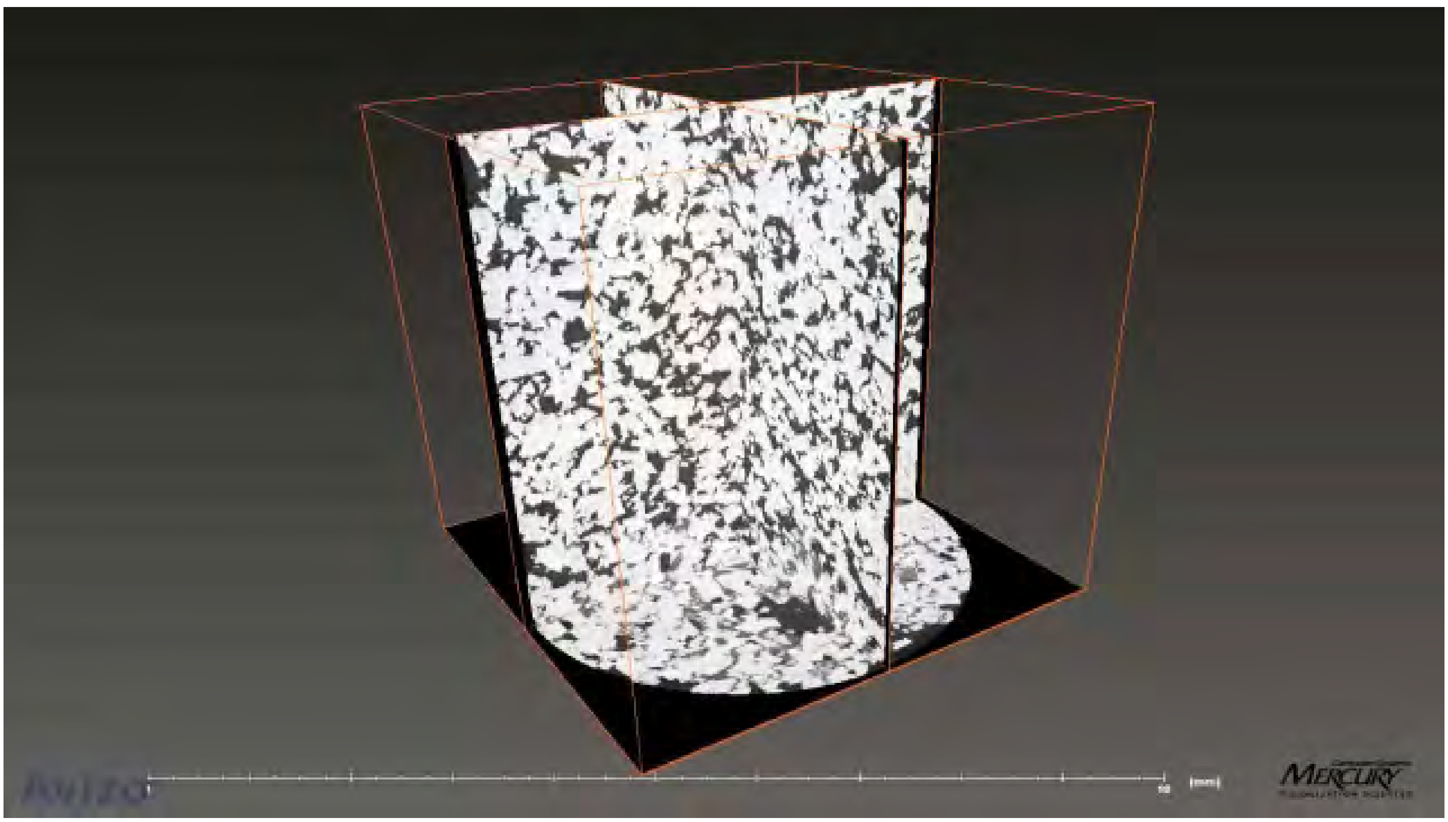
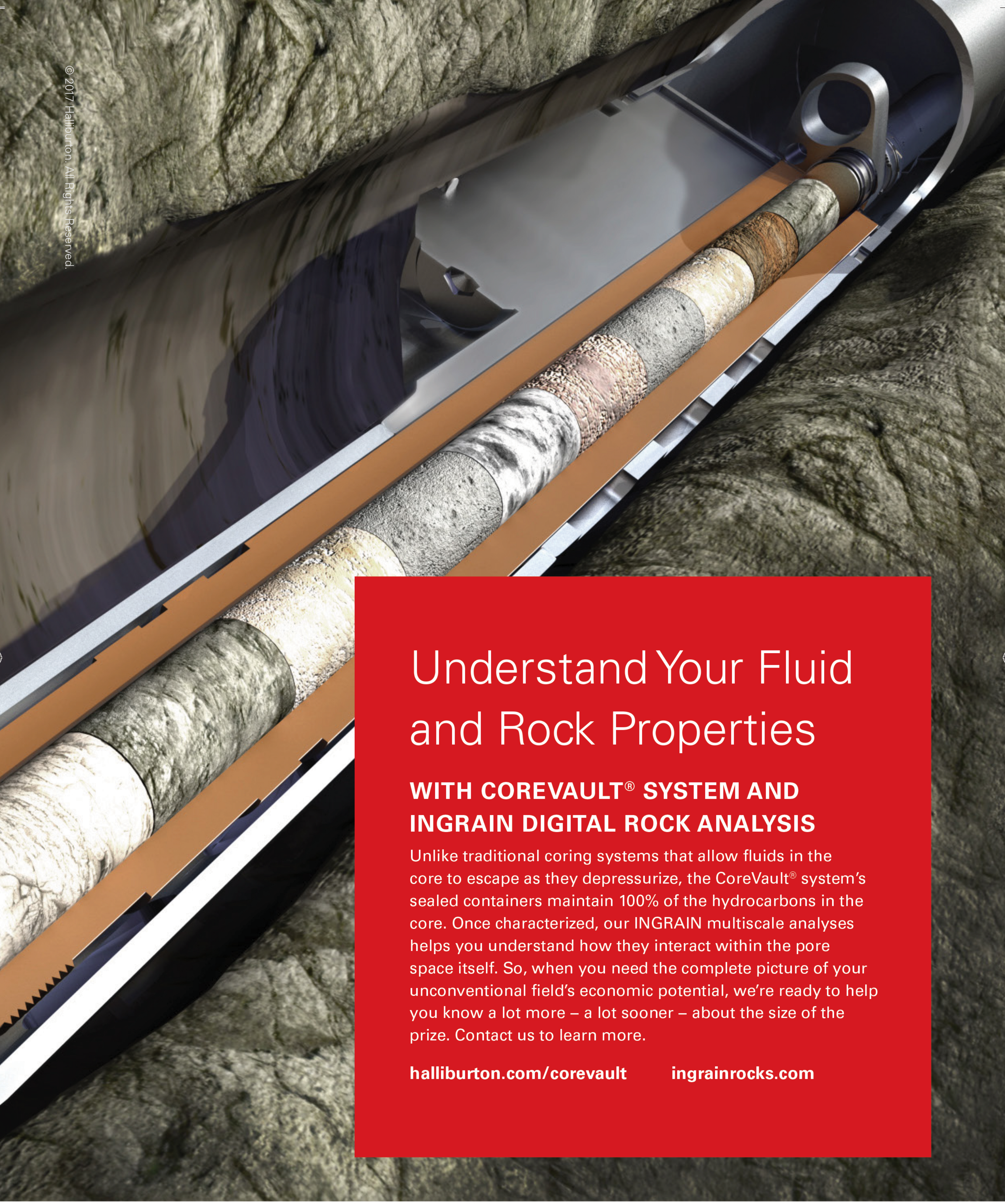
ISSUE 2 | VOL 3 | MARCH 2020

THE SPWLA TODAY

NEWSLETTER



SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS



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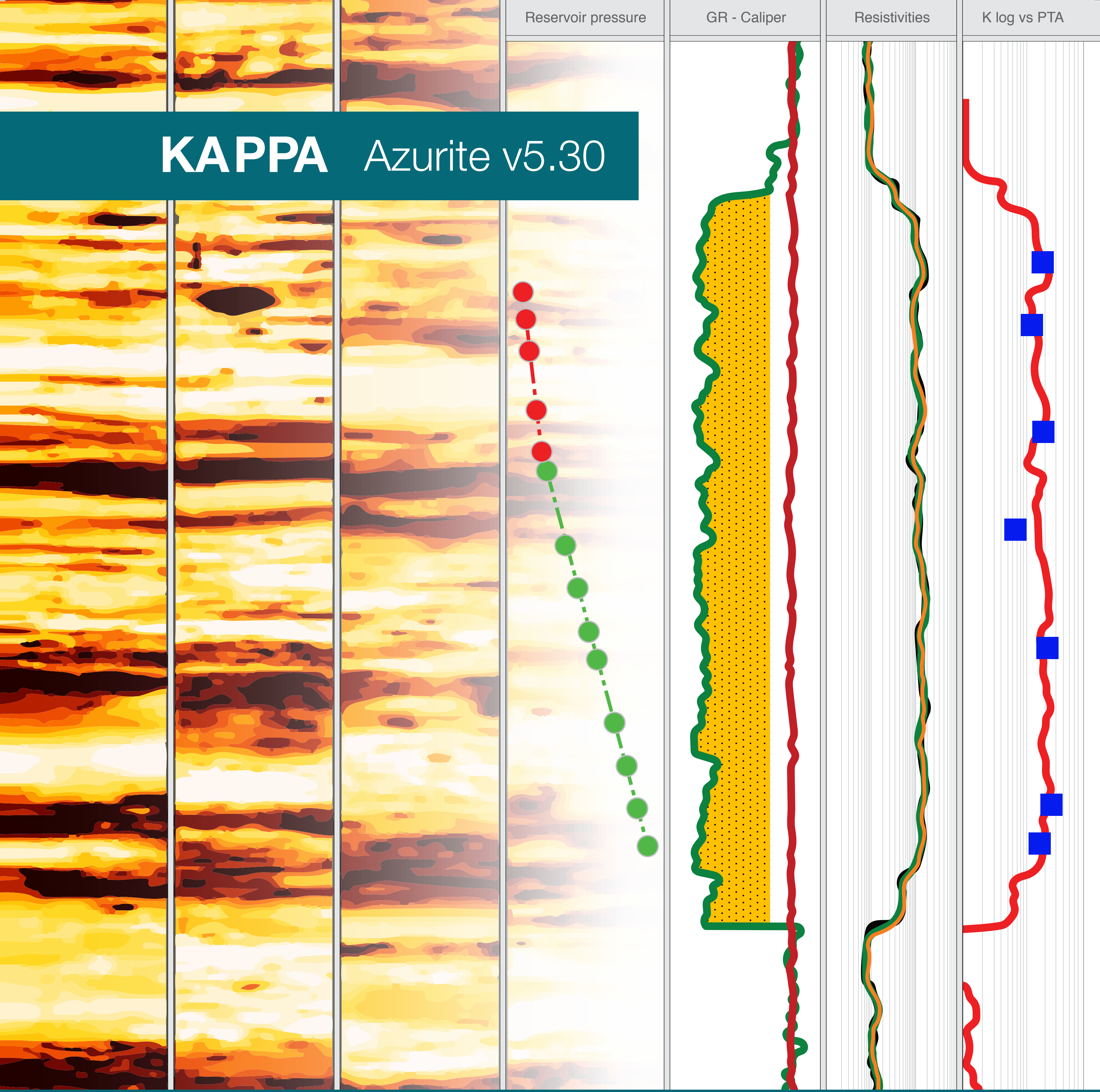
KAPPA Azurite v5.30
Reservoir pressure
GR - Caliper
Resistivities
K log vs PTA

INSIDE THIS EDITION

Notice: Articles published in SPWLA Today are not subject to formal peer review but are subject to editorial review and are verified for technical consistency and relevance.

CALENDAR OF EVENTS

March 10–11, 2020

Using Mudlogging as a Formation Evaluation Tool 2020
SPWLA FRANK S. MILLARD TRAINING CENTER
Houston, Texas
www.spwla.org

April 6–7, 2020

Data-Driven Methods for Petroleum Engineering and Geoscience
SPWLA FRANK S. MILLARD TRAINING CENTER
Houston, Texas
www.spwla.org

April 16–17, 2020

SPWLA Spring 2020 Topical Conference
Topic: Unconventional Petrophysics
Houston, Texas
www.spwla.org

June 20–24, 2020

SPWLA 61st Annual Symposium
Banff, Alberta, Canada
www.spwla.org

August 2020 – Rescheduled

SPWLA Bangkok – Asia Pacific Regional Conference
Theme: "Petrophysics: From Exploration to Brownfield; The Impact of Formation Evaluation on Oil and Gas Field Development Decisions"
Bangkok, Thailand
www.spwla.org

About the Cover

A micro-CT scan and corresponding segmented pore-grain volume for a Middle Eastern dolomite, hopefully animated. Our electronic publishing format provides opportunities to convey information beyond the text and static images of traditional publishing. This month's multimedia cover is an example of what will be coming in the future as we explore additional means for enhancing the value of our publications. We would appreciate your feedback on the experience.

From the Editor

Tom Neville
2019–2020 Vice President
Publications

Greetings and welcome to the March 2020 edition of *SPWLA Today*. Hopefully by now you will have seen the notice that registration is open for the SPWLA 61st Annual Logging Symposium, to be held in Banff, Canada from June 20 to 24. In this edition of *SPWLA Today* we highlight the abstracts of papers that have been selected for presentation at this year's symposium. After reviewing these I hope you will agree with me that the technical program is shaping up to be one of the best ever, and I hope to see as many of you as possible in Banff for the Symposium.

Something else that is coming up soon is the election of the 2020–2021 SPWLA International Board of Directors. The slate of candidates for the upcoming election was published in the January issue of *SPWLA Today*, and you should soon receive the candidate's position statements and biographies, as well as the ballots. I would like to take this opportunity to encourage you all to vote in the upcoming elections; participating is a sign of commitment to your Society.

This issue sees the return of our new "My Library" column, with John Kuhla sharing some of his favorite publications. You will see that John favors reprint volumes in his library. In the days before the widespread availability of technical papers via electronic distribution channels, reprint volumes were a way of delivering key technical references to professionals who did not have access to the original publications. Although reprint volumes may seem anachronistic, the availability of curated lists of what are considered to be seminal papers on specific topics is still of great value; we just need to rework the concept to fit with the current technology. With that in mind, one thing we are looking at developing is virtual reprint volumes—hyperlinked lists of key technical papers from different subject areas that every petrophysicist could benefit from. Look out for more information about this soon.

As a bit of an experiment with other applications of technology to improve the value of our publications, we are also taking advantage of our digital format to provide an interactive cover for this month's edition of SPWLA Today. I am very interested to hear your feedback on how well this works, as this is a prototype for other interactive publications we are planning in the future. And, as always, I welcome your feedback about everything else related to SPWLA's publications.

Tom Neville
Vice President Publications
tom.neville@slb.com

From the President

Jesús M. Salazar
2019–2020 SPWLA President

March is the month of elections, not only in the US, with the primaries already upon us, but also in the SPWLA. This year, we have a very strong slate of candidates running for several positions. I'm happy to see that our efforts to have a more diverse and inclusive board of directors and membership, in general, keeps moving forward. Out of the seven open positions we have women running in four of them. I ask every petrophysicist and petrophysics enthusiast reading these lines to vote; please support your favorite candidate. Remember that you need to be a member in good standing (i.e., paid up) to have the privilege of casting a ballot. So, if you have not already done so, please renew your membership ASAP. I wish all the best to the nominees and thank them for volunteering to the Society. I also want to remind the nominees that being part of the board is not only something that looks nice on your resume, it's a one- or two-year commitment you make with your constituents to work for the continued improvement of our Society.

The first quarter of 2020 is almost gone and I'd like to show our membership numbers at the close of 2019. I'm including several plots to illustrate the membership changes in the last 7 years and the demographics for 2019. We closed 2019 with a total of 2,651 paid members, which represents a 10% improvement with respect to the previous year. Figure 1 shows the time evolution in the number of members along with the nominal oil price during most of the last decade. As you can see, the number of members pretty much tracks the ups and downs of the price West Texas Intermediate (WTI) crude oil. Even though we're a bit far off those peak membership numbers, we consider that having more than 2,600 members is solid and it reflects in the financial health of the society. Despite a slight recovery in the price of oil price in 2018, the membership hit a low at the end of that year before rebounding in 2019. Hopefully, we will continue to see the growth trend continue in 2020 and beyond; if you have not done so, please renew your membership. Figure 2 shows the percentage distributions of our members by category and geographical location around the world. To no surprise, most of them reside in North America, followed by Europe and Asia. We've been making efforts to attract more members from Latin America and Africa by implementing the Group 2 pricing for those countries and by directly contacting potential members to lead chapters. I'm happy to see that we have more than 300 student members and continue receiving requests to start new student chapters. If you want to start a chapter or wish to have a more active role in the SPWLA please contact me or your regional director.

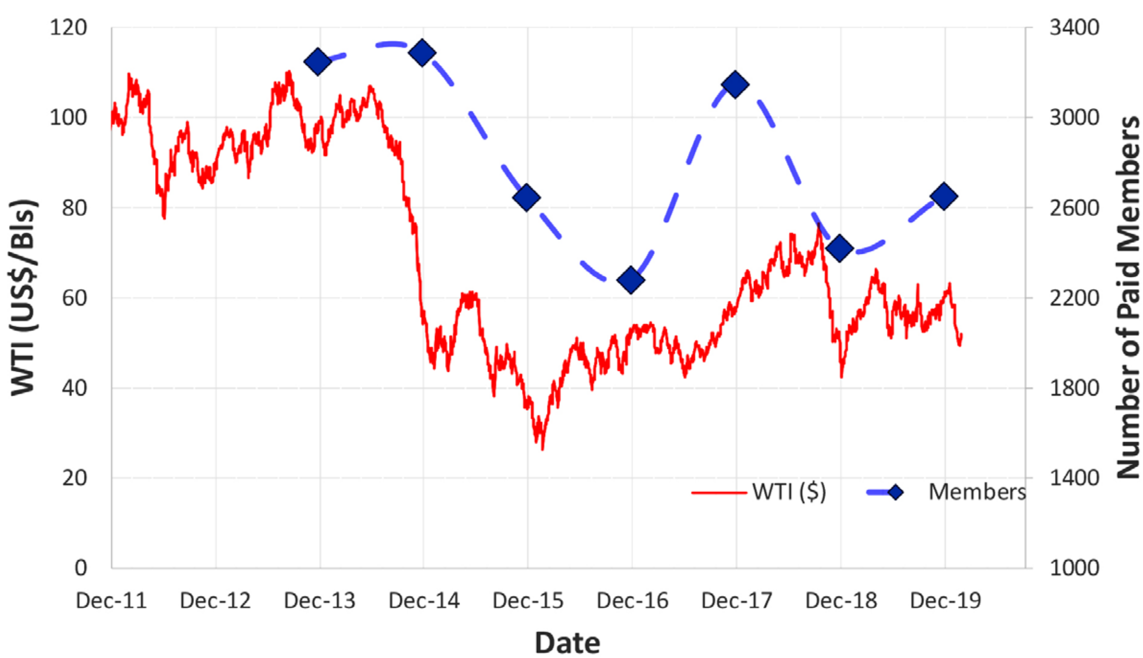

Fig. 1—Number of SPWLA members over the past 7 years compared to oil price. At the end of 2019, we had 2,651 paid members. The downturn between 2015 and 2017 put many of our members in job transitions and affected the membership registration. The bump observed at the closing of 2017 was helped by having a well-attended symposium in Oklahoma City. Large attendance at Symposiums usually boost the membership numbers because membership is offered with the higher registration cost for nonmember delegates.

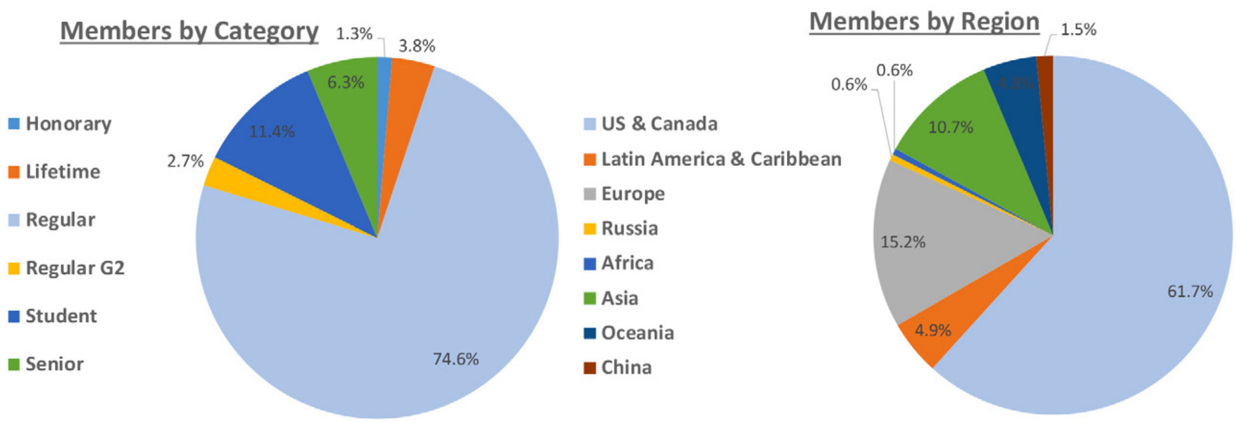

Fig. 2—Relative distribution of members by category and geographical locations for SPWLA's membership at the close of 2019. For members' category description refer to our website; location is based on the physical address provided in each member's profile.

To complete my analysis of the membership numbers. I'm including some demographics of age and gender. This one was a bit tricky, only 84% responded about their age, and 86% about their gender. I removed some outliers, such as two or three with an age less than 18 years old, and one with age of 120 years. Figure 3 shows the age distribution that ranges between 20 and 94 years old, from our very young student members all the way to our respected senior members that remain involved in the society. We really appreciate the loyalty of all our members. It is interesting to see the bimodal distribution of age with one peak around 45 (that's where I stack), another one at 65 and a dip between 50 and 60, which reflects the general age gap in the oil and gas E&P industry for people who started they career during downturns in the late 1980s and early 1990s. Finally, the embedded pie chart shows the split between male and female members, our membership is extremely male dominated we have more work to do in recruiting women to join our society. I'm happy to see that more women keep joining our discipline but many of them have not become members yet. We still need to push and motivate people if we want to make it back to 3,000+ members, let's target the young generation of petrophysicist who are the future of this organization.

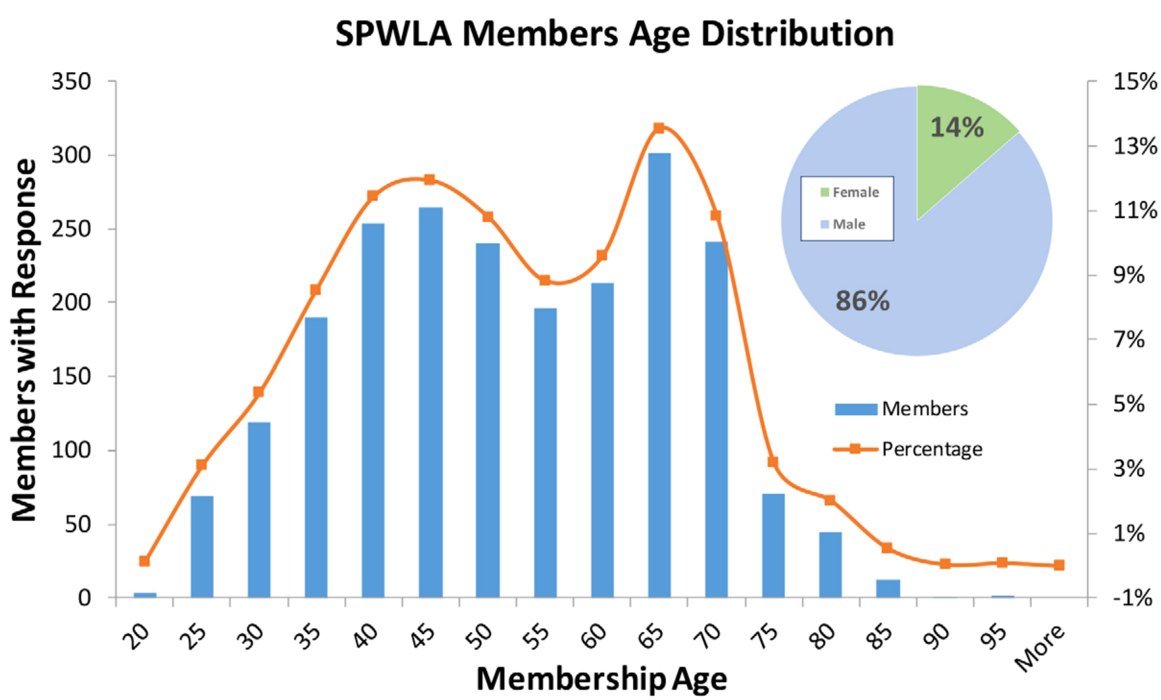

Fig. 3—Age and gender distribution of SPWLA members for 2019. The average age of our members is approximately 50 years old.

The decline in membership is not exclusive to SPWLA, it is a general problem for the oil gas industry. Most companies, both operators and service providers, have reduced their workforce considerably in the last 5 years, including geoscientists and engineers. They prefer to work very lean to be able to survive in an environment of $50/barrel, or less. I'm optimistic that our discipline will survive the ups and downs of the industry and make alliances with the evolving digital technologies to improve our interpretation and workflows and create value in a sustainable fashion.

We need to educate the younger generation that a career in the oil and gas industry is still possible and that we can produce the energy we need sustainably. I already started doing my part, last month I talked to Carnegie Vanguard High School (Houston) students about college and careers and how I ended up working as a petrophysicist, after going to college and graduating as a physicist. It was a productive conversation with a group of bright kids and hopefully a few of them will bring the message home and start thinking about a career in science and engineering. The last figure of this article shows a photo of my daughter Aranza and yours truly. Aranza happens to attend Carnegie HS and through my presentation now she understands a little bit more about what dad does for a living.

I close with this note reminding everybody that the 61st Annual Symposium is right around the corner and registration is now open. Whether you're presenting a paper, showcasing your technology, or just going for the educative opportunity, please plan ahead and take advantage of the early bird Symposium's price and reduced rate at the hotel. We have a lineup of six excellent workshops and two exciting field trips and plenty of learning opportunities from the record breaking 130+ papers selected for oral presentations and posters thanks to the flexibility of parallel sessions. You will also have the opportunity to attend to three evening social events, the business lunches during the week, or if you fancy something quicker and more informal, this year we include a networking business lunch where you can catch up with colleagues, friends, or clients.

Fig. 4—With my daughter during my presentation at Carnegie Vanguard HS in Houston. during College and Career Day. I spoke about science, especially physics, and discussed my path to working in petrophysics, including my years of volunteering for the SPWLA and SPE, and how the oil and gas industry can be sustainable and contribute to the development of new energy resources. I got a very nice thermal mug for my weekend morning coffee ☺

Stay connected my friends,
Jesús M. Salazar, Ph.D.
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Up Next

James Hemingway
2019–2020 SPWLA
President-Elect

Hello Fellow Petrophysicists!!

Hopefully, 2020 is off to a good start for everyone. The business trend that I have never been able to adapt to is stability 😊 and we are in a slow but stable economy. Who knows, we might just decide that a little stability is good for this industry. More on that when we prepare for 2021.

I'm happy to announce that the board of directors has selected Boston as the location for the 2021 annual symposium, scheduled for the week of May 16. There were a lot of things for the board to consider but overall the combination of a rich history, cultural activities combined with an easily accessible location at the Hynes Convention Center in historic central Boston, will hopefully make this a great event. There are over 60 energy related companies in the area including Aramco, Schlumberger and Shell. In addition, Boston is a global hub for technology R&D and is home to universities such as Harvard and MIT.

Boston Skyline (Credit: King of Hearts - Own work, CC BY-SA 4.0)

Harvard University (Credit: Harvard University)

Registration should be open for the symposium in Banff. I'm looking forward to seeing everyone at what is shaping up to be a great conference.

Best Regards,
James Hemingway, P.E.
SPWLA President-Elect

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Michael O'Keefe
2019–2020 VP Technology

Dear Friends and Colleagues,

The results are in! I have released the Technical Program for the 61st Annual Symposium. They are summarized in this edition of *SPWLA Today*, and can also be found on our Symposium website at: www.spwlaworld.org/technical-program-2020

I wish to sincerely thank all 45 members of the SPWLA Technical Committee for their enormous contribution in reviewing 100 anonymous abstracts each. We were able to achieve an average of 10 to 15 reviewers per submission, which made for a fair and balanced assessment.

Of the 384 abstracts submitted, only the top 145 were accepted—that is just 38% of the total. There is no doubt that many worthy abstracts were unfortunately turned away. However, we must work within the limited time we have available;

- Oral Presentations 99
- Poster Presentations 46
- Rejections 239

These numbers repesent an increase of +50 oral presentations over the 2019 symposium, which is made possible by running parallel sessions for most of the agenda. Some 'traditionalists' may be upset at not being able to attend every symposium presentation, however I am convinced that expanding our footprint and enabling a higher participation is for the benefit of our Society at large. Choose your Session!

A breakdown of abstracts into author-submitted categories is summarized in the table below;

Topic	No. Abstracts
Formation Evaluation of Unconventional Reservoirs	86
Case Studies	69
Formation Evaluation of Conventional Reservoirs	69
New Borehole Logging Technology	53
Advances in Machine Learning	48
Formation Evaluation Behind Casing	21
Completion Petrophysics and Reservoir Surveillance	19
Deepwater Reservoir Analysis	10
Petrophysics in Brownfields	9
Total	**384**

After reviewing the table above, I came to the realization that these categories were far too broad to be useful in defining 'Sessions' for the Symposium. So, Tegwyn Perkins and I shall fix this for the next year of online submissions. In the meantime, I reread every single abstract and manually recategorized each into two specific categories. My reanalysis of the submissions is as follows;

Categories	Percent
Unconventional reservoir	9.83
Machine Learning	7.80
Core intepretation	6.36
Log interpretation	6.36
Acoustics	5.78
Geomodeling	5.06
Bore hole Imaging	4.77
Nuclear magnetic resonance	4.62
Casedhole logging	4.48
Integrated interpretation	4.19
Nuclear (porosity/density)	4.05
Carbonate	3.90
Formation testing	3.76
LWD	3.32
Resistivity	3.32
Geomechanics	2.60
Reservoir monitoring	2.31
Dynamic modeling	1.88
Wellsite Operation	1.88
Downhole fluid analysis	1.73
Conventional reservoir	1.59
Geochemistry	1.45
Complex Lithology	1.30
Rock physics	1.30
Thin-bed Interpretation	1.30
Geosteering	1.16
Completion	1.01
Dielectric	1.01
Production logging interpretation	1.01
Basin interpretation	0.87
Total	**100**

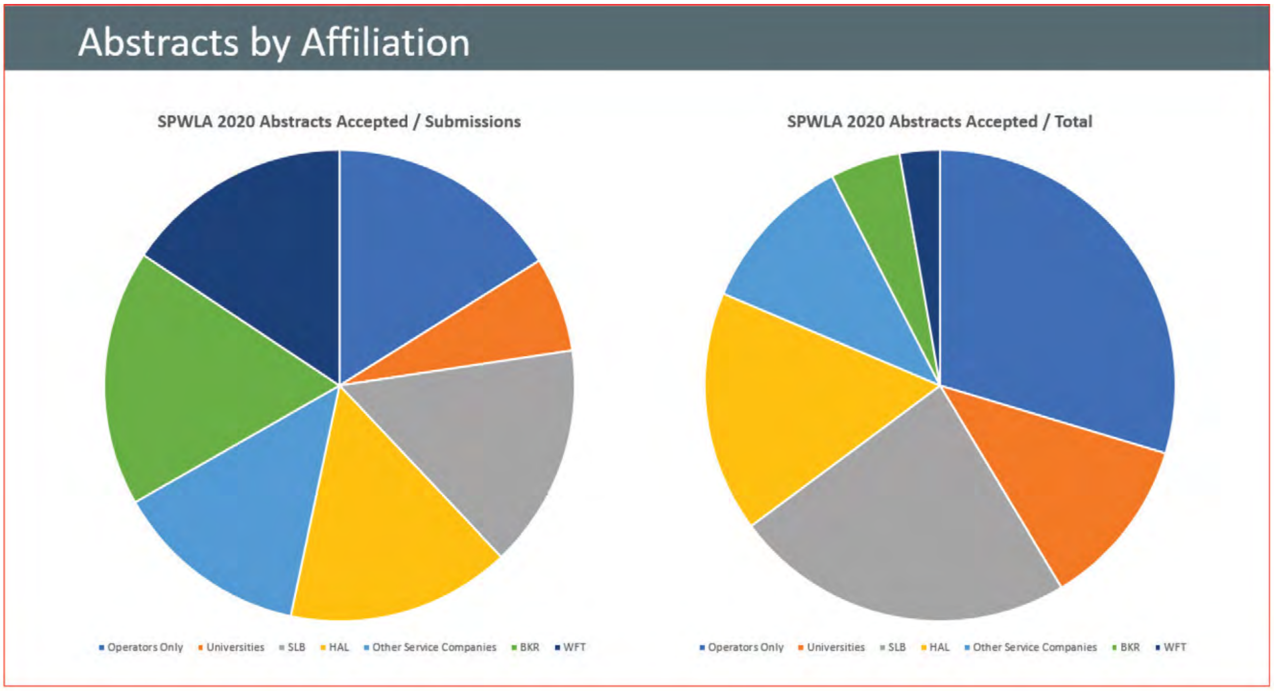
I guess a lot of members would be begging the question—who actually authored these papers?

Abstracts by Affiliation

Affiliation	Submitted	Accepted	2019 Accepted	Accepted/Submitted (%)	Accepted (%)
Operators only	94	43	25	46	30
Universities	92	17	38	18	12
Schlumberger	78	34	30	44	23
Halliburton	55	24	7	44	17
Other service companies	42	16	0	38	11
Baker	14	7	6	50	5
Weatherford	9	4	6	44	3
TOTAL	**384**	**145**	**113**	**38**	**100**

- 145 Abstracts were accepted in 2020, compared to 113 the previous year.
  - More focus on oral presentations (+50), less on posters
  - But both are treated equally in our published transactions!
- All major service companies had equal distribution.
  - 44% acceptance of submissions for Schlumberger, Halliburton, and Weatherford (Baker Hughes slightly more at 50%)
  - Halliburton has > 3 times the number of papers compared to last year (24 vs 7)
  - Large increase in smaller service companies (good!)
  - Note that counting was slightly different in 2019 for operators and smaller service companies

- Operators had 46% acceptance, and represent the majority of papers
  - 75% increase from previous year. This is a positive indicator.
- Significant reduction in the number of accepted submissions from Universities
  - Don't know exactly why this is. All reviews were anonymous.



Symposium Workshops

We have an absolutely fabulous line up of workshops this year that will be delivered by some of the most experienced leaders in our Industry! I encourage everyone to sign up, they go far beyond anything you have experienced previously.

ID	Workshop Title	Schedule	Instructor (Organizer)
WS-1	3D Printing in Geoscience and Engineering	Saturday	Sergey Ishutov (postdoctoral fellow, University of Alberta) Kevin Hoder (postdoctoral fellow, University of Alberta Rick Chalaturnyk (Professor, University of Alberta)
WS-2	Electromagnetics	Saturday	Martin Luling (Schlumberger) Barbara Anderson (Schlumberger, retired) David Allen (Schlumberger) Scott Jacobsen (Consultant)
WS-3	Uncertainties in Petrophysics: Methods of Statistical Analysis and Data Visualization	Saturday	Michel Claverie (Schlumberger) Lalitha Venkataramanan (Schlumberger) Marco Pirrone (Eni) Laurent Mosse (Schlumberger) David Allen (Schlumberger)
WS-4	Geomechanics 101	Sunday	Jeff Taylor
WS-5	NMR: The Emergent Primary Porosity Tool, and Beyond	Sunday	Jinhong Chen (Aramco Services Company) NMR SIG (SPWLA)
WS-6	Recent Progress in Resistivity and Dielectric Logging	Sunday	Hanming Wang (Chevron) Hezhu Yin (ExxonMobil) Teruhiko Hagiwara (Aramco) Michael Rabinovich (BP) John Rasmus (Schlumberger, retired) Michel Claverie (Schlumberger) Nikita Seleznev (Schlumberger)

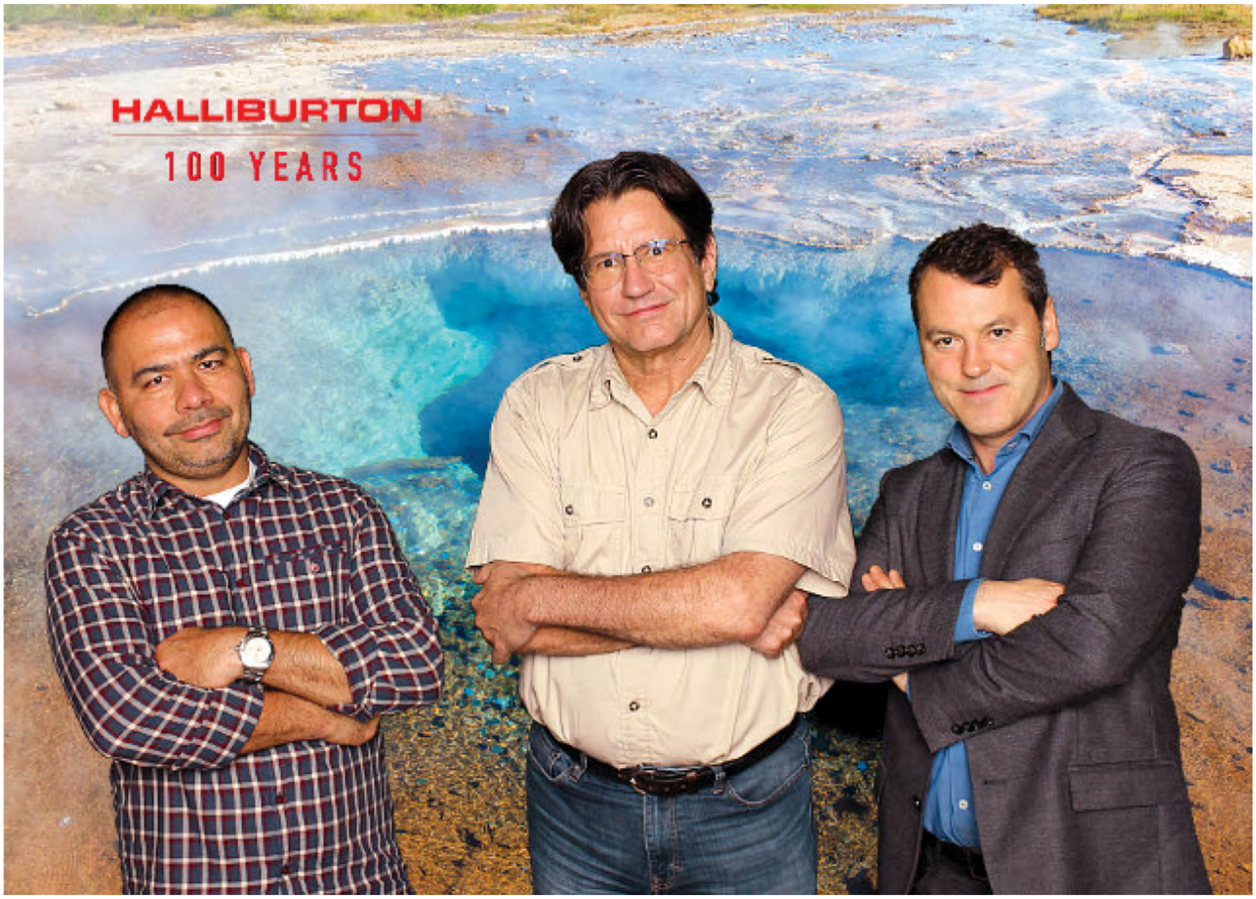
Last note: We have SPWLA elections coming up next month, I am standing for President-Elect. I hope you can continue to support me to deliver for SPWLA!

Best Regards,

Michael O'Keefe.
Vice-President Technology.

Send a photo, Tom asks! Well apart from pie charts, this is the best I could come up with 😊

SPWLA VP Technology: From 2018–2019–2020



Lin Liang
2019–2021 Vice President
Information Technology

Digital Transformation in the Upstream Oil and Gas Industry

The oil and gas industry has been pushing for a digital revolution during the past few years. Both oil companies and the service companies have been forced to make difficult strategic choices and learned little by trial and error. Today, the industry appears taking a firmer stand on the need for digitalization, although there are still people remaining skeptical. Considering the extensive use of computers and the internet nowadays, we have already been in a digitized world for many years. Such indicators include the digital design of hardware, software-based data processing and interpretation, digital office and communication support, and a modern ERP system. Nevertheless, while the so-called “smart well”, “smart field”, and “digital field” have been advocated for years they have yet to succeed on a large scale. Why do we need to redigitize? What’s different about this digital transformation? The significance of the new digital transformation goes far beyond that.

Technology advancements in the Internet of Things (IoT), cloud computing, robotics, data science and machine learning (ML), artificial intelligence (AI), etc. have been continuously shaping the Internet economy, especially for those 2C businesses that have witnessed significant changes almost every year. On the other hand, traditional industries have shown a strong reluctance in accepting or adopting new digital technologies, due to their conservative nature, less open competition, closed ecosystem, geopolitics, etc. Large upstream oil and gas players have remained essentially unchanged for years. However, the current downturn, since 2014, has forcefully provided an excellent opportunity for the industry to take on the major challenge of redigitalization. The most adaptive and fast-acting participants will likely have a greater chance of winning the market in the future.

Due to a lack of IT talent, many large enterprises choose to collaborate with major IT solution providers. Some IT companies focus primarily on providing infrastructure, while some of them also get their feet wet on the business side. Centralizing on new technology applications, the market has also spawned many small startups.

Below, I would like to share some of my thoughts on a few selected aspects in this transition period.

Digital Platform

The recent initiative to establish an Open Subsurface Data Universe (OSDU) forum opens the door to potentially significant changes in the oil and gas industry. This forum aims to develop a standard data platform that brings together subsurface data covering everything from exploration, development, to wells. On top of the universal data platform, it will potentially enable an API-driven digital platform (let’s call it Open Subsurface Service Universe (OSSU) for convenience) serving for various business applications. More importantly, the openness of the data platform will greatly lower the bar for small players or talented individuals to enter the oil business. Imagine a digitized world where open platforms allow everyone to conveniently develop and deploy their APIs or APPs, and get rewarded based on their usages. For companies that plan to develop their own applications but don’t want to spend resources developing every component in the process, they can easily access and invoke the corresponding APIs from OSSU. The high Internet speed brought by 5G will make the combination of OSDU and OSSU an effective solution for next-generation platforms. Web-based front-end plus subscription-based and/or usage-based payment models will replace the traditional license-based software models and make fundamental changes to the way how business gets done. SaaS and PaaS models have been a growing trend for future-oriented service providers.

Open Source

The iteration of technology becomes much faster than ever. Open source has never achieved popularity in the oil industry due to its historical conservatism, but now we might see an interesting trend toward a more open industry. Thanks to OSDU and potential OSSU, small independent entities will have their chance to get more involved in various ways, through open source and further making business opportunity via providing fine-granular support and service.

Machine Learning and Artificial Intelligence

AI is no longer a buzz word getting ready to change the world; it is reshaping the world now. Significant progress has been made on applied AI. However, we are still in the very early stage of cognitive AI.

ML has attracted wide interests from the oil industry in the past 3 to 5 years. It can be used to solve many problems that could not be solved previously using elegant physics-based approaches. Such examples include quality control and preprocessing of well-logging data, image analysis and interpretation, drilling dynamics prediction and optimization, job planning, etc., or more efficient solutions by combining ML with physics. Much effort has been spent in developing data-driven, supervised machine-learning solutions for various applications. Despite significant progress made in improving the interpretability and uncertainty quantification of neural networks, quality control of the output results becomes a key issue because of the lasting concern in the generalization capability of the trained neural networks. Most data-driven ML-based solutions are not perfect at their early stages, as they are usually trained on limited scope or amount of data. In order to deploy these solutions, it is essential to have a digital platform to support its self-evolution when a solution is used by the users. The life cycle of such a self-evolving solution should be managed in an automated manner to avoid the need of maintaining a year-round development team constantly working on the same project. Naturally, the ideal way to deploy a data-driven ML solution is through microservices, rather than being bundled into a standalone software installation kit.

Physics-driven ML refers to methods that use knowledge of physics to guide, constrain, or compensate for ML or perform ML from data generated by applying the laws of physics. Although a physics-based solution (if one exists) is generally preferred because of its better accuracy and generalization capability, there are good reasons to combine knowledge of physics with ML. In many application scenarios, forward modeling based on physics can be very expensive, which leads to a very low interpretation efficiency. For a problem with a manageable dimension of variables, offline training based on synthetic data generated by a physics-based solver can be used to greatly improve the interpretation of relevant measurements in terms of speed, accuracy and uncertainty quantification.

Blockchain

As a technology designed to solve trust-related issues, blockchain has been a hot topic for fintech applications. If globalization is an irreversible trend (although there have been some headwinds recently), detrust will be one of the key elements of the future economic atlas. Application of blockchain technology in the oil and gas industry is currently concentrated in the supply chain, oil trading, etc. In the future, it is also possible to apply this technology to cross-organization asset management and data management, especially when traceability and transparency are required on certain specific business models. For example, how to allow data to be monetized? The combination of digital signature and blockchain technology may provide essential building blocks for such applications. Technologies related to decentralization and detrust will have a profound impact on the future geopolitics and reshape the related business and economic landscape.

Management

Finally, digital transformation is not just about technology. The adaptability of management and teams to the new model is the key to the success of the transformation, and the transformation will force changes in working methods and even lead to new business models.

As a traditional industry, the shortage of IT talent is a challenge for effective digital transformation. How to restructure the organization to maximize the use of human resources and form agile teams is critical to successful transformation. For companies with multiple vertical business product lines, it is important to strike a proper balance between business-leading or IT-leading decisions. To avoid potential confusion and improve the reusability of shareable products and middleware, a unified digital transformation team shall prove to be a good strategy.

A good architect is a key to the foundation of a digital platform. Making the right decisions for platform architecture greatly increases its chance of success. Ideally, a pilot team should be formed to explore and design the architecture and make decisions on the selection of relevant development technology stacks. During the exploration phase, tasks can be broken down into small steps and executed with rapid iterations. When it matures, it can expand to the entire company and all teams working on different product lines.

The progress of companies in digital transformation is necessarily uneven, and it is yet to predict which solution will ultimately win the future. But we can't look back. "The best way to predict the future is to create it".

Lin Liang
Vice President Information Technology

Learning Opportunities

Katerina Yared
2019-2020
Vice President Education

Dear Petrophysics Aficionados!

2020 is off to a great start. We have filled all our 2019–2020 monthly Distinguished Speaker webinars that so many of you attend and like! Thank you for your support and attendance and the great questions we get form you all!

I would like moment to thank all our 2019–2020 Distinguished Speakers! They are the backbone of what our society stands for: knowledge sharing and education. Thank you all for taking the time to share your knowledge and visit our chapters worldwide!

Sign Up For The Upcoming DS Webinars Today:

Date	Webinar Title	Presenter
March 3 and 4	Digital Rock Technology for Accelerated RCA and SCAL: Application Envelope and Required Corrections	Nishank Saxena Shell
April 14 and 16	'Log-Soak-Log' Experiment in Tengiz Field: Novel Technology for In-Situ Imbibition Measurements to Support an Improved Oil Recovery Project	Yegor Se Chevron Energy Technology Company
May 12 and 13	Experimental Investigation of Mud-Filtrate Invasion Using Rapid Micro-CT Imaging	Colin Schroeder The University of Texas at Austin
June 2 and 3	Investigation of Physical Properties of Hydrocarbons in Unconventional Mudstones Using Two-Dimensional NMR Relaxometry	Harry Xie Core Laboratories

Also, we have a great lineup of training classes and conferences coming up at our Frank S. Miller training facility in Houston, Texas. For example:

- March 10 and 11, "Using Mudlogging as a Formation Evaluation Tool 2020," led by Bill Donovan
- April 6 and 7, "Data-Driven Methods for Petroleum Engineering and Geoscience," led by Dr. Siddharth Misra.

Please be sure to sign up for them and other events on our web page www.spwla.org.

Call for abstracts for our 2020 Spring Topical Conference on "Unconventional Petrophysics" is still open. Send your abstract to abstract@spwla.org. We look forward to discussing the new methodologies and techniques we must use to tackle challenges in the unconventional shale reservoir world. I would like to thank the committee and the committee chairs (Jinhong Chen and Matt Blyth) for leading this urgently needed STC. The conference discussions will be informal off the record to encourage open discussions.

We are also looking forward receiving the student paper abstracts for our ISPC at our SPWLA Symposium on June 21 in Banff! The deadline for submission is March 30th at papercompetition@spwla.org! Thank you to Aaron Shelby-James for being the ISPC lead for SPWLA 2020.

Registration is now open (www.spwla.org) for the SPWLA 61st Annual Logging Symposium and I can't wait to reconnect with you all there!

Finally, I would also like to thank my left and right hands in terms of SPWLA Social Media committee, Mathilde Luycx (Exxon) and Rushil Pandya (Texas Tech University). I would only be half the social media officer I am without you!

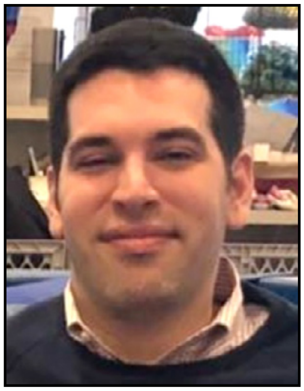
Remember the hashtag for our 2020 Symposium is #SPWLA2020. Start spreading the love, people! #IsharebecauseIcare

Respectfully yours,

Katerina Yared

Katerina Yared
VP Education 2018–2020

Regional Understandings – North America 1



Adam Haecker
2018–2020 Regional Director
North America 1

This column is called regional perspectives, and in this case, it is really true! Jesus, our glorious El Presidente, has asked Kelly and I to review the areas we cover since there was a big disparity in number of chapters between the North America 1 and North America 2 directorships. This happens over the years as chapters close down and new ones crop up. To give you some historical context in 1983 there were over 70 chapters worldwide, today there are only 32 professional chapters. In North America, we are also blessed with seven student chapters, which is an additional consideration for the directors. Most of these student chapters are clustered in central Texas and Louisiana. So basically, we tried to split the chapters up equitably and that meant drawing a fairly tight circle around Houston, the Oil Mecca of the world.

Here is the new chapter distribution between the North America Director 1 and North America Director 2. This includes student chapters. On the map, blue circles with 1 are covered by Director 1 and those in the red circles with 2 is are covered by Director 2 (simple right?).

Now, each director will have approximately eight chapters. The following table presents a breakdown of which chapters will report to which regional director. If highlighted in orange, it was changed. This will tilt more student chapters towards Director 1, but if we want to preserve geography, we have to do it this way.

In any event, to minimize disruption, the change will take place with the election of the new Directors this summer.

Director 1	Director 2
Dallas	Appalachia
Houston	Bakersfield
University of Louisiana Lafayette	Boston
New Orleans	Denver
Texas A&M College Station	Oklahoma City
Texas A&M Kingsville	Permian Basin
University of Houston	Texas Tech University
University of Texas	Tulsa
	University of Oklahoma

If you have some feedback on the changes let us know. We tried to keep local student chapters with the nearest professional chapter under the same director. This is an exciting time to be part of SPWLA and perhaps the shrinkage or change in distribution of chapters is part of a larger trend in the industry towards consolidation around Houston. Maybe not!

Good night and good luck!

Regional Understandings – North America 2

Kelly Skuce
2019–2020 North America 2
Director

Dear SPWLA Members,

I am writing this month's column from the comfort of the airport here in Calgary waiting to jet off to sunny Hawaii. A much-needed vacation is needed this year, but I do have a couple topics below to create some conversation, so please email me your comments, questions, and concerns at Director-NA2@spwla.org.

The Annual Logging Symposium in Banff, Canada, is fast approaching. If you have been out of touch, registration for the symposium is live (the hotel is already booking up fast). The Technical Committee, headed by Michael O'Keefe, VP Technology, has done a great job selecting papers for us all to hear and see. Parallel sessions this year has allowed us to put together a larger selection of papers, however (TOPIC 1) there will be the added difficulty of selecting which sessions to attend. The events surrounding the conference look great; Gondola trip to the top of Sulphur Mountain, Mount Stephen Burgess Shale hike (very strenuous, this one), and the scenery of Banff in the majestic Rockies!

(TOPIC 2) The areas of responsibility for the two Regional Directors in North America has been a question of late. Who has responsibility for each chapter and why? As each director only overlaps with another for a year, which chapters fell under each director was just what the other one didn't have in their list. As I am located in Calgary, Alberta and Adam Haecker (the other Regional Director) is in Tulsa, Oklahoma, I have created an issue where I am located quite a distance from the other chapters (and neither of us is in Houston with the mothership). Adam and I are trying out an idea of shaking up the chapters and creating some type of sensible division to them. What creates a problem is the majority of the professional (and student) chapters are in the states of Texas, Oklahoma, and Louisiana, with the exception of four (Boston, Denver, Appalachia, and Bakersfield). Should we add Mexico and Canada to the list (they are part of North America, right)? Mexico has a slight language barrier (may identify better with the Latin American Directorship, please tell me if I am wrong) and Canada doesn't have an official SPWLA chapter, but a sister society with the CWLS. All this could be naught as I have been receiving regular updates from all the chapters in my region. All of them are having regular meetings making sure I am informed of their plans which speaks to a healthy community of petrophysical discussion which I am proud to be a part of.

See you all in June!

'Nuff said!
Kelly Skuce

Regional Understandings – Middle East and Asia

Shouxaing “Mark” Ma
2019–2020 MEA
Regional Director

Dear Colleagues,

As the saying goes, “the future belongs to those who prepare for it!” As an industry representative, how does SPWLA prepare its future? We all collectively have a responsibility to help to develop the young professionals, our future depends on them!

There are many ways for professional development; mentoring, coaching, and other means of knowledge sharing and transferring. With the availability of new technologies, virtual learning and knowledge sharing become common cost-effective practices.

As you already know, there is a LinkedIn group dedicated for knowledge sharing and transferring, “Learning and Practicing Petrophysics Together.” With more than 1,000 members, mostly young professionals and students, you are encouraged to actively participating in group discussions, ask questions, challenge industry experts.

Happy learning from each other!

S. Mark Ma
SPWLA Director – Middle East and Africa Region

SPWLA FORTH BOARD OF DIRECTORS MEETING
SPWLA BUSINESS OFFICE
HOUSTON, TEXAS
DECEMBER 4, 2019

President, Jesús M. Salazar called the meeting to order at 8:00 am. In attendance Vice President Finance Doug Patterson, Executive Director, Sharon Johnson. Remote attendance President-Elect, James “Jim” Hemingway, Vice President Technology, Michael O’Keefe, Vice President Education, Katerina Yared, Vice President Information Technology, Lin Liang, Regional Director N. America 1, Adam Haecker, Regional Director N. America 2, Kelly Skuce, Regional Director Asia/Australia, Jennifer Market, Regional Director Middle East, Mark Ma. Absent from the meeting Vice President Europe, Craig Lindsey, Vice President Publications, Tom Neville, Latin America, Nadege Bize-Forest.

A motion made by Doug Patterson to waive the reading of the minutes from the October 9th board meeting was seconded by Katerina Yared. Passed by majority vote.

Action Item: Katerina Yared to send the list of the Distinguished Speakers 2019–2020 to the Board members.

A motion made by Doug Patterson to accept the list of Board Candidates presented by Zhipeng Zach Liu was seconded by Katerina Yared. Passed by majority vote.

A motion made by Jennifer Market to accept the SAID revised bylaws was seconded by Adam Haecker. Passed by majority vote.

A motion made by Michael O’Keefe to accept the Hydrocarbon Reserves – Special Interest Group of SPWLA was seconded by Doug Patterson. All approved and the motion passed.

A motion made by Doug Patterson to accept the SCA revised bylaws was seconded by Kelly Skuce. All approved and the motion passed.

Action Item: Kelly Skuce to add Doug Patterson to the SPWLA/CWLS 2020 Annual Symposium committee meetings.

