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Enhanced oil recovery techniques for heavy oil and oilsands reservoirs after steam injection

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HIGHLIGHTS

- A detailed critical review of EOR techniques after steam injection is provided.
- Typical processes include ISC and hybrid thermal recovery processes.
- Both the recovery mechanisms and field performance are included.
- Some other processes (electrical method, in-situ upgrading and solar energy, etc.) are involved.
- The current challenges and future directions of heavy oil recovery processes are discussed.

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ABSTRACT

The in-situ steam-based technology is still the main exploitation method for heavy oil and oilsands resources all over the world. But currently most of the steam-based processes (e.g., cyclic steam stimulation (CSS), steam flooding and steam assisted gravity drainage (SAGD)) in heavy oilfields have entered into an exhaustion stage. Considering long-lasting steam-rock interactions, how to further enhance the heavy oil and bitumen recovery in the post steam injection era is currently challenging. In this paper, we present a comprehensive and critical review of the enhanced oil recovery (EOR) processes in the post steam injection era in both experimental and field cases. Specifically, the paper presents an overview on the recovery mechanisms and field performance of thermal EOR processes by reservoir lithology (sandstone and carbonate formations) and offshore versus onshore oilfields. Typical processes include an in-situ combustion process, a thermal-solvent process, a thermal-NCG (non-condensable gas, e.g., N_2, flue gas and air) process, and a thermal-chemical (e.g., polymer, surfactant, gel and foam) process. Some other processes and new processes are also presented in this work. This review shows that offshore heavy oilfields will be the future exploitation focus. Moreover, currently several steam-based projects and thermal-NCG projects have been operated in Emeraude Field in Congo and Bohai Bay in China. A growing trend is also found for an in-situ combustion process and a solvent assisted process in both offshore and onshore heavy oilfields, such as EOR projects in North America, North Sea, Bohai Bay and Xinjiang. The multicomponent thermal fluids injection process in offshore and the thermal-CO_2 and thermal-chemical (surfactant and foam) processes in onshore heavy oil reservoirs are some of the opportunities identified for the next decade based on preliminary evaluations and proposed or ongoing pilot projects. Furthermore, the new processes of an electrical method, in-situ upgrading (e.g., ionic liquids, addition of catalyst and steam-nanoparticles) and novel wellbore configurations have also gained some attention. We point out that there are some newly proposed recovery techniques that are still limited to a laboratory scale study, with the need for further investigations. In such a time of low oil prices, cost optimization will be the top priority for all the oil companies in the world. This critical review will help them identify the next challenges and opportunities in the EOR potential of heavy oil and bitumen production in the post steam injection era.

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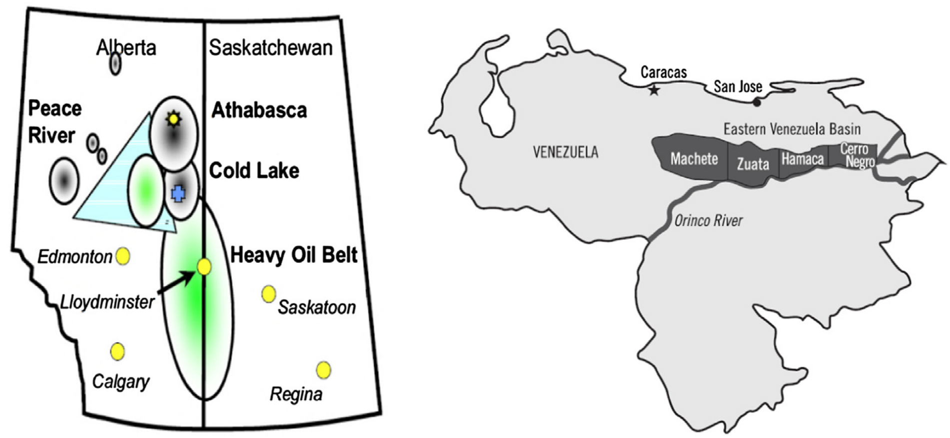

(a) Oil sands reserves in Alberta. (b) Orinoco petroleum belt.

Fig. 1. Heavy oil resources distribution in Canada and Venezuela [96,5].

1. Introduction

According to EIA's International Energy Outlook 2017, the total world primary energy consumption is about 575 quadrillion Btu (British thermal units) in 2015 and is expected to increase by 15.3% from 2015 to 2035, and then to 736 Btu by 2040 [1]; the world consumption of liquid fuels will rise from 95 million barrels per day (b/d) in 2015 to 113 million b/d in 2040. For liquid fuels, the consumption of crude oil has a very high proportion. The total crude oil resources are approximately 9–11 trillion barrels (bbls) in the world, among which more than 2/3 are heavy oil and bitumen. Out of the total eight trillion bbls of heavy oil and bitumen resources, Canada and Venezuela possess about 2–3 trillion bbls each [2–4]. In Canada, almost all of the heavy oil and oil sands deposits lie in Alberta, as shown in Fig. 1(a). In Venezuela, these oil resources mainly lie parallel to the northern bank of the Orinoco River and extend from east to west along the Orinoco petroleum belt, as shown in Fig. 1(b) [5]. Effective development of these heavy oil and bitumen resources will have an important influence on the world energy supply.

Different from the conventional light oil, these types of crude oils are usually characterized by their high viscosity and high density in the original formation temperature condition. Therefore, in order to effectively recover them, reducing their viscosity (μ_o) and improving their mobility (k/μ_o) are the top priority. Considering the temperature sensitivity of the heavy oil or bitumen viscosity, a thermal recovery process is introduced. For a thermal recovery process, a hot fluid such as steam is cyclically or continuously injected into a formation. Then both the formation rock and fluids around wells are heated, and temperature increases. Thus, the oil viscosity is reduced, and the mobility of heavy oil and bitumen is improved. As shown in Fig. 2, as temperature increases, the oil viscosity reduces by orders of magnitude. A thermal recovery technique was first started in Trintopec's operations in 1966, with a small cyclic pilot project in the Palo Seco field [6]. Until now, it is still the main exploitation method for heavy oil and bitumen resources all over the world. Especially, considering the high heat-carrying capacity of steam, it is the most commonly-used and ideal hot fluid for a thermal recovery project [7–9,11]. The in-situ steam-based technology has been widely applied for an EOR process for heavy oil and oilsands reservoirs for a long time. Additionally, it is the most advanced one of all EOR methods in terms of field experience and thus has the least uncertainty in estimating its performance [4]. Generally, there are usually three types of steam-based thermal recovery techniques, cyclic steam stimulation (CSS), steam flooding and steam assisted gravity drainage (SAGD) [10,12].

For steam-based recovery processes, after steam is injected, a heated zone with high pressure forms around an injection well. Then, as the steam injection continues, the pressure in this zone goes up. Especially, considering the heterogeneous feature of formation parameters, the injected steam preferentially penetrates into a highly permeable path in an oil reservoir. For CSS, as the CSS cycles increase, a channeling path can form within the reservoir. It is the same as the concept of a chief zone in waterflooded light oil reservoirs. A steam channeling path is usually represented by high permeability or high connectivity between wells. Moreover, there are also many indicators to identify the phenomena of steam channeling/steam breakthrough [13], e.g., bottom hole temperature, wellhead temperature, water cut and a liquid rate. It is generally caused by the long-lasting steam-rock interactions [14–15]. After the occurrence of steam breakthrough, the thermal efficiency of steam is dramatically reduced. Thus, an enhanced recovery process is required in the post steam injection era.

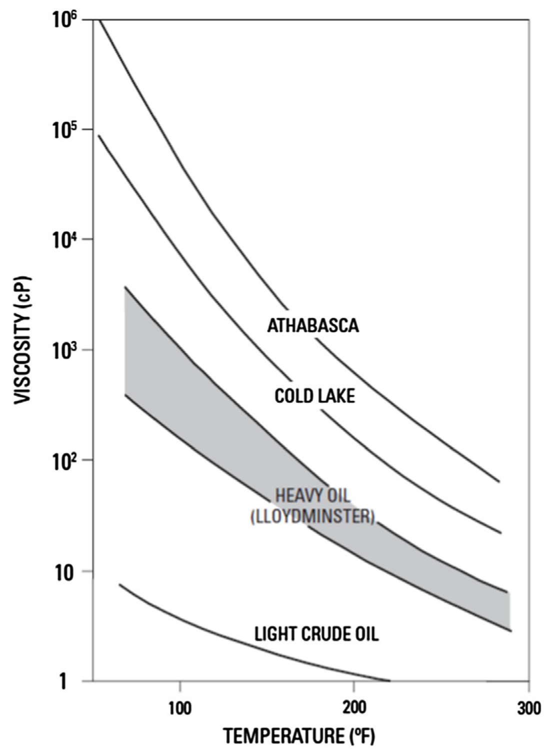

Fig. 2. The viscosity of crude oil vs. temperature [3,4].

Currently, most of the heavy oil and oilsands reservoirs over the world have entered into a later stage of steam-based recovery processes

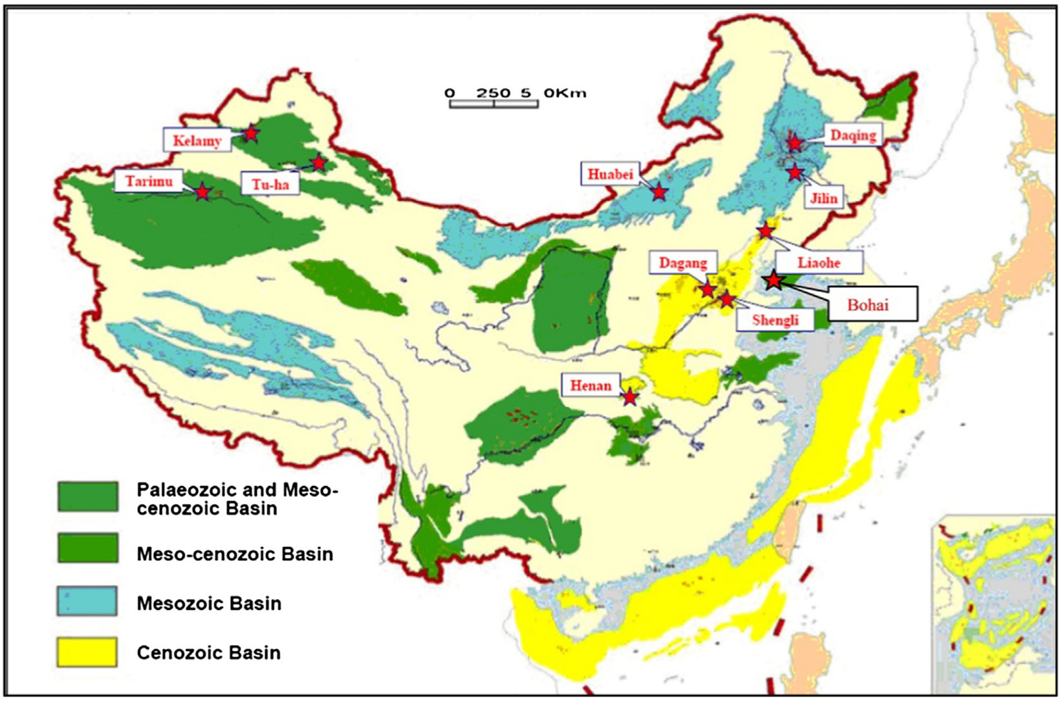

Fig. 3. Heavy oilfield locations in China [97].

[16–18]. CSS cycles may increase up to over 10 or even 20 cycles. The main heavy oilfield locations in China are shown in Fig. 3, including Liaohe oilfield, Shengli oilfield, Xinjiang oilfield and Henan oilfield. Most of these heavy oilfields in China are facing a challenge to convert the previous low economic recovery techniques (i.e., CSS and steam flooding) to high economic ones, especially in such a time of low oil prices. For Shengli oilfield, an economic strategy of "Three Costs and Four Performance Zones" is proposed for inefficient wells in recent years [20,21]. Under the guidance of this strategy, many inefficient wells in Shengli oilfield have been temporarily closed to save operation costs. How to further enhance the heavy oil recovery in the post steam injection era is really challenging.

Guo et al. [19] gave a comprehensive review on the existing in-situ heavy oil recovery techniques, which can fall into three categories, including thermal injection, chemical injection and gas injection. Different from their review, in this paper, we will aim at the EOR techniques in the post steam era. Through a broad literature review, the post steam injection techniques can be categorized into an in-situ combustion process, a hybrid thermal-solvent process, a hybrid thermal-NCG (non-condensable gas) process, a hybrid thermal-chemical process and other emerging methods (e.g., an electrical method, in-situ upgrading and novel wellbore configurations). Additionally, we will present a critical review of the EOR processes in the post steam injection era in both experimental and field cases. Specifically, this paper gives an overview on the recovery mechanisms and field performance of thermal EOR techniques by reservoir lithology (sandstone and carbonate formations) and offshore versus onshore oilfields.

