SPWLA 64th Annual Logging Symposium
Lake Conroe, Texas, USA, June 10–14, 2023
Technical Program

NOTE: Tentative Program: Selected papers listed below may not be in the order in which they will be presented. The final technical program may differ from that shown due to paper withdrawals. All technical sessions will be held at the **Margaritaville Lake Resort***. Photography and video/audio recording of any kind are strictly prohibited in all areas, including technical sessions, workshops, and exhibition hall.*

AUTOMATED METHODS OF FORMATION EVALUATION

A Method for Determining Formation Porosity From Gamma Ray Energy and Time Spectrum Induced by Pulsed Neutron in Cased Well

Hui Zhang, Feng Zhang, Fei Qiu, Xiaoyang Zhang, Yiming Yu, and Han Wang, School of Geoscience, China University of Petroleum (East China)

Pulsed-neutron gamma energy spectroscopy and neutron lifetime measurement systems enable the evaluation of the elemental content, saturation. And recent studies have demonstrated that neutron porosity can be determined using a measurement system consisting of a pulsed-neutron generator (PNG) with a gamma detector. However, the measured neutron gamma porosity is not the same as the compensated neutron porosity of openhole wells using Am-Be chemical sources (φ_{CN}). Algorithms introduced in the past have included matching methods for porosity using superthermal neutron counting ratios that use density to eliminate source energy differences between instruments.

This study mainly focuses on the difference in the action process between the pulsed-neutron gamma instrument and the conventional chemical source instrument. The new porosity evaluation parameter Rm is constructed by extracting and combining the measurement information of gamma energy and time spectrum. The parameter uses its own measurement information while eliminating the effect of porosity differences between two measurement systems with different source energies and different detection types. It achieves the reproduction of φ_{CN} in cased wells for different instrument design structures, which is of great economic and practical value for solving the lack of openhole data in actual logging and obtaining multiple parameters of the formation.

The measurement system uses a D-T source (14 MeV) with multiple gamma detectors. The fast neutrons emitted by the pulse source will first have inelastic scattering with the formation, and then elastic scattering will occur. Thus, there is a difference in the deceleration length of fast neutrons emitted by high-energy pulsed sources and conventional chemical sources. In this case, the count ratio obtained from the pulse source measurement is less sensitive to the hydrogen content index of the formation. Also, due to the different processes of production between thermal neutrons and scattered gamma rays, differences can exist between the neutron porosity determined by the gamma-to-thermal neutron counting ratio.

This paper focuses on the problem of neutron porosity response mismatch caused by the dual difference of action processes between pulsed-neutron gamma and conventional compensated neutron measurement systems by extracting the information of multiple parameters in the gamma energy spectrum and time spectrum. Combining inelastic count ratios (Rin) and sigma with the capture count ratios, it is used to eliminate the effects of the differences in source energy and detection type with φ_{CN}. Thus, the measurement sensitivity is greatly improved, and the reproducibility of φ_{CN} logging response is achieved.

To construct a porosity evaluation model based on the structure of the detection system, the Monte Carlo simulation method is used to model the D-T source instrument for gamma detection and the chemical source instrument for thermal neutron detection. We change the formation to different minerals and clay, then record the gamma energy and time spectrum information from multiple gamma detectors. The two auxiliary parameters, sigma and Rin, were obtained by the forward method to construct the porosity evaluation parameters (Rm). Finally, the neutron porosity evaluation model is established using Rm. Furthermore, the inelastic count ratio measured by multiple detectors constitutes an I_b parameter to eliminate the effect of the borehole on neutron porosity measurement.

Finally, we processed two sand-shale logs with different diameters in Shanxi, China. Neutron porosity evaluated by our method is compared with φ_{CN}. In a low hydrogen-bearing formation (φ_{CN} < 20 p.u.), the absolute error of neutron porosity matching is reduced from 3 to 10 p.u. to less than 1 p.u. A high hydrogen-bearing formation (φ_{CN} > 20 p.u.) is reduced from the original 10 to 15 p.u. to less than 1.5 p.u. The logging example further verified the effectiveness of this method in evaluating formation neutron porosity by using a pulsed-neutron gamma detection system in cased hole. It also verified the accuracy of matching with the openhole compensated neutron porosity.

This paper focuses on the problem of neutron porosity response mismatch caused by the dual difference of action processes between pulsed-neutron gamma and conventional compensated neutron measurement systems by extracting the information of multiple parameters in the gamma energy spectrum and time spectrum. Combining inelastic count ratios (Rin) and sigma with the capture count ratios, it is used to eliminate the effects of the differences in source energy and detection type with φ_{CN}. Thus, the measurement sensitivity is greatly improved, and the reproducibility of φ_{CN} logging response is achieved.

Accurate Mineralogy When Logs Are Scarce or of Limited Fidelity: Innovative Data Analytics Solution Leveraging Core-Logs Integration

Laurent Mosse and Chiara Cavalleri, SLB; Massimiliano Borghi and Marco Pirrone, Eni S.P.A Natural Resources

The accurate and robust quantification of mineralogy is a critical step in formation evaluation. It enables porosity and saturation computations and provides input to the definition of lithofacies and lithostratigraphic units; it also contributes to completion and stimulation designs. In the context of carbon capture and storage (CCS) projects, knowledge of mineralogy impacts long-term storage capacity, injectivity, and sealing integrity evaluations.

Mineralogy evaluation from logs has long been studied, and several techniques have been developed to reconstruct the mineralogy from combinations of log measurements. For example, in multimineral solvers, a volumetric interpretation is performed using a system of weighted linear response equations to solve for selected minerals and fluids. The number of mineral components to be solved is limited by the number, quality, and information content of input logs. When the evaluation is based on a limited set of logs, it is not always possible to solve robustly for a representative set of minerals, and the resulting mineralogy remains inaccurate or unstable.

A novel core-log integration workflow is proposed to solve this challenge by leveraging the inherent correlations between minerals as associated with depositional settings. A principal component analysis (PCA) is first performed on a local representative core mineralogy database to understand the dimensionality of the system. Once the number of independent pieces of information needed to describe the system is defined, a non-negative matrix factorization (NMF) is applied and provides a set of mineral assemblages. Figure 1 shows an example of how a set of four assemblages enables an accurate representation and reconstruction of complex core data composed of seven minerals. The ability to reduce the dimensionality of the system through the definition of ad-hoc mineral assemblages enables solving for accurate mineralogy in cases where well-log data are limited in number or fidelity, for example, when the evaluation is performed using old legacy logs or with casedhole logs only.

A field example from a complex depleted reservoir being repurposed for CCS is presented, demonstrating the applicability and versatility of the methodology. The existing petrophysical model, based on legacy openhole logs, is now reinterpreted and is extended to sealing layers not covered by openhole logs, using more recent pulsed-neutron casedhole logs. The resulting accurate mineral and petrophysical models enable a more efficient evaluation of CO_2 storage capacity and identification of potentially CO_2-reactive facies and markers.

This novel data analytics workflow, proceeding from core-log integration, will find applications in many scenarios and for different applications in addition to the CCS case study presented.

Automatic Injection of NanoTags for Improved Cutting Depth Correlation

Gawain Thomas, Marta Antoniv, S. Sherry Zhu, and Martin Poitzsch, Aramco Americas; Hyung T. Kwak, Saudi Aramco

Real-time evaluation of drill cuttings in the field is highly desired because direct petrophysical characterization of the formation, when integrated into mud-logging workflows, can effectively support logging and measuring while drilling (LWD and MWD) and geosteering. In unconventional reservoirs and for extended-reach horizontal drilling circumstances, an economically affordable method for formation evaluation can optimize well placement, improve the efficiency and safety of drilling and completion, and ultimately maximize recovery cost effectively. Conventional mud-logging technology determines the cuttings' depth based on the lag time of the return trip up the annulus. The return trip may be underestimated, however, from overgauge drilling, hole caving, gravitational debris accumulation, etc. Thus, the depth assignment may result in uncertainties of 10 to 20 ft or more, assuming a lag time of 30 minutes.

We have demonstrated that injecting polymer nanoparticles (NanoTags) into drilling mud can label cuttings for accurate determination of the cuttings' depth of origin. The NanoTagging technology uses the downward lag time, estimated via the internal volume of the drillpipes and mud hydraulics, and thus reduces the uncertainties of the cuttings' depth of origin due to variation in annular volume. We demonstrated the NanoTagging technology in 2019 via a field test when drilling a gas well in a carbonate formation, where the cuttings' depth variation was reduced to ± 1 ft at a drilling speed of about 1 ft/min.

Here we report our design and demonstration of the automatic injection of barcoded NanoTags during the drilling of a gas well located in a carbonate formation in 2022. The automatic processing of the recovered cuttings to extract tags from the cuttings after the field test is also discussed.

Our newly designed and in-house constructed air-powered rapid-multiplexing tag injection apparatus consists of high-pressure fluid tanks for tag colloids, air lines for pressuring the tank, needle valves for flow rate control, one-way check valves, and a LabView-based automation software to operate the apparatus. During the drilling of a gas well located in a carbonate formation, we programmed the injection time and flow rate for each tag based on the flow rate of the water-based mud (WBM). We then injected three NanoTags into the mud pumps' intake line through a small valve on a flange. The apparatus delivered sharp pulses of each tag, which mixed into the mud without any adverse impact on the drilling operations.

We have also customized a robotic platform to prepare the field cuttings for analysis. The robotic platform weighed cuttings, added solvent, filtered the cuttings, and vacuum-dried 48 batches of cuttings within 24 hours. This workflow recovered the tags from the field cuttings, and the nanograms of tags recovered from the limestone samples were detected by pyrolysis-GCMS. The customized automation platform significantly reduced the time and manpower that were required to prepare the cuttings for characterization.

The automation of the NanoTagging technology has improved the efficiency and accuracy of mud logging cost effectively. The technology will also create new opportunities for logging in conditions where traditional mud logging is not available.

Far-Field Lateral Tectonic Strain Prediction From Straddle Packer Formation Stress Measurements

Javier Alejandro Franquet, Baker Hughes

The objective of this work is to provide estimated lateral tectonic strain values to geoscientists and petroleum engineers from easy-to-use subsurface depth correlations. These correlations are obtained from over 600 straddle packer microfrac tests conducted across the world. This methodology does not have the purpose of replacing rigorous in-situ stress derivation from fracture closure measurement tests and borehole failures such as breakouts or induced fractures observed from image logs. These correlations, however, can provide probable tectonic strain ranges vs. depth in exploratory areas where wellbore data and stress tests are not available.

Hundreds of microfrac stress testing data collected during the last 30 decades have been analyzed to obtain the far-field tectonic strain values. The lateral strains are obtained by an inversion method using the basic petrophysical formation properties and the straddle packer in-situ stress measurement balancing the elastic tensor relationship of stress equal to stiffness time strain. The average formation porosity, density, compression, and shear slowness across the microfrac testing interval are used to calculate Young's modulus, Poisson's ratio, tensile strength, and Biot's poroelastic coefficient. The minimum and maximum lateral strain values are obtained once the predicted tectonic stress values match the microfrac testing results of each formation breakdown and fracture closure measurements. Finally, basic depth correlations are derived, so lateral strain values can be easily predicted to solve geomechanics challenges across 500 to 18,000 ft deep.

The predicted tectonic strain data shows values between 0.01 to 1.6 mStrain. The minimum lateral strain values are more constrained than the maximum lateral strain, which seems to have a higher variability with depth. Both lateral strain profiles exhibit a clear increase at depths higher than 9,000 ft, where the tectonic stress effects amplify in subsurface rock sediments. Multiple pore-pressure gradient conditions varying from 8 to 18 ppg are studied across multiple basins since overpressure zones have poroelastic implications in the effective stress state.

This is the first-time lateral Earth strain correlations vs. depth are presented in the industry that could be used to predict tectonic stresses easily at specific depths if the rock stiffness is known. These empirical equations can be used by geophysicists to derive effective stress profiles from seismic attributes with an acceptable uncertainty before a well is drilled.

Generative Adversarial Networks-Based Forward-Inverse Method for Geophysical Logging

Rongbo Shao, LiZhi Xiao, GuangZhi Liao, Sihui Luo, and Gang Luo, China University of Petroleum

Forward and inverse models are the central and common problems in well-logging evaluation. Logging inverse problems, however, are ill-posed, pathological, and uncertain, which are caused by the inverse problem itself and are a difficult problem to be faced in the interpretation of logging data. Manual log interpretation relies solely on geophysical mechanics and logging data to understand downhole conditions, which are complex and variable. The subjectivity of the interpretation expert can have a significant impact on the interpretation results, and re-analysis of the data set using new data analysis and processing tools, such as machine learning, could lead to significant discoveries. For data-driven supervised learning models, the quality and quantity of the data set directly determine the quality of the model, and the construction of the data set is also the most time-consuming step in machine-learning modeling. However, there are some problems in geophysical logging data sets, such as small samples and few labels, which seriously restrict the development of machine learning.

Considering the importance of data to the development of logging AI technology and the outstanding performance of the generative adversarial network (GAN) model in data generation, we propose to use the GAN model to generate logging data according to the prior information and evaluate formation with logs. The generator (G) is a forward model, which inputs random noise *z* and virtual formation representations y', and outputs conventional logging curves X'=G(z,y'). The predictor (P) and discriminator (D) are inversion models. In the dscriminator construction, we use the advantages of the CNN model in two-dimensional data processing and analyze the data from two aspects of depth and feature. The predictor inputs logging data and outputs predicted formation representations y^*=P(X), in which construction, we use the advantages of Bi-LSTM in sequence data analysis for formation representations prediction. The discriminator inputs the logging data and outputs the probability that the curve is true. In the model training process, the forward and inverse models are fixed in turn, and the two are trained alternately to continuously improve the model performance and finally reach Nash equilibrium. Compared with traditional GAN, we added a predictor to predict formation representations and input the formation representations to the generator to control logging data generation.

We make use of the game method of the GAN, combining the forward and inverse models. Experiment results show that with a small amount of labeled logging data, we could get a forward model capable of generating logging data from given virtual formation representations, and the forward generation data distribution matches the measured data distribution. In terms of logging reservoir parameters prediction, it can effectively overcome the obstacles of small samples and few labels on model training and get a logging intelligent inversion model with ideal performance.

This method has specific practical value for intelligent oil-gas exploration to build machine-learning forward-inversion models for intelligent reservoir evaluation and logs data generation with small sample data.

High-Performance Stochastic Inversion for Real-Time Processing of LWD Ultradeep Azimuthal Resistivity Data

Mikhail Sviridov, Anton Mosin, and Dmitry Kushnir, ROGII Inc.

Logging-while-drilling (LWD) ultradeep azimuthal resistivity (UDAR) tools become an essential part of well placement because they are deep enough to explore the reservoir as a whole and expose it in a similar scale with seismic sections. Due to the increased formation volume being investigated, UDAR measurements depend on many formation parameters and require multilayer models to be interpreted, as well as effective inversion approaches.

Stochastic inversion algorithms have many advantages and are used extensively in field applications. Working with multiparametric models, these algorithms might become time consuming, which limits their applicability to real-time data processing, especially while drilling with high penetration rates. This paper presents an advanced stochastic algorithm with sufficient performance to invert UDAR data in real time.

The proposed inversion supports all existing UDAR tools with coaxial, tilted, or orthogonal antennas and has a flexible interface for adding new tools with arbitrary types of measurements. Besides that, there is an option to consider the modular configurations of UDAR tools by setting the number of transmitter/receiver subs and the distances between them.

The inversion utilizes a 1D layer-cake formation model and enables simultaneous processing of resistivity data logs by intervals. The algorithm is based on the stochastic Monte Carlo method with reversible jump Markov chains and can be launched automatically without prior assumptions about the reservoir structure. The algorithm automatically adjusts model complexity through the data fitting based on the detection and resolution capabilities of tool responses. Finally, inversion provides an ensemble of unbiased formation models, their probabilities, and uncertainty estimates of the recovered model parameters.

Working in high-dimensional parameter space, stochastic inversion algorithms might not be effective due to the limitation of sampling procedures that often do not consider relations between model parameters and their influence on tool responses. To guarantee real-time results, the proposed algorithm employs a Metropolis-adjusted Langevin technique that evaluates the gradient of the posterior probability density function and generates proposals being accepted as very likely. Additionally, a special semi-analytical solver is utilized to compute the gradient simultaneously with tool responses with almost no extra computational costs.

The presented algorithm has two concurrency levels to ensure near-optimal speedup for all stages of the geosteering job. First, the computation is parallelized over inversion intervals that are independent of each other and can be processed concurrently without any computational losses. This level is important for both pre- and post-well stages when a lot of inversion intervals are processed at once. At the second level, which is crucial for the real-time stage with only a few intervals being processed at a time, the parallelization is implemented over Markov chains with the necessity to synchronize computational threads to enable exchanging states between different chains and eventually avoid sticking in local optima. The workflow was adjusted specially to enable inversion running on computers with 32 and more cores by reducing both memory fragmentation and the number of requests from computational threads to the operating system to prevent its overload and eliminate possible deadlocks.

The paper will demonstrate both inversion capabilities and performance estimated on a series of industry-adopted benchmarks and field data sets.

Presented high-performance inversion may help oilfield operators to improve their understanding of full-scale reservoir structure while drilling, delineate pay zones better, and eventually achieve higher reservoir contact by making more informed geosteering decisions.

Machine Learning and Artificial Intelligence Within Petrophysics: Past, Present, and Future

Andrew McDonald, Geoactive Limited

The adoption of machine learning (ML) and artificial intelligence (AI) has revolutionized many industries and interdisciplinary fields, including medicine, chemistry, and physics. Within subsurface disciplines, its popularity is increasing and is being applied to a wide range of geophysical data. In petrophysics, ML is being applied to identify and repair well-log data impacted by poor borehole conditions or sensor issues, classification of the subsurface into distinct facies, bypassing traditional empirical petrophysical techniques, optimizing workflows, and more. This paper focuses on the fundamental concepts and key terminology within ML and AI and how it has developed in the past, how it is today, and how it will be in the near future.

ML techniques have been around for many decades, with the first mathematical model of an artificial neuron being described in 1943. Later in 1950, the first concept of a machine that could learn and have the potential to become artificially intelligent was described by Alan Turing and is known as the Turing Test. Through subsequent decades, and as computing power advanced, the development of ML and AI technologies prospered but was interspersed with declines in interest in the subject known as AI Winters. Within the geosciences, ML has been applied as early as the 1960s to analyze cyclicity within sedimentary deposits, volcanology, hydrology, and to well-log analysis.

Within this paper, a selection of commonly applied algorithms for both classification and regression will be covered, including artificial neural networks, classification and regression trees (CART), Naïve Bayes, and support vector machines. Each algorithm presents its own advantages and disadvantages when applied to well-log and petrophysical data.

The ML workflow is an iterative process and involves numerous steps, from project outline to data preparation and, eventually, the training, validation, and testing of an ML model, all before it is deployed to an operational setting. A key step in this workflow is ensuring data are of good quality prior to modeling. It is an important factor in determining the success and development of an effective and robust machine-learning model. Well-log data can be impacted by a variety of issues, from missing data to invalid responses. The consequences of such impacts are discussed.

ML and AI can bring many benefits to conventional petrophysical workflows, including reducing time spent on manual data quality control tasks, repairing invalid data, and splicing multiple logging passes.

As more people adopt ML within their petrophysical workflow, caution should be exercised when placing significant reliance on them, especially when there is a lack of foundation in their operation. ML and AI should be considered another tool within the petrophysical toolset, and when combined with domain knowledge can be very powerful.

Numerous other industries have published detailed historical reviews on ML and its applications to their disciplines. This paper presents a similar technical and historical perspective of ML within the petrophysics discipline and would bring our discipline in line with others.

Permeability Modeling on Highly Porous Brazilian Presalt Carbonates, Assisted by Automated Reservoir Rock Typing Derived From Ultrasonic Borehole Images

Adna Grazielly Paz de Vasconcelos, Marcos Antonio Nunes Junior, Patrick Pereira Machado, Laura Lima Angelos dos Santos, Nadege Bize-Forest, Giovanna da Fraga Carneiro, and Danilo Jotta Ariza Ferreira, SLB

Textural facies interpretation can be an extensive and time-consuming process, especially if performed for highly heterogeneous formations, such as Brazilian presalt carbonates. The combination of borehole images (BHI) and nuclear magnetic resonance (NMR) logs, which reflect pore-size distribution, may be a valuable option for facies pattern definition and, consequently, for rock types and reservoir quality inference. Additionally, BHI can assist in the identification of particularly high perm-porosity intervals, where vuggy and fractured sections are present and where NMR logs lose their sensitivity to pore size, being more influenced by fluid type.

Therefore, this paper presents a methodology for reservoir rock-types inference and permeability modeling based on ultrasonic BHI data, combining statistical and machine-learning (ML) techniques for automated textural sorting. The unique textural patterns observed in the high-resolution BHI can reflect the pore network structure and assist the inference of petrophysical behaviors, providing important inputs to build reservoir models.

The proposed solution integrates an automated ML image interpretation workflow, wireline NMR data, and routine core analysis into a fit-for-purpose solution to assist permeability modeling on highly porous Brazilian presalt carbonates.

We applied this innovative workflow to a challenging presalt well, in which core permeability can vary up to 2 orders of magnitude. The BHI textures were derived from a data-driven unsupervised application based on statistics and machine-learning algorithms and capable of clustering BHI textures with low human intervention. Then, the available core data were associated with each classified textural rock type, and its porosity-permeability relationships were used to compute a new upscaled permeability log based on NMR porosity.

Throughout the ML approach, we obtained a fully data-driven reservoir rock typing for the studied well, requiring no further input data beyond the BHI itself. Each textural cluster is representative of a similar pore network, and its core samples present a clear porosity-permeability trend, indicating a strong relationship between borehole image classified textures and petrophysical characteristics.

After the new permeability log computation, the overall correlation between core and log permeabilities doubled for this well when compared to a correlation of core and NMR log permeabilities. Regarding the zones where porosities are higher than 15%—where the conventional techniques based on NMR-derived porosity fractions present low accuracy—the improvement in core and log permeability correlation was eight times higher.

Our integrated interpretation approach accelerates the use and increases the value of BHI logs for presalt fields, improving permeability estimation from NMR logs, especially in zones where NMR-based permeability models fail due to geological features such as vugs and fractures.

Following this approach, reservoir rock types are defined based solely on BHI logs in a purely data-driven process, while porosity-permeability correlations are obtained from cores belonging to the same textural unit obtained from the BHI. Hereby, we demonstrated that the workflow provides a quick and smart solution for NMR-derived permeability calibration in cored wells, automation of reservoir rock-typing classification in non-cored intervals, and a great potential to extend the porosity-permeability correlations to other non-cored wells, based only in its BHI related textures.

Propagating Image-Based Rock Classes From Cored Wells to Non-Cored Wells Using Supervised Machine Learning for Enhanced Formation Evaluation

Pallavi Sahu, Andres Gonzalez, and Zoya Heidari, The University of Texas at Austin

High-resolution image data are instrumental in quantifying the rapid variation of rock fabric in formation evaluation that conventional well logs fail to capture. However, the acquisition of high-resolution image data for all wells of an entire formation is expensive and time consuming. Therefore, extrapolation of rock fabric information of expert-derived facies from high-resolution core image data to non-cored wells is necessary for efficient formation evaluation of non-cored wells. The objectives of this paper include (a) to train supervised learning models in wells with core images or image logs to identify image-based rock classes in un-imaged wells using conventional well logs, (b) to compare the performance and accuracy of the obtained supervised learning models to classify the lithofacies using only conventional logs and estimated petrophysical and compositional properties of nearby wells without any image data, and (c) to derive class-based petrophysical models to enhance formation evaluation using conventional well logs in wells without image data.

First, we conduct conventional formation evaluation to estimate petrophysical properties such as porosity, permeability, water saturation, and volumetric concentrations of minerals. Then, we employ conventional well logs and estimated petrophysical properties with a feature ranking method for feature selection prior to model training. The selected predictor features and image-based rock classes are used as inputs to train the selected models. We train three supervised learning models—random forest, gradient boosting, and support vector machines—to predict image-based rock classes in nearby wells without image data. We used a k-fold cross-validation approach to train the models and tune the hyperparameters. Finally, we used class-based petrophysical models from the cored well to estimate class-based petrophysical properties in the nearby wells.

We apply the proposed workflow to two wells in siliciclastic intervals with rapid spatial variation in rock fabric. First, the cored well is used to train/test supervised learning models, honoring high-resolution CT-scan images and core photos incorporating rock fabric. The trained models are used in a nearby well to predict image-based rock classes. Comparison of predicted image-based rock classes in the nearby well using the trained models with expert-derived lithofacies resulted in accuracies of up to 80%. The time spent in the training step for the support vector machines algorithm was significantly lower than for the cases of the other two algorithms, up to four times faster than the random forest algorithm and five times faster than the gradient boosting algorithm, with similar accuracy values. Finally, class-based estimates of petrophysical properties in the nearby well decreased the mean relative error by 20% compared to formation-based estimates.

The results of the proposed workflow will contribute to extrapolating high-resolution core rock fabric information acquired in cored wells to nearby un-imaged wells. The novelties of this workflow include (a) incorporating rock fabric information that improves accuracy in predicting the petrophysical properties and rock types of nearby un-imaged wells, (b) speeding up and improving the process of class-based formation evaluation with minimal calibration efforts, and (c) optimizing the need for imaging (core images or image logs) efforts.

Robust and Automatic Shale Volume Interpretation Using Adaptive Lithological Thresholds Built on Depth Trends, Statistics, and Geological Units

Kjetil Westeng, Aker BP ASA; Yann Van Crombrugge, Inmeta; Peder Aursand and Egil Fjeldberg, Aker BP ASA

The volume fraction of shale (VSH) throughout the well is of great importance for formation evaluation, geomechanics, and numerous other workflows. Neither porosity, saturation, nor permeability can be understood if one does not first have a good grasp of the VSH. The objective of this paper is a method for automated VSH calculation which is effective, un-biased, and to lesser degree affected by the log coverage in the well, as well as able to handle the variation in both radioactivity and density-neutron response as a function of depth and formation.

The method combines statistics and dynamic filtering with geological context to create adaptive depth trends representing the log response of shale and sand/carbonates.

Algorithm main steps:

1) Calculate dynamic sand and shale trends for each curve within each geological unit
2) Identify section and tool change – centered rolling quantiles are reset where a tool change is identified
3) Identify nonshale intervals by using the trends from Step 1 and custom thresholds (these can be adjusted by the user)
4) For each nonshale window, detect the first inflection point before and after the window and interpolate between these two
5) Combine the interpolated curve with the rolling quantile curve
6) Calculate VSH_GR and VSH_DENNEU using the respective final trend curves
7) Combine these with the final aggregated curve VSH_AUT

The method can, e.g., handle variation in matrix radioactivity within a lithostratigraphic system as well as depth trends in shale properties. The efficiency and avoidance of manual parameterization make our method ideal for a fast evaluation of the full wellbore as the starting point for a more detailed manual interpretation or for fast and consistent massive multiwell evaluations. The method solves the normalization issues that often can affect the accuracy and bias of automated solutions, and the result can therefore be useful as an engineered feature in various machine-learning-based well interpretation schemes.

This automated VSH interpretation method has been applied to more than 1,000 wells from various areas in the North Sea and the Norwegian Sea. It has been proven to provide a reliable interpretation compared to manual interpretation. In contrast to many other methods for automated VSH interpretation, our proposed method will, by design, be by which intervals are and are not covered by each log. This work will show how the method can be applied to calculate the VSH from both the gamma ray log and from the density-neutron porosity relationship.

The method can easily be adapted to other regions and geological settings and has broad applications in traditional well interpretation as well as in machine learning. The method does not rely on training on proprietary data, and we utilize publicly available statistical functions and geological information, making it fully reproducible.

Strata-Constrained GWLSTM Network for Logging Lithology Prediction

Jianjun Li, China National Logging Company; Haotian Lv, Xi’an Jiaotong University; Haining Zhang, China National Logging Company; Hui Li and Baohai Wu, Xi’an Jiaotong University

Precise rock lithology identification from well logs is critical for reservoir characterization and field development. Traditional knowledge-based lithology interpretation is highly dependent on the interpreter’s experience and judgment, which could lead to erroneous decision making or biased prediction. To reduce human involvement and improve interpretation efficiency and consistency, a knowledge-constrained long short-term memory (LSTM) network solution is introduced.

In this study, LSTM networks are applied with different constrains to obtain the mapping relations and validate the knowledge-constrained LSTM model accordingly. The entire workflow mainly includes input logging data preprocessing, different constrain validations during the LSTM model training, and validation processes. This study covers and compares the direct LSTM model without constrains, rectangular constrain LSTM (RCLSTM), and Gaussian window weighted constrain LSTM (GWLSTM). In particular, GWLSTM applies a sample cluster as input instead of single sample points. The weight of the sample point is controlled by a distance-correlated Gaussian window, which means the closer to the predicting point, the greater the impact on the prediction.

LSTM, RCLSTM, and GWLSTM models are tested on a field data set of five wells in a typical sandstone gas reservoir. Two wells are used to train the network, while the other three wells are used for network assessment. The test results demonstrate that by applying LSTM networks to establish the mapping between the logging curves (e.g., CNL, DT, DEN, GR, and RD) and rock lithology, rock lithologies in target formation can be predicted from well logs. Moreover, the lithology predictions by the GWLSTM model are more accurate than those of conventional LSTM and RCLSTM models, especially for thin layers.

In conclusion, GWLSTM networks improve lithology identification accuracy by taking stratigraphic sequences into consideration. And the Gaussian window constrains are more effective than rectangular window constrains for thin layer predictions. Lastly, GWLSTM doesn’t require a large training data set, which makes it advantageous for reservoirs with limited wells.

Using Artificial Intelligence to Predict Contamination During Formation Fluid Sampling

Anup Hunnur, Sefer Coskun, Emiliano Hall, and Jujie Yang, Baker Hughes

Formation fluid samples acquired using advanced wireline or LWD tools are the most representative because the reservoir fluid is maintained in single phase all throughout the acquisition. The foremost issue with these samples is the mixing of formation fluid with the mud filtrate used while drilling. While immiscible fluids can easily be differentiated and tracked, miscible fluids make it difficult to quantify the fraction of mud filtrate in the mixture.

Until recently, the cleanup trend in miscible fluids was thought to be along an exponential curve. Fitting an exponential curve to the fluid properties showing the cleanup trend would provide the current contamination level and could then be used for predicting the time and volume needed to achieve a desired level of cleanliness. Recent studies, as well as simulation studies, though, have debunked the idea that a single exponential fit can explain the cleanup trend completely. The early and late time data fit appears to have different constants and exponents. Thus, explaining the cleanup process for all reservoir and wellbore conditions with a single exponential parameter is subjective, highly user-dependent, and nonrepeatable.

To overcome these challenges, an artificial intelligence (AI)-based method has been developed using more than 15,000 fluid sampling simulation models. These simulation sets represent the sample cleanup process in varying reservoir, wellbore, and drilling fluid invasion conditions. The trends observed in actual measured data are then compared to the trends from the simulated data to determine a statistically significant number of best simulation model sets, which are then used to determine the expected contamination level and the associated uncertainty.

The cleanup process of miscible fluids may vary significantly due to the potentially wide range of rock and fluid properties and mudcake efficiency. The AI technique presented in this study is based on the fluid flow dynamic and accounts for the most critical variations in reservoir conditions. As a result, it has been successfully applied to estimate the contamination level in real time during the sampling process, and the determined contamination levels are within the range of those from PVT lab analysis. This new method, using an advanced AI-powered algorithm, offers a more robust, reliable, and repeatable analysis of contamination levels over previous methods.

CASE STUDIES

A Novel Workflow for Well Placement Optimization Within Highly Fractured Carbonate Reservoirs Through the Integration of Rock and Reservoir Fluid Geochemistry Measurements and Petrophysical Log Data: A Multiwell Field Case Study, Adiyaman, Turkey

Melike Ozkaya Turkmen, Turkish Petroleum Corporation (TPAO); Kemal Hekimoglu, Geolog International; Onur Yuruker, Elif Cihan Yildirim, and Mustafa Biterge, Turkish Petroleum Corporation (TPAO)

The structural complexities in the southeast of Turkey create considerable challenges, as production is limited to the accumulations within confined zones dictated by fracture systems and flow dynamics, where favorable rock, reservoir, and fluid properties coexist. The diagenetic processes in these carbonates result in rapid variation in the rock matrix and complex pore distribution. Therefore, the assessment of petrophysical properties necessary for the efficient exploitation of hydrocarbon-bearing carbonates is crucial. A series of lateral wells were drilled in a recent production campaign within these fields with the aim of optimizing production. Homogeneous gamma/resistivity responses from these clean carbonate reservoir rocks and the borehole tortuosity issues related to hole instability created limitations with the traditional approach of using LWD data for geosteering. Also, the lack of local experience in drilling laterals in the area, far behind bit measurements, created additional challenges for geosteering using conventional methods, therefore necessitating a novel approach. The objectives of this paper include (a) integrating petrophysical log data with surface mineralogy for rock classification, (b) establishing expected responses from surface data in relation to the modeled rock classifications, (c) generating a vendor-independent geosteering workflow to standardize the real-time surface/downhole data QC procedures and the rules for steering decisions.

Conventional techniques were employed to capture variations in the rock properties using available petrophysical log data (spectral GR, resistivity, density, porosity, SP, DT, image, neutron spectroscopy) from 20 offset wells. The 1,508 drill-cutting samples from the same offset wells were analyzed in-lab to measure the inorganic geochemical compositions. Data resolution was synthetically increased using conventional interpolation methods through the qualitative correlation with spectroscopy log data where limited legacy cuttings data from offset wells were available within targeted zones. Estimation of the rock properties to establish analogs to be followed during drilling required the integration of rock mineralogy and petrophysical data. A dedicated prewell model was constructed for each of the 10 lateral wells within the campaign using log data, rock geochemistry measurements, and seismic interpretations. During the drilling of the laterals, detailed geochemical characterization using ED-XRF and XRD analysis from cuttings sampled at high frequency (every 1 to 2 m), quantitative mud gas measurements (C1 to C5), and LWD logs (azimuthal GR and resistivity) were integrated in real time. These data were used to visualize and interpret the relative stratigraphic position, the relative hydrocarbon saturation, and fracture/fault distribution along the wellbore. The geochemical compositions of the cavings recovered were analyzed to allocate their origination depth using a hierarchical clustering approach. Finally, a dedicated workflow was created to streamline the decision-making process for steering between the operator’s production and engineering department, the directional drilling subcontractors, the geosteering, and the geochemistry specialist.

The proposed workflow was refined with experiences during the course of the campaign and was applied to the 10 lateral wells collaborating with multiple directional drilling and geosteering service providers. Employing all geosteering techniques (model/stratigraphy based, multiwell, and multilog), it was possible to land, navigate, and reach well TD keeping an average of > 90% inside the target, giving the operator’s reservoir team better information to make decisions in real time. We demonstrated that when sedimentary diagenetic factors are favorable, it is possible to detect fracture and fault systems through the measurements of a variety of mineral species precipitated. Furthermore, the structural displacement degree was possible to be evaluated through the correlation of the geochemical fingerprint of the rocks before and after faults. Breakout zones within the wellbore were identified through the geochemistry-based statistical cavings allocation methodology described and later were correlated and confirmed with image logs. This assessment was used to support the drilling decisions and procedures to be utilized.

A unique contribution of the proposed workflow is to establish a detailed methodology to integrate a diverse data set of rock and reservoir fluid geochemistry and petrophysical measurements to optimize rock classification and support formation evaluation efforts. The workflow aims to improve the procedures compared to similar applications in the past in terms of the variety of measurement techniques used and the vendor-independent nature of the implementation. This approach is crucial to establishing a communication standard between multiple service providers and departments within the operator organization with the sole objective of streamlining the geosteering decisions.

Bed Boundary Mapping Technology Improves Coal Mining by Revealing Its Complex Geological Structures

Hatem Abeida, Qiming Li, and James Mather, Oliden Technology; Valentin Woehling, Lucas Drilling Pty Ltd; Jason Patterson, AngloAmerican; Andy Hall, Pentagram Petrophysics Pty Ltd; Greg Runge, Lucas Drilling Pty Ltd

Drilling horizontal wells in the coal mines in Central Queensland, Australia, is key to understanding the complex nature of the coal seams and their lateral extension prior to underground longwall mining. These coal seams are geologically complex, with faulting, varying dips, and bed thinning frequently encountered. Consequently, the requirement arose for an advanced logging tool with the capacity to provide accurate geosteering, reveal complex geology, and ultimately improve footage within the coal seams.

Conventional geosteering using gamma ray correlation with offset wells has been widely used in geosteering the horizontal section of these wells. The process of confirming coal seam structures involved a risky and time-consuming process. It required branching out, logging shoulder beds, and then pulling back into the main bore to drill ahead, repeated a few times throughout drilling the horizontal section. Even though this might work in certain applications, the approach has some limitations when drilling these zones. It is reactive due to the shallow depth of investigation of gamma ray measurements and the fact that the sensor may be located too far behind the bit to aid efficiency. More importantly, it involves the risk of drilling into the hazardous shoulder shale and wasting drilling time and footage out of target.

For the last 3 years, an advanced geosteering technique utilizing the deep-reading directional resistivity tool has been used for bed boundary mapping in this high-resistivity environment. The tool provides conventional propagation resistivity, azimuthal gamma ray, and directional resistivity with a greater depth of detection than other tools in its class through the use of longer transmitter-receiver spacing for directional antennas. Importantly, these directional measurements are available in all three frequencies (125 kHz, 500 kHz, and 2 Mhz) to allow a greater selection of measurements for structure inversion/interpretation optimal to the particular geology and application. Incorporating long-spacing 2-Mhz directional resistivity measurements, the multilayer bed mapping technology confirmed and accurately interpreted structural changes in the coal seams where the top and bottom of the coal seam were mapped.

The traditional method employed by the coal mining industry of detecting coal seams geometry relies on reactive steering, driving the need for multiple openhole sidetracks throughout the well. The bed boundary mapping technique has enabled the operator to overcome the limitations of the conventional geosteering technique. The outstanding result and gained experience gave the operator the confidence to run the tool and geosteering services in more wells to resolve the coal seams' complex structures and map their boundaries.

The inversion result provided geological insights into the coal seams' structures. The improved geological model based on the inversion has shown that the coal seam is geologically complex, and the correct delineation of its boundaries and identifying their precise true vertical depth can add significant value to the planning, evaluation, and execution of mines.

Changing the Game: Well Integrity Measurements Acquired on Drillpipe

Tonje Winter and Laurent Delabroy, Aker BP; Abe Vereide, bp; Lynda Memiche, Roger Steinsiek, and Ian Leslie, Baker Hughes

The industry is continuously challenged to improve the efficiency and safety of operations. This is evident over the last 30 years in the development and improvement of measurements acquired while drilling. However, this has, in general, until now not been applied to well integrity measurements such as casing integrity and cement evaluation, which have traditionally been acquired using wireline deployment. This paper will show the results of a new drillpipe-deployed tool that can be run in parallel with existing well operations. The results will be compared to traditionally acquired wireline-deployed tools and will demonstrate that these measurements and the resultant interpretation can successfully be acquired on drillpipe, thus allowing for much-improved efficiency of operations.

Conventional wireline-conveyed ultrasonic pulse-echo technology tends to use a single transducer and a rotating head. To mimic this and to allow for full 360° coverage with a drillpipe-conveyed tool, then three transducers are situated circumferentially around the tool, and full azimuthal coverage is achieved by rotating the drillstring, either from surface or downhole. Additionally, due to limitations in uphole telemetry, achieving real-time measurements and answer products requires downhole processing of the acquired waveforms. We will show how this is achieved and compare the measurements acquired both ways.

Two well were selected with different degrees of difficulty in terms of measurement acquisition and also showing different well trajectories and mud types. Both wells were logged with both the new drillpipe-deployed technology and traditional wireline technology. Digitally comparing both sets of data and interpreting the results for cement evaluation, it is quite clear that the results are comparable and that both sets of data are good for traditional cement evaluation from pulse-echo technology.

The significance of these results means that there is now a new way to acquire critical well integrity data rather than resorting to a standalone wireline run. The fact that the data can be acquired in parallel with other rig operations allows for large efficiency gains to be made and multiple times when the data can be acquired.

First Multiphysics Integration of 3D Resistivity Mapping With 3D Sonic Imaging to Characterize Reservoir Fluid and Structural Elements

Redha Al-Lawati, Mauro Viandante, Adam Donald, Maren Eide, Ibrahim Abdullah, Eman Samir, Pascal Millot, Amani Al Shaqsi, and Othman Al Badi, SLB; Fahad Al Qassabi, Marwa Al Shaqsi, Adil Al Hamadani, Khalil Al Arafati, Clive Johnson, Khalil Hassan, and Jalal Al Shukaili, Oxy Oman

Well placement and real-time evaluation of high-angle and horizontal wells is a well-established workflow that effectively ensures a consistent distance to the caprock and delineates sublayers within the reservoir. Contrasts in deep resistivity measurements are interpreted as changes to hydrocarbon saturation or formation composition. Wellbore images show layer boundaries and fractures that intersect the wellbore. Sonic imaging in the same environment provides information about contrasts in acoustic impedance associated with geological features such as structural and stratigraphic boundaries and the presence of natural fractures/faults. This paper will discuss how combining all three measurements provides rich insights to reservoir characterization in a horizontal well drilled through a carbonate reservoir.

The integration of 3D resistivity mapping with 3D sonic imaging provides unprecedented reservoir insight. The 3D resistivity mapping is challenged by resistivity response to formation boundaries or fluid changes within the volume of investigated rock. Incorporating 3D sonic imaging with its sensitivity to lithological or stratigraphic boundaries and natural fractures provides a more comprehensive interpretation.

There are three major discoveries within this case. There is a consistency of dip, azimuth, and distance to the caprock for both the acoustic and resistivity measurements; however, there is also a clear reflection from the bottom of the reservoir layer. The free-water level within the layer can be determined as the resistivity profile defines the saturation changes until the bottom boundary and potential oil-water contact. Secondly, there is correlation between steeply dipping or near-vertical acoustic reflectors running parallel to the well trajectory and the lateral changes in the resistivity profile on either side of the wellbore. This is interpreted as saturation changes laterally caused by the presence of near-vertical fractures or compartmentalized flow units due to the nature of the rock or existing baffles/barriers within faulted blocks. The third observation is the layering and heterogeneity within the caprock. The subtle resistivity contrasts and variable subhorizontal reflectors that vary with strike and dip. The convention of the caprock of being a homogenous unit is confronted by the measurements highlighting its heterogeneous and anisotropic nature.

In a field with complex reservoir architecture (stratigraphy and fractures) and complex fluid relationships, the case study shows how the first multiphysics integration of 3D resistivity mapping with 3D sonic imaging enables:

- Unbiased integration based on independent measurements to characterize reservoir features (fractures, lithology anisotropy, layering)
- Validate interpretation in complex geological environments with structures remotely detected away from the wellbore
- Fluid distribution understanding at reservoir scale as a function of structural features and stratigraphic elements
- Novel input for properties distribution and reservoir dynamics as opposed to exiting geostatistical methods to model reservoir properties

This case study represents the first multiphysics integration of 3D resistivity mapping and 3D sonic imaging to characterize reservoir fluid and structural/stratigraphic elements. The integration of all the measurements, along with borehole images, provides an innovative approach that helps to unlock full reservoir understanding.

Integrated Petrophysics and Rock Physics Results and Log QC and Editing in Deep HPHT Chlorite-Rich Wilcox Sands, Fandango Field, South Texas – A Case Study

Jeffrey Baldwin, Global Rock Scope, and Fred Jenson, GeoSoftware

This work uses an integrated petrophysics-rock physics workflow to simultaneously evaluate formation volumes (e.g., porosity and lithology) and edit well logs in high-porosity and high-permeability chlorite-cemented Wilcox sands in deep, high-temperature, high-pressure wells of South Texas, USA, Fandango Field.

Data include standard logging suites plus sonic logs, thin section and SEM imagery, and geological analyses. Shaly-sand petrophysics and rock physics models are modified to account for chlorite effects. Rock physics templates integrate elastic and nonelastic calculations using visual tools augmented with versatile overlay templates.

Imagery is used to model chlorite rims around sand grains as opposed to pore-filling chlorite. Hashin-Shtrikman bounds are used to model the elastic properties of chlorite rims. Petrophysical volumes are used to drive an Xu and White effective medium rock physics model. The rock physics workflow provides QC for the petrophysical analyses and vice versa. Fluid substitution is used to correct density and sonic logs for oil-based mud invasion effects.

Finally, modeled DTC and DTS logs were either substituted in intervals where sonic logs are unreliable or used in place of sonics that were not run. For example, shear logs are of low quality in many places, or there was never a shear log run. The rock physics model is used to solve these inadequacies.

Rock physics crossplot templates demonstrate that computed elastic properties fall within correct V_{clay} and S_w bounds. Porosities in chlorite-rich sands can be higher than 25%, with water saturations below 15%. Fluid substitutions in invaded sands can increase porosity by as much as 2.5% bulk volume. Via sonic log substitutions, complete quad-combo log data suites are generated or verified for each well in this project.

This integrated workflow demonstrates the utility and advisability of linking petrophysics and rock physics modeling workflows, a linkage that includes the use of rock physics template overlays. This integrated approach can improve both petrophysics and rock physics, leading to improved reservoir characterization as well as preparations for seismic work.

Integrated Physical and Digital Chalk Relative Permeability Evaluation: A Case Study

Abraham Grader, Bob Engelman, and Caroline Mignot, Halliburton; Knut Arne Birkedal, Nils Andre Aarseth, and Kristoffer Birkeland, Aker BP

The Valhall chalk field has produced more than 1 billion barrels of oil equivalents over the last 40 years, primarily from the homogeneous Tor Formation. The underlying Hod Formation is more heterogeneous and less maturely developed. The extent of heterogeneity poses a challenge in the evaluation of multiphase fluid flow properties. Objectives: Use digital core analysis to generate early relative permeability data to leverage and compare with conventional physical steady-state relative permeability data.