A motion made by Jennifer Market to accept the education committee presented by Katerina Yared was seconded by Adam Haecker. All approved and the motion passed.

Action Item: Jim Hemingway to follow up with the Chapters entering bids to host the SPWLA Annual Symposium in 2021. Additional information is needed to make a decision on the location. Plan a January 20th meeting with the board to discuss the outcome.

A motion made by Adam Haecker to accept the CEFES Chapter bylaws on contingent of a modification to the dues clause in Article 7 to read “SPWLA Members in good standing are exempt of dues and/or membership fees. For non-SPWLA Members, dues and fees may be levied by recommendation of the President and as approved by a majority vote of the qualified membership of the Chapter. Dues shall become delinquent two months after being approved, and members in arrears shall be classified as “not in good standing.” All approved and the motion passed.

Action Item: Adam Haecker and Kelly Skuce to reassign the current N. America Chapter assignments to those suitable to their respective regions. Report the changes to the Board and business office.

Action Item: Sharon Johnson to create a tab on the SPWLA website to add all committees.

A motion made by Doug Patterson to adjourn the meeting at 11:45 am.

Respectively Submitted by
Sharon Johnson, Executive Director

Next BOD meeting: February 12, 2020, SPWLA Business Office Houston and Remotely.

SPWLA FIFTH BOARD OF DIRECTORS MEETING
SPWLA BUSINESS OFFICE
HOUSTON, TEXAS
FEBRUARY 13, 2020 (date change)

President, Jesús M. Salazar called the meeting to order at 8:00 am. In attendance Vice President Finance Doug Patterson, Executive Director, Sharon Johnson. Remote attendance President-Elect, James "Jim" Hemingway, Vice President Technology, Michael O'Keefe, Vice President Education, Katerina Yared, Vice President Publications, Tom Neville, Vice President Information Technology, Lin Liang, Regional Director N. America 1, Adam Haecker, Regional Director N. America 2, Kelly Skuce, Regional Director Asia/Australia, Jennifer Market, Regional Director Middle East, Mark Ma, Regional Director, Latin America, Nadege Bize-Forest. Absent from the meeting Vice President Europe, Craig Lindsey.

A motion made by Kelly Skuce to waive the reading of the minutes from the December 4th board meeting was seconded by Doug Patterson. All approved and the motion passed.

Action Item: Katerina Yared to investigate the purpose of two Pakistan Student Chapter (s).

A motion made by Adam Haecker to accept the TAMU Student Chapter bylaws and Charter was seconded by Doug Patterson. All approved and the motion passed.

A motion made by Doug Patterson to accept the proposed policy for dues waiver as written herein was seconded by Katerina Yared. Passed by majority vote.

SPWLA Dues Waiver for disability or unemployment for renewing members up to two consecutive years

- Provide a written request by email to membership@ spwla.org
- Submit a dues waiver request annually
- After 2 years offer 50% reduced membership fees if still disabled or unemployed (must submit dues waiver annually). This would have a cap of two years, after two years they revert to the full membership fees.

Action Item: Jesús M. Salazar to write a proposal for an Article Change for Board of Director position terms.

Action Item: Katerina Yared to send a message to the Distinguished Speakers to advance their talk/presentation time from 15 to 20 minutes to 35 to 40 minutes. Also update the Directors Manual to reflect the new rule.

Action Item: Entire Board to send a paragraph of their current board position for the volunteer page on the website to encourage new interest and recruits.

Action Item: Stephanie to add a form under the volunteer tab on the website for interested persons to apply.

Action Item: Sharon Johnson to send the Board an updated Charter list of Chapter who have signed.

Action Item: Adam Haecker and Kelly Skuce to reassign the current N. America Chapter assignments to those suitable to their respective regions. Report the changes to the Board and business office.

A motion made by Nadege Bize-Forest to adjourn the meeting at 11:15 am.

Respectively Submitted by
Sharon Johnson, Executive Director

Next BOD meeting: April 15, 2020, SPWLA Business Office Houston and Remotely.

Now You See It, Now You Don't; Interpreting Resistivity Logs from a Gas-Hydrate Test Well in Northwestern Canada

Barbara Anderson
SPWLA President
1994–1995
SPWLA Gold Medal for
Technical Achievement
2007

The idea for this column came to mind while searching through published papers for material to use for introducing discussion topics at an Electromagnetics Workshop that Martin Lüling and I are cochairing at the Banff Symposium. One of the planned topics is "Using Laboratory Measurements on Cores to Establish Ground Truth—Oh Really?" The photo shown in Fig. 1 was included in background material for a paper describing logging and testing performed during the Mallik 2002 Gas Hydrate Production Research Well Program (Anderson et al., 2008). It seemed like showing a core that disappeared while being examined in the laboratory would be a good introduction to this workshop topic. This hydrate case study is also a good example of how specialists in different areas of petrophysics can work together to find a unique solution to a complex problem.

Gas hydrates are naturally occurring ice-like combinations of gas and water. For years, it has been speculated that gas hydrates could become a major source of natural gas. However, gas recovery from hydrates is hindered because the gas is in a solid form, and hydrates commonly occur is hostile Arctic and deep marine environments. Some hydrate deposits look like ice pebbles dispersed in conglomerates, while others look like the solid icy core shown in Fig. 1. The most common methods of gas recovery from hydrates is dissociating or "melting" them in-situ, either by heating the reservoir or decreasing the reservoir pressure.

Fig. 1—Photo of a gas-hydrate-bearing core from the Mallik 5L-38 research well. The gas hydrate is the white material that has been ignited by the lighter in the technician's hand (courtesy of the Mallik 2002 Gas Hydrate Production Research Well Program).

In 2002, the partners in the Mallik Gas Hydrate Production Research program drilled a test well, Mallik 5L-38, in the Mackenzie Delta, Northwest Territories, Canada. This location was chosen because it has one of the highest gas-hydrate concentrations in the world. The partners included international members from Canada, the United States, Japan and India, which all have significant offshore hydrate deposits.

The test well was cored and significant gas hydrates were found between 900 to 930 m. This was chosen as the interval for the production test since it was also bounded by shales. An openhole logging suite that was run prior to the production test included array induction, array laterolog, acoustic velocity, density, nuclear magnetic resonance and 1.1 GHz electromagnetic propagation logs. The Reservoir Saturation Tool (RST) was run before and after the thermal test to monitor formation changes. A Cased Hole Formation Resistivity (CHFR) tool was run after the thermal test.

The thermal test involved injecting heated brine down a circulating string that started at the wellhead. The fluid was circulated past the open perforations in the casing, and fluid and produced gas were returned to the surface in the annulus between the circulating string and casing. The fluids and produced gas were separated in high- and low-pressure separators. Gas was measured and flared, as shown in Fig. 2. At the end of the 5-day thermal test, the measured cumulative gas production was

516 m^3.

My role in the analysis was to try to determine the size and shape of the annular region of gas-hydrate dissociation that occurred around the wellbore by iterative forward modeling of the CHFR log that was run after the test. The final results are shown on the left in Fig. 3.

Fig. 2—Photo of the gas flare from the thermal production test in the Mallik 5L-38 research well (courtesy of the Mallik 2002 Gas Hydrate Production Research Well Program).

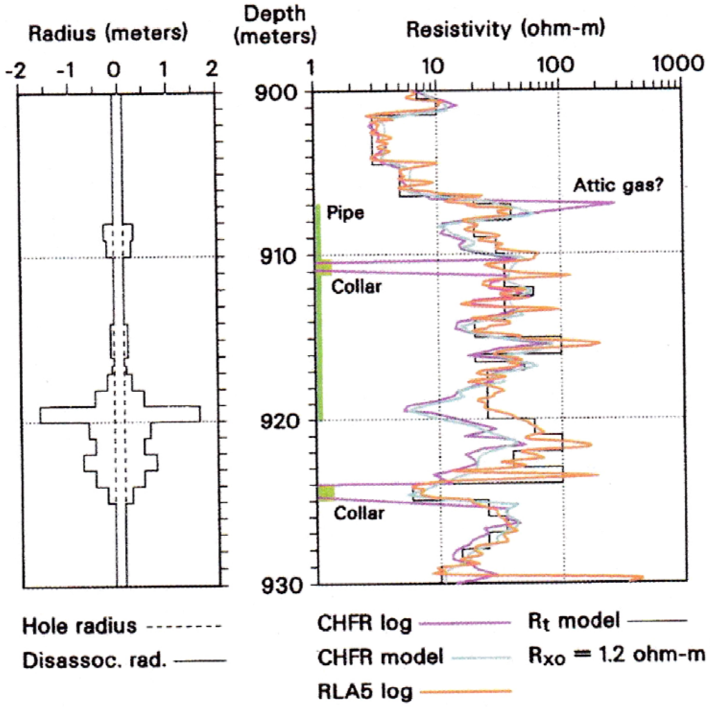


Fig. 3—Modeled dissociation radius is shown on the left, and a comparison between actual and modeled CHFR logs on the right. Also shown on the right are a wireline laterolog curve (RLA5) and modeled R_t for reference (from Anderson et al. (2008)

Now You See It, Now You Don't; Interpreting Resistivity Logs from a Gas-Hydrate Test Well in Northwestern Canada

Baseline formation resistivity values (R_t) were established from the deep laterolog data. The resistivity in the region of gas-hydrate dissociation near the wellbore (R_{xo}) was determined from the electromagnetic propagation and RST measurements. The radius of dissociation as a function of depth was then determined by means of iterative forward modeling of the CHFR tool response using a 2D finite-difference code. The final solution was obtained by varying the modeled dissociation radii until the modeled log overlaid the field log.

Pretest gas-hydrate production computer simulation had predicted that dissociation would take place at a uniform radius over the test interval. However, the post-test resistivity modeling showed that this was not the case. The resistivity-derived dissociation radii were greatest near the outlet of the pipe that circulated hot water in the wellbore. The radii were smallest near the center of the test interval, where a conglomerate section with low values of porosity and permeability inhibited dissociation.

The free-gas volume calculated from the resistivity-derived dissociation radii was less than 20% different than the surface gauge measurement.

Barbara Anderson

REFERENCE

Anderson, B.I., Collett, T.S., Lewis, R.E., and Dubourg, I., 2008, Using Open Hole and Cased-Hole Resistivity Logs to Monitor Gas Hydrate Dissociation During a Thermal Test in the Mallik 5L-38 Research Well, Mackenzie Delta, Canada, *Petrophysics*, **49**(3), 285–294.

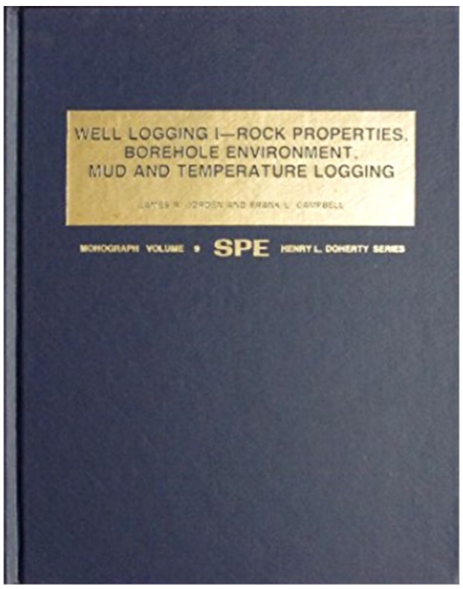
My Library

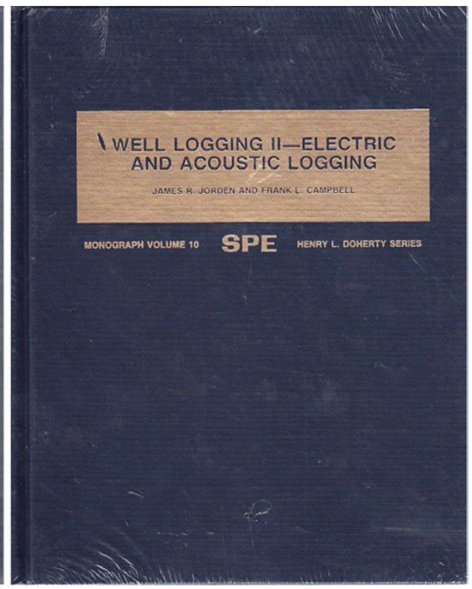
John Kuhla

My university education is a BS (University of Pittsburgh) and MS (University of Houston) in Petroleum Engineering. My consulting career expanded into the geoscience world, but always with my engineering perspective for a touch of reality. After 46 years in the business, I continue to work at the intersection of geology, geophysics, and reservoir engineering (with completion, drilling and landman work too)! Here I share five of my favorite petrophysical references, primarily from a historical perspective (pre-1990s) but required and necessary reading for a complete technical understanding of petrophysics.

Jorden, J.R., and Campbell, F.L., 1984, *Well Logging I: Rock Properties, Borehole Environment, Mud and Temperature Logging*, SPE Monograph **9**. ISBN: 1-55563-002-2.

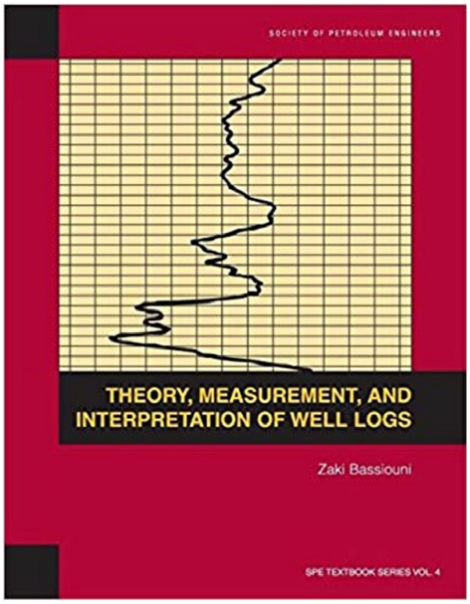
Jorden, J.R., and Campbell, F.L., 1986, *Well Logging II: Electrical and Acoustic Logging*, SPE Monograph **10**. ISBN: 0-89520-323-5.





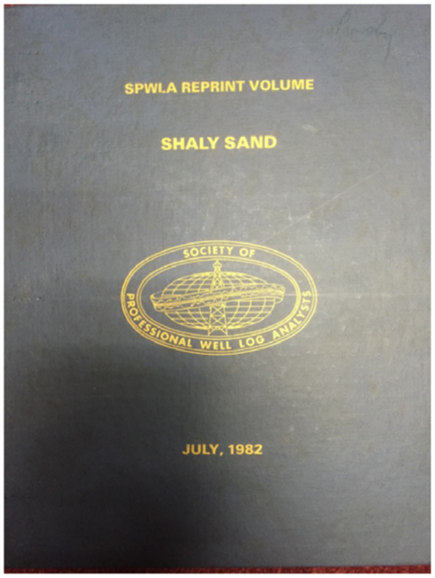
This was originally planned to be a complete, multivolume series on "Well Logging" but sadly the SPE moved on to other topics and no one stepped in to carry on the work of Jorden and Campbell. Both volumes have an excellent "suggested reading lists" for those who want to dig deeper into these topics. I most frequently refer to Chapter 2 in Volume I, "Fundamental Properties of Reservoir Rocks and Waters." Multiple definitions of "formation evaluation" are provided in Table 1.3, so you can better understand the work we do. Volume II has only two chapters, "Electrical Logging" and "Acoustic Logging" and the basics of these tools through the early 1980s are rigorously explained. For each Volume, there is a companion "Chart Supplement" that provides even more underlying information on each chapter topic.

Bassiouni, Z., 1994, *Theory, Measurement and Interpretation of Well Logs*, SPE Textbook Series **4.** ISBN: 978-1-55563-056-0.



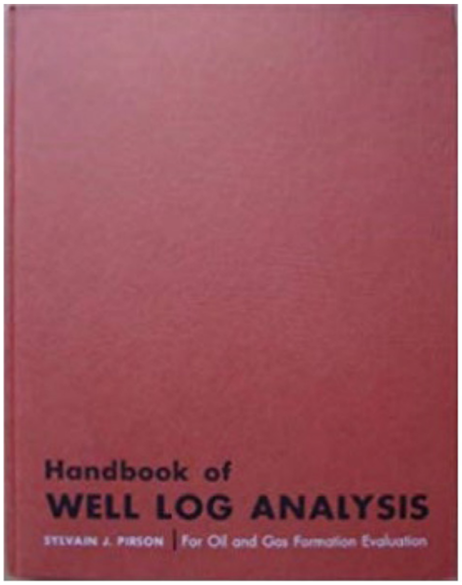
This volume, one in the SPE textbook series, covers the full range of well-log basics with worked problems. Zaki's purpose in writing this book, and I paraphrase, was to (1) understand the mathematical and empirical models, (2) understand the log measurement and tool operation and (3) understand how to analyze and interpret these logs. Zaki, was the chairman and professor of the Petroleum Engineering Department at LSU. He was also the editor of an SPE monograph on shaly sands.

Lang, W.H., Jr., chairman, 1982, *SPWLA Reprint Volume: Shaly Sand*. 43 papers, extended bibliography.



For any petrophysicist who wants to know about clay and shale properties and their response on logs and the interpretation models for shaly sands (derivation, application and intricacies), this is the go-to reference. This volume is out of print and one project that the SPWLA should re-open and update. Each of the five technical chapters are introduced by one of the editors. Each introduction explains the contents of the chapter papers and offers insights and opinions regarding conclusions. There are some amazing perspectives offered on the history of shaly sand analysis also. The editors of this volume were the premiere technical experts at this time in the petrophysical world. There is a very detailed bibliography included in Chapter VI.

Pirson, S.J., 1963, *Handbook of Well Log Analysis; For Oil and Gas Formation Evaluation,* Prentice Hall. ISBN: 0133828042.



Yes, this is old, but it provides an understanding of how to interpret well logs acquired prior to 1962. If you're trying to evaluate vintage logs (or to recognize the type and name of one of these), this book will take you through the procedures and also the pitfalls in interpretation. There are many worked examples and problems. This was used in the Petroleum Engineering department at the University of Texas and in Sylvain's teaching career in the industry. Just read the preface to understand where our industry was in the premodern era.

There are many more petrophysical references, services company manuals, chartbooks in my bookcases and my archives. I hope that there is follow-up to this article as I'd like to hear what other references populate fellow petrophysicist's libraries.

John Kulha has many years of experience in petrophysical, engineering and geoscience studies integrating log interpretation, rock data, and reservoir performance in a team environment worldwide. John, a recognized authority in petrophysics, has presented courses and seminars worldwide over the last 30 years. John is a member of the SPE, SPWLA, AAPG, and HGS and is the author and editor of numerous publications and posters. John graduated with a BS in Petroleum Engineering from the University of Pittsburgh and an MS in Petroleum Engineering from the University of Houston.

SPWLA 61st Annual Logging Symposium
Banff, Canada, June 20–24, 2020
Technical Program Abstracts

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 Fairmont Banff Springs Hotel and Convention Center. Photography and video/audio recording of any kind is strictly prohibited in all areas including technical sessions, workshops and exhibition hall.

ADVANCES IN MACHINE LEARNING

A Machine-Learning Workflow to Build the Mechanical Earth Model

Bhuvaneswari Sankaranarayanan, Ivan Diaz Granados, Aria Abubakar and Saad Kisra, Schlumberger

Mechanical Earth Model (MEM) is a numerical representation of the state of the internal stresses and rock mechanical properties for a specific stratigraphic section in a field or along a well trajectory. It has multiple applications in drilling and completion such as deriving a safe mud-weight window to prevent wellbore instability events, like kicks, cavings and stuck pipes etc. The conventional process for building the MEM often takes weeks of data analysis by a team of geomechanics experts. Our objective is to develop a machine-learning solution to automate the workflow of building the MEM based on the information available for a small, representative set of offset wells.

The MEM comprises the mechanical lithology flag and a set of interpreted logs of the elastic, strength and other rock properties. It is built by analyzing input measured logs namely, shear slowness, compressional slowness, density, and gamma ray through a geomechanics workflow. Additionally, when available, it also needs to be calibrated with core data and with drilling events, such as kicks and mud losses. We formulate this workflow as a supervised-learning problem and solve it using two different machine-learning(ML) techniques: random forests, a tree-based method that models the input log data as independent points; and the long-short term memory (LSTM) networks, a neural-network-based method that models the data as a sequence along the measured depth of the well logs. We obtain close-to-perfect test performance—100% accuracy for lithology prediction and a low mean absolute error for the mechanical properties on the Norwegian Sea data of 17 wells, out of which only four wells were used for training.

The measured input logs could be obtained from wireline acquisition and analyzed offline, or obtained from the LWD acquisition while drilling, requiring analysis in real-time. One of the challenges with real-time processing is having to work with missing regions of measurements in the logs. Geomechanics domain experience tells us that synthetically filled logs are a very good substitute for the real logs in the subsequent steps of building the MEM. Consequently, we propose to fill these gaps through synthetic log generation by applying an unsupervised auto-encoder-based approach.

Our results on the supervised-interpretation part show that machine-learning models can accurately learn the underlying correlation between input and output logs, even for fairly complex geology having different lithologies and skewed formation layers. Our preliminary results on applying the auto-encoder approach to synthetically fill gaps in the data is promising.

Finally, the ML automation for building the MEM can reduce the turnaround time, potentially multiplying the scale of well operations that are running simultaneously in a large field and can also establish an objective, robust MEM as opposed to the subjectivity in the built model arising from the varying interpretations of domain experts who might have different intuitions for the same data and might follow different workflows.

AI-Boosted Geological Facies Analysis From High-Resolution Borehole Images

Shiduo Yang, Yinyu Wang, Isabelle Le Nir and Alexis He, Schlumberger

Borehole images provide many different texture features for facies analysis and natural fractures identification. However, most of these features' classification is achieved manually. The workflow proposed here is to implement geological "facial recognition" from borehole images and other petrophysical measurements. The image segmentation is the first step to split the geological "facies" from continuous borehole images. Then the clustering based on the texture similarity and petrophysical measurements is the second step to major facies categories. The major facies categories were labeled and saved to data base for machine learning. The geological facies are recognized from new borehole image with a prebuilt model.

A borehole image can be visually recognized as a composition of successive zones; different zones have different statistical properties, which can be used to characterize the image and generate the zonation. The continuous histogram and variogram derived from image data were used for image segmentation. From the high-resolution borehole images, the segments obtained are numerous enough to perform the so-called unsupervised classification. Among various methods of unsupervised classification, we choose to use a neural network—competitive self-learning (CSL) for automatic clustering. The segments are assigned as facies with local geological setting.

The classified image features are then saved as labeled images for machine learning. Sequentially the image features can be identified automatically for continuous facies analysis in similar depositional environment.

We demonstrated this workflow in different depositional environments. Nine facies are recognized from a water-based mud image in a braided river environment from China and six facies are identified from an oil-based mug image in a lacustrine system from United States. The results from this approach were verified after comparing manual interpretation from core.

Automatic Facies Classification From Well Logs

Vasileios-Marios Gkortsas and Lin Liang, Schlumberger-Doll Research; Yngve Bolstad Johansen, Aker BP; Lalitha Venkataramanan, Schlumberger-Doll Research; and Harish Datir, Schlumberger

Facies classification is an essential element for petrophysical formation evaluation and reservoir characterization and can significantly improve the chances of success of a well. Electrofacies are defined as clusters of similar log responses throughout a well or a set of wells and combining them with core measurements can lead to geological facies. We develop a general purpose workflow for unsupervised electrofacies classification, which can be used for different application scenarios.

There are three major challenges in electrofacies classification. First, this type of classification is usually unsupervised since most of the times there are no labeled data and thus a proper method should be chosen. Second, the optimal number of clusters is usually unknown and thus is required to be an input given by the user. Finally, the clustering results are often not repeatable for different realizations of the classification.

To address the first challenge, we use the Gaussian mixture model (GMM) approach which is a probabilistic model that assumes all the data points are generated from a mixture of a finite number of Gaussian distributions with unknown parameters. Regarding the second one, we identify the optimal numbers of clusters automatically without any user intervention, using a method based on the repeatability of the clustering results. The final challenge is addressed, associated with the second one, by performing multiple realizations of the GMM and choose for clustering one of the realizations that converge to the most repeatable log-likelihood.

The proposed workflow consists of the following steps. First, the input logs are normalized using a standard scaling. Second, we choose a range of numbers of clusters and for each of them we perform multiple realizations of GMM. Third, the optimal number of clusters is automatically determined using a method based on the repeatability of the clustering results. Finally, after having determined the optimal number of clusters, we choose for clustering one of the realizations from the second step that converges to the most repeatable log-likelihood.

We applied the classification workflow on field data coming from the Ivar Aasen oil field, located on the Gudrun Terrace on the eastern flank of the Viking Graben in the Norwegian North Sea, using triple-combo logs as input (gamma ray, thermal-neutron porosity and bulk density) and compared the resulted facies with the ones provided by core data. Applying Step 2 of the workflow, we perform multiple realizations of GMM for a range of clusters. Each realization is run for multiple iterations, with the output parameters from one iteration being used to initialize the next iteration to guarantee convergence. The optimal number of clusters we identified from the Step 3 of the workflow is 10, same as the one from core data. We compared the facies from our workflow with the facies determined from core data by plotting the permeability-porosity relationship for each of the facies determined by the two approaches, and we observed high similarity on the structure and on the linear fits of the permeability-porosity relationships from the two approaches for the majority of the facies.

Automating Microfacies Analysis of Petrographic Images

Sonali Pattnaik, Songhua Chen, Wei Shao and Adly Helba, Halliburton

Carbonate facies identification presents a great challenge to geologists because of complex chemicophysical alterations and biological origin. Traditionally, a detailed carbonate facies analysis is carried out by visually segmenting the thin-section images into petrographic elements—grains, pores, cement, hydrocarbons, etc. This thin-section analysis of carbonates provides invaluable insights into the deposition and post-deposition diagenetic history, rock composition, and texture that matters to formation evaluation, such as grain size, sorting, type and distribution, cementing, grain compaction, as well as pore type and pore-size distribution, etc. However, visual facies identification by humans is inevitably affected by opinion, experience, and lack of quantitative assessment, thus lacks consistency while working across teams. Moreover, examining larger sets of complex thin-section images is a time-intensive and daunting task.

This paper describes a fully automated method to revolutionize the process of petrographic thin-section segmentation and augment geologists with a facies identification tool that can interpret large and complex image data consistently, quickly, and backed by quantitative analysis. Here, we perform semantic segmentation of thin-section images of carbonates into its constituent petrographic elements and use the segmentation results for facies characterization. Semantic segmentation is a classification task performed at pixel level, i.e., recognizing what is in the image at pixel level. Usually these methods are employed in a supervised setting where the ground truth labels are provided at pixel level. However, it is quite difficult to generate thousands of labeled data for carbonate rocks. This is due to their high heterogeneity in grain size, shape, biological origin, post-depositional digenetic evolution, and depositional environmental influence. Hence, unsupervised image segmentation and analysis becomes a better choice as it does not require any labelled data.

For effective understanding of facies characteristics, an end-to-end data pipeline is created to perform pore segmentation and semantic segmentation on the image data set. We accurately segment the intra-and inter-pore spaces from the matrix using a k-mean clustering technique. Segmentation of grainstone into its constituent petrographic elements using both convolutional neural networks and k-means was helpful in understanding post-depositional diagenesis processes. Semantic segmentation results coupled with simple linear iterative clustering and normalized graph cut technique recover the grain volume and boundaries consistent with the traditional definition of grains. Various statistical results involving pore and grain size distribution, oil saturation, cement-to-grain ratio, etc. are extracted from the segmentation results.

Digital Sampling: Multivariate Pattern Recognition, Machine Learning, and Equation of State, a Real-Time Approach to Evaluate Clean Formation-Fluid Properties and Mud-Filtrate Contamination

Bin Dai, Cameron Rekully, Christopher Jones and Tony Van Zuilekom, Halliburton

Acquiring physical samples from an open hole is usually a one-opportunity event where a formation tester is sent downhole with a limited number of sample chambers, either on a logging-while-drilling (LWD) or wireline conveyance system. The samples are acquired, retrieved, and sent to a laboratory for analysis, which takes place weeks to months later. By the time the laboratory has performed an analysis, the section has been cemented, and perhaps the rig has finished operations and moved onto the next phase. Success of the sampling operation is predicated on the samples being acquired from the right locations (where to sample?), at the right time to minimize drilling fluid-filtrate contamination (when to sample?), and in a manner that preserves the integrity of the sample and is representative of the formation fluid (how to sample?). Digital sampling is a technique that that can be used to both optimize the when, where, and how of physical samples taken and further augment the information collected with sensor analysis from locations that are not physically sampled.

This work shows a new workflow that can be used to extrapolate clean fluid properties with moderately high-contamination levels in a rapid pumpout. Based on the extrapolated clean fluid properties, an operator can make a decision whether to continue the pumpout to obtain physical samples or abort the pumpout if the fluid properties extrapolated (digital sampling) at the location are sufficient for the operation decision making. The workflow starts with applying principal component analysis (PCA) to a multichannel sensor measurement of fluid pumped out of the formation during a formation test sampling operation. Because the fluid pumped out contains only two endmembers (clean formation fluid and mud filtrate), the PCA scores of sensor measurements form a line in the PCA space, and solution bands of endmembers can be estimated based on physical constraint of sensor measurements (nonnegative, etc.). Then, a trend-fitting method is used to predict the asymptote of the first principal component score. The asymptote value can be inverted to sensor signal using PCA inversion, and the sensor signal represents the clean formation-fluid measurement. Lastly, machine-learning-based composition models can be used to predict the clean fluid compositions based on the sensor signal. The composition data then is used to predict fluid physical properties, such as bubblepoint, viscosity, and compressibility, using an Equation of State (EOS) model.

A series of rapid pumpouts at different depths can be used to map a formation for selection of where to sample, constrain contamination models to improve contamination estimation, determine when to sample, and optimize the pumpout parameters to obtain a representative sample in the shortest period of time.

We have applied this workflow to a number of formation sampling jobs at multiple wells, the real-time results match with the laboratory analysis result in term of contamination level and clean fluid properties (compositions, GOR, bubblepoint, density, etc.)

Downhole Signal Compression and Surface Reconstruction Based on Dictionary Machine Learning

Jian Li, Bin Dai, Christopher M. Jones, Etienne M. Samson and Darren Gascooke, Halliburton

In the upstream oil and gas industry, a prime technical bottleneck is often the communication between the downhole tools and the surface. For example, the physical speed of mud-pulsing telemetry is limited to 10 to 20 bits/second, whereas modern logging-while-drilling/measurement-while-drilling (LWD/MWD) equipment can make many measurements and generate thousands of bits per second. Conventional lossless data compression improves the total information transmission and, in combination with selective data management, can allow the most critical decision making information to be reviewed at surface. Also, downhole preprocessing does allow some interpreted information to be transmitted to the surface. However, even with these techniques the total amount of information received at the surface is only a very small portion of the data collected on the formation. Petrophysicists would benefit from receiving a more complete downhole sensor data set in real time.

In this work, a suite of smart, lossy, data-compression and reconstruction methodologies were applied to formation-testing sensor data, using the theory and algorithms of the new technical field of Compressed Sensing. This suite of methodologies is based on the possibility of sparsely representing signals with a set of over-complete basis functions called a dictionary. The dictionary is constructed by a machine-learning process that tries to (1) recognize the most common patterns in previous signals and (2) adjust the basis functions, such that the recognized patterns can be represented by combinations of a minimum number of those basis functions. Once the dictionary is thoroughly learned, future signals are expressed by selecting the minimum number of basis functions. The selection of the basis functions and the corresponding combination coefficients form the reconstruction structure to be transmitted to the surface.

The above methodologies were tested by compressing and reconstructing the downhole densitometry data acquired during more than 1,000 formation-tester sampling pumpouts. It was found that an absolute compression ratio of 10 could be achieved with a root mean squared error (RMSE) of 0.5% of the signal range. Compared to the conventional method of sampling, averaging, and surface interpolation, the smart method of this work can use 30% fewer bits to achieve a reconstruction mean square error (MSE) that is 18 times smaller. Such significant improvements in communication efficiency can greatly help with both the accuracy and quantity of data allowing the petrophysicist to make enhanced interpretation with confidence. The application of this technique to signal processing, and the application of this work to other sensor types, is discussed.

Dual Neural-Network Architecture for Determining Permeability and Associated Uncertainty

Ravinath Kausik, Augustin Prado and Lalitha Venkataramanan, Schlumberger-Doll Research; Harish Datir, Schlumberger; and Yngve Bolstad Johansen, AkerBP

The computation of permeability is vital for reservoir characterization as it is a key parameter in the reservoir models used for estimating and optimizing hydrocarbon production. Permeability is routinely predicted as a correlation from near-wellbore formation properties measured through wireline logs. Several such correlations, namely SDR permeability and Timur-Coates permeability models using magnetic resonance measurements, K-lambda using mineralogy, and other variants have often been used, with moderate success. In addition to permeability, the determination of the uncertainties, both epistemic (model) and aleatoric (data) are important for interpreting variations in the predictions of the reservoir models. In this paper we demonstrate a novel dual deep-neural-network framework encompassing a Bayesian neural network (BNN) and an artificial neural network (ANN) for determining accurate permeability values along with associated uncertainties.

Deep-learning techniques have been shown to be effective for regression problems but quantifying the uncertainty of their predictions and separating them into the epistemic and aleatoric fractions is still considered challenging. This is especially vital for petrophysical answer products as these algorithms need the ability to flag data from new geologies that the model was not trained upon as ‘out of distribution’ and, assign them higher uncertainty. Additionally, they need sensitivity to heteroscedastic aleatoric noise in the feature space arising due to tool and geological origins. Reducing these uncertainties is key to designing intelligent logging tools and applications, such as automated log interpretation.

In this paper we train a BNN with NMR and mineralogy data to determine permeability with associated epistemic uncertainty, obtained by determining the posterior weight distributions of the network, using variational inference. This provides us the ability to differentiate in and out-of-distribution predictions, thereby identifying the suitability of the trained models for application in new geological formations. The errors in the prediction of the BNN are fed into a second ANN, which is trained to correlate the predicted uncertainty to the error of the first BNN. Both networks are trained simultaneously and therefore optimized together to estimate permeability and associated uncertainty.

The model is trained on a “ground-truth” core database representing samples from different geologies. The cross validation of the permeability predictions on these core samples demonstrates a greater than 70% reduction of the mean square errors, in comparison to the traditional KSDR and KTIM. We also demonstrate a 50% reduction of the mean square errors of the log permeability predictions on wells from the Ivar Aasen field, using cores for validation, and an additional 10% reduction through the use of data from neighboring wells for the training. We discuss how this approach can provide “value of information” for the different tools, providing insight for exploration and field development plans.

Integration of 3D Volumetric CT-Scan Image Data With Conventional Well Logs for Improved Detection of Petrophysical Rock Classes and Flow Units

Andres Gonzalez and Zoya Heidari, University of Texas at Austin; and Olivier Lopez, Equinor

Core measurements are often employed to detect rock types for improved well-log-based petrophysical evaluation and subsequent formation evaluation in noncored wells. However, acquisition of such measurements can be time-consuming, delaying rock classification efforts for weeks or months after core retrieval. On the other hand, well-log-based rock classification cannot provide high-resolution detection of rock types in heterogeneous and anisotropic formations. Interpretation of 2D CT-scan data has been identified as an attractive and high-resolution option for enhancing rock texture detection, classification, and formation evaluation. Acquisition of CT-scan data is accomplished shortly after core retrieval, providing high-resolution data for immediate use in petrophysical workflows. However, these 2D images cannot capture 3D variation of rock texture, which can cause uncertainty in detection of rock classes. Integration of 3D volumetric CT-scan data and conventional well logs can significantly enhance formation evaluation through quantifying spatial anisotropy and heterogeneity as well as capturing rock texture more reliably compared to 2D CT-scan images.

The objectives of this paper include (a) to derive rock fabric-related features from 3D volumetric CT-scan image data using image analysis techniques, (b) to integrate the CT-scan-based rock fabric features with conventional well logs and routine core analysis for fast and accurate detection of petrophysical rock classes and flow units, and (c) to employ the detected petrophysical rock classes for improved formation evaluation and for making reliable production decisions.

First, we conducted conventional well-log-based formation evaluation to obtain petrophysical and compositional properties of the evaluated formations. Then, we developed a new workflow for preprocessing of volumetric CT-scan image stacks and subsequent image-based rock fabric/texture feature extraction. The aforementioned 3D image-based rock fabric features were then used in conjunction with conventional well logs through an iterative workflow for detection of petrophysical rock classes and flow units. Finally, the detected petrophysical rock classes and flow units were employed for improved formation evaluation and permeability estimates.

We validated the proposed workflow using a data set from a siliciclastic sequence with rapid spatial variations in rock fabric and pore structure. The use of volumetric CT-scan image stacks for feature extraction compared to 2D CT-scan images, improved the extracted features by consistently capturing anisotropy and heterogeneity in rock fabric (i.e., rock fabric variations in both vertical and radial directions, opposed to only vertical in 2D CT-scan images). Petrophysical rock classes derived by integration of image-based rock fabric features and conventional well logs were in agreement with rock classes derived using core measurements and analysis performed by experts. Furthermore, use of the obtained petrophysical rock classes and flow units in formation evaluation of the evaluated depth intervals significantly improved estimates of petrophysical properties such as permeability by more than 40% compared to conventional porosity-permeability models. A unique contribution of the proposed workflow compared to previously documented rock classification methods is honoring 3D spatial variation in the rock fabric through volumetric CT-scan images which significantly enhances formation evaluation in spatially heterogeneous and anisotropic formations.

Machine-Learning Proxy Enabling Interpretation of Wellbore Measurements

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Petrophysical characterization includes the evaluation and integration of data from several well-logging measurements. Each measurement is sensitive to different reservoir properties and present different depths of investigation. During the well construction the mud filtrate can invade the near-well region, replacing the formation fluids by mud filtrate. This may impact density and resistivity measurements, as a result, we may estimate incorrect porosity and saturation, and therefore oil volume. To correct for actual fluids saturation in the pore space, we need to account for mud-filtrate properties and the invasion profile.

Data-driven models using artificial intelligence are fast and can use real data to make predictions, but do not consider the physics driving the reservoir properties. However, by coupling them to extensive training data sets from physics models, it can generate fast and accurate models for reservoir analysis. To generate our proxy model, we developed a near-well reservoir model in an industry reference reservoir simulator to generate an extensive database of scenarios that could physically represent the saturation changes by mud invasion. A neural network was trained in this data set and was exposed to both unknown synthetic data and well data.

The trained NN was able to reproduce the results for predicting the invasion and saturation profile from the reservoir simulator with more than 99% accuracy for all depths of investigation. Additionally, an integrated petrophysical interpretation estimation requires the mud invasion to be calculated several times for each data point on a well, and this task can only be achieved at a reasonable computational cost using the data-driven model, given that the computing for the data-driven model is less than 1% of the same configuration of the physics simulation. Finally, we applied the machine-learning proxy model to a complex carbonate well drilled with water-based mud. The results showed a good correlation with the resistivity channels from logging measurements for near-well and far-field properties and the inverted depth of invasion.

The density tool is sensitive to a combination of different depths of investigation up to 8 inches, therefore the measurement is affected by the fluid invading the near-well region. In case of light oil-bearing in the interval drilled with water-based mud, the changes in fluid density in the near-well region caused by mud invasion might be higher than 0.25 g/cm^3, and if this effect is not considered in the petrophysical modeling it will result in a biased smaller porosity, with differences in the order of 2 p.u., which will affect the final estimated volume of oil in the reservoir. To avoid this bias in estimated porosity, the data-driven model was applied to the correction of porosity and fluids saturation. The methodology improved the density porosity when compared with core porosity and therefore, the final estimation of oil volume.

Machine-Learning-Enabled Automatic Sonic-Shear Processing

Lin Liang and Ting Lei, Schlumberger-Doll Research Center

Flexural-dipole sonic logging has been widely used as the primary method to measure formation shear slowness because it can be applied in both fast and slow formations and can resolve azimuthal anisotropy. The flexural-dipole waveforms are dispersive borehole-guided waves that are sensitive to borehole geometry and mud and formation properties, and therefore the processing techniques need to honor the physical dispersive signatures to obtain an accurate estimation of shear slowness. Traditional processing techniques are based on either a model-dependent method, in which an isotropic model is used as a reference to compensate for the dispersion effect, or a model-independent method, which optimizes nonphysical parameters to fit a simplified model to the field dispersion data processed by a modified matrix pencil algorithm. All these methods require inputs, such as the mud slowness and an initial guess of formation shear. Consequently, these methods often fail to interpret the dispersion signature properly when those inputs are inaccurate or when the waveform quality is poor due to bad borehole conditions and thin layers. The users must manually tune the processing parameters and/or choose different methods as a workaround, which causes extra time and effort to obtain the result hence imposes a significant challenge for automating sonic shear interpretation.

We develop a physics-driven machine-learning-based method for enhancing the interpretation of borehole sonic dipole data for both wireline logging and logging while drilling. Extensive synthetic databases (i.e., lookup tables) are generated from an anisotropic root-finding mode-search routine and used to train neural-network models as accurate and efficient proxies. Those neural-network proxies can be used for real-time sensitivity analysis and performing inversion to the measured sonic dipole dispersion data to estimate relevant model parameters with associated uncertainties. Alternatively, various machine-learning methods can also be developed based on the generated training data set and that can be used for inferring relevant model parameters with uncertainties from the field data directly. We introduce how these trained models can be used to enhance the labeling and extraction of different dispersion modes. We developed a new method that outperforms previous model-dependent and model-independent approaches because the new method introduces a mechanism to constrain the solution with physics that also has the capability to incorporate more complicated physical dispersion signatures.

This new method needs neither prior information, such as mud slowness and formation shear slowness, nor any tuning parameter to be played by the user. It also paves a way to automatically identify different anisotropy mechanisms, such as intrinsic, layering, stress, or fractures. This leads to significant progress toward automated sonic interpretation.

The algorithm and workflow have been tested on field data for challenging borehole and geological conditions and compared with traditional flexural-dipole processing techniques with great success.

Machine-Learning-Enabled Real-Time Monitoring and Control of Logging Operations

Hani Elshahawi, Shell; Juan P. Garcia and Marcos D. Garcia, Baker Hughes

The aging workforce in the oil sector will cause a knowledge loss to both operators and service companies as a large number of people retire in the coming years. The oil and gas industry is a multifaceted business, with the larger companies having operations in multiple geographies with a varied and multinational workforce. Managing and containing the future knowledge loss will involve different solutions. It is quite challenging for companies to manage knowledge transfer in different locations and areas of activity.

This paper describes an approach using machine-learning specifically natural language processing to ingest documented technical discussions during logging operations and provide real-time technical support to ongoing jobs based on the database of jobs done in the past.

Wireline logging operations often require real-time interactions during the the operations. The logging engineer together with the logging company technical support provide technical knowledge of tool physics and operations, while petrophysicists, G&G specialists, and other operating company experts have intimate knowledge of the formations, the reservoirs, and the well environment. Depending on the nature of the job and challenges during the operation these discussions may contain valuable insights for future projects. Over the last decade, these technical discussions changed from verbal in-person events or phone and radio conversations to online exchanges using chat applications.

We have successfully used historical records of past operational chats to create a real time advisory/expert system that captures the insights of expert users using text analytics and natural language processing and integrates with other data analytics and machine-learning routines. Applying these technologies to logging operations in real time is powerful because it enables the incorporation of robotic process assistants which automate tasks that would otherwise be manual, laborious, and time-consuming or altogether infeasible. Instead, our applications are able to provide exception-based monitoring capabilities and timely technical assistance to less experienced technical professionals. With the “Big Crew Change” already behind us, we predict that these technologies will become a key wireline logging requirement in the near future.

Method for Predicting Formation Fluid Contamination From Pumpout Data and Formation Properties Using Machine-Learning Methods

Peter Olapade, Bin Dai and Christopher Jones, Halliburton

It is well known that the acquisition of representative formation fluid samples is essential for proper reservoir management and development. However, because of overbalance pressure in the mud column, mud filtrate invades and contaminates the reservoir fluid during the drilling process before the mudcake around the wellbore is properly formed. Although water-based mud (WBM) is immiscible with formation fluid, oil-based mud (OBM) is miscible with it. Samples with OBM contamination levels greater than at least 10% for oils and 3% for volatile oils and gas condensates may be considered unusable, because the OBM contamination alters the formation fluid properties and phase behavior, thus preventing an accurate characterization of the reservoir fluid.

Despite a large body of research, it is very difficult to avoid contamination. Unfortunately, openhole sampling is usually a single-opportunity event. By the time the laboratory analysis is complete, it is not possible to acquire additional samples. Consequently, it is important to ensure that contaminated fluid is adequately cleaned up before taking the sample. Cleanup time depends on multiple parameters, including formation permeability, fluid viscosity, depth of invasion, and wellbore mud-column overbalance pressure. The most current method for predicting contamination relies on curve fitting to a single property, such as density or GOR. Curve fitting depends on the assumption that when the properties being monitored do not change significantly as the pumping continues, the contamination level is low. However, this can also be because of a steady-state effect, even at a high contamination level. In addition, the contamination value from the curve-fitting method is sensitive to data selection and also depends on the endmember filtrate and formation fluid properties, which cannot be measured directly either downhole or in the laboratory.

In this work, we present a technique for predicting contamination using pumpout density and volume and formation properties, such as drawdown mobility, formation pressure, overbalance and drawdown pressure. By combining multiple parameters, such fluid density, drawdown mobility, formation pressure, overbalance, and drawdown pressures, predicted contamination values are better constrained. Moreover, this technique does not depend on endmember properties and is based on constraining pumpout data with formation properties from pressure-testing data. With this technique, a large data set of pumpout volume, density, and formation properties data acquired from wells from different regions of the world are used to develop a predictive model using a machine-learning approach. The pumpout density is represented as optimized parameters of an inverse power law model.

The contamination estimation method has been validated with several data sets from different regions of the world.

Open Subsurface Data Universe: Truly Leveraging Subsurface Data

Shyamalan Ramaswami, Hani Elshahawi and Johan Krebbers, Shell

The current structure of subsurface data storage and handling in the oil and gas industry limits the ability to truly leverage the value of our data. Data ingestion, cleanup and management tasks require significant amounts of time and effort. Data volume, variety, veracity, and velocity are among the challenges as are the following :

- Data are linked to applications, which means that instead if being data-driven, we remain application-driven instead.
- It takes far too much time to locate the data you need as a user.
- Data are stored in silos, hence there is no lineage between data sources and as a result (as an example) no lineage

from wells back to exploration.
- Metadata are generally not stored with the relevant data.
- Limited-to-no search capabilities: Since we have no metadata the ability to cross reference and search for information is severely limited
- Closed formats make it difficult to incorporate new ideas or methodologies to existing data platform formats. The portfolio is therefore dominated by a few dominant players, which tends to limit innovation

Due to the limitations of the status quo, in early 2018 Shell initiated its Subsurface Data Universe (SDU) program focused on storing all subsurface and wells data in a public cloud-based single data platform and an open architecture that allows new applications to be developed based on the usage of Microservices, Kubernetes as the container-orchestration system, and HTML5 (3D support) for user interface.

Once this project got underway within Shell, it was obvious that to be a transformational change to address the challenges faced with data today, the eventual platform needs to be open source and industry wide. Thereafter, informal discussions started with other operators to validate interest in the market for this idea. There clearly was great interest as all operators had to make similar changes, and for that reason Shell approached the Open Group (www.OpenGroup.org) with the request to start a new a joint industry forum called the Open Subsurface Data Universe (OSDU). Over time, the objectives of the OSDU have evolved, and will continue to do so, but it currently seeks to:
- Create a single data platform with a common data format accessed by a common set of APIs and, therefore, suppliers can focus on a myriad of applications that can be used with the data and usable universally.
- Enable secure, reliable, global, and performant access to all subsurface and wells data.
- Accelerate the development and deployment of emerging digital solutions in support of better decision making.
- Create an open, standards-based ecosystem in which suppliers compete to provide the best applications and services.
- Provide flexibility to the customers who will be able to select the best of breed services.

So far, over 100 companies have joined the OSDU Forum and these members quite diverse as (a) large and small operators, (b) software and hardware companies including start-ups, (c) service companies, (d) cloud providers and (d) academia.

Petrophysical Workflows Versus Machine Learning—A Comparative Case Study in the Dakota Group, Williston Basin

Saptaswa Basu, Sergey Skvortsov and Kyrre Johansen, ConocoPhillips

This work compares the traditional petrophysical workflow to machine-learning methods to compute porosity and permeability in the Inyan Kara Formation of the Dakota Group in the Williston Basin. Quality of data set (variability, size and robustness), basic theoretical approach, method, results, applicability in the geological area and predictive power are the fundamental basis of this comparison.

Produced-water disposal into a shallow Dakota Group presents risks to nearby development drilling, potentially generating high-pressure zones in the overburden. Accurate pressure predictions for the Dakota are very valuable for drilling design and development timing decisions. Along with disposal volumes, porosity is the critical variable which determines the formation pressure. The Dakota does not contain hydrocarbons, resulting in limited porosity log data. However, there are abundant resistivity and gamma-ray logs through this interval. Therefore, a data-analytics model is used to compute porosity based on location and available resistivity and gamma-ray logs. Also, a modified Archie equation is used to compute porosity from resistivity and gamma-ray data. Data-analytics-based porosity and resistivity-based porosity are compared with available neutron-density log-derived porosities.

The team working this project was comprised of a petrophysicist, reservoir engineer and geologist who compiled, analyzed and built a geo- and reservoir model based on this work to predict formation pressure in the Dakota Sands.

Reducing the Uncertainty of Multiwell Petrophysical Interpretation With New Data-Driven Methods

Wen Pan, Carlos Torres-Verdín, Michael Pyrcz and Ian Duncan, The University of Texas at Austin

Well-log interpretation provides estimates of rock properties, such as porosity, hydrocarbon pore volume, and permeability. Petroleum engineers construct reservoir models based on these well-log-derived petrophysical properties to estimate reserves, forecast production, and designate new infill-well locations. However, some inherent limitations of conventional well-log interpretation prevent accurate estimation of reservoir properties, especially in the context of multiwell interpretation. For example, the spatial continuity of permeability observed from core measurements is rarely used during interpretation. Petrophysical calculations included in interpretation workflows are usually performed well-by-well and often do not take advantage of the local and spatial correlations between well logs and petrophysical properties. Furthermore, uncertainty analysis does not typically consider the covariance of properties at different depths, nor does it take into account the propagation of uncertainty between measurements at different scales. This paper successfully overcomes the aforementioned problems by developing three new, data-driven, multiwell petrophysical interpretation methods.

The three new data-driven interpretation methods work as follows:
1. To make use of the spatial continuity (or lack of) of petrophysical properties between wells, we calculate the variogram of petrophysical properties from core measurements, and use cokriging to estimate the corresponding properties in wells devoid of core data. Results are used as a-priori distribution in the subsequent interpretation. Furthermore, interpreted properties are assumed stationary random variables.
2. To take advantage of the relationships between well logs,

petrophysical properties, and spatial continuity, we use convolutional neural networks (CNNs) to map well logs to the residuals of conventional petrophysical interpretation. Both well logs and interpretation residuals are assumed codependent.

3. To quantify and propagate the uncertainty of interpretation results, we use generative adversarial networks (GANs) to simulate possible spatial distributions of petrophysical properties. The outcome of this machine-learning method is compared to that of Bayesian updating.

Six types of well logs and over 9,000 feet of core measurements from 35 wells in the Seminole San Andres Unit are used to validate our new multiwell interpretation approach. After performing the interpretations, we calculate the mean squared error (MSE) of permeability between core data and well-log interpretation and compare the performance of different uncertainty quantification methods. Results are as follows:

1. After using cokriging, the MSE decreases by 9.6% compared to that obtained from conventional well-by-well interpretation methods.
2. After fitting the residuals with CNNs, MSE further decreases by 32.4%.
3. Realizations from both GANs and Bayesian updating reproduce the variance and variogram of the residuals of core measurements, while those from GANs are more accurate than obtained with Bayesian updating.

We found that the usage of spatial correlation and data-driven calculation methods substantially improves the estimation of permeability in complex geological environments when core data are available in key wells. The use of GANs coupled with enforcement of spatial correlation generates permeability realizations in wells devoid of core data and propagates uncertainties in well-log interpretation for reliable reservoir modeling. The main limitation of the above data-driven methods is that the number of cored wells needs to be large enough to obtain statistically significant results.

Supporting Critical Well-Delivery Decisions by Using Machine Learning to Aid Interpretation of Wellsite XRF Data

Robert Webber and Ben Fletcher, CNOOC International Ltd.; and Thomas Bird, Leap Beyond Ltd.

The success of a recent infill drilling campaign on a major UK North Sea oil field required a real time assessment of which reservoir units had been encountered, and an indication of reservoir quality. This was necessary in order to decide whether and how to complete each well. Wellsite XRF data was acquired as a critical component of the formation evaluation program to address both of these uncertainties. This paper describes how a machine-learning algorithm was developed to provide a robust interpretation of the encountered stratigraphy from XRF data.

The oil field that forms the case study of this paper is composed of sequences of erosive channel complexes that have produced sandstone and mudstone units with very little well-log character that can be used to distinguish between the sand units. Production performance is however strongly dependent on which of the sand units are encountered. Chemostratigraphy is a technique that addresses this issue by characterizing sedimentary rock successions using inorganic geochemical data. Elemental abundances measured on core or cuttings have proved useful in identifying subtle differences between the mudstone and sandstone units, and this data is currently used as the basis of the reservoir correlation. Achieving successful production performance from the current drilling campaign involved making operational decisions (with time frames measured in hours) based on criteria that included the sand unit encountered. These decisions included whether to complete the well, to sidetrack to an alternative location, and how to complete the well. Manual (expert) interpretation of the wellsite XRF data set was not optimal either for meeting decision time frames or for providing a robust measure of interpretation uncertainty. Data-science methods were applied to address this challenge because it was anticipated they had the potential to evaluate the subtle relationships in the geochemical data set in a rigorous and consistent fashion.

A machine-learning algorithm was developed that took as input the wellsite XRF data from cuttings and provided an interpretation of clay and sand units, with associated uncertainty. There were several challenges which needed to be addressed, caused by biases and inconsistencies in the field database of elemental data, such as differences between the type of elemental analysis and fundamental differences between data acquired from core and cuttings. Limitations in the strength of the interpretation were clearly identified so that decisions could be made with full knowledge of the inherent uncertainty. The algorithm was further improved by post-processing the results and applying stratigraphic rules “in effect developing an electronic geologist.”

In this instance machine learning has proved its value in application to a subsurface interpretation challenge. As well as improving on an existing process, the application of data-science techniques provided significant insight into the data set and previous interpretation biases.

The Benefits and Dangers of Using Artificial Intelligence in Petrophysics

Steve Cuddy, Baker Hughes

Artificial Intelligence, or AI, is a method of data analysis that learns from data, identify patterns and makes predictions with minimal human intervention. Essentially AI solves problems by writing its own software. AI is bringing many benefits to petrophysical evaluation. Using case studies this paper describes several successful applications. The future of AI has even more potential. However, if used carelessly there are potentially grave consequences.

A complex Middle East carbonate field needed a bespoke water saturation equation. AI was used to ‘evolve’ an ideal equation, together with field specific saturation and cementation exponents. One UKCS gas field had an ‘oil problem’. Here, AI was used to unlock the hidden fluid information in the NMR T_1 and T_2 spectra and successfully differentiated oil and gas zones in real time. A North Sea field with 30 wells had shear velocity data (V_s) on only four wells. V_s was required for reservoir modeling and well bore stability prediction. AI was used to predict V_s in all 30 wells. Incorporating high vertical resolution data, the V_s predictions were even better than the recorded logs.

As it is not economic to take core data on every well, AI is used to discover the relationships between logs, core, litho-facies and permeability in multi-dimensional data space. As a consequence, all wells in a field were populated with these data to build a robust reservoir model. In addition, the AI predicted data upscaled correctly unlike many conventional techniques. AI gives impressive results when automatically quality controlling (QC) and repairing electrical logs for bad hole and sections of missing data.

AI doesn't require prior knowledge of the petrophysical response equations and is self-calibrating. There are no parameters to pick or cross-plots to make. There is very little user intervention and AI avoids the problem of "rubbish in, rubbish out", by ignoring noise and outliers. AI programs work with an unlimited number of electrical logs, core and gas chromatography data; and don't 'fall-over' if some of those inputs are missing.

