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SPE International®

Norway Council

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# The First

**SPE Norway magazine**

*To gather members*
*To share knowledge*

## Are you ready for the new SPE Norway Season 2015 – 16?

**WE ARE! Check out the SPE Norway season calendar, news and updates in this issue!**

**Read about**
**Oil price, Reservoir Engineering, Drilling, GeoExploration novelties**

**Special Topic**
**Proper Risk Planning crucial for successful vacation**
***p.42***

**Don't forget to vote for the best picture from the summer time!**

photo Caroline Sørensen, Student Chapter Arctic University of Norway
Top of the Mountain Festvågtinden in Henningsvær

The electronic version is available on the page of your section website.

## A Note from the Editor

*Vita Kalashnikova*
*Editor The First /*
*QI Geophysicist*
*PSS-Geo AS /*
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*Maria Djomina*
*Editor The First /*
*Communications Manager,*
*AGR /*
*Maria.Djomina@agr.com*

*In April 2014, the first issue of The First was published by SPE Oslo section as a gift to all members, sponsors and followers. That year the SPE Oslo celebrated its 20th birthday. The magazine contained abstracts of previous technical presentations, info on student and YP activities. We also invited other SPE Norway sections to publish their sections activities. The SPE Norway events with a strong technical program and diverse member base is an interesting meeting place. Our members travel all over Norway, and we do know each other. We want to share knowledge, our achievements and just to spend a good time together discussing the latest industry news. Thus, the idea came to create a joint SPE Norway issue (check out our issue #5!). We hoped, that magazine will provide a chance to get to know the SPE Norway a bit better. And, I believe, it works! Rising interest of the members and companies brought The First to another level.*

*Today, the **SPE Board Committee on Communication and Knowledge Sharing (CKS) has approved "The First" as the SPE Norway Magazine regional publication.** And now, we are going to make periodical release of "The First", SPE Norway magazine, highlighting the various activities in the oil & gas sector pertaining to different SPE sections in Norway.*

*Speaking about new level…*

*I'm really glad to introduce to you the new editor, Maria Djomina, Communications manager, AGR. I'm very happy that now we have a professional in our editorial team. She has more than 10 years' experience from PR&Communication and I am sure her experience and skills will certainly improve our voluntary publication. Finally, we will have an editor who can actually write ;)*

*Also, I would like to introduce to you new board member of Bergen Section Giedre Malinauskaite. She is going to use her experience in marketing, positioning and brand development to help Bergen section develop further. If you have any question related to publication of The First feel free to contact her: (giedre.malinauskaite@fourphase.com)*

*Also, I would like to say thanks to Tor Landbø Opseth (Oslo Internet chairman), for his great work of magazine distribution and help in making of the issues.*

*Enjoy your reading and do not hesitate to send us feedback or ideas for upcoming editions.*

*And, wish you all a great season 2015-2016 kickoff event at your section!*

*Vita Kalashnikova*
*Editor The First*



**Inside this issue** — **The First**

### Would you like to join Editorial team? Email to the Editors or contact your section!

**Do you want to have your best shot on the front page of The First? Send it to us!**

SPE Oslo section has open positions for Treasurer and Young Professional Chairman.
Please let us know, no later than September 11, if you would be interested to join the board of directors.
The responsibility of each role is outlined at: http://spe.org/sections/som.php

*The First — the SPE Norway Regional Edition Magazine*

*Editors*
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*Electronic version is available on the SPE Norway sections websites*

www.spe.no

### Editorial Contents

## Statsraaden

To follow up the 1000 years of ***Bergen tradition*** as a trading city ***SPE Bergen*** invite all members to a journey with the old tall ship ***Statsraad Lehmkuhl***. During a bright spring night local petroleum engineers and visitors are enjoying life when sailing along fjords and the coastline listening to seagull crying, musicians playing and a good meal.



*Words and pictures by Thorbjørn Kaland*


# SPE Bergen

## The Bergen section may proudly show a history of decades with exciting conferences and meetings!

### ODS

The One Day Seminar (ODS) in the concert hall Grieghallen has during 22 years become an institution gathering engineers and scientists from all parts of Europe, Middle East, and the US. All presentations at ODS are being published as a SPE paper. This keeps the quality on a high level and the participants may access all the papers for further study after the presentation.
Next ODS is set to April 20$^{th}$.
The deadline for subscribing abstracts for ODS 2016 is set to 23$^{rd}$ of October 2015.

### Technical Nights

This is the name of SPE Bergen's monthly meetings with technical presentation, discussions and refreshments.
Set your schedule for the technical nights:

17$^{th}$ of September
15$^{th}$ of October
11$^{th}$ of November
18$^{th}$ of January.

The meetings will be arranged at Scandic Hotel, Håkons gaten, Bergen.
The first meeting will start with Jeremy O'Brian (Halliburton) who will give the presentation: Uplift ™ - Halliburton's approach to revitalizing Mature Fields and how to increase recovery rate.
The next presentation will be given by the SPE Distinguised Lecturer Donald Purvis (Marathon Oil) with the presentation: Cement Testing: Are We Looking at the Right Things the Wrong Way?

*Student Chapter with SPE president and local major*

## Lutefisk

One of the strange challenges for SPE Bergen is to explain to all our international colleagues and visitors why one of our most acknowledged meals is a cod destroyed in alkaline fluid, and how all petroleum engineers in town are queuing up and fighting for a seat during the well known SPE Lutefisk dinner. It might be the aquavit or the entertainment, but most people claim their great passion for the Lutefisk. The Lutefisk event this year is set to November 26th.

*SPE Lutefisk dinner*

# SPE Bergen section board

The events mentioned above are set up to gather local petroleum engineers for technical updates, sharing experiences, maintain a good social network and to strengthen our business to meet the future with new solutions and technology.

None of these events would be possible without a hard working dedicated board:

*SPE board barbeque meeting*

**Bjørn Erik Sissener** (Welltec) Chairman
Christine Madsen (Past Chairwoman)
Njål Grønnerød (Statoil) Technical Nights
**Kristian Johnsen** (Baker) Web updates, Technical Nights
**Thorbjørn Kaland** (Halliburton) ODS Program committee Chair, Press contact
**Marit Midthjell** (Archer) Treasurer
**Ronny Larsen** (Cape Omega) Sponsorship
**Brynjulv Kvåle** (ALTUS Intervention) Vice Chairman
**Lars Petter Hauge** (UIB) Secretary
**Kjell Rune Hoff** (Baker) Chair Young Professionals
**Eirik Walle** (ClampOn) Lutefisk, Statsraaden, Sponsorship
**John Werner Solgren** (Statoil) recruitment, Treasurer
**Giedre Malinauskaite**, Marketing



*Compiled by Marius Stamnes*

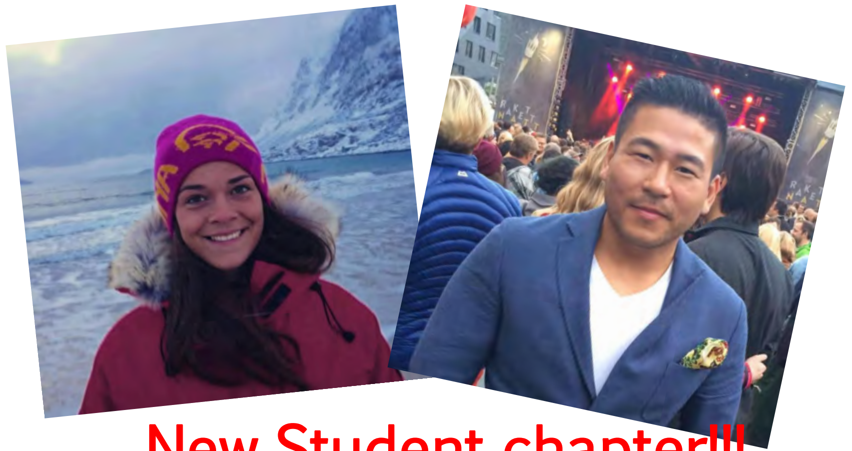
## *News-News-News!!!*

## *SPE Workshop in Arctic Norway:*

SPE Northern Norway Section are proud to announce that our annual SPE Workshop in Arctic Norway will be managed in cooperation with SPE International in the future. More information on this will be shared at a later stage.

## UiT the Arctic University of Norway SPE Student Chapter:

We are very excited to announce that SPE has approved our second SPE Student Chapter! Welcome, students of the University of **Tromsø!** We are looking forward to building a strong partnership between our section, our new student chapter and the Harstad/Narvik SPE Student Chapter!



## New Student chapter!!!

***Caroline Sørensen**, President, UiT the Arctic University of Norway SPE Student Chapter and **Kim Ivanowitz**, Vice President, UiT the Arctic University of Norway SPE Student Chapter*

*The rest of the board are: Simon Aron Ring, Anna Fossli, Astrid Marie Geicke, Jørgen Torgersen, Olav Helland Skare, Marius Paulsen Haugen og Simen Hartvigsen*

## Harstad University College/ Narvik University College SPE Student Chapter:

*President: **Kim Ove Kristoffersen***
*Vice President: **Børge Andreassen***

*The rest of the board are: Tommy Andre Seljestuen, Ole Kristian Lie, Marius Eidstø, Eivind Skoglund Hansen, Guro Rue Johnsen*

The Harstad University College/Narvik University College SPE Student Chapter was founded in Harstad, April 2014. This was done as a means of enhancing collaboration between the students and the industry in these two neighboring cities.
Since then we have hosted a number of events in both cities, including lectures and presentations by professionals, visits to companies, as well as social events.

Our biggest event to date was our «Young Talent» event in collaboration with the **SPE Workshop in Arctic Norway** in Harstad, March 2015. We had several big names from the industry on our speaker list, as well as the Mayor of Harstad, Marianne Bremnes. In 2016 we are planning to collaborate on the Young Talent event with the newly founded student chapter in Tromsø, making it an even bigger event.

As with all newly founded organizations, our primary focus has been to make our presence known, and building a strong membership base. This year we see that we are able to reap the fruits of our efforts. Word has gotten around, and we are now experiencing an elevated interest from both students and local companies.

In 2014 we sent a representative to the ATCE in Amsterdam, and this year we are able to send three delegates to the SPE Regional Student Development Summit in Aberdeen, Scotland. Here they will attend a mix between technical sessions and soft skill sessions on the industry within the North Sea Region. At the last day of the summit, our three delegates will hold three separate presentations on a pre-assigned topic. Each of our delegates will collaborate on these presentations with students from other student chapters across Europe. We believe that this will help our student chapter make bonds with other chapters in the North Sea Region, and hopefully promote future collaboration.

*Text by: Kim Kristoffersen, President Harstad University College/Narvik University College SPE Student Chapter*

***SPE Young Talent event***

*Picture from the SPE Young Talent event at the 2015 SPE Workshop in Arctic Norway. The Harstad University College/Narvik University College SPE Student Chapter board in front together with Mayor Marianne Bremnes from Harstad.*

| | SPE Norway Event Calendar 2015 |
|---|---|
| Oslo Kickoff Event 16 September<br>Stavanger Kickoff Event 17 September<br>Harstad Kickoff Event 17 September | **Well Design and Integrity: Importance, Risk and Scientific Certainty**<br>Brun Hilbert<br>Exponent Failure Analysis Associates, Inc. |
| Bergen Kickoff Event 17 September | **Cement Testing: Are We Looking at the Right Things the Wrong Way?**<br>Donald Purvis<br>Consultant for Marathon Oil |
| September | **Young Energy Breakfast at Statoil**<br>Northern Norway section |
| 13 October | **Technological Innovation in Oil and gas Industry**<br>Oslo, Dinner meeting |
| October/ November | **SPE Northern Norway Petroleum seminar, co-hosted with Harstad University College/Narvik University College SPE Student Chapter**<br>Northern Norway section |
| 10 November | **Optimism in Reservoir Production Forecasting**<br>– Impact of Geology, Heterogeneity, Geostatistics, Reservoir Modeling, and Uncertainty.<br>William (Scott) Meddaugh Midwestern State University<br>Oslo, Dinner meeting |
| 26 November | **SPE Bergen Lutefisk**<br>Another steady tradition is our annual Lutefisk dinner in November. Some 150 participants enjoy the Lutefisk with its proper add-ons. This is Norwegian pre-Christmas culture at its best, and always a great success |

## Season 2015-2016 Kick-off at Nobel Prize Dinner Hall at Grand Hotel Oslo


Program

17:30 - 18:00 Reception and Ice-breaking
18:00 - 19:30 Presentation and Q&A
19:30 - 22:00 Dinner
22:00 - 23:30 Coffee & Avec - Networking

**September 16, 2015**
**5:30 PM - 11:30 PM**

Grand Hotel: The Mirror Room
(Nobel Prize Dinner Hall)
Karl Johans gate 31
0159 Oslo

Technical program — page 10



## Season 2015-2016 Kick-off event Stavanger


**Date: 17th of September**
**Time: 18:30**
**(Presentation start 19:00)**
**Place: Radisson Blu Atlantic Hotel, Stavanger**

Registration required for the following dinner only, not the presentation.

Technical program — page 10

## Season 2015-2016 Kick-off event Northern Norway

**Friday 18th of September**

**Program:**
**19:30** Bus transport from Thon Hotel Harstad
**20:00** Presentation and Q&A
**21:00** *Activities by Aktiv Events known from the Norwegian TV Show "71 Degrees North", followed by barbeque and refreshments*

Place: Harstad Racing Track

Technical program — page 10

Distinguished Lecturer Program

Oslo Section — September 16, 2015
Stavanger Section — September 17, 2015
Northern Norway Section — September 18, 2015

## Well Design and Integrity: Importance, Risk and Scientific Certainty

**Brun Hilbert**
*Exponent Failure Analysis Associates, Inc.*

**Abstract:**
The term "Well Design and Integrity" has taken on added meaning as a result of intense media scrutiny and public interest regarding hydraulic fracturing and the tragic Macondo well blowout in the Gulf of Mexico. The complexities and costs of well design have increased significantly to meet the challenges of ultra-deep wells exceeding 30,000 ft., ultra-HPHT wells (500F and 30,000 psi), and ultra-deepwater drilling (exceeding 10,000 ft.). As a consequence, the risk to companies designing wells for these applications has increased. As we know from recent events, the consequences of failures can be enormous, and minimizing the risk of such catastrophic failures is imperative. It is not simply coincidental that the engineering tools for well design have become ever more complex. Tools such as nonlinear finite element analysis (FEA), computational fluid dynamics (CFD), and multi-physics software are now commonly used. What are these tools and the input data required for output of dependable and accurate results? This presentation will summarize applications of these tools, exhibiting their input requirements, and output interpretation and quality. Applications will include threaded connection pressure integrity, cement and rock strength and deformation, formation-cement-casing interactions, all of which involve complex nonlinear material and interface behavior. I will discuss computational modeling of the temperature dependent, visco-plastic response of salt and "soft" porous rocks, and compactive behavior of high-porosity formations. Downhole tools may include stainless steels, elastomer and polymer components. Seal rings and inflatable packers are highly temperature dependent and exhibit significant creep behavior. Calibration of material model parameters is vitally important, but for non-metals can require a significant number of samples, which are difficult and expensive to acquire and test. The correct selection of a validated material model can be the key to success or failure in minimizing risk.

**Biography:**
Dr. L. Brun Hilbert, Jr. is a Principal Engineer in the Mechanical Engineering Practice at Exponent Failure Analysis Associates, Inc., and consults in mechanical and petroleum engineering. In his work, Dr. Hilbert analyzes the root cause of failures, and performs proactive consulting to assist clients in failure prevention, design improvement, and risk minimization. He has worked in the upstream petroleum industry for over 30 years and has been an SPE Member since 1982. He performed applied research in the Drilling & Completions Division of Exxon Production Research Company. He holds a Ph.D. degree in Rock Mechanics from the University of California, Berkeley, and an MS degree in Mechanical Engineering and BS degree in Mathematics from the University of New Orleans.



# Season 2015-2016 Kick-off event

Bergen

Bergen Section — September 17, 2015


## Thursday, September 17, 2015
## 7:00 PM

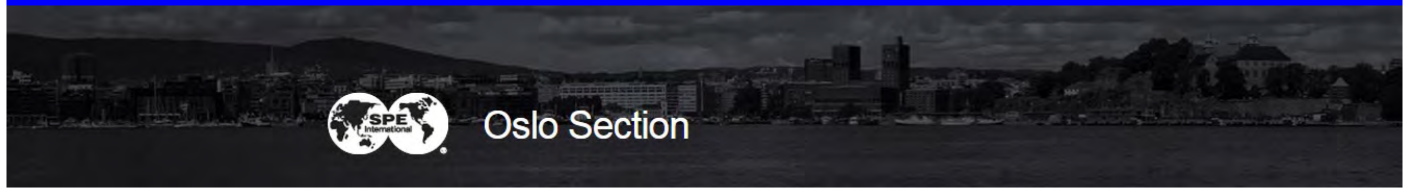
Distinguished Lecturer Program

**Cement Testing: Are We Looking at the Right Things the Wrong Way?**

**Donald Purvis**
*Consultant for Marathon Oil*

The most important aspect in wellbore construction is creating and maintaining wellbore integrity and zonal isolation. The potential of freshwater contamination has captured the attention of the public and media. A crossflow between productive intervals or saltwater zones can result in environmental and legal challenges, and lost production. The number of wells developing annular pressure over time has become a concern and expense for operators. The design and placement of a competent cement seal in the annulus is critical in addressing these issues. This presentation describes how the testing has progressed from Code 32, the first API code, to the present day ISO and API guidelines. The audience should gain a better understanding of what cement is needed to do and the laboratory tests required to make sure it does.

Don Purvis is an independent technical consultant who has done extensive research on cement flow dynamics and testing methodology. He has held research, engineering, and management positions with major service companies and operators. He holds two process patents and has authored multiple technical papers and journal articles. He has given technical presentations on good cementing practices both inside and outside of the oilfield community. Purvis holds an electrical engineering degree from Oklahoma State University.




## Dear Colleague and Friend,

On behalf of Society of Petroleum Engineers (SPE) Oslo Section, it is a great pleasure to welcome you to season 2015-2016. I am very pleased to inform you that we have arranged several technical programs and meetings for the coming season covering multiple disciplines within the industry.

I would like to inform you that the Oslo Section has earned the **Gold Standard** designation for 2015,

**Oslo Section has earned the Gold Standard designation for 2015!**

in recognition of its exceptional programs in industry engagement, operations and planning, community involvement, professional development and innovation. For the season 2015-2016, we will continue the technical programs from previous season and will try to cover multiple disciplines within the industry.

Here is the highlight of the events and technical meetings during the past season 2014-2015:

**Season 2014-2015 Kick-off Event:** The Conditions For IOR/EOR in The Future, *September 16 2014*

**Norwegian Patent Registration Office:** Patent Registration and Protecting Intellectual Property in Oil Industry, *October 15 2014*

**Distinguished Lecturer**: The Science and Engineering of Internal Corrosion Control in the Upstream Petroleum Industry, *November 6 2014*

**In partnership with FORCE (NPD):** Microbial Enhanced Oil Recovery (MEOR): From Theory to Field Implementation, *November 18 2014*

**Traditional Christmas Dinner**, *December 2 2014:*
Lundin Norway AS: Evaluating Polymer and WAG on Johan Sverdrup using a Next Generation Simulator DNO International: Lessons and Experiences From Kurdistan

**Distinguished Lecturer:** Drilling Fluid Influenced Magnetic Shielding of Directional Measurement Tool: Causes and Consequence, *January 20 2015*

**One-Day Conference & Exhibition:** Big Data Solutions and Analytics in Upstream Oil and Gas Industry, *February 10 2015*

**Distinguished Lecturer**: Comparing Formation Evaluation Measurements Made Through Casing with Openhole Logging Measurements, *March 10 2015*

**Distinguished Lecturer:** Understanding and Checking the Validity of PVT Reports, *May 19 2015*

**One-Day Annual Finance Event with Oslo Børs and PwC:** Risks and Rewards in Oil Industry: Navigating in a Volatile Oil Price Market, *May 27 2015*

We at SPE Oslo are committed to offer a unique opportunity to contribute to the oil and gas industry through our programs and activities. The main vision of SPE Oslo is to provide opportunity for oil and gas industry to share knowledge and for professionals to enhance their technical and professional competence.