Accurate digital and physical description of capillary pressure and relative permeability in the high-porosity chalk is complicated by both low permeabilities and heterogeneity. The main challenge with chalk is that flow occurs in a nano-environment. Physically, the nano-environment translates to low permeability, difficult rock preparation, and extensive experimental time, especially for steady-state flow experiments. Representative three-dimensional digital rocks were generated using a combination of X-ray computed tomography (CT) and focused ion beam-scanning electron microscopy (FIB-SEM) methods. The digital rocks were used to simulate two-phase flow and generate relative permeabilities and sensitivity to wettability.

The attached figure presents the overall workflow that covers the scales from the whole core to the nanopores. The right side of the figure shows a photograph of a 1.5-in.diameter core and a micro-CT slice of it in grayscale. The three-dimensional digital image presents a representative volume with the pores highlighted in blue. The green and blue Kr square points are processed lab results. The solid red lines are digital Kr data. The presentation details how the digital Kr data were obtained as well as the sensitivity of the results to wettability.

Physical steady-state and digital relative permeabilities on a number of core plugs and subsets are compared in this study, which discusses the advantages of performing both as part of the formation evaluation process. The physical and digital results compare reasonably well. The physical results provide a relative permeability anchor, and the digital results provide the leverage of early results, parametric sensitivities, and quality assurance. Hence, integration between digital and physical core analysis yields a more robust understanding and input for uncertainty modeling.

Multiwell Production Allocation via Petroleum Fingerprinting: A Case Study in the Norwegian Sea

Placido Franco and Roberto Galimberti, Geolog Technologies Srl; Thorsten Uwe Garlichs, Wintershall Dea Norge ASA

Reservoir geochemistry is an established science that offers rapid, low-cost evaluation tools to aid in understanding development and production problems. In the last 30 years, thanks to significant advances in analytical chemistry and data processing, petroleum geochemical fingerprinting has allowed geochemists to carry out production allocation studies by mathematically unmixing a commingled oil fingerprint into the contributing flow inputs (endmembers). The present contribution deals with a successful pilot case study finalized to assess the applicability of geochemical production allocation to some production wells in an offshore field in the Norwegian Sea.

The first phase of the study focused on a baseline assessment through endmember characterization. This process involved initial geochemical fingerprinting of the five contributing oil inputs to build a robust mixing model, which was also tested through analysis of synthetic laboratory mixtures. Subsequently, production samples were analyzed. The main challenge in this phase was individuated in the high oil similarity since production comes from a single target that shows only minimal molecular variations potentially able to contribute to the necessary geochemical differentiation across the field. Moreover, the relatively high number of wells to allocate and the proximity of some of them provided further elements of complexity. The selected analytical methodology employed for oil fingerprinting was based on gas chromatography-mass spectrometry (GC-MS) alkylbenzenes analysis, while fingerprint deconvolution was carried out using an original, in-house developed algorithm.

The geochemical production allocation of several commingled oil samples resulted in a good agreement with existing multiphase flowmeter data, being the overall average discrepancy lower than 6%. The advantages of petroleum fingerprinting for production allocation have been extensively reported by many authors. Indeed, despite being relatively recent compared to more established techniques, the low cost, minimum impact on operations, and adaptability to many production programs led to the rapid diffusion of this allocation approach. The main limitation relies on the necessity to find significant compositional differences in the endmember oils that make up for the production, requiring carrying out a preliminary feasibility study. The results obtained from the present pilot study asserted the effectiveness of the proposed fingerprinting approach to allocate the production in the investigated area, standing as backup, calibration, and quality control to the used metering technique, as well as to provide further data for reservoir management.

Petroleum fingerprinting allows us to directly analyze production streams, providing a rapid and inexpensive quantitative assessment of production allocation without requiring any production deferment. The reported pilot study proved the effectiveness of geochemical production in the studied area, historically metered by means of multiphase flowmeters, which are more expensive and not always accurate. More importantly, the present case study proves the methodology’s efficacy in a single-level multiwell production, which is a typical scenario where the proposed methodology generally presents applicability limitations.

Temperature Sensitivity of NMR Responses of Porous Media

Zhen Xie, Lizhi Xiao, Lu Zhang, Sihui Luo, and Guangzhi Liao, China University of Petroleum, Beijing

Temperature affects the responses of 1D and 2D NMR spectra of fluids in porous media, which may cause errors in reservoir evaluation using downhole NMR data. The purpose of this paper is to study how temperature affects the NMR T_2 spectrum and D-T_2 spectrum of porous media.

In this paper, the Monte Carlo-Random Walk method is used, and the simulation parameters are set according to the temperature sensitivity of surface relaxation in Korb surface relaxation theory and the temperature characteristics of bulk diffusion. The temperature response characteristics of the T_2 spectrum, one-dimensional confined diffusion attenuation, and D-T_2 spectra are studied, and the influencing factors are analyzed. Then, we measured the temperature dependence of the T_2 spectrum and D-T_2 spectrum of saturated water and 68-lb white oil of artificial sandstone with different physical properties by using a water bath circulating heating device.

The numerical simulation results show that the obvious movement of the general sandstone T_2 spectrum caused by temperature mainly comes from the influence of surface relaxation. Temperature can also increase the confined diffusion in porous media in the case of reinforcement diffusion, which causes the D- T_2 spectrum to move up. The degree of upward migration is related to pore size and porosity. And the simulated D-T_2 spectra at all temperatures are consistent with the Padé nterpolation equation, indicating that the simulation results are correct and applicability of the Padé interpolation equation when the bulk diffusion increases a lot. The experimental results show that the T_2 spectrum of impure sandstone has a significant left shift with the change of temperature, and the T_2 at the peak of macropore is consistent with Korb theory. The variation of D-T_2 spectra of artificial sandstones with different porosity and pore size with temperature is consistent with the simulation results. Due to the different temperature sensitivity of surface relaxation and bulk relaxation of 68-lb white oil in artificial sandstone, the T_2 spectrum in different pore structure cores shows different response characteristics with temperature. It is difficult to directly characterize the change of T_2 with temperature. Based on the BT equation, we derive a method to rapidly determine the surface relaxation temperature sensitivity of oil in sandstone and the interconversion of transverse relaxation time at different temperatures. This method is basically consistent with the experimental results.

We studied the temperature sensitivity of the T_2 spectrum and D-T_2 spectrum of saturated single-phase fluid porous media. The method of quantitative characterization of the T_2 spectrum and D-T_2 spectrum with temperature was established or verified. The above research results and cognition can be used to guide the subsequent reservoir high-temperature logging data correction so as to improve the accuracy of reservoir evaluation.

FORMATION EVALUATION OF CONVENTIONAL RESERVOIRS

3D Electromagnetic Modeling and Quality Control of Ultradeep Borehole Azimuthal Resistivity Measurements

Sofia Davydycheva, 3DEM Modeling&Inversion JIP; Vladimir Druskin, 3DEM Modeling&Inversion JIP and Worcester Polytechnic Institute; Carlos Torres-Verdín, Junsheng Hou, and Wardana Saputra, The University of Texas at Austin; Michael Rabinovich, bp; Frank Antonsen, Equinor

Reliable interpretation of borehole electromagnetic (EM) measurements acquired in horizontal and high-angle wells requires fast, robust, and versatile solutions of forward and inverse problems of Maxwell's system in complex three-dimensional (3D) anisotropic formations. Based on recent advances in numerical simulation methods, we implement 3D anisotropic EM modeling and inversion software and algorithms to simulate and quality control (QC) ultradeep azimuthal resistivity (UDAR) measurements. The combination of fast modeling and inversion under complex and anisotropic 3D earth-model conditions enables us to accurately quantify the limits of resolution and uncertainty of UDAR measurements.

The software and algorithms allow fast and robust modeling based on the finite-volume homogenization technique together with a special reduced-order gridding procedure. This modeling strategy enables the use of model-independent finite-volume grids in tool coordinates combined with a global-model grid accepting inputs from commonly used 3D earth-model rendering formats. While the tool moves along the well trajectory, the formation determined on the 3D global grid shifts and rotates in tool coordinates. Furthermore, we implement several fast direct and iterative solvers in our modeling/inversion workflow, all of which yield practically identical results. Parallel computing also allows real-time modeling.

Our modeling approach is effective for the multidimensional inversion of UDAR profiling/logging along arbitrary well trajectories. Benchmarks and examples of UDAR simulations on operator's 3D subsurface models confirm the efficacy of our simulation method. The accompanying figure describes a benchmark example including a 3D simulation of commercial UDAR measurements acquired across a spatially complex formation model with two faults. Numerical simulation time for 3,000 couplings of logging points and tool configurations is less than 8 CPU hours on a typical laptop and less than 20 seconds on a supercomputer. The benchmark was also verified against an independent 3D EM modeling method. Our 3D fully anisotropic modeling software can be used for real-time inversion QC of commercial UDAR tool measurements. A 3D simulation based on a two-dimensional (2D) model of the well curtain section (obtained as stitched-together 1D models: results obtained from 1D inversion of commercial measurements) and comparison of this simulation to actual tool measurements identify the sections of the well trajectory where 2D-3D inversion is needed to decrease the data misfit to acceptable values (i.e., measurement noise levels).

Future endeavors include fast, fully anisotropic 2D-3D measurement simulation using adaptive upscaling of 3D models and novel 2D-3D inversion algorithms specifically designed for UDAR measurement conditions. Our goal is to develop real-time 2D and 3D inversion of UDAR measurements for well geosteering and refined 3D subsurface model rendering as additional measurements and geometrical constraints are included into the inversion by asset teams.

3D Ultradeep Azimuthal Resistivity (UDAR), a Tool for Identification of Bypassed Pay in Mature Fields

Rosamary Ameneiro Paredes, Nigel Clegg, and Arthur Walmsley, Halliburton; Ingvild Andersen and Svein-Tore Brundtland, ConocoPhillips

Some mature chalk fields of the Norwegian Continental Shelf have a long history of enhanced oil recovery programs utilizing water injection. Small-scale depositional heterogeneity, diagenetic changes, and subseismic faults created barriers or conduits for fluids resulting in variable fluid distribution across the field with complex sweep patterns. Imaging and mapping the fluid distributions play key roles in optimizing well placement and maximizing production. In this partially swept setting, evaluation of the formation and fluid resistivity around development wells plays a major role in the identification of bypassed reserves and the planning of additional target wells to intercept these zones.

This paper illustrates the application of three-dimensional (3D) UDAR inversion in one of the major chalk reservoirs to map the variability of fluids, enabling bypassed pay zones to be targeted, thereby improving economic production. The one-dimensional (1D) UDAR inversion was deployed in combination with conventional LWD logs in real time to optimize well placement. The target well encountered a significant section of the waterflooded reservoir. The 1D UDAR inversion only shows the vertical distribution of the fluids as mapped from their resistivity values; however, UDAR images indicated laterally displaced hydrocarbons to the north-west of the wellbore. A 3D UDAR inversion was performed post-well to map the lateral distributions of the fluids.

During real-time operations, 307 ft of oil-bearing formation was identified in the formation evaluation (FE) logs. The 3D UDAR post-well inversion identified an additional 407 ft of hydrocarbon mapped to the north-west of the wellbore, extending up to 120 ft laterally from the wellbore while drilling in a relatively low-resistivity environment (1 Ω·m). Three major structural trends correlating with seismic features were identified as the potential cause for the fluid confinement. To increase hydrocarbon recovery in the area, a sidetrack well was planned to intersect the hydrocarbon volume identified from the 3D reprocessing. Anticipating the challenging topology of the new target zone, the 3D UDAR inversion was utilized during the real-time operation. The planned sidetrack successfully intersected the hydrocarbon body, where it was originally detected from the previous well. Additionally, 442 ft of bypassed hydrocarbon was identified from the sidetrack well logs, exhibiting a preferential distribution of the oil-bearing formation to the north-west of the wellbore. In this case, the additional pay was not evident from the seismic analysis, demonstrating the importance of data provided by the 3D UDAR inversion to deliver more detailed subsurface imaging for well planning and real-time operations.

Understanding the lateral extension, fine-scale reservoir architecture, and confinement of the reservoir in three dimensions has a significant impact on mature field development. The 3D UDAR analysis allows the identification of bypassed pay, even at great distances from the wellbore (within the range of 100 ft under the conditions of this case study). This is crucial information for field development planning, supporting justification for additional sidetrack or infill well opportunities that have not been identified in 3D or four-dimensional (4D) seismic, increasing the economic ultimate recovery.

A New Petrophysical Workflow to Characterize Magnesium-Rich Clay Minerals in Presalt Lacustrine Carbonate Reservoirs

Pingjun Guo, Anindya Nandi, Allison Scribner, Elton Ferreira, and Karrie Miller, ExxonMobil

Complex clay types in presalt reservoir rocks make it a challenging task to characterize phyllosilicate and magnesium-rich clays. Reservoir quality and properties such as porosity and permeability are adversely influenced by the presence of magnesium clays that were precipitated within volcanic and lacustrine carbonates deposits under alkaline conditions. Accurate identification and quantification of magnesium clay minerals have a broad business impact on reservoir characterization, basin thermal history assessment, and diagenesis prediction. However, magnesium clays, having high magnesium contents and low potassium and aluminum concentrations in chemical compositions, lack characteristic features in well-log responses, such as GR, which make petrophysical models less effective in correctly interpreting reservoir rock and fluid properties. Although magnesium elemental weight fraction is measured using newer-generation neutron spectroscopy tools, magnesium-rich clay minerals are not properly accounted for in vendor-specific mineral closure models and commercial petrophysical software platforms, and overestimation of dolomite volumes in lacustrine carbonate reservoirs is rather common.

A new petrophysical workflow was developed to include a hybrid multimineral solver in which conventional and neutron spectroscopy logs are integrated to solve for mineral volumes. The mineral inversion algorithm, which is simultaneously constrained with log response endpoints and mineral chemistry constraints, allows building new minerals using either core chemistry data, such as X-ray fluorescence (XRF), or regional geological knowledge. The log response endpoints are estimated using nuclear modeling codes such as SNUPAR. The new workflow is applicable to any vendor data and can be easily implemented in any established petrophysical software platform.

The new workflow has been successfully applied in a number of wells in the Santos and Campos Basins, offshore Brazil, where magnesium-rich clays were formed commonly as kerolite, stevensite, saponite, and pyroxene. These minerals have distinct features in chemical composition, with magnesium at 18% by weight and aluminum at less than 1% by weight, and their neutron log response is 11 p.u., which is significantly lower than phyllosilicate clays. Results show that the new integrated workflow is capable of resolving presalt reservoir rocks into carbonate, clastic, and volcano-clastic minerals. A comparison of the new mineral model and an existing model is shown in Fig. 1. The existing mineral closure model tends to overestimate dolomite volume, while the new workflow is capable of properly quantifying both conventional and magnesium clays. As shown in Fig. 2, the new clay mineral model agrees with the NMR T_2 log mean (T2LM), which is inversely proportional to clay-bound water volume. The log-derived mineralogy is also consistent with petrographic observations of thin-section images.

In summary, the new integrated workflow incorporating mineral chemistry has a clear advantage of producing reliable and consistent rock mineral logs for formation evaluation, stratigraphic correlation, rock physics, and petrofacies models across the Campos and Santos Basins.

Characterizing Petrophysical Uncertainties of Thin-Bedded Gas Sands With Cores and Production Data

Ting Li and Adil Manzoor, Chevron

In this paper, we study the largest producing gas field in SE Asia that supplies about 50% of the domestic gas demand. During the development of the field, production data analysis revealed that conventional sands received pressure support from thin-bedded sands, which were originally considered nonreservoir rocks. Following this analysis, a petrophysical framework was constructed to estimate gas-filled pore volume in the thin-bedded facies (TBF). Subsequent perforations in the TBF and production logs (PLT) confirmed the productivity of these intervals and the validity of the petrophysical model. Although this model delivered several viable scenarios of gas in place, the inherent uncertainty in key petrophysical properties was not addressed. In this paper, we characterize the uncertainties of the volume of shale (V_{sh}), porosity, facies, and water saturation (S_w) in TBF.

The primary guidance we rely on for uncertainty modeling is the dynamic data, such as PLT or shut-in tubing pressure after perforation. Core is also available in the TBF, but most samples contain shale laminations, making core-scale porosity and S_w more pessimistic than reality.

The V_{sh} uncertainty is derived from Monte Carlo simulation, which samples gamma ray endpoints for sand and shale from distributions defined by log data. The 1,000 realizations are produced at each depth, and the P10 and P90 realizations are used as low and high cases, respectively. The mid-case V_{sh} is taken from a deterministic multimineral model.

The uncertainty of sand porosity comes from Monte Carlo simulation of the equation phi_sand=(phi_log-V_{sh} *phi_shale)/(1 – V_{sh}), where V_{sh} and phi_shale are sampled from known distributions derived from log data. The low- and high-case porosity are defined by P10 and P90 of the realizations. The mid-case porosity comes from the deterministic petrophysical analysis. We validate this model in thick sands, where the three cases of porosity collapse into one curve and match core porosity very well.

Facies prediction is driven by PLT results at thin-bedded intervals in three wells. We create a mid-case facies model based on neutron-density separation. This model was calibrated with the flow behavior from PLT results. To generate low and high cases, we take the V_{sh} uncertainty and other conventional wireline logs into an unsupervised clustering, which gives an appropriate range of uncertainties for these petrophysical properties.

For mid-case S_w, since the resistivity log always gives a pessimistic result in TBF, we build a saturation height function based on capillary pressure data. The low and high cases are created by observing the spread in capillary curve fits and changing the Thomeer parameters to form the upper and lower bounds around the mid case.

The interpreted petrophysical properties and facies, along with their ranges of uncertainties, were used to populate the geological reservoir model, which was simulated and history matched. The results show a good match with the observed pressure and flow rate.

The novelty of this paper is that it documents a complete workflow to quantify petrophysical uncertainties in thin laminations (centimeter scale) with only conventional wireline logs, flow tests, and limited cores.

Development of a Staged Effective Medium Model With a Thomas-Stieber Model to Estimate Permeability

Michael Myers, Lori Hathon, and William Horvath, University of Houston

A Staged Differential Effective Medium (SDEM) model is applied to interpret the permeability in thin-bedded shaly sands. In this model, the permeability varies with the amount and distribution of clay minerals. The model allows continuous interpolation between a series and parallel distribution of the clay minerals. Dispersed clays are added before structural clays and matrix grains. The longest length scale, clay laminations, are the last phase added to the massive sand matrix. The resulting equations include the distribution parameters for each inclusion. The standard Thomas-Stieber (T-S) model is extended to allow for differing clay properties. This more accurate analysis allows a quantitative separation of clay types that are distributed at these different length scales using only density and gamma ray log data.

The three endpoints of the Thomas-Stieber triangle (clean sand, clay-filled sand, and shale) are determined from log data, thin sections, and scanning electron microscope (SEM) observations. Dispersed clay porosity and shale laminae porosity were estimated using SEM imaging and image segmentation. The dispersed clays were observed to have substantially higher porosity than the laminar clays. Clay laminae and pore-filling dispersed clays are, therefore, given differing porosities and gamma ray responses in contrast to a standard T-S model. The SDEM model is then used to iteratively extract the clay properties according to their differing length scales. The initial regression determines the distribution parameter of the shale laminae. The properties of the clay-filled sand allow the impact of the dispersed clays on permeability to be determined. Core data are used to calibrate the permeability model.

Dispersed clay is found to reduce the permeability much more rapidly than clay laminations; sand macroporosity is more strongly correlated to permeability than the net/gross (N/G). Macroporosity is defined as the total percent bulk volume of macropores, or sand porosity minus the bulk volume fraction of dispersed clay. Macroporosity ranges from the total porosity in clean sand to zero when the dispersed clay is completely pore filling. Using macroporosity as the control on permeability acknowledges the negligible contribution of the microporosity associated with dispersed clays.

The standard Timur-Coates parameters are not appropriate for use in this reservoir. Both the NMR and the SDEM models have to be calibrated to the measured core data. The permeability estimations using the SDEM model have a comparable uncertainty to that of standard NMR permeability models.

This work introduces the use of SDEM models applied in conjunction with the T-S plot for the estimation of permeability. This allows geology-based models incorporating the differing length scales of the clays to be built. Because the model performs as well as the NMR-based permeability models, the application of the SDEM model can result in significant financial savings. The use of the T-S plot means that varying N/G and volumes of dispersed clay are accounted for, giving increased accuracy and the ability to extrapolate the model.

Dielectric Characterization of NMR Surface Relaxivity

James Funk, University of Houston

NMR and dielectric measurements provide unique petrophysical tools to probe the molecular dynamics of restricted geometries. Both techniques exhibit time-dependent relaxations sensitive to electromagnetic surface interactions and sensitivity to diffusion length scales in the case of NMR relaxation. However, diffusion rates typical for pore fluids limit the accessible length scales probed with NMR.

Dielectric measurements provide additional length scale interactions and measurements that can be incorporated with conventional NMR. These clarify the relaxation time T_1 and T_2 size assignments typically represented by r_1 and r_2 surface relaxivity and define the lateral extent of the “fast diffusion limit.”

Using protocols established with the coupled physics used in magnetic resonance electrical properties tomography (MREPT) for imaging dielectric properties of tissues, we adapt a dielectric permittivity differential length to area correlation based on Maxwell’s equations. An established staged differential effective medium model for matrix and vug dielectric dispersion and a dielectric-T_2 mapping technique are used to evaluate the NMR relaxation, diffusion, and formation factors based on measured length scales from scanning electron microscope (SEM) images of the matrix and micro-CT images of the vug system.

Correlated NMR and dielectric measurements during spontaneous brine imbibition provide an additional technique to address surface relaxivity by comparing changes in dielectric permittivity in parallel with characterized surface relaxation rates (T_{1S} or T_{2S}). Rates are compared with BPP model correlation times established through dry matrix high-frequency limit dielectric relaxation and T_1 NMR dispersion based on comparative 2 MHz and 23 MHz T_1 distributions.

The dielectrically classified T_2 distributions show good correlations with petrophysical properties and image-based size distributions. Modeled surface relaxivity in the matrix fraction falls within the expected range with vug values related to the overlap in the distributions.

The technique uses the extensive dynamic mobile charge length scales from dielectric measurements (Maxwell-Wagner effect) to refine our interpretation of easily measured NMR multi-exponential response. Although based on carbonates with clay-free surface conductance, adaptation to scaled clastic dielectric dispersion measurements is proposed.

Dielectric Dispersion Model for Qualitative Interpretation of Wettability

Chang-Yu Hou, Jiang Qian, and Lalitha Venkataramanan, Schlumberger-Doll Research Center; Laurent Mosse and Wael Abdallah, SLB; Shouxiang Mark Ma, Saudi Aramco

Formation dielectric dispersion is known to be affected by the formation wettability state. Typically, a hydrocarbon-wet formation has a reduced DC conductivity with a less dispersive permittivity response over a broad frequency range. In this work, we focus on how formation wettability changes affect complex dielectric dispersion in the frequency range (MHz to GHz) of a typical multifrequency downhole tool. The goal is to study the feasibility of inferring the formation wettability state using the dielectric dispersion obtained from downhole tools.

To capture the effect of wettability changes, we adapt a physical picture characterizing the hydrocarbon-wet state by the presence of effective trapped water droplets isolated from a continuous water phase. By modifying the conventional bimodal-like models, we establish a new class of dielectric dispersion models that includes the trapped water fraction as an additional model parameter. Thus, the modeled dielectric dispersion is controlled by a few key petrophysical parameters: the water-filled porosity, the brine salinity, the water phase tortuosity exponents, and the trapped water fraction. Our model construction shows that we can clearly relate the trapped water fraction to the wettability state of the rock. When the trapped water fraction approaches zero, the new model naturally reduces to the water-wet limit. In contrast, a significant fraction of trapped water indicates that the formation is in a more hydrocarbon-wet state. The trapped water fraction is designed as the sole model parameter indicating the formation wettability state. Hence, we can better examine whether the model response with respect to the trapped water fraction can be correlated to the wettability changes.

By comparing dielectric dispersions of cores before and after core wettability changes from water-wet to hydrocarbon-wet, our new model can explain the data with wettability changes more parsimoniously than conventional models. However, for practical applications, it is still difficult to employ a straightforward inversion scheme to unambiguously determine the wettability changes from inverted values of trapped water fraction. This is due to limited information content of the dielectric signal that does not support the independent inference of all desired petrophysical parameters. Instead, we found a phenomenological feature, established through a self-consistent model study and benchmarked with experimental data, that correlates with wettability changes. By fixing the trapped water fraction value and fitting the model to dielectric dispersion, the inverted total water-filled porosity increases monotonically with the increased trapped water fraction for water-wet cores but remains constant for hydrocarbon-wet cores. Intuitively, water-wet formations have a fully connected water phase, which requires enough connected water volume to fit dielectric dispersions and leads to the monotonical increase of the inverted total water-filled porosity. In contrast, forcing a sufficient connected water phase is not required for fitting the dielectric dispersion of hydrocarbon-wet formations due to the presence of effectively trapped water.

The observation of this feature in the newly constructed model enables us to establish a workflow for delineating whether the formation is predominately water-wet or hydrocarbon-wet with the downhole dielectric tools.

Enhanced Reservoir Characterization and Horizontal Well Placement With the Use of High-Definition and Three-Dimensional Reservoir Mapping-While-Drilling Systems in Campos Basin, Offshore Brazil

Guillermo Cuadros and Antonio Mainieri Vieira da Cunha, SLB

This paper presents the experience using the latest developments of reservoir mapping-while-drilling (RMWD) technologies to aid geosteering and reservoir characterization of horizontal wells in Campos Basin, offshore Brazil.

It includes an overview of the main challenges faced for horizontal well placement optimization within turbiditic sands, a technical description of the technologies and workflows implemented, and examples of applications and results.

The latest developments in RMWD implemented in Campos Basin include the high-definition (HD-RMWD) and the three-dimensional (3D-RMWD) systems. The ultradeep electromagnetic measurements acquired are converted into a map of the resistivity profile around the borehole using inversion algorithms.

The HD-RMWD provides multilayer detection by introducing a new higher-power transmitter and a one-dimensional (1D) deterministic parametric inversion engine that provides a finer two-dimensional (2D) map along the well trajectory when compared to the previous generation system. This combination results in enhanced capabilities for geosteering and reservoir characterization.

The new 3D-RMWD extends the application of this type of technology to the most complex reservoir settings and enables azimuthal geosteering. A set of new measurements—the full 360° tensor—is acquired and transmitted in real time using a new data compression algorithm and is converted into 3D resistivity volumes using a cloud-based 2D transversal inversion technique.

The HD-RMWD system was implemented in 2021 to enhance proactive horizontal placement in the Campos Basin. For landing, an actual detection of around 20 m has helped to set casing in the desired target, identifying the presence of upper layers when present. Within the reservoir, the radial depth of detection achieved with a three-receiver configuration was in excess of 30 m, which was enough to map the top and base of sandstone reservoirs while identifying the occurrence of multiple thin beds, their dipping, and fluid contacts when present.

The 3D-RMWD technology has recently been introduced in Campos Basin, and the initial results show great potential for application for reservoir characterization in complex non-1D geological environments and enable geosteering not only vertically but also in azimuth to optimize hydrocarbon drainage.

Additionally, these technologies have also shown their capabilities to reduce the need for pilot wells.

The previous RMWD system was used in offshore Brazil for 13 years, and this paper presents the experience gained from using the latest developments. The HD-RMWD system represents a significant advance by providing a finer resistivity map around the borehole, while the 3D-RMWD technology opens a whole new area of application, especially for complex reservoir characterization, and provides means for azimuthal geosteering, which is an avoided practice at this time. When used to its maximum potential, this 3D mapping technology is expected to enable horizontal well placement closer to fault planes or parallel to reservoir boundaries to optimize hydrocarbon drainage.

Experimental Workflow for Quantifying the Performance of Geophysics-Based and Conventional Core-Based Wettability Assessment Methods

Zulkuf Azizoglu and Zoya Heidari, The University of Texas at Austin

Conventional wettability assessment methods (e.g., Amott-Harvey and USBM) are often time consuming and require core-scale measurements. We recently developed wettability models based on two-dimensional (2D) nuclear magnetic resonance (2D-NMR) and/or resistivity measurements, which can be applied to well logs for simultaneous assessment of water saturation and wettability. However, they require core-scale verification, which has been challenging due to the uncertainties in wettability distribution inside the core samples as well as the lack of a dependable ground truth on the wettability of a given sample. The objective of this paper is to develop a setup that can provide a wide range of ground-truth wettability indices to (a) test reliability of a variety of wettability assessment techniques and (b) enable the advancement of the geophysics-based methods for wettability assessment.

Glass beads are used to create synthetic core samples. We use a siliconizing fluid to alter the wettability of the beads and confirm this alteration with sessile drop tests. Next, we aggregate beads of different wettability to create cylindrical artificial grain packs with a controlled wide range of wettability states. For this purpose, we design and fabricate an experimental fixture that tightly packs the beads between two electrodes. This fixture is designed in a way that enables performing both NMR and resistivity measurements. Then, we saturate the samples with a hydrocarbon/water mixture and perform 2D-NMR and resistivity measurements. We use 2D-NMR measurements to estimate water saturation. Then, we use our newly introduced resistivity-based wettability index model (which uses water saturation and resistivity as inputs) to quantify wettability. Finally, we test the reliability of the estimated water saturation and wettability.

We observed that the average relative error between the estimated wettability indices and the fraction of water/hydrocarbon-wet beads is less than 20%. Moreover, we showed that water saturation and wettability could be simultaneously estimated by integration of 2D-NMR and electrical-resistivity measurements with average relative errors of less than 10% and 15%, respectively. The results clearly demonstrate that the introduced workflow can be reliably used in the simultaneous quantification of water saturation and wettability index. We also demonstrated that the experimentally obtained resistivity model parameters related to the shape of the grains (i.e., depolarization factor) are consistent with the one calculated from analytical solutions for spherical grain geometry. This observation verifies that the model parameters of the resistivity-based wettability index model are based on geometry and can be estimated via simplifying assumptions.

The outcomes of this paper enable the detection of the most reliable geophysical-based wettability assessment method and the comparison of their performance against conventional methods. This comparison might suggest a need for redefining a standard wettability index that can be uniquely estimated. In this work, we used artificial rock samples to enable a direct comparison of the estimated wettability indices and actual wettability fractions, which is not possible in actual core samples. Moreover, the use of artificial samples enables testing of the wettability assessment methods in rocks with different pore-size distributions. Finally, results are promising for in-situ and real-time assessment of wettability using borehole geophysical measurements.

Field Trial Results of Novel Percussion Coring in Low UCS Formations

Dave Saucier, Jennie Cook, Dmitry Lakshtanov, Nathan Lane, Glen Gettemy, Robin Eve, Pavel Gramin, Rana Samir Elghonimy, Yuliana Zapata, and Kevan Sincock, bp; Ian Draper and Timothy Gill, Baker Hughes

This paper presents the preliminary results of two field trials where a novel percussion sidewall core acquisition tool was deployed. The work continues the development of the new core acquisition technology previously presented by Draper et al. (2022) and Lakshtanov et al. (2022). This technology leverages digital rock physics (DRP) to assess core quality.

A novel percussion sidewall core acquisition method was trialed in two appraisal wells targeting carbon capture and storage (CCS) prospects. The percussion bullets used included an internal sleeve that protects the core samples from handling damage during extraction and analysis. The percussion sidewall sampling was part of an extensive evaluation program that also included whole core and rotary sidewall core acquisition. Coring program targets were sandstone intervals predicted to have low unconfined compressive strength (UCS), and core recovery was expected to be a challenge. The novel percussion method was deployed to test the acquisition technology under real field conditions and provide a basis for validating the merits of the method against conventional coring and core analysis methods.

Percussion core samples were acquired during individual wireline runs in two field trial wells. On the first well, tool problems unrelated to the novel bullet design resulted in core recovery, which was lower than expected. Modifications were applied, and very high core recovery was achieved on the second well. High-resolution X-ray micro-computed tomography (micro-CT) images of the core samples indicated that a suitable volume of material was available for DRP and conventional percussion core sample analysis. Preliminary assessments indicate that the method is competitive with other rock sampling methods in terms of cost, risk, and value.

Deployment of a novel percussion sidewall coring technology in two field trial wells has demonstrated the applicability of the sleeved bullet concept to real downhole conditions. DRP and conventional evaluation of the core samples have shown that samples are of good quality and can yield critical reservoir characterization information. The novel percussion coring technology addresses several historic challenges to characterizing soft (low UCS) formations. Combined with DRP and conventional core analysis, this technology offers a cost-effective and efficient method of reservoir characterization.

Influence of Grain Shape and Size on the Performance of Dielectric Permittivity-Based Water Saturation Assessment Models

Zulkuf Azizoglu and Zoya Heidari, The University of Texas at Austin

Dielectric permittivity mixture models commonly assume simple geometries for the constituting rock components, which affect their reliability in rocks with complex pore geometry and rock fabric such as carbonates. The combined influence of pore geometry, grain shape, and grain size on the performance of those models in water saturation assessment remains to be tested. Frequency-domain dielectric permittivity simulations can model the influence of pore and grain geometries on dielectric permittivity without a need for explicitly defining those parameters. Individual impacts of the aforementioned properties can be quantified and separated in the pore-scale domain via dielectric permittivity simulations. Therefore, the objectives of this paper are to (a) design pore-scale rock samples with different grain shapes and sizes, (b) investigate the influence of grain shape, grain size, and pore connectivity on the dielectric permittivity of the pore-scale rock samples as well as rock images from carbonate and sandstone formations, and (c) evaluate the performance of multiple dielectric permittivity mixture models in the quantification of water saturation.

We construct three-dimensional (3D) synthetic rock models with spheroidal grains. We use different aspect ratios (i.e., the ratio of the radius of the major axis to the radius of the minor axis) and grain sizes for spheroids. Next, we numerically alter the water saturation. We perform frequency-domain dielectric permittivity simulations (through the solution of Maxwell's equations in the frequency domain) in actual and synthetic samples in the frequency range of 100 Hz to 5 GHz. Finally, we test the performance of multiple dielectric permittivity mixture models (e.g., Maxwell-Garnett, Hanai-Bruggeman, CRIM, etc.) in the estimation of water saturation from dielectric permittivity measurements.

We observed that the relative permittivity (i.e., the real part of the dielectric permittivity) increased with an increase in the aspect ratio of the spheroid grains. The electrical conductivity (which is associated with the imaginary part of the dielectric permittivity) decreased as the grains became flatter, which is due to the decreasing efficiency in electrical current flow. The dielectric permittivity dispersion is much less significant for rounder spheroid grains. The dispersion and absolute values of the relative permittivity and electrical conductivity decreased with the decreasing water saturation. We documented that overlooking the influence of pore and grain geometries can lead to average relative errors in water saturation up to 100% in the sandstone and carbonate samples. Taking into account the grain geometry and using Maxwell-Garnett formulation with the background medium properties estimated with the CRIM equation resulted in the lowest average relative errors (10%) in water saturation quantification.

The documented results quantified the impacts of grain size, grain shape, and pore connectivity on dielectric permittivity. This analysis was possible through pore-scale modeling of dielectric permittivity dispersion. The outcomes demonstrate the limitations of the current dielectric permittivity mixture models in the calculation of dielectric permittivity and assessment of water saturation under different conditions. Therefore, the results of this work can help in quantifying the uncertainty associated with the use of existing dielectric permittivity mixture models depending on the pore and grain geometry of any given rock.

Inversion-Based Multiwell Petrophysical Interpretation of Well Logs and Core Data via Adaptive Rock Physics Models

Joaquin Ambia Garrido and Carlos Torres-Verdín, The University of Texas at Austin

Formation evaluation, and specifically hydrocarbon volume estimations, are tightly dependent on the rock physics model (RPM) used for the interpretation of well logs and core data. The latter models are known to exhibit small but significant variations throughout multiple wells located in the same hydrocarbon field. To improve the accuracy and reliability of the interpretation, the RPMs are typically adjusted ad hoc. We automate the multiwell interpretation process by relying on local petrophysical inversion of well logs and core data. A spatial correlation function is used to implement the RPMs, both vertically and laterally. Besides improving formation evaluation in each well, our inversion-based method mitigates layer-boundary, geometrical, and instrument-related effects on well logs and identifies data outliers and data imbalances where further quality control might be needed.

First, we invert each available well log into an equivalent physical property represented by a layer-by-layer blocky log with an associated uncertainty (earth model; piecewise constant with discontinuities in the boundaries). This mitigates any tool, shoulder-bed, or borehole-condition dependency. Then, we use the extra measurements (well logs and core data) from a key well to determine an initial RPM (e.g., Juhasz parameters and minerals density), as well as probabilistic prior distributions for all properties, e.g., porosity and water saturation. Next, we propagate the RPM and prior distributions throughout the field using Bayesian petrophysical/compositional joint inversion (PJI) for all petrophysical properties in every well, concomitantly propagating uncertainties to petrophysical/compositional properties. With each non-key well having a full set of physical (from logs) and petrophysical/compositional properties, we generate new priors and RPMs for each well by minimizing the PJI misfit. These new priors and RPMs are used to further refine priors and RPMs on neighboring wells. We enforce consistency via spatial variograms for RPMs. The process is repeated iteratively while tightening the variogram until no further improvement is possible. This method guarantees that the variation of RPMs is consistent across spatial correlations. The accuracy of the method is improved as more field data are available to corroborate and refine local RPMs and prior distributions.

By using adaptive RPMs over tool and borehole-condition mitigated layer properties, we were able to match core data constituted by porosity, fluid saturations, and mineral composition. Our results replicated 87% of the core data within the 95% confidence interval; in contrast, using a universal RPM replicates a lower 80% of the core data within the 95% confidence interval. Traditional interpretation methods cannot capture confidence intervals and yield significantly poorer matches in all properties; when comparing specifically hydrocarbon pore volume, our method shows an average 5% accuracy improvement.

We generalized a logging-tool- and borehole-condition-independent Bayesian inference petrophysical estimation method to a multiwell framework. By considering the entire hydrocarbon field as a single petrophysical joint inversion of well logs and core data, we increased the accuracy of formation evaluation and/or identified outliers or data imbalances, which signaled poor or biased data that required further quality control.

Inversion-Based Thomas-Stieber Approach to Estimate Storage and Flow Properties of Heterogeneous Shaly Sandstones

Ali Eghbali and Carlos Torres-Verdín, The University of Texas at Austin

We generalize the Thomas-Stieber (T-S) concept to develop an inversion-based interpretation method of well logs to estimate storage and flow properties of arbitrarily heterogenous sandstone-shale sedimentary sequences. Firstly, we use well logs to simultaneously estimate shale lamination volume, Vlam, and dispersed clay concentration, Vdisp. Estimation results are used to calculate storage and flow properties by implementing rock classification and rock-class-dependent petrophysical models. The general inversion-based T-S estimation method overcomes practically all the limitations of the standard T-S approach, such as (i) assuming the same properties for shale layers and grain-coating clay and (ii) T-S diagram axes (porosity-shale volume) are not readily available measurements. We also introduce a permeability model for arbitrary shaly sandstones that accounts for sandstone-shale laminations and dispersed clay. Permeabilities calculated parallel and perpendicular to the bedding plane are improved and successfully benchmarked against core measurements by combing the estimated Vlam and Vdisp.

After establishing the forward model that relates Vlam and Vdisp to well logs, we minimize the squared difference between the available logs and their numerical simulations. The relationship between Vdisp, Vlam, and nuclear logs is nonlinear, while material balance must be honored in the estimation. Likewise, the choice of well logs for inversion, e.g., bulk density, gamma ray, or neutron, depends on their sensitivity to specific layer composition. Using an efficient gradient-based optimizer, we estimate Vlam and Vdisp and their uncertainty. When Vlam is not negligible, vertical and horizontal resistivity from triaxial induction become key measurements to assimilate electrical anisotropy in the estimations. Water-saturation models that account for the excess electrical conductivity of clay are invoked when Vdisp is nonzero.

Next, we calculate the throat-radius reduction of a bundle of capillary tubes based on Vdisp. We also calculate the effect of sandstone-shale laminations on anisotropic flow properties. The resulting anisotropic permeability, verifiable against cores, is a function of shale-free sandstone, shale lamina, clay permeability endpoints, formation factor, Vlam, and Vdisp. When NMR data are available, predicted time-relaxation modalities should match the measurements.

We verified the inversion-based interpretation workflow with two synthetic and one field case with core measurements. Inversion results decrease pore-volume errors by a factor of 3 compared to standard well-log analysis. Estimated permeabilities match core data within 2.6% on a logarithmic scale. We remark that rapid variations in the physical properties of clays/shales and rock composition require adjustments of the simulation endpoints. Nuclear logs are shallow-sensing measurements (only investigate the flushed zone), whereby the changes in input well logs are dominated by changes in Vlam and Vdisp. Depth-matching and borehole environmental effects are considered part of the inversion procedure.

Results differentiate between pore-filling clays and laminated shales, while standard Thomas-Stieber-based well-log interpretation assumes the same endpoints for both. Furthermore, Thomas-Stieber methods assume a linear relationship between shale/clay volumes and nuclear logs that is inadequate and erroneous; they propagate measurement noise to interpretation results, while our inversion method mitigates instrument noise effects and explicitly accounts for the nonlinearity between measurements and estimated properties. Finally, there is no publication that relates the permeability of sandstone to permeability endpoints in thinly laminated, clayey-sandstone/shale sequences.

The Evaluation of Wellsite Gas Data From Lateral Development Wells – A Comparison Between Petrophysical Pay and Wellsite Gas Defined Pay, A Case Study From the Inner Moray Firth, UK

Lloyd Jones and Julian Moore, APT UK; Tim Dodd, TD Consultancy Services

Wellsite gas data are collected routinely over the full well section in most wells; it gives a continuous record of the composition and amount of gas in the pore rock cut while drilling (with some caveats around mud weight relative to pore and fracture pressures). The composition of the gases, when corrected for the effects of solution in oil-based muds, can be related to the composition of oil and gas in the formation via the correlation of light gas compositions to large PVT data sets initially and, in appraisal and development settings, to correlations to local PVT data.

While the absolute amount of gas corrected for drilling variables is often variable between wells, gas values related to a background gas level in non-pay lithologies are often more correlated between wells. We term gas normalized to a background level as anomalous gas value(s) or AGV. The AGV derived from gas data in a known pay zone can then be used to predict additional and missed zones of pay. The amount of gas in excess of the background should, in theory, be proportional to the hydrocarbon pore volume in the rock.

This paper compares LWD-derived petrophysical pay to wellsite gas-defined pay during the exploration, appraisal, and development of the Blake Field in the Inner Moray Firth, UK. In addition, a workflow to estimate a continuous GOR through the reservoir sections ranging in size from 100 to 3,000 ft is also presented.

The presented case study shows that quantitative net pay estimates derived from the normalized and calibrated wellsite gas data can be correlated to wireline/petrophysical-derived pay estimates, but with the addition of also indicating hydrocarbon phase. In extensive development wells, where running wireline tools can be challenging and often expensive, insights derived from standard mud gas data can often be invaluable.

In recent years, some operators have begun to integrate wellsite gas data together with wireline, petrophysical, and PVT data, e.g., McKinney et al. (2008), and used as a net pay estimator, e.g., Malik et al. (2020), but, is to be utilized extensively across the industry and particularly in a development setting. In a development scenario, reservoir and fluid properties are likely to be well understood. This knowledge should enhance the potential utility of wellsite gas methods for net pay calculations and reservoir fluid properties, enabling cost reduction in standard development well data acquisition programs.

The Fundamental Flaws of the Waxman-Smits and Dual-Water Formulations, Attempted Remedies, and New Revelations From Historical and Recent Laboratory Complex Conductivity Measurements

John Rasmus, Consultant; David Kennedy, QED Petrophysics; Dean Homan, SLB

The Waxman-Smits formula[1] was introduced in 1967 as a parallel conductance model to improve previous models. A careful inspection of Waxman's and Smits' model reveals that it is not a parallel conduction model by the conventional definition.

First, Waxman-Smits assumed that "the electrical current transported by the counterions associated with the clay travels along the same tortuous path as the current attributed to the ions in the pore water" (Waxman-Smits, 1967), removing an essential feature of a parallel conduction model, that there be two separate conductors. Based upon this assumption, they assign the same geometrical factor to both current paths. The geometrical factor is defined as the reciprocal of the formation resistivity factor ($1/F$ or j^m). Waxman-Smits found experimentally that a shaly sand appeared to have an F that was larger than a clean sand and introduced F^* to account for this. Therefore, the tortuosity of the current paths through the clay and the pore water was deemed to be equivalent, with both tortuosities increasing equally as the clay content increased.

Second, a parallel model requires that the bulk conductivity of a volume be weighted by the fractional volumes of the separate clay and interstitial water current paths. Clavier, Coates, and Dumanoir[2,3] discovered during the field testing of the new 1.1-GHZ electromagnetic propagation tool that there existed a volume of clay water of near-constant salinity in shales. These two concepts are not accounted for in the Waxman-Smits model. A re-evaluation of the Waxman-Smits database by Clavier et al. revealed that the F^* increase was primarily due to the Waxman-Smits model not accounting for the physical presence of the volume of the clay-bound water. The inclusion of the clay-bound water volume in the dual-water model produces a true parallel conductivity model. However, like Waxman-Smits, it assigns the same tortuosity to both the clay and pore water current paths.

Theoretically and experimentally, the value of the clay water conductivity (C_{cw}) at room temperature was found to be 6.8 S/m. Therefore, for a pore water conductivity (C_w) less than 6.8, the clay adds to the rock conductivity relative to an Archie rock, as written in the Waxman-Smits model. However, when C_w is greater than 6.8, the clay water subtracts from the rock conductivity relative to an Archie rock. This cannot be accommodated by the Waxman-Smits formulation. To correct for this model deficiency, B was made a function of salinity and temperature when, theoretically, it is a function of temperature only.

Thirdly, neither model accurately predicts the rock conductivity at pore water salinities below approximately 0.5 S/m. Having a proper model at these lower salinities is important for geothermal evaluations, waterflooded reservoirs, and naturally occurring freshwater reservoirs.

We have re-evaluated the Waxman-Smits database and the Vinegar-Waxman induced polarization database and supplemented these with broadband complex conductivity measurements of various clay minerals mixed with glass beads at various salinities.