2. Conventional steam-based recovery processes

CSS, steam flooding and SAGD processes are the most commonly-used steam-based recovery techniques for heavy oil and oilsands reservoirs [10,22]. In this section, the current status of these steam-based recovery processes will be discussed in detail.

2.1. Cyclic steam stimulation (CSS or Huff n' Puff)

CSS is the simplest form of steam injection operation, and has been widely used for the recovery of heavy oil and oilsands reservoirs in the world. This operation generally includes three major phases: steam injection (several weeks), soaking (3–5 days) and oil production (tens/hundreds of days) [7,22,22]. All these phases are performed within a same well. After the phase of oil production, steam is reinjected to start a new cycle. The recovery mechanisms of CSS essentially consist of oil viscosity reducing, heat swelling and solution gas driving. It is predominantly performed in vertical wells [12]. Typical oil recovery factors are 20–35% with SORs (steam-oil ratios) of 3.0–5.22. Alvarez and Han [18] have made a critical review on the current status of CSS technology, and discussed the commercial projects in the world. It is usually applied in those heavy oil reservoirs whose pay thickness is greater than 30 ft, reservoir depth is less than 3000 ft, porosity is higher than 0.3 and oil saturation is greater than 40% [4,22]. It is still the main recovery method for most of the heavy oilfields in the world. In China, almost 75% of the heavy oil production comes from the CSS projects [24,25,22]. On the other hand, in recent years, thin heavy oil reservoirs have also become an important part to boost the oil production. For this type of heavy oil reservoirs, the conventional vertical well-based CSS technique (VW-CSS) is no longer economical because of huge overburden and underburden heat losses. The horizontal well-based CSS technique (HW-CSS) has been performed in this type of heavy oil reservoirs [26–29]. Also, because of a reduction in directional drilling costs and the improvement of sweep efficiency, the HW-CSS process has been considered one of the successful EOR processes in heavy oil reservoirs.

For the conventional CSS process, specifically in a later stage of CSS operation, the thermal efficiency of steam is dramatically reduced. Thus, a follow-up recovery process is required. Considering this situation, many attempts have been made for the improvement of the CSS process, e.g., a combined CSS process with multiple wells, a steam flooding process and a steam-additive process [30–32]. First, for the combined CSS process with multiple wells, one single well group or several well groups are considered as an operation unit, as shown in Fig. 4. These well groups generally possess a higher steam breakthrough degree or a higher recovery factor within certain layers. They utilize a steam channeling path to perform the steam injection process with a well-group operation mode instead of the conventional single well

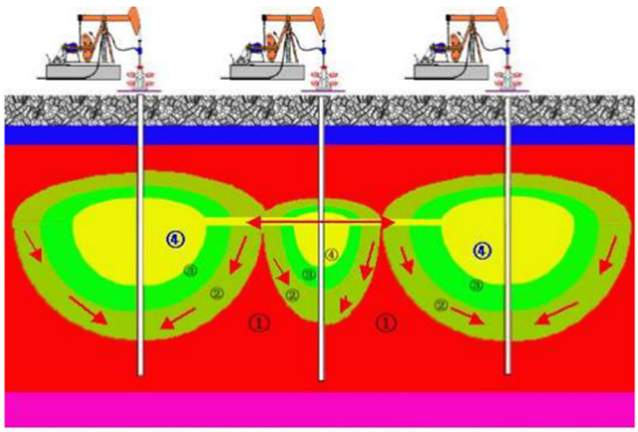

Fig. 4. The combined CSS process with multiple wells: ① original crude oil; ② heated area; ③condensate area; ④ steam zone.

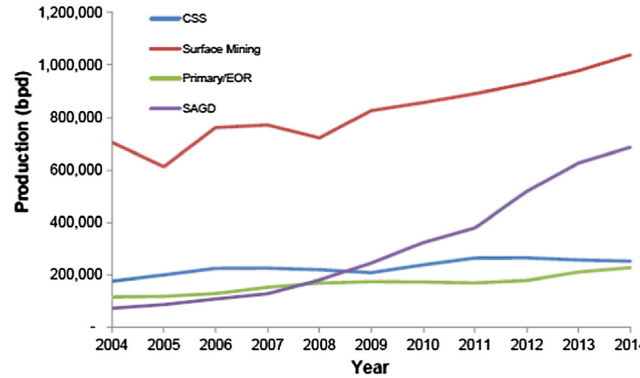

Fig. 5. Annual Crude Oil Production from Oil Sands by Technologies in Canada [45].

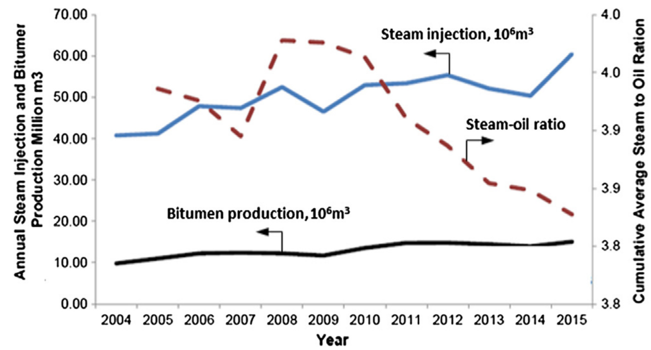

Fig. 6. CSOR for the annual crude oil production from oil sands CSS methods [45].

operation. It can effectively recover the remaining oil between wells. In addition, retarding steam overlay is another important mechanism of this process. The other follow-up techniques of steam flooding and steam-additive processes will be discussed in detail in later sections.

The CSS process can also be applied to improving a steam chamber expansion in the SAGD process [33–35]. It is called a Fast-SAGD process or hybrid CSS/SAGD process, and it is proposed based on the CSS and SAGD processes. In the Fast-SAGD process, an offset well is drilled between adjacent SAGD well pairs and is performed under CSS operation to accelerate the steam chamber growth sideways [36]. In the hybrid CSS/SAGD process, a CSS well is placed between the SAGD well pairs. This well is operated in a CSS mode until steam chambers are in contact with each other and then switched to SAGD operation. In comparison, the hybrid CSS/SAGD process can recover a greater amount of bitumen with lower steam injection than CSS, SAGD and Fast-SAGD [34]. Xu et al. [37] numerically investigated and optimized the performance of the hybrid CSS/SAGD process in Long Lake heavy oil reservoirs with lean zones, and it is observed that the hybrid CSS/SAGD process can perform better than the conventional SAGD in oilsands reservoirs with lean zones.

For field operation, CSS is one of the most widely-used in-situ recovery techniques for heavy oil and bitumen resources. Most heavy oil reservoirs in the world apply this strategy first. It was first applied in Venezuela in 1959. Since then, this method has been applied in many oilfields across the world, such as the San Joaquin Valley and the Los Angeles Basin in United States, Cold Lake in Canada, Lake Maracaibo in Venezuela, and Liaohe oilfield in China [38–40]. Nehring et al. [41] provided a list of significant heavy oilfields and polls in United States. There are 89 fields and 219 pools. Among them, based on a reservoir screening process, there are 41 pools qualified for the CSS process, 101 pools qualified for steam flooding, 32 pools qualified for the ISC process and 45 pools qualified for any thermal recovery methods. Except for a few thin pools, nearly all the pools that are qualified for a steam flooding process are also qualified for a CSS operation. Then, for the oilsands resources in Alberta, Canada, CSS has evolved more than 45 years in Athabasca, Cold Lake, Peace River and Grosmont [42–44]. Fig. 5 gives the annual crude oil production from oilsands by different technologies in Canada. As shown, the annual oil production from the CSS process is about 250,000 bpd. Fig. 6 shows the CSOR (cumulative SOR) for the annual crude oil production from oilsands CSS methods. From 2004 to 2014, the CSOR of all the CSS projects performed in Alberta shows a decline trend in steam consumption per barrel of bitumen. In 2015, the average CSOR for CSS bitumen production is about 3.8 [45]. The Athabasca oilsands possess a large deposit of oil-rich bitumen located in northern Alberta, and almost all the oil resources in Athabasca are deposited in the Fort McMurray formation [10,46]. The commercial production of oil from Athabasca oilsands began in 1967 by Great Canadian Oil Sands Limited (current: Suncor Energy) using the method of surface mining. In Athabasca, except surface mining, the CSS technique provides the highest oil production output among the other in-situ recovery techniques [45]. Furthermore, CSS has also been applied in Cold Lake by Imperial Oil since the 1980s and is also used by Canadian Natural Resources at Primrose and Wolf Lake and by Shell Canada at Peace River. Another application is in fractured carbonate heavy oil reservoirs, such as the Grosmont Formation in northern Alberta. It is a dolomitized, karsted and fractured carbonate reservoir that contains a massive bitumen accumulation [44,47]. CSS operation in Grosmont is the most widely and successful in-situ recovery process. One of the best performed CSS wells in Grosmont, well 10A-5-88-19W4, has recovered about 100,000 bbls of oil through over 10 cycles, with a CSOR of 6 [47,48]. In addition, the Lake Maracaibo area in Venezuela is another successful application of the CSS process for heavy crude oil [38,49]. CSS operation in the Lake Maracaibo area began in 1971, and until 1995 a total of 325 wells have been stimulated with 860 cycles [38]. In China, CSS operation for the heavy oil recovery began in Karamay oilfield (CNPC, Xinjiang) since the 1960s. Then, based on the successful operation in the pilot tests of Karamay, the CSS technique was expanded to recover the heavy oil reservoirs in Liaohe oilfield, Shengli oilfield and Henan oilfield. In 1995, the total heavy oil production in China has increased up to over 10 million tons. Currently, China has become one of the major countries of heavy oil production in the world [50,46]. Furthermore, CSS and steam flooding processes have been also widely applied to recover the heavy oil resources in the countries of Russia [51], Indonesia, Colombia [52,53], Oman and Mexico [54–56].

2.2. Steam flooding (steam drive)

Steam flooding is a logical follow-up stage of the CSS technique. In this process, steam is continuously injected into a reservoir using a vertical well or horizontal well. Therefore, a proper well pattern is usually required for a successful steam flooding operation, including injectors and producers. Steam flooding is similar to water flooding in concept [41,22]. Steam is continuously injected into a reservoir through an injector and travels through the reservoir. It effectively heats the heavy crude oil within a formation and its surrounding rocks. Then, the condensed water flows to a producer, which efficiently displaces the crude oil. The recovery mechanisms of steam flooding basically include the improvement of an oil/water mobility ratio, changes of relative permeability curves, steam distillation and emulsification behavior [7,22,57]. Based on a screening criterion, the steam flooding technique is usually suited for a reservoir whose thickness is greater than 10 m, porosity is greater than 20%, permeability is greater than $200 \times 10^{-3}\,\mu m^2$, oil viscosity is less than 20,000 cp (@RC) and oil saturation is higher than 0.5 [22,57]. But, on the other hand, with the progress of science and technology and the changes of oil price, this screening criterion is also changing.

For field operation, the projects of Kern River in USA and Cold Lake in Alberta are the two successful steam flooding cases in North America [58,59]; Imperial [60]. First, for the steam flooding project in Kern River, it was initially performed in a ten-pattern area. In this area, the formation average depth is 213–243 m; the reservoir original pressure is about 1.55 MPa; the oil viscosity is 2710 cp @85°F; the formation thickness is 29.5 m. For the performance of steam flooding in this area, the cumulative production/injection ratio of this test was 0.81, and the oil recovery factor of steam flooding reached about 37% (based on the oil reserves before steam flooding) [61,62]. But, as the steam injection continued, the occurrence of steam breakthrough in some production wells hindered to continue this test. Therefore, some adjustments were conducted, including a steam injection rate reduction, a water flooding process, well repairing, infill drilling and profile control [63–65]. Especially for the methods of profile control, there are a hybrid thermal-solvent process, a hybrid thermal-NCG process and a hybrid thermal-chemical process. These post steam flooding techniques will be discussed in detail in later sections. Then, for the Cold Lake project in Alberta, it has been operated by Imperial Oil since 1975. Currently, about 55 infills are located into 34 producing pads (totally almost 700 wells) [60]. In addition, the Qi40 reservoir in Liaohe oilfield is another successful steam flooding project in China. Involving the previous CSS stage, the total oil recovery factor after steam flooding has reached about 55.7% [50,66]. Except the operation in Qi40, steam flooding has also been performed in many heavy oil reservoirs in China, such as Jin45 (a reservoir with a boundary aquifer) and the Wa38 reservoir in Liaohe oilfield, Shan83 (a reservoir with a boundary aquifer) and the Shan56 reservoir in Shengli oilfield, and the BQ10 reservoir in Henan Oilfield [25,67,68].