SPE Oslo is also strongly engaged in creating Young Professionals network in Oslo. Throughout the seasons, SPE Oslo has funded both young professional events like quiz nights, technical seminars and networking dinners. Further, SPE Oslo continues to sponsor a very active SPE Oslo student chapter.

For any questions or concerns, please do not hesitate to contact myself (email: jf@coreenergy.no phone: +47 90251512) or any of the board members.

Sincerely,
Jafar Fathi, PhD
Chairman, SPE Oslo Section

# Navigating in a volatile oil price market

**Per Fossan-Waage**
*Director PwC*
*Oslo*

*SPE Oslo Branch, Oslo Børs and PwC organized in May the third, consecutive seminar addressing the challenges faced by the oil industry. As with the similar events in 2013 and 2014, the seminar in 2015 was brimming with interesting topics like where the oil price is heading, the impact of shale oil, whether the industry is in a paradigm shift, restructuring within the oil and gas sector and much more.*

*Reputable speakers like John Olaisen (ABG Sundal Collier), Teodor Sveen Nilsen (Swedbank), Gunnar Slettebø (partner PwC Stavanger) and others did their part to inform the audience in Oslo about what to expect in the coming years. Case presentations like Det Norske's acquisition of Marathon Norge added spice to the menu.*

*With a great lunch at the top of the PwC building and reception at Oslo Børs in the afternoon, the annual seminar has turned out to be a popular meeting place in Oslo for many in the industry.*





# The Price of Oil

*Forthcoming, Cambridge University Press, November 2015*

**by Roberto F. Aguilera, Adjunct research fellow Curtin University, Australia and Marian Radetzki, Professor of Economics Luleå University of Technology, Sweden**

***Why it rose stupendously over the past 40 years,***
***why it is likely to fall in the coming decades, and***
***what it will mean for world politics, the world economy and the environment***

In this article, we provide a synopsis of our book, The Price of Oil, which is to be published by Cambridge University Press in November 2015. We argue that although oil has experienced an extraordinary price increase over the past few decades, a turning point has now been reached where scarcity, uncertain supply and high prices will be replaced by abundance, undisturbed availability and suppressed price levels in the decades to come. We also examine the implications of this turnaround for the world economy, as well as for politics, diplomacy, military interventions and the efforts to stabilize climate.

**Roberto F. Aguilera**
*Adjunct research fellow*
*Curtin University, Australia*

**Part I. Oil's extraordinary price history: how can it be explained?**

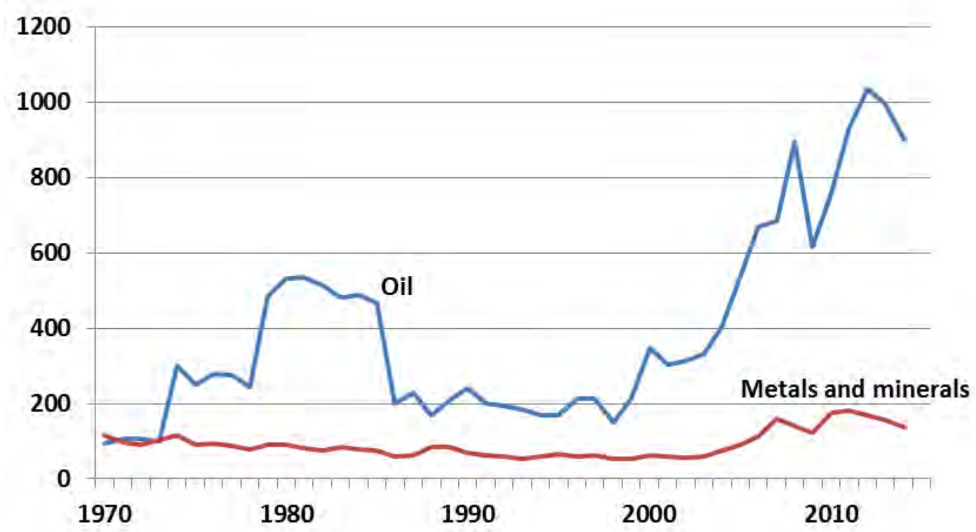
Oil price developments over the past 40 years have been truly spectacular. In constant money, prices rose by almost 900% between 1970-72 and 2011-13 (Figure 1). This can be compared with a 68% real increase for a metals and minerals price index, comprising a commodity group which like oil belongs to the exhaustible category. The objective of this part is to explain the price exceptionality of oil.

We do not share the widespread opinion, held by a majority of market specialists, that OPEC's interventions since the early 1970s have had a major influence on the price behavior of oil. While OPEC cooperation has undoubtedly had short term impacts on the oil market, its interventions are completely inadequate for explaining the longer run price performance. Underlying our position is a number of academic studies pointing to the short run and shallow nature of the oil group's supply-restraining actions. However, it needs mentioning that actions of Saudi Arabia in isolation to limit output, and even more, the country's cautious approach to capacity expansion, have clearly contributed to the oil price evolution.

In our view, a number of political rather than economic forces have shaped the inadequate growth of upstream production capacity, the dominant factor behind the long run upward price push. This is particularly, but not exclusively, true in OPEC, the country group with a leading share of global oil reserves.

Widespread nationalizations of the oil sector in the 1970s replaced private multinationals with state owned enterprises. The latter did not invest much in capacity expansion because of a persevering lack of technical proficiency in many cases and a tendency of their government owners to use the surpluses generated by oil production in support of the state

**Marian Radetzki**
*Professor of Economics*
*Luleå University of Technology, Sweden*




*UN's Manufactured Unit Value Index (MUV) in US dollars used as deflator.
Sources: UNCTAD and UNSTAT on the web.

*Figure 1: Price indices from 1970-2014 in constant money*, 1970-1972 = 100*

budget, so leaving insufficient resources for investment. A variety of goals apart from profit were often imposed on the state owned firms, resulting in high costs and inefficiencies that further reduced investments in new capacity.

Private multinationals had been deprived of a sizable proportion of conventional oil reserves in the nationalization wave, so they could not easily compensate for the state owned deficiencies in capacity expansion. Furthermore, as prices and profits rose in consequence of rising demand and stagnant production capacity, virtually all producing governments, inside and outside OPEC, sharply raised taxes and other impositions, further reducing the willingness to invest. In this way, a vicious circle was put in place, and its operation was made viable by the very low price elasticity of demand (i.e. unresponsive demand to even significant price changes) in the short- and medium-term.

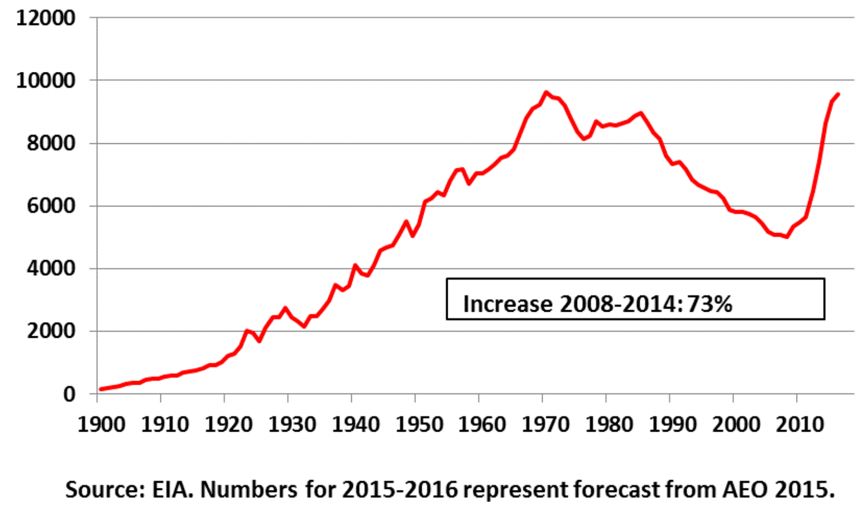



*Figure 2: US crude oil production, 1900–2016, thousand barrels per day*

While some believe that depletion and thus rising costs can explain price developments, the continuous rise of global oil reserves along with the high level of pre-tax profits in the industry are clear indicators that depletion has not been a factor behind the observed oil price evolution.

The resource curse, represented by domestic and international conflicts over the oil rent, is probably the most important explanation to the extraordinary oil price developments. We have looked at only six countries – Iran, Iraq, Libya, Nigeria, Sudan and Venezuela, all richly endowed with oil resources – to conclude that the resource curse had suppressed their recent production levels below peaks attained decades ago by a total of 7 million barrels per day, corresponding to no less than 55% of overall annual oil consumption in the European Union. In the absence of such suppression, oil prices would clearly have been far below the heights seen between the end of 2010 and autumn 2014.

**Part II. The shale and conventional oil revolutions: low prices ahead**

The shale oil revolution has unexpectedly and forcefully begun to transform the energy landscape in the United States. Beginning less than ten years ago, the revolution – employing technological innovations in horizontal drilling and hydraulic fracturing – has turned the long run declining oil production trends in the US into rises of 73% between 2008 and 2014 (Figure 2). The shale oil costs become broadly competitive at oil prices of $50 per barrel, lower than the costs of Canadian oil sands and Brazilian deep offshore pre-salts. An exceedingly high rate of productivity improvements in this relatively new industry promises to strengthen the competitiveness of shale output even further. The revolution has had a number of positive effects for the US economy in terms of, for example, investments, employment, fiscal revenue and a strengthening trade balance.

The US lead in the shale revolution has many explanations, including large-scale and long-lasting conventional oil exploitation, a well-developed fossil fuel infrastructure, established production of inputs, many small adventurous prospecting and production enterprises, a relatively sympathetic public approach to the new industry and the incentive to the landholder of underground resources ownership.

A series of environmental problems related to shale exploitation have been identified, most of which are likely to be successfully handled as the infant, “wild west” industry matures and as environmental regulation is introduced and sharpened.

Geologically, the US does not stand out in terms of shale resources. A very incomplete global mapping suggests a US shale oil share of no more than 17% of a huge geological wealth widely geographically spread, with lead positions held by countries like Argentina, Australia, Mexico, China, Libya and Russia. Given the mainly non-proprietary shale technology and the many advantages accruing to the producing nations, it is inevitable that the revolution will spread beyond the US.

We have assessed the prospects of non-US shale oil output in 2035, positing that the rest of the world will by then exploit its shale resources as successfully as the US has done in the revolution’s first ten years – implying that the global revolution will occur with a substantial delay and at a much slower pace than the one achieved by the US. With roughly a 17% share of global shale resources, the US in 10 years expanded its output by 3.9 mbd. Assume, then, that the rest of the world is equally as successful as the US was between 2004-2014 in exploiting its share of the resources between 2015-2035. This would yield rest of world output of 19.5 mbd in 2035 (Table 1), which is similar to the global rise of all oil production in the preceding twenty years – a stunning deduction with far-reaching implications in many fields.

Another related revolution is beginning to see the light of the day. It is being gradually realized that the advancements in horizontal drilling and fracking can also be applied to traditional oil extraction, thereby substantially improving the productivity of conventional, mature and declining oilfields worldwide. This is yet another method to achieve enhanced recovery, in addition to the usual enhanced oil recovery technologies involving the injection of steam, chemicals or gas into formations. Several basins in the United States and other countries are already experiencing this new phenomenon, which we call the conventional oil revolution. Parenthetically, it should be noted that some of Norway’s declining fields may be candidates for this type of revitalization.

**Table 1: Speculative ROW *shale oil* impact to 2035, mbd**

| Global 2014 oil output | Global rise, 20 years (1994-2014) | US share of shale oil resources, EIA (2013a) | US shale production rise, 10 years (2004-2014) | ROW shale production rise, 20 years (2015-2035) |
|---|---|---|---|---|
| 88.7 | 21.6 | 17% | 3.9 | 19.5 |



**Table 2: Speculative ROW *conventional oil* rise by 2035 resulting from spread of shale extraction methods, mbd**

| Global 2014 oil output | Global rise, 20 years (1994-2014) | US share of oil reserves, BP (annual) | US conventional oil production rise, 8 years (2008-2016) | ROW conventional oil production rise, 20 years (2015-2035) |
|---|---|---|---|---|
| 88.7 | 21.6 | 2.6% | 0.5 | 19.7 |

In a similar fashion to the output projections for shale oil, we assume that conventional oil in the rest of the world is able to benefit from the application of shale oil extraction methods just as US conventional oil did. Since 2008, the shale technologies have led to a US conventional oil rise of around 0.5 mbd. Imagine now that the ROW is correspondingly successful by 2035 in applying the related technologies to its share of conventional oil reserves as the US has been until now. This would yield a further addition of conventional oil amounting to 19.7 mbd by 2035 (Table 2).

The combination of the two revolutions sum up to a total output rise of 39 mbd. This equals almost half of global oil output in 2014, is nearly twice as much as the global increase in all oil production in the 20-year period 1994–2014, and is close to one-third greater than OPEC’s output in 2014.

The pace of the shale and conventional oil revolutions is likely to be slowed somewhat if the price levels observed in the first half of 2015, averaging some $57 per barrel (Brent spot), persevere for several years, and the ultimate price fall caused by the revolutions will be less dramatic. In a five year time perspective, we believe there is a likelihood that prices will recover a bit from the 2015 quotes, pending the shale revolution’s international spread. However that will be, it is our view that the major long-term conclusions from our analysis remain unaltered even with oil prices persevering for many years at the 2015 levels. The main reasons are that shale oil is likely to remain broadly economic at those lower market prices, and that many producers will thrive in a low price environment as they are incentivized to slash costs and increase operational efficiencies.

We firmly believe that the combined impact of the two revolutions will have an overwhelming impact on oil, by far the economically most important primary commodity in human use. The oil output increases alluded to above are bound to have a strong price-depressing impact, either by preventing price rises from the first-half 2015 levels, or by pushing them back to these levels if an early upward reaction takes place. Our *reference case* conclusion on prices envisages a level of about $60 in 2035, while a more optimistic scenario which appears increasingly likely, sees a price of $40 by then. The price implications of the revolutions will in turn influence many other conditions that shape human life, be they economic, political, diplomatic or military. This, however, is the subject of the book’s third part.

**Part III. Global implications for the macroeconomy, the environment and for politics**

The global spread of the revolutions and the ensuing price weakness that we envisage for the coming two decades will, on balance, provide a great advantage both to the oil industry and to the world economy at large. Successful shale and conventional oil developers could reap benefits similar to those bestowed on the US in its progress in recent years.

Not surprisingly, there would be important negative repercussions on public income from oil in producing/exporting nations that fail to compensate for the effects of the oil price decline by expanding output with the help of the revolutions. Juxtaposed against this conclusion is our supposition that the effects of the resource curse will be ameliorated as prices decline.

The two revolutions will apparently cement and prolong the global fossil fuel dependence, with implications for climate. At the same time, the expansion and cheapening of natural gas in consequence of the revolutions will make it possible to shrink coal use in power production, thereby reducing $CO_2$-emissions, as is already evident from the US experience since some years. The efforts to develop renewables for the purpose of climate stabilization, however, will become more costly, requiring greater subsidies, in consequence of lower fossil prices.

The abundance caused by the revolutions will lead to hard to fathom changes in international political relations. We assert that much of the oil importers’ urge for political intervention and control will dissipate as the criticality of access becomes less urgent with normalization of profit levels and more ample and diversified oil availability. For instance, the heavy diplomatic and military presence of the United States in the Middle East is likely to be questioned when the country’s dependence on oil from the region is reduced. The growth and geographical diversification of supply would not only suppress prices, but would also promote competition among suppliers and make it more difficult for producers to influence the market to their advantage or for their governments to use energy sales in pursuit of political ends.

There is no doubt that successful shale and conventional revolutions will bring about exciting changes in many fields. Our book aims to explain what they are and where they will occur. However preliminary, we believe our findings will be highly useful as a starting point for discussions and analyses to follow in many coming years.

# Understanding and Checking the Validity of PVT-Reports

by Klaus Potsch, EC&C; formerly OMV-E&P

*Dr. Klaus Potsch*
*EC&C;*
*formerly OMV-E&P*

**Introduction** - The motivation for the lab work is that the knowledge of phase behavior and flow behavior is crucial for simulation of reservoir behavior and design of surface facilities and pipelines to the refinery. PVT experiments have been performed for decades. The need to review their accuracy, their evaluation together with consistency tests arises because of new equipment (mercury is banned in almost all labs). With the easy accessible oil being already produced, the complexity of the production process and the more extreme parameters of unconventional oil and gas demand a more sophisticated methodology in the experiments and an improved reporting. Quality control of the lab-data is therefore essential before using the numbers in the calculations. The specialization of the engineers asks for a detailed review of the methods and content of a PVT-report.

**Sampling** - The prime objective is to employ samples of the reservoir fluid in the experiments, that are identical (or close to) the reservoir fluid itself, usually labeled as a representative sample. Along with the sampling report a well test report helps to get insight into the sampling conditions and reservoir parameters. Circumstances to be observed are: firstly, an essential step in sampling one has to make sure that the well is already clean; secondly, samples should be taken from single phase streams; thirdly, taking samples at an early stage in the life of a reservoir is advisable. Later samples deviate from being representative.
Reservoir pressure is often a limiting factor in proper sampling. Saturated reservoirs or reservoirs close to saturation pressure pose a challenge, especially for low permeable formations. Where a pressure draw-down is needed for proper inflow, the fluid pressure may has dropped already locally below saturation pressure and hence into the two phase region from where in principle an original fluid sample cannot be obtained.
In case of a bottom-hole sample (BHS), mud or other fluids (or N2) used during drilling and completion may have entered the sample chamber. In order to proceed with the sample, the following procedure can be applied to get reasonable results from a contaminated sample:

- Perform the experiments with the contaminated material.
- Match the experiments with an equation of state (EOS). Basic rules are found in Whitson (2000), Whiston (1983), Whitson (1984)
- Analyze the contaminated sample.
- Analyze the oil based mud.
- Numerically decontaminate the sample from the mud numerically (find the most probable distribution of single carbon numbers).
- Recalculate the experiments with the decontaminated fluid and use the result as "real" properties for the reservoir fluid.

For that procedure a maximum contamination of 5 vol.% is suggested. Diesel as an oil based mud usually causes unwanted complications in determining the clean composition. Artificial mud, though more expensive, should be preferred because of a narrow distribution in the composition.
Separator samples (SS) are easier to collect and should always be taken as a backup for the BHS. In both cases, stable flow rates are essential. Separator should be large enough to avoid mist in the gas stream (carry-over) and gas in the liquid stream (carry-under).
The phase envelopes of the separator gas and separator liquid should intersect at the separator conditions (p,T).