The assumption of equivalent tortuosities seems dubious based on observations of scanning electron microscope (SEM) photos showing actual clay morphologies. Our recent broadband complex conductivity laboratory experiments of pure clay and 250 µm diameter glass beads have allowed us to quantify tortuosity changes due to the introduction of clay into an otherwise pure glass bead environment.

For the inaccuracies of both models at low salinities, we propose a correction method based on our knowledge gained from the study of the quadrature conductivity measurement from cores and recent laboratory measurements.

We have fully described the parameters of the Waxman-Smits and dual-water formulations in terms of petrophysical and electrochemical concepts and proven that the Waxman-Smits B factor salinity corrections are an empirical correction that is unnecessary in the dual-water formulation. The dual-water formulation is proven to be a truly parallel conductance model, while the Waxman-Smits model is not. Finally, we provide an electrochemical-based correction to correct the dual-water model for the low-salinity conductivities, which is based on our recently gained knowledge of the quadrature conductivity behavior.

The Impact of Fractures on Producibility and Completions in the Wafra Maastrichtian Reservoir

Sunday Adole, Ting Li, Peter Wilkinson, Bambang Gumilar, Joshua Azobu, Andrew Ranson, Yegor Se, Jim Turner, and Karen Whittlesey, Chevron U.S.A. Inc.

The Wafra Field is located in the Partitioned Zone (PZ) between Saudi Arabia and Kuwait. Designing the right completion strategy to minimize water cut has been challenging in the Maastrichtian reservoir. One of the biggest challenges relates to variable hydrocarbon mobility and understanding of production from fractures. Also, there is uncertainty around the initial mobile water saturations in pay zones. Many wells come online with a high initial water cut, while other wells show low initial water cut before a sharp increase in produced water volume within a few months.

Previous studies identified fracture production in at least one well based on core observations and production logging. In this paper, we make an integrated analysis of oil production from apparent tight zones with irregular fractures. A rich suite of borehole measurements was acquired across the field. Mud logs, wireline triple combo logs, formation pressure and fluid samples, core data, image logs, NMR logs, geochemical logs, and production logs (PLT) were collected. Initial production (IP) rates and well tests were utilized to provide the ground truth for our log interpretation.

In many wells, oil production does not come from interpreted pay zones (porosity > =15%, water saturation < 50%) but rather from apparently tight rocks. The wireline logs offered limited insight into how fluids entered the wellbores. Conventional cores revealed either vugs or fractures in the rock with an aperture of several centimeters filled with oil. A PLT in one of the wells shows a significant inflow of relatively light oil and no water from an impermeable rock matrix.

Wireline logs were interpreted with a multimineral model to compute rock and fluid volumes. The capture spectroscopy data provided clay concentrations, which led to a more robust porosity and matrix permeability interpretation. Image log processing revealed fracture networks with a considerable aperture in zones with higher production. Interpretation results were validated by core, fluid samples, mud logs, and production data (PLT, well tests).

Ongoing assessment of fracture-related production and improved understanding of the role vugular zones and matrix permeability contribute to fluid mobility is key to future Maastrichtian development.

The significance of this work is that it presents a multidisciplinary approach, combining openhole and casedhole petrophysics, to optimize producibility and completions.

Using XRF and FT-IR on Cuttings to Characterize Mineralogy for Conventional Production: Example From the Central Basin Platform

Jonathan Madren and Stephen Montoya, Chemostrat, Inc.; Jessica LaMarro, Forty Acres Energy

Analysis of cuttings samples can be useful for calibrating log results and supplementing log data when limitations from conventional logging have been noted. In order to characterize the value of this approach, cuttings wells from a conventional field in the Central Basin Platform in New Mexico have been collected for analysis. These test samples are from an area undergoing waterflooding for secondary recovery in the Queen Formation, and the results from this effort are discussed in this context.

In total, 150 cuttings samples from four wells were analyzed using benchtop X-ray fluorescence (XRF) and Fourier-transform infrared (FT-IR) instruments. These samples were sieved to minimize contamination from cavings and reconstituted fines. Validations for the quality of the cuttings were made through the levels of barium detected, which should give insight into the amount of drilling mud contamination along with a visual inspection. A chemical gamma log was produced using the measured U, Th, and K in order to depth correct the samples to the log and understand if the samples were likely heavily contaminated with nonrepresentative components. A split of these samples was prepared for FT-IR by washing with toluene to remove any residual organic material on the surface and dried in an oven at 70°C for 6 hours to remove excess moisture from the sample. The mineralogy from the FT-IR spectra was modeled using representative XRD from the basin.

The XRF and FT-IR analyses were used to determine the mineralogy of the formation independently and then were used concurrently to minimize the uncertainty of the mineral modeling effort. The XRF analysis proved to be very useful in validating the assessed value of minerals that do not respond to infrared energy, such as pyrite, and the FT-IR helped to validate the distribution of minerals that would be hard to characterize due to the difficulty of identifying light elements such as Na or Mg. The limitations of the FT-IR method are made clear due to the importance of the quality and quantity of XRD data used to constrain the model for mineral predictions.

Cuttings have shown to be useful in characterizing mineralogy in this field study in a timely, cost-effective way, which can improve log evaluations of these types of fields. This can be especially useful when dealing with log data of different vintages and quality. Characterization of the mineralogy of these fields can be important not just for the initial development of the field but also for ensuring compatibility for waterflooding along with CO_2 flooding/sequestration.

FORMATION EVALUATION OF UNCONVENTIONAL RESERVOIRS

3D Temperature and Hydrodynamics Modeling in Horizontals to Assess the Fractures Performance

Maxim Volkov, TGT Diagnostics

Unconventional wells have revolutionized the oil and gas industry in the last decade. Downhole diagnostics play an essential part in understanding the well completion and reservoir performance. Diagnosing reservoir performance is primarily by acquiring data about the geometry of the developed fracture network or, in other words, stimulated reservoir volume. Operators perform diagnostics using different instruments from conventional production logging tools (PLT), DTS/DAS, and tracers, but even in the case where the data quality is perfect, data sets are limited to the following:

- Scanning of the wellbore flow only
- High thresholds for flow rate and fluid composition

- Poor flow type classification and indication of flow behind the casing/liner/gravel pack
- Qualitative assessment of temperature and acoustic data, especially in multiphase flow
- Limited characterization of fracture performance.

This presentation discusses the development of a new generation of temperature modeling in horizontals to enable the quantification of flow behind the casing and the analysis of pressure, temperature, and flow distribution within the fracture length. The modeling is calibrated by downhole temperature and spectral acoustic data obtained, and this data generate a three-dimensional (3D) grid of flow distribution, pressure, and temperature along the horizontal wellbore.

The 3D temperature modeling method has been successfully tested in horizontal injectors and producers globally. A “blind” comparison to industry-standard PLT measurements and other temperature modeling techniques was performed to evaluate the accuracy and thresholds and indicate the advantages and limitations. It showed good matching to PLT in terms of rate and phase distributions in case of radial inflow to the wellbore; however, in case of the complex flow path with the presence of annular flows, flows behind the casing or failures in swell packers demonstrated the capability to perform quantitative assessment of each scenario. This opens new opportunities to evaluate complex flow scenarios in horizontals and better understand reservoir performance.

Based on the analysis of the public information available, 3D modeling of temperature, pressure, and flow distribution, including the scenarios of matrix to fracture, fracture to the wellbore, matrix to the wellbore, as well as annular and wellbore flows, is a new approach available today that was not present earlier due to complexity and the requirement of high computing power.

A Compact Multisensor LWD Tool Optimized for Unconventional Reservoirs

Cory Langford, Scientific Drilling; Craig Barnett, Consultant; Medhat Mickael, Innovative Downhole Solutions

High-cost deepwater, high-pressure/high-temperature (HP/HT), and extended-reach wells in conventional reservoirs drove impressive developments in logging-while-drilling (LWD) technology in recent decades. However, the length, cost, and mechanical specifications of traditional LWD tools make them generally unattractive for use in onshore unconventional reservoirs, which present very different economic and technical challenges. This has led to the development of a compact integrated LWD tool optimized for geosteering, evaluating, and optimally completing unconventional reservoirs.

Azimuthal spectral gamma ray, high-resolution ultrasonic imaging, and azimuthal sonic sensors are incorporated into a single 14.5-ft (4.4 m) sensor collar. Applications of the azimuthal spectral gamma ray sensor include real-time geosteering, organic content evaluation, and clay content determination in uranium-bearing shales and carbonates. The ultrasonic imager provides high-resolution borehole images in both water-based and oil-based muds for fracture and fault detection, stress orientation, formation dip, and borehole stability applications. The ultrasonic imager also provides high-resolution caliper data. Azimuthally oriented compressional and shear slowness measurements from the azimuthal unipole sonic sensor provide important geomechanical, geophysical, and petrophysical information, including Poisson’s ratio, porosity, and VTI shear anisotropy in horizontal wells.

Log examples from various North American basins demonstrate the applications of this integrated LWD logging suite. Spectral gamma ray data from the Marcellus Shale differentiates high clay formations from cleaner, organic-rich, uranium-bearing formations, facilitating the evaluation of both organic content and clay content from K, U, and Th data. Ultrasonic imager data from the Marcellus Shale and Permian Basin reveal natural fractures and formation dip, as well as borehole breakout in both normal and thrust fault stress regimes. Azimuthally focused unipole array sonic measurements from a horizontal well in the Wolfcamp Formation resolve intrinsic VTI anisotropy. Together, these measurements allow operators to locate and geosteer in unconventional strata with higher organic content and/or geomechanical properties, which are more conducive to hydraulic fracturing. These measurements also facilitate engineered completions, where frac stages are selectively placed to group together rocks with similar mechanical properties in each individual stage.

Incorporating multiple logging sensors with particular value for unconventional reservoirs into a single compact drill collar represents a new direction in LWD technology. In addition to the primary drilling and evaluation applications, recent log data have also revealed several novel uses, including (1) observing the early time progression of borehole breakout by comparing ultrasonic images acquired while drilling and shortly after drilling, (2) detecting gas influx while drilling from decreases in ultrasonic imager amplitude, and (3) monitoring significant variations in mud slowness during various drilling operations using the ultrasonic mud cell. This integrated logging suite has also found applications beyond unconventional reservoirs, including use in fractured granite geothermal drilling and, when combined with LWD resistivity, in conventional offshore wells.

A Novel Workflow Based on Core and Well-Log T_1T_2 NMR Measurements for Improved Field-Scale Assessment of Fluid Volume in Shale and Tight Reservoirs

Luisa Crousse, Artur Posenato Garcia, Boqin Sun, Elton Yang, Mason Edwards, Mehrnoosh Saneifar, and Robert Mallan, Chevron U.S.A. Inc.

Oil production in the US is increasingly dependent on shale and tight assets. However, there are still many challenges associated with the exploration and exploitation of these reservoirs. Reliably characterizing fluid saturations and volume fraction of movable fluids can be difficult due to numerous factors, including variable formation water salinity, complex lithology, the thin-bedded nature of the formation, and the presence of organic and inorganic pore systems. Additionally, the accuracy of interpretation models is constrained by the limitations associated with available laboratory measurements. In tight formations, calibrating resistivity models can be very expensive and time consuming due to the intrinsic pore structure of the rocks. Measured saturation and porosity core data by Dean Stark and retort methods are very limited. Meanwhile, the accuracy of these data is greatly affected by fluid losses. To address these challenges, we introduce a new workflow integrating experimental data at core and pore scales with a T_1T_2 2D NMR log for improved field-scale characterization of fluid volumes.

The introduced workflow integrates the interpretation of a T_1T_2 NMR log with scanning electron microscope (SEM) images, thin sections, and laboratory low-field NMR measurements. SEM images and thin sections are utilized for the assessment of formation-by-formation pore-size variations. From laboratory NMR measurements, we estimate the expected 2D NMR responses for water- and hydrocarbon-saturated samples. Then, we integrate the interpretation of these laboratory measurements with borehole NMR data. To accomplish this, we utilize a novel interpretation workflow that first approximates the 2D NMR measurements into a superposition of 2D Gaussian distributions. Next, we apply a clustering algorithm to the data space containing the T_1/T_2 mean values and amplitudes calculated for each Gaussian. And finally, we correlate the centroid of each cluster with the fluid and pore types identified in the laboratory.

We verified the reliability of this novel workflow on multiple wells to cover several different shale and tight formations. We demonstrate that water and hydrocarbon fluid volumes estimated by the introduced workflow are consistent with the results obtained from Dean Stark and retort methods. Furthermore, we verified that the average difference between the volume fraction of water obtained from the interpretation of dielectric measurements and the new workflow is less than 1 p.u. In addition to more accurate fluid volumes quantification, the new workflow predicts the amount of movable water and hydrocarbon. These predictions have been confirmed by available production data.

The novel contribution of this workflow was to improve the reliability and accuracy of the water and hydrocarbon saturation assessment in shale and tight reservoirs. A significant impact obtained from the application of the introduced workflow is the identification of multiple zones containing hydrocarbon that have not been previously identified with other interpretation techniques.

Advanced Formation Evaluation and Water Saturation Prediction in the Middle Bakken Member, Williston Basin

Ilyas Mellal, Abdeldjalil Latrach, and Vamegh Rasouli, University of Wyoming; Ouafi Ameur-Zaimeche, University of Kasdi Merbah Ouargla; Mohamed Lamine Malki, University of Wyoming; Omar Bakelli, University of North Dakota

Multiple challenges are associated when characterizing complex reservoirs using well logs. The Middle Bakken Member (MBM), as a tight and multimineral reservoir with a low-resistivity pay, presents several petrophysical challenges. The objective of the paper is to characterize the MBM rock properties from pore to log scale using thin sections, routine and special core analysis, conventional and advanced well logs, and machine-learning algorithms.

For a detailed understanding of the MBM rock properties, we used a complex petrophysical workflow by integrating quad-combo logs along with advanced logs, including electron capture spectroscopy and nuclear magnetic resonance (NMR), using both deterministic and probabilistic methods. Bakken minerals and fluids volumes were estimated by combining quad-combo logs along with elemental dry-weight fractions and calibrated with the X-ray diffraction (XRD) and routine core analysis data. Porosity, clay-bound water, and movable fluids were estimated using NMR. Due to the low-resistivity reading in the reservoir and the inaccuracy of the water saturation and permeability estimated from well logs, thin sections from different depths of the MBM were analyzed to understand the pore types, cementing materials, and grain packing. Finally, machine-learning algorithms were applied in a total of 1,503 Dean-Stark water saturation samples using the triple-combo logs to estimate water saturation and generalize the results in the North Dakota portion of the MBM.

We found that from the multimineral model of the evaluated wells that the MBM is composed of six main minerals, where quartz and dolomite are the main minerals of the reservoir. The model provided an accurate prediction of the minerals compared to the XRD analysis, except for some scattered XRD points, which are assumed to be due to the laminations that exist in the reservoir.

Archie derivatives were tested in the Bakken using constant Archie parameters to estimate water saturation; the results showed a disagreement with the Dean-Stark water saturation. By analyzing thin sections, we found that three minerals act as a cementing material, and their volume varies along the reservoir, which makes the estimation of the cementing exponent constant along the reservoir interval a wrong approach.

Machine-learning algorithms were employed to predict water saturation from the triple-combo logs. Several models were compared: linear regression, ridge regression, support vector machines, neural networks with backpropagation, and decision trees. For the comparison, both correlation coefficient and mean squared error were used. Decision trees proved to be the most reliable model, with an R2 of 0.87. The decision trees model gave almost perfect predictions, except for a few outliers that lowered the correlation coefficient. This relatively simple model proved to be a powerful tool for predicting the water saturation in the MBM.

Machine-learning-based models proved to be a robust tool for water saturation prediction in the MBM and outperformed the classical physical and analytical models. Furthermore, the used decision-trees-based model is a white box model whose parameters can be extracted and interpreted.

Advances of Borehole Reflection Imaging in Reservoir Evaluation With High Resolution and Deep Radial Investigation

Wenzheng Yue, Zi Wang, Xin Liu, Shanshan Fan, and Dongjian Yin, State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum-Beijing

The single borehole reflection imaging method (SBRI) has increasingly played an effective role in reservoir evaluation and identification. The SBRI method can image the distribution of fractures and vugs

around the borehole with the reflection waves extracted from array acoustic logging data. However, the insufficient resolution of imaging has limited the application of SBRI in unconventional formations. Moreover, more information besides the reflection events should be comprehensively utilized to refine the evaluation.

In this research, the Shearlet transform method has been introduced in the processing of logging data for obtaining the complete reflected compressional wave with the minimum loss of energy. Additionally, a radial profile of velocity near the borehole can be achieved by the inversion of tomography based on the arrival time of the compressional wave. Combining them with a migration algorithm, the resolution of imaging could be enhanced to show more detail of the reflectors. Moreover, the improved method is able to eliminate the effects of pseudo-interface in the imaging.

Imaging features of the fractures and vugs in reservoirs have been investigated by processing the field logging data with the improved method via extraction and migration of the reflections, which can be used to reveal the mesoscale geostructure around the borehole and to identify subtle reservoirs. The imaging results of the data from an oil field in central China indicate that the features of the reflection event are obviously different for the different reflectors; the fractures and vugs within 20 to 30 m around the borehole can be directly observed in the image with a resolution of about 20 cm. The feature of the geo-interface is of a continuous event with strong energy, while the fracture is of an un-continuous event with a large curvature. Besides the events, the information on fluids distribution and lithology structure has been extracted and imaged to enrich the evaluation of unconventional shale reservoirs. By comparing the SBRI results with the seismic profile crossing the borehole, the consistency between them can demonstrate that the SBRI method can be used to further refine seismic events in geophysical exploration.

A high-resolution SBRI method has been developed to enhance the quality of imaging the distribution of reflectors around the borehole. Besides reflection events, fluids distribution and lithology structure can also be obtained to evaluate the reservoir and formation. Moreover, a method of refining seismic events with the SBRI results has been investigated for comprehensive reservoir evaluation.

An Adsorption Prediction Model With Multiple Factors: Application of Simplified Local Density Model on Organic-Rich Shale

Ruikang Cui and Jianmeng Sun, China University of Petroleum (East China)

Shale gas is the frontier field of oil and gas exploration and the hot spot of recent oil and gas research. The evaluation of its resources is the basis of the whole gas field development plan and development potential evaluation. The adsorbed gas amount of shale, which is usually determined by fitting the Langmuir equation to an isothermal adsorption experiment, is a crucial parameter in determining the gas content and resource potential of shale. The actual adsorption capacity of shale gas reservoirs is significantly underestimated by the Langmuir equation because it does not account for the distinction between excess and absolute adsorption capacity. The applicability of the simplified local density model in the adsorption process of porous media has not been extended to the actual formation conditions. Therefore, a simplified local density (SLD) model with excess adsorption capacity combined with isothermal adsorption experiments under different conditions was selected, and the Levenberg-Marquardt (LM) algorithm was used to construct a shale adsorption model considering the influence of pressure, temperature, and moisture.

For this purpose, several isothermal adsorption experiments of methane under different temperatures and water saturation conditions were carried out, and the adsorption mechanism of shale under the influence of single factors of temperature and moisture was analyzed, respectively. Subsequently, the adsorption mechanism of shale under the combined effect of temperature and moisture was further analyzed, and an adsorption prediction model that considered the combined effects of temperature and moisture was established based on the SLD model and LM algorithm.

The results showed that the SLD model could fit the adsorption data of a shale gas well under different specific conditions, and the average absolute deviations were less than 10%. When temperature and moisture affected the adsorption capacity of shale gas at the same time, they would weaken each other because they mainly influenced the adsorption of methane in the same pores of shale. The temperature- and moisture-dependent model based on the SLD model can be used to predict the adsorbed gas amount of shale under different temperatures and water saturation.

Isothermal adsorption experimental data of Longmaxi shale and other literature (Yu et al., 2015; Yang et al., 2017; Gasparik et al., 2013) verifies the validity and applicability of the model. This study explores the relationship between the adsorption capacity of shale in shale gas reservoirs and various influencing factors through experimental measurements and applies the SLD model to the formation conditions for the first time. A multifactor adsorption model suitable for the accurate calculation of shale adsorbed gas content is established, which cannot only reduce the workload of experimental measurement on the premise of ensuring the calculation accuracy but also provide guidance for the evaluation of adsorbed gas.

Elucidating Wettability Alteration on Clay Surface Contacting Mixed Electrolyte Solution: Implications to Low-Salinity Waterflooding

Isa Silveira de Araujo and Zoya Heidari, The University of Texas at Austin

Many mechanisms have been proposed in the literature to explain wettability alteration at low-salinity waterflooding. Examples of these mechanisms include electrical double layer (EDL) expansion and multicomponent ion exchange. However, no consensus has been reached on which one is the key mechanism in low-salinity enhanced oil recovery. Moreover, these mechanisms are poorly understood. Parameters such as salinity, electrolyte type, and the presence of clay minerals are often associated with the degree to which the injection of low-salinity water increases oil production. Therefore, an investigation of the geochemistry of the clay-fluid interface is crucial to understand the role of petrophysical properties such as wettability on oil production. We use molecular dynamics (MD) to (i) investigate, at an atomistic scale, wettability alteration mechanisms such as EDL expansion and multicomponent ion exchange, (ii) quantify the impacts of different types of electrolyte and its mixture at varying ionic strengths on interfacial properties between oil/brine/clay system, and (iii) investigate wettability alteration by means of water adsorption quantification.

In this work, we investigate interfacial interactions of systems composed of oil/brine/clay. Clay is represented by illite, and brine is composed of water molecules and different electrolyte types, such as NaCl, CaCl, BaCl, and their mixtures at varied concentrations. Oil is represented in this system by heptane molecules. Initially, the modeled oil/brine/clay interface is composed of brine containing only one type of electrolyte. These systems will be studied at a range of chlorine concentration from 0.3 to 1.0 mol/dm^3. Subsequently, we investigate the interfacial properties of the oil/water/clay where brine is composed of mixtures of electrolytes. MD simulations were performed at 330 K, and number density profiles of water, hydrocarbon, and ions inside the illite nanopores were computed.

From the density profile of water, hydrocarbon, and ions perpendicular to the clay surface, the structure of the fluid was analyzed. As salinity increases, sodium cations tend to leach out potassium cations from the illite surface into the solution. The position of the adsorption planes of the ions was identified at different salinity levels. These adsorption planes do not change with salinity, indicating that EDL expansion might not be the dominant wettability alteration mechanism in low-salinity waterflooding. When mixtures of salts were analyzed, it was found that sodium ions are always fully hydrated by water molecules. However, divalent cations such as calcium are present in the stern layer and can form bridges between clay and hydrocarbon. Regarding the distribution of hydrocarbon in the nanopores, it is found that these organic molecules form aggregates inside the nanopore at all simulated ionic strengths.

Despite being widely known as an efficient method for achieving enhanced oil recovery, the underpinning mechanism for wettability alteration at low-salinity waterflooding is still not fully understood. The outcomes of this work improve our understanding of the most effective mechanism in wettability alteration. Moreover, the molecular-scale simulations of clay, water, and hydrocarbon interactions occurring during enhanced oil recovery elucidate the role of different types of ions and the impact of salinity on this process.

Estimation of Permeability Anisotropy and Depositional Cycles in Organic-Rich Chalk by NMR Restricted Diffusion

Xinglin Wang, Rice University; Eva G. Vinegar, The University of Texas at Austin and Vinegar Technologies, LLC; Yunke Liu and Philip M. Singer, Rice University; Harold J. Vinegar, Vinegar Technologies, LLC; George J. Hirasaki, Rice University

We present a new method for studying permeability anisotropy and paleo-depositional cycles by combining NMR anisotropic restricted diffusion measurements and scanning electron microscope (SEM) images on the core. In particular, the method is applied to measuring a depositional cycle from the Tethys Sea in the late Cretaceous period in the Ghareb Formation, which appears to be equivalent to the present-day El Nino-Southern Oscillation cycle.

The NMR anisotropic restricted diffusion measurements were made with a 2.3-MHz NMR core analyzer on adjacent 1-in. core plugs drilled parallel (horizontal) and perpendicular (vertical) to the bedding plane. The cores at connate water saturation were then saturated with methane at 1,200 psi and then saturated with decane for NMR measurements using unipolar stimulated-echo pulse sequences. Different values of diffusion time were used to probe both the short L_D (diffusion length) regime with decane to determine surface-to-volume ratio S/V and the long L_D regime with methane to determine 1/tau, where tau is the diffusive tortuosity. Pore size and tortuosity were estimated based on the NMR restricted diffusion vs. diffusion length data and then used in a modified Carman-Kozeny model to predict the permeability anisotropy.

The figure shows NMR anisotropic restricted diffusion measurements (restricted diffusivity (D/D_0) vs. diffusion length (L_D)) on decane-saturated cores with connate water (C10(H_2O)) and methane-saturated cores with connate water in horizontal and vertical directions.

The S/V is the same for horizontal and vertical directions, indicating the pore size is the same in the two samples. The permeabilities, computed from a modified Carman-Kozeny model, show that tortuosity is the main factor in the anisotropy of the measured core permeabilities. The diffusive tortuosity is much greater in the vertical direction than in the horizontal direction due to the additional diffusional restriction from the depositional laminations.

We find that the L_D at which the vertical core reaches its tortuosity limit is significantly shorter than in the horizontal direction. We interpret the value of L_D ~100 µm, where the vertical diffusion reaches the asymptotic limit, as the half-spacing between laminations due to the depositional cycle.

SEM images of the organic-rich chalk in this zone show several layers of shell fragments with the half-spacing between laminations of about 100 µm, which is consistent with NMR restricted diffusion results.

We propose a new method to measure the permeability anisotropy using NMR restricted diffusion and the Carman-Kozeny model. This method can reduce the diffusive coupling using hydrocarbon saturation on cores with connate water and make a more accurate permeability estimation.

The Ghareb Formation has been carefully dated in this region, and the rate of deposition is known. Thus, the laminations shown in the NMR restricted diffusion enable us to estimate the duration of the depositional cycle in this late Cretaceous period (~69 Mya). Surprisingly, we find that the timing of this paleo-depositional cycle was very close to the present-day El Nino-Southern Oscillation cycle.

Fluid Behavior Analysis in Fresh-State Shale Cores Using Higher-Frequency (23 MHz) NMR T_1-T_2 2D Mapping

Selenne Barrios, Christie Woodroof, Phil Hawley, Omar Reffell, and Z. Harry Xie, Core Laboratories LP

The need to understand the behavior of fluids and their interactions with, as-received state, unconventional reservoir rock matrices is crucial to the understanding of core sample fluid invasion, flowback recovery, hydrocarbon production assessment, and enhanced oil recovery efficiency in unconventional reservoirs. This study uses a higher-frequency (23 MHz) nuclear magnetic resonance (HF- NMR) T_1-T_2 2D mapping technique to evaluate fluid imbibition and mobility in the porous matrix of as-received unconventional core plugs due to heterogeneity in fluid content, clay composition, and organic matter. To analyze the fluid migration, twin fresh-state shale samples from the Eagle Ford and Niobrara Formations were imbibed in oil and simulated formation brine separately for three weeks. NMR fluid saturation mapping measurements were taken at designated time intervals during the saturation process, as well as at the preserved native state and fully pressure-saturated state. Fluid invasion and evaporation patterns were analyzed considering the mineralogic and geochemical composition of the samples.

A higher-frequency (23 MHz) nuclear magnetic resonance (HF- NMR) T_1-T_2 2D mapping technique was used in the experiments on twin fresh-state shale samples from the Eagle Ford and Niobrara Formations. X-ray diffraction (XRD) and multi-heating rate (MHR) rock-eval pyrolysis were combined with the NMR measurements to evaluate liquid behavior in shales.

Our results show that fluid mobility in fresh-state unconventional samples is highly dependent on the chemical characteristics of the saturating fluid (water vs. oil) and influenced by specific properties of the porous reservoir media, specifically clay content, chemical composition, and properties of the fluids present in the cores, and the total organic content (TOC), all of which can serve as wettability controls.

HF-NMR is very sensitive to liquid volume changes in shale samples. Our results illustrate the importance of a thorough fluid saturation estimation as part of the rock core analysis, utilization of low invasion coring tools and techniques, optimized drilling mud selection according to the formation properties, utilization of pressure core tools, and the need to further develop techniques to reduce fluid invasion due to water and oil-based muds during the drilling process and exposure to ambient conditions.

Integration of NMR Log and Core Data to Determine a Generalized Petrophysical Model Applicable in the Austin Chalk

Mohammad Azeem Chohan, Baker Hughes; Richard Hand and Brian Nicoud, Chesapeake Energy Corporation

Austin Chalk is a well-known formation in the South Texas region, targeted for its abundant hydrocarbon resources. Operators utilize advanced logging systems and core data to gain a better understanding of the petrophysical properties of the formation. Nuclear magnetic resonance (NMR) from wireline logging and from core analysis aids in determining properties such as fluid volumes and saturation. However, since both measurements are different due to their frequency ranges and experimental procedures, the petrophysicist finds it can be challenging to correlate the two pieces of information. In this paper, we analyze NMR data from core analysis and wireline logs, calibrate appropriate T_1-T_2 cutoff values to identify hydrocarbons, and compute saturations and permeability models. We then build a petrophysical model for the formations of interest, which is applied to multiple wells in the area. This methodology directed us to ideal landing zones with the highest porosity, lowest water saturation, and largest pore size as measured by the NMR signal.

NMR log data were calibrated post-acquisition with core NMR data as well as core retort tight rock analysis (TRA) to accurately reflect subsurface fluid volumes, saturations, and permeability. The core data were used to find T_1 and T_2 cutoff values to quantify fluids and identify a T_1:T_2 ratio for accurate

saturation analysis. Furthermore, permeability from cores was used to calibrate the Coates-Timur permeability index for each formation.

The process shows a locally strong correlation between core and log data. We were able to calibrate the NMR log data using lab core analysis to accurately quantify fluid volumes and saturations. The new parameters were applied to multiple wells in the area and directed us to the optimum landing zone in the formation of interest.

We demonstrate how to utilize core NMR data to calibrate NMR T_1 and T_2 log information for accurate fluid quantification in the Austin Chalk Formation. The petrophysical model was applied to multiple other wells in the region, which helped identify the most profitable pay zone.

Key Formation Properties in Carbonates From Generic LWD Resistivity Tool Data

Scott Jacobsen, Barbara Anderson, James Hemingway, Eric Decoster, Alan Sibbit, Raghu Ramamurthy, and Peter Swinburne, NoHiddenPay, LLC

Worldwide, carbonate rocks are recognized as the dominant rock type for hydrocarbon reservoirs. The giant fields in the Middle East are mostly carbonates; however, carbonate reservoirs are present in most sedimentary basins globally and offer major contributions to world hydrocarbon production. At the same time, the fine structure/texture/fabric of carbonates is very complex and varies widely across different formations offering a perennial challenge to petrophysics to characterize their fluid content and fluid mobility.

Formation evaluation primarily requires accurate water saturations, which often are based on electromagnetic measurements, usually resistivity measurements. Archie relationships become dubious in carbonates due to widely varying Archie-model exponents. High-frequency electromagnetic measurements made by wireline logging tools have been used in carbonates to determine both formation dielectric permittivity and electric conductivity and can directly provide formation water saturation and water salinity from the two independent measurements without invoking an Archie model.

We propose this same non-Archie type of relationship where inputs of m, n, and R_w parameters are not required to provide accurate saturation determinations, and potentially other key reservoir characteristics, by utilizing standard data from generic logging-while-drilling (LWD) resistivity tools. We thus take advantage of the operational advantages of LWD data acquisition in both new wells and in the large archives of legacy data in carbonate reservoirs globally.

All LWD propagation-resistivity tools in use today provide phase-shift and attenuation measurements, usually at two frequencies in the mid-100-kHz and low-MHz range from an array of transmitters (the LWD band). These phase-shift and attenuation data are simultaneously inverted for formation permittivity and conductivity properties at these frequencies. The inversion results are cross validated against a mechanistic electromagnetic/dielectric property model (DPM) derived from the nuclear log data in the LWD data set.

Inverted formation permittivity and conductivity values are entered into an empirical petrophysical interpretation algorithm to give estimates for water-filled porosity and saturation with minimal additional input. A new mathematical inversion of the DPM is also implemented to solve for both water salinity and water-filled porosity simultaneously.

These algorithms have been proven in clean and shaly sandstone formations. The present paper studies the validity of such algorithms in carbonates.

We present several field-log examples of LWD propagation-resistivity measurements in carbonates from wells in various Cretaceous carbonate chalk formations for the North Sea. We also explore carbonates with complex rock fabrics from wells drilled in selected regions of the Middle East and South Atlantic rift basin reservoirs.

All have been inverted for permittivity and conductivity and then processed for salinity-independent water-filled porosity and water salinity of the formations. We find that these are benchmarked with good success against ground truth data.

Formation dielectric permittivity properties and their attendant dispersion in LWD-band frequencies have heretofore been largely ignored. We show that they can be effectively utilized in a novel approach to solve for water-filled porosity and hydrocarbon saturations in carbonates while obviating the need to involve Archie-type parameters in the interpretation.

Microstructural and Petrophysical Evaluation of the Uinta Group

Carlos Arengas Sanguino, Mark Curtis, Son Dang, and Chandra Rai, University of Oklahoma

The microstructure of unconventional reservoir rocks controls the storage and flow of hydrocarbons. The highly heterogeneous nature of the Uinta Formation presents a complex and varying microstructure that directly impacts the petrophysical properties measured in the laboratory. Porosity, mineralogy, and grain size vary significantly with depth and laterally in the Uinta. Here we assess crucial controls on porosity and pore-throat size of a section of Uinta core using imaging techniques and petrophysical laboratory measurements.

Samples from 598 ft of Uinta core were characterized. Petrophysical properties were measured by source rock analysis (SRA), X-ray fluorescence (XRF), Fourier-transform infrared spectroscopy (FTIR), nuclear magnetic resonance (NMR) spectroscopy, high-pressure pycnometry (HPP), and mercury injection capillary pressure (MICP) measurements. Microstructural analyses were performed using scanning electron microscopy (SEM), energy dispersive spectroscopy (EDS), and micro X-ray computed tomography (µ-XCT).

Significant heterogeneity in microstructure was observed with depth in the core. Porosity, pore body size, mineralogy, and grain size varied significantly with depth and laterally. Many samples showed high porosities, in the 10 to 20% range, with some depths having porosities above 20%. These higher porosity samples tended to be associated with dolomite-rich layers that had well-sorted grains and a homogeneous microstructure throughout the layer. Pore body diameters range from nanometers to hundreds of microns. Pore-throat radii ranged from two to three nanometers to tens of nanometers. SEM showed that the presence of clays influenced pore-throat radii with high clay content leading to smaller pore-throat radii.

The heterogeneity of the Unita is significant. Understanding how the microstructure controls petrophysical parameters such as porosity and pore-throat size helps to understand the storage and transport in the Uinta and facilitates the development of strategies to increase productivity and profits in the Uinta Basin.

Quantification of Kerogen Wettability Using Adsorption Isotherms

Sabyasachi Dash, Isa Silveira de Araujo, and Zoya Heidari, The University of Texas at Austin

Assessment of fluid production in organic-rich mudrocks can be affected by different rock components, fluid mobility, and geochemistry. Kerogen wettability can significantly affect the preferential movement of fluids in organic-rich mudrocks as it constitutes a significant fraction of mudrock volume. In previous publications, the determination of the wettability of kerogen and organic-rich mudrocks is typically achieved using contact angle measurement through the sessile drop method, which might not be considered as a ground truth quantitative measure of wettability. This method also requires pellets of kerogen to create a surface for the contact angle to be measured. No standardized procedure exists for making pellets under stress conditions and saturating fluid to simulate reservoir conditions. In this paper, we introduce a novel method for quantifying the wettability of kerogen as a function of thermal maturity using adsorption isotherms.

We start by crushing organic-rich mudrock samples and sieving them at 170 mesh to obtain a uniformly crushed sample of approximately 90 µm in particle size. We then use a chemical extraction process using hydrochloric and hydrofluoric acid to demineralize the crushed mudrock samples and to obtain pure kerogen. The thermal maturity of the samples is estimated using pyrolysis and vitrinite reflectance measurements. We use the extracted kerogen samples with different natural and synthetically altered thermal maturity levels to perform adsorption isotherm experiments. These measurements are used to quantify the amount of adsorbate adsorbed on the surface of a sample with varying pressure keeping the temperature of the setup constant, which can be converted to a quantitative measure of wettability.

We successfully applied the aforementioned method to several samples covering a wide range of thermal maturity levels collected from a challenging organic-rich mudrock formation. The adsorption test on pure extracted kerogen samples showed a 40% relative decrease in water adsorbed at 98% relative humidity level with an increase in the natural thermal maturity of the samples from a hydrogen index (HI) of 198 (Sample A, the lowest thermal maturity) to 130 (Sample B, the highest thermal maturity) mg-hydrocarbon/g-organic-carbon (mg-HC/g-OC). When Sample A was heat treated at 450°C, the HI was reduced to 32 mg-HC/g-OC, and the adsorption test showed a 70% relative decrease in water absorbed compared to the sample in its natural thermal maturity state. The decrease in the amount of water absorbed from Sample A to Sample B correlated with the decrease in the amount of water produced from the locations/wells the samples were collected from. We compared the results from the adsorption isotherm experiments with contact angle measurements. Sample A formed a 15° air/water contact angle compared to Sample B, forming a 109° air/water contact angle.

The novelties of this workflow include (a) estimation of the wettability of kerogen quantitatively using adsorption isotherms, (b) eliminating the challenges of making pellets and errors associated with contact angle measurements for wettability assessment, (c) quantifying the influence of thermal maturity on the wettability of kerogen and organic-rich mudrocks, which in turn affect hydrocarbon/water production, and (d) the possibility of enhancing prediction of water/hydrocarbon production by taking into account geochemistry and thermal maturity of organic-rich mudrocks.

Quantifying the Sensitivity of Dielectric Dispersion Data to Fracture Properties in Fractured Rocks

Ibrahim Gomaa, Zulkuf Azizoglu, and Zoya Heidari, The University of Texas at Austin

Evaluation of fluid storage and flow capacity of a fractured rock system needs a comprehensive characterization of all the fracture properties. These properties include the fracture surface roughness, aperture size and distribution, fracture orientation, fracture network connectivity, and fracture-matrix connectivity. In-situ quantification of fracture properties is challenging as it relies on collected data from core samples, which are hard to acquire, or on indirect geophysical measurements, which often hold oversimplified assumptions for fracture properties. The objectives of this paper are to (a) quantify the sensitivity of dielectric measurements to fracture surface roughness, aperture size and distribution, fracture connectivity, and orientation through numerical modeling, (b) quantify the influence of fluid phase saturation, salinity, and temperature on the dielectric measurements in fractured formations, and (c) investigate the combined influence of fractures and matrix pore network on dielectric measurements.

First, we developed synthetic models of fractured rocks with a wide range of fracture surface roughness using fractal theory. Then, we developed different cases where the fracture aperture size and distribution, fracture connectivity, and fracture orientation were allowed to vary. We used the synthetic fracture models as inputs to a numerical dielectric permittivity simulator under different fluid phase saturations, salinity, and temperature conditions. The numerical simulator solves Maxwell's equations that describe the propagation of electromagnetic waves using a finite volume algorithm in the frequency domain. The outcomes of numerical simulations include real and imaginary parts of complex dielectric permittivity as a function of frequency in the range of 1 Hz to 3 GHz.

We applied the aforementioned method to synthetically created fractured rocks covering a wide range of fracture properties (i.e., fracture roughness, aperture size and distribution, fracture orientation, and fracture network connectivity), rock matrix properties, and fluid properties/saturations. We observed an increase of one degree of magnitude (from 105 to 106) in the relative permittivity of the fractured rock models with increasing fracture roughness at low frequency (i.e., from 1 Hz to 10 KHz) in the presence of only one single fracture. This impact was more significant in the presence of more fractures. The outcomes of numerical modeling demonstrated that the fracture orientation with respect to the applied electrical field should be considered during the interpretation of dielectric measurements. Results of the sensitivity analysis demonstrated that dielectric permittivity measurements are sensitive to different fracture properties at different frequencies. This is promising for the simultaneous assessment of fracture properties through the interpretation of multifrequency dielectric measurements.

The outcomes of the proposed methods enable reliable characterization of fractured formations through integrated analysis of multifrequency electrical measurements. The ability to assess fracture properties in real time from electromagnetic measurements will pave the way to building robust fluid-flow and reservoir simulation models. In addition, the proposed method enables reliably evaluating fluid flow and energy storage capacity of naturally fractured geothermal reservoirs.

Research on the Pollution Mechanism of Drilling Fluid on Low-Porosity and Low-Permeability Sandstone Gas Layers Under High-Temperature and High-Pressure Conditions

Jin Dai and Guangzhi Liao, China University of Petroleum, Beijing

The evaluation of the degree of damage caused by drilling fluid to formation damage is an important work in reservoir protection, and it is also of great significance to oil and gas production. This paper explores the degree of damage caused by drilling fluid to formation damage under high-temperature and high-pressure conditions.

In this study, an indoor drilling fluid formation damage experiment was designed to simulate the formation damage process of drilling fluid to the wellbore during drilling under high-temperature and high-pressure conditions, and a formation damage evaluation model was established to quantitatively evaluate the pollution of drilling fluid to reservoirs under high-temperature and high-pressure conditions. The damage degree of the drilling fluid was explored through the observation of core casting thin sections before and after contamination and scanning electron microscopy, and the mechanism of drilling fluid damage to the reservoir was explored through glass etching experiments.

The experimental results show that the dynamic filtration time of the core in the high-temperature and high-pressure drilling fluid reaches a completely polluted state in 120 ~ 205 min, the absolute damage rate of the drilling fluid to the core. For porous and permeable cores, the relative damage rate of cores is greater than the absolute damage rate, and the opposite is true for high-porosity and permeable cores. The observation results of thin sections of core castings and scanning electron microscopy before and after contamination show that the degree of contamination of intergranular pores by drilling fluid (average 70.92%) is greater than that of feldspar dissolution. The pores (average 44.97%) are larger than kaolinite intercrystalline pores (average 33.57%).

During the drilling cycle, the solid phase particles in the drilling fluid will intrude into the core pores and adhere to the core pores and pore surfaces, resulting in core contamination, and the macroscopic performance is a decrease in permeability. For low-porosity and low-permeability sandstone, the damage of drilling fluid to core is mainly manifested as solid phase and liquid phase damage. The solid phase damage is mainly caused by the blockage of pores and throats by solid particles ranging in size from 0.1 to 30.0 μm in the drilling fluid. Liquid damage is mainly caused by the water lock and hydrocarbon lock effects formed by the oil-water two-phase interface, gas-water two-phase interface, or the oil-gas-water three-phase interface.

Study on Fluid Mobility of Tight Sandstone Gas Reservoir by Dividing Pore-Throat System Based on Fractal Theory

Xinxu Dong, Department of Geology, Northwest University, China

In order to explore the occurrence characteristics and percolation ability of movable fluids in tight reservoirs, this study looks at eight typical samples of the Shanxi Formation in the southeastern margin of the Ordos Basin.

Casting slices, scanning electron microscopy, high-pressure mercury injection, and nuclear magnetic resonance (NMR) are selected as testing methods. On the background of the study of reservoir characteristics, the pore-throat distribution of the Shanxi Formation reservoir is described finely by constructing a pseudo-capillary pressure curve transformed by NMR. On this basis, different levels of pore-throat systems are divided according to fractal theory, and their effects on the occurrence and percolation ability of movable fluids are discussed.

The results show that the reservoirs in the study area can be divided into three types according to pore types, mercury injection curve shapes, and parameters. From Type I to Type III, larger dissolution pores decrease, intergranular micropores increase, and effective reservoir space and percolation capacity continue to decrease. The pore-throat distribution curve of Type I and II samples based on the pseudo-capillary pressure curve is morphologically similar to that of high-pressure mercury injection, and the peak value is consistent. Class III samples contain many nanoscale pore throats, which can not be detected by high-pressure mercury, which makes the peak value of pore-throat distribution calculated by NMR shift to a small pore throat. Based on the fractal turning point obtained by fractal theory, the pore-throat space is divided into three relatively large, medium, and small pore-throat systems. The reservoir and percolation capacity of the tight gas reservoir is mainly related to the development degree of the macropore-throat system. Among them, the porosity has the best correlation with the absolute space size of the macropore-throat system, while the permeability and movable fluid saturation are closely related to the proportion of the macropore-throat system in the reservoir space.

This study analyzes the differential causes of tight reservoir and percolation fluid capacity, which can provide a basis for the optimization of tight gas reservoir evaluation parameters.

Use k_o-b Plot to Interpret Gas Permeability Measurements in Low-Permeability Reservoirs

Wenxiu Song, Michael Myers, Lori Hathon, and Munir Aldin, University of Houston

Klinkenberg (1941) proposed that gas permeability is a function of the intrinsic permeability (k_o) and a slippage factor (b), which is proportional to the reciprocal mean pore pressure (1/Pm). This work investigates the use of Klinkenberg corrections to understand the applicability to low-permeability samples. This is done by generating k_o-b plots at multiple mean pore pressures to examine the physics of transport in shale gas reservoirs. For a 100-psi pressure drop applied to gas flow, there are no unique k_o and b values that fit the time-dependent pressure profiles of the inlet and outlet pressure chambers in a pulse decay measurement. For any assumed k_o, there is a corresponding value of b which fits the chamber data within experimental error. A k_o-b curve of equivalent fits may therefore be generated. To determine both ko and b, at least two significantly different mean pore pressures are required. Included in the figure is an example of a k_o-b plot and a detail of the intersections of the curves, which give the unique values of k_o and b at the mean pressure of the two measurements. The objective is to understand the applicability of a Klinkenberg-type correction.

The permeability is measured on 1-in. diameter by 1-in. length core plugs using the pulse decay technique. The samples are measured at several different mean pore pressures, ranging from 250 to 1,450 psi, while the effective stress is kept at a constant 1,000 psi. The range of data spans the critical pressure for room temperature measurements. The pressure change in the upstream and downstream chambers are monitored, and these data are modeled using COMSOL Multiphysics® software to obtain the k_o-b curve for each separate test. The b value is assumed, and then the best-fit value of k_o is determined. The figure shows an example of the inability to determine a unique value of k_o-b. By plotting the optimum fit values at each measured mean pore pressure, the k_o-b plot is generated.