AI programs currently being developed include ones where their machine code evolves using similar rules used by life's DNA code. These AI programs pose considerable dangers far beyond the oil industry and are described in the paper. A 'risk assessment' is essential on all AI programs so that all hazards and risk factors, that could cause harm, are identified and mitigated.

Using Machine Learning to Improve the Accuracy of Real-Time Acoustic Data for Pore-Pressure Prediction

Lei Wu, Baker Hughes

Pore-pressure predictions have huge impact on drilling safety and the economics of drilling design and well construction for offshore wells. Wellbore-derived pore-pressure models often use acoustic data due to its insensitivity to salinity changes. The data quality of LWD acoustic data is crucial for the reliability of real-time pore-pressure predictions and ultimately improving the drilling process and reducing HSE risks.

In real-time, correlation peaks from downhole processing of monopole data are sent to surface, peaks could be compressional, tool mode, coherent noise, or refracted shear… Normally those real-time peaks are either sent to the office for the geoscientist to pick, or geoscientists remotely log into the field computer to pick the correct compressional peak at each depth. It is time and resource consuming.

In the paper, one machine-learning method, the adaptive boost (AdaBoost) method, is implemented to automatically pick compressional slowness in real-time. The AdaBoost algorithm is used in conjunction with other types of learning algorithms, such as, semblance value, tool-mode characteristics, correlation with other FE curves, to improve performance. The output of those learning algorithms ('weak learners") is combined into a weighted sum that represents the final output of the boosted classifier. The method is adaptive in the sense that subsequent weak learners are tweaked with the higher weight of error for those instances misclassified by previous classifier. The final model can be proved to converge to a strong learner. With conventional combination of "weak learners", the accuracy of real-time compressional is ~75 to 80%. After optimization using the AdaBoost method, the accuracy is improved to ~95%. The comparison results with those two methods in different environment are shown in the paper.

CASE STUDIES

21st Century Density Measurements for Australian Mineral Logging

Jennifer Market, MPC Kinetic; Ashley Grant, BHP; Huw Rossiter and Brenton Armitage, MPC Kinetic

Density is one of the key measurements in Australian mineral logging, used for hardness mapping, geomechanics modeling, and seismic correlation. Yet, until recently, the robustness of downhole density measurements has suffered from inconsistent calibrations and uncompensated sensors, which are significantly affected by hole condition. In addition, ground stability risks often lead to no downhole density data being collected at all, adding significant uncertainty to the mine model.

Improvements to downhole density measurements are underway on three fronts. First, compensated tools are being introduced, allowing for more reliable measurements in adverse hole conditions. Secondly, calibrations, which have historically varied from mine to mine, are becoming standardized. Finally, new tools and techniques have been developed to be able to measure density reliably through diamond and reverse circulation (RC) drill rods, which allows for logging in areas with unstable ground conditions.

The paper begins with a review of the design of modern compensated tools compared with single-detector devices, showing case studies of the significant improvement in reliability with the dual-detector tools and how the increased robustness of the measurement leads to more consistent 3D hardness maps. Then the reverse circulation drilling environment is introduced, focusing on the measurement challenges to acquire reliable density data through multiple concentric rods and how it differs from casedhole logging. Finally, cased studies of in-rod density maps are considered.

Acoustic Borehole Image-Log-Based Fracture and Vuggy Porosity Analysis of a Brazilian Presalt Carbonate Reservoir From the Santos Basin, SE Brazil

Leandro Hartleben Melani, Ulisses Miguel da Costa Correia, João Paulo da Ponte Souza, Michelle Chaves Kuroda, Bruno César Zanardo Honório and Alexandre Campane Vidal, University of Campinas (Unicamp)

The Brazilian Presalt carbonate reservoirs are characterized by strong diagenetic processes, which have a major impact on reservoir quality, resulting in a very complex and highly variable pore system, including fractures and vug/karst features. Such different porosity scales add complexity to the flow characteristics of the reservoir. The higher resolution of borehole image (BHI) logs makes them a valuable tool for analyzing such heterogeneities at the well scale, widely applied for more reliable reservoir evaluation. Our goal is to perform fracture and in-situ stress analysis and characterize the vuggy porosity using high-resolution image logs, in order to quantify and understand the distribution of these features in a Presalt carbonate reservoir from the Santos Basin.

The natural fractures were analyzed in terms of type (open and closed), orientation, and density. These features are dominantly striking to NNE–SSW, with a secondary set oriented NNW–SSE. In the in-situ stress analysis, drilling-induced fractures and borehole breakouts indicated a dominant NNE–SSW trend for the maximum horizontal stress (SH_{max}) and a perpendicular NNW–SSE orientation for the minimum (Sh_{min}), respectively. The open fractures' dominant set shows a nearly parallel orientation to the interpreted in-situ maximum horizontal stress, which usually suggests major contribution to the fluid flow.

For the vuggy porosity analysis, we applied the SOM (self-organizing maps) neural-network method for image segmentation of BHI logs to extract vuggy features from the background image, based on pattern recognition of the acoustic amplitude variations. We used the extracted features to build a vuggy porosity log, which is a quantitative index of the vuggy porosity fraction. This log captures the vertical heterogeneity of vuggy features over the reservoir and highlights zones with the major occurrence, which may indicate important pathways to fluid flow when connected to the enhanced fracture-network.

Summarizing the results for this Presalt carbonate reservoir: (1) the distribution of fractures and dissolution features seems to be stratigraphically controlled at well scale, probably influenced by distinct mechanical units, which defines different characteristics of fracturing and dissolution patterns within these units; (2) extensive vuggy porosity was observed for the whole Upper Sag unit, which shows from small vuggy features to large caverns (up to metric scale); (3) the associated dissolution process has also enlarged the fractures within the reservoir; (4) the Upper Sag interval is characterized by a complex network of vugs/caverns and fractures, which may have a great impact on permeability and productivity (supported by production tests). Then, despite the good matrix porosity and permeability within the sag interval, the occurrence of fractures and vug features is a key factor affecting the reservoir performance, directly related to higher permeabilities. Therefore, the BHI logs were suitable for a detailed investigation of the occurrence of fractures and dissolution features for this Presalt carbonate reservoir. A major challenge is to understand the 3D distribution and connectivity of the fault/fracture and vuggy porosity system for these dual-porosity carbonate reservoirs, which may be relevant to predict potential high-permeability zones. This may provide valuable constraints for reservoir modeling, crucial for enhancing exploration and production strategies.

Acquiring a Baseline Casing-Thickness Log for Future Corrosion Monitoring Without Pulling the Tubing

Dirk Valstar, Schlumberger

The oil and gas industry requires periodic corrosion evaluation of production casing. Conventionally, this requires moving in a rig and pulling the tubing to directly inspect the production casing. When there is not any damage observed, the tubing is reinstalled and the well is restored to its operating configuration. This paper describes how the combination of ultrasonic thickness measurement and electromagnetic (EM) thickness measurement can be used to confidently establish a baseline for future comparison.

The ultrasonic measurements are recorded over the production casing before installing the tubing to provide an accurate status of the actual thickness of the production string. Ultrasonic logs must be run in liquid, hence acquiring this data at the time of construction simplifies the operation and minimizes the acquisition cost. Conversely, the EM thickness log can be acquired in gas or liquid and reacts to all metal present at any given depth in the wellbore. Running the EM thickness log inside the tubing once it is installed yields a true representation of the state of the surrounding pipe strings.

With the baseline thickness log in the tubing recorded, we can simply run an EM thickness log in the well regardless of the fluid in the hole and compare this with the initial baseline log to verify if any corrosion has occurred. If no corrosion has occurred, operations can continue and there is no need to pull the tubing. Because this dual logging approach is an additional investment up front, it is often deferred, but the future cost savings can be substantial. This paper includes a case study in which a salt dome storage operator acquired the baseline logs to enable the storage operator to monitor the 20-in. production string at any moment in the future without pulling the two leaching strings currently in the well.

By logging the combination of ultrasonic thickness measurement and EM thickness measurement, operators can confidently establish a baseline for future comparison and save time and cost of conventional rig-based corrosion evaluation of production casing.

Advanced Borehole Acoustic Logging Measurements Applications and Their Contributions in Frac Design Optimization. A Case Study in Tight Carbonate, Tuba Reservoir, North Kuwait

Ramdane Bouchou, Baker Hughes Kuwait

The Tuba Formation is deposited on a carbonate-ramp profile with lithofacies associations ranging from proximal-ramp to distal-ramp environments. Even though the field northern area consists of deeper-water facies, the reservoir shows favorable porosity and permeability trends. The constructed detailed static and dynamic models, with current producing wells performance, indicate that the formation has long-term potential of oil production improvement. However, drilling and completion option poses major challenges due to formation heterogeneity across the field and the reservoir rock mechanical behavior.

A suite of openhole logs was planned to evaluate the formation for drilling and completion efficiency improvement and thus field production optimization. A wireline acoustic log was one of the acquired logs, and has played a fundamental role in the evaluation.

Monopole, inline dipole and crossline dipole acoustic data are used in the analyses. The analyses include basic slowness analysis, dynamic rock mechanical properties, azimuthal anisotropy analysis, Stoneley permeability analysis, geomechanics analysis and deep shear-wave image (DSWI) analysis.

The present case study illustrates a large number of borehole acoustic waves analyses performed on borehole acoustic data, acquired in a 3,000-ft horizontal well drilled in the Tuba formation. The results are then integrated with other openhole data to understand the reservoir and to help locating the best zones to fracture.

Frac completion optimization includes selection of producible zones, identification of geological barriers to the frac, and also identification of the natural fractures. The productive zones are selected using the NMR results (porosity, permeability and oil saturation) and the Stoneley permeability results. Acoustic-wave analyses results, such as anisotropy, stress profile, fracture migration, brittleness and hardness help selecting the easy fraccable intervals and identifying the existence or nonexistence of geological/stress barriers which can help the frac placement with more control on the frac height growth for an optimized frac design. DSWI shows the well trajectory, detects any fractures crossing or noncrossing the wellbore. It shows also the well position relative to the beds boundaries and the reservoir thickness along the horizontal section. When all of the gathered information is combined, we can get an idea of the frac initiation direction and extent. This can help with connecting the natural fracture system near wellbore to the hydrocarbon pore volume, thus increasing the possibility of enhancing production.

Multistage stimulation of the well has resulted in a significant increase in production. This will help the acceleration of Sabriyah field development. Ultimately, this will lead the way for North Kuwait to achieve its objective of maximizing long-term production.

Advanced Petrophysical Analysis and Water Saturation Prediction in Three Forks Reservoir, Williston Basin

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The Three Forks Formation, as the lower part of the Bakken petroleum system, is a complex reservoir with variable mineralogy, thin-bed characteristics, and low permeability. Advanced logging tools and techniques are required to characterize and estimate water saturation (S_w), porosity, and mineralogy in this type of formations.

In this paper, to overcome these challenges, we used three different methods to estimate S_w. The first model was based on an integrated petrophysical workflow proposed to evaluate the reservoir quality. A complex petrophysical model was developed for Three Forks reservoir by the integration of the advanced logging to the workflow including elemental capture spectroscopy for the mineralogy and grain density, nuclear magnetic resonance for the porosity, clay-bound water, and free fluid, and multifrequency array dielectric measurements for water saturation. Both deterministic and probabilistic methods were used to assess the output component and fluid volumes. The integration of the elemental dry-weight fractions with conventional logs allows more accurate mineralogical determination and calculation.

The complex petrophysical model results provided the basis to extrapolate the model to the wells that are remote from any advanced logging and core analysis. The challenge was to rescale the input components to the minimum components to be solved and set the appropriate matrix parameters, uncertainties and weight multipliers for each equation. Also, additional constraints were necessary to supply the model with more information.

In the second approach, S_w was estimated from dielectric measurements, which is independent of resistivity. The two models showed good agreements with core measurement results. This confirms the Archie parameters and the formation water resistivity used as an input into the modified Simandoux equation.

In a third attempt, the application of machine-learning and deep-learning algorithms were applied to estimate S_w using only conventional logs. This was with the aim of generalizing the results to the entire extent of the Three Forks reservoir in the Williston Basin. The performance of support vector regression was compared to that of backpropagation neural-network model based on the correlation coefficient, root mean square error, and maximum absolute error indexes. The results suggest the use of the two algorithms complementary to each other for S_w estimation. These methods captured the complexity of the Three Forks formation where the laminations are in abundance with a complex pore size distribution.

On the other hand, the NMR T_2 log mean was applied to investigate the pore size distribution and its relation with S_w. The average T_2 log mean values of equal or greater than 8 msec was defined as cutoff corresponding to oil-bearing intervals in the Three Forks formation.

Casedhole Reservoir Evaluation as a Means of Risk Reduction, Production Enhancement and Cost Control for Mature Fields: A Case Study From México´s Northern Region

Angel Olivares, Weatherford International

As new reservoirs become more difficult and expensive to find and produce, the need for innovative solutions for mature fields and bypassed reserves has increased exponentially. México´s North region reemergence as an important focus of workover and development wells activity on a tight budget represents an important challenge for operators and service companies alike.

The main concerns for mature fields that have been produced for more than 50 years should be tackled by applying the right mixture of technology an analysis. This case study shows how casedhole reservoir evaluation can be the key for solving different unfavorable scenarios that arise constantly on the different fields of this area.

The Burgos basin's most productive gas reservoirs are reached after drilling though some formations known to cause wellbore instability, including lost circulation and stuck pipe, often leading to sidetracking and even lost wells. All these factors used to make openhole logging a necessary risk that companies had to take. By applying a combination of through-casing logging, gamma ray, neutron, density, sonic and a pulsed-neutron tool that allows gas identification in very-low-porosity sands a complete petrophysical evaluation was achieved avoiding potential stuck tools, fishing and hole abandonment issues thus lowering nonproductive times. Costs were also optimized by performing rig less operations, which are a real budget saver.

A similar approach proved useful on a different geological setting, when wells drilled in the Tampico-Misantla Basin started having trouble drilling though the deeper formations and had to be cased before logging, logging through casing with the same combination of tools replicated the success now for heavy-oil producing limestone reservoirs.

For this case study, the workover campaign cannot be overlooked, since it normally represents the bulk of activity for mature fields trying to re-energize stalled projects by finding new opportunities for production. One of this fields presented massive and uncontrolled water injection into its formations for several years. Original openhole logs painted a very optimistic picture of fluid saturation that proved inaccurate when the first wells from the campaign started producing mostly injection water. Casedhole reservoir evaluation using pulsed-neutron technology tools on the correct logging mode resulted on a total game changer for the wells near the injection arrays, providing a way to identify which parts of the reservoir were flooded by the EOR methods, which were depleted, and which actually represented bypassed reserves for production.

In conclusion, this case study provides success stories which prove the valuable contribution of casedhole reservoir evaluation and the importance it will have moving forward in this area of México and in general for mature fields worldwide.

Conclusive Proof of Weak Bedding Planes in the Marcellus Shale and Proposed Mitigation Strategies

Julie Kowan, Baker Hughes; and Luke Schanken, EQT Corporation

Wellbore instability has been experienced in areas of the Marcellus shale and can become particularly troublesome in the superlaterals that are becoming more prevalent in that play. Often the instability while drilling these very long lateral wells is minimal; problems are more likely to occur while tripping out after reaching TD. The most common instability events when pulling out of the hole appear to be tight hole, packoff and stuck pipe. These problems often worsen with time, indicating there is some time-dependence to the failure mechanism.

In order to develop effective mitigation strategies to combat the instability, it is imperative that the failure mechanism be correctly identified. Previous publications have suggested that bedding planes may play a role in some of the drilling problems experienced in the Marcellus shale. In this paper, we will present a case study from the Marcellus that shows conclusive proof of weak bedding plane failure along a lateral well, where thousands of feet of anisotropic failure were captured with a LWD image log.

This image provided confirmation of the presence and failure of anisotropic bedding planes in the Marcellus shale. The image was also used to validate an existing geomechanical model for the area and gave the operator more confidence in the mitigation strategies developed from that geomechanical model, which had been based on the assumption that weak bedding was contributing to difficulty experienced on multiple lateral wells when tripping out of the hole.

This case study will begin with an overview of the geomechanical model, including the drilling history, stress/pore pressure model and rock properties. Next, some highlights from the image log, showing anisotropic plane failure, will be featured as well as a comparison of the image to the geomechanical model. This case study will conclude with a review of proposed mitigation strategies that could be implemented by the operator to limit the risks posed by weak beds and minimize instability, when drilling laterals in this area, or similarly complex areas, of the Marcellus shale.

Delineating the Geothermal Structure and Flow Properties in a Subhorizontal Well With the Use of Wireline and LWD Data in a Multiphysics Approach

Erik Wielemaker, Chiara Cavalleri, Giovanni Sosio and Alejandra Reynaldos, Schlumberger; Pierre Ungemach, Miklos Antics and Melanie Davaux, Geofluid

Geothermal projects are rapidly developing in continental Europe to provide for an alternative energy source. These projects typically involve a doublet, a producer and injector well, which often involve vertical wells drilled with minimal measurement technology. In this paper we will discuss how high-end wireline measurements guided the decision making for completion strategy in sub horizontal well in France for geothermal, a world premiere in geothermal well design. In addition, we will describe how these measurements aided understanding of the overall structural model. The single doublet project provided a 150% increase in geothermal productive/injective capacity vs. previous twin doublet designs.

The study was carried out in the Cachan project in the Paris Basin, which was developed to provide Paris with geothermal heat. The project targets thin porous oolithic layers within a dolomite formation. These oolithic layers provide an excellent geothermal target to produce from. The well was geosteered with LWD density images, after which, wireline NMR measurements and dipole sonic were conveyed through the long horizontal drain on tractor to provide operational efficiency.

A multiphysics approach combining the density images, high-resolution magnetic resonance porosity-permeability data and oriented sonic measurements is applied to fully understand the homogeneity of the layers along the well and determine the flow properties and possible compaction effects.

NMR logs were primarily used to understand the porosity and permeability variations of the oolithic reservoirs with high resolution and highlighted the intervals with highest fluid movability through the thin layers.

NMR measurements are applied to describe the pore system and assess the fluid movability through the thin layers. NMR carbonate porosity partition analysis and advanced workflows are then used to classify rock type with similar reservoir quality and assist with the definition of rock properties cutoffs' for development strategy.

In addition to typical applications for rock mechanics and petrophysics, the sonic data helped exploring any possible effect of the proximity of the adjacent layers within the very thin oolithic section. By combining measurements from different spacings and taking the opportunity to analyse the nonstandard individual azimuths from the sonic technology a more detailed structural model was obtained after integrating with the density image. This allowed us to understand whether permeability variations were truly related to layer variations or a result of the measurements sensing properties of an adjacent layer and define the heterogeneity of the oolites.

Moreover, the lateral continuity of the layers and structures were captured by exploring the far-field sonic reflectors imaged with a dipole sonic source. Multiple reflectors could be traced over hundreds of meters providing not only an understanding of the overall homogeneity but also how layers extended away from the wellbore. This allowed us to obtain a detailed understanding of the structures along the horizontal well. Reflectors could be observed up to 40 m away from the wellbore.

Free or Bound? Thomeer and NMR Porosity Partitioning in Carbonate Reservoirs, Alta Discovery, Southwestern Barents Sea

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The main petrophysical challenges in carbonate reservoirs are often to define meaningful rock types, then to establish robust permeability and saturation models for these rock types, as well as to develop a realistic estimation of irreducible water saturation (S_{wirr}). Realistic S_{wirr} estimation is important for predicting production behavior (expected development of water cut) and thus ultimately for planning the future development scheme of a discovery.

In this study, we present the 2014 Alta discovery, located in the southwestern Barents Sea. More than 50% of the expected hydrocarbon resources reside within complex carbonate reservoirs of Permo-Carboniferous age that display highly variable rock properties.

Initial screening revealed that primary rock textures and pore geometries were for a large part overprinted by diagenetic processes. Hence, a better control on the reservoir's diagenetic evolution will be needed to apply a full-scale rock typing workflow. In the meantime, it was decided to proceed with a simplified reservoir characterization approach based on the main stratigraphic building blocks. Sufficient core coverage allowed for using permeability measurements from core samples as direct input to a 3D reservoir model. A customized core analysis program, using whole-core samples, was designed to characterize the effect of large-scale vuggy pores.

For modeling water saturation, a workflow based on Thomeer hyperbola was developed that describes mercury injection capillary pressure (MICP) curves. The results adequately specify the saturation in all the stratigraphic building blocks. However, saturation uncertainty in the reservoir is high due to a highly variable cementation factor (m), unknown wettability and the presence of residual oil below the current free water level (FWL). The Alta structure has been, and still is, leaking gas, causing the FWL to rise over time. To address the otherwise underestimated volumes in the transition zone above the current FWL, a deeper pseudo-FWL was created and used as input to the saturation height function.

Despite log-based water saturation (Archie) and core measurements (Dean-Stark) indicating more than 80% water saturation for less permeable reservoir rocks within the oil leg, production tests did not produce water at normal rates. This clearly demonstrated the need to distinguish "nonproductive" pore systems (with capillary-bound fluids; in this case water) from pore systems contributing to production ("free" fluids).

A large MICP data set confirmed that most reservoir rocks exhibit a mix of different pore types and pore throat diameters. To model this accurately, porosity partitioning in nonproductive microporosity and free porosity using the NMR logs was performed. Calibrating appropriate T_2 cutoffs by matching core MICP to NMR logs in these heterogeneous rocks is seriously hampered by the large difference in sample size. Applying both MICP and NMR measurements to a subset of core plugs helped resolving this challenge. Comparing the corresponding free porosity to total porosity revealed near-linear relationships for different reservoir rocks.

For irreducible water saturation (S_{wirr}), S_{wbound} is calculated using the NMR-based free porosity. S_{wbound} is considered to be a close approximation of S_{wirr}.

The resulting full-field simulation showed a significantly improved match between model output and recorded well test data.

Gravity-Assisted Wellbore Segregation During Hydrocarbon Sampling in Low-Permeability Rock

German Garcia, Schlumberger; Olatunde Akindipe, ConocoPhillips; and Hadrien Dumont, Schlumberger

Low-permeability formation evaluation in wells drilled with water-based mud (WBM) is a common occurrence in the North Slope of Alaska. This case study describes how downhole fluid segregation was recently used to collect high-quality hydrocarbon samples with a wireline formation tester in a well drilled with WBM with severe skin damage. We discuss the procedure and the hardware used and show examples of the effectiveness of the proposed technique.

The sampling interval is initially subjected to relatively high drawdown using a 3D radial probe to bring the hydrocarbon closer to the wellbore. This step is necessary because the unfavorable mobility ratio causes WBM invasion fluid to move preferentially while pumping at low drawdown. The 3D radial probe is then retracted, and the string is repositioned to cover the same interval with a straddle packer assembly to provide wellbore annular space for filtrate and hydrocarbon to segregate during an initial flow period. A simultaneous two-pump technique is then used to collect the segregated hydrocarbon and discard the WBM filtrate.

We discovered that a combination of tool inlets, with and without dead volume, can assist in displacing mud filtrate, bring the target hydrocarbons to the wellbore, and enable the collection of high-quality samples. This technique takes advantage of the gravity segregation occurring between hydrocarbons and WBM filtrate in the wellbore.

After pumping at one target interval using a probe with no dead volume, the maximum hydrocarbon fraction observed in the downhole fluid analyzer was only 5%. Once the straddle packer was set at the same depth, the cleanup period showed that the annular space between the tool and the wellbore was offering residence time for both phases to segregate due to density contrast. When the segregated hydrocarbon column in the wellbore reached the straddle packer inlet, a two-pump technique was used to pull the WBM filtrate in the downward direction at high rate while the hydrocarbon was "skimmed off" with the upper pump running at slow rates. The segregated hydrocarbon is collected in sampling receptacles located in the upper part of the string.

Laboratory results confirmed that the samples collected without residence time contained 95% WBM filtrate whereas the bottles collected with the proposed technique showed 90% hydrocarbon.

No reference in the literature was found on using downhole residence time coupled with dual-pump action to separate hydrocarbons from WBM filtrate using the straddle-packed interval as the inlet. We believe this technique innovatively uses the capabilities of current formation testers to collect high-quality hydrocarbon samples where this has previously been challenging. With minor changes, this technique can also be applied in cases where water samples are attempted in wells drilled with oil-based mud.

Innovative Formation-Tester Sampling Procedures for Carbon Dioxide and Other Reactive Components

Ralph Piazza, Alexandre Vieira and Luiz Alexandre Sacorague, Petrobras; Christopher Jones, Bin Dai, Megan Pearl and Helen Aguiar, Halliburton

Three questions must be answered to optimize any openhole sampling program. These questions are where to sample, when to sample, and how to sample? Samples must be acquired from the right locations in order to answer the critical questions posed by the asset evaluation and production teams. Samples must be obtained at the right time to minimize contamination while using valuable rig time efficiently. Also, samples must be taken in a manner that provides the laboratory with the most representative analysis of the subsurface reservoir fluid.

Carbon dioxide is a corrosive acetic gas component often found in petroleum reservoirs. Special and relatively costly completion and production equipment is required to produce reservoir fluids containing carbon dioxide. Also, carbon dioxide must be scrubbed at cost from petroleum before that petroleum is shipped. Lastly, carbon dioxide may cause flow assurance issues with regards to scale of inorganic and organic component, thereby requiring costly mitigation. Therefore, an accurate estimate of carbon dioxide concentration in the reservoir fluid is required to make a financial estimate of an asset value.

New formation-tester carbon dioxide analysis technology has allowed a new reflection upon these questions with respect to carbon dioxide sampling due to previously unobserved phenomena. Specifically, carbon dioxide may bind with caustic components of drilling-fluid filtrate in either a reversible manner or be consumed by caustic components in an irreversible manner. Observation of a reversible reaction has been used to validate the phenomena, but also provides a cautionary warning that for different chemical reactions in which carbon dioxide may be consumed, openhole samples may significantly underestimate the amount of carbon dioxide in the reservoir fluid. New sampling procedures, applicable to existing formation testing infrastructure, will be discussed that have the potential to mitigate this sampling issue, projecting the correct carbon dioxide content in the reservoir fluid. The new sampling procedures are validated with the carbon dioxide monitoring technology, but are not strictly dependent on it. These proposed sampling procedures are applicable to the measurement of all reactive petroleum components, such as hydrogen sulfide.

Integrated Fractures Characterization of Tight Carbonate Reservoir to Unlock the Reservoir Development Opportunity, a Case Study in Onshore UAE

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Reservoir-X in Field-A is a very tight marginal carbonate reservoir which has proven potential and recently undergoing development on many other fields in UAE. Motivation for the present study was to properly characterize the fractures contribution to reservoir productivity to assess the feasibility of reservoir development. Geological data of the reservoir from drilled wells and observation from cored wells show the presence of natural fractures in the reservoir.

Multidiscipline data gathering and evaluation has been carried on 26 wells and seven cored wells. These include borehole image evaluation (wireline and LWD), sonic evaluation, core observation, routine core analysis, production test, seismic attribute analysis, regional geology and drilling events analysis.

High resolution LWD microresistivity formation images over 3,200 ft in the horizontal section was acquired, processed and interpreted. Advance sonic deep shear image and stoneley fracture analysis from three wells were performed and compared to the same wells where core CT-scans and image logs were acquired to evaluate the fractures propagation away from the borehole. This information was used to interpret fracture type, fracture orientation and computation of fracture attribute.

Core observation was conducted on six cored wells by using visual inspection, whole-core CT-scans, dual-energy plug CT-scans, thin sections and routine core analysis data. The data are then integrated with the log data.

Detailed fault interpretation was done on 3D seismic data in the region of interest. 3D variance and curvature attributes were generated on conditioned seismic data for edge detection and was further used to extract the seismic discontinuity planes (SDPs). Extracted SDPs were carefully analyzed with respect to the orientation of fracture present in the wells

All events of drilling breaks, bit drop, and abrupt loss of drilling mud from drilled wells were recorded and analyzed to support fracture identification, particularly at the uncored wells or in the case of image log absence. Production tests from some appraisal wells provide indication of fracture productivity.

The fractures were then classified based on process origin, their

attributes and ranked accordingly to their potential contribution toward production.

The study confirmed that Reservoir-X has two main reservoir zones with different fractures intensity and attributes due to their distinct mechanical properties.

Some open fractures were observed but the potential contribution to production is yet to be validated by more comprehensive dynamic data. The study results become basis for planned PLT and DST.

Integrated Reservoir Evaluation Using Advanced Wireline Technology to Optimize Landing Points and Reservoir Drainage in an Unconventional Reservoir: A Powder River Basin Case Study

Erika A. Zahn, Isabel C. Arbelaez, Jennifer L. Kharrazi, Geoff McBryan, Paul Pavlakos and Pedro Romero, Weatherford International

An enhanced reservoir characterization requires advanced measurements and customized workflows. While having detailed measurements in the reservoir is helpful, an integration of data is required for a full petrophysical analysis. The optimization of landing points and reservoir drainage is critical during the production planning of unconventional plays, which plays an important role in the world's hydrocarbon reserves. Customized reservoir characterization workflows for specific reservoir attributes and diagenetic configurations are the solution to overcome rock and reservoir quality uncertainties.

This paper describes a case study in Powder River Basin with the integration of organic-shale petrophysics using geochemical spectroscopy and focused magnetic resonance measurements, for unconventional reservoir characterization. Accurate quantification of the mineralogy, lithology and total organic carbon was achieved during the integration and validation stages, for a better understanding of saturations and reservoir quality. Advanced magnetic resonance and spectroscopy characterization were correlated with openhole and core information to show the precision of the customized workflow.

The application of this customized workflow assisted in providing an enhanced reservoir evaluation of sweet spots, which improved planning for drilling and completions strategies. Sensitivity analysis builds a stronger integrated workflow and customization, which has a positive impact on optimizing landing points and reservoir drainage performance.

Latest Wireline Conveyance Technologies Set a New World Record, Achieving Gravity Descent to 79° in Open Hole, Enabling Significant Time and Cost Savings

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Formation evaluation data acquisition via wireline logging yields highly accurate data in an efficient manner, but has historically been inhibited by ledges/washouts, differential sticking, high deviation limitations, and poor data resulting from stick-slip tool motion. Pipe-conveyed logging has been the traditional solution for high-deviation or high overbalance logging; however, it introduces several inefficiencies and hazards of its own.

This paper details how the deployment of novel wireline conveyance technologies has replaced pipe-conveyed logging for ADNOC offshore operations, ushering in a new era of logging efficiency and cost savings.

The new technology encompasses ultrahigh-strength cables, wheeled carriages, and angled hole finders, and takes a holistic approach to tool conveyance, reducing drag while ensuring optimum data quality by orienting sensors positively within the wellbore. In addition, wheeled carriages greatly reduce the tool-borehole contact area, preventing the incidence of tool sticking. Ultrahigh-strength cables provide increased overpull capability, particularly for heavy toolstrings.

The wheeled carriages carry the toolstring off-center, allowing the mass of the toolstring to induce a "righting moment" to ensure correct orientation in the wellbore. Planning software can be used to predict drag and thus the maximum deviation to which the toolstring can descend.

These latest wireline conveyance technologies have been deployed on multiple operations in the UAE, successfully delivering improved data quality each time. Further, the risk of differential sticking and toolstring holdup in high angle wells virtually eliminated. Large gains in logging efficiency have been realized, particularly with the elimination of time-consuming pipe conveyed logging.

The wheeled carriages have been used to centralize array sonic tools and orient pad-type tools without the need for drag-inducing bowspring centralizers or powered calipers. The ability to carry the entire toolstring weight on ultra-low friction wheels has culminated in wireline conveyance to a world record deviation of 79° in open hole.

Buoyed by the success of the wheeled carriage system, a well formation tester, with an extensive sampling program, was successfully deployed on wireline. A torque-free, ultrahigh-strength cable was used to ensure safe retrieval of the toolstring in the event of sticking. An estimated 3.5 days of rig time was saved over comparable operation using pipe-conveyed deployment.

The oriented carriages and high-strength cables eliminate the inherent risks of wireline logging and bring efficiency and improvements in data quality that, until recently, were not possible. Applications include high deviation, sampling from the "undamaged" high side of the wellbore, coring parallel to bedding planes, centralization of imaging and acoustic tools without powered calipers and navigation past ledges.

The UAE is at the forefront of bringing these innovative technologies to the industry.

Petrophysical Implications of Magnesian Clays in Brazilian Presalt Reservoirs

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Marine carbonate reservoir formation evaluation is typically not concerned about the presence of clays, provided that the deposition of good quality carbonate platform facies is normally limited to clear waters. Conversely, the South Atlantic lacustrine Presalt deposits are composed of a complex mixture of carbonates, silica and Mg-clays (e.g., kerolite, stevensite, mixed-layer kerolite-stevensite, sepiolite, and saponite), precipitated under extreme alkaline environmental conditions. These clays are peculiar in terms of composition (e.g., kerolite - $(Ca_{0,03}Sr_{0,02}Na_{0,01})_{0,06}(Mg_{2,88}Al_{0,01})_{2,89}Si_{4.02}O_{10}(OH)_2.nH_2O$) and occurrence, exhibiting laminated, massive, ooidal, peloidal, and coating habits. They are very distinct from the conventional clastic or common diagenetic clays that occur in siliciclastic reservoirs, requiring different petrophysical interpretation models. For instance, the conventional approach for clay content evaluation using gamma rays is not adequate, considering that Mg-clays are poor in radioactive elements, such as potassium. Moreover, the density vs. neutron crossplot does not display a clear contrast pattern between clean reservoirs and clayey rocks. On the other hand, NMR logs exhibit a highly distinctive clay-bound water relaxation time (< 3ms) in Mg-clays-rich intervals, similar to a shale pattern, even though the proportion of such clays in relation to carbonates (calcite and dolomite) is rarely higher than 30%. In addition, Mg-clays strongly affect sonic logs, decreasing both shear and compressional velocities, which can be useful to identify them in crossplots of density vs. interval transit time.

Mg-clays are quite unstable minerals, what resulted in their dissolution and/or replacement by other minerals. A reasonable amount of porosity within Presalt reservoirs has been interpreted as secondary, formed by dissolution of these clays. Their occurrence and preservation is erratic and they are absent in most of wells, but in some of them Mg-clays-rich carbonates may be over 200 meters thick. The intervals with preserved Mg-clays are not considered reservoirs, as despite their fair porosity, they have very low permeability (< 0.1 mD). In contrast, preserved Mg-clays are scarce in the reservoir facies, indicating that, either they were not deposited in those areas and/or periods, or that significant changes in the chemistry of the lacustrine fluids have extensively dissolved them, or they were dissolved during diagenesis. In conclusion, the understanding, evaluation and prediction of Mg-clays occurrence are of paramount importance for the petrophysical interpretation in the exploration and development of Presalt reservoirs.

Petrophysical Modeling and NMR Analysis for Reservoir Characterization of Mixed Carbonate-Clastic Formation of Mumbai Offshore Basin, India

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Carbonate reservoirs of the Mumbai High are heterogeneous in nature and comprise of carbonates with shaly intercalations. Owing to heterogeneity, the realistic reservoir characterization becomes a challenging task. The T_2-cutoff values in such formation also vary thus making understanding of the NMR porosity distribution subjective. Sedimentological studies (thin section, XRD, SEM), petrophysical studies (ϕ, k, a, m and n) were carried out on 20 samples and NMR core analysis (T_2 cutoff, NMR ϕ) were carried out on 43 samples. The results of sedimentological and petrophysical studies are used for a realistic petrophysical multimineral processing model of the formation. The core derived T_2-cutoff values are used to reprocess the CMR data. Two T_2-cutoff values of 52 ms and 25.5 ms are standardized for carbonate and clastic parts of the formation respectively and the CMR data is reprocessed with these values. An innovative logic has been developed to combine the results of CMR processing using variable T_2-cutoff values and taking the lithology as an input. The continuous FFV, BVI and BVM are created for different lithologies. CMR T_2 distribution is used to calculate pore sizes using the equation $r = CT_2$, where C = $\rho s*Fs$, is the conversion coefficient. The values of surface relaxivity (ρs = 0.069) and shape factor (Fs = 2.5) are standardized for the formation and pore sizes are calculated. The results are matched with the pore sizes observed from SEM image data. The study helps in characterizing the complex carbonate reservoir of mixed carbonate-clastic formation of the Mumbai High. The standardized petrophysical model gives the realistic reservoir parameters in the formation and the reprocessed CMR data shows the realistic porosity distribution within the formation. The pore sizes calculated from the T_2 distribution give a good picture of the reservoir quality. The model prepared will help in better reservoir characterization of the wells in the area with similar formation characteristics.

Positive Tool Orientation Significantly Improves Data Quality and Enables Gravity Descents of Wireline Toolstrings to Near-Horizontal Deviations in the Middle East for Sonic and Borehole Image Data

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This paper details innovative techniques of orienting wireline toolstrings in the borehole and the corresponding data-quality benefits for reservoir structural imaging using sonic reflectivity surveys and seismic imaging integrated with borehole images.

The system, comprised of wheeled carriages and angled guides, takes a holistic approach to wireline tool conveyance, reducing drag while ensuring optimum sensor orientation, standoff, and pad contact for each logging service.

Correct orientation is achieved through management of tool center of gravity relative to the wheel axes. Positive toolstring orientation via ultralow friction wheels, instead of traditional positioning accessories, improves data quality and allows gravity descents to extreme deviations (up to 80°) that have previously been performed by drillpipe conveyance (TLC), LWD or tractor. Ultrahigh-strength cables in conjunction with the significant friction reduction offered by the wheels ensures safe retrieval.

The oriented conveyance system addressed the following wireline-log data-quality issues:

- Sonic centralization
- Formation Imager rotation
- Stick-slip motion, causing "smeared" and missed data.

Centralization of the array sonic tool is critical for data quality.

It is equally important that the logging tool is parallel to the wellbore with no sag or tilt. In deviated wells, it is often difficult to place enough standoffs/bowspring centralizers while maintaining smooth tool motion for quality data. In addition, powered calipers for centralization introduce additional drag which increases the likelihood and severity of stick-slip. Smooth tool motion is especially critical when sonic imaging data are acquired to examine fractures and structure in the far-field. Centralizing sonic tools using wheeled carriages remedied these problems and resulted in improved data quality in a recent well with 79° deviation.

Excessive stick-slip of wireline toolstrings causes the most significant degradation of borehole image quality. This is mainly caused by the stretching and compressing of high-resolution data samples acquired per time unit. In addition, tool rotation caused by cable torque might result in image overlapping for tools using a pad architecture. The new system locks the tool into a set orientation preventing rotation. The wheeled carriages facilitate smooth tool movement resulting in improved quality data.

The improvements in data quality combined with efficiency enhancements and the reduction of risk during wireline logging delivers a superior method of carrying out operations. The integrated sonic and VSP imaging results combined with the borehole imaging provide answers needed to reduce uncertainties in field development.

Stress-Dependent Fracture Property Delineation and Sweet Spot Zonation in Unconventional Geothermal Reservoir: South Sumatra Basin, Indonesia

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The recent demand for green and renewable energy sources has gained significant economic importance in terms of reducing greenhouse gas emissions. Located within a volcanic setting, Indonesia has approximately 40% of the world's geothermal energy resources, hence the geothermal power market is remarkably huge, with reported installed capacity of 1,900 MW in 2018, the second largest globally after the United States. The effort to increase the output of this untapped resource is very encouraging and requires good understanding and evaluation of these complex volcanic reservoirs. This includes the structural evolution in the area and locating sweet spots in the lithocolumn for deciphering the controlling factors that govern the producibility within the field.

Well-logging measurements, including borehole imaging and acoustic tools, were deployed to investigate the characteristic and patterns in the lithocolumn to identify sweet zones for good reservoir sections. The workflow includes borehole-imaging-based applications and structural and fractures characterization. The promising sections are correlated to drilling results to delineate optimum zones and the intrinsic properties of the sweet spots. The structural framework is then correlated with the wells in the same field to understand factors that control the contribution of each zone and the lateral continuity of these reservoirs in regard to the overall geological evolution in the area.

The assessment was made employing fracture identification from borehole microresistivity images classified based on their morphology into various classification fractures, with effective fracture types being the primary interest. The dominant strike direction of these fracture sets was observed to be north–south with aperture values obtained from resistivity imaging estimated between 1 and 8 mm with a mean of 4 mm. The in-situ stress within the study area were observed to be in the northeast–southwest direction based on drilling-induced linear features, which was then correlated to the properties of the fractures contributing to steam production.

This work provides insight into factors to identify properties of productive fractures for steam gas reservoir production. Understanding the characteristics of fracture properties and geometry in relation to the geological evolution of the structural framework in this area can be beneficial to identifying infill wells for optimum recovery of renewable sources of energy.

Stress Measurement Campaigns in Scientific Deep Boreholes

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NAGRA, the Swiss agency in charge of finding sites for the disposal of radioactive waste, has embarked on a multiyear, multiwell scientific data-gathering program to qualify three possible sites for radioactive waste disposal. The three sites are located in Northeastern Switzerland and are 10 to 20 km apart.

The program calls for not only complete coring of the boreholes but also a comprehensive suite of logging (including vertical seismic profiles, VSPs) and laboratory test data on core samples, as well as large-scale hydrological tests. In particular, assessing the current state of stress is one of the key inputs to the final site assessment, because it provides the base state from which the perturbations due to the construction of the site and the heat generated by the waste are evaluated.

Building a mechanical geomodel requires iteration with data acquired at different scales—from core plugs to the decakilometer geological structure. Stress measurements obtained with the microhydraulic fracturing technique are considered here to provide stress information at the meter scale. Because of the large amount of data gathered from multiple sources at multiple scales, a process has been developed to ensure that the location of the stress tests synchronizes with as many other sources of information as possible.

Special care was taken to develop a dedicated test protocol for stress measurement because the minimum horizontal stress is close to the vertical stress (either larger or smaller) and because the wellbores show many drilling-induced features (e.g., opening of stylolites). To complicate matters, a wide range of breakdown pressures was expected, and the range of permeabilities dictated the use of multiple methods to reliably estimate the closure stress. The protocol includes estimation of the magnitude of both the minor horizontal stress from conventional microhydraulic-fracturing tests and the major horizontal stress from dry fracture reopening and sleeve reopening tests.

In this paper, we report on the design process and the evolving development of the stress-test protocol and share some preliminary results from the first two wellbores: one from the Nordlich Lägern area and one from the Zürich Nordost area. Although tests were performed in the same geological units in boreholes that are about 10 km apart, it was found that the stress regime was different in the two boreholes. This is consistent with information from regional structural geology.

Successful Fluid Characterization in a Multiple Layer Carbonate Reservoir for Production Optimization Using Formation-Testing Technology

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The Middle Minagish formation is the major producing oil reservoir in West Kuwait where accurate formation evaluation is crucial. The complex carbonates of this field, coupled with a long history of production and water injection gives rise to substantial variation of oil and water saturation throughout the field. These complexities necessitate a careful completion design for optimal production. The objective of this case study is to show the success of the formation sampling and fluid identification in a multiple layer carbonate reservoir. The operation of the formation-testing technology was conducted across a water zone, in challenging wellbore conditions and water-based mud. The timely, precise results aided to better characterize the reservoir and fluid properties.

A formation-testing tool string is deployed in a deviated 8.5-in. openhole to acquire pressure data, fluid type identification prior to the well casing and completion. The main fluid-typing sensors were resistivity, density, viscosity, capacitance, pressure and temperature. The formation-testing program was accomplished successfully, and the objectives were met based with minimum fluid sample contamination, as validated with later laboratory results, highlighting the real-time data precision for decision making.

The formation-testing and sampling data were integrated with the openhole interpretation in real-time to support the well completion final design. Overall, the formation fluid identification and sampling data show a clear discrimination between the formation and drilling fluids, supporting decision-making. In addition, a water sample has been collected and later used for water compositional analysis to test its compatibility for future field development applications.

A novel formation tester along with using real-time monitoring allow achieving the logging and welling objectives with high-quality data. The results supported the well completion design and resolved uncertainties of Minagish Oolite reservoir to maximize production and increase the operation efficiency.

The Greater Enfield Project: Successes and Lessons Learned From Challenging Three-Field Horizontal Development Well Campaign

Chris Woods, Josh Sutcliffe, John Bretherton, Vanessa Lim, Glen Brabham and Darren Baker, Woodside Energy Ltd

Woodside and Mitsui E&P Australia's Greater Enfield Project involved the development of three oil accumulations: Laverda Canyon, Norton over Laverda and Cimatti, through the drilling and completion of 12 horizontal development wells (six oil production wells, including three trilaterals and six water injection wells). All wells targeted stratigraphically complex reservoirs with narrow drilling windows situated within thin reservoir intervals across multiple fault blocks.

This paper will cover innovative petrophysical solutions developed in support of activities from planning through to execution and beyond to meet field specific challenges. These ranged from a requirement for real-time conglomerate identification in Laverda Canyon, navigation of thin (1- to 10-m thick) dipping and faulted reservoir in Cimatti and real-time avoidance of transgressive green sand in Norton Over Laverda. All of this required 24-hour monitoring by the asset team, including petrophysicists with real-time workflows.

Planning products discussed include items such as "frames" sensitivities due to limited telemetry and the requirement for significant bottom hole assemblies. In addition, extensive ultradeep azimuthal resistivity (UDAR) prejob modeling was conducted and will be shown via examples of accurate transition zone profiles and representative facies properties.

The successful real-time workflows that will be discussed cover elements of real-time data streaming and visualization, with petrophysical software. This include the integration of UDAR data with bespoke reservoir characterization techniques, such as "probability" facies, to help optimize geosteering decisions and guide completion design. Importantly, focus was also given to continuous direction and inclination data for the purpose of dogleg management to migrate torque and drag risk for screen installation.

To calibrate and optimize real-time workflows, each well underwent a detailed after-action review (AAR). Insights allowed for the identification of an optimal inversion solution for higher confidence-boundary identification, however, this was not always the P50 solution. In addition, it was realized formation static temperature estimation to support mud breaker formulations, could be acquired from logging-while-drilling measurements prior to drilling out previous hole section shoes, along with stabilized temperatures in longer horizontals (> 2000 m). Finally, post-drill evaluation methods of incorporating azimuthal data were developed to more accurately reflect wellbore properties for use in reservoir modeling.

The Importance of Core-Log Integration in Laminated Reservoirs With Complex Mineralogy: Case Study in Longá Formation, a New Exploratory Play in the Parnaíba Basin, Brazil

Bruno Menchio Faria and Manuella Yebra, ENEVA

The exploration of hydrocarbons in the Parnaíba Basin has as main targets Poti and Cabeças Formations. The advance of geological knowledge obtained from the drilling of wells, the Longá Formation began to be treated as a possible new exploratory play. This formation is characterized by the intercalation of shales, siltstones and sandstones, some authors suggest that it can act as seal or source rock. During the drilling of a well, with the subsequent detection of gas, three whole-cores of 18-m length were extracted for a better lithologic assessment as well as of its depositional environment aspects. In addition, a complete set of conventional and nuclear magnetic resonance logs were acquired plus laboratory analysis of routine core analysis, capillary pressure, nuclear magnetic resonance, x-ray diffraction and rock mechanics for a complete petrophysical evaluation. As it is a laminated reservoir, with complex mineralogy and remarkable presence of conductive minerals , such as pyrite and siderite, which cause strong suppression of the resistivity curve, the petrophysical evaluation of Longá Formation poses a great challenge and it is an example of the difficulties encountered by petrophysicists in this type of reservoir .

The effective porosity was calculated by means of well logs using a variable matrix density curve in conjunction with nuclear magnetic resonance logs so as to obtain a more robust porosity model, calibrated with core data, thus considering the mineralogical complexity of this reservoir. To optimize the cost of NMR logging, a synthetic effective-porosity curve model was generated from the machine-learning technique known as domain transfer analysis (DTA) and the results were applied to future drilled wells. Water saturation was obtained through a saturation-height modeling and its values compared to the irreducible water saturation derived from the NMR and calibrated with the T_2 cutoffs obtained in the laboratory. The clay volume was estimated by using the neutron-density logs and calibrated with laboratory results of X-ray diffraction.

The core-log integration made it possible to obtain important information about the depositional environment, lithology detection, reservoir characterization, calibration of the main petrophysical parameters and mechanical properties of rocks, which provides subsidies for the realization of a hydraulic fracturing, contributing to the production optimization and exploratory risk reduction. The productivity of the well increased by about 500% after stimulation, the subsequent drilling of a few more exploratory wells revealed the first commercial field of the Longá Formation in the Parnaíba Basin.

Wideband Logging-While-Drilling (LWD) Sonic to Extract Compressional Slowness in Large Boreholes and Extremely Slow Formations

Doug Murray and Neil Kelsall, Schlumberger

This study focuses on the use of logging-while-drilling (LWD) sonic tools to estimate compressional slowness in large boreholes drilled in formations with slownesses near the drilling fluid speed. In very slow formations compressional head waves tend to be refracted away with little energy making them difficult to identify in an environment where strong LeakyP modes are developed.

LeakyP is a borehole-wave mode traveling along the solid-fluid boundary, its amplitude decays exponentially from the borehole wall. It is excited by a monopole source in very slow formations. Unlike head waves, leakyP modes are dispersive and asymptote to formation slowness at low frequency and mud speed at high frequency. Formation compressional slownesses can be extracted from the leakyP low-frequency component. This is particularly useful in environments where compressional head waves are weak or nonexistent. New-generation, wide-bandwidth LWD sonic tools can estimate compressional slowness directly from leakyP without prior environmental knowledge like V_pV_s.

Due to historical LWD sonic low-frequency limitations in shallow, large borehole, offshore environments; workflows were developed to estimate formation compressional slowness based on leakyP dispersion modeling and VpVs. While these workflows have had some success, a better approach would be to deploy an LWD sonic with significant, very low frequency monopole energy. With energetic low frequency waveforms, formation slowness could be computed directly from the leakyP low-frequency asymptote.

In this paper, we use latest generation LWD broadband sonic tools acquired in multiple large boreholes (from 17- to 26-in. diameter) in extremely slow formations to extract formation compressional slowness. In a multitude of wells positive comparisons with wellbore seismic interval velocities were obtained.

The advent of LWD sonic tools with significant monopole energy at low frequency in all drill-collar sizes is changing the approach to sonic slowness acquisition in large boreholes in very slow environments. Historically in the industry this has been a problematic acquisition for both LWD (limited low-frequency content) and wireline logging (challenging deployments in large unconsolidated boreholes).

X-Ray Diffraction, X-Ray Fluorescence and Neutron-Induced-Spectroscopy-Based Correction to Ivar Aasen Geomodel; an Oilfield From the Norwegian North Sea

Egil Romsås Fjeldberg, Yngve Bostad Johansen, Geir Frode Kvilaas, Lodve Hugo Olsborg and Tor-Ole Jøssund, Aker BP; and Harish Datir, Schlumberger

The Ivar Aasen (IA) reservoir is located within a sedimentary sequence of Mid-Jurassic to Late-Triassic age. It comprises shallow marine to fluvial, alluvial, floodplain, and lacustrine deposits overlying a regionally extensive, fractured calcrete interval. The sequence exhibits a complex mineral composition and is heterogeneous at a scale below that of a logging sensor. Shale layers, redeposited shale and calcrete fragments are present in various forms throughout the sequence.

Extensive data acquisition in form of advanced wireline logs and coring with analysis performed in “geopilot” wells before production start, enabled a novel thin-bed formation evaluation technique based on a modified Thomas-Stieber method. The method increased the in-place oil volumes within the Triassic reservoir zone named Skagerrak 2. This led to several improvements and a modified drainage strategy of Ivar Aasen. Several good producers were placed in the complex net of the Skagerrak 2 formation. Results from these producers have encouraged development of even more marginal and complex net, deeper into the Triassic sedimentary sequence. Therefore, another “geopilot” was drilled into the deeper Triassic sediments, internally named Alluvial Fan. This zone exhibits conglomerate clasts in a matrix varying between minimum clay, silt, feldspars and very fine to very coarse sand fractions, grading towards gravel. Previously, this zone was considered to be mostly non-net. Applying the same interpretation method as for Skagerrak 2, the Alluvial Fan promised economic hydrocarbon volumes. The latest geopilot proved the producible hydrocarbons, and followingly a producer was also successfully placed in this part of the reservoir.

Production data and history matching from the beginning of production have long-established the previous increase of oil volumes in IA Triassic sediments. Acquired 4D seismic also support the increased oil volumes of the IA 2018 geomodel with connectivity, but there are other indications of additional upside, as the simulation model still lacks significant energy and volumes to substantiate these results. It can be mentioned that a rather large pore-multiplier is currently used to achieve match in the time series. Advanced studies of mineralogy and spectroscopy have showed that a significant amount of the previously interpreted carbonate, needs to be reinterpreted as ferron-dolomite. The latter is a heavier mineral that increases the matrix density, hence also the total porosity, which concurs with the significant energy addition needed in the model.

The additional findings described provided another needed first-order correction to further enhance the evergreen geomodel. This paper describes this methodology which resulted in improved petrophysics and reservoir properties of the Alluvial Fan, yet again demonstrating the value of advanced wireline logs and detailed analysis in total impacts the IA reserve volumes. Repeated success with the applied spectroscopy data and the thin-bed methodology, today, even the deeper Braid Plain formation has become of economic interest. It is expected to lie within the oil zone, an upthrown block in the northern part of the IA field and could be developed into the next target.

COMPLETION PETROPHYSICS AND RESERVOIR SURVEILLANCE

A Geomechanical Workflow and Sensitivity Study for Calibrating and Predicting Elastic Moduli and Minimum Horizontal Stress From Well Logs in an Anisotropic Formation

John Quirein, Brian Hornby, Philip Tracadas, Maged Fam and Amit Padhi, Halliburton

Shales and other formations exhibit vertical transverse isotropic (VTI) anisotropy in the sense that rock properties are different in the vertical and horizontal directions. Elastic moduli, the vertical and horizontal Young's modulus and Poisson's ratio, are required to estimate formation stress in VTI anisotropic formations. The elastic moduli can be described in terms of five stiffness coefficients. Two of the stiffness coefficients (C33 and C44) are obtained from density and vertical compressional and shear logs. A third elastic stiffness (C66) is estimated using full-waveform sonic measurements of Stoneley and Flexural mode data, along with input log data. The other two stiffness coefficients (C11 and C13) must be estimated by construction and calibration of a model. Calibration and construction of a model ideally occurs via use of laboratory static and dynamic measurements of the velocities and elastic moduli, and failing that, trends drawn from published laboratory and field data can be used. Using the predicted and calibrated static elastic moduli, along with total vertical stress, pore pressure and the Biot Coefficient, one can calibrate using fracture injection test data the formation minimum and maximum horizontal stresses, thus accounting for the horizontal elastic strains.

An empirical model is constructed and calibrated to estimate C11 and C13 from C33, C44, and C66, thus filling in the five required parameters to compute the dynamic elastic stiffnesses. The model is constructed such that if the vertical and horizontal shear velocities are equal, there is no formation anisotropy. Finally, using core data, a dynamic-to-static elastic moduli correction is defined and used to compute the final static elastic moduli. It is assumed, for simplicity, that the total vertical stress, pore pressure, and Biot coefficient are correct, and the principle elastic strains are solved for from fracture injection test data. With all these parameters and the model defined, it is possible to estimate the maximum and minimum formation stress, and thus, the fault regime (normal, strike-slip or reverse).

Robustness and sensitivity of the calibrated stiffness-coefficient and elastic-moduli model is demonstrated using laboratory data. Results are also presented and discussed for a real unconventional shale example. Here, the model correctly distinguishes between an isotropic formation and the shales above and below. A two-layer model is derived for each shale; a highly anisotropic layer with high total organic carbon and a weakly anisotropic model where there is minimal or no organic carbon. This model is consistent with the core data and demonstrates the necessity of adequate sampling.

A New Approach Towards Petrophysical Surveillance in a Giant North Sea Field

Tracey Victoria Vaitekaitis, Adrian Zett, Alexandra Love, Shakeel Ahmad, Alwin Noordermeer, Gerardo Cedillo and Xiaogang Han, BP

Petrophysical surveillance in Clair Field faces challenges due to reservoir properties, completion design and limited technology offers. Low-porosity, low-salinity reservoirs under waterflood recovery, with high angle—horizontal wells completed with sandface valves limits the ability to log for saturation monitoring. The wells are packer segmented between major flow units, making it difficult to assess the inflow profile from individual units (sand bodies) and almost impossible to differentiate the matrix from natural fractures contribution. The presence of heavy fluids (completion or asphaltenes) pose further challenges to conveyance and frequently affects the sensor responses. A surveillance campaign conducted early this year led to significant improvement, with results that helped us better understand the reservoir and wells behavior and change the surveillance strategy.

