Low-Energy Processes for Unconventional Oil Recovery

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Mohammad Reza Fassihi
BHP

Anthony R. Kovscek
Stanford University

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Society of Petroleum Engineers
222 Palisades Creek Drive
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http://www.spe.org/store
service@spe.org
1.972.952.9393

Preface

Unconventional hydrocarbons are generally portrayed in the media as "dirty" to produce. While this characterization is generally incorrect because the industry subscribes to good environmental health and safety practices, many unconventional hydrocarbons do have a greater greenhouse gas (GHG) footprint in comparison to conventional crude oils. For heavy oil and bitumen, this greater GHG footprint is created, in large part, because steam is generated on the surface by burning natural gas and the steam is then injected to enhance oil recovery. Accordingly, there has been an emphasis on quantifying the environmental aspects of hydrocarbon production and on developing recovery methods that result in smaller environmental and GHG footprints. Likewise, the role played by unconventional resources in the energy supply spectrum has grown.

Despite the petroleum industry's desire to evaluate and potentially implement less carbon-emission-intensive recovery processes for unconventional oil recovery, we noticed a gap in industry literature related to low-energy processes. We proposed the idea in early 2010 of publishing a book on the topic of low-carbon-intensity recovery processes for unconventional resources to the Society of Petroleum Engineers' (SPE) book committee. We contacted Mike Prats and sought his feedback on publishing a book that would supplement the information in his *Thermal Recovery* monograph. Additionally, we circulated the outline to a number of outside experts and solicited their comments on content. After receiving positive feedback, we began the journey of developing this book that focuses on low-carbon-intensity recovery techniques creating smaller environmental footprints that increase recovery factors for low-mobility oil such as heavy oil, oil sands, viscous oil, tight oil, and oil shale. We consolidated the contents and honed the themes through many discussions with subject matter experts during an SPE forum titled "Low Carbon Intensity Processes for Low-Mobility Oil Recovery" that was held 27 July–1 August 2014 in Newport Beach, California.

Now, years after conceptualizing a new volume, we are happy to present this book to you. We believe that this new monograph, in combination with Prats' classic work, provides a comprehensive treatment of the thermal and nonthermal options available to engineers and geoscientists who tackle the difficult problem of converting unconventional resources to reserves. We find great promise for enhanced recovery with a reduced environmental footprint using polymer solutions, activation of solution gas drive and waterflood recovery mechanisms through selective periods of voidage replacement ratio less than unity, steam foam, and in-situ combustion, among other techniques.

We present the state-of-the-art in technologies associated with recovering hydrocarbons from unconventional reservoirs. Importantly, we have strived to be both broad and deep in our analysis. The references cited are our best effort in linking the topics to their source; however, like many other publications, you may find some shortcomings in our first edition. In such cases, your feedback is very important to us in shaping future versions of this monograph.

Many people helped us during this time to ensure that this book is of high quality and that the standards associated with SPE monographs were met. We are especially indebted to Dr. Johan van Dorp, principal technical expert for Shell Oil Company, who reviewed Chapters 1 through 10 and wrote the Preface to this book. Also, Dr. Lilian Lo, formerly with ConocoPhillips, and Dr. Louis Castanier, Stanford University, who collectively reviewed Chapters 1 through 10. Dr. Besak Kurtoglu, formerly with Marathon, reviewed Chapter 11. Professor Mojdeh Delshad from The University of Texas at Austin was our SPE contact, champion, and the final reviewer of our work. We sincerely acknowledge all of the feedback and encouragement they provided. Finally, a great thank you to our families who patiently endured many hours of separation from us and their encouragement that helped us to finish this project.

Reza Fassihi
Tony Kovscek

About the authors

Mohammad Reza Fassihi is a distinguished advisor with BHP Petroleum in Houston, where he is responsible for subsurface technical assurance on global projects. Before his current assignment, he was the unconventional technology manager with BP. Fassihi has more than 35 years of experience in petroleum research and development, as well as field application of reservoir management best practices. He has a broad experience of design, plan, and execution of waterflood and enhanced-oil-recovery (EOR) projects. Fassihi has authored or coauthored more than 40 papers in reservoir simulation, thermal recovery, special core analysis laboratory (SCAL) methodology and integration, well testing, reserves estimation, depletion planning, surveillance, and unconventional resource development. He holds a BS degree in general engineering from Abadan Institute of Technology, and an MS degree in chemical engineering and a PhD degree in petroleum engineering, both from Stanford University. Fassihi is an SPE member, associate editor of *SPE Journal*, a member of the SPE Editorial Review Committee, and a member of the SPE/DOE IOR Symposium Technical Committee. He has been a member of the steering committee for many SPE forums and was an SPE Distinguished Lecturer in 2003.

Tony Kovscek is the Keleen and Carlton Beal Professor of Energy Resources Engineering at Stanford University, where he joined the faculty in 1996 as an assistant professor. Kovscek advanced to associate professor and received tenure in 2003. Currently, he is chair of the Energy Resources Engineering Department. Kovscek holds BS and PhD degrees in chemical engineering from the University of Washington and University of California at Berkeley, respectively. To date, he has authored or coauthored more than 125 peer-reviewed publications and roughly 120 SPE meeting proceedings manuscripts. His publications report on studies of enhanced recovery processes for unconventional resources including hydrocarbons such as shale and heavy oil in tight media. Kovscek and his research group apply advanced, nondestructive imaging techniques to understand complex multiphase flows of gas, water, and oil in porous media. He has been honored with the 2015 SPE Lester C. Uren Award and the 2006 SPE Distinguished Achievement Award for Faculty. Additionally, Kovscek received the Stanford School of Earth Sciences Award for Excellence in Teaching in 1997, the SPE Western North America Region Technical Achievement Award in 2005, and he was the inaugural Global Climate and Energy Project (GCEP) Distinguished Lecturer in Carbon Sequestration in 2008. From 2009 to 2012, he served as the executive editor of *SPE Journal*, and he has served on the SPE Editorial Review Committee in some fashion continuously since 2000.

Reviews

"This monograph [Low-Energy Processes for Unconventional Oil Recovery] is the first book after Thermal Recovery Monograph by Michael Prats published in 1982 that provides up to date and comprehensive discussions on thermal and non-thermal recovery methods of heavy/unconventional oil resources. The book has an emphasis on environmental challenges concerning the production of unconventional oil. Several cold recovery methods of chemical flooding, air injection are discussed in addition to nuclear, solar and electrical means of insitu oil upgrading. I am certain this book will be very popular as a ref. for professional engineers and a text book for undergraduate/graduate students." – Mojdeh Delshad, research professor at PGE department at University of Texas, Austin

"Heavy oil and unconventional oil recovery is increasingly under scrutiny by society because of the high energy intensity. Low-Energy Processes for Unconventional Oil Recovery is a must-read for petroleum engineers aiming to select and engineer the most efficient Enhanced Oil Recovery (EOR) technology. Technical aspects are covered in-depth on a broad range of EOR processes, together with clear and accurate guidance to evaluate CO_2 footprints." – Johan Van Dorp, consultant Enske Energy B.V., former RE consultant, Thermal EOR principal expert, Shell

Introduction

Low-Energy Processes for Unconventional Oil Recovery fills a gap in the oil and gas literature. Today in our globalized society, the oil industry has to demonstrate how oil recovery can be done responsibly over the life-cycle of the project, clearly articulating the energy efficiency as well as carbon dioxide (CO_2) and environmental footprints of the chosen recovery processes. There is no silver bullet solution, and Industry, Academia, and Governments must collaborate to pursue avenues to reduce greenhouse gas (GHG) emissions by improving energy efficiency from "well" to "wheels." The produced CO_2 can also be sequestered, but the evaluation of carbon capture and storage requires careful analysis of the additional CO_2 budgets and total energy balances.

World unconventional and heavy-oil production amounts to some 10 million B/D or almost 10% of global oil supply. Two million B/D of this is produced by means of steam injection processes using either cyclic steam stimulation, steamdrive or steamflood, or steam-assisted gravity drainage (SAGD). Many projects are on the drawing board, but need improved energy efficiency and lower CO_2 footprint to enable project sanction.

