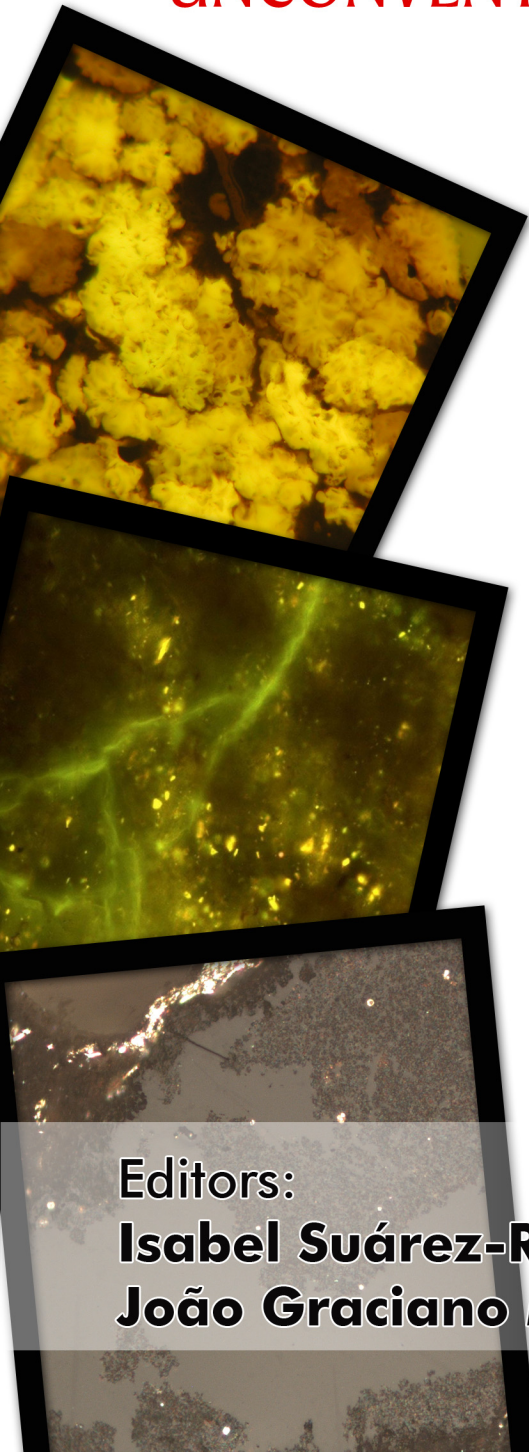


GEOLOGY: CURRENT AND FUTURE DEVELOPMENTS

VOLUME 1

THE ROLE OF ORGANIC PETROLOGY IN THE EXPLORATION OF CONVENTIONAL AND UNCONVENTIONAL HYDROCARBON SYSTEMS



Editors:
Isabel Suárez-Ruiz
João Graciano Mendonça Filho

Geology: Current and Future Developments

(Volume 1)

*(The Role of Organic Petrology in the Exploration of
Conventional and Unconventional Hydrocarbon Systems)*

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The Role of Organic Petrology in the Exploration of Conventional and Unconventional Hydrocarbon Systems

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PREFACE

Welcome to the e-book entitled “The Role of Organic Petrology in the exploration of Conventional and Unconventional Hydrocarbon Systems”. This book is intended to serve as a basic guide for all those who might be interested in one of the hot topics of applied organic petrology: hydrocarbon systems (conventional and unconventional). The book explains what hydrocarbon systems are, how they form and how and why they are investigated by means of organic petrology, a branch of Earth Science that started as coal petrology at the beginning of the 20th Century.

The authors who have contributed to this book are Senior Organic Petrologists with a broad experience working in this field for Petroleum Companies, Universities and Research Institutions, or for Private Laboratories linked to these Oil and Gas Companies.

The Editors of this book would like to thank Fariya Zulfiqar, Assistant Manager of Bentham Science Publishers, for her kindness, her support and for giving us the opportunity to publish this volume. We would also like to thank all those who, in one way or another, contributed to making this work a success, many of whom are included in the acknowledgement section of the chapters.

Above all, we hope you enjoy this book and find it inspirational in your work

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INTRODUCTION

Fossil fuels are currently the world's primary source of energy and have contributed to global economic development over the past century. Today, fossil fuel companies are still exploring, drilling and/ or mining for these energy sources and new and innovative technologies have been developed to improve the efficiency of extracting hydrocarbons (oil and/or gas) particularly from the so-called unconventional resources. Conventional hydrocarbon systems or conventional reservoirs are those that can be exploited by means of wells with little need for stimulation treatment or heat injection. Unconventional resources, on the other hand, are those where hydrocarbons are extracted mainly by means of large-scale hydraulic fracture treatments either because the hydrocarbons are located in geological formations of very low permeability and porosity or because they have a high viscosity.

For years, organic petrology was successfully used as a tool for the characterization of organic-rich rocks in the exploration for oil and gas in conventional systems, although in constant competition with other faster geochemical analytical techniques. Nowadays, organic petrology has been converted into a powerful tool for characterizing unconventional hydrocarbons systems of all types, providing information where other analytical techniques are ineffective. In addition, it is worth mentioning the solid background that the organic petrologist must possess to meet the challenges posed by these unconventional resources which are sometimes very complex. All of these factors have inspired the creation of this book.

Intended Readership

The purpose of this book is to provide a broad and comprehensive pool of information on the role that organic petrology plays in the investigation of geological formations that might produce and/or accumulate hydrocarbons (oil and/or gas).

Organic petrology is one of the disciplines that by means of organic petrography, palynofacies analysis and the visual assessment of kerogen, integrates a multidisciplinary set of approaches for the exploration and evaluation of fossil fuel resources, regardless of whether they can be subsequently exploited by conventional or unconventional procedures.

As can be seen from its contents, the way it has been organized and its didactic character, this book is intended for a wide audience that includes scientific researchers and teachers of geology, applied organic petrology and hydrocarbon exploration, graduate and undergraduate students of these disciplines, and engineers and technicians working in specialized laboratories dedicated to oil and gas exploration.

Organization of the Book

This book describes in detail the role of organic petrology with its varied methodologies applied to the exploration of sedimentary systems containing fossil fuels.

The book contains eleven chapters organized in such a way that each chapter has its own identity and contains enough information to justify being studied independently of the others. However, all the chapters together make the book an even more powerful tool with abundant information related to the role of organic petrology in the field of hydrocarbon exploration.

The first two chapters of the book are focused on the fundamentals of organic petrology while the remaining chapters deal with real cases around the world where organic petrology is applied to different hydrocarbon systems.

Chapter 1 presents a general view of what forms the basis of fossil fuels: sedimentary organic matter. The origin of organic matter, and the conditions necessary for its production, accumulation and preservation are explained together with the processes of thermal transformation during its geological history with special emphasis on the steps in which organic matter generates hydrocarbons (oil and/or gas). This chapter pays special attention to kerogen and kerogen types, although this is a recurring concept mentioned in most of the other chapters. It explains how kerogen is investigated by means of organic petrology techniques, particularly by transmitted white light and fluorescence mode microscopy in order to assess and classify the individual organic components and their associations (via palynofacies analysis and the visual assessment of kerogen) and to allow a proper assessment of the paleoenvironmental deposition and thermal maturity of the sedimentary sequences with oil and gas potential.

Chapter 2 is strictly focused on the study of organic matter (i.e., dispersed organic matter – DOM, or matter concentrated in coal) by means of organic petrography in reflected white light and fluorescence mode. The petrography of DOM, the methodology employed, sample preparation, and the identification and diagnosis of its organic components (macerals) as well as zooclasts, zoomorphs and secondary organic products are explained in some detail. This chapter also discusses the petrographic assessment of thermal maturity by means of vitrinite reflectance, and its advantages and limitations in relation to other maturity parameters. Thermal maturation is fundamental to understanding petroleum systems (hydrocarbon generation, migration, accumulation and preservation) and basin dynamics. A scheme illustrating the correlation between optical and geochemical maturity parameters and the phases of oil and gas generation and different coal stages is included at the end of the chapter.

Chapter 3 is devoted to oil shales. It describes oil shales as sedimentary rocks containing immature organic matter from the point of view of hydrocarbon generation. They are organic-rich, fine-grained sedimentary rocks with kerogen from which liquid hydrocarbons could have been produced if they had evolved under natural conditions. Currently they can produce hydrocarbons if subjected to unconventional processes. Most conversion technologies involve heating the shale in the absence of oxygen to a temperature at which kerogen decomposes (pyrolysis) into gas, condensable oil, and a solid residue. This usually takes place between 450 °C and 500 °C. Oil shales have attracted attention as an alternative source of oil when the price of crude oil is high. Although oil shale deposits are found worldwide it is Estonia and China that have well-established oil shale industries, while Brazil, Germany, and Russia also utilize oil shale to some extent. This chapter includes examples of the application of organic petrology to the investigation of oil shales in different locations.

Chapter 4 deals with source rocks with mature organic matter, the different types of source rocks and their petroleum potential. A petroleum source rock is described as an organic-rich sedimentary rock which has the capacity to generate and expel liquid and/or gaseous hydrocarbons. These rocks are unevenly distributed through geological time but the Upper Jurassic and Cretaceous sedimentary intervals have generated a large part of the known reserves worldwide. These intervals with source-rocks include highly prolific world class marine (shale and carbonate) and lacustrine source rocks. Emphasis is given to the characterization of kerogen in potential or proven source rocks as a fundamental step for petroleum exploration. Thus, this chapter describes the organic petrography of kerogen in different types of source-rocks and establishes links between petrographic composition, kerogen type, organofacies, and generation potential. All this is illustrated with examples of source rocks from various locations in the world and different ages. The final section of the chapter describes the petrographic indicators of petroleum generation. The characterization of kerogen in potential or proven source rocks is therefore fundamental for petroleum exploration and is commonly used to evaluate a source rock

Chapter 5 explains how organic petrology methods are applied to characterize some selected shale oil and shale gas reservoirs (the so-called “the magnificent nine”) in the US. These reservoirs have been commercially exploited for many years. They were selected on the basis of variations in their thermal maturity, their organic richness, kerogen type(s), depositional environment, age, and mineralogical composition. Particular emphasis has been placed on the role that organic petrology plays in predicting the type of hydrocarbons (oil, wet gas/condensate liquids, and dry gas) that these shale reservoirs will produce. Also explained is the use of the reflectance of solid bitumen and zooclasts from Lower Paleozoic shales, to determine accurately the correct degree of thermal maturity and to predict the hydrocarbon products that can be expected. The transition of dispersed organic matter from the early oil window through the condensate and wet gas stages to the dry gas window is illustrated through a series of images from some selected plays. This chapter also explains the importance of porosity in the matrix of shale reservoirs and its role in providing storage sites and interconnected migration pathways even in cases of high thermal maturity.

Chapter 6 deals with shale oil resource systems and illustrates them using the example of La Luna Formation of Cretaceous age located in Colombia. The petrological study of this system includes organic petrography, palynofacies analysis and the visual assessment of kerogen, (coupled to Rock-Eval pyrolysis data) to define the organic matter/kerogen types, their richness, provenance, paleosedimentary environment and thermal maturity. The complexity of these systems is explained in terms of organic composition because they contain the primary organic matter (kerogen) and also secondary products originated from the thermal degradation of the organic matter. Organic petrography was the only method by means of which a high content in solid bitumen could be accurately identified in this shale oil reservoir. Solid bitumen is a critical organic component in the development of the organic porosity, which is important because it contributes to the routes of migration of hydrocarbons as well as to the ability to retain hydrocarbons (oil/gas in place). This contribution also illustrates the capacity of organic petrology through its various methodologies to solve and clarify erroneous interpretations based on data used as proxies for organic petrology information.

