London Petrophysical Society ***(a chapter of the SPWLA)***
One-day Seminar

"What's So Special About Core Analyses?"

Thursday 26th March 2015
at the Geological Society, Burlington House, London

This is the latest in our line of "Basic FE" seminars, and is intended as an introduction to Core Analyses for Petrophysicists and other Geoscientists. This one-day seminar will provide a basic understanding and vocabulary for professionals from a wide-variety of backgrounds and it should work to improve the way we can work together as a team to achieve effective integration of core data into the understanding of our reservoirs.

Agenda

start	*end*	*Topic*	*Presenter*	*Company*
09:00	*09:15*	*Registration*	*LPS*	*LPS*
09:20	*09:30*	*Introductions*	*LPS*	*LPS*
09:30	10:10	Overview - petrophysical fundamentals - porosity, permeability, capillarity	Prof. Mike Lovell	Leicester Uni
10:10	10:50	Innovative coring technology and wellsite handling techniques for better quality core	George Williamson	Baker Hughes
10:50	*11:10*	*Break*		
11:10	11:50	Introduction to analysing cores - plugging, cleaning/drying, basic analysis and some basic QC	Craig Lindsey / Richard Ashcroft	Core Specialist Services
11:50	12:30	Calibrating log-to-core for porosity, electrical properties and saturations	Mike Millar	BG
12:30	*13:15*	*Lunch*		
13:15	13:55	Wettability and Relative Permeability	Andrew Cable	Weatherford Labs
13:55	14:35	Capillary pressure and height-function	Adam Moss	BG
14:35	15:15	Core Analysis in Unconventional Reservoirs	Prof. Ernest Rutter	Manchester Univ
15:15	*15:35*	*Break*		
15:35	16:15	Southern North Sea SCAL case study	Paul Hoddinott	E.on
16:15	16:55	Insight to core space processes and their implication	Prof. Richard Dawe	Emeritus Prof UWI
16:55	17:10	Wrap-up	LPS	LPS
17:10		*Wine and Savouries*		

Petrophysical fundamentals: porosity and water saturation, permeability, wettability & capillary pressure

Mike Lovell, University of Leicester

Abstract

This talk sets the scene for a day of presentations and detailed discussions on petrophysical core analysis. We will consider the simple definitions of a range of basic petrophysical properties, the frequently complex concepts behind these innocuous statements, and the vocabulary we use to discuss them.

Porosity is the potential storage space in the reservoir. In a simple approach to sandstones it may be based on the space between the cemented grains, although in carbonates the porosity can take many other complex forms; in unconventional reservoirs porosity may exist between the inorganic minerals and also develop during maturation within the organic material. We can define a number of different porosities, based on either the total volume of space (total porosity) or, particularly in a reservoir containing a significant proportion of clays, the volume of space that is accessible to hydrocarbon fluids (effective porosity). In core analysis it is important to understand what volume of space you are measuring in your porosity determination and how this relates to other (log and core) measurements or to the conditions in the reservoir, as depending on how the core has been handled and treated the measurement may yield a porosity value that is neither total nor effective.

Saturation is an evaluation of how much hydrocarbon occupies the pore space. Typically when we estimate the amount of hydrocarbons in a reservoir from logs or core we first determine how much water occupies the pore space (water saturation) and then assume the remainder of the pore volume contains hydrocarbons. The hydrocarbon saturation is then determined as the proportion of the pore volume containing hydrocarbons, through a volumetric or mass balance approach. In unconventional reservoirs such as shale gas this can be further complicated, or on occasion simplified, depending on precisely where you consider the hydrocarbons to be located in your petrophysical model.

Permeability concerns the ease with which a fluid flows and is normally based on Darcy's Law. As such permeability is not the flow rate, although it is proportional to it; permeability has dimensions of length squared. We can consider a single phase permeability when the rock is fully saturated with one fluid, or an effective permeability when more than one phase is present. The ratio of these two allows us to define a relative permeability. In anisotropic formations permeability is dependent on the direction of fluid flow, and for core analysis this places significance on the orientation of the core plug relative to any rock fabric and/or well orientation. In unconventional reservoirs the determination of permeability is often difficult because of the low permeability values involved and remains a topic of debate; hence the common requirement to fracture the formation to produce hydrocarbons.