**Sample transportation** - In the laboratory, the opening pressures and temperature is recorded. A liquid container, for safety reasons, is always shipped with a gas cap. At separator temperature, the saturation pressure of the liquid sample should equal the separator pressure. In order to check whether a valve of the gas container leaked, the amount of gas at the sampling site and in the lab should be the same. For that purpose one checks it with the gas law. The calculation of the $Z$-factor requires the knowledge of the composition of the gas. In general, compositional analysis for all containers should be done.
The analysis of the content of a BHS or a SS container requires a flash to ambient (laboratory) conditions. When recombining a gas and liquid phase pair of a SS, the collection of both samples at the same time should be ensured. Usually several pairs are collected. The selection of the most representative pair is often based on the oxygen content in the gas sample, which indicates air contamination of the sample. Actually, pairs of containers should be evaluated and then determined which of the recombined fluids is the most reliable.
Another check of the validity of pairs of SS can be carried out in the Hoffmann-plot in which the logarithm of the equilibrium or $K$-value is plotted versus the characterization factor $F$ for every component (Whitson 2000).
It clearly reveals if some components have been detected with too low an amount in either phase. The sources of errors can be in the gas analysis with the higher components (points are too high) or with the lower carbon numbers, which may have already evaporated from the sample (points too low). The experimental $K$-factor can also be compared with the $K$-factor from Wilson's correlation (Whitson 2000).

*Dr. Klaus Potsch is elected lecture of Society of Petroleum Engineers Distinguished Lecturer 2014-15 season.*



**Volumetric behavior of the reservoir fluid** - Once a representative sample has been transferred to the PVT-cell, experiments are performed that mimic the flow in different stages for black oil and gas-condensate from the reservoir to the surface. All experiments are carried out at reservoir temperature. The abbreviations in the Figs. are CCE- Constant Composition Experiment, DLE – Differential Liberation Experiment and CVD – Constant Volume Depletion. The first experiment usually carried out is the CCE or sometimes also called the Constant Mass Experiment (CME).

**Determination of the saturation pressure** - The key to finding the saturation pressure is to use any function of pressure the first derivative of which is discontinuous in that point. The sought function is different for BO and GC.
For a BO the plot ln$Vt$ ($Vt$ is the total cell volume, oil and gas) versus p. Above the bubble point pressure the function is approximated by a straight line following the nature of a slightly compressible fluid. Its slope gives the oil compressibility. It is generally in the order of $O(10^{-3})$ MPa$^{-1}$.
A function that achieves the same goal for a GC is the function $p.V_t/Z_{1ph}$. It is proportional to the number of moles in the cell. The single phase real gas factor $Z_{1ph}$ is calculated from the overall composition of the GC. Above the dew-point the function should be a straight horizontal line. In reality this is rarely the case. Firstly because the thermodynamic equilibrium might not have been reached in the cell and secondly because the correlation for the Z-factor has limited accuracy. Below the dew point the $Z$-factor is not correct. Therefore the curve departs from the straight line.
Other experiments are needed to mimic processes in the reservoir.
The typical production path of a black oil reservoir is simulated by the differential liberation experiment (DLE) is the representative experiment. When the pressure drops below the bubble point, solution gas is liberated. While in reality it partitions into the gas cap and the well stream. In the DLE it is assumed that all the gas moves to the gas cap.
The experiment tailored for the production of a GC is based on the assumption that the volume of the reservoir is constant and from step to step a portion of the gas is removed.

**Consistency checks for laboratory experiments** - Textbooks contain a tool for checking the consistency of the BO CCE: The function $Y(p,p_b,V_t,V_b)$; $b$ refers to the bubble point. It has no derivation based on thermodynamic principles, but nevertheless has proven itself to be useful. The Y-function works as well for the GC CCE. If $V_t$ is set up properly, it can also applied to the BO DLE and GC CVD. For that purpose, the cumulatively liberated gas that is removed from the cell is added numerically at each pressure step to the oil (cell) volume.

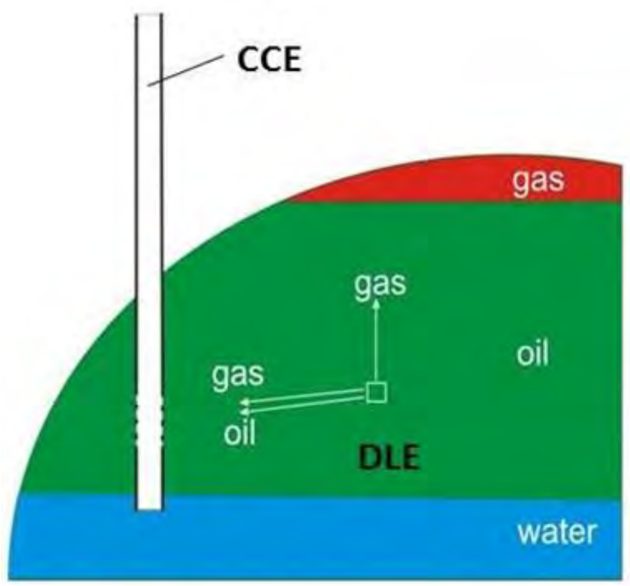
**From the reservoir to the surface, BO** - The fluid follows first a DLE inside the formation and then a CCE in the production string. In lab-experiments we see for the flash process (single step CCE) smaller values for $B_o$ and $R_s$ than in a DLE. This is the result of using different stock tank volumes (or densities) in the experiments.
The fluid undergoes in the reservoir blow the bubble point pressure a change that is characterized by the DLE curves (black lines) until it enters the tubing where it is described by the CCE. Bo and Rs are neither experimented nor known. We only know the values at $p=p_b$ and $p=p_{STC}$. In order to calculate the flash values one needs to make two assumptions: firstly, the ratio between the solution gas ration of the CCE $R_{sf}$ and the DLE $R_{sd}$ is constant and secondly, the difference between the formation volume factor – $B_{od}$ - $B_{of}$ – is proportional to the difference of the solution gas ratios $R_{sd}$ -$R_{sf}$.

**Dynamic behavior (viscosity)** - It is evident that the viscosity is reduced by the increasing amount of gas in solution with pressure increasing. The smaller molecules act as ball bearings and facilitate the easier motion of the larger molecules. That suggests a relationship between viscosity and FVF. The temperature has especially for the viscosity a major influence. It is therefore advantageous to exclude the first order temperature depenence by including the quantities at atmospheric pressure, $B_{o1}$ and $\mu_{o1}$: $\ln(\mu_{o1}/\mu_o(p)=A(1-\exp(-c(B_o(p)-B_{o1})))$. Unfortunately it is not possible to find a universal function for this dependence. The constants A and c cannot be related to $T_{res}$ or $\rho_{STO}$.

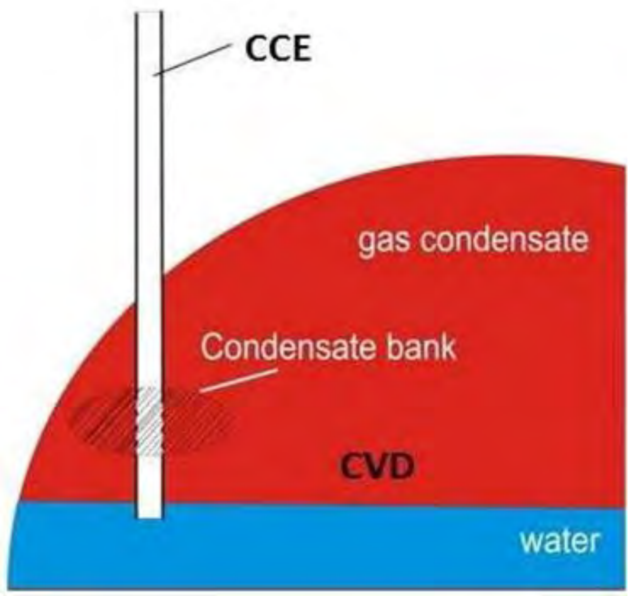
**Conclusions** - This paper covers the quality issues of PVT studies. Starting from sampling, sampling transportation to the laboratory experiments critical points are highlighted. Tools for checking the validity of reports are given, in particular

- properly defined Y-functions allow for the first time to compare CCE and DLE for BO and CCE and CVD of for GC,
- the FVF can be checked via gas in solution and gas composition,
- outliers in viscosity measurements are detectable via a relationship with the FVF.

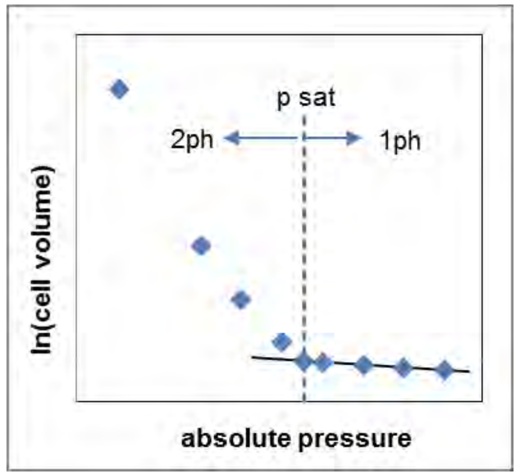
Finally, a discussion accuracy of the parameters measured listed.



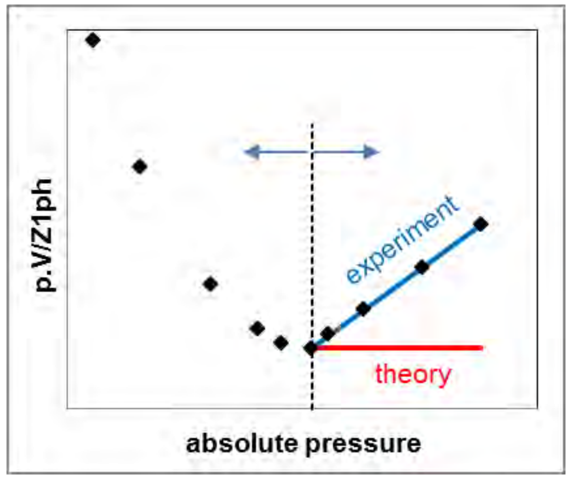

*Black oil reservoir*



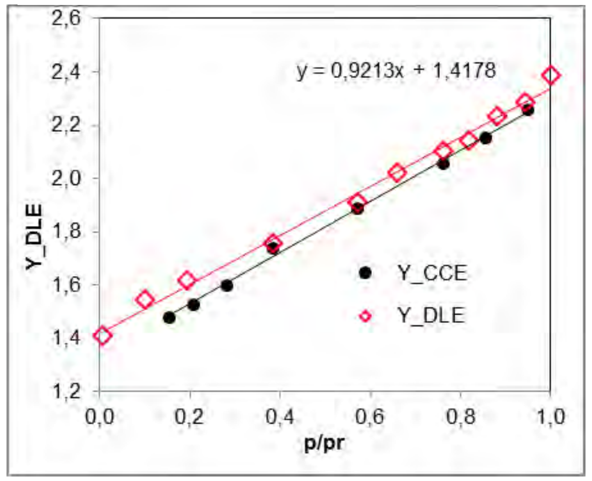

*Gas condensate reservoir*



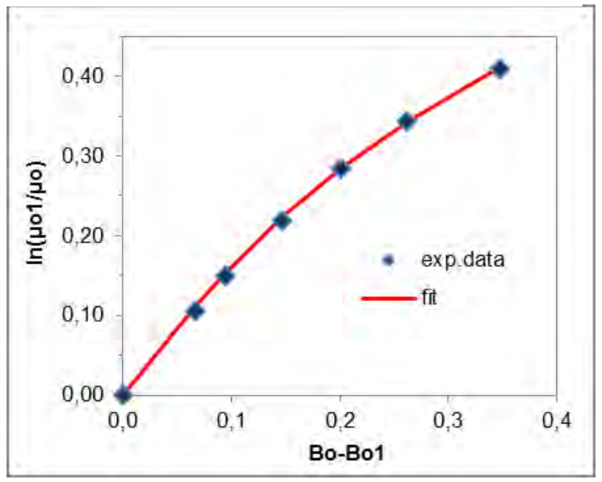

*BO CCE, determination of the bubble point pressure*




*GC CCE determination of the dew-point pressure*




*Comparison of Y-function for CCE and DLE*




*Viscosity function versus volume increase*

| | pro | con |
|---|---|---|
| BHS | sample ready for cell, no recombination necessary | risky, small volume, composition through flash that may be inaccurate in GOR,<br>Δp downhole inaccurate |
| Surface sample | easy and at any time accessible | GOR for recombination may be questionable |
| composition of a phase | detailed information | prior to analysis a flash may be necessary, what carrier gas was used, how many runs of the chromatograph were carried out?<br>Grouping of higher ends needs check |
| GOR | | changing from volume to molar units requires densities and molecular masses which are sometimes questionable for higher ends, $M_{liq}$ very inaccurate |
| recombination | | as above |
| CCE | easiest experiment accuracy depends on the type of sample, $p_b$ determination within ±1bar | if performed too fast – inaccurate<br>if p is always adjusted – thermodynamic equilibrium may not be reached, p too low or V too large<br>step sizes too large |
| DLE | | $R_s$: the gas readings may be inaccurate<br>$B_o$: limiting factor = volume reading of the cell and $V_{STO}$ |
| CVD | | reaching $V_{pd}$ after each step is difficult<br>Well stream: heavy ends may be lost in not heated valves which results in an inaccurate mass balance |

*Discussion of the overall accuracies of experiments*



# Improved Operator Insight and Maximising Production in Offshore Fields

**by Lars Anders Ruden, Emerson Process Management**

*Lars Anders Ruden*
*Strategic Marketing Manager, Roxar Flow Measurement, Emerson Process Management*

Operators today are facing significant challenges in maximising production while reducing costs – at a time of geologically complex fields, challenging operating conditions and the pressure of low oil prices.

How are my wells performing? Are there any conditions that affect production flow? How do I keep my assets working for the full life of the field? All these questions and more must be answered, with operators' ability to maximise returns dependent on understanding reservoirs and generating accurate production information.

**Measuring Flow Rates – Current Challenges**

One of the key elements behind optimising production today is the accurate measurement of flow rates and fluids.

Real-time flow rates for oil, gas and water mixtures generate vital information. They detect critical information relating to water/gas breakthrough, hydrate information and increased sand production and ensure that wells are operating to the limit of their capabilities.

Yet, accurate flow measurement also comes with significant challenges. Many oil & gas wells, for example, are being produced over a wider range of process conditions, more liquid and water are present - especially in high GVF and wet gas fields – and there is also a need to detect changing fluid composition and salinity.

Furthermore, with the current low oil prices, the presence of undetected formation water and water coning, and the dangers of hydrates, scale, corrosion, and - in worst case scenarios - well shutdowns can have a highly negative impact on the field's economics.

**New Technology Developments**

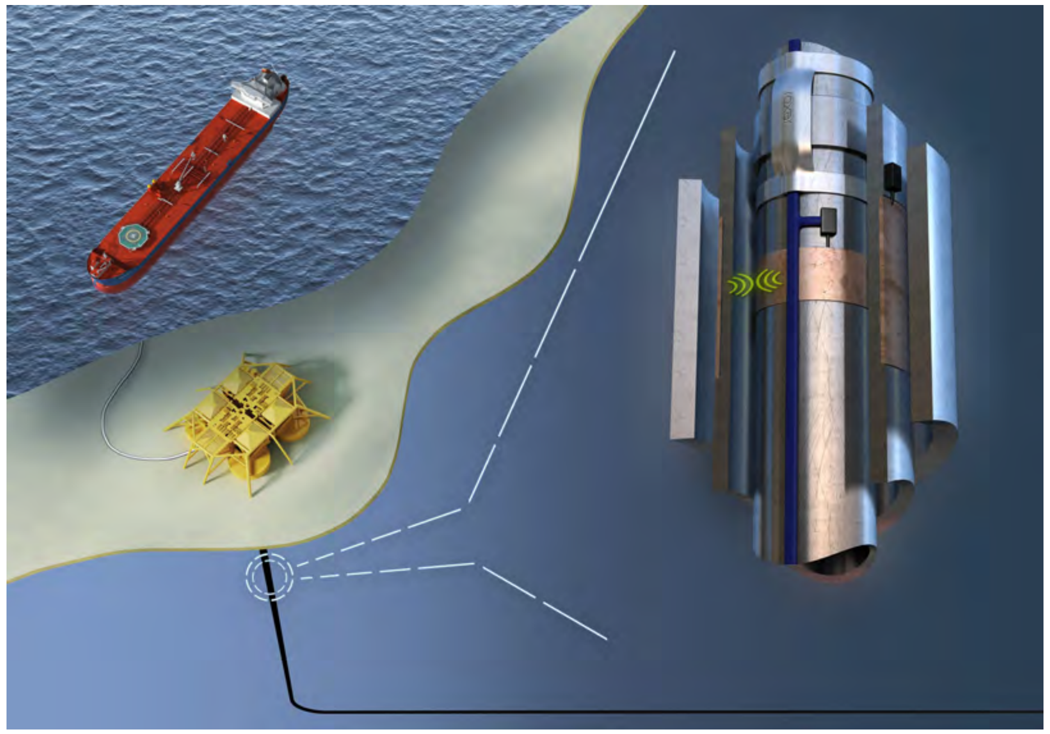
The latest technology developments in subsea and topside multiphase metering, however, are addressing these challenges.

Advanced signal processing, new field electronics (and in the case of subsea meters retrievable electronics) and electrode geometry are today providing more accurate characterizations of flow.

The field electronics system behind the Roxar Multiphase Meter, for example, allows for capacitance and conductance measurements to be combined in one unit and a Field Replaceable Insert Venturi improves accuracy and stability as well as removing uncertainties in sizing meters based on uncertain production forecasts.

The rise in wet gas fields with fast changing fluid compositions and increased salinity has also led to new technological developments that form the basis of the latest Roxar subsea Wetgas Meter.

The meter in question improves measurement uncertainty and salinity measurement as well as extends the operating range for wet gas meters. Let's take a look



*The Roxar Downhole Wireless PT Sensor System monitors annulus B pressure and temperature wirelessly and continuously online for the life of the well*


*The rise in wet gas fields with fast changing fluid compositions and increased salinity has also led to new technological developments that form the basis of the latest Roxar subsea Wetgas Meter*



at these different areas.

**Improving Measurement Uncertainty**

The microwave electronics behind wet gas meters have had a significant impact on measurement uncertainty.

The growth in digital frequency measurements has allowed for improved stability and time resolution as well as more accurate and sensitive wet gas measurements, where the microwave system is able to clearly differentiate between very small amounts of water content.

Emerson has also introduced a new multivariate analysis function, giving true PVT (Pressure, Volume, Temperature) independency on water fractions, especially in high GVF (Gas Void Fraction) flows. The multivariate analysis functionality is the result of the extensive analysis of raw data from several flow loop tests performed at Statoil's K-lab in Norway and CEESI (Colorado Experiment Engineering Station Inc.) in the United States.

It is this combination of the new microwave system with multivariate analysis that allows for an improved uncertainty specification of ±0.01% abs WVF (Water Volume Fraction) at GVF 99-100% and the detection of changes in the water content of the flowing well at as little as 0.2 ppm (parts per million). Such sensitivity has never been reached before and represents less than a droplet of water finely distributed in a volume equal to that of four car fuel tanks.

**Salinity Measurement**

Salinity measurement has also become increasingly important in managing wet gas fields and in determining risk mitigation strategies, such as chemical injection to prevent scaling and corrosion.

Recent technological developments in wet gas metering allows for the direct measurement of salinity via a new ceramic microwave based sensor.

The new sensor developed by Emerson is a dielectric cavity resonator mounted flush in the wall of the meter body, with one end facing the flow. The sensor is extremely sensitive to saline water on the sensor surface and is also highly predictable when faced with increasing salinities and water levels.

Combined with highly sensitive and accurate water measurement, the new salinity system provides a powerful and unique tool for the early detection of formation water breakthrough and the optimization of injection rates for MEG, scale and corrosion inhibitors.