Chapter 7 focuses on the application of organic petrology to high-maturity shale gas systems, and includes well known examples from the US and other parts of the world, such as Europe

and China. Special emphasis is also given to solid bitumen as the main component of the remnant organic fraction in these systems. The petrographic characteristics of solid bitumen at this stage of organic maturity are also described. Moreover, the chapter also refers to the application of other types of microscopy such as high magnification SEM for characterizing organic porosity and as a mean of complementing the information on the distribution of organic matter. Mention is made of the application of organic petrology techniques in North American shale gas systems and elsewhere in the world to delineate thermal maturity windows via reflectance measurements. This chapter also includes a large, updated reference section on shale gas systems.

Chapter 8 focuses on the world-class tight gas play in the Western Canadian Sedimentary Basin, The Montney Formation (Early Triassic) that is mainly composed of siltstone. A multidisciplinary study including organic petrology has shown that the reservoir quality in the gas window of the Montney tight gas siltstone is strongly influenced by the pervasive presence of solid migrabitumen, the main component of organic matter. Solid bitumen represents a former liquid oil phase which migrated into intergranular pore spaces and was subsequently thermally degraded by burial and increase in temperature. The presence of solid bitumen has affected the reservoir quality of this Formation by obstructing porosity and hindering fluid flow. The proportion of solid migrabitumen filling the pores is expressed as bitumen saturation which controls the pore throat size and absolute permeability. This chapter shows that the reservoir quality in the economically key porosity range of 3-7% of the Montney tight gas is influenced more by bitumen saturation than by conventional determinants of porosity and permeability such as grain size, sorting, clay content and cementation. The concept of pore-occluding solid migrabitumen is an important (negative) control of reservoir quality and is applicable for evaluating other tight gas plays.

Chapter 9 addresses the topic of coal bed methane. Coals hold a unique position in conventional and unconventional hydrocarbon systems in that organic matter forms the bulk of the rock and organic petrology is therefore an essential part of reservoir characterization. This is because understanding the variability of organic matter is the key to understanding the variability in gas content and gas composition. This chapter describes the generation of coalseam gases (thermogenic gas and biogenic gas generation) and the mechanism of gas storage by coal. Because gases within coals have a dominant storage mechanism of adsorption within the fundamental structure of organic matter the importance of coal lithotypes in relation to gas distribution and pore systems is discussed. The same applies to coal macerals, associated porosity, adsorption capacity, and gas generation. Moreover the importance of coal rank as the primary factor governing the generation of thermogenic gases is also pointed out. Description of coal seams at all levels, from macroscopic through to microscopic scale is essential for understanding the variability of coalseam gas content, generation, composition and distribution.

Chapter 10 discusses one of the few existing examples of the application of organic petrology to the investigation of spent source rocks in a paleo-petroleum system in the Cameros basin. This is an inverted extensional basin of the intraplate Iberian Chain formed during the Mesozoic Iberian rift (Late Jurassic-Early Cretaceous) in Spain. The source rocks of this basin have exhausted their ability to generate hydrocarbons due to their overmature stage and the most relevant accumulations of hydrocarbons are a small number of tar sandstones in the post-extensional rift deposits. Evidences of the migration of hydrocarbons have been found in

fractures filled with solid bitumen and small patches of bitumen detected by optical microscopy. The type of organic matter initially contained in the rocks has been inferred by microscopic analysis and vitrinite reflectance data have been used to differentiate the thermal maturity conditions that existed in the basin. The alteration textures detected in the organic matter are attributed to the circulation of hot hydrothermal fluids during the evolution of the basin and to anomalous trends in temperatures. Petrographic information has provided the necessary data to reconstruct the thermal history of this basin and validation by numerical modeling has led to a better understanding of the geodynamic evolution of the area. It is shown that organic petrology contributes to an understanding of the evolution of this type of spent source-rocks by explaining the causes behind the deactivation of petroleum systems and the total transformation of organic matter.

Chapter 11 concludes with a summary of prospects for shale resource plays. In this section the role of organic geochemistry coupled to organic petrology is emphasized.

It is hoped that the contents of this book will serve as a useful guide to the reader and that the knowledge it imparts can be directly applied to other basins with analogous types of rocks.

About the Editors

Dr. Isabel Suárez Ruiz is a scientific researcher and Head of the Organic Petrography Laboratory at the National Coal Institute (INCAR-CSIC, Spain) working in the field of basic and applied organic petrology. She is a geologist and was awarded her PhD in 1988 from the University of Oviedo (Spain) for her doctoral thesis on Jurassic oil shales and source rocks in North Spain. She has spent extensive periods of time carrying out research in the field of petrology and organic geochemistry on rocks containing dispersed organic matter, coals, and solid residues from coal utilization, in well-known laboratories in France (Orléans, post-doctoral studies) and in the United States (SIU at Carbondale in Illinois, as Adjunct Assistant Professor of Geology; and CAER in Lexington, Kentucky as Visiting Scientist). She also spent shorter periods of time in the Mexican Institute of Petroleum (Mexico DF, Mexico) and in the Colombian Institute of Petroleum, ICP-ECOPETROL (Bucaramanga, Colombia) working on organic petrology applied to conventional and unconventional hydrocarbon systems. Moreover, she has developed multiple international collaborative projects (in USA, France, Portugal, Mexico, Peru, Colombia, ...) and several national projects with Universities, Research Institutions, and Companies related with fossil fuels in Spain. She is also a member of Scientific International Committees, and a member of the Coal Advisory Group of the Research Fund for Coal and Steel (RFCS) Program of the UE. For several years she was the Chair of Commission III of the International Committee for Coal and Organic Petrology (ICCP), Convenor of the Coal Blends Accreditation Program-CBAP and coordinator of two working groups. She was also Vice-president and President of The Society of Organic Petrology (TSOP) and currently she is the Chair of its Research Committee. She has been advisor for national and international PhD Theses and Master works in Geology and has contributed to the Master Courses in Natural Resources at the Oviedo University in Spain. She is author and co-author of a large number of peer-reviewed papers (more than one hundred), book chapters, the editor of two books and two ATLAS related to topics of coal and organic petrology. In recent years she has received several international awards in recognition of her scientific and research work and contributions to science, one of which was The Organic Petrology Award from ICCP in 2006.

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Organic Matter: Concepts and Definitions

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Abstract: The concept of sedimentary organic matter, as well as the definitions and meanings of different organic facies have become an important tool in paleoenvironmental characterization, basin analysis and fossil fuel exploration. The application of this concept is the best way to integrate the techniques of microscopy to the study of kerogen contained in sedimentary rocks. The present chapter aims to provide a general view of sedimentary organic matter in relation to the techniques used for its application in the field of geosciences, with special emphasis on its contribution to both fundamental and applied scientific knowledge. Organic petrology is a branch of Earth Science that studies the organic matter present in sedimentary sequences, particularly in coal (concentrated organic matter) and finely disseminated in sedimentary rocks (dispersed organic matter - DOM) by using a set of petrographic methods generally in combination with various geochemical analytical techniques. The parameters obtained from petrological studies are important for defining the organic facies, geothermics and paleogeography of sedimentary basins, for investigating the geological structure, the present and past thermal regimes of the earth's crust as an aid to basin analysis, for assessing the mining and utilization of coal, and for the exploration of fossil fuel resources. All this explains the rapid development of organic petrology [1]. Thus, organic petrology studies based on the presence and concentration of sedimentary organic matter in both conventional and unconventional hydrocarbon systems have become, in recent years, a powerful tool for the characterization of the depositional paleoenvironment as well as for the evaluation of sedimentary sequences with oil and gas potential. Although the scope of organic petrology is broad, it employs just a few fundamental principles, one example of which is organic content characterization that is used to assess the type and quality, and thermal maturity of kerogen.

Keywords: Organic matter, Thermal maturity, Kerogen, Organic petrology, Optical microscopy.

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INTRODUCTION

World reserves of oil and gas seem to be limitless and research and development fields in the hydrocarbon industry have increased their operational efficiency in the search for new reserves.

Petroleum prospecting in the world today covers a wide range of sectors but the exploration, extraction, primary treatment, refining, transport, and exploitation of oil and natural gas are the major mechanisms that sustain the oil industry. Studies related to oil and gas exploration and exploitation have become crucial to the energy sector, mainly in relation to the pursuit of self-sufficiency in production.

Given this scenario, a multi and interdisciplinary approach to the characterization of sedimentary organic matter to achieve a better understanding and characterization of source and reservoir rocks in both conventional and unconventional exploration would contribute to the discovery of oil and gas occurrences. Success in finding conventional and unconventional hydrocarbon systems depends on the integration of several disciplines in an integrated approach towards organic matter characterization, including the study of the type and level of thermal maturity of kerogen.

Organic petrology is the study of organic matter present in rocks, especially in sedimentary rocks, including coals, source rocks, oil shales, gas shales, *etc.* It can also be applied to metamorphic rocks and the exploration of low-grade metamorphic domains for now shale gas is of considerable importance. According to Cook [2], in terms of qualitative analysis, organic petrology explains some of the properties of rocks that contain organic matter, while quantitative organic petrological analysis can supply predictive information.

Organic petrology studies based on concentrations of sedimentary organic matter in both conventional and unconventional hydrocarbon systems have become in recent years, a powerful tool for the characterization of depositional paleoenvironments and for evaluating sedimentary sequences with oil and gas potential. It is precisely the presence of organic matter in sedimentary rocks that actually configures as one of the major elements, which differentiates conventional reservoirs from unconventional shale reservoirs.

SEDIMENTARY ORGANIC MATTER

The organic matter in sequences of sedimentary rocks ranges from occurrences of finely disseminated organic particles to concentrated organic matter in coals. Usually, an organic facies is mostly a mixture of complex and heterogeneous organic materials. The characteristics of this mixture depend on the origin and nature of

the organic matter (planktonic biomass, bacterial community, land plants, or reworked material), organic productivity, inputs to the sedimentary environment, physicochemical conditions existing in the environment, early diagenesis and the thermal maturity that accompanies the burial of sediments and metamorphism [1].

Organic matter present in sediments and sedimentary rocks is composed of kerogen (insoluble in organic solvents) and bitumen (soluble in organic solvents), and it usually represents the smallest proportion of the sedimentary fraction. It is made up of organic molecules derived directly or indirectly from the organic part of the organisms (composed of the elements C, H, O, N, and S). Skeletal parts, shells, bones, spines, and teeth are not included [3, 4].

According to Tyson [4], the study of organic matter in sediments and sedimentary rocks focuses on the interaction between the biosphere and geosphere. A proper appreciation of the subject requires an understanding of the environmental controls, which govern the production of organic matter in the biosphere, the ecological and sedimentological processes, which control its deposition and distribution, the biogeochemical, and geomicrobiological factors, which influence its preservation, and the geochemical and physical processes, which determine its modification during its incorporation into the geosphere.