The subject has been under much research and development over the last decade and is still undergoing many developments. As such, this monograph by Reza Fassihi and Anthony (Tony) Kovscek presents a state-of-the-art analysis. Both authors have published extensively on a broad range of enhanced-oil-recovery (EOR) subjects and are recognized as experts in the subjects covered.

Dr. Fassihi is a distinguished advisor with BHP Petroleum in Houston and is responsible for subsurface technical assurance on global projects. Before this, he was the unconventional technology manager with BP. He has more than 35 years of experience in petroleum research, development and reservoir management, including waterflood and EOR projects. He has authored/co-authored more than 40 peer-reviewed papers on a broad range of petroleum engineering and research topics. He holds a PhD degree in petroleum engineering from Stanford University.

Dr. Kovscek is a professor at Stanford University since 1996 and is the Keleen and Carlton Beal Professor as well as the current chair of the Energy Resources Department. His PhD research was in chemical engineering at the University of California at Berkeley. He has authored more than 125 peer-reviewed publications, mainly focusing on enhanced-recovery processes for unconventional resources.

The authors bring together their complementing expertise to provide the reader with an in-depth discussion of a range of alternative recovery techniques. Most recovery methods are focused on heavy-oil recovery, but some have applications in light oil reservoirs as well. With the recent industry drive and focus to recover hydrocarbons from tight rock and shale resources, a chapter has also been devoted to shale oil recovery to be fully aligned with the scope of this book.

The following is a brief outline of the topics covered:

- Chapter 1 discusses the challenges of heavy-oil production. Worldwide occurrence of unconventional resources is presented by category and the importance of oil mobility is explained. A range of recovery technologies is introduced, and examples are provided of energy efficiency and CO_2 emissions.
- Chapter 2 describes technical aspects of the oil extraction methods that can be applied in unconventional oil recovery. Amongst others, it includes primary recovery, steam-based processes, polymer flooding, solvent injection, and air injection. Screening tools are provided.
- Chapter 3 is devoted to fluid and rock properties, including thermal properties and wettability. The role of oil-phase constituents and the complexity of reservoir fluid characterization are explained in detail. Several useful correlations are provided.
- Chapter 4 provides primary heavy-oil recovery tools with cold heavy-oil production. It includes a discussion on cold heavy-oil production with sand (CHOPS) and describes the importance of foamy oil behavior. Several CHOPS case studies are presented.
- Waterflooding and its derivatives, such as polymer flooding, are the subject of Chapter 5. The importance of these techniques is growing with polymer flooding being applied within ever greater oil viscosity reservoirs

with tuned injection schedules. The viscosity reducing potential of emulsions in aqueous flooding techniques is also described. The chapter is concluded with a discussion on CO_2 water-alternating-gas (WAG).

- Chapter 6 builds on Prats' monograph on thermal recovery and Butler's work on SAGD with a thorough treatment of steam injection and enhancements with steam additives. Energy efficiency and CO_2 emissions are calculated, and the improvement potential of solvent addition to steam in terms of recovery and energy efficiency is described. Recent field cases with solvent or diluent addition to steam are provided.
- Chapter 7 provides the reader with an in-depth and state-of-the-art description of air-injection techniques. It includes heavy-oil in-situ combustion and high-pressure air injection; the latter is focused on lighter oils in tight reservoirs. Oxidation kinetics and the different oxidation and cracking regimes are discussed in detail, together with laboratory techniques and field examples. The importance of selection of the right reservoirs for air injection is emphasized, with screening and forecasting tools provided. The modeling challenge is also discussed and calculation of energy efficiency and GHG emission is included. Associated field experience is described with several relevant cases, and important safety and operational aspects are clarified in detail.
- Alternative sources to heat the reservoir are introduced in Chapter 8. External heat sources, such as nuclear energy or solar heating, as well as in-situ techniques with electromagnetic heating and in-situ upgrading are presented. Energy efficiencies are compared and improvement options provided.
- In Chapter 9, important reservoir simulation challenges are covered. In a thorough discussion, complex aspects of reservoir simulation are explained in an easy to understand manner, and the intricacies in application to the complex recovery techniques that are discussed in this book are elaborated upon.
- Chapter 10 informs the reader about process facilities and operation as well as integration aspects. Important surface-facility technologies are presented with their operational parameters. The impact of the choice of the process on the energy balance and emissions is of course also covered.
- Chapter 11 describes the unconventional shale resources in terms of reservoir characterization, production mechanisms, and methods of enhancing liquid-rich shale oil recovery. Many methods discussed here are at a research phase and, hence, their field applicability is still uncertain. But, operators are working toward maturing these technologies.

I consider this publication as a significant contribution to the petroleum industry and recommend its use as a professional reference to help guide EOR project design and as a training tool for petroleum engineering schools.

Assen, The Netherlands
Johan van Dorp,
Shell Group principal technical expert for thermal EOR (2008–2016)

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Chapter 1

The Challenges of Unconventional Oil Recovery

1.1 Overview

Thermal recovery is the principal enhanced-oil-recovery (EOR) technique currently in use to recover extra heavy, heavy, and viscous crude oil (Prats 1982; Butler 1991). As crude-oil temperature increases, crude-oil viscosity decreases dramatically, thereby thinning heavy crude oil and improving its fluidity and mobility within the reservoir. In addition, thermal recovery is emerging as a technique to release oil held in the matrix of fractured and/or dual-porosity media such as diatomite (Kumar and Beatty 1995; Kovscek et al. 1997; Murer et al. 2000) and carbonate (van Wunnik and Wit 1992; Boukadi et al. 2007; Novak et al. 2007; Brown et al. 2011; Gross et al. 2011). In fractured settings, heat penetrates the matrix by conduction even if steam cannot enter because of capillarity. Accordingly, oil recovery is enhanced because heat sweeps the portions of the reservoir never contacted by injectant. In this sense, thermal recovery is unique in that oil recovery is enhanced even if not contacted directly by the injected fluid.

In most thermal recovery projects, saturated steam is the injectant of choice, although air is an interesting alternative. Also, some projects propose to add solvents to injected steam. The solvent reduces the vapor pressure and saturation temperature of the steam, potentially providing energy savings as a result of savings in steam injection rate. The solvent is also miscible in crude oil and provides additional viscosity and density reduction. In addition, to control the steam mobility in heterogenous reservoirs, foam has been added to steam in several field tests. A comprehensive analysis of steam-foam field tests indicated that steam-foam injection is most efficient in layered reservoirs (Patzek 1996; Delamaide and Kalaydjian 1996). The incremental recovery attributed to injection of surfactant to steam was an average of 3.9 bbl of oil per kg of injected surfactant.

Since the publication of the *Thermal Recovery* monograph by Michael Prats (1982), technology has expanded considerably, thereby extending classical thermal recovery techniques into more and more complex situations. For example, the drilling of horizontal wells has expanded the utility of oil drainage under the action of gravity, and steam-assisted gravity drainage (SAGD) has come into existence. In addition, air injection into reservoirs of lighter oil has been tested and shown to be successful. On the other hand, environmental challenges associated with emissions of carbon dioxide (CO_2) to the atmosphere have made the application of low(er)-energy thermal methods and cold production more desirable to shrink the so-called carbon footprint of viscous and thermal oil recovery.

This monograph is intended to be a complement to Prats' book and aims to provide updates regarding thermal applications. Because the physics of reservoir heating, heat losses to the overburden, and the phase behavior of water have remained unchanged, the reader interested in an in-depth treatment of such topics is referred to Prats (1982). What follows is a description of the unconventional oil resource base and its categorization by gravity and in-situ viscosity. The engineering and environmental challenges to produce this vast resource thereby become apparent.