There were several different elements that we considered that led to successful results. Candidate selection is important for saturation monitoring. For the specific environment of the field we found that access to logging-while-drilling data (baseline capture cross section) is critical. This will also be considered for data acquisition in the remaining infill wells to be drilled. A different approach was taken for flow diagnostic in terms of sensor selection and data acquisition procedure. Generally, there is a limit on rig-up height, hence a need for short toolstrings. Access to short toolstrings is also important in data gathering due to better sensor collocation and less flow disturbance, translating into a more representative downhole measurement. A tandem string of both new compact flow diagnostic sensors and traditional production logging sensors was deployed. The traditional sensors failed due to harsh well conditions while the compact system delivered reliable results without mechanical failures. One major achievement was the value we extracted from Doppler-shift measurements, demonstrating that in this specific environment they can replace mechanical spinners. The compact flow-diagnostic tool enabled us to change the acquisition program, reducing the logging time. This translates to less risk, less production deferment and less wear to sensors. A new multidetector pulsed-neutron tool with surface and memory readout capabilities was deployed for first time in Clair field to monitor the saturation changes. The data proved useful to monitor the saturation change and to complement the flow diagnostic behind pipe. It also helped us to understand the dynamic behaviour of fracture vs matrix.

The paper will describe the new surveillance approach, the sensors response and the results impact on our field management strategy.

A New Formation Evaluation Philosophy to Integrate Production Surveillance Data With Reservoir Simulation Models: A North Sea Case Study

Robert Webber and Jesus Aponte, CNOOC International Ltd

This paper introduces a new petrophysical interpretation philosophy for the evaluation of casedhole saturation logs and PLT data. The approach has been developed to reduce the inherent uncertainty associated with casedhole water saturation estimates, and to provide a petrophysical interpretation product that can be incorporated into the objective function of reservoir simulation models.

The location and movement of the flood front, or sweep, in an oil or gas reservoir is a key uncertainty in field management. Reliable knowledge of sweep in a reservoir is critical to making effective field development decisions, such as identifying opportunities to add perforations to unswept zones or derisking infill drilling locations. Field development decisions are often supported by reservoir simulation models, however it is difficult to constrain these models with saturation estimates from casedhole logs. Water saturation estimates derived from casedhole logs typically have a high uncertainty, especially where the salinity of the flood front is unknown.

To address these challenges a new formation evaluation approach has been developed which involves the creation of a Boolean sweep interpretation to indicate the breakthrough of the flood front. This interpretation is a simplification of the true petroleum physics at work in the reservoir, however it can be demonstrated to be a valid characterization of this specific oil field. This case study show-cases a rich data set of production surveillance information which provide support for the 'style of sweep' interpretation in several ways. The benefit of this interpretation product is that it can be built into the objective function of the reservoir simulation history match, in a simple and quantitative fashion.

This case study highlights the utility that production surveillance data can provide to improve the understanding of dynamic reservoir behavior. The approach in this paper shows examples of how this understanding of sweep can directly constrain reservoir simulation models. Reservoir models that are conditioned in this way can support more effective field development decisions.

Unlocking Data Analytics in Sonic and Ultrasonic Logs for the Automatic Evaluation of Cement-Bond Scenarios

Dario Reolon, Federica Di Maggio, Giuseppe Galli, Sara Moriggi and Marco Pirrone, Eni S.p.A.

Cement-bond evaluation is a critical step in the early-life stages of newly drilled wells since it rules the way for obtaining useful information about wellbore integrity. Conventionally, this is carried out by means of a detailed interpretation of casedhole sonic and ultrasonic log data. However, this standard approach can be highly time-consuming and challenging in long completion sections and when complex scenarios have to be handled in operative times.

In this respect, oil companies have stored huge data sets for their wells, with quality-checked casedhole acoustic logs and associated interpretations in terms of wellbore integrity. This paper deals with a novel, probabilistic data-analytics approach aimed at obtaining a fast and robust cement-bond facies classification. The latter is deemed able to automatically provide an exhaustive quantitative cement-placement evaluation, hence avoiding time-consuming processes and possible subjectivity issues.

The implemented methodology takes advantage of the multiresolution graph-based clustering (MRGC) algorithm that gathers its knowledge by recognizing patterns in sonic and ultrasonic logs/maps from dozens of wells, including hundreds of thousands of meters of logged intervals. This allows the system to learn through experience how the log measurements are related to the common cement-bond scenarios (e.g., good, partial, poor cementation, dry or wet microannulus, free pipe). The MRGC is then integrated in a Bayesian framework to obtain the probability of the cement-bond facies, the most probable scenarios, and the associated uncertainty by means of entropy computation. In detail, an automated screening can be performed in newly drilled wells to detect possible problems of hydraulic sealing.

The potentialities of the discussed method are demonstrated by real case applications consisting of cement log data collected from several blind-test wells. First, the probabilistic approach is used to predict the cement-bond scenarios together with the uncertainties of their classification. Then, an unbiased evaluation of the results is performed. The successful outcomes coming from the last step of the workflow shows how, with a statistically representative and good quality data set, data analytics can efficiently mimic high-skill expert work in harsh circumstances and within a time-efficient template. In fact, this data-driven methodology takes few seconds to provide an exhaustive interpretation against, at least, one day with the conventional one.

DEEPWATER RESERVOIR ANALYSIS

Challenges in the Petrophysical and Dynamic Characterization of Deepwater Turbidite Deposits of the Colombian Caribbean Offshore—Case Study

Juan Alejandro Angel, Ricardo Andres Gomez and Carlos Alberto Mora, Ecopetrol S.A.

The Colombian Caribbean region has become an exploratory target and recent discoveries confirm its future potential as a gas province to overcome the near-future expected gas deficit.

A petrophysical and dynamic characterization workflow is implemented for this challenging Pleistocene deepwater play, where the depositional environment is the result of turbidity processes

The reservoirs consist mostly of thin to very thin sand layers, corresponding mainly to the Tb, Tc, and Td divisions of the Bouma sequence, as observed in the cored intervals. The greatest challenge in the characterization of this particular reservoir is the vertical resolution, considering the very low thickness of the layers, which become very difficult to detect using standard-resolution logs. Thus, tomography images and resultant curves from CT-scans and their integration with routine and special core analyses were used to reveal the true nature of this complex reservoir

The proposed methodology focuses in the integration of routine and special core analysis for the petrophysical and dynamic characterization of the reservoir, where the pore-throat-radius distribution from high-pressure mercury injection becomes the backbone of the differentiation between what is considered reservoir and what is not. The pore-throat radius estimated from high-pressure mercury injection (R35) correlates extremely well with textural features and clay content in the rock and therefore, this parameter (R35) was used to define the different classes for rock typing. The way forward was to develop a multilinear regression model of R35, as a function of very high-resolution tomography outputs in the cored zones and then see how it may be extrapolated to the uncored zones using available high-resolution logs.

Special petrophysical analyses, such as low-field NMR, porous-plate capillary pressure, electrical properties and relative permeability curves (steady-state) showed correlation with the defined rock types and in turn allowed to know the gas accumulation potential of the area.

Finally, rock and fluid (dry gas) properties have been used to build a single-well radial model to design initial well tests (DST) and predict production performance from each interval (selective tests). The simulation model represents the lateral and vertical heterogeneity related to the geological environment (turbidites). The final results have defined the flow and shut-in times during tests to optimize budget.

Digital Rock Analysis of Coquina Carbonate Rocks for the Presalt Scenario

Caroline Mignot, Felipe Branco, William Godoy, Santiago Drexler, Luis Horta Jr., Bruno Castro, Vitor Silos, Andre Barretto, Barbara Quedimann, Enrique Estrada and Milena Siqueira, Halliburton

Morro do Chaves coquinas are highly complex carbonate rocks. They present a heterogeneous pore system and matrix, challenging the standard methods to provide a correct reservoir-quality evaluation. A digital rock analysis (DRA) workflow combines the most advanced X-ray computed microtomography (micro-CT) 3D imaging methods and modeling with the state-of-the-art in multiscale fluid flow numerical simulations. The application of DRA properly integrated with physical measurements can considerably improve the results, thereby reducing time and costs.

The coquinas studied in this project are analogous to the presalt Itapema and Coqueiros Formation. Presalt complex embodies 50 billion barrels of potential oil production and is the most important discovery in the industry within the last decade, where just the Buz-10 well alone produces more than 65,000 BOPD.

From well logs to nanoscale, our DRA delivers rock fabric and pore-structure hierarchy that is an essential part of building static and dynamic reservoir models. DRA multiscale integrated analyses were performed to support rock-type characterization and numerical fluid-flow simulations, creating a disruptive industry solution for complex carbonate rocks.

The principal objective of this research project was the use of a new DRA technology to characterize carbonate rocks, including multimodal systems evaluation.

Several laboratory measurements—mercury injection capillary pressure (MICP), thin-section analysis, and fast special core analysis (SCAL)—supported the digital results. The digital activities we performed involved porosity and absolute permeability estimates, formation factor, cementation exponent (m), elasticity, pore characterization, trend analysis, rock-model diagram, digital SCAL, reservoir-rock-typing characterization, upscaling methodologies, and data integration analysis.

We can conclude that the adaptation our workflow for complex carbonate rocks created an optimized roadmap for sample screening, evaluation, and time saving compared to standard procedures, which is paramount for a better prediction of reservoir forecast. The results helped us to understand the rock matrix and pore system of coquina samples, as well as the dynamic of fluid flow within these systems. These multiscale studies improved the workflow and the evaluation of actual presalt rock samples and well logs.

High-Resolution Electrofacies Analysis Applied to Deepwater Siliciclastic Reservoir Economic Evaluation, Northeast of Brazil

Anelise de Lima Souza, Pedro Paulo Pires de Deus Rocha, Lenita de Souza Fioriti and Fernando Jorge Pedrosa Maia Junior, Petrobras

Northeast Brazil has the most important discovery of the country after the Presalt carbonate reservoirs. It is a play of Calumbi Formation in the deep waters of the Sergipe Basin. The Calumbi Formation is essentially a pelitic sequence extending from the late Cretaceous to the recent, with psamitic incursions that constitute its turbiditic reservoirs.

In the newly discovered play, the reservoirs consist of channel and lobe complexes of Campanian-Maastrichtian age. The connectivity between the correlatable reservoir heights as well as the extent of the various reservoir facies are crucial factors in the economics of production projects in the area. In this sense, the high-resolution electrofacies analysis greatly contribute to the understanding of the connectivity and to the volume estimation, as they allow for a more detailed interpretation and control of facies and granulometry variation in porous heights and its distribution across geological models.

In the present study, unsupervised classification based on the multiresolution graph-based clustering (MRGC) method was used. Available rock data were initially classified into lithofacies according to Mutti facies. For the interpretation of the electrofacies, a reclassification was made based on the lithofacies described in the Bouma sequence, resulting in five clusters correlated to the following facies: F3 – Conglomerate; F5 – Coarse/Very Coarse Sandstone; F8 - Medium/Fine Sandstone; F9TbTd - Interlaminated Sandstone (subdivided, when it's possible, into IAF - Sandstone-predominant interlaminated deposit - and IFA - Shale-predominant interlaminated deposits); F9Te - Shale and Marl; and F1 - Slump facies.

The quality control was performed for all available logs: gamma ray, density, neutron, sonic, spectral gamma ray, resistivity and acoustic image logs. The petrophysical core data were incorporated into the analysis for rock data depth calibration. After log processing and validation, the correlation between core and well-log data was made through the following steps (1) core depth calibration using core gamma and the reference gamma-ray curve of the first log run, (2) fine depth calibration by correlating textures and geological surfaces observed in the image logs and core, (3) repositioning of side samples by calibration with marks observed in acoustic image logs and with petrophysical core analysis, and (4) calibration with facies description of cores and side samples.

Textural facies were extracted from resistivity image logs through the generation of self-organizing maps (SOM), which worked as the input that would guarantee the high resolution of the electrofacies analysis. The textural maps were done by analyzing the contrast variations between a point and its neighbors, through a covariance matrix, which worked to represent facies heterogeneity or homogeneity.

The study was carried out and validated in an integrated way among petrophysicists, sedimentologists and reservoir geologists, ensuring that the products could be applied both in exploratory interpretation studies and in production development projects. The use of SOM with MRGC method presented excellent results, with a good correlation between the electrofacies and the rock data and showing a good resolution as required to better understand the reservoirs of the Sergipe Basin.

Recent Rotary Sidewall Coring Advancements for Deepwater, With a Background Overview

Charlie Jackson, Halliburton

Rotary coring has become significantly more important as an alternative to conventional coring due to the high total cost of conventional coring operations. Coring wells below 30,000 ft encounter significant rig costs along with operational challenges, and the amount of time involved even for wireline operations. Formation pressures can exceed 30,000 psi and differential pressures over 5,000 psi also exceed the capabilities of traditional rotary-coring tools.

New Technology has been introduced to enhance the recovery of rotary sidewall cores to improve operations and capabilities on these challenging wells. The improvements include:

- 1.5-in. diameter core samples, on a 35,000-psi tool.
- New high-powered coring tools with significantly more power for cutting Lower Tertiary well-cemented rock (Wilcox, etc.).
- Higher torque and horsepower at the bit.
- High-powered surface systems, and high-strength wireline cables.
- New drill bits and catcher rings for using the higher power and harsh coring environment.
- Cutting and handling advancements for soft and hard formations.
- Combinability improvements to reduce wireline trips.
    - Dual-coring tools with the ability to have different catcher rings and bits downhole simultaneously on a single run.
    - Combination of rotary coring and formation sampling to obtain—formation pressures, fluid samples and cores on a single run.
- Full downhole monitoring of the coring operation, which includes the drilling functions like torque, bit force, penetration rate, depth of the core drilling, along with tool orientation.
- A unique method to seal the cores in a pressure-compensated coring tube downhole to capture all the formation fluids in the rock in the borehole environment.
- Core recovery information to enable 100% core detection downhole so extra cores are not cut where they are not needed during the job, since the individual core plugs are measured downhole for recovery
- Complete rotary-coring downhole operations can be monitored remotely for offsite interaction during the coring operation

In addition, we will include some historical information on rotary sidewall coring going back to the 1980s and earlier to highlight the improvements and challenges that have been resolved with new technology. We will also give real examples of the different applications above and where they have been significantly beneficial for deepwater and other operations. The paper will contain numerous diagrams, pictures and core photographs.

Reservoir Connectivity Assessment Using New Formation-Testing Platform and Image Log Evaluation Indicates Connectivity Across a Large Reservoir Offshore Mexico

Francois-Xavier Dubost, Schlumberger; Joel Speights, Talos Energy; Jesus A. Canas and Oliver C. Mullins, Schlumberger

The appraisal phase is a unique opportunity to evaluate reservoir continuity for reducing key uncertainties required for field development decisions and planning. Appraisal activities for large offshore reservoirs hence necessitate optimal fluid and formation data acquisition and analysis to reduce reservoir uncertainties. This is critical for assessment of vertical and lateral reservoir connectivity, flow assurance or fluid production behaviors under future EOR schemes.

Reservoir fluid geodynamics (RFG) studies incorporating downhole fluid analysis (DFA) measurements and analysis of reservoir fluid samples help establish origin and history of the fluids in the reservoir—from charge through to present day. This new discipline coupled with geochemical, image and core analysis allow addressing important risk factors, such as vertical and lateral reservoir connectivity.

The Upper Miocene-age Zama oil discovery located in the offshore Sureste Basin of Mexico, was initially identified as a three-way dip structure sealed against a salt structure. It consists of massive individual turbiditic sands as seen on borehole images and logs, overlain by a thick hemipelagic shale. During field appraisal, formation-testing data and representative fluid samples were required to assess reservoir connectivity and for input to engineering studies. The initial appraisal wells could not be sampled effectively using established sampling technologies since many reservoir intervals were poorly consolidated, and well trajectories were complex.

Hence a new formation-testing platform was deployed in two appraisal wells. This new system enabled focused sampling and DFA, with collection of pure samples while maintaining controlled low-pressure drawdowns during sample cleanup. In real-time, DFA measurements were used to guide the sampling process, identify additional depth intervals requiring characterization, and enable assessment of reservoir continuity between different flow units using RFG principles.

More than 30 pressure-compensated fluid samples of high-quality and purity were efficiently collected at multiple depths. Subsequent laboratory analysis of the sampled fluids confirmed the favorable case of laterally extensive connectivity of the stacked-sands sequences. Petroleum geochemistry analysis also corroborated fluid gradient and asphaltene concentration gradient models; providing further insights on timing of migration and reservoir charging. Interpretation of geological image logs and subsequent full core analysis were consistent with DFA gradient analysis, and the lateral connectivity predictions were confirmed during a multi zone well test.

This case study shows how RFG analysis using advanced formation-test data coupled to image and log evaluation provides connectivity predictions for a large field offshore Mexico.

Wireline-Conveyed Pressure and Sampling Technology Usage for MiniDST and Microfrac

Hoda Tahani, Mehdi Azari, Gibran Hashmi, Mark Proett and Fransiska Goenawan, Halliburton

Some reservoirs are very challenging to achieve the stress regime and geomechanical properties, especially in tight heterogeneous formations. Usually for geomechanical analysis and earth modeling, acoustic and imaging data play a major role in calculating earth stresses value and direction. For all cases, comparison with stress analysis performed on core data is a must for calibrating dynamic calculations to static stresses and validating both values and directions. In cases where there is no core or core analysis available, results can be compared with other data for validation among which is the minifrac.

A new formationtester techniques was used to significantly decrease the falloff and cleanup time in tight formations. This can provide accurate in-situ measurements of formation breakdown, fracture reopening and propagation, and closure at the reservoir. The formation tensile strength can also be estimated from the difference between breakdown and reopening downhole pressures. The fracture-closure pressure was identified by different methods (1) square root of time (SRT), (2) log-log pressure decline analysis, and (3) G-function analysis by plotting the *GdP*/*dG* on a pressure vs. G-time plot.

Due to the high costs involved in offshore exploration wells for well-test operations, the tests should be designed to meet the objectives at lower costs. A mini-drillstem test (miniDST) is one of the best and most efficient ways to obtain the flow capacity (*kh*) of the zone being drained by the probe under dynamic conditions, the reservoir-static pressure and collect reservoir fluid samples. In certain circumstances, vertical and horizontal permeabilities may be obtained. The formation-testing and sampling tool was used to conduct several miniDSTs and collected samples at different depths of the reservoir.

This paper describes the application of using wireline miniDST and microfrac to obtain reservoir pressure and fluid samples, as well as in-situ reservoir stress analysis for various heterogeneous carbonate formations, comparing the results with the results of rock mechanic analysis using the acoustic data and using of image interpretation, confirming the heterogeneity of the formation. It includes a description of the objectives, prejob planning, conclusions, and lessons learned.

FORMATION EVALUATION BEHIND CASING

A New Borehole-Compensated Neutron-Gamma Porosity Measurement Optimized for Casedhole Formation Evaluation

Weijun Guo, Halliburton

Neutron-porosity measurement is important for quantifying reservoir asset and optimizing production values. The neutron-gamma porosity measurement is common for casedhole logging. One key reason is that pulsed-neutron logging is the primary downhole technology for residual hydrocarbon monitoring. The addition of a porosity curve is cost effective. Another benefit is the deep penetration from the 14-MeV neutron, i.e., larger depth of investigation; however, its measurement sensitivity and large borehole effect are well-known limitations. These limitations may lead to large petrophysical uncertainties.

This paper introduces a new neutron-gamma porosity algorithm and its testing results. The new algorithm combines the inelastic count rates and capture count rates from a standard pulsed-neutron logging operation. The inelastic count rates are corrected for the capture background to optimize the measurement sensitivity. A detailed study was completed to optimize the capture count rates. Through this optimization, the capture count rate matches the net inelastic count rate for the borehole effects. The borehole-compensated ratio, between the net inelastic count rate and the total capture count rate, has been characterized for the new porosity algorithm.

The study originated from developing a comprehensive understanding by integrating a broad set of underlying nuclear data, including neutron slowing-down length, scattering cross section, and activated gamma-ray yields. The comprehensive understanding of the particle transport led to the new borehole compensation concept. This paper presents the detailed results to illustrate the borehole-compensation improvements by more than 20%. The parameters of study covered primary environmental factors, such as borehole size, formation water salinity, and borehole fluid salinity. Depth of investigation results are derived from a large nuclear modeling database. For practical petrophysical applications, lithology curves are shown for this new porosity measurement. A detailed error analysis compares results from different porosity algorithms and concludes the significant improvement of the measurement sensitivity to be within 1.5 p.u. for the entire range from tight to porous rocks.

In summary, this paper introduces a new neutron-gamma porosity measurement. This new measurement has been optimized by integrating nuclear tool physics and large set of data. Error analysis was conducted for tight and porous rocks. The improved 1.5-p.u. measurement sensitivity and intrinsic borehole compensation may lead to significant uncertainty reduction for petrophysical applications.

Gas Pressure Estimation in Cased Hole Using a Pulsed-Neutron Log

David Rose, Alberto Abouganem Stephens, Tong Zhou and Laura Bolerjack, Schlumberger; and Kevin Kenning, Renaissance Offshore

In mature, multilayered gas reservoirs, a common problem is determining whether unperforated potential gas zones behind casing that were identified on openhole logs are still at original reservoir pressure or have been depleted over time via offset well production. If the unperforated zones are still near original reservoir pressure, a workover targeting the zone can be justified to maintain well production as existing production declines. If the unperforated zones are depleted, a workover will not be economical.

One way to solve this problem is by running a casedhole pulsed-neutron log that can make three independent formation measurements of sigma, porosity (TPHI), and fast-neutron cross section (FNXS) in the well and using an interpretation workflow to estimate the current gas pressure. The workflow consists of selecting an appropriate equation of state for the gas, assuming a chemical composition of the gas, determining the pulsed-neutron measurement variation versus pressure for the gas, and forming an equation solving for pressure where all other variables in the measurement response equation are assumed to be known, including water saturation. Information can be integrated from openhole logs, such as porosity, lithology, and water saturation. Performing the workflow for the three independent measurements gives three estimates of gas pressure, which brings confidence to the interpretation if they are consistent.

A case history from the Gulf of Mexico is presented. A potential gas zone in a producing well behind casing was considered for a workover and was evaluated with the interpretation workflow. Three gas pressures were computed based on the casedhole pulsed-neutron measurements and formation evaluation from previous openhole logs. All indicated a current pressure near the original reservoir pressure. A workover was performed, and the well was successfully produced with the measured gas pressure consistent with the pressures predicted from the interpretation workflow. The well is economically producing, justifying the workover costs and demonstrating the usefulness of this workflow.

Integration of Nuclear Spectroscopy Technology and Core Data Results for Through-Casing TOC Measurement and Saturation Analysis a Case Study in Najmah-Sarjelu Reservoir, South Kuwait

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The acquisition of openhole logging data is not always guaranteed because of difficult drilling environments. In such cases, formation evaluation, and thus completion program becomes a real challenge. The situation becomes more complex when dealing with unconventional reservoirs with very tight carbonates and organic carbon-rich formations. This paper presents a method to measure TOC and to estimate oil saturation in such challenging environment.

A suite of wireline tools (GR, spectralog, density, neutron, nuclear spectroscopy), was run through 7.625-in. casing to evaluate the formation and to quantify the total organic carbon (TOC) and the oil in the pores. The nuclear spectroscopy tool, which was the master tool, measures the total carbon in the formation. Part of this carbon is attributed to the inorganic matrix (carbonates), another part is attributed to the organic matter in the matrix (kerogen), the remaining carbon, or extra carbon, is mainly the carbon inside the pores. The process consists of integrating the conventional logging data, the spectroscopy data, the core data and some geological constraints to estimate corrected porosity, mineralogy and TOC in the kerogen-rich intervals. The extra carbon, which is not attributed to the matrix and TOC, is used to estimate oil saturation. Finally, core data are used to validate the analysis results.

The presented methodology has been applied to a casedhole well with no openhole data previously acquired, due to drilling issues. The primary target of the well, in the deep section, produced water; then the operator decided to revisit the second target and complete it for testing. It has to be pointed out that over the well cemented intervals, the results showed a very good matching of the corrected total porosity and the core total porosity. Relying on TOC and saturation analysis results, the operator has selected the most promising intervals to be tested. Testing results have shown excellent matching between production results and oil saturation analysis results.

TOC and oil saturation quantification using nuclear spectroscopy technology and core data results showed its success in both tight carbonates and organic carbon-rich reservoirs. This method will be a solution to evaluate and complete any wells with no openhole data acquired, and also to evaluate and complete the unconventional formations where the conventional methods have shown their limitations.

Maximizing the Value of Data Acquisition: Gas Pressure Assessment Through Casing—A Complex Casedhole Pulsed-Neutron Case Study From the Netherlands

Chiara Cavalleri, Schlumberger; Gerrit Brouwer and Dimas Kodri, Nederlandse Aardolie Maatschappij; David Rose and Jan-Bart Theodoor Brinks, Schlumberger

The paper describes the experience of casedhole logging for formation evaluation and input to redevelopment potential of an oil producer well with a challenging production history. This includes an intelligent assessment of formation gas pressure through casing, which was later confirmed by perforating.

The target reservoirs are lower Triassic sandstones and were drilled as a gas exploration prospect. Based on openhole log data the prospect appeared to be oil bearing. The well has been producing oil for several years, and now is a candidate for a gas cap blowdown.

The presence of heterogeneous layers with varying rock quality and producibility indexes coupled to complexity in fluids distribution and zonal isolation issues complicate the development process and ability to optimize recovery from any contributing level.

Recently a new-generation casedhole formation evaluation tool that provides multiple independent formation property measurements was recorded to enhance the knowledge of the formation parameters, while describing the fluids saturation at the current time. Sigma, neutron porosity, fast-neutron cross section, and elemental concentrations with total organic carbon from inelastic and capture spectroscopy are simultaneously recorded. Because the well is highly deviated in the zones of interest, the tool is efficiently conveyed on wireline using tractor technology.

The evaluation techniques used to study this rich set of data reveal information that is essential to the petrophysicists and geologist, but also to the reservoir and production engineers.

A multimineral solver analysis guided by the prior knowledge of the rocks using cores from offset wells, quantifies the porosity and fluid volumes, while giving access to detailed knowledge of matrix and rock composition for refined reservoir models.

Additionally, a novel method to determine gas pressure at the current time from the casedhole log measurements was applied, to support reservoir management. The highly sensitive sigma, neutron-porosity, fast-neutron cross section gas properties can be parameterized as a function of pressure and temperature if the formation and fluid properties are known. This is a well-established principle that can finally be applied independently and directly to multiple measurements. The computation is done independently and checked against each other for consistency and support to optimal parameter setting, in an iterative manner. This is particularly important in this scenario where the complexity of the wellbore environment and history of the well could have complicated the ability to achieve enough precision on the estimated pressures when coming from a single method or modeling has to be involved.

The log results, with validation, and implication on the well redeveloped are presented together with a more general digression on the methodology and applicability based on this well experience.

The importance of meticulous job preparation, prejob modeling and data quality control are also highlighted.

The information is key to define future well development management strategy and clarifies the role that casedhole logging can play as part of the complete well evaluation process.

Multidetector Pulsed-Neutron Tool Application in Low-Porosity Reservoir—A Case Study

Aditya Arie Wijaya and Rama Aulianagara, Halliburton; Fetty Maria Naibaho, Fransiscus Xaverius Asriwan and Usman Amirudin; Pertamina Hulu Sanga-Sanga

In mature fields, pulsed-neutron logging is commonly used to solve for remaining saturation behind casing. For years, sigma-based saturation has been used to calculate gas saturation behind casing; however, the high dependency of sigma-to-water salinity of the formation, especially in the low-dynamic range of porosity lower than 10 p.u., has proven to be challenging in low-porosity, gas-prone reservoirs. A new measurement from a third detector from a multidetector pulsed-neutron tool (MDPNT) is proposed to provide a better estimation of the gas saturation in such a low-porosity reservoir.

Two sets of independently measured sigma and the third detector were taken in a cased well, with a dual-tubing system of long string and short string. For the third-detector measurement, the measurement was based on the ratio of slow-capture-gate and inelastic-gate component from decay curve created by the long detector. This ratio can be used to detect gas in a tight reservoir with minimum salinity and lithology effect. This data will then be used to calculate the gas saturation from the third detector, and the result is compared to sigma-based gas saturation.

At an interval where the porosity is above 10 p.u., the sigma-based gas saturation and MDPNT-based gas saturation are very much in agreement. However, in a reservoir with porosity in the range of 10 p.u. or below, the sigma-based measurement starts to show its limitation. Meanwhile, the MDPNT-based gas saturation clearly shows the remaining gas saturation where sigma-based measurements failed to detect. Subsequent decision was made based on the log analysis result, and perforation was done at potential interval based on MDPNT result. The results from the production test confirms the MDPNT-based gas saturation with over 600 MSCFD gas production added.

This study showcases a new technology to solve a low-porosity gas reservoir issue where a sigma-based measurement has failed to determine the remaining gas saturation. Using two different measurements in the same well, the results from the MDPNT measurement were superior to the sigma-based measurement in low-porosity rock.

Self-Compensated Casedhole Pulsed-Neutron Spectroscopy Measurements

Tong Zhou, David Rose, Jeffrey Miles and Jason Gendur, Schlumberger; Haijing Wang, Chevron U.S.A. Inc.; and Michael Sullivan, Chevron Canada Ltd.

Formation elemental composition and mineralogy

measurements, including organic carbon from recently developed spectroscopy tools, provide critical information for formation evaluation in both conventional and unconventional reservoirs. These measurements can be obtained under casedhole conditions by using a slim pulsed-neutron tool with two spectroscopy detectors. One primary limitation is that users must manually provide offsets for the elements (Si, Ca, and Fe) present in casing and cement before performing the oxide closure computation to obtain elemental concentrations. This process is time-consuming, and the results could be inaccurate and subjective, especially without any local reference. The other main limitation is that the formation element signals are smaller in cased hole than in open hole. This increases the noise in the oxide-closure-derived environmental yield-to-weight normalization factor (FY2W), which is propagated to all the elemental weight fractions.

A self-compensated spectroscopy algorithm was developed to overcome these two limitations. The key breakthrough is the use of raw measurements with very-high precision from the two spectroscopy detectors to predict FY2Ws instead of using the oxide closure or inelastic-capture (INCP) closure methods. The capture FY2W is mainly determined by the borehole and formation sigma. It can be characterized by using multiple measured apparent sigma values in different timing gates from multiple detectors, which have different sensitivities to borehole and formation sigma. The inelastic FY2W is mainly determined by the borehole and formation geometry and hydrogen index. It can be characterized by using multiple detector count-rate ratios in both burst-on (inelastic) and burst-off (capture) timing gates. This method reduces the noise in the FY2Ws by an order of magnitude, which improves the precision of all the final elemental weight fractions. Two independent sets of apparent elemental weight fractions can be calculated from the two spectroscopy detectors. The measured elements from the detector with shorter spacing are more sensitive to the borehole environment including the casing and cement, whereas the ones from the detector farther away are more sensitive to the formation. This enables self-compensation for casing and cement effects. The new processing can be done without user intervention and results in a more accurate, more precise, and less subjective elemental composition and mineralogy. More than 1,600 laboratory measurements in different conditions were used to characterize the algorithm. Several log examples demonstrate the excellent performance of the new compensated spectroscopy measurements in cased hole, which are validated by core data, cuttings analysis, and measurements from a high-resolution spectroscopy logging in the same wells before they were cased.

The Fourth Phase—New Downhole Sand-Detection Technology Shows Exciting Results and Presents Low-Cost Remedial Opportunities

Adil Al Busaidy, Wee Wei Wa and Parijat Mukerji, Schlumberger; Daniel Chua Min Wei, Azli Yacob, Ahmad Majdi and Aiman Redzuan, CHOC

Detecting sand production downhole has always been a challenge, tools relying on simple acoustic measurements were prone to error from road noise or production noise, false detections were common making quantifying sand production impossible. A new technology that counts sand grain impacts and impact energy allows us to quantify sand production, in effect measuring a fourth phase, solids. Early application of this technology shows real promise and opens the doors for cost-effective and highly targeted remedial action to be taken.

This paper covers results from four wells. The main objective was to find water production and the secondary objective to quantify sand production. Production logs were recorded, three of the four wells used a minispinner array to better describe the fluid motions in these deviated wells, water and gas holdup probes generated data to provide an intuitive and coherent interpretation. The sand-impact detection tool was also run on each well and the fourth phase, sand, was clearly seen with excellent repeatability, even at very low count rates.

Previous to this work, distributed acoustic sensors (DAS) had been used in the field for sand detection with limited success. While DAS has been used in some environments with success, in this case the data were inconsistent with the producing interval and could not be used as a diagnostic tool with any confidence.

The Value of Data Integration in a Complex Well Scenario: A Case Study From the West Netherlands

Abhinandan Kohli, Shell; Chiara Cavalleri, Schlumberger; Zulkifli Ahmad, NAM; Emile Fokkema, Shell; Oscar Kelder and Daniel Sprague, NAM

For over 40 years pulsed-neutron logging (PNL) has been used in the industry to determine hydrocarbon and water saturation for reservoir management. Earlier, this technique was mainly used for time-lapse contact movement analysis and for a qualitative assessment of the saturation. Present-day PNL tools can perform a quantitative assessment of petrophysical properties of the reservoir including shale volume, porosity and saturation. The ability to record new rock properties and multiple independent measurements expands the applications of casedhole evaluation to environments that are not accessible and to cases where a standalone evaluation is required.

PNL technology has been successfully used in the West Netherlands to estimate petrophysical properties, mineralogy, and for diagnosis of bypassed hydrocarbons and depleted zones. The casedhole environment here tends to be complicated by the presence of multiple casing strings and completion elements in the borehole, and due to variable annular fluids and conditions. Every measurement is used and interpreted in relation to its statistical uncertainty and level of interpretability. In a complex well, near-wellbore conditions and well dynamics determine to what extent a standalone casedhole evaluation can be performed.

The paper describes an example of log acquisition and data integration in a development well that was recently drilled. Casedhole logging is performed to determine the oil potential in Lower Cretaceous reservoirs, following the discovery of oil in a nearby field. At the same time the logs are interpreted to quantify the remaining gas saturation in deeper Triassic sandstone targets.

Important reservoir properties are measured through-casing and combined to reconstruct porosity and mineralogy at different levels. Gas measurements are converted into volumes. The presence of deep oil-based-mud invasion and the large and complex borehole conditions limited the ability to confidently isolate and directly compute the possible contribution from the measurement of total organic carbon (TOC). This could potentially lead to an overestimation of oil, if considered independently. Other techniques, such as carbon/oxygen analysis, could not be applied as such techniques are not characterized for this wellbore environment.

An intelligent evaluation approach that integrates casedhole neutron porosity and sigma, elemental dry weights from capture and inelastic spectroscopy, including TOC, with resistivity from logging while drilling (LWD), is applied for accurate reserve characterization and informed decision making. This combined with quantitative elemental modeling proved very useful in demonstrating that the oil lead identified in the formation has only residual oil and should not be pursued further. A review and comparison of different interpretation methods with their associated uncertainties is required to constrain the petrophysical model.

This further highlights the importance of data integration to maximize confidence in the evaluation results in such complex boreholes. The right amount of data exchange and communication between various disciplines led to a sound conclusion of the project in turn helping stop the execution of an appraisal opportunity; thus avoiding a potential waste of € 3.5 million.

FORMATION EVALUATION OF CONVENTIONAL RESERVOIRS

1D Modeling of Lithotypes and Petrophysics for the Grant Group and Anderson Formation, Canning Basin, Australia

Daniel Mauricio Rojas Caro and Maria Liceth Cabrera Ruiz, UIS-Universidad Industrial de Santander; Erick Johan Illigde Araujo, Juan David Badillo Requena, and Alessandro Batezelli

Petrophysical characterization represents an important aspect in the petroleum industry, playing an essential role in the integrated management of reservoirs and the optimization in recovery processes. In this way, the developing of modeling of 1D lithotypes and petrophysical for the Grant Group Formations (Carolyn, Winifred and Betty) and Anderson Formation of the Bunda Block 3D 2009 of the Canning Basin, located in the Northwest of Australian Onshore, was proposed. Initially, the creation of an information inventory (core analysis drilling, well logs and pressure test-drillstem test) was necessary for assessment of the feasibility of the project's objectives. Besides, the generation of the model of shaliness (V_{sh}), which was the pillar for modeling of well logs (*NPHI, RHOB*) by hole quality, that allowed lithotypes classification through neural nets of the Petrel Software, having as input well logs (DTp, PEF, NPHI, RHOB, and V_{sh}). Inside modeling of petrophysical properties, calibration data was incorporated as X-ray diffraction (XRD) and core-gamma. The effect of minerals on the response of rock bulk density, neutron porosity and resistivity were reflected on the effective porosity model. Equally, hydrodynamics affected the response of the resistivity log, leading to the complex identification of oil/water contact (OWC), affecting the generation of the water saturation model, being necessary the implementation of correlation Poupon-Leveaux or Indonesian, using differentiated values of water resistivity for the different zones of the formations of study. Finally, horizontal permeability models were generated from effective porosity and horizontal permeability from the core.

A Data-Driven Graphical Method to Evaluate Gas Reservoirs With Density-Neutron Logs

Khadija Al Daghar and Sultan Budebes, ADNOC; Chanh Cao Minh, Kais Gzara, Vikas Jain and David Maggs, Schlumberger

The Poupon-Gaymard and Segesman-Liu equations are widely used to correct density-neutron logs for gas/light hydrocarbons effect. The equations assume an "average" gas, an "average" oil at "average" reservoirs conditions plus other empirical formula to model complex hydrocarbons that might not be applicable to all reservoirs. Since time-lapse data contain information about the hydrocarbon properties at reservoir conditions and could show fluids changes with invasion, we propose to use time-lapse data to correct for gas effect. The result is an easy-to-use density-neutron crossplot overlay to determine total porosity free of gas effect. The graphical method provides valuable insights about various forms of existing crossplot porosity equations. Once total porosity is determined, hydrocarbon density and saturation follow.

Al Daghar et al. laid out the general framework of formation evaluation using multimeasurements time-lapse data. In the simple case of two measurements, density and neutron, the measurement space reduces to the familiar density-neutron crossplot. The porosity space becomes the line joining the matrix point to the water point. Since gas has lower density and hydrogen index than water, any data point affected by gas will plot in the northwest corner above the porosity (water) line. The direction (slope) of the gas effect is given by tracing the time-lapse data back to the water line. Two workflows can be used to compute the gas-corrected porosity. The first is to compute the intersection of the data points projected along the gas slope onto the porosity line. The second is to rotate the density-neutron axes perpendicular to the gas slope. Then, gas-corrected porosity can be read directly from the new axis. Since the rotated axes are linear combinations of the original axes, the second workflow readily gives the respective weight factors of the density and neutron logs in the gas-corrected porosity equation.

We successfully apply both methods to one gas well in Europe and two gas wells in the Middle East. In all wells, time-lapse porosity differs to various degree with porosities derived from conventional combination rules such as the square root rule, the 1/2 density plus 1/2 neutron rule, and the 2/3 density plus 1/3 neutron rule. We attribute the discrepancies to the gas properties (composition and/or pressure) downhole being different from those used in the rule-of-thumb algorithms.

One Middle East well has three time-lapse data sets. This allows us to compare the results of using all three data set (1 + 2 + 3) versus using only two data sets (1 + 2) and (1 + 3). Here, 1 denotes the data set acquired while drilling, 2 is after drilling first data set, and 3 is after drilling second data set. The conclusion is that two data sets are sufficient to obtain good results provided there are observable changes in the logs caused by invasion.

An additional benefit of obtaining accurate porosity in the presence of gas is the derivation of residual gas saturation *Shr*. This is done on the European well where we observe good agreement between *Shr* derived from density-neutron logs and *Shr* computed from R_{xo} log via Archie's equation.

A Novelty...Since 1975—Consolidated Practices and Pragmatic Workflows for Sand/Shale Thin-Bed Analysis.

Enrico Pernarcic, Christopher Blair and Emmanuel Caroli, TOTAL

It could seem unreasonable to add a new paper about thin-bed analysis (TBA) techniques in 2020, the subject having been covered by so many papers from different perspectives in the past decades.

Still, in front of a new data set, the log analyst is often lost amid a multitude of tools, and the practical implementation of TBA is far from straightforward. In addition, the log analyst has to deal with some eternal debates (shale versus clay volume, total versus effective porosity, net and cutoffs, ...) hidden like an "original sin" of log-analysis but prompt to arise at any moment to generate misunderstandings and potentially leading to a wrong use of the TBA results in geomodels.

For these reasons the application of thin-bed analysis is often perceived as overly complicated and difficult.

As an operator of several fields with major stakes in clastic turbidites, the company gradually acquired a broad experience on quantitative interpretation of sand/shale thin beds.

Over time, learning from mistakes and achievements, the strong points and drawbacks of each technique became clearer and some consolidated practices and workflows were installed. It was also noticed that some of the most robust and pragmatic in-house methodologies were never published.

The paper attempts to answer to some frequently asked questions about TBA: When is it pertinent? What is the added value? What is the most efficient and robust workflow?

Instead of presenting in detail a new case-study, the goal is to summarize the lessons learned during years of practice and focus on a pragmatic approach that proved to be useful in a number of cases.

Advanced Evaluation Methods of Carbonate Rock Matrices—A Case Study on Major Hydrocarbon Reservoirs in the Middle East

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Seventy percent of Middle East hydrocarbon reserves are hosted within carbonate reservoirs out of which significant amounts are contained inside intercrystalline micro- and nanopores located between micritic matrix crystals. Evaluations of such matrices are crucial and require proper understanding of their geological and petrophysical characteristics. However, the small size of micritic crystals (< 4 µm), and the small pore sizes and throats held by them (< 0.4 µm), make the conventional characterization methods difficult. This research presents a way to overcome this challenge using a robust workflow that combines digital and conventional evaluation methods to characterize micritic matrices hosted within ancient carbonate rocks derived from major oil reservoirs in the Middle East geologically and petrophysically.

Sixty-six (66) core plugs were fully characterized by high-resolution X-ray CT images at range of 500 to 40 µm/voxel, thin-section photomicrographs, poroperm, and mercury injection capillary pressure (MICP). These analyses provided a detailed understanding of the geological and petrophysical variations within the plug samples under investigation. Accordingly, smaller-scale subsamples were obtained mainly from the micritic regions in the plugs and scanned at nanoscale resolution equal to 0.064 µm/voxel. Porosity and permeability of each nanoscale subsample were quantified and computed digitally by solving the Stokes equation using the lattice Boltzmann method. Pore-throat sizes were also computed digitally for all subsamples to understand the effect of diagenesis parameters on the petrophysical behaviors of the micrite matrix.

The integration between petrophysical and geological characteristics at plug scales and nanoscale reveals a direct relation between diagenesis, micrite crystal sizes, and hosted pore sizes against porosity and permeability of micritic matrix. This was proved through computed porosity and permeability at nanoscales, which showed a distinct correlation trend.

The digital and conventional characterization methods gave a better understanding of the geological and petrophysical properties of micritic matrices in the Middle East and generated a distinct poroperm trend for them that would not have been achievable using conventional methodologies alone.

Advanced Measurements Eliminating the Risk of Bypassing Large, Laminated, Low-Resistivity Reservoir and Enhancing the Saturation-Height Model—A Norwegian Sea Case Study

Harish B. Datir, Schlumberger; Tarek Sweden and Elena Vasyutkina, Wintershall; Calum Mcdowell and Karl Erik Sylta, Schlumberger

Balderbrå exploration well targeted the Late Cretaceous Maastrichtian Springar Sandstone Formation. The reservoir is a four-way dip closure and was expected to have gas-bearing deepwater fans, charged by Lange source rock formation and sealed by the intraformational shale. The formation encountered in the exploration well poses a unique challenge. The pessimistic information from logging-while-drilling (LWD) data suggested little presence of hydrocarbons, but it contradicted strong mud-log gas indications. If the formation evaluation would have been made based on LWD conventional log measurements, it would have been a limited discovery case and most of the reservoir with hydrocarbons could have been missed completely if not tested.

The low salinity of formation water, thinly bedded nature of the reservoir, complex mineralogy with varying amount of clay and its types, made it harder to accurately estimate the important petrophysical properties of the reservoir. The effective and total porosity along with water saturation were crucial for initial reserves estimates. If it would have been classified as a technical discovery based on the LWD logs; that would have resulted in limited coring and its analysis, leading to an inaccurate saturation-height model (SHM) and the hydrocarbon volume underestimation. A combination of high-resolution and high-fidelity wireline measurements, multifrequency multispacing dielectric log, triaxial resistivity, high-resolution density and advanced neutron-induced spectroscopy data were acquired to assess this complex reservoir definitively. Interpreted results of these measurements proved the true potential of this thinly bedded reservoir system and helped to enhance the SHM in conjunction with advanced log data.

The advanced log measurements provided accurate estimates of grain density, total and effective porosity, water saturation (S_{wt}, S_{xo} and S_{wirr}), mineral volumes, clay type, rock type, facies analysis and permeability. The paper elaborates in details of a workflow, how to use these advanced log results in a thinly laminated low-resistivity pay reservoir and to support SHM in the hydrocarbon saturation and free water level (FWL) estimates. It also demonstrates a comparison of the evaluation results using conventional and advanced logs as input and how the reservoir could have been bypassed, poorly cored and assessed if it was interpreted using only the acquired LWD logs.

The final hydrocarbon saturation obtained with advanced high-resolution and high-fidelity measurements resulted in 2 to 4 times higher net pay thickness and approximately 2.56 times more in place volumes, compared to the conventional LWD log-based analysis. The paper clearly illustrates how easy it is to bypass such a low-resistivity pay interval even without being negligent. After acquiring all the well logs and preliminary reservoir data evaluation, the field is expected to have 90 meters of net pay thickness. Initial estimates of the field now indicate between 7 to 19 billion standard cubic meters (Sm^3) of recoverable gas and 1 to 3 million Sm^3 of recoverable condensate. This paper demonstrates how high-fidelity advanced wireline log measurements successfully unraveled the true reservoir potential.

An Integrated Petrophysical Workflow for Fluid Characterization and Contacts Identification Using NMR Continuous and Stationary Measurements in High Porosity Sandstone Formation, Offshore Norway

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The Alvheim field in the Norwegian North Sea was discovered in 1998. Alvheim consists of three principal oil and gas fields in good quality Paleocene sandstone reservoirs—Kneler, Kameleon, and Boa. However, the Gekko structure of the Alvheim Area was drilled in 1974 based on the best available 2D-seismic-data interpretation to test the extension of the Heimdal formation. Oil and gas were found but were not considered economically feasible due to insufficient oil column thickness to develop until new technology rekindled interest in those prospects. Aker BP and its partners drilled two wells, Well-A and Well-B, in 2018 to confirm a thicker oil column in the Heimdal formation as well as to acquire more information about the complexity of the reservoir. Well-A, drilled on the south of the structure, and Well-B, drilled on the north of the structure, encountered very good reservoir quality. The wells were successful in their initial objectives and a project to develop these resources is currently in the selection phase.

The challenges of formation evaluation including distribution of pore geometries, permeability, reservoir quality, and hydrocarbon identification could be mitigated by studying the nuclear magnetic resonance (NMR) log response. NMR fluid typing has been widely used in the oil industry since the 1990s. NMR fluid typing today is a combination of the contrast of spin-relaxation time T_1, the spin-spin relaxation time T_2, (T_1T_2), and the diffusivity (T_2D) of formation fluids. NMR fluid typing can be obtained from continuous and/or stationary measurements. The objective of this paper is to showcase the integrated petrophysical workflow that helped us determine exact gas/oil and oil/water contacts, using NMR fluid typing, resistivity-based water saturations, pressure gradient analysis, and crosswell comparisons.

Continuous and stationary NMR data was acquired in both wells using T_2-diffusion and T_1T_2 activation sets. This paper also highlights the comparison of NMR stationary data with continuous measurements from both wells. The stationary data confirm the quality of the depth-based acquisition and indicates continuous measurement data quality is sufficient for reliable NMR fluid identification without depending on time-consuming stationary NMR measurements. This is of particular interest as cost of operating and data acquisition in the North Sea is a crucial challenge for many oil companies and a better management of rig time is constantly required.

Analysis of Lateral Fluid Gradients From DFA Measurements and Simulation of Reservoir Fluid Mixing Processes Over Geologic Time

Qing Chen and Morten Kristensen, Schlumberger; Yngve Bolstad Johansen, Aker BP; Vladislav Achourov, Soraya S. Betancourt and Oliver C. Mullins, Schlumberger

Downhole fluid analysis (DFA) is one pillar of reservoir fluid geodynamics (RFG). DFA measurements at varying depths and multiple wells provide both vertical and lateral fluid gradients. These gradients, especially the asphaltene gradient derived from accurate optical density (OD) measurements, are critical in thermodynamic analysis to assess the degree of equilibration and identify RFG processes.

Recently, an RFG study was conducted using both DFA and laboratory data from six wells in a light-oil field in the Norwegian North Sea. Fluid OD gradients show that most of the reservoir has equilibrated asphaltenes with a lateral variation of 20%. This indicates connectivity in the large portion of the reservoir, which is confirmed by 2 years of production data from the field. There are two outliers off the asphaltene equilibrium curve implying isolated blocks: one is located on the extreme east flank of the field and the other on the extreme west flank. The asphaltene fraction varies by a factor of six between these two blocks. Such variation reveals that different charge fluids entered the reservoir, and the equilibrated asphaltenes are the result of an after-charge mixing process. Additionally, although GOR gradients and fluid composition demonstrate apparent equilibration, different gas/oil contacts (GOCs) exist in the reservoir indicating a lateral solution gas gradient. Geochemistry analysis shows same level of mild biodegradation in all fluid samples, including those from the two isolated blocks. This leads to the conclusion that biodegraded oil spilled into the whole reservoir before the two now-isolated blocks were separated from the main part. Furthermore, lateral asphaltene gradients at different time after charge have been preserved, one is current gradient (a variation of 20%), and the other is in the two isolated blocks (a variation of 6%).

This unique data set provides a valuable opportunity to constrain a simulation of reservoir fluid mixing processes after charge. The purpose of the simulation is to investigate whether lateral composition gradients can persist over geologic time in a connected reservoir. Numerical simulation was performed over geologic time in 2D isothermal reservoir models filled by pseudofluid with a lateral density gradient. This density gradient imitates the variation of composition (hence GOR and asphaltene) in the two isolated blocks in the above North Sea field. Simulation shows that this lateral gradient creates differential pressure and causes fluid flow, forming a convection cell. However, in a reservoir with realistic vertical/horizontal aspect ratio, such fluid flow cannot trigger enough mixing to eliminate the lateral gradient over geologic time. Next, diffusion was included in the simulation of the mixing process. The reservoir model was initialized with two different GOCs producing subtle lateral GOR and density gradients. During simulation, the mixing process transports gas from higher-GOR regions to lower-GOR regions and reduces the difference between the GOCs. Yet, for a reservoir laterally extensive relative to its height, a lateral GOR gradient only induces a tiny diffusive flux of methane. Consequently, we conclude that lateral GOR and asphaltene gradients can persist for geologic time, which is consistent with the observation from the field.

Arps' Approximation Revisited and Revised

W. David Kennedy, QED Petrophysics LLC

Resistivity interpretations for conventional reservoirs depend upon an ability to estimate the resistivity of mud filtrate in flushed zones. An estimator, in use since 1953, was invented by Jan Jacob Arps. Arps worked out a method to use mud-filtrate resistivity and its temperature as measured on the surface to estimate its resistivity at any other temperature, in particular the increased temperatures encountered at depth in wellbores. The method is known as Arps' approximation. It is also indispensable for extrapolating formation-water resistivity from one depth and temperature to another depth at a different temperature.

Arps' approximation is based upon resistivity-temperature-salinity data as recorded in the International Critical Tables of Numerical Data, Physics, Chemistry and Technology (known as the ICT). There are 81 such data points extracted by Arps from the ICT. It is Arps stated goal to fully document his method; still, it is quite difficult to grasp his technique. However, the resulting Arps approximation is so simple and useful that it has not been subjected to further analysis in the intervening 68 years.

A re-examination of the basic ICT data has led to the formulation of a "first principle" relating the conductivity of a sodium chloride solution to its temperature as a function of salinity. The first principle takes the form of a simple differential equation from which the Arps approximation can be derived. Whereas Arps uses four pages and 2,970 words written on 579 lines, this is done on five lines using the first principle, straightforward step-by-step algebra, and four additional, but simple, equations without any reference to the ICT data.

A "reference temperature" arises in the derivation; this reference temperature is determined from the ICT data. In the Arps approximation the reference temperature is given as T0 = 6.7707°F. In my analysis using the ICT data, Arps' Table 5 and Figure 2, I was surprised to discover an error made in Arps analysis of T0. Arps asserts that the least-squares fit of these data result in T0 = 6.7707°F. However, this value is inconsistent with the data used to compute the parameters of the least squares fit.

These discoveries give impetus to a re-examination to the evaluation of this constant not only to correct arithmetic errors, but also as to the choice of data to include. For example, the ICT data are weighted toward low salinity (21 samples at 60, 100, 300 ppm) data and includes 10 samples at 32°F; would these low-salinity low-temperature samples unduly bias estimates at temperatures and salinities more representative of oil-field brines? Answering these questions leads to a collection of possibly more appropriate values for T0.

A final question is: does any of this re-analysis of the T0 value have an impact on present and prior analysis using the Arps approximation? Fortunately, the answer to this question is "No"! Still, the new five-line derivation from a first principle and revaluation of T0 improves our understanding of this venerable and ubiquitous approximation.

Change of Saturation Exponent in Polymer Waterflooded Reservoirs: A Case Study From Offshore Africa

Benoît Guivarch and Emmanuel Caroli, TOTAL

The calculation with the Archie equation of water and oil saturations from electrical resistivity logs in water flushed reservoirs has historically been challenging. Previous publications on experiments conducted at the laboratory have demonstrated that, in waterflooded reservoirs, the imbibition regime impacts the resistivity index and may lead to an Archie saturation exponent "*n*" different from the SCAL drainage measurements (referring to the "*n*" hysteresis between drainage and imbibition observed in oil-wet rock samples).

While core, log and reservoir techniques can approach the residual oil saturation (SWTT/NMR/core S_{or}), they are not commonly used in the realms of a deep offshore field development for operational and cost reasons. This paper presents the results of a case study, offshore Africa, from a highly deviated well that intercepts turbiditic sands (high porosity, oil-bearing) irregularly swept by viscosified polymer-water (injected nearby). Thanks to in-situ sampling of the injected fluid, the water saturation was derived from the sigma log (neutron-capture cross section) in order to pinpoint the undisturbed zones and then, by comparison with the resistivity saturation equation, estimate the magnitude of change of the "*n*" parameter in the flushed zones.

Beyond the added value of the so called "old sigma" log, which uncertainties and limitations will be discussed, the extra-information gained by knowing both the polarity and the magnitude of change of the "*n*" parameter gives access to an indication of the in-situ change of reservoir properties. The polymer additives present in the injected water may be the cause of the deduced electrical hysteresis and can lead to insightful understanding of reservoir behavior in waterflooding context. Such results finally lead to a better estimation of the remaining hydrocarbon in place.

Effect of Pores Types on Electrical Properties of Carbonate Rocks and Determination of the Electrical Parameters From NMR Logging

Kewen Wang, Ning Li, Hongliang Wu, Zhou Feng, Peng Liu and Taiping Zhao, Petrochina

Water saturation is a key reservoir property, which is usually calculated from resistivity logs with Archie's equations. Due to a variety of pore types and complex pore spaces, understanding the electrical properties of carbonate formations is of great challenging. Conventionally, the electrical parameters (m and n in Archie's equations) are assumed to be fixed values along the whole interval in carbonate evaluations. However, the values of m and n can vary at different depths due to the heterogeneity of carbonate formations.