The characterization of the organic matter contained in sediments and sedimentary rocks is an important issue for different disciplines, such as Biology, Geology, Engineering, and Environmental Sciences. The characterization method used depends largely upon the age of the organic matter (or of the host sediment), the background of the investigators, and above all, the objectives of the study. The use of transmitted light microscopy and bulk geochemical methods for the characterization of the total particulate organic matter present in sediments and sedimentary rocks provides information that can be evaluated in the broader context of the general factors, which control the sedimentation, distribution, and preservation of organic matter. This information can then be sorted for the benefit of paleoenvironmental analysis, and for assessing the potential for hydrocarbon generation [4].

Origin and Characterization of the Sedimentary Organic Matter

Photosynthesis is the basic process behind the mass production of organic matter on the earth and it constitutes the basis for the production of organic matter by autotrophic organisms. The photosynthesis process consists in the reaction of the hydrogen (H) present in the water molecule (H_2O) with carbon dioxide (CO_2), and the absorption of energy (light), to produce organic matter in the form of glucose ($C_6H_{12}O_6$). Thus, primitive autotrophic organisms, such as photosynthetic bacteria

Organic Petrology in the Study of Dispersed Organic Matter

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Abstract: The dispersed organic matter (DOM) in sedimentary sequences derives from biological precursors and experiences changes during burial in sedimentary basins over millions of years. Organic petrology is an essential tool in the study of DOM due to its importance in exploration for fossil fuel resources, although organic matter represents the lowest amount fraction in sedimentary rocks. The study of the type and amount of organic matter, as well as the source and depositional environment define the organic facies and type of kerogen for establishing the hydrocarbon source potential of rocks during the exploration for both conventional and unconventional hydrocarbon resources. Furthermore, optical parameters have been established to determine the organic maturity and therefore, the paleotemperature history of sedimentary sequences, as organic matter is the most temperature-sensitive constituent present in sedimentary rocks.

Keywords: Dispersed organic matter (DOM), Organic petrography, Organic petrology, DOM classification, Thermal maturity.

INTRODUCTION

Organic matter in sedimentary sequences ranges from finely disseminated occurrences of organic particles to concentrated organic matter in coals. The dispersed organic matter (DOM) is a diverse mixture of very complex and heterogeneous organic materials which represent the organic facies of a sedimentary section. The characteristics of this mixture depend on the origin (type) and nature of the organic matter (planktonic and bacterial biomasses, land plants, reworked material), as well as its early diagenesis and thermal maturity

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that accompanies the sediment burial [1 - 32]. References before 2012 to these matters can be found by Suárez-Ruiz *et al.* [5].

The type and amount of organic matter also depend on the sedimentary environment of each basin. The chemical classification of kerogen (the insoluble fraction in organic solvents of the organic matter) based on H/C and O/C atomic ratios, typically distinguishes four main kerogen types associated to various geological settings [33]. Type I kerogen occurs particularly in lacustrine environments where selective accumulation of algal material or severe biodegradation of the organic matter takes place; Type II is usually related to open marine sediments where autochthonous organic matter derived from a mixture of microorganisms, phyto- and zooplankton has been deposited in a reducing environment; Type III kerogen is derived essentially from terrestrial plants accumulated in coal-forming environments; and finally, Type IV is a secondary kerogen type that corresponds to organic matter carbonized through combustion and/or oxidation (pre-depositional alteration). Vandenbroucke and Largeau [4] modified some definitions of this classification, indicating that Type I kerogen may derive from various highly specific precursors of an aliphatic nature in different sedimentary environments, Type II kerogen can be associated with planktonic organic matter in open marine and fresh water lacustrine environments, and Type III kerogen is from higher plants and can be associated with terrestrial inputs into lacustrine or marine settings. Type I kerogen displays a very high potential for liquid hydrocarbon generation, which decreases in Type II kerogen. The oil potential of Type III kerogen is moderate, although it may still generate abundant gas at great depths.

Under the microscope it is possible to assess the type of kerogen (Fig. 1), by identifying the organic components associated to lacustrine, marine and terrestrial paleoenvironments [2, 5]. The presence of *Botryococci* algae is commonly indicative of a lacustrine environment (kerogen Type I), even though it can also occur in sediments deposited in marine environments, presumably because they are resistant to degradation during transport; *Tasmanites* or *Gloeocapsomorpha* algae are indicative of marine paleoenvironments (kerogen Type II); plant tissues, gelified materials or solid colloids, mainly derived from botanic tissues (woody and cortical tissues), are associated to a terrestrial contribution (kerogen Type III); and the presence of components from the inertinite group are associated with kerogen Type IV.

Organic petrography is an important tool for characterizing the complex assemblages of organic constituents present in sedimentary sequences. Optical microscopy is a non-destructive method of analysis and the cost of sample preparation is minimal. It is used to observe and identify the organic components

preserved (plants, organisms and organic mixtures) in sediments and reveals the general fabric of relationships that cannot be directly obtained from chemical or geochemical analyses.

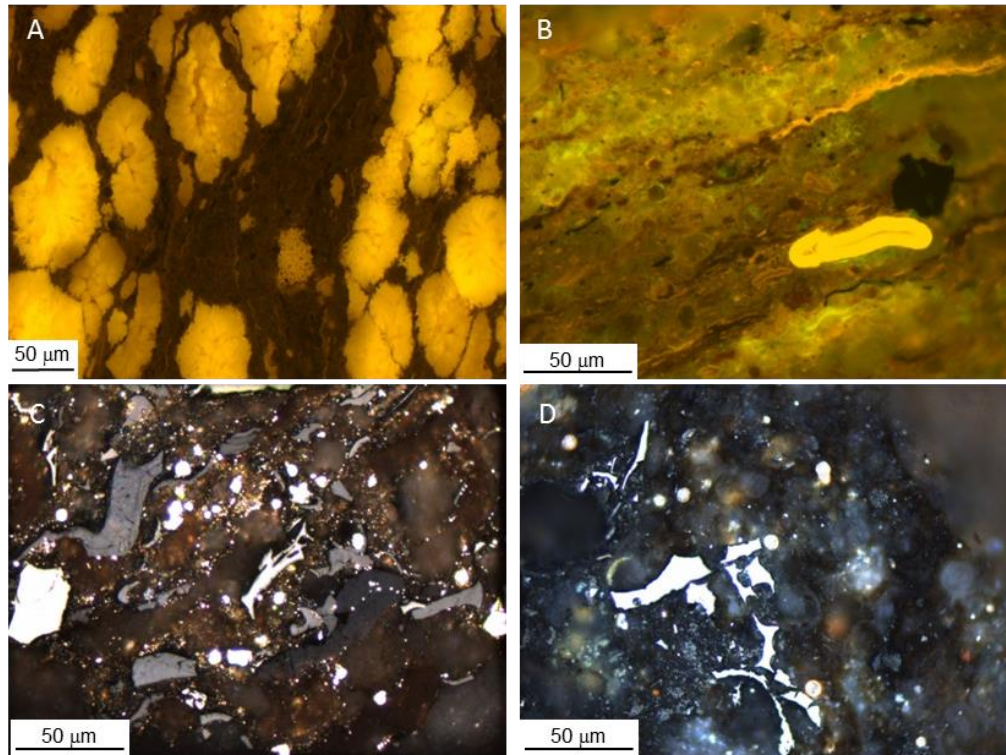


Fig. (1). Types of kerogen identified under the microscope. A) Type I (lacustrine); B) Type II (marine); C) Type III (terrestrial); D) Type IV (carbon residue). Photomicrographs taken in fluorescence mode (A and B) and reflected white light (C and D).

Analysis of DOM has been largely used for organic maturity determinations and for characterizing oil shales and source-rocks for many decades especially in the 20th Century. Currently it is also used to investigate the organic content in the so-called source-rock reservoirs (shale oil [22, 27, 32, 34 - 37], and shale gas systems [12, 34, 38 - 42]). It permits the identification of secondary organic products such as solid bitumen [12, 18, 22, 31, 32, 37, 43 - 46] and hydrocarbons in the rocks and the assessment of rock maturity when other geochemical maturity parameters are not of any use.

Even classical optical microscopy has become routinely used in DOM studies together with other types of conventional microscopic analysis such visual

Oil Shales

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Abstract: The concept of oil shale, the requisites for a sedimentary rock to be considered an oil shale and the distribution and typification of the main oil shale deposits worldwide are addressed in this chapter. As the chapter forms part of a volume devoted to the contribution of organic petrology to the study of conventional and unconventional hydrocarbon resources a significant part is devoted to the petrographic characteristics of oil shales and the difficulties involved in their analysis. In particular aspects related to the quantification of organic components, and the level of maturation have been covered in detail. At present, only a few countries are commercially exploiting oil shales both as fuel to be burned and as a means to obtain shale oil. However the reserves are huge and emerging technologies such as in-situ recovery processes are being tested. The volatility of oil prices and the need to secure energy sources have been the driving force behind this re-evaluation and characterization of little known oil shale deposits in recent years, which will hopefully contribute to a revival of scientific and political interest in oil shale research.

Keywords: Oil shale, Shale oil, Vitrinite reflectance suppression, Fluorescence variability.

INTRODUCTION

The term oil shale is generally associated with the extraction and production of shale oil. The exploitation of oil shale to produce petroleum-like substances is an old practice that dates back to times when knowledge of organic-rich rocks was limited. According to Mushrush and Speight [1] the first British Crown patent number 330 was issued in 1694 to Eele, Hancock and Portlock [2] for finding a way to extract and make great quantities of pitch, tar and oil out of a “sort of stone”. The first oil shale plant was came into service in Autun, France in 1838 and the second half of the nineteen century saw plants developing in Scotland (1850), Australia (1865) and Brazil (1881) [3]. To these early times we owe the terms torbanite (after Torbane hill in Scotland) or kukersite (after Kukruse Manor

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in Estonia), both of which are intimately linked to the term “oil shale”. Elsewhere the expansion of oil shale plants continued during the first 30 years of the twentieth century, reaching its highest point during World War II [4]. Afterwards the availability of liquid hydrocarbons from petroleum led to a slow-down in the growth of the oil shale industry.

Oil shale processing was initially linked to obtaining shale oil from retorting, a process that involves heating in the absence of air at relatively mild temperatures (around 500 °C) to produce the cracking of kerogen, although higher temperatures are commonly required afterwards to burn the spent shale [5]. Regardless of the technology used, ex-situ processing involves pyrolysis, and sometimes hydrogenation and thermal dissolution; all three intended to maximize the extraction of liquid hydrocarbons from the oil shale [6]. Ex-situ processing also requires mining, grinding, heating and refining, operations which increase the price of the oil, making it quite often uncompetitive. Because of these higher costs, shale oil is currently obtained only from a few oil shale deposits in China (10000 barrels a day), closely followed by Estonia, and Brazil (3870 barrels a day) [6]. Given the decrease in oil reserves and the volatility of oil prices, other countries such as Australia, the United States, Canada, Jordan, Israel, and Egypt are contemplating the establishment or re-establishment of this industry [7].

Shale oil extraction is not the single way of processing oil shale. Most of the oil shale mined in Estonia is burned to produce electricity [8], and at Dotternhausen (Germany), oil shale is also burned in a cement plant both to produce electricity and to exploit its by-products [9]. Although most of the present-day plants in Estonia use pulverized fuel technology, fluidized bed technology, which decreases the costs of grinding, reduces the environmental impact and is especially suitable for use with low grade fuels, offers further opportunities for the exploitation of oil shale resources for electricity production [10]. It can also be used in combination with oil shale retorting processes [11, 12].