1.1.1 Unconventional Hydrocarbons. Unconventional resources are categorized, as shown in **Fig. 1.1**, according to resource net energy density and technical maturity. The estimated resource size for each category, including conventional oil, is shown in **Fig. 1.2**. The initials "UCG" stand for underground coal gasification, a process for converting solid coal to combustible gases, such as methane, in the earth without mining the coal. The initials

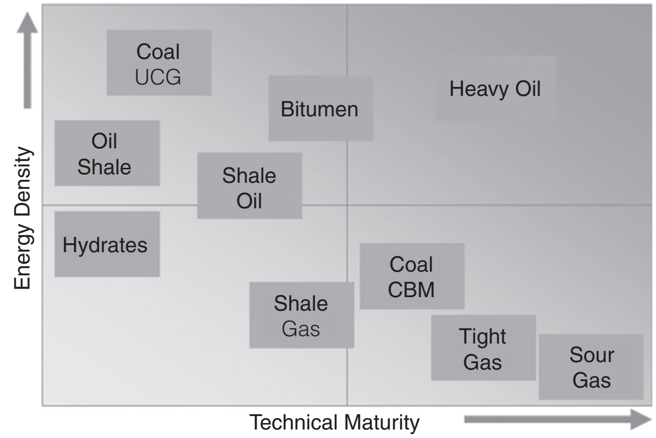


Fig. 1.1—Unconventional resources categories.

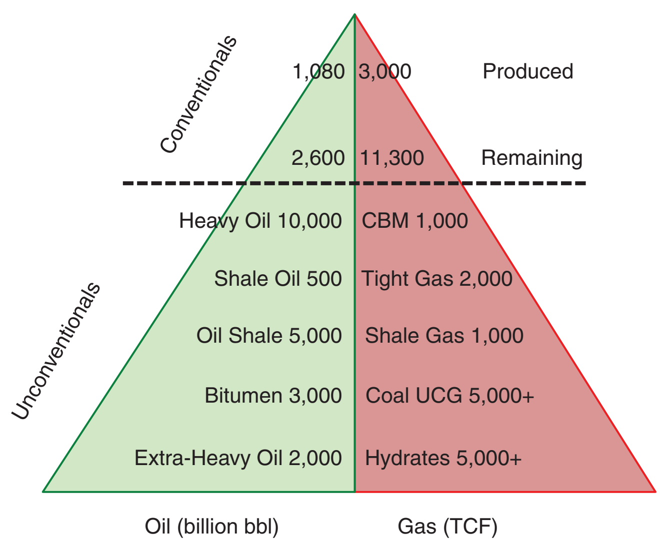


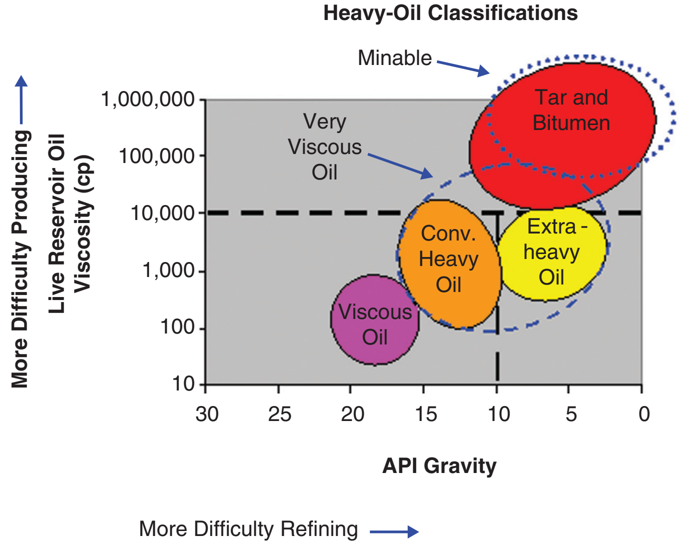
Fig. 1.2—Estimated in-place volume of unconventional resources. (Wikipedia).

"CBM" refer to coalbed methane and its recovery from coal seams. Tight gas and shale gas refer to gas resources in millidarcy- and nanodarcy-permeability rocks, respectively. The terms "oil shale" and "shale oil" also need to be clarified. Oil shale refers to fine-grained sedimentary rock containing kerogen. The latter is a mixture of organic chemical compounds that make up a portion of the organic matter in sedimentary rocks. Upon heating, chemical reactions within the kerogen result in the formation of a liquid oil and gas. The rate of heating is important in determining the gravity of the oil produced as well as the fraction of liquid created vs. gas. Shale oil refers to the liquid hydrocarbon that is held in tight shale matrices and is currently producible through the application of hydraulic fracturing. Shale oil is generally conventional oil held in nanodarcy-permeability rocks. Throughout this monograph, "oil shale" and "shale oil" are used with these distinct meanings.

This monograph specifically deals with recovery of bitumen, heavy oil, and oil shale. Shale oil and shale gas recovery are discussed in Chapter 11. Coals and hydrates are not discussed.

1.1.2 Unconventional Oil Resource Base. Density, or API gravity,* is the key distinguisher of different classes of unconventional oils. The term "heavy" is applied to any crude oil at 22.3 °API or less with a viscosity greater than 100 cp. If the crude oil is 10 °API or less and its viscosity is greater than 10,000 cp, it is referred to as "extra

* API gravity is defined as $^{\circ}API = \frac{141.5}{SG} - 131.5$, where SG is the specific gravity, that is, the ratio of crude oil to water density.



Minable hydrocarbons	Athabasca, Canada
Very viscous–not waterfloodable, no "cold flow"	Ugnu, Alaska
Very viscous–not waterfloodable, "cold flow"	Cerro Negro, Venezuela
Viscous oils–waterfloodable	Schrader Bluff, Alaska

Fig. 1.3—Classification of unconventional crude oils.

heavy" because the crude is denser than water. Natural bitumen is oil having a viscosity greater than 10,000 cp and an API gravity less than 7 °API. In comparison, conventional crude oils such as Brent or West Texas Intermediate have gravities from 38 to 40 °API (Alboudwarej et al. 2006). Low-gravity crude oils are generally more difficult to refine because they contain large concentrations of high-molecular-weight components, heavy metals, sulfur, and so on. It is crude-oil viscosity, however, that makes these oils challenging to produce because well productivity is inversely proportional to crude-oil viscosity. **Fig. 1.3** shows this relationship for some of the typical heavy and viscous oils.

Generally, these unconventional oils are not good candidates for waterflooding because of their large in-situ viscosity at initial reservoir temperature. An appropriate recovery process (steam injection, in-situ combustion, polymer, solvent EOR, and so on) is needed to improve their poor primary-recovery efficiency (see below). In contrast, viscous oil is being developed through extended horizontal drilling and multilaterals to provide acceptable production rates. Some pressure maintenance is required and is often provided by water injection, again often using nonconventional well configurations. Waterflood performance differs from that in conventional applications owing to the adverse mobility ratio and the interaction with unconsolidated shallow sands. Thus, to improve the sweep efficiency, polymer flooding has become a key low-cost, low-energy technique for heavy and viscous crude oil between 10 and 1,000 cp at reservoir conditions in fields such as Daqing in China, Marmul in Oman, and Pelican Lake/Brintnel in Canada.

For most offshore reservoirs, the heavy-oil definition is applied to more-intermediate-gravity oil. An example is shown in **Fig. 1.4**, where heavy-oil fields in the UK Continental Shelf are displayed. The lines on this graph represent equivalent productivity.

As discussed by Alboudwarej et al. (2006), unconventional crude-oil resources are generally found in shallow deposits trapped on the flanks of huge depressions known as foreland basins. Because of the lack of sealing caprocks, microorganisms react with the crude oil and change its properties. Over geological time, through biodegradation, the light- and medium-density hydrocarbon components are converted into methane and heavy oil. The latter has a greater density, viscosity, and acidity and often includes heteroatoms such as nitrogen, oxygen, sulfur, and heavy metals. Other mechanisms such as water washing and phase fractionation also participate in this process (Alboudwarej et al. 2006). Water washing refers to the dissolution of light and medium components into aquifers, thereby leaving oil with increased density.

