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Review article

Comprehensive review of enhanced oil recovery strategies for heavy oil and bitumen reservoirs in various countries: Global perspectives, challenges, and solutions

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ABSTRACT

This study presents a comprehensive review of enhanced oil recovery (EOR) methods tailored specifically for high permeable heavy oil/bitumen (HOB) reservoirs, encompassing reservoir properties, production techniques, and associated challenges. In contrast to existing literature, this research uses a novel approach by delving into the production history and methodologies employed in prominent HOB-producing countries.

As a result, some comprehensive primary reservoir threshold criteria are created via coupling the presented information in various literatures. Also, the analysis reveals diverse global strategies for HOB production. Canada's majority of HOB reservoirs, with average gravity less than 11 API, employ surface mining and cold production with sand. Russia's higher gravity HOB reservoirs face challenges with combustion methods. Venezuela emphasizes multilateral horizontal wells and EOR methods like down-hole electrical heaters, surfactant injection and thermal methods. In the USA, a novel downhole steam generation method shows promise. Argentina focuses on Centenario formation production with steam injection and polymer/gel treatment after water flooding, while China utilizes cyclic steam stimulation (CSS), Fire flooding and integrated technologies after water flooding. Oman's Marmul field uses polymer and alkaline-surfactant-polymer flooding for water-cut reduction while Sudan employs infill horizontal wells, deeper re-completion, cement squeezing, partially perforating for the same purpose. As a final conclusion, surface mining is prevalent for low-depth bitumen reservoirs, whereas cold methods are preferred during the early stages of heavy oil production. Furthermore, among the EOR methods, CSS has the biggest share in oil production specially in Colombia (Middle Magdalena basin), Canada (Athabasca field) and China.

These findings underscore the importance of tailoring extraction methods to the unique characteristics of each HOB reservoir for optimal production efficiency. By leveraging insights from global production histories and innovative techniques, substantial improvements in oil recovery and operational efficiency can be achieved, paving the way for sustainable utilization of this vital energy resource.

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1. Introduction

Heavy oil and bitumen (HOB) reservoirs are distributed all over the world. It is estimated that HOB resources make up about 70 % of the earth's oil deposits, comprising 15 % heavy oil, 25 % extra heavy oil, and 30 % oil sands and bitumen [1,2]. Due to the high global demand for energy, the decline in conventional oil production, the existence of vast heavy oil sources with historically low recovery factors, and advancements in extraction methods, HOB reservoirs are receiving increased attention as a significant energy source [3–7].

1.1. Nature of heavy oil

Some papers define heavy oil with an upper limit of 20° API [8–12], while others use an upper limit of 22.3° API, as defined by the World Petroleum Congress and the US Department of Energy [11], or 22° API, as defined by the US Geological Survey [13,14]. In this study, the upper limit of 22.3 °API is used to define heavy oil encompassing all recognized definitions. All classifications include extra heavy oil as a portion of heavy oil having an API gravity less than 10°API (1000 kg/m3) [11,15]. Natural bitumen, also known as tar sands or oil sands, is a solid or semisolid mixture of hydrocarbons with an API gravity of less than 10° and a viscosity greater than 10, 000 cp (10,000 mPa s), according to the "United Nations Institute for Training and Research" definition and various researchers [10, 11,16].

Heavy oils are usually characterized by low API gravity, high viscosity, low hydrogen/carbon ratios, low gas/oil ratio, and high amounts of sulfur, asphaltenes, and heavy metals as compared to conventional oils that occur in similar locations [10,11,15,17–19].

1.2. The role of asphaltenes in heavy oil behavior

1.2.1. Definition and structures

Asphaltenes are vital for heavy oil properties identified by their insolubility in alkanes but solubility in aromatic fluids. They are complex, large-molecular-weight, polar compounds that are sensitive to aggregation and precipitation in specific conditions [20]. Two hypothetical structural of them are [21].

- The "continental" or "island" model depicts monomeric asphaltene structures with a molecular weight of approximately 500–1000 Da, consisting of 6–7 aromatic rings bound by various aliphatic groups with heteroatoms.
- The "archipelago" or "rosary type" model suggests individual asphaltene monomers as polycondensed groups, each containing 5–7 aromatic rings joined by short aliphatic side chains potentially containing polar heteroatomic connections. This model has a larger molecular weight, around 6000 g/mol.

1.2.2. Aggregation and precipitation of asphaltenes

Asphaltenes are complex, large-molecular-weight, polar compounds that are sensitive to aggregation and precipitation in specific conditions, causing issues such as reduced well productivity and increased production costs. Asphaltenes can form solid deposits and asphaltene-mineral aggregates, contributing to the stiffening and solidification of heavy oils [21].

The stability of a crude oil can be assessed using the Stankiewicz plot, which considers SARA (Saturates, Aromatics, Resins, and Asphaltenes) fractions. This method involves plotting the saturates/aromatics ratios against the asphaltene/resins ratios, thus distinguishing stable and unstable regions [22].

1.2.3. Asphaltene precipitation management

Asphaltene precipitation can be managed through various methods like mechanical cleaning, ultrasonic treatment, chemical treatment with solvents, thermal treatments, and bacteria treatment. Preventive strategies include adjusting oil production parameters and using inhibitors and dispersants to maintain asphaltene solubility. Before testing the effectiveness of an asphaltene inhibitor or dispersant, it is essential to determine the onset of asphaltene deposition, defined as the minimum amount of flocculant required to initiate asphaltene deposition. The inhibition capacity of additives is assessed by the increase in flocculant/oil ratio necessary to achieve the onset of asphaltene flocculation [21,23].

1.3. High permeability reservoirs

Permeability is a crucial property of rock as it controls the flow rate of fluids within the formation [24]. Protecting reservoirs with high permeability, particularly high-permeability sandstone reservoirs, is a critical issue. The reduction in productivity due to formation damage is more severe in highly permeable formations compared to those with low permeability. In highly permeable sandstones, the pore throat sizes show a wide distribution range, making temporary bridging more challenging than in low-permeability reservoirs. In addition, two important agents of formation damage are the invasion of solid particles and the filtrate of drilling fluid, both of which intensify as core permeability increases [25].

1.4. Aims of the paper

This paper aims to provide a comprehensive review of recovery methods for highly permeable (>0.5D) HOB reservoirs. It encompasses analyzing EOR methods and global distribution patterns of HOB reservoirs, and addressing production challenges. Additionally, the paper highlights key HOB-producing countries by examining oil and reservoir properties and production histories, focusing on regions where data is available.

In contrast to other review papers in the field of oil recovery of heavy oils, which often provide broad overviews without a clear focus on the reservoir properties where the production method is implemented, this study seeks to bridge this gap. By exploring the concise reservoir properties of heavy oil fields and delving into the production history of these fields, this research aims to provide a more contextually grounded understanding of the challenges faced in the recovery of heavy oils and the potential solutions to overcome these.

2. Heavy oil and bitumen production methods

HOB recovery methods can be divided into two main types: thermal and non-thermal methods.
Non-thermal methods are.

1. Bitumen Mining [26–28]**:**
   - Extraction of bitumen from oil sands using surface mining techniques.
   - Requires extensive land use and water resources.
2. Cold Heavy Oil Production with Sand (CHOPS/CHOP) [29,30]:
   - Involves producing oil with sand, creating wormholes for increased permeability.
   - Low energy cost, but can cause equipment wear in case of sand production.
3. Water Flooding [31–33]:
   - Injection of water to displace oil towards production wells.
   - Simple and cost-effective but limited by oil viscosity and sweep efficiency.
4. Gas Injection [34–37]:
   - Injection of gases (e.g., CO2, nitrogen) to reduce oil viscosity and maintain pressure.
   - Effective but can suffer from gas breakthrough and low sweep efficiency.
5. Foam Flooding [38,39]:
   - Combines gas and surfactants to improve oil displacement and reduce gas mobility.
   - Reduces gas channeling but requires careful foam management.
6. Polymer Flooding [40,41]:
   - Injection of polymer solutions to increase water viscosity, improving sweep efficiency.
   - Costly and sensitive to salinity and temperature.
7. Pressure Pulse Technology (PPT) [42]:
   - Uses pressure pulses to improve fluid mobility and recovery.
   - Promising in enhancing recovery, but its effectiveness varies with reservoir conditions.
8. Cyclic Solvent Injection [43–45]:
   - Injection of solvents cyclically to dissolve and mobilize heavy oil.
   - Reduces viscosity without heat, but solvent recovery can be challenging.
9. Vapor Assisted Petroleum Extraction (VAPEX) [46]:
   - Utilizes vaporized solvents to reduce oil viscosity and mobilize it.
   - Less energy-intensive but slower than thermal methods.
10. Microbial Recovery (MEOR) [47,48]:
    - Uses microbes to alter oil properties and improve recovery.
    - Environmentally friendly, but performance depends on reservoir conditions.