The arrival of new technologies for the in-situ recovery of shale oil involving electrical, gas or microwave heating over a number of years, so that the generated by-products can then be recovered, opens up additional opportunities for the exploitation of oil shales without the need for steps such as mining and grinding required in the ex-situ processes [13, 14]. An example of thermally conductive in-situ conversion is being tested by Shell in an experimental facility located in the Piceance Basin (Colorado, USA). The energy yield of the extracted liquid and gas matches that predicted by the standardized assay test. A recent compilation of oil shale production processes can be found in Speight’s book, which reviews both traditional and potentially promising future technologies [6].

THE CONCEPT OF OIL SHALE

As mentioned in the Introduction, the concept of oil shale is associated with the production and recovery of shale oil and, as for any rock with commercial possibilities; definitions are often splashed around with economic implications. The term “oil shale” itself refers to oil, an organic liquid, which is not actually present as such in the rock, and to shale, a term used in geology to refer to a fine-grain, low-grade metamorphic rock. The rock itself does not contain oil and quite often is not a shale but rather marlstone or carbonate shale. Most of the definitions of oil shale tend to be vague: “any sedimentary rock capable of yielding economic quantities of oil by retorting” [15] (with no reference to mineralogy where the term “economic” is linked to market conditions). Some definitions comprise information on the grain size: “diverse fine-grained rocks, which contain refractory organic material that can be refined into fuels” [4], excluding tar sands because of their greater grain size and most bitumen-rich rocks because of the adjective “refractory”. The term “refractory” refers to resistance to degradation or to poor solubility in organic solvents and, although it is a characteristic of oil shale organic matter, it is not exclusive to oil shale organic matter. Refractory kerogen also refers to organic matter which has already expended its hydrocarbon potential (spent Type IV kerogen of Tissot and Welte [16]).

The definition of the United States Geological Survey is similar to that of Yen and Chilingarian [4] but includes a reference to the amount of shale oil that might be generated, which is described as substantial: “a fine-grained sedimentary rock containing organic matter that yields substantial amounts of oil and combustible gas upon destructive distillation” [17]. Although it is implicitly included in some of these definitions, none of them make any specific reference to the fact that the organic matter in oil shales is essentially indigenous organic matter, *i.e.*, sedimentary organic matter deposited at the time of formation. This is an important characteristic which differentiates oil shale from other bituminous rocks where migrated bitumen has accumulated and could be processed to obtain hydrocarbons.

Regarding richness a wide variability of boundaries is also accepted. Coal is considered the most organic-rich rock and the most common traded coals rarely have more than a 30-35% ash yield, although a recent UN classification of coal expands this limit to 50% [18], in which case oil shales would contain more minerals and less organic matter than sapropelic coals. However exact amounts are rarely mentioned in any definition. The lowest amount of organic matter for a sedimentary rock to be considered an oil shale is also difficult to establish, it being generally accepted that oil shale progressively downgrades into black shale, with the decrease in organic matter content. Where the exact limit is situated will

Source Rocks, Types and Petroleum Potential

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Abstract: Petroleum generating source rocks can be lacustrine, marine shale, marine carbonate or terrigenous/coaly, generally corresponding to Type I, Type II, Type II-S and Type III kerogen based on source rock screening data (Rock-Eval pyrolysis and TOC determination) plotted in modified van Krevelen diagrams. Rock-Eval and similar pyrolysis techniques are relatively cheap and allow analysis of many samples. However, the pyrolysis method can be problematic as it provides bulk geochemical data of the kerogen composition, which may lead to incorrect kerogen typing. This is particularly an issue for rocks with mixed kerogen compositions or for rocks with a deteriorated source potential due to, for example, slight oxidation of organic matter. Organic petrography in incident white light and fluorescing-inducing blue light of the macerals in source rocks adds granularity to the bulk geochemical characterization and is thus a strong supplementary tool for characterizing kerogen. Petrographic examination of source rocks can inter alia: (1) enhance kerogen characterization by providing qualitative or quantitative information on the maceral composition, including the proportions of oil-prone sapropelic and refractory kerogen, (2) identify mixtures of organic matter types or even slight oxidation of the sapropelic kerogen due to reduced fluorescence intensity and thereby prevent incorrect interpretations of kerogen, (3) document lateral and vertical organic facies variations within source rocks, and (4) provide evidence for petroleum generation by identifying oil droplets, oil films, solid bitumen, exsudatinite, micrinite or pyrolytic carbon. Despite the fact that reflected light microscopy is more expensive, time-consuming and complex than classic geochemical kerogen typing examination of representative or problematic source rock samples may provide just the missing piece that is required to better understand source rock composition and quality.

Keywords: Source rock, Maceral, Kerogen type, Organofacies, Petroleum, Oil, Organic petrology, Rock-Eval.

INTRODUCTION

A petroleum source rock is an organic-rich sedimentary rock which has the capacity to generate and expel liquid and/or gaseous hydrocarbons. Petroleum source

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rocks are unevenly distributed through geological time with six stratigraphic intervals accounting for the vast majority of the world known hydrocarbon accumulations [1]: Silurian, Upper Devonian, Upper Carboniferous-Lower Permian, Upper Jurassic, Lower-Middle Cretaceous, and Palaeogene-Miocene. The Upper Jurassic and Cretaceous intervals have generated a significant part of the known reserves worldwide and include highly prolific world class marine (shale and carbonate) and lacustrine source rocks.

Prolific source rocks of all types are formed under depositional conditions with a high potential for the preservation of organic matter, which normally requires high organic productivity, a very low oxygen availability to the point of anoxia in the sediment and at the seabed, and a low siliciclastic sediment input to prevent the dilution of organic matter. A source rock is typically characterized by a high content in total organic carbon (TOC) [>2 wt.%] composed of hydrogen-rich kerogen, with excellent source rocks having more than 4 wt.% TOC. The quality (type) of the kerogen determines the primary hydrocarbon phase (oil, oil/gas, gas) that a source rock will generate upon maturation through the oil window and a combination of quality and quantity determines the volumes of hydrocarbons that can be generated and expelled. Characterization of the kerogen in potential or proven source rocks is therefore fundamental in petroleum exploration and typically evaluation of a source rock is performed by standard geochemical screening analyses comprising TOC determination and pyrolysis using a Rock-Eval instrument or an equivalent instrument (*e.g.*, Source Rock Analyzer (SRA), HAWK). Screening analyses are generally an efficient way to characterize a source rock interval because the cost is relatively low, allowing the analysis of a large number of samples and the data provide key parameters, such as TOC, the amount of free hydrocarbons in the rock (S_1 ; mg HC/g rock), the remaining generation potential (S_2 ; mg HC/g rock), sometimes the amount of oxygen expressed as the S_3 peak, and T_{max} (the temperature at peak S_2 generation) [2]. Several useful indices can be calculated, including the Hydrogen Index [$HI=(S_2/TOC)*100$] and the Oxygen Index [$OI=(S_3/TOC)*100$]. However, data obtained from Rock-Eval type pyrolysis can sometimes be problematic for interpreting accurately because the kerogen type, organic maturity and the mineral matrix all affect the results [3]. Kerogen is compositionally extremely complex [4], and as Rock-Eval data represent the bulk geochemical composition of the kerogen interpretation of mixed kerogen types solely based on Rock-Eval data can be erroneous. Further, critical consideration of very low TOC contents, contamination by oil-based drilling mud, and saturation of the Rock-Eval flame ionization detector (FID) are required to avoid misleading interpretations [5].

Organic petrography (reflected white light and fluorescing-inducing blue light) is considerably more time-consuming and also more expensive, and it cannot

substitute organic geochemical screening of source rocks, but the devil is in the detail and organic petrography is a powerful complementary method to gain a significant insight into kerogen composition in petroleum source rocks by providing a higher degree of granularity of the organic entities in the kerogen.

This chapter describes the organic petrography of kerogen in different source rock types and links their petrographic composition to the classic kerogen Types I, II and III, the organofacies concept [6], and their generation potential.

CHARACTERIZATION AND CLASSIFICATION OF SOURCE ROCKS

The amount of hydrogen in the organic matter is the limiting factor for hydrocarbon generation, and different maceral types contain varying hydrogen contents. This was shown earlier on the H/C *versus* O/C plot (“van Krevelen diagram”) [7], where the maceral groups vitrinite, liptinite and alginite define specific bands in the diagram, reflecting decreasing atomic ratios with increasing maturation due to the gradual release of hydrogen and oxygen (Fig. 1). Briefly, liptinite macerals, including alginite, are derived from hydrogen-rich precursors and are thus the essential oil-prone components in source rocks; this is particularly the case for alginite, bituminite, cutinite and suberinite. The H/C ratio is generally high. Vitrinite/huminite macerals are coalification products of humic substances, which originate from ligno-cellulosic vascular plant cell walls. Vitrinite/huminite is mainly gas-prone, but post-Upper Cretaceous vitrinitic material can be partly oil-prone. The H/C ratio is generally moderate. Inertinite, which can be found in minor proportions in almost all source rocks, consists of polyaromatized carbon-rich organic matter with no petroleum generation potential and the H/C ratio is therefore very low.

Atomic H/C and O/C ratios determination are time-consuming and relatively expensive, and the original van Krevelen diagram, in particular in the oil industry, has been replaced by a modified diagram. In the modified van Krevelen diagram the atomic ratios are substituted by HI and OI (HI *versus* OI diagram) that are used as indirect measures of the hydrogen and oxygen content, respectively. Commonly OI is substituted with T_{\max} (HI *versus* T_{\max}) because OI is regarded as more uncertain due to a possible unwanted contribution from carbonate-bonded oxygen.

Each kerogen type is typically dominated by a single maceral group as reflected by the original van Krevelen diagram. The maceral pathways have thus both in the original van Krevelen diagram and in the modified alternatives been replaced by Types I, II and III kerogen (Fig. 1) [8]. The kerogen types are largely synonymous with the three primary source rock types (Fig. 2): (1) Lacustrine Type I source rocks, (2) Marine Type II source rocks (shale), and (3) coaly Type III

Organic Petrology Characteristics of Selected Shale Oil and Shale Gas Reservoirs in the USA: Examples from “The Magnificent Nine”

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Abstract: Production of natural gas from mud rocks (shale) is not new in the United States. Gas has been produced from Devonian-age shales in NE US since 1821 while the first industrial-scale shale gas development (Big Sandy Field in Kentucky) from the Ohio Shale took place in the 1920s. An exponential growth in shale gas exploration and production, led by the Barnett Shale in Texas, has occurred since the late 1990s. In 2014, shale gas production in the US reached 9.6 TCF (26 BCF/D), which corresponds to almost 40% of total gas production. The fast decline curve of shale gas wells necessitates the drilling of thousands of additional wells in order to keep up with the demand. Due to a decline in natural gas prices in recent years, the focus has shifted to shallower shale oil reservoirs.