Currently, the steam flooding process is still an important follow-up technique of CSS heavy oil reservoirs. It is a preferred method for most of the CSS heavy oil reservoirs. But, as the steam flooding process continues, steam breakthrough and low sweep efficiency (vertical and horizontal) caused by reservoir heterogeneity have become the top concerns for many oil companies. Therefore, how to further enhance the oil recovery in a later stage of the steam flooding process is challenging, and the hybrid thermal-solvent/NCG/chemical processes have been applied.

2.3. SAGD (steam assisted gravity drainage)

The SAGD recovery process was initially proposed by Dr. Butler and his colleagues in the 1980s [69–71]. In this process, a horizontal well pair is parallelly placed in a bottom section of a reservoir. The upper horizontal well performs as a steam injector, and the bottom one is a producer. The vertical distance between them is about 5–7 m. A normal SAGD project basically involves two phases, a preheating (startup) phase and a SAGD phase. The preheating phase aims to create a thermal connection between a producer and an injector. CSS, steam circulation, fracturing, electrical heating and solvent co-injection are the commonly-used startup approaches for the SAGD process [72–74]. After that, steam is continuously injected from the upper injector, and a steam chamber is created. According to the different stages of steam chamber expansion, the SAGD phase includes the stages of vertical expansion, horizontal expansion and exhaustion [75,57,7]. Once the steam chamber front reaches the top of a reservoir, it expands horizontally. Analogously, once the steam chamber arrives at the reservoir boundary, the steam chamber depletes and the oil production rate starts to reduce [75]. During SAGD operation, the heated oil and condensate water flow downward along the boundary of a steam chamber, and finally are produced from the bottom producer [10,4].

Different from the techniques of CSS and steam flooding, in SAGD, the dominating driving force for oil drainage is gravity. Al Bahlani and Babadagli [76] gave a critical review on the current status and future trends of the SAGD process. It is found that for the EOR mechanisms, except the conventional mechanisms of steam injection, the multiphase fluid flow and emulsification phenomenon in the edge of a steam chamber are also two important ones [77–79]. First, for the fluid flow behavior in a steam chamber boundary, based on an assumption of single oil-phase flow in the steam chamber boundary and without consideration of the effect of the heat convection mechanism, Butler [75] proposed an ideal productivity model for the SAGD process. But after the comparison between Butler's model and field data, it was found that his model cannot match the data very well. Therefore, many researchers have currently proposed some modified models for the SAGD recovery performance on the basis of Butler's model. Based on the experimental observations that a steam-zone shape is an inverted triangle, Akin [80] proposed a mathematical model for the SAGD process. In this model, both the effects of steam distillation and asphaltene-deposition are considered. Sharma and Gates [81] considered the impact of oil saturation and relative permeability on an oil mobility profile at the edge of a steam chamber to propose a novel model for the SAGD performance. On the other hand, the heat transmission mechanism in a steam chamber boundary is recently another hot topic for the SAGD process. Butler [75] and Reis [82] believed that heat conduction is the primary heat transfer mechanism of steam chamber expansion. But actually, the effect of heat convection is also a nonnegligible issue. Irani and Ghannadi [83], Li and Chen [84], Zhang et al. [85] and Keshavarz et al. [86] took into account the effects of heat conduction and heat convection and proposed some modified prediction models for the SAGD process. It was found that the effect of heat convection on the oil drainage process was a function of temperature. At the side of a steam chamber, the water saturation is higher, temperature is higher, and the effect of heat convection is enhanced. But for the side of a cold oil reservoir, because of low temperature, the effect of heat convection is significantly reduced. Second, for the emulsification phenomenon, Noik et al. [77] used the DSC (Differential Scanning Calorimeter) technique, microscopy and image analysis to characterize the water-in-oil emulsion and the reverse emulsion characteristics in produced fluids in the SAGD process. Using a CMG simulator, Ezeuko et al. [87] numerically discussed emulsification in the boundary of a steam chamber in the SAGD process. It was shown that the presence of emulsion can further improve the oil mobility, promote the SAGD performance and increase OSR. Hascakir [88] comparatively analyzed the emulsion features of the steam flooding and SAGD processes from experimental observations. On account of the increased interaction time of asphaltene with water in a steam chamber, SAGD can produce more water-in-oil emulsions than steam flooding. From the experimental point of view, there are always many related investigations on the recovery performance of the SAGD process since it was proposed by Butler [89–92]. Experimental setups include 2D, 3D and visualized experiments in the SAGD process. For a suitable reservoir type, SAGD can be applied to not only conventional thick heavy oil reservoirs but also reservoirs with a bottom aquifer [73,93,94]. It can be considered as a recovery method with a constant pressure drop. Therefore, the application of the SAGD process in reservoirs with a bottom aquifer does not cause the issue of water coning. Compared with the performance in conventional thick heavy oil reservoirs, the cumulative oil recovery factor in the reservoirs with a bottom aquifer is not significantly reduced.

For field application, the SAGD technique has been widely applied as an EOR process for heavy oil reservoirs, especially for the oil sands reservoirs in Alberta [95–99]. Currently, more than 15 commercial SAGD projects have been operated or are still in operation in Canada, mainly in Athabasca, Cold Lake and Lloydminster, as shown in Fig. 1(a) [100–102]. In China, the operation sites of SAGD projects are located in Xinjiang oilfield in Karamay and Liaohe oilfield in Panjin [103–106]. Especially in Liaohe oilfield, a modified SAGD process using the combination of vertical and horizontal wells was proposed as a follow-up process to CSS [103]. In order to quickly predict the recovery performance (recovery factor and CSOR) of SAGD in oil sands reservoirs, an empirical correlation has been proposed by the methods of numerical simulation and grey relational analysis [101]. Through the utilization of this correlation, the SAGD recovery performance can be quickly obtained. Furthermore, for the operation parameters of the SAGD process, operation pressure is an important parameter for SAGD. It is generally around the reservoir pressure. The operation pressure in most SAGD projects is about 2–4 MPa [107–109]. But for the operation in reservoirs with a bottom aquifer, a pressure-decline process is generally required before the SAGD stage [73].

It is well known that the SAGD process is an energy intensive development technology. Therefore, to reduce the steam consumption and improve the recovery performance of the SAGD process is the most important issue for field application, especially in such a time of low oil prices. But actually, during the SAGD process, because of the existence of reservoir heterogeneity, steam fingering and an uneven steam-liquid level between an injector and a producer, a steam chamber expansion is always nonuniform along a horizontal wellbore [71,110,111]. It significantly affects the normal operation of a SAGD project. Currently, the methods of observation wells, temperature measurement and 4D seismic surveillance have been applied to monitor the steam chamber expansion of the SAGD process in field [112,113]. Among them, as an effective method to detect the steam chamber expansion, 4D seismic operation has been conducted in many SAGD projects, such as the applications in Hangingstone, Surmont and Christina Lake in Alberta and the operation in Du84 in Liaohe oilfield [114,115].

For the post steam injection stage using a SAGD operation, a hybrid thermal-solvent process (ES-SAGD, expanding solvent-SAGD), a hybrid thermal-NCG process (SAGP, Steam and Gas Push or Flue gas-SAGD), CAGD (Combustion Assisted Gravity Drainage) and a hybrid thermal-chemical process (FA-SAGD, foam-assisted SAGD or CAFA-SAGD, chemical additives and the foam assisted SAGD) have been proposed and tested in the laboratory, which needs further investigations prior to field implementation.

3. In-situ combustion (ISC)

In-situ combustion is another important recovery technique for heavy oil and oil sands resources. It is also known as fire flooding [116,117]. In this process, a heater or igniter is first placed into an injection well. Then air or oxygen-enriched air is continuously injected down the well. In some projects, water is also simultaneously injected with air to create steam and reduce the air requirements. After that, the heater or igniter is operated until ignition, and thus the surrounding rock is effectively heated. Then, the heater is withdrawn, and air injection continues to maintain the advancement of a combustion front [118–120]. A combustion reaction can provide enough heat to mobilize heavy crude oil. Thermal cracking (oil upgrading) and combustion gases are the two important features of ISC. The combustion gases can retain in reservoirs. Therefore, a mixture of combustion gases, light oil components produced by thermal pyrolysis, steam and hot water help the movement of heavy oil toward a producer from an injector [22,12]. After the combustion reaction, the produced coke is remained (generally precipitated on the mineral matrix) behind the moved crude oil to provide enough fuel for the combustion process. For ISC, the temperature of a combustion zone can reach 345–650 °C (650–1200 °F). There are several variation types of the ISC process, including forward combustion (dry forward combustion and wet forward combustion), reverse combustion and THAI (Toe to Heel Air Injection) processes [75,121,122]. In forward combustion, a combustion front moves in the same direction as the air flows. Combustion begins with the gas injection well and the combustion front moves from the injection well to the production well. From the injection well to the production well, there basically are a combustion zone, a coking zone, an evaporation (pyrolysis, distillation) zone, a light oil zone, an oil-rich zone, an uninfluenced area and several other zones. When a certain amount of water is added in gas, it is called the wet forward combustion. Generally, wet combustion is more effective than dry combustion. It is because of the performance of steam flooding in wet combustion. On the other hand, for reverse combustion, a combustion front moves in a direction opposite to the flow of air [22,12]. In this process, the combustion zone is initiated around a production well. Compared with forward combustion, reverse combustion is especially applicable to reservoirs with a lower permeability. In a forward combustion process, a reservoir can be plugged by the mobilized fluids ahead of the combustion front. But in reverse combustion, the mobilized fluids move behind the combustion front. The THAI technology is another variation type of the ISC process. It combines a vertical air injection well with a horizontal production well. During operation, air is injected from the vertical well. A combustion front sweeps the reservoir from toe to heel of the horizontal production well. This technique can recover about 80% of the OOIP while partially upgrading the crude oil in-situ. In comparison with the current steam-based recovery processes, the THAI process is more effective to operate in those reservoirs with lower pressure, lower quality, thinner thickness or deeper formation depth. Recently, Rahnema et al. [123] experimentally and numerically investigated the recovery performance of the CAGD (Combustion Assisted Gravity Drainage) process. This technique is a new form of the ISC process using a horizontal well pair. The horizontal injector is placed at the top of a formation, and the horizontal producer is located around the reservoir bottom. After air is injected, the combustion process is initiated by an electric heater. Also, a combustion front develops towards the heel-end of the injector and extends laterally. Then the heated oil begins to flow towards the horizontal producer by gravity drainage. This process can efficiently produce bitumen reservoirs by creating a stable combustion front propagation.

The ISC process is well suited as a follow-up method to steam-based recovery processes (CSS, steam flooding, and SAGD) [119,117,124–126]. First, for the post CSS reservoirs, the reservoir characteristics are usually manifested with lower reservoir pressure, higher water saturation, presence of residual heat and steam channeling path. These low oil saturation channels after steam stimulation can facilitate the movement of a combustion front [127,12,128]. For the ISC process after CSS, the fluids and combustion front move along the paths heated and depleted during the cyclic steam injection phase [129]. Galas et al. [130] described the behavior of fluids movement and the associated changes of fluid properties. For this process, the stability of ISC should be also concerned with. Combustion is generally not maintained successfully when no water is present in a reservoir, and there is an optimum bitumen/water ratio which can improve the efficiency of a combustion front [131]. Moore et al. [119] performed four combustion tube tests on pre-steamed cores. Their results indicated that the ISC process can be effectively operated on the conditions of low oil saturation, and the oxygen requirements for ISC are also reduced because of the increased temperature in these preheated channels. Except the post CSS reservoirs, the ISC process can also be applied to improving the recovery performance of post SAGD reservoirs [132]. A

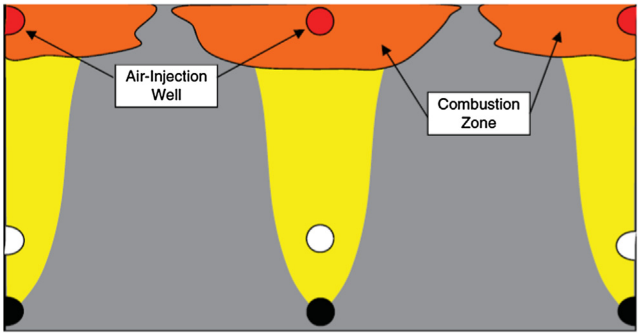

Fig. 7. Schematic of SAGD/ISC hybrid recovery process [135].

novel hybrid process which combines the advantages of SAGD and ISC processes has been proposed [133–135,126]. In this process, an additional air injection well is placed below the reservoir overburden, as shown in Fig. 7. In the first SAGD phase, the steam injection process is mainly conducted to establish the connectivity between wells and warm up the pattern. Then, as a mature steam chamber is created, the steam injection process is terminated and a combustion process is started by air injection from the top well [135]. Lots of numerical simulation work about this process has also been performed [136,137].