In general, unconventional crude oils are challenging to produce with existing technologies. Also, once produced, they are price disadvantaged because considerable processing is required to refine them into fuels. The composition of unconventional oil depends on the degree of biodegradation of each resource.

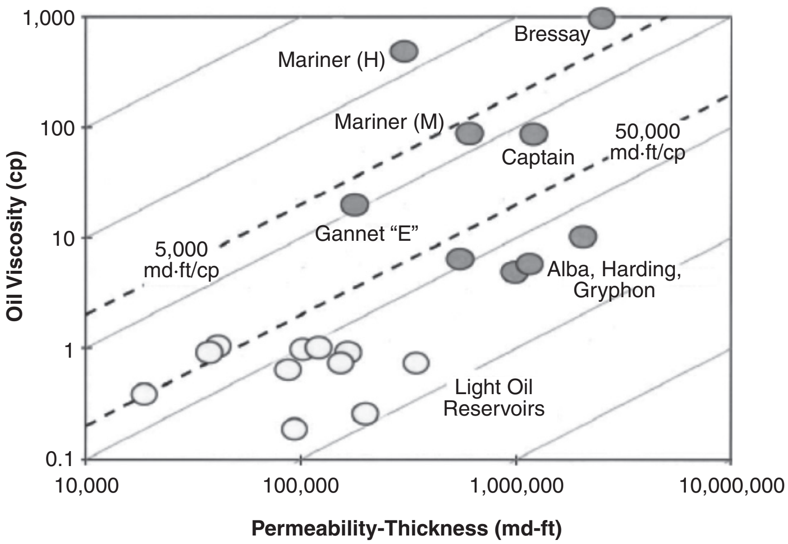


Fig. 1.4—Viscosity vs. permeability-thickness product for heavy-oil fields in the UK Continental Shelf (Jayasekera and Goodyear 2000).

Heavy oil, extra-heavy oil, and bitumen make up approximately 70% of the world's total oil resources of 9–13 trillion bbl (Alboudwarej et al. 2006). The resource sizes of bitumen, extra heavy oil, and other heavy oil are approximately 3.2, 2.5, and 0.9 trillion bbl, respectively (see **Table 1.1**). Because of large production costs, however, use of most of these resources heavily depends on crude-oil price. **Fig. 1.5** displays this interdependency for different unconventional oils.

1.1.3 Natural Bitumen and Extra-Heavy Oil. There are numerous natural bitumen and extra-heavy-oil deposits in the world. If produced on a massive scale, they are likely to be competitive with conventional oil in terms of cost. A major factor is mitigation of negative environmental impacts, the costs of which have not been completely quantified.

Natural Bitumen. According to the 2010 World Energy Council (WEC) report, natural bitumen is reported in 598 deposits in 23 countries. It occurs in both clastic and carbonate reservoir rocks and commonly in small deposits at, or near, the Earth's surface. The three Alberta, Canada, oil sands areas—Athabasca, Peace River, and Cold Lake—together contain 1.73 trillion bbl of discovered bitumen in place, representing two-thirds of world supply (WEC 2010). In addition, the Grosmont carbonate platform in Alberta contains approximately 450 billion bbl. Other locations with large volumes of bitumen are Kazakhstan, mostly in the North Caspian Basin, and Russia, mostly in the Timan-Pechora and Volga-Ural Basins. Although many more deposits are identified worldwide as evidenced by oil seepages, no resource estimates are reported.

Extra-Heavy Oil. Table 1.1 presents the geographical distribution of extra-heavy-oil deposits in the world. The Orinoco Belt in the Eastern Venezuela Basin accounts for approximately 90% of the discovered plus prospective extra-heavy oil in place, or nearly 1.9 trillion bbl. Extra-heavy-oil production accounts for more than 20% of Venezuela's oil production. Extra-heavy crude oil is deposited either as a standalone or accumulation with conventional oil.

In total, Table 1.1 shows an extra-heavy-oil and bitumen volume of approximately 5.5 trillion bbl discovered in place. This volume is slightly less but of the same order of magnitude as the estimated volume of original oil in place in the world's known conventional oil fields (WEC 2010).

1.1.4 Oil Shale. Table 1.1 shows that total world resources of oil shale are at approximately 5.5 trillion bbl of crude-oil equivalent. Oil shales ranging in age from Cambrian to Tertiary occur in many parts of the world. The deposits range from small occurrences to many billions of barrels of potentially extractable shale oil. **Fig. 1.6** shows the location of major oil shale deposits in the world (Allix et al. 2011).

Most oil shales are fine-grained sedimentary rocks containing relatively large amounts of organic matter, known as "kerogen," from which significant amounts of oil and combustible gas can be extracted by pyrolysis. Kerogen forms a complex macromolecular structure that is mostly composed of carbon, hydrogen, and oxygen, and small amounts of sulfur and nitrogen. Kerogen is mixed with varied amounts of mineral matter consisting of fine-grained silicate and carbonate minerals. It is insoluble in common organic solvents. Some oil shale may contain

	Resources (billion bbl)	Reserves (billion bbl)	Cumulative Production (billion bbl)
Extra-Heavy Oil[a]			
Latin America (mostly Venezuela)	2,448	59	15
Asia	18	1.7	0.9
Others	19	1.7	1.4
World	2,484	63	17
Natural Bitumen[a]			
North America (mostly Canada)	2,451	174	6
Asia	427	42	0
Europe	349	29	0
Africa[d]	18	1.8	0
World	3,245	246.8	6
Oil Shale[c]			2,008 mb/d[e]
North America[b] (mostly USA)	4,280	NA	0
Africa	159	NA	0
Europe	368	NA	6.3
Asia and Middle East	637	NA	7.6
Others	114		3.8
World	5,558		17.7
Shale Oil[f]			
Brazil	82	NA	
Congo	100	NA	
Russia	247	NA	
China	354	NA	
USA	3,707	NA	
World	4,786		

a. Energy Technology Systems Analysis Programme (2010)
b. Johnson et al. (2011)
c. Beckwith (2012)
d. Meyer et al. (2007)
e. World Energy Council (WEC) (2010)
f. World Energy Council (WEC) (2013)

Table 1.1—Unconventional oil resources, reserves, and production.

small amounts of bitumen. Because of its insolubility, the organic matter should be retorted at temperatures of approximately 340°C to decompose it into a synthetic crude oil and gas (WEC 2010).

1.1.5 Problems With Unconventional Oil. Unlike conventional oil reservoirs where oil generally flows easily, the low oil mobility in extra-heavy oil, bitumen, and oil shale prevents application of established displacement recovery processes to such reservoirs. The main issue is the impact of unfavorable water/oil or gas/oil mobility ratio on poor oil recovery. Thermal methods are useful as a means of lowering the in-situ viscosity of crude oil and enhancing the mobility of the oil. Other methods have also been applied with some degree of success with a low-to-moderate recovery factor. These processes are discussed in the next chapter.

There is increased sensitivity concerning environmental impacts of energy-intense recovery techniques, including the great need to reduce the carbon, water, and ground-surface-access footprint. The lengthy chain of (1) source water (shallow aquifer or river), (2) sweetening and softening, (3) steam generation and transportation, (4) produced-water treatment, and (5) water disposal (deep aquifers) has emerged as one of the key issues in many countries.