The parameters above (porosity, saturation and permeability) are basic, essential petrophysical characteristics. But the distribution of fluids in a reservoir is of primary interest and this is controlled by two additional parameters, wettability and capillarity. Most reservoir rocks are deposited in aqueous environments, and consequently the pore space starts out at, or close to, 100% water saturation. It is only though the process known as drainage that the reservoir becomes charged with hydrocarbon, as the hydrocarbon enters the reservoir or storage rock, and the original pore fluid, or pore water, drains. This pore fluid is typically saline. (Equally, water may displace hydrocarbon in the reverse process, and this process, known as imbibition, occurs during production through a water drive). Both these processes can be simulated in the core laboratory.

The movement and distribution of fluids is controlled by a number of parameters, including the wettability, the capillary pressure, and the buoyancy pressure of the fluid. These in turn are determined by the chemistry of the fluids and solids (or minerals), the pore size and pore size distribution, and the physical surface character of the solid minerals, as well as temperature and pressure. Much of this activity occurs at the pore scale, and it is these complex interactions between each of the fluids, and the fluids and the solids, that determine the distribution of fluids at the reservoir scale. In considering the distribution of fluids it is important to separate out the concepts of free fluid level, or free water level, which is determined by pressure measurements in a well or capillary measurements on core samples, from the concept of hydrocarbon-water contact, which is determined by the static determination of a change in water saturation to less than 100%.

Wettability, in a simplistic approach, determines which fluid is in contact with the solid frame of the rock, and depends on the relative strength of the intermolecular forces between the water and the mineral grains and the hydrocarbon and the minerals grains. We can define a wettability contact angle, θ, and the chemistry of the solids and fluids are fundamental to determining whether a rock will be water wet or oil wet. Sandstones are often water wet while carbonates may have a tendency to be oil wet; in unconventional shale gas reservoirs we often assume the organic matter is hydrocarbon wet while the silicate minerals are normally assumed to be water wet.

Capillary forces are determined by this contact angle, but also the radius of the pore, and the interfacial tension. The interfacial tension is simply a measure of the 'strength' of the interface between two immiscible substances whether two liquids, a liquid and a solid, a liquid and a gas, or a solid and a gas. In general the smaller the pore size the larger the capillary pressure that holds the water in place prior to drainage. To enable the water to drain and the reservoir to be charged with hydrocarbon, the capillary forces must be overcome by the buoyancy force. Buoyancy is simply another way of considering gravity, where rather than focusing on the denser fluid (water) sinking we consider the less dense fluid (hydrocarbon) migrating upwards and displacing the water when it overcomes the capillary pressure. This buoyancy pressure depends on the density difference between the pore water and the hydrocarbon, and the height of the hydrocarbon column. In unconventional reservoirs the reservoir is often the source, and while wettability is important and controls the distribution of hydrocarbons, the fluids have typically migrated only a short distance and so capillary effects are of less significance.

Core analysis provides a range of measurement techniques that contribute significantly to the petrophysical analysis of conventional and unconventional reservoirs. Integrating these core data with downhole log data provides a better understanding of the reservoir, and reduces uncertainty in establishing the location and distribution of hydrocarbons. In addition they can enable an appreciation of the processes that have led to the present day distribution of hydrocarbons and provide insight into how the reservoir may perform.

Innovative coring technology and wellsite handling techniques for better quality core

George Williamson   Baker Hughes

Abstract:

Recovery of high quality core significantly enhances the processes of formation evaluation. Proper handling of core on surface is just as critical as the acquisition of good core, during drilling. However, poor handling of core can lead to catastrophic damage of the internal core (rock) fabric, leading to poor and highly inaccurate laboratory results. Correct onsite core-handling procedures and core preservation techniques can provide petrophysicists the answers they need for critical reservoir issues. These include rock analysis, fluid determination, flow characteristics, storage capacity and production potential of the rock mass.

Using the accurate formation data obtained through carefully planned coring and core handling programs, Petrophysicists, Reservoir Engineers and Geologists can fine tune drilling and completion programs for improved asset management over the productive life of a well or wells. In addition, carefully managed and preserved core samples provide increased certainty for operating company economic valuations, via their petrophysical investigations.