The results are shown in the figure for the k_o and b values of a pyrophyllite outcrop sample. Pyrophyllite has been used as a standard because it is observed to be uniform and microfracture free. The values of both k_o and b are both a strong function of mean pore pressure. The intersections of the k_o-b plots illustrate that as mean pressure increases, the gas slippage factor decreases. The simple inverse pressure relationship commonly assumed for the Klinkenberg correction does not hold. The k_o-b values follow different trends above and below the critical pressure. The two trends observed intersect at the critical pressure, which validates the physical interpretation of the measured values. Further work will be aimed at developing an improved understanding of the controls determining these pressure-dependent k_o and b values

Previous studies have often neglected the slippage effects when calculating the gas permeability, often assuming a b value of zero. This study determines the k_o-b values as a function of mean pore pressure. The values of b are large, as expected, but decrease with increasing mean pore pressure. The values are significant even above the critical pressure.

PETROPHYSICS IMPACT ON INTEGRATED RESERVOIR MODELING

Density of Supercritical CO_2 and Implications on Project Volumetrics and Efficiency

Adam Haecker, Milestone Carbon

Carbon capture, utilization, and sequestration (CCUS) is an area of research that has been studied for decades but only recently has moved from theory to practice, from Department of Energy (DOE) small-scale test projects to large-scale industrial applications. It is one of the methods that is a great hope to tackle the climate crisis and limit temperature increases to 1.5°C. Petrophysics of CCUS is a rapidly expanding field. This study examines how supercritical carbon dioxide (SC CO2) should be modeled volumetrically.

This study will evaluate the sensitivity of the critical parameter in the volumetric equation, the density of SC CO2 in the subsurface, using machine-learning and Monte Carlo techniques to match measured data. Many published equations omit key terms such as compressibility and proper unit conversions. The study is sourced from decades of chemistry measurements that have precisely measured CO_2 properties at various states (Span, R. and Wagner, W., 1996). The compressibility, formation volume factor, density, and other CO_2 properties directly translate to storage efficiency (E_{CO2}), which can have significant implications on the viability of a project.

Density of SC CO2 is the controlling factor on a myriad of properties that relate to CCUS. At low temperatures and pressures, it can have wild swings based on small changes in initial reservoir temperature and pressure. It is very volatile from the critical point at 1,070 to 5,000 psi and changes from 0.00186 g/cc at natural gas standard temperature and pressure to a much denser 0.7 g/cc at reservoir temperatures and pressures (Bachu, 2006). The ratio of the surface volume and density to reservoir conditions is a factor of 376 times. As depth, pressure, and temperature increase past the critical point, first, the density goes through wild swings from 1,070 to 3,000 psi. As the pressure and temperature continue to increase, the density of SC CO2 starts to converge toward 0.7 g/cc. The effects of pressure and temperature above 5,000 psi and 200°F offset, creating a nearly constant density. This is due to the pressure causing an increase in density but the temperature perpetuating a decrease in density. This rule of basic chemistry is illustrated succinctly by the ideal gas law, PV=nRT. The variability of the density of SC CO2 or lack thereof has implications on how projects will be designed. This further relates to storage efficiency (E_{CO2}), and examples will be shown via multiple case studies where simple tank models were performed to validate efficiency.

Finally, one area that is often omitted in the literature is the purity of CO_2. It is always assumed that the gas to be sequestered is 100% CO_2, but this is rarely the case in practice, except in very specific industrial applications like ethanol plants. The effects of reducing the purity of CO_2 will be examined as they relate to the density and, thereby, the compressibility of the gas.

Development of Oil-Water Transitional Zone by Rim Lowering in a Mature GOGD Field

Kavita Agarwal, Manish Choudhary, Sharif Bahri, Rawan Ghatrifi, and Mohamed Yarabi, PDO

Field X is one of the largest oil fields in the Sultanate of Oman and has highly fractured carbonate reservoirs. The field has been under production since 1967 and has undergone multiple phases of production, including pressure depletion, simultaneous gas and water injection within different units and sectors, in addition to steam injection trial.

A redevelopment of the field starting in 2010 switched the development from waterflood to gas-oil gravity drainage (GOGD) for most parts of the field. The primary reservoir has a long oil-water transition zone exceeding 50 m. Historical development was focused on primary above the oil-water transition zone. A large volume of injected water remains in the reservoir, lowering the efficiency of GOGD in areas of the field.

A new development opportunity was identified to develop the long transitional zone as well as de-water the reservoirs that had historical waterflood, thus reducing the gap to top quartile recovery.

A systematic appraisal cum development plan was initiated in the asset to develop the transitional zone. There had been no recent wells drilled through the transition zone to validate the remaining oil saturation. Integrated modeling suggested that oil saturation exceeding 60% should be present.

Two vertical appraisal wells were drilled targeting the transitional zone and provided invaluable data on reservoir quality and remaining saturation. The wells were also hooked up to validate the productivity of the zone.

Further analytical modeling was conducted to test the concept of rim lowering. Horizontal rim lowering well opportunities were identified and located 20 to 30 m vertically below the horizontal final rim wells in areas with high water cut. Many wells were designed to intentionally cross fracture corridors for improved gross production.

A phased development was proposed to validate performance prior to large-scale development.

The first phase of rim lowering wells was drilled in 2021 and early 2022. The long horizontal wells were logged and provided information on reservoir quality. Production data for the last 6 months to 8 months indicate that most wells outperform the base case forecast. This confirms the long-term producibility of the transition zone. Further, these wells have reduced water cut in updip wells enhancing GOGD and have accelerated the tail production.

Log data have also helped to map out areas with poor reservoir quality and will be used to adjust the development plan. The rim lowering project will lower the oil rim by 10 to 30 m, exposing more rock volume to the GOGD process and, thus, an increase in oil production and recovery

The case study describes one of the few implemented concepts of rim lowering in a mature GOGD field. The concept can now be used to expand the development of transition zones in similar fields in the Sultanate of Oman.

From Hydrocarbon Pore Volume to Recoverable Oil-In-Place and the Optimization of Well Spacing

Scott Lapierre, Shale Specialists, LLC

Recent trends among certain shale oil producers have included a focus on returning capital to shareholders via stock buybacks and dividends while simultaneously endeavoring toward net-zero carbon emissions. However, the public record of oil production from key shale basins indicate drastically foreshortened producing lifespans counterproductive to sustaining long-term dividends and reducing carbon emissions. A method of combining uncertainty-minimized, petrophysically derived, hydrocarbon pore volume (HPV) with a novel first-principles quantification of available reservoir drive energy is demonstrated to dramatically improve predrill and early time forecasts, thus, enabling the predetermination of a well spacing capable of extending revenue-generating lifespan while boosting IRR and cutting in half the amount of atmospheric CO_2 released per barrel of oil.

Workflows for uncertainty minimization in the quantification of hydrocarbon-filled porosity (HCFP) are presented, which combine multiple, independent analyses to quantify original oil-in-place (OOIP) from basic log data. Each independent method—calibrated to core measurements reprocessed and corrected for known flaws—is combined into a composite average to triangulate and confine a narrower range in which a reservoir's actual hydrocarbon content may fall. Building upon recently published works of multiple author groups implicating oil phase decompression (i.e., oil "expansion") as the primary reservoir driver responsible for delivering oil production to the surface enabled the redefinition of "recovery factor" in terms of first principles fully independent of traditionally required production information. The uncertainty-minimized OOIP is combined with the novel first-principles-derived recovery factor to compute recoverable oil-in-place (ROIP). The novel ROIP is compared to historical production, and the workflow for optimizing well spacing and stimulation intensity is described.

Recovery factors were derived for two multiwell developments from the Midland Basin and were combined with the uncertainty-minimized hydrocarbon pore volume to compute the ROIP. ROIP was compared to state-reported oil production, revealing cumulative production after > 1,800 days, coming within 10% of the DU's predicted ROIP. Well spacing and stimulation intensity were optimized for the DU's specific ROIP, and forecasts were generated. Economic returns and CO_2 per barrel were modeled for both cases. They suggested significantly longer cash-flow-positive lifespans from a reduced capital expenditure requiring less diesel-fueled industrial activity were possible.

Several disparately subtle discoveries from engineering, geochemistry, and petrophysics are combined into a collaborative and intuitive workflow that generates more reliable forecasts and closes the model-measure-optimize loop for well spacing experimentation. Additionally, working backward from the novel determination of ROIP specific to a drilling unit allows predetermination of the optimal well spacing and stimulation intensity required to maximize recoveries per acre, per well, and per capital dollar. Furthermore, key elements of workflows from multiple disciplines are co-developed and integrated to provide answer products that are proven to increase IRR and producing life optimized for sustaining dividends into the future while funding production growth while minimizing CO_2 per barrel.

SPECIALIZED MEASUREMENT TECHNIQUES AND INTERPRETATION METHODS

A Methodology for Portraying Three-Dimensional Positional Uncertainty Using Along-Hole Depth, Inclination, and Azimuth Measurement Accuracies

Harald Bolt, DwpD Ltd., Depth Solutions

Along-hole depth (AHD) is the most fundamental subsurface measurement made. AHD, together with inclination (I) and azimuth (A), are used to describe the three-dimensional (3D) position of the wellbore and hence the 3D position of the recorded subsurface parameters. This is used to describe the well geometry in 3D, drilled geological horizon locations, reservoir descriptions and models, and fluid contacts and gradients. Operators are presented with a model for managing their 3D positioning and positional uncertainty based on AHD, I, and A measurement values and accuracies. Geo- and petrophysical data, depending on rig state, can be logged to measured depth (MD) and then matched to specific 3D positions while providing bespoke 3D positional uncertainty. The operator's 3D positional uncertainty is determined and managed by defining the well survey parameters, the measurement method chosen, and equipment accuracy specifications.

A wellbore is considered as a sequential series of intervals; these approximated to straight-line descriptions of AHD, I, and A. Using basic geometry, vertical (V), North (N), and East (E) positions are defined per interval. AHD, I, and A calibration and observation, correction, and model-fit accuracies are used to define the interval uncertainties. These interval uncertainties are used to derive the separate interval V, N, and E contributory uncertainties. These are sequentially concatenated, resulting in V, N, and E positional uncertainties. The 3D positional uncertainties are influenced by AHD, I, and A measurement accuracies, well geometry, conveyance specifications, and interval spacing.

AHD accuracy is the most important contributor to V uncertainty. The MD can be derived using drillpipe as well as wireline conveyances and corrected to AHD. Individual V, N, and E positional uncertainties are shown to be dependent on well geometry, sampling interval spacing, conveyance specifications, as well as AHD, I, and A measurement accuracy choices. The 3D positional data and positional uncertainty are compared against results using conventional MD and high-accuracy corrected AHD. Four example well geometries demonstrate that each well has its own unique, and quite different, 3D positional uncertainty profile. Geological modeling and reservoir descriptions are provided with specific uncertainties. Fluid levels and gradients are defined against V using auditable uncertainties. The measurement process and accuracy decisions can hence be tuned to meet the operator’s 3D positional uncertainty requirements for well placement and reservoir description. This results in better data and decisions and improved asset value.

Operator 3D positional uncertainty requirements are used to define the well survey plan, including optimization of equipment used and measurement procedures. These choices define V, N, and E positional uncertainties. Each well has its own unique description of the 3D position and positional uncertainties, the same way as the subsurface is uniquely described. Optimization of accuracy choices arrives at a value-for-money approach to AHD, I, and A measurement, resulting in 3D positional uncertainty tailored to operator needs.

A New Focused UDAR Inversion to Highlight Finer Geological Features in Transitional-Resistivity Formations

Hsu-Hsiang (Mark) Wu, Halliburton; Amitabha Chatterjee, Aker BP; Nigel Clegg, Jin Ma, Yijing Fan, Karol Riofrio, Clint Lozinsky, Michael Bittar, and Alban Duriez, Halliburton

Ultradeep azimuthal resistivity (UDAR) tools have made a significant impact on logging-while-drilling (LWD) geosteering, geomapping, and geostopping operations. The technology explores large formation volumes, bridging the gap from the near-wellbore to seismic scale with higher-resolution formation determination surrounding the wellbore. Due to the ultradeep detection range of up to 225 ft away from the wellbore, a multilayered inversion is required to transform the UDAR measurements into a visual representation of formation geological features. However, this introduces a high-dimensional parameter space in the inversion and potentially results in high inversion uncertainty and/or inversion artifacts, posing decision-making challenges in certain formation conditions.

A new UDAR-focused inversion, improving upon an existing deterministic UDAR inversion, is proposed to address such inversion uncertainty. The focused inversion attains intricate formation insights at the cost of some loss in detection range compared to the existing inversion. Various synthetic and field examples have demonstrated great success with high-fidelity formation determination from the new inversion, especially for illustrating gradational resistivity profiles.

Complex geological and fluid boundaries often show gradational changes from high-resistivity hydrocarbon zones to low-resistivity shale or water zones, resulting in low-resistivity contrasts at the boundaries and contacts. UDAR measurements highlight these gradual resistivity variations as a stepped profile across the transitional boundary. To represent a boundary in this way, the number of multilayered inversion unknowns must be significantly increased to describe these types of resistivity transitions. However, the maximum number of layers available in previous inversions limits the inversion capabilities to produce an accurate model fit in these complex environments.

A new focused inversion is presented to include two novel features. First, a more realistic formation model is proposed with a resistivity transition section to better fit the gradational resistivity features. In addition, the sectional model allows fewer unknowns to the inversion to describe multilayer resistivity profiles. Finally, the new inversion promotes individual measurement sensitivity to refine and invert such formation transition zones.

We first observed struggling results of the existing inversion based on a multilayer and multitransition formation model example with very low-resistivity contrast boundaries in a prewell modeling analysis. The challenge led to the new focused inversion for distinguishing more layers with low-resistivity contrast, whereas the current algorithm loses some layers based on the same UDAR measurements. Further validation on a field example is displayed in Fig. 1. The new inversion results are capable of determining the high fidelity of the formation properties; on the other hand, it can lose detection range toward the edge of the inversion as compared to the current inversion algorithm.

A new UDAR-focused inversion is introduced to accurately determine the high fidelity of the formation properties, especially for gradational resistivity profiles. This improves reservoir understanding and allows more accurate well placement decisions to be made.

A New Method to Identify Vertical Reservoir Pressure Communication by Combining Borehole Sonic and High-Frequency Electrical Imaging Data

Harish Datir and Tianhua Zhang, SLB; Knut Arne Birkedal, Aker BP

Natural fractures and faults are the imprint of tectonic and structural history of the rock section. A well-extended fracture network handles fluid channeling and unexpected pressure communication. At the wellbore, electrical images are often used to identify the existence of fracture/fault. In oil-based mud (OBM), interpreting open fracture/fault is difficult, as OBM-filled open features can appear resistive. When the borehole surface is full of spirals and drill marks, or the mud is not homogeneous, ultrasonic images quickly lose sensitivity to the fracture/fault. Further inside the formation, the 3D far-field sonic (3DFFS) analysis can provide a good map of reflectors representing the fractures and faults zone. But it cannot directly confirm if the fracture or faults are open or closed. In this paper, we present a new method for analyzing open fractures/faults using electrical dielectric permittivity derived Hayman image. Fracture instability is further analyzed based on eccentering-corrected multi-radius image and borehole shape. Then, overlapping the wellbore fracture/fault planes with 3DFFS processed reflectors, we can characterize the extension of fracture/fault from the wellbore into the formation and identify potential pressure communication channels.

In OBM, the MHz frequency imager data, through advanced inversion processing, can generate resistivity, dielectric permittivity, and standoff images. Through post-processing, a new Hayman image can be generated by combining dielectric and resistivity information. Joint analyzing resistivity and Hayman image can help resolve open fracture/faults when borehole rugosity is very high when ultrasonic and standoff images lose sensitivity to fracture/faults. The OBM imager can also provide multi-radius images and be transformed into a borehole shape. Eccentering-corrected borehole cross section can indicate drilling and stress caused borehole shape deviation from circular. Combining the above two analyzes, we can not only identify open/closed fractures/faults but also get an indication of fracture stability based on the borehole shape deformation. Once identified, the open fractures/faults and the unstable closed fractures can be mapped away from the wellbore wall via the 3DFFS data. This allows us to identify the orientations and alignments of the wellbore and far-field events.

In the case study pilot well, joint interpretation of the resistivity and Hayman image identify two more open fractures in the upper-middle section of the well. Many closed fractures and two closed faults are identified. The eccentering-corrected borehole radius shows a maximum borehole diameter direction rotation at the very bottom of the well. Comparing the maximum borehole diameter direction and the closed fracture/fault azimuth direction, most of the closed fractures and the top fault can be subject to drilling, resulting in borehole stress and becoming unstable. Overlaying those fractures/faults with 3DFFS reflectors, we can see the borehole image unstable interval has the highest density of sonic reflectors.

There is azimuth orientation between the wellbore image fractures and sonic reflectors in the top part of the well interval. The azimuth alignment increases with increased TVD.

The new method of Hayman-aided open fracture detection, fracture instability using multi-radius borehole shape image, and fracture extension combining sonic far-field processing methods are applied on a pilot well. The fracture network is mapped. Through the fracture network analysis, we identified open fractures and unstable closed fractures, which extend into the formation. The open fractures and unstable fault opened during the water injector can form a pressure communication channel vertically along the well. The observations agree with the field pressure communication observed while the well is put into injection. These spatially resolved fractures, faults, and fracture network are essential for subsurface understanding and future well placement in this field. It is a critical input to the dynamic reservoir model.

A New Method to Improve the Calculation Accuracy of Element Content in Natural Gamma Spectrometry Logging While Drilling

Zhiyuan Liu, Feng Zhang, Xiaoyang Zhang, and Jilin Fan, China University of Petroleum, East China

In recent decades, with the deepening of exploration and development of unconventional oil and gas resources worldwide, logging while drilling (LWD) has developed at an astonishing rate. Natural gamma spectrometry LWD technology is able to provide both total gamma rays and potassium, uranium, and thorium element concentrations in rocks, which has become one of the important means for clay content estimation, rock brittleness assessment, and organic matter analysis in the evaluation of unconventional reservoir. The main challenge in LWD natural gamma spectrometry technology is that the spectral count rate is usually very low due to the shielding of the drill collar, leading to severe statistical fluctuations in measured gamma spectra and large errors in the calculation results of the element content.

In this paper, an effective solution combining the synthesized detector response matrix and maximum likelihood estimation (MLE) spectral inversion is proposed. Firstly, the simulation model of the gamma detector is established by the Monte Carlo method to obtain the 256 × 256 synthesized response matrix. Then, the low-count rate gamma spectrum measured while drilling is deconvoluted and reconstructed by the Boosted-Gold algorithm to eliminate the statistical fluctuations. Finally, the high-precision maximum likelihood method is applied to calculate element content.

In our research, the simulated gamma spectra of formations with different radioactivity levels and element content were simulated to compare the performance of different spectral analysis methods. The results indicated that this new method is of statistically higher accuracy than traditional least squares analysis, especially for uranium and thorium, the errors of which were less than 0.5 ppm and 1 ppm, respectively. Furthermore, extended experiments on the response characteristics of different sizes and types of gamma detectors, such as NaI and $LaBr_3$, as well as the influence factors of hole size and drilling fluid, were carried out to provide technical support for the design of LWD natural gamma spectrometry instruments and the calculation of potassium, uranium, and thorium content.

As a whole, a new method is proposed to improve the calculation accuracy of element content in natural gamma spectrometry LWD, the superiority of which has been proved through simulation, contrast, and experiments. This innovation provides a novel idea for solving low-count rate gamma spectra and is helpful in promoting the popularization and application of LWD gamma spectral technologies.

A Novel Data Processing Method for Array Induction Logging in Tight Carbonate Reservoirs Drilled With Oil-Based Mud

ChaoLiu Li, Han Tian, and Zhou Feng, PetroChina Research Institute of Petroleum Exploration & Development; Lei Wang, China University; Hongliang Wu and Falong Hu, PetroChina Research Institute of Petroleum Exploration & Development

The targeted reservoir, which is referred to as the Sinian Dengying Formation in the central Sichuan Basin, is a typical tight carbonate sediment rich in vugs, and it features low matrix porosity with R_t 200

Ω·m, even 2,000 Ω·m at some specific sections. This sediment is often buried below a layer of gypsum, so many wells are drilled with oil-based mud ensuring borehole stability. It leaves no choice of resistivity measurements other than the array induction tool. However, the signal-to-noise ratio (SNR) of raw conductivity signals is very low, with negative values existing for these coils with short T-R spacing. As a result, array R_t logs with different depths of investigation (DOI) from the classic "software focusing" algorithm overlaps and flattens out, which is too poor for fluid typing and quantifying the reserve.

This paper presents a novel weak conductivity signal processing method, which significantly improves the accuracy of array R_t logs, and provides an effective way to the evaluation of such complex carbonate gas reservoirs.

This novel method includes several steps: (1) estimating the lower limit of conductivity based on the Archie equation supposing that formation is gas saturated, (2) careful selection of the raw signals with better SNR from these coils with longer spacing (the signal of short spacing is seriously affected by oil-based mud (OBM)) and making some appropriate correction to avoid negative value, (3) building an inclined layered initial model (depends on real geometry) and forward modeling the theoretical array induction signals based on its specification of these chosen coils, comparing the modeled signals with the actual signals, adjusting the model and repeating the comparison until the best fit to get the equivalent conductivity, and (4) finally, the resolution matching algorithm, which is commonly used in the industry, is applied to these equivalent logs with different T-R spacing and array R_t logs with a designated resolution, and DOI is produced. Moreover, by setting the horizontal and vertical resistivity, respectively, in the initial model, the array R_h and R_v logs with given RES and DOI can be extracted respectively at tilted electrical anisotropic formation.

The traditional algorithm combines the weak signal of all coils and produces distorted array R_t logs. The new method yields more reasonable results by optimizing signal input and performing appropriate corrections. More importantly, the invasion characteristics of R_t logs with different DOIs are kept and shown more clearly, which is very useful for fluid-type interpretation.

As a typical case, DLL and HRLA tools are introduced. After that, OBM is replaced by WBM at Well A. HRLA gives information about the invasion profile. The comparative analysis shows that this new method provides a proper resistivity logs output with a closer result to that of RLLD at shallow-invasion intervals. In addition, the invasion profile from different DOIs becomes clearer and serves as an indication of fluid typing, which is validated by an oil test at several wells.

A Novel Oil Saturation Evaluation Method by Using Double Particle Detector Cs_2LiYCl_6:Ce(CLYC)

Qixuan Liang, Feng Zhang, Hui Zhang, Fei Qiu, and Yiming Yu, School of Geosciences, China University of Petroleum, East China

Based on the different processes of luminescence, a new double particle nuclear detector called the potassium cryolite scintillation such as Cs_2LiYCl_6:Ce(CLYC), $Cs_2LiLaCl_6$:Ce(CLLC), Cs_2LiYBr_6:Ce(CLYB), and $Cs_2LiLaBr_6$:Ce(CLLB) is capable of collecting neutron and gamma ray simultaneously, has extensive application prospect in nuclear well logging. In our previous research, a pulsed-neutron well-logging system using Dual-CLYC detectors is proposed for collecting equivalent gamma ray spectrum and thermal neutron time spectrum. The effectiveness of this pulsed-neutron system in cased-well gas evaluation has been verified. To further realize the oil saturation evaluation in a cased well, a high-sensitivity method is built by combining the ratio of equivalent gamma from the different detectors and the ratio of carbon to oxygen (C/O) base on the Dual-CLYC pulsed-neutron system.

Affected by hydrogen index, capture cross section, and element component, the field distribution of thermal neutron and gamma ray is controlled by the formation porosity and oil saturation. To clarify the response of the stratum, measured by CLYC, a numerical simulation model is established to generate the equivalent gamma ray spectrum under the different porosity, oil saturation, and formation matrix. The thermal neutron counts, C/O, and capture gamma ray count negatively correlate with porosity. The C/O and capture gamma ray positively correlate with oil saturation except for thermal neutron counts. The thermal neutron collected by the CLYC detector is represented by the equivalent gamma ray, consisting of the capture gamma ray background and thermal neutron equivalent gamma ray. Therefore the thermal neutron information represented by the equivalent gamma ray has higher sensitivity of porosity and saturation.

Due to the property of the double particle detector, the Dual-CLYC pulsed-neutron system is able to give consideration to the conventional function of gamma ray or He-3 detector pulsed-neutron logging instrument. Moreover, the thermal neutron information extracted from its unique equivalent gamma ray spectrum has a higher porosity and oil saturation sensitivity than the He-3 detector. Therefore, compared with the conventional C/O oil saturation evaluation method, the sensitivity of the novel oil saturation evaluation method by the ratio of thermal neutron counts and C/O can reach 75% under the 30% porosity, which is almost seven times to conventional method. Besides, the sensitivity of porosity calculated by equivalent gamma rays is one time to thermal neutron from He-3.

The neutron and gamma ray field distribution caused by formation can be more accurately characterized by the double particle detector in real time. Therefore, depending on its gamma ray and thermal neutron information, the CLYC detector is able to directly calculate the formation parameters, which is reduced the precision error caused by simplification in the process of parameter characterization.

A Step Change in Neutron-Induced Gamma Ray Spectroscopy: Using a High-Resolution $LaBr_3$:Ce Detector in an Integrated LWD Tool

Fabien Haranger, Francoise Allioli, Markus Berheide, and Paul Craddock, SLB; Daniel Finnvik Øpsen, Neptune Energy; James Grau, Consultant; Mathias Horstmann, David Maggs, Marie-Laure Mauborgne, Alexis Pallain, Richard J. Radtke, Rubi Rodriguez, David Rose, and Benjamin Rouanet, SLB; Christian Stoller, Consultant

A consistent approach to evaluating mineralogy and petrophysical attributes through a field’s life cycle is essential to ensure proper assessment of the reservoir potential. Accurate mineralogy provides a deep understanding of the sedimentological and depositional environment and allows the identification of weaker or more friable formations that can pose challenges to drilling and completion operations. Advanced logging-while-drilling (LWD) measurements are taken to provide an accurate evaluation of complex clastic and carbonate lithologies. This is done when standard services are inconclusive or ambiguous and deploying wireline is not viable because of highly deviated boreholes. Neutron-induced gamma ray spectroscopy is a cornerstone for evaluation in these complex reservoirs as it provides the essential rock matrix information for an accurate petrophysical interpretation. An upgrade of our LWD tool equipped with a pulsed-neutron generator provides the radical improvement needed to get closer to wireline-quality lithology results.

This major advance is made possible by replacing the sodium iodide (NaI:Tl)-based spectroscopy detector with an advanced ruggedized lanthanum bromide ($LaBr_3$:Ce) detector combined with refined spectral acquisition. LWD-specific challenges affecting the measurement, such as drilling conditions and spectral tool background contribution, are addressed. This combination significantly improves spectral quality, precision, and accuracy. Neutron-induced gamma rays of the different elements have unique signatures that can be used to detect and quantify the presence of these elements in the formation. A major advantage of the spectroscopy measurement lies in the fact that the interpretation does not require user input. The measurement is self-consistent, improving answer quality while also reducing interpretation errors or biases. Precise identification of the elemental constituents opens the door for an accurate lithology determination and a holistic approach to processing and interpreting with the assistance of trained neural networks. This maximizes the interpretation efficiency and the reliability of the answer products. The downhole spectral processing delivers high-definition spectroscopy while drilling and provides substantial operational gains and essential input for real-time decisions.

The new spectroscopy measurement is currently being field tested with several operators worldwide in a variety of lithologies from clastics to carbonates. The results confirm the predicted major improvement in the accuracy and precision of the measured elemental concentrations and the resulting enhancements in the lithology determination. In some cases, comparison with the results from a large-diameter $LaBr_3$:Ce-based wireline spectroscopy is available, and good agreement has been found. Furthermore, obtained LWD logs were benchmarked against coreDNA and XRD/XRF measurements.

The measurement technology is presented, and field test results are discussed, providing a first look at the exciting new technology. This technology promises to provide high-quality lithology answers in LWD, leveraging the collocation of the spectroscopy measurement with the neutron porosity, sigma, neutron gamma density, and resistivity measurements.

A Universal Data Format for Wellbore Logs

Thomas Bradley, Simon Austin, David Holbrough, Warren Fernandes, and Xuandong Wang, Baker Hughes

In the formation evaluation industry, multiple data formats are used. Some of these are industry standards (for example, LAS and DLIS) and are often used for data interchange and archival, whereas others are proprietary. However, many of these industry-standard formats suffer from legacy issues: for example, limited metadata storage, inability to efficiently store complex data (or nonstandard extensions being required), or are unsuited for storing data from modern tools and interpretation results, especially multidimensional data (such as generated by azimuthal resistivity tools). This paper describes a proposed universal format for the storage of wellbore-centric formation evaluation data. The format is suitable for complex 3D data, for example, those generated by deep and extra-deep azimuthal resistivity tools, borehole acoustic reflection images, VSPs, borehole imaging tools, multifingered caliper logs, and depth of detection data. The format also naturally collapses down when utilized to store simple conventional logs that contain one value per depth in the wellbore. For this reason, it is a good standard for data exchange between applications. It is suitable for both field and interpreted data.

The proposed format provides spatial details of every data point in the wellbore. The position of each data point is defined by reference back to the measure point of the sonde, which in turn is defined by the wellbore deviation survey and its coordinate reference system: both these can be natively included in the file so enabling the recorded data to be located in physical 3D space. Each data point in space may have an unrestricted number of parameters. An example might be horizontal and vertical resistivity, maximum value based on uncertainty, minimum value based on uncertainty, and a number of flags indicating if it is within the depths of detection of the logging tool defined by different criteria. Metadata such as tool information, acquisition parameters, well location, etc., can also be included in the file.

The versatility of the proposed format gives the capability to store and exchange all data that is recorded and referenced to a defined location in a wellbore, including metadata. It is suitable to be used as a data interchange format between usually incompatible applications and as a long-term data archiving format.

The proposed format requires a detailed definition so that computer scientists can implement it in applications used for subsurface modeling, and detailed standards can be defined. As many wellbore data formats compress very efficiently, concerns of size can be addressed by natively including data compression in the format specification

Advanced Well Integrity Assessment by Using the New Generation of Acoustic Analysis Tool, Multifrequency Electromagnetic Tool, and Pulsed-Neutron Log in Oxygen Activation Mode: Colombia Case History

Johana Reyes, Osmary Mendez, Jose Mata, and Zunerge Guevara, Halliburton; Jorge Falla, Alberto Muñoz, and Hernando Trujillo, Hocol SA

Well integrity logs are fundamental for the optimization of the production of wells and for mitigating risks of environmental disasters. The information obtained helps identify potential problems and design correct remediation plans when encountered.

This paper presents an actual example from Colombia that demonstrates how the well integrity log data was used as input for the operator to decide future operations in a producing well that was presenting a leakage at surface. This leak could eventually lead to serious environmental issues.

Two wells were analyzed to understand the issue; the first was an injector well that was suspected of having the leakage, and the second was a nearby producing well that was showing unexpected water production at surface, which was analyzed and determined that it was coming from the injector well.

The injector well was completed with 9.625 in. surface casing, 7 in. production casing, and 3.5 in. tubing. The entire well was logged in a rigless scenario with the multifrequency electromagnetic tool to determine metal loss across all strings and complemented with temperature logs. Additional diagnostics were performed, opening the annulus space to stimulate the leak while running the acoustic noise tool upward. Stationary measurements were done to confirm areas where leaks were identified.

In the subsequent run, a pulsed-neutron log in oxygen activation mode was logged with the annulus open to identify the water movement direction.

After logging the injector well, the producer well was analyzed by using multifrequency electromagnetic and temperature logs for proactive corrosion monitoring and to better define completion integrity.

The integration of these three different technologies clearly indicated the location of the leak in the production casing. More precisely, the vertical and radial position was determined using acoustic and multifrequency electromagnetic tools. This analysis increased the chance of success for a safer operation after a well intervention program.

An Adaptive Spectra Fitting Method for Elemental Measurement Using a Pulsed-Neutron Tool

Ge Yi and Qiong Zhang, University of Electronic Science and Technology of China

Compared with traditional radioactive sources, pulsed-neutron sources can emit high-energy neutrons in well-logging tools and are controllable. The detection of neutron-induced gammas leads to the estimation of multiple formation properties, which include elemental concentrations derived through the analysis of gamma spectroscopy, leading to the identification of mineral composition for complex reservoir evaluation. However, in the field test, due to the diversity of the environment, the extraction of the net inelastic energy spectra is difficult, and the energy resolution of the spectra is unstable. As a result, the accuracy of multiple elemental concentrations inversion is reduced. In order to improve accuracy and enhance the robustness of results, an adaptive method for obtaining elemental concentrations is introduced in this paper.

The proposed method is developed by combining accurate net inelastic acquisition and adaptive energy resolution matching into a framework of elemental concentration computing. It composes of two steps: 1) Firstly, the falling edge of the pulse is automatically found on the gamma time spectra by computing the gradient of time spectra. The proportion of capture gammas in the neutron burst period is then calculated based on the position of the falling edge using a double exponential fitting iteratively of the time spectra. Even if the falling edge is not fixed due to the hardware conditions of the pulsed-neutron generator, a net inelastic gamma spectrum can be acquired. 2) The hyperparameter grid search for hyperparameter is introduced into the framework, and the optimization of energy resolution parameters is carried out while minimizing the objective function. It aims to achieve adaptive matching of energy resolution under external electronic noise and temperature change in the surrounding environment. After the operations of introducing the first and second steps, the robustness of the elemental concentration measurement is enhanced, and more accurate results are computed stably in a variety of environments based on a pulsed-neutron elemental logging tool using a BGO detector.

The proposed method is validated for complex downhole environments. In several simulations of different pulsed-neutron timing schemes and formation environments, the concentration of 14 elements, such as Al, Si, Ca, etc., has been successfully obtained to verify the effectiveness of the method. And the accuracy of the method is verified in five test pits, including silica, calcium carbonate, etc.

This method is applied to a well in the Bohai Sea, which contains complex metamorphic rocks, such as granite gneiss and biotite schist, with complex mineral composition. The elemental concentration calculated by this method is in very good agreement with X-ray fluorescence (XRF), which verifies its reliability. Future work will expand to mineralogy and focus on more complex reservoir evaluations in unconventional formations.

An Improved Cement Bond Evaluation Approach for Unconventional Development Wells: A Case Study Integrating CBL and Permanent Downhole Gauge Data

Pingjun Guo, David Stiles, Michael Owens, Graham Johnston, and Brett Zastoupil, ExxonMobil

The paper describes a case history using an improved cement bond evaluation workflow integrating traditional cement evaluation logs and downhole permanent temperature and pressure data in a tight oil play in southern Oklahoma. A pair of producer and monitor wells were drilled and completed in a field development study project. Comprehensive data collection and analytics were carried out to devise an optimized well placement strategy in a basin with heterogeneous reservoir rocks and stacked pay zones. With the permanent installation of pressure and temperature gauge arrays and fiber-optic sensors in the casing annulus of the monitoring well, it is critical to accurately assess cement quality and well integrity to ensure that satisfactory zonal isolation is achieved. Minimal cross-gauge interference is desired for reliable real-time data acquisition during fracture stimulation and production monitoring.

Cement evaluation log interpretation is inherently qualitative and subjective in nature. To this end, a multiphysics data interpretation workflow was used to integrate downhole distributed temperature and pressure data recorded during cementing operations with conventional acoustic cement evaluation log data. A thorough cement evaluation logging program was devised to collect sonic and pulse-echo ultrasonic logs under standard and pressurized wellbore conditions. Also included in the logging program was a time-lapse component comprised of additional logging runs after the hydraulic fracture operation performed in the nearby producer. The comparison of before and after frac data analyses provides valuable insight into the interpretation process to evaluate the growth of fractures originating from the producer and propagating to monitor wellbores.

Results from the integrated workflow indicate that zonal isolation has been achieved across the instrumented segment of the monitor wellbore. Shown in Fig. 1 are sonic and ultrasonic cement evaluation logs and ultrasonic casing integrity logs. Although features such as micro-debonding and small-scale liquid-filled voids were observed in certain intervals, these low-impedance features do not appear to be interconnected. No fluid channels and conduits around fiber-optic cables were observed. Shown in Fig. 2 are borehole temperature profiles recorded by 14 temperature gauges before, during, and after a cementing job. Along with pressure gauge data, temperature data illustrate cement slurry flow as well as cement hydration and hardening processes. The ultrasonic pulse-echo log proved to be critical in understanding casing integrity. The time-lapsed cement evaluation logs show signs of cement quality improvement, indicating that a post-completion compaction trend acts upon the wellbore.

In summary, although the assessment of cement integrity is a complex task, it is shown that a workflow incorporating multiphysics measurements has a clear advantage of producing much more reliable and consistent results.

Comparison of Minimum Principal Stress Data From Wireline Microfrac and Extended Leakoff Test in Norwegian Continental Shelf

Danil Maksimov, Dler Mirza, Olav-Magnar Nes, and Nils-Andre Aarseth, Aker BP; Venkat Jambunathan, Gibran Hashmi, Sayyid Ahmad, Bob Engelman, and Michael Evans, Halliburton

Minimum principal stress data are essential for well design, drilling, completion, plug and abandonment, and reservoir injection planning optimization. This data can be obtained using extended leakoff tests (XLOT), which are performed after drilling a short openhole section below the casing/liner shoe. XLOT test data are only acquired just below casing/liner shoes. Least principal stress data can also be acquired using a wireline testing tool configured with the straddle packer section (SPS), which gives the flexibility to perform multiple microfrac tests at different zones of interest in a single run to obtain the minimum stress profile.

The process of microfrac with a wireline tool involves setting the packers at a desired depth, inflating the packers to isolate the interval, injecting into the packed-off interval to increase the interval pressure until the rock breaks down, propagating the induced fracture by continuing injection and then shutting off the injection and observing the pressure falloff. The falloff data are analyzed to estimate the minimum principal stress. This method works in rocks with some permeability so that the fluid can naturally leak off into the formation through the fracture. Caprocks and other shales are extremely low permeability with very small to no leakoff. A recent technology development provides a flowback option at a controlled rate to remove the injected fluid from the packer interval, thereby reducing the interval pressure and enabling fracture closure.

This technology was successfully applied in a well in the Norwegian Sea, where XLOT data was also acquired. Typically for XLOT, larger volumes of fluid are injected, thereby extending the induced fracture in the order of 15 m from the wellbore. In contrast to the XLOT, much smaller volumes are injected during microfrac tests, thereby extending the fracture only a short distance of the order of 1 to 3 m from the wellbore. In this paper, the results from the microfrac with wireline formation tester are compared with the conventional XLOT test. There is a good agreement in the estimated minimum stress from both measurements. The analysis of pre- and post-frac borehole electrical images to determine stress orientation is also discussed.

A well where both types of tests were conducted enables a unique opportunity to compare the results provided by two different techniques measuring formation minimum principal stress. This is also the second well for the same operator in which the flowback technology was successfully used for caprock microfrac.

Developing Live Oil Property Models With Global Fluid Database Using Symbolic Regression

Songhua Chen, Christopher Michael Jones, Bin Dai, and Wei Shao, Halliburton

Global equations for predicting GOR, API gravity, and saturated viscosity from downhole testing and sampling measurements have been developed using a symbolic regression (SR) machine-learning method. The performance analysis confirms that these new models outperform the existing empirical and neural network-based models with the relative error approaching a similar level of the direct downhole measurements. They are sufficiently robust to be a reliable QC tool to be used globally.

The genetic-programming-based SR method has been applied to a global fluid sample database consisting of nearly 700 samples collected from more than 500 wells located in many parts of the world to obtain solution GOR, API gravity, and saturated viscosity prediction equations. The database consists of environmental parameters such as pressure and temperature measurements, measured fluid properties such as fluid density $\rho(T)$, methane density $\rho_{CH4}(P,T)$, saturated compressibility γ_{sat}, methane and oil compressibilities, $\gamma_{CH4}(P,T)$ and $\gamma_{oil}(P,T)$, among others, as well as the target live oil properties of solution gas-oil ratio GOR, saturated viscosity μ_{sat}, and API gravity. Pair plots and correlation heatmaps are used first to assess the relevancy of the input variables with the targets and, from which, narrow down the input variable pools. The random nature of genetic evolution processes embedded in SR ensures a nonsubjective selection of the input variables to the target prediction equations. By varying termination conditions, fitness functions, and/or by including or excluding conditional-branch-enabling math operators, multiple predict equations are obtained. Subsequently, the best models are determined based on statistical measures of error, the absence of outliers from the prediction equations, and their honoring to the physics of the input variable dependencies.

The SR-generated solution GOR prediction equations are compared with the benchmark Standing equation and also the neural-network-based prediction model. The optimal equation from SR yields the relative error, computed with RMSE/range, of approximately 5%. This is significantly lower than that from the use of a Standing equation or neural-network-based prediction, as the latter two yield a relative error of about 20%. The 5% relative error approaches the current downhole GOR measurement performance uncertainty, indicating that the GOR prediction equation generated using our SR workflow indeed reached its optimal limit. Similarly, the prediction equations for API gravity and saturated viscosity are also performed highly satisfactorily, with relative errors in the range of 10 to 12%. Considering the performance is based on the large, diverse global fluid database, such performance is remarkably robust. The prediction equations are to be used routinely in operations, mainly as a QC tool to identify potential invalid GOR or API measurements and as a substitution when no valid direct measurements are available.

- A comparison of prediction equations trained with and without methane density and compressibility data indicated that including these methane properties improves the overall performance over the entire GOR range.
- Unlike the Standing equation, these new equations require no bubblepoint pressure, a quantity that is difficult to obtain downhole accurately.

Development and Baseline Comparison of a New Pulsed-Neutron Spectroscopy Tool for Carbon-Oxygen Analysis and Three-Phase Saturation Monitoring

Ian McGlynn, Toyli Anniyev, Feyzi Inanc, David Chace, Peng Yuan, David Soans, and Ardi Batubara, Baker Hughes

A new multidetector pulsed-neutron logging tool is introduced. Pulsed-neutron capture (PNC) and carbon/oxygen (C/O) measurements from pulsed-neutron logging tools are used as part of a fundamental assessment for multiphase fluid saturation quantification, formation evaluation, and reservoir monitoring. The C/O ratio is traditionally acquired from integrating gamma ray inelastic count rates from two discrete energy windows as a proxy for C and O, requiring baseline normalization for interpretations. Taking advantage of the new tool's enhanced spectroscopy characteristics, a spectral deconvolution method based on carbon and oxygen elemental yields for determining hydrocarbon saturation insensitive to water salinity is presented.

An advanced slim tool has been developed to acquire an optimized combination of PNC sigma, C/O, and gas saturation measurements in a single pass to provide multiphase fluid saturation analysis behind casing or in openhole environments. The design combines a high-output neutron source, a fully digital pulse processing and data acquisition system, and three high-resolution shielded $LaBr_3$ gamma ray detectors. The new design allows the reduction of logging time by as much as three times without loss of precision.

Tool development was performed at an instrument characterization facility for a series of controlled conditions, including lithology, porosity, formation fluids, borehole sizes, borehole fluids, casing, and cement thickness. Extensive Monte Carlo N-Particle (MCNP) modeling results were matched with lab measurements and provided additional simulated response conditions beyond the practical limits of physical testing. New elemental standards were developed for a spectral deconvolution method using a weighted non-negative least-squares (WNNLS) algorithm to determine C and O yields in addition to other elemental components.

Hydrocarbon saturation is determined from C/O measurements using a custom MCNP simulation process as a reference to predict tool response in well-logging environments. Measured C/O values are then compared to the predicted C/O references for water and hydrocarbons at specific conditions.

Validation and verification of the new pulsed-neutron tool and spectral C/O analysis were initially performed for two-phase saturation evaluation baseline comparison at thoroughly studied and characterized test wells. Multiple passes of C/O, PNC, and optimized simultaneous C/O and PNC acquisition modes were logged. Each measurement was compared to previously acquired reference data. A statistical assessment was performed to compare and evaluate acquisition modes, logging speeds, and the number of logging passes.

A sensitivity test of spectral C/O measurements compared to windows C/O methods was performed in a high-temperature casedhole heavy oil sandstone well. As a continuation of a long-term observation study, this well provided a unique opportunity to compare against several years of monitoring. Three-phase saturation evaluation (heavy oil, water, steam) was then performed using an advanced analysis workflow. The workflow uses a patented triangulation technique combining spectral C/O values that are proportional to hydrocarbon saturation with inelastic ratio-based gas saturation measurements.

Spectral C/O measurements were found to be comparable to windows C/O measurements and with increased accuracy. Especially valuable is the opportunity to reduce multiple logging passes and the inherent uncertainty associated with depth matching and integrating multiple acquisitions. With the available combination of sigma, spectral C/O, gas saturation ratios, and porosity, a triangulation of multiphase saturation assessment is feasible in any reservoir conditions (salinity and oil density independent methods). Simultaneous oxygen activation measurements allow detection and velocity determination of shielded water flow, which can provide insight into channeling, leaks, and other well integrity problems that can affect reservoir performance.

Field Testing of a Propagation At-Bit Resistivity Tool

Tsili Wang, Well Resolutions Technology, Inc.

Despite its great potential in geosteering, geostopping, well placement, and other applications, at-bit propagation resistivity technology has seen little progress in the past 40 years. No commercial tools are available today on the markets. Compared to conventional logging-while-drilling (LWD) resistivity tools, at-bit resistivity tools bring measurements right at or close to the bit, substantially reducing the blind time for wellbore adjustment decision making. Today, conventional LWD resistivity technologies, primarily propagation and azimuthal resistivity technologies, are routinely available for commercial uses, but at-bit resistivity technologies are rare except for a few electrode-type tools. The latter not only are limited in depth of investigation but also often experience difficulties in oil-based muds or other nonconducting drilling fluids. In this paper, we report some of the latest progress in the at-bit resistivity technology. We shall discuss the design and field testing of a propagation-type at-bit resistivity tool.