Thermal methods usually yield a higher oil recovery factor because of heating the oil and consequent reduction of viscosity. Some examples of thermal methods are.

1. Hot Fluid Injection [49,50]:
   - Injection of hot water or fluids to reduce oil viscosity.
   - Simple and effective but less efficient than steam-based methods.
2. Steam-Based Methods [51–56]:
   - Injection of steam to heat oil, improving its flow.
   - Widely used, very effective but energy-intensive and costly.
3. In-situ Combustion [57–61]:
   - Ignition of oil in the reservoir to generate heat and gases that mobilize oil.
   - High recovery potential but challenging to control.

Table 1 shows a detailed description of each method.
Table 2 shows the range of acceptable reservoir parameters for some heavy oil recovery methods. The data is gathered and reproduced from tables in some literatures referenced in the caption.

This table demonstrates that achieving optimal oil recovery using enhanced oil recovery (EOR) methods requires thorough initial reservoir characterization. The most effective method for one reservoir may be entirely unsuitable for another. For example, in-situ combustion might be suitable for a reservoir with a thickness of 20 ft, a depth of 10,000 ft, and a permeability of 100 mD. However, steam injection or hot water flooding would not be applicable in such a low-permeability, low-thickness, and deep reservoir due to several reasons. Firstly, with a permeability of only 100 mD, steam and hot water have difficulty penetrating the reservoir, leading to inefficient heat distribution and reduced oil mobilization. Secondly, at a depth of 10,000 ft, steam injection suffers from excessive heat loss, resulting in insufficient thermal energy reaching the oil, which makes the process less effective and more costly. Lastly, a thickness of 20 ft is too thin for efficient steam or hot water flooding, as rapid heat dissipation occurs, leading to poor thermal sweep efficiency and early steam breakthrough [52,69,70].These factors combine to make steam injection and hot water flooding unsuitable for the given reservoir conditions, while in-situ combustion offers a more viable alternative due to its ability to generate heat directly within the reservoir.

Another example is the study by Delamaide et al. (2017) on heavy oil field production methods. Their research showed that steam injection typically results in greater oil recovery compared to polymer flooding and is effective in much higher oil viscosities (i.e., viscosity greater than 150 cP). However, polymer flooding has lower operating costs and is not constrained by reservoir depth or thickness. Therefore, it is recommended to develop heavy oil reservoirs using polymer flooding where thermal methods are not feasible [71].

Table 1
Heavy oil and bitumen production method: advantages, limitations, and recommendations to overcome the limitations.

Method	Advantages	Limitations	Recommendations
Bitumen mining [26–28]	High recovery rates, well-established technology	Environmental impact, land disturbance, water usage	Use advanced water treatment technologies, implement stricter environmental regulations, and minimize land disturbance.
Cold heavy oil production with sand [29,30]	Simple and cost-effective, increases permeability	High sand production causing equipment wear, limited to certain reservoirs	Use advanced sand control techniques, optimize well design to manage sand production.
Water flooding [31–33]	Cost-effective and easy to implement, widely used	Limited by oil viscosity and sweep efficiency	Use polymer or surfactant flooding to enhance sweep efficiency, combine with gas injection for better results.
Gas injection [34–37]	Reduces tension, maintains pressure, CCS strategy	Gas breakthrough, gas cost, asphaltene risk	Use asphaltene inhibitors, use industrial CO2, optimize injection, explore hybrid techniques
Foam flooding [38,39]	Improved oil sweep efficiency, reduced interfacial tension, viscosity, plugging	Foam instability, high surfactant cost, high foam production, poor mobility control, channeling	Optimize surfactant and alkali concentrations, Develop stable foams, nanofluids
Polymer injection [40,41]	Improved sweep efficiency, reduced water coning	High initial cost, polymer degradation, adsorption by reservoir rocks, reaction with recoverable oil	Use cost-effective, heat-resistant polymers, optimize polymer concentrations and injection strategies
Pressure pulse technology (PPT) [42]	Enhances fluid mobility, non-intrusive	Effectiveness varies with reservoir conditions	Conduct thorough reservoir analysis before application, combine with other EOR methods for improved results.
Cyclic solvent injection [43–45]	Energy efficient, lowered viscosity, improved oil mobility	Solvent loss, High operating costs, solvent degradation; potential corrosion, asphaltene precipitation	Optimize cyclic periods, cost-effective solvents, improve solvent recovery, monitor asphaltene regularly
Vapor assisted petroleum extraction (VAPEX) [46]	Energy-efficient, reduces oil viscosity effectively	Slower than thermal methods, may require large amounts of solvent	Optimize solvent type and concentration; combine with steam injection for faster recovery.
Microbial methods [47,48]	Environmentally friendly, cost-effective	Limited understanding, pore plugging risk, Sensitive to reservoir conditions	Optimize microbes and nutrients, continuous monitoring, Strain engineering, comprehensive field studies
Polymeric nanofluid flooding [62,63]	Stable in high temperature and salinity, applicable in low permeable reservoirs, improving oil rheological behavior, IFT and wettability, decreased polymer adsorption	High cost, complexity of nanofluid synthesis, nanoparticle interactions and retention in porous reservoir media	Optimize the nanofluid composition to reduce the cost and enhance the properties, utilize computational models to optimize the injection strategies
Steam based methods [51–56]	Reduces viscosity and so effective in high-viscosity oils, widely used	High energy/water use, water treatment issues	Use renewable energy sources, advanced recycling techniques, manage scaling with additives
In-situ combustion [57–61]	Generates heat in-situ, cost-effective, effective for deep reservoirs	Complex control, safety concerns, environmental risk	Use advanced control systems, hybrid combustion methods, manage by-products
Hot water flooding [49,50,64]	Low-cost method, reduced oil viscosity through heating, simple operation	High energy requirement, limited viscosity reduction for heavy oil, increased water production, limited by heat retention	Insulate, combine with other methods (thermal enhanced oil recovery methods)

Table 2
Heavy oil and bitumen recovery methods with primary reservoir threshold criteria [65–68].

Method	Gravity (API)	Viscosity (cp)	Oil composition	Oil saturation (%)	Lithology	Net thickness (ft)	Formation permeability (mD)	Depth (ft)	Temperature (F)
Surface mining	>7	0, Cold flow	Not critical	>8 wt% sand	Mineable oil sand	>10	Not critical	>3:1 overburden: sand ratio	Not critical
Steam	>8	<200,000	Not critical	>40	Highly porous sandstone	>20	>200	<4500	Not critical
Combustion	>10	<5000	Asphaltic component	>50	Highly porous sandstone	>10	>50	<11,500	>100
Hot CO2	>10	>12	Not critical	>25	Porosity>10 %	>10	>10	2300-15,00	Not critical
Immiscible gases	>12	<600	Not critical	>35	Not critical	Not critical	Not critical	>1800	Not critical
Hot water	>12	50-8000	Not critical	>12	Sandstone	>30	>1000	<3000	Not critical
Polymer	>15	<150	Not critical	>50	Sandstone preferred	Not critical	>10	<9000	<200-140
Microbial	>15	May-50	Not critical	>25	Porosity>15 % NaCl<10–15 %	Not critical	>50	<7900–11,500	<208, preferably <176

3. Challenges of crude oil production from heavy oil reservoirs

The production of heavy oil reservoirs has specific challenges due to their contrasting conditions compared to conventional oil reservoirs. Some of these challenges stem from the unique properties of heavy oil, while others are rooted in the characteristics of the host rock.