This is an important topic and both experienced professionals and those relatively new to the industry are encouraged to attend.

Biography: George Williamson

George graduated from Robert Gordon University with a Post-Graduate Diploma in Offshore

Engineering and a B.Sc. in Chemistry in 1984. Since 2008, he has worked as a Product Line Manager for coring in the Europe Africa Russia Caspian region. Prior to this, George spent several years in the field, with coring and down-hole drilling tool divisions, as well as onshore technical and operational support positions.

Introduction to analysing cores

Richard Ashcroft   Core Specialist Services

Abstract

Core provides the only direct and quantitative measurement of reservoir parameters, essential for effective static and dynamic reservoir modelling. Errors made during core handling, preparation and the measurement of basic rock properties, such as porosity and permeability, can have far reaching consequences: the accurate quantification of Archie parameters, capillary pressure and relative permeability all depend upon the accuracy of these base values. Errors made early on in core analysis will ultimately compound and translate to errors in HIP, recovery an asset value.

This presentation provides an overview of laboratory planning, core handling, plugging, cleaning and drying techniques used to ensure plug samples are appropriately prepared for the measurement of porosity and permeability.

Examples of common problems associated with some of these measurements are also highlighted and some pointers are given on basic QC.

Bio: Richard Ashcroft
Richard has 27 years of experience in the core analysis industry. After 25 years working in the lab, most recently as the SCAL lab supervisor for Core Lab in Aberdeen, Richard joined Core Specialist Services in 2013. Core Specialist Services are a consultancy specialising in the planning, design and management of core based studies.

Calibrating Log-to-Core for Porosity, Electrical Properties and Saturations

Mike Millar BG Group

Abstract

Integrating core analyses data and logs is fundamental to good Petrophysics. We need to make sure that the core analyses data is representative of the formation conditions, especially overburden stress. We also need to ensure that the core and logs are on depth.

Core can be used to derive input parameters to determine porosity from logs. It is important that the correct parameters such as matrix and fluid density, are chosen to ensure the most accurate formation porosity is calculated. Porosity is a fundamental component of the Archie saturation equations.

The talk will also cover how core analysis can be used to determine the water saturation of your reservoir. The talk will show how, in certain circumstances, water saturation can be determined directly from core with Dean-Stark extraction. It will also explain how to derive input parameters for the Archie equations from core with Formation Resistivity Factor and Resistivity Index measurements. Resistivity logs, combined with porosity, provide the primary data for calculating water saturation in most wells, and this means that the Archie equations are of fundamental importance to Petrophysics.

In essence, Archie was able to show that water saturation is inversely proportional to the increase in formation resistivity as you move from a water filled interval into a hydrocarbon filled interval in your reservoir. The resistivity of the water filled interval, Ro, can be derived from porosity if the Formation Factor exponent, m, is known. This can be determined from core or logs. Water saturation can then be derived from the ratio of Ro to formation resistivity in the hydrocarbon-leg, Rt, using the saturation exponent, n. The saturation exponent can be measured on core.

To use Archie successfully we have to assume that formation water salinity is consistent between the water-leg and the hydrocarbon-leg and that the matrix is non-conductive. The Archie equations have problems when sediments occur in beds thinner than the resolution of the resistivity tool, also when the matrix is conductive, for example in shaly sands. Core analysis can also provide input parameters for the Waxman-Smits shaly sand equation.

The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics. G. E. Archie, 1942. SPE-AIME Transactions

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Wettability & Relative Permeability

Andrew Cable, Laboratory Manager, Weatherford Laboratories

Abstract

Careful considerations are required to provide measured relative permeability data that are fit for purpose. Relative permeability (and capillary pressure) data are used as input data into full field simulation models to forecast production profiles and recovery factors.

In this presentation, Andrew will describe core selection and preparation processes that are necessary for quality laboratory measurements. Primary drainage methods are described including the use of γ-ray insitu saturation monitoring that is used to minimise data uncertainty. A short section will be provided on wettability – what it is, how it might be measured and how important it is to get it right when measuring oil-water relative permeability.

The remainder of the presentation will discuss the measurement of water oil relative permeability, both unsteady-state and steady-state methods, and how core flood simulation is used to history match observed transient data. Case history pressure and oil production data will be shown together with resulting imbibition kr and Pc curves.