The new tool, by design, measures both attenuation and phase difference at low MHz frequencies. Much of the development effort was centered on the challenge posed by short-spaced antennas. Because of the restriction on the tool length for the sake of BHA steerability, much shorter coil spacings were to be used as compared to conventional LWD resistivity tools. As a result, the attenuation and phase difference quantities to be measured would be much smaller, in some cases even orders of magnitude smaller, than those of conventional LWD tools. Higher frequencies help increase the measurability of the quantities but may greatly reduce the depths of investigation of the tool. Moreover, high frequencies may also introduce large dispersion effects into the measurements, making the at-bit resistivity data more difficult to interpret.

To test the tool design, especially the selection of the frequencies, prototype tools were built for lab experiments and field trials. A water tank was used to simulate a conducting medium. Both attenuation and phase difference data were acquired and compared against the numerical models of the water tank. The water tank data was also used to help define the limits of the resistivity measurements. More lab experiments were designed to verify the azimuthal resolution capability of the tool as predicted by the numerical modeling. Both the water tank and metal reflectors were used to demonstrate the azimuthal resolution of the tool. As an integral part of the tool development effort, thorough numerical modeling was performed to study the tool response to various important scenarios, including (1) resistivity anisotropy, (2) borehole effects, (3) tool eccentricity effects, and (4) bed boundary effects.

In this paper, we shall report some of the important results from the numerical modeling studies. Our emphasis will be on the field testing of the new tool. We shall discuss a few case studies from the US and Canada. We shall present field data from dual-sensor (resistivity and gamma) at-bit tools. We shall discuss how the at-bit resistivity data compare with the conventional LWD resistivity data. We shall also discuss how the dual-sensor data can be used as a means to validate both at-bit resistivity and gamma data when an independent resistivity log is not available for comparison.

Fundamentals of Distributed Acoustic Sensing for Inflow Profiling

Peter In ‘t Panhuis, Shell

When light travels through an optical fiber, the smallest vibration impinging on the fiber will cause small disturbances in the back-scattered light. This principle is the foundation for distributed acoustic sensing (DAS), a fiber-optic technology that can turn an ordinary telecom fiber into a sensitive distributed sensor capable of detecting both acoustic and thermal disturbances over distances of several kilometers. DAS offers a wide range of applications for continuous and real-time monitoring of all well operations along the entire length of the wellbore without a need for well interventions. In this paper, we will demonstrate some of the foundational principles, experimental data, and key data processing steps to illustrate how DAS may be used for in-well production or injection profiling.

Laboratory experiments were conducted in a horizontal flow loop, with multiple fibers clamped on the outside, with accelerometers and pressure sensors mounted to provide a reference signal, and with a separate inflow line to simulate perpendicular inflow of different types of fluids into the main flowline. Different types of orifices were used on the inflow line to model different types of flow restrictions. By pumping fluids at different rates through the main flowline and the inflow line, while monitoring the acoustic signatures using DAS, flow-noise correlations could be derived (see attached figure). It showed that flow noise could be predicted based on a single parameter that encompasses the impact of both inflow rate (Q) and inflow geometry, where the latter is represented by the diameter of the orifice (D) and the number of orifices (N).

The results from the flow-loop experiments were used to develop algorithms for quantitative single-phase flow allocation, which were implemented into software workflows and successfully applied to actual field data to monitor injection and production performance. The impact of different acquisition parameters and key processing steps will also be demonstrated, and how they may impact data quality.

Finally, advanced signal processing steps were applied to filter and distinguish the key parameters of interest, to improve the signal-to-noise ratio of the data, and to reduce the potentially large volume of data produced by DAS to allow for more efficient and quick decision making. These algorithms were subsequently implemented into the first software designed for the visualization, processing, and interpretation of DAS data for production and injection monitoring and have since been used for the interpretation of data from more than 100 wells from producing assets across the world.

High-Resolution Optical Spectral Reconstruction and Downhole Fluid Analysis Using Broadband Spectrometer and Matching Pursuit Inversion

Zhonghuan Chen, Bin Dai, and Christopher Michael Jones, Halliburton

Absorbance spectra (optical density) measurement of downhole fluids, as one of the key sensing capabilities of modern formation testers, is widely used in drilling mud-filtrate contamination monitoring, formation fluids composition analysis, and reservoir compartmentalization studies. Conventionally, a narrowband filter-based spectrometer is used to record optical absorbance spectra of downhole fluids with limited spectral resolution due to the limited number of narrowband filters being used. A broadband filter-based compressive sensing spectrometer enables rugged instrument design and achieves higher spectral resolution and improved signal-to-noise ratio for downhole fluid spectral measurement. A highly efficient inversion method is developed to invert the broadband spectrometer measurements to obtain high-resolution spectra.

The proposed matching pursuit inversion method is a dictionary-learning method that leverages a fluid spectral database as the learning dictionary. The optical spectra in the fluid database are measured in a spectral measurement laboratory. During the inversion process, the iterative algorithm matches the observed data on the sampled fluid with the spectral data in the dictionary and finds the best-matched fluid iteration by iteration. The absorbance spectrum of the sampled fluids is reconstructed as a weighted linear combination of a small number of spectra in the fluid database (sparse representation).

In an experiment, the matching pursuit spectral inversion is applied to measurements of two spectrometers configured with different optical filters. Even if the inversion problem is highly under-determined, the reconstructed spectra are consistent on the same fluids. We also compare the reconstructed spectra with the spectra measured by a commercial laboratory spectrometer for a set of fluids; the spectra closely matched. Analysis shows, as full information in the fluids spectral library can be used in the matching pursuit method, it reduced the uncertainty and improved the reliability.

We also demonstrated several field applications using reconstructed spectra, including real-time mud-filtrate contamination monitoring and downhole fluid composition analysis. With the efficient implementation of the matching pursuit method, the proposed inversion can meet the requirement of real-time mud-filtrate contamination monitoring. Moreover, with high resolution to distinguish the absorbance peaks of gas (1,650 nm) and oil (1,720 nm), the reconstructed spectra can clearly depict the gas-oil-ratio change during the formation sampling process.

Holistic Integrated Approach for Reliable Leak Detection Using Beamforming of Acoustic Waveform and Basic Casedhole Logging

Maciej Kozlowski, Kresimir Vican, Rodney Howard, and Chung Yee Lee, Halliburton; Ana Maria Garcia Dominguez, ENEGAS

Well integrity is the obvious condition for safe and reliable well operations; therefore, reliable logging diagnosis and description of present leaks are necessary to plan and conduct effective and safe remediation.

The case study well is a subterranean gas storage reservoir located on land. During a recent workover, the upper completion was removed, and as a best practice, a multifinger caliper survey was performed to check the status and integrity of the casing. No major problems with casing integrity were identified. The operator subsequently installed a new upper completion, and a successful pressure test was conducted confirming tubing integrity. However, a significant pressure drop was observed during testing annulus A between the tubing and the casing.

Since no potential leak point could be ascertained from the multifinger caliper logging, the customer confirmed a requirement to perform further diagnosis with casedhole logging in the tubing to detect the leak. The proposed methodology included the acquisition and analysis of basic production logging sensor analysis in both static and dynamic conditions, along with spectral noise leak detection tool logging in continuous and stationary modes.

The results of the subsequent logging acquisition program were consistent and pointed out a few areas of concern where the source of the leak could exist. The key element of investigation was the beamforming analysis of the acoustic waveform. Beamforming yields an estimate of the radial distance of the noise source of the leak from the tool. The beamforming analysis combined with corroborating data from high-resolution temperature (PRT), multifinger caliper (MIT), casing collar locator (CCL) pinpointed the leak source at a collar connection, thus distinguishing it from tubing to casing or formation noise as the source of the leak.

This holistic approach required analysis of all available logging data – starting from basic casedhole logging sensors and advanced techniques for radial noise location. Especially beamforming technology allows for the identification of radial distance as well as the drawing of the flow map at the leak point.

Identification of Bitumen With Pyrolysis Analysis on Core/Cuttings and NMR Relationship in Middle Marrat Reservoir Rock

Ahmad Shoeibi, Geolog International B.V.; Saad Al-Ajmi and Meshari Al-Hashash, Kuwait Oil Company; Milton Sanclemente and Antonio Bonetti, Geolog International B.V.

The main objective of this study is to show the correlation between the bitumen presence identified using Pyrolysis analysis in core/cuttings and the petrophysical data from NMR logs in the Jurassic Marrat Formation in Kuwait. Since the presence of bitumen in the reservoir represent a flow barrier and is causing additional formation damage, the identification of the bitumen intervals has become critical for well completions and for the development strategy of Middle Marrat reservoirs in North Kuwait.

In this study, several core and cuttings samples from Middle Marrat were analyzed with geochemical methods, especially XRD and pyrolysis analyses, in order to provide the characterization of the minerals and of the organic matter, including the determination of bitumen presence. Thanks to the instrument's compact size and robustness, the analyses could be performed onsite.

Additionally, NMR logging was employed in many of the corresponding well intervals. The comparison between porosity from the NMR log and porosity from the density log was used as an indication of the presence of solid bitumen.

The results of five wells in the same field are presented in this paper. In each reservoir section, the pyrolysis analysis was applied to the core, cuttings, or both. The measurement was hindered by drilling fluid organic contaminants, affecting S1 and, in some cases, also S2 peak determination in cuttings samples drilled with oil-based drilling fluids. Contaminated samples could, however, be cleaned with the use of organic solvents, which guaranteed the efficient removal of the contaminants while retaining the insoluble part of the bitumen. The post-treatment pyrolysis analysis revealed the amount of this residual bitumen.

At the same time, petrophysical interpretation of the NMR and basic openhole logs showed the presence of bitumen in the same intervals in which pyrolysis analysis identified the bitumen. However, in one of the wells, the NMR tool failed while logging, and in another one, the logging was canceled due to hole restrictions. This scenario is not uncommon due to well complexity and instability, leaving the surface analysis of cuttings/core as the only method able to detect the bitumen intervals in the reservoir, even in the presence of oil-based mud.

This research represents the first characterization of the Middle Marrat reservoir, including bitumen detection by means of pyrolysis on cuttings/core, integrated with NMR logs interpretation. The correlation between the two techniques validated the pyrolysis approach, substantiating the possibility of using it alone when logs are not available. The resulting bitumen intervals identification can be the key to successful reservoir management, implementing completion strategies that maximize flow contribution from the greatest possible extent of net pay.

Integrated Petrophysical Evaluation of Reservoir Fluids Affected by Production Using Combination of NMR and Elemental Spectroscopy Log Data Combined With Core Experiment Analysis

Artur Kotwicki, Aker BP; Maciej Kozlowski, Venkat Jambunathan, Bob Engelman, and Robert Gales, Halliburton; Kristoffer Birkeland and Torstein Skorve, Aker BP

Production in East Frigg Alpha and Beta structures started in 1988 and produced gas until production was shut down in 1997. The oil accumulation in these structures was considered non-economical at that time and was not produced. Technological advances in drilling horizontal wells have led to a renewed interest in economically producing oil from this field. The main uncertainty in the redevelopment of this field is related to the remigration of the oil column due to extensive gas production. An appraisal well was drilled on the East Frigg Alpha structure in 2022 with the objective of testing the remaining oil potential.

An extensive logging program, including nuclear magnetic resonance (NMR), elemental spectroscopy, and fluid sampling, was planned in addition to quad-combo log data for fluid identification and quantification of remaining oil and gas volumes. Elemental spectroscopy data, along with the other log data, were used as input to probabilistic solvers to obtain the mineralogy and quantify the oil and gas volumes. Extensive coring was performed to provide basic log calibration and information about movable fluids. Saturation was determined from center core plugs sampled offshore. Twin plug sets were drilled using brine and mineral oil as cooling agents in order to better address invasion effects. Additional centrifuge experiments were performed on fresh core material to investigate movable fluids phases associated with selected reservoir sections.

Intra-reservoir baffles combined with historic gas production have triggered significant hydrocarbon remigration. Two thin oil-bearing intervals were found at shallow depths, separated by a water-filled zone. Underlying intervals contained residual hydrocarbons and the original water leg. Formation sampling on wireline was operationally constrained to the shallow reservoir section, confirming movable oil. Fluid distribution in deeper sections relied purely on wireline NMR and spectroscopy, further supported by core analysis. Combined data evaluation suggests the complex distribution of movable oil, residual gas, and variability in oil quality.

Integration of all available data provided internally consistent interpretations critical to understand fluid movement and to evaluate further commercial potential. The results prove the importance of advanced logging and proper planning of core experiments for time-critical decisions.

Integrated Reservoir Characterization and Effective Reservoir Identification by Advanced Logging Series for Complex Volcanic Gas Field – A Case Study From Songliao Basin, China

Zhifeng Wang, Tianguang Wang, and Min Wang, SINOPEC Northeast Oil and Gas Branch Company; Fangfang Wu, Yang Li, Xianran Zhao, Jinlong Wu, Shenzhuan Li, and Daiguo Yu, SLB

Volcanic reservoir is difficult to evaluate due to complex lithology and strong heterogeneity. To better characterize the reservoir and identify good reservoirs, we combined elemental spectrum logging data, electrical image data, array sonic data, two-dimensional (2D) nuclear magnetic resonance (NMR) data, as well as dielectric permittivity logging data to carry out an integrated study including lithology identification, lithofacies analysis, fracture and fault analysis, effective porosity calculation, pore structure analysis, fluid identification, and optimized saturation calculation

First, lithology and lithofacies were identified based on elemental spectrum logging data, electrical image data as well as core data. Second, beddings, fractures, and faults were identified and classified, and the borehole structure was analyzed. Third, effective porosity was obtained, and pore structure was analyzed with NMR data. Reservoirs with high porosity and good pore structure were identified. Finally, the fluid type was analyzed by combining 2D NMR logging data and dielectric permittivity logging data, and gas saturation was calculated; innovatively, gas saturation of the mud intrusion intervals was compensated.

The implementation of this integrated method achieved big success in the study area. Lithology identified mainly includes tuff, breccia-bearing tuff, volcanic breccia, sedimentary tuff, sedimentary volcanic breccia, and sedimentary breccia-bearing tuff. And the minerals and lithology vary a lot from well to well. Volcanic lithofacies include volcanic explosive facies and volcano-sedimentary facies. Good reservoirs are mainly distributed in breccia-bearing tuff, tuff, and volcanic breccia of explosive facies, with high albite content, high effective porosity, and more big pores. There are a lot of microfaults and fractures developed in the reservoir. They have the same strike direction as the regional fault, which are quite important for hydrocarbon migration and the development of dissolution. The best reservoirs with free-fluid porosity higher than 3% were located at the fault-fracture developed zones. Fluid types were identified by integrating 2D NMR plots and dielectric permittivity logging data. For some intervals with very high free-fluid porosity, the inverted resistivity from dielectric permittivity data are much lower than the resistivity of conventional logs because of mud invasion. In this case, gas saturation was compensated by integrating 2D NMR data and array dielectric data. The best interval with the highest effective porosity and highest gas saturation was selected for the test, and the result from the test agreed with our evaluation very well.

Conventional logs can hardly evaluate pore structures and connectivity for such complex reservoirs. The accuracy of gas saturation was greatly improved by combining 2D NMR data and array dielectric data, especially for mud invasion zones. The achievements from this study have dramatically improved the geological understanding of the reservoir and provided valuable information for the deployment of new wells.

Magneto-Electric Antenna and Its Application in Geosteering Tool Design

Shanjun Li and Weishan Han, Geoprance, LLC

Using coil antennae as transmitter and receiver to develop a geosteering tool, one has to increase the spacing between the transmitter and receiver to detect formation boundaries far away from a well trajectory. This causes the dimension of some tools to go up to 100 ft. We propose a magneto-electric antenna for the development of geosteering tools to overcome the problem of tool lengthening.

We introduced a magneto-electric antenna, which has both functions of coil antenna and electric antenna at the same time. When a conductive wire is bent into a semicircle arc, it can be regarded as a combination of two imagined antennae. One is a coil antenna formed by the semicircle arc and an imagined straight conductive wire connecting between the two ends of the arc. The other is an electrode antenna formed by the imagined straight wire. The semicircle arc antenna can thus be used as a coil antenna and as an electrode antenna; therefore, we named it the ME antenna.

We propose a prototype tool that includes a coil antenna as a transmitter and an ME antenna as a receiver, and experimentally verify the definition of the ME antenna and demonstrate that the induced voltage on the ME antenna can be measured, and use numerical simulations to investigate the characteristics of ME antenna.

The experiment results prove the correctness of the definition of the electromagnetic antenna and also prove that the induced voltage on the ME antenna can be measured.

The simulated results show that:

1. The smaller the spacing between the transmitter and the receiver, the stronger the signal reflected by the boundary will be received by the ME antenna.
2. The signal strength received by the ME antenna is far stronger than that received by a coil antenna used by the existing commercial tools.
3. The signal received by the ME antenna is very sensitive to the boundary position.
4. The average of the signal measured by the ME antenna equals that measured by the imagined coil antenna while the tool was rotated, proving that the ME antenna can be used as a coil antenna.
5. The difference between the measured signal and the average of the signal equals that measured by the imagined electric antenna, proving that the ME antenna can be used as an electrode antenna.

When a conductive wire is bent into a semicircle arc, it can be regarded as a combination of two imagined antennae. One is a coil antenna formed by the semicircle arc and an imagined straight conductive wire connecting between the two ends of the arc. The other is an electrode antenna formed by the imagined straight wire. The semicircle arc antenna can thus be used as a coil antenna and an electrode antenna at the same time; therefore, we named it the ME antenna. A prototype tool including one coil antenna as the transmitter and one ME antenna as the receiver was designed to study the characteristics of the ME antenna and test its feasibility.

Multiscale and Cross-Discipline 3D Micromodel Generation Applied to De-Risk Complex Cretaceous Carbonates

Eduardo Cazeneuve, Yasmina Bouzida, and Vladimir Smirnov, Baker Hughes; Maniesh Singh, Jahan Zeb Ahmed, Nepal Singh, Swapan Kumar Dey, Rafael Celma, Sami Sheikh Alawi Shehab, and Mariam Nasser Abdulla Alblooshi, ADNOC

Carbonate reservoir evaluation requires a realistic geological characterization. It is essential particularly to overcome some challenging situations and decisions associated with early water breakthrough (EWBT) like the ones observed within the top Cretaceous “A” formation.

The complexity of the depositional, diagenetic, and structural history of these carbonates creates unpredictable links or pathways with aquifers that bring undesired water at the production stage.

Consequently, having suitable conceptual geological models tied to different measurements facilitates their understanding that helps to better predict their occurrence and extension, and helps to plan for suitable well placement, optimize completion design, and improve hydrocarbon production while avoiding water affluence to the wellbore.

The principal mission of this case study was to evaluate the deep shear wave imaging (DSWI) technique that generates a seismic-like image from deep inside the reservoir. This image can be used to act as a bridge between borehole imaging (BHI) and conventional seismic measurements by capturing subseismic events up to 90 ft in this case, well beyond the borehole wall, that are not within the range of detection of seismic data.

A statistical assessment from BHI was used to benchmark or as a reference for this DSWI evaluation. Then, the end results were incorporated together with the rest of the petrophysical and seismic data and used to assess the value of the combined measurements.

This was achieved by merging different multiscale data measurements and cross-discipline analysis in 3D, allowing to establish a conceptual micromodel around to wellbore vicinity up to 90 ft, thus, having the ability to forecast faulted zones that are prone to connect with the aquifer.

As a result of this case study, a similar workflow will be applied to upcoming wells, trying to expand the knowledge of the subsurface, seeking to improve and refine the generated micromodel of this particular and challenging reservoir.

Evidence from dynamic data will be used once the second stage of the project starts, such as (fluid types and rates, tracers, pressures, etc.) to analyze their contribution to the EWBT and refine the model to better predict these connections.

NMR Fluid Substitution – Pursuing the Fundamental Controlling Parameters of a Low-Mobility Reservoir

Soren Christensen, Aker BP; Holger Thern, Jon Torkel Petersen, and Tor Eiane, Baker Hughes

Chalk is a highly uniform low-mobility endmember of the carbonate rock group bordering unconventional reservoirs with matrix oil permeability often below 1 md. The fundamental control of the distribution of saturation and flow is most often pore-throat radius (*PTR*) and capillary entry pressure (P_{ce}). For clastic sand reservoirs, the interpreter doing saturation-height modeling (SHM) may not appreciate that the proxies for these controls applied in modeling, typically porosity and permeability, are, in fact, nothing more than proxies. When modeling a low-mobility reservoir, however, it is commonly observed that modeled saturation fails to match calculated saturation from logs. The reason is often that the assumed, and typically unconsciously applied, link between the proxy and PTR/P_{ce} is broken. It is, therefore, important to establish a workflow that enables the characterization of *PTR* and a refined permeability (k) to facilitate understanding when modeled S_{wt} from SHM fails to match calculated saturation.

Downhole petrophysical measurements are typically governed by a combination of rock and fluid properties. The concept of fluid substitution (FS) is to create a measurement response at a different saturation than at which data was acquired downhole. For nuclear magnetic resonance (NMR), FS is used to eliminate the hydrocarbon contribution from T_1 and T_2 distributions and, thus, establish the pure response of a water-filled rock. In 2015, Christensen et al. presented the first study conducting successful FS for a chalk reservoir. Based on theoretic considerations and laboratory measurements, the T_2 geometric mean (T_{2gm}) of the water-saturated rock was estimated and converted into *PTR* and *k*. By linking T_{2gm} and total porosity to *PTR* and thus P_{ce}, fundamental parameters controlling the distribution of saturation and flow properties of a low-mobility chalk reservoir were derived. In this study, the NMR FS methodology is applied to a more complex North Sea chalk reservoir – the Norwegian twin fields Valhall and Hod. Data for calibration of the model were acquired from 10 core samples, and the established models were calibrated from core to log scale for application to downhole NMR logs.

The very basis of the FS model was, this time, challenged by the core data. The core T_2 and *PTR* distribution data acquired for calibrating the estimation of *PTR* and *k* deviated from earlier observations. Closer inspection of the rock samples revealed the presence of micro-stylolites and foraminifera as possible explanations. However, a modified workflow was developed, enabling a successful calibration and application of the FS workflow. The NMR FS methodology appears to be more versatile than originally concluded. On the one hand, the established model is capable of identifying important flow units that otherwise would not have been appreciated. On the other hand, it identifies less prolific intervals from a flow perspective that otherwise would have entered 3D reservoir modeling as “normal” rock.

This study adds to the limited work published in the field of NMR FS, and the results point to an underexplored and untapped potential of NMR. Further work in different formations and environments can pave the way for broader applications

Pore System Characterization of Carbonate Formations: A Multiphysics Approach Through Acoustic and NMR Measurements

Juntao Ma, Lin Liang, Xi Yan, Gongrui Yan, Marie Van Steene, and Wael Abdallah, SLB; Shouxiang Ma, Saudi Aramco

Pore system characterization and, thus, permeability estimation in carbonate rocks have always been challenging due to the complexity of the carbonate rocks. Both acoustic and nuclear magnetic resonance (NMR) measurements have been employed individually to characterize different aspects of pore structure. In this study, we combine acoustic and NMR measurements for an improved, quantitative pore structure characterization of carbonate rocks.

We first calculate the volume fractions of crack pores (microcracks and microfractures with a low aspect ratio), reference pores (interparticle pores with a medium aspect ratio), and stiff pores (moldic and vuggy pores with an aspect ratio close to one) through the inversion of an effective medium rock physics (EMRP) model using acoustic compressional and shear measurements. We then add the microporosities and macroporosities inferred from NMR interpretation to determine the volume fractions of six pore groups (microcrack, micro reference, micro stiff, macrocrack, macro reference, macro stiff) by joint inversion. We finally calculate the semi-long axis (l), semi-short axis (s), and cross-section area index (l×s) for the six pore groups through the aspect ratios from acoustic measurement and pore surface area to volume ratio for micropores and macropores from NMR. The derived pore geometry parameters are used along with the total porosity to build an empirical model for permeability estimation based on calibration with core data.

This integrated pore characterization method was implemented to work on log data. Applying the developed workflow to field data demonstrated promising results for carbonate pore system characterization. The total porosity is partitioned into six pore types with corresponding pore body size information of the long axis and short axis. Comparisons with interpretation based on borehole images and core analysis present consistent results. Subsequent permeability estimates based on derived pore geometry parameters improved the permeability evaluation compared to conventional methods, confirming that the integration of NMR and acoustic data enhances understanding of rock productivity.

Through the integration of NMR and acoustic measurements, this novel workflow significantly improves carbonate pore characterization by defining groups of subpores, together with the pore body size information for each pore type. In addition, carbonate rock permeability estimation is improved by introducing a cross-sectional area index by integrating the pore surface area to volume ratio from the NMR measurement and the aspect ratio from sonic measurements. This new method leads to improved formation evaluation and reservoir characterization in carbonate reservoirs.

Pressure Gauge Performance Prediction in Real Wellbore Conditions for Pressure Transient Testing

Jason Milne, Adriaan Gisolf, Richard Jackson, Chen Tao, Hadrien Dumont, Francois Dubost, and Ashers Partouche, SLB

Pressure transient testing with formation tester tools has existed for decades but was historically constrained to formations of limited thickness and permeability. With advances in formation tester technology, the permeability-thickness envelope and the tested radius of investigation have increased. Formation testers can be conveyed on wireline and drillpipe, enabling highly efficient operations. However, this can also expose pressure gauges to pressure and temperature variations over time, which can lead to gauge drift. This paper addresses the quantification of pressure gauge dynamic response and performance for improving pressure transient test design, execution, and analysis. In practice, all pressure sensors have response errors, including short-duration and long-term drift as well as temperature response effects which can impact gauge accuracy and resolution. The consequence of non-ideal pressure gauge responses can lead to uninterpretable data or to misinterpretation of reservoir effects. Reservoir engineers continue to emphasize the need to quantify the actual performance and limitations of pressure gauges in pressure transient testing in real well conditions for specific wellbore and reservoir environments.

A new method to separate the dynamic effects and gauge response errors from the true reservoir response has been developed. The method hinges on a model to quantify the dynamic uncertainty in a pressure gauge's output. This enables estimation of the error in calibrated pressure over time in response to the recent history of pressure and temperature that the gauge has been exposed to. The dynamic uncertainty model has been established by integrating physics-based modeling with over 10 years of calibration data, with short-term and medium-term drift measurements on thousands of high-performance pressure gauges passing through in-house calibration and test facilities. The dynamic uncertainty model is applied to a pressure and temperature profile provided by a wellbore dynamics simulator for a specific job sequence. The pressure transient derivative is then calculated from this simulated data together with the quantified uncertainty, yielding the worst-case impact of gauge response on the derivative plot.

We demonstrate the application of this approach for several different scenarios and describe the impact of gauge performance for planned operational and test sequences. In each example, the well pressure and temperature profile are simulated for a planned operational sequence, and the gauge drift and resolution are quantified for that specific sequence for different gauge technologies. In one of the example scenarios, the gauge drift can be easily mistaken for a reservoir boundary. By changing the operational sequence, the drift impact can be reduced to the extent that it no longer impacts the simulated pressure transient response for the target reservoir zone.

The ability to predict pressure gauge drift magnitude is new and unique. It is combined with a simulator to predict the gauge temperature and pressure exposure for operational sequences, creating an extremely powerful tool for understanding the impacts of real gauge behavior on pressure transient analysis. Job sequences can now be designed to maximize pressure transient value while simultaneously minimizing the risk of misinterpretation.

Quantification of the Process of Mud-Filtrate Invasion in Heterogeneous Rocks by Combining X-Ray Computed Tomography and Numerical Simulations

Mohamad Abdo, Carlos Torres-Verdín, Colin Schroeder, and Pierre Aérens, The University of Texas at Austin

Understanding the behavior of mud-filtrate invasion and mudcake buildup in permeable rocks is important for the accurate interpretation of borehole measurements such as resistivity, density, neutron, and magnetic resonance. The typical approach is to assume homogeneous formations and piston-like fluid displacement, a situation hardly encountered in the field. For example, in spatially heterogeneous rocks, the invasion depth becomes space-dependent, adding uncertainty to shallow-sensing well logs. Mud-filtrate invasion and fluid flow are often described by simulating radial injection in the borehole, while experimental fluid-fluid interactions are investigated using Cartesian flow. Furthermore, it is rare to find research papers not limited to water-based mud and supported with consistent simulation and experimental results, i.e., radial injection simulation and radial flow experiments. The objective of this paper is to combine observations made with time-lapse X-ray CT images of mud filtrate invading spatially heterogeneous rocks and numerical simulations to quantify flow-dependent petrophysical properties of spatially heterogeneous rocks, such as saturation-dependent capillary pressure, relative permeability, and wettability.

We document an improved mud-filtrate invasion experiment using either water-based mud (WBM) or synthetic oil-based mud (SBM) and a 3-in. diameter and 2-in. long cylindrical cores initially saturated with either brine, oil, or air. A 0.5-in. diameter borehole for injecting fluids at constant pressure was drilled in each sample to replicate actual borehole conditions. The resulting invasion process was time-lapse monitored via X-ray scanning. Rock samples used for the experiments varied from homogeneous to heterogeneous rocks with bimodal pore/throat size distributions. Numerical history matching of experimental results was performed by varying saturation-dependent (a) capillary pressure, (b) invading relative permeability, (c) irreducible water saturation, and (d) residual hydrocarbon simulation.

By accurately tracking the injected volume of mud filtrate during experiments and the radial advancement of the invasion front, it was possible to estimate saturation-dependent wettability, capillary pressure, and relative permeability via history matching. Estimated Brooks-Corey capillary pressure parameters for layered heterogeneous samples agree with mercury-injection capillary pressure within 11.2%. Imbibition experiments provided sufficient contrast between native and invading fluids to highlight changes in the radial time-lapse evolution of fluid saturations. Petrophysical heterogeneity in laminated samples was emphasized when the samples were presaturated and invaded with an immiscible fluid. The petrophysical properties of each layer were estimated by history-matching invasion experiments with numerical simulations of presaturated laminated samples. On the other hand, invasion fronts in laminated dry rock samples were piston-like due to higher transmissibility between thinner layers. Only the petrophysical properties of the most permeable layers were estimated from the history matching of experimental measurements of invasion in dry rocks.

History-matching laboratory experiments of invasion underline the effect of geometrical heterogeneity on fluid flow in porous media and the role played by apparent petrophysical properties. It also provides information on petrophysical properties that vary spatially across relatively large rock samples (i.e., 3 in. wide and 2 in. long). X-ray tomography, combined with numerical multiphase flow simulations, provides unique results with relatively small resolution and a large sampling size. The experimental procedure is dynamic and is less time consuming than laboratory measurements traditionally and commercially used to measure flow-related petrophysical properties.

Resolving Chloride Ion Concentration Through In-Situ Optical Spectroscopy: A Venture Into Downhole Water Chemistry Analysis

Rohin Naveena-Chandran, Farrukh Hamza, Vinay Mishra, Rojelio Medina, Jimmy Price, Bin Dai, and Yasin Abulaiha, Halliburton; Ricardo Freitas, Scott Hanson, Aygul Kostinovsky, Wei Wang, and Emily Troxell, Chevron

In sampling reservoir water, there exists an inherent challenge to distinguishing formation water from a water-based mud filtrate. This is further compounded when attempting to type between injected and formation waters under in-situ temperature and pressure conditions. The prevailing industry method is laboratory fluids analysis on surface; however, this incurs both time and potential representation inaccuracies. It is, therefore, a prudent endeavor to expand the boundary of downhole fluid analysis (DFA) into water chemistry applications to recognize ionic properties within fluids.

The following study presents an innovative methodology using a wireline formation tester (WFT) and DFA-based optical spectroscopy to quantify chloride ion concentration. Demonstrated through spectral deconvolution, an optical spectrum of water within the near-infrared (NIR) region is segmented into two components corresponding to deionized water and chloride contributions. The component representing chlorides contains unique spectral attributes that vary between concentration levels. Subsequently, an environmentally calibrated model is developed, incorporating these spectral attributes to determine chloride ion concentrations corresponding to different fluid salinities. The results not only distinguish filtrate from water but also show unique characteristics between waters in situ.

Two applications of using downhole chloride data are highlighted in a wireline acquisition program. In the first case, downhole chloride values are used to fingerprint fluids to differentiate between injected and formation water. A second case is presented to show how a petrophysical interpretation is optimized by using multiple chloride values instead of a single assumption

To date, the industry has been unable to quantify chlorides as a contribution to water chemistry in situ. This venture introduces a novel method of wireline pumpout and sampling to distinguish chlorides, as well as the premiere use of spectral deconvolution as a technique within DFA. These results have broad applications to diagnose water production, injection, and compatibility for saltwater disposal (SWD) and carbon capture and sequestration (CCS) projects

Salinity Effect on CO_2 Solubility in Live Formation Water Under Reservoir Conditions

Jie Wang, Intertek Westport Technology Center/University of Houston, and Christine Ehlig-Economides, University of Houston

Dissolution of CO_2 in saline waters is considered one of three main CO_2 trapping mechanisms, along with structural/stratigraphic trapping and mineralization. CO_2 can dissolve in fresh/saline water under typical reservoir pressure and temperatures. Its solubility is dependent on pressure, temperature, and salinity.

The typical assumption in open literatures regarding CO_2 solubility studies—that saline water or fresh water is considered as a liquid without any pre-dissolved gases under pressures and temperatures—is not true because any formation water contains appreciable dissolved gases for all pressure and temperature conditions. An example of gas-water ratio (GWR) can be ~1 scf/stb for a saline aquifer and ~5 to 6 scf/stb for formation water in an oil reservoir. Therefore, it is essential to quantify the effect of brine salinity on CO_2 solubility in live saline waters. Just as live oil is reservoir oil containing solution gas, “live” brine is defined as saline water with dissolved gases in it.

Two sets of experiments were conducted under typical reservoir conditions. The first set of experiments evaluated the CO_2 solubility in live formation water. The second set of experiments evaluated how variation in the live brine salinity affected CO_2 solubility. These experiments involved a synthesis of the brine with three different salinities (low, medium, and high), recombination of live formation water, CO_2 addition in a high-pressure and high-temperature pressure-volume-temperature (PVT) visual cell, and determination of bubblepoint pressure within the PVT cell.

The results showed that CO_2 solubility in live formation water is significantly less than that in “dead” water under reservoir conditions. The CO_2 solubility vs. pressure curve has a much steeper slope, which indicates that CO_2 can no longer be dissolved in the live brine once it reaches a certain solubility. In addition, the brine salinity affects CO_2 solubility in live formation water by further reducing CO_2 solubility with increasing live brine salinity.

Understanding CO_2 dissolution in live saline water is essential for future carbon capture and sequestration (CCS) evaluation and execution.

Through-Tubing Casing Inspection for Well Integrity Evaluation Using Physics-Driven Machine-Learning Nonlinear Correction

QinShan (Shan) Yang, GOWell; Mohamed Larbi Zeghlache, Saudi Aramco; Marvin Rourke, Alexander Tarasov, Ryan Rugg, Neil Sookram, and Moustafa Ismail, GOWell

Multiple casing inspection is a major part of well integrity evaluation during the entire well life cycle. One important aspect is casing deformation that can be prevalent in fields with formation swelling or subsidence, tectonic activity, salt creep, corrosion-induced or well completion defects. Worldwide experience shows that deformation will generally occur on the outer casing of the well. Therefore, a practical method that allows inspection of these tubulars is essential to evaluate and ensure well integrity. The challenge with existing logging technologies for pipe inspection, including calipers, ultrasonic, magnetic tools, and cameras, is the presence of tubing in the well that is costly to pull in order to evaluate the outer casing. Although there are available technologies that provide circumferential average thickness measurements for multiple concentric pipes, they cannot provide a casing deformation analysis.

In order to address this longstanding challenge, this research work introduces a new tool using magnetic technology that enables measurement of casing deformation behind completion tubing, avoiding the cost of pulling tubing for surveillance purposes. In addition, this technology provides the capability to evaluate the tubing eccentricity inside the casing.

Through-tubing casing inspection presents challenges in mainly two areas; the first is the tubing shielding effect. On average, only 20% of the magnetic flux density reaches the casing area behind the tubing. Secondly, when the tubing is eccentered inside the casing, it generates substantial nonlinear interference. This later distorts the casing measurement signal by creating a nonlinear effect on its response. A novel solution is developed to generate a unique compressed-and-focused magnetic field in order to increase the flux density in the casing area by two to three times, providing an increased signal-to-noise ratio. It also incorporates an array of magnetic sensors to measure the magnetic flux density distributions azimuthally around the tool. To improve the response, a physics-driven machine-learning method is tailored for the dimensionality reduction on the parameters’ domain, reducing the dimensions from 5D to 3D. An optimized Gaussian processes regression method is developed to process the raw logging data. In conjunction with casing inspection, the solution can quantitatively estimate the tubing eccentricity allowing for the removal of its nonlinear effects, including the extreme scenario of tubing touching the casing. This provides an estimated 5% deformation ratio accuracy for casing diameters up to 13.375 in.

This technology can be combined with other single or multibarrier inspection logging tools, such as multifinger calipers and multipipe thickness log tools, respectively. This provides an integrated solution with complete well integrity evaluation.

The tool’s performance has been validated in the lab as well as in the field, spanning different well conditions and casing/tubing combinations. Examples of applications in the oil and gas fields include through-tubing well integrity monitoring for production, injection, or gas storage wells, free-point logging, pipe eccentricity for plug and abandon operations, and tubing clamp orientation detection.

Through-Tubing Lightweight Cement (TT-LWC) Evaluation in Production Wells

Hichem Abdelmoula, Jinsong Zhao, Qinshan Yang, Marvin Rourke, and Neil Sookram, GOWell; Mohamed Larbi Zeghlache, Saudi Aramco

Cement placement and bonding are critical for zonal isolation and well integrity assurance. Cement bond evaluation with sonic logs has been used in the hydrocarbon industry for over 50 years, and for about 30 years, higher-resolution ultrasonic logs have also been available to improve cement placement diagnostics. However, when there is tubing in the well, these traditional technologies fall short because they cannot evaluate cemented casings or liners behind tubing.

Reliable through-tubing (TT) cement evaluation is technically very challenging, but finding an effective solution for it has been long desired in the oil and gas industry. The benefits are obvious because it positively reduces intervention time and costs, as operators would not need to remove the tubing string to conduct cement evaluation, as currently required with existing technologies. This TT cement evaluation challenge also increases significantly when there is a need to inspect casing cemented with lightweight cement (LWC) because of its low density and limited acoustic impedance contrast with borehole fluids.

This paper presents the study of a new method for TT-LWC measurement and evaluation. Instead of conventional acoustic wave propagation, the proposed method relies on the novel principle of measuring the nonharmonic resonance modes of the coupled elastic structure comprised of the multiple pipe strings in the well. A transducer is used to emit one or more continuous sinusoidal excitation signals to activate the nonharmonic resonance modal shapes in the multipipe structure. The vibration impedance of the structure is tested for the power requirements to maintain stable vibration modals, allowing the power losses corresponding to the energy being coupled across the casing-LWC bond interface and dissipating into the formation to be measured. The research shows that the system resonance frequencies and their corresponding mode shapes are affected by Poisson's ratio and Young's modulus of the material behind the casing. The proposed TT-LWC solution overcomes the main challenges associated with the low-density and low-impedance LWC conditions. The new solution uses a pad-free apparatus for cement evaluation applications in wells with or without tubing.

An additional challenge in any TT cement evaluation is the effect of tubing eccentricity and its heavy impact on the measurements through the tubing. The paper also covers the tubing eccentricity correction algorithm from sectorized measurements made with the tool. The absence of radial symmetry affects the structure vibration and creates an uneven distribution in the sinusoidal excitation in the tubing-casing annulus. Tubing eccentricity affects the impedance measurement, resonance frequency, and mode shape, resulting in inaccurate bond evaluation. A machine-learning (ML) based algorithm was developed to analyze the eccentricity and the cement bond condition on the impedance measurements from each sector.

The solution was evaluated with simulations and lab tests, and the performance and reliability were examined in different pipe combinations, conventional and LWC bond conditions, and tubing eccentricity scenarios.

The results confirm the ML algorithm effectively removes tubing eccentricity contribution from the measurements, and this novel nonharmonic resonance technique provides valid TT bond evaluation for conventional and lightweight cement.

Use k_o-b Plot to Determine Fracture Impacts on Gas Permeability Measurements

Wenxiu Song, Michael T. Myers, and Lori Hathon, University of Houston

Klinkenberg (1941) proposed gas apparent permeability is a function of the intrinsic permeability (k_o), slippage factor (b), and the reciprocal mean pore pressure (1/Pm). This research uses Klinkenberg correction to generate a k_o-b plot to analyze the physics of transport in shale gas. According to the Klinkenberg equation, there is no unique k_o-b to represent the apparent permeability under the same

mean pressure. For a single test, a large range of k_o can be modeled, with each k_o corresponding to a value of b. Then a k_o-b curve can be generated. To determine both k_o and b, at least two significantly different mean pore pressures are required. And the intersections of the k_o-b plot represent the true answers.

Permeabilities are measured on core plugs using the pulse decay technique. One manmade (homogeneous) and three natural samples from the different formations are prepared to be 1 in. long and 1 in. in diameter. All the samples are measured under continuously increasing mean pore pressure, which increases from 250 to 1,450 psia, and the effective confining pressure is kept at 1,000 psi. The pressure change in the upstream and downstream chambers are monitored, and these data are modeled by COMSOL Multiphysics® to obtain k_o-b values for each test. To model the curves, a fixed b value is set, and then try to fit with a large range of k_o. The root mean square error (RMS) is calculated for each fit, and the minimum RMS represents the optimum fit. Figure 1 shows the optimum fits to the experimental data at various k_o-b with the corresponding RMS. By plotting the optimum fit values, the k_o-b plot is generated (Fig. 2).

The results show that k_o-b values of the manmade sample are a function of mean pore pressure (Fig. 2). The intersections illustrate that at high mean pressure, the gas slippage factor decreases. The k_o-b values show different trends when the injected gas phase transfers from subcritical to supercritical. For the nature cores, the k_o-b plot converges at a low slippage factor ($b \approx 0$), which indicates that these nature samples have open fractures. And the microfractures are observed in CT-scan images. To heal the fractures, we injected epoxy into the samples and repeated the pulse decay test under the same condition. The newly generated k_o-b plot shows that the permeability was reduced by one order of magnitude after fracture healing, but the k_o-b still converges with decreasing b, which indicates that the injection of epoxy cannot completely heal the fractures.

The previous studies often neglected the slippage effects when calculating the gas permeability. This study separates k_o-b values to obtain the true answer from different mean pore pressure tests. Besides the permeability, the obtained k_o-b plot can represent the characteristics of the sample.

Using Formation-Tester Measurements to Estimate Depth of Invasion and Water Saturation in Deeply Invaded Tight-Gas Sandstones

Tarek Mohamed, Mohamed Bennis, and Carlos Torres-Verdín, The University of Texas at Austin; German Merletti and Camilo Gelvez, bp

Mud-filtrate invasion displaces in-situ formation fluids away from the wellbore in porous and permeable rocks. In the presence of water-based mud (WBM), invasion is accompanied by salt mixing between mud filtrate and formation brine. Formation resistivity will vary radially away from the borehole due to post-invasion distribution of water saturation (S_w) and electrolyte concentration. In tight sandstones, the depth of mud-filtrate invasion often exceeds the depth of investigation (DOI) of deep-sensing resistivity logs. Thus, deep and electrically conductive filtrate invasion coupled with shoulder-bed effects result in the overestimation of S_w, leading to underestimated hydrocarbon pore volume. Reliable methods are needed for the accurate assessment of the radius of invasion (ROI) and S_w in deeply invaded formations.

Formation-testing operations are impacted by mud-filtrate invasion, where often long fluid pumpout is needed to acquire hydrocarbon samples with minimal mud-filtrate contamination. However, unlike other well-logging tools, formation-testing probes do not have a fixed DOI that limits their ability to pump out mud filtrate until acquiring original formation fluids (i.e., sensing the uninvaded zone). We use an in-house petrophysical and fluid flow simulator to perform numerical simulations of formation testing, mud-filtrate invasion, and well logs to estimate ROI and S_w. The simulations are initialized with the construction of a multilayer petrophysical model. Initial guesses of volumetric concentration of shale, porosity, S_w, irreducible water saturation, and residual hydrocarbon saturation are obtained from conventional petrophysical interpretation. Fluid-dependent petrophysical properties (permeability, capillary pressure, and relative permeability), mud properties, rock mineral composition, and in-situ fluid properties are obtained from laboratory measurements. Using our multiphase formation testing simulator, we simulate actual fluid sampling operations by defining five drawdown durations performed with a dual-packer formation tester over 9 hours. Additionally, apparent resistivity logs and nuclear logs (e.g., gamma ray, bulk density, and neutron porosity logs) are numerically simulated to match the available well logs.

The studied sandstone reservoir is characterized by low porosity (up to 14 p.u.), low-to-medium permeability (up to 40 md), and high residual gas saturation (40 to 50%). The deep mud-filtrate invasion resulted from extended overbalanced exposure to saline WBM (17 days of invasion and 1,100 psi overbalance pressure) coupled with the low mud-filtrate storage capacity of tight sandstones. Therefore, the uninvaded formation is located far beyond the DOI of resistivity tools, whereby deep resistivity values are lower than those of uninvaded formation resistivity. Through the numerical simulation of formation testing, we estimated ROI and S_w. Likewise, we quantified the hydrocarbon breakthrough time, which matched the measured hydrocarbon breakthrough time.

We introduce a new application of formation-tester measurements to address deep mud-filtrate invasion. The simulation accuracy of formation testing was cross validated by matching pumpout flow rates and pressures separately to avoid a non-unique match of flow rates. We complemented our analysis by matching available well logs with their numerical simulations. Confidence in the results was greatly enhanced through the agreement between two independent analyses: numerical simulations of both formation-tester measurements and well logs. Estimated ROI was about 2.5 m, and estimated S_w was about 13% lower than S_w derived from resistivity logs, therefore improving the appraisal of the original gas in place.