In this paper, we discuss the effect of pore types on electrical properties of carbonate rocks based on the rock experiments and pore-scale numerical simulations. Three types of carbonate rocks from the Ordovician formation are selected: Type I without vugs and fractures, Type II with developed secondary vugs, and Type III with fractures. For all the cores, high-resolution micro-CT tests, NMR measurements both at 100% water saturation and at bound-water saturation are first conducted. Then the resistivities at various water saturations are measured by gas displacement with porous plates. The microporosity, vug porosity, fracture porosity and bound-water saturation of all abovementioned rocks are quantitatively calculated based on the micro-CT and NMR T_2 spectrum, and the electrical properties are examined. The results indicate that both fractures and micropores have significant effects on the resistivity of carbonate rocks, and the resistivities decline with the existence of more fractures and micropores. On the other hand, the effect of vugs on the resistivity response is negligible. This observation is consistent with our experimental results by using the synthetic vuggy porous media with different vug distributions. Moreover, the dual-medium models including matrix-vug model and matrix-fracture model are established. The electrical characteristics of these two models are simulated with the invasion percolation algorithm. The simulation results indicate that the vugs have weak influences on the resistivity response if they are not connected by fractures; the fracture shows strong effect on the resistivity while its influence on the saturation is negligible.

Meanwhile, it is found that the electrical parameters have good correlations with bound-water saturation: the values of m linearly decrease with the increasing of bound-water saturation in all three types of carbonate rocks; the exponent n in the cores with $m < 2.0$ linearly decreases with the increasing of bound-water saturation while the exponent n in the cores with $m > 2.0$ linearly increases with the increasing of bound-water saturation. Then we propose an approach for calculating m and n values that can vary continuously with depths in carbonate reservoirs with NMR bound-water saturation. Finally, the method is verified by the applications in carbonate reservoirs in the Ordos basin.

Enigmatic Reservoir Properties Deciphered With Petroleum Systems and Reservoir Fluid Geodynamics Analysis of Wireline Data

Rob Pierpont and Kristoffer Birkeland, OMV; Li Chen, Vladislav Achourov, Soraya S. Betancourt, Jesus A. Canas, Julia C. Forsythe and Oliver C. Mullins, Schlumberger

Adjacent reservoirs in the Wisting oilfield, Barents Sea have been evaluated using extensive data acquisition across multiple disciplines; where several surprising observations were made. Differing levels of biodegradation were measured in the adjacent reservoirs, yet related standard geochemical markers seemed to be contradictory. Unexpectedly, the more biodegraded oil had less asphaltene content, and this reservoir had some heavy-end deposition in core, but upstructure, not at the oil/water contact as would be expected especially with biodegradation. Wax is observed in one of the two reservoirs. These many puzzling observations along with unclear connectivity gave rise to uncertainties about field development planning. After a highly integrated analysis, all of these seemingly disparate observations are explained with a simple model of the evolution of the reservoir fluids in geologic time.

Considerations from petroleum system modeling helped frame the nature of the fluids entering the reservoir. Extensive petrophysical data and wireline formation sampling and downhole fluid analysis (DFA) provided a detailed view of the reservoirs. Surveying the fluids in target formations as well as fluid evaluation in nearby formations was key in the overall understanding. Conventional gas chromatography (GC) and two-dimensional gas chromatography (GC×GC) provided a high-resolution view of relevant fluid geodynamic processes. Geochemical interpretation of the fluid compositional data clarifies complex charging and fluid geodynamic processes. Lab PVT and wax appearance temperatures are performed and show consistency with geochemistry.

Combined petroleum systems and reservoir fluid geodynamic analyses resolved the observations into a single, self-consistent fluid geodynamic scenario. A spill-fill sequence of trap filling with biodegradation helps explain differences in biodegradation and wax content. A subsequent, recent charge of condensate, stacked in one fault block and mixed in the oil reservoir in the second fault block, explains conflicting metrics of biodegradation. Specifically, the original black oil was biodegraded and wax components removed, while the recent condensate charge remained largely nonbiodegraded. Asphaltene instability and deposition at the upstructure contact between the condensate and black oil, and the motion of this contact with charge, explain core deposition

observations. Moreover, this process accounts for asphaltene depletion in the corresponding oil. DFA asphaltene gradients and variations in geochemical markers clarify likely connectivity and baffling associated with these reservoirs; this analysis is very consistent with seismic imaging in the oilfield. The reservoir fluid geodynamic scenario provides a benchmark of comparison for all types of reservoir data and readily projects into production concerns. The initial apparent puzzles of this oilfield has been replaced with a robust understanding of the corresponding reservoirs.

The optimal combination of petroleum systems modeling and reservoir fluid geodynamics to help explain complex observations in reservoirs is performed here and represents a desired workflow for many reservoirs. The coherent integration of data from many disciplines especially wireline explain seemingly contradictory observations and yields a robust understanding of the reservoirs.

Evaluating Petrophysical Properties and Volumetrics Uncertainties of Sand-Injectite Reservoirs—Norwegian North Sea

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Sand injectites on Norwegian Continental Shelf have proven their commercial significance. Some are already producing, e.g., Volund, Viper, Balder, Ringhorne and Kobra fields, while others in production licenses (PL) 340 and 869 have recently been discovered and appraised. Extensive literature on the geology of sand injectites has been published. However, few references are available on the petrophysical and geophysical aspects of sand-injectite reservoirs. In this paper, the petrophysical properties of sand-injectite facies; dykes, sills and brecciated sands are discussed, along-with their identification from seismic data. A perception that volumetrics of sand injectite reservoirs cannot be reliably evaluated is assessed.

Sand injectites in PL340 and 869 were interpreted as the mobilized sands from the Hermod and Heimdal formations of Paleocene age into the overlying mudstones of Balder formation and Hordland group of Eocene age. The mudstones acted as a seal, forming an intrusive stratigraphic trap. The trap geometry varied locally depending upon the dykes and sill geometries of the sandstone. Dykes had large vertical reach with corresponding high hydrocarbon column, while sills had low vertical relief with large lateral extent. It was observed that many of the thinner dykes and sills were brecciated sands, with shale clasts from the host rock buried within the mobilized sands.

Petrophysical logs responses for clean sills and dykes behaved the same way as they would in a clean sandstone reservoir, with the possibility of missed pay if sills and dykes were very thin. Sills appeared as blocky clean sand on logs, but it was difficult to differentiate dyke from a sill or thin sand using logs. Dykes are high-angle features and are identified either by core studies or borehole images when intersected by a well, or by seismic. Brecciated sand intervals appeared bizarre on core, and log responses were that of a shaly or thin sand which also depend on the measurement volume of the logging sensors. Log responses, like resistivity and thermal-neutron porosity, were highly affected by the shale clasts. For this reason, a fractional net/gross interpretation technique was used to evaluate the formation and volumes of hydrocarbons. To further verify these results, they were compared to observations directly on core.

To qualify to what extent petrophysical logs and interpreted products thereof can be relied upon to evaluate the hydrocarbon volumes of sand-injectite reservoirs, a high-resolution petrophysical interpretation was generated using a computerized tomography (CT) scanned core image. Core-image sand counting, and image-derived high-resolution bulk density logs with shale-corrected resistivity were used. Results of the high-resolution interpretation featured an excellent match with routine core analysis data. The fractional net/gross method used was the modified Thomas-Stieber method. When compared to the high-resolution interpretation from the CT images, match was confirmed. This result confirms that Thomas-Stieber also is a suitable method for brecciated rocks, which leads to some useful recommendations on how to best log and do petrophysical evaluation in such reservoirs.

Evidence of Multiple Pairs of Drilling-Induced Tensile Fractures in Deep Boreholes

Jean Desroches, Rocks Expert and Thomas Berard, Schlumberger

Drilling-induced tensile fractures (DITFs) in deep boreholes have been extensively documented and analyzed. In vertical boreholes, they usually form a pair of longitudinal fractures oriented along the azimuth of the far-field maximum principal horizontal stress (SH). DITFs can be observed on borehole-wall resistivity or ultrasonic images and their azimuth is used on a routine basis to infer the orientation of SH.

In this paper, we provide evidence, from borehole-wall images, of the occurrence of not one, but two or more pairs of DITFs. One of them, hereafter referred to as the primary pair, is always oriented along SH. The number and orientation of the other ones, referred to as secondary, vary on a case-by-case basis. In some cases, two pairs of secondary fractures are observed, oriented symmetrically with respect to the primary set and at an angle in between SH and the azimuth of the minimum horizontal stress direction, Sh. In other cases, only one pair is observed, oriented along Sh.

We draw a parallel with the multiple pairs of tensile fractures that form, first along SH and then in between SH and Sh, when inflating a packer or when pressurizing a borehole with a so-called strengthening fluid (that is, a fluid loaded with particles or fibers and able to seal the cracks through which it is flowing). In such cases, and unlike hydraulic fracturing, the pressure applied to the borehole wall is not transmitted, or only for a limited time, inside the fractures. Such "dry" loading causes tensile stress to develop at the borehole wall away from, and while, the first pair of tensile fractures is created and propagated. The variable location of the secondary failure is taken as indicative of the rotation of the most tensile hoop stress region at the borehole wall during loading. Our observations imply that care must be taken when interpreting DITFs to correctly infer principal horizontal stress directions.

Experimental Investigation of Two-Phase Flow Properties of Heterogeneous Rocks for Production-Oriented Petrophysics

Pierre Aérens, Carlos Torres-Verdín and Nicolás Espinoza, The University of Texas at Austin

An uncommon facet of formation evaluation is the assessment of flow-related, in-situ properties of rocks. Most of the models used to describe two-phase flow properties of porous rocks assume homogeneous and isotropic media, which is hardly the case in actual reservoir rocks, regardless of scale. Carbonates and grain-laminated sandstones are but two common examples of the latter situation. Accurate description and modeling of multiphase fluid flow in spatially complex rocks require experimental and numerical methods that integrate all salient details about fluid-fluid and rock-fluid interactions. Such laboratory-simulation efforts are necessary to develop realistic models of fractional flow, i.e., saturation-dependent capillary pressure and relative permeability for rock classification and production-related formation evaluation studies.

We introduce and successfully verify a new high-resolution visualization technique that (1) provides pore-scale experimental data to quantify saturation patterns in heterogeneous rocks, and (2) enables the evaluation of effective two-phase flow properties. The experimental apparatus comprises an automated injection system and an X-ray microfocus scanner. Rather than using traditional cylindrical cores, thin rectangular rock samples embedded in a polycarbonate core holder are employed to monitor the advancement of the invasion front. The thickness of the samples is one order of magnitude smaller than the remaining dimensions, so that flow variability perpendicular to the sample is negligible. Thus, only two-dimensional (2D) radiography images are acquired to monitor flow complexity. During the experiment, the core is scanned quasicontinuously while the fluids are injected, allowing for time-lapse visualization of the flood front. Numerical simulations are then conducted to match the experimental data and quantify effective saturation-dependent relative permeability and capillary pressure. Mercury injection capillary pressure (MICP) and nuclear magnetic resonance (NMR) measurements are also performed to further describe the rock samples and verify the reliability of the experimental injection/monitoring method.

Experimental results provide quantitative evidence that flow patterns and in-situ saturations are highly dependent on the nature of the heterogeneity and bedding-plane orientation during both imbibition and drainage cycles. In homogeneous clastic rocks, fluid displacement is piston-like, as predicted by the Buckley-Leverett theory of fractional flow. Assessment of capillary pressure is performed by capturing the time-lapse water saturation profiles during imbibition. In complex clastic rocks, high-resolution time-lapse images reveal preferential flow paths along high-permeability intralayers causing low sweep efficiency. The estimated effective relative permeability curves compare well with steady-state measurements. Our experimental procedure also underlines that capillary pressure and transmissibility differences play an important role in the geometry of the fluid-displacement front at early times (i.e., low injected pore volumes). However, vertical transmissibility plays a significant role at late injection times thereby decreasing rock heterogeneity effects on the fluid-displacement front. In the case of complex carbonates, fluid-displacement fronts are extremely irregular and patchy; pore/throat bridging takes place at irregular times. Overall, our method is fast and reliable to assess mixing laws for transport properties of rocks in spatially complex formations and to avert irregular fluid-displacement fronts at early or late times which can have a significant effect in production by primary or secondary means.

Fast and Practical Application of Log Property Modeling to Improve Petrophysical Answers in High-Angle Wells

David Maggs, Schlumberger; Vanessa Mendoza Barron, Shell; Mathias Horstmann and Mohammad Taghi Salehi, Schlumberger

Logging measurements in high-angle wells are often complicated by various geometric effects and generally require correction before use in accurate petrophysical evaluation. The geometric effects include, but are not limited to, shoulder beds, proximity to beds that may or may not have been crossed, polarization horns, laminations and nonuniform invasion.

The paper demonstrates how log property modeling was applied using a fast and practical workflow to improve petrophysical answers. The wells studied are located in the Norwegian sector of the North Sea and penetrate a sequence of fairly thin sand and shale layers. The well trajectories range from deviated pilot holes through high-angle tangents. In the wells studied, both propagation and laterolog resistivity measurements and their associated wellbore images were acquired, as well as azimuthal GR, density and neutron porosity logs. The difference between the laterolog and propagation resistivity measurements highlights the challenges of using the logs directly. A new workflow was used to quickly model the high-angle logs and cross-validate the responses. Although the largest geometrical effects were observed on the resistivity logs, the nuclear measurements were also affected to a lesser degree, and new fast forward models were applied in the same workflow to obtain the GR, density and neutron-porosity log properties. The combination of the resistivity responses, and the ability to quickly and efficiently model the logs, provided improved confidence in the derived formation properties which were subsequently used for saturation computations.

An example of the effect of thin laminations on high-angle well resistivity logs is shown. In addition, an example of asymmetric fluid invasion caused by gravity segregation of mud filtrate demonstrates how resistivity images aid interpretation in complex geometries. To help visualize these geometries a three-dimensional display tool is applied that allows for more intuitive understanding of the complex azimuthal and radial information provided by multidepth of investigation resistivity images.

Log modeling results and the workflow to achieve them in a fast and efficient manner are demonstrated. Petrophysical answers using the measured logs are compared with the answers developed from the geometrically corrected responses. These demonstrate that with an efficient workflow additional valuable information can be extracted from routinely acquired data, reducing the uncertainty associated with log interpretation in high-angle and horizontal wells.

Formation Evaluation With NMR, Resistivity and Pressure Data—A Case Study of a Carbonate Oilfield in the Lower Congo Basin

Ting Li, Nicholas Drinkwater and Karen Whittlesey, Chevron

In this paper, we examine fluid interpretation techniques in a prolific oilfield in offshore West Africa. The reservoir rocks are dominated by Cretaceous limestone, with a small fraction of dolomite and siliciclastic minerals. Due to concerns of radiation hazard, the drilling team has selected a sourceless logging program, consisting of LWD NMR, resistivity and formation tester, to log the reservoir section in 6.5-in. holes. Therefore, standard log interpretation, which relies on multimineral analysis, is no longer viable. The purpose of this study is to answer questions related to asset appraisal and development with these limited measurements.

Whole cores were collected from both geological structures of the oilfield and the lab-measured porosity, permeability, water salinity, Archie *m* and *n* and Dean-Stark S_w. Comparison of core and NMR log indicates that NMR total porosity is barely affected by hydrocarbon in the pore space. We use a statistical method called factor analysis to deconvolve independent fluid modes, such as clay-bound water, capillary-bound water and oil+oil-based-mud (OBM) filtrate, from the T_2 distribution. The number of modes to solve for is determined by principal component analysis. The free-fluid T_2 cutoff is chosen based on the identified modes. The NMR irreducible water saturation (S_{wirr}) computed with this cutoff agrees with Dean-Stark S_w, measured on core samples assumed to be fully invaded by OBM. Continuous S_w is calculated with Archie's equation with lab-measured parameters and validated against Dean-Stark S_w above the transition zone. The Timur-Coates model is used to estimate matrix permeability, using core-calibrated multiplier and the T_2 cutoff from factor analysis. The permeability, S_w and S_{wirr} curves are then used to compute continuous effective permeability to water and oil.

The first application of this interpretation workflow is to confirm the free water level (FWL) derived from pressure gradients. We found the S_w profile largely controlled by heterogeneity in rock textures. Good-quality rocks have negligible transitions zones and contain little free water above FWL. Poor-quality rocks have longer transition zones, but the relative permeability to water is too low for the water to flow, as confirmed by production. Pressure depletion suggests excellent connectivity within the reservoir, so these poor-quality rocks are considered a local feature. Log analysis of five recently drilled wells confirms the reservoir-wide FWL, which translates to a significantly increased OOIP over initial estimation.

The second application is perforation design and understanding water production. Zones with good porosity and low mobile water volume are selected for perforation and a safe distance is maintained from FWL. As a result, all producer wells exhibit zero water cut, except one. The water-producing well has a permeable aquifer filled with mobile water at 60 meters (in TVD) below the deepest perforation. After reviewing the cement-bond log, our interpretation is that due to a poor cement job, this water traveled up hole behind casing and entered the annulus through the deep perforations.

From Plug Measurements to Dynamic Simulations: Upscaling Effects on Modeled Hydrocarbon Volumes

Iulian N. Hulea, Shell Projects and Technology

Building reliable subsurface models requires detailed knowledge of both the rock and fluids involved. One critical petrophysical property determining the viability of a development is the hydrocarbon saturation. In 3D geological models, the saturation is populated via saturation-height models (SHM) and free-fluid levels (FWL). In populating a 3D model with meaningful properties, measurements at various scales are integrated. For example, core measurements acquired at resolution far superior to that used in the 3D models require an upscaling step. The process of upscaling is not a trivial one and in this work we follow this process for SHM and its connection to permeability.

In this work, we analyze available choices for SHM upscaling in various ranges of sensitivity with respect to the FWL position as well as different rock quality properties. Also, various degrees of heterogeneity are analyzed. In investigating the upscaling effects, the saturation prediction accuracy based on upscaled input rock properties (like arithmetic/geometric and harmonic upscaled permeability) is central. For homogeneous rocks a workflow is detailed with the purpose of detecting the upscaling limits highlighting the possible errors that might appear in the process.

Given the fact that rock quality enters the SHM via the permeability and that permeability upscaling follows a route that ultimately attempts to honor well performance, a natural question is what is the relevance of such a permeability model as input for the SHM. Our results highlight the best choices for an upscaled SHM and its input— (upscaled) permeability—not necessarily the upscaled permeability used to predict well performance.

In conclusion, we have developed workflows that allow the determination of the ideal (for saturation) upscaled model resolution and a thorough evaluation of possible inputs into the SHM. The necessary model resolution in order to contain the predicted saturation error under a predefined maximum error limit is discussed.

High-Resolution Electrofacies Using Machine Learning to Decrypt High Poro-Perm Zones in Cyclic Succession of Pliocene Bioclastic Limestone: Case Study From Madura Strait Area, East Java Basin

Iko Sagala, Ophir Indonesia; Sarvagya Parashar, Ivan Wu Zhia Ming, Nuntanich Jittham and Banu Andhika, Halliburton

The Mundu Formation has proven to be a prolific reservoir in the Madura Strait area of the East Java Basin. It is a Pliocene bioclastic limestone mainly composed of plantonic foraminifera of genus Globigerina interpreted to have been deposited in moderately deep water (150 to 250 m), possibly on a detached platform. The porosity of Mundu Formation is typically dominated by intraparticle porosity where the best intervals have less lime mud and less clay association.

An integrated workflow has been adopted to decipher high-resolution facies sequences using microresistivity images and nuclear magnetic resonance (NMR) derived techniques. First, microresistivity images were analyzed and transformed into calibrated porosity images using a technique to calibrate the acquired image data to image porosity by using various filtering techniques. The image data are averaged over a moving window, and a transform is constructed, which calibrates the average image data to porosity.

This transform is then applied to the "pixel-by-pixel" image data, and a moving adjustment for bias is made. The second step is to analyse the T_1 and T_2 relaxations from the nuclear magnetic response. Both relaxations are sensitive to the pore surface/volume ratio. Lithologies exhibit several pore sizes, and the analysis of raw NMR data results in a distribution of relaxation times reflecting the contributions of each pore size. In the present study, the Classi-PHI model was designed to work with T_2 relaxation distributions, linking relaxation time to pore radius suggests a discreet correspondence between pore size and relaxation time. The model used a methodology that allows portions of signal from a pore-size group to spill across the discreet boundaries. Thus, the pore-size quantification in Classi-PHI takes on a fuzziness near the discrete relaxation time cutoffs corresponding to pore-radii breakover points.

High-resolution integrated facies were analyzed and classified in accordance with their possible mode of occurrence. This, in turn, indicated the possible paleoenvironment of the deposition. This is extremely helpful to locating high pore-perm layers of grainstone in overall thinly bedded sequences of packstone and wackestone and subsequently sheds light upon the ambiguities observed in mobility testing across the same lithocolumn.

High-Resolution Spectral Reconstruction: Method and Applications for Contamination Measurement, Digital Sampling, and Continuity Assessment

Yngve B Johansen, Kevin Best and Artur Kotwicki, AkerBP; Christopher Jones, Cameron Rekully, Bin Dai, Bob Engelman and Anthony Van Zuilekom, Halliburton

Injectite sands form reservoirs of complex interconnectivity. In the process of forming an injectite-sand reservoir, sand become highly mobile like a fluid, and move from areas of higher pressure at deep depths to shallower depths of lower pressure. The fluid sands fracture rock and are injected within a zone of lower permeability. The sands often leave an interconnected trail with intrusions at various depths. Therefore lower zones flow and higher zones may have a highly localized interconnected vertical conduit. The resulting semi-interconnected reservoir thin stack structure is very difficult to assess by conventional means since the interlacing reservoir sands may be either continuous or discontinuous at and across multiple levels.

Downhole fluid analysis has the potential to resolve some of this ambiguity. Downhole fluid spectra contain a wealth of information to fingerprint a fluid and help to assess continuity. A new spectral inversion technique has been developed to overcome these limitations. The new spectral reconstruction technology has been developed providing very accurate spectral profiles with respect to laboratory measurements. The spectral reconstruction technique is accomplished as with a novel single-beam optical configuration as opposed to the more common used dual-beam reference path optical configuration. To enable a single-beam configuration for spectral measurements, a digital-twin model of the spectrometer is used to compute a reference profile in real time. The technique uses specially designed channels, tailored to enable the calculation of a digital-twin reference. As such, the reconstruction is more independent of drift with respect to devices that use a separate reference path. By also borrowing from compressed sensing techniques, the reconstruction technique also allows for higher fidelity measurements across a larger wavelength range.

The reconstructed data may then be used for a variety of purposes, such as contamination measurement, reservoir continuity assessment and digital sampling. Digital sampling is the process of extrapolating clean fluid properties from formation fluids not physically sampled. The reconstruction occurs at wavelengths from 450 to 3,300 nm, which is a wider optical region that has historically been accessible to formation testers. The expanded wavelength range allows access of the mid-infrared region for which synthetic drilling-fluid components have much optical activity. This reconstruction may allow contamination to be directly determined. However, because the spectrum is calculated and not measured directly, care must be taken with the interpretation as some uncharacterized signatures may provide a nonunique inversion problem. This paper will discuss fluid continuity assessment from six depths of an injectite reservoir structure based on the reconstruction of spectral data from fluids at these six depths. The applicability of the technique to contamination assessment and digital sampling will also be discussed.

Identifying Fracture-Filling Material in Oil-Based Mud via Dielectric Borehole Imaging

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Natural fractures maintain a significant role in many hydrocarbon plays in both conventional and unconventional reservoirs. In exploration and development scenarios, specific fracture properties, such as orientation or density, are important. More critical is their internal architecture: Are the fractures open to fluid flow or filled with minerals?

Borehole microresistivity imaging tools are widely used to determine these fracture characteristics. In wells drilled with water-based muds, open fractures are filled with conductive borehole fluid that enables distinguishing water-filled open fractures from resistive mineral-filled fractures and the surrounding rock. However, many wells today are drilled with oil-based muds (OBMs). Here, mineral-filled fractures and OBM-filled open fractures are equally highly resistive and cannot be directly distinguished using resistivity images only.

The latest-generation wireline OBM microresistivity imagers operate in the megahertz frequency range, radiating the electrical current capacitively through the nonconductive mud column and delivering photorealistic borehole images. Both electrical conductivity and dielectric-permittivity components constitute the measured signal. The quantitative interpretation uses a sequence of model-based parametric inversion runs to first estimate the mud properties of the log and subsequently invert for the button standoff to the rock surface and the formation resistivity and dielectric permittivity within the volume of investigation.

Our example case shows highly resistive, high-angle fractures from the resistivity images with their orientation and density. The standoff image determines if the mud column penetrates the fracture plane, showing an apparently high standoff compared with the surrounding rock. If the standoff appears high in the fracture plane, the fracture is classified as open to fluid flow. However, are these fractures indeed fully dilated and open or are they filled with different materials—are they partially mineralized with calcite and partially open, filled with mud?

To further determine the fracture filling and susceptibility to fluid flow, a new workflow employs the material dependency of the relative dielectric permittivity. The relative permittivity is estimated as function of resistivity and frequency pixel by pixel on the resistivity image. The estimate formula is empirically derived from several hundred laboratory measurements on core plugs with different fluid saturations and salinities. The resulting borehole image enables distinguishing materials in the volume of investigation.

This new image shows that drilling-induced fractures have low dielectric values, which correspond to the oil in open fractures controlled by the mud. The image also shows some fractures with slightly elevated dielectric values, corresponding to rock-forming minerals (calcite), and low partially values across only part of the fracture, which are interpreted as mud, saturated with oil. As result, these types of fractures are classified as partially open with vuggy mineral fill, consistent with the core description. Higher dielectric values on the image are attributed to shales and other rocks with increased clay content. Simulation results confirm the sensitivity of such estimated relative permittivity with respect to rock parameters, such as rock-matrix permittivity and water-phase tortuosity.

Improved Petrophysical Evaluation of a Sandstone Reservoir Using NMR—A Case Study, Onshore Kuwait

Pedro A. Romero Rojas and Larisa Tagarieva, Weatherford International; and Shaikha Faisal Dawood Turkey, Kuwait Oil Company

The effect of mud filtrate and eventually fine migrations in high-quality rocks influence considerably the reading of NMR and conventional openhole logs. It positions a remarkable challenge in extracting useful formation evaluation information inside the virgin zone, e.g., the rock porosity, water saturation, matrix permeability, and in turn, the rock quality index. The ratio between the free fluid over the irreducible-bound fluid is a rock quality indicator. It is per analogy associated with the pore-throat radius dominating the fluid flow. Pore size itself can be negatively affected by the fines migration which causes a reduction of the porosity filled by the free fluid.

In this case, free-fluid porosity is corrected with the help of the deeper reading neutron-density data. After this correction the NMR-derived water saturation in the flushed zone, is used to calculate the water saturation exponent in the Archie equation in the virgin zone.

The determination of the oil saturation in the flushed zone from NMR logs have been done in two ways: First, by applying the widely used 2D-NMR methods, diffusion vs. T_2 and T_1/T_2 vs. T_2 maps and second by means of a statistical driven machine Learning methodology. The comparative analysis of the oil saturation in the flushed zone against the oil saturation in the virgin zone leads to acute quantification of the flushed hydrocarbon volume.

Inversion of Anisotropic Elastic Constants and Mud Speed Using Borehole Sonic Modes

Ting Lei, Romain Prioul, Adam Donald and Edgar Ignacio Velez Arteaga, Schlumberger

Quantification of shale elastic anisotropy is one of the most important tasks in wellbore and reservoir geomechanical analysis. Most of the shales, conventional or mudrocks, exhibit vertical transversely isotropic (VTI) anisotropy that has five independent elastic stiffness constants. For sonic and seismic interpretation, these five elastic constants can also be conveniently described by the vertical P and S velocities and the three Thomsen parameters. Traditionally, the P and S velocities can be reliably obtained from monopole P arrival and dipole flexural low-frequency asymptote, respectively. Thomsen parameters can be estimated in a vertical well from dispersive borehole sonic modes only if the mud velocity and density are known. All these unknowns may exhibit strong dependencies among each other, as observed from dispersion sensitivity analysis. Consequently, the inversion of anisotropic elastic constants and mud speed from borehole sonic modes is a challenging task.

We present a new data-driven approach that can jointly estimate the anisotropic parameters and the mud velocity. The estimation is carried out without simple correlation of the Thomsen parameters. Instead, the three Thomsen parameters are treated as unknowns and we apply physical constraints to the inversion based on rock physical bounds as well as extensive library of existing core data lab measurements. The inversion is done by a four-parameter (mud velocity and the three Thomsen parameters) grid searching algorithm with the objective to minimize the misfit between measured and theoretical VTI dispersion curves. The theoretical dispersion curves are precomputed taking advantage of high-performance computing and stored as lookup table to speedup inversion. Consequently, this new method can be divided into three sequential substeps (a) estimation of the mud velocity profile and uncertainties using a sensitivity weighted regression algorithm, (b) estimation of VTI constants with the uncertainty propagated from mud-velocity profiles, and (c) automatic sensitivity analysis to further reduce the originally selected physical bounds to improve data quality in the presence of noisy data.

The new approach was developed using the Python programming language with a package that supports dynamic multiprocessor parallelization over logging depths. It is validated against different borehole sizes and mud velocities using synthetic sonic logs generated from VTI constants of core samples. It is also applied to unconventional field data. The synthetic test and field data application show that this new data-driven approach is reliable and efficient. It can automatically invert mud slowness change over depth that is caused by solid deposition. More importantly, it is found that Thomsen parameters that have poor sensitivities to the borehole sonic mode are properly quantified with large uncertainties. Therefore, this new approach enables a potential solution for automatic VTI constants estimation in vertical wells.

Mapping Complex Injectite Bodies With Multiwell Electromagnetic 3D Inversion Data

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Electromagnetic (EM) inversion processing of ultradeep resistivity has advanced from one-dimensional (1D) to three-dimensional (3D). These advances have brought improvements to the quality of the inversion results and provided additional reservoir information. The large depth of investigation of ultradeep LWD azimuthal EM tools (100 to 225 ft) means that distant boundaries may not be detected by any other sensor in the toolstring, making it difficult to verify the results. As inversion results represent a model of the subsurface resistivity distribution and not a direct measurement, it is important to have high confidence in the results. With the multifrequency, multicomponent data used in 3D inversion, it is possible to do a direct comparison of the component data measured by the tool to the modeled component data. If the data show a good fit across multiple frequencies, this provides confidence in the resultant model. However, as measurement sensitivities decrease with distance, it is possible to create an apparently good match between the measured and modeled component data with a model that is geologically unrealistic. Increased confidence in the results can be achieved when it is possible to verify them independently, such as by mapping a particular zone from multiple wellbores.

This paper details results from a trilateral well in an injectite reservoir, where the sand distribution, and the associated resistivity distribution, was very complex. One-dimensional inversions showed the vertical distribution of the sand, but the results were sometimes distorted by lateral resistivity variations. Ultradeep azimuthal resistivity images showed the resistivity distribution around the wellbore, but it is the 3D inversion of the data that allowed the structures to be resolved clearly. These results can be corroborated by direct comparison with the azimuthal resistivity images, but the position of major sand bodies near the start of the laterals allows a further step to be taken to increase confidence in the 3D results. The laterals all diverged from the same main bore and remained close together initially, in an area containing major sand injectites. Three-dimensional inversions from two of the wells overlap and define similarly shaped structures, providing high confidence that the 3D inversion produces a good representation of the sand distribution. The third lateral diverged quickly but the 3D inversion results from it still showed a major sand unit that could be traced back to the first lateral.

In complex geobodies, such as the injectites described here, significant lateral variation in the reservoir distribution is expected, which is not captured by 1D inversion. Understanding the shape of these structures and their potential connectivity using 3D inversion provides a major increase in reservoir understanding, critical to completion design. Independent verification, by overlaying inversion results from adjacent wells, provides an additional proof beyond the methods available in a single wellbore.

Maximizing Value From Mudlogs: Integrated Approach to Determine Net Pay

Mayank Malik, Scott Hanson and Simon Clinch, Chevron

In the current business environment, Operators are increasingly striving to reduce logging expense when possible, while maintaining safety of the drilling operations. Mudlogging has been remarkably successful through the downturn due to the value of information derived from the analysis as well as relatively low cost. Information about the lithology and fluid content of the borehole during drilling is valuable for drilling optimization and qualitative petrophysical assessment.

This paper takes mudlogs a step further to quantify net pay and estimate reserves. We outline methods for estimating gas-in-mud based on characterized gas-measurement systems and obtain bulk volume of gas per volume of rock drilled. Corrections are discussed for each mud-gas system based on their mechanical operating parameters: mud flow into the gas extractor, gas-sample suction rate out of the gas extractor, recirculated gas, and estimated gas-extraction efficiencies. Applying these corrections yields normalized bulk gas volume and gas/oil ratio which is calibrated with petrophysical assessment from wireline logs and PVT samples. Finally, correlations between bulk hydrocarbon volume and permeability are used to estimate volumetrics.

Case studies presented show that the calibrated mudlogs can be used for quantitative assessment of bulk volume of hydrocarbons in high-angle/horizontal wells where conveying wireline logs might be challenging. Additionally, GOR estimates derived from mudlogs can be used for fluid typing and optimizing the fluid-sampling program. Results presented clearly show that mudlogs can provide continuous, real-time, and quantitative petrophysical assessment.

Motion Artifact-Free Data Delivery in Real Time From a Low-Gradient NMR Tool

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Porosity and relaxation time distributions are the primary outputs of all downhole nuclear magnetic resonance (NMR) tools. The distributions can be subdivided to provide valuable results (i.e., bound- and free-fluid volumes, moveable fluid identification, and the estimation of oil viscosity within heavy oil or tar formations). Porosity measured by NMR is subject to environmental influences, such as temperature, local magnetic field, mud type, and, in particular, tool motion.

Motion causes a plethora of distortions to the data and affects all low-gradient NMR logging tools. Lateral motion distorts the echo train, at times manifesting as erratic noise or a complete loss of cohesion. Axial motion, on the other hand, can cause loss of magnetization or severe over-polarization. Relaxation-time distributions are also affected by tool motion. Methods for axial motion, artifact-free data exist, but real-time telemetry (mud pulse) bandwidth limitations have made practical implementation challenging.

The drilling environment also introduces challenges to real-time processing. To deliver porosity and distributions free of motion artifacts, the motion of the tool must be known. Axial motion can be easily calculated at surface; however, processing the data from the time domain to a relaxation-time domain—a process referred to as inversion—at the surface for acceptable accuracy requires more echoes than is feasible for mud-pulse transmission. To address both the requirement for surface data processing and the limits on data transmission, we introduce in detail a split inversion.

The inversion is split into two parts. A first inversion is performed where the bulk of the information is processed downhole, the data are reconstructed, and then sent uphole. The reconstruction focuses on the primary points of interest for the measurement, such as amplitudes for a T_1 sequence or subsample echoes for a T_2 echo train. This smaller set of data, which retains the signal/noise ratio of the full data set, effectively compresses the data and makes it easier for transmission. A second inversion is performed at the surface, accounting for the rate of penetration. This second inversion uses documented methods for motion-inclusive inversion or motion correcting the data prior to inversion. The motion-inclusive inversions demonstrated in this paper use a kernel with motion information to directly obtain a porosity and distribution that are free from motion artifacts.

This paper demonstrates the methodology for using the split inversion, surface ROP information, and computational modeling for motion-inclusive inversion to enable the delivery of reliable NMR data. The method is applied to an example log in which the porosity can be benchmarked against other porosity tools. Additionally, correct porosity and distributions are obtained with the split inversion and compared to the real-time answer that would otherwise be delivered without the ability to rectify the over-polarization observed in the well. The results presented are applied to the axial motion, which can be calculated reliably at the surface, unlike lateral motion. The split inversion method can also be used as a data compression method for any NMR tool.

Openhole Pressures Can Reveal Relative Permeability Hysteresis in a Gas-Water Reservoir

Tracey Gray, Andrew Carnegie and Ryan Crawford, Woodside Energy Ltd**.**

Openhole pressures were measured by formation tester in the gas and water zones of a high-permeability sandstone gas reservoir. The pressure data yielded useful insights about those rock types that exhibit hysteresis in the gas/water relative permeabilities .This case study demonstrates that the age-old criterion of using pretest drawdown mobility to predict pressure supercharging should not be applied without first checking whether unexpected supercharging in pressures relates to hysteretic effects in the relative permeability of the rock being tested.

Pore Structure Characterization of a Complex Carbonate Reservoir in South Iraq, Using Advanced Interpretation of NMR Logs

Milad Saidian, BP America Inc.

The Rumaila field is in South East Iraq and contains multiple reservoir intervals, including the Upper Cretaceous Mishrif carbonate reservoir, one of the major reservoirs in the world, that has been producing for more than 50 years. One of the key challenges in the Mishrif is to characterize the pore structure distinction between primary and secondary porosity. The secondary porosity in the form of large pores, if present, dominates the petrophysical properties, especially permeability. Advanced logs, e.g., nuclear magnetic resonance (NMR) and image logs can be used to understand the variations in pore structure, both qualitatively and quantitatively. In this paper, we focused primarily on four new wells with very comprehensive logging and coring programs.

NMR logs were acquired using different tools and pulse sequences. This resulted in uncertainty in porosity and T_2 distributions and consequently complications in the NMR interpretation. We observed two key issues: porosity deficit due to lack of polarization and T_2 distribution truncation due to the low number of echoes. We used a single pore model to reproduce the NMR response in different pore sizes and fluid types for different pulse sequences. The results showed that the NMR response, especially in water (water-based-mud filtrate) filled large pores, is sensitive to polarization time, echo spacing and tool gradient strength. NMR log data confirmed the modeling results. We recommended an optimum pulse sequence and tool characteristics to fully capture the heterogeneous rock and fluid system in this carbonate reservoir.

NMR logs, when available, were the primary tools to identify the large pores. We present a consistent workflow for NMR log analysis that was developed to identify and quantify large pores and extended to all wells in the field. We used advanced NMR interpretation techniques, e.g., factor analysis (FA) in a series of oil wells drilled with water-based mud. Using FA, we identified a cutoff value of 847 ms for large pore volumes. In this manuscript, we also present an integration of laboratory measurements e.g. NMR, mercury intrusion capillary pressure (MICP) data, whole-core CT scanning and thin-section analysis in our interpretation workflow. We also compared the pore-size distribution and large pore volume from image logs with NMR logs and other laboratory data and observed very consistent results. All the available information was integrated to build an "NMR-based" petrophysical model for porosity, rock type, permeability and saturation determination. The NMR-based model was very comparable with the classic FZI rock typing. The results of this study were used to modify the NMR acquisition program in the field and to build a petrophysical model based on only NMR and image log measurements for carbonate reservoirs.

In this paper, we will discuss NMR modeling and corresponding log data from various wells to confirm the results. Furthermore, we will present a novel interpretation workflow integrating laboratory measurements and log data, which led to the modification of the NMR acquisition program in the field and creation of a data-driven petrophysical model based on only NMR and image log measurements for carbonate reservoirs.

Pore-Scale Investigation of Porosity-Resistivity-Permeability Relationships: Implications for Rock Typing

Zhonghao Sun, Ayaz Mehmani and Carlos Torres-Verdin, The University of Texas at Austin

Predictive relationships among porosity, electrical resistivity, and permeability are critical for reliable formation evaluation. Empirical and semiempirical relations such as Archie's, Timur-Coates's, and Kozeny-Carman's equations have been widely used for quantification of petrophysical properties. However, several fundamental questions still remain concerning the reliability and accuracy of such relationships and their variants, as well about their range of validity. The first point of concern regards the physical meaning of the parameters associated with the equations and their controlling physical properties, such as the porosity exponent, *m*, in Archie's equation. Second, the selection of parameters can be ambiguous, for example, porosity when considering a wide pore-size distribution range. Third, the reliability of the relationships becomes questionable when extrapolating them to spatially complex rocks, or to a wider porosity range. Underlying these questions is the fundamental notion of petrophysical rock classes, wherein a rock class is defined as exhibiting uniform petrophysical equations and constant associated parameters regardless of porosity. Answers to the above questions will not only enhance our understanding of electrical resistivity and permeability in complex rocks, but also lead to physics-based, self-consistent predictive relationships that are valuable for (1) rock classification, (2) reserves estimation, and (3) multiphase flow assessments.

In this study, we use microfluidics augmented with pore-network modeling to shed physical intuition and quantify the range of practical validity of fundamental porosity-electrical resistivity-permeability relationships. We introduce a new fabrication procedure as well as an experimental system that provide precise electrical measurements of microfluidic chips with designed pore space patterns and varying degrees of water saturation. Additionally, a simple and robust two-dimensional pore-network model is used to numerically simulate electrical conduction and fluid flow in porous media to reproduce the microfluidic measurements. We combine our experimental and numerical methods to investigate the effects of different pore geometries, evolution of por-size distributions due to diagenesis, and porosity, on electrical resistivity and permeability. Further analyses of flow patterns and interstitial flow velocity distributions from pore-network modeling provide physical insights that underpin flow phenomena in porous media. One of the most important questions underlying our work is what constitutes a petrophysical rock class and for how wide a porosity range can one assume constant petrophysical parameters within a rock class. Specific examples are considered for clastic, carbonate, and mudrock systems in the analysis.

Results indicate that both pore-size distribution and its evolution with diagenesis impact the porosity-electrical resistivity-permeability relationships considerably. An *m* close to 2 is obtained when the pore-size evolution is dominated by spatially uniform changes in grain surface. The exponent *m* increases when the pore-size distribution widens and becomes nonuniform. We show that *m* is not constant with porosity due to changes in interstitial flow patterns. Our study indicates that the use of pore-size distributions, rather than a single *m* or porosity, is critical to construct physically reliable, and self-consistent petrophysical relationships for interpretation of well logs and core measurements in spatially complex rocks. Quantitative guidelines are given to define and detect petrophysical rocks classes from well logs.

Realization of Oil-Wet Facies and Fluid Saturations in Tilted Water/Oil Contact Reservoirs

Reinaldo Jose Angulo Yznaga, Kresimir Vican, Venkat Jambunathan and Ehab Negm, Halliburton

Representing fluid saturations in nonwater-wet formations always presents challenges. The complexity of the formation characterization presents even greater challenges in reservoirs that contain a tilted water/oil contact (WOC). Nonwater-wet conditions are historically and commonly observed in carbonate rocks. This wettability condition may create a large hydrocarbon saturation region below the free water level (FWL), which is an important parameter used as a reference point for pressure and fluid saturation distribution. This state may result from the dynamic interaction of rock and fluid during the geological time when the reservoir is evolving and suffering diagenetic changes. Knowledge of the fluid distribution is needed to understand the mechanisms of oil entrapment, oil volumetrics, and potential recovery mechanisms involved in reservoirs under these wettability and WOC conditions. This paper presents a method to characterize and model the phenomena of nonwater-wet formations in reservoir with a tilted WOC.

Openhole logs, core data, image logs, and computational analytics methods were applied to characterize, classify, and map facies. Capillary pressure information and formation tester data were integrated and compiled for each facies. In this work, a method was developed to model saturation-height functions representing nonwater-wet formations and tilted WOC phenomena.

Fluid and saturation properties are estimated and assigned to each reservoir point. The method was validated by applying the new method to actual well data. The new method provides saturation properties in formations with complex fluid-rock interactions and phenomena.

This work introduces a novel method to estimate saturation-height functions and saturation distribution for reservoirs with complex fluid-rock interaction and distribution, such as nonwater-wet formations in tilted WOC conditions.

The Log-Derived S_w Compared to Surface Measurement of Core S_w: How They are Reconciled

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The log-derived S_w is lower than Core_S_w when fluids are lost as the core is brought to the surface. Previous interpreters have noted this fact and either used preserved core or ignored the differences. Now we have a solution. The lost fluids are equivalent to the free porosity measured by a nuclear magnetic resonance log (NMR). The method for calculating the log-derived surface saturation is to first determine the hydrocarbon pore volume, (HCPV). Then subtract the free-hydrocarbon volume. Convert the net hydrocarbon volume to saturation using the total porosity. Why is this method important? There are very few preserved core measurements of S_w. This method provides a comparison of core and log S_w that does not require a preserved core. The required measurements are resistivity, SP, elements from nuclear spectroscopy, density, neutron, NMR and, of course, core S_w to compare to.

We show several examples. Bitumen sands, conventional and unconventional (Lower Montney).

- In Bitumen oil sands, the NMR clearly shows there is free porosity. The operator has used core S_w measured on the surface without the preserved core. In addition, our method to obtain R_w from the SP is innovative and provides a good variable R_w value to use in the dual-water saturation equation. The cation exchange capacity (CEC) is obtained by identifying the clay families and their associated CEC. The same methodology is followed for the other examples.
- An example is presented from a low-porosity Cretaceous zone.
- An example is shown in the Lower Montney formation where the permeability is very low. As the permeability decreases, the fluid loss from the retrieved core also decreases.

The method shown is empirical, designed for the petrophysicist who does not have a research laboratory available. There is some adjustment required when the NMR is unable to "see" certain hydrocarbons due to the nature of the measurement (such as dry gas). However, the results certainly show whether the log interpretation is validated by core, despite not having preserved core.

The picture below illustrates the problem. On the left is S_w from core and log. Notice the large separation. A reaction might be the log calculation is wrong, assuming the core is correct. On the middle track there is the same data plus the correction to a surface value of S_w (S_w_surface) using the free-fluid porosity. Now, we see that both core S_w and log S_w are correct, just different pore volumes of fluids are measured. The core-perm in the right track shows 0.7 to 3 mD for the core and log. It appears that permeability < 0.02 mD has little to no free porosity, so will lose little fluid as core is brought to surface.

The bottom line is core S_w can be used to confirm log S_w when there is a free-fluid measurement to assist and complete mineral-based log interpretation is used.

Time-Lapse NMR and Multifrequency Dielectric Measurement Demystifying the Native Oil Properties in a Complex Injectites Reservoir; a Case Study From Norwegian Sea

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The Frosk prospect was drilled to prove oil in injectite sands. The quality and oil biodegradation were considered to be the main risks based on the wildcat well drilled in 1981. To advance fluid characterization and to analyze the flow potential, Wireline NMR was used in coring the sidetrack while LWD NMR was run in the geological sidetrack. To access the oil properties and flow potential, LWD NMR had two passes over the reservoir section, one while drilling, and the second as a ream-up pass. The same injectites were logged in the coring sidetrack with WL NMR. Time-lapse data from LWD and diffusion-based fluid-typing NMR on WL along with other advanced measurements showed significant improvements in formation evaluation and explained the deviations in NMR estimated oil properties. Triaxial resistivity and dielectric were also logged in the coring sidetrack to access the petrophysical properties of brecciated sands along with an extensive wireline sampling program. The initial assessment proved that the conventional measurements did not characterize these highly permeable brecciated sands, which have varying degrees of shale clasts.

Considering the oil is biodegraded, the initial assessment of LWD time-lapse NMR based on the early T_2 relaxation, suggesting that there was a secondary heavier oil factor within the reservoir native oil, showing towards a secondary charge system. A similar T_2 relaxation signature was also seen on WL NMR. Prior knowledge of the oil could easily misinterpret simple analysis of only time-lapse LWD NMR data and the WL NMR without diffusion information. It also includes some drawbacks on fluid sampling in the paper. WL NMR provided direct diffusion-based native-oil viscosity. Diffusion analysis was able to separate the OBMF signatures from the native oil because of sufficient viscosity contrast, and when combined with dielectric it disputed the residual early T_2 signature to be a heavier oil left behind post invasion process. Given this, a technique called NMR factor analysis was used on LWD NMR to separate the poro-fluid distributions of the native oil from the cumulative total T_2 distribution. T_2LM associated with the native-oil factor has been calculated and then transformed into the oil viscosity, which concurs with the integrated WL NMR-dielectric analysis.

The proposed paper documents the described workflow. It provides a tool for the log analyst to understand the time-lapse LWD NMR data and the multidepth of investigation diffusion-T_2 WL data. Overall, the NMR data when combined with Dielectric, unraveled additional information about the oil biodegradation. In the absence of dielectric with the known fact of oil biodegradation, standalone NMR measurement in OBM fits the behavior of heavier oil left behind post-OBMF invasion. Laboratory-derived oil viscosity agrees with the reinterpreted NMR viscosity for LWD and WL. The integrated analysis of advanced log also helped to calibrate the conventional basic log by providing a robust and accurate T_2 cutoff, which separates the bound- and free-fluid at downhole conditions, enabling precise estimates of Irreducible water saturation (S_{wIrr}) without performing a core NMR measurement.

What's Next for Neutron-Gamma Density?

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The neutron-gamma-density (NGD) measurement was introduced in 2012 for the logging-while-drilling (LWD) environment as an alternative to the traditional Cs^{137}-based gamma-gamma density measurement. It has been used worldwide to measure formation density, especially in places where the transport, storage and licensing of radioisotopic sources is difficult due to environmental concerns, safety or security. Additionally, the method has been found to be important in borehole environments where an LWD tool can be stuck while drilling due to formation swelling in shales or other mechanical issues encountered downhole. A density tool having radioisotopic sources like CS^{137} is required to be cemented in the well when they become stuck, whereas a tool using NGD does not have a source that must be abandoned. NGD can mitigate risks associated with complex well geometries and tortuous 3D horizontal wells.

This paper reviews the status of the current NGD measurement, describing its performance capabilities and limitations. Changes to the measurement algorithm are proposed that would improve both the statistical precision and accuracy of the current NGD measurement without having to modify tool hardware. In particular, the use of a compensated NGD method would provide correction for tool standoff and make the measurement less sensitive to environmental factors, such as borehole size and mud weight.

Also reviewed are recent publications that discuss the theoretical underpinnings of the NGD method, its applications and limitations in the LWD environment, and its challenges. The paper concludes with a discussion of how the method might be applied to help mitigate the mud-invasion problem in LWD and how it might be applied to wireline logging tools in both the open- and casedhole environments.

FORMATION EVALUATION OF UNCONVENTIONAL RESERVOIRS

A Comparison and Applications of Three Different Maximum Horizontal Stress Predictions

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Accurate prediction of formation stresses encountered during drilling that could cause fracturing or formation damage in the near-wellbore area is clearly important. In addition, development of a geomechanical model by prediction of stresses is important for selecting "sweet spots" and locations for fracturing a well. Unfortunately, models used to make continuous depth-based stress predictions involve many parameters that are derived from laboratory tests, fracture injection tests, and the actual fracturing of a well—all contributing to the uncertainty of the predictions.

It is generally recognized the most difficult component of stress to predict is the maximum horizontal stress. The objective of this paper is to describe three approaches for estimating the maximum horizontal stress (1) from borehole breakouts and borehole-wall fractures, (2) from anisotropic poroelastic stress equations, and (3) predicting an upper bound for the maximum horizontal stress from a stress polygon. It is shown how stress prediction and interpretation can be improved by simultaneously applying each approach, depth-based, using wellbore acoustic and borehole image data calibrated to laboratory and field measurements.

The three methods applied require knowledge (prediction) of the minimum horizontal stress prior to predicting the maximum horizontal stress. Thus, the standard anisotropic stress equation for minimum horizontal stress is used, and a discussion for obtaining calibration parameters is presented.

A workflow is developed for using the available ancillary data for calibration. The results provide depth-based predictions of overburden and pore pressure, as well as minimum and maximum horizontal stress from which a fracture initiation pressure can be predicted. In addition, a depth-based fault regime, either normal, reverse, or strike slip, is computed from the stresses. Finally, results are presented from log and core data for an unconventional reservoir well.

A New Method for Calculating Poisson's Ratio From XRD and Wireline Mineralogy Using a Calibrated Clay-to-Shale Volume Transformation

Carrie Glaser, Willamette Petrophysics; Jane Hearon and Jason Edwards, Fracture ID

The mechanical properties of a formation control the initiation and growth of hydraulic fractures. Because hydraulic fracture efficiency can significantly impact the economics of a field, understanding mechanical property heterogeneity in the stimulated rock volume may be as impactful as traditional petrophysical deliverables such as permeability or OOIP. Characterization of the vertical stress profile and mechanical heterogeneity in pilot wells, as well as strength, ductility and closure stress in horizontal wellbores, are critical elements of a complete petrophysical analysis in unconventional reservoirs.

A key challenge in delivering geomechanical analyses is the prohibitive cost of data acquisition. Extensive core testing to establish calibration is both expensive and time-consuming. Dipole sonic logs, the traditional industry-standard method for calculating in-situ mechanical properties, are challenging to acquire and costly in horizontal wellbores. In vertical wells the effect of compounding error on the calculation of Poisson's ratio, Young's modulus and stress, previously estimated may be as much as 20, 26 and 28%, respectively. Combined, these limitations significantly reduce the availability of high-quality, calibrated geomechanics data, especially in horizontal wells.

We propose a mineralogic model as one solution to the paucity of core-calibrated geomechanical data available. The methodology we have developed improves estimates of Poisson's ratio used to calculate closure stress, and dramatically increases the availability of core- and log-derived mechanical property data by using more common and less expensive data sets. In this study, we present a workflow that estimates Poisson's ratio using X-ray diffraction (XRD) analyses from core and from triple-combo wireline mineralogy interpretations. We also introduce a method to 'calibrate' a clay-to-shale volume transform that empirically accounts for textural variability between reservoirs of similar bulk mineralogic composition. Finally, we present a recommendation for a capital-efficient core analysis strategy to establish geomechanical calibration.

This workflow has been applied to (1) expand the available core-calibration data set using inexpensive and widely available XRD analyses, (2) use triple-combo wireline data to estimate geomechanical properties where sonic logs are not acquired, and (3) estimate mineralogy in horizontal wells by calculating Poisson's ratio from drill-bit accelerometer data.

The methodology is validated using core measurements of geomechanical properties, dipole sonic logs, cuttings and correlation to well production. Results are presented from the Wolfcamp Formation in the Permian Basin, the Eagle Ford Shale and other U.S. onshore unconventional reservoirs.

A New Method of Estimating Tortuosity and Pore Size in Unconventional Formations Using NMR Restricted Diffusion Measurements

Xinglin Wang, Zeliang Chen, Philip M. Singer, Rice University; Harold J. Vinegar, Vinegar Technologies, LLC; and George J. Hirasaki, Rice University

Tortuosity and pore size are two petrophysical properties useful for estimating permeability. Given the small pore systems in unconventional rocks, the free diffusion of the pore fluids is restricted by the pore walls. NMR restricted-diffusion measurements of fluids in porous media can provide both tortuosity and pore-size information.

In this study, we focused on a series of low-permeability organic-rich chalks with connate water present. We pressure-saturated the core samples with two hydrocarbons (high-pressure methane and decane) and conducted NMR measurements under pressure to obtain their restricted diffusivity in the hydrocarbon-bearing porosity.

In planning the NMR restricted-diffusivity measurements, we chose an optimum series of diffusion-encoding times for the pulse-field gradient (PFG) pulse sequence to obtain the correlation between the restricted diffusivity (D_{re}) and free diffusion length (L_D). On the D_{re} vs. L_D relation, the restricted diffusivity of decane falls in the short diffusion-length region (thus determining surface-to-volume ratio and pore size) while high-pressure methane falls in the long diffusion-length region (thus determining tortuosity in the asymptotic limit).

By applying the Pade fit to these two hydrocarbon-restricted diffusivities, we can better estimate the tortuosity and pore-size of the hydrocarbon-filled pore space. We compared our new method to our previously published method fitting a Pade approximation curve to a suite of NGLs. We find that this new method improves logistics, robustness and accuracy.

A Novel Technique for Determining Critical Desorption Pressure of Coals Using Pressure Transient Analysis

Jack Harfoushian, Schlumberger Australia

A critical measurement for optimizing production from coal-bed methane (CBM) wells is the desorption pressure of coals. Unlike conventional reservoirs where trapped gas is stored in and produced from porous media, movement of CBM gas requires extraction of formation water from coal cleats and fractures to reduce formation pressure down to critical desorption, allowing methane to be released from the coal matrix.

Measurement of total gas content in coals is commonly done by retrieving core samples to surface. This is often achieved by obtaining large samples of core in a short amount of time, with the aim of minimizing the amount of lost gas. The total gas content is then determined by adding the amount of gas measured at surface to the estimated amounts of lost gas and residual gas. Similarly, the current industry practice for estimating critical desorption pressure of a coal seam is not done in situ. Instead, this important measurement is approximated by taking into account the measurement of gas content and reservoir pressure, and by conducting isothermal adsorption tests on core samples. This process is time-consuming and the results often contain high levels of uncertainty.

In this paper, a novel technique will be presented for the accurate determination of critical desorption pressure using wireline formation testers. The measurement is made in situ while testing a coal seam for pressure, permeability and productivity. Case studies will be presented where this technique was successfully implemented in coal-bed methane wells in Queensland, Australia.