**Extending the Operating Range**

Finally, another key development in wet gas metering is the extension of the operating range.

While the main focus of the new wet gas metering developments is in the 98–100% GVF range, where improved measurement uncertainty is being seen, progress is also taking place in the lower GVF as well.

As the liquid content and water content increases in the wet gas flow, the medium absorbs more and more of the microwave energy, limiting the operating range of the microwave resonance measurements. By introducing new microwave electronics that allows for transmission-based measurements in addition to resonance, this limitation can be overcome.

**Going Downhole**

Information on pressure and temperature downhole is also crucial for maximising production - not only warning the operator of threats to production and flow assurance but also providing crucial support to existing production systems, such as Electrical Submersible Pumps (ESPs) and well optimisation.

To this end, Emerson's Roxar downhole monitoring systems and high pressure and temperature gauges are today deployed in production, injection, observation and highly complex multi-zone intelligent wells across the world, where they generate reliable and real-time downhole information crucial to reservoir operations.

Statoil's Gullfaks C production platform in the North Sea, for example, has been using the same Roxar downhole gauge, uninterrupted and without maintenance or replacement for over 22 years.

Yet, there are still areas of the reservoir and the well where operators struggle to access crucial information.

One such information gap is between the well casings of subsea wells in a part of the well known as the annulus and, in particular, the annulus B located between the innermost casing strings.

While the annulus B is an area most likely to see the first indication of high pressures from further down the well, at present operators have little way of discovering this as the annulus B and the pressure & temperature information within is out of reach to operators after seating in the wellhead and the cementing of the casing.

In many cases, the completion engineer is faced with either increasing the pressure ratings of the casing to compensate for worst-case scenarios or relies on shallow well zones well to absorb pressure rises. In some instances, wells have even been unnecessarily shutdown in an effort to protect well integrity.

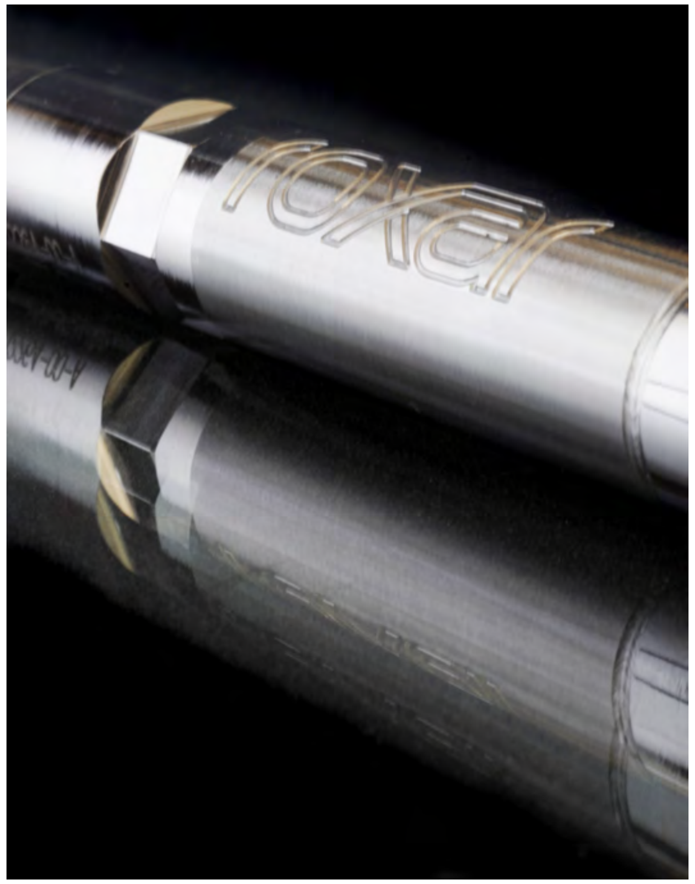
It is this need to improve the monitoring of subsea production or injection wells and, in particular, the B annulus that has driven the development of Emerson's Roxar Downhole Wireless PT Sensor System. The tool provides early warnings of abnormal pressures, protecting casing integrity and monitoring any pressure build-up and, in the worst-case scenarios, avoids production shutdown.

Emerson announced the successful first deployment of its Roxar downhole Wireless PT sensor system in 2014 on Statoil's Skuld field in the Norwegian North Sea where the result for Statoil will be a tool for well integrity monitoring and offshore safety, adherence to Norwegian safety requirements in monitoring pressure in the B annulus, and improved control over their production operations.

**A Sustainable Production Strategy**

Reservoir management today is all about creating a sustainable production strategy.

In generating real-time data on flow rates, pressure/temperature data and salinity, operators can enjoy improved insight into well production and a maximising of production in offshore fields.




*Emerson's Roxar downhole monitoring systems and high pressure and temperature gauges are today deployed across the world*

# The Earth's fastest and most scalable reservoir simulator..... in the cloud!

**by Alberto Diaz, Simulation Engineer, Rock Flow Dynamics**

*Alberto Diaz*
*Simulation Engineer,*
*Rock Flow Dynamics*

**"What is the shape of water?" asks one Senior Reservoir Engineer with a wry smile. Then looks down at his coffee mug, pointing at what is in all essence hot water (perhaps some steam) plus coffee beans (now in a new form from their original state only 5 minutes earlier). To accentuate the point the Senior Reservoir Engineer proceeds to lift the coffee mug, takes a gulp, and once consumed asks, (again with a wry smile) "what shape is it now?!?!".**

The point that is being made is that describing the shape of water itself is actually really quite complex. What form is it in? What temperature is it? Where is it situated and what supporting structures does it own? Are there other factors affecting its shape that we need to consider?

Of course, the reality is that the shape of water is really quite complex. In actual fact, it's really rather difficult to describe and define too. Particularly when there are always other factors that can affect the shape of water that are completely out of the control of an individual, for example the temperature in the room or if you are in a coffee shop that has heavy traffic of people of vehicles outside causing constant vibrations. So one may say…..there is always room for a degree of uncertainty when we answer the original question of "what is the shape of water?".

"But wait just a second……..does the water know what shape it has?", provokes the Senior Reservoir Engineer.

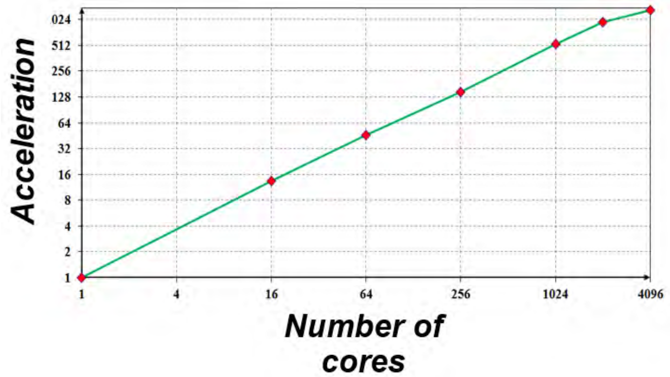
Well of course the water knows what shape it is. It is indeed the subject matter and does not need to define itself to anyone. If it alters form……it does so without having to tell anyone or worry about the consequences.

We are now 293 words later writing about a mug of coffee which let's be fair, is far from defined. If we amplify this concept to an oil field in the North Sea, let us consider some possible dimensions. The field lies on top of 100 metres of water at total depth of 1,500 metres; the reservoir is 22 square kilometres and has an average pay thickness of say give or take 50 meters. What shape is the oil??? And how many cups of coffee would that look like???

The uncertainty we face as an industry is enormous. And when we consider the costs involved in an attempt to successfully and commercially recover hydrocarbons it is essential that we reduce limitations on how we study our reservoirs in search of optimal 'bang for buck'. Many may therefore agree that the role of a Reservoir Engineer is to communicate the probabilities for success to those who make the decisions to drill.

Reservoir simulation is a widely accepted technical practice when planning to drill. It is an exercise that offers technology to use intelligent mathematical algorithms given a range of parameters and assumptions to describe the physical aspects within a reservoir and predict fluid flow behaviour.

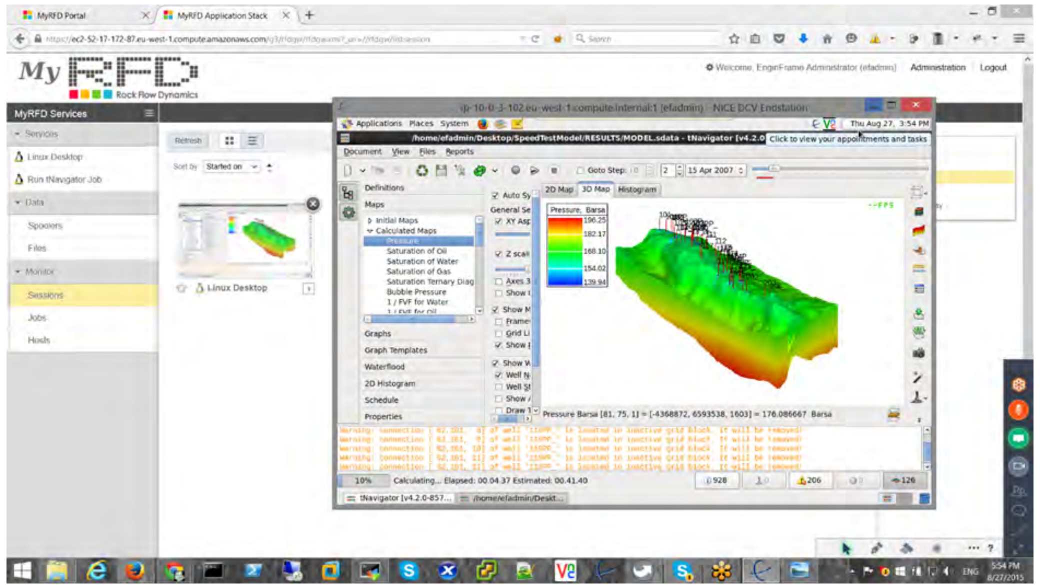
The point of simulation is that in comparison to the reality of drilling a well, it is very cheap. One may run many simulations of drilling scenarios on a field at a tiny fraction of the actual cost. It helps us to understand the potential behaviour of the well in order to make the best decisions.




The ethos behind the development of the tNavigator reservoir simulator was to create a reservoir simulation technology that was built for speed. If a model can be run fast, it offers two undeniable benefits. Number 1 is that you have additional time to run more simulations, therefore having more data to analyse as your results provide a greater range of probabilities to be considered. And number 2 is that if the simulation is faster the reservoir engineer has more time to actually do the analysis (and challenge it) which in itself should allow the probability range to be better understood and better defined. tNavigator has seen an exceptional rise in growth with the industry recognising the benefit of speed. This is coupled with a synchronised user interface to visualise data on the fly during simulation allowing the engineer to really interrogate data that was previously difficult or impossible to get at.

The vision was to change the way the industry thought about simulation. Addressing complex, full fielded, high resolution models to run them in a reasonable time frame at a cost friendly price. The unique 'Hybrid Algorithm' that embodies tNavigator allows near unlimited scalability on the acceleration of reservoir simulation models.



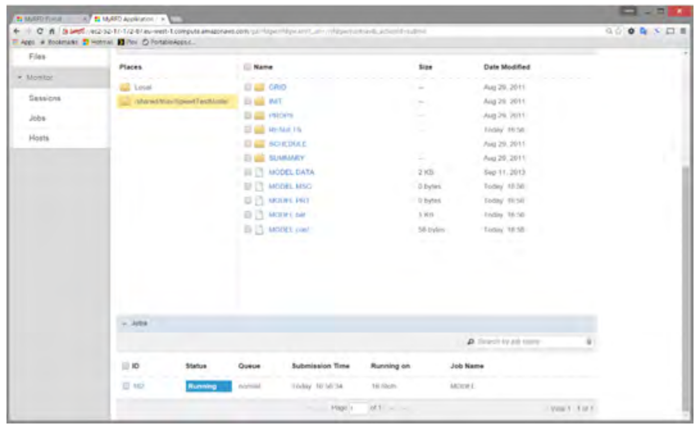


Such examples of scalability include a 22 million active cell model being run on 4096 cores showing the simulation time reduced from 2.5 weeks to just 19 minutes; a model running at 6 weeks being run on only 320 cores at 5 hours; and a 43.5 million active cell model being reduced from 3 days to just 40 minutes on 240 cores.

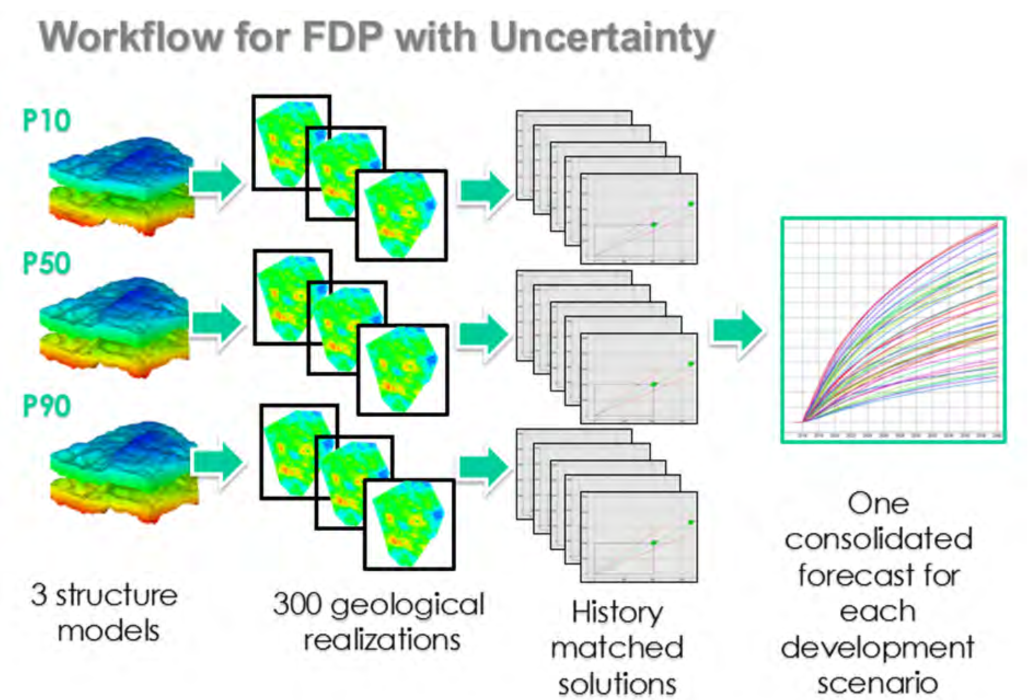
All different sizes of oil companies are seeing the value of introducing a cluster to their business for reservoir simulation practice. Their engineers now become far more productive and the implementation of such hardware is a very low burden on the IT department, space and resources.

The imminent next direction for all of this 'game changing' technology is to be available on the cloud. Rock Flow Dynamics have created a fully-fledged cloud solution. The user / business can create an account, upload data and work with the functionality that would be available on a tNavigator user desktop screen. It offers access to giant High Performance Computing clusters with no additional investment of computing power is required inside of the office.

The industry will have some reservations about cloud based offerings. Number 1 is undoubtedly security? tNavigator initially will be available on Amazon Web Services (AWS). The same guys we give our credit card details to every year in order to buy presents and search for new clothes, music, kitchenware etc. The highest protection available is being used to secure data with no stone left unturned.



AWS are seen as a prime fit for reservoir simulations in the cloud. They have more available hardware than all other commercial cloud services and state of the art node configuration to allow a seriously scalable simulation offering. Clients eagerly anticipate the launch of the fully fledged cloud solution and see it as an ideal pairing for a lightweight in-house cluster where the reservoir engineers can do the day to day jobs, and then for larger scale uncertainty studies with thousands of reservoir model iterations there are cloud based applications with unlimited computational hardware available.




One of many case studies using cloud based hardware comes from a project that incorporates uncertainty quantification and probabilistic forecasts into the same simulation workflow.

The workflow involved 3 structural models with P10, P50 and P90 ranges. 300 geological realisations of each model were then history matched and consolidated for each development scenario. 83 history matched forecasts were used to provide conclusions. In order to get to this point, some 8100 history matched cycles were run over 2 days using a giant cluster.

The cloud is the perfect match for allowing the reservoir engineer to make probabilities less uncertain. We will never fully define the shape of our reservoir……..but we can undoubtedly get a lot closer to the 'truth'.

# Enhancing Drilling Efficiencies, Reducing Costs and Creating a Safer Environment

**by Tore Grelland, Cubility AS**

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The quality of drilling fluids, drilling waste volumes and issues around Health, Safety & the Environment (HSE) represent major cost and efficiency issues in today's drilling environment, particularly with the current low oil prices.

Drilling costs, for example, are predicted to come down by a third by 2016, according to industry analysts Wood Mackenzie. While reduction in rig and vessel rates are likely to account for a major portion of these savings, there is also an increased focus on solids control to support such cost efficiencies as well as improve drilling performance.

**The Importance of Drilling Fluids & Traditional Technology Limitations**

Drilling fluids - also known as muds - play a crucial role in North Sea and global drilling activity today. They cool and lubricate drill bits, carry drill cuttings to the surface, control pressure at the bottom of the well, and ensure that the formation retains the properties defined for that well.

Yet, despite their crucial role, for too often the solid control technologies that guarantee their effectiveness remain rooted in the past. Any effective drilling fluids strategy is dependent on the efficient separation of drilled solids from the drilling fluids and yet traditional technologies come with significant limitations.

Chief among these technologies is the shale shaker. The shaker is a vibrating sieve where a metal cloth screen vibrates, generating high G-forces, while the drilling fluids and other elements returning from the well flow on top of it.

Through the vibration and high G-forces, solids are filtered out for overboard discharge or for treatment on the rig or onshore and the cleaned mud is then re-incorporated into the active fluid system and reused to drill the well.

Yet, the high G-forces from shale shakers often break down the drilled solids into too finer particles, reducing the ability to remove them and increasing the solids content in the drilling fluids.

The result is a decline in drilling fluid efficiency. This can lead to a negative impact on penetration rates and Equivalent Circulating Density (ECD) and also generate wear and tear on both surface and downhole equipment.

Another drawback is that vibrating type shale shakers often result in high volumes of mud being lost with large amounts of drilling waste generated and less mud able to be reused within the system. With the cost of an average oil-based mud used on the Norwegian Continental Shelf around US$1,300 per cubic meter and the treatment and disposal of drilling waste conservatively estimated to cost US$1,580-1,750 per ton, any mud that isn't reused can have a highly negative cost implication.

The same goes for the chemicals required to maintain the mud's properties.

Finally, from an HSE standpoint, shale shakers lead to a poor working environment with personnel exposure to high noise levels and vibrations as well as the emission of oil and other vapours.

**An Alternative Solution – The MudCube®**

It's against this backdrop that drilling contractors and operators today are looking for an alternative means of separating and treating drilling fluids on onshore and offshore facilities. One such alternative is the MudCube® from Norwegian-based company Cubility.

The MudCube is the industry's first compact solids control system that eliminates the traditional process of using high levels of vibration and shaking for separating fluids and solids.

With the MudCube, drilling fluids are vacuumed through a rotating filter belt using high airflow to separate the cuttings from the fluid more effectively. The cleaned drilling fluids are then returned to the active mud system and the drilled solids - carried forward on the filter belt - are discharged either directly overboard (if they meet environmental discharge regulations) or to a cuttings handling system.

The improved separation capabilities of the MudCube leads to better quality mud, fewer chemicals required to maintain the mud's properties (one operator and mud company recently reported the reduced use of premix chemicals as bringing savings of as much as $270,000), more mud recycled back to the mud tanks to be reused for drilling, and less waste.