For field application, in 1978, a pilot test using the combination of CSS and ISC was performed in the Cold Lake area of east-central Canada by BP Resources Canada Ltd. [129,130]. Other projects which utilized the cyclic oxygen or air injection were also carried out, such as the Husky Oil's Tangleflag combustion and Amoco Canada’s Morgan fireflood projects [130]. Turta et al. [138] provided a review on four commercial ISC projects in the world, including two projects in India, one project in Romania and one project in USA. Among them, the ISC project at Suplacu de Barcau, Romania is the largest dry ISC process. There are more than 2700 wells and over 50 years of air injection history [139]. In this oilfield, CSS is initially started in November 1966, and ISC is chosen in 1970 as the main EOR method. The Balol and Santhal projects in India are operated in a wet mode, and have been in operation for more than seven years. The fourth ISC project in USA is located in Bellevue, Louisiana, and operated by Bayou State Oil Corporation (BSOC). This project is also in a dry combustion mode and has been in operation for more than 34 years. Currently there are 15 air injectors and 90 producers. In addition, in the Athabasca area, the toe to heel air injection process has also been piloted [140]. This process utilizes a single horizontal well and a vertical air injector around the toe of the horizontal well, and a combustion front moves along the horizontal wellbore from toe to heel [22,133]. In China, there are more than 20 field pilots in Xinjiang, Liaohe (Du 48, Du 66 oilfields), Shengli (Jinjia and Le’an oilfields) and Jilin oilfields [141,124,142,143]. Currently there are about 62 pilot tests on fire flooding. Typically for the operation of block H1 in Xinjiang oilfield and block Du66 in Liaohe oilfield, both of them are operated in the post CSS reservoirs or post steam flooding reservoirs. Block Du66 is a multilayered heavy oil reservoir in Liaohe oilfield [143]. Before 2005, the CSS process was performed in this reservoir. But both the observed oil production and OSR (oil-steam ratio) in the CSS phase were unsatisfactory. Therefore, since 2005, an ISC pilot test has been carried out. Currently, there are more than 91 well groups in operation using the inverted nine-spot pattern fire flooding process in block Du66.

4. Hybrid thermal-solvent process

Solvent is an important additive for an EOR process for heavy oil reservoirs. A hybrid thermal-solvent process has attracted tremendous research attention in recent years [144,145]. In such a process, a small amount of vaporized but condensable hydrocarbon solvent is added to steam. Solvent and steam are co-injected simultaneously or periodically into a reservoir to improve the recovery performance of heavy oil resources [146–148]. After injection, the solvent condenses along with steam at a bitumen-vapor interface and mixes with bitumen to further reduce the oil viscosity and enhance the oil production rate. There are generally five types of hybrid thermal-solvent processes, LASER (liquid addition to steam for enhancing recovery), SAS (steam-alternating-solvent), ES-SAGD (expanding solvent-SAGD), SAP (Solvent-Aided Process) and SESF (Solvent Enhanced Steam Flooding). First, the LASER process is a cyclic steam injection with the addition of a C5+ condensate to the steam during injection. The addition of C5+ solvent further reduces the in-situ oil viscosity, and improves recovery by more than 5%. It is a potential follow-up process for the CSS process [144,149,150]. Currently, LASER has been pilot tested in the H trunk project in the Cold Lake area by Imperial Oil. SAS is another new promising process. Different from LASER, SAS involves injecting steam and solvent alternately [151–153]. Zhao et al. [154] experimentally compared the difference between the SAGD process and the SAS process using a 2D high-temperature and high-pressure model. In their SAS experiment, a mixture of propane and methane was used as the solvent. It was observed that the SAS process takes the advantages of SAGD and VAPEX (vapor extraction) processes to minimize the energy input in heavy oil recovery. The third process is the ES-SAGD process or SA-SAGD (Solvent-Aided SAGD) process which is an enhanced SAGD process [145]. In this process, solvent (hexane, heptane or octane) and steam are co-injected into a reservoir to assist the oil drainage process [155–158]. In ES-SAGD, the condensation and diffusion of liquid solvent into bitumen play an important role in a successful operation of this process. Because of the performance of liquid solvent, the operating temperature in the ES-SAGD process is often much lower than in SAGD so that the heat loss is reduced. The ES-SAGD process can significantly improve an oil production rate and decrease a steam-oil ratio (SOR). The fourth process is the SAP process [159]. This process was developed by EnCana in 1996 and was piloted at its Senlac thermal project in 2002. In SAP, butane was used as the solvent for co-injection with steam [159,160]. The last one is the SESF process. It was proposed based on the extension of a solvent aided CSS process and a solvent aided SAGD process. The main mechanisms of this process are enhanced gas drive and solvent bank miscible displacement [161]. The SESF process is especially suited for the recovery process of thin heavy oil reservoirs [162]. The addition of solvent further improves the thermal efficiency of steam and reduces SOR. Also, the occurrence of wettability alteration in the SESF process is also an important observation [163]. In this process, the injection of solvent can control the wettability alteration due to its interaction with asphaltenes in heavy crude oil [164]. Aradali et al. [153], Lin et al. [165] and Bayestehparvin et al. [166] have given a critical review on a hybrid thermal-solvent process.

The EOR mechanisms of a hybrid thermal-solvent process include not only the mechanisms of conventional steam injection, but also the extra effects of solvent additives. First, the condensed solvent fraction can dissolve into bitumen to improve the fluid flowability in a reservoir. It further reduces the oil viscosity. Specifically, in a hybrid thermal-solvent process, the phase equilibrium or PVT behavior of a heavy oil/solvent/steam system at different temperatures and pressures is an important issue that needs to be investigated. Moreover, it has attracted much attention in recent years [167–169]. The EOS (equation of state) modeling method is a promising method, and has been applied to characterize this behavior [170–172]. Second, the mechanism of emulsion breaking is also concerned with during this process. Kar et al. [173] experimentally characterized the emulsions of SAGD and ES-SAGD processes. It is found that the produced oil in the ES-SAGD process has lower emulsion stability. In order to decrease the effect of emulsification on the steam-based recovery performance, an asphaltene soluble solvent is recommended and can be applied in operation. Considering its unique advantages, the application of this hybrid process further reduces the steam requirement and greenhouse gas emission compared with the previous thermal recovery processes.

One interesting thing for this process that should be mentioned is the selection of a solvent type. In order to maximize the oil production performance of a hybrid thermal-solvent process, an optimal solvent type is inevitable. First, reservoir temperature is an important factor to select the optimal solvent for application. Using the heavy oil samples from the Lloydminster area in Alberta, Pathak et al. [148] experimentally studied the performance of heated solvent (propane or butane) in heavy oil recovery. It was observed that the recovery performance gradually decreased with increasing temperature and pressure of the system. When the operation temperature is slightly higher than the saturation temperature of the solvent used, it can yield the best recovery performance. Hascakir [88] also discussed the effect of solvent types (propane, n-hexane, carbon dioxide or toluene) on the performance of a solvent-aided steam flooding process and a solvent-aided SAGD process using an experimental method. Coelho et al. [174] performed six core flooding experiments to investigate the effect of pore-scale interaction, solvent flow rate and clay on the performance of a hybrid solvent-steam process in bitumen reservoirs. The presence of clay also has an important influence on the performance of solvent-aided steam processes.

On the other hand, pure solvent based recovery processes have been also applied, including the CSI (cyclic solvent injection) process and the VAPEX process. Compared with the previous hybrid processes, a pure solvent process is a non-thermal recovery technique. First, in the CSI process, a solvent gas (e.g., carbon dioxide, methane, propane, or butane) is injected cyclically instead of steam in the CSS process and then soaked for several days, and finally oil production begins [175–177]. This process has been piloted in the post-CHOPS (Cold Heavy Oil Production with Sands) heavy oil reservoirs which are too thin for an economic steam-based recovery process. For CSI, the behavior of solvent-oil mass transfer in reservoirs is one of the most important mechanisms [178,179]. Using the Saskatchewan heavy oil with a viscosity of 1423 cp at 22 °C, Firouz and Torabi [177] conducted fourteen solvent huff-n-puff experiments (carbon dioxide, methane, propane, and butane) to investigate the effect of operating pressure, soaking time, and solvent composition on the CSI process. It was observed that for all the types of solvents studied, the produced oil was much lighter than in non-solvent processes (in terms of density and viscosity). The governing EOR mechanisms were recognized to be solution gas drive, a viscosity reduction, extraction of lighter components, formation of foamy oil, and a diffusion process. Based on the mechanisms of sufficient solvent dissolution and possible asphaltene precipitation, the VAPEX technique was proposed and tested for an EOR process for oilsands reservoirs [75]. In this process, a pair of horizontal wells is drilled as a production well and an injection well similarly as in the SAGD process [12]. The physics of the VAPEX process are essentially the same as those of the SAGD process. But compared with the SAGD process, VAPEX can significantly reduce energy costs and can be applied to thin reservoirs, even with a bottom aquifer [180,181]. That is due to the non-thermal characteristics of VAPEX. In addition, in order to combine the advantages of heat transfer and solvent diffusion, warm VAPEX and hybrid VAPEX are applied. [182] compared the difference of three VAPEX types in heavy oil reservoirs. Warm and hybrid VAPEX approaches combine the heat and mass transfer mechanisms inherent in solvent and thermal processes. The addition of heat can help increase the depth of the drained live oil.

For field application, some of the hybrid thermal-solvent techniques have been successfully tested at both laboratory and field scales [144,150]. Table 1 lists the theory, scheme, and field performance of three representative hybrid thermal-solvent processes. Bayestehparvin et al. [166] gave a critical review on the application of solvent in a thermal recovery process of heavy oil reservoirs. There are many field implementations of this hybrid process in oilsands reservoirs in Canada, including the EnCana-Senlac pilot (butane co-injection, ES-SAGD), Nexen-Long Lake pilot (ES-SAGD), Laricina Energy-Grosmont carbonate reservoir pilot (solvent cyclic SAGD, SC-SAGD), ExxonMobil and Imperial Oil Resources-Cold Lake pilot (LASER, SA-SAGD), Suncor-Firebag pilot (Naphata co-injection) and Devon-Jackfish pilot (hexane co-injection) [183]. In China, a cyclic steam-CO_2 co-injection process (SAP) and a continuous steam-CO_2 co-injection process (SESF) have been applied to improve the recovery performance of the post steam injection reservoirs in Liaohe oilfield and Shengli oilfield [184,185]. Furthermore, for the SAGD operation test in Fengcheng oilfield in Xinjiang, a new startup approach of xylene-steam co-injection has been proposed to accelerate the preheating process between an injector and a producer [186]. After operation, it was observed that the startup time of the SAGD process was reduced by about 60 days compared with the conventional preheating method of steam circulation.

5. Hybrid thermal-NCG process

NCG (non-condensable gas) is another additive for a thermal recovery process of heavy oil and oilsands reservoirs. For a hybrid thermal-NCG process, NCG is co-injected with steam simultaneously or periodically into a formation to assist an oil drainage process [187,188]. It has been widely applied for the production of heavy crude oil [189,190]. The commonly-used NCG additives include nitrogen, carbon dioxide, air, flue gas and methane [191–193]. Similarly, a hybrid thermal-NCG can be also operated by a cyclic injection mode, a continuous injection mode and even a gravity drainage mode [194–196]. For mechanisms, the addition of NCG further reduces the oil viscosity, improves the steam injectivity, increases the size of heated areas, recovers the reservoir energy and also provides additional drive energy [197–199].