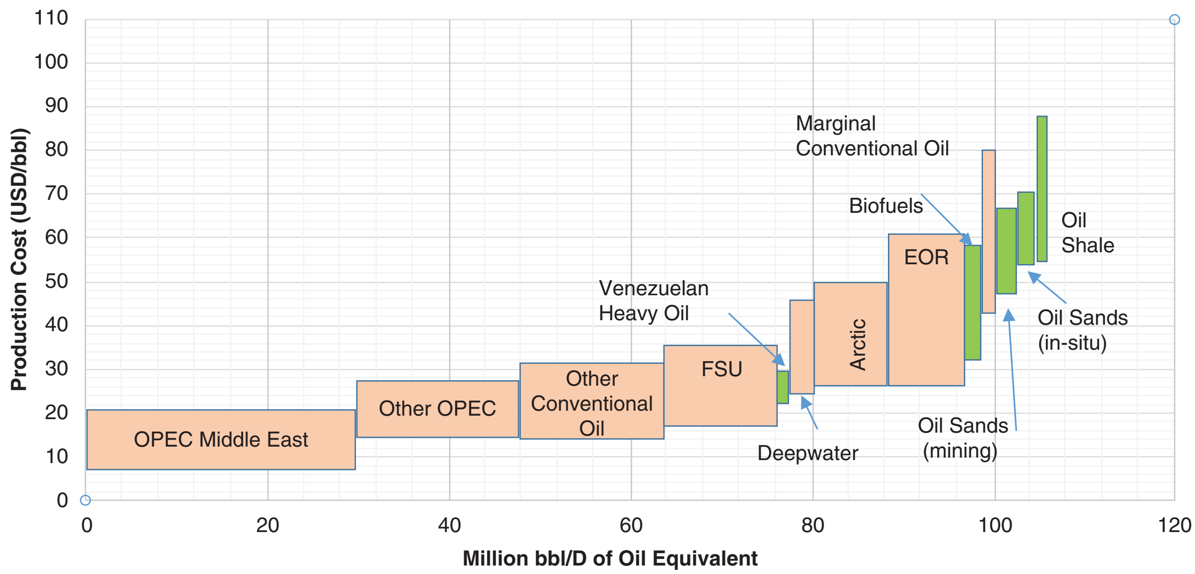


Fig. 1.5—Transportation fuels supply curve in 2020 as a function of oil price (courtesy of Booz Allen Hamilton).

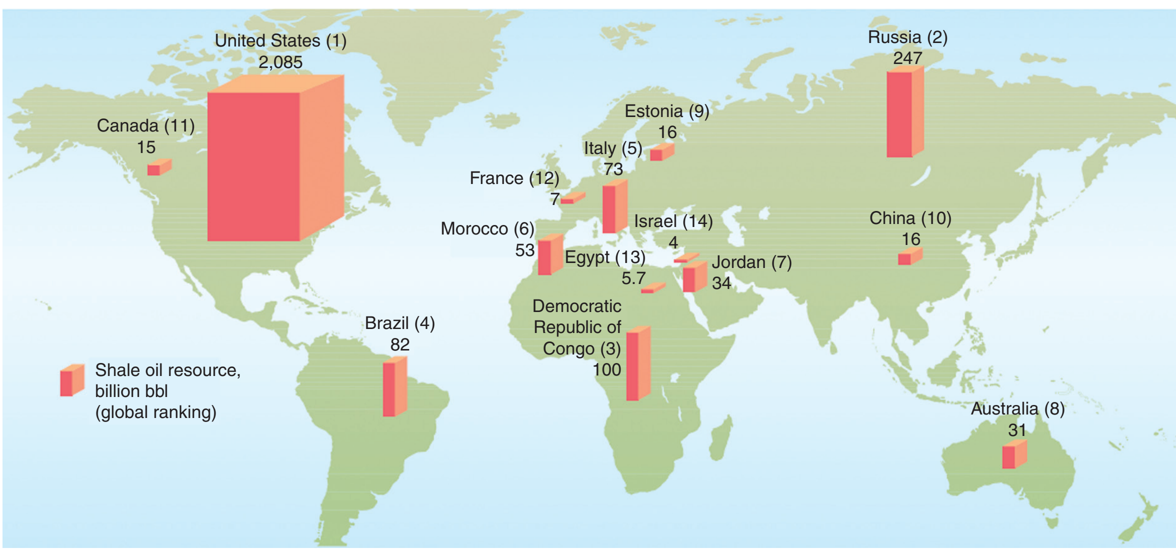


Fig. 1.6—World oil shale deposits (Allix et al. 2011).

An example of a technique that reduces all footprints is cold heavy-oil production with sand using multilateral horizontal wells.

Environmental Challenges of Unconventional Oil Production. Kovscek (2012) extensively discussed environmental issues associated with thermal recovery methods. A summary of key challenges follows.

- Water for steam generation
- Access to inexpensive and clean-burning fuel for generating steam
- Energy intensity that increases life-cycle CO_2 emissions
- Air pollution
- Public acceptance
- Surface footprint (many wells at a dense spacing in steamdrives)

Water Management. The key metric for gauging the energy efficiency of steam injection as well as estimating the water requirements is the oil/steam ratio (OSR) and its inverse the steam/oil ratio. The OSR is the volume of oil produced per volume of steam injected. The steam volume, however, is recorded as condensed water at standard conditions. Accordingly, for an OSR equal to 0.2, five volumes of water (as steam) are required to produce a volume of oil. The range of OSR in field operations generally spans from 0.1 to 0.5, implying that the water needed for steam EOR ranges from 10 to 2 volumes of water per volume of oil produced, respectively. Clearly, these estimates of water use do not account for recycling and reuse (Kovscek 2012). Notice that the energy-break-even OSR is approximately 0.08, irrespective of steam operating pressure and temperature, because the steam enthalpy only weakly depends on temperature.

To date, the reported OSRs for steam-based thermal recovery projects in Alberta, Canada, have been somewhat on the larger and more water-efficient side. Approximately 2.5 to 4 bbl of water are used for every barrel of bitumen produced (Government of Alberta 2012). Steamdrives in California generally have a lower OSR (0.15–0.3), whereas soak projects generally have better OSR.

Differences in water requirements are related to the maturity of the project, the geology of the oil-sands deposit, and so on. Oil-sands recovery operations have made active use of water recycling as well as substitution of nonpotable aquifer water to reduce volumes of fresh water needed. With recycle ratios of 70 to 90%, as little as 0.5 bbl of fresh water is needed to produce 1.0 bbl of bitumen (Government of Alberta 2012). Given the scope of expansion of oil-sands recovery operations, however, total water withdrawal from the Lower Athabasca River in Alberta has become significant. The water withdrawal was 0.74% of the annual average flow in 2010 (Government of Alberta 2012). A water management framework has capped the available water for thermal operations. In total, all oil-sands projects combined are allowed to withdraw no more than 3% of the average annual flow.

CO_2 Emission. The most important aspect currently affecting thermal recovery seems to be the carbon footprint of heavy oil and thermal recovery compared with conventional recovery methods. This arises from the fuel used to generate steam or to compress air for in-situ combustion. In addition, upgrading the crude oil adds to the carbon footprint. Water treatment for steam generation can be as high as 10–20% of the energy footprint. Also, in in-situ combustion, the flue gas produced and vented dominates the CO_2 emissions. Thus, greenhouse gas (GHG) emissions depend on type of crude oil as well as specifics of the recovery process, specifics of steam generation (if applicable), and so on. **Fig. 1.7** presents a comparison of average emissions estimates for Canadian bitumen, California thermal operations, and conventional oil production. This is based on full-cycle usage, including the final refined products. As shown, generally the production-related GHG emissions are less than the fuel emissions.