As mud properties are field proven to be very stable throughout the entire well when using the MudCube, there are also corresponding low maintenance requirements to control drilling fluid properties with optimum parameters. For drilling rigs costing millions of dollars a day, the financial benefits of this are clear.

Effective solid control from the MudCube also results in improved drilling efficiencies with higher rates of penetration (ROP), reduced stuck pipe incidents, and wellbore stability.

Another benefit comes from the size of the MudCube and the fact that it can free up much-needed rig space and weight and improving the drilling rig's variable deck loads (VDL). It is estimated that a typical MudCube-system can save up to 25 tons on existing facilities and much more on new-builds.

Finally, the remote, automated operations of the MudCube and its' enclosed system with reduced vibration and noise levels and the elimination of oil vapour also brings considerable workplace benefits. At a time when HSE regulations are becoming increasingly stringent in the North Sea and elsewhere, this is a significant benefit.



Cubility's MudCube

Cubility's MudCube

**Global Applications**

Since its 2012 introduction to market, the MudCube has been adopted on offshore and onshore rigs in the North Sea, Far East, North and South America and the Middle East.

Applications include installation on the Maersk Gallant rig where the MudCube is addressing space utilization, HVAC and HSE issues; the Maersk Giant rig which led to improved working conditions and drilling efficiencies with less drilling fluid being lost and more returned to the mud tanks for reuse; the Maersk Resolve rig in Denmark; the Peregrino A platform operated by Statoil Brazil where the conventional solution was not controlling solids effectively when drilling in sand formations;; and the Scarabeo 5 platform in the Norwegian Continental Shelf.

Since installation, the Maersk Giant has embarked on an ambitious drilling program in the North Sea with the MudCubes used in the drilling of thirteen wells to date.

Cubility has also recently signed a multi-million dollar deal on the Johan Sverdrup field, one of the most important industrial projects in Norway over the next 50 years. Located 155 kilometers west of Stavanger, Johan Sverdrup is one of the five biggest oil fields on the Norwegian Continental Shelf with expected resources of between 1.7 to 3 billion barrels of oil equivalent. Production start-up is scheduled for the end of end 2019 and will consist of four platforms on which the MudCubes will be based.

In this case, the MudCube will provide the operator Statoil with improved drilling efficiencies, lower mud consumption, reduced waste volumes and improved HSE. The partnership is also testament to the long-term partnership and collaboration Cubility has enjoyed with Statoil.

**Improving Drilling Efficiencies**

It's only through challenging traditional technologies and focusing on innovation that drilling efficiencies can be realised, costs contained and a safer environment generated in today's oil & gas sector. It's through tools, such as the MudCube, that operators can put in place effective solids control strategies that achieve these goals.

# Source Rock Evaluation of Triassic Black Shales from Austria

**by Nektaria Panou & Steven Mueller, Oslo University**

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The lower Carnian (Late Triassic) black shale intervals in the Northern Calcareous Alps (NCA) in Austria are organic rich deposits that were deposited in a marine environment on the north-western Tethys shelf. They represent potential petroleum source rocks.
At the time of deposition, the area was characterized by the demise of carbonate platforms and reefs, accompanied by a biotic turnover and environmental changes (Simms and Ruffell, 1990). A lithological change from carbonates to siliciclastics is interpreted to be the result of increased continental runoff. Increased runoff, in turn, was caused by a phase of increased precipitation in the adjacent continental areas and is known as Carnian Pluvial Event (CPE).

**Geological setting**
The investigated area is located around Lunz am See approximately 100km west of Vienna (Fig.1). The studied sequence is cropping out at several locations in the region. The sections compose a lithostratigraphical succession from the Reifling Formation, the Göstling Member and the Reingraben Formation (Fig.2). Initially, the carbonate platform fed the basin in which the limestones were deposited. With the onset of the CPE the sea-level dropped (Hornung et al., 2007). The platform demise started when periplatform–mud with reefal influence deposited in a deep and low–energy setting (Göstling Member) (Hornung and Brandner, 2005). The increase in fresh water caused a nutrient excess and lead to oxygen depletion due to eutrophication (Hornung et al., 2007). Then decrease in the oxygen supply continued and indicated a dysaerobic setting. Subsequently, a massive river system running from the Fennoscandian Craton across most of Western Europe deposited large volumes of siliciclastic sediments into the shallow shelfs leading to a drowning of the carbonate platforms (Arche and López-Gómez, 2014). The high terrigenous influx and very low carbonate supply resulted in an almost restricted anoxic setting (Hornung and Brandner, 2005). This sedimentological change in the Western Tethys region of the NCA is regionally also known as the Reingraben Turnover (Schlager and Schöllnberger, 1974).

**Methods**
Palynofacies analysis on microscopic slides and Rock-Eval pyrolysis from crushed rock samples were performed on sedimentary organic matter extracted from these Carnian black shales covering the CPE. In addition, the data were integrated with bulk C-isotope data from organic matter and organic carbon data (TOC). The results are used for the reconstruction of the palaeoenvironmental conditions during the black shale formation and source rock potential.
Palynological slide preparation was done according to standard procedures at the University of Oslo, bulk $\delta^{13}C_{org}$ and TOC analysis was performed with an Elemental Analyzer–Isotope Ratio Mass Spectrometer (EA–IRMS), by Iso Analytical Ltd (UK). The Rock-Eval analysis was carried out at Deltares (The Netherlands). For palynofacies analysis approximately 300 particles per slide were counted with Nikon Optiphot (transmitted light) and a Leitz Diaplan (fluorescence light) microscopes with magnifications of ×20, ×40 and ×65 (oil immersion).
The paleoenvironmental interpretation is based on palynofacies kerogen classification and the AOM-phytoclast-palynomorph (APP) ternary diagram (Tyson 1993, 1995). The source rock potential is based on quality, quantity and thermal maturity of the organic matter.

**Results and discussion**
The interpretation of the results shows that the sediments were deposited in an epeiric neritic shelf of dysoxic-anoxic redox conditions with small intervals of suboxic-oxic and high algae and bacteria productivity (Fig. 3). The high productivity was caused by the humid climate during the CPE. Rivers from the Fennoscandinavian hinterland transported nutrients into the depositional setting and created stagnating conditions in the shelf basin which resulted in eutrophication due to flourishing algae and bacteria. The high content of amorphous organic matter (AOM), up to 15% in the claystones of Göstling Member, is of algal-bacterial origin and is a result of the high concentration of organic matter. Furthermore, a negative bulk carbon isotope excursion coincides with the change in organic matter (Fig. 4). This excursion is thought to be related to the release of isotopically lighter carbon as a result of a volcanic eruption which had a global impact on the carbon cycle (e.g. Dal Corso et al., 2012).
Rock-Eval pyrolysis results are combined with palynofacies data for evaluating the source rock potential of these black shales (Fig. 4). The majority of the studied rocks have TOC values of less than 2% and are interpreted to be barren or contain only gas prone hydrocarbons. Only few source rocks contain sufficient TOC to be economically relevant with TOC values of more than 2%; they are mainly gas prone. In addition, the rocks are immature with $T_{max}$ values lower than 435°C and a production index of less than 0.1. Very few source rocks have reached an early/peak maturity stage. The clay intercalations of the Reifling Formation are considered as kerogen type IV (inert), while the palynofacies suggests kerogen type III (gas-prone). This discrepancy is due the high abundance of wood particles that show a weak fluorescence and indicates oxidized particles; these opaque particles are inertinite. The Göstling Member contains mudstone intervals that are characterized by kerogen type III but the palynofacies show



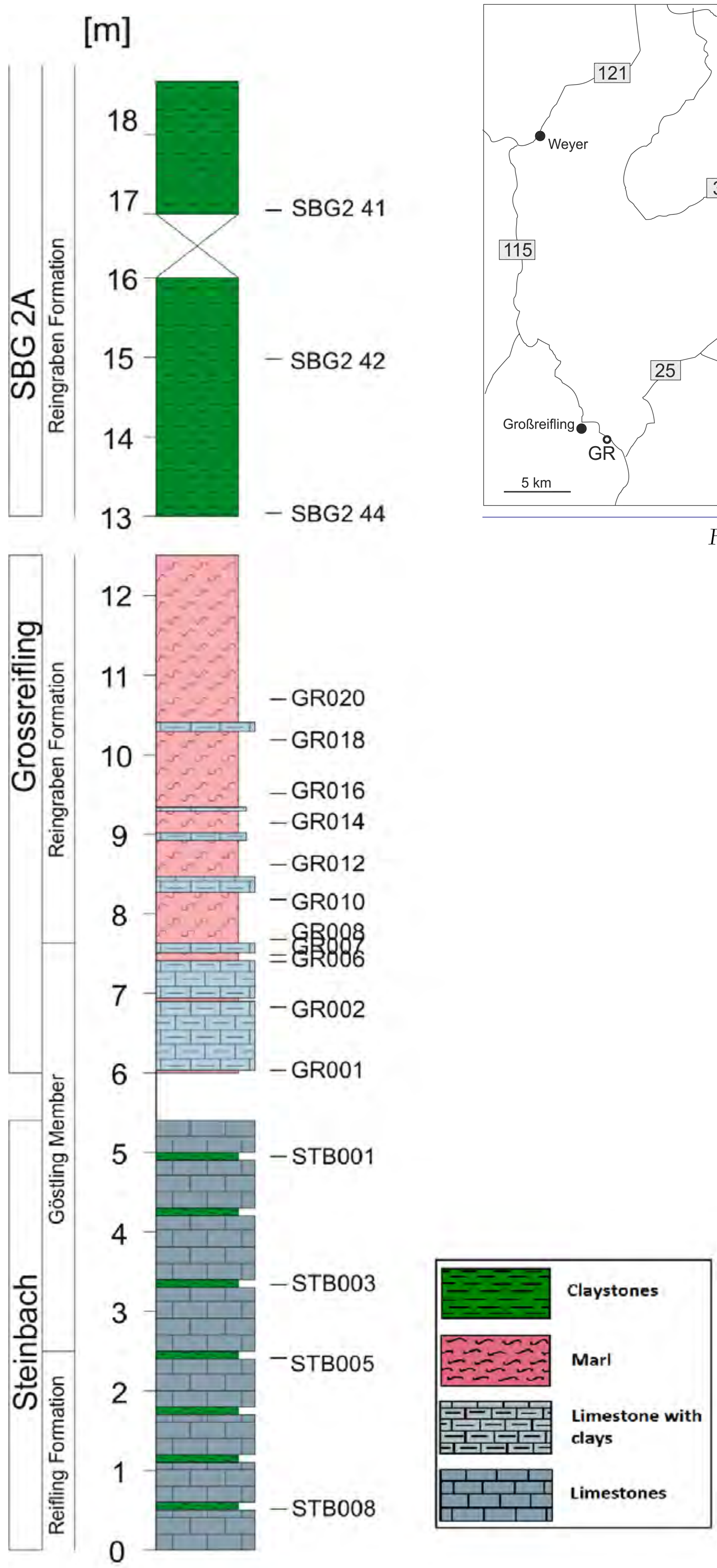


Fig.2: The lithostratigraphy and samples of the studied succession (Panou, 2015)

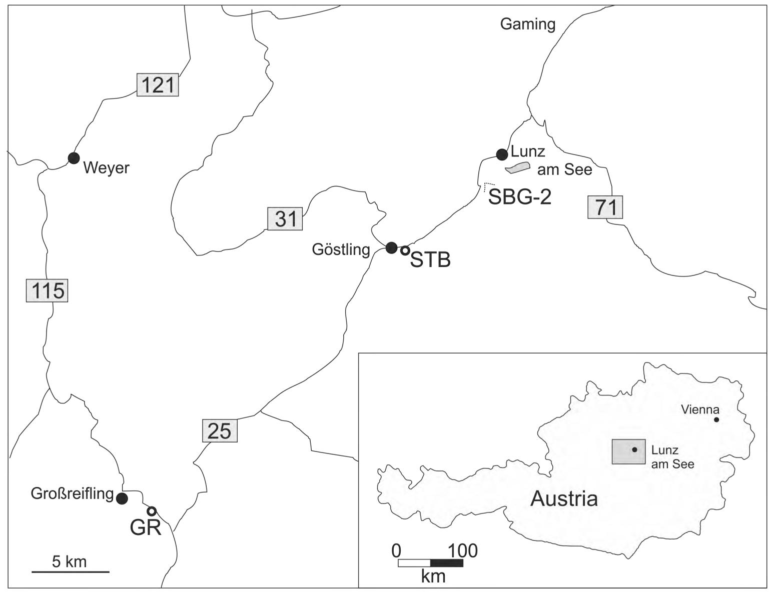


*Fig. 1: Map of outcrop localities (from Panou, 2015)*

kerogen type II (oil-gas-prone) due to high concentrations of AOM and more marine algae. The TOC values reach up to 15% in the lower part of the Member indicating excellent to good hydrocarbon potential. However, the Hydrogen Index (HI) is low. This misleading is explained by the high degree of weathering of the outcrops where the samples were taken. Additionally, the limited thickness of the source rock intervals prevented generating economic volumes of hydrocarbons. Lastly, the organic rich Reingraben Formation is mainly of kerogen type III whereas palynofacies show kerogen type II. The weathered outcrop samples influence the HI to lower values. Nevertheless, the TOC is lower than 2%, this verifies that these shale intervals could potentially only have generated only small gaseous amounts of hydrocarbons. The upward part of the Reingraben Formation is characterized by poor source rock quality and is a type IV kerogen. These samples contain mainly translucent phytoclasts which are weakly fluorescent and indicate that they are oxidized particles (pre-form of opaque phytoclasts).

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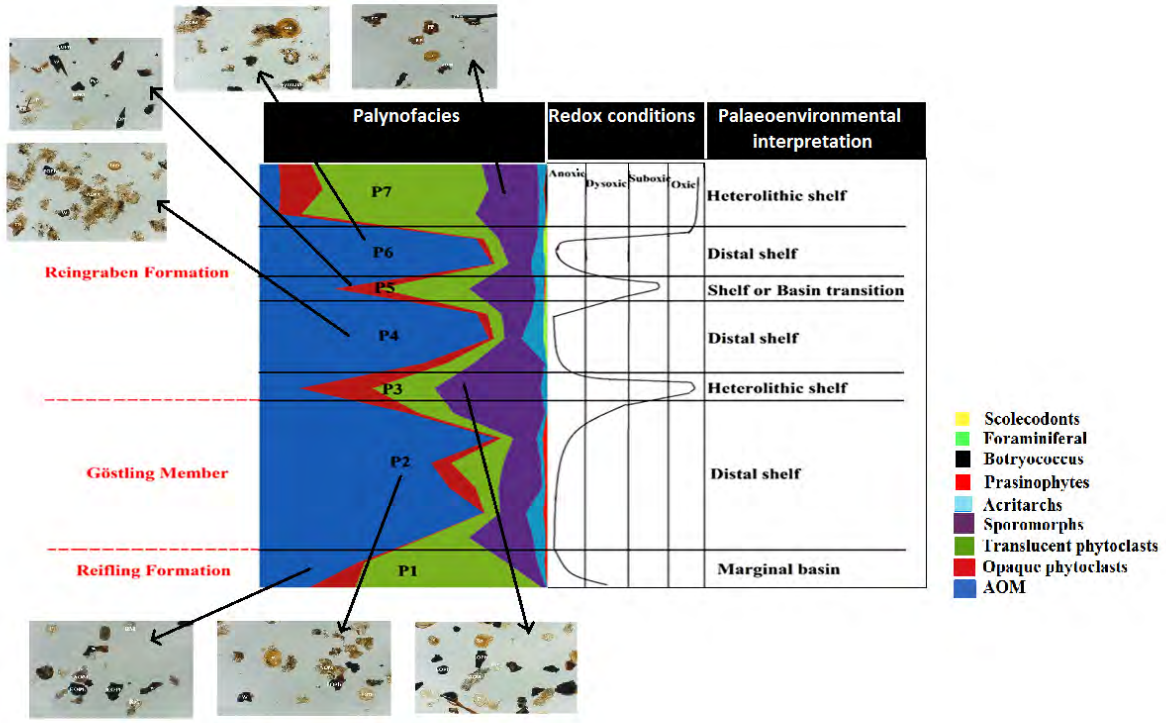


*Fig.3: Palynofacies, redox conditions and palaeoenvironmental interpretation throughout the succession. The images are representatives of each palynofacies (Panou, 2015)*

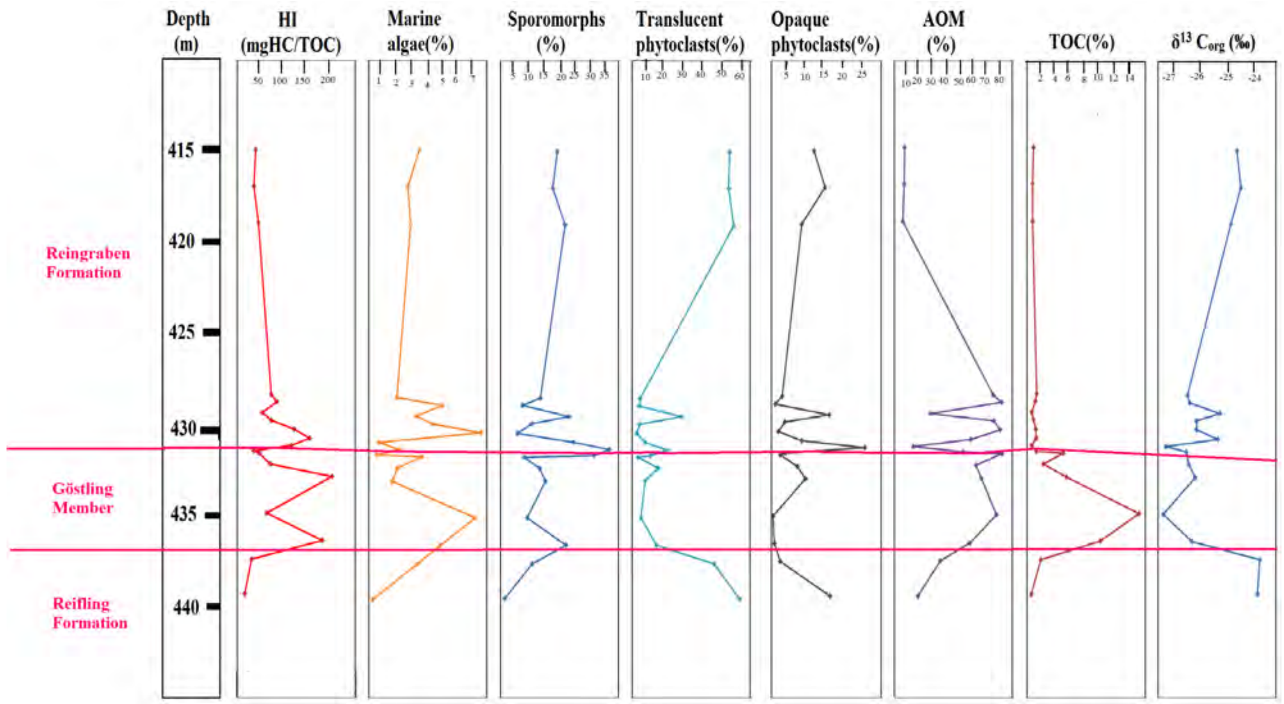


*Fig. 4: The main palynofacies categories compared to HI, TOC and $\delta^{13}C_{org}$ (Panou, 2015)*

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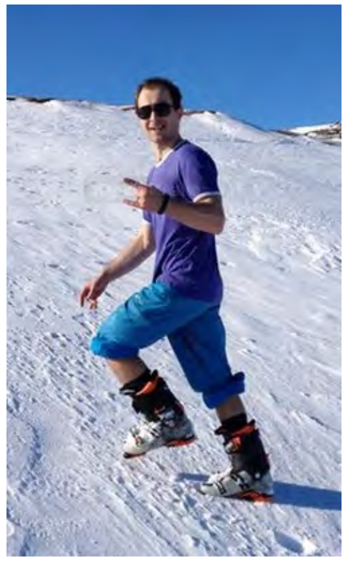
# P-wave AVO in tilted transversely isotropic media

**by Yuriy Ivanov, NTNU, Trondheim**



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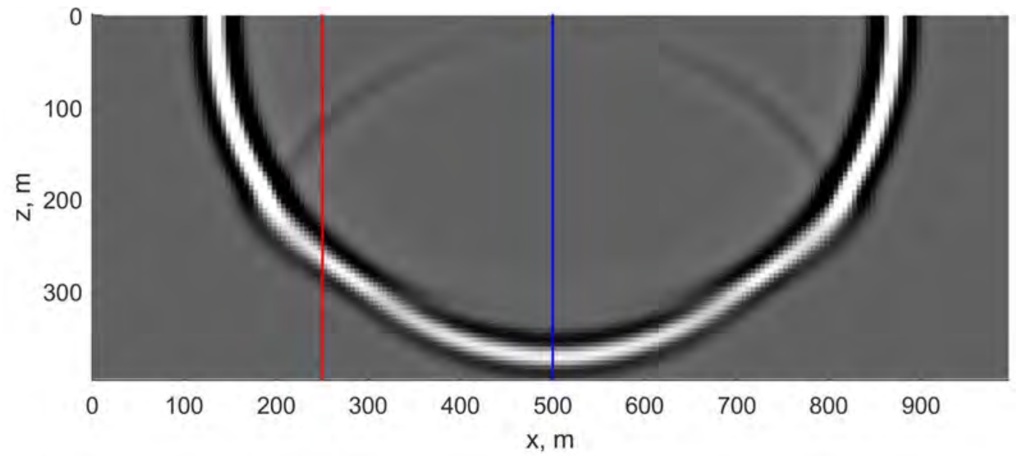
The importance of accounting for seismic anisotropy in seismic exploration and reservoir exploitation has become an accepted fact somewhat two decades ago. Nowadays, modern processing work flow would include seismic anisotropy and very often seismic acquisition is planned in such a way that seismic anisotropy can be estimated.