First, cyclic injection processes typically include the processes of N_2-CSS, CO_2-CSS, flue gas-CSS, CH_4-CSS and air-CSS. All of them can be used to improve the recovery performance of post CSS reservoirs, and the most effective operation among them is the CO_2-CSS process, which is due to the high solubility of CO_2 in heavy oil and the effect of miscible gas injection [200]. Compared with the CSS process, the heat energy required for a hybrid CO_2-CSS process is much lower. On the other hand, because of a lower saturation temperature, the addition of CO_2 also reduces the injection temperature [201,97]. Srivastava et al. [202] experimentally assessed the suitability and effectiveness of three gases for heavy oil recovery, including pure CO_2, flue-gas (15 mol% CO_2 in N_2) and produced-gas (15 mol% CO_2 in CH_4). Both the PVT behavior and core flooding experiments were involved. From their experimental results, it was found that CO_2 was the best suited gas to recover heavy oils. Additionally, in the pure CO_2 case, the solubilization mechanism of CO_2 can dominate the process, whereas, in the produced-gas and flue-gas cases, except the solubilization mechanism, the free-gas drive was also important. Specifically, among several hybrid processes, for the cyclic steam-air injection process, after air injection, it can react with heavy oil in a formation through a LTO (low temperature oxidization) reaction. Then the produced mixture gases (including CO_2, CO and CH_4) after LTO and the unreacted N_2 enhance the recovery process. Compared with the conventional CSS process, this hybrid thermal-air injection process can significantly increase the oil production [203,204]. In addition, in order to further reduce the oil viscosity and improve the mobility ratio on the basis of the hybrid thermal-NCG process, the surfactant of an oil viscosity reducer (VR) was also used, such as in the processes of HDNS (Horizontal well, Dissolver, Nitrogen, and Steam), HDCS (Horizontal well, Dissolver, CO_2, and Steam) and HDAS (Horizontal well, Dissolver, Air, and Steam). These techniques have been applied to effectively recover extra-heavy crude oil reserves.

Second, for the continuous injection mode, the gas additives used in the CSS mode can be also applied in a steam flooding process, such as CO_2 assisted steam flooding, N_2 assisted steam flooding and flue gas assisted steam flooding [205–208,196]. Simultaneously, because of the high solubility, a steam-CO_2 mixture is superior to either steam-N_2 or steam-flue gas combinations. Alnoaimi [209] experimentally and

Table 1
Summary of the representative solvent-steam co-injection field implementations.

Technique	Theory	Scheme	Field pilot test
SAP	Butane-steam co-injection	Addition of ~15 wt% of C_4 at P = 2500–4000 kPa	(1) 2002, Senlac, ΔSOR↓ = 40%; (2) 2004, Christina Lake, Δq↑ = 30%, ΔSOR↓ = 35%; (3) Cenovus-Narrows Lake;
LASER	Pentane-steam co-injection at late cycles of CSS	Addition of 6 vol% of C_{5+} into steam at CSS Cycle #7	(1) 2002, Cold Lake, Δq↑ = 35%, ΔSOR↓ = 32%; (2) 2011, Imperial Oil-Cold Lake, 240 well large pilot;
ES-SAGD	Hexane-steam co-injection	Addition of 5–10 vol% of C_7-C_{12} into steam at P = 1400 kPa	(1) 2006, Nexen-Long Lake pilot, Δq↑ = 6%, ΔSOR↓ = 7%; (2) 2010, Laricina Energy-Grosmont, ΔSOR↓ = 30%; (3) Devon-Jackfish pilot; (4) Conocophillip-Surmont; (5) Suncor-Firebag area; (6) Statoil-Leismer field.

numerically investigated the effect of gas additives on the recovery performance of a steam flooding process in naturally fractured carbonate heavy oil reservoirs. It was found that the addition of NCG to the steam flooding process can further accelerate the oil production process at an early stage. Gumrah and Bagci [198] studied the performance of a steam-CO_2 drive process in a physical model of 1/12th of an inverted regular seven-spot pattern. A vertical and horizontal injection-production well configuration and the optimum CO_2/steam ratio to maximize the oil recovery were discussed. The NCG-SAGD process is another type of a hybrid thermal-NCG process. It was also called the SAGP process (Steam and Gas Push) [210]. It is a modification of the conventional SAGD process. Similar to the SAS process mentioned previously, in this process, a small amount of NCG, such as N_2, CO_2 or CH_4, is added to steam [211,212]. During operation, the injected NCG accumulates in an upper part of a steam chamber to reduce the temperature in the chamber and the heat loss rate to overburden. Thus, the steam requirement is reduced and the oil/steam ratio (OSR) is improved [213–215]. For this type of oil drainage process, there are many related publications from the theoretical, experimental and numerical aspects. In order to accurately simulate the flowing behavior of NCG in a SAGD steam chamber, many analytical and semi-analytical models have been developed [10,72,216]. For experiments, Canbolat et al. [217] and Yuan et al. [218] experimentally investigated the effect of NCG (methane, nitrogen) addition on SAGD performance. Alnoaimi [209] and Al-Murayri et al. [219] numerically discussed the performance of NCG-SAGD in a homogeneous model. From their simulation results, it was observed that although this hybrid process can reduce the heat loss rate to overburden, a reduction in the oil production rate and the oil recovery factor negates the benefits of such a heat loss reduction, especially for the N_2-SAGD and CH_4-SAGD processes. That is due to the low solubility of these gases in heavy crude oil. Therefore, most of the injected gases accumulate in the vicinity of a steam chamber and reduce the heat transmission into cold bitumen at the steam chamber boundary. But for the CO_2-SAGD process, because of its high solubility, CO_2 acts as a solvent. Therefore, it corresponds to an ES-SAGD process. For an air-SAGD process (CAGD) or oxygen-SAGD process (SAGDOX), in-situ upgrading and in-situ combustion are the most important mechanisms during operation [220,123].

Recently, another new type of heat carrier (MTFs, multiple thermal fluids) has been introduced into a recovery process of heavy oil reservoirs [221,222,73,223,224]. Different from a conventional saturated steam, MTFs are proposed based on the combustion and jetting mechanisms of a rocket engine, as shown in Fig. 8. As a new heat carrier, MTFs are different from a conventional gas mixture of steam and NCG. First, MTFs are directly produced from a combustion process in a generator, and it is under the conditions of high temperature and high pressure. The NCG fraction in MTFs is a mixture of N_2, CO_2, CH_4 and CO. Therefore, a MTFs-based process can be also considered as a steam-solvent-gas co-injection process. Second, in field operation, MTFs are always injected into a reservoir directly after generation. It is different

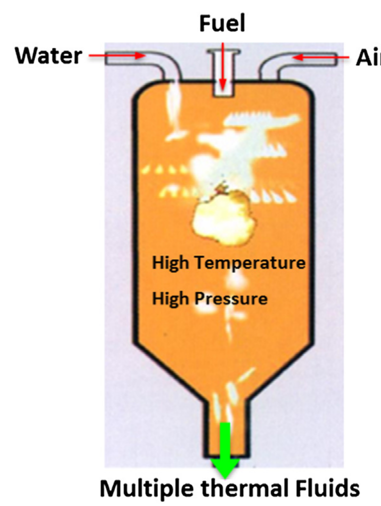

Fig. 8. Schematic of MTF Generator.

from the separate injection method of a conventional case. Liu et al. [221], Liu et al. [222], Dong et al. [225] and Xu et al. [223] studied the performance of the MTFs stimulation process in the heavy oil reservoirs of Bohai oilfield in China. Since 2009, many MTFs-based recovery projects have been carried out in the heavy oilfields in China, and an obvious oil production increment is achieved [226,97,227].

For field application, currently, a hybrid thermal-NCG process has been widely applied for an EOR process for heavy oil and bitumen reservoirs. Especially in China, since 1989, the steam-N_2 process has been piloted. Until now, it has been successfully tested in most of the heavy oilfields in China, including Liaohe, Shengli, Xinjiang and Henan oilfields [24,228,25]. After operation, an obvious improvement in the oil production rate and OSR can be observed. The main operating techniques include a cyclic steam-N_2/CO_2 injection process, a cyclic MTFs injection process, steam-N_2/CO_2 flooding, and flue gas-SAGD. Specifically, for a pilot test of the flue gas-SAGD process in Liaohe oilfield, four SAGD well-pairs are tested. After operation, the OSR is increased from 0.16 to 0.21, and the steam consumption volume is also reduced by about 3.5×10^4 m^3 [229]. In recent years, based on its successful operation in Shengli oilfield, the cyclic MTFs injection process has been extended to the recovery process of Bohai offshore heavy oilfield [218,225,223]. In addition, except the recovery processes above, NCG has been also operated to control the water coning behavior during the CSS process in heavy oil reservoirs with a bottom aquifer [230]. For this type of heavy oil reservoirs, water coning is always limiting their effective development. In order to prevent or slow down the occurrence of water coning, NCG or NCG-foam can be used. After operation, the rising of an aquifer can be effectively controlled to some extent.

6. Hybrid thermal-chemical process

Chemical additives can be also added into steam to improve the performance of thermal processes, including alkali, surfactant, polymer, NCG (N_2, CO_2) foam and gels. For the post steam injection heavy oil reservoirs, this type of hybrid process can be used to effectively control the steam injection profile, especially for NCG foam and gel systems. A hybrid thermal-chemical process can recover more oil than the conventional pure steam-based recovery processes [231–233]. First, for a hybrid steam-alkaline process (HASP), in addition to the conventional steam-based EOR mechanisms, the extra mechanisms include emulsification, wettability alteration, IFT reduction and rigid film breaking [234]. The commonly-used alkali include Na_2CO_3 and NaOH. Tiab et al. [235] and Okoye and Tiab [234] experimentally examined the performance of a steam-alkaline flooding process and a pure steam flooding process. It was observed that the steam-alkaline flooding process can recover more OOIP (original oil in-place) than the conventional steam flooding process under a similar condition. Especially when the remaining oil saturation after the primary recovery process is low, the steam-alkaline flooding process can be more effective [235]. Second, a hybrid steam-surfactant process (HSSP) uses a small amount of surfactant co-injected with steam to enhance the oil recovery of a steam-based recovery process. The mechanisms involve IFT reduction, wettability alteration, oil relative permeability enhancement and in-situ emulsification [236,237]. Gupta and Zeidani [238] experimentally and numerically investigated the performance of the SSP (or HSSP) and SAGD processes, and it was found that SSP can further increase an oil production rate, reduce the CSOR and enhance the ultimate oil recovery factor. They also developed a set of criteria for selecting and testing surfactants in SSP application. Babadagli et al. [239] used biodiesel (BD) as a surfactant additive to investigate the recovery efficiency of HSSP. The application of BDs (fatty acids methyl esters) can significantly increase the efficiency of bitumen recovery in the SAGD and CSS processes. Srivastava and Castro [240] provided a successful field application of surfactant additives (called TFSA, thin film spreading agents) to enhance the recovery performance of thermal processes in heavy oil reservoirs. Third, a polymer additive is generally used for a non-thermal recovery process, especially for a waterflooded heavy oil reservoir. This process is well suited for an EOR process for offshore heavy oil fields, such as the Bressay Field and Bently Field in North Sea, UK and Bohai oilfield in China [17,241]. The SZ36-1 reservoir in Bohai oilfield is one of the most successful polymer-based heavy oil EOR projects [242,73]. In addition, in order to improve the SAGD performance in oil sands reservoirs with top water, Zhou and Zeng [243] numerically discussed the performance of high temperature polymer in this process. Through the injection of polymer, a stable high viscosity layer can be developed at the bottom of top water. Polymer injection was technically feasible to improve the SAGD performance in oilsands reservoirs with top water. Recently, another new hybrid thermal-chemical process, called Alkali-Co-Solvent-Polymer (ACP), was developed at the University of Texas and University of Calgary [244–246]. In this process, different additives perform differently during operation. Alkali is used to reduce an interfacial tension, polymer is used to increase the water viscosity for mobility control; co-solvent is used to optimize the phase behavior and prevent the formation of highly viscous emulsions [244]. Then, through a combination of electrical resistance preheating and hot water flooding, this process can well handle the challenges of injectivity, heating and oil displacement and production [247].