Thick sequences of shale containing varying volumes of gas are found in many basins across the US. Shales are extremely heterogeneous in their properties but at a scale not generally considered. Main challenges include, among others: screening exploration targets, identifying intervals to fracture stimulate and/or drill horizontal wells, and predicting production rates and EURs. Developing a Shale Gas Model is very complex because: a) not two shale rocks are alike, and b) there are many parameters that influence the oil/gas storage capacity and producibility, some of which are uncontrollable. The quantity (expressed by TOC content) and quality of the organic matter (expressed by the S₂ and HI parameters from Rock-Eval Pyrolysis) and its thermal maturity (measured by vitrinite reflectance-VRo) are few very important – and easy to assess – parameters that influence oil and gas generating/storing capacity in the mostly microporous matrix system present in shale source/reservoirs, commonly referred to as ‘unconventional’ rocks.

The objective of this chapter is to provide the reader with a better understanding of the variability in the above parameters in nine oil and gas reservoir shales in the United States- (referred thereunto as “The Magnificent Nine”). Particular emphasis will be given to the role that organic petrology plays in predicting the types of hydrocarbon (oil, wet gas/condensate liquids, and dry gas) that will be produced. These nine US

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shale formations were selected based on variations in their thermal maturity, organic richness, kerogen type(s), depositional environment, age, and mineralogical composition. They are the following: Utica, Marcellus, Woodford, Bakken, New Albany, Eagle Ford, Niobrara, and Green River. The ninth formation is the Wolfberry, which is considered to be a 'hybrid' play or a combination of unconventional and conventional. It is hoped that the contents of this chapter will serve as a useful guide to the reader and that learnings can be directly applied to basins around the world that contain analogous types of rocks.

Keywords: Organic petrology, Rock-Eval pyrolysis, Fe-SEM, USA shales, Unconventional hydrocarbons, Exploration.

INTRODUCTION

The last ten years have seen an explosion in the drilling and production of hydrocarbons (both oil and natural gas) from argillaceous and calcareous rocks in the United States that were considered to be 'tight' in terms of very low matrix permeability. It all started in 1981 with the famous Barnett Shale in Texas but it took almost 20 years (until 1998), during which time this gas play experienced five different stages of development through advances in horizontal drilling and multi-stage fracture stimulation technologies, before commercial production was achieved economically. The above technologies were pioneered mainly in the USA and have changed old beliefs about tight petroleum systems. This resulted in making the USA the world leader in the production of liquid and gaseous hydrocarbons in 2014 [1]. Almost 2.3 million barrels of oil per day and 28 billion cubic feet of gas were produced in 2013 from ten (10) shale/tight oil as well as dry gas shale plays.

One of the first types of analyses conducted by an exploration and production company is Total Organic Carbon (TOC), Rock-Eval pyrolysis, and organic petrology (vitrinite reflectance in oil – VRo and, sometimes, visual kerogen assessment or VKA). Rock-Eval and TOC analyses are quick and inexpensive, and can be done on core, rotary or percussion sidewall cores (RSWC, PSWC), on old cores/cuttings, and even on new drill cuttings and fresh outcrop samples. VRo and/or VKA, typically follow a review of the TOC/RE data and selection of the best samples in terms of petroleum generating potential. Scanning electron microscopy, being the most expensive of the three types of analyses, is normally done on few samples. Because of the importance in obtaining analytical data as quickly as possible on samples from a newly-drilled core hole, we decided to focus on the above types of data in this chapter, without suggesting that other types of analyses (XRD, thin sections, rock mechanics) are less important.

Format Style

The format of this chapter is similar to that of an Atlas; that is it includes a large number of photomicrographs and description of their content but has a limited discussion. The main objective is to show the reader the variability in the types of dispersed organic matter (DOM) found in selected unconventional shale systems in the United States. The first part of the Atlas description will be achieved through the introduction of a series of photomicrographs taken under both reflected incident and fluorescent light sources. Measured reflectance in oil (Ro) values will be shown on the photos themselves or in the captions, along with conversions to vitrinite reflectance-equivalent (VRO-eq) values when the measurements were taken on bitumen or on zooclasts. Every effort will be made to show the evolution of the DOM over the entire spectrum of thermal maturity. The second part includes representative photomicrographs taken under field emission scanning electron microscopy (Fe-SEM) to show the various types of organic porosity developed on the organic matter. The third part consists of Rock-Eval 6 and TOC data for selected shales.

A total of nine (9) shales have been selected. Their location is shown in Fig. (1). They are: Utica (1), Marcellus (2), Woodford (3), Bakken (4), New Albany (5), Eagle Ford (6), Niobrara (7), Green River (8), and Wolfcamp/Spraberry (Wol-fberry) (9).

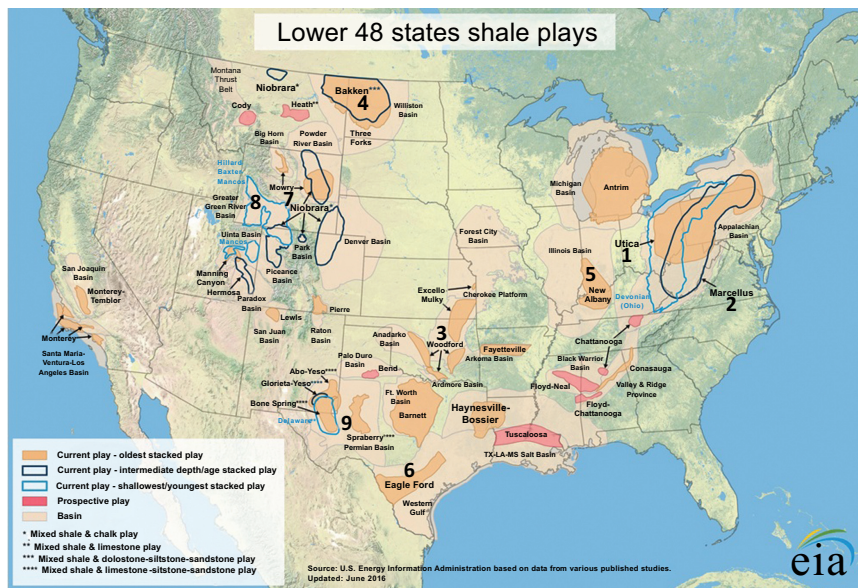


Fig. (1). Shale Plays in the Lower 48 US states [2].

Shale Oil Resource Systems and Solid Bitumen

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Abstract: Shale oil resource systems are oil reservoirs of fine grained facies with abundant organic matter (in many cases TOC > 2%), low porosity (normally between 4 to 14%), low permeability (in the micro- to nano Darcy range) containing *in situ* generated oil or short distance migrated oil. They produce light oil or condensate, usually generated from the mid to late oil window phase. These shale oil reservoirs cannot be exploited by means of conventional production technologies (vertical wells) and may require a different type of advanced, completion and development techniques. From the point of view of organic composition these systems are complex because they contain primary organic matter but also secondary products from the thermal degradation (cracking) of primary organic matter. It is here where organic petrology contributes to understanding shale oil reservoirs by identifying and estimating what kind of primary organic matter was deposited (marine or terrigenous, algae, spores, bacteria woody remains), and what the secondary organic products are, whether oil or solid bitumen and, in this way conveying an idea of the type and degree of organic matter richness in the rocks. Moreover, organic petrography also assesses the degree of maturity reached by the organic matter which in combination with the characteristics of the organic matter will define the type of fluid generated (oil or gas) during the thermal evolution.

The Upper Formation (Turonian-Santonian age) of the organic-rich Cretaceous sequence located in the Middle Magdalena Valley (MMV) basin from Colombia is described here as one of the examples of shale oil reservoirs in which organic petrology has played a fundamental role in assessing the type of organic matter contained in the system, its provenance, paleosedimentary environment and thermal maturity. Moreover organic petrography is the only method of identifying sedimentary levels in this shale oil reservoir with high content in solid bitumen as a critical organic component in the development of organic porosity. The development of porosity contributes to the routes of migration of hydrocarbons and must be taken into account when evaluating the quality of these systems, their capacity to retain hydrocarbons (oil/gas) and their potential exploitability.

This contribution also points out the capacity of organic petrology through its various methodologies, organic petrography, the visual assessment of kerogen and palynofacies

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analysis, to solve and clarify erroneous interpretations that can be made from data used as proxies for organic petrologic data.

Keywords: Shale oil, Kerogen, Solid bitumen, Organic petrography, Palynofacies, Thermal maturity, TOC, Porosity.

INTRODUCTION

Petroleum (oil and/or thermogenic gas) originates from the thermal breakdown of organic matter in the subsurface [1, 2]. The organic matter (algae, bacteria, the products of organic decomposition, and/or land plant remains) deposited together with inorganic sediments generally in low energy environments is converted to petroleum, usually as burial and temperature increase with the increase in subsidence. Once petroleum is formed, it can be expelled from the source rock into adjacent rocks, which must have higher porosity and higher permeability or more conduits (carrier rocks) through which it can flow more easily. However, when liquid petroleum (oil) does not flow to the carrier rocks, it accumulates in the same source rock or it migrates only short vertical or horizontal distances. In this case a shale oil resource system can be envisaged.

A shale oil resource system is described [3, 4] as an organic-rich mudstone that has generated oil which is stored in the organic-rich mudstone levels or has migrated short distances into juxtaposed, continuous organic lean intervals. Therefore, a shale oil system is both a source and a reservoir rock. This type of system displays a TOC content higher than 2% and contains kerogen of good quality, producing light oil or condensate, usually generated from the mid to late oil window. In these systems the fine facies are present or dominant, they display a low porosity (normally between 4 to 14%) and low permeability, usually in the micro- to nano Darcy range. According to Jarvie [4] organic-rich shale oil systems can be subdivided into three types based on their dominant organic and lithologic characteristics: i) no open fractures, ii) fractured, and iii) hybrid, (*i.e.*) having juxtaposed ductile organic-rich and brittle organic-lean lithofacies.

The nomenclature used in systems that produce oil after stimulation by hydraulic fracturing it is varied. In the US, the oil and natural gas industry employ the term tight oil production rather than shale oil production [5]. The oil industry uses the term tight oil production because it is a more encompassing term covering the different geologic formations that produce oil. Tight oil is produced from low-permeability sandstones, carbonates (*e.g.*, limestone), and shale formations. The use of the term “tight oil” is rather recent, and does not have a specific technical, scientific, or geologic definition. The US Energy Information Administration (EIA) has adopted the convention of using the term “tight oil” to refer to all

resources, reserves, and production associated with low-permeability formations that produce oil, including those associated with shale formations. In the literature some equivalent terms such as shale oil resource systems [4, 6], shale oil reservoirs [7 - 10] and source-rock reservoirs [11, 12] are found.

Shale oil resource systems cannot be exploited by means of conventional production technologies (vertical wells) and may require a different type of advanced completion and development techniques for hydrocarbon extraction. These systems are therefore included in the range of unconventional petroleum systems. The rapid advances in technology, mainly in horizontal drilling and multi-stage hydraulic fracturing (fracking) have contributed to the tremendous growth in oil production, especially in the United States. According to data from EIA [8] the oil production from shale oil reservoirs in the US increased from about 0.5 million barrels of oil per day in 2011 to 4.5 million barrels of oil per day in 2015.