Using Californian crude as an example, Kovscek (2012) noted that equivalent CO_2 life-cycle emissions, including steam-based thermal recovery, upgrading, refining, distribution, and combustion of the resulting gasoline, are at approximately 105 to 120 g of CO_2/MJ of gasoline on a reformulated blendstock for oxygenate blending (RBOB) and lower heating-value basis (Brandt and Unnasch 2010). This quantity includes cogeneration of heat and electricity using natural gas and is typical of heavy-oil recovery in California. The portion of this total CO_2

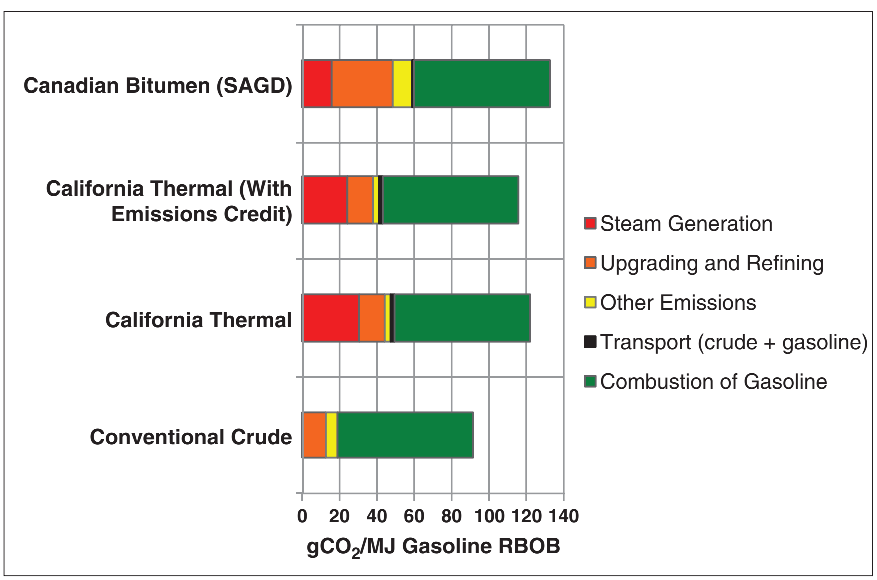


Fig. 1.7—Greenhouse gas emissions from steam-based EOR compared with conventional recovery (Kovscek 2012). Data from Brandt and Unnasch (2010); Brandt (2012). Canadian bitumen estimates obtained using GHGenius (Brandt 2012).

emission associated with the thermal recovery aspect using natural gas as the fuel is estimated as an average 23.8 g/MJ of gasoline RBOB after taking emissions credits for cogeneration (Brandt and Unnasch 2010). The range of emissions stemming from steam generation is placed at 13.0 to 25.5 g/MJ gasoline RBOB and varies mainly with OSR.

The Canadian thermal recovery operation is estimated to lie in a similar range, with equivalent life-cycle CO_2 emissions of 100 to 130 g of CO_2/MJ of gasoline RBOB (Brandt 2012). Of this figure, approximately 32% of the equivalent CO_2 emissions result from extraction using heat, upgrading, and refining. Bitumen is a lower-gravity resource in comparison to heavy oil and is more difficult to produce.

For comparison, conventional oil-refinery feedstock when subjected to the same analysis has equivalent CO_2 life-cycle emissions ranging from 85 to 105 g of CO_2/MJ of gasoline RBOB (Brandt 2012). In this case, extraction, refining, and upgrading contribute only 17% of the emissions. Thus, the conventional case is about one-half that of thermal recovery for these components.

Combustion of the fuel amounts, on average, to approximately 70 g of CO_2/MJ of gasoline RBOB. In addition, the energy content of gasoline is approximately 124 MJ/gal (US). Gasoline produced from oil recovered using thermal recovery results in oilwell-to-gasoline-tank emissions of approximately 13.0 to 14.9 kg CO_2/gal (28.6 to 32.8 lbm/gal). In contrast, conventionally produced crude oil emits 10.5 to 13.0 kg CO_2/gal (23.3 to 28.7 lbm/gal). Brandt and Unnasch (2010) characterize the benefits of cogeneration in terms of the electricity that is being displaced from the electrical grid by the electricity produced in the oil field through cogeneration. If, for instance, natural gas is used for cogeneration and coal-fired electricity is displaced, then the life-cycle emissions are estimated as roughly 115 g of CO_2/MJ of gasoline RBOB. Without cogeneration, the life-cycle assessment emissions rise to 121 g of CO_2/MJ of gasoline RBOB.

In summary, the combustion of fuel to generate steam for thermal oil recovery adds a significant component to overall CO_2 emissions. At present, most heat for thermal recovery is generated using natural gas that is the least carbon-intense fossil fuel. Hence, substitution of other fossil fuels only increases the total CO_2 emissions. The process of cogeneration of electricity and steam is substantially more complicated in comparison with other methods of steam generation but does result in substantial reduction in CO_2 emissions.

Fuel and Air Pollution. The fuel used to fire any steam generator affects the carbon footprint of steam EOR as well as the generation of other undesirable air pollutants (e.g., SO_x, NO_x, particulates). On the basis of energy content per unit of CO_2 generated, natural gas is the least-carbon-intense fuel, followed by lease crude oil. Coal or petroleum coke as a boiler fuel produces approximately twice as much CO_2 in comparison with natural gas. On the other hand, natural-gas use creates the least amount of pollution. If, however, lease crude or petroleum coke is used to fire a steam generator, flue gases may contain substantial sulfur in the form of SO_2, SO_3, and particulates. Further, various standardized technologies are available to reduce emissions of nitrogen oxides (NO_x). The sulfur oxides in flue gas are readily removed by passage through a wet scrubber that absorbs the sulfur oxides and neutralizes the acid by reaction with alkaline components of the wet-scrubbing solution. Sarathi and Olsen (1992) provide additional details. Therefore, the current practice of employing natural gas appears to be the most environmentally friendly from a fossil-fuel-powered steam generator perspective. On the other hand, the petroleum coke produced from bitumen is low cost and insulates operations from variability in the cost of natural gas.

Public Acceptance. Potentially the greatest factor that may limit current and future thermal recovery operations is public acceptance of the emissions increases relative to conventional and other alternative fuels—that is, the roughly 20 g CO_2/gal increase outlined in the preceding subsection. Alternatives are available to mitigate some aspects of the carbon footprint, as discussed in this monograph.

***Other Challenges*.** Aside from environmental challenges, there are other factors to consider when developing heavy oil. Some of these factors are included in the following list.

- Limited reservoir energy gives a low primary-recovery factor.
- There is unfavorable mobility for displacement processes.
  - Heterogeneities can dominate reservoir performance.
  - Conformance of injected fluids needs to be managed to obtain acceptable reservoir sweep.
- Some low-energy EOR processes are still unproven.
- Gravity helps sweep but gives small drainage rates.
- If feeding an upgrader, one must produce crude oil on plateau rate to meet the capacity requirements of the upgrader.

1.1.6 Development Planning. Unlike development of conventional reservoirs, the limitation on energy supply, production facilities, and reservoir access imposes a modest production plateau on development. Hence, heavy oil and bitumen are produced over an extended period of time generally at or near a plateau rate, as shown in **Fig. 1.8**. This is achieved by phasing in new patterns and projects over time, as represented by the different colors, to combat the steep individual declines. In this way, an overall plateau rate is maintained for as long as possible to keep facilities running at capacity. The steep decline in each phase is caused by poor pressure response to the stimulated reservoir volume from the virgin sections of the reservoir.

1.1.7 Technology Landscape for Heavy-Oil and Bitumen Production. A full listing of the applicable technologies to produce unconventional resources is shown in **Fig. 1.9**. If the resource is sufficiently shallow, mining

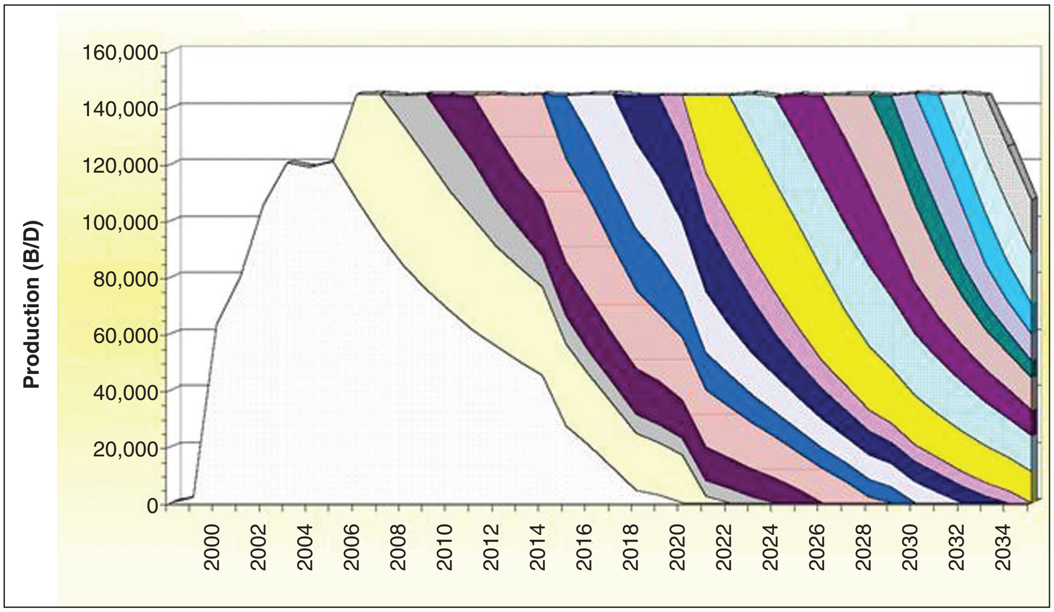


Fig. 1.8—Typical heavy-oil development plan.