Heavy oils are accumulated mostly in highly permeable sandstones, which introduces problems such as physical migration of in-Situ fines, sand production problems, and physical invasion of both artificial solids (e.g., weighting agents, fluid loss control agents, or artificial bridging agents) and naturally occurring drill solids (e.g., silicate, carbonate, dolomite or other formation fines) into the formation often due to the presence of large pore throats [25,72–75].

The viscosity of heavy oils tends to significantly increase as the asphaltene content increases. Furthermore, heavy oils have high tendency to create foamy oil due to their high inherent viscosity and gas-oil interfacial tension characteristics. This propensity becomes more pronounced when pressures fall below the bubble point pressure. This process results in significant increases in apparent viscosity which in turn, leads to impaired productivity and permeability. Also, the generation of stable water-in-oil emulsions can increase viscosity by several orders of magnitude. The high concentration of wax and asphaltene in heavy crude oils can pose a significant challenge if they become destabilized and precipitate out as solid deposits. Consequently, in-situ permeability will be reduced significantly, and surface production problems such as plugging may occur. Treatment equipment may also experience difficulties [25,76]. Table 3 illustrates the challenges of oil production from highly permeable HOB reservoirs and the corresponding solutions.

These challenges illustrate the complex nature of heavy oil and bitumen production, necessitating specialized techniques and solutions to enhance efficiency and productivity.

4. Worldwide heavy oil and bitumen distribution

Heavy oil/bitumen (HOB) reservoirs can be found all over the world. Almost all of them were originally conventional crude oil that migrated from deep formations to near the surface, where the oil was biologically degraded. Bacteria activities caused to hydrogen removal. Also, some of lighter hydrocarbons evaporated and exited. The end results would be the production of heavier oil [15,65,119]. Since the degradation amount is different in various regions, the ratio of heavy oil to light oil resources varies from one region to another. For example, the Western Hemisphere has 69 % of the technically recoverable heavy oil and 82 % of the technically recoverable natural bitumen in the world. In contrast, the Eastern Hemisphere has about 85 % of the light oil reserves in the world [120].

The most considerable extra-heavy oil accumulation in the world is in the Venezuelan Orinoco heavy-oil belt and the greatest amount of known recoverable bitumen is in the Alberta accumulation [120–122]. Fig. 1 shows the worldwide distribution of heavy crude oil and natural bitumen reported in the US geological survey report.

Due to their undesirable properties, heavy oil and bitumen accounted for only about 25 % of the crude oil produced in 2015. However, the heavy oils produced in various locations are among the best available. As a result, a significant portion of these resources remains untapped. Nonetheless, heavy oil and bitumen can be viewed as substantial energy sources if appropriate production and upgrading methods are employed to enhance their properties [124–126].

Fig. 2 shows the distribution of regions and authors throughout the world which are studying in the field of EOR for heavy oils (in the years between 1973 and 2024). According to the Scopus database, China, Canada and United states have the most affiliation of authors in the world with published works in the field of heavy oil EOR. Also, Tayfun Babadagli, Riyaz Kharrat and Mikhail Varfolomeev, M.A. have the most published works in this field.

5. Worldwide heavy oil/bitumen reservoirs

Venezuela and USA with about 34×10^9 and 18×10^9 tons technically recoverable reserves of heavy oil are the top two heavy oil-rich countries and North America (specifically Canada) and Russia with about 40 and 15 milliard tons technically recoverable reserves of bitumen are the top two bitumen-rich regions in the world [124].

In this section, several countries with significant heavy oil and bitumen resources are identified. In the following sub-sections, the largest and most important reservoirs in each country are explained in greater detail. Fluid and reservoir properties, sourced from various references, are summarized in Table 4. Additionally, where available, the history of oil production is reviewed in the subsequent sections. This comprehensive analysis allows for the identification of the most effective recovery methods for these types of reservoirs.

5.1. Canada

Canada, which holds 15 percent of the world's oil reserves, is the country with the second-largest proven crude oil reserves. A large portion of these vast reserves is in the form of oil sands located in the Alberta province. The most important formations are Athabasca, Cold Lake, and Peace River; among them, Athabasca, with 80 percent of total oil sands of Canada, has the largest deposits [127,167]. The reservoir and fluid properties of these formations are detailed in Table 4.

About 20 percent of Canadian oil sands are recoverable by surface mining because of their lower depth (<75m). Almost 80 % of proven heavy oil reserves in western Canada are in layers with less than 5m thickness. For such thin layers, thermal methods cannot be

Table 3
The challenges of oil production from highly permeable HOB reservoirs and the corresponding solutions.

Problems related to the properties of heavy oil		
Property	Problems	Solutions
High concentration of asphaltene, wax and solids	• Destabilization and flocculation from solution as solid bodies • High reduction in permeability • Plugging problems in surface production and treating equipment • Increasing viscosity with asphaltene content [20, 77–79]	Using some materials and technologies like: • nanoparticles as asphaltene precipitation inhibitors [80–82] • Ultrasonic waves [83, 84] • Resins and polymers which can delay or shift the onset pressure of asphaltene precipitation [85, 86] • Surfactants (enhance the stability of asphaltenes and act as inhibitor of wax deposition) [87, 88]
Low GOR (gas-oil ratio)	• Reducing efficiency in production due to insufficient gas drive in some cases [89, 90]	• Using enhanced oil recovery methods like in-situ combustion and gas injection [91, 92]
High viscosity	• Difficulty in flowing and pumping the oil • Increasing energy requirements • Rapid breakthrough of injected water [76, 93–95]	Using some materials and technologies like: • Nanoparticles [80, 94] • Supercritical CO2 [96] • Ultrasonic waves [97–99] • Some kinds of polymer surfactants (for example hyperbranched copolymer grafted with hydrophilic surfactant monomers can reduce the heavy oil viscosity) [100–102] • Multi-metal catalyst solution [103] • A polycyclic–aromatic hydrocarbon-based water-soluble formulation [104]
Tendency to form emulsions	• Increasing pressure drop due to high apparent viscosity • Reducing productivity • Challenges in separating water-in-oil or gas-in-oil emulsions [105, 106]	• Ionic liquids like trioctylmethylammonium chloride and 1-butyl-4-methyl-pyridinium tetrafluoroborate [107, 108] • Microwave and ultrasonic demulsification methods [108, 109] • Oxygen-enriched non-ionic demulsifier [110] • Amphiphilic copolymer as demulsifier [111] • Polymer-modified magnetic nanoparticles as viscosity reduction of heavy oil emulsion [112]
Problems related to the reservoir characteristics		
Property	Problems	Solutions
High permeability sandstones	• Physical invasion of both artificial and drill solids into the formation due to existing large pore throats leading to blockages and permeability reduction. • Physical movement of fine particles within the reservoir • Sand production leading to issues in production equipment and wells [25, 113]	• Reducing formation damage via the proper design of drilling fluids [114] • Heavy oil desanding by hydrocyclones [115, 116] • Chemical treatment with ultra-thin trackifying agent which allows to sand particles and fines to be held in the reservoir [117] • Injection of organosilane-polymeric chemical compositions [118]