NCG-foam and gel systems are the commonly-used techniques to effectively plug a steam chief zone and control a steam injection profile. In comparison, the plugging strength of a gel system is higher than that of NCG-foam [248,249]. First, NCG-foam includes N_2-foam, CO_2-foam and CH_4-foam [250,248,251]. In order to form an effective foam system in a formation, the selection of hydrosoluble surfactant (foaming agent) is important. Currently, there are many types of foaming agents, including anionic, cationic, nonionic and amphoteric [252]. In porous media, through the effective mixing of NCG and a foaming agent, foam can be formed. But for field operation, in order to guarantee effective performance, a strict evaluation scheme of a foaming agent is necessary, including the static performance (foam stability, foam volume, and foam size) and dynamic performance (resistance factor and period of validity). Sometimes, a foam stabilizer, such as polymer, is added into a foam system to enhance the foam strength, and it is called polymer-enhanced-foam (PEF). Telmadarreie and Trivedi [253] used a micromodel to discuss the performance of CO_2-foam and CO_2-PEF injection in a carbonate heavy oil recovery process. For thermal recovery processes, through the injection of a foam system, the steam viscosity increases and the steam mobility reduces. NCG-foam can effectively control viscosity fingering, gravity override and steam breakthrough [254,255]. NCG-foam can effectively plug a steam channeling path and improve the sweep efficiency in heterogeneous heavy oil reservoirs. Chen et al. [256] numerically demonstrated the performance of foam-assisted SAGD (FA-SAGD). It was found that because of the improvement of steam injection profiles, the FA-SAGD process had a better expanded steam chamber, and yielded better recovery performance than conventional SAGD. Some other chemical additives have been also applied to enhancing the performance of foam in thermal recovery processes. Lau [257] experimentally investigated the performance of an alkaline (Na_2CO_3) steam foam system in a steam drive process. It was found that the addition of alkaline further increased a foam-propagation rate and improved the foam mobility. Also, the presence of alkaline can reduce the oil/water interfacial tension to enable the formation of oil-in-water emulsion. Thus, the residual oil saturation is reduced. Li et al. [258,259] numerically discussed the performance of chemical additives and the foam assisted SAGD (CAFA-SAGD) process in heavy oil reservoirs. It was found that the addition of chemical additive further promoted the in-situ foam generation and reduces the interfacial tension. A high temperature gel (HTG) blocking agent is another effective chemical additive to control the steam injection profile in a reservoir. Also, it can be effectively used to mitigate the influence of steam breakthrough in heavy oil reservoirs [260,261]. Different from a conventional gel system for waterflooded reservoirs, HTG has a higher thermal stability [262]. Currently, there are a number of available HTG systems [263,264,249]. To select a suitable HTG system for a specific reservoir is related not only to temperature, salinity and hardness level of the water used, but also to the lithology of the reservoir [262]. A cost factor is also non-negligible, especially in such a time of low oil prices. He et al. [264] experimentally evaluated a thermo-reversible gel formed from hydroxypropyl methylcellulose (HPMC). It was found that this thermo-reversible gel was a good candidate for in-depth conformance control in steam-stimulated wells. Wang et al. [249] proposed a novel HTG to control a steam breakthrough path in heavy oil reservoirs, and a parallel sandpack experiment was also conducted to evaluate its performance. Based on its experimental observation, this gelling system has a strong salt resistance and dilution resistance. It can effectively plug a steam breakthrough path and force the subsequent steam to enter into a low permeability path. Although both the NCG-foam and gel systems can effectively plug a steam channeling path and improve a steam injection profile, they also have some differences. First, compared with NCG-foam, the major advantage of a gel system is that it is relatively insensitive to some reservoir conditions, such as the presence of oil [265]. For NCG-foam, the presence of oil significantly impacts the foam stability and plugging strength. Second, gels are more sensitive to the changes of pressure gradients. In operation, a critical breakthrough pressure gradient is another important parameter to evaluate the performance of HTG [249].

For field application, hybrid thermal-chemical processes have been widely applied to improve the thermal recovery performance of heavy oil and oilsands reservoirs. First, for hybrid steam-alkali/surfactant processes, some field applications have been reported in Canada including the SA-SAGD (surfactant assisted-SAGD) pilot by [266,267,268]. In China, hybrid steam-surfactant processes have been performed in many typical heavy oil reservoirs, mainly located in Shengli, Liaohe and Henan oilfields [24,25,22]. Specially, a viscosity reducer (VR) and oil displacement agent (ODA) are the most commonly-used surfactants [269–271]. Then, for an application of polymer additive, it is usually used for a heavy oil non-thermal recovery process, and many field tests have been reported in UK, Canada, China and Suriname [272–274]. In UK, most of the polymer-based operations are located in the North Sea offshore oilfields, including Captain Field (OV (Oil Viscosity): 88 cp), Bently Field (OV: 1500 cp) and Bressay Field (OV: 1000 cp). The polymer flooding projects for heavy oil reservoirs in Canada include the oilfields of East Bodo (OV: 600–2000 cp), Pelican Lake (OV: > 1500 cp), Provost (OV: 825 cp) and Seal (OV: 3860 cp). In Canada, polymer flooding has been successfully performed in heavy oil reservoirs with oil viscosity up to 6000 cp [274,233]. In China, since 2008, block SZ36-1 in Bohai offshore oilfield has performed a polymer flooding process. It is one of the most successful polymer-based heavy oil EOR projects in China. In addition, the heavy oil reservoirs of JZ9-3 and LD10-1 in Bohai oilfield also performed polymer flooding operation. An application of a NCG-foam system can date back to the 1980s, which was a prosperous rise period of a steam foam injection process in USA, including heavy oilfields in California and Wyoming [275,276]. Especially for the Kern River and Midway-sunset oilfields in California, NCG-foam was applied to improve the recovery performance of a steam flooding process [252]. NCG-foam was also designed to improve the performance of CSS for Tia Junan oilfield and Bolivar oilfield in Venezuela [275,276]. In China, many field operations of NCG-foam have been reported on a post CSS process and a post steam flooding process in Henan and Shengli oilfields [24,22]. Especially for the operation in Gudao and Jinglou, NCG-foam has become one of the important techniques to improve the performance of CSS and steam flooding [277,278]. Finally, an application of gel has been in many steam-based recovery processes to plug a steam breakthrough path and improve a steam injection profile. First, for the operation in West Coalinga Field, California, USA, HTG was injected in six steam drive wells. After injecting HTG, a redistribution of reservoir heat was found from the temperature observation well data. Thus, areal sweep efficiency was significantly improved [260]. In China, this process was mainly applied in Henan oilfield and Bohai offshore oilfield. Especially for the operation in the NB35-2 reservoir in Bohai oilfield, a weak gel system was used to improve the CSS performance [279]. Another application of a gel system to the Permian-carboniferous reservoir in the Usinsk oilfield is located in Russia. In this project, a non-organic gel-forming composition “GALKA” was applied to enhance the performance of steam flooding. Between 2002 and 2009, it was injected into 22 injection wells. After operation, an increase in the incremental oil production by 50–90%, more than that of the steam flooding process, can be observed.

7. Other methods

Although ISC and many hybrid processes have been applied to improve the performance of post steam injection reservoirs, some other promising EOR methods still exist. They can be grouped into three categories below.

7.1. Electrical method

An electrical method to improve heavy oil and oilsands recovery is an important alternative thermal method. Especially for reservoirs whose temperature is not too low and oil viscosity is not too high (Orinoco oil belt in Venezuela), an electrical method is a potential EOR technique. According to the frequency of the electrical current used, it can be classified into three categories, low frequency electric resistive (ohmic) heating, medium frequency EM induction heating and high frequency (radio frequency or microwave) EM heating [280–283]. Compared with other hybrid methods, steam injection is no longer required for an electrical method, and, therefore, the issue of heat loss is not a major controlling factor for its application. In addition, it may be also applied in a deeper reservoir.

7.1.1. Electrical resistive heating

Heating with frequency less than 300 kHz can be described as electrical resistive heating (ERH) [284]. The main components of an ERH system include an electrode assembly, a power conditioning unit, a power delivery system, a grounding system and a recording/monitoring system [285]. In this process, electric current heating is applied to increasing the temperature around a wellbore and reducing the oil viscosity, so the well productivity is significantly increased. At low frequency, resistance heating dominates the recovery process compared to the dielectric heating that dominates at high frequency. For ERH, ionic heating is dominant, which is performed by heating ions via energy transfer from a heater, with more mobile electrons which carry the bulk of the current [286]. Furthermore, ERH can also integrate with other methods to further enhance the heavy oil recovery, such as electrical heating-SAGD, gas and electrical heating assisted gravity drainage (GEAGD) and VAPEX.

7.1.2. Electromagnetic (EM) heating

Electromagnetic heating aims to transfer EM energy to heat energy. In EM heating, an electromagnetic antenna or an induction coil is placed in a wellbore to heat up a reservoir [286–289]. An EM heating process is directly related to the frequency employed [286]. As the reservoir temperature increases, the oil viscosity reduces and oil flows toward a production well. This process has been investigated since the 1970s, and some field pilot tests were also performed in the 1990s [290,291]. Especially, an EM heating method has been introduced to improve the SAGD performance (EM-SAGD) [292]. On the other hand, compared with the conventional steam circulation approach for SAGD startup, an application of EM heating can significantly reduce the startup time [293]. Greff and Babadagli [294] provided a critical review on EM heating for heavy oil and bitumen recovery. Compared with low-frequency electrical resistance heating (ERH), radio frequency heating has a higher potential to improve the recovery performance of heavy oil reservoirs [295].

7.1.3. Electro-thermal dynamic stripping process (ETDSP)

An electro-thermal dynamic stripping process (ETDSP) is another kind of electro energy-based recovery method. It is a special kind of the electrical resistive heating method. It can well handle the environmental issues that the public is concerned with, in order to reduce greenhouse gas emissions and fresh water usage [296]. This process is well suited to recover heavy oil deposits whose depth is too shallow for steam injection and too deep for surface mining. A proof of a concept field pilot test was performed in the McMurray formation by E-T Energy Ltd. in 2007. After operation, the recovery factor was demonstrated to be 75% OOIP or more [297].

7.2. In-situ upgrading

7.2.1. Ionic liquid (IL)

Ionic liquid is a kind of organic salts that are made up of organic cations with organic (inorganic) anions [298,299]. It is an alternative additive for upgrading heavy crude oil and improving oil quality in a formation. In operation, the polar components of heavy oil (asphaltene and resins) can diffuse in IL. Thus, the viscosity of crude oil is reduced, and a reduction of polar components is also observed [300]. The other mechanisms include IFT reduction, catalysis, hydrocracking and hydrogenation [301]. Many positive responses of IL have been reported recently. But IL is considered too expensive for industrial applications. Recently, another kind of ionic liquid, Deep Eutectic Solvents (DESs), is proposed [302]. Based on a comprehensive core flooding experimental investigation, Mohsenzadeh et al. [299,303] studied the performance of DESs operation for the recovery of heavy oil and bitumen reservoirs. It was found that steam flooding after DESs injection can yield a higher recovery factor than a continuous steam flooding process. Also, an obvious in-situ upgrading phenomenon was observed, such as an increase in API gravity, a sulphur reduction (16%) and an increase in saturate hydrocarbons in products.

7.2.2. Addition of catalyst

In order to improve the stability of an ISC process, many supported catalysts have been added into the process for catalytic upgrading. The addition of catalyst can significantly improve the stability of ISC, enhance the oxidation reaction and benefit the cracking of hydrocarbons. Metallic (salt) additive is one of the most important types of catalysts used in an ISC process [304,305]. It can further enhance the oxidation reaction and the cracking of hydrocarbons [306–309]. Shah et al. [310] experimentally discussed the effect of catalyst type and operating conditions on the recovery performance of the THAI process; the studied catalysts included alumina supported CoMo, NiMo and ZnO/CuO. Abu et al. [311] and Hart et al. [312] also experimentally investigated the catalytic upgrading behavior of Ni-Mo/Al_2O_3 catalyst in the ISC and THAI processes. Amanam and Kovscek [313] established an experimental procedure of a combustion tube to study the catalyzed behavior of copper nanoparticles (Cu-NP) in an ISC process for extra heavy crude oil. It was found that the presence of Cu-NP can help maintain a high front temperature.

7.2.3. Nanotechnology (nanoparticle)

As an important frontier technology, nanotechnology has been applied in many fields, such as chemistry, biochemistry, biomedicine, physics and engineering. Currently, it has been also applied in EOR processes for heavy oil reservoirs. Specifically, nanoparticles have become an important EOR additive to enhance heavy oil recovery [314–316,289]. Commonly-used nanoparticles include the types of aluminium, aluminium oxide, copper, copper oxide, cobalt oxide and nickel [315,317]. In a formation, nanoparticles can perform as an adsorbent or catalyst to further enhance heavy oil upgrading and recovery performance [315]. The main mechanisms of recovery enhancement include catalytic hydrocracking and wettability alternation [318,319,308]. In addition, the reservoir wettability changes from an oil-wet condition to a water-wet condition. Based on a 2D etched glass micromodel experiment, Cui and Babadagli [320] comparatively investigated the mechanisms of conventional sulfonate surfactants and nanofluids for heavy oil recovery. It was found that nanofluids showed a different behavior from the conventional surfactants. An interface between rock grains and nanofluids was observed. It can cause the occurrence of capillary imbibition and thus improve heavy oil recovery. Lakhova et al. [321] studied the aquathermolysis characteristics of heavy crude oil using nano sized particles of metal oxides. They found that the presence of nanoparticles further reduced the oil viscosity and increased the content of saturated hydrocarbons in produced oil. In addition, nanoparticles can also be used to catalyze an in-situ combustion process for heavy crude oil [313]. Hashemi et al. [315] and Idogun et al. [322] provided a detailed literature review on the application of a nanoparticle-EOR process.