Assessment of a shale oil resource system [13] involves:

1. A geologic characterization of the major shale basins and formation(s). Thus the conditions are: i) a minimum TOC content of $\geq 2\%$; ii) a thermal organic maturity inside the oil window and therefore, the oil prospective area should have a vitrinite reflectance from 0.7% to 1.0%; iii) a prospective depth range of 1,000 m to 5,000 m; iv) a shale mineralogy because it is this that governs the efficiency of hydraulic fracture; and v) other conditions such as overpressure, geologic complexity, volumetric data, oil saturation to determine the possibility of commercial exploitation of oil, *etc* [4]. On the other hand, it is now known that sedimentary levels up to 1.2-1.3% vitrinite reflectance can also occur in liquid plays (*e.g.*, Eagle Ford in Texas). However, these higher maturity locations are often not commercial plays.
2. Definition of the prospective area and risk factors for the shale formations.
3. An estimation of the risks of exploiting the shale oil resource in-place.
4. A calculation of the risk of technically recoverable shale oil resource.

In the geological characterization of major shale basins and formation(s) organic petrology, particularly organic petrography (microscopical characterization), plays an important role. Although the scope of organic petrology is broad it addresses two fundamental tasks when it is applied to the evaluation of source rocks, reservoir rocks or source rock reservoirs: identification of the type and nature of organic matter contained in the geological formations, and determination of organic maturity providing data and contributing to a multidisciplinary assessment for hydrocarbon exploration.

For geopolitical and economic reasons, there has been a shift in exploration and development towards locating other producible shale oil resource systems [14, 4]

Application of Organic Petrology in High Maturity Shale Gas Systems

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Abstract: Application of incident light microscopy techniques for organic petrology in high temperature thermogenic shale gas systems demonstrates that solid bitumen is the dominant organic matter. Solid bitumen is retained as a residual conversion product as oil-prone kerogen cracks to hydrocarbons or occurs from the cracking of once liquid oil. Oil-prone Type I/II kerogens are not present in shale gas reservoirs, already having converted to hydrocarbons. Type III/IV kerogens (vitrinite and inertinite) are refractory and persist in shale gas reservoirs to high maturity with little morphological change apart from condensation and aromatization causing higher reflectance. Organic petrology applications are most useful for thermal maturity determination and delineation of hydrocarbon windows through measurement of vitrinite reflectance and vitrinite reflectance equivalents from other organic matter (zooclasts and/or solid bitumen). Depositional organo-facies determination generally is not possible in the gas window of thermal maturity; fluorescence microscopy is not useful as organic matter is no longer autofluorescent. Application of scanning electron microscopy (SEM) allows observation of an interconnected nano-scale organic porosity in shale gas systems but suffers from inability to identify organic matter types. SEM approaches to shale gas reservoir characterization therefore should not attempt differentiation of kerogen types or kerogen vs. solid bitumen identification unless correlative organic microscopy is performed. Herein are reviewed organic petrology results as used in the shale gas systems of North America, Europe and China, including SEM applications, citing recent examples from the literature.

Keywords: Shale gas, Organic petrology, Solid bitumen, Vitrinite reflectance, Thermal maturity, Gas window.

INTRODUCTION

Shale gas systems are widespread in North America where the 'shale revolution' has caused a surge in oil and gas production since about 2005 [1 - 3]. Evaluation

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workflow in these systems has rapidly evolved as the oil and gas industry recognized the importance of detailed reservoir characterization for successful shale development [4]. For example, focus on organic-hosted porosity in shale reservoirs [5] has developed into a digital rock physics analysis which delivers information on a voxel basis, rendering 3-D arrays of mineral and pore space which can be numerically simulated to estimate reservoir properties [6]. Herein, application of organic petrology to shale gas systems is discussed, an important and useful approach to unconventional reservoir characterization, particularly for delineation of thermal maturity (hydrocarbon zone) windows [7, 8]. This chapter is limited to high temperature thermogenic shale gas systems (generally 150-160°C and above [9]), wherein the presence of commercial gas resources arises from thermal maturity advance and the cracking of kerogen or once liquid oil. Organic petrology applications in shallow biogenic shale gas systems (generally <80°C) are not discussed.

Organic petrology generally is regarded as the evaluation of origin, composition and distribution of sedimentary organic matter in rocks through incident light microscopy approaches [10]. This technique has a long tradition in the characterization of source rock reservoirs. Pioneering studies in the 1950s-1970s first used maceral reflectance as a hydrocarbon prospecting tool [11, 12]; data from organic petrology techniques was further extended to validation of burial history and basin evolution models in the 1980s [13]. Since the advent of the shale revolution organic petrology is increasingly applied to analysis of source rock thermal maturity, commonly in conjunction with information from geochemical screening (organic richness and composition from programmed pyrolysis) [14]. Petrographic organo-facies determination generally is not applicable in shale gas systems because oil-prone organic matter has been converted to hydrocarbons; solid bitumen is the dominant organic matter present (see below) and organofacies determination relies more on geologic or geochemical inference than by direct observations from organic petrography.

The term 'shale gas' is a misnomer as shale is seldom the reservoir [15] and gas is seldom the only product. Instead, 'shale', as used herein, describes a broad set of fine-grained low permeability hydrocarbon source rocks, ranging from micrite to mudrock, which typically are present across a wide range of thermal maturities, from updip oil to downdip dry gas, *e.g.*, Duvernay or Eagle Ford Formations in North America [3]. The common denominator among these internally charged tight hydrocarbon reservoirs is that a sufficient amount of retained hydrocarbon is present as solid bitumen, acting as a sorbent and reservoir for natural gas which can be produced in commercial quantities after artificial stimulation (hydraulic fracturing) from horizontally drilled well bores. Produced gas is present either as free gas in organic/inorganic porosity, or is sorbed to or potentially dissolved in

the solid bitumen. A second type of shale gas reservoir includes externally charged systems such as the Montney of western Canada, where oil has migrated into a tight rock, later cracking to gas due to thermal maturation and leaving a solid bitumen residue [16].

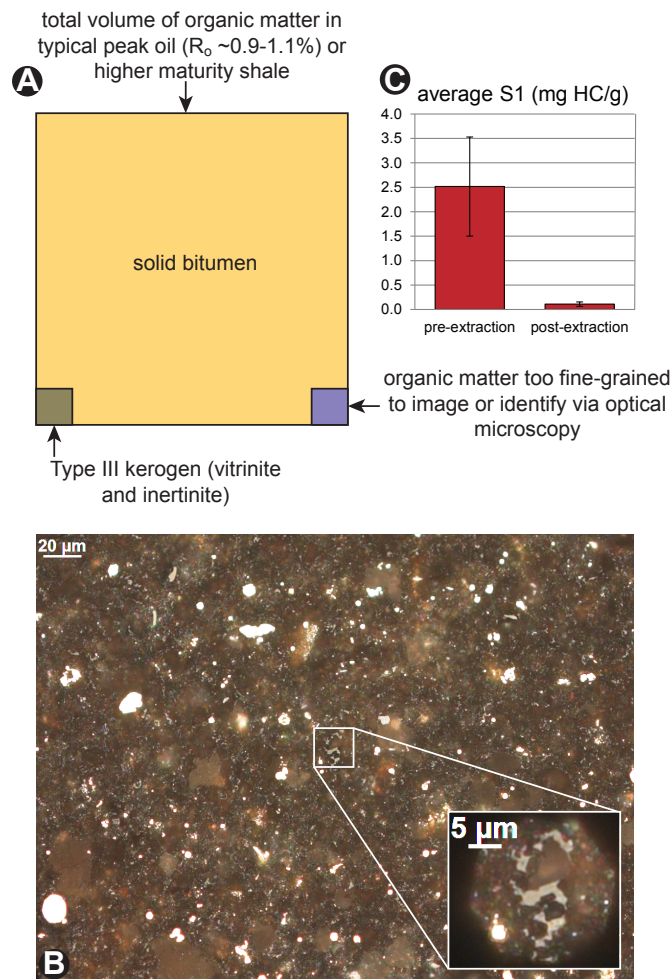


Fig. (1). A. Generalized and schematic representation of petrographically observable organic matter in thermally mature shale ($\geq 0.9\%$ R_o) showing relative proportions of organic matter types present. B. Thermally mature ($\sim 1.5\%$ R_o) organic-rich [~ 3.0 wt.% total organic carbon (TOC)] Barnett Shale showing solid bitumen (gray-white) network which is the dominant organic matter. C. Removal of solid bitumen from thermally mature ($\sim 1.0\%$ R_o) Barnett Shale as documented *via* pre- and post-extraction S1 values from pyrolysis (data from [25]). Similar reductions were also observed for S2 and TOC. From [3].

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Tight Gas Systems

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Abstract: The Early Triassic Montney Formation is a world-class tight gas play in the Western Canadian Sedimentary Basin, mainly composed of siltstone. The majority of the organic matter in the Montney siltstone consists of solid migrabiten. This represents a former liquid oil phase which migrated into the larger paleo-intergranular pore space. Physicochemical changes in the oil led to precipitation of asphalt aggregates. These asphalt aggregates were then consolidated into solid migrabiten while being subjected to thermal cracking (or pyrobitumen at higher thermal maturity). Petrophysical measurements of drill-core samples across the basin in conjunction with organic geochemistry and petrographic observations show that reservoir quality in the Montney tight gas is strongly influenced by the pervasive presence of pore-occluding solid migrabiten. Solid migrabiten obstructs porosity and hinders fluid flow, and thus shows a strong negative correlation with reservoir qualities such as porosity and pore throat size. Bitumen saturation is the proportion of solid migrabiten filling the intergranular paleopore network. This is the dominant control on pore throat size and absolute permeability. In the economic portions of the Montney tight gas fairway, siltstones are found to have porosities in the range of 3 to 7%. The conventional determinants of porosity and permeability, such as grain size, sorting, clay content and cementation, have less of an influence on the reservoir quality in this economically key porosity range than the bitumen saturation.

Keywords: Solid migrabiten, Montney Formation, Reservoir quality, Wettability, Rock-Eval, Extended slow heating (ESH), Fluid-like hydrocarbon residue (FHR).

INTRODUCTION

The total organic carbon (TOC) content of the mudrocks in the unconventional petroleum systems is an important attribute for assessing reservoir quality and

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hydrocarbon productivity. A strong positive correlation between the TOC and the reservoir attributes of the rocks, such as porosity and permeability, in many unconventional plays [1, 2] has led to the observation that organic porosity is an important control on reservoir quality (*e.g.*, Barnett, Doig and Eagle Ford) and the primary storage mechanism for hydrocarbons in organic-rich mudstones [3].

The unconventional tight gas reservoirs are generally defined as rocks with matrix permeability of <0.1 millidarcy (mD) and matrix porosity of <10% [1]. These conditions require horizontal drilling and hydraulic fracturing to produce hydrocarbon at economic rates. The rocks forming the tight gas reservoirs are mostly siltstone to fine-grained sandstone, which are generally coarser grain than their shale gas counterparts. The high energy depositional setting required for transportation and settling of coarse grain sediments such as silt and sand prohibits deposition of large quantities of hydrogen-rich primary kerogen (algal matter). Density of algal matter is approximately half of the mineral matrix and hydrodynamically tends to deposit along with much lighter, fine clay particles in the shale facies. Therefore, the tight gas mudrocks are often devoid of significant quantity of primary kerogen so the majority of organic matter in these rocks came from a previous hydrocarbon liquid phase that migrated and matured in these rocks.