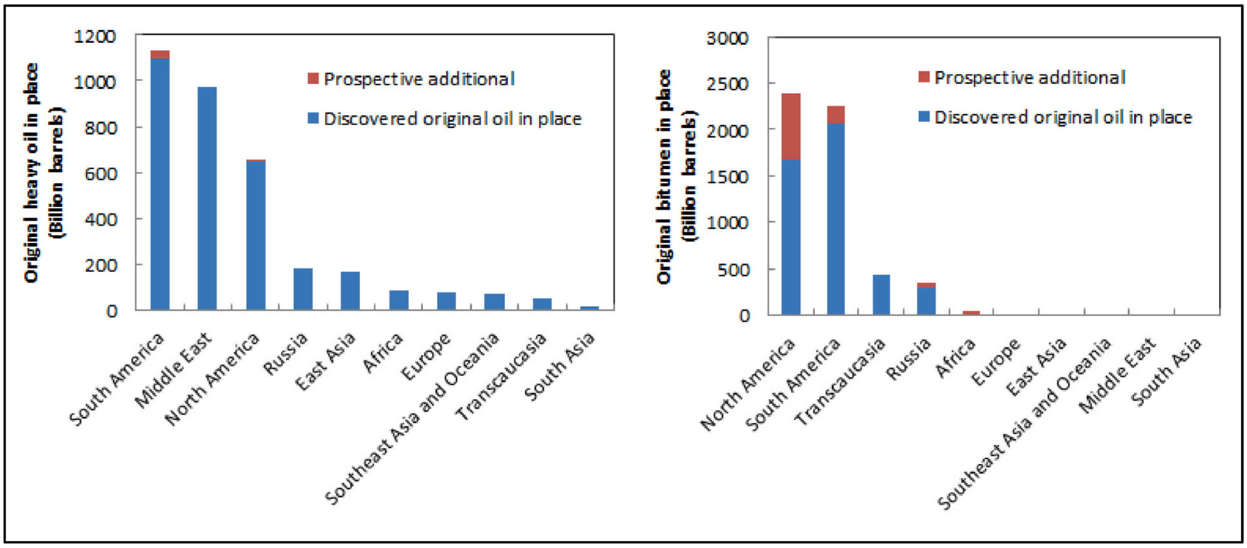

Fig. 1. Regional distribution of heavy oil and bitumen (reproduced from the data of an article by Meyer et al. (2007) which is an open access paper [123]).

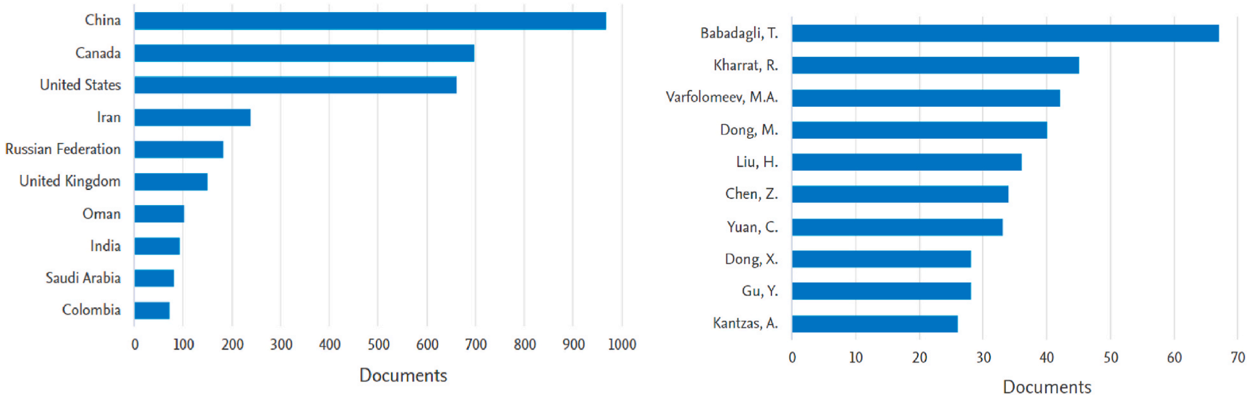

Fig. 2. Distribution of regions and authors worldwide which are studying in the field of EOR for heavy oils (based on Scopus database).

effective because of high heat loss to neighboring layers. CHOPS method is usually used in thin layers with 1–7 m thickness.

Some Horizontal wells have been widely used in Canada to cold heavy oil production since the late 1980s, but low recovery factors (less than 10 %), early water breakthrough, short well life, and expensive workover have resulted in reducing the attraction of this method in Canada [15,168].

Steam injection is a thermal method commercially used since the 1960s for thick layers and has been successfully used in Canada. The first SAGD[1] pilot tests in Canada were conducted from 1987 to 1992. After that, the steam injection method was being replaced by the SAGD method, especially in Athabasca area. Cyclic steam stimulation is another steam-based method that is used in Canada in oil reservoirs with depths higher than 1000 ft, especially in Cold Lake and Peace River areas [15,169].

Alkaline-polymer (AP) flooding is an example of chemical recovery methods in Canada, which is usually conducted for heavy oils with relatively high API gravity. For example, AP method was performed in Etzikom Field in Alberta, which contains heavy oil with density of 0.94 gr/cc and viscosity of 100cp. The reservoir thickness was about 24 ft with porosity of 19.7–23.4 % and permeability of 1000 mD. After a long period of waterflooding (from 1971(, Alkaline-polymer (AP) flooding began in the year 2000. Sheng (2013) reported that the method showed an acceptable increase in oil production (Further details were not found in the literature.). Another example is David Lloydminster “A” pool, which was under waterflood from 1978 to 1987 with 31.2 % oil recovery factor. The oil gravity is about 22.3 API, and the formation permeability is about 1.4 D. AP injection resulted in producing extra 21.1 % OOIP [68].

5.2. Russia

Russian heavy oil reserves are about 22.6 Bbbl (3.6 Bm^3), approximately 18 percent of its total reserves. Recoverable heavy oil in Russia exists in four main areas, the Volga-Ural basin, Timan-Pechora basin, eastern Siberian basin and the southern, up-dip portion of the West Siberian Basin [133]. The amount of heavy oil resources in each basin is shown in Table 5.

Some typical fields in Russia with their oil and rock properties are listed in Table 4. Russkoye heavy oil field with average oil gravity of 19.7 API is located in a remote location, in the West-Siberian basin. This field, with about 1.3 billion tons of oil in place, was discovered in 1968. Oil Production in Russkoye faced a lot of difficulties and challenges because of the highly unconsolidated formation, presence of gas cap and aquifer, high heterogeneity of the reservoir, permafrost zone (temperature ranges from −30 °C to −50 °C), and high viscosity (>200 cP).

Initial pilot tests, which include in-situ combustion, immiscible gas oil displacement, and injection of hot water performed in the 1980s, showed unsatisfactory results. So, the field production was suspended for about 20 years. From 2006 to 2012, the second phase of field development was conducted with laboratory tests and in-field activities. The pilot test results demonstrated that developing the field with horizontal wells and implementing a one-line waterflooding pattern is an efficient process. Additionally, their studies indicate that horizontal wells, particularly those drilled in the under-the-gas-cap zone with a horizontal borehole length of 600 m, are even more effective. In the years leading up to 2019, the field was developed using horizontal wells and "fishbone" technology. According to their studies, the mother hole should be drilled in a formation characterized by lateral continuity, sufficient vertical thickness, and an appropriate distance from the water-oil contact. This optimal distance not only increased the duration of water-free oil production but also significantly improved vertical sweep efficiency, undoubtedly affecting the recovery factor. Additionally, all lateral fishbone wells must have the same diameter as the mother hole in the field. Based on the successful results, a major development of the field using "fishbone" technology is planned [134,171].

Zybza Glubokii Yar reservoir is another heavy oil accumulation in Russia with oil viscosity of 2000cp at reservoir temperature of 29 °C with naturally fractured lithology. In 1972, the in-situ combustion method was implemented to improve oil recovery. Gas-burner ignition was initially used but encountered difficulties due to the oil bed’s thickness of only 5.5 m, well below the effective 15 m needed

[1] Steam assisted gravity drainage.

Table 4
Oil and rock properties of some of the biggest heavy oil and bitumen resources in the world.