Validation of Downhole Fluid Analysis and Machine-Learning Compositional Determination

A. Ballard Andrews, Matthew Sullivan, and Evgeniya Deger, SLB; Bilal Hakim, Tom Messonnier, and Brandon Thibodeaux, TALOS; Elham Mahmmodaghdam, Richard Jackson, Shawn Taylor, and Oliver C. Mullins, SLB

Downhole fluid analysis (DFA) relies on accurate in-situ composition and gas-oil ratio (GOR) derived from vis-near infrared optical spectra. New advanced optical spectrometers have been introduced into the field on a new wireline formation testing platform. In this report, measurements of live crude oils collected with a research-grade spectrometer are compared with the same samples using DFA tools and logs. In addition, spectral interpretation using advanced machine-learning algorithms is shown to yield the same composition of C1 to C6+ as obtained from PVT reports within an absolute error bar of 1% and GOR within a relative error bar of 15%. Data are shown from three separate crude oil samples with excellent matching of laboratory and downhole spectra.

Machine-learning algorithms are employed to train the calibration model on a large library of light to heavy oils, gas condensates, and gases. More specifically, factor analysis replaces the original variables with linear combinations of new variables that best capture the spectral variations relevant for predicting the compositions. The optimal preprocessing and regression algorithms are determined through cross validation on the training-validation splits.

The spectra acquired downhole on live oil samples are shown herein to be identical to spectra obtained on the same samples under reservoir temperature and pressure conditions in the laboratory using a high-resolution optical spectrometer (with discretized spectra to match downhole spectrometers). In addition, the compositional predictions from the spectral analysis are compared with PVT reports of these samples. Methane (C1), ethane (C2), propane (C3), butane (C4), and pentane (C5) and carbon dioxide (CO_2) are predicted with absolute accuracies of ±1 wt% and higher carbon numbers (C6+) with absolute accuracy of ±2 wt%. An artificial neural network (ANN) is trained on a large PVT and gas chromatography (GC) database to a relative accuracy of ±15% scf/bbl.

Excellence in spectroscopy and machine-learning algorithms provide new value in DFA tools and interpretation, which together establish new frontiers in wireline logging. These enhanced capabilities of fluids measurement and interpretation extend the capability of reservoir evaluation, especially through reservoir fluid geodynamics (RFG).

SPORSE: BEYOND PICKING DIPS FROM IMAGE LOGS

A Machine-Learning Approach Performed on New Technology for Images in Oil-Based Mud for Advanced Electrofacies Analysis – A Case Study From the Norwegian Sea

Sayyid Ahmad, Halliburton; Henrik Waage, Kristoffer Birkeland, Dler Mirza, and Nils Andre Aarseth, Aker BP; Peter Barrett, Bob Engelman, Robert Gales, and Venkat Jambunathan, Halliburton

Exploration projects often require high-quality image data acquired in oil-based mud-filled boreholes to evaluate thin laminated sandy shale formations. The introduction of a new oil-based electrical imager technology allows detailed facies analysis and open and closed fracture identification. Simple cutoff methods are widely used for lithofacies identification and facies classification, which can be a time-consuming task. However, this work presents an automated machine-learning-based electrofacies classification using a combination of resistivity and permittivity-dominated image log data integrated with other conventional data. An advanced data set was acquired in a near-vertical well drilled in the Norwegian Sea to target Middle Jurassic shallow marine sand complexes with varying depositional environments.

Machine-learning workflows are created after loading all images, other conventional log data, surface seismic, and vertical seismic profile (VSP) data. Before running any facies prediction, the advanced workflow encompasses four preconditioning steps for data standardization: 1) data preprocessing for speed correction, button/pad repair and alignment if needed, 2) data reduction by features and instance selection as well as dimensional reduction, 3) parametric testing to see if the available data follow rules of normality, and 4) normalization of data is performed if required. After standardizing the data, different classifiers are tested iteratively for facies prediction. Each step of machine learning, from data conditioning to facies prediction, is constrained by consideration of the sedimentological and depositional environment. After running the models, the resultant electrofacies were compared with lithofacies interpreted manually by using core and conventional log data acquired in the same well. In addition to machine-learning-based facies classification, fractures were classified into open and closed fractures by interpreting the resistivity and permittivity image components.

After iterating the classifiers, six electrofacies were created and discussed based on k-means clustering and self-organizing maps. By integrating high-resolution image log texture and conventional well-log patterns, different depositional environments were linked to the electrofacies identified. Facies 1, 2, and 3 were found to be sand-dominated facies, which comprise mainly transgressive to regressive sands followed by the deposition of aggrading sandy packages deposited in mixed-energy, coastal-deltaic settings during the Lower-to-Middle Jurassic. Facies 4 was found to be silt-dominated heterolithics facies that represent a relatively transitional environment of deposition. Facies 5 and 6 were found to be mudstone-dominated facies, which possibly represent local or regional transgressive events during local or regional flooding events.

The classified electrofacies work is integrated with surface seismic and VSP and can potentially be used for future input to describe lateral and vertical rock distribution patterns and for improving static and dynamic reservoir models for enhanced reservoir understanding. In addition, fracture interpretation with permittivity-dominated images is demonstrated and can be used to further improve completion design and well productivity.

Application of GANs to Resolution Enhancement of LWD Real-Time Images to Support Decision Making

Willian Andrighetto Trevizan and Candida Menezes de Jesus, Petrobras

In the current scenario of project management, where the agility and optimization of operations have been prioritized, the practice of logging while drilling has gained space compared to traditional wireline logging. In theory, acquiring quality petrophysical properties during drilling brings greater agility in decision making about completion and optimizes operation costs. However, regarding borehole image logs, due to limitations in transmission capacity, the actual available data in real time contain about 50% (for resistivity images) of the full azimuth information, being insufficient for the identification of critical geological structures capable of impacting the communication between production or injection zones, or the quality of cementation, such as fractures, caves, and geomechanical collapse zones. The tool's memory data with the full information may take a few days after the end of drilling to be delivered by the service company, which in some cases is not enough time for fast decision making regarding completion.

In this work, we tested models based on generative adversarial neural networks (GANs) to reconstruct the complete memory data based on real-time input. As in conventional GAN schemes, a generator is trained to receive a real-time input and create a "memory-like" image, while a discriminator is trained to tell real and fake images apart. To regularize the convergence of training, we used an architecture known in the literature as CycleGAN, where another pair of generator-discriminator is trained simultaneously to do the reverse process, recreating the real-time data.

Variations of the training process and data sets were used to generate different CycleGAN models. They were trained using logs of presalt reservoirs in the Buzios Field, and performance was assessed on logging intervals not seen by the algorithms during training. The results achieved so far have been very promising, as in certain intervals, resultant models were able to capture the presence of fractures and caves, as well as the general texture of resistivity LWD image logs, as shown in the figure attached.

This methodology represents a way of circumventing telemetry limitations, where missing information is added indirectly to the real-time data as the artificial intelligence (AI) algorithm learns the main characteristics of a field/reservoir. Therefore, previous knowledge from the field can be used to continuously optimize future operations, efficiently incorporating the available database into the workflow of petrophysicists for the recognition of geological and geomechanical structures in time to support decision making in completion operations.

Characterizing Deep-Buried Basement Metamorphic Condensate Gas Reservoir by Borehole Image, Spectroscopy Logs, and Core Data, Bohai Bay Basin, Eastern China

Guoqiang Zhang, CNOOC Ltd.-Tianjin; Bo Liu, Xianlei Zeng, and Yehong Cao, Baker Hughes; Bin Tao, CNOOC Ltd.-Shenzhen; Zhongqing Zhang, Baker Hughes

The recently discovered BZ19-6 basement reservoir of Bozhong Sag in Bohai Bay Basin is a proven condensate gas reserves of over 100 billion m^3. It is the largest deep-buried condensate gas field discovered in the metamorphic basement, with a gas column over 1,000 m. A clear understanding of the controlling factors of the reservoir quality and reservoir distribution is vital to the timely formulation of field development strategy, which may affect following production and recovery.

Basement reservoir quality is mainly determined by weathering, lithology, and fracture network due to very low matrix porosity and permeability. The fractures in the target area are unevenly developed due to the multitectonic movements and stress field rotation. In addition, the mineralogical composition of the basement lithology is complex due to the metamorphism and alteration, which may further affect the reservoir quality. Characterizing effective fractures distribution and minerals of the basement lithology across the area is crucial to classify reservoir quality.

Porosity and permeability are analyzed based on 311 core samples, and it shows average porosity of 3.91% and average permeability of 0.33×10^{-3} md. Plenty of thin sections were made to analyze and classify lithology into unfavorable and favorable lithology for reservoir quality. Ultrasonic borehole image was used to identify different types of fracture based on the amplitude image and traveltime image. In total, fractures are categorized into four types: they are close fracture, fully open fracture, partially open fracture, and vuggy open fracture. The fracture orientation and density of different types for 10 wells are summarized across the whole area.

Spectroscopy logs, X-ray diffraction (XRD), and X-ray fluorescence (XRF) are combined for vertical mineralogical composition and elemental analysis. Core and thin sections are also used to validate the mineralogical alteration from a microperspective.

Then, the spectroscopy logs and ultrasonic borehole image were first integrated to identify the structural transition boundary (STB) across the area. Finally, the connection between the reservoir quality, fracture network, and lithology was established.

Based on thin sections and spectroscopy logs, fractured or carbonated granite gneiss is attributed to favorable lithology with high porosity, while altered andesite, clayified granite gneiss, and diorite are attributed to unfavorable lithology with low porosity.

Ultrasonic borehole image shows fracture orientation rotated in the STB where main elements (Mg, Si, Al, and Fe) correspondingly change and above which effective (vuggy and open) fractures are mainly developed. The test data shows that high production is in the zonation with more effective fractures and higher porosity.

Linking element change from spectroscopy logs to fractures orientation variation from ultrasonic borehole image logs for structural analysis is a novel perspective to zoom in on the reservoir compared to seismic or outcrops. The reservoir quality and fracture characterization result will aid in making efficient decisions on developmental strategies, including optimization of future well planning and placement.

Fracture Width Characterization by Integrated Analysis of Electrical Image and Acoustic Stoneley Reflectivity

Peter Barrett, Philip Tracadas, and Eglee Lopez, Halliburton

Assessment of fluid conductivity of fractures in interbedded formation types is challenging for resistivity imagers due to non-unique electrical conductivities of fluid and fracture fill. Natural fractures can enhance formation permeability and improve fluid flow; thus, it is important to characterize fracture networks that intersect the borehole and their fluid conductivity for applications such as water disposal, hydrocarbon production, geothermal fluid exchange, or carbon dioxide storage. This case study applies a multisensor workflow to assess fracture fluid conductivity in a large marine sandstone that is used as a water disposal field.

The Ford, West (Wolfcamp) Field in the Delaware Mountain Group, located in Culberson, Texas, consists of mostly sandstones/siltstones interbedded with limestones and organic-rich shales. In many carbonate rocks, fractures can be filled with low-resistivity clay-sized particles. As a result, the electrical borehole image logs may misinterpret such fractures as open fractures. The high-formation resistivity tends to cause borehole images to highlight any conductive materials (such as fine clays) that may be present within the fractures and vugs, which cause potential ambiguity with similar readings from open fractures filled with brine. Traditional methods of calculating fracture aperture, such as Luthi-Souhaite, give an estimate of the aperture but have always been seen as qualitative without a means of calibration. Borehole image logs can identify fracture features with reasonable confidence, but fracture conductivity can only be verified with a pressure test.

In a well drilled with WBM in this field, a microresistivity borehole imager and a sonic tool were logged and used in combination with a formation testing tool and injection rates and pressures to evaluate fluid conductivity of fractures crossing the borehole and to monitor well performance. This paper presents the results based on a new workflow that uses acoustic low-frequency Stoneley waves to characterize natural fractures (their conductivity and borehole washout volume) that intersect the borehole and compares these with the fracture aperture results from the Luthi-Souhaite method. With sonic logging, the Stoneley wave mode is essentially a low-frequency pressure wave traveling along a well's axis. When the Stoneley wave intersects a fluid conductive fracture, pressure is released into the fracture in proportion to the conductivity of the fracture.

Comparison of the direct signal to the secondary Stoneley wave created by this effect gives an estimate of effective fracture width or fluid conductivity by using a wideband frequency inversion model by Kostek et al. (1998). By combining Stoneley fracture analysis with the Luthi-Souhaite fracture computation from high-resolution borehole images, the truly open natural fractures can be characterized and calibrated within a formation while ignoring false signals from washouts, bedding changes, and sealed (not fluid-conductive) fractures.

This methodology can be applied in traditional production scenarios, carbon capture and storage (CCS), or geothermal projects. It provides a way to calibrate the Luthi-Souhaite methodology with wireline data rather than needing core data, saving time and money. It can be effectively applied to existing wells where no core data are available, bringing accuracy to dynamic modeling.

Heterogeneity Index From Acoustic Image Logs and Its Application in Core Samples Representativeness: A Case Study in the Brazilian Presalt Carbonates

Lucas Abreu Blanes de Oliveira and Leonardo Gonçalves, Petrobras

Heterogeneous reservoirs are challenging for petrophysical models based on laboratory analyses. The low representativeness makes models calibrated at the core scale unsuitable for estimating petrophysical properties at the log scale, generating unsatisfactory results. In the case of Brazilian presalt carbonates, complex depositional and diagenetic processes generate a porous medium with vugs, fractures, and caves of various sizes that are rarely appropriately sampled. In intervals with large pores, samples collected will represent the rock matrix, underestimating laboratory measurements such as porosity and permeability. Although most petrophysicists understand the importance of the representativeness of rock samples in their models, techniques to quantify them and guide their use are scarce and usually subjective. Therefore, the present work proposes calculating a heterogeneity index from acoustic image logs to support the choice of representative rock samples based on a case study in the Brazilian presalt carbonates.

First, an investigation depth window is defined, usually related to the vertical resolution of well logs. In this case study, a 1-m window was chosen and applied to the image log. The image window is then divided into two equal-sized parts, and the standard deviation of each part's average image amplitudes is calculated and stored. This process is repeated several times with smaller equal-sized parts until reaching the minimum size, in this case study, defined as four image pixels. Finally, a relationship between the partitioned window's size and the amplitude average's standard deviation is obtained. As the image log is related to the borehole wall, it can approximate the well cylinder, and this partitioned window can be related to a specific sample volume. A function that relates the volume to the standard deviation is then fitted. In homogeneous intervals, the standard deviation of the amplitude averages should show little to no variation as the volume decreases. However, in heterogeneous intervals, the standard deviation would increase as the volume decreases, with a greater rate as heterogeneity increases. Therefore, the slope of the fitted function can be considered a heterogeneity index. Furthermore, it is possible to use the function to estimate a given standard deviation for a volume, indicating the representativeness of a given sample volume.

The heterogeneity index was calculated for the case study well, with 414 1.5-in.-diameter core samples collected. It was used to select samples from homogeneous intervals suitable for calibrating permeability through the Timur-Coates equation. Based on the index, 315 samples were kept in the model, and 99 were considered unsuitable. The R2 coefficient between selected core samples and log porosities increased by 28% compared to the correlation with all samples. Likewise, the permeability R2 increased by 14% after removing unrepresentative samples from heterogeneous intervals. The standard deviation equation per volume in these regions indicated that representative models could only be created with whole core samples.

The present work demonstrated the importance of quantitatively estimating the formation's heterogeneity through image logs.

Quantification of Complex Pore System Using Borehole Resistivity Image Log in Heterogeneous Carbonate Reservoirs From the West Coast of India

Soumya Chandan Panda, Suraj Kumar, Surendra Kumar Prasad, and Yogesh Bahukhandi, Oil and Natural Gas Corporation Ltd, India

The goal of this work is to evaluate and quantify the total porosity contributions (matrix, vugs, connected vugs, resistive, etc.) from high-resolution resistivity image data only in a highly heterogeneous carbonate reservoir from the west coast of India.

The study well was drilled as a horizontal well with a 6-in. drainhole to exploit hydrocarbon. Conventional and FMI logging was carried out in the reservoir section of the well. Image textural analysis is carried out in the well to study the heterogeneity in the complex carbonate reservoir. A static and dynamic image is created using histogram equalization. FILTERSIM, a recent multipoint statistics (MPS) (Zhang, 2006; Hurley and Zhang, 2011), is used to fill gaps in the image and create a full image, which is essential for heterogeneity delineation. The mosaic image is created, which represents the heterogeneities against the matrix (background) image using the grayscale reconstruction transform (Luc, 1993), which removes the features not traversing the image. After creating the mosaic image, heterogeneity delineation is carried out in which step size, value, contrast, and surface proportion of each heterogeneity are computed and represented as curves. Heterogeneity delineation comprises three steps that are heterogeneity analysis, heterogeneity cutoff values, and heterogeneity classification. Heterogeneities are classified manually wherever they are not captured by the algorithm. Finally, the porosity map is generated through the below equation (Newberry et al., 1996), where φ_{GVR} is the computed porosity, φ_{log} is the porosity, R_{LLS} is the shallow resistivity, C_i is the value of the conductivity image, and m is the cementation factor.

$$\varphi_{GVR} = \varphi_{log} \, (R_{LL}\mathrm{s}^* \, \mathrm{C_i})^{1/m}$$

The process produces a set of curves corresponding to the different contributions to the total porosity.

Carbonate reservoirs are highly heterogeneous in terms of porosity, permeability, and facies. Porosity and permeability exhibit a nonlinear relationship in carbonates due to porosity creation and destruction during diagenesis, unlike clastic formations. The results from textural analysis indicate various types of porosity systems where hydrocarbon is deposited in a secondary porosity system (vugs and connected vugs). Porosity partitioning in Well-X against the reservoir interval (XX00 to XX13 m) indicates total porosity of 20 p.u., contributed by isolated vugs (green), connected pores (red), resistive (blue), and matrix (beige) porosity. The pie chart prepared shows the contribution from isolated vugs at 15%, connected pores at 15%, matrix porosity at 50%, and resistive porosity at 20%. The above results are in agreement with the results from the well testing carried out in Well-X, which flowed economical quantities of hydrocarbon. The valuable insight into the porosity distribution in this reservoir will also enhance production during the enhanced oil recovery stage.

Qualitative and quantitative characterization of heterogeneous carbonate reservoirs from resistivity image logs using a novel approach by carrying out porosity partitioning using image textural analysis and providing quantitative evaluation of carbonate porosity system. In the current study, the contribution of isolated vugs (15%) of the total porosity opens doors for enhanced oil recovery after an acid job in the later stages of reservoir development.

Using Image Logs to Characterize and Correlate Mass Transport Deposits in the Bone Spring and Wolfcamp Formations, Delaware Basin

Jarret Borell, Joshua J. O'Brien, and Sloan Anderson, Devon Energy

The purpose of this work is to show an integrated workflow in which image logs can be used to identify and help define the architecture of deepwater mass transport deposits (MTDs) in the Bone Spring and Wolfcamp Formations in the Delaware Basin. Recognition of MTDs (i.e., debris flows, slumps, slides) has implications for reservoir characterization, formation top selection, mapping, and the understanding of facies architecture. This has significance for drilling and completion of horizontal wells in these unconventional targets, especially when the MTD is subseismic or the seismic is poor.

The characterization of MTD features presented involves an integration of more than 10 cores and over 40 image logs. Physical features associated with MTDs on the image log have been calibrated to core using core descriptions, slab photos, and CT imagery. Bedding is characterized from the image logs and separated into the background (normal depositional events) and deformed beds associated with MTDs. Faulting and detachment surfaces are also characterized. Dip patterns identify intervals to further examine for overturned beds, repeated sections, and rafted blocks. These intervals are scrutinized using detailed image logs to verify repeated or overturned facies patterns compared to offset wells or sections of the same well with an undisturbed rock section.

Systematic description of deformation features in core can be integrated with image logs to identify regional MTDs in the subsurface. The results will show examples of MTD features that include matrix material, deformed bedding, bed-scale normal- and reverse-slip faults, folded and overturned bedding, and repeated bedding in core and image logs. Typical bed dip patterns observed in MTDs will be shown along with cross sections illustrating how these patterns can aid correlations and mapping. Figure 1 shows a short cross section with an identified MTD that is up to 250 ft thick and spans 16 miles.

This study builds upon previous work by providing a core-calibrated framework for systematically characterizing bed dips and patterns in MTDs using image logs. When applied regionally, this work has been important to understanding sediment deposits, explaining regional changes in thickness, and informing depositional models and play concepts. Image logs provide clear-cut evidence of deformation that standard log suites do not resolve. Moreover, this work has been integral to understanding depositional settings in the Delaware Basin, where seismic quality is low in comparison to other fields.

SPORSE: EXPERIMENTAL AND DIGITAL CORE ANALYSIS APPLICATIONS IN SUPPORT OF CARBON AND HYDROGEN STORAGE PROJECTS

A Comparative Study to Document the Impact of Cyclical Injection Depletion During Hydrogen Storage in Sandstone Reservoirs Using Digital Core Analysis

Mohamed Sarhan, Lori A. Hathon, and Michael Myers, University of Houston; Alon Arad, Automated Analytics

Integrating renewable energy into the global energy market requires the development of numerous storage sites for both natural gas and hydrogen. Concerning hydrogen storage, siliciclastic reservoirs represent promising candidates. Risks associated with storage in these reservoirs include mineralogic alteration or geomechanical failure due to the cyclic injection/depletion associated with hydrogen storage. Developing predictive models for these situations with standard core analysis can be challenging. Alternatively, combining pre- and post-test pore scale studies using two-dimensional (2D) and three-dimensional (3D) digital rock imaging and image analysis techniques with geomechanical measurements performed on the same rock volume provides a powerful approach to investigating the impact of cyclic injection/depletion cycles on reservoir properties. This paper will investigate four different clastic sedimentary reservoirs for cyclical hydrogen injection/depletion under a range of reservoir conditions.

Three of the tested samples are industry standards: the Castlegate, Boise, and Bentheim Formations. The fourth is a subsurface reservoir, a Miocene sandstone from the Louisiana Gulf of Mexico Shelf province. The measured porosity and permeability for these samples range from 23 to 30% and 600 md to 7 darcies, respectively. Helium will be used as an analog for hydrogen in this study due to its similarity in size to hydrogen and because we focus principally on the physical impact of repeated cycles of injection/depletion on the formation properties. To monitor this impact, a multiscale multidimensional workflow will be deployed.

Pretest samples are imaged using micro-computed tomography (CT) to reconstruct pore/grain geometries and used to numerically simulate physical properties. Because CT data cannot distinguish mineralogy or capture pore/matrix features below the image resolution (3 µm), thin sections are cut from each sample after CT imaging for examination using optical and scanning electron microscopy. By coupling the information from these different imaging modalities, using a newly developed tool for multimodal/multidimensional image registration, a more representative digital rock can be obtained for modeling pore structure, fluid transport, and geomechanical response to multiple injection/depletion cycles. The intended workflow is illustrated in Fig. 1.

Utilizing 2D-image segmentation, numerous characteristics of the pore and grain systems are characterized using Quantitative Petrographic Interpretation (QPI) software for 2D image analysis. Several 2D measures of porosity characteristics are in good agreement with those obtained using 3D imaging. The thin section is registered with the CT volume, allowing mineralogic information to be incorporated into the analysis. We illustrate 3D/3D alignment as well to document each sandstone's physical response and to establish the limits of repeated injection/depletion stresses. Porosity, grain size, compaction state (contact % among grains), cement volume and distribution, and framework grain mineralogy are all observed to be strongly related to the ability of sandstone to undergo repetitive injection/depletion cycles without undergoing failure.

Combining multiscale multidimensional imaging techniques provides a powerful tool for quantifying petrophysical properties. This results in a better understanding of the physical response of multiple cycles of injection and depletion on reservoir quality and, thereby, storage efficiency.

Measuring Time-Scaling Creep in Salt Rocks for Fluid Storage

Talha H. Khan, Gabriel C. Unomah, Michael T. Myers, and Lori Hathon, University of Houston

Salt is an elastoviscoplastic material with low permeability and exhibits time-dependent deformation or creep. Experimental measurements of power law creep behavior in salts help predict the long-term geomechanical behavior of the underground carbon dioxide and hydrogen repositories. Previous geomechanical experiments have focused on the creep axial strain of unconsolidated sands and ductile salt rocks without describing the degree of the creep behavior of radial strain. Time-scaling axial creep has been studied in unconsolidated sands under a uniaxial stress state of constant lateral strain by Dudley et al. (1998). To our knowledge, time-scaling creep of both radial and axial strain has not been investigated in salts. Hence, a comparative testing procedure and analysis method are proposed on twin plugs for different test durations that give a time-independent response. Firstly, the axial and radial strain data of both plugs are shown independent of test duration for salts (time scaling). Secondly, pre- and post-microstructural imaging techniques will visualize and validate resultant compaction strains, crystal dislocation densities, or formation of subgrains for both creep tests.

The tests will be conducted on the triaxial testing apparatus in the University of Houston laboratories. The confining pressure and axial stress will be increased in steps, followed by a hold period during which the axial stress is held constant with constant deviatoric stress. Pre- and post-test thin sections, scanning electron microscopy (SEM), and micro-computed tomography (CT) scan data will be obtained to demonstrate the compaction strain mechanisms.

The stress-strain curves in both twin salts will show strain hardening. There is a predictable power law relationship between strain (radial and axial) with time. The expected creep behavior observed in the salts of both time duration results from increasing dislocation densities of salt crystals and the associated development of subgrains. The axial and radial strain of the different stress paths normalized for time deformation duration will show similar creep behavior, hence displaying time-scaling creep behavior in salts. The microstructural imaging of both salts of varying deformational durations will show compaction strains and the formation of subgrains within the host salt crystals. The temporal scale invariance and power law relationship exhibited by creep behavior in salt are suggestive of self-organized critical systems or fractals.

The experiment provides a means of decoupling the time-dependent behavior from the stress-strain behavior for numerical simulations to predict the long-term geomechanical stability of salts after CO_2 or H_2 injection.

Supercritical CO_2 Storage in Shale Reservoirs: Implications of the Clay Mineral Interactions and Nanoscale Porosity System

Clara Palencia, Benjamin Harrel, and Ahmed Shehata, Intertek

Solar and wind power generation technologies currently do not exist to replace fossil fuels; therefore, long-term underground CO_2 storage is the only practical solution for heavy industries to keep providing energy to the world and simultaneously meet their net-zero commitments by 2040. Geological sequestration (GS) includes depleted oil and gas reservoirs, coalbed methane, shale gas reservoirs, and aquifers. Aquifers have the greatest potential because of their relative abundance, but shale reservoirs are attractive in terms of areal extension, multiple porosity systems, and CO_2 adsorption to shale, which increases their overall storage capability. Unfortunately, there is still a general lack of understanding of CO_2-water-mineralogy interaction, particularly at high-temperature/high-pressure (HTHP) conditions. Additionally, there are inconsistencies among the existing data published in the literature.

Static rock-fluid interaction experiments and high-frequency nuclear magnetic resonance (NMR) core measurements were acquired to evaluate the impact of mineralogy, clay mineral volume, and speciation on the total space available for storage. Three different core samples from shale reservoirs were used in the study, a terrigenous argillaceous (Haynesville Formation), a carbonaceous argillaceous (Eagle Ford), and a siliceous argillaceous sample (Barnett), with the idea of evaluating what kind of shale reservoir is more suitable to store CO_2. In addition, nanopore gas adsorption and mercury injection capillary pressure (MICP) were combined to analyze the full pore spectrum of three different shale gas reservoirs.

High-frequency NMR (24 MHz) T_2 distribution and T_1T_2 maps were acquired in as-received, water-saturated, and post-supercritical CO_2-water-rock exposure to evaluate the evolution of the bound water and the porosity systems. Preliminary results suggest that the bound- and free-water peak position of T_2 distribution spectra of the post-CO_2 injection shifted to the left, indicating an interaction between the CO_2 and both waters that are making hydrogens atoms decay faster. The shift is clay mineral type dependence. From the preliminary results, it is observed that the CO_2 adsorption capacity differs significantly from one shale play to the other, indicating an average of 5 to 10% gain in total porosity when compared to MICP data alone. In the carbonaceous argillaceous mudrock sample, reactions with CO_2 created precipitates, heterogeneities, and unstable conditions for CO_2 storage. The same analysis was performed in cuttings in other to compare results.

These results will not only increase the understanding of CO_2 in clay-bound water systems promoting safety and potential CO_2 storage in clayey sediments but also broaden the knowledge of the positive and negative effects of different shale mineralogy as potential sites for CO_2 storage. This research is an early step to evaluate the impact of maturity, clay content, and microscale and nanoscale fabrics on CO_2 storage or utilization as an enhanced oil recovery (EOR).

A New Workflow for Estimating Reservoir Properties With Gradient Boosting Model and Joint Inversion Using MWD Measurements

Hyungjoo Lee, Andrew Pare, Kenneth McCarthy, Marc Willerth, Paul Reynerson, Tannor Ziehm, Timothy Gee, and Alexander Mitkus, Helmerich & Payne

Triple-combo logs are important measurements for estimating geological, petrophysical, and geomechanical properties. Unfortunately, wireline and advanced LWD logs are typically dropped from the formation evaluation plan for unconventional wells due to economic constraints or borehole instability risks. Available measurements are typically measurement-while-drilling (MWD) natural gamma ray (GR) logs, along with surface measurements such as weight on bit (WOB), rate of penetration (ROP), torque, revolutions per minute (RPM), and differential pressure. The development of a robust and rapid model for predicting reservoir properties using this limited data set would be of high value for geological evaluation. Estimating such properties is a challenging task due to the nonlinear relationship between the available log data and unknown reservoir properties.

A novel workflow is presented that combines two sequential models. First is a machine-learning algorithm to predict triple-combo logs from drilling dynamic measurements and GR logs. To train the machine-learning algorithm, well logs obtained from multiple wells located in the Eagle Ford and Permian Basins are scrutinized to identify important features. This process includes depth shifting, outlier detection, and feature selection, which allows for strategic hyperparameter tuning. Several regression algorithms are investigated, and it is found that gradient boosting algorithms yield superior prediction performance. Unlike commonly used regressors such as random forest methods, boosting algorithms train predictors sequentially, each trying to correct its predecessor. After triple-combo logs are predicted from measurement-while-drilling (MWD) logs, a physics-based joint inversion model is applied to estimate reservoir properties such as total porosity, clay volume, water saturation, volumetric concentrations of lithology, permeability, rock type, and geomechanical parameters.

The trained model is deployed on a blind test well, and the predicted logs show excellent agreement when compared to the corresponding triple-combo measurements. The multimineral inversion using predicted triple-combo logs yields a geologic model that is validated with both mud logs and ECS measurements. Therefore, real-time estimated geological, petrophysical, and geomechanical properties can reveal complex geologic information to mitigate uncertainty related to drilling optimization, reservoir characterization, development plan, and reserve estimate.

Using the MWD logs to predict triple-combo logs followed by a joint inversion is an innovative approach for a geological evaluation with a limited data set. The developed workflow can successfully provide (1) geologic lithofacies identification and rock typing, (2) more confidence in real-time drilling operation, (3) reservoir properties prediction, (4) missing log imputations and pseudo-log generation with forward modeling, (5) guidance for future logging and perforation (6) reference for seismic QI and well tie, and (7) computation time saving from days to minutes.

SPORSE: GEOLOGICAL EVALUATION WHILE DRILLING

Customized Workflow for Proactive Geosteering in Thin Heterogeneous Carbonate Reservoirs Utilizing Deep Resistivity Inversion

Hesham Elmasry, Halliburton; Ahmed Fateh and Abdullah Al-Haji, Aramco

Well placement techniques have been evolving in the past years to improve reservoir exposure and optimize well placement. Although the traditional reactive geosteering methodology in thin reservoirs has improved reservoir exposure, it cannot anticipate sudden dip changes or potential exits.

Thin reservoirs impose significant challenges for well placement to maintain the trajectory in the target zone, avoiding any potential exits. Reservoir exits may complicate completion designs, requiring isolation of specific zones, or may result in lower productivity in the case of exits into a poor-quality reservoir.

A new approach has been adopted, integrating azimuthal deep resistivity inversion and shallow logging-while-drilling (LWD) measurements. The approach optimizes well placement by detecting distant bed boundaries based on their differing characteristics. This approach has provided better insight into the subsurface geology. The methodology incorporates prewell modeling using multiple offset wells. Preplanning is key for optimizing the well placement strategy and tool setup. Based on the available data, the model is updated in real time for improved decision making. The post-well analysis provides crucial data to update the model for future wells and capture the lessons learned from each well.

The new process optimized the landing in thin reservoirs while mapping adjacent layers in the lateral section. The well trajectory was adjusted before any potential exit by mapping the reservoir boundaries and reacting to dip changes utilizing the deep azimuthal sensitivity. The methodology integrated other logs to update the geological model in real time. This has also improved well delivery time and reduced tortuosity by minimizing the number of inclination corrections. The completion design has also been optimized by minimizing the need for any zonal isolation

Proactive geosteering using deep resistivity inversion in thin reservoirs has improved well placement significantly compared to traditional shallow azimuthal measurements. The technology and techniques have been tailored to the reservoir challenge to maximize reservoir exposure, minimize well construction time, and minimize completion cost.

Improving Well Placement and Reservoir Mapping Using Multi-Interval Inversion of Deep and Extra-Deep LWD Resistivity Measurements

Darya Andornaya, Yuriy Antonov, Kjeld Ghysels, Elena Konobriy, and Sergey Martakov, Baker Hughes; Kåre Røsvik Jensen, Equinor

Deep and extra-deep logging-while-drilling (LWD) resistivity measurements are commonly used in the well construction phase to land and navigate within complex geology. The measurements' complexity often prohibits their visual interpretation for steering decisions. Such decisions are made after data inversion and based on the two-dimensional (2D) or three-dimensional (3D) visualizations of resulting inversion models (or pictures).

While the main objective of inversion is achieving a good match between measured and simulated data, its result is a resistivity model that is used for geological interpretation. To deliver a high-confidence interpretation, many important considerations impacting the inversion result have to be addressed, such as accuracy, uncertainty, geological sense, etc.

In this paper, we present a goal-oriented approach where one-dimensional (1D) inversion with lateral regularization is run on several data intervals simultaneously. The algorithm can balance both data match and model continuity, delivering geologically meaningful models.

The inversion algorithm is generic enough to accommodate any set of measurements with arbitrary weight settings enabling goal-oriented (multiresolution) inversion. Having deep and extra-deep measurements available in the same well, it is reasonable to run multi-interval inversion on the former for near-wellbore analysis or the latter for large-scale reservoir mapping.

The developed algorithm delivers more geologically robust resistivity models with improved lateral continuity of layers' resistivity, thickness, and boundary positions. The level of additional lateral regularization between models can be controlled by a user based on available knowledge about geology or preconfigured for automated execution. Further QC of data match and tool sensitivity ranges helps to understand the validity of features mapped in the inversion results.

In summary, the paper focuses on the analysis of the quality of the inversion result and the reliability of interpretation, covering aspects of

- Lateral continuity vs. data misfit
- Parametric models vs. picture
- Confidence in geological interpretation vs. depth of detection
- Real-time vs. pre- and post-well processing
- Tuning for a particular application vs. general black-box approach

We developed a new data inversion algorithm for the deep and extra-deep resistivity tools. The approach delivers laterally consistent resistivity models without compromising data match. In cases of sharp structural changes such as faults, it also may be used as an indicator for intervals better suitable for 2D/3D processing. At the same time, the resulting model preserves quantitative parameters (boundaries, resistivity/anisotropy values, dip) for interpretation and allows the estimation of confidence for those parameters.

The robustness of the method is demonstrated on synthetic benchmarks and field data from the North Sea.

Limits of 3D Detectability and Resolution of LWD Deep-Sensing Borehole Electromagnetic Measurements Acquired in the Norwegian Continental Shelf

Nazanin Jahani, NORCE Norwegian Research Centre; Carlos Torres-Verdín and Junsheng Hou, The University of Texas at Austin; Jan Tveranger, NORCE Norwegian Research Centre

Hydrocarbons are often found in three-dimensional (3D) and non-spatially continuous rock formations that exhibit electrical anisotropy. A real-time well geosteering method that adjusts the well trajectory based on the inversion of deep-sensing electromagnetic (EM) measurements can be effective for efficient subsurface resource recovery. Nevertheless, the inversion may lead to uncertain spatial resistivity images of formations around and ahead of the well trajectory, which can cause incorrect geological interpretations and fatal geosteering decisions. Therefore, it becomes imperative to quantify the uncertainty of the inversion results in real time. The limited spatial resolution of borehole EM instruments is a key source of uncertainty. Our primary objective is to quantify (a) the maximum radial distance of detection away from the well trajectory and (b) the spatial resolution of 3D subsurface targets for a commercially available triaxial deep-sensing borehole EM instrument operating in the Norwegian Continental Shelf with respect to (a) measurement acquisition parameters, (b) distance between the well trajectory and the targets, and (c) embedding geological environments.

First, we constructed several synthetic cases, including geological targets with varying resistivity contrast, varying radial distances from the borehole EM instrument, and varying measurement acquisition parameters. Next, we adapted our study to a geological formation stemming from actual 3D geosteering conditions present in the Norwegian Continental Shelf. We implemented a finite-volume method to numerically solve Maxwell’s equations for 3D electrically anisotropic heterogeneous rock formations. Measurement noise was assumed zero-mean 2% Gaussian. Magnetic fields were calculated as the percent difference between measurements acquired for formations with and without high-resistivity contrast targets. Additionally, we assumed that the borehole EM instrument could reliably detect targets if the latter percent measurement difference exceeded the threshold for measurement noise.

There are several factors that limit the distance to which borehole EM measurements can accurately resolve 3D targets, such as resistivity contrast with the background formation, electrical anisotropy of both background formation and embedded targets, measurement noise, frequency of operation, and distance between transmitters and receivers. We found that low-frequency borehole EM measurements can resolve conductive targets at relatively long radial distances from the wellbore, whereas high-frequency measurements can resolve resistive targets relatively far from the well trajectory. In addition, high-conductivity contrasts between the target and background yield a more accurate definition of the target location away from the well trajectory. Likewise, a higher electrical anisotropy factor for the background formation makes it more difficult to resolve conductive targets. Based on the results obtained from the synthetic study, we interpreted a 3D resistivity image which was generated from the inversion of EM measurements acquired across a turbidite formation on the Norwegian Continental Shelf. We found that the uncertainty of inversion results correlates with both the resolution of the borehole EM instrument and its range of detectability. We also define the geometrical shape and resistivity accurately in locations with reliable EM measurement resolution. Estimation of uncertainty in our study can enhance the accuracy of both geological interpretation and real-time 3D well geosteering.

Despite several publications proposing the detectable range of borehole EM instruments, no study has considered the radial range of detectability in a 3D geological environment with electrical anisotropy. We generalized the detectability range and resolution of borehole EM instruments as a function of skin depth and transmitter-receiver spacing. Our findings are used to quantify the uncertainty associated with inverted borehole EM measurements acquired in a complex turbidite formation on the Norwegian Continental Shelf.

Reservoir Connectivity Characterization and Controlling Factor Analysis by Advanced Logging-While-Drilling Electrical Image Data and MDT Data for Offshore Sandy Conglomerate Reservoirs

Yunjiang Cui, Lei Xiong, and Peichun Wang, CNOOC China Limited, Tianjin Branch; Fangfang Wu, SLB, Ruihong Wang, CNOOC China Limited, Tianjin Branch; Shenzhuan Li, Xianran Zhao, Jinlong Wu, Hongjie Gong, and Xin Zhou, SLB

The sandy conglomerate reservoir has a wide distribution in the Bahai Bay Basin, which has become one of the most important exploration targets. However, the characterization of reservoir connectivity is quite difficult due to strong reservoir heterogeneity and complex logging responses of conventional logs. To identify the characteristics of good connectivity reservoirs, advanced logging-while-drilling (LWD) electrical image data and modular formation dynamic tester (MDT) data were integrated, and the controlling factors were investigated.

First, based on LWD electrical image data as well as conventional logs, the lithology, including shale, siltstone, fine sandstone, gravel-bearing sandstone, and conglomerate, was identified. Second, formation beddings, cross beddings, fractures, and faults were identified and classified based on the LWD electrical images. Third, the resistivity spectrum, grain size, and sorting index were obtained quantitatively to characterize the reservoir. And innovatively, gravels were extracted using the image segmentation method, and gravel concentration and gravel size were computed. Finally, the characteristics of tight reservoirs and effective reservoirs were summarized by combining the MDT data, and the controlling factors of reservoir connectivity were concluded.

The heterogeneity of sandy conglomerate in Bohai Bay Basin can be well characterized by the resistivity spectrum; the stronger the heterogeneity, the wider the resistivity spectrum, and the greater the sorting index. The resistivity spectrum was divided into four parts according to resistivity ranges. Generally, the greater the high-resistivity part, the more gravel content there is; the greater the low-resistivity part, the more clay content there is.

There were a total of 49 MDT results, and 16 of which were tight reservoirs due to calcareous cementation or high clay content. Calcareous cementation was characterized by a wide resistivity spectrum, more high resistivity part, high sorting index, and high bulk density. High clay content was characterized by more low resistivity part and high or medium gamma rays. Calcareous cementation was caused by diagenesis, and high clay content resulted from deposition. Both made the reservoir connectivity poor with low permeability.

There were 26 MDT results with high mobility, which were normally located at gravel-bearing sandstone and conglomerate layers. These points can be characterized by a relatively narrow resistivity spectrum, more high resistivity part, less low resistivity part, medium gravel content, medium to fine gravel size, and relatively low sorting index. Calcareous cementation and clay content have a negative influence on reservoir connectivity, while sorting, gravel content, and gravel size have a relatively positive influence on reservoir connectivity.

Without knowing the controlling factors, it is difficult to choose the proper depth for MDT to avoid tight and invalid results. The achievements have dramatically improved the geological understanding of the reservoir and provided valuable information for MDT point selection and deployment of new wells, especially for horizontal wells.

Risk Reduction in the Derivation of While-Drilling Wellbore Geomechanical Properties by Utilization of Real-Time Surface Logging and Gamma Ray Data Through the Application of Machine-Learning Techniques to Pre-Existing Data Sets

Jalal Dashti, Jarrah Al-Jenaie, Bader Al-Ajmi, and Othman Matar, Kuwait Oil Company; Ahmad Shoeibi, Ivo Colombo, Federica Lupone, and Eliana R. Russo, Geolog Technologies

The understanding of geomechanical parameters is fundamental in addressing several issues related to drilling and reservoir characterization, such as borehole stability, hydraulic fracturing design, and reservoir simulation. The geomechanical parameters are usually calculated from sonic and density well logs. However, these logs may not always be available, especially in highly deviated and horizontal wells, for either technical or economic reasons. Conversely, surface logging is present during drilling operations most of the time, especially for safety reasons, and the drilling parameters collected are rarely used in the geomechanical characterization of the subsurface.

The aim of this work is the development of a fast and reliable method for geomechanical parameters evaluation using surface logging data (weight on bit (WOB), rate of penetration (ROP), torque, rotation per minute (RPM), standpipe pressure) and well-log data (gamma ray (GR) log, sonic log, bulk density log). Moreover, a flexible workflow has been developed to derive the GR data from X-ray fluorescence (XRF) analysis of cuttings via the computation of a chemical gamma ray (CGR) in case of failure of the downhole tools.

The presented methodology embeds different machine-learning algorithms, such as random forest, XGBoost, and support vector regression, to derive Young’s modulus, uniaxial compressive strength, Poisson’s ratio, bulk modulus, shear modulus, and seismic velocities V_p and V_s, hereinafter simply named geomechanical parameters. The machine-learning models are trained and tested on data coming from 11 wells drilled in the same geological units but in different fields in Kuwait. During the train and validation phase, the drilling parameters are combined with GR, sonic, and bulk density logs of 10 wells to compute the geomechanical parameters using the empirical relationships available in the literature. The model is then tested against data coming from an unseen well (blind test) to predict the geomechanical parameters using only the drilling data and GR log.

The results demonstrate that the model trained with drilling parameters and well-log data from wells drilled in different fields is able to predict the geomechanical properties of a new well in the same geological units. These outcomes highlight the potential value of this procedure and highlight several implications for reservoir characterization, e.g., enabling detection of zones of potential borehole instability and computing the proper mud-weight window, and also in the completion phase, providing valuable geomechanical information, e.g., identification of potential fracture intervals and estimation of in-situ stress.

This approach also represents a cost-effective method to obtain geomechanical parameters reducing the requirement of sonic and density logs in newly drilled wells. Once the model has been trained, it is possible to predict the geomechanical parameters in newly drilled wells using only surface logging data and GR log, obtaining the results in real time, quasi-real time, and post-drilling phase. In addition, the GR data can be either from downhole tools or derived from XRF analysis of cuttings, allowing this methodology to also be a viable and supportive backup where downhole logs are present and a reliable alternative when they are not.

SPORSE: MONITORING AND VERIFICATION OF CONTAINMENT IN CCUS PROJECTS

CCUS Plume Monitoring: Verifying Surface CSEM Measurements to Log Scale

Kurt Strack, KMS Technologies; Cesar Barajas-Olalde, EERC-University of North Dakota; Sophia Davydycheva and Yardenia Martinez, KMS Technologies

In carbon capture, utilization, and storage (CCUS) monitoring, dynamic plume monitoring and reservoir seal are key issues. Plume monitoring is best addressed with electromagnetics (sensitive to the resistivity contrast) and reservoir leakage with microseismics. A case history from North Dakota illustrates how we can tie surface-controlled source electromagnetic (CSEM) measurements to the three-dimensional (3D) anisotropic models derived from the available logs. This allows us to certify baseline measurements within the context of the borehole information.

The key to this workflow is to derive a 3D anisotropic model from the logs that include all the log responses and lithology. An initial 3D modeling feasibility has in-field noise measurements to determine the best survey operational parameters based on expected fluid substitution models and noise levels. For the acquisition, careful instrument calibration and verification of all acquisition parameters are essential. Concurrent with the acquisition, a near-real-time quality assurance is carried out, which includes the results in a feedback verification loop to influence the data quality of the acquisition positively.

With this process, we are able to define the length of acquisition time that yields sufficiently good data quality that can then be used for unsupervised inversion. The only influencing component in the inversion is the data weights derived from the repeated measurements (stacking weight). The resulting sensitivities show us that the data are sensitive in our case history (North Dakota) to a depth of 3,000 m. We carried out magnetotelluric and CSEM measurements. All data are consistent and match the 3D response of the anisotropic electrical log as well as the seismic section available in the area. The entire process is data-driven with minimum human interaction or inclusion of model assumptions.

