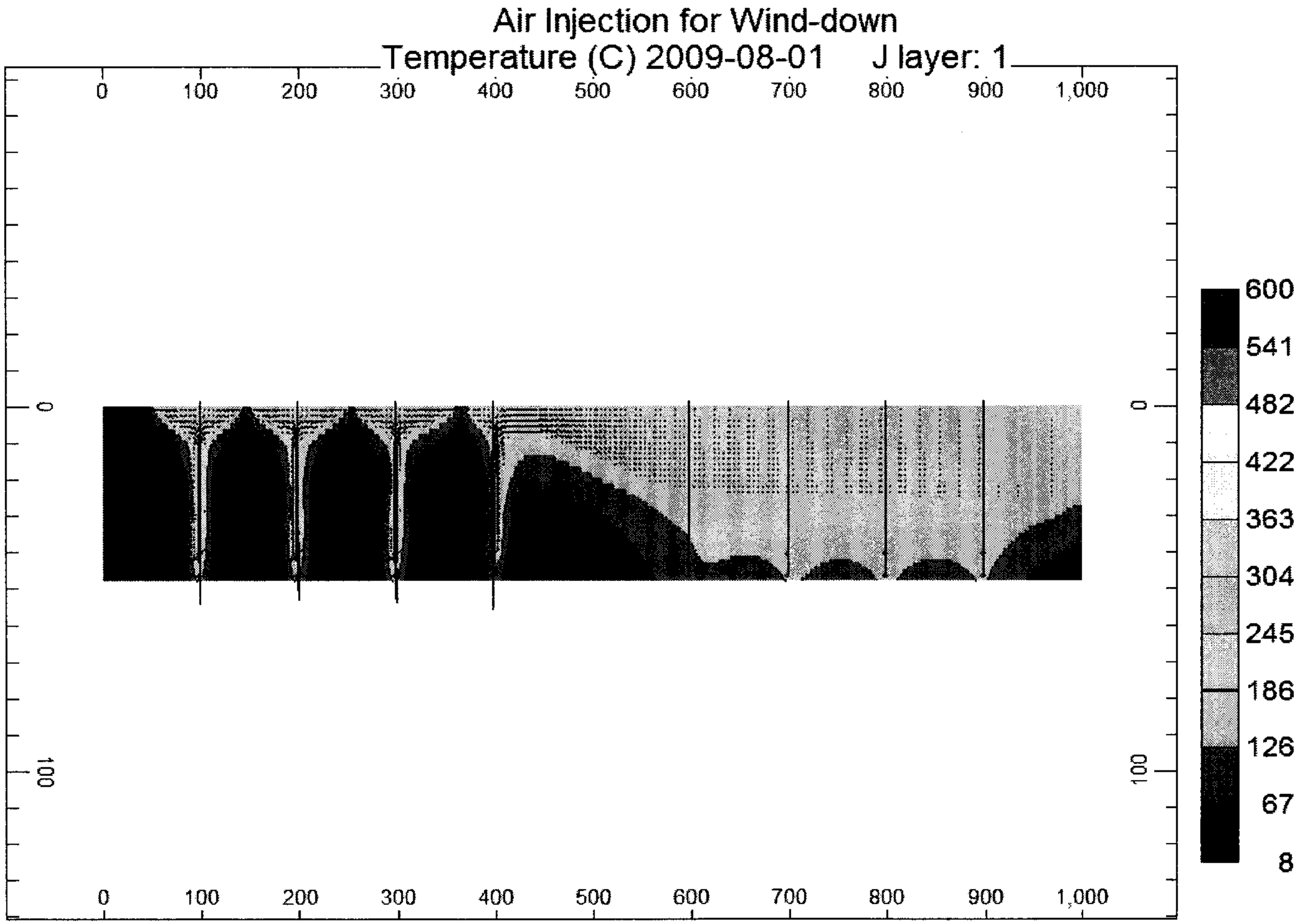
CA 02678348 2009-09-11

Fig. 22A



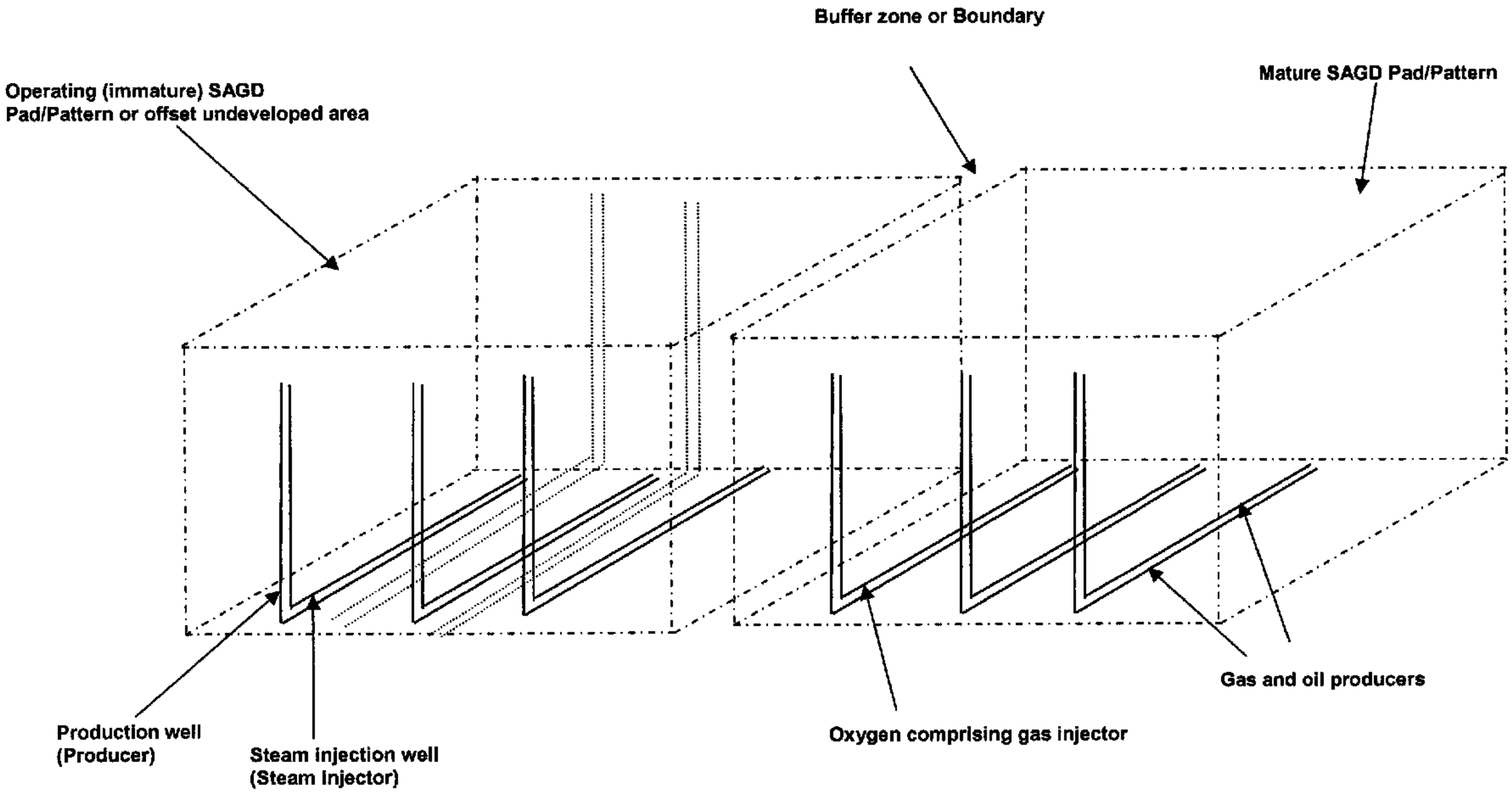
Legend: temperature; scale unit: degree Celsius ºC

Fig. 22B



Legend: temperature; scale unit: degree Celsius ºC

CA 02678348 2009-09-11


Buffer zone or Boundary
Operating (immature) SAGD
Pad/Pattern or offset undeveloped area
Mature SAGD Pad/Pattern
Production well
(Producer)
Steam injection well
(Steam Injector)
Oxygen comprising gas injector
Gas and oil producers