Ref	Country	Field name		R.T	Oil gravity (API)	μ_o (cp)	φ (%)	K (D)	TVD (m)	h (m)	P (MPa)	T (°C)
[12,68, 127–132]	**Canada**	Cold lake		UnC sandstone	10.2	100,000	37	3	300–600	33	3	13
		Athabasca		UnC sandstone	8.5	Up to 1,000,000	34	0.5–5	0–400	50–55	0.1–3.5	15
		Peace River		semi UnC sandstone	7	100,000	25–31	0.2–1.65	550	25	NM	16–40
[133–138]	**Russia**	Volga-Ural Basin	Ashalchinskoye	siliciclastic	14.4	27,000	NM	2.6	80–100	25	0.44	8
			Mordovo-Karmalskoye	siliciclastic	15.7	6815	NM	1.06	88.5	26.5	4.5	8
		Timano-Pechora basin	Yaregskoye	siliciclastic	18.2	16,000	25–26	2.5	180	26	NM	NM
			Usinskoye	carbonate	14.5–16.7	NM	NM	0.38–10	1100	320	NM	NM
		West-Siberian basin	Russkoye	UnC rock	19.7	>200	NM	NM	664	NM	NM	NM
		NM	Zybza	siltstone with fracture	14	2000	NM	0.05–1	660	5.7	NM	NM
[139,140]	**Venezuela**	Orinoco belt		UnC sandstone	8–9	8500	32	2–18	884	66–88	7.9	60
		Bolivar Coastal field		UnC sandstone	10–18	21, 635, 100-10000	33–38	1–3	488–1128	15–60	9.4–12.3	38–60
		Santa Barbara reservoir		sandstone	8–19	10,000	30	0.0063	4267–5029	12–77	100	121–160
[141–143]	**USA**	Elkhart County, Texas		sandstone	18	1400	38	6	540	23	NM	23.3
[144–146]	**Argentina**	Centenario formation		UnC sandstone	15–20	250–700	30	0.5–3	600	30–50	2.75	NM
[147–156]	**China**	Liaohe		sandstone	0.96–1.01	500–500000	20–35	0.3–5.5	550–2400	10–100	>6.8	66
		Xinjiang		sandstone, conglomerate	0.91–0.94	2000–50,000	20–36	0.1–3	150–600	5–35	NM	NM
		Shengli		sandstone	0.94–1.09	200-80,000	15–33	0.1–15	650–2400	2–50	NM	NM
		Jilin		sandstone	0.92–0.93	250–400	33–39	1–6.5	250–400	5–35	NM	NM
		Tu-ha		NM	0.96–0.97	11,000–27,000	12~33	0.1–0.63	2300–3500	20–45	NM	NM
		Dagang		sandstone	0.95–1.01	3300–8000	27	3.4	1400–1700	45	NM	35–80
		Daqing		sandstone	0.91–0.94	100–800	20–35	0.1–2	200–2400	3–7	NM	NM
		Extra heavy oil in field “A”		NM	1.02–1.05g	NM	27–29	1	1600–1800	20	NM	NM
		Chunfeng field, Well Pai 601P36		debris-feldspar	<10	50,000–90,000	30	0.45	400–570	2–6	NM	22–28
[157,158]	**Colombia**	Middle Magdalena basin		sandstone	10.5–12.5	4031	24–30	0.5–2	335–670	10	6.9	46
		Llanos basin		sandstone	8.5	2500	28–30	>1	810	1.6–3	7.8	68
		Caguan-Putumayo basin, Mirador Reservoir		sandstone	9	2500–4000	33	3–10	>1200	36	8.5	57
[68,159–164]	**Oman**	Mukhaizna		sandstone	14–18	1200–3600	25–35	0.1–4	720	100	NM	50
		Marmul		sandstone	18–21	40–120	26–34	8–25	576–976	20	9.5	46
[165,166]	**Sudan**	Fula field- Bentiu reservoir		UnC sandstones	18	497	26–34	2–9.53	1250	30–40	10.3–11	64
		Thar Jath field		moderate to UnC sandstone	2 types: 17, 20	2 types: 140, >680	18–35 %	0.1 to >10	700–981	NM	NM	74

Ref: references, **R.C:** Rock type, **μ_o:** Oil viscosity, **φ:** Rock porosity, **K:** Rock permeability, **TVD:** True vertical depth, **h:** Reservoir thickness, **P:** Reservoir pressure, **T:** Reservoir temperature, **UnC:** Unconsolidated, **NM:** Data are not mentioned in the literature.
The oil gravities are reported in API. Only for Chinese oil fields the gravities are reported in g/cm^3 measured at 20 °C. Furthermore, the reported viscosities are measured at reservoir condition. Only the oil viscosities of Chinese fields are reported at 50 °C.

Table 5
Regional distribution of Russian heavy oil and bitumen resources [170].

Basin	Region	Resource, Bm^3	Resource, BBO	The share of total heavy oil, %
West-Siberian basin	Khanty-Mansiysky region	1.69	10.64	25.7
	Yamalo-Nenets region	1.03	6.51	15.7
Volga-Ural basin	Republic of Tatarstan	0.85	5.35	12.9
	Republic of Bashkortostan	0.36	2.29	5.5
	Udmurt republic	0.32	2.01	4.8
Timan-Pechora basin	Komi republic	0.41	2.56	6.2
	Nenets region	0.36	2.26	5.4
East-Siberian basin	Krasnoyarsk region	0.34	2.15	5.2
Offshore basins	South part of the Barents sea and offshore Sakhalin island	0.21	1.34	3.2
Total		5.57	35.11	84.6

for gas heaters. The high temperatures of the gaseous heat carrier (530–820 °C) exacerbated problems. Maintaining a high current density of injected air during ignition caused the oil concentration in the bed to drop below the necessary level for sustaining combustion. Consequently, the method was switched to electric heating, and the ignition period was extended to 37 days in the form of preheating during ignition operation. Under a constant injection pressure and air injection rate, the oxygen content of produced gas increased slightly and reached more than 10 % during 12 months after ignition. So the project has stopped, and the results were considered totally negative. The researchers concluded that the application of in situ combustion for heavy oil production in fractured reservoirs is impossible [135]. In the next years, cyclic well stimulations using gas-steam and thermal gas heat carriers were conducted to enhance the production of heavy oils in the field. The results showed that this method is successful and has greater response in oil-saturated areas with high permeability [172].

Thermal-steam stimulation (TSS) stands out as a key strategy for heavy oil production in Russia, offering notable results, yet entailing high cost and complexity. To enhance its efficiency, different technologies may be employed. One innovative method integrates TSS with physico-chemical processes using surfactant-based systems. These systems are engineered to generate carbon dioxide and alkaline ammonium buffer solution within the reservoir. This novel approach leverages the idea that the energy from the reservoir or the heat carrier can initiate self-regulating chemical systems within the reservoir. From 2002 to 2009, field trials for this method were conducted in the Usinsk oil field, Russia. Applying the method led to water cut decrement by 10–20 % and oil rate increment by 40 %. Some integrated methods of hot and cold technologies were also conducted in the Usinsk oilfield. During 2008–2013, the combined methods of alternative injection of steam, thermotropic gel-forming, and oil-displacing systems were applied in 172 wells of the field. The result was satisfactory with water cut decrement about 5–20 % [173].

5.3. Venezuela

According to the 2019 edition of the BP[2] Statistical Review of World Energy reports, Venezuela has the biggest proven oil reserves in the world. The major part of crude oil in Venezuela is in the form of heavy and extra heavy oil, which are accumulated in the Orinoco Heavy Oil belt in Eastern Venezuela, the Bolivar Coast fields in Western Venezuela, and Santa Barbara and Pirital fields in the Northeast of Venezuela. Orinoco belt with approximately 1300 Bbbl of STOIIP has about 90 % of the discovered extra-heavy oil in the country and is the greatest accumulation of heavy oil in the world [139,174–176].

Table 4 shows the properties of the largest heavy oil accumulations in Venezuela. **Orinoco belt** was discovered in 1935, and about sixty exploration wells were drilled until 1958. Some evaluation activities started in 1965, and the first estimation of 693 Bbbl of STOIIP was reported in 1967. Further evaluations have started in 1978 by Petróleos de Venezuela, S.A. (PDVSA). They divide the Orinoco heavy oil belt into four areas of Lagoven (Cerro Negro), Meneven (Hamaca), Maraven (Zuata) and Corpoven (Machete), and so they could assign one to each of the national operating companies. The efforts of them have resulted in recording 15000 km of seismic and drilling 700 exploration wells until 1979 [175,177].