Anisotropy is the dependence of a physical property (in seismic case, we are talking about seismic wave propagation velocity $v$) upon the direction of measurement. Mathematically it can be formulated in the following way:

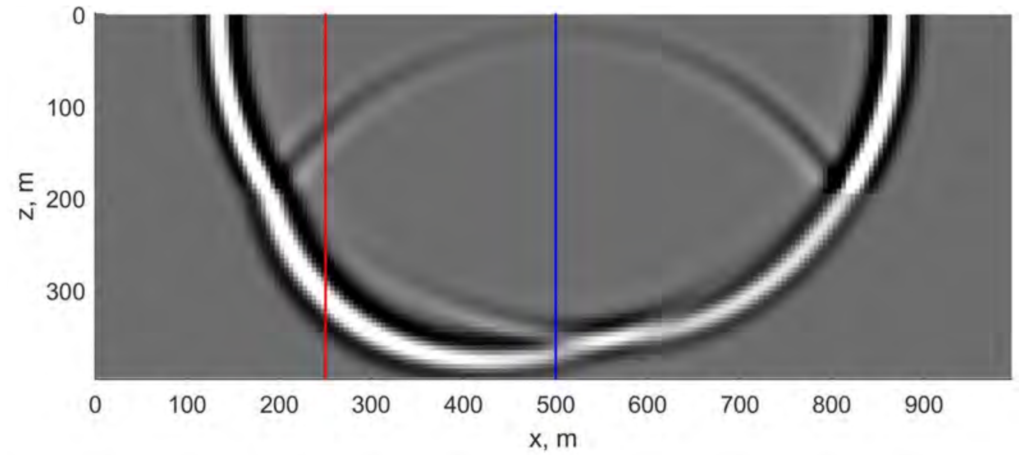
$$v \equiv v(\vec{x}, \vec{n}),$$

velocity $v$ is measured at the point $\vec{x}$ in space along the direction $\vec{n}$. As a result, anisotropy affects both kinematic and dynamic properties of the wavefield, and if we are to obtain a reliable subsurface image, it cannot be ignored. Anisotropy in subsurface is very often associated with intrinsic properties of rocks, fine layering, or sets of fractures (which can occur due to e.g. special stress regime). Understanding of the seismic anisotropy can be useful in exploration and reservoir characterization since it can provide additional important information. For example, shale reservoirs are very often discovered based on the effect of seismic anisotropy. There is number of different mathematical models to describe seismic anisotropy. The simplest is vertical transverse isotropy or VTI model. Finely (compared to the wavelength) layered medium will exhibit VTI properties, affecting seismic wave propagation through it.

Amplitude variation with offset techniques are widely used nowadays, because reflection amplitudes are highly resolved in depth/time, unlike traveltime methods, providing a detailed measure of local properties of the subsurface. It has been also noticed that effect of seismic anisotropy on reflected and transmitted amplitudes is strong even when the magnitude of anisotropy is small (Ruger, 1998) and, hence, can be estimated using AVO analysis. Understanding the behavior of P-wave reflection coefficient in presence of anisotropy

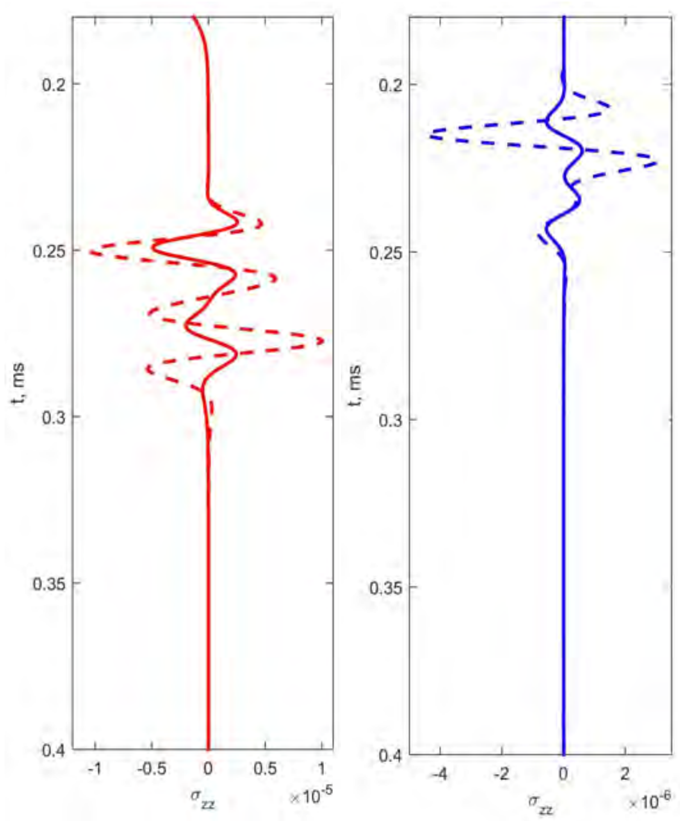



*(a) VTI layer*




*(b) TTI layer*

*Figure 1: Wavefront distortion due to presence of TTI anisotropy*




*(a) Receiver at 250m* *(b) Receiver at 500m*

*Figure 2: Distortion of reflected amplitudesdue to presence of TTI anisotropy*

is crucial for this purposes. Analytical expression for P-wave reflection coefficient even in the case of isotropic media is too complicated to provide insight into the influence of medium parameters. In order to overcome this problem, various approximations are developed in the assumption of weak contrast at the reflection boundary and weak anisotropy (Thomsen, 1986). Existing approximations are developed in case of vertical (VTI) or horizontal (horizontal transverse isotropy or HTI) symmetry axis (equivalent to horizontal and vertical stratification or fractures). However, in reality, it is not rare to find rock beds or set of fractures tilted with respect to the reflection boundary. These complex situations can be described by a more general model such as transverse isotropy with a tilted axis of symmetry (TTI), and can occur, for example, near the flanks of salt domes or in fold-and-thrust belts (Isaac and Lawton, 2004). The importance of fracture sets, especially dipping, characterization for the industry has been increased over the past decade. As an example, fractures in the Emilio field (Adriatic Sea) are identified and characterized by Angerer et al. (2002). One important effect of TTI anisotropy is that reflected *S*-wave can occur on vertical and near-vertical *P*-wave incidence angles.

In present study, I demonstrate the effect of tilt angle on wavefield and in particular, on the reflected amplitudes. Proposed 3D approximation for the 3D plane-wave *P*-wave reflection coefficient at the boundary between TTI half-spaces is not shown here due to complexity of the expression (Ivanov and Stovas, 2015). Figure 1 shows how tilt affects the wavefront of the P-wave traveling in TTI layer after it has encountered a boundary. Model consists of two layers with a horizontal boundary at the depth of 200 m, top layer is isotropic, bottom - TTI. Layers have identical properties ($v_{P0}$=2.3 km/s, $v_{S0}$=1.8 km/s (velocities along the symmetry axis for anisotropic layer), $\rho$=2.3 g/cm3 anisotropy is introduced into layer 2 ($\varepsilon$=0.25, $\delta$=–0.2).

P-wave source is located at the surface at x=500 m. Receivers are located at the surface z=0. In Figure 1a tilt angle introduced into layer two is 0°, we observe symmetrical wavefront, whereas tilt of 45° (counterclockwise) is introduced into layer two in Figure 1b. Wavefront distortion is clearly visible. Effect of the tilt angle upon amplitudes can be seen in Figure 2, where color represents the receiver where signal was measured (according to (Figure 1), solid line corresponds to VTI case, and dashed line - to TTI. Reflected P-wave AVO curves extracted from recorded seismograms are show in Figure 3. It can be seen that overall amplitude along the profile is higher for the model with TTI layer. Another important observation is that minimum of the TTI amplitude curve is shifted from the normal incidence location (offset=0) towards the "dip of layers" constituting TTI medium.

Present study shows that dependence of the P-wave refection coefficient on the direction of symmetry axis even for a weakly anisotropic medium is strong and complex and cannot be neglected. Using of anisotropic (TTI) AVO in combination with other methods of fracture characterization can be used to increase the amount and accuracy of information about fractured reservoirs derived from conventional seismic data.

*Author is thankful to Wiktor W. Weibull for the finite difference code.*

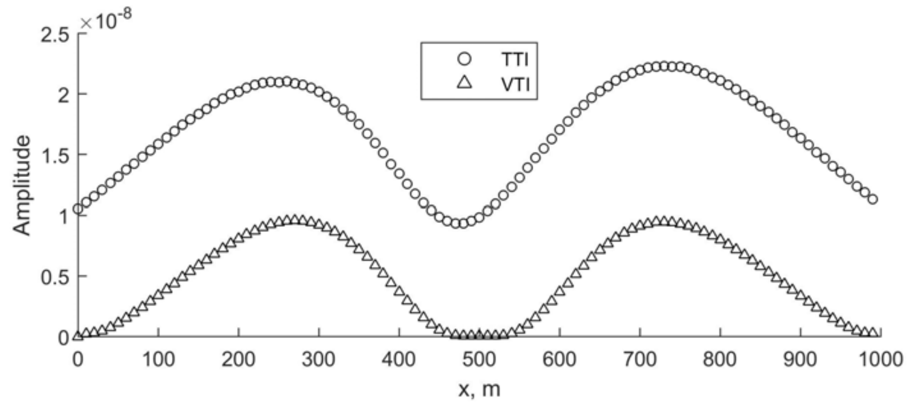



*Figure 3: Comparison of P-wave AVO curves for VTI and TTI models*

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# Depth migration model building and model verification sequence

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The importance of using a correct velocity model for seismic migration process is not deniable. Nevertheless, even for the most sophisticated modern migration algorithms velocity model building is ignored or simplified to an interval seismic velocity. In this article, we will share a very simple and effective way of constructing velocity models for migrations and depth conversions. Also, we will show how radically better well known Kirchhoff Anisotropic Wavefront Propagation Depth migration result (based on proper velocity building model and appropriate applied pre-migration processing sequences) can be compared to depth migrated data by one of the modern algorithms.

PSS-Geo provides Kirchhoff Anisotropic (TVI &TTI) Wavefront Propagation Depth migration from anisotropic interval velocity models. Such models are built in a step by step manner involving integration of diverse geophysical information in multiple iterations of imaging at progressively deeper depths to continuously update and verify the model.

Our methodology is based on the definition of a vertical interval velocity model and an anisotropy field. As a rule of thumb the vertical velocity field should represent a valid Time/depth function typically used for depth conversion in interpretation work; the anisotropy field should be congruous with surface seismic velocities as for its sub horizontal raypaths.

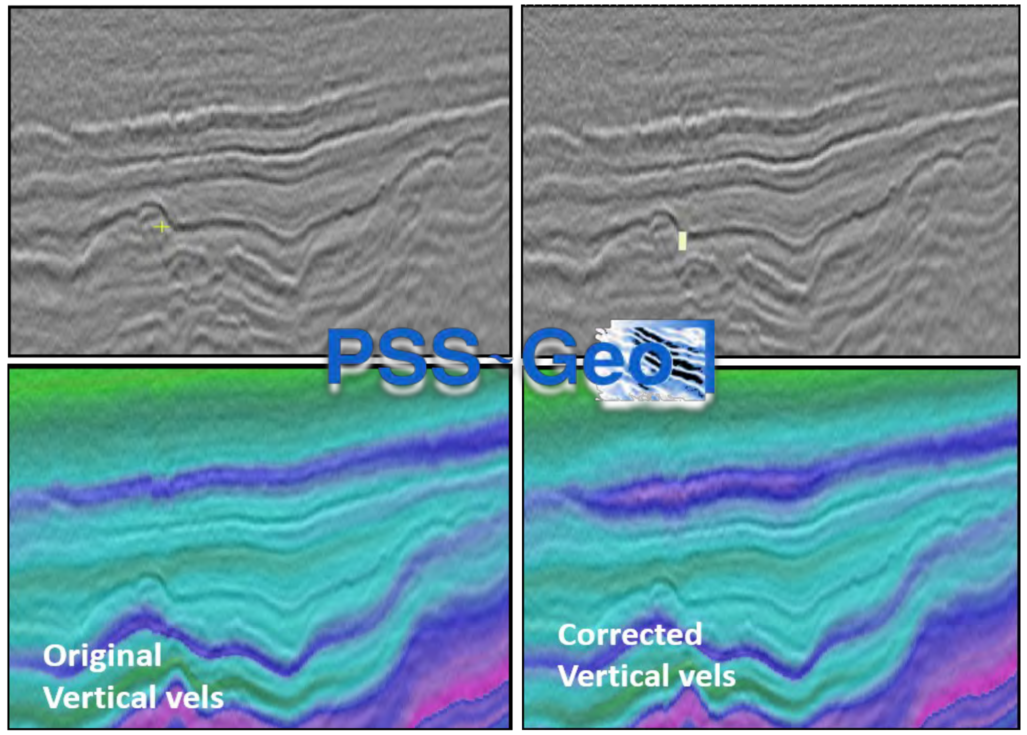
We are focused on the creation of models that are both correct in the time and depth relationship and highly plausible from the geological interpretive point of view. The objective of the anisotropic approach is to optimize the image quality - flat gathers - and to tie the main reflectors to the wells within 1% whilst still maintaining a geologically sensible spatial distribution of the velocities for each layer. A typical sequence will include a:

**1) Building a starting interval anisotropic velocity model**

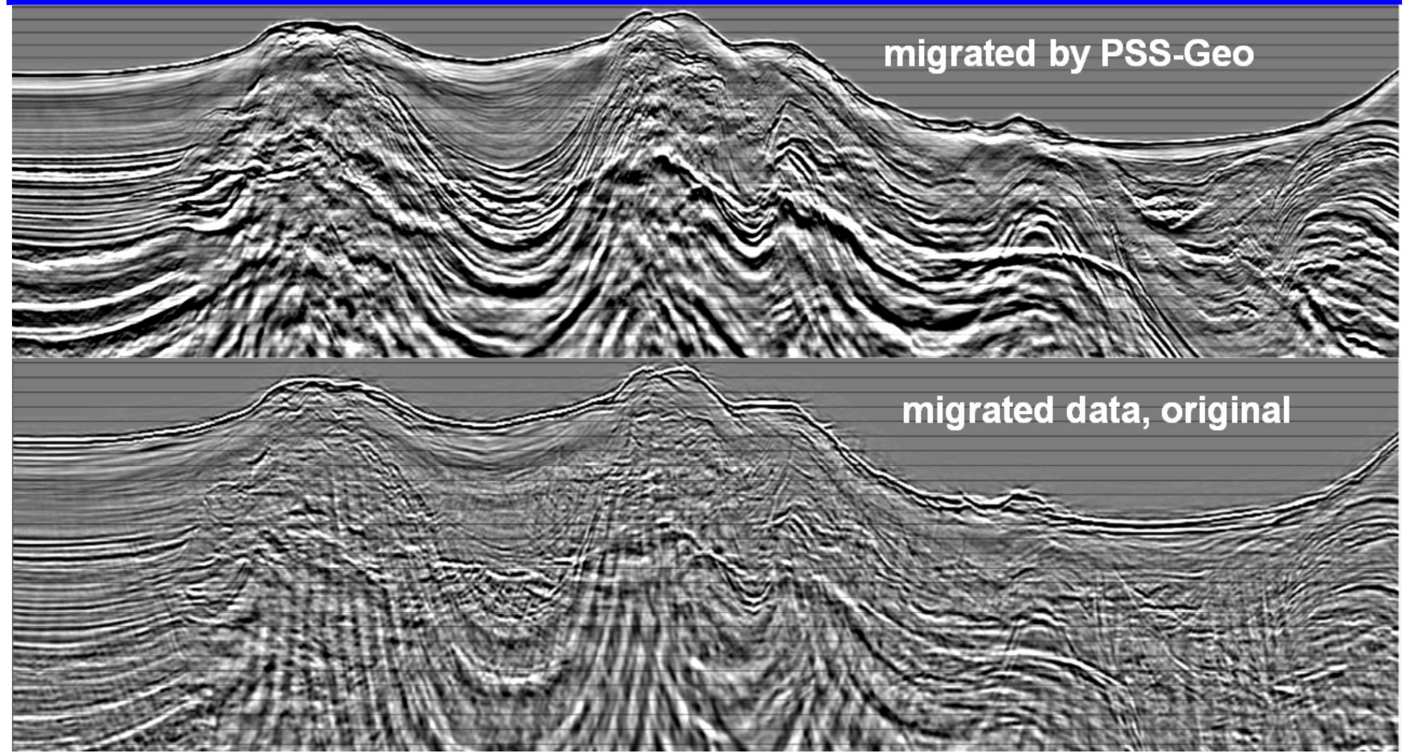
- Build an initial vertical velocity model <u>using suitable check-shots</u> within the survey and time interpreted horizons. The check-shot could be verified/optimized by doing a well-tie to the PSTM stacks.

An initial horizontal (anisotropy) velocity model can be derived using Dix converted and smoothed RMS velocities or from an isotropic V0 model with corresponding gradients (k).