Recent organic petrography and pyrolysis studies of a world-class Early Triassic Montney tight gas play in the Western Canadian Sedimentary Basin (WCSB) have shown that virtually all of the kerogen contained in these siltstones is found in the form of solid migrabitumen. Solid migrabitumen was originally introduced as a liquid oil phase which filled the pore network of this regionally extensive marine siltstone succession [4 - 6]. Thermal degradation of oil and pre-bitumen asphalt has subsequently led to formation of solid migrabitumen [6, 7].

The significance of solid migrabitumen has become more recognized, in the assessment of unconventional tight and shale gas plays, in recent years [6, 8 - 16]. In this chapter we discuss petrophysical, organic geochemical and petrographic observations to show the role of solid migrabitumen as a major influence of reservoir quality in the Montney tight gas play.

The Montney tight gas fairway located immediately to the northeast of the Cordilleran deformation belt in the WCSB of Alberta and British Columbia is partially formed from the Early Triassic Montney Formation which is up to 320 m (1050 ft) thick in this region [17 - 19]. This formation is composed primarily of siltstone and was deposited predominantly in a lower shoreface to offshore environment [19 - 21] (Figs. **1a** & **b**).

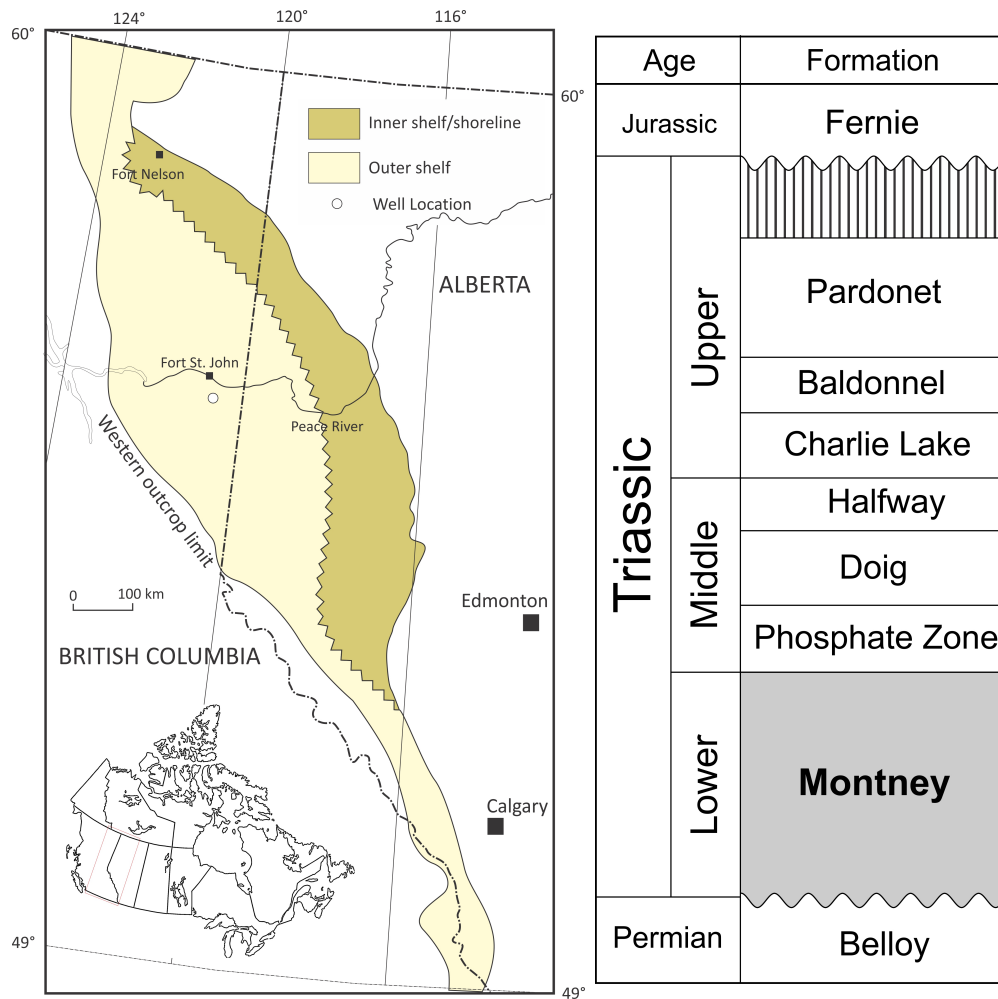


Fig. (1). (a) Distribution map of Triassic strata in the subsurface of western Canada. (b) Stratigraphic column of Triassic strata in the WCSB (modified after Davies, 1997).

Turbidite depositional environments have also been observed in parts of the Lower Montney section [20]. Prior to the time of maximum burial (approximately 50 to 60 Ma [22]), the Montney tight gas fairway was present in the thermogenic gas window and formed an indirect basin centered gas accumulation [23]. This accumulation formed unconventional gas system in which migrated and trapped oil was thermally cracked to gas.

ORGANIC MATTER IN THE MONTNEY TIGHT GAS SILTSTONE

Present-day TOC in the Montney tight gas fairway typically ranges from 0.25 to

Coal Bed Methane

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Abstract: Coals hold a unique position in conventional and unconventional hydrocarbon systems in that organic matter forms the bulk of the rock. Gases within coals have a dominant storage mechanism of adsorption within the fundamental structure of the organic matter rather than the conventional state as a compressed gas in intergranular spaces or dissolved within liquid hydrocarbons. Gases form an integral part of the coal substance. Multiple phases of gas generation are the norm and result in complex relationships between gas content and organic petrology. Thermogenic gases are produced during normal burial metamorphic processes. Biogenic gases are produced during earliest coalification as well as post-coalification, after uplift. Understanding the variability of the organic matter is key to understanding the variability in gas content and gas composition. Coal type is determined at the peat stage and strongly influences mechanical properties of the coal, amount and type of gas generated, timing of gas generation and storage capacity. Coal type needs to be studied at the macroscopic level through lithotype analysis; at the microscopic level *via* maceral analysis and; geochemically. Rank studies by vitrinite reflectance are preferred over bulk geochemical techniques and provide insights into the timing and generation of thermogenic gases. Petrographic studies can also be used to detect the presence of igneous intrusion, which affects both gas composition and storage capacity. The importance of individual, detailed basin studies cannot be overstated. Attempts to make global generalizations usually fail due to the complexity of the starting material coupled with unique geological histories.

Keywords: CBM, Lithotype, Maceral, Coal type, Coal rank, Gas variability, Gas content, Methane.

INTRODUCTION

In unconventional hydrocarbon systems, it is common for the organic matter to play an important role in gas storage. Coal seams have a unique position in that the rock type is predominantly organic matter. The properties of the organic matter therefore dominate both storage and production mechanisms.

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Whilst, it is common to refer to the gases extracted from coals as coalbed methane (or CBM; also CSM for coalseam methane), some jurisdictions prefer the use of coalseam gas (CSG) in recognition that methane is not the only gas present. Gases commonly found in coals include methane (CH_4), ethane (C_2H_6), propane (C_3H_8), carbon dioxide (CO_2), nitrogen (N_2) and rarely hydrogen sulphide (H_2S). Methane usually predominates but in some cases carbon dioxide may be the main gas. CBM is taken to include any of these gases. Liquid hydrocarbons also occur.

When assessing a CBM play, it is desirable to have high gas content, high methane composition (>98%), large reservoir, good deliverability and low production / exploration costs. Thick, laterally continuous coals are clearly desirable but thin, high gas content coals or thick, low gas content coal can also be economic. Similarly, demonstrated coal continuity is not always essential (*e.g.* the laterally discontinuous, podlike seams of the Surat Basin, Australia). Gas deliverability is related to the stress regime, permeability, mineralization and gas saturation. Shallow reservoirs help to contain exploration and development costs as well as often having better permeability characteristics. An impermeable seal is not a necessary characteristic as the gas is stored by adsorption and held in place by hydrostatic pressure. Economic extraction of gases from the coals is extremely successful in many areas around the world and specific methodologies for reservoir engineering have been developed [1, 2].

Coals are usually understood by three fundamental aspects: (1) rank; (2) type and; (3) grade. Coal rank is essentially the degree of thermal metamorphism, although pressure may play a significant role. Basin type and basin history play key roles in rank evolution. Coal type is usually thought of as being the different organic constituents but a broader concept may also include inorganic components. Coal type is fixed at the time of peat accumulation and is little influenced by rank. Grade is the amount of inorganic matter present. It is largely controlled by the depositional environment, especially the interaction of the clastic systems with the peat mires.

These three fundamental aspects combine in different ways to influence gas generation, storage and production. However, other geological processes also need to be considered, such as the effects of igneous intrusion as well as groundwater movement.

A great variety of coal properties need to be evaluated in addition to the organic petrology. Of particular interest is the development of pore systems, which is influenced by both rank and type.

Generation of Coalseam Gases

Methane is the most common gas found in coal seams. Other hydrocarbon gases may also be present, especially ethane and propane, as well as non-hydrocarbons like carbon dioxide and nitrogen. Gases can be generated by either thermogenic or biogenic processes. Both early and late stages are generally recognized.

Thermogenic Gas Generation

Thermogenic gas generation commences at about the end of subbituminous coal stage, or at about 0.6% vitrinite reflectance, but the exact timing is affected by coal type and specific basin history [3]. Once commenced, thermogenic gas evolution continues throughout rank increase, predominantly by cracking and expulsion of low molecular weight hydrocarbons, especially methane. Large quantities of CO₂ are also evolved but due to the high solubility of CO₂ in water, these are removed during seam dewatering. Small amounts of N₂ are also produced. The total volume of gases produced thermogenically is around 300 to 400 m³/t which is ten times greater than the maximum storage capacity of any coal of any rank and indicates that substantial volumes of gas must migrate out of the seams.

A post-coalification stage of thermogenic gas production occurs in some area due to igneous intrusion into the seam.

Biogenic Gas Generation

Early and late stages of biogenic gas production are generally recognized. Early biogenic gas occurs up until around the commencement of thermogenic gas production *i.e.* at about the subbituminous to bituminous coal rank boundary. This gas is probably lost during compaction, in part due to the poorly developed micropore network. At higher temperatures, methane-producing bacteria can no longer survive. Late stage biogenic gas production occurs post-coalification and is related to uplift and groundwater movement.

Two major processes are envisaged, that of acetate fermentation and CO₂ reduction [3, 4]. Isotope evaluation of the gases allows discrimination to be made between the different biogenic processes operating as well as between thermogenic and biogenic processes (Fig. 1). In addition to methane generation, H₂S may also be generated by biogenic processes at the groundwater interface.

Mechanism of Gas Storage by Coal

The storage of gases by coal is widely accepted to be one of physical adsorption within a microporous network [1, 5 - 7]. A number of lines of evidence can be

Spent Source Rocks in a Paleo-Petroleum System: A Case Study

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Abstract: In this work, the important role of organic petrology in the reconstruction of the evolution of a paleo-petroleum system, whose source rocks have exhausted their ability to generate hydrocarbons due to their overmature state, is demonstrated. Whereas geochemical screening is generally used to characterize immature-to-mature source rocks, in the case of overmature spent source rocks, organic petrology is used to determine the type and amount of organic matter initially contained in the rocks. In this paper, a case study of the Cameros Basin (North-Central Spain) is presented. By means of vitrinite reflectance measurements, a marked difference in maturity has been determined throughout the basin. Immature to oil-window thermal conditions were reached in the southern part of the basin, whereas overmature to dry-gas thermal conditions were observed in the central and northern areas. In the northern sector the organic matter shows several thermal alteration textures as a consequence of the circulation of hydrothermal fluids during the evolution of the basin. In some of the overmature units, the presence of micrinite residues, framboidal pyrite in the mineral matrix and a large amount of solid bitumens suggest that these rocks originally contained abundant organic matter and that hydrocarbons were generated during the thermal evolution of the basin. These deposits can therefore be considered as the original source rocks of the Cameros Basin petroleum system. Evidence of the migration of hydrocarbons is frequently found in the form of fractures that vertically propagate through the organic matter rich-layers. The hydrocarbon accumulations formed by these rocks could have given rise to tar sandstone deposits that are located in the south of the basin.