Oil production from this area was developed primarily by cold methods and diluent (Naphtha) injection in the wells. Favorable reservoir conditions allowed the use of multilateral horizontal wells, and the studies showed that the best point of diluent injection is the "toe" of the well [12,178]. Up to 2013, about 20 percent of this area was being developed using horizontal well cold production with recovery factors of 8–12 %. This method is still the most common procedure for oil production in this area. But, because of low recovery factor of cold heavy oil production (CHOP), several other methods are used for enhancing heavy oil recovery that include downhole electrical heaters, injection of surfactants, sealing gels (for water entry shut off), "dewatering" techniques and using the azimuthal resistivity tools (in thin heterolithic reservoirs). In recent years thermal method pilot tests as a follow-up process are attracted more attention, but most of them were not reached the commercial stage [178,179].

5.4. USA

The United States of America has substantial reserves of heavy and extra-heavy oil in 16 states, among them California and Texas,

[2] British Petroleum.

with a share of 61 percent, have the biggest sources in the USA [180]. It is worth noting that the production of oil sand/extra heavy oil in the USA is relatively insignificant, with the majority of production coming from heavy oil. The total resources of heavy oil in the USA are approximately 100 Bbbl of OOIP [181]. San Juan basin serves as the primary accumulation area for heavy oil in the USA [124].

The USA has the enormous resources of oil shale, recognized as the most concentrated hydrocarbon deposit on Earth [182], but these resources are not pertinent to our current discussion. It is interesting to note that approximately 22 % of the OOIP in the USA is found in carbonate formations, which almost all of them are light oil [183]. Table 4 shows the properties of two heavy oil reservoirs found in the USA.

A novel steam generation method for steam flooding tests was proposed and examined for Heavy Oil Extraction in Elkhart County, Texas using a downhole steam generator. The oil production of this area was developed using conventional steam injection wells between 1982 till 2008. In 2013, a downhole steam generator attached to a coiled tubing (CT) control line was implemented. Hascakir and coworkers (2018) reported that the oil production increased and the results were satisfactory, but it was observed that the viscosity and gravity of produced oil were not improved because of emulsion formation. This problem is a common issue in all steam injection tests, but a benefit of the new technology was that any additional chemical could be injected with the steam during the process and so the problem of emulsification can be solved by adding proper chemicals. According to their studies, this method is a good choice even for small, low rate heavy oil fields if injected chemicals are appropriately selected [142].

5.5. Argentina

Argentina has numerous unconventional shale reservoirs as well as tight rocks of gas resources in six main hydrocarbon-producing basins of Paleozoic, Cretaceous, Cuyana, Neuquen, Golfo San Jorge, and Austral. Heavy oil production is mainly related to unconsolidated sandstone reservoirs in Neuquén basin, Centenario formation like Cerro Fortunoso, El Corcobo Norte, and Llancanelo fields [184]. Table 4 shows the properties of Centenario formation.

Heavy oil production from **Centenario** formation initially started with primary recovery method, in 1967. Some years later in 1980, conventional water injection was initiated, but the production was lower than predicted. So a detailed reservoir characterization study was initiated in 1983. From reservoir management starting until 1997, additional 2.5 million m^3 oil was produced [185].

In 2004, a new heavy oil accumulation with about the same properties in this formation was discovered and started oil production with cold method followed by water flooding, in 2005 for pressure support. After two years in 2006, production has reached 30,000 BOPD using more than 470 drilled wells, and a steam injection pilot started [145,146]. However, sand production was undesirable and resulted in severe water channeling. So polymer injection as the first conformance pilot project started in 2008. In this method, small volumes of gel slugs with high concentrations were injected and then followed by a short shut-in period. After one year, WOR[3] was decreased from 6 to 1 [146].

El Corcobo Norte field represents another significant heavy oil accumulation within the Centenario formation, first discovered in 2005. From the outset of production, waterfloodng has been employed. In 2012, due to issues with worm-holing and channeling within the field and a focus on analyzing incremental volumetric efficiency for the Lower Centenario formation, a pilot project for polymer flooding was initiated. For six years up to 2018, polymer injection was executed, with no reported issues and achieving the desired viscosity (20–25 cp at 38° C). The polymer quality remained stable and repeatable. Given these results, it was determined that this method proved effective, leading to the design of an expansion project aimed at scaling up the initiative [186,187].

5.6. China

Chinese heavy oil fields are spread across a vast area, with over 1.9 billion tons of oil reserves in place (OOIP). The ten major heavy oil fields include Daqing, Jilin, Liaohe, Huabei, Dagang, Xinjiang, Tarimu, Tu-hu, Henan, and Shengli. Among these, Liaohe is the largest heavy oil-producing field in China. The heavy oil produced in China generally has high resin content, with low levels of asphaltene and wax [147].

China has a variety of reservoir types due to its diverse geological conditions. For example, some reservoirs, such as the Gaosheng Block in the Liaohe oil field have both a gas cap and bottom water. Others, like Shu 1-7-5 in the Liaohe oil field contain edge and bottom water. Additionally, some reservoirs consist of a single layer like Block 9 in the Karamy area while others, such as Block Qi 40 in the Liaohe oil field, are multilayered [147,151]. Table 4 provides detailed properties of various heavy and extra-heavy oil fields in China.

The commercial development of heavy oil production in China began in 1982 through a cyclic steam injection pilot test in the Liaohe Oil Field, and it has since grown substantially due to the development of steam-based methods. In China, the predominantly utilized techniques are cyclic steam stimulation (CSS), water flooding, and steam flooding. Among them, CSS accounts for the largest proportion of annual heavy oil production, making it the most significant method [147].

In the year 2007, commercial production of oil from extra heavy oil reservoirs in China initiated in an area referred to as "Area A". Producing oil in this region presented several challenges such as the deep burial depth of the producing intervals, low mobility, and high viscosity of the oil. Over the course of a decade, a wealth of experimental test data, pilot test results, and field production data were accumulated, which demonstrated that a specific set of technologies were effective for this field. The methods were subsequently

[3] Water oil ratio.

optimized for operational use. The method employed, known as the "HDCS" method (consisting of “horizontal well + oil-soluble compounded dissolver + carbon dioxide + steam”), was found to be an appropriate solution for oil production from formations with depths ranging between 1600 and 1800 m, as their oil viscosity is approximately 180,000 to 260,000 cp [148]. Furthermore, it was reported that the HDCS method has been successful in producing extra-heavy oil from the Shengli field [188]. Tao et al. (2010) reported that in some parts of the Shengli field, another combination technology of “under-pressure foam flow-back + oil soluble viscosity reducer + immiscible carbon dioxide + steam huff and puff” was operated successfully [189]. Similar method of “horizontal well + viscosity reducer + nitrogen + steam” (HDNS) was studied carefully by Wang et al. (2013) and carried out as a pilot test in Well Pai 601P36, Chunfeng Oilfield. It was reported that the method was successful and was resulted in steam sweep volume, oil displacement efficiency and crude oil flowability increasing, and oil viscosity reducing [150].

Another oil recovery enhancement method applied in Chinese heavy oil fields is fire flooding. For example, in deep and thick blocks of G3 and G3618 located in the Liaohe oil field, fire flooding was started in 2008. Depth of reservoirs was 1600m, and average reservoir thickness was more than 60 m. During about one decade of production, two operating issues have challenged the procedure: combustion front gravity override and the low areal sweep efficiency. The subsequent studies showed that three main procedures for process control must be implemented: using hybrid well configuration (vertical-horizontal), reconfiguring to line drive plus hybrid configuration, and air injecting at top positions. After applying the proposed procedures in 2017, the oil production of block G3618 was increased by 30 %, and the daily production of G3 block was increased by 80 %. So, they reported that fire flooding could be an effective method to improve the oil recovery at the end of steam huff and puff of thick heavy oil reservoirs [190].

5.7. Colombia

Colombia’s heavy oil production is around 0.63 million barrels per day (BOPD) [191]. Llanos basin, with about 70 % of the country’s production, is the main source of heavy oil in the country [192].

The main heavy oil basins in Colombia and their properties are listed in Table 4.