Achieving log scale resolution from surface measurements is a significant breakthrough, and thus, we are able to verify baseline measurement before we actually do the repeat measurement and, based on the results, further fine-tune the repeat survey.

Molecular-Scale Quantitative Evaluation of the Competitive Adsorption of Methane and Carbon Dioxide on the Different Constituents of Organic-Rich Mudrocks

Ibrahim Gomaa, Zoya Heidari, and D. Nicolas Espinoza, The University of Texas at Austin

Carbon dioxide (CO_2) and methane (CH_4) adsorption in organic-rich mudrocks can significantly be affected by clay minerals and kerogen as dominant components of the rock. Previous publications have explored the adsorption of CH_4 and CO_2 on kerogen and clay structures separately and overlooked their competitive adsorption behavior on the molecular scale. The objectives of this paper are to (a) evaluate the CH_4 and CO_2 adsorption capacity of different kerogen types and thermal maturity levels under reservoir pressure and temperature, (b) evaluate the CH_4 and CO_2 adsorption capacity of illite and kaolinite with different pore structure, and finally (c) improve the conventional Langmuir adsorption models to account for the competitive adsorption of CH_4 and CO_2 within the different components of organic-rich mudrocks.

We used realistic kerogen molecular models that were condensed and optimized to mimic the actual kerogen structures. Kerogen molecules of different types (e.g., type I, II, and III) and different thermal maturity levels were transformed into dense porous structures through an annealing process. Meanwhile, illite and kaolinite samples were modeled, honoring their chemical composition, surface charges, and pore size. We then performed Grand Canonical Monte Carlo (GCMC) simulations to evaluate the CH_4 and CO_2 adsorption isotherms for kerogen and clay structures. To investigate the effect of reservoir temperature on the adsorption capacity, adsorption isotherms were constructed for a pressure range of 1 to 20 MPa under temperatures of 300, 330, and 360 K. The change of gas adsorbate density along with atomic radial distribution function (RDF) was evaluated to quantify the interfacial interactions between the gases and the adsorbent surface. Moreover, the diffusion coefficients of CH_4 and CO_2 were calculated for the simulated kerogen and clay structures.

Results showed that the available pore volume for kerogen type III was found to be twice as much as kerogen type I. This is a result of the increase in the kerogen aromaticity from 29% for kerogen type I to about 57% for kerogen type III. In addition, increasing thermal maturity from kerogen type IIA through type IID led to an increase in the available pore volume and kerogen aromaticity by 50% and 92.6%, respectively. These changes in the kerogen geochemistry and pore structure led to variations in the adsorption capacity for both CH_4 and CO_2. Meanwhile, The CH_4 and CO_2 adsorption capacity values of illite and kaolinite were much lower than that of kerogen molecules. Pore size and surface area in clay minerals were proven to be the main controlling factor in determining the clay adsorption capacity for the tested gases. However, the negatively charged illite samples showed more adsorption affinity to the polar CO_2 molecules than the nonpolar CH_4 molecules.

The proposed methods improve the conventional Langmuir adsorption models of organic-rich mudrocks that used kerogen as the only adsorbent component. Moreover, the improved adsorption models can be used as guidelines for enhanced gas recovery or CO_2 sequestration applications in organic-rich mudrock. This also can be extended to different formations where both kerogen and clay particles may coexist.

On the Nature of CO_2/Brine Mixing in Assessing the Feasibility of CCS Monitoring

Kristoffer Walker, Alexei Bolshakov, Hermes Malcotti, Lei Wei, and Artur Posenato Garcia, Chevron

Carbon capture and sequestration (CCS) is becoming an important topic as the world searches for ways to reduce atmospheric CO_2 emissions and mitigate global warming. Two of the most important tasks in CCS are monitoring the capacity of the injection reservoir and detecting leaks through the overlying seal. Time-lapse surface seismic and vertical seismic profiling (VSP) are fit-for-purpose technologies for these tasks only if the reservoir rock physics model and nature of pore fluid mixing have been determined and are accurate. The objective of this presentation is to demonstrate the importance of using borehole acoustics, lab measurements, and other petrophysical logs in observation wells close to injection wells to provide this information and enable these monitoring technologies to be successful.

The detectability of time-lapse signatures and the importance of measuring the fluid mixing model is investigated by creating synthetic data. Simulations of flow and pressure diffusion are combined with rock physics, borehole acoustic wavefield modeling, and synthetic seismogram modeling to predict the realizable saturation and pore pressure changes due to CO_2 injection for different scenarios. A workflow is presented to quantify the nature of pore fluid mixing and subsequent sensitivity thresholds for changes in saturation and pressure.

We find that the degree of “patchiness,” which quantifies the nature of CO_2 brine mixing and represents the continuum between a Reuss average for uniform mixing to a Voigt average for pure random mixing, determines not only the sensitivity level of seismic and VSP to saturation but also if seismic and VSP will even be useful or not for saturation quantification. The patchiness of a reservoir is often overlooked, and it can only be quantified via time-lapse acoustic monitoring of compressional and shear velocities, CO_2 saturation with pulsed-neutron logging, and pore pressure with cemented pressure gauges in the observing wells during the process of CO_2 breakthrough. Because patchiness has fractal characteristics between seismic and borehole acoustic scales, its measurements can be applied to seismic scales. Of equal importance to patchiness is the dry frame moduli, which are established from a quad-combo log and core measurements prior to injection. A customary practice is to measure at lab scales both bulk and shear moduli of representative core samples under various confining pressures to derive the dry frame moduli and measured moduli at log scales to extend the ground-truth measurements vertically to seismic scales. Lastly, we find that steel casing does not impede the ability of wireline acoustic tools to measure both compressional (V_p) and shear velocities (V_s) correctly to accuracies within ±2%.

This paper demonstrates for the first time the importance of using both time-lapse borehole acoustics and pulsed-neutron logging in an observing well during CO_2 breakthrough to quantify the style of CO_2/brine mixing. This information enables one to assess the feasibility of using time-lapse seismic/VSP for saturation monitoring and, when it is deemed feasible, to quantify CO_2 saturation.

The Effective Diagnostic Capability of Pulsed-Neutron Logging for CCS Monitoring Purposes

Saida Machicote, Marco Pirrone, and Simone De Lisio, Eni SPA

The actual importance of carbon capture and storage (CCS) projects requires in-depth studies on several disciplines. In particular, measurement, monitoring, and verification (MMV) plans include critical activities at the so-called spy wells for the proper understanding of carbon dioxide (CO_2) plume development far from the injectors. In this respect, time-lapse pulsed-neutron logging (PNL) represents a mainstay for the quantitative evaluation of fluid saturation changes behind casing. However, the latter task may not be straightforward in case CO_2 injection is performed into depleted gas reservoirs. This paper deals with a deep study to evaluate the diagnostic capability of various PNL measurements for fluid identification and saturation monitoring purposes in CCS projects.

First, accurate analytical and numerical modeling of typical PNL responses of mixtures of water, reservoir gas (methane or others), and CO_2 has been performed. These include fast neutron interactions, inelastic/elastic scatterings, and capture, together with their dependence on pressure, temperature, and acquisition environment. The outcomes of the first step lay the groundwork for the definition of the most effective PNL interpretation approach, as appropriate. In detail, after the selection of fit-for-purpose curves and their physics-based models, a joint inversion is performed to reconcile models and actual measurements in order to solve for water saturation, reservoir gas, and CO_2 fractions in selected cases. The uncertainty of the outputs is also quantified by means of an ad-hoc Monte Carlo approach, starting from the standard uncertainties of the input PNL data.

In turn, two real case studies are presented. The first is a depleted gas reservoir characterized by multiple layers hydraulically separated and with aquifers of different strengths. The second is more homogeneous from the lithological standpoint, but it is highly depleted since no strong aquifer has provided pressure support during the development phase. For both, baseline PNL acquisitions have been performed in spy wells to fix the water saturation scenarios before CO_2 injection and to calibrate the PNL model parameters. Then, several simulations of PNL response have been performed in order to forecast the deviation from the acquired baselines, according to the possible arrival of plumes composed by reservoir gas-CO_2 mixtures with different relative concentrations, in case displacing different amounts of water volume fractions and at different pressure and temperature regimes. The driver for the selection of the above scenarios is the dynamic behavior during injection obtained from the available dynamic reservoir models. Therefore, random errors have been generated for the simulated PNL curves to be used for the subsequent uncertainty quantification in obtaining the desired water saturation and reservoir gas-CO_2 relative concentrations, mimicking future time-lapse interpretations. The latter represents a useful template to understand the real PNL monitoring capability in such environments and the best subset of neutron interactions to exploit for the purpose.

The presented workflow provides robust insights on when and how much PNL monitoring is effective in a given CCS project. This information is fundamental for the MMV plan to schedule the proper time-lapse PNL campaign.

Time-Lapse Pulsed-Neutron Logs for CCS: What Have We Learned From All These Monitoring Runs?

Robert Laronga, SLB

Pulsed-neutron logs are a staple of time-lapse monitoring programs for saline-aquifer carbon capture and storage (CCS) projects and are unsurprisingly the most frequently run wireline log in both injection and monitoring wells. While the emphasis imposed by government regulators and the focus of operators to date has been on the verification of CO_2 containment, it is envisioned that a savvy interpretation of the multiple independent measurements should be able to unlock much greater value for the project than merely detecting the location of stored CO_2. Recently introduced capabilities for novel measurements and improved environmental compensation should further increase the repeatability, interpretability, and value of these logs.

We reviewed more than 30 time-lapse pulsed-neutron logs acquired over a period of 15 years on mature CCS projects using both standard and new-generation pulsed-neutron tools, including measurements of formation sigma, hydrogen index, and fast neutron cross section. Special attention in processing is required when changes occur to the wellbore environment between runs, although this is mitigated by the improved environmental compensation scheme of the newer tool. We performed both standalone estimates of CO_2 saturation from single-physics time-lapse measurements and simultaneous interpretation of multiple independent time-lapse measurements and studied the results side-by-side with openhole log interpretation, core analysis, and well-test results from the evaluation phase. The apparent changes in saturation were framed within the context of the injection history and important events in the life of the wells.

A first finding is that differences in apparent CO_2 saturation between the various independent measurement physics of the pulsed-neutron tool are often reconcilable and may carry additional information about the state of the well or reservoir. With respect to verification of containment, depending on the well configuration, it may be possible to differentiate between CO_2 in the formation and CO_2 in the annulus. The interpreted CO_2 saturation itself can have different significance depending on the timing of acquisition and the type of well. Measured at the right time, it is a direct in-situ measurement of e_{CO2}, the formation CO_2 storage efficiency. In other cases, the interpretation reveals formation dry-out in the near wellbore region of injection wells, a condition that may presage loss of injectivity. We now understand that it is important for operators to plan the timing and frequency of pulsed-neutron runs according to what they want to measure and not based solely on regulatory obligations.

In a CCS project, time-lapse pulsed-neutron logs should be thought of as much more than simple indicators of the presence and migration of CO_2. They give important information about migration pathways. But they can also help to quantify essential uncertainties on reservoir performance that are difficult to ascertain during evaluation. For example, e_{CO2} is notoriously difficult to quantify with openhole logs since the formation is initially at zero CO_2 saturation. Yet it is one of the keys to determining the ultimate storage capacity of any reservoir. Time-lapse pulsed-neutron logs provide an abundance of information that, if properly history matched, can go a long way toward improving our models of CCS reservoirs to better navigate both the economic and operational risks associated with these projects.

SPORSE: NEW LANDSCAPE OF MUD GAS LOGGING – GEOSCIENCE MEETS ENGINEERING

A Simple Approach Using Standard Mud Gas Data to Distinguish Oil and Gas Zones in Depleted Reservoirs

Tao Yang, Alexandra Cely, Nan Cheng, Sandrine Donnadieu, and Marianne Iversen, Equinor

For production wells in depleted reservoirs, identifying the oil and gas zones for completion is a long-lasting challenge. This is not because the conventional logging-while-drilling tools are not working but due to the increased complexity of the reservoir fluids under depleted conditions. In this scenario, the reservoir fluids are no longer in single-phase but in two-phase conditions due to released gas from reservoir oil or displacement of reservoir fluids because of aquifer movement during production. There is a strong business need for an accurate fluid-typing solution without additional data acquisition.

We use a field example to demonstrate a new method based on the standard mud gas data. The Troll Field is a giant gas field with a thin oil zone on the Norwegian Continental Shelf. Before gas blowdown, horizontal drilling has been extensively used in the field to produce the thin oil zone. The effort has been a great success story until recent years. A wide density-neutron log porosity separation is often observed in many places along the horizontal sections of the production wells. Following the classic interpretation, these sections are regarded as “gas zones” even if quantifying the amount of gas (free or residual) is challenging. Such interpretation leads to multiple zones of the production well not being completed due to the concern of gas breakthrough. However, are these “gas zones” really filled with free gas, or could most of them be filled with oil?

After investigating the reservoir fluid database from the field, we found that the component ratio methane to ethane (C1/C2) has a large difference between reservoir oil samples and reservoir gas samples. Water-based mud was used for the field, and the standard mud gas composition (methane to propane) agrees well with reservoir fluid samples. Therefore, we proposed using the simple ratio of C1/C2 as the reservoir oil or gas indicator. The reservoir fluid database from the field defined the C1/C2 threshold to distinguish reservoir oil from gas. We deployed a compositional reservoir simulation model and cuttings analysis to verify the robustness of the new method. Good agreements were achieved among different methods, supporting the simple ratio approach. After implementing the new method, many questionable “gas zones” are now interpreted as oil zones, which become production candidates.

Standard mud gas is widely available for all wells and does not require additional data acquisition costs. The simple approach using standard mud gas data provides a cost-efficient and reliable method to distinguish reservoir oil and gas in depleted reservoirs. The new method is not sensitive to a small amount of released gas or trapped gas in the reservoirs and provides the opportunity to complete more oil zones for production. With increased activities in producing matured fields, the business value of the new method is significant.

Evaluation of PVT Comparisons and GOR Prediction Based on Advanced Mud Gas Data: A Case Study From Snorre Field

Priscila Furghieri Bylaardt Caldas and George Kirkman, Halliburton

This study shows the application of real-time advanced mud gas (AMG) to characterize reservoir fluid and a comparison to production results on the Snorre Field. The AMG is corrected for the efficiency of extraction, and its results generate a comparison to pressure-volume-temperature (PVT) samples from the field. Furthermore, machine learning is demonstrated to contribute to real-time petrophysical and operational decisions.

The field of surface data logging has used AMG in real time for over a decade. For this study, a constant volume, constant temperature (heated) mud gas extractor was used. To account for the unique efficiency of gas extraction for each species of interest, an extraction efficiency correction (EEC) method was applied. The EEC method provides in real time the quantitative composition of formation fluid through analysis of the methane through pentane components. These results are comparable to downhole PVT samples and have been used to optimize wireline tool runs and fluid sampling programs over the years.

The consistent dynamic EEC data provided from AMG are demonstrated to successfully distinguish the types of fluids as compared to PVT samples in the Snorre Field. These data are presented as continuous logs, which allow for the evaluation of the thickness of reservoir zones. This information is available while drilling, and with modern real-time data services, operators can access it from almost anywhere. The gas-oil ratio (GOR) prediction results are compared to GOR production, showing acceptable accuracy for data collected while drilling. The promising results generate confidence in the application of quality AMG data to development wells for real-time petrophysical and operational decisions.

The field case demonstrates a new and broad application area for AMG in production wells using EEC results to compare to PVT and GOR prediction of the Snorre field with later production analysis.

Operationalization of Advanced Mud Gas Logging in Development Drilling: Examples From the Recent HPHT Infill Campaign in the Central North Sea

Maneesh Pisharat, SLB; Sadat Kolonic, Josef Schachner, Richard Shipp, Hemmo Bosscher, Pim Van Bergen, and Olaf Podlaha, Shell Exploration & Production Company

Standard mud gas logging has served the drill-engineering discipline foremost in executing safe well delivery. Additional subsurface insights are often considered less important when commissioning this service. Consequently, standard mud gas (SMG) logging remains routine despite the advances in quantifiable advanced mud gas (AMG) logging capability. Such advances make it more operationally feasible to deploy AMG and thereby markedly enhance the acquired subsurface insights. This was demonstrated during a recent high-pressure/high-temperature (HPHT) infill campaign in the Central North Sea (CNS).

Wells targeting deep Jurassic formations have used AMG technology for continuous compositional analysis while drilling. For a mature field experiencing production-related changes to reservoir fluid, the main objective of collecting AMG data is to aid early assessment of downhole hydrocarbon variability. Operationally this is being performed while drilling in liner (DIL) and in the absence of logging while drilling (LWD). For example, identifying reservoir tops, fluid dissimilarities, and an independent saturation flag is critical operational information. These help to guide decisions on completion strategy and logging behind casing, which in turn aids rig time optimization and offsets the deployment costs.

Post-drill systematic integration with other geochemistry data (e.g., gas isotopes, mineralogy, and kerogen compositions) and independent petrophysical techniques (such as triple combo) enables the identification of possible missed pay zones furthermore. Once the “field” is calibrated, the AMG data increase fluid phase interpretation confidence in support of near-time operational decisions and overall reservoir management. An example is the confirmation of new flow unit contributors to perforations for future well interventions/abandonment consideration. Further value upside and differentiation are achieved by collecting the AMG data across the overburdened chalk. The latter provided the first-time in-field granularity on chalk fluid facies, reservoir architecture, and connectivity.

In addition, we highlight the added value of information, practical applicability, and consideration for future ultradeep HPHT developments. We advocate the increasing feasibility and appropriateness of progressing AMG to a more routine deployment state in similar field settings and beyond.

In the medium term, the quantitative mud gas records acquired by continuous physical sampling may further improve our understanding of vertical fluid evolution in the present-day overburden. Understanding this deep subsurface sediment-(hydro)carbon, i.e., rock-fluid interactions, offers additional potential subsurface solutions. Effects such as active cycling of carbon-bearing phases during fluid migration under post-burial prereservoir conditions could be addressed. These remain challenging in carbon capture underground storage (CCUS) project implementation.

1. Support collection of AMG data in a brownfield to aid early assessment of downhole hydrocarbon fingerprinting while DIL and in the absence of LWD log in the HPHT environment
2. Support the identification of wellbore breathing, reservoir tops, fluid properties, and independent saturation flag to aid decisions on completion strategy and behind-the-casing logging
3. Assessment of chalk fluid facies, reservoir architecture, and connectivity in the field

AMG samples the mud at the surface, extracts light hydrocarbon, and quantifies the composition. Three data processing steps convert measured hydrocarbon into gas volume per unit of rock drilled. They are corrected for extractor response, contamination, and volume changes due to variations in drilling parameters. The corrected data are used for compositional analysis, identification of pay zones, and deriving saturation flags.

AMG has proven to be a pragmatic, independent additional fluid assessment technology tool during this infill campaign. It carried low operational risk compared to downhole logging/sampling in HPHT. It has proven an inexpensive methodology to maximize data acquisition outside the primary reservoir objective at a minimum cost. Hence the recommendation is to employ this technology as standard with additional benefits in the absence of not being able to acquire logging data.

Systematic and routine AMG in a mature field development drilling may thus far prove to be a means of an inexpensive pseudo-production logging tool (PLT) analyzing dynamic filed performance and determining the zonal contribution (in case of co-mingled stacked sands or multiple pays or swept zones) in the total production. Detecting fluid (dis)similarities and linking these to subseismic faulting or juxtaposition would further allow corroborating 4D seismic interpretations and aid infill drilling strategy.

Furthermore, amendments to well trajectory/well placement for improved sweeping efficiency, section TDs/casing shoe depth (gas cap expansion), completions, or front-end design are some examples of effective mitigation of downside risk contribution through improved fluid understanding from AMG if deployed routinely on infill wells.

Reducing Uncertainties and Improving Hydrocarbon Recovery in Brownfields Through an Innovative Integrated Workflow

Boudiba Younes, Maneesh Pisharat, and Mohammed Kelkouli, SLB; Ferhat Nettari, Nordin Meddour, and Bilal Seddar, Groupement Berkine; Reda Adam Bebbouchi and Abdelhakim Berbra, SLB

In producing fields, remapping reservoir fluid content and new contacts are one of the most important objectives in pursuit of optimized well productivity. Wireline logs and formation testing (FT) data are widely used for this purpose. Continuous fluid data from advanced mud gas (AMG) analysis with downhole logs can be used to generate a comprehensive data set for reservoir evaluation. Each method has its limitation and advantage. Combining and interpreting the output from fundamentally different data sets require an experienced petro-technical expert with specific skill sets.

To calculate hydrocarbon volume and estimate and forecast reserves, formation fluid evaluation has primarily relied on a traditional method that depends heavily on formation pressure measurements. This was achieved through the analysis of gradients and local fluid contacts. This approach can be misleading for brownfields, where a sizable amount of producible hydrocarbon is left in the reservoir.

For characterizing formation fluid, a novel approach utilizing complimentary technologies was adopted. For early hydrocarbon detection and FT program optimization, AMG data were first gathered while drilling. Post-drilling openhole logs, formation pressure, and fluid data were acquired not only to verify the AMG findings but also to fill in the gaps regarding water-swept zones, reservoir pressure and depletion, exact fluid contacts, and fluid characteristics to reduce uncertainties.

During the job execution, AMG data were effectively used to provide early formation fluid identification and contacts. This information was used to optimize the wireline advanced fluid analysis stations. AMG analysis identified multiple fluids (wet gas, gas condensate, oil and water) and revealed a much greater complexity of the reservoir, which could not be achieved with standard formation evaluation or other fluid contact identification techniques based on regional gradient analysis. The fluid types and contacts identified by AMG were then confirmed by the wireline downhole fluid analysis. Using this workflow, a high-potential recoverable hydrocarbon oil was identified over a reservoir that was classified as a water zone based on initial evaluation and knowledge.

In this field, an innovative method was adopted for reservoir fluid characterization. This approach, based on digital integration and a unified workflow, was used successfully for fluid contact identification, targeted fluid sampling, and identifying and recovering more hydrocarbon from the swept zones.

Utilization of Mud Gas Logging to Map Reservoir Oil Viscosity – A Case Study for the Breidablikk Field

Alexandra Cely, Ingvar Skaar, Gunnar Digranes, Berit Frantzen, and Tao Yang, Equinor ASA

Breidablikk is a greenfield on the Norwegian Continental Shelf and just started the preproduction drilling of 23 wells in two structures. We have only two reservoir fluid samples from exploration wells in each structure with relatively high viscosity of 4 cp and 8 cp, respectively. Currently, we assume each structure has constant oil viscosity homogenously. Any change in the viscosity in each direction can lead to a 20 to 30% difference in oil recovery. Therefore, it is important to update the viscosity distribution in the reservoirs along with the drilling activities

Different methods can be used to acquire reservoir oil viscosity, including downhole logging and sampling, mud gas logging, extracts from cuttings, and surface oil sampling. Our previous studies demonstrate that mud gas provides real-time and continuous reservoir oil properties. However, due to the low concentration of hydrocarbon components in mud gas (like ethane and propane), it is challenging to apply the machine-learning models we developed for standard black oil and gas condensate. Therefore, we developed a different approach to predict the oil viscosity based on the light mud gas component ratios.

A thorough study has been performed based on the reservoir fluid database from the Bredabikk Field and the neighboring Grane Field. The results show the methane/propane ratio is the best parameter correlated to reservoir oil viscosity. Before adopting the new method from mud gas, we extensively compared results with other methods, including the measurement of pressure-volume-temperature (PVT) samples and oil extracts from cuttings. The comparison shows the approach based on mud gas provides an oil quality classification that allows distinguishing between high- or low-viscosity reservoir oil along a given well. The threshold for the two categories is identified from the reservoir fluid database. The mud gas method agrees well with the PVT measurements, which are regarded as the ground truth answer. The cutting extracts study supports the conclusion on oil viscosity provided by the mud gas analysis. Therefore, we decide to deploy mud gas data as the main method for future wells

The new approach using mud gas logging provides a real-time and cost-efficient method to identify the continuous reservoir oil viscosity following the well path. Along with drilling more wells, we achieve a detailed and accurate reservoir oil viscosity distribution in different reservoirs. The viscosity mapping of the reservoirs lays the ground for further optimizing the drilling target and well placement and improving the oil recovery.

SPORSE: NMR FOR THE NEXT FRONTIERS: MACHINE LEARNING, HIGH FIELD, AND NEW LOGGING APPLICATIONS

A New Workflow for Assessment of Fluid Components and Pore Volumes From 2D NMR Measurements in Formations With Complex Mineralogy and Pore Structure

Artur Posenato Garcia, Robert Mallan, and Boqin Sun, Chevron U.S.A. Inc.

It is challenging to reliably identify fluid components and to estimate their saturations in formations with complex lithology, complex pore structure, or varying wettability conditions. Common practices for assessing fluid saturations rely on the interpretation of resistivity measurements. These techniques require model calibration, which is time consuming/expensive and can only differentiate conductive and nonconductive fluids. Interpretation of 2D NMR maps provides a viable alternative for identifying fluid components and fluid volumes. However, conventional techniques for the interpretation of 2D NMR rely on cutoffs in the T_1-T_2 or D-T_2 maps. The application of cutoffs is prone to inaccuracies when fluid-component relaxation responses overlap. To address these shortcomings, we introduce a new workflow for identifying/tracking fluid components and estimating their volumes from the interpretation of 2D NMR measurements.

We developed an algorithm that approximates 2D NMR maps with a superposition of 2D Gaussian distributions. The algorithm automatically determines the optimum number of Gaussian distributions and their corresponding properties (i.e., amplitudes, variances, and means). Next, a clustering technique is implemented to the data space containing the Gaussian distributions parameters obtained for the entire logged interval. Each Gaussian is assigned to a cluster corresponding to different fluid/pore components. We then calculate the volumes under the Gaussian distributions corresponding to each cluster at each depth. The volumes associated with each cluster translate directly into the pore volumes corresponding to the different fluid components (e.g., heavy/light hydrocarbon, bound/free water) at each depth.

We successfully verified the reliability and robustness of the new workflow for enhancing petrophysical interpretation in two organic-rich mudrock formations with complex mineralogy and pore structure. The fluid volumes estimated by the introduced algorithm were compared against fluid volumes obtained from resistivity-based methods, laboratory measurements, and production data in both formations. The introduced 2D NMR workflow significantly improved the reliability of pore/fluid typing and assessment of fluid volumes in dozens of wells covering over 100,000 ft of log data in unconventional plays. Additionally, this work enabled the identification of the presence of light hydrocarbon in an interval where other interpretation methods have not been able to detect it.

A highlighted contribution of this work is that, in contrast to the alternative petrophysical interpretation techniques for fluid characterization, the introduced workflow does not require calibration efforts, user-defined cutoffs, or proprietary data sets. Furthermore, approximating 2D NMR data with a superposition of Gaussian distributions improves the accuracy of estimated pore volumes of fluid components with overlapping NMR responses. The clustering using the Gaussian distributions parameters as inputs enables depth tracking of different fluid components without making use of user-defined 2D cutoffs. Finally, the multidimensional nature of the introduced clustering provides the unique capability of identifying different fluid components with 2D NMR response located in the same range of coordinates in a T_1-T_2 map.

A Review of the Latest Developments in Laboratory NMR Techniques for Unconventional Shale Characterization

Z. Harry Xie and Omar Reffell, Core Laboratories LP

The complexity of the microstructure and fluids in unconventional reservoirs presents a significant challenge to the traditional approaches to the evaluation of geological formations and petrophysical properties due to the low porosity, ultralow permeability, complex lithology, and fluid composition. Nuclear magnetic resonance (NMR) techniques have been playing major roles in unconventional shale characterization in the last decades as NMR can provide critical information about the reservoirs for quantifying their petrophysical parameters and fluid properties and estimating productivity. Laboratory higher frequency (HF), e.g., 23-MHz NMR techniques, especially two-dimensional (2D) T_1-T_2 mapping, and applications have been essential for the noninvasive characterization of tight rock samples for identifying kerogen, bitumen, heavy or light hydrocarbons, and bound or capillary water. The traditional T_2 cutoffs need new definitions to reflect the inferences from water and hydrocarbons separately. The legendary crushed rock analysis method, as applied to unconventional formations, has shown great success in evaluating total porosity and water saturation but suffers from inconsistency in results due to desiccation and solvent effects. The industry has witnessed significant development of HF-NMR techniques that couple advances in petrophysics, petroleum engineering, and geochemistry with a broad range of applications. This article will summarize key advances in laboratory NMR applications in unconventional shale characterization, including monitoring processes of liquids equilibrium, desiccation, and imbibition in fresh shale samples, determination of activation energy of hydrocarbons in shales, monitoring changes in a shale sample during liquid flooding experiment, and direct measurements on kerogen. Future NMR applications, such as in EOR, gas condensation, and saturation profile, will be discussed.

In this article, we will review the following techniques: laboratory NMR, especially 23 MHz, techniques for unconventional shale sample measurements, 2D NMR T_1-T_2 mapping with an inter-echo spacing time of 0.7 ms at various sample temperatures, and early-time NMR signals acquired using the solid-echo pulse sequence together with pyrolysis results in kerogen studies.

We will review the necessaries and advantages of the HF-NMR techniques and applications, explain the importance of the inter-echo spacing time in shale NMR experiments, give examples of monitoring liquid redistribution and desiccation in fresh shale samples, compare the results from NMR, Dean-Stark, and pyrolysis, examine the multidiscipline approaches as better tools to solve petrophysical problems. Examples include kerogen study using the solid-type NMR measurement combined with geochemical pyrolysis and NMR combined with capillary pressure.

There has been significant advancement of NMR techniques in unconventional shale evaluation over the last decade. It is time for us to summarize such technological advances and draw conclusions to help us in planning unconventional core analysis programs.

A Study on NMR Logging Data Processing With Deep Learning

Gang Luo, Lizhi Xiao, Sihui Luo, Guangzhi Liao, and Rongbo Shao, China University of Petroleum, Beijing

Nuclear magnetic resonance (NMR) is a powerful tool in biomedical, chemical analysis, the oil industry, and other scientific fields. It provides information on molecular structure for the analysis of molecular dynamics and interactions. In recent years, deep learning (DL) has attracted great interest in various research fields because of the availability of high-performance computing. The employment of DL methods to effectively address shortcomings in NMR data processing is a new research field, such as signal reconstruction, MRI reconstruction, and peak picking of protein spectra. In general, the application of DL in NMR can be further summarized in three aspects: high signal-to-noise ratio (SNR) NMR signal reconstruction, high-resolution spectral reconstruction, and automatic interpretation of spectra. Inspired by these successful applications, we consider that DL can be applied to the construction of low-field NMR relaxation spectra, which would help to accurately characterize the structure and properties of rock porous medium.

Low-field NMR techniques use Carr-Purcell-Meiboom-Gill (CPMG) pulse sequences to accurately measure the formation. The measured echo signals always have strong noise and are used to determine the T_2 spectra by inverse Laplace transform (ILT). T_2 spectra provide information on pore structure, fluid saturation, and permeability to further evaluate reservoirs. However, the ILT process is ill-conditioned, and the solutions are not unique. The results may reduce the resolution of spectra, thus influencing subsequent interpretation and application. To overcome these problems, we proposed the signal denoising framework and spectra inversion network based on DL. First, an NMR forward simulation process was implemented to generate data sets for DL model training. Signal parameters and Gaussian distribution are regarded as prior knowledge integrated into the simulation process. Second, the autoencoder network was trained by a forward simulation data set to remove the noise contained in the signals. After compression and reconstruction, signals with high SNR can be obtained. Finally, we design the attention multiscale convolutional neural network (ATT-CNN) for spectra inversion. The energy changes of the signals were extracted by the attention mechanism. A multiscale convolution neural network (CNN) is designed to extract the local noise fluctuations and global attenuation characteristics of the echo signals.

Simulated data and rock core data measured in the laboratory were used to verify the effect of DL models. The NMR signals were input into the autoencoder model for denoising. The output signals with high SNR were going through the ATT-CNN model to obtain the T_2 spectra. The traditional inversion method based on regularization is also used as a comparison. The result demonstrated that the ATT-CNN model could be more adapted to low SNR echo signals and inverse more sparse and stable spectra. Meanwhile, the pore-size distribution and porosity of rock cores could also be accurately characterized based on high-resolution spectra.

This work shows that prior knowledge constrained to the data set and network model can make inverse spectra more accurate. DL methods can become a powerful tool for revealing the structure and properties of the porous medium. We hope that this optimization scheme inspires more applications, especially in formation evaluation.

Determine Oil and Water Saturations in Preserved Source Rocks From 2D T_1-T_2 NMR

Stacey Althaus, Jin-Hong Chen, Qiushi Sun, and J. David Broyles, Aramco Americas

2D T_1-T_2 NMR has been widely proposed as a method to determine the fluids present in unconventional source rocks. However, the assignment of the components in the 2D T_1-T_2 NMR has so far been based on conceptual consideration and lacks rigorous experimental verification. Therefore, many of the assignment variations appearing in the literature can be misleading. For example, large T_1/T_2 peaks in the 2D T_1-T_2 NMR have been suggested to be fluid in small pores coupled with kerogen through dipolar relaxation. Our recent thorough 500 MHz NMR relaxation experiments found that the dipolar relaxation between nanoconfined fluids and the solid matrix is not large enough to explain the measured T_1/T_2 result. The objective of this paper is to determine what quantitative data can be obtained using 2D T_1-T_2 NMR from source rocks with high confidence. We found the oil and water saturation can be accurately measured in preserved source rock plugs.

2D T_1-T_2 NMR data were collected on 66 preserved plugs from five wells of a source rock reservoir using an Inversion-Recovery CMPG pulse sequence on a 12-MHz NMR instrument. The acquired 2D data were inverted using an optimized inversion software: MUPen2D. We then obtain oil and water saturation from the 2D T_1-T_2 NMR using an in-house developed NMR MATLAB App. The porosity of all the plugs was measured using a combined NMR and gas porosimetry (CNG) method. Oil and water saturation were also obtained using an industry-standard method developed by Gas Research Institute (GRI) on the rock material close to where the plug was drilled.

The oil and water saturations measured on the preserved plugs using 2D T_1-T_2 NMR and CNG were consistent with those from the GRI method using crushed rocks and an invasive cleaning procedure. The results show that oil and water saturations were accurately determined from 2D T_1-T_2 NMR on preserved source rock samples with high confidence. The measured results can be further used to determine the production potential of a source rock well in combination with log data.

The NMR method is nondestructive and noninvasive and takes less than 4 hours on a preserved source rock plug, while GRI is destructive and invasive and can take several weeks for an accurate measurement on one sample. High-field data of relaxation measurements were applied to low-field T_1-T_2 maps to further understand the components in the source rock system.

Field Implementation of LWD NMR ROP Correction Enables Faster Drilling

Gabor Hursan and Osama Ramadan, Saudi Aramco; Marie Van Steene, Albina Mutina, and Shin Utsuzawa, SLB

Logging-while-drilling (LWD) nuclear magnetic resonance (NMR) data acquisition has historically been a limiting factor in drilling performance. Increasing the rate of penetration (ROP) beyond a certain threshold leads to overestimated NMR porosity. This condition exists because the NMR tool’s magnetic field profile creates time-dependent formation magnetizations, which are not considered in standard data processing. A newly designed and implemented ROP correction for the slimhole LWD NMR tool results in doubling the ROP.

A thorough understanding of the NMR spin dynamics physics in time-dependent magnetic fields, in conjunction with the detailed knowledge of the slimhole LWD NMR tool architecture, underpins the reliability of the ROP correction. The central point of this correction is to characterize two spin types during tool motion, i.e., those spins leaving the NMR sensitive region and the spins coming into the NMR sensitive region. Keeping track of these spins during NMR measurements allows for deriving the correct porosity from motion-affected NMR data. The ROP correction was developed based on extensive computer simulations, which were verified by laboratory experiments.

Field testing was performed to validate the ROP correction algorithm and the field processing workflow. The ROP correction was tested in several wells. In two wells, relogging at multiple ROPs enabled testing of the correction algorithm while other parameters were carefully controlled. The ROP correction field tests defined an operational envelope for ROP vs. formation properties (i.e., longest T_1 longitudinal relaxation time) for the slimhole LWD NMR tool. The ROP correction allowed for doubling the logging speed from 75 ft/hr without correction to at least 150 ft/hr with correction in microporous reservoirs where the T_1 polarization time of most formation fluids does not exceed 5 seconds. In challenging, extremely slow-relaxing carbonate reservoirs whose T_1 exceeds 5 seconds, the ROP correction enabled a drilling speed increase from 65 ft/hr to at least 110 ft/hr, representing a 70% increase in ROP. Additional field testing is being performed to expand the ROP envelope even further. After completing the field-testing phase, the ROP correction was implemented in real time in several fields, where it enabled drilling the wells with record ROP for LWD NMR borehole assemblies in these fields, despite the slow polarization buildup in the macroporous carbonate reservoirs.

Based on advanced tool physics modeling, the novel slimhole LWD NMR ROP correction enabled an increase in ROP by 70 to 100%, even in slow-relaxing formations such as macroporous carbonates.

Improvement of T_2-P_C 2D NMR Inversion Method for Characterizing Pore-Throat Connectivity

Gong Zhang and Yingyao Qin, Yangtze University

As a nondestructive, efficient, and noninvasive detection method, nuclear magnetic resonance (NMR) technology plays an important role in petrophysics. The NMR experiments of water-saturated cores and cores in a centrifugal state can distinguish movable fluids from bound fluids and obtain bound water saturation. The bound water saturation is a key parameter that determines the development effect of low-permeability oil and gas reservoirs. The T_2-P_c two-dimensional spectrum combined with relaxation time and capillary pressure can not only obtain the irreducible water saturation under different pressure drawdowns but also reflect the pore structure characteristics and visually evaluate the reservoir connectivity. However, the conventional data processing process for obtaining the T_2-P_c map is complex and cumbersome, and the kernel function of the inversion method is a mutation function. In addition, it is necessary to obtain data on different centrifugal forces through multiple sets of experiments, which is a time-consuming process.

A 2D NMR inversion method (JEI-L) based on logistic function is proposed from multiple groups of displacement echo data. First, the T_2-P_c 2D echo joint inversion method directly inverts multiple groups of echo data, which avoids the complicated data processing flow of common methods and improves data processing efficiency. The logistic function is used as the inversion kernel function to describe the gradual process of displacement pressure, thus avoiding the influence of discontinuous displacement pressure and improving the resolution of the T_2-P_c map.

The numerical simulation and core experiment results showed that compared with the JEI method with the Heaviside step function as the inversion kernel function, the optimized echo joint inversion method (JEI-L) can obtain a more refined T_2-P_c map (Fig. 1). It can more accurately characterize the pore-throat distribution of cores, thereby providing richer reservoir information for oil and gas exploration and development. The improved JEI-L method is suitable for low signal-to-noise ratio and few centrifugal force echo groups. Based on this, it is possible to reduce the number of centrifugal force groups during the experiment and significantly improve the efficiency of T_2-P_c 2D NMR core experiments.

The improvement of the T_2-P_c 2D NMR inversion method based on logistic functions shows the importance of an accurate description of the processes of non-MR physical quantities in the study of multidimensional correlation spectroscopy. It is necessary to construct a kernel function that can accurately describe the physical process through research to obtain the desired multidimensional spectroscopic results.

Learnings From Impact and Implications of Signal-to-Noise in NMR T_1-T_2 Logging of Unconventional Reservoirs

Olabode Ijasan, ExxonMobil

Data quality and signal-to-noise ratio (SNR) in NMR well logging are dependent on various factors such as logging tool, porosity available for low-field NMR relaxation, bulk fluid wait time, logging speed, echo stacking level, rock heterogeneity, and background noise due to tool movement. As SNR decreases, inversion of NMR relaxation spectra becomes challenging due to ill-conditioning and tradeoffs between solution existence, bias/uniqueness, and stability. These tradeoffs inevitably lead to over-regularization that causes the broadening and smearing of relaxation peaks. In unconventional reservoirs, because of micropore to nanopore sizes and low porosities (5 to 15%), poor SNR, over-regularization, and smeared T_1-T_2 peaks are very common. These impact interpretation of fluid saturations with adverse implications for hydrocarbon volume estimates. In this paper, we introduce a novel semi-analytical technique to compensate for the over-regularized smearing of T_1-T_2 relaxation peaks due to poor SNR in unconventional reservoirs.

A common notion in T_1-T_2 fluid partitioning methods is that a fluid type exhibits a continuous footprint in T_1-T_2 space. This can be true when SNR is adequate to give distinct fluid relaxation in T_1-T_2 space, e.g., in benchtop NMR of core samples, or in conventional reservoirs. However, in borehole NMR T_1-T_2 maps acquired in unconventionals, we observe that a continuous relaxation spectra footprint can be a combination of different fluid types because the fluid peaks smear together. Therefore, we introduce a novel NMR semi-analytical smeared-peak (NMR-SASP) prediction technique to correct for the effects of over-regularization in T_1-T_2 space and reconstruct original pore volumes of the different poro-fluid types. The NMR-SASP correction assumes that the smearing effect approximates a pore-volume-weighted geometric average. We validate the NMR-SASP model with relevant numerical experiments and field measurements in unconventional reservoirs.

For different borehole logging tool types (single frequency vs. multifrequency tools), acquisition modes (stationary vs. moving-pass logging), logging speeds, and stacking levels that replicate varying SNRs, we observe a gradual degradation in T_1-T_2 map resolution as SNR worsens, i.e., as over-regularization intensifies (example in Fig. 1). The NMR-SASP technique serves as a subsurface calibration scheme that uses high-SNR stationary measurements to correct or de-smear poor-SNR moving-pass measurements. Consequently, this improves accuracy in fluid pore volume predictions by up to 60% (refer to Fig. 2).

The learnings show that logging protocols that combine specific acquisition parameters and processing strategies with acceptable compromises and are designed to increase SNR are mandatory for the reliable characterization of unconventional reservoirs, e.g., slower logging speeds, subsurface stationary measurements for benchmark calibration, and appropriate stacking levels. Furthermore, with the novel NMR-SASP technique introduced in this paper, we mitigated the impact of smeared T_1-T_2 fluid modes and improved the reliability of fluid saturation predictions from moving-pass NMR measurements acquired in unconventional reservoirs.

Multifield Evaluation of T_2 Pore-Size Distributions and T_1-T_2 2D Maps

Michael Dick, Taylor Kenney, and Dragan Veselinovic, Green Imaging Technologies; Bruce J. Balcom and Florin Marica, University of New Brunswick MRI Research Centre; Derrick Green, Green Imaging Technologies

Low-field NMR instruments (~2 MHz) are popular for use in petrophysics laboratories as they compare favorably and reliably to NMR logs done downhole in the field. The lower field also reduces the issue of high magnetic susceptibility of core samples as compared to higher field instruments. However, higher field instruments present several distinct advantages, including faster scan times for a given SNR and superior detection of short relaxation elements due to their shift to longer relaxation times. For these reasons, higher field instruments have become more popular in recent years for use in core analysis. Previously, we investigated the validity of comparing T_2 distributions and T_1-T_2 maps for various samples recorded at 2, 12, and 20 MHz. In this paper, we continue this work by increasing the suite of samples studied and expanding the fields investigated to even higher frequencies.

This paper will include T_2 measurements as well as T_1-T_2 maps of bulk fluid (doped H_2O), sandstone plugs, carbonate plugs, and shale plugs at three new higher field strengths (33, 65, and 126 MHz). This new higher field data, when coupled with the previous data for these samples (2, 12, and 20 MHz), will create a data set with almost a two-order of magnitude increase in magnetic field strength. This new data set will lead to an excellent understanding of the effect of field strength on the NMR measurement of T_2 distributions and T_1-T_2 maps. Beyond the samples listed above, a set of measurements has also been completed at all six magnetic fields on common clay and kerogen samples. Clay and kerogen can be common rock components in many petrophysical samples (especially unconventionals). As a result, it is important to understand how their T_2 distributions and T_1-T_2 maps are also affected by field strength. For example, does the T_2 distribution of clay-bound water change with a field in the same manner as water within the pores of a sample?

For all samples tested, the higher magnetic field decreased the scan time for the same SNR for both T_2 and T_1-T_2 measurements. For example, for the shale sample, a T_1-T_2 map with an SNR of 165 took 2,895 minutes at 2 MHz but only 4.5 minutes at 20 MHz. This corresponds to a 645 times decrease in scan time.

The higher field also increases the separation between water and light hydrocarbons from heavier components in T_1-T_2 maps. It was found that T_2 distributions can shift to both shorter and longer values with an increasing magnetic field. This makes interpreting T_2 distributions recorded at different fields difficult. For the clay samples, a significant difference in T_2 distributions or total signal amplitude as a function of frequency was not observed.

With the increase in the prevalence of higher field NMR instruments, there is now plenty of NMR core analysis data taken at various magnetic fields being recorded in labs throughout the petrophysics industry. This paper has shown how T_2 measurements and T_1-T_2 maps on various samples compare at six magnetic field strengths. We hope this work can be used throughout the industry as calibration when comparing measurements at various fields.

NMR Fluid Substitution for Multimodal Carbonate Pore Systems

Wei Shao and Gabriela Singer, Halliburton; Gabor Hursan and Shouxiang Ma, Saudi Aramco

Nuclear magnetic resonance (NMR) petrophysical interpretation is largely based on the correlation between NMR relaxation time and formation pore-size distribution, assuming the reservoir is fully saturated by the wetting fluid within the logging tools' sensitive volume. NMR fluid substitution (FS), a set of methods to eliminate the effect of nonwetting fluids from NMR data acquired in partially saturated rocks, has been developed and established for simple, mostly unimodal pore systems. This paper evaluates the effectiveness of existing FS methods in multimodal carbonate pore systems and proposes a new technique to overcome the limitations of prior approaches in these types of reservoirs.