Capillary Pressure and Saturation Height Functions

Adam Moss - BG Group

In this presentation I will introduce the basic capillary pressure theory and review various workflows for the construction of a saturation height function.

The most important criteria when choosing a mathematical function to describe the relationship between saturation and height are that:

- The function must provide a good fit to the measured data over a wide water saturation and rock quality range. Differences between the function and the real data must be examined so that the uncertainties can be assigned.

- The function must be able to be integrated easily for zonal average hydrocarbon saturation calculation. In other words, it must be possible to effectively map in the reservoir model the parameters (porosity / permeability / facies etc.) upon which the core derived model is based.

In order to predict water saturation from the saturation height (SHT) model it is necessary to determine in-situ capillary pressure. To do this we need to know the height above the free-water level (FWL) and the fluid properties (density).

Numerous core based SHT functions are available however it is advantageous to apply one that can be easily deployed in the reservoir model. For example, a function which depends only upon the ability to predict, map and model porosity is easier to apply than a function that uses permeability. Permeability can be much more problematic to predict and map in the reservoir model. That said; if the best performing function uses permeability it may be unavoidable to attempt to apply it in some form. It is recommended that several different potential SHT models are investigated in order to determine which best represents the physics of the reservoir in question.

Examples of both the Leverett J function and Thomeer models will be presented in this presentation.

Leverett, M.C.: "Capillary behaviour in porous solids", Trans AIME, 142, 1944
Thomeer: "Introduction of a Pore Geometrical Factor Defined by The Capillary Pressure Curve", JPT, March, 1960, SPE Paper 1324.

INFLUENCE OF EFFECTIVE PRESSURE ON MUDSTONE MATRIX PERMEABILITY: IMPLICATIONS FOR SHALE GAS PRODUCTION

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Interpretation of shale gas well test data commonly assumes rock matrix permeability k is constant as gas pressure drawdown occurs, but increase in effective pressure P_{eff} (overburden pressure minus pore pressure P_p) with drainage of the reservoir leads to partial elastic closure of pore throats and decrease in permeability extending for hundreds of metres from a hydraulic fracture. By taking into account such permeability change, through measuring it as a function of effective stress in laboratory experiments, more realistic estimates of gas in place and likely yield can be made.

We tested two different shales over a full range of likely reservoir pressure conditions (up to 70 MPa effective pressure), to establish the similarities and differences in their generic patterns of behaviour. Samples included Whitby Mudstone, a clay-bearing, silt-rich mudstone with 6-9% porosity, 1.5 wt% TOC, and clay-rich mudstone from the Haynesville Formation (8% porosity, 3.1 wt% TOC) (Texas). In both cases we measured permeability during pressure cycling, on the one hand keeping pore gas pressure constant and varying total pressure, and on the other hand keeping total pressure constant and varying pore pressure. This allowed determination of how 'effective' is the pore pressure relative to total (confining) pressure. Samples were tested both parallel and perpendicular to the bedding-parallel fissility.

In both shales, initial application of pressure produces a large permeability decrease, and subsequent pressure cycles exhibit reproducible behavior described by

$$\log k = A + \gamma (P_{eff} - b\, P_p)$$

In Whitby shale, Biot coefficient b ~ 2 thus pore pressure changes permeability more than does effective pressure. In Haynesville shale b ~ 1, but γ is much larger, thus permeability is very sensitive to P_{eff} changes. We use simple reservoir modelling, formation-parallel flow with a single hydraulic fracture, to illustrate the consequences of these results.