Application of Machine Learning to Interpret NMR Wireline Measurements

Son Dang, Heyleem Han, Carl Sondergeld and Chandra Rai, University of Oklahoma

Determination of fluid saturation for unconventional reservoirs is challenging, but critical. nuclear magnetic resonance (NMR) has been proven as a valuable tool in both wireline and laboratory measurement to address this challenge. Due to the complexity in pore network and texture of organic-rich tight rocks, the interpretation of fluids' saturation using only one-dimension distribution of T_2 relaxation time (1D T_2) is not straightforward. Two dimension T_1-T_2 map (2D T_1-T_2) provides better approach to define phases' saturation, by applying both T_2 cutoff and T_1/T_2 ratio cutoff. However, for most of NMR wireline measurement, only 1D T_1 and 1D T_2 are available. Therefore, we propose a new workflow using machine-learning (ML) algorithms applied on wireline 1D T_1 and 1D T_2 data, to interpret fluid saturation. We also demonstrate a case study with two wells from Meramec formation.

To develop the ML algorithms, both inputs and outputs for the training data set were based on laboratory measurements on 105 wax-preserved Meramec plugs, which were sampled from two Meramec cores. Beside routine petrophysical analyses, such as mineralogy and total porosity, all of these sample were subjected to NMR tests, including 1D T_2, 1D T_1, and 2D T_1-T_2 map, using 12 MHz Oxford® instrument. The training inputs include the combination of 1D T_2 and 1D T_1 core data; these relaxation distributions were processed to make their formats equivalent to wireline NMR data format. The training outputs include HC saturation, fast-relaxation brine saturation (immovable water), and slow-relaxation brine saturation (movable water); these parameters were estimated using laboratory measured T_1-T_2 map. Hydrocarbon estimations were also independently crosschecked with the S1 results from modified Rock-Eval analyses; in this protocol, S1 peak breaks down into five fractions using multisteps ramping pyrogram, which provide better estimation of in-situ hydrocarbon (HC). The results from 65 samples, from the same Well A, were used for the training set; whereas, the results from the other 40 samples (15 from Well A, and 25 from Well B) were used to validate the algorithms. Elastic net regression (ENR) was proven to be the most suitable algorithm with the best prediction accuracy for this workflow. Finally, we applied the developed ENR model to wireline 1D T_1 and T_2 data to estimate three-fluid saturations.

Since the interpretation of NMR response to fluid saturation is not universal for different formations, this workflow provides a unique approach, using core measurements to customize the determination of fluid contents for a particular formation. The inversion results from wireline data agree well with core measurement. It confirms Meramec formation has a significant fraction of slow-relaxation brine, which resides in carbonate-rich matrix. Using simple T_2 cutoff > 3ms cannot distinguish slow-relaxation brine and HCs, which leads to the overestimation of oil in place. The ratio of immovable water to total water has a strong positive correlation with clay content; for typical target zones in Meramec, more than 75% of brine content is immovable.

Application of TGIP-NMR on an Appalachian Unconventional Shale Using 2D T_1-T_2 NMR Logs

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Gas-shale resources are more difficult to evaluate than traditional gas reservoirs, because the hydrocarbon exists not only as pore-filling free gas, but also as adsorbed gas on high-surface-area kerogen. Each of these phases has a different density and their downhole NMR signals cannot easily be separated. In addition, the effective hydrogen index of the hydrocarbon phase cannot be determined. The Langmuir adsorption isotherm has been the preferred method for estimating gas in place (GIP) in unconventional shales for many years. However, operators have not been able to consistently history match gas production results based on the Langmuir method, due to the uncertainty of the measurements, interpreted results and assumptions in modeling. This is especially true in the US Appalachian unconventional gas-shale plays, where the amount of free and adsorbed gas calculated from multimineral models and Langmuir isotherms is low compared to production history matching. Additionally, measurements of Langmuir isotherms require laboratory core investigations that are not always performed, consequently the limited number of measured isotherms is often insufficient to characterize the heterogeneity of the entire resource.

The total-gas-in-place (TGIP) NMR method enables the direct conversion of NMR measurements into TGiP by counting hydrogen nuclei directly, circumventing the requirement to know the hydrogen index, pore size, pore pressures and formation temperature for GIP determinations. The TGIP-NMR methodology was applied to an unconventional shale well in the Appalachian basin. The work involved a cluster-based interpretation of continuous T_1-T_2 logs for a more accurate measurement of the clay-bound water and gas fractions. This method provides superior performance in comparison to 1D NMR methods based on T_2 cutoffs or applications of multimineral saturation models, where estimates of salinity, R_w, and knowledge of hydrocarbon parameters are required.

Although the TGIP-NMR method has emerged as a new candidate for the determination of GIP in unconventional shale plays, it is important to recognize its limitations. NMR T_1-T_2 based TGIP can provide an accurate answer in high-kerogen high-porosity zones of unconventional shales. However, the TGIP-NMR method is sensitive to the uncertainties in the measurement of the volume of water in the shale rocks. With the very low volumes of water in the Appalachian unconventional gas-shale plays, an accurate estimate of clay-bound and irreducible water based on a T_1-T_2 analysis is essential for the TGIP calculation. Additionally, in very low porosities, approximately 2 p.u. or less, the results from TGIP could be suspect due to noise in the T_1-T_2 measurements.

Bayesian Method for Rapid Multiwell Interpretation of Well Logs and Core Data in Unconventional Formations

Tianqi Deng, Joaquín Ambía and Carlos Torres-Verdín, The University of Texas at Austin

In formations with complex solid and fluid composition, it is standard practice to estimate porosity, water saturation, and mineralogy depth by depth by minimizing the error between well logs and their numerical simulations subject to realistic petrophysical constraints. Previous studies have extended this method for its application to unconventional formations using Markov Chain Monte Carlo (MCMC) sampling under a Bayesian inversion framework. The capability of including predefined, a-priori correlations between minerals/fluids compositions and quantifying uncertainty makes Bayesian inversion especially suitable for unconventional organic-shale formations. However, no multiwell application of this method is yet available in the industry because of the high computational cost associated with Bayesian inversion and lack of complete well logs/core data sets in many of the wells.

We introduce and successfully verify a new interpretation workflow for rapid multiwell interpretation of wireline logs and core data. First, well logs are explicitly corrected and normalized for tool and borehole effects (e.g., shoulder beds) by running separate inversions for each well log. This step outputs layer-by-layer physical properties (e.g., resistivity, density, neutron migration length, and sigma). Next, we perform Bayesian joint inversion of multiple logs using the previously estimated layer-by-layer physical properties for wells where core data and spectroscopy logs are available. Individual mineral/fluid properties and petrophysical models (e.g., mixing laws and porosity-saturation-resistivity equations) are calibrated with core data and interpretations of spectroscopy logs. Finally, statistical correlations between minerals/fluids are generated from interpreted wells and used to estimate petrophysical properties (e.g., mineral and organic composition, porosity, and water saturation) for other wells in the same field. Next, the interpretation workflow is implemented in other nearby wells penetrating formations with similar geological properties.

Our interpretation workflow circumvents several difficulties when applying the Bayesian method for multiwell interpretation. First, running separate inversions for each well log ensures that the input layer-by-layer physical properties be consistent within the entire field and free of any uncertainty caused by shoulder beds and different borehole instruments or drilling conditions. Second, we implement a precomputed surrogate model based on machine-learning methods for nuclear property calculators, which can be extended to any property and petrophysical/compositional model, including nonlinear and arbitrary heuristic models. This method requires only 1% of the computational cost for running nuclear calculators and generates results with an average relative error of 1%, thereby allowing applications to large data sets. Third, we adopt an extended hierarchical Bayesian framework to consider rock types as an unknown. This framework automatically implements different petrophysical models for each rock type.

The proposed method is applied to wireline data acquired across multiple wells in the Fayetteville and Wolfcamp shales. Results of estimated TOC, porosity, water saturation, and mineralogy are in good agreement with data from core analysis and XRD: 80% of the core data are within the 95% credible interval of the estimation. Although this workflow is developed for unconventional formations, it can be extended to any formations with complex lithology. The calibration of petrophysical models and statistical correlations is critical for improving the accuracy of petrophysical estimations.

Complex Conductivity Model for Highly Mature Kerogen-Bearing Formations

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It has been observed that highly mature kerogen-bearing formations in the dry-gas window can have very low resistivity that cannot be explained with existing saturation equations or models. The resistivity can read less than 0.2 Ω-m in these relatively low-porosity formations. These formations have traditionally been condemned as wet without further investigation, because there is no method to reliably compute the hydrocarbons in place in these situations. A recent breakthrough in induction processing allows us to determine both the resistivity and permittivity simultaneously from low-frequency (20 kHz) field induction measurements. We processed many wells penetrating these anomalously low-resistivity formations to determine if they had a distinct resistivity-dielectric permittivity pattern. We found that some anomalously low-resistivity kerogen-bearing formations have a very elevated permittivity.

Where low-frequency permittivity and conductivity are both high, we propose that this signal is dominated by the effect of graphitic kerogen, which is conductive and often has a high aspect ratio. To explain the measured induction resistivity and permittivity we developed a solution for the polarization response of spheroidal conductive grains immersed in brine, which accounts not only for the geometric and conductive effects of the grain independently, but also the interplay between them. Based on this solution, we construct an effective medium model that describes both the conductivity and permittivity signals for formations containing highly mature and water-wet graphitic kerogen. In addition to the usual petrophysical parameters, such as the water-phase tortuosity exponent, the brine salinity and the water-filled porosity, the model depends on the volume fraction, the typical size (distribution), and an effective aspect ratio of graphitic kerogen. The conductivity and permittivity predicted by the model are consistent with the EM response of highly mature kerogen-bearing formations. In field applications, the volume fraction of graphitic kerogen can be obtained through advanced formation evaluation based on spectroscopy logs. Then, given the water-phase tortuosity exponent, the brine salinity, and a fixed size distribution of graphitic kerogen, one can invert for the formation-water saturation together with the effective aspect ratio of the graphitic kerogen, based on both the conductivity and permittivity signals at typical resistivity tool frequencies. As a result, the newly established model could provide the foundation for an improved saturation interpretation of highly mature and water-wet kerogen-bearing formations. Because the change from water-wet to oil-wet graphitic kerogen could change the permittivity and conductivity in a nonproportional amount, including the wettability effects is an interesting and important step for future works.

Determining Water-Filled Porosity of Tight Oil Reservoirs With a New Interpretation Method for Dielectric-Dispersion Measurements

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Tight oil reservoirs present a unique opportunity for dielectric dispersion logging. Dielectric logging is sensitive to the water content and provides water-filled porosity without having to know Archie's empirical parameters or water salinities, as is required with resistivity log interpretation. Moreover, because of the extremely low permeability of the shale reservoirs, there is effectively no invasion of the borehole fluids into the formation. Thus, in these reservoirs, dielectric-dispersion logging directly provides water-filled porosity of the undisturbed zone.

We investigated the interpretation of the dielectric-dispersion measurements in a couple of tight oil formations. A representative core collection was obtained from two intervals. The core material was characterized in terms of lithology and total organic carbon content. The cores were cleaned and saturated with brines that match the formation water salinities. Next, the dielectric-dispersion measurements on cores were obtained under controlled laboratory conditions of pressure, temperature and brine salinity.

Based on these data, we have developed a new method for the interpretation of multifrequency dielectric logs in tight oil reservoirs. The new method has a significant advantage over the existing approaches because it does not require an input for either matrix or hydrocarbon permittivities, including kerogen permittivity, to derive water-filled porosity, as is the case with the existing approaches. The new method enables the elimination of all associated uncertainties with formation mineral models in complex lithologies, unknown mineral permittivity endpoints and, most importantly, the poorly defined permittivity of kerogen. The new method only requires relatively well-known input of formation temperature and an estimate of formation water salinity. Thus, the new method provides a more robust, streamlined, and consistent interpretation of the dielectric-dispersion logs in tight oil and reduces the uncertainty on the estimate of hydrocarbons in place.

The new method performed better on core dielectric-dispersion data compared with commonly used bimodal and SMD dielectric models. Next, the new method was used to derive water-filled porosity from dielectric-dispersion logs obtained over two major production zones. When combined with independent porosity estimates, the results from the new method compared well with the water saturations independently measured on cores, proving the applicability and accuracy of the new method for evaluation of tight oil. The new method is applicable to all shale reservoirs, including shale gas.

Hydraulic Fracturing Evaluation Using Single-Well S-Wave Imaging: Improved Processing Method and Field Examples

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Hydraulic fracturing produces artificial fractures and creates oil and gas seepage channels. It has now grown into an indispensable technology for oil and gas exploration and development, which leads to the evaluation of hydraulic fracturing effects, i.e., the development of hydraulic fractures, as well as the connection with natural fractures, becoming necessary.

In this paper, we introduce the single-well S-wave imaging method, commonly used to recognize reflectors, such as natural fractures and caves outside the well, to do the hydraulic fracturing evaluation. The specific implementation is to acquire array acoustic logging data once in the open hole, before fracturing, and then to measure again in the cased hole, after fracturing. The difference between the two imaging results reflects the development of hydraulic fractures. However, the normal processing steps of S-wave imaging cannot meet the demand, due to the complex hydraulic fracture network and the interaction with natural fractures. For this purpose, six types of noise that affect the signal/noise ratio of S-wave imaging are concluded: low-frequency and high-frequency noise; bad channel; multiple wave; formation boundary wave; and random noise. A set of improved processing methods for suppressing these types of noise in S-wave imaging are further developed.

Field applications demonstrate the improved processing methods that effectively suppress these noises and imaging of real reflectors becomes clear. By comparing imaging of field data before and after hydraulic fracturing, artificial fractures growing along the borehole wall can be observed. More importantly, we can see the extension of artificial fractures radially into the formation as far as 25 meters and even the connection with natural fractures. It should be pointed out that the S-wave imaging method cannot directly identify the main hydraulic fractures almost vertical to the well, but can identify the numerous secondary hydraulic fractures almost parallel to the well, which always accompany the main fractures.

As we all know, microseismic monitoring is a widely used technology to image hydraulic fractures. So in this paper, we attempt to combine S-wave imaging of high resolution but short detection distance with microseismic imaging of low resolution but far detection distance to evaluate hydraulic fracturing. In an actual well, the corresponding depth positions and directions of natural fractures are determined by S-wave imaging before hydraulic fracturing, and microseismic events representing hydraulic fractures are recorded. Comparing S-wave imaging and microseismic imaging, it is found that the layer that microseismic events appear most frequently is also the layer with numerous natural fractures, and the extension azimuths of both artificial fractures and natural fractures are consistent, which indicates that it is practicable to use S-wave imaging and microseismic imaging to jointly evaluate hydraulic fracturing.

Hydrocarbon Gas Behavior in Nanopore Confinement Organic-Shale Systems

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SEM analysis, MICP, and BET studies of shale gas formations show that organic rich shale rocks have pore sizes in the order of nanometers. It is important to understand phase behavior of methane and other hydrocarbon gases in such pore systems to properly characterize reservoir fluid phase, calculate gas in place (GIP) and estimate hydrocarbon saturation during pressure drawdown.

We have developed an experimental procedure to use nuclear magnetic resonance (NMR) to measure the density of hydrocarbon gases in nanopore-dominated gas-shale reservoirs at reservoir temperature and pressure, and also quantify the moles of gas that can be packed in such rock systems under these conditions.

The experimental setup consists of a 12-MHZ NMR spectrometer with the capability to perform 1D, 2D and 3D gradient measurements. An overburden cell made of zirconia, along with flourinert (both have no NMR signals) is used to put the shale core plug under reservoir overburden stress conditions. Hydrocarbon gas is injected into the sample though a pressure source, which allows for regulation of the injected gas pressure from 100 to 10,000 psi. The entire gas-pressure injection setup is vacuumed before injecting gas into the sample. The confining fluid is heated using a flow-loop system that in turn heats the sample. The setup is calibrated for each hydrocarbon gas scenario using a Macor ceramic plug and Berea sandstone. Density values of methane for the Macor and Berea sandstone came in agreement with published NIST values.

Helium porosity and NMR T_1T_2 measurements on the as-received shale plug are done to measure void space and residual water and oil saturations. The samples are then loaded in the overburden cell and brought up to reservoir stress and temperatures, while simultaneously injecting hydrocarbon gas from both sides of the plug to saturate the void space. High precision pressure gauges are used to constantly monitor the gas pressures and keep then stable. Hydrocarbon volumes in the pore system at different pressures are measured using NMR T_1T_2 scans during the buildup/ saturation and the drawdown/ desorption processes. The proposed technique gives accurate volumes of gas that can be packed in the nanopore shales and suggests 35 to 60% more GIP as compared to existing techniques that incorporate monolayer Langmuir adsorption isotherm measurements. Additionally, it was found that the entire gas in the pore system behaves as one phase with density approaching close to liquid-phase densities.

Impact of Geochemistry and Reservoir Temperature and Pressure on Contact-Angle Measurements for Assessment of Kerogen Wettability

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Kerogen can be one of the major constituents of organic-rich mudrocks. Wettability of kerogen can directly affect the multiphase fluid-flow properties, water production, and resistivity of organic-rich mudrocks. The chemical composition of kerogen varies with change in kerogen type and thermal maturity. Therefore, geochemistry of kerogen, in addition to high temperature and pressure reservoir conditions can affect the wettability of kerogen. In a previous publication, we experimentally demonstrated that kerogen wettability varies significantly with thermal maturity and that it could be water-wet at low thermal maturities. However, these experiments could not capture variation of kerogen wettability in wide range of kerogen type and reservoir temperature/pressure conditions. We also demonstrated, using molecular dynamics (MD) simulation, that water adsorption capacities of kerogen can vary with change in temperature/pressure conditions. However, the water-adsorption capacities obtained from simulation could not be compared directly with the experimentally measured wettability. Therefore, the objectives of this paper include (1) quantifying the impacts of reservoir temperature/pressure conditions as well as molecular structure on the contact angle of water droplet on kerogen using MD simulations, and (2) cross-validating the wettability results from modeling with experimental results.

We use MD simulations and experimental work to achieve the aforementioned objectives. The inputs to the simulation include molecules of kerogen packed in a cubical simulation box with periodic boundary conditions. We then perform NPT and NVT simulations to construct a porous kerogen structure. We then simulate the contact angle formed by a water droplet on the surface of kerogen. These measurements are performed for kerogen molecules of Types I, II, and III at different thermal maturities. We model the contact-angle measurements at temperature and pressure conditions in the range of 298 to 380 K and 10 to 50 bars, respectively. The wettability results at room temperature/pressure conditions are compared with experimentally determined wettability using the sessile-drop method on isolated kerogen samples from two formations, which contain Type II and Type II/III kerogen.

Simulation results showed that the water contact angle formed on kerogen surface increases 14% with 22% increase in oxygen content. The increase in the contact angle is attributed to the strong attraction between oxygen containing functional groups in kerogen and water. Increase in temperature from 298 to 380 K reduced the contact-angle measurements by 17%, whereas increase in pressure increased the water wettability of kerogen. The results obtained from the MD simulations were in agreement with experimental results of kerogen wettability for Types II and III kerogen. The results were also compared against the water-adsorption capacity of kerogen at reservoir temperature/pressure conditions, which indicates that kerogen surface with low water contact angles had higher water-adsorption capacity and vice versa. The documented results and workflows contribute to improving formation evaluation of organic-rich mudrocks by providing quantitative information about wettability of kerogen. The outcomes of this paper can also potentially contribute to understanding the role of organic content and its geochemical properties in fluid-flow mechanisms, which can be used to predict water production in organic-rich mudrocks.

Integrated Evaluation of Chemistry and Mineralogy From Core and Log Measurements

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Various measurement techniques are available to evaluate chemistry and mineralogy at different scales, from X-ray diffraction and X-ray fluorescence on discrete core samples, through hyperspectral scanning of continuous core, to natural and neutron-induced gamma-ray spectroscopy logging. Each has its own strengths and weaknesses and they should not be used in isolation. However, due to a lack of appropriate workflows and methodologies, the different measurements are typically not integrated and links between them are qualitative at best. This paper describes a framework for quantitatively integrating multiple measurements at multiple scales to allow improved evaluation of mineralogy and chemistry.

At the discrete core, continuous core, and log scales, chemistry and mineralogy measurements can be linked through element-mineral transforms and mineral-element transforms. These can be used to quality control less-reliable measurements, calibrate interpretation models, or estimate chemistry from mineralogy and vice versa. A workflow for integrated chemistry and mineralogy evaluation has been developed based on paired element-mineral and mineral-element transforms at each scale, with integration between the evaluations at each scale. More complete and reliable data acquired on discrete core samples are used to optimize processing and calibrate interpretation at the continuous core scale, and then in turn at the log scale. This leads to a robust interpretation model that can be applied in uncored intervals or wells, maximizing the value of the limited core data that may be available.

It has long been recognized that unconventional resources, particularly shale gas and liquids resources, display significantly more complex mineralogy than conventional sandstone and carbonate reservoirs. This complexity impacts evaluation of both reservoir and completion quality and accurately evaluating mineralogy is key to successful formation evaluation in unconventional resources. In many cases this has led operators to acquire large suites of core and log measurements, but the integration of mineralogy and chemistry data acquired from cores and logs has typically been weak, reducing the value of these expensively acquired data sets.

The workflow described in this paper provides a rigorous methodology for integrating these different measurements at different scales both to improve the accuracy of evaluating mineralogy and chemistry from the individual measurements themselves and to generate interpretation models that can be used to reliably extrapolate these results outside of cored intervals. The workflow will be illustrated using examples from several Australian basins.

Integrated Reservoir Characterization Using Unsupervised Learning on Nuclear Magnetic Resonance (NMR) T_1-T_2 Logs

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A novel interpretation workflow was developed using an automated unsupervised-learning algorithm on nuclear magnetic resonance (NMR) T_1-T_2 log data to quantify fluid-filled porosity and saturation, producible oil volumes, and to characterize matrix pore sizes and formation wettability. Core porosity and saturation measurements, scanning electron microscope images (SEM), rock-eval pyrolysis, wettability measurements and mercury injection capillary pressure (MICP) tests are compared with the NMR interpretation for calibration and validation.

Understanding fluid types and volumetrics is the key for reservoir characterization. The traditional static formation evaluation model based on triple-combo logs (density, neutron, resistivity and gamma ray) has been widely used to characterize formations to provide cost-effective answers of lithology, total porosity and water saturation. Nevertheless, the dynamic result from production often shows quite different water cut than total water saturation, because the static model cannot distinguish immovable hydrocarbons from producible oil. NMR T_1-T_2 log data show unique signatures of formation fluids, such as gas, immovable hydrocarbon, producible oil, immovable and free water. The NMR data also provide fluid and matrix properties, including fluid viscosity, pore geometry and fluid-pore interaction. However, due to the downhole environment and the resolution limitation of the logging tool, the signatures of the fluids are not always well-separated. It is challenging to visually separate the signal contributions of different formation fluids on T_1-T_2 maps.

An automated unsupervised-learning algorithm is implemented in the new workflow to separate different T_1-T_2 signatures of pore fluids for fluid typing and provides fluid porosities and saturations. T_1-T_2 signatures of separated fluids are used to characterize fluid mobility, pore sizes and formation wettability.

The new approach is successfully applied to multiple wells for a field case study to characterize the saturation and producibility of hydrocarbon and water, which routine petrophysical models are unable to distinguish. Results are corroborated with dynamic production data showing high free water and high residual oil. This is also validated by routine and special core analyses. Integration of NMR, MICP and SEM gives pore-body and pore-throat size distributions with body/throat ratio (BTR), giving better understanding of formation permeability. High T_1/T_2 ratio of the oil suggests that the formation is partially oil-wet. The wettability results from NMR are consistent with the core-wettability test and production results. Understanding which portion of a reservoir contains movable fluids impacts target zone selection and reserves estimation.

Lateral Landing Point and Hydraulic Fracture Design in Diyarbakir Basin, Turkey: An Unconventional Shale Oilwell Case Study

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This is the first unconventional reservoir evaluation in Diyarbakir Basin, Turkey for Türkiye Petrolleri Anonim Ortaklığı (TPAO). It is the first-time experiences learned from unconventional plays in North America have been successfully applied in Turkey to help the operator uncover a new play and determine reservoir and completion quality that was previously overlooked.

This case study presents how challenges associated to unconventional shale reservoir evaluation and limited data for formation evaluation were addressed. For petrophysics evaluation, challenges are low porosity, unknown formation water salinity, and uncertainties of estimating the kerogen volumes, which introduces uncertainties in the computed reservoir quality (RQ). For geomechanics evaluation, the uncertainties are acquiring accurate slownesses (vertical and horizontal slownesses), computing stresses and anisotropy parameter, which introduces uncertainties in the computed completion quality (CQ).

For the pilot-hole logging, The latest wireline technology and the latest unconventional workflows were used to compute the petrophysical properties, such as mineralogy, porosity, permeability, saturation and kerogen. XRD/XRF core test results were used to validate log-derived TOC and mineralogy volumes. With the borehole imaging tool, structural dip as well as natural faults and fracture intensity and orientation were identified. In-situ stress features were not present in this well and results were used from neighboring wells in the field. Advanced acoustic computations allowed us to observe several zones with stress-related anisotropy and intrinsic anisotropy. The information was input directly into the computation of geomechanics properties for fracture gradient determination. Gathering all formation evaluation from petrophysics, geology, acoustics and geomechanics interpretation, an integrated RQ-CQ analysis was done to identify the best lateral landing selection.

In the lateral well section, the logging-while-drilling (LWD) data were used to compute two quality factors, RQ-CQ for the completion design. The lateral well data were calibrated to the pilot-hole section and were validated to the core cutting data available in the heel section. The quality factors are critical to properly place the perforation and hydraulic fracture stages to have effective and optimum hydraulic fracture performance.

In conclusion, the pilot-hole evaluation provided good results for the best lateral landing selection. In the lateral section, using the RQ-CQ analysis an effective and optimum hydraulic fracture performance zones were selected.

Lessons Learned From Cross-Validation of Fiber Optics and Microsensor Production Logging Measurements in Unconventional Wells

Yegor Se, Chevron

The well design with long lateral section and multistage frac completion has been proven effective for development of unconventional reservoirs. Top-tier well production in unconventional reservoirs can be achieved by optimizing hydraulic completion models, which necessitates an understanding of flow behavior and hydrocarbon contribution allocation.

Historically, conventional production logging (PL) surveys were scarcely used in unconventional reservoirs due to limited and often expensive conveyance options, as well as complicated and nonunique inflow interpretations due to intricate and changing multiphase-fluid behavior. The assessment of the cluster performance gradually shifted towards distributed acoustic (DAS) and temperature (DTS) sensing methods using fiber-optic cable, which continuously gained popularity in the industry. Fiber-optic measurements were expected to generate substage resolution production profiles along the lateral, which characterize flow by individual perforation clusters and help identify optimal and suboptimal completion designs. Encapsulation of the fiber in carbon rods provided alternative conveyance method for temporary DTS/DAS measurement, which gained popularity due to cost-efficiency and operational convenience.

Recent development of microsensor technology greatly reduced the size and the weight of the PL toolstring and allowed adding PL tool to the end of the carbon rod, opening a mutually beneficial and innovative surveillance combination to assess cluster performance in unconventional reservoirs. Array holdup and velocity measurements across the wellbore revealed interesting patterns in multiphase flow behaviors, which could cross-validate and constrain DTS/DAS interpretation.

This paper summarizes the lessons learned, key observations and best practices from the unique four-well data set acquired in the gas-rich Duvernay shale.

Measuring Multiple Organic Matter Components in Organic-Rich Rocks Using Combined Techniques of Low-Field NMR and Advanced Programmed Pyrolysis

Z. Harry Xie, Humberto Carvajal-Ortiz and Thomas Gentzis, Core Laboratories, L.P.; and Paul Hackley, U.S. Geological Survey

It is of great interest to engineers and geoscientists to understand organic matter behavior (e.g., kinetics) as thermal maturity progresses, in order to determine the hydrocarbon potential of organic-rich source-reservoirs (liquid-rich unconventionals, or LRU). Although geochemical and spectroscopic methods have been routinely used for qualitative and quantitative measurements of organic matter, it is always attractive to have practical techniques that are nondestructive, inexpensive and less time-consuming.

Here, we present a combined laboratory technique, integrating both low-field (20 MHz) nuclear magnetic resonance (NMR) and advanced programmed pyrolysis (multiheating ramps, MHR), and organic petrography using reflected white and ultraviolet (UV) light microscopy to measure the “solid” components in LRU source-reservoirs, which are typically associated with kerogen, different types of bitumen, and sometimes heavy hydrocarbons.

In this study, samples were selected from thermally immature outcrops of the Upper Jurassic Kimmeridge Clay Formation in the UK and the Green River Shale Formation in the USA. The samples were artificially matured via hydrous pyrolysis at temperatures of 300, 330 and 360°C, respectively. The solid echo-pulse sequence was used to acquire the early-time NMR signals which represent rigid solid matter in rock samples that have short relaxation times of less than 20 µs. The NMR solid echo signals were fitted into a composition of a Gaussian function and two exponential functions to better describe NMR responses of source rocks with the shortest relaxation time of 12 µs. The Gaussian component in the NMR signal is the measure of rigid solids, which are typically associated with kerogen in the source rock. The same samples were analyzed using the advanced MHR-pyrolysis to reveal physically and chemically different petroleum fractions in the system.

The comparison results show that the amplitude of the Gaussian component measured by NMR strongly correlated with reactive organic matter (aka S_2) from pyrolysis. The NMR relaxation times of the solid portion are directly proportional to the thermal maturity determined by both organic petrography and programmed pyrolysis.

This study concludes that the nondestructive NMR method provides a complimentary and rapid way to study solid organic matter in conjunction with advanced pyrolysis methods. The combined techniques enable us to further study the organic matter behavior and hydrocarbon generating potential in LRU source-reservoirs.

Methodology to Make Quantitative Estimates of Variable Reservoir Wetting Properties in Unconventional Reservoirs Using Triple-Combo Well-Log Data

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In many unconventional oil-bearing reservoirs it is generally recognized that the system has mixed reservoir wetting properties. Part of the porosity system is water-wet and part is oil-wet. Unless specialized analytic techniques have been applied to rock samples, it has not been possible to define wetting characteristics. Additionally, there are no readily available methods to address the issue of fluid flow in mixed-wetting environments.

In previous publications, the authors described a technique to quantify effective organic porosity in the shale fraction, as compared with the effective inorganic porosity in the clean fraction, using triple-combo well logs. Porosity/resistivity crossplots were also presented to demonstrate the effective inorganic porosity is water-wet and the effective organic porosity is frequently oil-wet.

This publication expands on the prior findings to include examples where the effective organic porosity is interpreted to have mixed-wetting characteristics controlled by absolute values of organic porosity. The degree of wetting can be quantified, controlled by absolute values of organic porosity.

For unconventional oil reservoirs, careful examination of the porosity/resistivity crossplots for the effective organic porosity indicates that the data for water saturations less than 100% often align on nonlinear trends. In standard petrophysical analysis, linear alignment is interpreted to honor the Buckles relationship (porosity × irreducible water saturation = constant) and the slope of the data is a direct measure of the difference between the Archie cementation exponent (*m*) and the Archie saturation exponent (*n*). For the interpretation presented here, values of the changing slope can be calculated to define, point by point, the changing value of "*n*" ("*m*" is kept constant), to be used in calculations of water saturation. Profiles of "*n*" often show a consistent and gradual increase from about 2 (water-wet) to 3 (oil-wet) as porosity increases.

Examples from a number of unconventional oil-bearing reservoirs are presented. Some are unequivocally oil-wet in the effective organic porosity fraction (Bakken and Wolfcamp), and others are interpreted to be mixed-wet (Niobrara and Eagle Ford).

The results show that mixed reservoir wetting characteristics can be estimated from readily available petrophysical data. Implications as to fluid flow behavior are significant, as well as the history of organic porosity generation through time.

Permeability Measurements on Shales Using NMR Spectroscopy

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Oil-rich shale formations have gained a lot of prominence in recent years. A major challenge in modeling and predicting production behavior from liquid-rich shale reservoirs is the absence of reliable permeability or relative permeability values. We have created an experimental design to carry out steady-state liquid permeability measurements on shale plugs at reservoir conditions of overburden stress, pore pressure and temperature using liquid hydrocarbon fluids and brines, while monitoring their relative saturations in a high-field 3D-gradient equipped NMR spectrometer.

The experimental technique begins with carrying out as-received NMR scans on shale core-plug samples. Micro-CT scans are used to filter plug samples that have microcracks. These samples are then saturated with hydrocarbons, and/or brines through a combination of vacuum-assisted spontaneous imbibition, pressure and temperature. Following saturation, NMR scans are done to find the saturation of the hydrocarbon fluid in the sample. The samples are then loaded in an overburden cell that does not have an NMR signal. As the sample is brought up to reservoir conditions of overburden stress and temperature, hydrocarbon fluid is injected in the cell from one side of the plug while keeping variable backpressure on the other end. The saturation front of the injected fluid is monitored using 2D- and 3D-gradient NMR scans and the relative saturations of hydrocarbon and brine in the sample are accurately monitored using NMR T_2 and T_1T_2 scans. During the whole process, injection flow rates are continuously monitored along with upstream and downstream pressures to compute permeability. Hydrocarbon fluid permeability can also be measured after saturating or injecting brine in the sample. This measurement is similar to a relative permeability measurement as it helps in measuring liquid hydrocarbon permeability in the presence of water saturation. The same can be done to establish brine effective permeability by injecting brine through the plug. The novel process has also been used to perform liquid pressure falloff tests and shut-in tests on shale plugs in order to simulate actual field reservoir engineering PTA routines.

This apparatus is capable of going to 10,000 psi in confining pressure, 9,000 psi of pore pressure and temperatures up to 100°C. Flow rates as small as 0.0001 ml/min can be measured. These measured permeability values have been successfully used in reservoir simulation studies in multiple unconventional shale plays, such as the Wolfcamp, Eagle Ford, Vaca Muerta.

Petrophysics to Borehole Acoustics Transforms Using Machine-Learning Regression for Unconventional Reservoirs

Romain Prioul, Schlumberger-Doll Research; Edgar Velez and Irina Mikhaltseva, Schlumberger; and Charles Laupretre, Student

For unconventional reservoir stimulation and completion, the use of wireline and logging-while-drilling logs to optimize the position of stages and clusters to stimulate similar completion quality rocks has shown to increase the percentage of successfully producing clusters. However, the market forces are such that only few lateral wells in unconventional reservoirs have adequate suites of openhole logs.

In North America, the introduction of capture and inelastic GR spectroscopy combined with a new slim sonic through-the-bit or the acoustic scanning platform have enabled new formation evaluation opportunities in casedhole conditions, leveraging the fact that cased hole is outside of the rig critical path. While these tools provide new and superior quality measurements, lateral heterogeneities of the formation, slow velocity intervals, eccentricity of the casing, or cement job quality can affect the interpretation of the sonic data, and new quality control methodologies are necessary.

We have developed a methodology to relate petrophysical volumes to sonic moduli in data-rich pilot wells by using machine-learning techniques instead of traditional rock physics modeling. When successful, the approach allows to quickly predict sonic slowness and moduli from petrophysical volumes. The predicted sonic slownesses and moduli can then be compared with the measured ones to help guide the interpretation of challenging intervals. The machin- learning "petrophysics to borehole acoustics" transforms can also be used for other applications, e.g., filling the gaps of low-fidelity sonic log intervals in pilot wells, filling the gaps in lateral wells where large-diameter sonic tools are not able to reach the end of the well, extending mechanical properties estimation through the curve, and predicting sonic moduli from cuttings-based petrophysical volumes in a lateral well when logs are not available.

We explored different machine-learning regression algorithms, specifically SVM, and gradient boosting. Starting with a statistical analysis of the data to perform renormalization and feature enhancement, we found that a multivariate linear regression approach followed by gradient boosting on the regression error worked best to optimize results on the test set while keeping a control on the overfit within the error on the training set using the pilot wells data sets. The model was written as an efficient and easy-to-use Python script, providing a very fast engine (few seconds) to train, test, and apply the model.

We applied the machine-learning regression algorithms to build a relationship between petrophysical volumes and borehole acoustics in an unconventional reservoir from North America using one pilot well's wireline logs. It was then applied to two lateral wells where spectroscopy and sonic through-the-bit logs were acquired. We show that the predicted logs from petrophysical volumes can help identify intervals where sonic labeling is challenged by local conditions and guide the relabeling of the data. We also show how the choice of the pilot training data set intervals, narrow or large, affects the prediction of the sonic moduli and the interpretation. This technique has the potential to provide a quick and efficient quality control method for completion quality in cased hole unconventional laterals.

Petrotechnical Assessment and Productivity Evaluation in the Pimienta Formation, an Unconventional Resource In Mexico

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Shale plays in Mexico are considered some of the most important in the world, with estimated technically recoverable resources of 545 trillion cubic feet (Tcf) of natural gas and 13.1 billion barrels of oil and condensate, according to the Energy Information Administration (EIA). The development of gas-shale plays, in particular, represent a compelling value proposition for Mexico to meet the increasing demand while reducing the dependency on natural gas imports.

This study presents a petrotechnical assessment and productivity evaluation in the Pimienta formation, building petrophysical, geochemical and rock physics models by using a data set from one offset well characterized with complete logs, including natural gamma-ray spectroscopy, resistivity, density, neutron, dipolar sonic and caliper, mudlogging reports, drilling reports, thin section, porosity and permeability. Rock mechanics tests to obtain elastic parameters and uniaxial rock strength were also executed.

The petrophysical analysis indicated a median permeability of 1,600 mD in the lower interval, an average of 2,000 mD and in the upper zone of the Pimienta formation 100 mD. Water saturation with an average value of 24.5%, an effective porosity of 7.5% and a V_{clay} of 11.3%. The petrophysical analysis indicated the presence of three main facies: limestone, dolomite, and claystone carbonate.

The Pimienta shale went through three maturation windows (oil window, transition window between oil and gas, and gas window) as it dips south. The best zones represent intervals of high total organic content (TOC), around 2.4% (hydrocarbon > 1200 ppm) and kerogen Type II-III and high median brittleness of 67%. These zones are associated with a median Poisson's ratio of 0.25 and an average dynamic Young modulus of 40.6 GPa. The reduction of acoustic impedance in the range of 12 to 10 km/s*g/cm^3 is associated with a reduction of porosity, rock compaction and increasing clay minerals content. Four types of facies were identified: limestone, mudstone-wackestone of bioclasts, dolomite-wackestone, and packstone carbonaceous clay.

The production analysis was evaluated through 17 stages. It indicated that 65% are stages with high productivity and the median low productivity represented 35%. The study presents a discussion about data validation, integration and proposed workflow.

Relationship Between Pore Size and NMR T_2 Time for Unconventional Shales

Felipe Cruz, Ali Tinni, Carl Sondergeld and Chandra Rai, University of Oklahoma

Determination of pore-size distribution is often required during reservoir evaluation processes. Among the pore-size measurement methods, NMR is often favored because of being a nondestructive rapid method. A large number of previous studies have demonstrated the existence of a linear relationship between NMR T_2 time and pore size in rocks with micrometer-sized pores. However, in unconventional shale reservoirs, the reliability of the relationship between NMR T_2 time and pore size has been questioned in several publications.

To investigate the relationship between NMR T_2 time and pore size in nanometer-sized rocks, such as unconventional shales, we have acquired the NMR T_2 distribution, mercury injection pore-throat size distribution, SEM pore-size distribution and subcritical nitrogen gas-adsorption pore-size distribution on shale and ceramic samples. The NMR measurements were conducted on brine and oil-saturated samples. The ceramic samples had single pore sizes of 50, 80 and 150 nm. Prior to the aforementioned pore-size measurements, the samples used in this study were characterized by measurements of their mineralogy and wettability.

The analysis and integration of the data acquired during this study revealed that in unconventional shales, NMR T_2 distributions are largely affected by pore coupling. The present study demonstrates for the first time in the formation evaluation literature the existence pore-size-dependent surface relaxivity. These phenomena prevent the extraction of pore-size distribution from NMR T_2 distribution for unconventional shale reservoirs.

Reservoir Pressure in Tight Gas Formations From a Pressurized Core System

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At reservoir conditions in a dry-gas well, the fluid is outside of the pressure-temperature envelope and thus in a single phase. The reservoir temperature is above the cricondentherm (maximum temperature above which liquid cannot be formed regardless of pressure). Hence, the fluid can only be in a gaseous phase.

Estimation of reservoir pressure in tight gas formations, such as unconventional reservoirs, has been elusive and highly uncertain. Industry common practices analyze buildups and drawdowns with pressure transient analysis (PTA). An example of PTA is well testing. In tight gas reservoirs, however, this method is neither reliable nor accurate since a virgin formation will not yield enough gas due to its low permeability, typically on the order of micro- or nanodarcies.

Other methods include rate transient analysis (RTA) or dynamic data analysis (DDA), which consist of applying the fundamental flow-pressure relationships on production data, matching the responses to preexisting reservoir models with the use of type curves. This method is more robust than PTA, but requires substantial time to collect enough data points in tight gas formations

While drilling conventional formations, wellbore fluids (of density ρ_m) exert a hydrostatic pressure (P_{hyd}) that is greater than the reservoir pressure (P_{Res}) so mud filtrate (of density ρ_{mf}) invades the formation up to a radius of invasion (r_i). Mud additives quickly create a pseudo-impermeable layer (mudcake) that prevents the filtration process to continue. While the formation effective porosity (ϕ_e) determines the extent of the r_i for low- to high-permeable formations, it is the formation permeability (k) that controls the instantaneous or spurt-invasion process. Similar fluid dynamics occur while coring. The mud present in the borehole transmits the P_{hyd} to the formation that is exposed by the core barrel while coring, which would tend to displace gas (of density ρ_g) deeper into the formation. However, in extremely low permeability, and with a coring process in the order of minutes, the r_i in the core is negligible so that the mud filtrates only cover ("paint") the core, but does not penetrate it.

A tight gas formation is a system where the fluids do not flow or barely flow, and hence are static as opposed to dynamic. And, since in-situ water and rock compressibilities are easily calculated, the only change in volume is due to gas, which correlates with pressure and temperature downhole and in lab conditions. The current methods use dynamic measurements. Our paper describes a static measurement of a static system.

This paper will describe a method that uses the data from pressurized cores obtained downhole. The fundamental gas laws, P1V1T2 = P2V2T1 and PV = ZNRT, together with mixing laws for density of fluids are used to calculate the original P_{Res} in a dry-gas-bearing tight formation. The method relies also on fluid and rock compressibilities, and the estimation of porosity from wireline logs.

Revisiting the Concept of Wettability for Organic-Rich Tight Rocks

Sanchay Mukherjee, Son Thai Dang, Chandra Rai and Carl Sondergeld, University of Oklahoma

Wettability is an important petrophysical property, which governs irreducible fluid saturations, relative permeability, or fluid invasion damage. Unlike conventional reservoirs, which have relatively uniform pore surface properties, the concept of wettability is questionable in organic-rich tight reservoirs. These rocks do not only have nanoporous system, but also possess multiple pore types with different surface affinities. Previous studies have proved that unconventional reservoirs consists of three major pore types: inorganic (assumed to be water-wet), organic (assumed to be oil-wet, controlled by organic matter and thermal maturity), and mixed-wet (controlled by organic-inorganic distribution). The current study revisits the concept of pore-type partitioning in tight rocks. We propose and demonstrate a new workflow to evaluate pore partitioning, using four twin samples from the Wolfcamp B shale.

Firstly, all specimens were vacuum dried at 100°C for 6 days to remove the free fluids until the weight stabilized. Total porosity was estimated as the sum of irreducible liquid volume (using nuclear magnetic resonance, NMR) and gas-filled volume (using helium high-pressure pycnometer). Two of the specimens were injected with a single fluid (either dodecane or 2.5 wt% KCl brine): first, via imbibition for 5 days, followed by step pressurization (up to 7,000 psi) to achieve 100% saturation. The other twin specimens were subjected to multiple-phase injection: starting with imbibition, then counter imbibition, and finally step pressurization with the replacing phase. During this process, we used brine-then-dodecane and dodecane-then-brine as the injection fluids. All four samples were continuously monitored by both gravimetric and NMR measurements until equilibrium. Sample weights and pore fluid volumes allowed us to calculate the relative fractions of both replaced and replacing phases.

The new approach classifies the connected pore network in this formation into three categories: absolute oil-wet, absolute water-wet and mixed-wet; respectively occupy 50, 15, and 35% of total movable pore volume. Mixed-wet pore is defined as the pore fraction, in which both oil and water can replace air under capillary suction. Using conventional NMR wettability index, based on the difference between brine and oil intakes, this sample would appear to be oil wet. However, this is a misleading interpretation. It is important to emphasize that mixed-wet pores are not equivalent to the neutral-wet systems. We observe that the mixed-wet pores prefer brine over oil. During the counter imbibition, the samples initially imbibed with dodecane, tend to intake brine while replacing out dodecane. Whereas, the samples initially imbibed with brine and then counter-imbibed with dodecane, do not show a significant change in fluid concentrations; instead, it required 1,000 psi of injection pressure to reenter dodecane back into the pore system.

During well completion, water blockage will likely happen to this formation, which can be reduced by the addition of surfactants into frac-fluids. Moreover, the effect of water blockage is expected to reduce or evade out with more than 1,000 psi of drawdown. The workflow, thus is promising to describe the pore network in tight formations, where pore-type partitioning is a more reasonable concept than wettability.

Ultrasonic Angle Reflectivity in Complex Rocks for Improved Interpretation of Sonic and Ultrasonic Logs

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Hydrocarbon-bearing rocks are rarely homogeneous. Significant spatial variations in elastic properties are often observed in rocks due to depositional, diagenetic, and structural processes. In laminated sandstones, complex carbonates, or unconventional formations, elastic properties can vary on scales from millimeters to meters. Detection of inhomogeneities and their size in rocks is crucial because they play an important role in fracture propagation, height containment assessment, and for improving well/reservoir productivity.

Unfortunately, the vertical resolution of commonly used logging instruments does not allow the detection of small-scale changes in rock elastic properties, which may have a significant impact on macroscopic mechanical properties. Similarly, most laboratory techniques used to measure rock elastic properties fail to distinguish midscale anisotropy; results are subject to spatial averaging effects. We introduce a new experimental method based on continuous measurements of angle-dependent ultrasonic reflection coefficients to identify and quantify changes in elastic properties along the main axis of a core sample. This technique has several technical advantages over commercial scratch-test measurement systems.

The developed laboratory system collects continuous reflectivity data along the sample to detect small-scale anisotropy caused by the presence of thin layers or fractures and detects changes in rock elastic properties. At each point, data are acquired at various transmitter-receiver angles (pitch-catch acquisition mode similar to borehole ultrasonic measurements) and reflectivity curves are constructed by extracting the maximum amplitude and calculating its ratio to the incident amplitude. Acquisition at different incidence angles is possible without moving the sample and keeping the distance traveled by waves constant, thereby eliminating the need for geometrical spreading corrections. A bounded pulse/spherical-wave model is employed to calculate the reflection coefficient from the sample rather than the classic plane-wave model. We achieve this design by modeling a plane wave passing through a narrow slit (source) giving rise to a spherical wavefront, which we decompose into single plane-wave components and propagate them in the coupling medium using the phase advance technique. At the reflector, each plane-wave element is modified by the corresponding reflection coefficient. Reflectivity vs. angle measurements are then matched with numerical simulations to estimate rock elastic properties.

Ultrasonic reflection-coefficient measurements are successfully used to estimate dynamic elastic rock properties for a wide variety of rock samples, conventional and unconventional. For homogenous samples, values are within a 5% range when compared to those obtained with the acoustic transmission method. Experimental data show that reflectivity curves are highly sensitive to changes in rock properties, including attenuation. Measurements collected at different points along anisotropic samples show significant deflection from homogeneous behavior. The change in shape is used to detect rock anisotropy and estimate the properties quantitatively.

Because the resolution of borehole acoustic measurements is limited by the receiver array length, sonic logs are not sensitive to changes in properties when bed thickness is below 2 to 3 ft. Laboratory reflection-coefficient data enable detection of inch-scale anisotropy within the rock leading to improved assessment of formation elastic properties. Furthermore, continuous core measurements provide high-resolution reflection coefficient information which is complementary to conventional sonic and ultrasonic logs.

Unravelling the Understanding of a Complex Carbonate Reservoir With the Use of Advanced Logs Integration

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The Alta discovery was proven in carbonate rocks with high formation water salinity from the Permian age, which has gone through extensive leakage processes, where ~200 m of water rise has been noted. This poses intrinsic challenges and complexities regarding imbibition, uncertainty around the current free water level (FWL) and pseudo-fluid-contacts within the field. Considering the impact of the imbibition process on saturations and later to the estimation of reliable drainage curve from the capillary pressure, imposes a huge uncertainty on the hydrocarbon volume estimation. The petrophysical methods described accurately describe and quantify the formation fluid volumes, which are essential for understanding the fluid distribution across the field.

The work described in this paper addresses the risk associated with the evaluation of heterogeneous complex carbonate reservoirs as mentioned above and provides integrated new solutions. In contrast to conventional reservoirs, where presence of clay is the key challenge for getting a reliable saturation, the largest uncertainty factors in the reservoirs described here is the complex tortuosity (Archie's m and n) and the pore-size distribution, which varies considerably across the field. Hence, conventional resistivity based water saturation (S_w) equation did not comprehend the heterogeneity present in this carbonate reservoir unless guided by core data over the entire reservoir interval. During the initial evaluation, it was absent and not available over the entire reservoir interval, leading to unreliable water saturation. To overcome the heterogeneity challenges integration of advanced petrophysical logs, such dielectric, elemental spectroscopy was used while NMR bound-fluid data were analyzed with respect to deep- versus shallow-zone water saturation to foresee the fluid movability in the near-wellbore region and improving the understanding of the present day FWL in each well. The paper also shows an alternative method of estimating S_w from the sigma log, an output from the new generation spectroscopy. This serves as an additional validation to the estimated water saturation in a heterogeneous complex mineralogy formation.

The petrophysical interpretation of saturation using the Archie equation was quality controlled and cross-checked with a saturation estimation based on sigma, calibrated with the use of advanced measurements. This in combination with an early sign of mobile versus immobile hydrocarbon and the initial depth estimate of FWL improved the confidence of a more accurate capillary pressure drainage curve. This resulted in a good understanding of the imbibition process, which drives the present water saturation. The results generated with this integrated analysis were the key inputs for obtaining initial hydrocarbon volumes. It was of critical importance to know the initial estimates of hydrocarbon volumes and its drainage strategy for deciding commercially developing this field.

Water Saturation in Unconventionals: The Real Story

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Understanding the volumetric concentrations of hydrocarbon and water in a producing reservoir is a critical component of predicting well performance, designing well placement and field development planning. Core testing procedures and petrophysical models in unconventional shale reservoirs have always faced the challenges of establishing representative insitu water and hydrocarbon saturations. When using existing techniques of core-calibrated petrophysics, actual well production often varies significantly from expectations. These variations may include scenarios such as lower overall oil production or strong oil production that is accompanied by large volumes of produced water. This has a serious impact on the development of major U.S. unconventional plays such as the Eagle Ford, Midland Basin and Delaware Basin, among many others.

Core taken from these formations is the key to better understanding what fluids are present and in what quantities. It is well agreed upon that changes in pressure and temperature as rock is taken from downhole, handled and transported to a laboratory facility affect the contents of the pore system. This generally results in a varying amount of void space that is measured in the rock at the lab. Standard practice calls for treating this void space as previously occupied by oil that has volatized during coring operations, transport, and core testing. Therefore, estimates of hydrocarbon-filled porosity are made using the volume of oil extracted from the rock during testing (whether thermally or via solvents) combined with the volume of void space measured. Water-filled porosity is assigned a value based on the actual water measured from the rock during the extraction process.

However, fluid-phase behavior in nanopore systems is not very well understood. Pore wettability and permeability are also important factors that may control what fluids are lost from the system. Given these uncertainties, the assumption that void space is associated with volatized hydrocarbon does not hold true. Through updated procedures and use of new equipment, it has been shown that this void-filled porosity is usually occupied by formation water. The discussion will show several experiments validating this idea including: comparisons between preserved and non-preserved samples, retesting old core to measure fluid changes with time, nuclear magnetic resonance (NMR) scans, flow-through and fluid-imbibition studies among others. NMR T_1 and dielectric Logs will be used as a downhole water saturation reference. Additionally, log interpretations calibrated to this new water saturation will be shown and compared to well performance.

What Happens to the Petrophysical Properties of a Dual-Porosity Organic-Rich Chalk During Early-Stage Organic Maturation?

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We observe a set of significant petrophysical changes at a critical stage of organic maturation in samples measured from an organic-rich source rock (~10 wt% TOC). The observations are from the same Late Cretaceous, Ghareb formation that display various stages of organic maturation. The Ghareb samples were cored from five wells from two basins at depths from 300 to 1200 m. Among the observed changes at this critical stage of organic maturation: permeability decreases suddenly; steeper Klinkenberg-corrected gas permeability-porosity relationship; electrical resistivity increases sharply and displays non-Archie behavior; NMR T_2 distributions display two well-separated peaks rather than one.

To explain these observations, we analyze the maturity of the organic-rich chalk using Rock-Eval and LECO analysis of the samples before and after bitumen extraction to determine bitumen content and maturity. We find that at a critical T_{max} value for this Type IIs kerogen, the rate of bitumen and condensate generation increases sharply. SEM studies show that the chalk contains micritic pores coupled to mixed-wet intergranular meso-macropores, and the macropores contain the kerogen. The occurrence of the double peak in the NMR data indicates the shift from fast-exchange to slow-exchange and thus the isolation of the micritic pore space from the meso-macropore space for both molecular diffusion and fluid flow. In this dual-porosity system, enough bitumen is generated that the macropore surfaces become more oil-wet and bitumen blocks the entrances to the micritic pore spaces. Using NMR restricted-diffusion measurements with high-pressure methane, the tortuosity of the light-hydrocarbon-filled pore space becomes very large at the critical stage of organic maturation.

This interpretation of bitumen-blocked pores represents a consistent understanding of the different petrophysical responses, supports the development of improved petrophysical models for this dual-porosity organic-rich chalk, and has important exploration and production implications.

NEW BOREHOLE LOGGING TECHNOLOGY

A Fast ANN-Trained Solver Enables Real-Time Radial Inversion of Dielectric-Dispersion Data and Accurate Evaluation of Formations at Unknown Salinity

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Dielectric-dispersion measurements are increasingly used by petrophysicists to reduce uncertainty in their formation evaluation, especially when encountered with challenging environments, such as those with low or unknown salinity and or a variable rock texture. A new multifrequency, multispacing dielectric logging service, developed recently, uses a sensor array scheme which provides wave attenuation and phase difference measurements at multiple depths of investigation up to 8 in. inside the formation. With this improvement in depth of investigation also comes a higher likelihood of radial heterogeneity due to, for example, a spatially variable shallow mud-filtrate invasion. Meaningful petrophysical interpretation relies on accurate electromagnetic (EM) inversion, which accommodates this heterogeneity, and converts raw tool measurements to true formation conductivity and permittivity.

Forward modeling solvers are typically beset with a slow processing speed precluding use of complex albeit representative formation models. An artificial neural network (ANN) has been trained to significantly speed up the forward solver, thus leading to implementation and real-time execution of a multilayer radial inversion algorithm. This algorithm has shown to accurately resolve mudcake effects, invasion profile and true formation properties of individual layers.

The paper describes the development, training and validation of both the ANN network and the inversion algorithm. Example oilwell data sets are chosen from a field where waterflood is being successfully used for secondary oil recovery. Long-term injection of fresh water and use of fresh drilling mud brings several challenges when it comes to the petrophysical evaluation of new wells. Sands vary in quality and are encountered at either low or altered salinity. A complex reservoir structure makes it difficult to establish hydraulic connectivity across wells where water channeling is known to occur, often leading to bypassed oil. The dielectric measurement, using the new inversion algorithm, shows consistent success in identification of potential hydrocarbon zones otherwise not achieved by conventional resistivity-based saturation techniques.

A New Formation Tester and its Applications in Extreme Ultrahigh-Temperature Reservoirs

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As oil and gas exploration and production extends to the deeper buried reservoirs, and the challenges have been encountered to lower porosities and high temperature (HT). Several reservoirs in Asia region, such as the North Malay basins in the joint development area between Thailand and Malaysia, Baiyun Sag and Qiong Dongnan basin in offshore China, are considered to have the highest temperature gradient due to their geological settings.