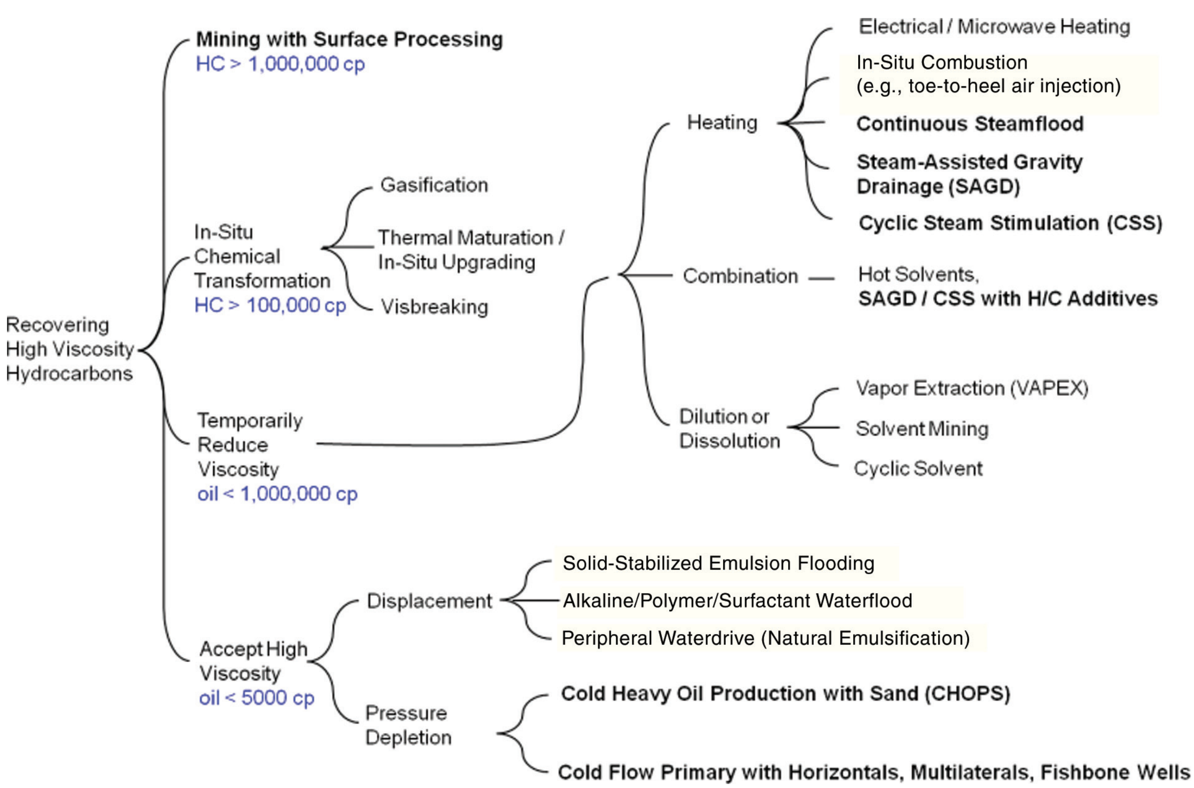


Fig. 1.9—Production methods for unconventional resources.

through removal of the overburden is a possibility for resources with a large concentration of hydrocarbon per unit volume of rock or sand. In-situ chemical transformation is especially attractive because it presents the possibility to alter the chemical makeup of the hydrocarbon in such a way that the product is upgraded relative to the initial hydrocarbon in place. The pathway of temporarily reducing viscosity usually involves heat or solvents, or both heat and solvents.

Some of the existing guidelines for application of these methods to particular unconventional resources are listed in **Fig. 1.10**. The huge in-place volume and low primary-recovery factor requires advances in current production technologies. In fact, we might need transformational technologies to be able to develop some existing fields. Some of the enabling and transformational technologies for the current recovery schemes are presented in **Fig. 1.11**.

Setting	Oils < 10,000 cp in High-Permeability Pay		Oils > 10,000 cp or Oil in Lower-Quality Pay		Kerogen in Oil Shales or Very Viscous Oils in Tight Rock	
	Process	**RF (%)**	**Process**	**RF (%)**	**Process**	**RF (%)**
Current	Primary depletion through horizontal and multilaterals	5–8	CSS in laminated play	20–30		
	CHOPS through vertical wells	5–8	Steam injection in medium pay	30–40		
Incremental Advancements	Extension of enhanced waterflooding to 100–5,000 cp oil	15–25	CSS with additives	30–40		
			Steam with additives	30–50		
			SAGD with additives	40–60		
Transformational	Low-energy solvent mining	35–50	Post-SAGD air injection	>50%	Thermal in-situ upgrading	30–40
	Post-CHOPS air injection	>50			Low-energy in-situ upgrading	30–40
	Post-CHOPS solvent injection	>50				

Fig. 1.10—Guidelines for application of different recovery processes.

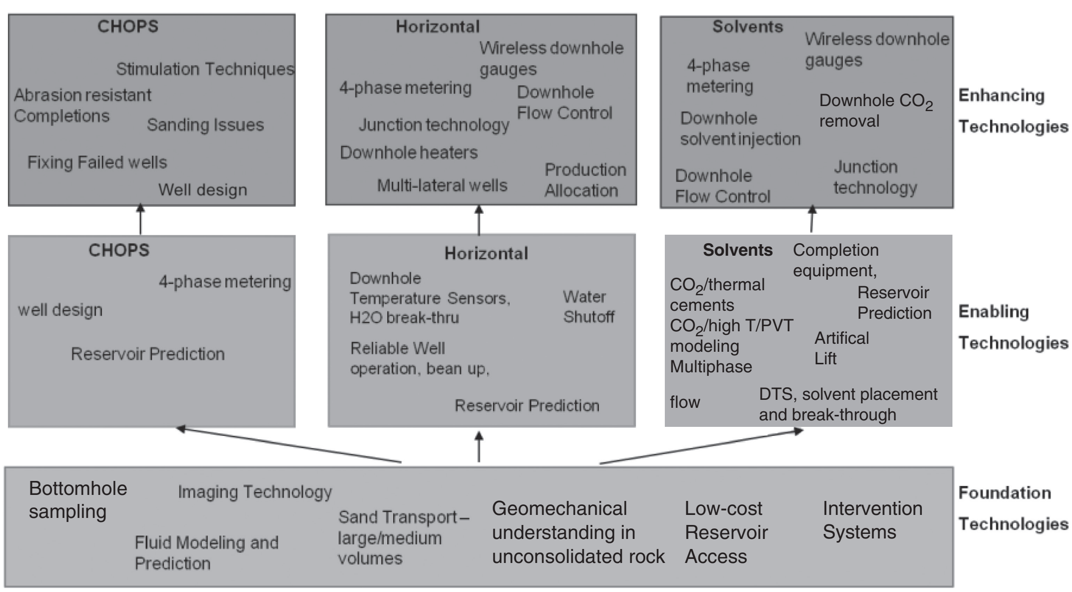


Fig. 1.11—Application of different technologies to recovery techniques.