Southern North Sea SCAL case study

Paul Hoddinott, E.On

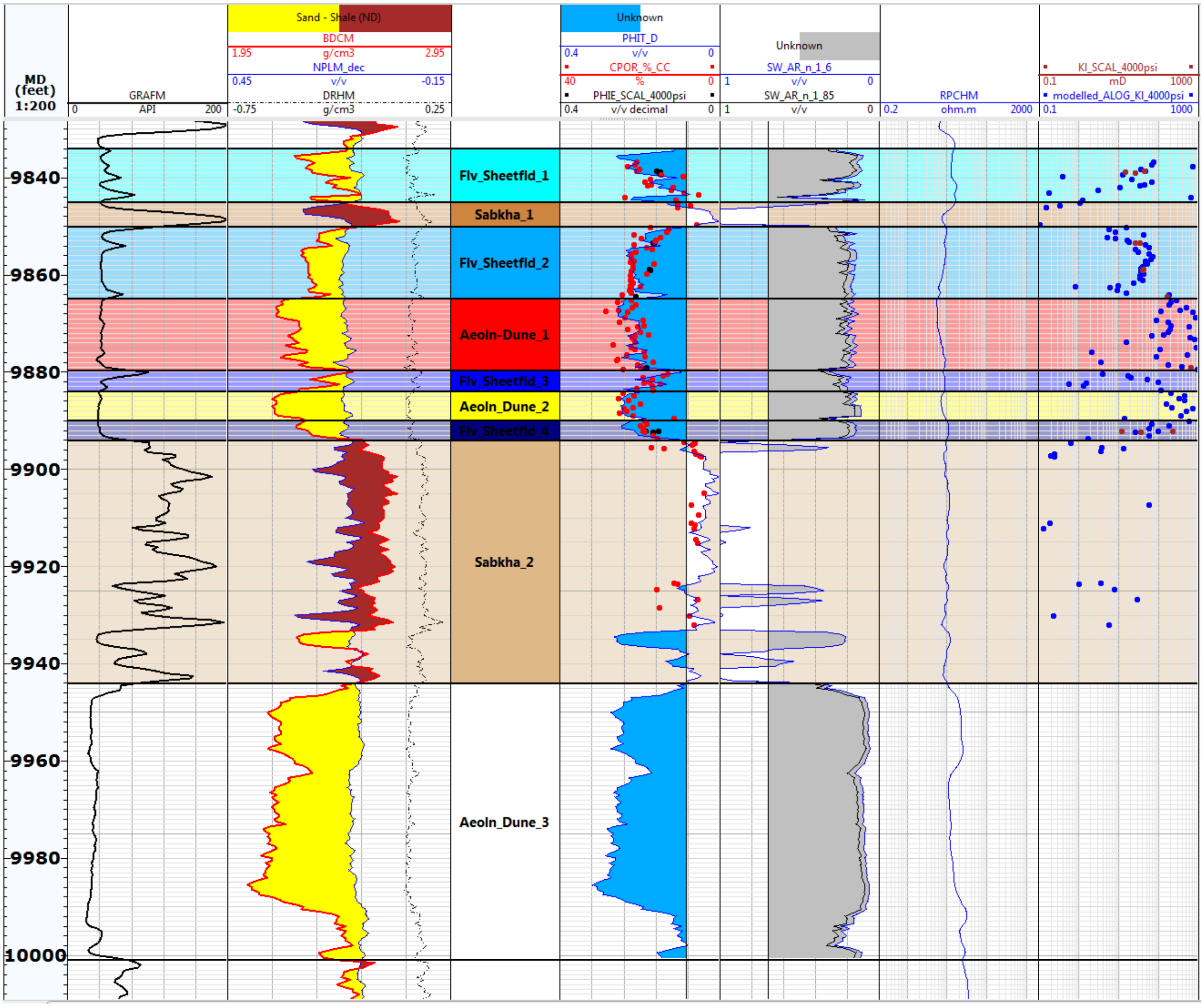
Abstract

This talk is a case study of a Special Core analysis (SCAL) programme of a significant gas discovery well in the UK Southern North Sea. The study will highlight the importance of relating core facies descriptions to reservoir properties in petrophysical analysis and integrating core to wireline/LWD data, for input to static and dynamic models. Throughout the case study reference will be made to data acquisition, data collection and sampling, reservoir quality index (RQI), selection of input parameters for updating petrophysical analysis, laboratory vs. reservoir stresses, the effect of overburden stress on petrophysical measurements and the practices and pitfalls of building permeability transforms to predict well deliverability.

The SCAL programme includes a wide range of measurements including:-
1/ Porosity, Formation Resistivity Factor (FRF) and Brine Permeability (Kw) at simulated overburden stress.
2/ Resistivity Index (SW-RI) using the centrifuge technique and a brief discussion of the advantages and disadvantages of this method.
3/ Capillary pressures using Primary Drainage Centrifuge and a discussion of how these data can be integrated into petrophysical analysis and applied to the static/dynamic models.
4/ XRD, thin sections and Mercury-injection capillary pressures using plug trims.
5/ Primary drainage Relative Permeability and the importance of Krg@Swi transforms.