- Near surface sub resolution velocity anomalies (pull-ups/down) can be detected and modelled to avoid distortion on deeper horizons.
- Depth migrate well tie or target lines. Measure anisotropy parameters in well positions, and build an anisotropy model. Typically initial anisotropy model is created interpolating the anisotropy between wells and supplied horizons. The anisotropy model can be updated/adjusted in each iteration




*Original interval seismic velocity and corrected velocity models. Corrected velocity model built by using logs data and anisotropic VTI/TTI gridded tomographic solution trough iterations approach. Bottom right picture shows anomaly appearance. Top two pictures are original seismic data*

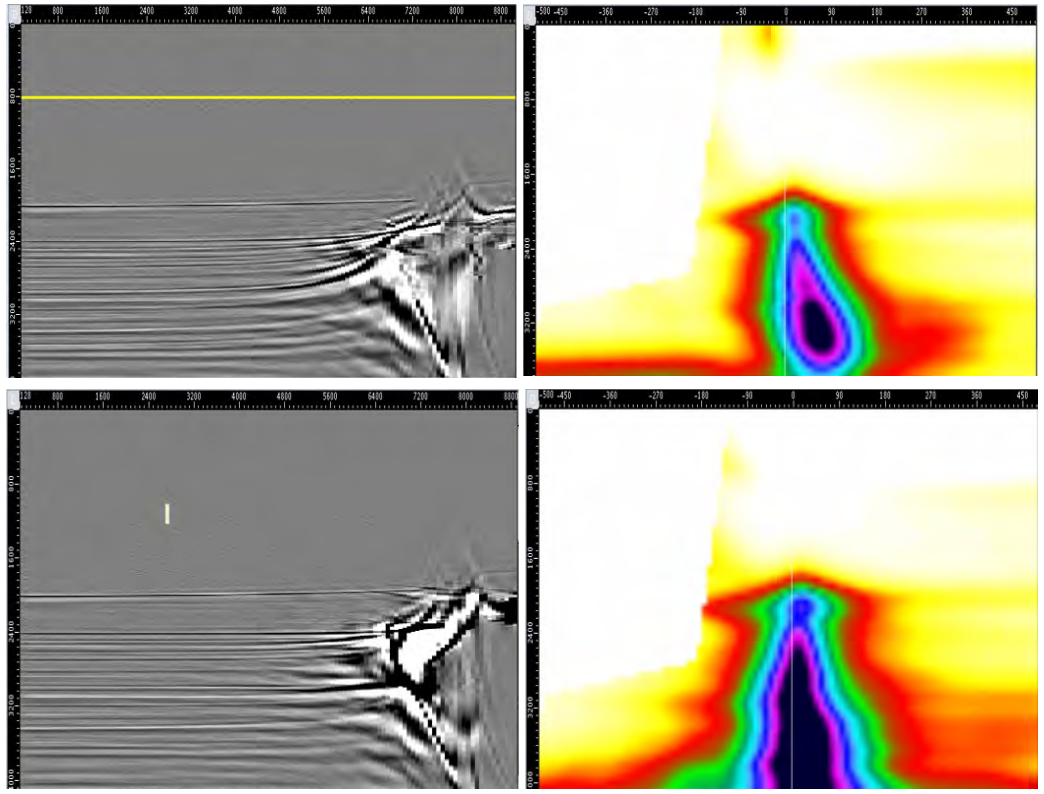



*Top picture is seismic data processed by PSS-Geo AS. Migration algorithm is old known Kirchhoff Anisotropic Wavefront Propagation Depth migration. Velocity model is corrected velocity model built by using logs data and anisotropic VTI/TTI gridded tomographic solution trough iterations approach. Bottom picture is the same seismic data migrated by modern algorithm with simplified velocity model.*

to ensure correct depth in well positions is maintained.

**2) Iterative tomographic inversion**

- On progressively deeper volumes the data is depth-migrated using Kirchhoff migration, to an appropriate depth, using the current velocity model.
- Residual moveout are auto-picked on gathers. Such pick must be representative of primary energy: a Hi-Res Radon demultiple, or other process, might be used to increase moveout measure quality. Events must be geologically meaningful as displayed on imaged stack.
- The residual moveout picked on the velocity analyses is inverted to update the interval velocity field using an anisotropic VTI/TTI gridded tomographic solution.
- The number of iterations required defined by the complexity of the area involved and the consistency of results.



*Top two pictures show a cdp gather and semblance scan of PSDM data migrated with the initial velocity model. Bottom pictures show the same cdp location this time migrated with the updated velocity model*

The 3D Pre-Stack Depth Migration is tied to the key wells to confirm the accuracy of the velocity field and anisotropy parameters.

Our approach is flexible and can allow for continuous update of vertical and anisotropic velocity models and aim at a depth image consistent with well data.

Whether it is a new or old migration algorithm, PSS-Geo AS recommend to use presented above sequence for velocity model building. Variations of this algorithm can be used effectively for depth conversion and time migration.

In spite of the chain of process, the algorithm is still cheap and has reasonably quick velocity model building solution.



# Prospectivity evaluation with 3D CSEM

**by Daniel Baltar and Neville D Barker, EMGS**

*A longer version of this article was previously published in First Break Magazine in September 2015. The authors thank First Break for permission to publish this shortened version here.*

Evaluation of the prospectivity potential of hydrocarbon exploration ventures is an integration process. Information provided by different technologies needs to be integrated into a single evaluation. This article details a method for embedding the additional information provided by 3D Controlled Source Electromagnetic (CSEM) surveys into existing (or independently-generated) prospect evaluations. The approach is based on a Bayesian update to the risk assessment (as widely used in industry for AVO, fluid seeps and other direct hydrocarbon indicators), extended into a coupled risk/volume update in order to account for, and leverage the additional volumetric sensitivity of the CSEM information.

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**CSEM-embedding workflows**

Three related workflows are described in the article (Figure 1):

1. The "EM Negative" workflow is used to assess the range of the original volume distribution and probability of success (PoS) that is consistent with a negative CSEM survey outcome (the case where no resistive anomaly is identified to be associated with the prospect).
2. The "EM Positive" workflow is used to assess the total range of the original volume distribution and PoS that is consistent with positive CSEM outcomes (the cases where a resistive anomaly is identified to be associated with the prospect).
3. The "Constrained EM Positive" workflow is used to assess the volume distribution, and corresponding PoS, that are compatible with a specific CSEM-identified resistor. We will focus on this workflow in the case study example.

**CSEM sensitivity**

The ability of CSEM to detect a hydrocarbon accumulation depends not only on the presence of hydrocarbons in the reservoir, but also on the size of the accumulation, and the surrounding resistivity structure. The dominant parameters determining the strength of the CSEM response are the Anomalous Transverse Resistance (ATR = Total Pay Thickness x Pay Vertical Resistivity) and the area of the accumulation, and thus a cross-plot of these parameters is key to the sensitivity assessment (Figure 2).

Detectability is established using a sensitivity threshold, which divides the ATR and target area domain into detectable and undetectable regions (solid black line). Additional factors which affect the ability to reliably recover or interpret a target resistor include dataset quality, and background complexity and uncertainty. These can be thought of as affect-

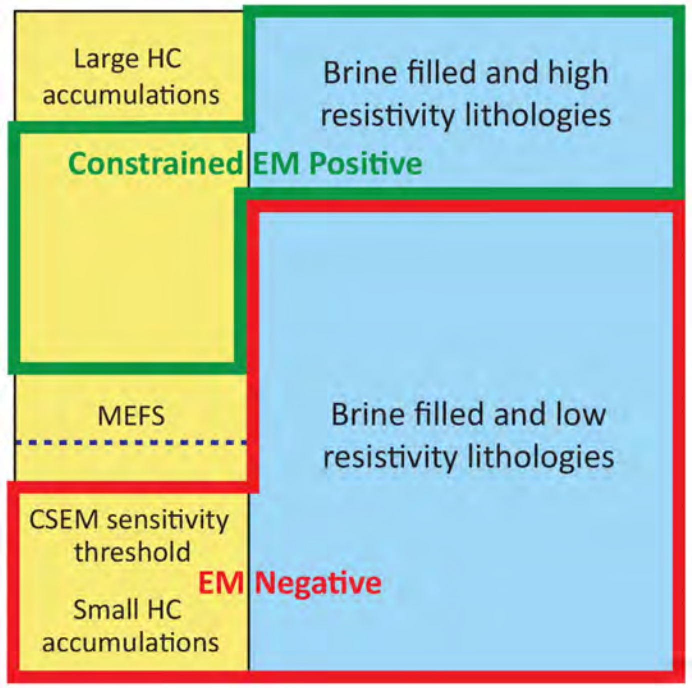


*Figure 1: Graphic representation of a prospect evaluation, and its partitioning with CSEM information. Blue region: brine outcomes (some with high resistivity; some with low resistivity). Yellow region: hydrocarbon (HC) outcomes, ranging from small to large accumulations. The Minimum Economic Field Size (MEFS) and CSEM sensitivity threshold to hydrocarbon outcomes are simplified as horizontal volume lines. From this arrangement, prior PoS corresponds to the area of the yellow region divided by the total area; the Probability of Economic Success, Pe = PoS * P(Recoverable volume > MEFS), is the area of the yellow region above the MEFS line, again relative to the total area*

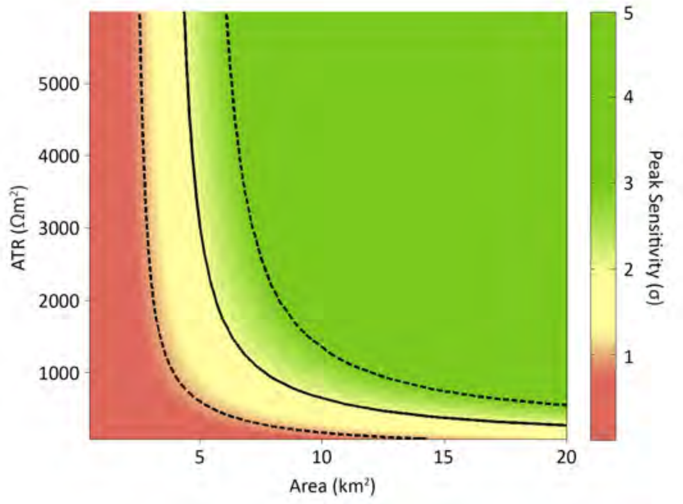


*Figure 2: CSEM sensitivity assessment for a single prospect*

ing the level of sensitivity below which we would not expect a resistor to be reliably identified from the data; two examples are illustrated in Figure 2 as dashed lines.

**Updating volumetric assessments with information from 3D CSEM data**

For volumetric updates, we broadly follow the approach detailed in Baltar and Roth, 2013, combining this with the more advanced CSEM sensitivity assessment detailed above. Given an existing probabilistic volume evaluation, only background and charged reservoir resistivity distributions, along with a CSEM-sensitive criteria, need to be added. A Monte Carlo simulation is carried out, with each realization classified as either detectable or undetectable by CSEM. In this way, two updated volume assessments are generated, corresponding either to the cases where we would expect an appropriate resistor to be identified in the CSEM data (EM Positive), or the cases where no such resistor could be identified (EM Negative).

With a specific EM Positive outcome, Baltar and Roth, 2013 describe how the characteristics of the identified resistor can be used to directly constrain the volume estimation, by the substitution of a new EM-derived net rock volume distribution (NRVem); we follow this approach in the Constrained EM Positive workflow.

**Bayes' theorem applied to EM**

According to Bayes' theorem, given an existing (prior) probability of finding hydrocarbons, P (HC) = PoS, and a certain CSEM outcome, EM, the new probability of finding hydrocarbons, P (HC|EM), can be calculated by applying:

(1)

$$P(HC\,|\,EM) = \frac{P(HC)}{P(HC) + R(1 - P(HC))}.$$

In order to evaluate P(HC|EM), the likelihood ratio, R, of each of the two possible EM outcomes is needed. The R for EM Positive (Rp) and EM Negative (Rn) outcomes are:

(2)

$$Rp = \frac{P(EMp\,|\,nHC)}{P(EMp\,|\,HC)}$$

(3)

$$Rn = \frac{P(EMn\,|\,nHC)}{P(EMn\,|\,HC)},$$

where EMp is an EM positive case, EMn is an EM negative case, HC denotes the case where hydrocarbons exist in the reservoir, and nHC the case where no hydrocarbons exist.

**Evaluation of EM response probability in the absence of hydrocarbons**

We can evaluate P(EMp|nHC) and P(EMn|nHC) together, since they are complementary: P (EMn|nHC) + P(EMp|nHC) = 1. P(EMp|nHC) is the probability of obtaining an EM positive outcome in the absence of hydrocarbons, an important interpretation pitfall to be considered when using resistivity data for hydrocarbon detection. Buland et al., 2011, from their experience estimate this probability to be 0.2 for a typical prospect; this probability will primarily depend on the geologic setting, and can be better-estimated from large-scale surveys.

**Evaluation of EM response probability in the presence of hydrocarbons**

We can also evaluate P(EMp|HC) and P(EMn|HC) as complementaries. They are estimated in different ways, depending on which volumetric workflow is followed. For the EM Positive and EM Negative workflows, P(EMp|HC) can be calculated directly from the outcome of the Monte Carlo simulation described in Baltar and Roth, 2013, and corresponds to the ratio of detectable volume cases to the total number of Monte Carlo iterations.

For the Constrained EM Positive workflow, P(EMp|HC) no longer relates to the entire range of potential positive outcomes, but is specific to the positive outcome obtained. Its value, the proportion of the prior net rock volume (NRV) that could produce a CSEM anomaly similar to the one actually measured, can be estimated from the overlap between the prior NRV and NRVem distributions:

P(EMp|HC) = Percentile of prior NRV at P01(NRVem) - Percentile of prior NRV at P99(NRVem).

For example, assume that the prior NRV P99 and P01 values are 80 m.km2 and 9000 m.km$^2$ respectively, and the corresponding NRVem values are 500 m.km$^2$ and 9000 m.km$^2$, then it follows that there is approximately a 70 percent (P99 NRVem = P70 NRV, and P01 NRVem = P01 NRV) chance of having an NRV that generates a resistive anomaly consistent with the 3D CSEM data.

Coupling of P(EMp|HC) to volumes in this way has three key benefits over stand-alone risk and volume assessments, which help reduce the risk of inappropriate use of the new information:

1. Likelihood ratio estimates in EM Positive and Negative workflows depend upon the data sensitivity: high sensitivity to a scenario, increases the data's R in that scenario, and vice versa.
2. Very precise NRVem estimates (narrow P10 – P90 range relative to the prior) require correspondingly high confidence in the information, or PoS to that outcome will be penalized.
3. Confidence in NRVem ranges partially (or wholly) outside the prior's range is partially (or wholly) penalized as being inconsistent with the original evaluation. By reducing (zeroing) PoS in such cases, the interpreter is forced to re-evaluate prospect risk factors to this new volume range.

**Real-life Constrained EM Positive example: Pingvin**

Fanavoll et al., 2014, used the NRV workflow from Baltar and Roth, 2013, to generate a pre-drill net rock volume prediction from a CSEM anomaly associated with an existing prospect in the Barents Sea (Figure 4). The Pingvin prospect was located in production license 713, approximately 65 km northwest of the 7220/8-1 Johan Castberg oil and gas discovery and 300 km northwest of Hammerfest. Subsequently, the operator, Statoil Petroleum AS, tested the prospect with wildcat well 7319/12-1 and encountered gas in the reservoir interval, announcing drilling results and preliminary volume estimates (NPD Drilling Announcement, 2014). We use this case to illustrate the practical application of the Constrained EM Positive workflow.

***Prior evaluation***

To consider the impact of CSEM in the evaluation of this prospect, and given that we do not have access to Statoil's pre-CSEM evaluation, we must first generate a reasonable prior.

In Fanavoll et al., we can observe two clear flat spots, naturally interpreted as GOC and OWC. Taking into account that prior to drilling this was a frontier setting and an unproven play, the probability of success must be low. On the other hand, the seismic indicators were good (flat spots and bright spots). We therefore conclude PoS would have been at the high end of the unproven play range, and use a value of 0.33.

We assess the area from available information: the area inside the first flat spot will be used as P90 and the area inside the second flat spot will be used as P10, thus P90 = 20 km², P10 = 60 km². For the thickness we use the same source of information, leading to P90 = 10 m, P10 = 35 m, and an NRV distribution as Table 1.

All other parameters (porosity, hydrocarbon saturation, recovery factor and formation volume factor) will be considered unaffected by the new CSEM information and will therefore be set aside for the rest of the example.



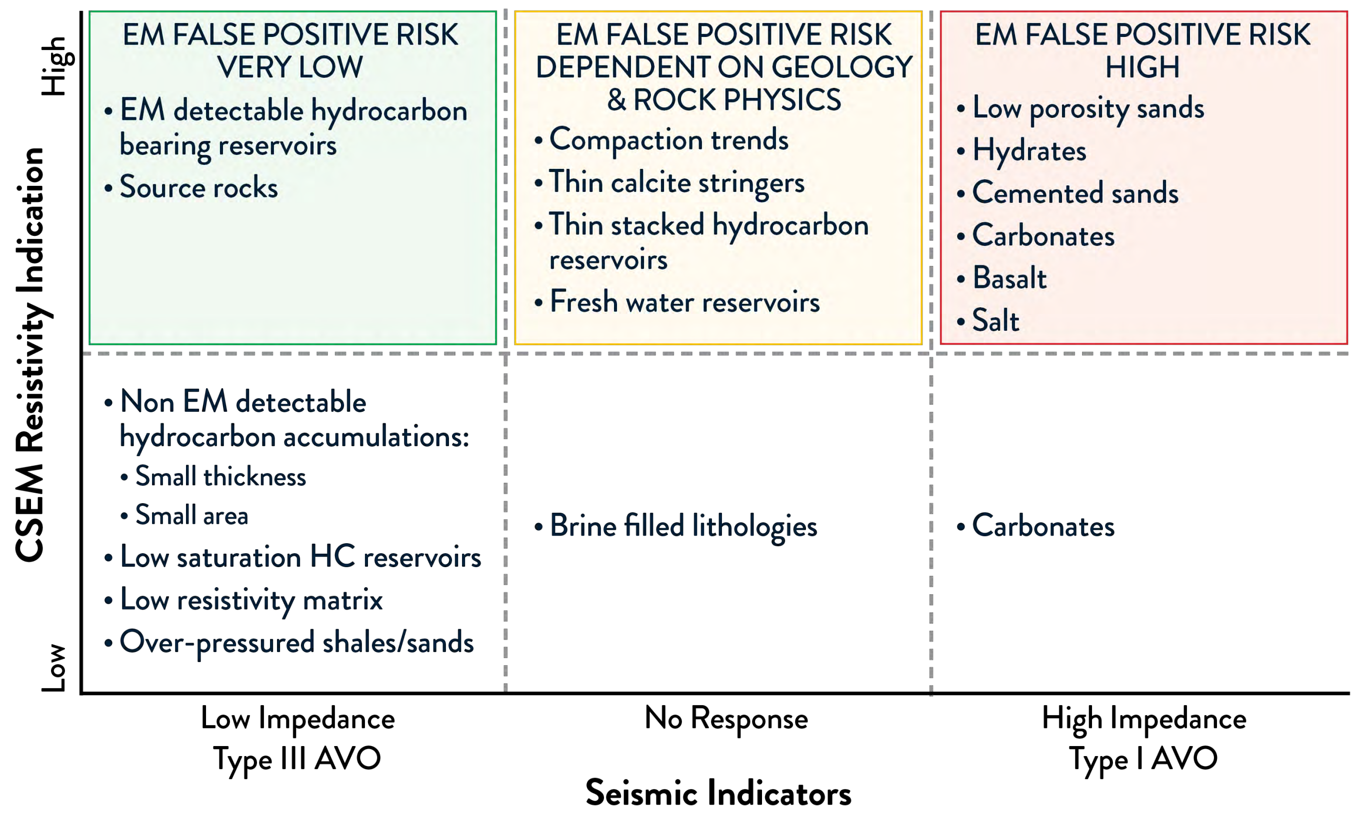


*Figure 3: Various geological scenarios as a function of their typical relative electrical and acoustic characteristics. A joint analysis is a useful de-risker for the "false-positives" possible from both resistivity DHI and seismic DHI in isolation*

***Fit of CSEM to prior***

This CSEM case is a clear positive response, therefore the positive likelihood ratio, Rp, (comprising P(EMp|HC) and P (EMp|nHC)) needs to be assessed. P(EMp|HC) can be calculated by the ratio between the prior NRV and NRVem. The calculation performed in Fanavoll et al. yields the NRVem probability distribution listed in Table 1. We graphically compare the overlap between both NRV distributions in Figure 5. P01 of the NRVem corresponds approximately to P25 of the prior NRV, therefore we estimate P(EMp|HC) = 0.75.