Middle Magdalena basin: The primary oil fields in the Middle Magdalena basin are Girasol, Jazmin, Under River, and Moriche. The oil production rate for each well in this basin ranged from approximately 20 to 35 BOPD during the cold production stage and increased to 70 to 90 BOPD during the hot production phase. Cyclic steam stimulation is the main thermal recovery method employed in these fields. In 2011, a new drilling and completion methodology was introduced for horizontal and highly deviated wells to enhance recovery. This approach involved improving the bonding between the cement, pipe and the formation, enlarging open hole diameter from 8 to 11.5 inches, implementing sand control techniques, and using a formation packer shoe (FPS). These advancements have significantly improved well productivity and reduced non-productive time from approximately 600 days to just one year [157, 193].

Llanos basin: Heavy oil production in the thick layers of the Llanos basin initially began using the CHOP method and using sand screens to prohibit sand production. However, over time, increased pressure and decreased production rates indicated that screens were becoming plugged with highly viscous oil and fine sands. As a result, the sand control equipment was removed. Eventually, the development of wormholes and channels led to further complications, prompting a detailed analysis of CHOPS method. The study concluded that the CHOPS method is suitable only for the thin pay zones of the Llanos basin [194].

Mirador reservoir: It is the main reservoir in the Capella field, located in the Caguan-Putumayo basin, discovered in 2008 and has been under continuous production using cold method since 2012. The primary production mechanism is gravitational drainage, with limited aquifer support. A CSS pilot test was conducted in 2010, leading to a fivefold increase in production compared to the stabilized cold production levels. By 2014, approximately 50 vertical and horizontal wells were drilled in this basin [195].

5.8. Oman

Oman’s heavy oil reserves are about three times the size of conventional oil reserves [164]. However, its heavy oil production accounts for 15–30 % of Oman’s total annual crude oil production. Various EOR methods are employed in the heavy oil reservoirs of Oman. These include steam injection in the Mukhaizna and Amal fields, Polymer injection in the Marmul field, miscible gas injection in the Harweel 2AB, and thermal gas-oil-gravity-drainage (T-GOGD) projects in Qarn Alam fields. Table 4 shows the properties of some Oman’s heavy oil fields.

Mukhaizna field: It was discovered in 1975. Cold primary production began in 2000 and during six years, 75 horizontal producer wells were drilled, resulting in the extraction of approximately 3 % of OOIP. Thermal development started in late 2006 with the introduction of steam injection. The initial injection patterns were developed with 500m producers while longer producers, measuring 1000 m, were introduced in 2008 [159,196]. By the end of 2017, continuous steam flooding had increased the average gross daily production to 123,000 barrels of oil equivalent (BOE) per day [197].

Marmul field: It was first discovered in 1956, but its primary production was initiated in 1980. Most areas of the field were supported with an edge water aquifer. However, the oil conditions resulted in low production. To combat this issue, a water flooding project was initiated in 1986. Unfortunately, the high viscosity of the oil and an unfavorable mobility ratio resulted in early water breakthrough. At that specific time, the oil recovery factor was around 15 %. Analysis suggested that employing polymer flooding would elevate the viscosity of the driving fluid making it the most suitable method for oil recovery in this field.

The Polymer pilot project was initiated in 1986, but the results show that it was economically unfeasible. The large-scale field application of polymer flooding commenced in 2010, with 27 injectors and a total injection rate of approximately 82,000 STB per day. Between 2010 and 2012, this method increased recovery by 10 %, delivering the highest production rate in the field’s history [68,160, 198]. The second phase of polymer flood studies commenced in 2015, focusing on ASP injection analysis through core flood experiments, single-well chemical tracer tests, and small-scale models.

The first ASP pilot was completed in 2016. By the year 2024, three trials using the ASP flooding technique have taken place in the Marmul field. Two of these trials (referred to as Pilot and Phase-1A) utilized distinct ASP mixtures and focused on distinct reservoir layers post water flooding. These trials yielded approximately a 20–30 % increase in oil extraction. The present Phase-1B ASP field trial is investigating the ASP solution's post-polymer efficiency in quaternary injection, showing an additional 7–10 % improvement in oil recovery [199–201].

5.9. Sudan and south Sudan

The heavy oil reserves of Sudan account for approximately 40 % of the country's total reserves, mainly sourced from the Muglad and Melut basins. The Muglad basin, in particular, hosts two significant heavy crude oil fields: Fula and Thar jath. The Fula field partitioned into four areas - Fula Main, Fula Central, Fula North, and Fula North East - intersects 34 ft of Aradeiba reservoir and 174 ft of Bentiu reservoir. The Thar Jath field containing roughly 1.2 B STOIIP lies within block 5A in the Muglad basin, south-central Sudan. This field encompasses two formations - ARA and BEN. The oil and reservoir properties of the Thar Jath field and Bentiu reservoir of Fula field are displayed in Table 4 [165,166,202].

The heavy oil in Bentiu reservoir is located in a series of massive sandstones, which are supported by strong bottom water drive. The initial oil production commenced in 2004 with 70 producers equipped with optimized perforation ratio of 30 %. The early stages of oil production were initiated with CHOP. However, the later cold production with sand has resulted in average productivity of 500 BOPD, 2–3 times of sand-controlled production. In 2006 about 50 producer wells were added to the stream to achieving full field production, and so water cut of the reservoir increased to near 10 % and continued increasing. The project of drilling 40 infill wells inclusive of horizontal wells without increasing reservoir offtake to suppress water coning was initiated in 2007. Water cut reached 46 % with Recovery factor about 13 % in 2010 [203].

In the year 2015, a significant drop in oil production was observed in the field, primarily due to water breakthrough in the majority of wells, with water cut nearing 90 %. To mitigate this issue and extract the bypassed oil zones in the upper Bentiu, a deeper recompletion policy was implemented. This was executed through several methods such as cement squeeze into the high water-cut areas, partial perforation of the lower part of pay zones with optimal techniques, and the operation of Progressing Cavity Pumps at low frequencies. The project successfully led to a reduction in water cut by 30–50 %, which remained stable for approximately six months [166].

5.10. Summary of production methods in different countries

In the preceding sections, several countries with HOB reservoirs were mentioned, and their production history is explained. Table 6 shows a summary of production methods.

6. Conclusion remarks

In this research proposed EOR methods for HOB reservoirs along with primary reservoir threshold criteria are summarized in Table 2. This table serves as a tool for initially selecting applicable methods for any highly permeable HOB reservoir worldwide. Also the paper extensively reviews several HOB reservoirs across different regions, delving into their properties, alongside detailed discussions on production history which the key conclusions include.

- The majority of HOB reservoirs in Canada exhibit a gravity less than 11 API. Surface mining proves effective in bitumen reservoirs at depths below 75 m, while the CHOPS method is favorable for heavy oil formations with thicknesses ranging from 1 to 7 m. Additionally, steam-based methods are viable for formations with a gravity exceeding 10 API. In such scenarios, SAGD method demonstrates efficiency in Athabasca (depth below 400 m), while CSS yields favorable outcomes in Cold Lake and Peace River regions where depths exceed 300 m.
- In Russia, a significant portion of HOB reservoirs have an average gravity greater than 13 API. Various methods have been trialed, with integrated hot and cold technologies showcasing superior commercial performance over TSS method. Conversely, the combustion method in reservoirs housing gas caps and aquifers with highly heterogeneous formations has proven unsuccessful.
- Venezuela contains vast oil reserves with average gravities between 8 and 19 API, predominantly concentrated in the Orinoco belt with gravities of 8–9 API. Initial stages witness success with multilateral horizontal wells coupled with diluent injection. Subsequently, down-hole electrical heaters, azimuthal resistivity tools (for thin heterolithic reservoirs), dewatering techniques, surfactant injection, and sealing gels are employed. Pilot thermal methods are also underway.
- Heavy oil production in the USA is limited. However, a novel downhole steam generation method has been explored in a HOB reservoir in Texas with a gravity of 18 API. This method, combined with tailored chemical injection, demonstrates promising outcomes when appropriate chemicals are utilized.
- Argentina primarily focuses on heavy oil production from the Centenario formation, ranging from 15 to 20 API. After initial cold production in this formation, water flooding followed by steam injection is employed to enhance recovery. Challenges such as water channeling and increasing water cut (because of high permeable unconsolidated sandstone) are addressed through gel treatments and polymer injections.