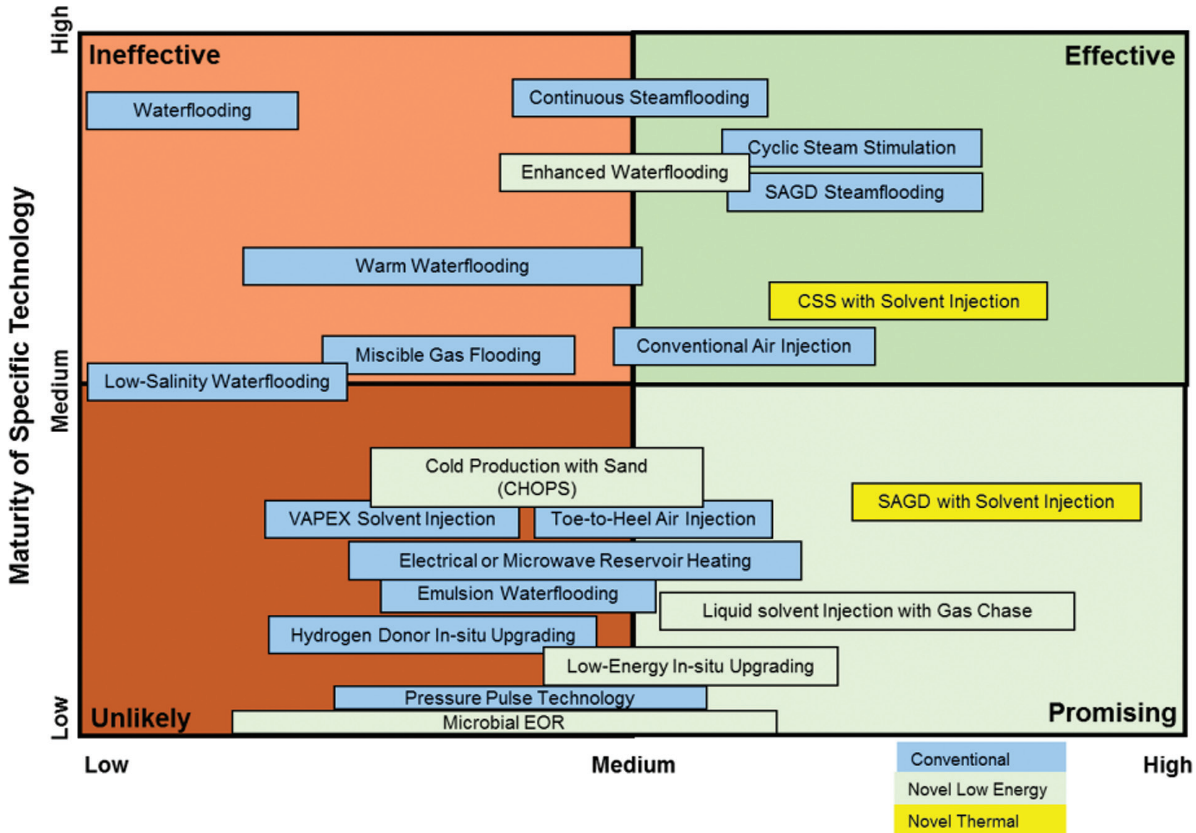


Fig. 1.12—Effectiveness and maturity of different recovery technologies.

1.1.8 Effectiveness of Current Depletion Technologies. Many of the recovery technologies shown in **Fig. 1.12** are still in their infancy. Further, some of these technologies are more effective than others in mobilizing unconventional oil. Effectiveness (i.e., recovery factor) strongly correlates to in-situ viscosity, with greater effectiveness at lower viscosity. A relatively objective assessment of the effectiveness of existing technologies is shown in Fig. 1.12. Condensing solvent injection is covered under the vapor-assisted petroleum extraction process.

1.1.9 Integrated Approach to Heavy-Oil Production. Because of the interplay between heavy-oil composition and its suitability as a feedstock for refineries, it is important to have an approach to heavy-oil development that is integrated across the spectrum from drilling through production, surface processing, and refining. Sometimes, a solvent that might have been used for improved oil recovery fouls the catalyst in an upgrading or refining facility. Also, use of a certain well completion might release sand particles that could cause severe abrasion in the surface equipment. A suggested integrated approach is shown in **Fig. 1.13**.

1.1.10 Monograph Summary. The balance of this monograph revolves around current understanding of how the engineering and environmental challenges of unconventional oil production are met. Successive chapters are organized around the following topics.

- Recovery methods for unconventional oils from primary recovery to EOR are reviewed in Chapter 2. Significant emphasis is placed on thermal recovery because of the beneficial effect of temperature on crude-oil viscosity.
- Chapter 3 presents an overview of unconventional oil fluid and rock properties relevant to established advanced recovery methods. Such information is needed for physical understanding, analytical models, and numerical simulation.
- Cold heavy-oil production, including techniques to maximize primary recovery, is presented in Chapter 4.
- Chapter 5 extends discussion of cold recovery processes to improved oil recovery and EOR. Topics range from waterflooding to enhanced methods, including polymer flooding, emulsion flooding, and water-alternating-gas injection processes for mobility control.

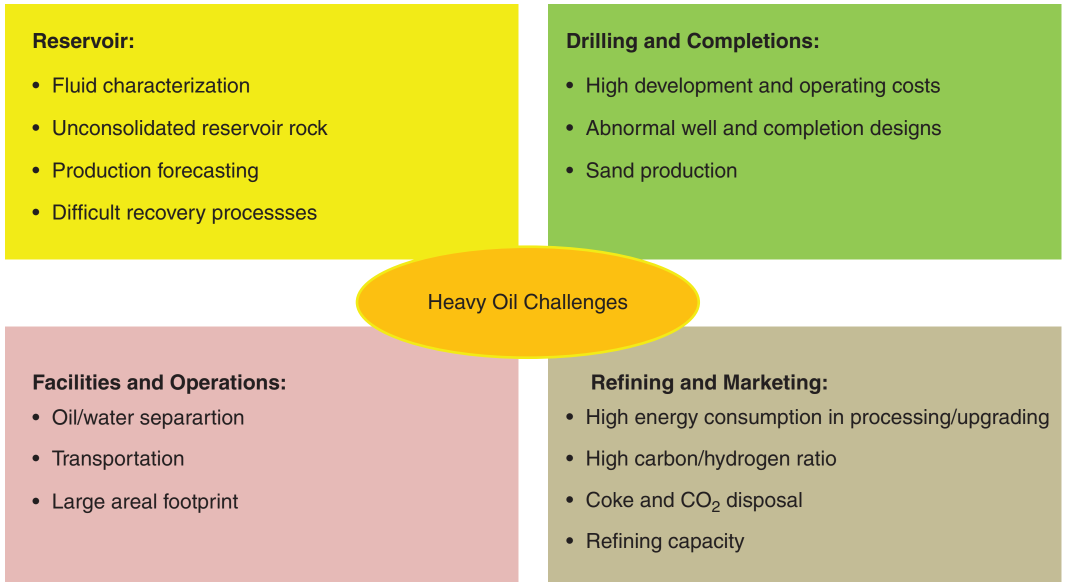


Fig. 1.13—Integrated development of unconventional oil.

- Steam injection ranging from classical steamflooding to SAGD optimization and surface-facilities considerations are discussed in Chapter 6.
- Chapter 7 presents air injection for heavy and viscous oils, the benefits and challenges of the process, and work flows for bringing the process out of the laboratory to the field.
- Alternative means of supplying thermal energy to the reservoir are surveyed in Chapter 8. Topics range from nuclear energy to solar thermal energy to electrical heating, including in-situ upgrading of heavy hydrocarbons.
- Mechanistic simulation has greatly improved our understanding of advanced recovery processes at core, project, and field scale. Chapter 9 summarizes current understanding and approaches to simulation at these various scales.
- Although surface facilities and operations are mentioned throughout the text, Chapter 10 is devoted to this topic.
- Finally, Chapter 11 reviews the state of the art in the application of EOR in unconventional liquid-rich shale resources.