Now we estimate the false positive risk. The excellent fit between the area distribution of CSEM and seismic DHI places this case in the upper left corner of Figure 3, leading us to conclude that P(EMp|nHC) is quite low. The limited number of similar cases (one example would be "Case A" in Escalera et al., 2013) limits our ability to narrow-down this number in a statistically sound way, so we use Buland et al.'s reference P(EMp|nHC) = 0.2, and reduce it to account for the fit to seismic DHI information, estimating P(EMp|nHC) as 0.1.

Computing Rp from Equation 2, and applying Bayes' theorem in Equation 1 gives an updated probability of success of 0.79.

It can be seen that, compared to the prior, the CSEM data and their good fit to seismic DHI information are pointing to a higher likelihood of finding hydrocarbons in the reservoir, but severely limiting the upper side of the NRV distribution. The announced discovery (NPD Drilling Announcement, 2014) comprised a gas column of "about 15 metres", and "Preliminary estimates place the size of the discovery at between 5 – 20 billion standard cubic metres of recoverable gas". Using reasonable estimates for the

| | Net Rock Volume (m.km²) | | | Probability of Success |
|---|---|---|---|---|
| | P90 | P50 | P10 | |
| Prior evaluation (before EM) | 280 | 600 | 1300 | 33% |
| With EM results | 50 | 150 | 450 | 79% |

*Table 1: A reasonable prior (before CSEM) NRV distribution and PoS for the Pingvin prospect, along with an NRVem distribution calculated directly from the CSEM results by Fanavoll et al., 2014, and the updated PoS from the Constrained EM Positive workflow*

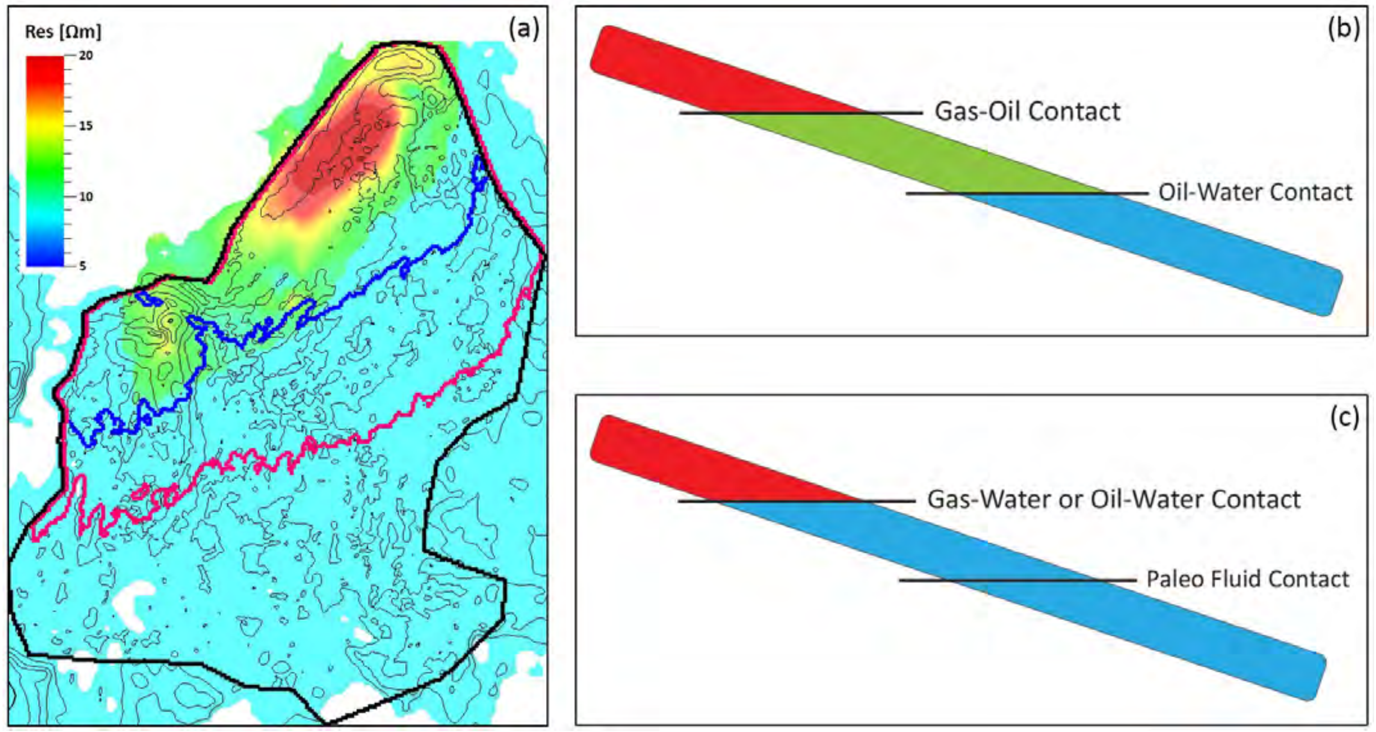


*Figure 4. (a): Pingvin prospect average resistivity map from CSEM inversion displayed with contoured reservoir thickness. Minimum (blue), medium (red), and maximum (black) scenarios based on seismic data are given by the three polygons. Reproduced from Fanavoll et al. (2014), Figure 7(b). (b) and (c): two competing interpretations of the double flat spot identified in seismic data. In scenario (b), the prospect is fully charged; the flat spots corresponding to gas-oil and oil-water contacts. In scenario (c), the prospect is only charged to the uppermost flat spot. CSEM information provides compelling evidence in support of scenario (c), as turned out to be the case*

other reservoir properties (porosity, saturation, recovery factor, and expansion factor), it can be shown that CSEM-predicted volume range is in line with the reported discovered volumes.

**Impact on a portfolio, and large -scale application of CSEM**

While described here in terms of a single prospect, the greatest value has been obtained from 3D CSEM data when the information is available at the portfolio scale and early in the exploration process: as well as reducing false-positive risk, spatially-extensive information can also be used to identify new exploration leads in known plays, aid in the development of new play concepts, or upgrade untested concepts (e.g., Escalera et al., 2013, Fanavoll et al., 2014). Within an existing CSEM-sensitive portfolio, the typical behaviors of individual prospects are summarized in Figure 6. These changes naturally lead to greater portfolio polarization, and the potential for significant changes in exploration decision-making.

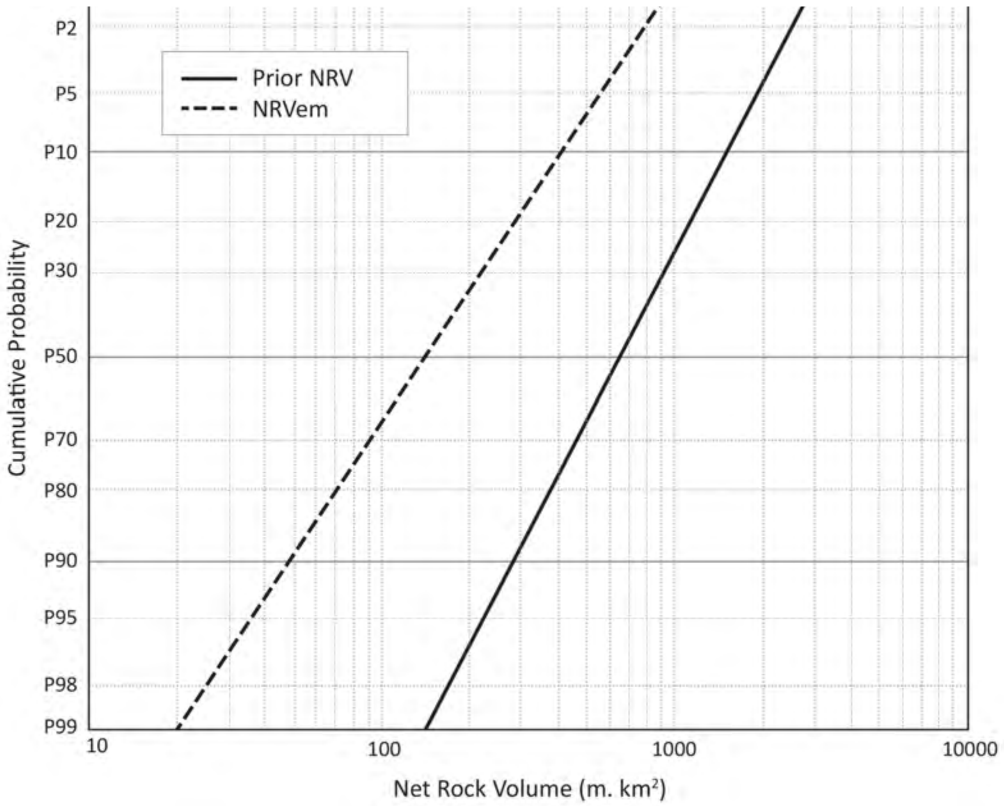


*Figure 5: The CSEM-derived NRV distribution (NRVem) from Fanavoll et al., compared to a reasonable NRV prior estimate for the Pingvin prospect, Barents Sea.*



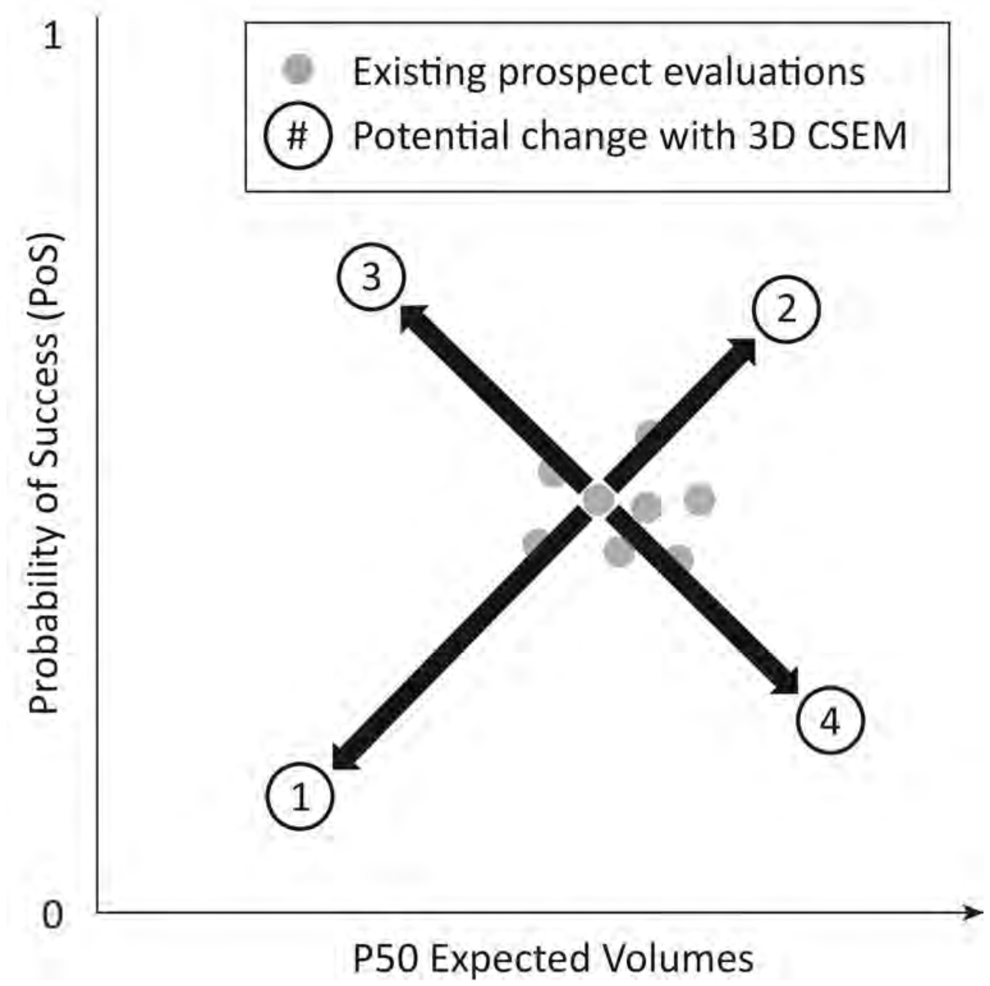


*Figure 6: A summary of the typical end-member outcomes seen after the addition of information from 3D CSEM to an existing prospect portfolio. (1) EM Negative. Reduction in expected volumes to below the level of EM sensitivity, removing potential upside, and corresponding reduction in PoS. (2) Large Resistor. When consistent with prior, the large resistor increases both potential volumes and PoS, especially in the presence of other supporting evidence from seismic or absence of false positive potential. (3) Very Small Resistor. Again, consistent with the prior, the small resistor has increased the PoS, but removed the upside, potentially pushing the expected volumes to sub-commercial levels. (4) Unexpectedly Large Resistor. Increase in volumes, but potential decrease in PoS if volumes are largely incompatible with prior (increased risk of false positive). Increased potential may, or may not, outweigh increased risk.*

**Conclusions**

The workflows presented here have been designed to leverage the primary strengths of the CSEM measurement, while keeping to a minimum the disruption and potential increase in risk associated with the adoption process. This has been achieved through:

1. A focus on updating existing evaluations, rather than proposing more fundamental changes to evaluation components
2. The use of data-driven (unconstrained) 3D CSEM inversion results as input, rather than more complex joint imaging products. This provides a more independent information source, from which in practice it is easier to estimate uncertainties and minimize interpreter bias
3. Adoption of industry-standard performance tracking methodologies. In the early stages of adoption, the logical approach is to start with a conservative estimate for the R parameters, making larger evaluation updates as experience with, and confidence in, the information increases.

Many further refinements are possible; these can be more easily developed and applied once a core CSEM-embedding framework, such as the one presented in this article, is in place. Variants may include coupling to additional lower-uncertainty volumetric parameters, such as the recovery factor (reservoir resistivity is linked to reservoir permeability), rock porosity, and hydrocarbon saturation.

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## What about you? How did YOU spend your summer?

***Photo: Vladimir Imanuilov, Technical Service Engineer, GE Oil and Gas, Australia. On photo — his wife.***

# Proper Risk Planning crucial for successful vacation

***Svein Lars Haughom***
*HR and HSEQ Senior Advisor at AGR,*

***HR and HSEQ Senior Advisor at AGR, Svein Lars Haughom, is an eager hiker and outdoor sports activist. Daily, he spends at least an hour on training. His latest outdoor training trip took him to Alaska where he hiked many kilometers during 14 days. Here's how Svein Lars planned the trip using planning and risk management aspects from his daily work delivering HSEQ support to offshore drilling operation.***

For the most of us, going on a holiday means experiencing something different than our daily life offers. Travelling to new places we dream of and visualise gives us new impulses, re-charges and develops our interests. There may be many reasons that make us take off time. On our return from a trip it is normal that we share our experiences with others.

I have observed many times that the stories that are being shared with me have a lot of positive experiences in them, but also contain dissatisfaction and irritation that could have been avoided. Either the car that was hired was too small, the hotel turned out to be not as expected, etc.
Last weekend, I heard a story of five girlfriends going on a weekend trip to Nice. On their arrival to the airport, it turned out that three of the girlfriends had booked the wrong flight which meant they were unable to board the plane as planned and had to travel the next day instead. Incredibly unfortunate if you ask me.
I like to travel too, sometimes a bit more extremely than others. But I always want to eliminate negative experiences so my trips would not be influenced by large and small irritating aspects that may have consequences for my overall memories.
The key word is planning. I believe most of us plan a trip but the execution of planning has puzzled me many times when I have heard the stories being told.
This summer, my vacation took me to Alaska, to Talkeetna district to be more exact. The area is covered by endless forests and rivers with rich wildlife and hardly any population. On first impression, it qualifies for a bit more extreme hiking destination than most would like to admit. But it is not so extreme when using systematic planning in preparing for such a trip. There could have been plenty of opportunities for surprises that may have had consequences on the trip. I started planning several years ago with details falling in its place a year in advance.



I am of the opinion that surprises that hit a traveller at some point anyway, should be thought through so that it would be possible to change the original plan and yet keep the experience positive.
I have been in search for a tool that would enable me to achieve just that. The Business Management processes that I use at my work describe risk management. This tool enables me easily to identify possible surprises based on my and other previous experiences. It is amazing what kind of ideas the Internet can give you for mapping the risks.
The tool also provides an opportunity to think through alternative solutions and improvement suggestions in order to avoid later inconveniences.
Did I make use of it? Yes, of highest degree. Forest fires, movement of predators in the crowds and electronic communication turned out to be a challenge. This was identified previously and alternatives were planned.
Did I meet my expectations for the trip? I got more than I could expect.
My next trip will be a city break, already being planned. Items that I have identified so far include the flight, hotel, pickpocketers, closeness to attractions, restaurants, etc.
Plan and map your risks and alternative actions ahead to preserve the good memory from your destination.

*Svein Lars has been with AGR since 2011 and works currently as HR Advisor. He has previously been involved in AGR managed drilling operations as Senior HSEQ Advisor located in Stavanger. Svein Lars' professional career includes working as an HSEQ professional at BakerHughes, ConocoPhillips and Norsk Hydro.*

*Grizzly bear area by the Talkeetna River*

1. The weather goddess was not in her best mood this summer – so her wrath had its effect on the Norwegian summer weather of 2015.
Silje Gjøse, Sr. HSEQ Advisor at AGR, Stavanger

Vote for the best picture!
The winner will get free pass to the SPE Norway dinner event in the Season 2015-2016!

2. RFD. We could not relax this summer, we celebrated **10** years birthday of the company!!! Starting the company in 2005 with 4 people sitting in the kitchen, we could not even think of becoming a company with 60 software developers, 70+ client companies and 600+ active users worldwide in 2015.



3. «While oil Prices are low». On photo — Yuriy Ivanov, PhD candidate at NTNU, Trondheim

4. "Serving for the oil business" Seljestuen family. Tommy A. Seljestuen, Business contact for SPE student chapter Harstad / Narvik

**5.** This picture is taken from a Cessna 172 at 10.000 ft above sea level over the mountains between Stavanger and Oslo. The wind speed is about 40 knots; strong enough to create waves of clouds.
If you want to experience wonderful moments of flying, free as bird, you are welcome to join SPE-Oslo Board's own pilot, Mahmood Akbar (Advisor Reservoir Engineering, AGR, Mobile 97787622).

**6.** Steven Mueller, a PhD candidate at the University of Oslo, riding a yak on 3500 meters at Napa Hai Nature Reserve in Shangri-La, Yunnan, China



**7.** Caroline Sørensen, Student Chapter Arctic University of Norway on top of Lofoten Islands highest peak Hermannsdalstinden 1029 moh.

Sent number of picture to
vita@pss-geo.com
The winner will get free pass to
SPE Norway dinner event
season 2015-2016!

# Thank you!