7.3. Novel wellbore configuration

7.3.1. Flow control device (FCD)

A FCD is a wellbore throttling device to control an inflow (or outflow) rate distribution along a horizontal wellbore, as shown in Fig. 9. Therefore, an ICD (inflow control device) and an OCD (outflow control device) are the two typical devices of FCDs for an injector and a producer, respectively. After installing FCDs in a horizontal wellbore, the flowing uniformity across the well can be significantly improved. Especially for wells with a long horizontal interval, FCDs can greatly improve the uniformity of fluid flow along the wellbore to avoid the occurrence of non-uniformity caused by frictional pressure drops in the wellbore. These devices can benefit an oil production process. Currently, they have been widely applied to improving the performance of HW-CSS and SAGD [323,324]. In operation, an application of FCDs can significantly improve the bitumen recovery and decrease SOR by improving the conformance of steam injection profiles along horizontal wells.

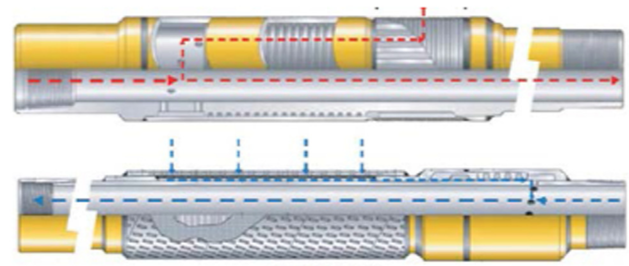

Fig. 9. Schematic of FCD.

7.3.2. Concentric (parallel) dual-pipe configuration

Except FCDs, a dual-pipe well configuration for steam injection or oil production has been proposed and applied in field. For a dual-pipe configuration, there are generally two pipes in a wellbore, and both of them can be used for steam injection or oil production. In some occasions, one pipe is used for steam injection and the other for oil production. Their relationship can be concentric or parallel, as shown in Fig. 10. Considering the limitation of a wellbore diameter, a parallel dual-pipe well configuration is usually used for a shallow reservoir, and a concentric dual-pipe is used for a deeper well. In China, these two types of well configurations have been widely applied for heavy oil recovery processes in Liaohe, Shengli and Xinjiang oilfields [25,22,325]. Furthermore, except a dual-pipe configuration, a multiple-pipe well configuration has been also operated to improve the recovery performance of heavy oil reservoirs.

8. New methods

8.1. Solar energy

For a thermal enhanced oil recovery (TEOR) process, reducing the cost of steam generation is always the top priority for many oil companies. For this purpose, a solar thermal steam generation system has gained much attention in recent years [326–328]. Compared with the traditional TEOR techniques, the solar based TEOR offers an opportunity to make the petroleum exploitation much environmental-friendlier, much cleaner and more effective. Akhmedzhanov et al. [329] proposed an innovative solar collector for a water heating and steam generation system to reduce the amount of natural gas consumption for steam generation. It was found that an application of a solar based TEOR process tremendously increased the net profit of heavy oil production. For application, solar facilities have been currently underway and planned in San Joaquin Valley, California and Kuwait [330]. The Bright Source project in San Joaquin Valley is adjacent to Chevron's Coalinga field. Currently, from this project, 60% quality steam is generated at 500°F and 700 psi [331]. Kuwait has also announced a future national oil production target, with a program of heavy oil development planned to reach 270,000b/p by 2030 [204].

8.2. Nuclear energy

Using nuclear energy to replace the traditional natural gas-fired facility for steam generation is another potential technology. Even in 1977, the role of nuclear energy for heavy oil and bitumen recovery in Alberta was proposed [332]. Using this clean energy to generate steam not only reduces greenhouse gas emissions but also reduces operational

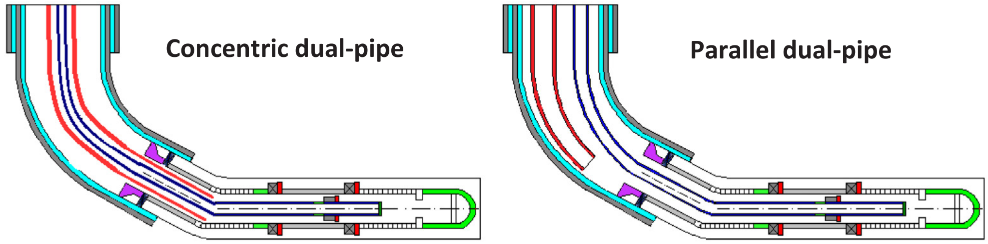

Fig. 10. Concentric and parallel dual-pipe well configurations.

costs. It is a potential method for the TEOR processes for heavy oil and bitumen resources. Dunbar and Sloan [333] compared the economics of a modified ACR-700 Advanced CANDU Reactor and a natural gas-fired facility to supply steam for the SAGD process. It was found that steam supply from a nuclear facility was more economic than a gas-fired facility. In addition, an advanced nuclear power plant was placed for heavy oil recovery in Venezuela [334]. In this nuclear power plant, three reactors were built successively. It can supply sufficient heat energy and steam for an oil production process and even electricity. In China, some small nuclear power plants have been also planned to assist the steam generation in the TEOR processes. But, because of environmental concerns with nuclear wastes, nuclear energy can be considered as a technology backup in future.

9. Discussion

9.1. Effect of asphaltene precipitation

Asphaltene fraction in heavy oil generally represents heavier components in crude oil with a higher boiling point. During a heavy oil recovery process, the occurrence of asphaltene precipitation (or deposition) in porous media has become an important issue, especially for solvent injection processes and some in-situ upgrading processes. For solvent based recovery processes, most of solvents used are asphaltene insoluble, such as C5 and C7 [335]. Therefore, asphaltene precipitation onto a rock surface during a solvent based recovery process is expected [88]. Although an application of solvent can significantly improve the recovery performance of heavy oil reservoirs, the occurrence of asphaltene precipitation in this process plugs pores in a formation and causes severe damage to permeability. Therefore, oil production rate in this process is significantly reduced [336,337]. Based on an experimental observation, it was also found that after solvent extraction, the asphaltene content of the residual oil fractions was significantly greater than that of the original oil, and the amount of asphaltene precipitation was decreased with an increase in temperature and the carbon number in n-alkane solvent [338]. The in-situ upgrading of oil leads to an additional viscosity reduction, and it benefits a recovery process.

In order to achieve a highly efficient production process, it is essential that we can effectively produce asphaltenic components and limit their precipitation. Haghighat and Maini [337] and Hematfar et al. [339] experimentally investigated the role of asphaltene precipitation in the VAPEX process. It was observed that reducing the injection pressure prevents the occurrence of asphaltene precipitation and decreases the degree of in-situ oil upgrading. Greff and Babadagli [340] experimentally discussed the improvement characteristics of heavy oil quality in a formation using nano-sized metal particles. It was found that the presence of nano-sized metal particles further catalyzed the breaking of asphaltenes, thus resulting in a reduction in oil viscosity and an increase in saturates and aromatic fractions. Kharisov et al. [335] provided a review on the available materials and nanomaterials for the asphaltene removal from heavy crude oil and compared the conditions of their adsorption capacities. Generally, their adsorption capacities depend on many influencing factors, e.g., surface charge, a particle size, pH, and temperature. For an actual application project, a strict evaluation scheme should be conducted. On the other hand, for hybrid solvent aided steam injection processes, using asphaltene soluble solvents is recommended [88].

9.2. Effect of reservoir lithology

Reservoir lithology is another important factor to determine a suitable EOR technique for heavy oil reservoirs. Based on the discussion above, currently most of the enhanced thermal recovery methods have been successfully applied in sandstone heavy oil reservoirs. But fractured carbonate heavy oil reservoirs are generally characterized with high oil viscosity, low matrix permeability, and unfavorable wettability of the matrix [341,342], which means that the EOR mechanisms of thermal recovery techniques for the fractured carbonate heavy oil reservoirs may be different from those in sandstone ones. For a steam-based recovery process in carbonate heavy oil reservoirs, its recovery mechanisms include not only the conventional steam injection mechanisms (oil viscosity reduction, thermal expansion, etc.) but also capillary imbibition and gravity drainage. For field performance of steam based processes in fractured carbonate heavy oil reservoirs, the Lacq Superieur oilfield in France first performed a steam drive pilot in October 1977 [343]. At the end of June 1980, incremental oil production was obtained (176 $Mbbl^3$). The CaoGu-1 reservoir in Shengli oilfield, the 9th heavy oil block in Karamay oilfield and Zao35 in Dagang oilfield in China are some other successful applications of steam injection processes in fractured carbonate heavy oil reservoirs [24,22]. In north Alberta, Canada, the development of Grosmont Formation is another successful one. In Grosmont, the processes of CSS, steam flooding, SAGD, ISC, solvent cyclic SAGD and cold solvent injection are all tested [44,47]. But on account of the effect of severe permeability heterogeneity, CSS operation is the most successful compared with steam flooding and ISC. During operation, it was observed that compared with steam, the operating cost without the use of steam was lower than with steam. Especially for a cold solvent injection process, its cost was expected to be about half than that of steam [47].

Among the EOR techniques discussed above, a hybrid thermal-solvent process is a promising technique for fractured carbonate heavy oil reservoirs. In decades, the group of Dr. Babadagli at the University of Alberta has published many related articles on a thermal-solvent recovery process for fractured carbonate heavy oil reservoirs. They proposed a steam-over-solvent injection process in fractured reservoirs (SOS-FR) for heavy oil recovery [76,344,345]. This process included three phases: initial steam injection to heat up a reservoir (Phase 1), solvent injection to recover matrix oil by a diffusion-imbibition-drainage process (Phase 2) and steam injection again to recover more oil and retrieve the solvent (Phase 3) [346,341]. Based on numerical simulation, it was found that a diffusion coefficient was one of the most important factors to affect the recovery performance of this process. Also, the effect of gravity drainage is non-negligible [347].

9.3. Criteria for selection of EOR methods

As discussed above, there are many EOR techniques for heavy oil and oilsands resources. But each of them is suitable only for a certain

Table 2
EOR techniques in the post steam injection era.

Techniques		Cyclic injection operation (CSS)	Continuous injection (plugging) operation (SF)	Gravity drainage operation (SAGD)
In-situ combustion (ISC)		(1) Air/steam coinjection; (Catalyst) ISC; (2) Cyclic air injection; (3) THAI.	(1) Fire flooding; (2) THAI; (3) HPAI;	(1) CAGD; (2) ISC/SAGD.
Hybrid Steam-solvent process	Additive	C_xH_y (light hydrocarbons), toluene, naphtha, diesel, etc.		
	Technique	(1) Solvent aided CSS; (2) LASER; (3) SAP; (4) CSI.	(1) Solvent-steam flooding; (2) SESF;	(1) SAS; (2) ES-SAGD; (3) SA-SAGD; (4) SC-SAGD; (5) VAPEX
Hybrid Steam-NCG process	Additive	N_2, air, CO_2, flue gas, methane, etc.		
	Technique	(1) N_2-CSS; (2) CO_2-CSS; (3) CH_4-CSS; (4) Flue gas-CSS; (5) Air-CSS; (6) HDNS, HDCS, HDAS.	(1) Steam-NCG flooding; (2) MTFs flooding;	(1) NCG-SAGD; (2) SAGP; (3) GAGD; (4) MFAGD (5) SAGDOX.
Hybrid Steam-chemical process	Additive	Alkali, Polymer, surfactant, foam, gel, etc.		
	Technique	(1) HSSP; (2) NCG-foam; (3) Gel.	(1) Alkaline-steam flooding; (2) SSP; (3) Polymer; (4) NCG-foam; (5) Gel.	(1) Surfactant aided SAGD; (2) FA-SAGD; (3) CAFA-SAGD.
Other processes		(1) Downhole electrical method: ERH, EM heating, RF heating, ETDSP, etc. (2) In-situ upgrading: ILs, catalyst, nanoparticle, etc. (3) Novel wellbore configuration: FCD (ICD/OCD), dual pipe, etc.		
New processes		(1) Solar energy; (2) Nuclear energy.		

type of reservoirs, and how to select the most suitable method for a given reservoir is challenging. If a potential reservoir can be screened, every technique can be profitable. For the screening process, not only the specific reservoir properties and its previous recovery history are important, but also its economic factor should be considered [348]. In this paper, all of the EOR processes discussed above are classified based on their operation methods, including cyclic operation, continuous (or plugging) operation and gravity drainage operation, as shown in Table 2. For the cyclic operation, these processes can generally be used as a follow-up technique for a steam-based CSS process. Similarly, for the continuous injection (or plugging) operation, they are generally used as the follow-up processes of steam flooding. For the gravity drainage operation, they can be applied to improving the recovery performance of the SAGD process.