Results from the SCAL programme have delivered important learnings on data collection, the sensitivity of petrophysical parameters, the varying effects of overburden stress and the role of geology and facies typing on reservoir properties, and anomalous relationships between Resistivity Index (RI) and Water Saturation (SW), including low Archie “n” values.
A brief overview of the applicability of the different Saturation-Height curve fitting models e.g. Leverett-J function, Corey-Brooks, Lambda and Thomeer, to Southern North Sea Leman gas fields exhibiting very different reservoir characteristics will also be covered.

Photograph of Preserved samples for SCAL



Petrophysical analysis of SNS discovery well showing wireline/LWD and core data

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What goes on inside a core?
Insight to core space processes and their implications

Professor Emeritus Richard Dawe, University of the West Indies;
radawe@yahoo.com

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The majority of reservoir rock is heterogeneous, even at the core scale. Computer tomography and inspection of any outcrop will confirm this. However, many processes to estimate the physical properties needed for reservoir calculations such as porosity, permeability, capillary pressure and relative permeabilities assume that the core is homogeneous. This may be convenient/essential for estimations of the parameters for oil-in-place calculations or for reservoir simulation input parameters, but experiments showing how the fluids really flow through the pores/cores and hence reservoir indicate that heterogeneities affect the flow and thus may challenge the assumptions.

There are many millions of pores per cc of reservoir rock and all fluids have to flow through them to be produced. This talk will illustrate flow inside model reservoir porous media, starting with modelling at the pore scale then to the core scale. The flow of miscible and immiscible fluids will be shown by way of some beautiful photographs of experiments of flow inside micromodels, 2-D visual cells containing networks through which fluids can pass, and inside core-scale heterogeneous materials using bead-packs, where the heterogeneities (simple permeability and wettability contrasts) have been deliberately put into the porous material. Core and pore scale single and two- and three-phase events will be illustrated, including the effect of permeability and wettability contrasts, saturation changes, (stationary) gas bubbles and low interfacial tension. The significance of how fluids really flow through reservoir core with heterogeneities will be highlighted.

As the scale-up of parameters derived at the core scale to real reservoir dimensions is based on a number of assumptions, some of which may be false, this scale-up may make the derived interpretations dubious. The impact on estimating any reservoir parameter based on fluid flow through homogenous vs. heterogeneous reservoir rock will be discussed. We will present some of our visual micro- and beadpack experimental evidence which may suggest how the essential reservoir physics is/is not being represented in reality. The practioner/listener is left to give their own interpretation of any measurements they may have!

Contents of talk

Heterogeneity of reservoir rocks, including demonstration by computer tomography
Reservoir Physics. - set up of the flow situations
Typical heterogeneities, pore scale, micromodels, core scale, permeability and wettabiliy.
Examples of flow of typical heterogeneities and wettability; single, 2-phase and 3-phase flow.
Interpretations - wrong assumptions in real life?
- wrong conclusions even if accurate measurements?
Consequences
The talk will contain no equations - only pictures.

Biography: **Professor Emeritus Richard Dawe** was the first holder of the TTMC chair in Petroleum Engineering at the University of the West Indies, Trinidad and Tobago, from 1999 until his retirement in July 2011. Before that he joined the University of Qatar, Doha in November 1997 as Occidental Chair in Petroleum Engineering having taken early retirement from Imperial College, London (1975 - 97) where he had risen to Reader in Reservoir Physics. From 1992 he directed the successful MSc in Petroleum Engineering. He had joined Imperial College, London in 1975 following academic appointments in Chemical Engineering at Leeds University and the University of Manchester Institute for Science and Technology (UMIST). He gained his BA, MA and DPhil from Oxford University (St Catherine's).
His research interests lie in the areas of reservoir engineering, particularly those concerned with how reservoirs behave and reservoir physical properties. He has published over 230 papers. He gained a Vice-Chancellor's Award UWI for excellence 2005 and the Fenrick De Four Award for Engineering NIHERST Trinidad in 2013.