Table 6
HOB reservoirs and their production methods in several countries.

Country	Main HOB resources	Production methods	The results of applying the method
Canada	Athabasca (8.5° API), Cold Lake (10.2° API) and Peace River (7° API)	Surface mining	Appropriate for bitumen sources with lower depth (<75m)
		CHOPS	Appropriate for heavy oils in formations with 1–7 m thickness.
		Horizontal wells	Did not have desirable benefits and so were not developed
		SAGD	In Athabasca has shown good results.
		CSS	In Cold Lake and Peace River areas (because of higher depth compared to Athabasca fields) has shown good results
		AP flooding	For heavy oils with relatively high API gravity and high WC was performed. For example, AP flooding in Etzikom field (19 API) and David Lloydminster "A" pool (22 API) has shown good results.
Russia	About 65 % of HOB resources exist in Volga Ural and West Siberian Basins.	TSS and integrated methods	TSS leads to satisfactory results, but because of its high costs, several integrated methods of hot and cold technologies including surfactant based methods, alternative injection of steam, thermostropic gel-forming and oil-displacing systems were used and led to satisfactory results.
		Gas injection, In-situ combustion, horizontal wells, hot water injection	Initial pilot tests of in-situ combustion, in Russkoye field (19.7 API, containing gas cap and aquifer, high heterogeneous formation) had not shown promising results. Later, horizontal wells with fishbone technology have resulted in good oil production.
Venezuela	Orinoco belt (8–9° API) has about 90 % of the discovered extra-heavy oil in Venezuela	Cold methods and diluent injection	It was used as primary production method but RF was low.
		Multilateral horizontal wells	Multilateral horizontal wells, with diluent injection at the "toe" of the well were developed widely in this area.
		EOR methods	Low RF of cold method leads to more attention than other methods like down-hole electrical heaters, azimuthal resistivity tools (in thin heterolithic reservoirs), dewatering techniques, injection of surfactants and sealing gels (for water entry shut off).
		Thermal methods	In recent years, pilot tests of thermal methods were conducted, but were not reached to commercial stage.
USA	Elkhart County, in Texas	Steam flooding	A novel method of downhole steam generation is examined. In this method, additional chemical can be injected with the steam during the process. The results showed that this method is a good choice if injected chemicals are correctly selected.
Argentina	Centenario formation (15–20° API)	cold production	Was used in primary stages.
		Water flooding	Was used to increase the recovery factor.
		Steam injection	Led to water channeling and increasing WC.
		Gel treatment	In some formations could decrease WC and yield in good results.
		Polymer injection	In El Corcobo Norte field led to acceptable results.
China	There are various types of HOB reservoirs with and without gas cap and aquifer, one layer or multilayer with different oil gravities.	Water flooding and steam-based methods	The most used methods in heavy oil reservoirs were water flooding, CSS and steam flooding from which CSS had the biggest share in heavy oil production.
		Integrated technologies	Integrated technology of "horizontal well + dissolver + CO_2 + steam" was appropriate for extra heavy oil production from 1600 to 1800 m formations with oil viscosity of 180,000 to 260,000 cp.
		Fire flooding	It was performed in deep (1600m) and thick (>60m) formations of Liaohe oil field using hybrid well configuration and air injecting at top positions. As a result, oil production was increased dramatically.
Colombia	Llanos basin (8.5° API)	CHOPS	The field development was conducted in 2012 with appropriate results for CHOPS method in thin pay of this basin.
	Middle Magalena (10.5–12.5° API)	Cold production	The primary production with oil rate of about 20–35 BOPD.
		CSS	It was used as the main thermal recovery method with oil rate of about 70–90 BOPD
		New method of well drilling and completion	Resulted in improving oil productivity.
	Mirador reservoir	Cold production	Primary production method (since 2012)
		CSS	Pilot test was resulted in the production increase up to five times.
Oman	Mukhaizna field, (14–18° API)	Primary cold production	Primary production method which was initiated in 2000.

(*continued on next page*)

Table 6 (*continued*)

Country	Main HOB resources	Production methods	The results of applying the method
		Developing horizontal wells	Conducted up to 2006.
		Steam injection	Conducted in late 2006 and leads to increasing daily oil production.
	Marmul field, (18–21 API, edge water aquifer)	Primary cold production	Resulted in low oil production.
		Water flooding	Resulted in early water breakthrough (because of high μ_o)
		Polymer flooding	Polymer pilot test (in 1986) showed that it was uneconomic. After a long period (in 2010) the large-scale polymer flooding increased RF about 10 %.
		ASP	Pilot test was completed in 2016 and it was reported that this method had successful results.
Sudan and South Sudan	Muglad and Melut basins are the main heavy oil producing basins	CHOP	Early production with low RF.
		CHOPS	Was resulted in 2–3 times of sand controlled method.
		WC decrement methods	Because of high WC near 90 %, some methods including progressing cavity pumps, optimized perforating and cement squeezing into the high WC areas, have been performed and led to WC decrement by 30–50 %

- China features diverse HOB reservoirs with varying characteristics such as the presence of gas caps, aquifers, and different oil gravities. In most reservoirs, CSS dominates heavy oil production, while an integrated technology combining horizontal wells, dissolvers, CO2, and steam proves effective for extra heavy oil production from 1600 to 1800 m formations with oil viscosity of 180,000 to 260,000 cp. In-situ combustion with air injection yields positive results in deep(1600m) and thick(>60m) formations of the Liaohe oil field.
- In the Uman and Mukhaizna field (14–18 API), primary cold production followed by steam injection achieved satisfactory results due to the favorable reservoir's thickness (100m) and depth (700m). However, in Marmul field (18–21 API), primary cold production followed by water flooding led to early water breakthrough, yet Polymer and ASP pilot tests showed promise in addressing this issue.
- The Llanos basin in Colombia has heavy oil with an average gravity of 8.5 API. Due to relatively low viscosity, the CHOPS method is successful in this region. Middle Magdalena experiences heavy oil production (10.5–12.5^{o} API) through CSS after early cold production stages. Despite low reservoir thickness(10m), CSS remains effective in this area.
- Sudan's Muglad and Melut basins are primary heavy oil producers. CHOPS outperforms CHOP due to high water cut. Various techniques, including progressing cavity pumps and cement squeezing, successfully reduce water cut by 30–50 %.

The study of the production methods in mentioned countries showed that the most common and commercial production method in low depth bitumen reservoirs is surface mining and the most common initial production method in heavy oil reservoirs with unconsolidated sandstone formation is CHOPS. Steam based methods specially CSS and SAGD are the most used procedure for enhancing oil recovery factor, especially in low-depth and high-thickness formations. A common problem in heavy oil reservoirs is water channeling and increasing WC. In these cases, polymer injection, ASP injection, flooding of gel or other plugging agents in high permeable zones, drilling horizontal wells and proper well completion has the most application in decreasing the water production, and increasing the oil recovery.

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Mina Seidy-Esfahlan: Writing – original draft, Investigation, Conceptualization. **Seyyed Alireza Tabatabaei-Nezhad:** Writing – review & editing, Supervision, Conceptualization. **Elnaz Khodapanah:** Supervision, Methodology, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Nomenclature

AP	Alkaline-polymer
ASP	Alkaline-surfactant-polymer
BOE	Barrels of oil equivalent
BOPD	Barrel of oil per day
CSS	Cyclic steam stimulation
CHOP	Cold heavy oil production
CHOPS	Cold heavy oil production with sand
EOR	Enhanced oil recovery
HOB	Heavy oil or bitumen
SAGD	Steam assisted gravity drainage
TSS	Thermal steam stimulation
TVD	True vertical depth
RT	Rock type
SARA	Saturates, aromatics, resins, and asphaltenes
T-GOGD	Thermal gas-oil-gravity-drainage
WOC	Water oil contact
WC	Water cut

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