For a given heavy oil reservoir, integrating the basic analysis on the current status of this reservoir and the above classification, a primary screening can be conducted to shrink the potential technique lists. In this procedure, the criteria of these processes should be also considered, such as the requirements on reservoir thickness, oil viscosity, permeability and a ratio of water-oil volumes. Then, we can have a list on the potential processes for each specific reservoir. After that, in-door experiments should be performed to test or evaluate the performance of additives or advanced EOR processes. Then, combing these experimental results, the potential list is further shrunk. Furthermore, advanced reservoir simulators (e.g., Eclipse-E500 and CMG-STARS) can be applied to provide a solid foundation for recommendation. Moreover, a precise economic evaluation is also important for the final recommendation, including the oil price, the costs of surface facilities and operation equipment, the source of additive and even the costs of water treatment. Finally, for the operation of a specific recovery process, an operating procedure should be carefully designed to take the advantages of every additive for a maximum benefit. For example, for the hybrid thermal-NCG (CO_2, N_2)-chemical process, an injection sequence of steam, NCG and chemical agents should be first optimized. Among them, steam is mainly used to reduce oil viscosity by heat transfer; NCG is used to improve sweep efficiency or further reduce the oil viscosity by gas dissolution (CO_2); chemical agents can be used to reduce the fluid viscosity (VR), control steam injection conformance or plug a steam channeling path (foam, gel).

To screen an optimal EOR technique is a very complicated work. In the screening process, many tests and assessments are performed before application in field. Only after its in-door experiments are successful, a technique may have a potential to be applied in field. But for some processes, even if an obvious oil increment can be observed in the lab, the performance of a field scale test can still be poor; on account of the effect of fluid adsorption and retention in a formation, the performance of most of hybrid processes in field scale tests is significantly different from that in the lab. The operation of a thermal-chemical process (N_2-foam, HTG) in Shengli and Henan oilfields, China is the most typical example. The consistence between lab and field operations is a top concern during the selection of EOR techniques.

9.4. Onshore versus offshore heavy oil resources

For the discovered heavy oil resources in the world, offshore heavy oil resources occupy a large proportion. Currently, most of the discovered offshore heavy oilfields in the world are mainly located in North Sea (UK, Norway), Mexico Bay (Mexico), Bohai Bay (China), Middle East (Saudi Arabia) and Latin America (Brazil), as shown in Fig. 11 [349,225]. As the oil production rate of onshore heavy oilfields reduces, to effectively develop offshore heavy oilfields has become the top target for most oil companies. Especially for offshore heavy oil reservoirs whose viscosity is high, a conventional cold oil production method (e.g., water flooding or chemical flooding) is no longer effective. A thermal recovery technique may become the only one option to unlock highly viscous offshore heavy oil reservoirs. Compared with the operation in onshore heavy oil reservoirs, the requirement for the operation in offshore ones is stricter. This is caused by the differences of production environments and operation conditions between onshore and offshore oilfields. In particular, a smaller well number, a higher recovery rate and a higher oil recovery factor are the primary requirements for offshore heavy oil reservoirs.

Table 3 shows the current status of some offshore heavy oil reservoirs in the world. As shown, most of the offshore heavy oil reservoirs go through a cold oil production method, including water flooding and polymer flooding. But for some special heavy oil reservoirs whose formation oil viscosity is much high, the cold oil production method is no longer effective, and the TEOR process is a suitable option. As shown in Table 3, a thermal recovery process has been carried out in the Emeraude offshore oilfield in Congo (steam flooding) and Bohai offshore oilfield in China (cyclic MTFs injection) [350,226]. For Bohai offshore oilfield, considering the diversity of heavy oil reservoir types, many thermal recovery processes have been experimentally and numerically evaluated, including ISC, steam flooding and SAGD. Based on the successful operation in Emeraude and Bohai oilfields, thermal recovery is one of the important techniques for the future development of offshore heavy crude oil. In future, how to effectively recover offshore heavy oil resources is the top priority for many oil companies, especially for those heavy oil reservoirs whose oil viscosity is much high and where a cold production method is no longer effective.

Fig. 11. Offshore Heavy Oil (OHO) Locations over the World.

10. Current research challenges and future directions

Different from waterflooded light oil reservoirs, an EOR process for heavy oil and oilsands resources is more challenging. As we discussed above, among many techniques, a hybrid process is always the most promising and easy-to-operate technology to enhance the heavy oil and oilsands recovery. Therefore, to effectively evaluate the performance of different hybrid techniques and screen an optimal hybrid process is the most important task, not only from the indoor experimental aspect but also from the field aspect. For this reason, a systematic and reliable experimental test is the fundamental requirement. Currently, many experimental investigations about EOR techniques have been published, including performance evaluation experiments, microscopic visualization experiments and 2D/3D scaled experiments. But on account of the unique properties of heavy crude oil, it is still very difficult to accurately detect an oil saturation distribution during scaled physical simulation, especially for large scale 3D experiments (CSS, SF, and SAGD). Moreover, the conventional test method by electrical resistivity for light oil reservoirs is no longer effective. Second, the EOR mechanisms of these techniques in different scales are another research challenge. For a recovery process for heavy oil and oilsands reservoirs, although some non-steam based processes have been proposed and tested in field, a steam based process (a pure steam process or a hybrid process) is still the primary method to guarantee economic oil production because of its reliability and effectiveness. Therefore, the behavior of heat and mass transfer of fluids in porous media is the key, especially for hybrid processes. Many attempts have been reported, not only from the theoretical aspects but also from experimental observations. For a hybrid process, the microscopic performance of hybrid fluids in rock surfaces, pores and throats is generally different from

Table 3
Current status of some offshore heavy oil reservoirs in the world.

Offshore oilfield	Ares	Operation companies	Offshore distance (km)	Water depth (m)	API °	Oil viscosity (cp@ RC)	Method
Captain Field	North Sea, UK	ChevronTexaco	130	104	19	88	Water flooding; Polymer flooding
Bently Field	North Sea UK	Statoil; Shell		110	10–12	1500	Water flooding; Polymer flooding.
Mariner Field	North Sea, UK	Statoil			12–14	508 67	Water flooding; Hot water flooding, steam flooding, SAGD (evaluated).
Bressay Field	North Sea, UK				11–12	1000	Water flooding; Polymer flooding, ISC, Steam flooding, Hot water (evaluated).
Grane Field	North Sea, Norway	Statoil	185	123	19		Water flooding.
Jubarte Field	Brazil	Petrobras	77	1066	17	3000@20 °C	Water flooding.
Snorre	Norway	Saga Petroleum					Water flooding; NCG-foam; WAG flooding.
Tambaredjo Field	Suriname	Shell; Esso; Elf			17	600	Water flooding; CSS test; Polymer flooding, ISC (pilot).
Emeraude Field	Congo	Elf Acquitaine	20			100	Steam flooding;
Lake Maracaibo	Venezuela	PDVSA		50	11.7	635	CSS.
Bohai oilfiled	Bohai bay, China	CNOOC		15		4580; 10,000	Water flooding; Polymer flooding; Cyclic MTFs.

their performance in large-scale reservoirs. It means that the EOR mechanisms in pore and field scales are inconsistent. Although good recovery performance for a hybrid process can be observed from lab scale experiments, its field-scale performance may not be satisfactory as it is expanded into field operation. A systematic evaluation method that integrates performances in different scales is the most urgent work. Another research challenge is the development of accurate numerical simulation software that can present the true recovery prediction for advanced EOR processes. Most of the current numerical simulators cannot reflect the changes of rock and fluids properties after long-term steam-rock interactions. Especially for the occurrence of steam breakthrough, we generally adopt some simplified methods, such as increasing permeability or transmissibility. Although the results of this simplification treatment can match experimental or field data, the real behavior of fluids in porous media is not simulated.

Currently, because of the shale gas revolution in North America, the oil price has reduced significantly than five years ago. For heavy oil and oilsands reservoirs, their economic profit is always the most important issue that should be considered. Especially, compared with the shale oil production, the exploitation cost of heavy oil and oilsands resources is much higher. Because of the low oil price and high cost, many heavy oil fields or wells in the world have been temporarily closed. Based on the discussion above, for heavy oil production, steam injection is usually the first option for most of the oil companies. Also, most of advanced EOR techniques require the injection of steam. The steam generation occupies a high proportion in the exploitation cost, and it also results in a high carbon emission. In such a time of low oil prices, environmentally friendly EOR techniques with a low cost will be an important future direction, such as an application of solar energy and the method of in-situ upgrading. Using solar energy to replace a traditional steam injection facility will not only tremendously reduce the cost of steam generation, but also carbon emissions. The application of solar energy will significantly reduce the dependence of thermal recovery techniques on natural gas supply. For the method of in-situ upgrading, in-situ combustion is a representative example. This technique has the distinct advantages for deeper and thinner heavy oil reservoirs. A low water requirement is also the most remarkable feature for this process. Because steam injection is no longer the primary requirement for this process, the heat loss rate, which usually controls the steam quality at a bottom hole, can be neglected. Also, ISC can be applied to heavy oil reservoirs with a wider range of reservoir depth, pressure, and reservoir thickness in comparison to other steam based processes. Although the technique of ISC has many advantages, a problem that must be addressed is the higher level of safety concern. In addition, it is very difficult to control a fire front in ISC. These two problems usually limit the success rate of ISC. On the other hand, offshore heavy oil reservoirs will be the future exploration focus. Therefore, easily-operated techniques with a high recovery rate, such as adding nanoparticle and electrical methods, will hold a considerable potential.

11. Concluding remarks

A comprehensive review on EOR techniques for heavy oil and oilsands reservoirs in the post steam injection process is presented in this paper. Specifically, it presents an overview on the recovery mechanisms and field performance of thermal EOR processes by reservoir lithology and offshore versus onshore oilfields. Typical processes include an in-situ combustion process, a thermal/-solvent process, a thermal-NCG process, and a thermal-chemical process. Some newly proposed processes (e.g., in-situ upgrading) are also considered in this work. Critical issues that we may encounter during the process of heavy oil production (i.e., asphaltene precipitation and reservoir lithology) have been also discussed in this paper.

Currently, most of the conventional steam-based recovery processes have entered their later stage. Especially for the processes of CSS and steam flooding, after long-time steam-rock interactions, the current physical properties of formations have changed compared with their original status. Steam breakthrough, low sweep efficiency and low steam efficiency are the most urgent problems for heavy oil recovery processes. For a specific heavy oil reservoir, choosing a suitable follow-up technique after a steam injection process is more important. A hybrid process has become an important technique to improve the heavy oil production in the post steam injection era. The commonly-used hybrid processes include a thermal-solvent process, a thermal-NCG process and a thermal-chemical process. Among them, both the hybrid thermal-solvent process and the hybrid thermal-NCG process are operated to reduce the oil viscosity and improve the oil quality. Finally, their recovery performance is significantly improved. In comparison, the hybrid thermal-chemical process is mainly operated to control a steam channeling path and improve the sweep efficiency. The EOR mechanisms of these three hybrid processes are different.

Offshore heavy oilfields will be the future exploitation focus. Moreover, steam-based projects and thermal-NCG projects have been operated in Emeraude Field in Congo and Bohai Bay in China. A growing trend is also found for an in-situ combustion technique and a solvent assisted process in both offshore and onshore heavy oilfields. The multicomponent thermal fluids injection process in offshore and the thermal-CO_2 and thermal-chemical (surfactant, foam) processes in onshore heavy oil reservoirs are some of the opportunities identified for the next decade based on preliminary evaluations and proposed or ongoing pilot projects. Furthermore, the processes of an electrical method (ERH, EM heating, and ETDSP), in-situ upgrading and some novel wellbore configurations have also gained recent attention. In addition, some newly proposed recovery techniques (ILs) are still limited to a laboratory scale study with needs for further investigations.

In such a time of low oil prices, how to effectively reduce an operation cost is the top concern for oil companies. To select a suitable follow-up recovery technique will not only tremendously reduce the operation cost but also improve the recovery performance. In a screening process, a systematic evaluation method that integrates the performances of EOR techniques in different scales will be the most urgent work. For the future trend, environmentally friendly EOR techniques with a low cost and accurate numerical simulation software are the important future direction for EOR processes for heavy oil and oilsands reservoirs.

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