This paper discusses a project for the new advanced ultrahigh temperature FT called “Merlin” to obtain both pressure profile and downhole fluid sampling with pumpout capability and downhole fluid sensor,s such as viscosity, density and resistivity, in such extreme HT environments. In addition, the Merlin tool dimensions (slim tool) have more clearance between the tool and formation, and therefore, less chance of having this tool get stuck in the slimhole logging.

The tool was first deployed in the North Malay Basin, since Q2 2018, five exploration wells were logged. The main objectives for this FT tool are to obtain formation pressure, identify reservoir fluid and quantitative CO_2 measurement zone by zone. For several jobs in the North Malay Basins, six pumpouts and fluid sampling were conducted. The results will be discussed operationally and technically, in terms of data quality and accuracy compared with surface analyses. In addition, this tool shows significant improvement operationally compared to the previous tool.

For deepwater offshore China, the client had been faced with challenges in exploxing a brand-new block, such as pore pressure distributions profile, reservoir quality, and extended logging period. The main objectives for the extreme FT are to obtain the formation pressure for drilling purpose, to understand the reservoir potential to optimize the perforation interval for DST tests, and to narrow the logging operation time window due to seasonal weather. The Merlin tool was proposed to log in this environment. This field example shows a significantly improved pretest and sampling capability in the lower mobility ranges in one run without sacrificing the testing efficiency, which the probe FT has not be achieved in the past. The effective time for a valid pretest can be achieved even in the range of mobility of 0.01 mD/cp, high pressure of > 11,000 psi, and high temperature of >180°C.

This paper discusses prejob planning and actual job execution results in both locations. The challenges of logging and lessons learned are addressed. This is the first attempt to evaluate reservoirs in the deeper and HT sections to properly understand reservoir fluids.

A New Method to Derive Contamination in Formation-Tester Samples Based on the Reaction of Caustic Filtrate Components With Carbon Dioxide

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The real-time determination of contamination levels with drilling-fluid filtrate in openhole formation-tester samples remains an insidiously difficult problem to track. To date, the most ubiquitous contamination estimation technique is trend fitting, which uses idealized fluid-flow behavior in an idealized formation through an idealized formation tester tool to hopefully derive an expected analytical behavior of that pumpout. Trend-fitting makes three assumptions that often prove to be false (1) that fluid properties will grade from filtrate to formation-fluid endmembers according to an idealized asymptotic trend, (2) that the asymptote of that trend is 100% clean formation fluid, absent of any filtrate, and (3) that the filtrate properties are known. In practice, real pumpouts are often difficult to describe by a model derived from an idealized case. The asymptote of the pumpout often represents a formation fluid contaminated with a nonzero steady-state level of drilling-fluid filtrate. Generally, the properties of the drilling-fluid filtrate are not known beforehand with enough precision to satisfactorily narrow the uncertainty of contamination estimation for sampling purposes.

New formation-tester carbon dioxide analysis technology brought new, valuable information to the sampling process by accounting for previously unidentified phenomena. Specifically, carbon dioxide may bind with the caustic components of drilling-fluid filtrate in a reversible manner or be consumed by them irreversibly. These caustic components of drilling-fluid filtrate can bind with carbon dioxide, thereby converting the carbon dioxide into a form that masks its chemical signature. This phenomena allows a unique opportunity to calculate drilling-fluid filtrate content in a sample independently of other methods, using only the principles of the chemical reaction. The proposed method further allows extrapolation of carbon dioxide reservoir levels. The same technique may be applicable to other reactive petroleum components, such as hydrogen sulfide.

A Preview to the Digital Component in the New Wireline Formation Testing Era

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Wireline formation testing (WFT) has been routinely used for reservoir characterization in the Gulf of Mexico. The significant impact that fluid composition has on designing and operating production and processing facilities for these complex reservoirs requires comprehensive fluid sampling during exploration and appraisal. Vertical and lateral connectivity, fluid compatibility when commingling to meet production targets, or asphaltene onset potential along the production flow path are examples of the need for thorough understanding of fluid property variations.

This case study combines the use of the newest generation of formation-testing platform with innovative workflows to acquire critical fluid data and refine the geological reservoir model in near real time. Conveyance difficulties foreseen in the S-shaped well suggested that the use of a shorter, lighter tool could increase the chances of success in a field where past key-seating episodes left few reliable alternatives for conveyance apart from drillpipe-conveyed logging. The application of the smart-sampling platform capabilities introduced important changes to the standard protocols used in these cases.

The increased cleanup efficiency of the new formation-testing technology enabled fast investigation of reservoir fluids at multiple depths with robust metrology for specific properties. The outstanding sample purity formed the foundation of advanced interpretation workflows. Using the high-quality fluid data, this case was used to perform a “proof of concept” of advanced interpretation workflows aimed at updating geological and fluid models in near real time once the downhole fluid analysis data become available at the end of each sampling station.

The formation-testing data and the near real-time answers expedited tailoring the completion of the well, which involved a nontrivial commingle decision. The fluid information also provided clarity for the geological model in a section of the field where the current seismic interpretation had shown uncertainty for the reservoir architecture in the downthrown block of the field.

The combination of new formation-testing hardware and short-cycle workflows makes this case study the first of its kind. The proof of hardware performance and data processing/interpretation capability cements the case for higher-density data streams and a shortened data life cycle. It serves as a preview of how digitally enabled formation-testing operations will be conducted in the future to provide new insights to reservoir understanding.

A Technology Update in Wireline Formation Testing

Thomas Pfeiffer, Simon Edmundson, Keith Nelson, Chen Tao, Hua Chen, Tamim Sawaf, Bo Yang, Lina Xu, Deo Dindial and Ashers Partouche, Schumberger

Wireline formation testing has evolved from discrete pressure measurements, introduced in the 1950s to measuring pressure gradients and fluid contacts since the 1970s. Technology introduced in the late 1980s and onwards added interval pressure transient testing, focused sampling, and downhole fluid analysis. Thirty years after that, this paper shows data examples of a recently developed formation-testing platform in a wide range of environments, and applications, that change how we plan, acquire, and use formation testing.

The dual-flowline architecture is designed to systematically address shortcomings of legacy technology, enabling focused sampling in the tightest conventional formations, as well as transient testing in high-mobility environments. Specialized prejob planning software evaluates conveyance options to minimize friction and borehole contact, estimates the available flow rate, compares cleanup performance of the different inlets, and simulates transient testing responses. During the operation, the platform uses hardware embedded automation algorithms that execute routine tasks in a consistent and highly efficient manner, leaving more time to the user to focus on data quality and value of the measurements.

Case studies from Mexico, Norway, USA and Oman demonstrate specific improvements in capability and performance. Field data from Mexico show focused sampling of gas condensate from a heterogeneous submillidarcy carbonate formation in a HPHT well drilled with oil-based mud. Controlled downhole decompression of crude oil in the flowline at a sampling station in Norway enabled real-time measurement of its bubblepoint pressure to within 0.4 bar [6 psi] of that measured in the laboratory. Another case study integrates accurate relative asphaltene gradients into an existing reservoir fluid study to prove reservoir connectivity across a large lateral distance in a producing field. Application of the dual packer subsystem demonstrates inflation within 4 minutes and pure oil samples within 90 minutes on station in a 1.5m-D/cP fractured basement formation. Data of focused water sampling in water-based mud in a low-mobility carbonate formation in Oman shows calibrated real-time formation water resistivity and salinity that matches surface measurements in a difficult multiphase flow scenario that identifies and characterizes the transition zone. The fine, low-rate pump control enables sampling just below reservoir pressure in Alaska, and a case from the Gulf of Mexico demonstrates the real-time impact of fluid properties on the understanding of reservoir architecture and completion design.

The presented examples highlight the impact of downhole automation, define the new operating envelope for formation testing in the most challenging environments, and highlight how the technology development leads to decision-making on a broad reservoir scale by providing contextual answers rather than an accumulation of facts and figures.

Analysis and Interpretation of Multibarrier Transient Electromagnetic Measurements

Sushant Dutta and Joseph Olaiya, Baker Hughes

Transient electromagnetic (TEM) or pulsed-eddy-current (PEC) tools offer salient advantages over conventional continuous-wave remote field-eddy-current (RFEC) tools for the inspection of multibarrier well systems. In this paper, we describe a state-of-the-art transient electromagnetic tool that is capable of inspecting up to five concentric barriers. We use this tool to illustrate the working physics of this technology and delineate its features and advantages.

The measurements result from a diffusion process, and therefore consist of time-decay curves. These curves exhibit space-time mapping, meaning that the signal at early time is sensitive to proximal barriers while the signal at late time is sensitive to proximal as well as distal barriers. This behavior enables the measurements to independently yield the wall thicknesses and/or metal loss/gain of multiple barriers. This technology yields extremely rich measurements because it uses wideband excitation. Through diverse modeled examples and field examples, we demonstrate techniques to maximize the information gleaned from these measurements. These techniques can complement automated inversion of measured data and are amenable to the use of machine learning and artificial intelligence methods.

Examples and features discussed include pipe collars, discrimination of internal (inner tubular wall) anomalies vs. external (outer tubular wall), tubular eccentricity and buckling or ovality. Key peculiarities often observed in multibarrier transient electromagnetic measurements are also discussed.

Application of Natural Fracture Characterization Using Stoneley-Wave Inversion in a Carbonate Reservoir

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Fractures can be used to increase the permeability of a formation for fluid flow; thus, it is important to characterize fracture networks that intersect the borehole and their fluid transmissivity for hydrocarbon production.

This paper describes a new workflow that uses low-frequency Stoneley waves to characterize natural fractures (their conductivity and borehole-washout volume) that intersect the borehole. These examples are from the presalt carbonates of the eastern Mediterranean Sea. Most features intersecting a borehole can be identified on borehole image logs with reasonable confidence, but fracture conductivity can only be verified with a pressure test. With sonic logging, the Stoneley-wave mode is essentially a low-frequency pressure wave traveling up the well. When the Stoneley wave intersects a conductive fracture, pressure is released into the fracture in proportion to the conductivity of the fracture. Analysis of the secondary Stoneley wave created by this effect, with the direct signal gives an estimate of effective fracture width or conductivity. By combining Stoneley fracture analysis with high-resolution borehole images, the truly open fractures can be located and confirmed in the formation while ignoring false signals from washouts, bedding changes, and sealed (nonproductive) fractures.

In most carbonates, fractures are filled with clay-sized particles, which increase the surface area for the conductive water. As a result, the borehole image log shows a conductive fracture, which can be misinterpreted as an open fracture. There is a small reflection due to the impedance change from solid, low-porosity carbonate to clay-sized mineralization in the fracture. 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.

In this paper, we describe a method of signal processing using the bandwidth frequency of 500 Hz to 4 kHz, separating out the unwanted direct arrivals using a frequency-domain algorithm, isolating and measuring the spectral energy of secondary arrivals, and then inverting for fracture width. Integrated interpretation of the Stoneley-wave results with borehole image log analysis is then done, with the result of separating the conductive fractures from nonconductive. The combination of the Stoneley inversion results with other openhole logs, like caliper, imaging, density, and slowness, provides borehole washout volume and helps identify the bedding effects. Depth-registration errors and optimal logging program design will be discussed.

Bed-Boundary Determination Using Joint Inversion of Deep Shear-Wave Imaging and Extradeep Azimuthal Electromagnetic Resistivity

Zhoutuo Wei, China University of Petroleum (East China)

Downhole deep acoustic and electromagnetic measurements, i.e., deep shear-wave imaging (DSWI) and extradeep azimuthal electromagnetic resistivity measurements (EM), have tens of meters detection range, enabling them to map geological structures at a reservoir scale. However, several problems occur when imaging the formation distributions using DSWI and EM individually, e.g., nonunique solutions due to the inherent azimuth ambiguity of DSWI and expensive time cost of EM data processing caused by the limited prior information.

We propose a joint inversion scheme to improve the reservoir mapping capability by using DSWI and EM data sets. First, the acoustic impedance image of bed boundaries around the borehole are obtained using a DSWI data set associated with prestack migration. These resulting boundaries serve as prior information for EM data processing. Accordingly, a series of possible formation models are established. Finally, using Bayesian inversion with Markov Chain Monte Carlo (MCMC) sampling, the true formation resistivity distribution is recovered rapidly. Combined with the determined resistivity bed boundaries, the DSWI 180° azimuthal uncertainty is eliminated simultaneously.

Numerical results performed over synthetic examples show that the joint inversion method of DSWI and EM is feasible. It not only improves the speed and accuracy of resistivity imaging, but also eliminates the inherent azimuthal uncertainty in DSWI data set. More specifically, taking a five-layered formation model for example, inversion of EDARM without the prior boundaries information requires more than 102 seconds per logging point. Based on multiple boundary distances to borehole extracted from DSWI, 16 possible inversion models are generated, leading to the increased complexity of resistivity imaging from EM. In each possible model, the invert parameters are reduced from 12 to 6 (i.e., resistivities of five layers and a relative dipping angle). Subsequently, the samples of MCMC are reduced from millions to several thousands. At least an order of magnitude improvement in speed over that previously offered using individual EM data is observed. From the above analysis, the resistivity and acoustic impedance images of the bed boundaries show their respective limitations. More importantly, we show how each data set contains complementary important information of these boundaries. While the images from individual DSWI and EM data sets may bias the reality, our joint inversion scheme leads to much improved geological boundaries.

Application of the joint-inversion scheme to the synthetic data supports the feasibility of mapping the reservoir using EM and DSWI. The attraction of the joint scheme is that different geophysical measurements are sensitive to different properties of the subsurface, so through joint inversion we significantly eliminate the null or blurred bed boundaries and achieve a true geological model. We believe that it has wider applicability to exploration and development of oil-gas field, even geosteering.

Calibrated Formation Water Resistivity Sensor

Thomas Pfeiffer, Mahmut Sarili, Cong Wang, Koichi Naito, Yoko Morikami and Hua Chen, Schlumberger; and Daniela Frese, Petroleum Development Oman

For every barrel of oil, we produce about three to four barrels of water. Water takes part in everything we do in upstream oil and gas. Water saturation directly affects hydrocarbon in place. In field development we inject water in the reservoir to sweep the oil out of its pores or to provide pressure support through the aquifer. In production, water can be source of corrosion and scaling in our pipes. Accurately measuring formation water resistivity goes beyond R_w as the basis of petrophysical well-log interpretation. In formation testing it is the key to tell different waters apart and to provide answers to some far-reaching questions around oilfield waters.

In this paper, we introduce a calibrated induction-based water resistivity measurement, configured to accurately measure water resistivity in the flow line of a formation-testing tool.

A case study of a low-permeability carbonate reservoir demonstrates the ability to differentiate formation water from WBM filtrate with low-resistivity contrast in the presence of mobile oil. Differentiating WBM filtrate and formation water in this difficult environment characterizes the transition zone and allows accurate interpretation of contacts, saturation and, ultimately, hydrocarbon in place.

The induction-based operating principle of the sensor eliminates electrodes and the associated fouling of the measurement due to coating or accumulation of particles on such electrodes. Instead of using electrodes, the sensor induces an electric current through a nonconductive, neutrally wetting flowline tube, that is proportional to the conductivity of the fluid column within that tube. The resulting voltage at the receiver coil is then converted into resistivity.

The calibrated sensor operates at temperature up to 200°C and pressure up to 35,000 psi. It measures a wide range of resistivity, from 0.01 to 65 Ω.m at less than 5% accuracy and a resolution of 0.001 Ω.m. This paper also discusses optimal sensor placement and operational techniques to achieve best results in multiphase flow environments.

The accuracy and resolution of the resistivity measurement allows direct comparison of guard and sample flow during focused sampling and provides differentiation even when the contrast between filtrate and formation water is low. The results may be compared to other sources of R_w or improve the accuracy of some alternatives to Archie, like dielectric dispersion.

Dispersion Asymptotic Analysis and its Applications in Acoustic Logging

Yibing Zheng, Weatherford International

This paper presents a robust method for evaluating the output from acoustic well-log waveform processing by analyzing the asymptotic behavior of dispersion curves. It is a data-driven approach that helps improve the accuracy of formation slowness measurement and identifies any need for a dispersion correction.

In acoustic well logging, many of the waves propagating inside the borehole are dispersive, such as wireline dipole and LWD quadrupole waves for the determination of formation shear slowness, and leaky P wave for compressional slowness in soft formations. Only at low frequency does the speed of these waves approach the true formation value, the wave speed being slower at higher frequencies. Slowness processing can therefore be influenced by strong high-frequency waves, resulting in measured slowness values greater than the true formation values.

The new method determines whether a dispersion curve is asymptotic to the true formation slowness by calculating the coherence of the slowness at each frequency interval of the dispersion curve to indicate the level of the velocity dispersion. This coherence indicator is then plotted against the averaged slowness within the frequency interval to show how well the asymptotic slowness is approached.

The method has been applied to wireline acoustic logging dipole waves in wells with both hard and soft formations, as well as to leaky P waves in soft formations. Results show that the method not only identifies the fastest waves in the data but also identifies where additional model-based dispersion corrections are needed. When the waveform's dispersion curve has a smooth approach to its true formation slowness, the asymptotic analysis shows a high value of coherence at that slowness indicting high confidence in the measured slowness. On the other hand, when the dispersion curve lacks the low-frequency asymptotic part, the analysis's low-value indicator suggests that a correction to the measured slowness is necessary.

The indicator generated by this method allows the quality of the formation slowness measurement to be assessed. Traditional data-driven dispersive QC methods can identify if the processed slowness is the slowest within the available wave energy, but does not assess the result's accuracy when the asymptotic part of the dispersion is missing due to lack of low-frequency energy. However, this method achieves both of these two objectives in a straightforward way.

First LWD Fully Triaxial Colocated Antenna Sensors for Real-Time Anisotropy and Dip-Angle Determination

Michael Bittar, Hsu-Hsiang (Mark) Wu, Jin Ma, Matthew Griffing and Clint Lozinsky, Halliburton

Electromagnetic resistivity tools measure the electrical properties of the downhole formation that are critical in determining the hydrocarbon saturation of a reservoir. In complex and heterogeneous reservoirs, both horizontal and vertical formation resistivities are required to obtain an accurate hydrocarbon saturation. For decades, wireline multicomponent induction-type of measurements have provided reliable determination of formation anisotropy, structural dip, and dip azimuth in wells with any orientation relative to the bedding planes. Logging-while-drilling (LWD) multiarray propagation resistivity tools have also demonstrated similar capability in deviated wells where the relative dip angle is between 45° and 90°. However, measuring anisotropy and dip angle in vertical and low-dip-angle wells still poses difficulties for LWD propagation resistivity systems because of the simple antenna structures employed.

This paper describes the development of a new LWD electromagnetic resistivity sensor equipped with an innovative, fully triaxial, colocated, tilted antenna structure. The tool, along with a unique processing scheme, enables the determination of horizontal and the vertical resistivity as well as the dip and strike angle of the formation while drilling in real time. The colocated sensor design is capable of acquiring multicomponent signals that are sensitive to formation anisotropy and structural dip in wells at any orientation. Modeling studies and several field trials have proven the design concept to detect these formation properties at any arbitrary wellbore deviation.

Test results from the new technology together with an azimuthally compensated LWD resistivity and a fully triaxial wireline measurements as reference are discussed. Very good comparison is observed in these trials, providing an independent verification of the tool performance. The azimuthal responses of the tool enable all multicomponents as well as 360° azimuthal resistivity and geosignals; allow a 3D resistivity mapping technique in real-time decisions at any wellbore deviation.

Formation Chlorine Measurement From Spectroscopy Enables Water-Salinity Interpretation: Theory, Modeling, and Applications

Jeffrey Miles, Laurent Mosse and Jim Grau, Schlumberger

Many methods of calculating water saturation require knowing the concentration of chlorides in formation water. The chlorides have a strong effect on the properties of water, and they impact saturation estimates based on resistivity, dielectric permittivity, and thermal-neutron absorption cross section. In this work, we introduce a new, direct, quantitative measurement of formation chlorine from nuclear spectroscopy, which enables a continuous log of formation water salinity within a limited radial depth.

Neutron-capture spectroscopy is sensitive to the presence of chlorine and would be a natural fit for measuring chlorine concentration, if not for the fact that the spectrum contains chlorine gamma rays from both the formation and borehole. The borehole chlorine background can be large and is highly variable from well to well and along depth. Historical efforts to derive water salinity from spectroscopy have relied on ratios of chlorine and hydrogen, which suffer from the presence of the borehole yield as well as hydrogen signal from hydrocarbons. A more reliable basis for salinity interpretation is provided by the direct use of chlorine, once its formation signal has been isolated. We partition the borehole and formation components of chlorine via two unique spectral standards. The contrast between the two standards arises from the fact that gamma rays undergo different amounts of scattering based on their point of origin. The shape of the borehole chlorine standard must be dynamically adjusted along well depth to account for environmentally-dependent gamma-ray scattering. We represent the borehole standard as a linear combination of two components, whose ratio is a continuously variable function of borehole size, borehole fluid density, and neutron transport in the formation. We validate our treatment of borehole chlorine with a database of over 2,400 simulated measurements spanning a diverse range of lithology, porosity, borehole size, and fluids. The final algorithm is derived from a combination of laboratory and modeled data. The formation standard describes the remaining chlorine signal, and its yield is readily converted into a log of formation chlorine concentration.

The chlorine concentration is useful for multiple petrophysical workflows. In combination with total porosity, chlorine concentration provides a minimum value for water salinity. A more advanced workflow uses a combination of chlorine concentration, organic carbon, and total porosity to simultaneously estimate water volume and water salinity. Chlorine concentration can also be combined with a selected water salinity to compute an apparent water volume for comparison with other methods. Finally, chlorine concentration allows calculation of a maximum expected sigma, which can be compared with the bulk sigma log to identify excess thermal absorbers in the matrix.

A potential limitation of the measurement is its radial depth of investigation, limited to about 10 in. for 90% of the signal. Therefore, the application of the method depends on formation permeability, the invading fluids, and the particular petrophysical workflow.

We first present the technique to identify the formation chlorine signal, supported by modeling and laboratory data. We then propose and illustrate workflows to interpret the formation chlorine concentration measurement in terms of water salinity.

High-Resolution Geological Interpretation in any Mud Type Using LWD Acoustic Borehole Image Logs

Stephen Morris, Morgane Bizeray, Florian Bender and Jeremy Titjen, Baker Hughes

Full geological interpretation is now possible from logging while drilling (LWD) in oil-based mud following the advent of high-resolution acoustic borehole imaging technology. The new service provides acoustic amplitude images of the borehole wall, in addition to borehole shape in a resolution that greatly surpasses previous capabilities in oil-based mud. The measurements include acoustic amplitude (this response is a mixture of petrophysical properties and borehole shape) and acoustic traveltime (showing the standoff of the borehole wall from the sensor). From the traveltime measurement, we calculate the borehole profile, which is shown in a tube plot and is used to project borehole shape properties. In water-based mud, the acoustic imaging tool can be run in combination with the existing high-resolution electrical imager. This combination is particularly useful for characterizing fractures with the dual resistivity and acoustic properties for a more confident interpretation. We show examples from wells with a range of geological complexity, including fractures, faults, geomechanical features, sedimentological variation and changes in borehole shape. Contrast between lithologies and structural features and the background is nearly equivalent to that seen in established images from LWD electrical measurements in the same environments.

Fractures with a high acoustic amplitude response show a marked contrast with the background lithology. In many cases, they reveal the processes of formation including cataclasis, intersections, age-determining relationships and impact on reservoir connectivity. The inclusion of borehole shape with the acoustic amplitude image gives a new value to fault interpretation, where post-drilling stress release can be interpreted from the shape of the borehole surrounding a fault. In this example, micro-slippage along a fault can be seen directly in the protrusion into the borehole of one side of the fault. Amplitude images are detailed enough to allow full image facies characterisation similar to that available from wireline image equivalents, but with the benefit of measurement of the formation before the buildup of mudcake. We show examples in clastic and carbonate lithologies that include primary sedimentary structures, secondary remobilization processed and diagenetic overprints. Sedimentary detail in coal beds is unprecedented, including variation in mineralogical components, bedding with compaction-related deformation and bioturbation.

Inversion-Based Interpretation of Borehole Acoustic Measurements Acquired in Invaded and Thinly Bedded Formations

Jingxuan Liu and Carlos Torres-Verdín, The University of Texas at Austin; and Elsa Maalouf, American University of Beirut

Borehole acoustic measurements are often used to calculate synthetic seismograms that correlate seismic amplitude data with acoustic logs. However, acoustic logs can be influenced by mud-filtrate invasion because they have a relatively shallow volume of investigation. In thinly laminated formations, the slowness measurements are also spatially averaged across the receiver array. Therefore, borehole acoustic logs need to be corrected for mud-filtrate invasion and spatial-averaging effects before conducting seismic-well log ties, especially when the available resistivity measurements confirm non-negligible invasion.

One method to correct borehole acoustic measurements for spatial-averaging effects and mud-filtrate invasion is to implement inversion-based interpretation methods where acoustic logs are forward modeled using two dimensional (2D) finite-element or finite-difference numerical algorithms. Simulations, however, demand large computational resources. To overcome the above difficulties, we develop inversion-based interpretation methods to estimate invaded and virgin-zone elastic properties via fast forward modeling of borehole acoustic modes using spatial sensitivity functions.

The fast forward model is implemented using two methods: The first method applies convolution between a 2D axial-radial spatial sensitivity function (which depends on both sonic instrument and borehole environment) and the true elastic properties of the layered and invaded formations where the 2D sensitivity is obtained by the product of the 1D radial sensitivity and 1D axial averaging functions. The second approach is to use a 1D (analytical or numerical) method to calculate the slownesses of individual invaded layers, and then applying the 1D axial averaging function to model spatial averaging effects.

We successfully verify the forward model with synthetic cases of thinly layered models where the radial invasion (fluid saturation) profile is obtained by simulating the process of mud-filtrate invasion and calculating the radial distribution of elastic properties with Biot-Gassmann fluid substitution. Forward modeled sonic logs are compared to slowness logs calculated using 2D frequency-domain finite elements and 2D time-domain finite differences, and yield relative errors below 2%. Furthermore, fast forward modeling decreases the computer simulation time by at least a factor of 1,000 compared to 2D numerical simulations.

Based on fast forward modeling, we develop a new two-step inversion workflow: In the first step, spatial-averaging effects on the acoustic measurements are mitigated to obtain layer-by-layer slownesses, while in the second step radial elastic properties are estimated from the calculated layer-by-layer slownesses and flexural frequency-dispersion curves. The new workflow delivers elastic properties of both invaded and virgin zones. Noisy synthetic and field examples are used to verify the reliability and efficiency of the inversion-based interpretation for various combinations of wireline and LWD instruments. We also consider the possibility of using time-lapse measurements (i.e., LWD plus wireline acoustic logs) to estimate radial and axial distributions of P- and S-wave slownesses. Elastic and petrophysical constraints are included to mitigate nonuniqueness and uncertainty due to noisy and low-sensitivity measurements. Comparison between inversion results and field measurements confirms the necessity and importance of reducing invasion and spatial averaging effects before developing correlations between seismic amplitude data and acoustic logs.

Modified Differential-Phase Semblance Method for Multimode Dispersion Estimation From Borehole Sonic Data

Ruijia Wang, Richard Coates and Jiajun Zhao, Halliburton

The sonic-wave fields produced by wireline and logging-while-drilling (LWD) dipole and quadrupole tools often consist of multiple borehole modes. Classic frequency-semblance methods used to process these data often lead to strongly excited modes overwhelming weak ones, or alternatively, to the erroneous detection of modes.

Conventional dispersio-processing methods can be separated into two groups: single- and multimode prediction algorithms. Single-mode methods are stable but only return one mode—the most energetic one. Single-mode methods include differential-phase frequency semblance (DPFS) and the weighted spectral semblance method. Multimode methods return multiple modes, but can be unstable in some cases. Multimode methods are often sensitive to unbalanced receiver arrays, poor data quality, and formation heterogeneity due to their assumptions on signal models in separating modes. In some extreme cases, for example, a formation with strong heterogeneity, multimode methods may yield erroneous ghost modes, or discontinuous dispersion curves for each mode.

Borehole modes with different slowness have different arrival times. Converting the data to the frequency domain can hide or encode these time differences in phase differences between adjacent frequencies. Conventional frequency-semblance approaches, which only use single frequencies independently from adjacent ones, ignore this phase information. Modifying the conventional methods to incorporate the arrival time of modes, or the phase difference between adjacent frequencies, facilitates multimode dispersion analysis.

This paper proposes an approach that employs the phase differences between adjacent frequencies for enhanced dispersion analysis. First, we select a target frequency and a frequency band around it. Then, we assume a slowness of the mode. Next, the phase difference of the waveform spectrum between the target frequency and a frequency in the selected frequency band is calculated from the predicted wave arrival time, which is obtained by integrating the traveltime of the waves over the propagation path with the assumed slowness and the related borehole parameters. In the next step, we tune the phase of the data by subtracting the calculated phase difference to ensure that all the data in the selected frequency band have close phase values to that of the target wave. Then, the tuned data are stacked to enhance the signals with the predicted arrival time and to mitigate noise and waves with different arrival times. Finally, we calculate semblance values based on the stacked data at different receivers by conventional approaches (e.g., DPFS). This process is repeated for different target frequencies and assumed slownesses to generate a 2D frequency-semblance map. We generate the final dispersion curves from the peaks on this map.

We validate the proposed approach with synthetic, laboratory, and field data. Results suggest the method can extract all modes from the sonic data. Additionally, the method provides reliable estimates, even if the number of receivers is small. Unlike the Prony and Matrix-pencil that are based on assumed signal models, the proposed approach is a modification of the single-mode differential-phase approach. Thus, it is more stable than other multimode algorithms and is less sensitive to unbalanced receiver arrays, poor data quality, and formation heterogeneity.

Nonlinear Acoustics Applications for Near-Wellbore Formation Evaluation

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We present some results from a research collaboration between Chevron Energy Technology Company and Los Alamos National Laboratory investigating the feasibility of applying nonlinear acoustics to formation evaluation. In this context, nonlinear acoustics refers to phenomena caused by the medium not honoring a Hooke's law type of behavior when subjected to intense acoustic excitation; the property of interest here is "beta," the coefficient of nonlinearity.

The generation of a scattered wave by noncollinear mixing of two acoustic plane waves in an acoustically nonlinear medium was first documented several decades ago. If selection rules specifying the frequency ratio of the two acoustic waves, their convergence angle, and the V_p/V_s ratio at their intersection are honored, the interaction between the two waves generates a third wave in a predictable direction, with frequency equal to the sum or difference between the two primary wave frequencies and an amplitude dependent on the nonlinearity at the intersection location.

If the two transmitted plane waves are oriented such that the third wave returns to the borehole, the phenomenon may be used as the basis for a logging tool measuring acoustic nonlinearity around the wellbore circumference, with a secondary measurement of the V_p/V_s ratio. Laboratory measurements supported by finite-element and analytical modeling confirmed that the mixing of two plane compressional waves generated a shear wave as predicted by the selection rules in a large Berea Sandstone block, confirming potential for a downhole tool with depth of investigation of about 30 cm.

Historic data show that nonlinearity in core samples is primarily caused by lack of mechanical integrity, for example microfractures in tight rock unconventional reservoirs or incipient near-wellbore failure while drilling. This prompts applications to fracture characterization and calibration of mechanical earth models.

The main practical challenge for a downhole logging tool is injecting powerful directional acoustic energy into the formation. We envisage an openhole tool making sequential station measurements using transmitters built into hydraulically controlled pads contacting the borehole wall. Noncollinear mixing is activated by maintaining the frequency of one transmitter constant while sweeping the other through the range of frequency ratios predicted by the selection rules, resulting in a received sum or difference frequency signal that rises to a peak and then falls. The peak signal amplitude indicates the coefficient of nonlinearity and is related to the lack of mechanical integrity caused by natural fractures or mechanical disaggregation. The frequency ratio at which it occurs is an indicator of the shear to compressional velocity at the location where the two beams cross. In this manner a map of the nonlinearity along or around the borehole can be envisaged.

The physics of acoustic nonlinearity is well established, and laboratory measurements have determined that the phenomenon of interest should occur and be measurable in the subsurface. Overcoming the engineering challenges would bring new formation evaluation insights unique to this measurement principle.

Quantitative Demonstration of a High-Fidelity Oil-Based Mud Resistivity Imager Using a Controlled Experiment

Ahmed Fouda, Baris Guner, Wei Bin Ewe and David Torres, Halliburton

The objective of this paper is to describe and validate a new approach for acquiring images that provide both qualitative and quantitative information of the formation electrical properties using a high-fidelity borehole imager (HFBI). This new multifrequency imaging tool is able to function at high frequencies (in the MHz range) in oil-based muds.

To allow for the quantitative interpretation of the HFBI data, a machine-learning approach was implemented. A full-wave electromagnetic modeling software is used to simulate a database that relates HFBI measurements to formation and mud properties, namely, formation/mud resistivity, formation/mud permittivity, and standoff. The machine-learning algorithm was trained on this database to obtain a regression function that provides accurate quantitative information on the logging environment of the HFBI. A test fixture that enables the change of the formation properties in different (known) mud environments allows for calibrating the database and verifying the accuracy of the learning algorithm.

The measurements from the HFBI are a function of the formation properties: resistivity and formation permittivity, frequency, and mud properties. The machine-learning algorithm can untangle HFBI data from multiple frequencies to obtain true formation resistivity images independent of the other parameters that affect the tool measurements. This, in turn, allows for providing not only true resistivity images at the wellsite, but formation resistivity in the near wall (i.e., R_{xo}). In addition, the algorithm provides calibrated formation permittivity values (and images), as well as a standoff image. The results have been validated in the fixture and with field logs.

This paper presents a methodology for the use of a machine-learning algorithm to obtain images and quantitative electrical formation properties at the wellsite that aid in the understanding of the formation.

New Technology Integration of Real-Time OBM Borehole Images and Formation Sampling While Drilling. Lessons Learned in Challenging Deepwater Gulf of Mexico Environments

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High-quality fluid samples and core are necessary for understanding the interaction between fluids and rock in a reservoir. Fluid samples can provide information about the charge history of the reservoir and the spatial distribution of fluids. Characterization of fluid properties drives production facility design and helps set production operating constraints. Information from fluid samples helps to address other issues, such as flow assurance, which can be particularly challenging in deepwater operations; not only due to the high thermal and pressure changes of the fluid from the reservoir to the surface, but also because of the high cost associated with a rig intervention to solve flow assurance problems.

Collecting fluid samples using wireline formation testers (WFT) is a mature process, whereas the use of sampling-while-drilling (SWD) tools is much less common. One reason preventing SWD from being used more frequently—like other logging-while-drilling (LWD) technologies—is the uncertainty of its performance when it is introduced into a new area. This concern is even higher in complex operations, such as those performed in deepwater Gulf of Mexico. When introducing SWD in a deepwater field, planning and execution of the operation should account for uncertainty associated with the new technology and incorporate lessons learned from prior WFT sampling operations performed in the same area. The planning process should start with building the business case and engaging key stakeholders to address their concerns. Modeling should be performed to understand uncertainties. Scenarios modeled during planning, along with real-time monitoring, greatly assist with identify potential problems that arise during execution.

This paper describes the planning and execution process applied for a deepwater Gulf of Mexico operation involving SWD performed in conjunction with real-time oil-based mud (OBM) borehole imaging. The process includes using decision trees to build the business case and modeling the SWD cleanup and sampling operation using available core and fluid data from offset wells in addition to the expected drilling parameters and downhole conditions. The process also includes modeling of OBM contamination effects on laboratory results of fluid properties necessary for evaluating and understanding flow assurance. The authors use experience and information available from WFT fluid sampling performed in the same reservoir over the past several years and compare SWD and WFT technologies from this experience.

Regarding the novel technology of OBM real-time images, this paper describes the planning phase, instrument configuration used, and challenges encountered with telemetry. It describes how real-time images assisted with probe placement during the sampling operation and how all of the available information was successfully integrated with the subsurface description.

Reservoir Structural Characterization at Multiple Scales Using Vertical Seismic Profiling, 3D Sonic Imaging From Dipole and Monopole Sources, and Wellbore Microresistivity Images: Case Study From Offshore Abu Dhabi, UAE

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High-resolution wellbore measurements, such as microresistivity images, are routinely used to define structural information, such as formation dip and azimuth, to compare with low-resolution seismic migration. The scale differences between microresistivity images and seismic images range from millimeters to hundreds of meters, which is then compared with vertical seismic profiling (VSP) data at tens of meters of scale and sonic velocities at 1-m scale. Sonic imaging techniques from both monopole and dipole sources can be further used to extend the volume of investigation around the wellbore as well as define true dip and azimuth of the formation extending 25 to 30 m into the reservoir.

When using the dipole source for sonic imaging and recording the single-receiver sensor data, we observe polarized shear reflections that present not just the linear and sinusoidal moveouts evident as a function of source-receiver offset and nominal receiver azimuth, but also a significant polarity signature that is a function of the reflected wave's particle motion direction. A variation of 3D slowness time coherence (STC) is presented that correctly processes these polarized shear reflections to determine the dip and azimuth of the reflector. We then demonstrate how this new 3D STC processing is integrated into an automated processing that locates and characterizes the reflected arrivals in the filtered waveform measurements and then maps the corresponding reflectors in 3D along the well track. Of particular note is how the automated processing with the new 3D STC variation resolves the 180° ambiguity of the reflected dipole signal noted by previous authors. This is particularly important when imaging or mapping formation structure in a deviated wellbore, because the single-sensor data can image both above and below the wellbore, compared with conventional modal decomposed dipole waveforms, where distinguishing top from bottom is ambiguous.

A case study is presented from offshore Abu Dhabi, in which an interbedded carbonate reservoir is examined with various acoustics measurements and microresistivity images. A detailed structural analysis is conducted using a walk-above VSP whereby the migrated image below the wellbore is used to compare with the sonic imaging results from azimuthal monopole and dipole sources. Migration images from the dipole shear clearly show subseismic scale layers when compared to the VSP migration. Structural dip and azimuth of these subseismic features provide detail 30 m into the reservoir.

Revealing Hidden Information; High-Resolution Logging-While-Drilling Slowness Measurements and Imaging, Using Advanced Dual Ultrasonic Technology

Matthew Blyth, Naoki Sakiyama, Hiroshi Hori, Hiroaki Yamamoto and Hiroshi Nakajima, Schlumberger; Adam Haecker, Continental Resources; and Mark G. Kittridge, Occidental Petroleum

A new logging-while-drilling acoustic tool has been developed with novel ultrasonic pitch-catch and pulse-echo technologies. The tool enables both high-resolution slowness and reflectivity images, which cannot be addressed with conventional acoustic logging. Measuring formation elastic properties in complex, finely layered, formations is routinely attempted with sonic tools that measure slowness over a receiver array with a length of 2 ft or more, depending upon the tool design. These apertures lead to processing results with similar vertical resolutions, obscuring the true slowness of any layering occurring at a fine scale. If any of these layers present significantly different elastic properties than the surrounding rock, then they can play a major role in both wellbore stability and hydraulic fracturing but can be absent from geomechanical models built on routine sonic measurements.

Conventional sonic tools operate from approximately 0.1 to 20 kHz and can deliver slowness information with approximately 1-ft or more depth of investigation. This is sufficient to investigate the far-field slowness values but makes it very challenging to evaluate the near-wellbore region where tectonic stress redistribution causes pronounced azimuthal slowness variation. This stress-related slowness variation is important because it is also a key driver of wellbore geomechanics. Moreover, in the presence of highly laminated formations there can be a significant azimuthal variation of slowness due to layering that is often beyond the resolution of conventional sonic tools due to their operating frequency. Finally, in horizontal wells, multiple layer slownesses are being measured simultaneously because of the depth of investigation of conventional sonic tools. This can cause significant interpretational challenges.

To address these challenges, an entirely new design approach was needed. The novel pitch-catch technology operates over a wide frequency range centered at 250 kHz and contains an array of receivers having a 2-in. receiver aperture. The use of dual ultrasonic technology allows the measurement of high-resolution slowness data azimuthally as well as reflectivity and caliper images. The new LWD tool was run in both vertical and horizontal wells and directly compared with both wireline sonic and imaging tools. The inch-scale slownesses obtained show characteristic features that clearly correlate to the formation lithology and structure indicated by the images. These features are completely absent from the conventional sonic data due to its comparatively lower vertical resolution. Slowness images from the tool reflect the formation elastic properties at fine scale and show dips and lithological variations that are complimentary to the data from the pulse-echo images. The physics of the measurement are discussed along with its ability to measure near-wellbore slowness, elastic properties and stress variations. Additionally, the effect of the stress-induced near-wellbore features seen in the slowness images and the pulse-echo images is discussed with the wireline dipole shear anisotropy processing results.

Revisiting the Fracture System in Austin Chalk With Recent Advances in LWD Borehole Imaging

Roda Bradley, Marty Krueger, Meredith Miranda and Thiago Correa, Conocophillips; Chandramani Shrivastava, Dzevat Omeragic and Yong-Hua Chen, Schlumberger

The presence of natural fractures in the Austin Chalk have historically played a very important role in exploitation of the hydrocarbon hosted in these unconventional reservoirs. Often, the fractures are observed, interpreted and characterized with the help of core and borehole images. However, for the wells drilled with oil-base mud or nonconductive mud, the options were limited to only e-line imaging. Often, running e-line logs comes with an increased risk in many drilling environments, more so in deviated and horizontal wells in development. A unique LWD technology of dual-physics imaging was deployed in the Austin Chalk recently to understand the fracture system across two different measurements.

The new technology consists of dual measurement of pulse-echo ultrasonic and electromagnetic apparent resistivity; and is deployed simultaneously at different frequencies to analyze the same features across different images. The amplitude, traveltime and resistivity images together help with the classification of open fractures against closed ones, and their possible morphology.

The study well showed different classes of fractures: resistive, conductive and partially conductive, in addition to the drilling-induced features and provided enough resolution to differentiate the tectonic fractures from possibly stress-induced ones. An additional classification of strata-bound fractures has been identified, these fractures were hitherto not characterized separately due to their limited presence on core in vertical wells, likely due to sampling bias or legacy images acquired with oil-base mud likely because of the borehole coverage limitation with e-line imagers. These fractures are strongly tied to a facies-scale mechanical stratigraphy overprint and it is believed that they could help with fluid flow if observed within the target interval.

An independent inversion technology for deriving resistivity was applied on the electromagnetic measurements for a more robust classification of open vs. closed fractures, in addition to regular measurements to further aid the characterization of the natural fracture system in the formation. This case study shows the application of novel measurements to characterize the fractures while drilling; thereby helping with optimal completion plans and further model optimization.

The Road to Achieving Business Value With Reflection Sonic Imaging

Brian Hornby, Kary Green, Amit Padhi and Jeremy Bader, Halliburton

Reflection sonic imaging has been around for decades. However, there are still open questions on range of application and what can be really taken to the bank to impact our business challenges. Imaging of near-borehole bed boundaries is well established; however, in many cases, the results simply reflect what we see from a borehole-wall imaging survey. Of bigger interest is seeing more complex geology away from the well that is not predictable by borehole measurements. Clear imaging of faults, overturned beds, and abrupt changes in structure has been demonstrated—all of interest to those hoping to understand the bigger geologic picture away from the well.

Beyond that, there is strong interest around imaging of fractures. This is a more controversial topic—here imaging of single fractures simply fails seismic imaging 101—which is that the wavelength of the incident wave, for example, a dipole-induced body-wave shear with a wavelength of ~3 m, is much greater than the size of the fracture, for example, 2 mm for a large fracture. Therefore, one may conclude that the fracture should be invisible to a signal of that wavelength. One can argue that if the fracture is truly a parallel-plate filled with fluid and with no part of the surface touching (unlikely, but for sake of discussion), then the shear modulus would disconnect at the fracture resulting in a large S-wave reflection. However, this ignores the instantaneous conversion of S wave to P wave in the fluid and back to S wave at the other side. It is clear that very large fractures, or perhaps a group of closely spaced fractures, may create a sufficiently large response so that quality images can be created. Therefore, the fundamental question is this—what size of fractures or cluster of fractures is needed to deliver reflected energy of sufficient quality so that useful images can be created away from the well?

To answer this question, we use numerical modeling (FDM) to simulate fluid-filled fractures parallel to a borehole, and examine the response of P- and S-wave incidents on the fracture or fractures for a range of fracture widths. Analysis of these data is used to understand the range of applicability for fracture imaging. In addition, we examine field borehole sonic data response, for both P and S waves, for conductive fractures intersecting a well. Quality control and detailed analysis are done in the time domain, and where useful arrivals are identified, Reverse time migration (RTM) imaging is used to create final images. Comparison of reflection sonic imaging results with borehole-wall imaging results are used to establish ground truth and consistency on imaged result and angle of features.

Finally, we discuss what we have learned so far in establishing the range of application for imaging complex geology and fractures, and discuss the way forward in terms of impacting our business.

Wireline Pressure Cores: Laboratory and Field Study of Pressure–Temperature–Volume Response Within a Closed Pressure Vessel

Don Westacott, Halliburton

Electric wireline pressure-core technology, first introduced to the E&P industry in 2013, provides wireline-conveyed large-diameter rotary core samples (1.5 -in.OD × 2.25-in. length nominal) obtained with accurate depth precision within a wellbore. Following the recovery of up to 10 rotary sidewall-core samples, the pressure vessel containing these rock cores is then pressure sealed downhole. Detailed laboratory analysis of recovered formation fluids and rock samples provides enhanced reservoir characterization information.

The wireline pressure-core technology system retains 100% of the rock and fluid samples within the downhole sealed pressure vessel. However, the pressure is not maintained and is reduced within this pressure vessel as the instrumentation is recovered from downhole conditions to surface. A principal factor in this pressure reduction is the temperature change/reduction from downhole borehole conditions to the surface. It is important to recognize that this pressure change is a complex function of reservoir properties including reservoir pressure, temperature, porosity, hydrocarbon saturation, hydrocarbon type, oil volume, gas/oil ratio (GOR), and rock bulk compressibility. The pressure vessel thermal characteristics, exclusion fluid compressibility, exclusion fluid gas solubility, and pressure vessel compensation piston displacement also play a role in pressure change from downhole to surface conditions.

This paper presents detailed laboratory experimental studies and field observations used to provide quantitative pressure, temperature, and volumetric response relationships with the sealed core pressure vessel. This data analysis and developed methodologies provide scientific determination of reservoir properties sealed within the pressure core system.

PETROPHYSICS IN BROWNFIELDS

Experimental Study on the Influence of Rock Fracture on the Relationship Between Water Saturation and Complex Resistivity

Baozhi Pan, Yuhang Guo, Ruhan A, Lihua Zhang, Boyang Wei and Weiyi Zhou, Jilin University

The fracture can be a good channel for oil and gas migration, which has a great influence on the permeability of the reservoir. Therefore, it is of great significance to identify fractures and get the characterization and physical properties of fractures for the prediction of oil and gas production.

In this paper, the water saturation S_w and complex resistivity of homogeneous and fractured rock samples in the middle and low frequency are measured by cutting the complete rock samples to make artificial fractures. The change rate of dielectric constant $I\varepsilon$ similar to the resistance increased rate IR is established. The electrical and dielectric properties of fractured rock are compared and analyzed. The experimental data show that there is no dispersion in the S_w -IR curve of the homogeneous rock sample, and there is a certain dispersion in the S_w-$I\varepsilon$ curve. Fractured rock sample: the wider the fracture width is, the higher the dispersion degree of IR and $I\varepsilon$, and the higher the dispersion point of IR corresponds to the water saturation value (S_{wc}); Fracture density has less effect on IR and $I\varepsilon$; when the fracture width is the same, with the increase of fracture angle θ (0° < θ < 90°), the larger the IR, the higher the dispersion degree of IR and $I\varepsilon$. Through the study of fracture electrical parameters, it can provide theoretical and experimental support for the research and development of complex resistivity, and then improve the reliability of reservoir fracture and oil-bearing identification.

Pulsed-Neutron Logging Technique to Detect Bypassed Oil and Edge-Water Encroachment in Complex Multilayered Reservoir in the Caspian Sea

Zhandos Zhangaziyev and Mohamed Hashem, Dragon Oil

This case study focuses on offshore brownfield in the Caspian Sea. The field is multilayered terrigenous sequence characterized by more than three kilometers of gas, condensate and oil reservoir with changing formation water salinity.

The conventional methodology adopted for producing stacked clastic sands has been to produce the deeper sands first, deplete these, and to then continue perforating stratigraphically shallower sands. This strategy is not without risk. The rotated flower structures and rapid burial history often mean there is high potential to miss potentially productive zones. This has a cost and production impact with additional infill wells, workovers, and near well sidetracks the result.

By better understanding reservoir heterogeneity and 'production baffles' present within the structures as part of an active surveillance program it is possible to produce a more robust model to optimize infill well production and existing well performance. To achieve this a continuous pulsed-neutron logging campaign is ongoing and this paper will demonstrate the added value the logging program brings to the field development in terms of production and reducing the number of inactive wells requiring recompletion.

The proposed case study explains the workflow and results of theextensive reservoir surveillance campaign performed with pulsed-neutron logging tools in different modes (capture, C/O, WFL modes). These data, combined with openhole and production logs, provided good information to understand the remaining potential of the field. Secondary gas cap expansion, edge-water encroachment, bypassed oil-bearing zones and current water saturation investigation allowed successful recompletion and intervention of inactive or low producing wells.

The abovementioned casedhole logging campaign resulted in significant oil production increase (more than 200%) and water rate decrease (30%) compare to initial results.

PDDA

Society of Petrophysicists and Well Log Analysts

Petrophysical Data-Driven Analytics

In 2019, SPWLA PDDA SIG established a scholarship ($1,000) to recognize and award academic researchers who demonstrate academic achievement and contribution to the field of applying data analytics to solve petrophysical challenges. After carefully reviewing the applications of more than 30 applicants, the SPWLA Education committee (an independent committee led by the SPWLA VP Education) selected Mr. Tianqi Deng as this year's winner.

Tianqi Deng is currently a PhD candidate in the Department of Petroleum and Geosystems Engineering and a Graduate Research Assistant in the Formation Evaluation Consortium Research Program at The University of Texas at Austin. He received his Bachelor of Science degree from China University of Geosciences (Beijing). He worked as an Intern for Aramco Services Company (Houston) and Quantum Reservoir Impact (QRI) as a petrophysicist in the summers of 2018 and 2019, respectively. He is also an officer of The SPWLA Student Chapter at The University of Texas at Austin.

His research interests include petrophysical data-driven well-log interpretation, machine learning, inverse problems and uncertainty quantification. He has published technical papers and conference proceedings in Petrophysics, SPWLA, IAMG, and SEG.

The SPWLA Education committee and PDDA SIG committee would like to thank all of this year's applicants for taking the time to apply for this year's scholarship award. We wish all of the applicants much success with their academic and research efforts.

List of PDDA-related publications by Tianqi Deng:

Deng, T., Xu, C., and Lang, X., 2019, Petrophysical Characterization of Vuggy Dolomite Reservoirs in the Kansas Arbuckle Formation Using a Neural Network Machine Learning Approach, presented at the 20th Annual Conference of the International Association for Mathematical Geosciences (IAMG), State College, Pennsylvania, August 10–16.

Deng, T., Xu, C., Jobe, D., and Xu, R., 2019, A Comparative Study of Three Supervised Machine-Learning Algorithms for Classifying Carbonate Vuggy Facies in the Kansas Arbuckle Formation. *Petrophysics*, **60**(6), 838–853.

Deng, T., Ambía, J., and Torres-Verdín, C., 2019, Fast Bayesian Inversion Method for the Generalized Petrophysical and Compositional Interpretation of Multiple Well Logs with Uncertainty Quantification, Paper FFFF, *Transactions, SPWLA 60th Annual Logging Symposium*, The Woodlands, Texas, USA, 15–19 June.

Lang, X., Sengupta, M., Xu, C., Deng, T., and Grana, D., 2019, Log-Facies Classification Using Expectation-Maximization, *SEG Technical Program Expanded Abstracts 2019*, 3161–3165.

Xu, R., Xu, C., Jobe, D., Jiang, J., and Deng, T., accepted, Integration of NMR and Conventional Logs for Vuggy Facies Classification in the Arbuckle Formation: A Machine Learning Approach, *SPE Reservoir Evaluation & Engineering-Formation Evaluation*.

Society of Petrophysicists and Well Log Analysts

Petrophysical Data-Driven Analytics

SPWLA 1st Petrophysical Data-Driven Analytics Contest
Call for Team Registration

Problem Statement

Compressional traveltime (DTC) and shear traveltime (DTS) logs are not acquired in all the wells drilled in a field due to financial or operational constraints. Under such circumstances, machine-learning techniques can be used to predict DTC and DTS logs to improve subsurface characterization. The goal of the the 1st Petrophysical Data-Driven Analytics Contest is to develop data-driven models by processing "easy-to-acquire" conventional logs from Well 1, and use the data-driven models to generate synthetic DTC and DTS logs in Well 2. A robust data-driven model for the desired sonic-log synthesis will result in low prediction errors, which can be quantified in terms of root mean squared error (RME) by comparing the synthesized and the original DTC and DTS logs.

You are provided with two datasets: Well 1 dataset and Well 2 dataset. You need to build a generalizable data-driven models using the Well 1 dataset. Following that, you will deploy the newly developed data-driven models on the Well 2 dataset to synthesize DTS and DTC logs. The data-driven model should use feature sets derived from the following seven logs: caliper, neutron, gamma ray, deep resistivity, medium resistivity, photoelectric factor and density. The data-driven model should synthesize two target logs: DTC and DTS logs.

Competition Timeline

Start Date:	March 1, 2020
Team Registration Deadline:	March 31, 2020 11:59 pm CST
Entry Deadline:	April 30, 2020 11:59 pm CST
End Date (Final Submission of Code Deadline):	May 7, 2020 11:59 pm CST

Registration

Please send your team name, team members, contact info, and affiliation to pdda_sig@spwla.org. The official competition website is https://github.com/pddasig/Machine-Learning-Competition-2020.

One Account Per Participant

You cannot register from multiple accounts and therefore you cannot submit from multiple accounts.

No Private Sharing Outside Teams

Privately sharing code or data outside of teams is not permitted. It's okay to share code if made available to all participants on the competition Github repository.

Team Limits

The maximum team size is five.

Submission

Your submission must follow the same format as the 'sample_submission.csv' file provided on the competition website, the final ranking is based on the RMSE score of the hidden dataset.

A blind test dataset from 20% of the hidden dataset is released for your evaluation, you may check your model performance based on this dataset as many times as you wish.

You may select up to three submissions for judging before the entry deadline, the highest score will be used for your rank.

You must submit your runnable code in a Notebook/JupyterNotebook format before the end date, any code submission with severe bugs or results in a different number from the data entry will not be ranked or awarded.

Competition-Specific Terms

Competition Title: Pseudo Sonic Log Generation
Competition Organizor: SPWLA – PDDA SIG
Competition Website:
https://github.com/pddasig/Machine-Learning-Competition-2020
Prize Policy: The top five winning teams will be awarded with prizes based on the final prize pool.

Novel and practical algorithms will be recommended for submission to the next *Petrophysics* special issue on PDDA.

Data Licensing

The data come from the VOLVE dataset owned by Equinor.
Data Access and Use: Creative Commons Attribution-NonCommercial-ShareAlike license.

Entry in This Competition Constitutes Your Acceptance of These Official Competition Rules.

The Competition named above is a skills-based competition to promote and further the field of data science. You must submit your registration to pdda_sig@spwla.org to enter. Your competition submissions ("Submissions") must conform to the requirements stated on the Competition Website. Your Submissions will be scored based on the evaluation metric described on the Competition Website. Subject to compliance with the Competition Rules, Prizes, if any, will be awarded to participants with the best scores, based on the merits of the data science models submitted. Check the competition website for the complete Competition Rules.