Keywords: Spent source rocks, Paleo-petroleum system, Thermal modelling, Overmature, Hydrothermalism.

INTRODUCTION

In a petroleum system a source rock is defined as a sedimentary rock that is capable of generating, or has generated, movable quantities of hydrocarbons [1].

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There are a small number of fundamental parameters that define the quantity and the type of hydrocarbons that can be generated by an effective source rock, such as its organic matter content, its quality (for yielding moveable hydrocarbons), the type (different types of organic matter have different hydrocarbon-generating potential) and its thermal maturity. The amount and type of organic matter are products of the paleo-depositional setting, while the thermal maturity is related to the structural, geothermal and tectonic history of the basin.

Organic matter can be found in almost all sedimentary rocks, particularly in fine-grained rocks. However, only in a few cases are paleo-environmental conditions favorable for the input and the preservation of enough organic matter in the sediment to allow the subsequent generation of hydrocarbons. The concentration of oxygen and the sediment supply are the two most relevant key factors for organic matter preservation during burial [2 - 5]. Thus, organic matter-rich deposits are generally formed in a depositional environment with a certain primary productivity, characterized by dyoxic-to-anoxic conditions and an intermediate rate of sedimentation of fine-grained sediments [2, 5 - 9]. The quality of a source rock is also determined by the type of sedimentary organic matter present (expressed in terms of kerogen type [8, 10 - 12],). The more oil-prone a kerogen is, the higher its quality will be [1], as in the case of kerogens of type I and type II.

The amount of hydrocarbons generated by a source rock depends, among other factors, on the original kerogen content of the rock. Rocks with less than 0.5% TOC are not generally considered as source rocks. In general, source rocks with a good hydrocarbon potential must have a TOC content higher than 2%. To evaluate the hydrocarbon potential of a source rock, apart from its organic carbon content, it is essential to know its thermal maturity [10]. Depending on the burial history, the chemistry and properties of the organic matter contained in a sedimentary rock change over time (millions of years). These changes can be measured to obtain the degree of maturity reached by the organic matter across its geological history. The degree of maturity combined with the amount of organic matter in a rock will determine the amount of hydrocarbons that can be generated.

On the basis of the quantity, quality and maturity of the organic matter, and according to Law [1], source rocks “can be divided into four categories: potential source rocks, effective, relic effective and spent source rocks”. Potential source rocks represent rocks containing a quantity of organic matter sufficient to generate hydrocarbons, when subjected to thermal maturation. Effective source rocks are rocks that generate and expel hydrocarbons into commercially exploitable accumulations. Relic effective source rocks are rocks that still contain a certain amount of organic matter but have stopped generating hydrocarbons, because they

have been affected by thermal cooling events, such as uplift or erosion. Spent source rocks are exhausted source rocks, which are not able to generate or to expel hydrocarbons anymore because they contain insufficient organic matter or because they have reached an overmature state. This contribution discusses an example of spent source rocks, where the organic matter is in an overmature state as consequence of the strong thermal evolution of the basin.

In overmature spent source rocks, most of the original kerogen has been transformed into hydrocarbons. It is difficult to determine from these spent rocks the original type and amount of organic matter contained in the system and the kind of hydrocarbons that were generated. In fact, in the case of overmature deposits, results from the geochemical screening used to characterize source rocks (*e.g.*, Rock-Eval, TOC, biomarkers, elemental analysis, *etc.*...) cannot be completely trusted.

However, the study and analysis of the remains of organic matter found in overmature source rocks by means of petrographic techniques can provide relevant data on the thermal transformation of organic matter and on the type of hydrocarbons that were generated and accumulated in the basin. Such data are also useful for elucidating the thermal history of the basin, as they provide an estimation of the temperatures recorded during the basin infill and contribute to a reconstruction of the geological evolution of the basin. In this way, models and interpretations of the burial history of a basin, of heat flow variations over time and of hydrocarbon and/or hydrothermal fluid migration paths can be validated.

THE CAMEROS BASIN CASE STUDY

The following casebook study of the Cameros Basin is presented in order to demonstrate the way in which the methods of organic petrology are applied to reconstruct the thermal history of a basin formed by overmature deposits and to show how its paleo-petroleum system has evolved. The Cameros Basin (north-eastern Spain) belongs to the Iberian Chain (Fig. 1), an intraplate chain formed during the Alpine Orogeny. The basin formed between the Late Jurassic and the Early Cretaceous, during the Mesozoic Iberian rift [13, 14]. The very high subsidence rate recorded in the area led to the burial of the basin deposits to a sufficient enough depth for them to reach a high temperature for hydrocarbon generation [15]. In the post-extensional and inversion phases, the basin area was affected by hydrothermal events, which thermally altered the basin infill deposits [16 - 25]. An interesting peculiarity of this basin is the co-existence of deposits characterized by different states of thermal maturity, from immature to overmature and partially altered by hydrothermalism, making it possible to observe all of the thermal transformation states of the organic matter.

Perspectives on Shale Resource Plays

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Abstract: Both conventional and unconventional petroleum systems assessments involve detailed analysis of the components and processes involved in the generation and storage of petroleum. A key of this assessment is the characterization of organic matter and its thermal maturity. Assessment of kerogen type and thermal maturity requires the use of multiple techniques to fully assess the petrological and geochemical risks associated with exploration and production (E&P) prospects and plays. A combination of visual and chemical techniques provides essential data to elucidate the various risks associated with finding and producing commercial amounts of petroleum.

Visual techniques for kerogen characterization provide information that cannot be derived strictly from chemical data. Similarly, chemical data enhances the findings of the organic petrologist. Kerogen type assessment is best provided by visual kerogen analysis and various chemical analyses such as pyrolysis gas chromatography. Detailed analysis such as pyrolysis gas chromatography and laboratory maturation techniques such as microscale sealed vessel analysis provides detailed chemical composition and product type at various levels of thermal maturity.

Imaging techniques have advanced the understanding of petroleum storage in source rocks as well as the mineralogical variability. Further input is needed from organic petrologists to understand the full complexity of the organic and inorganic matrix.

Thermal maturity is also best addressed by a combination of visual and chemical techniques. The most common technique and industry standard is vitrinite reflectance. However, on marine shale source rocks, vitrinite is typically only present in minor amounts and is morphologically similar to bitumen or at higher thermal maturity, pyrobitumen. A solution to this conundrum is to perform vitrinite reflectance measurements on shales or coaly organic matter up-hole from the shale reservoir of interest. Identification of reasonably organic-rich and more mixed to gas prone organic matter provides indications of up-hole samples more suitable for vitrinite reflectivity analysis. These data can then be projected through the shale of interest if the burial history is understood. Clarification of thermal maturity can be addressed by utilization of chemical techniques especially quantitative aromatic hydrocarbons.

It is essential to provide E&P teams interpreted kerogen and thermal maturity data. Otherwise, the complexity of the data can easily confuse experts and management that

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are not familiar with the idiosyncrasies of such analysis. Not all data can be considered equal due to various limitations such as sample choice for specific analysis.

Keywords: Shale resource plays, Unconventional shale resources development, Organic Geochemistry, Imaging, Interpreted thermal maturity (i%Roe), Sweet spotting.

INTRODUCTION

Petroleum systems analysis details various components and processes that affect the risk associated with finding commercial amounts of petroleum. This approach, even before being formalized, has now been broadly applied across exploration and production teams and their management resulting in greater success in assessing the risks associated with exploration and production (E&P) [1]. Management expects a coherent and integrated assessment of these risks that requires a team approach. While it is desirable to have independent analysis of different aspects of the petroleum system, it is inherently necessary to integrate all results into a coherent assessment that management can act upon. However, analytical results are often presented to exploration and production (E&P) teams without such integration in part because of having independent analyses completed and requiring E&P and engineering teams to perform such integration. The best results will be obtained with a truly integrated team, *i.e.*, directly interacting geoscience and engineering personnel, towards achieving a final risk or properties assessment. While it is easy to speak of integration, it is not simple to achieve. However, it is critical to successful application of petroleum systems technologies and interpretations.

Advances in assessment of both conventional and unconventional systems has been dramatic over the past decade. The fact that unconventional systems have had such success in recent years has reborn efforts to better understand the components and processes that affect potential production targets. Source rock volumetrics and processes such as retention, cracking, expulsion, migration, and storage of petroleum have been reassessed with increased understanding.

Another key component in assessing exploration targets and discoveries are the physico-chemical properties that affect its production. Geochemistry should include a specific prediction of the reservoir contents in terms of expected physico-chemical properties such as API gravity, viscosity and GOR. These data relate to petroleum quality and pressure that are critical in prospectivity for production as well as sweet spotting and completion techniques.

BACKGROUND

Development of low porosity, low permeability source rocks and juxtaposed non-source lithofacies describe the exploration and production work completed on unconventional prospects. Organic-rich source rocks are usually mudrocks or mudstones, but are more commonly referenced as shales, which will be used in this paper. Shales are often viewed as seals, which they may be and that describes both their ability to contain a trap, but also their ability to retain much of the generated petroleum in organic-rich intervals. Of course other rocks may be seals as well and also barriers to help keep stimulation efforts in the sweet spot of an interval.

Organic petrology is a geoscience focused on the physical and analytical description of the composition, structure, and concentration of organic matter found in rocks in order to accurately classify the organic constituents. It is also utilized to establish the extent of conversion of this organic matter referred to as its thermal maturity. Thermal maturity is a record of the paleo-temperature exposure of the rock usually a sediment.

While petrology is employed in the coal sector, over the decades it has become increasingly involved in the petroleum sector with description of organic matter and its thermal maturity. Obviously a key component in the petroleum system is the source rock itself and a key process is the maturation of the kerogen and the transformation of specific constituents of kerogen that lead to the formation of petroleum. However, organic petrology has often been completed in isolation from integrated teams that can elucidate and assist with the assessment of thermal maturity and kerogen assessments. This is not the fault of petrologists, but is a fact of the analytical approach often taken by service laboratories and independent E&P and engineering teams. As such there may be conflicts among data types particularly visual and chemical assessments that must be resolved and explained.

Recent application of argon ion milling has provided ultra-thin section preparations that allow imaging at the nanoscale level. Such preparation and analysis reveals the presence of pores in organic matter [2] that appear to be the principal means of gas storage in many organic-rich shale resource systems. Imaging work is not a new approach but combining this technology in the assessment of shale resource systems having abundant organic matter needs the assistance of organic petrologists. This was demonstrated recently by Cardott and Curtis [3].

Understanding thermal maturity is a key aspect of the process inherent in understanding a petroleum system. However, organic petrographic determination of thermal maturity is difficult in marine shales due to the limited amount of the

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