Existing FS methods are subdivided into two approaches, based on (1) the SDR and Coates permeability estimations or (2) the Brownstein equation and thin-film model. Historically, these methods were validated for mostly sandstones and only a limited number of carbonate samples. This work thoroughly evaluates the effectiveness of the existing FS methods using 20 carbonate samples with a multimodal pore system. The plugs were prepared to mimic hydrocarbon charge and drilling mud-filtrate invasion and measured by NMR at 100% water, irreducible water, and residual oil saturations. Four different existing FS methods were applied to partially water-saturated data to approximate T_2 distributions at 100% water saturation, and each approximation was subsequently compared with actual measurements of the fully water-saturated samples. Finally, this paper also presents a new FS method for carbonate multimodal pore systems. The new technique consists of a nonlinear inversion method that uses the Looyestijn water saturation profile model to describe the process of hydrocarbon displacing water and an inversion process that minimizes the L2 or L1 distances between the modeled and observed T_2 distributions. The inversion derives the T_2 distributions at 100% water saturation and the Looyestijn water saturation profile parameters.

Existing FS methods in complex carbonate rocks may not be able to reconstruct the details of the pore-size distribution that is required to evaluate its modality. Also, they tend to overestimate mesoporosities and underestimate macroporosity significantly. The new FS method, validated by 20 carbonate samples with a variety of pore-size distributions, yields satisfactory results both in terms of T_2 distribution matching and pore typing. The new method eliminates false, hydrocarbon-related bimodality from NMR data in unimodal pore systems while it correctly retains the bimodal T_2 distribution where the fully water-saturated NMR spectrum is bimodal.

Compared with the existing FS methods, the new FS processing performs well for all carbonate pore-size distribution patterns. This method increases the accuracy of NMR-based pore size and rock-type evaluation in partially hydrocarbon-saturated, complex carbonate pore systems.

Partitioning Fluids in NMR T_1-T_2 Measurements Using Gaussian Mixture Models and Surface Fitting

Jonathan Markell and James Davidson, Netherland, Sewell & Associates, Inc.

There has been increasing interest in the analysis of NMR T_1-T_2 maps for fluid-type identification and quantification in unconventional reservoirs. The overlap of the signals from the various reservoir fluids makes the accurate quantification of the fluid volumes difficult. The application of higher-frequency NMR instruments has helped to separate the fluid signals to some extent, but overlap is still an issue. A variety of methods have been applied in efforts to partition the various fluid regions on the map, including the application of T_1 and T2 cutoffs, region bounding with interpreter-defined polygons, and unsupervised machine-learning algorithms, such as principle component analysis and cluster analysis. A significant shortcoming of all of these methods is that the calculated volumes for each fluid are simply the cumulative sum of the amplitudes that are contained within the selected region of the T_1-T_2 map. In areas where the fluid signals overlap, attempting to partition the fluid regions in this manner can be extremely difficult. Since the fluid signals are not sharply defined and are shaped more as a distribution, creating regions that preserve the total volume of each fluid is practically impossible.

To handle these issues and shortcomings, a surface-fitting solution that assumes each fluid signal is roughly Gaussian in shape is proposed. The NMR data are preprocessed, either manually or using image processing, to determine large regions of overlap. Each of these regions is then run through clustering analysis with Gaussian mixture models to determine the initial parameters for the surface fitting. The representative fluid volumes are then calculated from each fitted Gaussian and post-processed to ensure total porosity balance.

Applying this method to synthetic data has resulted in the accurate reproduction of constituent fluid volumes. Consistent, reproducible results have also been obtained for NMR core samples from the Eagle Ford and Marcellus shales. Further testing with core measurements is needed to ascertain this method’s accuracy, along with log NMR measurements to determine its efficacy for possible downhole applications.

Unlike current methods that require sharp defined edges when partitioning fluid volumes, this method allows for the separation and quantification of individual overlapping signals. It also removes some of the subjectivity that is inherent with other fluid-typing methods.

SPORSE: PETROPHYSICAL WORKFLOW AUTOMATION WITH AI/ML

A Method for Automatic Depth Matching of Multiwell Logging Curves Based on Deep Reinforcement Learning

Xiong Wenjun and Lizhi Xiao, China University of Petroleum, Beijing; Dakuang Han, Research Institute of Petroleum Exploration and Development, PetroChina, Beijing; Wenzheng Yue and Guangzhi Liao, China University of Petroleum, Beijing

Depth correction and matching of logging data are necessary tasks in logging data processing, which aims to align the depths of multiple logging curves with the same stratigraphic horizon. Up to now, the traditional depth matching method is mainly based on manual experience and correlation function correction method to compare multiple curves and align the depths of similar curve segments one by one. However, the scale of data used for multiple well-logging data is large, which requires a lot of manual involvement and results in low efficiency, and is highly influenced by subjective experience, offset, noise, and other factors. To this end, we propose a depth reinforcement learning method based on artificial intelligence to match the curve depths in the data set.

In this paper, we extract features from the logging curve and approximate the state value function Q(s,a,θ) by a convolutional neural network (CNN) and adopt a utilitarian strategy to select the action corresponding to the current maximum Q-value function by the DDQN algorithm to correct the logging curve depth in order to obtain the maximum cumulative reward. The top-down data sequence of the logging curve is followed by a sliding window to scale and translate the curve to match the depth of the target well and complete the job of automatic logging curve depth matching.

The practical application results show that the efficiency of curve depth positioning and matching can be significantly improved on the conventional logging data set of multiple wells, and the purpose of automatic depth calibration is achieved in the vertical depth matching. This method has small depth error correction, high efficiency, low cost, and is independent of data type, which provides a new idea to solve the problem of curve depth matching in logging data processing.

In recent years, with the rapid development of computer technology, Michael Bittar and other scholars first investigated the depth matching of logging curves using a deep reinforcement learning (DRL) method in 2021, which accomplished the interaction between agent and environment through seven translational action spaces for the purpose of curve depth matching. We overcome the limitations of attribute parameter design on previous RL methods and use the DDQN algorithm based on DRL to accomplish automatic matching of curve depths in the logging data set, and this new method design has several innovations, which are as follows:

1. We have improved the previous interaction of a single agent with the environment. The new approach will take into account the interaction of multiple agents with the environment, which can accomplish multiple logging curve depth alignments simultaneously.
2. The previous action design process of DRL is only through the logging curve left and right translation to complete the depth alignment. The new method will take into account the stretch, contraction and translation, and other actions. The method is more complete and applicable.
3. In order to prove that the model generalization and reliability are better, the new method will improve the chapter content of model validation.

AI-Driven Image-Based Digital Twin Rock Properties – Fast, Consistent, and Cost Effective

Ghadeer Alsulami and Shouxiang Ma, Saudi Aramco; Katrina Cox and Allen Britton, Core Lab

Rock properties derived from laboratory core analysis have been used as references for formation evaluation and integrated reservoir studies for decades. Some of the challenges in obtaining core analysis data are that it is expensive to acquire core samples, it is time consuming to perform laboratory measurements, results may not be consistent from one laboratory to another, and it can be costly if many analyses are required. The main objective of this study is to test a new innovative method of extracting probability-based analog rock properties, the digital twin, from high-resolution images (HRI) of thin sections by taking advantage of the power of artificial intelligence (AI).

The method is based on a proprietary AI technology, which is comprised of two components. The first is the creation of a database that consists of conventionally measured rock properties of multiple rock types, each of which has been subjected to a thorough quality control program and associated HRI of thin sections. Such a database forms the foundation of this technology. The second component of the process is the development of an image recognition AI model comprised of the HRI of thin sections of the core analysis samples from part one.

Once created and validated, such an AI model can be used to analyze, in instances where cores are unavailable, HRI sourced from alternative formation-representative samples such as oddly shaped rotary sidewall cores or even drill cuttings. In these situations, the HRI of thin sections is prepared and compared, through the AI model, to images in the database. If a match is obtained, the rock properties associated with the matched image in the database, which can be thought of as its pore geometry similar digital twin, would be retrieved and serve as probability-based analog data for that sample. This unique combination of core database and image recognition is at the core of this analytical process.

The above methodology was applied to a new database of core analysis data and HRI of thin sections, and a customized AI model was developed, tested, and verified with satisfactory results. In addition, we are pushing the envelope of further development of this technology by extending its application to the analysis of drill cuttings and evaluating the effect of cutting sizes on the performance of the AI model using data generated from core plugs. Twenty sets of synthetic cuttings in 5, 4, and 2 mm size fractions created from conventional core plugs, which had previously been used in the creation of the AI model, were prepared. A thin section of each cutting size fraction was scanned, and each scan was then submitted to the AI model for analysis, and analogue matches were identified. Preliminary results demonstrate the potential of applying this technology to estimate rock properties as part of well-mud logging.

An innovative method has the potential to expand the capabilities of mud logging to estimate rock petrophysical properties from thin section image analysis in near-real time while drilling.

AI-Guided Interpretation: Automated Quality Assessment for Depth-Matched Images

Kristina Prokopetc, Alexis He, Salma Benslimane, Jossselin Kherroubi, and Nadege Bize-Forest, SLB

Multipad wireline tools have multiple levels of sensors at distinct locations on the probes to provide detailed, core-like microresistivity images. The correct and seamless alignment of the pads is crucial to ensure the continuity of the geological features visible on the image used in the interpretation of the formation traversed by the tool. Today, pad image alignment can be performed using different techniques, manual or automatic. Results often have local remaining misalignments, which need further manual intervention. However, this requires interpretation experts to visually assess the quality of the pad alignment first, which can take hours. Thus, how can we automatically evaluate the quality of the applied pad alignment technique?

In this paper, we propose an automated workflow that takes a microresistivity image and a corresponding image after an alignment correction method is applied to it to provide an assessment of their relative pad alignment quality. The assessment is based on areas with geological features relevant to the interpretation. First, we rely on the versatility of conventional local feature detection, complemented by a structural similarity metric to correct for global depth shifts between original and corrected images. Second, we partition the borehole image into fixed intervals and perform geological feature identification formulated as a supervised classification task. To this end, we create a model capable of learning what a relevant feature or interesting geologic pattern is that spans multiple pads and provides sufficient constraints to evaluate the pad alignment. This step works as a filter to focus attention only on intervals with visible geological features. The third and final step is to compare the images using a supervised similarity learning approach with a Siamese network model. This model can learn what is a good alignment relative to a bad alignment. The result of our workflow is a quality curve of pad alignment and a set of local flags showing unaligned areas that need immediate attention from the interpreter.

We prove the performance of our solution on images obtained from different wireline multipad tools and show the application for quality evaluation of two existing methods used to correct local misalignments. The impact of our solution is threefold: 1) it helps to find interpretation-relevant borehole intervals; 2) it can evaluate the quality of the results of any automatic method used to correct image misalignments and enables method comparison; 3) it indicates to the interpreter the intervals for depth match parameters to be modified.

To the best of our knowledge, this is the first attempt to use a learning-based approach to facilitate pad alignment for wireline imagers.

Automation of LWD-Resistivity Workflows With Hybrid Physics + AI-ML

Danil Safin, Henrik Andersson, Yuriy Antonov, and Arvi Cheryauka, Baker Hughes

In this paper, we employ the energy-based (EB) approach and test its applications to automate pre-, real-time-, and post-well logging-while-drilling (LWD) workflows. We describe the conditions and initial outcomes of this pilot development. The references are made to the current state of ultradeep azimuthal resistivity (UDAR) technology, typical noise levels, and uncertainties in well trajectory parameters. At the same time, the emphasis is placed on an automated probabilistic inversion/mapping of tool signals, workflow updates, and distinguished features governed by the proposed approach.

EB is a hybrid physics + artificial intelligence/machine-learning (AI/ML) approach that operates with categorical inputs and is balanced by offline model-based training, online optimization, and customized tuning. It is built upon stochastic considerations where measurements, characteristics of drilling survey, and parameters of surrounding formation represent the degrees of freedom of a particular numerical experiment. Currently, we initialize our method with a statistically distributed quasi-3D model bank comprised by smoothly varying layer cake models, standard tool settings, mean trajectory values, and correspondent trial signals. Our automated workflow consists of a running prediction-correction window, depth-of-penetration/depth-of-detection/depth-of-resolution (DoP/DoD/DoR) sensitivity indicators, and delivery of confidence percentiles with respect to custom geosteering and formation parameters.

To validate the EB approach applied to the real-time and post-well UDAR workflows, the outcomes from a series of numerical tests and field cases are assessed. We analyze compliance and accuracy within quasi-3D formation models. Next, we navigate to understand and quantify the errors resulting from 2D to 3D unconformities like regional faults and layer pinchouts. Also, we demonstrate the performance of automated mapping using the measured logs obtained in the Norwegian sector of the North Sea.

EB-governed workflows can be deployed in (semi)automatic or, in more general terms, interactive fashion depending on the LWD task, operator’s experience, data conditions, and geological complexity of formation.

Best Practices in Automatic Permeability Estimation: Machine-Learning Methods vs. Conventional Petrophysical Models

Oriyomi Raheem, Wen Pan, and Carlos Torres-Verdín, The University of Texas at Austin

Multiple physics-based and empirical models have been introduced in the past to estimate permeability from well logs. Estimation of flow-related petrophysical properties from borehole geophysical measurements is challenging in the presence of spatially complex rocks. This paper documents best practices for permeability estimation by comparing results obtained with both machine-learning methods and conventional petrophysical models. Furthermore, comparisons are performed of different salient statistical and petrophysical features obtained with the two approaches.

We preprocessed core data acquired in key wells that incorporate expert knowledge, depth-matched core porosity with log-calculated porosity, interpolated triple-combo well logs to core depth, and performed feature engineering on the resulting data suite. Dimensionality reduction techniques were implemented, such as principal component analysis (PCA), singular value decomposition (SVD), discrete wavelet transforms (DWT), and deep-learning-based autoencoders to generate latent-space well logs, from which models were trained to estimate permeability. From the latent space models, we performed regression using random forest, k-nearest neighbors, artificial neural network (ANN), and Timur-Coates model to estimate the logarithm of permeability from core porosity and well logs (gamma ray, bulk density, neutron porosity, and photoelectric factor). Finally, the uncertainty of the estimated permeability was calculated based on the validation variance function for the test set. Results were compared based on the relative standard error of permeability estimations. To reach general conclusions, the methods were tested on data sets from a variety of carbonate and clastic (shaly and clean) rocks, both conventional and unconventional.

Results indicate that random forest and neural networks best estimate permeability from triple-combo well logs across a wide range of variation (0.001 to 2,000 md) with an average of 16% relative standard error when using the original well logs. Estimations improved using latent-space well logs with discrete wavelet transforms. Machine-learning algorithms reduced the estimation error to less than 13% while implementing a fully connected autoencoder resulted in less than 10% error. The Timur-Coates model is the most reliable for data sets with a priori information about irreducible water saturation, yielding less than 22% relative standard error, yet it requires prior data classification to improve estimation accuracy. Estimation workflows proved to be generalizable, as they can be used for permeability estimation in both conventional and unconventional reservoirs.

The new procedure is computationally efficient, with estimations obtained in less than 2 minutes of CPU time. Uncertainty estimates show that permeability calculations are accurate, as their distributions border the true values within ± 5 md. However, it is important to note that training wells must cover the widest possible range of measurements and petrophysical and fluid properties to improve the estimation of permeability in test wells. Data normalization does not always improve machine-learning estimations, especially across very low (0.0001 to 20 md) or high (150 to 2,000 md) permeability ranges, where it resulted in a 25% increase in permeability estimation error compared to non-normalized data.

Evaluation of the Efficiency of Machine-Learning Techniques to Estimate Petrophysical Properties of the Albian Carbonate Reservoir in the Campos Basin Using Well-Log Data

Mohammad Saad Allahham and Abel Carrasquilla, UENF/LENEP

This work aims to study the permeability, porosity, and facies of the Campos Basin using statistical analysis and machine-learning (ML) models, including decision trees, discriminant analysis, support vector machine, logistic regression, nearest neighbors, naive Bayes, Gaussian process and ensemble, together with the geophysical data (gamma rays, density, neutron, sonic, and resistivity) log of each well which can identify the petrophysical properties of the wells and compare the results given with the original data of each well.

The study was made by applying methods of ML techniques by getting into well-log data for groups of wells. All these wells belong to the same field at some offset distance. The targets that were taken for this study are permeability, porosity, and facies.

The first process is called preprocessing, and it is an important process to understand, analyze, clean, and prepare the final data, creating a data frame, clearing null data from our data, and doing static analysis of each well, which makes it easy to choose which well will be used to train models of ML, in addition, drawing attractive and informative statistical graphs of our data and do different processes to understand the relationship of our data.

Subsequently, in the second process, we use the file that was prepared and generated to use it for machine learning, using 24 classification techniques and 19 regression techniques to train our models.

Then, we apply the generated models to estimate the new petrophysical values (permeability, porosity, and facies) for all wells used in this work.

By applying the DM and ML techniques, excellent results were found in the present work, first for the training models with an accuracy of 97.2%, which was used to estimate facies, and 0.99 and 0.97 of R-squared, which were used to estimate permeability and porosity, respectively, in addition to the results of the estimation of the petrophysical properties, which obtained with 0.95 to 0.96 of R-squared of estimated facies, 0.96 to 0.99 of R-squared of estimated permeability, and 0.95 to 0.98 of R-squared of estimated porosity for blind test wells.

The results showed the importance of this work and its improvement for each of the previous works, as the results of this research outperformed the results of other studies for several factors, either when not using the optimal well for training or the correct data has not been used, as this work demonstrates the correct way to use machine learning in the oil industry.

In conclusion, this work can be considered an essential reference for the users of these models in the solution of related problems to predict essential petrophysics in heterogeneous reservoirs in the petroleum industry.

Machine-Learning-Enabled Joint Interpretation of Dipole Sonic and Borehole Image Data

Gurami Keretchashvili, Institut Polytechnique de Paris; Ting Lei, Pontus Loviken, Josselin Kherroubi, Lin Liang, Adam Donald, and Romain Prioul, SLB

Borehole sonic and formation image logs represent two widely used measurements for formation evaluation. Many important geomechanical and geological features, such as thin layers, breakouts, natural fractures, drilling fractures, stress effects, and intrinsic anisotropic effects, can be detected by either or both measurements. These features have noticeable impacts on geomechanical and petrophysical applications. Therefore, it is important to label and classify them as accurately as possible. On the one hand, the borehole sonic measurement, which is usually used to provide valuable inputs for rock elastic properties, is now regularly used to classify anisotropy mechanisms with the development of a wideband dipole dispersion extraction algorithm. However, due to its long wavelength, the dipole sonic measurements do not probe borehole walls at high resolutions or with high confidence. The borehole image measurement, such as microresistivity and ultrasonic data, on the other hand, can provide rich information around borehole surfaces at a much higher resolution. An efficient way to integrate the two measurements yields a better understanding of geomechanical and geological features.

In this study, we present a new machine-learning (ML)-enabled workflow that integrates the interpretation of borehole dipole sonic data and microresistivity borehole image data. The first step is to label sonic dispersion features under three main categories based on cross-dipole dispersion signatures. The first category is about borehole and tool conditions, where dipole dispersion showing various levels of frequency shifting signature are labeled. The second category, extrinsic anisotropy, is to label logging intervals with the existence of strong or weak azimuthal anisotropy dispersions. This type of azimuthal anisotropy can be caused by several factors, including fractures, stresses, or dipping layers. The third category, intrinsic anisotropy, labels intervals into various degrees of vertical transverse isotropy (VTI) types based on a physical-driven ML classifier. In the second step, cross-dipole dispersion splitting labels are further compared against borehole image data using analytical and ML methods. The comparison is carried out to resolve the non-uniqueness issue found in the first step, where different physical factors might demonstrate similar dispersion signatures. Consequently, the new comparison workflow allows us to distinguish ambiguities efficiently and accurately between tool decentralization and breakout and between layer-induced and stress-induced azimuthal anisotropy. Finally, modeling studies are performed to verify the labeling accuracy.

We apply the developed workflow to a field case. The study first demonstrates that it can be difficult to label all features relying on either measurement independently. However, joint interpretation can resolve ambiguity and improve classification significantly. Labeled data were then used for a geomechanical study to build a mechanical earth model (MEM). It was found that an increased level of accuracy in the classification can enable a better estimation of formation in-situ stresses in the MEM workflow.

The labels enable a good understanding of the in-situ elastic mechanism. The ambiguity issues resolved using this ML workflow help to de-risk geomechanical analysis in a way that is automatic.

Novel Approach for Machine-Learning-Assisted Carbonate Reservoirs Saturation Height Modeling and Automated Pore Network Characterization

Nader Gerges, ADNOC Upstream; Luisa Ana Barillas Cortez, Gennady Makarrychev, Chris Darous, Alaa Maarouf, Sushmita Kuruba, Midhun Madhavana, and Lulwa Almarzouqi, SLB

Key data sets for permeability modeling, rock typing, reservoir characterization, and saturation height modeling (SHM) include capillary pressure (P_c) measurements and conventional core analysis (CCA). The P_c data QA/QC and modeling are time consuming and sensitive to the intricate pore network in Carbonate rocks. In this study, we automate the P_c-based pore network characterization and use machine learning (ML) for capillary pressure modeling in an effort to improve workflow efficiency and lessen interpretation bias. Additionally, a framework for advanced analytics was developed to enable interactive quality control and user visualization.

We developed and tested the proposed algorithms on real data from a large carbonate oil field in the Middle East. There are around 500 MICP samples of good to exceptional quality. The parent-plug porosity and permeability are also available for all samples.

The suggested methodology considerably enhances the P_c-based pore network characterization workflow, according to preliminary testing. We can automatically identify low-quality data and outlier samples using sophisticated data science outliers' identification methods. These outlier samples are removed, eliminating data-quality artifacts in the interpretation.

The automated pore network characterization method makes it simple to comprehend the porosity modality and partition. The petrophysical grouping at the MICP level is built, honoring this characterization.

We provide a thorough comparison of the outcomes of standard approaches to petrophysical rock type with the outcomes attained utilizing the suggested pore network characterization methodology. Although the focus of this study is to improve the petrophysical grouping component of the rock typing, further integration with geology and diagenetic overprints is required to improve the overall workflow.

We use ML methods to compute the final saturation height functions and automatically create the optimum P_c analytical model. Compared to the currently available conventional methodologies in commercial petrophysical software, this unique workflow enables more complex mathematical modeling. The overall results provide an enhanced mathematical solution limited by the reservoir physical constrains.

Traditional techniques have been used in the petrophysical approach to core-based saturation modeling for several years. The newest developments in data science workflows are utilized in this novel method to QA/QC P_c and core data, characterize the reservoir, and build models. The suggested methodology provides a considerable increase in terms of efficiency as well as in the characterization of carbonate reservoirs and the accuracy of saturation modeling.

With the new information extracted from the P_c arrays, more representative rock-typing schemes are defined, which will greatly improve the saturation modeling workflows and 3D volumetric calculations using advanced ML techniques.

SPORSE: PETROPHYSICS BEYOND PETROLEUM – STATE OF TECHNOLOGIES

Integrated Petrophysical Studies for Subsurface Carbon Sequestration

Shuvajit Bhattacharya, Sue Hovorka, Carlos Uroza, Seyyed Hosseini, Alex Bump, Sahar Bakhshian, Ramon Trevino, and Iulia Olariu, Bureau of Economic Geology, The University of Texas at Austin; Autumn Haagsma, Battelle

Petrophysics is a core component of subsurface characterization and monitoring for carbon sequestration. The United States Environmental Protection Agency's underground injection control rules for carbon storage (class VI wells) include subsurface characterization, CO_2 plume modeling, and monitoring during pre-injection, injection, and post-injection, where petrophysicists can play important roles. Many carbon capture and storage (CCS)-related petrophysical studies are limited to porosity and permeability for storage capacity and injectivity; however, there are several scientific questions and regulations that need a thorough formation evaluation.

We present three case studies to show how integrated fit-for-purpose petrophysical approaches helped address a few critical questions, such as the impact of formation water salinity, pore pressure, and fractures on the feasibility of CO_2 storage. Although not addressed in this study, we recognize the importance of petrophysics to study the integrity of the confining zones, CO_2 trapping mechanisms (i.e., CO_2 mineralization), wellbore integrity, and monitoring.

We use triple-combo logs and fluid salinity data from the Gulf Coast, Texas, for the first case study on salinity. For the second study on pore pressure, we analyze quad-combo logs and mud weight using a combination of Eaton's and sonic overpressure indicator (SOPI) approach in the southern Gulf Coast, Texas. We integrate core, borehole image log, and shear wave imaging information in the last case study on a naturally fractured carbonate reservoir.

CCS operations are required to ensure the underground sources of drinking water (USDWs) are not endangered due to brine or CO_2 plume migration. Results show that a reservoir has 25 to 30% porosity, 10 to 1,000 md permeability, and a high net-to-gross thickness at a depth of 3,000 to 7,000 ft, but an updip portion of the reservoir is in the freshwater zone (salinity < 10,000 mg/L), posing risks to groundwater contamination due to updip CO_2 migration and requires further assessment and strategic monitoring.

The second case study shows the importance of pore pressure in assessing CO_2 storage capacity and minimizing compression costs. The carbon storage window is between the supercritical CO_2 depth and the overpressure boundary. As pore pressure increases, the "pressure space" available for storage below geomechanically defined fracture pressure is diminished. Our pressure map reduces uncertainties in identifying the overpressure boundary in multiple wells by a few 100 ft (containing multiple potential sandstone reservoirs) compared to the published studies. This increased storage capacity estimates of the entire zone.

The last case study shows the importance of locating near-wellbore and far-wellbore fractures and their controls on CO_2 storage in a fractured carbonate reservoir. Results show that fractured dolomites have higher porosity and permeability than host limestone, which is tight. Borehole shear imaging results show that high-angle fracture zones can be located up to approximately 120 ft away from the injection well, which can store CO_2. Some of these fractures are closed and partially open, leading to reduced storage capacity.

The study offers lessons learned from multiple case studies, showing pertinent problems where petrophysics can help facilitate successful CCS operations. It shows how existing and emerging technologies can be implemented, as well as the need to develop new concepts and tools for CCS.

Nuclear Logging in Geological Probing for a Low-Carbon Energy Future – A New Frontier

Ahmed Badruzzaman, Pacific Consultants and Engineers

This paper examines the potential of nuclear logging techniques, ubiquitous in the petroleum industry, to extract geological information needed to transition to the low-carbon energy future being envisioned and explores the technological advances needed.

Monte Carlo modeling and assessment of available measurements are utilized to examine four likely areas of application.

Monitoring injected CO_2 for CCS to mitigate climate change: PNC Sigma from a slim, generator-based dual-detector tool was able to track injected CO_2 gas plume in a high-salinity formation. The tool's simulation-derived spectral-fitted C/O ratio showed promise of directly identifying CO_2 in aquifers, especially with a breakthrough. C/O ratios would be problematic in depleted gas reservoirs where injected CO_2 would displace methane. The inelastic/capture ratios at the farthest detector of a three-detector tool appeared promising at CO_2 saturations below 70%. Diffusion/transport effects, not generally accounted for, would have to be incorporated if capture data are used at high CO_2 saturations.

Assessing sites to bury high-level waste (HLW) from nuclear plants: Conventional reservoir characterization using density/PE, neutron porosity, and source-based n-gamma spectroscopy have shown promise. A D-T-based tool providing thermal and epithermal neutron porosity and mineralogy simultaneously would be a better option. The low-energy X-ray density tool being tested would provide a better lithology indicator.

Monitoring buried nuclear waste: A moisture content map, in conjunction with a map of radioisotope movement, would indicate the presence of water in the subsurface and allow monitoring of pathways for contaminants migrating into water tables. Despite successful tests of commercial tools at the Hanford site for this application, they are not utilized, primarily due to a lack of calibration for fission product isotopes, and, in high radiation environments, these isotopes pose for scintillators. Additional calibration, radioactivity-free scintillators, and radiation hardening of devices are a must.

Downhole quantification of minerals for electric vehicles and photovoltaics: Projected demands for these minerals would exceed currently available volumes, manifold, potentially requiring subsurface access to them vs. current near-surface open-pit mining. D-T-based mineralogy tools could locate them, but at high concentrations and if nuclear interaction probabilities are high. Generators emitting 10^9 n/s or higher and a low capture correction for inelastic would be preferred. Our simulation results indicate complex capture correction can be avoided if inelastic gamma rays, emitted below 100 nanoseconds, are utilized. This would require scintillators capable of recording gamma rays in tens of nanoseconds instead of microseconds.

Nuclear, with its unique ability to characterize *and* monitor the subsurface, is well placed for the new frontier of geological probing for low-carbon energy generation, especially if the technology gaps identified are closed. Two areas need further attention: simulation technology and tool concept. Codes with dynamic visualization and nuclear data libraries with a full suite of elements of interest in petrophysics to design, calibrate, and assess tools, especially to provide a priori space-time profiles of attendant multiple radiation types, are needed. Secondly, the industry should consider switching from its current dual tracks for nuclear tools—radioactive sources for characterization and D-T generators for monitoring—to composite, advanced accelerator-based, multiple-parameter tools incorporating AI-guided PHM systems to minimize generator failure.

Petrophysical Analyses for Supporting the Search for a Shale-Hosted Nuclear Repository

Joachim Strobel, BGE

The Bundesgesellschaft für Endlagerung mbH (BGE) is responsible for identifying a deep geological repository site in Germany, which should allow the disposal of high-level radioactive waste and ensure the best possible safety for at least one million years. The three-phase site selection process is currently in the second half of its first phase, during which around 90 potentially suitable sub-areas are evaluated via individual representative preliminary safety assessments. These subzones cover all types of potential containment rock: allochthonous and autochthonous salt, shale, and basement.

Such a comprehensive assessment is especially challenging for a host rock that covers vast areas like shale or autochthonous salt. This paper focuses on the estimation of some relevant petrophysical parameters of the host-rock shale.

One of the steps toward estimating the mentioned parameters requires the analysis of numerous logs from the areas of interest and their vicinity.

Unfortunately, computing these parameters is a much more complex problem than it seems. While gamma ray (GR) logs have been the petrophysicist's workhorse for decades, they allow no quantification of shale properties. Radioactivity itself is no specific property of shale or its physical parameters. Computing a "min-max" curve may appeal as a good shale indicator, but it has little significance for evaluating the quality of the shale in the context of a nuclear repository. Density and acoustic logs are indirect measurements only, requiring a matrix parameter and, in the case of the acoustic log, a mixing law.

Hydrogen-sensitive logs like neutron or nuclear magnetic resonance (NMR) show the best potential for evaluations. However, thermal neutron logs suffer from a magnitude of corrections and the presence of thermal absorbers. On the other hand, the NMR logs require a minimum relaxation time below 400 ms and consideration for perturbations caused by iron.

Decades of research gave good algorithms for defining wet clay porosity from resistivity logs, but these methods are not validated in pure shale layers and need knowledge of the penetrating water salinity.

Starting from critical wells with core control, a solver-based model using NMR, epithermal neutron, and resistivity data estimates robust shale porosities and clay volumes with tortuosity as a by-product. Transposing the model allows its application to wells with less comprehensive data.

A second option is based on the fact that shale compaction acts on clay water and intergranular porosity. Hence, compiling porosity results from the log analyses allows the derivation of compaction-depth trends that guide parameter selection for wells with fewer data.

Another log-derived parameter is the homogeneity of a rock formation as seen by statistical data quantifying the jaggedness of a logging curve, such as vertical variograms, curve differentiation, or variable filter techniques.

The paper looks at the definition of shale and its porosity within the context of containment. It shows how a GR log can be deceiving, with a higher reading meaning worse shale properties. It offers a vague depth-compaction trend based on NMR and epithermal neutron data. That trend can be compared to early log-based porosity computations, potentially eliminating areas with a strong surplus porosity.

State of Integrated Formation Evaluation for Site-Specific Evaluation, Optimization, and Permitting of Carbon Capture and Storage Projects

Erik Borchardt, SLB

Participation in over 80 carbon capture and storage (CCS) projects spanning 25 years has led to the evolution of a recommended well-based appraisal workflow for sequestration in saline aquifers. Interpretation methods are expressly adapted for CCS applications to resolve key reservoir parameters, constrain field-scale modeling, provide answers required for the permitting process, and de-risk unique CCS technical challenges, such as:

- Storage capacity – a more challenging parameter to evaluate than hydrocarbon reserves since the reservoir is at zero CO_2 saturation during evaluation.

- Injectivity – key to minimizing wells needed to safely achieve the target storage rate.
- Containment – does the field provide a permanent and safe trap for CO_2? Contrary to hydrocarbon reservoirs, the caprocks of these reservoirs have never held a column of buoyant fluid, and the reservoirs will be subject to elevated pressures never seen before.

A further challenge complicating the above is the eventual impact of the three-way interaction between matrix, brine, and impure CO_2 streams.

Most logging, sampling, and laboratory techniques are adapted from established domains such as enhanced oil recovery, underground gas storage, and unconventional reservoir evaluation, though some CCS-specific innovation is also needed. Storage evaluation begins with established methods for lithology, porosity, permeability, and pressure, while special core analysis (SCAL) determines CO_2 storage efficiency and relative permeability. Containment evaluation spans multiple disciplines and methods: the petrophysicist's task to quantify seal capacity relies heavily on laboratory analysis, while geologists leverage downhole imaging tools to verify caprock structural/tectonic integrity. Geomechanics engineers define safe injection pressure via mechanical earth models (MEMs) built on advanced acoustic logs calibrated by core geomechanics, wellbore failure observations, and in-situ stress tests. The impact of matrix-brine-CO_2 interactions is studied via custom SCAL experiments and/or pore-scale digital rock simulations that faithfully represent chemical and thermal processes. Wireline formation tester samples provide representative formation brine as feedstock for SCAL. Water samples also enable operators to prove injection within regulatory limits while establishing baselines for the future monitoring program. Examples applied to recent CCS projects in North America are presented.

At present, a well-planned integrated approach making optimum use of cores, logs, and fluid samples can affirmatively address the main challenges of CCS. There remain opportunities for improvement; wireline logs cannot provide all the answers, and SCAL is absolutely necessary to determine elusive parameters such as e_{CO2} having a critical impact on simulation outcome, project footprint, and economics. We envision that practical limits on the quantity of SCAL experiments will be overcome by smarter methods of SCAL-log integration and by digital rock simulations as opposed to new measurement technologies.

CCS evaluation programs are among the most comprehensive ever seen, but this investment is proportional to the technical, commercial, regulatory, and social risks these capital-intensive projects must successfully navigate. The value of information to this end is supported and enhanced by fit-for-purpose commercial software for dynamic simulation of CO_2 storage, fully honoring the details, providing operators better visibility for decision making, risk management, and preservation of the regulatory and social license to operate throughout a project lifetime that may last more than 100 years.

Underground Hydrogen Storage in Porous Media: The Role of Petrophysics

Esuru Rita Okoroafor, Texas A&M University

The demand for hydrogen is growing. The IEA 2021 Hydrogen report showed that global hydrogen demand reached 94 Mt in 2021, a 5% increase in demand from 2020. Hydrogen demand is expected to reach 180 Mt by 2030. This increasing demand would require storage at scale. Of existing and potential hydrogen storage technologies, underground hydrogen storage in porous media is being considered for large-scale hydrogen storage based on successes with underground gas storage. However, there are no detailed site selection criteria for underground hydrogen storage in porous media. The objective of this study is to showcase the key geological and reservoir engineering parameters that affect underground hydrogen storage and demonstrate how petrophysical data could help in screening sites, site characterization, and hydrogen plume monitoring.

We used numerical simulation modeling of a synthetic reservoir to create a base-case model representative of the hydrodynamic conditions relevant to underground hydrogen storage in porous media. We carried out a two-step sensitivity analysis. In the first step, we determined the key parameters impacting the storage and flow of hydrogen in porous media. In the second stage, we examined in detail the extent further ranges of those key parameters had on hydrogen storage potential. The findings of the two-step sensitivity analysis resulted in the development of preliminary site selection criteria.

The study showed that the reservoir depth or current pressure, the reservoir dip, and the flow capacity were the top three factors impacting the optimal withdrawal of hydrogen. These highly sensitive parameters also indicate the need to reduce the uncertainty associated with these parameters when selecting potential sites for hydrogen storage in porous media. When the site selection criteria were applied to depleted fields in Northern California, we were able to see how uncertainties in geological and reservoir parameters can change a site's ranking for potential hydrogen storage.

This study quantifies uncertainties in data and identifies where and how petrophysical measurements could reduce the uncertainty associated with the key parameters relevant to underground hydrogen storage, selecting optimal sites for hydrogen storage, and tracing hydrogen leaks during the monitoring phase.

SPORSE: THE ROLE OF ADVANCED BOREHOLE ACOUSTICS IN A DIVERSE ENERGY INDUSTRY

Dispersion Corrections on LWD Quadrupole and Wireline Dipole Array Data Revisited

Tim Geerits, Stefan Schimschal, Anna Swiatek, Lei Wu, Rex Sy, and Doug Patterson, Baker Hughes; Alexei Bolshakov, Kristoffer Walker, Andee Marksamer, Lorelea Samano, and Andrew Reynolds, Chevron

In slow formation borehole acoustic wireline logging (WL) and logging while drilling (LWD), it is common to obtain formation shear slowness from the dispersive borehole guided flexural and quadrupole wave, respectively. Due to poor signal-to-noise ratio and/or tool eccentricity effects, it is not always possible to obtain formation shear slowness directly via conventional slowness-time-coherency (STC) methods. Consequently, a dispersion correction is frequently needed to QC and/or correct the STC result. We propose a hybrid method that allows for a model-based as well as a phenomenon-based approach. The latter is ideally suited to address, identify, and overcome the limitations and dependence of the former on tool eccentricity, tool model, inaccurate knowledge of borehole fluid slowness, formation anisotropy (vertical transverse isotropy), etc.

Our method minimizes the over-frequency (f) cumulative difference between two slowness dispersion curves, S...(f, Ss, ..,etc.) and S_SFC(f), in the least-squares sense. S_SFC(f) denotes the dipole (WL) or quadrupole (LWD) slowness dispersion curve as obtained from the array slowness-frequency-coherency (SFC) data and S...(f, , Ss, ..,etc.) either denotes a model-based (... = "MB") or phenomenon-based (... = "PB") slowness dispersion curve. The PB method uses known analytical function families that are parametrized by several—not per se physical—parameters (e.g., Scholte wave slowness, cutoff frequency, etc.) in addition to the formation shear slowness (Ss). Such functions have sufficient degrees of freedom in describing WL dipole or LWD quadrupole slowness dispersion curves under all kinds of (non-ideal) circumstances (e.g., unknown borehole fluid slowness, tool eccentricity, etc.). Typically, all parameters in such a phenomenological description require inversion. In the MB method, one assumes a very specific physical model/configuration (e.g., elastic tool centered in a fluid-filled borehole and surrounded by a homogeneous and isotropic elastic formation), which, depending on model complexity, may require a significant amount of computation.

We have applied both inversion methods to a variety of LWD quadrupole data sets, where the MB inversion was characterized by an elastic tool centered in a circular fluid-filled borehole surrounded by a homogeneous isotropic elastic formation. Where the model fitted reality, both methods were in excellent agreement. Where the model did not fit reality (e.g., due to tool eccentricity/borehole rugosity, etc.), only the PB method obtained the correct answer.

The proposed PB approach allows for accurate formation shear slowness inversion in a variety of practical circumstances that are not properly addressed in the MB approach (e.g., tool eccentricity/borehole rugosity, etc.). Different outcomes are indicative of what these circumstances might be.

Iterative Cement Bond Logging Without Calibration

Jiajun Zhao and Ruijia Wang, Halliburton

Cement bonding logging (CBL) has recently evolved to include logging-while-drilling (LWD) sonic tools due to the multiple benefits of LWD logging. Yet, there is an LWD-specific challenge, which is the contamination of the casing mode by the drill collar mode. To resolve this issue, existing approaches require calibration in 100% bond zones or free-pipe zones. This calibration step involves human intervention and could pose a hindrance to accurate CBL if these zones cannot be correctly identified. This paper proposes an automated process for iterative CBL using an LWD tool. This process does not require calibration based on the identification of 100% bond zones or free-pipe zones.

The proposed iterative CBL starts from preprocessing. The preprocessing workflow results in three variables: the magnitude at the first receiver (RX1), the apparent attenuation (AppAtt), and the apparent attenuation difference (delta AppAtt). After obtaining RX1, AppAtt, and delta AppAtt, we can calculate bond indices in the main processing. The calculation requires the prediction of the summation model, a theoretical model indicating the relation between AppAtt and the real attenuation RealAtt.

We pass field data through the workflow in Fig. 1. In Track 4, we show two possible RealAtt values inverted from the right and left branches of the summation model. Track 6 shows the branch indicator, which has an initial random distribution. Based on the branch indicator, we choose one from the two possible RealAtt at each depth and then obtain the RealAtt log. Next, we calculate the correlation coefficient between RX1 and RealAtt. Supposing that the coefficient has reached a minimum after several iterations, we then convert RealAtt into cement bond indices by linear mapping, as shown in Track 2. However, since the branch indicator is initialized randomly and the correlation coefficient does not reach a minimum, the resultant bond indices jump frequently, which is incorrect. To minimize the error in the final bond index log, we need to iteratively update the branch indicator depth by depth until the correlation coefficient between RX1 and RealAtt reaches a minimum. The results are shown in Fig. 1. The final bond index log is very close to the benchmark values in Track 2, validating the proposed workflow.

We propose an automated processing workflow for iterative CBL using an LWD tool. This new processing utilizes the trend of amplitude log change instead of individual amplitude values and thus is ideal for processing where we cannot calibrate amplitude logs. Furthermore, unknown parameters, such as the branch indicators and the model parameters, are iteratively updated to achieve reasonable cement bond indices without human intervention. This iterative LWD CBL method enables quantitative cement bond logging without calibration or human intervention and is applicable to post-processing LWD CBL as well as onsite and real-time processing if required.

Multiple String Cement Bond Logging With Acoustic Wireline Tools for Plug and Abandonment: Possible and Impossible

Alexei Bolshakov, Kristoffer Walker, Yegor Se, and Scott Cole, Chevron

Plug and abandonment (P&A) is the last step in the life cycle of producing oil and gas wells. Once production has depleted the reservoir or the well no longer produces economically, the decision is made to P&A the well, reclaim the area, and relinquish the lease back to the owner. There are regulatory requirements that are associated with this process, one of which is to ensure that the strata and freshwater aquifers remain adequately isolated from the hydrocarbon-bearing reservoirs. For example, a cement bond log (CBL) is typically acquired in cased wells to verify the presence of cement across critical intervals and to ensure zonal isolation.

Traditional CBL workflows are successfully used in wells with one casing string to detect cement presence. However, these same workflows are not reliable when used in wells with production tubing and/or through multiple casing strings. In these cases, the operator may have to pull out production tubing and/or mill out the inner casing to get a reliable log. Finding ways and technologies to avoid these costly procedures can significantly simplify the P&A process.

We investigate if combinations of various monopole and dipole modes generated by standard acoustic tools can be used to successfully evaluate cement quality behind multiple casing strings and in the presence of production tubing and/or microannulus. Such an approach could provide a cost-effective solution for P&A.

We use standard high- and low-frequency monopole modes and a wideband dipole mode excited by a borehole acoustic tool to evaluate cement sheath quality in the presence of production tubing and/or multiple casing strings. We first predict the dispersion curves of flexural and monopole modes present for different scenarios, including the presence and absence of cement and microannuli at various interfaces. We then generate a set of waveforms using the finite difference method and investigate which of the modes can be detected in the waveforms. And finally, we compare our results to data obtained in the field.

We find that logging with acoustic borehole modes generated by regular borehole acoustic tools in the presence of production tubing is a very difficult, if not impossible, task. At the same time, a combination of various acoustic modes (flexural, Stoneley, and pseudo-Rayleigh) can be used for CBL behind multiple casing strings. Each of the modes reacts to the presence/absence of cement behind various casing strings in its own way: frequency “shifts” and local frequency maxima are developed. We also demonstrate that the absence of cement behind a casing string and/or the presence of microannulus may cause the appearance of additional dispersion modes. Some of these modes can be detected in the field data and used for CBL.

The paper validates using regular borehole acoustic modes for CBL and develops a methodology for the analysis of these modes in the presence of multiple casings.

The Road to Achieving Business Value With Reflection Sonic Imaging

Brian Hornby, Hornby Geophysical Services, LLC

Reflection sonic imaging has been around for decades. However, there are still open questions on the range of applications and what can be really taken to the bank to impact our business challenges. Clear imaging of faults, fractures, overturned beds, and abrupt changes in structure are all of interest to those hoping to understand the bigger geologic picture away from the well. Guiding drilling in horizontal wells with real-time sonic imaging of reservoir boundaries is another prize that has not yet been achieved but needs to be firmly on the radar. In this paper, we concentrate on dipole-induced shear wave imaging and show an example of imaging reservoir boundaries in an extended reach/horizontal well acquired by a drillpipe-conveyed slimhole crossed-dipole sonic tool. An additional effort shows the investigation of fracture imaging in data from several wells, with a goal to establish under what conditions fractures can be imaged from a wellbore.

A new reflection sonic imaging workflow was developed and is applied to dipole-induced shear waves to the image structure of interest. In a manner like seismic imaging processing, a key component of this workflow is the generation of a multidimensional velocity model in earth coordinates that is used for the prestack migration of the reflection sonic data. The model can then be iteratively updated using reflection sonic imaging results. Another key part of the workflow is identifying specular reflections from the structure of interest in the time domain before applying any imaging algorithm. Prestack migration is then applied, and then the process is iterated to ensure that a better image result is achieved with any time-domain data processing step.

Imaging of sonic data acquired in an extended reach/horizontal well details high-resolution images of the reservoir boundaries relative to the well. It was found that simple treatment of the received data and an automatic migration processing flow were sufficient to achieve the key objectives of imaging these boundaries. Here the potential business value impact is that imaging results may be delivered in time to affect well decisions such as where to frac the well. For fracture imaging, results, where attainable, show high-resolution displays of the fracture topography and so delineate the actual tortuous path of the individual fractures away from the borehole. Preliminary results show that the best images come from large individual fractures or groups of aligned fractures with insufficient signal for imaging resulting from low aperture fractures or multiple fractures at different orientations. Ongoing research is looking to establish initial guidelines for imaging fractures based on effective fracture width and other considerations.

On the road ahead, thoughts on what needs to be in place for routine business value to be achieved will be presented, including desired technology advancements. On the business side, a key question for end users is this: “What would we do differently with the information from this image?” To answer this question, essential is involvement by multidiscipline asset team specialists, including petrophysicists, geologists, and seismic interpreters, to integrate sonic imaging into their workflow.