Pseudosonic Log Generation With Machine Learning A Tutorial for the 2020 SPWLA PDDA SIG ML Contest

Yanxiang Yu, Siddharth Misra, Osogba Oghenekaro, and Chicheng Xu

ABSTRACT

Compressional and shear sonic traveltime logs (DTC and DTS respectively) are crucial for subsurface geomechanical characterization and seismic-well tie. However, these two logs are often missing or incomplete in many oil and gas wells. In this tutorial, we applied the machine-learning algorithm and used seven "easy-to-acquire" conventional logs to predict the DTC and DTS logs. A total number of 20,525 data points (corresponding to distinct depths) collected from three wells were used to train regression models using machine-learning techniques. Each of the data points has seven features, which are the conventional "easy-to-acquire" logs, namely caliper, neutron porosity, gamma ray, deep resistivity, medium resistivity, photoelectric factor and bulk density, respectively, and two targets, which are the sonic traveltime logs, DTC and DTS, respectively. The objective is to develop regression models that can process the seven features and generate the two targets. Various data preprocessing and supervised-learning techniques from Scikit-learn toolbox are applied to train the regression models. Random forest (RF) regressor has the best performance in synthesizing DTC and DTS logs at R^2 score of 0.988. Finally, for purposes of blind test, the RF regressor is applied on the hidden dataset from a different well. The root-mean-square-error (RMSE) value achieved in the blind test is provided to the competition organizers for ranking our performance relative to other participants.

INTRODUCTION

Sonic traveltime logs contain critical geomechanical information for subsurface characterization around the wellbore. Often, the sonic logs are required to complete the well-seismic tie workflow or geomechanical properties prediction. However, due to budget control and operational issues, these logs are not always acquired and are run in limited number of wells. Other well logs, like gamma ray, resistivity, density, and neutron logs, are considered "easy-to-acquire" conventional well logs that are run in most of the wells. When sonic logs are absent in a well or an interval, a common practice is to synthesize them based on neighboring wells that have sonic logs and their subsurface properties from the conventional logs. See He et al. (2018, 2019) for additional details.

There has been an increasing excitement about applying machine-learning and artificial intelligence (AI) methods in the oil and gas industry. In this approach, the sonic log synthesis or prediction by processing conventional logs using machine-learning techniques is a perfect demonstration of the power of machine-learning application. Many free and open-source packages now exist that provide powerful additions to the petrophysists' or rock physicist's' toolbox. One of the best examples is scikit-learn (http://scikit-learn.org/), a collection of tools for machine learning in Python to compete the-machine learning process for this problem. Check Hall (2016) for more details. In this tutorial, we'll be using functions from this library and provide a machine-learning workflow to predict the DTC and DTS logs by processing conventional logs. The prediction models are trained by processing data from Well 1 data, and use feature sets derived from the seven conventional logs: caliper, neutron, gamma ray, deep resistivity, medium resistivity, photoelectric factor and density,. Then the model is used to generate the two targets, i.e., DTC and DTS logs, in a similar Well 2. The predicted values are saved in the same format as the given sample_submission.csv, and submitted together with notebook for judgement.

EXPLORING THE DATASET

The dataset we use comes from the Equinor Volve field data from the link [https://www.equinor.com/en/how-and-why/digitalisation-in-our-dna/volve-field-data-village-download.html]. We use Pandas library to load the data into a dataframe, which provides a convenient data structure to visualize and perform exploratory data analysis on the available logging data. For example, we apply the data.describe() function to gain a quick overview of the statistical distribution of the training data, as shown in Table 1.

```
>>> import pandas as pd
>>> df1 = pd.read_csv('train.csv')
>>> df1.describe()
```

Table 1–Statistical Distribution of the Original Training Dataset

	CAL	CNC	GR	HRD	HRM	PE	ZDEN	DTC	DTS
count	30143.000000	30143.000000	30143.000000	30143.000000	30143.000000	30143.000000	30143.000000	30143.000000	30143.000000
mean	-8.394576	-23.692615	38.959845	3.977690	1.547299	-17.446739	-20.229982	-54.891703	-9.737567
std	129.970219	157.142679	108.504554	365.112753	456.908969	149.083136	148.809506	372.858812	440.314119
min	-999.000000	-999.000000	-999.000000	-999.000000	-999.000000	-999.000000	-999.000000	-999.000000	-999.000000
25%	8.058350	0.122800	17.248750	0.717700	0.712050	0.053100	2.226700	66.304350	118.534350
50%	8.625000	0.193600	36.821800	1.623000	1.628100	4.941500	2.432200	78.355100	137.689300
75%	9.048850	0.337150	58.346150	3.158300	3.280600	7.856650	2.551350	107.022500	182.973150
max	21.064200	3490.158200	1470.253400	10000.000000	60467.761700	28.106400	3.259700	155.980300	487.438400

From Table1, we can see a total of 30,413 samples (data vectors) are loaded, and each of them consists of nine data columns: caliper (CAL), neutron (CNC), gamma ray (GR), deep resistivity (HRD), medium resistivity (HRM), photoelectric factor (PE), density (ZDEN), compressional traveltime (DTC) and shear traveltime logs (DTS).

Handling the Missing Data

"-999" is shown as the missing values in all features. To handle the missing values, we first replace all the values equal to "-999" to "np.nan", and then remove all the rows that contain the nan by using data.dropna() function. This is another quick implementation provided in the Pandas dataframe. After removing all the missing values, there are 20,525 data vectors left as shown in Table 2.

Identifying the Features and Targets

In this dataset, the first seven data columns are the features that are required for the desired machine-learning task, and the last two data columns are the targets. We extract the feature vectors and the associated target vectors from the training and testing dataset as:

```
>>> y_target = df1_data[:,-2:]
>>> X_feature = df1_data[:,:-2]
```

Splitting the Dataset into Training and Testing Datasets

A standard practice before doing any further data preprocessing and training the supervised-learning model is to separate the data into the training and testing datasets, where the testing set can be used to evaluate the generalization of the model in terms of overfitting or underfitting. Once the train-test split is performed, the test dataset should not be touched, to avoid information leakage from testing dataset to training dataset. The testing dataset should be used only for purposes of evaluation the generalization capability of the model. More information on this can be found in Misra et al. (2019b). In the code shown below, we randomly separate the training dataset to 80% training set and 20% testing set. There are several other ways of splitting the dataset as shown in the references.

```
>>> from sklearn.model_selection import train_test_split
>>> X_train, X_test, y_train, y_test = train_test_split(X_feature, y_target, test_size=0.2)
```

Outlier Detection

One of the findings from Table 2 is that the maximum values of all features are dramatically larger than their mean values, which indicates anomalies and outliers exist in the dataset. Therefore, some special treatments may be helpful to improve the performance of the model trained. Here, we haven't explored any other methods other than removing the missing values. We suggest that the contestants try their best to quality control the log data. More information on this can be found in Misra et al. (2019a).

Data Transformation Using Scalers

While many machine-learning algorithms assume the feature data to be normally distributed with zeros mean and unit variance, from Table 2, we can see it's clearly not the case with our training data. StandardScaler from sklearn.preprocessing toolbox is a handy function that can help to standardize the input data, and the following codes shows the standardization process. It is important to note that scaling should be performed first on the training dataset to learn the scaling parameters. Following that, the entire testing dataset should be transformed using the scaler that learned the scaling parameters from the training dataset. When the entire dataset is scaled at the same time, it will lead to data leakage

Table 2—Statistical Distribution of the Training Dataset After Removing Missing Values

	CAL	CNC	GR	HRD	HRM	PE	ZDEN	DTC	DTS
count	20525.000000	20525.000000	20525.000000	20525.000000	20525.000000	20525.000000	20525.000000	20525.000000	20525.000000
mean	8.426679	0.274416	49.889253	2.598719	5.835466	3.833792	2.410734	88.312221	182.051067
std	1.845912	3.062495	54.811017	3.465665	422.449589	4.375818	0.181713	23.542419	84.670122
min	5.930400	0.014500	1.038900	0.123600	0.134100	-0.023200	0.680600	49.970500	80.580400
25%	6.629100	0.120300	16.036800	0.810000	0.797300	0.049800	2.236100	70.423100	127.148800
50%	8.578100	0.187700	37.498000	1.814900	1.829300	3.287800	2.466500	79.695400	142.678500
75%	8.671900	0.329000	61.140700	3.337400	3.463300	7.061300	2.563700	102.482800	192.757800
max	21.064200	365.885000	1470.253400	206.718200	60467.761700	28.106400	3.259700	155.980300	487.438400

between the training and testing dataset. More information on this can be found in Misra and He (2019).

```
>>> from sklearn.preprocessing import StandardScaler
>>> scaler = StandardScaler()
>>> X_train_scaled = scaler.fit_transform(X_train)
>>> X_test_scaled = scaler.transform(X_test)
```

Handling missing values, train-test split, removing outliers, and data transformation using scalers and normalizers are standard steps involved in the data preprocessing before building the machine-learning model.

Training the Supervised Model

We now have the data ready for training a supervised regression model. Sklearn library provides many convenient functions for the regression model, LinearRegression is a good starting point that acts as baseline. Another baseline that is nonlinear in nature is provided by k-nearest neighbor regressor. The GridSearchCV method from sklearn.model_selection function needs to be used to ensure that the regression method is trained and evaluated on all the statistical variations in the training dataset so that we can find the most generalizable form of the regressor. GridSearchCV should be performed only on the training dataset. GridsearchCV performs hyperparameter optimization of *n* hyperparameters for each split out of the *k* total splits of the training dataset. If there are n hyperparameters and k-fold cross-validation is desired, then k*n models will be trained and evaluated on the various splits of the training dataset. R-squared (R^2) score is used as the scoring criteria to evaluate the best model. The code below shows few of the steps in training the RandomForestRegressor.

```
>>> from sklearn.model_selection import GridSearchCV
>>> clf = RandomForestRegressor(n_estimators=100)
>>> grid = GridSearchCV(estimator=clf, param_grid=param_grid, scoring='r2', cv=5)
>>> grid.fit(X_train_scaled, y_train)
>>> best_model = grid.best_estimator_
```

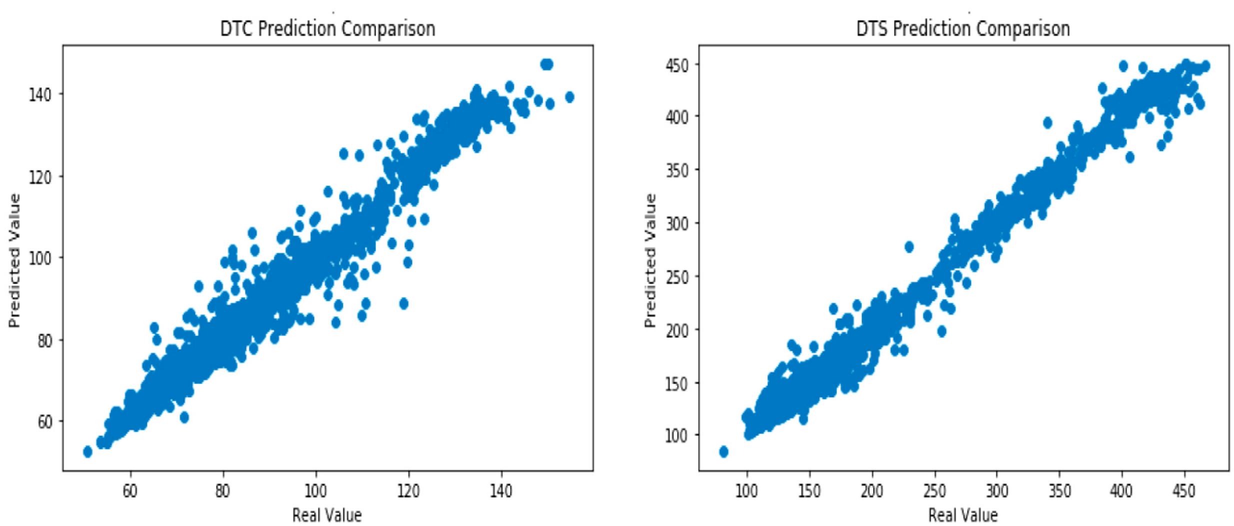
After training on the X_train and y_train, the random forest regression model needs to be evaluated on the test dataset. The random forest regressor exhibits a good performance on the test dataset, which in terms of R^2 is 0.988 and RMSE is 5.55. Figure 1 shows the predicted value versus the original value for the testing dataset, we can see a very good match.

Blind Testing on the Hidden Dataset

The random forest regressor is then applied to the hidden dataset for purposes of blind testing. Note that the blind-test data also need to be transformed with the same scaler generated by train dataset. After all the values are predicted, we'll save it to a csv file, and submit it to the committee for scoring, as shown below:

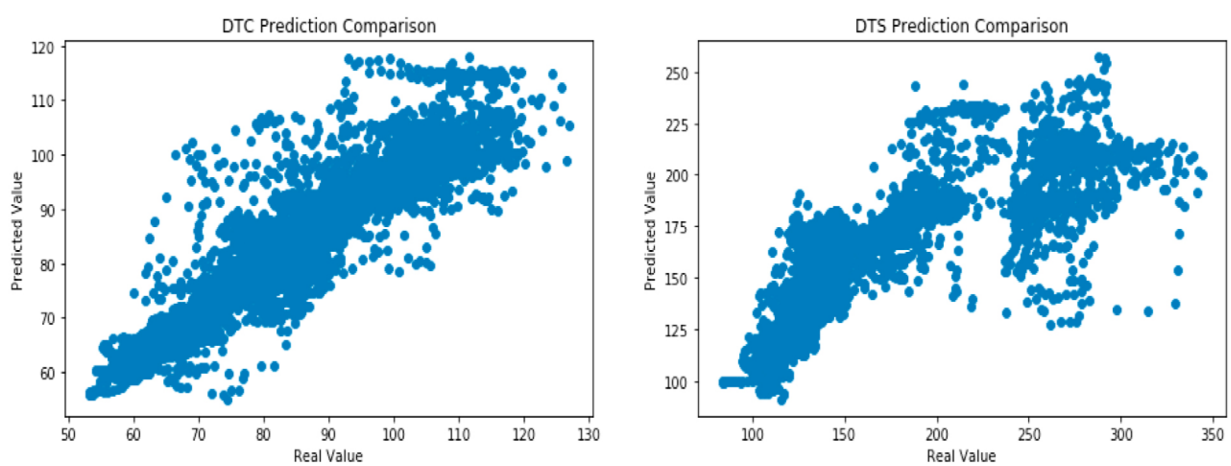
```
>>> df2 = pd.read_csv('test.csv')
>>> for col in df2.columns.tolist():
>>>     df2[col][df2[col]==-999] = np.nan
>>> df2.dropna(axis=0, inplace=True)
>>> df2_data = np.array(df2)
>>> x_trainwell2 = scaler.transform(df2_data)
>>> well2_predict = RF_best.predict(x_trainwell2)
>>> output_result = pd.DataFrame({'DTC':well2_predict[:,0], 'DTS':well2_predict[:,1]})
>>>      output_result.to_csv(path_or_buf='./submission.csv', index=False)
```

The comparisons between the predicted results with the true values in the hidden test dataset are shown in Fig. 2.



(a) **(b)**

Fig. 1—Predicted values of (a) DTC, and (b) DTS versus the true values on the testing dataset from the random forest model.



(a) **(b)**

Fig. 2—Predicted values of (a) DTC, and (b) DTS versus true values in the hidden test dataset

The RMSE score of 17.79 is achieved, and it is over three times larger than the performance on the test dataset. From Fig. 2, we can clearly see the DTS prediction is less accurate than the DTC prediction, especially in the zones of large DTS (slow formations). Therefore, it is suggested the pseudolog prediction should be limited to a certain stratigraphic interval instead of the whole depth.

CONCLUSION

In this tutorial, we demonstrate using a machine-learning workflow on a practical petrophysical problem: preparing a dataset, training and testing a regression model, and finally blind-testing (similar to the real-world deployment) the model on the hidden dataset. Libraries and open-source tools, such as scikit-learn provide powerful algorithms that can be applied to problems with few lines of code, which greatly helps to facilitate the research of data science in the petrophysics area.

In addition to the procedures mentioned above, many other methods may be applied to improve the performance and stability of the model, such as making special treatments to the anomalies and outliers, train different models for zones that shows very distinct DTC/DTS range, training other regression models and/or combining them.

For more details about the data and code, please check the Github repo: https://github.com/pddasig/Machine-

Learning-Competition-2020.

ACKNOWLEDGEMENTS

A note of thanks goes to Equinor for releasing the Volve dataset. We also thank the members of the SPWLA PDDA SIG ML Contest Committee Brendon Hall, Yan Xu, Michael Ashby and Weichang Li for their contributions.

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Misra, S., Osogba, O., and Powers, M., 2019a, Unsupervised Outlier Detection Techniques for Well Logs and Geophysical Data, Chapter 1, *in Machine Learning for Subsurface Characterization*, Elsevier, 1–37. ISBN: 978-0-12-817736-5.

West Texas Wildcatter and Oilman: Clayton "Clatie" Williams Jr. 1931-2020

In this edition:

West Texas Wildcatter and Oilman: Clayton "Clatie" Williams Jr.

1931–2020

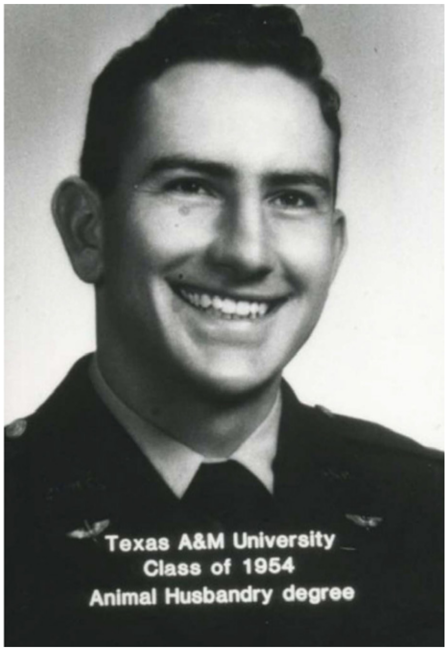
by Kanay Jerath

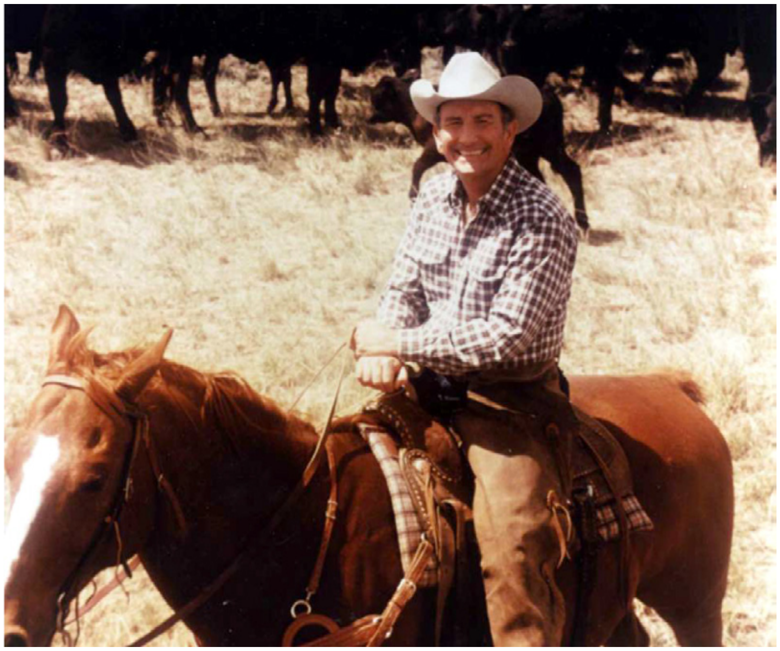
"I run my business like Christopher Columbus; when he left, he didn't know where he was going; when he got there, he didn't know where he was; and when he got back, he didn't know where he'd been. And like Christopher Columbus, I did it all on borrowed money!"

This is just one of the few quotes from Clayton Williams, who truly belonged to the dying breed of men and women known as wildcatters. The Permian basin has likely seen lots of them, but probably none as memorable, successful and remarkable as him. Born and bred in the West Texas towns of Alpine, Ft. Stockton and Midland, this Aggie had humble and rustic beginnings like a lot of people native to that area. A degree in animal husbandry, serving in the US Army, waiting tables or selling life insurance; none of these are probably the things one would associate with a wildly successful oilman. However, it seems there is no right way of getting into the oil and gas industry. It's all about the attitude, perseverance and hard work.

Clayton entered the oil business when he started working as an independent oil lease broker at the age of 26, in 1957. From his Coyanosa oil and gas discovery, he founded Clajon Gas in 1959, which went on to be the largest individually owned gas company in Texas when he sold it in 1988. He loved building pipelines and eventually built pipelines throughout Texas. It is well known in professional circles, that Clayton outworked everyone around him.

Not limiting himself to the oil and gas industry, in 1984, Clayton founded the first all-digital long-distance company in Texas, ClayDesta Communications. Because an actor was too expensive, Clayton starred in his own commercials that were filmed on his Alpine Ranch. He went on to be an industry leader in oil and gas exploration, production and transportation, Brangus cattle, commercial alfalfa operation at Fort Stockton Farms, oilfield services, telecommunications and diversify into banking and real estate. Along the way, he founded more than two dozen companies. Clayton Williams Energy owned 3,000 wells scattered over Texas, New Mexico, Louisiana, Alabama, Oklahoma and Utah and was a publicly traded





Clayton passed on February 14, 2020, at the age of 88 but left a legacy behind.

company on the New York Stock Exchange until he sold it in 2017. When Williams sold Clayton Williams Energy to Noble in 2017, the sale included 2,400 gross drilling locations in the Wolfcamp A, B and C zones. Clayton's outspoken leadership during Texas' economic ups and downs earned him respect as a survivor and a man with tremendous tenacity and foresight. A strong advocate of the industry, he found creative ways to get the regulators' attention, one time appearing before the Texas Railroad Commission in a dinosaur costume to make his point that if regulations weren't eased, he'd soon be "extinct."

Always a Texas Aggie, he continued to support his alma mater, Aggie football and contributed to many scholarship projects. He also found ways of giving back to the student community, by teaching a course in the business school at A&M from 1983–1989 and donating funds for the alumni center, named in his honor. Being human, Clayton's career and public life was not devoid of controversy, especially some of his statements while he was running for Governor of Texas. He eventually lost that race and never ran for public office again. Nevertheless, his success in the oilfield and the tenacity with which he pursued his life goals will always be an inspiration to the younger generation!

Content adapted from Midland Reporter Telegram, Wikipedia and Mr. William's online obituary.

ABERDEEN CHAPTER
(Aberdeen Formation Evaluation Society, AFES)

Recent Events

20 February 2020 – An informal evening bowling social event was held at Lane7

Upcoming Events

11 March 2020 – March midmonth evening lecture by 2019–2020 SPWLA Distinguished Speaker Nigel Clegg presenting "The Final Piece of the Puzzle: 3-D Inversion of Ultra-Deep Azimuthal Resistivity LWD Data."

18 March 2020 – PremierCorex lab/work shop tour.

02 April 2020 – Full-Day Seminar on "Core: The Most Valuable Asset in Your Reservoir." Call for abstracts is now out. Please see website for details (www.afes.org.uk).

05–06 May 2020 – Devex 2020, Aberdeen.

AUSTRALIAN CHAPTER
(Formation Evaluation Society of Australia, FESAus)

General News

FESAus, the Australian chapter of SPWLA combines the formation evaluation societies from around Australia predominantly FESQ as well as, New South Wales, Victoria and South Australia. Technical meetings are held in Perth on the second Tuesday of each month, with webcasts of the presentations available soon after for members from other states to view. Please visit www.fesaus.org for meeting information.

The new year commenced with Wes Emery beginning his term as President and Dr. Jean-Baptiste (JB) Peyaud as Monthly Meeting Coordinator.

2020 Committee members

President	Wesley Emery
Vice President	Vacant
Company Secretary	Vacant
Acting Treasurer	Wesley Emery and Adrian Manescu
Treasurer	Vacant
Website Coordinator/ Data Standards Focal Point	Diego Vasquez
Secretary/ Inter-Society Liaison/ Social Coordinator/ Special Events and Awards	Leanne Brennan
Monthly Meeting Coordinator	Jean-Baptiste
Membership Coordinator	Siobhan Lemmey
New Technology Forum Coordinator	Vacant
New Technology Forum Coordinator	Vacant
Education Group Leader	Vacant
Audio Visual Coordinator	Nigel Deeks
Sponsorship Coordinator	Vacant
Audio Visual Coordinator	Yang Xingwang
Newsletter Coordinator	Bronwyn Djefel
Queensland Representative	Marcel Croon
South Australian Representative	Matthew Pfahl
Victoria Representative	Matthew Durrant
NSW Representative	Harris Khan

Upcoming Events

March 2020 – Nigel Clegg will be joining us in March in Perth, Australia, as part of the SPWLA Distinguished Lecturer Series 2019–2020. His presentation is titled, "The Final Piece of the Puzzle: 3D Inversion of Ultra-Deep Azimuthal Resistivity LWD Data."

Australia Chapter March 2020 meeting speaker Nigel Clegg.

BAKERSFIELD CHAPTER
(San Joaquin Well Logging Society, SJWLS)

General News

The SJWLS continues to hold its monthly lunch and learn meetings at the California Resources Corporation conference room at the CRC Plaza, 900 Old River Road, Room B112 on the third Wednesday of the month.

The Bakersfield Chapter thanks Robert (Bob) Gales for his commitment to the Society and serving as our local Chapter President. Bob recently moved from Bakersfield to Houston to accept a position with Halliburton.

Katy Larson (California Resources Corporation) has accepted the position of Chapter President, and Benjamin Panepucci (Schlumberger) has accepted the position of Chapter Vice President.

The Bakersfield Chapter is working with California State University Bakersfield Petroleum Engineering students to start a student chapter. We are encouraging student involvement with a discounted student rate for meetings. As we develop our relationship with the university, we hope to offer scholarship opportunities to Petroleum Engineering and Geology students.

Recent Events

15 January 2020 – The speaker was Ron Balliet (Halliburton) and the topic of his talk was "Evolution of NMR Applications for Heavy Oil, Conventional and Unconventional Reservoirs." Ron had a very enthusiastic crowd present. Halliburton sponsored raffle prizes and we thank Halliburton for their donation.

SJWLS January meeting. Speaker Ron Baillet (Halliburton) (left) receiving speaker's gift from Chapter President Katy Larson.

February 2020 – Ken Haney (California Resources Corporation) discussed "CRC's Elk Hills CCS Project and Synergy with the Energy Future." CRC sponsored the cost of lunch. We thank CRC for their donation.

Upcoming Events

March 2020 – 2019–2020 SPWLA Distinguished Speaker Chelsea Newgord (University of Texas at Austin) will present her talk on "A New Workflow for Joint Interpretation of Electrical Resistivity and NMR Measurements to Simultaneously Estimate Wettability and Water Saturation."

BANGKOK CHAPTER

General News

The Bangkok Chapter of SPWLA holds Technical Meetings in Bangkok on the last Thursday of each month. There was no meeting in February 2020 as the regional conference AP2020 is scheduled for the first week of March 2020.

Meetings are fully sponsored for SPWLA Members. Nonmembers can attend free of charge with email registration prior to the meeting. Students are always free of charge.

Please visit https://www.spwla.org/SPWLA/Chapters_SIGs/Chapters/Asia/Bangkok/Bangkok.aspx for meeting information. Email: bangkok.chapter@spwla.org bangkok.chapter@spwla.org

2019 Chapter Committee Members

President	Andrew Cox
Technical Coord	Numan Phettongkam
Treasurer	Sirinya Maykho
Web Coordinator	Alexander Beviss
Secretary	Ronald Ford
Sponsorship	Ryan Lafferty
Student Liaison	Kruawun Jankaew
Member at Large	Greg Heath

Recent Events

30 January 2020 – Paul Johnson (Senior Petrophysicst, PTTEP) gave a presentation titled "Volcanic Petrophysics: Evaluation by Crystal Ball, a Fertile Imagination and a Calibrated Eyeball." Attendance was excellent for Paul's light-hearted presentation about the challenges and pitfalls of petrophysical evaluation of volcanic reservoirs. While no specific interpretation rules can be given for volcanics, a general approach was outlined.

Bangkok Chapter January 2020 meeting. Chapter President Andrew Cox (left) presenting speaker Paul Johnson (PTTEP) with the speaker's gift.

Upcoming Events

30 April 2020 – Raghava Tharimela (Technical Advisor, EMGS Asia Pacific) will give a presentation on "Reservoir Column Height and Saturation Mapping Using CSEM."

Special Announcement:
Due to concerns about the Novel-Coronavirus in Asia, the organizing committee has decided to postpone the SPWLA Bangkok Regional Conference until August 2020.

BOSTON CHAPTER

General News

The Boston chapter is delighted with the selection of Boston as the host city for the 2021 SPWLA Annual Logging Symposium. It is truly a privilege to host this gathering of the world's petrophysicists. An organizing committee has been formed, and work is well underway to plan for the event. Mark your calendars for May 15–19, 2021!

Recent Events

17 January 2020 – The Chapter hosted Zikri Bayraktar (Schlumberger-Doll Research) for his lecture titled "Machine Learning in Oil-Base Mud Microresistivity Imager Interpretation." The talk was engaging, well attended, and provoked many questions.

Boston Chapter January 2020 meeting. Zikri Bayraktar (Schlumberger-Doll Research) spoke on machine learning with OBM images. Pictured from left to right: Sherry Zhu (Boston Treasurer), Paul Craddock (President), Zikri Bayraktar, Lin Liang (VP Outreach and Technology), and Jeffrey Miles (Secretary).

SPWLA general members and Boston-affiliate members are invited to browse our chapter website http://boston.spwla.org for up-to-date information on our mission and events, including event details and registration.

DENVER CHAPTER
(Denver Well Logging Society, DWLS)

General News

Join us for the monthly DWLS meetings, which are held the third Tuesday each month, beginning in September and running through May. Meetings take place in the Mercantile Room at the Wynkoop Brewing Company in downtown Denver, Colorado. The networking social begins around 11:20 am, lunch is served at 11:45 am, and the technical presentation starts at noon. The cost for the DWLS luncheon is $25 and guests are welcome to attend. Visit the DWLS website at http://dwls.spwla.org to make your luncheon reservations, renew your membership, or join the society.

Recent Events

21 January 2020 – The luncheon speaker was Ridvan Akkurt (Schlumberger) who presented a talk entitled, "Machine Learning for Well-Log Normalization." The abstract and more information on Ridvan can be found on the DWLS website in the newsletters - http://dwls.spwla.org/Newsletters.htm.

DWLS January 2020 meeting. Speaker Ridvan Akkurt (Schlumberger).

18 February 2020 – Max Peeters (Petrophysical Consultant) gave a presentation titled "Clay Types Derived from Logs Using the Petrophysical Stepchild 'Photo-electric Effect' and Apparent Matrix Densities."

DWLS February 2020 meeting. Speaker Max Peeters (Petrophysical Consultant).

The DWLS monthly meetings are held the third Tuesday of the month, from September through May. Be sure to visit our online calendar to see what is scheduled for the upcoming speaker line up.

Upcoming Events

17 March 2020 – Daniel A Krygowski (The Discovery Group) will be presenting "Pattern Recognition in a Digital Age: A Gameboard Approach to Determining Petrophysical Parameters." Visit the DWLS website at http://dwls.spwla.org to make your reservations.

DWLS March 2020 meeting. Speaker Daniel A Krygowski (The Discovery Group).

The DWLS monthly meetings are held the third Tuesday of the month, from September through May. Be sure to visit our online calendar to see what is scheduled for the upcoming speaker line up.

FRANCE CHAPTER
(Société pour l'Avancement de l'Interprétation des Diagraphies, SAID)

SPWLA France is in the process of renewing its board. An extraordinary general assembly took place at the end of January and, unanimously, all delegates accepted a change of status and bylaws. SPWLA France is now running on fresh rules that better adhere to the SPWLA charter. Next step is the renewal of our board; SPWLA France is actively seeking candidates that want to run for election. Activities and technical sessions will restart soon with a program defined by the new board.

FORMATION TESTING SPECIAL INTEREST GROUP

General News

We are honored to announce that David Di Gloria from Exxon Mobil and Anup Hunnur from Baker Hughes had joined the FT SIG steering committee.

We completed our 2019 webinar series and got positive feedback from participants. It was a great opportunity to reach out to people from all continents. Thanks to those who participated!

Upcoming Events

07 May 2020 – The Formation Testing SIG annual technical meeting at BP Helios Building. It will be during the same week as the OTC. Speakers and the agenda will be announced by end of March in our SPWLA webpage.

HOUSTON CHAPTER

General News

The SPWLA Houston chapter holds monthly lunch seminars in different areas of the greater Houston area (Downtown, North and West). The networking session usually starts at 11:30 am followed by a speaker presentation at noon with a Q&A session at the end. Meetings usually end at 1 pm but speakers generally stay if attendants have questions or comments to follow up. Contact our chapter or check our website for more details about it: https://www.spwla-houston.org/.

Our website is being revamped and a completely new and modernized version will be available soon for all our members.

Recent Events

12 February 2020 – Downtown: 2019–2020 SPWLA Distinguished Speaker Bo Gong (Chevron) delivered a lecture titled "Estimating Net Sand From Borehole Images in Laminated Deepwater Reservoirs With a Neural Network." Her talk was engaging with a great introduction, it was well attended and provoked several questions and comments that were addressed by Bo. Thanks again to Bo and Chevron for their effort and sharing their experience and applications on borehole image logs! Thanks also to DeGolyer and MacNaughton for sponsoring the venue throughout our 2019–2020 season!

Houston Downtown February 2020 meeting. 2019–2020 SPWLA Distinguished Speaker Bo Gong (Chevron) delivering her lecture.

Houston Downtown February 2020 meeting. Javier Miranda, Houston Chapter VP (right) presenting speaker's gift to Bo Gong (Chevron).

NEW ORLEANS CHAPTER

Recent Events

16 January 2020 – Brian Horby (Halliburton) gave a presentation titled "Achieving Business Value Using Borehole Sonic Data."

20 February 2020 – Nishank Saxena (Shell) gave a presentation on "Digital Rock Technology for Accelerated RCA and SCAL: Application Envelope and Required Corrections."

Upcoming Events

20 March 2020 – TBD

16 April 2020 – TBD

04 May 2020 – We will hold our joint SPWLA/New Orleans Geological Society/Professional Landmen's Society of New Orleans Golf Tournament at Beau Chene Country Club in Mandeville, LA. Money raised will go to Children's Museum of New Orleans. Last year we were able to donate $5,000.

21 May 2020 – "Machine Learning in Oil-Based Mud Microresisitivity Imager Interpretation," Zikri Bayraktar (Schlumberger)

NUCLEAR LOGGING SIG

General News

The current sign-ups for the Nuclear SIG are in and 395 SPWLA members joined the SIG making us perhaps the largest. Thanks to all who joined and to those who have continued on this journey with us. The Executive Committee will develop plans for the SIG in consultation with members. A formal survey of the members to gauge areas of interest is being considered. Please stay tuned.

A gradual transition has been underway the past year with members retiring, changing jobs, etc. We express heartfelt thanks for their great service. Some on the Leadership team are staying on for another couple of years to help manage the large influx of members and to launch the SIG in a new trajectory.

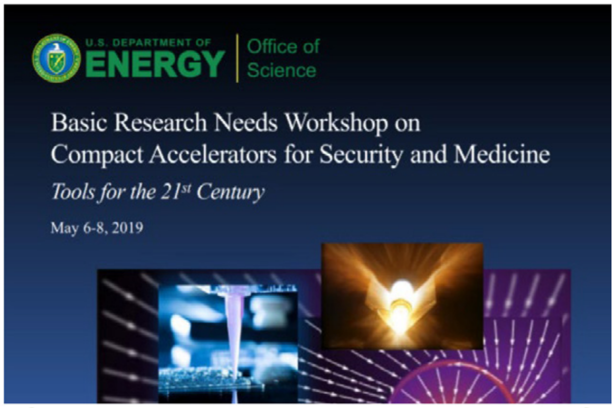
Nuclear logging was discussed in two major US government reports:

(1) A US Department of Homeland Security Report- Released on January 7, 2020

The White Paper assesses current radioisotope-based technologies used in eight applications including well logging and their nonradioisotopic alternatives. Several nuclear logging enthusiasts made online presentations to the ATWG. Ahmed Badruzzaman served on the ATWG.

Details in: https://www.cisa.gov/publication/non-radioisotopic-alternative-technologies-white-paper

(2) A US Department of Energy Report Released on January 24, 2020



The report focuses on R&D ideas on accelerators for the next 5 to 15 years in a variety of applications, including nuclear logging. Several nuclear logging experts participated in the workshop and helped prepare the report. Ahmed Badruzzaman served as a Working Group Colead of the two-day workshop held in Washington, DC. Industry participants and a couple of retired nuclear logging stalwarts commented on the first draft.

Details in: https://science.osti.gov/-/media/hep/pdf/Reports/2020/CASM_WorkshopReport.pdf

OKLAHOMA CITY CHAPTER

General News

The Oklahoma City chapter is now holding our monthly Luncheons at VAST in Devon Tower.

Recent Events

January 2020 –Sidi Mamoudou (University of Oklahoma) presented on "Hydrocarbon Production Characterization During Huff-n-Puff EOR Using NMR and Hawk Pyrolysis in Eagle Ford Shale."

February 2020 – 2019–2020 SPWLA Distinguished speaker Stacey Althaus presented her paper "NMR Measurement of Porosity and Density from Drill Cutting of Unconventional Tight Reservoirs."

Upcoming Events

10 March 2020 – Chelsea Newgord (University of Texas) will give a presentation on "A New Workflow for Joint Interpretation of Electrical Resistivity and NMR Measurements to Simultaneously Estimate Wettability and Water Saturation."

PERMIAN BASIN CHAPTER

General News

If you find yourself in West Texas on the fourth Tuesday of every month, please join us for either a luncheon at the Midland College in the Carrasco Room starting at 11:30 am or a social at a local restaurant starting at 6:00 pm. Guests and students are welcome to attend the networking and technical lunch meeting or social. For more details, visit us at SPWLA Permian Basin Chapter.

We are still looking for an interim president. If you have any suggestions please email us at permianbasin@spwla.org.

Recent Events

January 2020 – Angela Schwartz (Stratum Reservoir Labs) presented a talk entitled "Advanced Characterization of Mineralogy in Unconventional Reservoirs; Examples From Permian Basin and the STACK Region of Oklahoma." Her talk reviewed XRD advancements that reveal more information about the geologic complexity of unconventional assets. These techniques included modeling the iron content in the dolomite/ankerite solid solution series, creating an index for quartz crystallinity to identify cutting samples with chert or chalcedony, and quantifying micas and glauconite independently from illite for a more detailed rock analysis, and therefore a better interpretation. The talk was well received, promoting a healthy discussion about the laboratory methods of reproducibility and accuracy.

Permian Basin Chapter January 2020 meeting. Chapter Vice President Amine Chenaf (left) thanking our February speaker, Angela Schwartz, by presenting her with our speaker's award.

25 February 2020 – Hani Elshawai (Principle Technical Expert, Shell) gave a presentation entitled "Machine Learning for Directional Drilling Applications."

QATAR CHAPTER

General News

We are based in Doha and welcome all professionals and students interested in well logging and formation evaluation. The SPWLA Qatar Chapter promotes technical talks in close partnership with our sister and well-established Qatar SPE Section (QSPE).

All our events are emailed to members, and if you want to be added to the mailing list, please email us at QSPWLA@gmail.com or talk to any of the committee member!

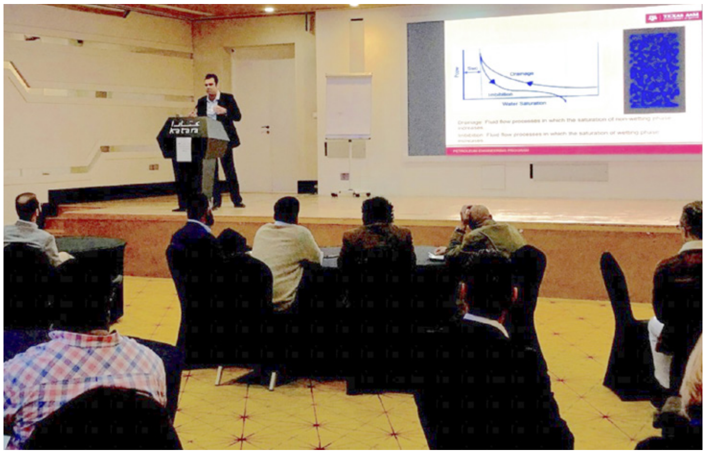
SPWLA Qatar Chapter is on LinkedIn! Follow us to stay updated about what is going on in the petrophysics community in Qatar and to hear about our chapter activities! Our website is up and running and can be accessed at https://www.spwla-qatar.com

In January, at the first technical talk of 2020, the committee had also a chance to meet and discuss the schedule of technical talks and the upcoming SPWLA Qatar Chapter Technology Day that is planned towards the end of February.

Qatar Chapter January 2020 meeting. Part of the SPWLA Qatar Chapter Committee. From left to right: Mohamed Fadlemula (TAMUQ); Mauro Viandante and Khaled Sassi (Schlumberger); Jose Oliveira Neto (Qatar Shell); Sharon Finlay (NOC); Ashok Srivastava (QP); Hussein Jichi (Baker Hughes); and Faisal Al-Mutawa (Qatargas);

Recent Events

27 January 2020 – Dr. Harris Rabbani (Postdoctoral Research Associate, Texas A&M Qatar) gave a presentation entitled "Analytical Pore-Network Approach (APNA): A Novel Method for Rapid Prediction of Capillary Pressure-Saturation Relationship in Porous Media." The talk was attended and was only possible due the generous support and partnership with the Qatar SPE Section.



Qatar Chapter January 2020 meeting. Dr. Harris Rabbani giving the technical talk.

16–17 February 2020 – SPWLA Qatar Chapter Technical Day. This is the first time we are holding the event and it was aimed at university students of Texas A&M University at Qatar. The event consisted of one afternoon of theory and basics on logging measurements (open hole and cased hole) followed by a morning on "go and see" for the students to have the possibility to view wireline logging tools, a wireline logging unit and LWD tools. The agenda is below., We would like to say thank you for all those involved who made it happen and the support received so far from TAMUQ University and Schlumberger.

2020 SPWLA Qatar Chapter Technical Day

Topic	Location	Start	Time (Mins)	End
DAY 1 (16-FEB-20)				
Arriving to TAMUQ	**TAMUQ**			
Welcome and Introduction		2:00 PM	10	2:10 PM
HSE Orientation/Presentation		2:10 PM	5	2:15 PM
Historical Perspective on Technology		2:15 PM	45	3:00 PM
Coffee Break		3:00 PM	15	3:15 PM
Basic Log Measurements, Tool physics & Applications (Resistivity, Nuclear)		3:15 PM	45	4:00 PM
Adavanced Measurements, Tool physics & Applications (NMR and spectroscopy)		4:00 PM	30	4:30 PM
Cased hole tools and applications		4:30 PM	30	5:00 PM
DAY 2 (17-FEB-20)				
Departure to Schlumberger base	**SLB**	8:00 AM	**60**	9:00 AM
Introduction/HSE		9:00 PM	15	9:15 PM
Welcome		9:15 PM	15	9:30 PM
Tour Start				
Wireline unit, Cables, Calibration			30	
Wireline tools (Open Hole)			30	
Coffee break			15	
Cased hole and production Logging			30	
Drilling (Motors/RSS), Measurements while drilling (MWD); Logging while drilling (LWD)			30	
Closing comments			15	
Going back to TAMUQ		**12:00 PM**	**60**	**1:00 PM**

SOUTHWEST CHINA (SPWLA-SWC) CHAPTER

Recent Events

04 January 2020 – The 2019 Chapter Workshop and the celebration of the 80th anniversary of well logging in China were held in Chongqing. More than 40 members from four universities and three companies attended the event. A meeting of the Chapter Board for December 2019 was also held.

The workshop, which was hosted by SPWLA-SWC, was organized by Chongqing University of Science and Technology (CUST), PetroChina Southwest Oil and Gas field Company Chongqing Gas Mine, and co-organized by the University of Electronic Science and Technology(UESTC), Southwest Petroleum University (SWPU) and Chengdu University of Technology (CDUT). All executive members of the chapter, staffs and students from the Chongqing University of Science and Technology (**CUST**), CNPC Logging Southwest branch, and Chongqing Gas Production Plant attended the workshop.

Professor Fuqiang Lai, Director of the Institute of Petroleum Geology at the Chongqing University of Science and Technology chaired the workshop. Professor Hua Wang at the University of Electronic Science and Technology, President of SPWLA Southwest China Chapter delivered an opening keynote speech on the development of logging technology worldwide and those in China over the past 80 years. Professor Wende Yan, Vice Dean of the School of Petroleum and Natural Gas Engineering at the Chongqing University of Science and Technology delivered a welcome speech and introduced the history, education and research situation of the school.

SPWLA-SWC January 2020 workshop. Some of the attendees of the 2019 SPWLA-SWC workshop in Chongqing.

SPWLA-SWC January 2020 workshop. Professor Hua Wang, Chairman of SPWLA-SWC Chapter, introducing the history and development of logging technology worldwide over the past eight decades.

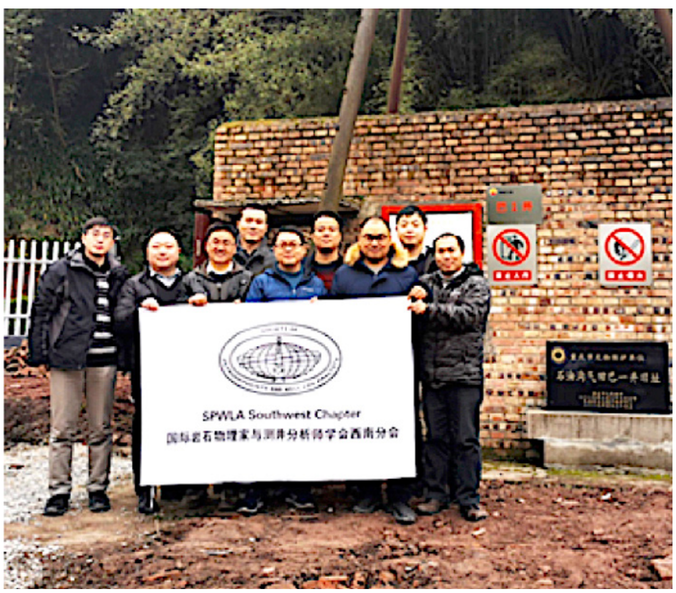
SPWLA-SWC January 2020 workshop. Professor Wende Yan, Vice Dean of the Petroleum and Natural Gas Engineering College at the Chongqing University of Science and Technology delivered a welcome speech.

During the technical sessions (see the agenda below), the invited experts and scholars delivered presentations on the topics of rock physics, logging and reservoir engineering. They shared the latest research progress and application results and had animated discussions with the participants.

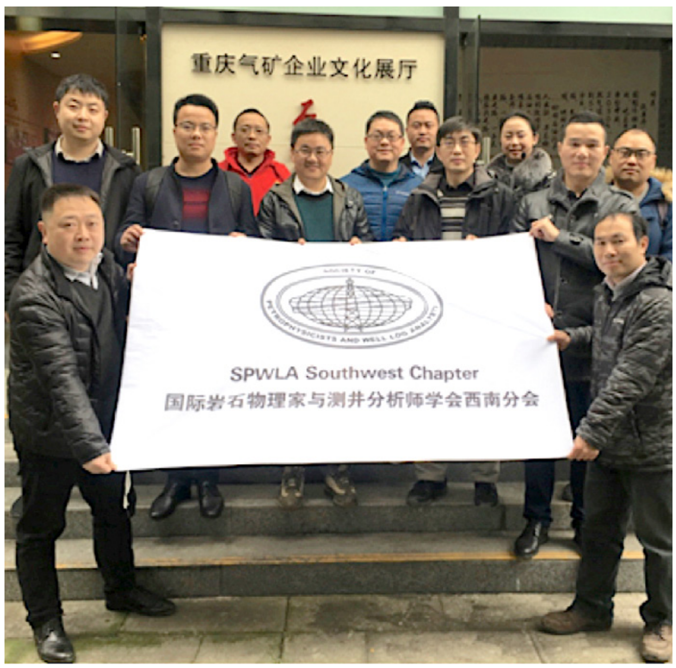
Agenda of the 2019 SPWLA Southwest China Chapter Workshop, January 4, 2020, Chongqing University of Science and Technology

No.	Time	Topic	Speaker	Institution	Chairperson
1	9:00–9:30	Status of SPWLA-SWC and the history of logging technology worldwide and in China over the past 80 years	Hua Wang, President of SPWLA-SWC	UESTC	Fuqiang Lai
		Borehole Acoustics and Rock Mechanics			
2	9:30–9:55	Shear-wave attenuation extracted from dipole acoustic logs	Qiaomu Qi	CDUT	Fuqiang Lai
3	9:55–10:20	Stress sensitivity of reservoir rocks	Wenlian Xiao	SWPU	
4	10:20–10:55	Full waveform method for cement bond evaluation	Hua Wang	UESTC	
		Tea break			
		Production Logging			
5	11:05–11:30	Laboratory Experiment equipment of LWD formation tester	Xinming Wang	UESTC	Yaojun Wang
6	11:30–11:55	Dynamic monitoring for the production in horizontal wells	Meng Chen	SWPU	
7	11:55–12:20	Long-term monitoring technique in intelligent wells and fiber sensing	Jianping Bai	CUST	
		Lunch and Break			
		Logging Interpretation			
8	14:00–14:25	Analysis and application of astronomical cycle using logging in lacustrine mud shale	Jiangping Yan	SWPU	Wenlian Xiao
9	14:25–14:50	Fracture and lamina identification in the Yanchang terrestrial shale based on borehole electrical resistivity image logging	Fuqiang Lai	CUST	
10	14:50–15:15	NMR log correction and applications	Liang Wang	CDUT	
11	15:15–15:40	Log facies classification and reservoir properties intelligent estimation based on active-learning method	Yaojun Wang	UESTC	
		Summary and Discussion			
		Board Member Meeting of 2019 December			

During the Chongqing time, in order to commemorate the 80th anniversary of the first well-logging event in China, SPWLA-SWC organized a visit to the "Logging Culture Exhibition Hall" at Chongqing Gas Production Plant and the Ba-1 wellsite at Shiyougou—the birthplace of the well logging in China. All the participants not only felt inspired by the history of the well-logging in China but also were motivated to further develop and promote the logging technology in their careers.



SPWLA-SWC January 2020 workshop. Executive members of the Chapter visited the Ba-1 wellsite—the first well-logging site in China, back in 1939.



SPWLA-SWC January 2020 workshop. Executive members of the Chapter visited the culture exhibition hall at Chongqing Gas and Mineral Enterprise.

Upcoming Events

All Chapter social events of the chapter will be cancelled until the 2019-Coronavirus can be eradicated.

STUDENT CHAPTER OF SPWLA AT THE UNIVERSITY OF TEXAS AT AUSTIN

General News

The Student Chapter of SPWLA at UT Austin has been working hard to recruit new chapter members, plan events, and prepare for the SPWLA student paper competition for the 2020 spring semester. During this year, we will cohost more events with other student organizations at UT Austin, including the Petroleum Graduate Student Association (PGSA), AAPG student chapter, and ARMA student chapter. From the cooperation with other student organizations, we look forward to introducing SPWLA to more students outside the petroleum engineering department. Moreover, we will continue our regular seminars throughout the school year.

Recent Events

22 February 2020 – The chapter partnered with the Petroleum Graduate Student Association (PGSA) and ARMA student chapter to participate in "UT Girl Day" at UT Austin. During this event, we introduced hydraulic fracturing principles to elementary and middle school students through a hands-on activity titled "Fracking with Jell-O".

28 February 2020 – The chapter will host a technical seminar by 2019–2020 SPWLA Distinguished Speaker Melanie Durand (Shell) titled "Crushed Rock Analysis Workflow Based on Advanced Fluid Characterization for Improved Interpretation of Core Data."

Upcoming Events

07 March 2020 – Chapter members will partner with the Petroleum Graduate Student Association (PGSA) and ARMA student chapter to volunteer in "Explore UT" at The University of Texas at Austin. Once again, the Student Chapter of SPWLA at UT-Austin will lead a hands-on activity titled "Fracking with Jell-O," for students from kindergarten to 12th grade.

27 March 2020 – The chapter will host a technical seminar by 2019–2020 SPWLA Distinguished Speaker Paul Craddock (Schlumberger) titled "Thermal Maturity-Adjusted Log Interpretation (TMALI) in Organic Shales."

27 March 2020 – the will be holding our local student paper contest. The paper contest will give students an opportunity to present their research in front of their peers as well as a panel of industry and faculty judges. The paper contest judges include Professors Carlos Torres-Verdín and Hugh Daigle, Dr. David Medellin, and Dr. Aymeric-Pierre Peyret.

SPWLA UIS STUDENT CHAPTER (COLUMBIA)

SPWLA Talks is a proposal for making presentations in a different way. In technical conferences, the interaction between audience and speaker is poor, while during technical SPWLA talks the speaker gives practical exercises, proposes ludic activities and interacts with us by answering questions, for example. The frequency for our proposed SPWLA Talks at UIS is one per trimester, as minimum, for a couple of hours to a half day.

This month we had the honor to share time with Javier Enrique Guerrero Arrieta, a petroleum engineer from the Universidad Industrial de Santander, and Master of Science candidate from the same university, and a Research member of Grupo de Recobro Mejorado (GRM), the enhanced oil recovery research group from our university. The conference was called *"Efecto de las propiedades del yacimiento sobre el fenómeno de gas atrapado,"* and was a platform for publicizing the 2nd Internal Student Paper Contest.

SPWLA UIS Student Chapter. Javier Enrique Guerrero Arrieta giving his presentation.

SPWLA UIS Student Chapter. Student members.

Eric Eslinger
1944–2019

Eric Eslinger passed away on September 11, 2019. Eric was born in Arlington, West Virginia, the son of the late Glenn and Jane Andrew Eslinger. He was a graduate of West Virginia University, and earned his doctorate from Case Western Reserve University in Cleveland, Ohio.

He worked in both the petroleum industry (research/operations with Cities Service/OXY USA/Occidental Petroleum in Tulsa for 9 years), the environmental hydrogeology industry (Alpha Earth, Inc.), and later operated his own consulting business, Eric Geoscience Inc., that became eGAMLS Inc. He also held academic positions at Mary Washington University, West Georgia University, Georgia Institute of Technology (adjunct), Union College (adjunct), and he was recently retired Professor Emeritus at The College of Saint Rose (Albany). He was an author or coauthor of numerous published technical articles and presentations at professional conferences.

His research interests included mineralogy-based petrophysics, flow unit delineation and reservoir characterization using probabilistic multivariate clustering analysis software Geologic Analysis via Maximum Likelihood System (GAMLS), reservoir quality and diagenesis interpretation, analysis and interpretation of core, cuttings, and outcrop using core description (sedimentology), XRD, SEM, and petrographic microscopy, and integration and synthesis of geologic, engineering, and petrophysical data.

Eric was a forerunner in incorporating mineralogy to solve petrophysical problems and, he, along with others, such as Drs. Michael and Susan Herron, independently developed methods to use the attributes of minerals to solve for hydrocarbon abundance. While they processed their methods in different ways, their goal was the same: use geologic information to solve geological problems. Eric's approach was to use maximum-likelihood methods to develop probable solutions for mineralogy from elements, thus solving an abundance of minerals as well as the abundance of hydrocarbons.

Eric was always pleased to share methods to advance the science the result of which made him a great teacher (professor. Eric was a friend you could count on to always do the right thing and use science to provide the basis for all his ideas. Eric loved taking students on geology field trips. He also loved reading, gardening, the outdoors, viewing beautiful landscapes, basketball, and following any sports team from West Virginia University. He will be dearly missed.

Eric is survived by his wife Trudy Stearns Eslinger; his children, Oliver Eslinger (Austin) of Pasadena, California, and Laura Lynn (Alex) of London, England; his sister Von Maddox of Prince Frederick, Maryland; and his grandchildren, Julian and Maya Eslinger, and Dylan Lynn.

Robert Everett

Welcome New Members—December 17, 2019–February 12, 2020

Mattash, Kamal, University Of Miskolc, Miskolc, Hungary
Aguilera, Roberto, RA GEOLOGIA E.U., Bogota, Cundinamarca, Colombia
Raja Mohan, Sharvnee, IFP School, Rueil Malmaison, France
Reasnor, Bryant, Chesapeake Energy, Edmond, OK, United States
Mahfoedz, Raihan, BP, Jakarta, Indonesia
Zubizarreta, Izaskun, Lloyd's Register, Aberdeen, United Kingdom
Kelly, Grant, Suncor, Aberdeen, United Kingdom
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